MODELING GAS INJECTION INTO SHALE OIL RESERVOIRS OF THE SANISH FIELD, NORTH DAKOTA

by

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ABSTRACT

The Bakken Formation, a late Devonian-early Mississippian relatively thin unit, is deposited in the Williston Basin, covering 200,000 square miles of the north central United States. It has tremendous oil reserves estimated to be in the billions of barrels. One field in this formation, the Sanish, which is located in the Mountrail County, North Dakota, is the focus of the current study. The primary recovery factor of the Sanish Field remains low and has been estimated to be less than 15%. Other than horizontal drilling and multi-stage fracturing application, enhanced oil recovery is the essential process to increase the recovery factor and maximize the potential production from this field.

Among several EOR options, CO_2 flooding may be effective to increase the recovery factor. Earlier studies of the Elm Coulee Field and in the Saskatchewan part of the Bakken indicated that the recovery factor could be increased by 10-15% when using gas injection. In this paper, a numerical reservoir simulator is used to evaluate the performance of CO_2 injection for the Bakken interval in a sector of the Sanish Field. There are presently three 10,000 foot laterals in the 4 square miles sector. For modeling purposes, reasonable data values were chosen from known ranges, and well and completion information from the research area was included.

A low primary recovery factor of 5.42% was obtained through flow modeling, and declining trends of the future production performance of wells in the research area were observed. Several different scenarios of gas injection are tested to analyze gas injection performance and evaluate its technical feasibility and effect. It appears that gas injection is suitable in such tight environments, as the recovery factors increased significantly for miscible CO_2 injection.

Sensitivity analysis was ran by using different injection rates, by adding additional wells to the pattern, by comparing different fracture conductivities and by evaluating different

injectants. Depending on the scenario, the recovery factor increases the most by 24.59% through adding four new horizontal injectors into the field sector. Moreover, gas injection was confirmed to be effective than water flooding. Maximum of 8000 psia injection pressure and maximum injection rate of 5000 Mscf/day along with more horizontal injection wells were estimated to be better options for gas injection in the study area.

This study can help to evaluate expected ultimate recovery (EUR) for future projects in the Sanish Field. It can also help to estimate the future economic viability of using gas injection and evaluate risks for the Sanish Field potential development. All these factors will directly impact the oil companies' interests and future unconventional resources development.

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LIST OF SYMBOLS

Symbol	Definition	Unit
A	Drainage Area	Acre
API	API Oil Gravity	degree API
BHP	Bottom Hole Pressure	psia
$Bscf$	Billion standard cubic feet	-
B_g	Gas Formation Volume Factor	bbl/Mscf
B_o	Oil Formation Volume Factor	bbl/STB
EOR	Enhanced Oil Recovery	-
EOS	Equation-of-State	-
FVF	Formation Volume Factor	-
$F_{solvent}$	Fraction of solvent	-
F_{gas}	Fraction of reservoir gas	-
GOR	Solution Gas Oil Ratio	scf/STB
K_{rw}	Relative permeability for water	-
K_{rg}	Relative permeability for gas	-
K_{ro}	Relative permeability for oil	-
K_{rf}	Relative permeability function	-
MMP	Minimum Miscible Pressure	psia
$MBOE$	One thousand barrels of oil equivalent	-
$MMBOE$	One million barrels of oil equivalent	-
MWD	Measurement-while-drilling	-
$NDGS$	North Dakota Geological Survey	-
$NDIC$	North Dakota Industrial Commission	-

$OOIP$	Original Oil-In-Place	bbl
PV	Pore Volume	ft^3
P_b	Bubble-Point Pressure	psia
RF	Recovery Factor	-
$SAGD$	Steam assisted gravity drainage	-
SRV	Stimulated Reservoir Volume	-
S_{oil}	Oil Saturation	-
S_g	Gas Saturation	-
$S_{solvent}$	Solvent Saturation	-
t	Time	day(s)
WAG	Water-Alternating-Gas	-
γ_g	Gas Specific Gravity	-
γ_o	Oil Specific Gravity	-
ϕ	Porosity	-
λ	Mobility of a Fluid	md/cP
ω	Todd and Longstaff Mixing Parameter	-
μ	Viscosity of a Fluid	cp
μ_m	Fully mixed viscosity	cp

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Finally, thanks to my parents for their love, support, and encouragement throughout my lifetime of education.

CHAPTER 1

INTRODUCTION

With the continuing demand growth of energy and consumption of conventional oil reserves, exploiting unconventional oil plays and developing them economically is attractive to the petroleum industry. Now, advanced technologies of horizontal drilling combined with multi-stage hydraulic fracturing application turns the development of these tight oil reservoirs into a reality. As a result, the Bakken Petroleum System in the Williston basin becomes one of the most important oil resources in the world. In 2008, U.S. Geological Survey (USGS) reported the Bakken Formation reserves from the Williston Basin of Montana and North Dakota was3.65 billion barrels of oil with 1.85 trillion cubic feet of natural gas dissolved. The Sanish Field, the focus of this research, is located in Mountrail County, North Dakota. Whiting Petroleum Corporation (WLL) owns 108,800 gross (66,500 net) acres of the Sanish field and operates most of the wells there (Whiting, 2011). Whiting's net production from the Sanish Field in the fourth quarter of 2011 is average 22.9 thousand barrels of oil equivalent (MBOE) per day. At the end of the year 2011, there are total 7.7 million BOE (MMBOE) production from the Sanish Field (Whiting, 2011). In order to ensure a long term of development and maximize the production from this tremendous potential, it is imperative to evaluate the application enhanced oil recovery in this area.

1.1 Location of the Study Area

The study area Sanish Field is located in northwestern North Dakota. The primary focus of this research is concentrated in the section 22, 23, 26, and 27 in Township T153N R 91W of the Sanish Field. It covers an area of 4 square miles.

1.2 Objectives and Scope

This research will focus on the performance of CO_2 flooding in the select area of Sanish field. The purposes of this project are shown as follows:

- ➢ Determine the technical feasibility and effect of CO_2 flooding enhanced oil recovery process in the Bakken Shale Formation. Afterwards, identify the recovery factor of the tight oil reservoir influenced by CO_2 injection.
- ➢ The research consists of four major steps: ①Reservoir properties; ②Reservoir fracture characterization; ③Reservoir modeling and simulation; ④CO_2 flooding implementation and evaluation.

  Since the reservoir data are not all available for each well, reasonable values are determined for the following properties (see Chapter 3):

  - Reservoir Pressure
  - Oil API Gravity
  - Solution Gas Oil Ratio
  - Porosity
  - Permeability
  - Initial Water Saturation
- ➢ Two types of reservoir models are built, Black Oil Model and Solvent Model. The accuracy of the models will be accessed by comparing simulation production results with historical production data. Then the production of each well will be predicted to demonstrate the future economic viability of Sanish Field using CO_2 flooding.

- Analyze gas injection performance for different scenarios. The parameters, including well type, numbers of well, gas injection operation, and injection type, are adjusted.
- Make recommends to confirm the widespread applicability of CO_2 flooding in fractured shale oil reservoirs of the Williston Basin.

1.3 Benefits

The benefits of modeling and evaluating gas injection as a potential for Bakken Formation in Sanish Field includes:

- Help to better understand the Bakken Formation.
- Help to evaluate Expected Ultimate Recovery (EUR) for future projects in the Sanish Field.
- Help to estimate future economic viability of using gas injection into shale oil reservoirs in Sanish Field.
- Help to evaluate the risk for Sanish Field potential development, and the Williston Basin development.

1.4 Organization of the Thesis

This dissertation is mainly divided into six chapters.

Chapter 1 introduces the main purposes and benefits of this study.

Chapter 2 is the background information, including the geological background of the Bakken Formation, general background of the study area. The enhanced oil recovery options and evaluation methods are briefly introduced in this chapter.

In Chapter 3, all the previous work from literature reviews are presented. The primary modeling data and well information are shown in the tabular forms.

Chapter 4 is the methodology of this research. It describes the details of the models being built, such as the setup procedure, section details of the black oil model, modification and extension of the solvent model, the functions of each model and so on.

Chapter 5 is the main part of this thesis, focusing on the results and analyses of the gas injection effects on shale oil reservoirs. Several different case scenarios are tested on the solvent model, outcomes of the sensitivity analysis are provided. The summary of all cases is shown in the last area of the chapter.

Chapter 6 is the last chapter, used to summarize the key conclusion of the study. The recommendations are suggested as well for future projects, studies, or applications.

CHAPTER 2

BACKGROUND

2.1 Geology Background of the Bakken Formation

The Bakken Formation, a late Devonian-early Mississippian relatively thin unit, is in between of the overlying Mississippian Lodgepole Limestone and the underlying Devonian Three Forks Formation (Figure 2.1). It has tremendous hydrocarbon with extremely high carbon content, as well as it is a crucial source rock for oil production in the Williston Basin. The map on the next page (Figure 2.2) shows that Williston Basin covers eastern Montata, northwestern South Dakota, most parts of North Dakota in the United States, and the rest portions are in southern Saskatchewan and Manitoba, Canada. Among these, the Sanish Field in the North Dakota is the focus of this research.

There are three distinct members consisted in the Bakken formation: upper shale, middle dolomitic siltstone, and lower shale member (Figure 2.3). The upper and lower intervals are lithologically similar composing of gray to black, slightly calcareous, fissile, organic-rich shale. The lithology of the Middle Bakken is various, mainly siltstones and sandstones with minor trace of silty shale, dolomite, and limestone. The depositional environment of the Bakken Formation is highly related with rock characteristics. The Upper and Lower Bakken were deposited in anoxic marine environment during periods of sea-level rise. The dolomitic member was deposited during higher energy conditions, such as a time of sea-level regression to create shallow water carbonate conditions (Pitman et al., 2001).

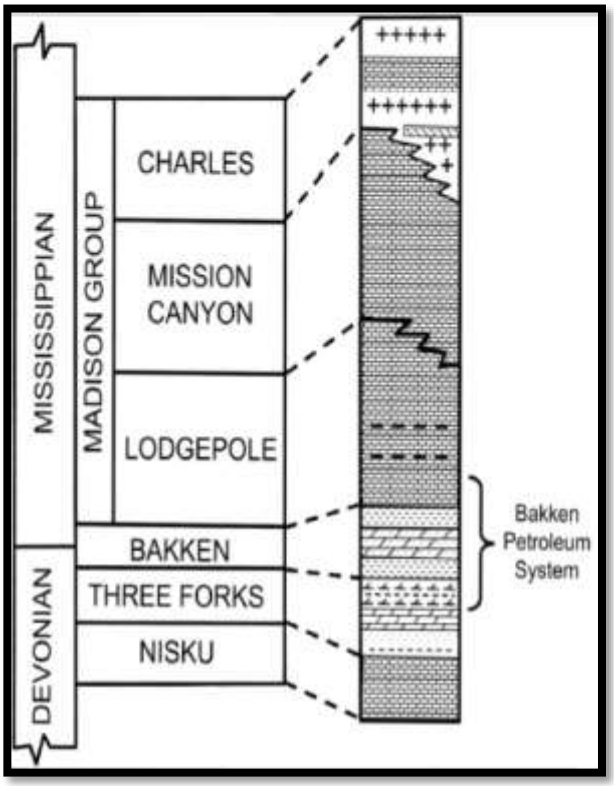


Figure 2.1Stratigraphic chart of the Williston Basin (Iwere et al., 2012)

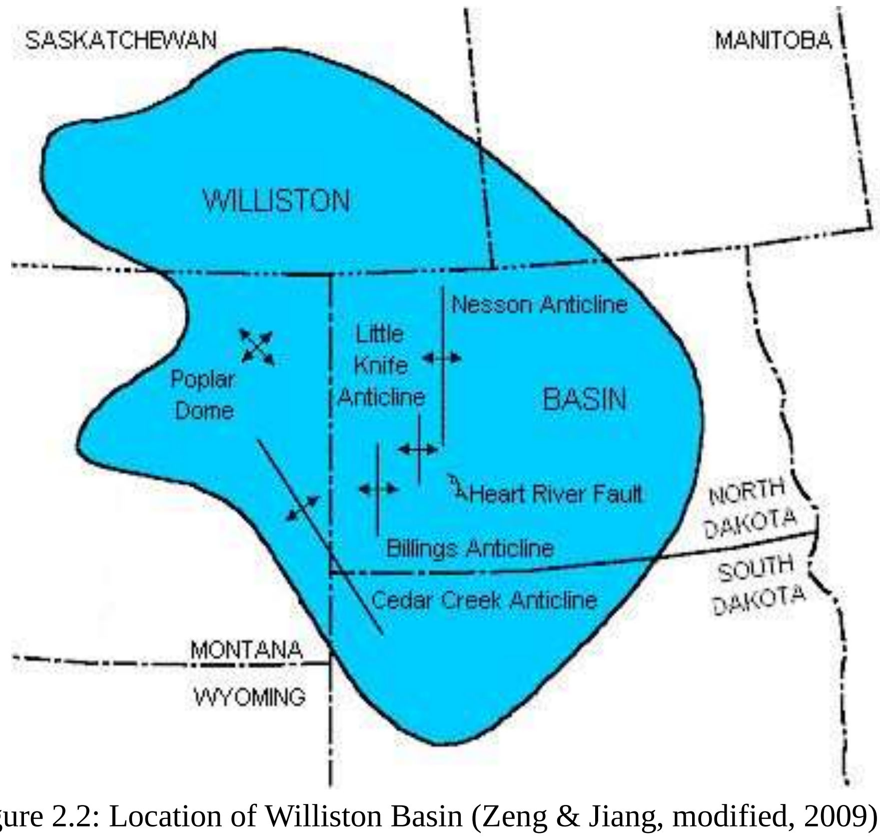


Figure 2.2: Location of Williston Basin (Zeng & Jiang, modified, 2009)

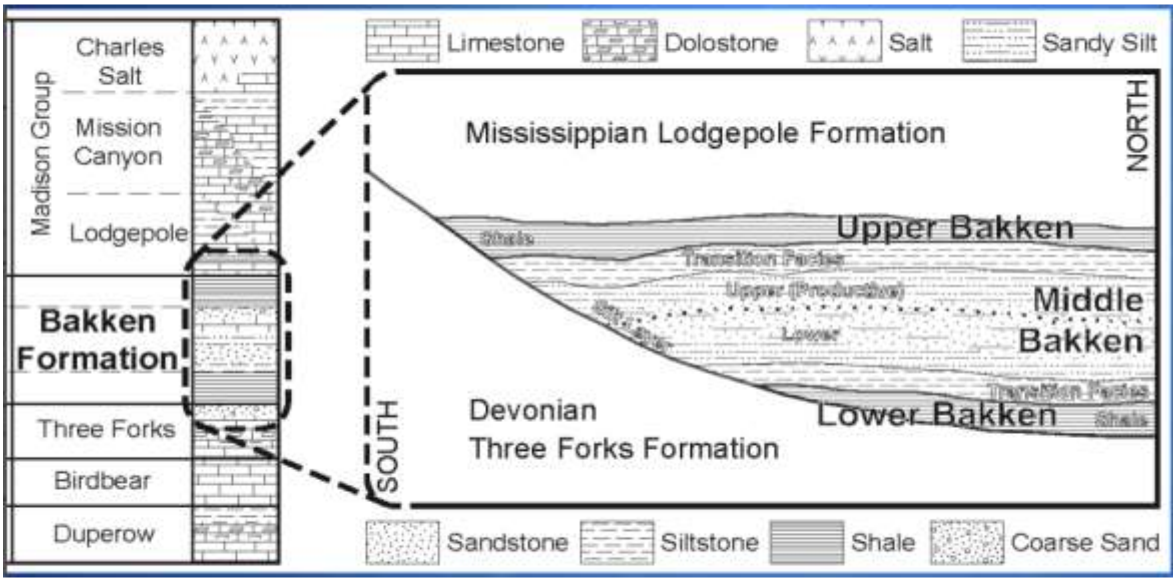


Figure 2.3: Lithofacies of the Bakken Formation (Hill et al., 2011).

2.2 Background of the Sanish Field

The Sanish Field (Figure 2.4) is located in Mountrail County, North Dakota. Along with the Parshall Field, they are the two most productive fields in the Williston Basin at the moment. From April of 2006, the Sanish Field starts to produce oil and gas mainly from the middle member of the Bakken Formation. For the last three years, it yields approximately over a million barrels of oil per month (Figure 2.5). Until September of 2012, Sanish Field has been cumulatively produced more than fifty million barrels of oil. The Middle Bakken in the Sanish Field is around 15-45 feet (ft), having a porosity value of 4-10% and permeability at average 0.04 millidarcy (md).

The primary recovery factor of the Sanish Field is about 14.9% (Dechongkit, 2011). The North Dakota Geological Survey (NDGS) estimates that there are approximately 167 Bbbl of oil based on an independent evaluation, which is in accordance with the large estimation by Price (1999) and Flannery and Kraus (2006). According to Mason (2012), total North Dakota Bakken area is 18,614 square miles (Table 2.1). So the oil-in-place per square mile in North

Dakota Bakken is 8.97 million bbls, and for the study area of 4 square miles, the oil-in-place is 35.88 million bbls.

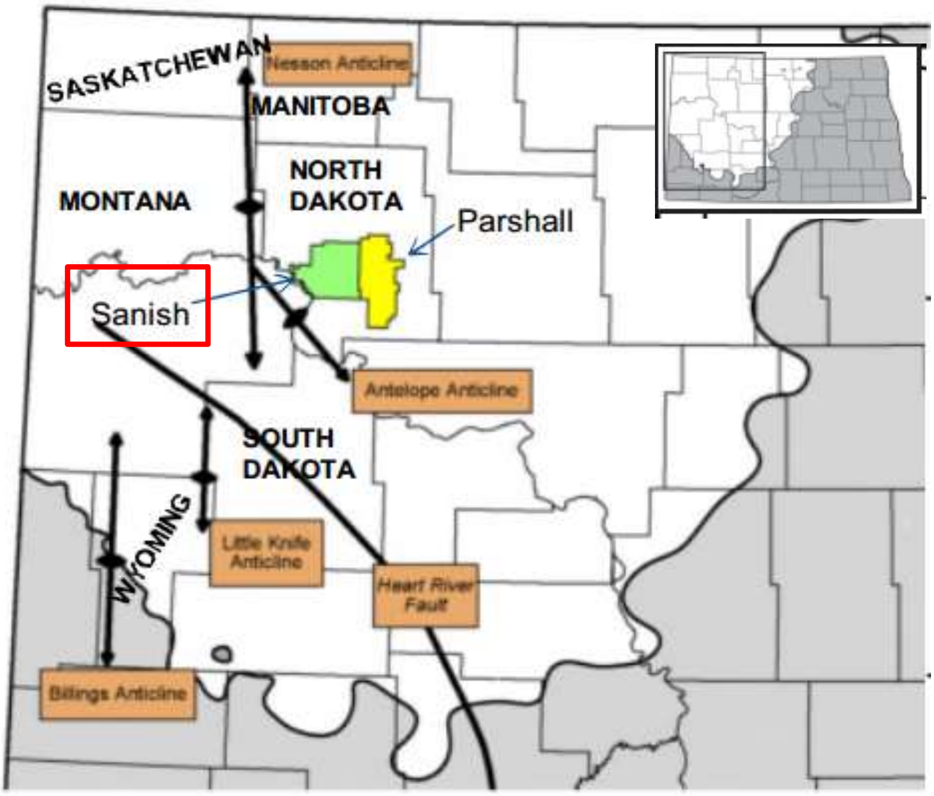


Figure 2.4: Sanish Field Location (Nordeng et al, 2010)

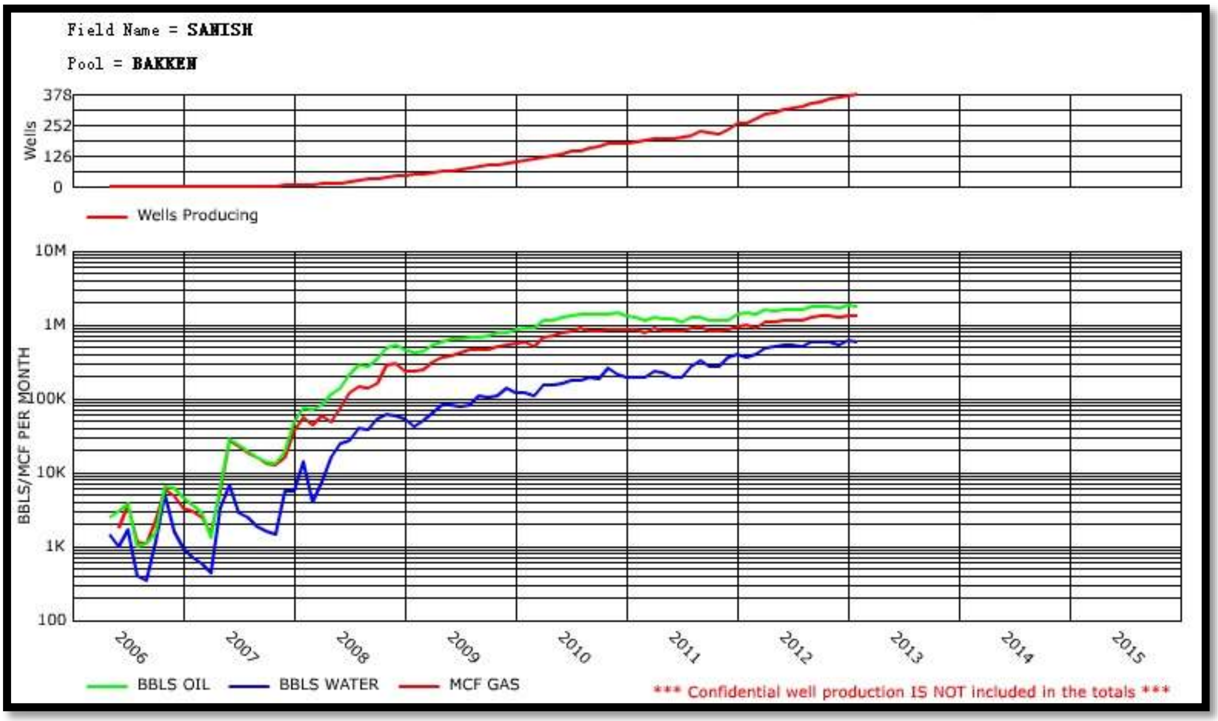


Figure 2.5: Monthly Production Rates and Well Amount of the Sanish Field (NDIC, 2012)

Table 2.1 Estimate of North Dakota Bakken Land Area (Mason, 2012)

North Dakota Bakken Counties	Total Area (Square Miles)	% of Area Risked	Net Risked Area (Square Miles)
Billings	1,151	50%	576
Burke	1,103	50%	552
Divide	1,260	50%	630
Dunn	2,010	100%	2,010
Golden Valley	1,001	10%	100
McKenzie	2,742	100%	2,742
McLean	2,101	5%	105
Mountrail	1,824	100%	1,824
Stark	1,338	50%	669
Ward	2,013	5%	101
Williams	2,071	60%	1,243
Total North Dakota Bakken Area	18,614		10,550
Land Area Under Lease			6,523

With the extremely low porosity and permeability, and low primary recovery factor, it was challenging to economically develop the field. So the combined application of horizontal drilling coupled and multi-stages hydraulic fracturing became the typical development strategy for these tight oil reservoirs.

2.2.1 Horizontal Drilling

Traditional oil and gas reservoirs were commonly drilled vertically from the surface downwards directly to penetrate the pay zone. But for unconventional reservoirs with relatively low permeability, horizontal wells have higher efficiency with more contact area. In general, two parts are involved in horizontal drilling operation. Firstly, wells are drilled vertically perpendicular to the target rock formation. Then the vertical part is deviated after the "kick-off" point until it runs parallel within the reservoir. During the drilling, in order to make sure the well reaches the target layer accurately and maintains in a horizontal direction, a measurement-while-drilling (MWD) tool is placed in the heading assembly and transmits digital direction data to the surface.

In fact, the first horizontal well (#33-11 MOI well) in the Bakken was completed in September 1987. It was successfully produced from the upper Bakken Shale with a pre-perforated, or slotted liner (Simenson, 2010). With regard to the shale oil reservoirs in the Sanish Field, the horizontal drilling technique had been applied to the oil and gas production successfully as well. Major reservoirs in the field are targeted at the Middle Bakken Formation with an average depth of 10,000 feet (Figure 2.6). So the horizontal wells are normally drilled vertically into 3,000-10,000 ft (1,000-3,000 m) above the targeted rock zone. Before starting the horizontal drilling process, MWD is used to determine the deviation point from the Upper Shale Bakken to the porous dolomitic sandstone region. Besides determining positional information, MWD system has been extended to formation evaluation through logging tools. Natural gamma ray log is consisted in the well steering segment to distinguish between shale and sand zones by detecting emitted potassium isotopes gamma ray, which is the common element found in shales. Subsequently, the horizontal lateral can extend up to 10,000-13,000 ft (3,000-4,000 m) after the deviation.

Compared to vertical wells, various advantages can be listed about horizontal drilling. The obvious one is that wells can hit targets where vertical drilling cannot reach. What is more, horizontal drilling in such thin reservoirs like the Bakken Shale Formation with an average thickness around 30 ft (9 m) is more effective than those drilled in thick reservoirs, due to the increased well contact area. Injectivity and sweep efficiency can also be improved during enhanced oil recovery process. Another advantage of advanced horizontal drilling is the extended horizontal long lateral through the reservoir can solve the circumstance which wellbore pressure is always lower than the reservoir pressure to allow radial flow of fluids.

Mostly, the pressure drops occur near the wellbore region, while the reservoir fluids reaching the production wells with a high velocity, the available area decreases for fluid flow. However, the growth of well length in horizontal wells leads the pressure drop reducing and yields higher drainage rates. As a result, productivity of shale oil reservoirs can be increased by orientating horizontal wells properly in the Bakken with a maximum amount of fractures intersected with wells.

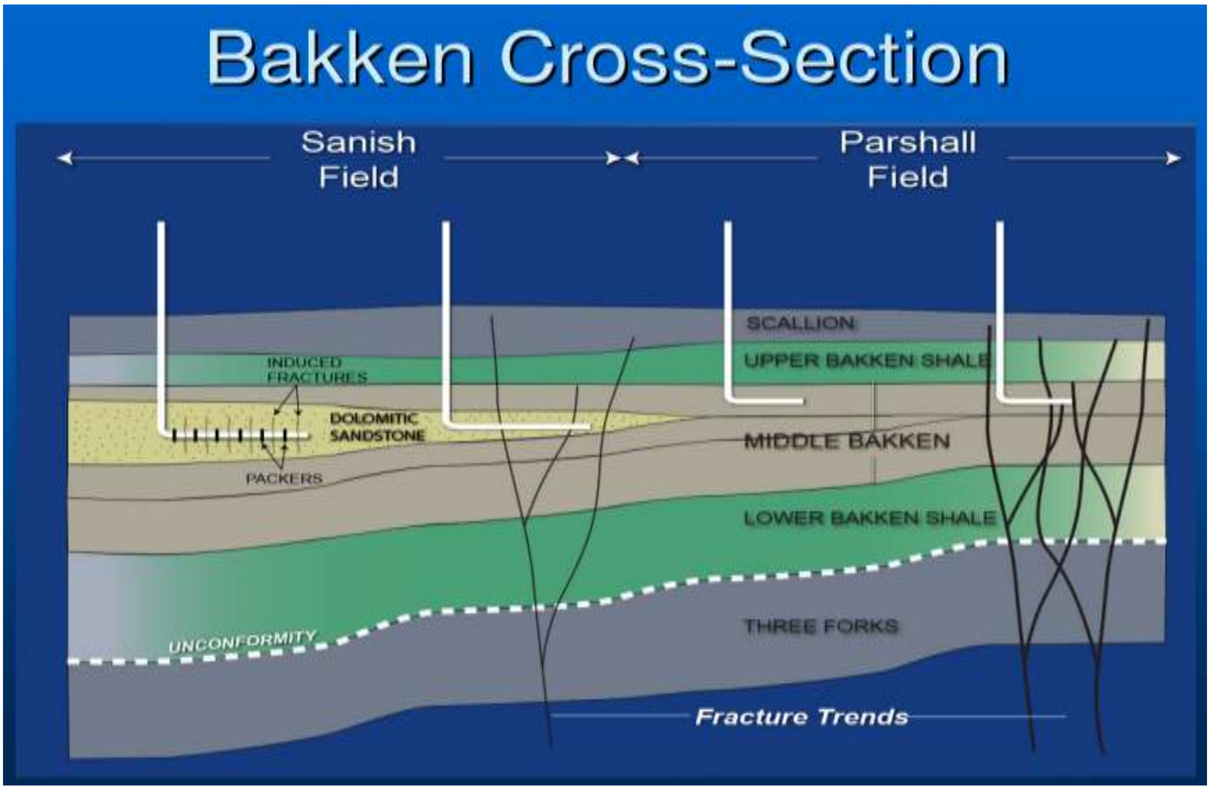


Figure 2.6 Horizontal drilling target in the Sanish Field (Paneitz et al., 2008)

2.2.2 Hydraulic Fracturing

Stimulation is necessary for tight unconventional reservoirs. The other significant technique contributing to oil recovery in the Bakken members is the most common type of stimulation—hydraulic fracturing, as for natural fractures may not be crash to produce much oil. It is a process to create a path for fluids to easily flow to a production well. The first successful example of using hydraulic fracturing to stimulate oil and natural gas production was in the 1940s in the United States (King, 2012). Afterwards, this method spreads quickly and widely, especially to those previously unproductive tight rock units. Now, the application of hydraulic fracturing in horizontal wells has turned the organic-rick Bakken shale into a very large oil field.

There are several well completion options for horizontal wells, such as an open hole, with slotted liners, pre-packed liners, liners with external casing packers (Lacy et al., 1992). According to case history data, the Openhole Fracture Completion System is applied to create multi-stage fracturing for the Bakken in the Sanish Field (Figure 2.7). Five primary technological components are included in this system, the liner top packer, open-hole packer,

Figure 2.7 Horizontal wellbore configuration (Paneitz, 2010)

ball actuated frac sleeves, wellbore isolation valve, and pressure-actuated sleeves (P sleeves) (Baker Hughes, 2010). These reactive-element packers (REPacker) are self-energizing and swelling-elastomer, thus a long-term barrier to annular flow around tubular assemblies can be provided. So unlike the traditional completion options, either cementing or perforating is not needed anymore. Therefore, this completion system does not only save the time and cost, hydraulic fracturing condition is also improved, as well as the production speed and reservoir drainage.

The whole process of well completion and hydraulic fracturing is described as follows. After the horizontal drilling is completed, open-hole packers and ball actuated frac sleeves are placed in the completion liner, using casing to put them at desire depth for maximum efficiency (Figure 2.8 a). At this moment, the wellbore isolation valve is in the open position allowing circulation through the system, and the sleeves are in the closed position (Figure 2.8 b). With approaching to the desire depth with completion liner, displacement operation begins.Once the completion fluids are in place, the first ball is dropped from the ball launcher and deployed to the frac sleeves (Figure 2.8 c). Then 2,000 psi pressure is applied, which will switch the well isolation valve to close. This process can isolate the whole system from the wellbore and also create a plug for the system to set up the open-hole packers. These packers are designed with high temperature, high pressure packing element system, as well as enough rubber volume, so that when the packers swell, it can ensure a seal condition (Figure 2.8 d). By continuing to increase the pressure to 3,000 psi, the liner packer will set (Figure 2.8 e). After circulating the completion back to the surface, setting tools can be removed from the well, leaving the zone completely isolated from the wellbore. In the meantime, the fracturing surface equipment should be rigged up to replace the initial rig. Then by pressuring up to 4,000 psi, the P sleeve is open and ready for the first stage of fracturing (Figure 2.8 f). The ball and ball seat divert the frac fluids out of the pores of the P sleeve, while the short radius packers isolating the formation intervals in the open hole.

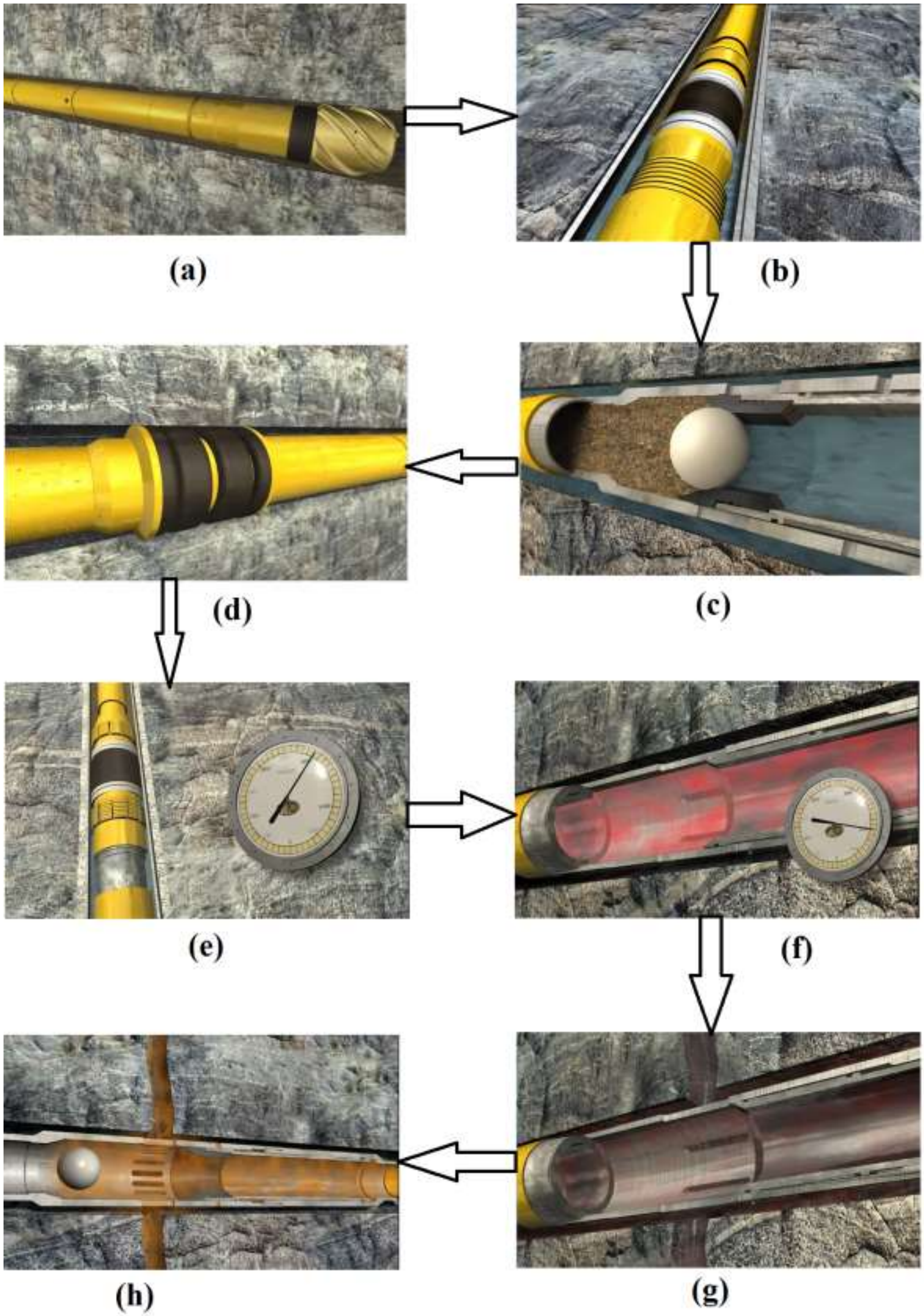


Figure 2.8 Multi-stage fracturing process in the Sanish Field (Baker Hudges Inc., modified, 2010)

Once the first zone is fractured (Figure 2.8 g), the second ball is deployed at this point and it is ready to pump the second stage. Each ball is sized and designed to seat only in their corresponding frac sleeves for each stage. The same steps are repeated with a corresponding ball until the entire horizontal section of the well is fractured. Finally, the well starts to produce and the pressure from below will push the ball off the seat, allowing the gas or oil to flow unrestricted to the surface (Figure 2.8 h). There are two main functions of the ball, one is to isolate the lower zone from the frac fluids, the other one is to shift the frac sleeves to the open position.

The pumping fluids are mostly water and sand plus a few chemicals. These chemicals are used to keep bacteria from generating and help carry the sand. They typically range in concentration from 0.1-0.5% by volume (Figure 2.9). When the pumping pressure is relieved, the suspended proppant (sand) stays in the rock to keep fractures open and allow the previously trapped oil or natural gas to flow to the wellbore.

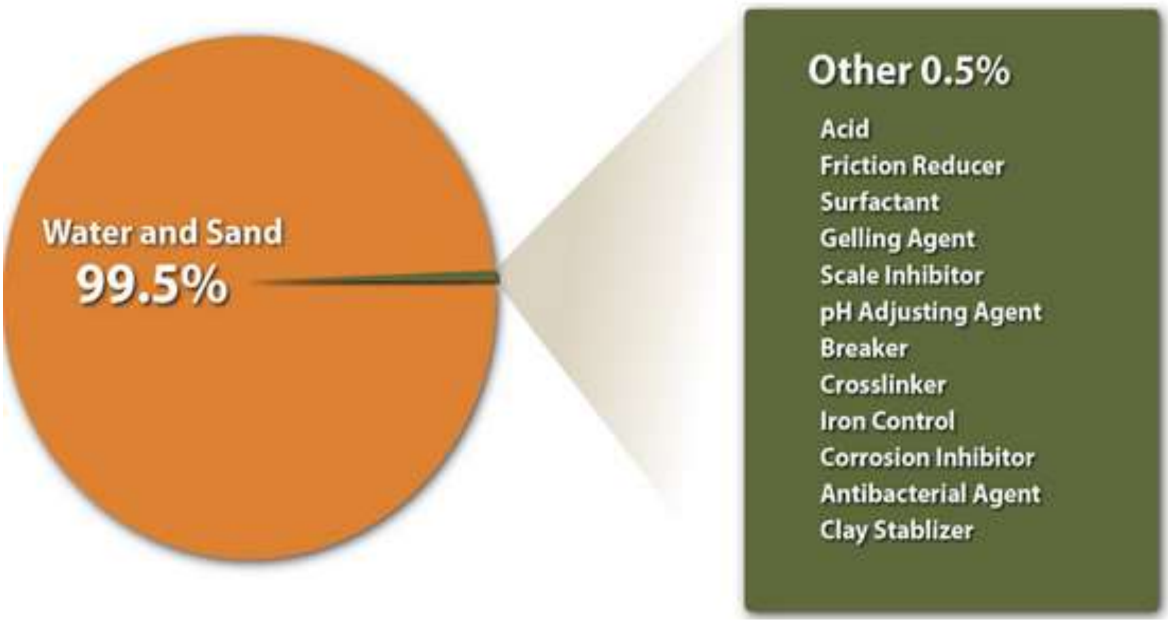


Figure 2.9 Diagram of fracturing fluids components and proportion (EERC, 2011)

A typical Bakken stimulation treatment usually consists of several fracturing stages. The three single-lateral wells in the research area have seven to ten stages (see Appendix A 1-3). Even though staged hydraulic fracturing in the horizontal wells creates greater conductivity to make the field develop economically, often, the initial attractive production rates will decline in a few years. Therefore, the enhanced oil recovery technique should also be taken into consideration for the long term production of these reservoirs.

2.3 Enhanced Oil Recovery Options

In general, there are primary three stages of oil field production development, primary recovery, secondary recovery, and tertiary recovery, also known as enhanced oil recovery (EOR). During primary recovery, nature drive is used to force the oil into wellhead, but only a small fraction of the original oil in place can be recovered. During secondary recovery, water flooding or gas injection is applied to provide pressure support and displacement. Even though productivity can be increased in time of secondary recovery, most reservoir's oil reserves are still extracted up depending on the EOR process. The mechanism of EOR technique is altering rock and fluid properties to increase oil production, mostly reduce fluid viscosity to improve flow.

For conventional oil plays, water flooding is commonly chosen by increasing pressure and pushing oil to the production wells to improve oil recovery beyond primary. Due to the low injectivity derived from shale's low permeability and porosity, water flooding may not be suitable for Bakken shale reservoirs. Thus, the three common types of EOR are discussed individually below, thermal, chemical, and miscible EOR.

Thermal EOR uses the heat from steam or hot water to reduce oil viscosity to make it easily flow, including cyclic steam (huff-n-puff), steam drive, steam assisted gravity drainage (SAGD) and in-situ combustion. Most thermal EOR techniques are inefficient for the Bakken oil. Because the average oil gravity of the Bakken Formation is about 42 °API which indicates it contains light crude oil. Since light oil has a lower viscosity, and thermal methods are widely applied in heavy oil recovery, so these processes are not evaluated in this project.

One variation of chemical EOR, is polymer flooding, where polymer is used to increase the viscosity of injected water. The increase of the viscosity difference between water and oil turns out more efficient displacement; however, water flooding is not the most applicable way for Bakken oil recovery. Therefore, polymer flooding also is out of the consideration. Other than polymer, surfactant and alkaline sometimes are added to the polymer formulation for specific cases. The most important function of surfactant is to decrease oil-water interfacial tension. In the meantime, displacement sweep efficiency enhances so that more trapped residual oil can get out from the formation. As a matter of fact, the feasibility of the surfactant EOR process is unclear to the Bakken reservoirs, yet, this is not the focus of this project. Miscible gas injection is the focus. Compared to the immiscible displacements, miscible displacements leave very little residual oil saturation and yields higher recoveries.

Carbon dioxide and hydrocarbon are the two major gases being used in the miscible injection. With many successful examples of CO_2 flooding, it has now become the leading EOR process for light oils. The potential of CO_2 flooding for Bakken oil production is also critical for this research. There are several features of CO_2 that are beneficially related to oil recovery. Firstly, the density is comparable to fluid density and higher than other gases. The second one is the viscosity of carbon dioxide remains very low at high pressure which leads to reduce the crude oil viscosity while dissolving in. Next, required minimum miscible pressure (MMP), which is the lowest pressure for first- or multi-contact miscibility to be achieved, is lower to accomplish miscibility with CO_2 than that with natural gas, flue gas, or nitrogen. Besides CO_2 is relatively abundant, the sources are found at many places in the U.S. including west Texas, Wyoming and North Dakota.

Modeling of two fields in the Williston Basin has been shown promising when applying CO_2 injection to increase the recovery factor of the Bakken Formation. According to Shoaib and Hoffman (2009), after eighteen years of continuous CO_2 injection, recovery factor of the Elm Coulee Field from Montana is raised by 16%. In addition, based on the Saskatchewan Research Council, the Saskatchewan field in Canada can recovery up 15%-25% of the original oil in place from Bakken Formation with CO_2 flooding (Luo, 2011). Although the Sanish Field is also in the Williston Basin, with its own reservoir characteristic, CO_2-EOR technique still needs to be accessed.

2.4 Evaluation Method

In this thesis, a numerical reservoir simulator is used to evaluate the performance of CO_2 injection into the Bakken Formation of the Sanish Field. Figure 2.10 provides the Sanish Field map along with a four section area chosen for building the reservoir models. The area is two miles by two miles with three production wells, named Locken 11-22H, Mcnamara 42-26H, and Liffrig 11-27H. After the structure and dimensions of the model is determined, two different types of reservoir models are built next based on the field sector. The first model, called Black Oil Model, represents the primary recovery process of the reservoirs. It defines reservoir properties, well details, and production rates corresponding to the actual production data. These data were collected from North Dakota Industrial Commission (NDIC) website (2012). A solvent model is built as the second one and it has enhanced oil recovery applications in it. CO_2 flooding performance is observed and analyzed in this model. Beyond that, different condition or parameters are executed to evaluate the effect on recovery, such as well type, numbers of well, injection operation, and injection type. Finally, the best option for oil recovery from CO_2 flooding is recommended for the Sanish Field.

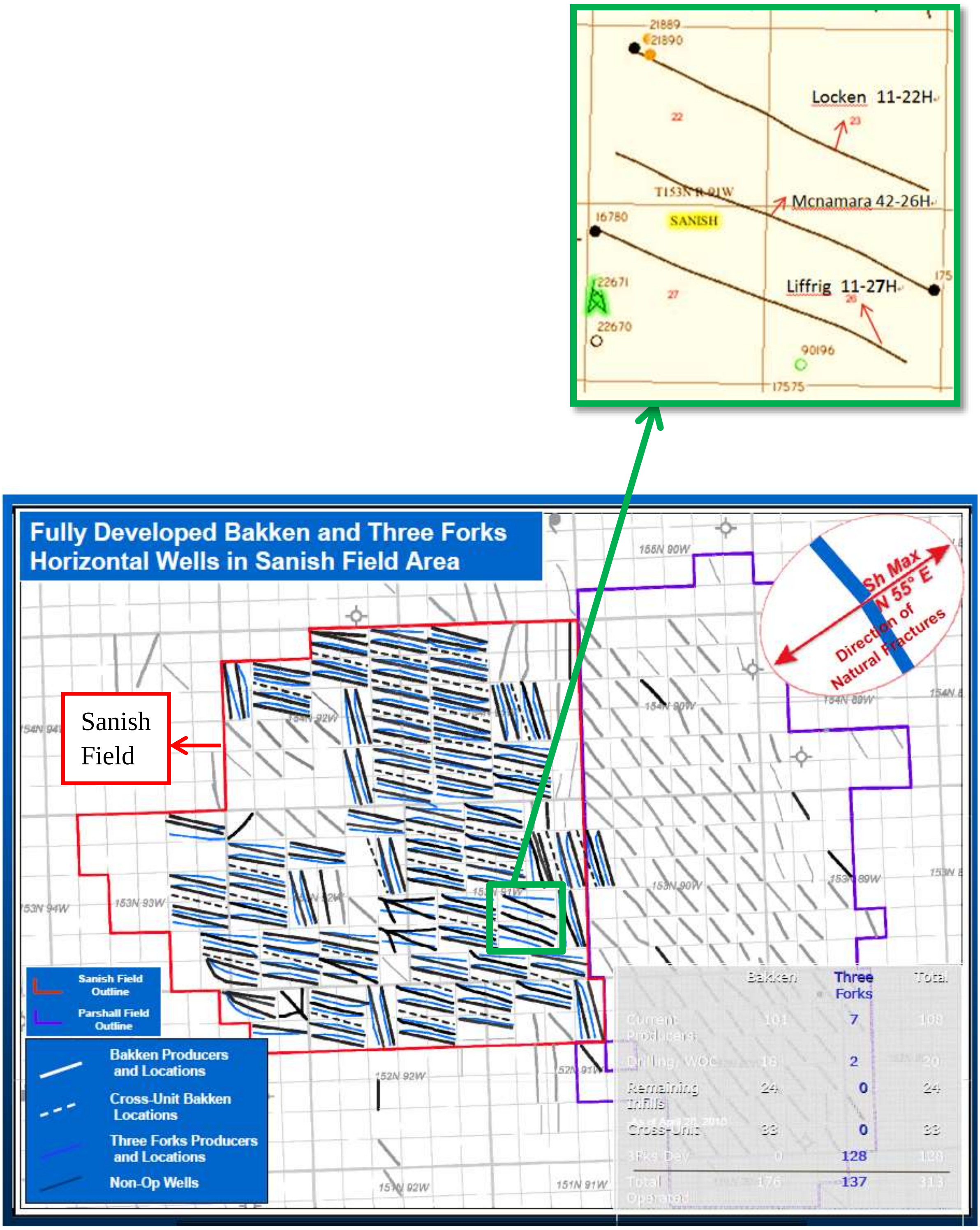


Figure 2.10: Well location of the Sanish Field (Paneitz, 2010) and Chosen Region (NDIC, 2012)

CHAPTER 3

LITERATURE REVIEW

The Bakken Formation in North Dakota has been developed only for several years. As mentioned before, the Sanish Field just started production in 2006, so, there have not been many papers published about the detail of their modeling gas injection procedure. Additionally, a lot of data such as rock properties, fluid properties, and reservoir condition are unspecific as well. Literature review shows that there are ranges of various properties of the Bakken (Table 3.1), and well information of the study area (Table 3.2).

3.1 Primary Model Data Acquisition

For the modeling purpose, a reasonable value of each property is estimated or chosen from their ranges. Some are selected by the average value of the range or average value of the Bakken mentioned in articles, such as oil API gravity (API), average middle Bakken permeability, and solution gas oil ratio (GOR). In Breit et al. (1992), they estimated the oil API gravity (API) of the Bakken from about 39 to 45 degrees API. In addition, Findlay (2009) evaluated the oil gravity for North Dakota Bakken is 42 degree API. So the average number of 42 degree API is chosen and used in the model. For the permeability, Andrea Simenson measured and analyzed lots of core samples from the Bakken in her thesis, and get the permeability range of 0.0001-1.9 millidarcy. She mentioned the average value for middle Bakken is 0.02 md. Moreover, Findlay (2009) provided the oil permeability in North Dakota Bakken ranges less than 0.01 -0.05 md. Then 0.04 md is finalized to use in the model.

Other values are just decided based on an estimation, for instance, porosity, middle Bakken tops, Gas gravity, and reservoir pressure. A 4-8% porosity range was defined in a final scientific/technical report (Sarg, 2012), based on analysis of the middle Bakken lithofacies with a number of core samples. Moreover, Sonnenberg et al. (2011) pointed out the porosity of Bakken Formation is between 6 and 10% . In accordance with these two references, 6% is considered reasonable and close to the middle value of ranges. In NDIC Department of Mineral Resources, Oil and Gas Division website, each well in the North Dakota has its own well file. From the files of three production wells in the research area, the middle Bakken tops range can be found, which 10,100 ft is determined for the consistent formation depth in the modeling. For the gas specific gravity, even though, Breit et al. (1992) presented the range was 0.77-0.88, the value was still evaluated 20 years ago. From the recent Clarks (2009) and Shoaib (2009), the value of gas specific gravity is around 0.95.

Besides, another two values, middle Bakken thickness and average water saturation, were obtained by reading the relevant map. Figure 3.1 is a map showing the middle Bakken net pay map (in feet) from Simenson (2010). The research area is marked in red square, so approximately 30 ft net pay thickness was read from it. Average water saturation of the Middle Bakken was getting from Figure 3.2 as the same.

To summarize all the primary data including rock property, fluid property and reservoir parameters from the literature reviews, Table 1 lists them all, consisting of the unit, value ranges, source references, and determined values for the modeling.

Table 3.1. Ranges of properties of the Bakken

Parameter	Unit	Values		Reference	Values used in the Model
		From	To		
Rock Property					
Porosity	%	4	10	Sonnenberg (2011) and Sarg (2012)	6
Average Permeability	md	0.0001	1.9	Simenson (2010) and Lolon et al (2009)	0.04
Middle Bakken Tops	ft	10,054	10,266	NDIC Well Files	10100
Middle Bakken Thickness	ft	10	40	Simenson (2010)	30
Fluid Property					
Oil API gravity	°API	36	45	Breit et al (1992) and Findlay (2009)	42
Water Specific Gravity	-	1.05		Shoaib thesis, (2009)	1.05
Gas Specific Gravity	-	0.77	0.88-0.96	Breit et al (1992) and Clark (2009)	0.95
Reservoir Condition					
Average Solution GOR	scf/STB	500	1500	Clark (2009) and Findlay (2009)	800
Reservoir Pressure	psia	6000	8000	Findlay (2009)	7200
Average Water Saturation	%	0.25	0.45	Simenson (2010)	0.25
Bubble Point	Psia	1800	4000	Findlay (2009) and Gonzales (2010)	3256

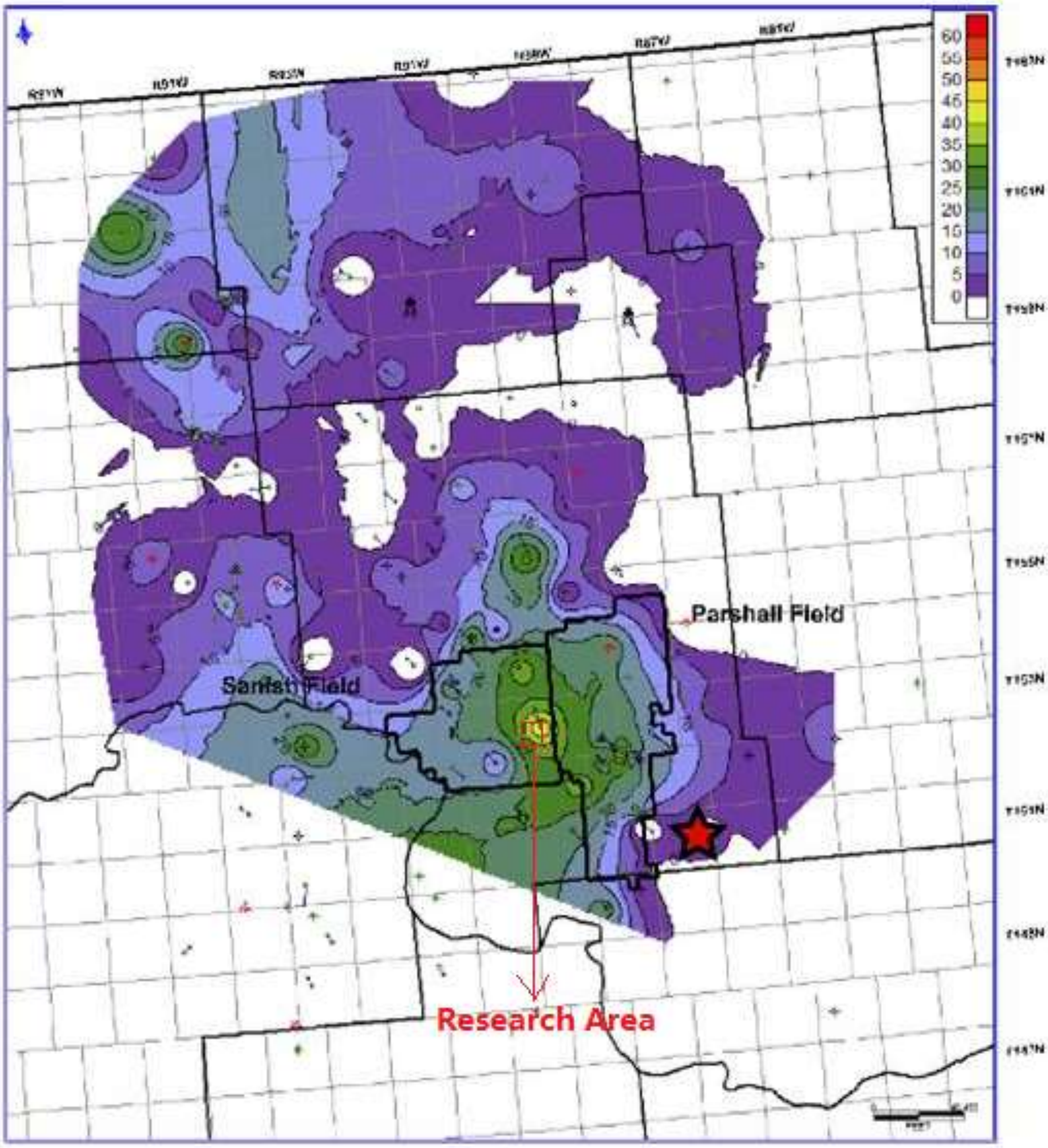


Figure 3.1. Middle Bakken net pay map (Simenson, 2010)

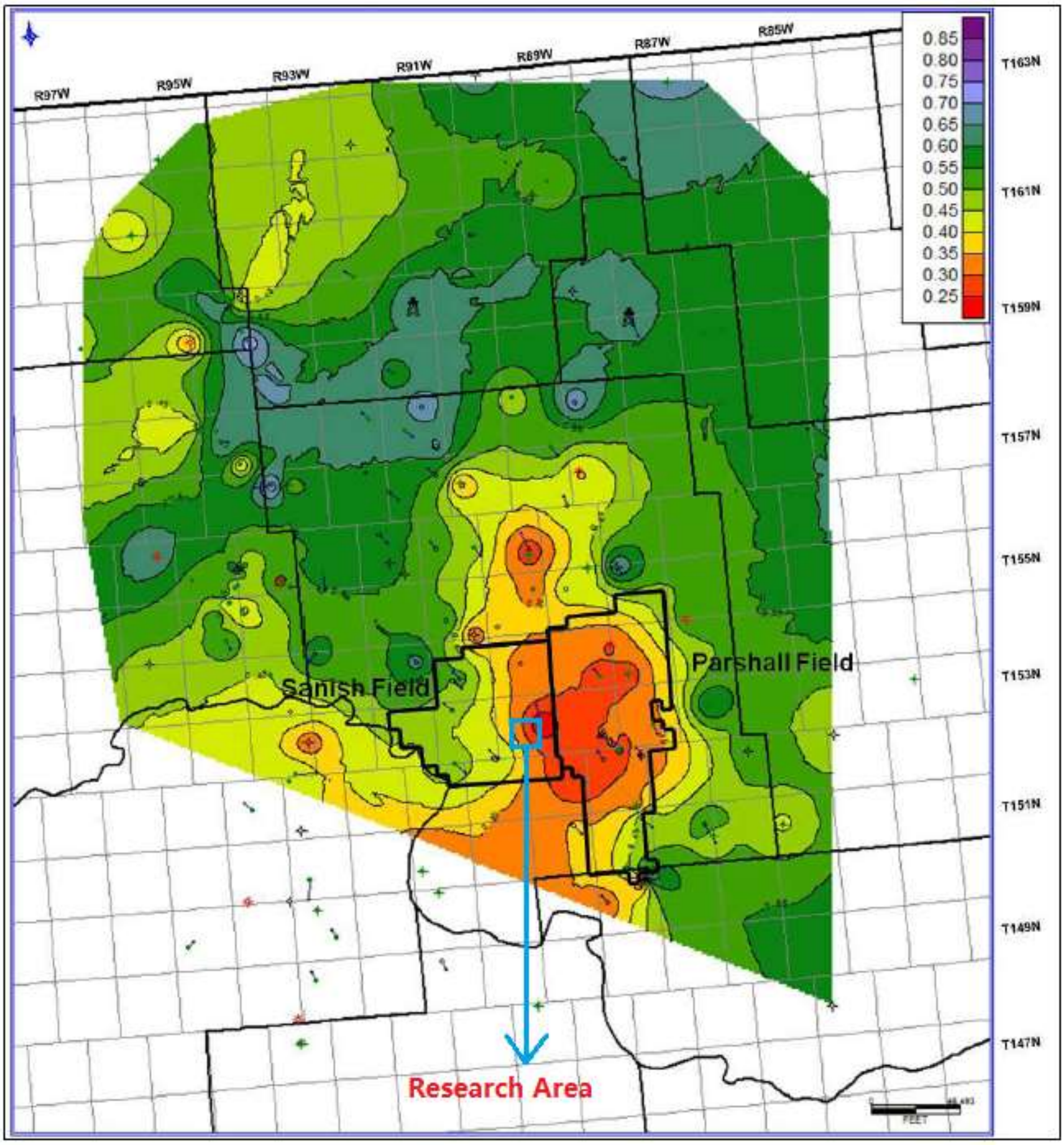


Figure 3.2. Middle Bakken average water saturation map (Simenson, 2010)

3.2 Well Information Acquisition

In order to assign the accurate location of each well into the model, the exact distance from every direction to the section boundary is found in each well's file. There are also other basic information as shown in Table 2.2. All three production wells are horizontal wells, targeted at the middle Bakken formation. They all produce oil and gas. The perforations are at depths of 10,000 ft to almost 20,000 ft. One reason this area was chosen is that the three wells there all start to produce during 2007 and 2008, so it provides nearly four years of production data that can be used to match with the simulation results. Moreover, fractures details also are provided in the well files, including the number of stages, position of fractures, and the perforation interval of each fracture. (See Appendix A)

Table 3.2. Well Information Summary (NDIC Well Files, 2012)

Well Name	Fracture Stages	Location	Drilling Type	Type of Well	Objective Horizons	Total Depth	Start Time	Max BHP (psi)	Surface Footage	Bottom Hole Footages	BH from Well Head
Locken 11-22H	7	NWNW 22-153-91	Horizontal	Oil & Gas	Middle Bakken	19375'	12/13/2007	6150	660' N 1270' W	540'E 540' E	4085' S 8752' E
Mcnamara 42-26H	10	SENE 26-153-91	Horizontal	Oil & Gas	Middle Bakken	19836'	12/06/2008	6372	2400' N 250' E	1910'S 542' W	4310' N 9771' W
Liffrig 11-27H	10	NWNW 27-153-91	Horizontal	Oil & Gas	Middle Bakken	19619'	01/23/2008	6106	800' N 225' W	546' S 540' E	3939'S 9795'E

CHAPTER 4

METHODOLOGY

The gas flooding performance of the research area is observed and evaluated through a reservoir simulator. For the past several decades, reservoir modeling has become more and more significant for developing and producing hydrocarbon reserves commercially. Numerical methods are integrated into high-speed computers to transform a research area into a more flexible and maneuverable tool (Mattax & Dalton, 1990). Not only the oil or gas reservoir behavior can be analyzed, the future performance is also assessed for prediction over a wide range of operating conditions.

For modeling purposes, the reservoir is divided into numerous blocks and represented by a mesh of points or grid blocks. The initial and boundary conditions are defined to provide the physical boundaries and properties are assigned to each grid block. These properties (pressure, flow properties) determine the direction and rate of fluid flow among adjacent blocks (Mattax & Dalton, 1990). In essence, all mathematical techniques are derived from three fundamental equations of reservoir engineering, Darcy's Law, Material Balance Equation, and Fluid Properties (PVT or EOS) (Brown, 2008). A set of equations incorporating Darcy's law and material balance is solved in the model to describe fluid flow and accounts for condition changes. Each flow calculation is computed over one of many time increments (time steps). Eventually, the results are output for a better understanding and evaluation of the reservoir performance.

The research area of this project is selected from the Sanish Field. It is a two miles by two miles region, including three horizontal production wells. The chosen sector is modeled using ECLIPSE, which is finite-difference reservoir simulation that can quickly and accurately predict the dynamic behavior for all types of reservoirs (Schlumberger, 2012). In order to build the model expediently, the section is rotated approximately 30 degrees till the horizontal section of the wells are parallel to the grid network (Figure 4.1). Based on the well information and hydraulic fracture data from the literature review, the basic model is built (Figure 4.2).

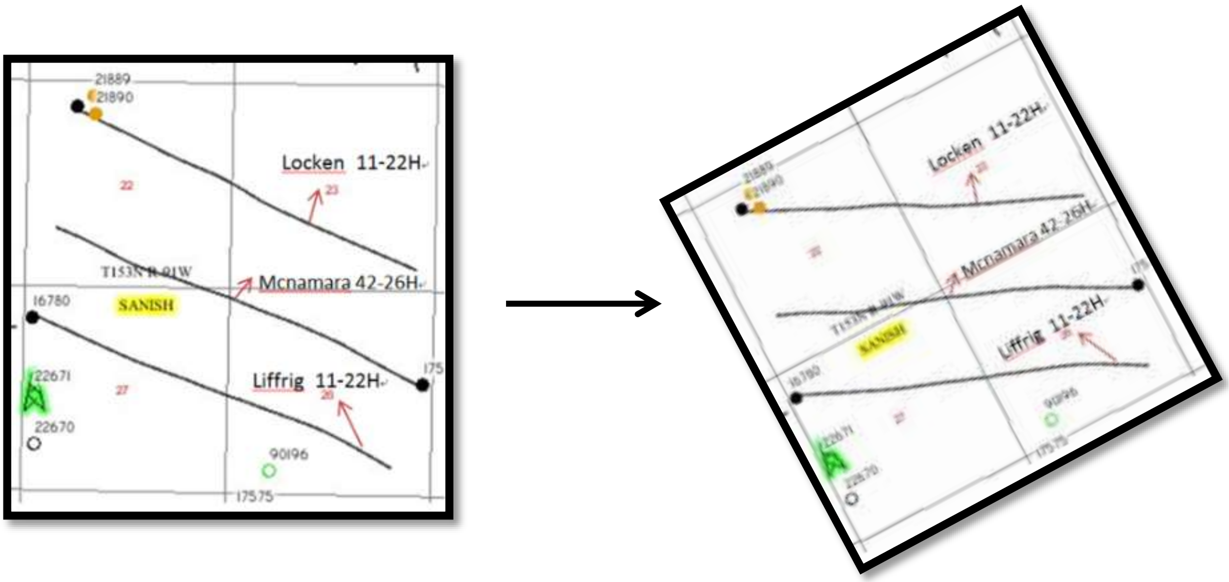


Figure 4.1 Rotation of the research area

4.1 Black Oil Model

The black oil model is used to simulate the reservoir system, basically the primary recovery. It includes modeling the simultaneous flow of three immiscible components: water, gas, and oil with dissolved gas. During the modeling, a gridded network is built first based on the reservoir. Regarding to each grid block, a unique location is designed, and various rock properties are distributed to it. In the second step, reservoir initial conditions and fluid properties are defined and assigned to the model. Then the well system is set up in the last stage of modeling. Well data and position, consisting of control mode and the constraint condition for production or injection, is specified in detail. In the end, time steps are required for calculating outputs.

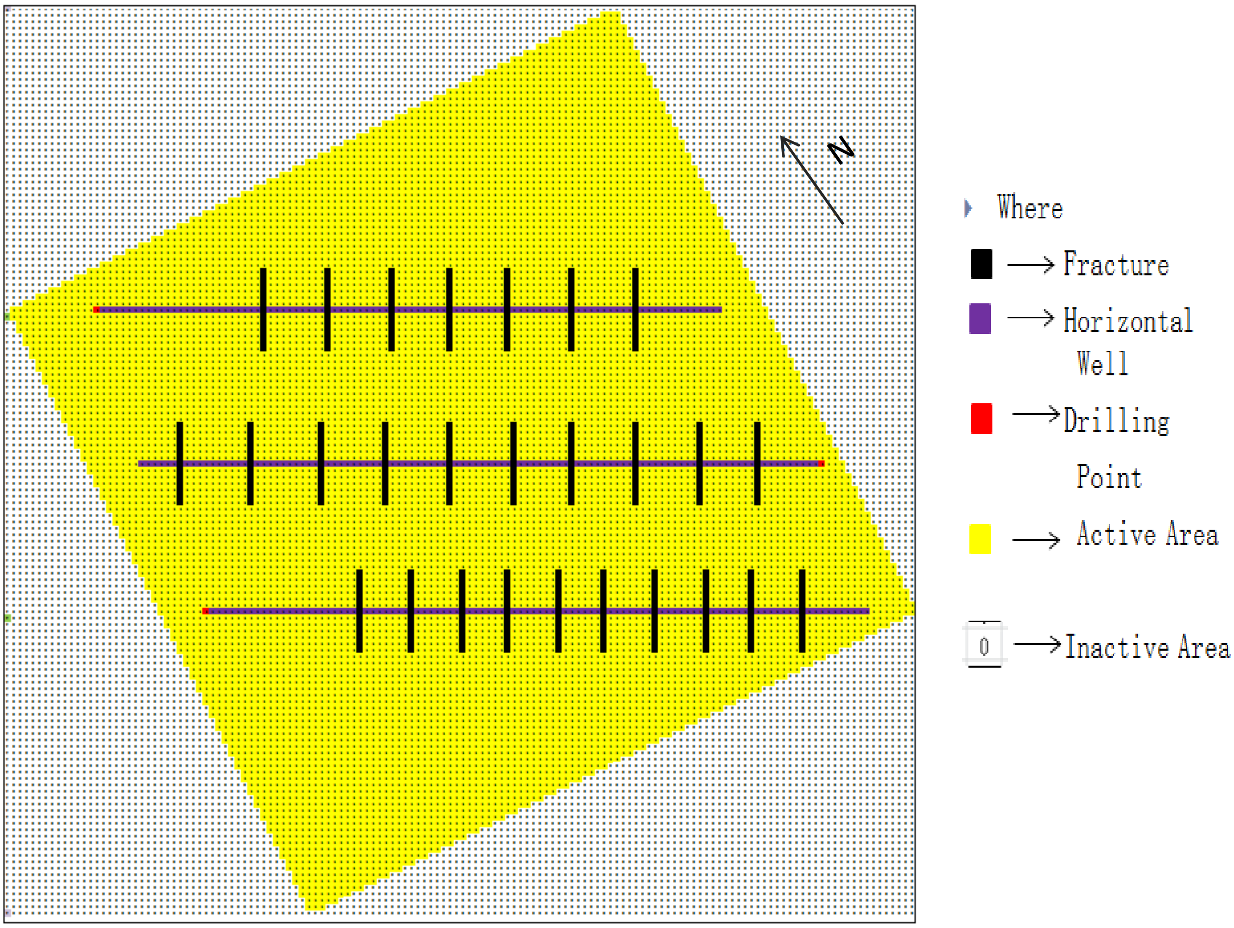


Figure 4.2 Modeling area and location of each well and fracture

4.1.1 Grid Network and Rock Properties

To begin with modeling, the two miles by two miles study area is divided into 141×141×10 grid cells separately in the x-direction, y-direction and z-direction. The grid blocks in the x- and y-directions are 100 feet in length with total 14100 feet, and 3 feet of thickness for each grid block in the z-direction, results in total net pay zone of 30 feet. Among the three members of the Bakken Formation, major contribution to oil production is from the middle dolomitic sandstone member, occurring at a measured depth of 10100 ft. In reservoir simulation, homogeneous porosity of 6% and permeability of 0.02 millidarcy are determined and defined into the target unit.

Because of the very low permeability value, hydraulic fractures are created with average fracture permeability value in 10millidarcies (Miskimins, 2012) and fracture half-lengths are 600ft. These fractures are incorporated by increasing the permeability of the grid blocks in the model (Figure 4.3). Based on the positions of these fractures for each well (Appendix A), the permeability of a grid block in the x- and y-directions is determined, and permeability in the z-direction is increased for the entire 10 layers. All these hydraulic fractures are in transverse direction with the path of the horizontal wells. However, defining fracture length and conductivity are insufficient to describe the stimulation performance in this ultra-low permeability shale reservoirs, it is essential to quantify the stimulated reservoir volume (SRV). In this case, SRV is defined in a longitudinal direction along the horizontal wells and represents them as zones of increased permeability in the reservoir grid.

For the three phases existing in the black oil model, water, oil, and gas, the relative permeability values between water-oil and gas-oil are defined as a function of saturations. The values being used in the models are shown in the following figures (Figure 4.4 and Figure 4.5).

When $S_w = 0.25 \quad K_{rw} = 0.0 \; K_{ro} = 1.0$ When $S_w = 0.75 \quad K_{rw} = 0.4 \; K_{ro} = 0.0$

When $S_g = 0.0 \quad K_{rg} = 0.0 \; K_{ro} = 1.0$ When $S_g = 0.5 \quad K_{rg} = 0.5 \; K_{ro} = 0.0$

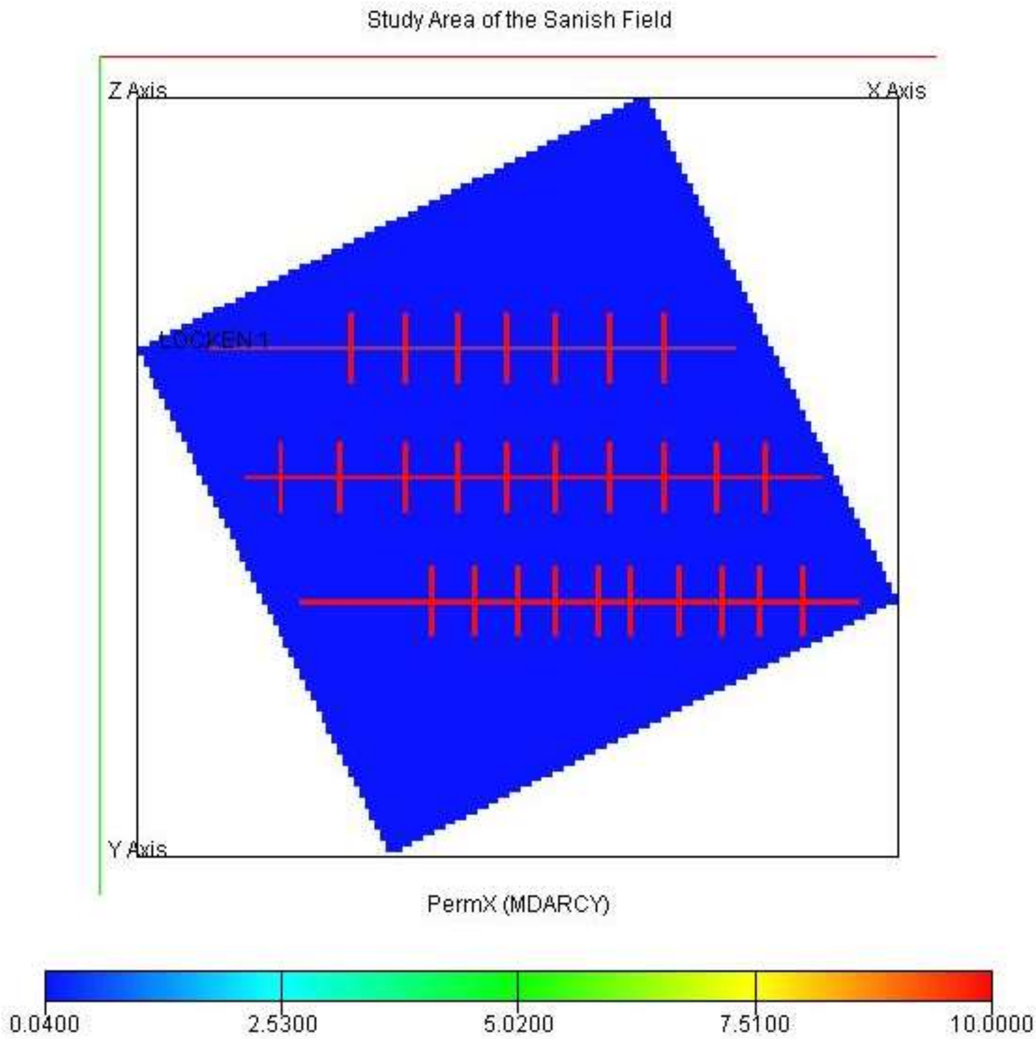


Figure 4.3 2-D View of Reservoir Grid Blocks Permeability (Blue represents the matrix permeability and red represents the hydraulic fractures permeability)

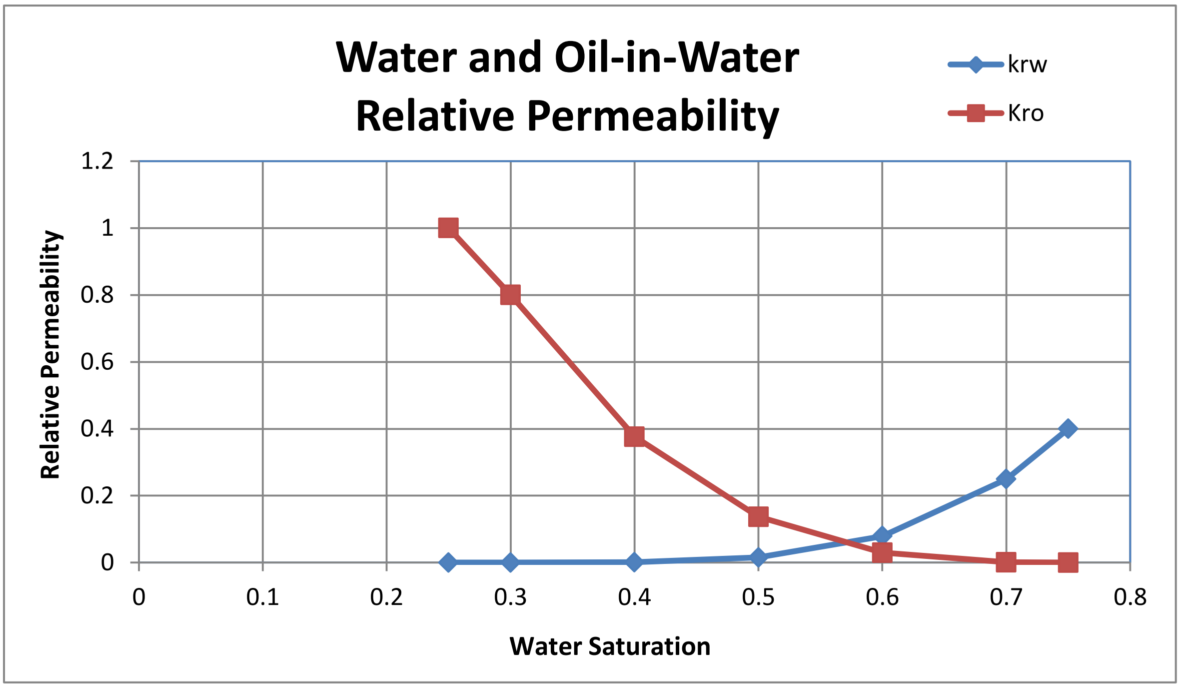


Figure 4.4 Water-Oil Relative Permeability vs. Water Saturation (Shoaib, 2009)

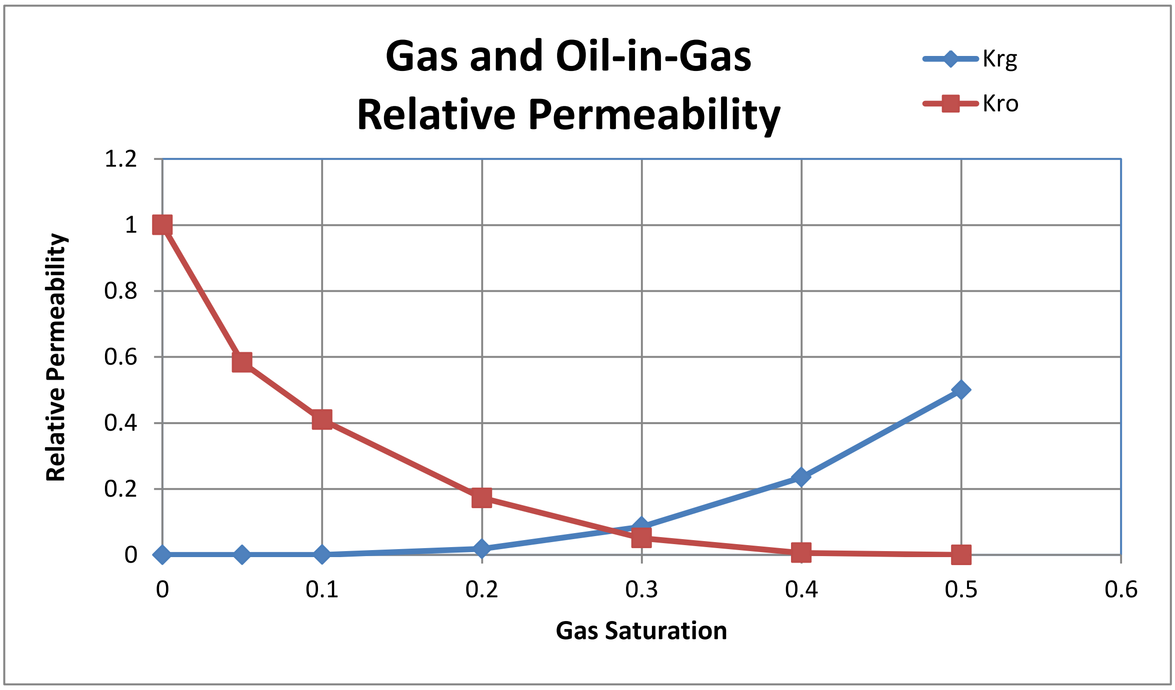


Figure 4.5 Gas-Oil Relative Permeability vs. Water Saturation (Shoaib, 2009)

4.1.2 Reservoir Condition and Fluid Properties

For the reservoir, its average reservoir pressure is around 7200 psia. The bubble point pressure is 3256 psi with an initial gas-oil-ratio (GOR) of 0.8 Mscf/bbl. The connate water saturation is 25%, which means the initial oil saturation has a high value of 75%. The reservoir oil from the Bakken Formation of this area has an average API gravity of 42 degrees, and the water specific gravity and gas specific gravity are 1.05 and 0.95. Other than these, water-oil and gas-oil relative permeabilities are defined as a function of the saturation. As well as formation volume factor (FVF) and viscosity is defined as a function of pressure in the model. These formation volume factor values and the bubble point are referenced from Gonzales's thesis paper. He built a formation linear flow model of the Bakken shale and the PVT data he used were obtained from the core samples from both McKenzie and Billings County in the North Dakota.

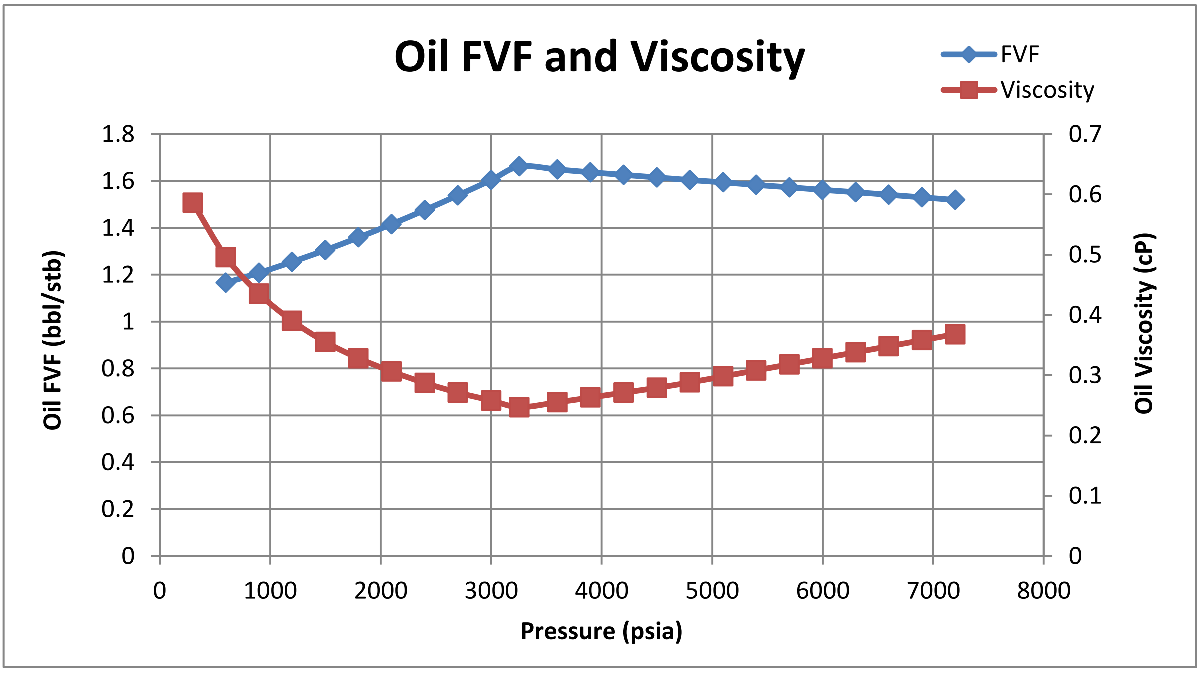


Figure 4.6 Oil Formation Volume Factor and Viscosity vs. Pressure (Gonzales, 2010)

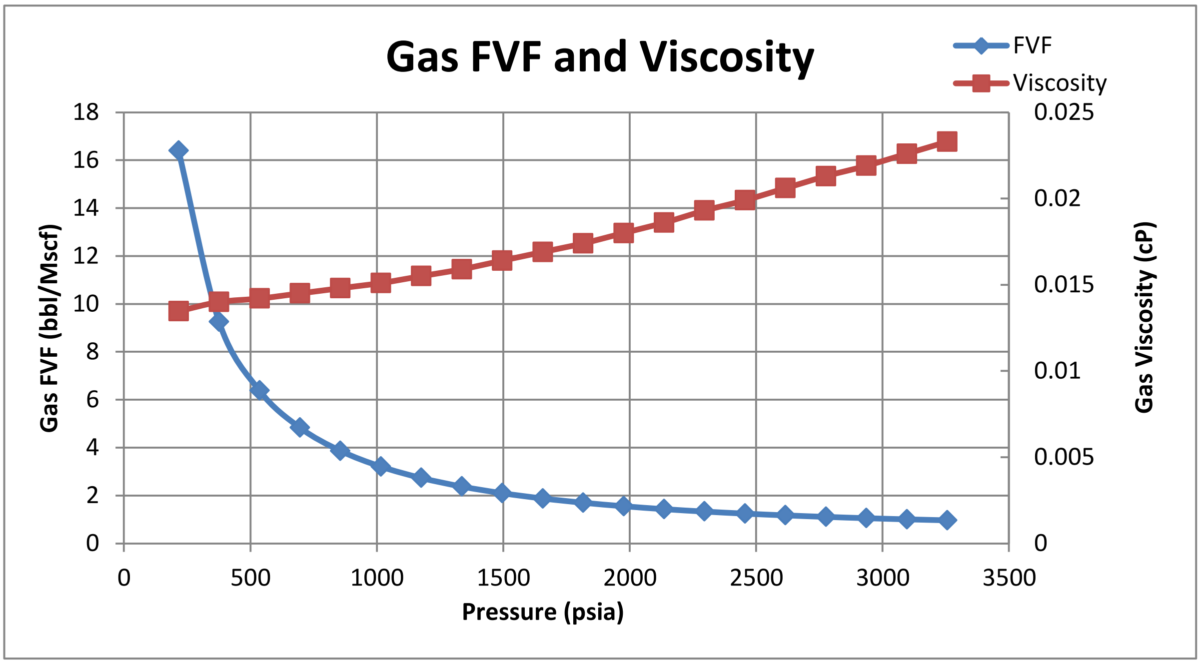


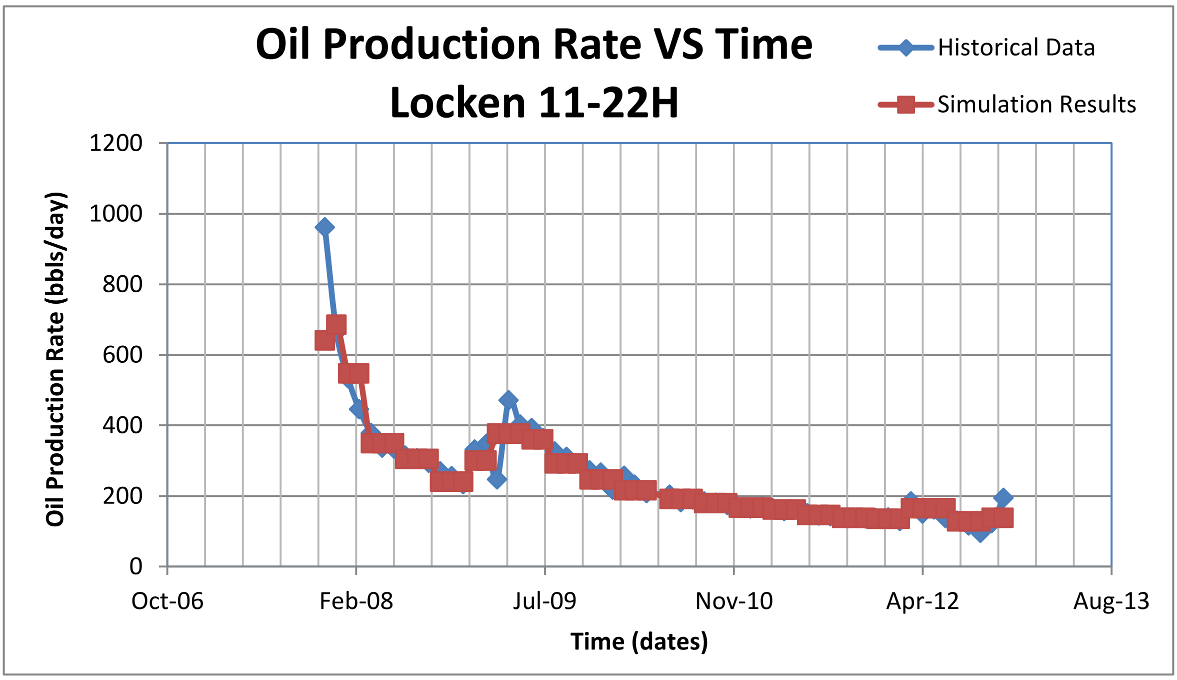
Figure 4.7 Gas Formation Volume Factor and Viscosity vs. Pressure (Gonzales, 2010)

4.1.3 Well Management

Once the well conditions and constraints are specified in this step, the process of building this reservoir model is completed. A reservoir simulator models these operations through a well-management routine. During this routine procedure, (1) each well's name and position of the wellhead are defined into the grid, (2) completion properties are specified, and (3) constraints are set. In the black oil model, the reservoir is on primary recovery. There are only three single lateral, horizontal production wells in the selected region, so no injection system is included in the model. The reason why constraints are required is that they are used as boundary conditions to model historical or desired production or injection data and allow operations to run within the defined limitations. There are mainly two types of constraints, well rates and pressures. In this case, three production wells start in December 2007 with historical data available through November 2012. In this period of time, the wells are oil rate constrained to match historical production data every three months. Afterwards, constrained condition is changed to respective bottom hole pressure, allowing the wells continuing productions for the evaluation of reservoir behavior on primary recovery in the future. Then run the model up to December 2042.

4.1.4 Simulation Results

The validity and accuracy of this simulation model rely on its proximity to the actual reservoir behavior by comparing simulated results with historical production data available. In this case, Figure 4.8 illustrates that simulated oil production rates from the three wells turn out a close match to the actual data from December 2007 to November 2012. Besides the consistency, all results reveal decreases in production rates for three wells. Figure 4 .9 provides the prediction of the combined oil production rate of three wells until December 2042. It indicates oil production rate all become lower than 50 STB/D, which leads to the key point of this research: application of enhanced oil recovery is necessary.



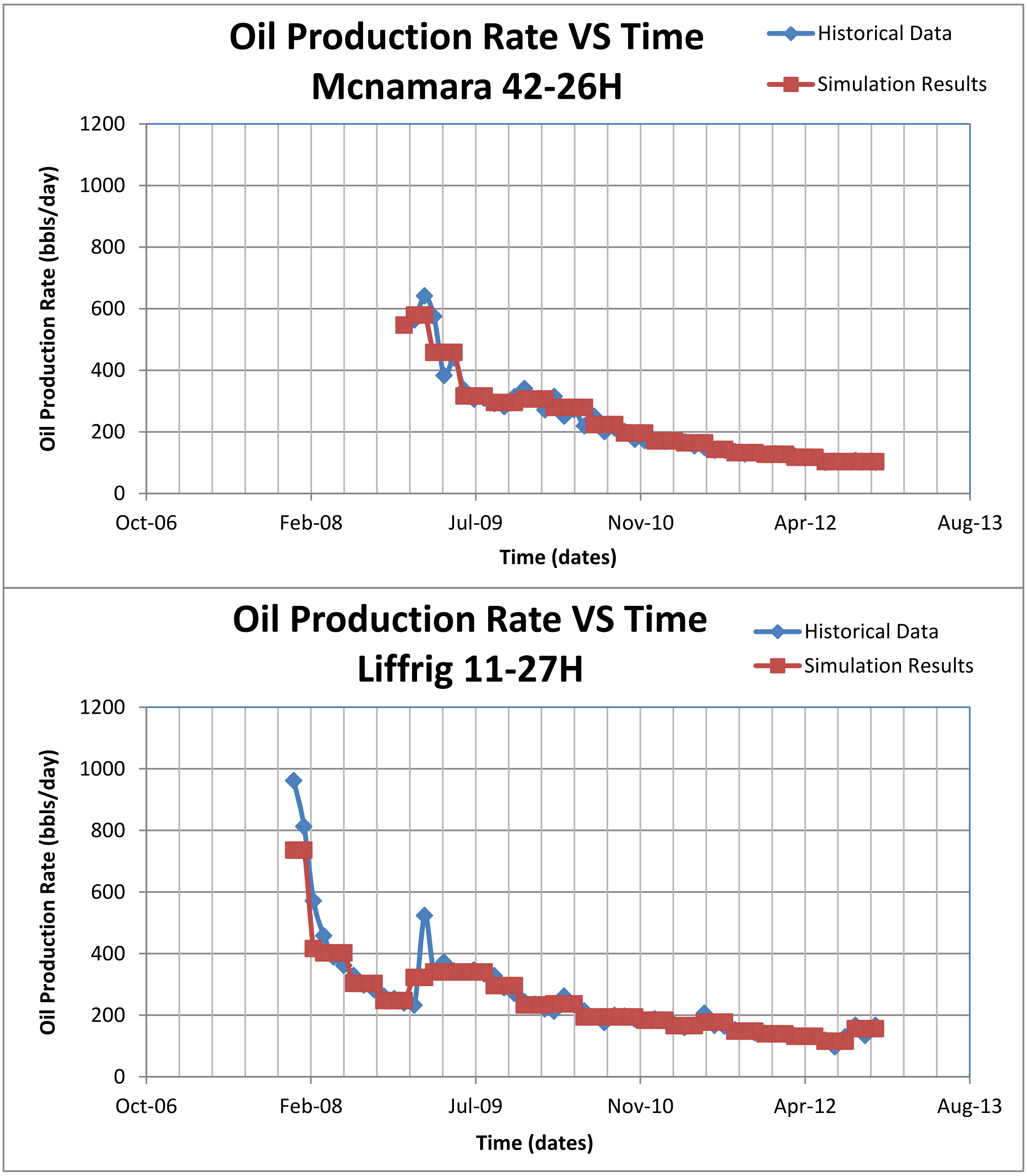


Figure 4.8 Comparison of historical and simulated production data (NDIC, 2012)

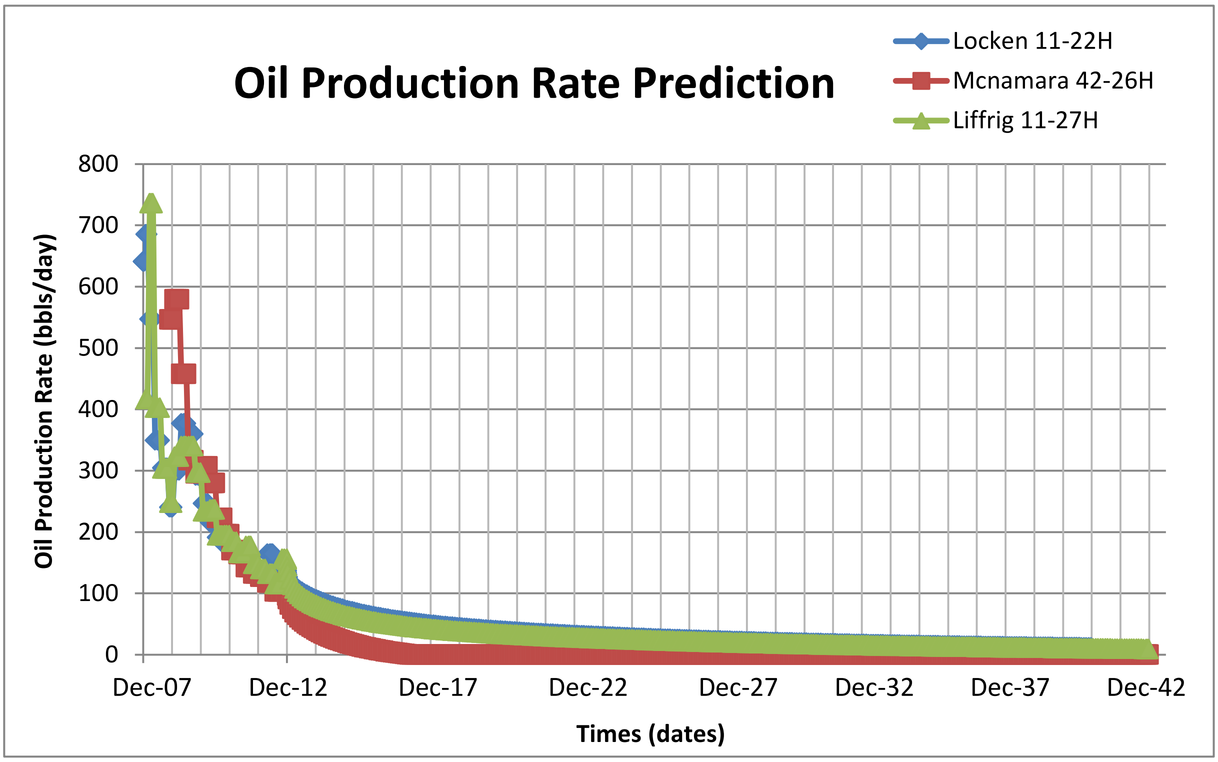


Figure 4.9 Prediction of simulated oil production rate of three wells

4.2 Solvent Model

The ECLIPSE Solvent model is an extension of the Back-oil model, aiming to simulate reservoir recovery mechanisms in which injected fluids are miscible with the hydrocarbons in the reservoir (Rhodes et al., 2012). This model is applicable for various gas injection schemes, without as much complexity as a composition model needs. During the modeling, besides oil, water, and gas, solvent is added as the fourth component, which is often referred to as the miscible fluids. In this case, the miscible fluid being used is CO_2.

During the CO_2 injection, a miscible displacement occurs if there is no phase boundary or interface between the injected fluid and the reservoir oil (Schlumberger, 2009). In the meantime, the pressure also needs to be higher than the thermodynamic MMP. Usually, miscible displacements do not happen immediately on the first contact, for example, the miscible process between CO_2 and crude oil does not complete until the CO_2-enriched oil and oil-enriched CO_2 finishing their transfer to become one phase finally. This approach uses Todd and Longstaff (1972) empirical model and in this study, it assumes the miscibility between the hydrocarbon and CO2 is first-contact process. In other words, CO2 and hydrocarbon components generate one phase on their first contact at pressures above the thermodynamic MMP and result in miscible displacement.

For the evaluation of CO_2 injection performance for oil recovery from the Sanish Field, the black oil model is modified into a solvent model. Different fluid properties are needed in the solvent model for the miscible displacement, particularly for the injection fluids. The well management is modified to contain an injection system. For the purpose of this research, several scenarios with different conditions are applied into the solvent model separately, simulated results will be analyzed in the next chapter to determine the effectiveness of injecting CO_2 in the shale oil reservoirs of the Sanish Field.

4.2.1 Extension of Fluid Properties

In the black oil model, the relative permeability for water, oil and gas are specified as follows:

$K_{rw} = K_{rw}(S_w)$ as a function of water saturation Equation 3.1

$K_{rg} = K_{rg}(S_g)$ as a function of gas saturation Equation 3.2

$K_{ro} = K_{ro}(S_w, S_g)$ as a function of both water and gas saturation Equation 3.3

In the solvent model, four components are presented. The relative permeability of each component is calculated proportionally to the concentration of each component. According to different pressure and fraction of solvent in the region, the changing degree of miscibility will also affect these relative permeability values. Due to the assumption of miscible displacement is happened on the first contact, there are mainly two status of miscibility, immiscible and miscible flood.

When the solvent saturation is too small or the reservoir pressure is below thermodynamic MMP, an immiscible region may develop with two gas components $(S_g + S_{solvent})$ existing. The total relative permeability of the gas phase is a function of the total gas saturation.

$$K_{rg} = K_{rg}(S_g + S_{solvent}) \qquad \text{Equation 3.4}$$

The fraction of each component in the gas phase is distributed as follows,

$$Fraction\ of\ solvent = F_{solvent} = \frac{S_{solvent}}{S_{solvent}+S_{gas}} \qquad \text{Equation 3.5}$$

$$Fraction\ of\ reservoir\ gas = F_{gas} = \frac{S_{gas}}{S_{solvent}+S_{gas}} \qquad \text{Equation 3.6}$$

Then the relative permeability of either gas component is taken as a function of its fraction.

$$K_{r-solvent} = K_{rg} \cdot K_{rfs}(F_{solvent}) \qquad \text{Equation 3.7}$$

$$K_{r-gas} = K_{rg} \cdot K_{rfg}(F_{gas}) \qquad \text{Equation 3.8}$$

In the Equation 3.7 and Equation 3.8, K_{rfs} and K_{rfg} are relative permeability functions which are typically straight line functions. In this case, they are set as $K_{rfs}(0.0) = 0.0$ $K_{rfs}(1.0) = 1.0$ $K_{rfg}(0.0) = 0.0$ $K_{rfg}(1.0) = 1.0$.

After enough solvent has been injected to begin displacing oil at pressures above the MMP , the displacement in the area with small reservoir gas saturation is miscible. The four components are presented in two phase character, water and hydrocarbon system. The relative permeability of hydrocarbon to water is taken into account and it is a function of oil, reservoir, and solvent saturations.

$$S_n = S_{oil} + S_{reservoir\ gas} + S_{solvent}$$

$$K_{rn} = K_{rn}(S_n) \qquad \text{Equation 3.10}$$

The oil and gas relative permeability is given by:

$$K_{r-oil} = \frac{S_{oil}}{S_n} K_{rn}(S_n) \qquad \text{Equation 3.11}$$

The total relative permeability of the gas and solvent is given by:

$$K_{r-\text{gas total}} = \frac{S_{solvent} + S_{gas}}{S_n} K_{rn}(S_n) \qquad \text{Equation 3.12}$$

Then:

$$K_{r-solvent} = K_{r-gas\ total} \cdot K_{rfs}(F_{solvent}) \qquad \text{Equation 3.13}$$

$$K_{r-gas} = K_{r-gas\ total} \cdot K_{rfg}(F_{gas}) \qquad \text{Equation 3.14}$$

Again, K_{rfs} and K_{rfg} are straight line functions of phase fraction. Though it is possible to modify the straight line miscible relative permeabilities, it is not considered in this case.

In addition to the case where the displacement behavior is either fully miscible or fully immiscible, there are also regions of transition where the displacement is alternating between miscible and immiscible, which is where exists in practice. There is a specified miscibility function in ECLIPSE used to represent the transition, imputing the solvent fraction in the gas phase and degree of miscibility. A parameter lies in the range from 0 to 1 and implies the amount of miscibility, where 0 stands for a fully immiscible displacement and 1 implies a fully miscible displacement. For the study area in the Sanish Field, a solvent fraction of 0.1 and greater leads to miscible displacement along with the pressure is higher than MMP.

No matter at which development stage of miscibility between CO_2 and oil, the big concern and the key parameter to design and access the applicability of a miscible gas flood is the minimum miscibility pressure. The Bakken Formation in North Dakota is generally at a depth greater than 8,000 feet, achieving the MMP for CO_2 injection is achievable. Published MMP for the Bakken Formation at Elm Coulee Field is 3100 psia (Shoaib, 2009). This value was measured by conducting a slim-tube test. The miscibility condition is typically determined by conducting displacement tests at various pressures during this kind of test. Recovery results are expected to increase by raising the test displacement pressures until it stay almost constant above the minimum miscible pressure. Slim-tube experiments are relatively simple to conduct and has become a generally accepted procedure to test displacement under idealized conditions (Green and Willhite, 1998).

The published MMP was obtained by testing the Montana Bakken sample with CO_2 at pressure values of 1400 psia, 2000 psia, 2650 psia, and 3100 psia while keeping the temperature constant at reservoir temperature. As results shown in the Figure 4.10, at 3100 psia, oil recovery exceeds 90% for 1.2PV of CO_2 injected. It indicates the pressure value of 3100 psia is the thermodynamic MMP for Montana Bakken. Since there is not much published information about MMP for CO_2 miscible flooding in the Bakken Formation, and the depth, API gravity, bottom hole temperatures in Montana Bakken are all similar to these in North Dakota Bakken. The 3100 psia is set as the thermodynamic MMP in the solvent model for CO_2 flooding in the Sanish Field Bakken Formation.

After determining the MMP, extensive PVT properties of the reservoir fluid-injection solvent should be defined as well. The surface density of CO_2 is assigned as 0.123628 lb/ft^3 (Shoaib, 2009). The formation volume factor and viscosity values of solvent are shown in Figure 4.11 as a function of pressure.

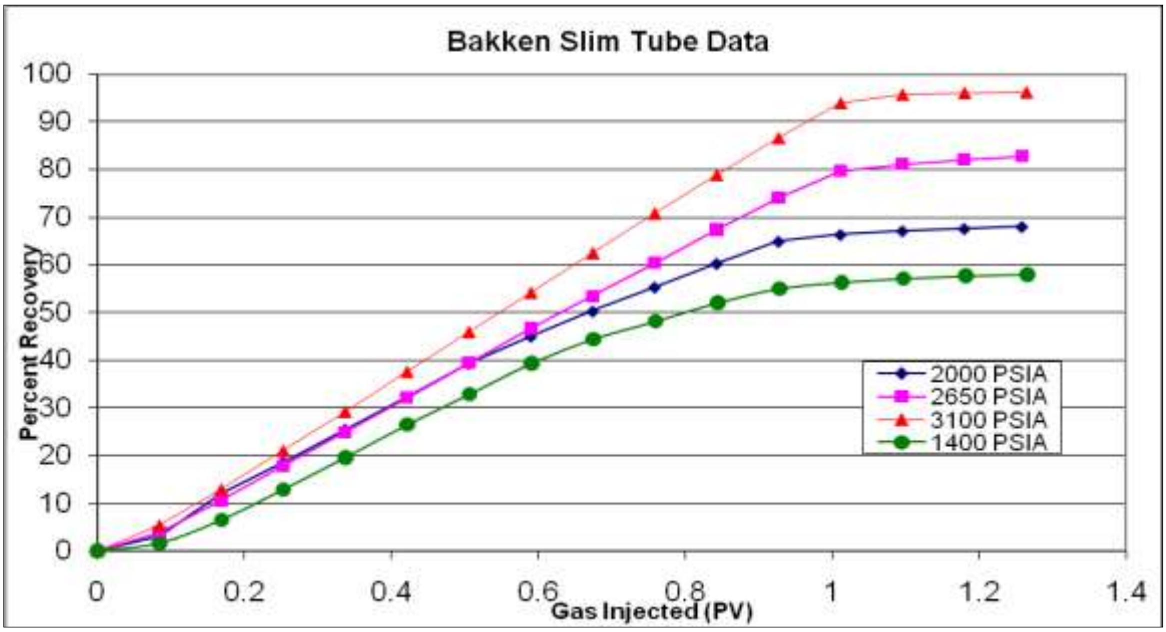


Figure 4.10 Slim-tube test results for Montana Bakken (Shoaib, 2009)

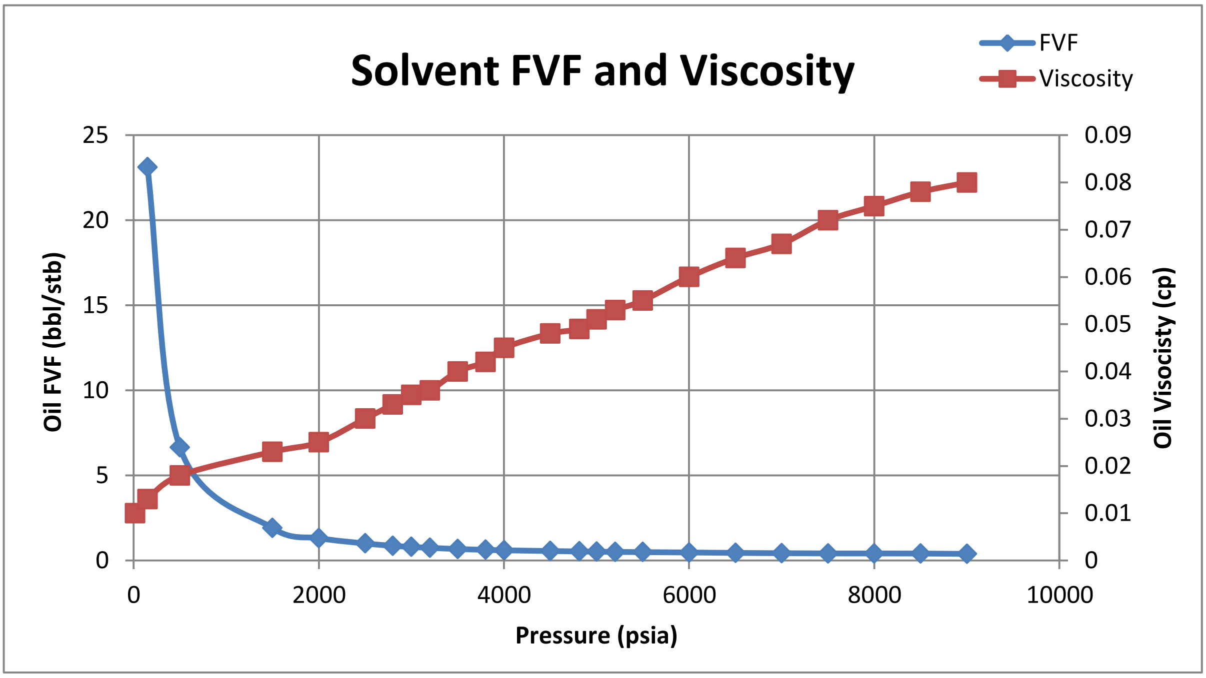


Figure 4.11 Values of solvent FVF and viscosity as a function of pressure (Shoaib, 2008)

Another issue associated with using CO_2 for EOR is that, compared to the crude oil and brine in the reservoir, CO_2 has lower density and viscosity. So the injected CO_2 has substantially higher mobility relative to the crude oil and brine. The mobility of a fluid (λ) refers to a measurement of its capacity to flow through the rock, defined as $\lambda = \mathrm{k}/\mu$, where k is the effective permeability of rock to fluid in millidarcy (md) and μ is the viscosity of fluid in centipoise (cP). When a less viscous fluid is injected displacing a more viscous fluid, the interface between these two fluids in a porous medium is unstable (Figure 4.12), which could promote fingering. During a gas flooding, viscous fingering and by passing the oil phase could cause early breakthrough of CO_2 to the production wells, slow production of oil and leaves a higher residual oil (Long and Yost, 2012, Stern, 2005). In this case, a single empirical mixing parameter (ω) is adjusted in the solvent model to alter the effective viscosity relationships from Todd and Longstaff empirical model. It involves a method to calculate effective viscosities between the oil and gas phases when mixing occurs.

In an immiscible simulator, the effective oil and solvent viscosities are calculated as follows,

$$\mu_{effective-oil} = {\mu_{oil}}^{1-\omega} {\mu_{m-oil+solvent}}^{\omega} \qquad \text{Equation 3.15}$$

$$\mu_{effective-solvent} = {\mu_{solvent}}^{1-\omega} {\mu_{m-oil+solvent+gas}}^{\omega} \qquad \text{Equation 3.16}$$

$$\mu_{effective-gas} = {\mu_{gas}}^{1-\omega} {\mu_{m-gas+solvent}}^{\omega} \qquad \text{Equation 3.17}$$

Where μ_m is the fully mixed viscosity and ω is the Todd-Longstaff mixing parameter (Schlumberger, 2009). The mixture viscosities are defined using the "1/4th-power fluid mixing rule" suggested by Todd and Longstaff.

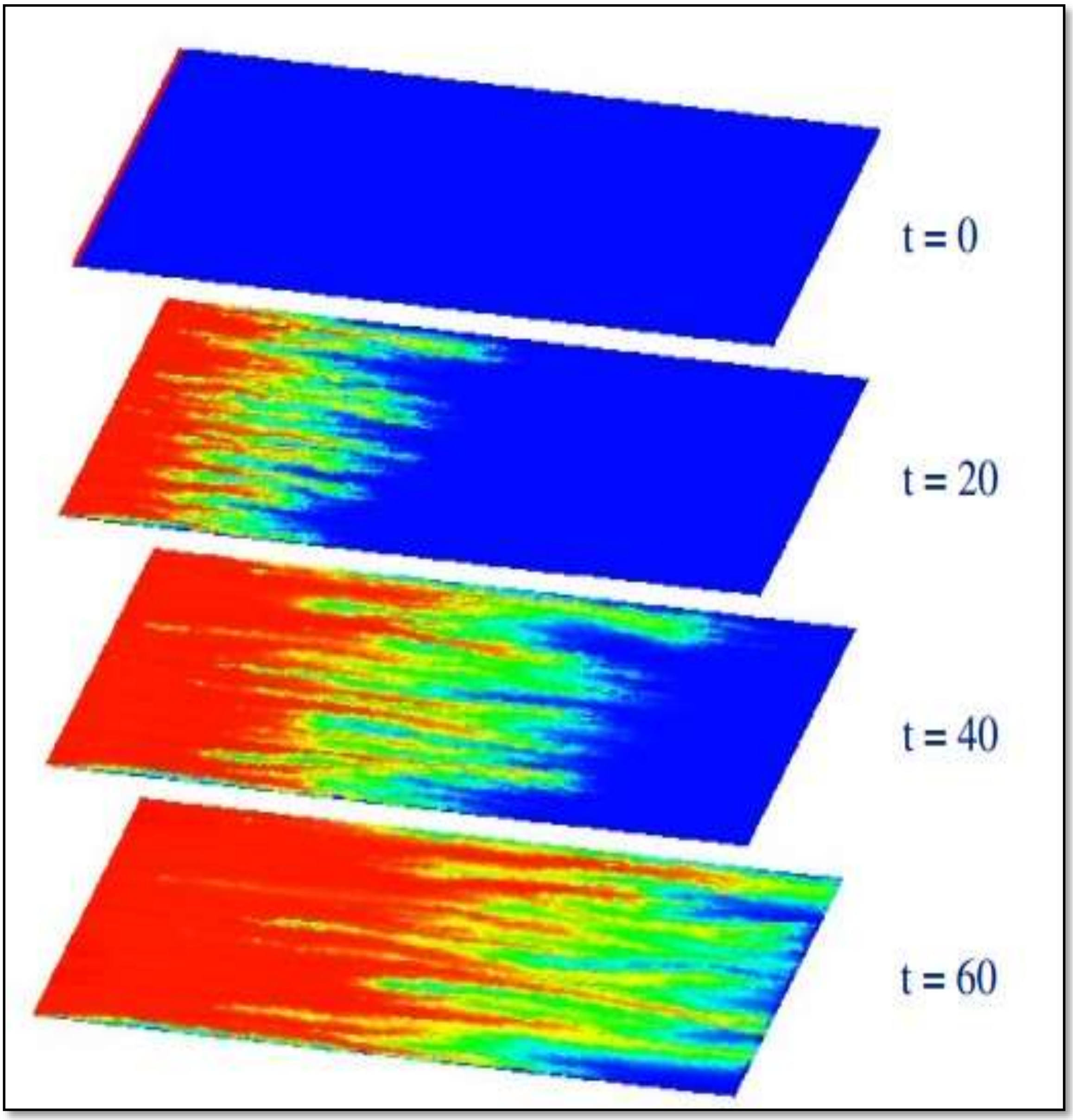


Figure 4.12 Numerical simulation outputs of viscous fingering model in different time steps. Blue represents the more viscous oil and red represents the less viscous solvent (Farmer, 2008)

So,

$$\mu_{m-oil+solvent} = \frac{\mu_{oil}\mu_{gas}}{(\frac{S_{oil}}{S_{oil+solvent}}\mu_{solvent}{}^{\frac{1}{4}}+\frac{S_{solvent}}{S_{oil+solvent}}\mu_{oil}{}^{\frac{1}{4}})^4} \quad \text{Equation 3.18}$$

$$\mu_{m-oil+solvent} = \frac{\mu_{oil}\mu_{solvent}\mu_{gas}}{(\frac{S_{oil}}{S_n}\mu_{solvent}{}^{\frac{1}{4}}\mu_{gas}{}^{\frac{1}{4}}+\frac{S_{solvent}}{S_n}\mu_{oil}{}^{\frac{1}{4}}\mu_{gas}{}^{\frac{1}{4}}+\frac{S_{gas}}{S_n}\mu_{oil}{}^{\frac{1}{4}}\mu_{solvent}{}^{\frac{1}{4}})^4}$$

Equation 3.19

$$\mu_{m-gas+solvent} = \frac{\mu_g\mu_s}{(\frac{S_{gas}}{S_{gas+solvent}}\mu_{solvent}{}^{\frac{1}{4}}+\frac{S_{solvent}}{S_{gas+solvent}}\mu_{gas}{}^{\frac{1}{4}})^4} \quad \text{Equation 3.20}$$

In order to calculate the effective viscosities between the pure component and fully mixed values, the Todd-Longstaff mixing parameter lies between 0 and 1. Thus, the value of ω controls the degree of fluid mixing within each grid cell. A value of $\omega = 1$ models the case when hydrocarbon components are considered to be fully mixed in each cell, no bypassing is seen and the dispersed zone is bigger than a typical grid cell size. On the contrary, when $\omega = 0$, the disposed zone is thin enough to be negligible between the gas and oil components, the viscosity and density of miscible components are equal to the values of the pure component (Schlumberger, 2009). In Stalkup's SPE monograph, he suggests choosing a value in the range of 0.5 to 0.7 for ω (Stalkup, 1984). For the solvent model of Sanish Field, the mixing parameter is assigned a value of 0.5.

4.2.2 Modification of Well Arrangement

With the purpose to simulate CO_2 flooding in the study area of the Sanish Field, an injection system is added to extend the black oil model to the solvent model. According to each specific scenario, different number of injection wells and different injection well types are going to be introduced in the next chapter. In general, defining an injection well is similar to a production well, such as each well's name, position of the wellhead, completion properties and constraint condition have to be defined. The control parameters for injection wells also include the type of fluid being injected, control mode for injection, injection flow rate at surface conditions, and upper limit value for the bottom hole pressure of the injection wells. All of the injection wells are defined and available from December 1st, 2012, until December 1st, 2042 for a total of 30 years. It is assumed to inject pure CO_2 for all the injection wells, so the fraction of solvent in the gas phase of each injection well is 1.0.

CHAPTER 5

RESULTS AND ANALYSES

This chapter presents the results of how much CO_2 was injected and the recovery factor (RF) estimated in the Sanish Field. These results are shown along with their sensitivity analyses. The first case is the conversion of an existing producer; the results of CO_2 injection for individual wells are analyzed by comparing different injection bottom hole pressure (BHP), injection rates, and injection type. Secondly, the addition of new wells both horizontal and vertical injectors are added to the study area of the Sanish Field, the effect of CO_2 injection for different number of wells and different injection well types are analyzed for the individual wells and the field sector. In the analyses, all the wells in the field sector are in production since December 1, 2007, the injection system starts on December 1, 2012 and continues for the next thirty years until December 1, 2042.

5.1 Case Scenarios A: Conversion of Existing Producer

There are three horizontal producer originally in the field sector, Locken 11-22H, Mcnamara 42-26H, and Liffrig 11-27H. From the black oil model, the prediction results for well production performance indicate that Mcnamara 42-26H will be shut in at April 8, 2017 because it cannot operate at given reservoir condition. In the solvent model, Mcnamara 42-26H is converted to an injection well from December 1, 2012 (Figure 5.1). The effect of CO_2 flooding on the recovery factor of the Locken11-22H and Liffrig 11-27H is analyzed with the following scenarios: (1) Maximum injection pressure (8000 psia) with different injection rate of 1000, 2000, 5000 *Mscf/day*, (2) Maximum injection rate of 5000 *Mscf/day* with different injection pressure of 6000, 7000, and 8000 psia, (3) continuous CO_2 injection versus water flooding.

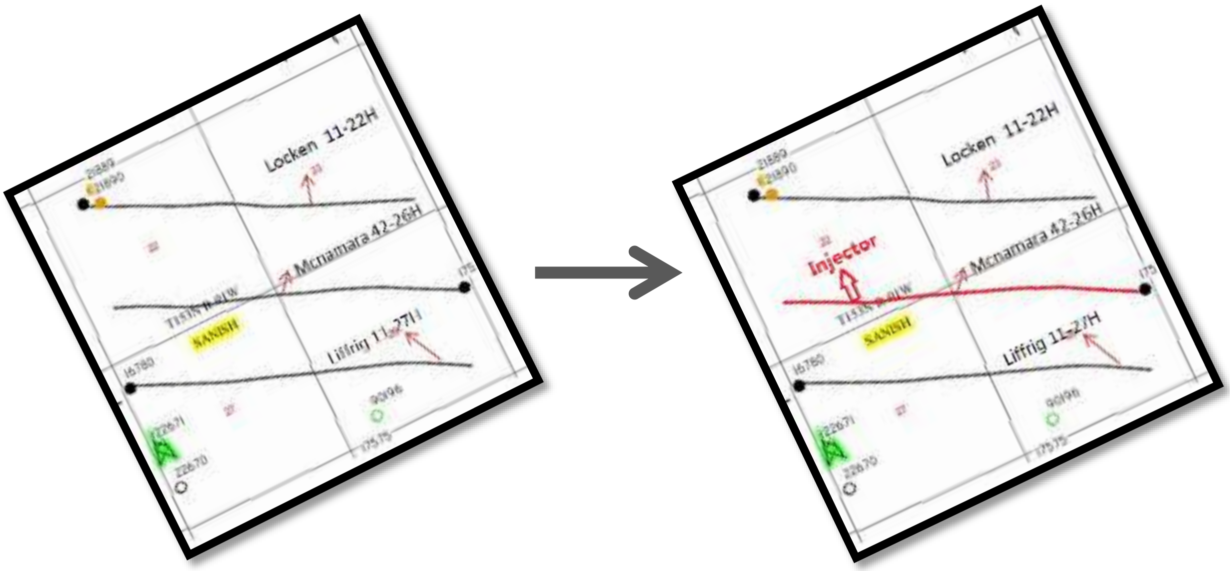


Figure 5.1 Conversion of Mcnamara 42-26H into an injection well

5.1.1 Scenario A-1: Maximum injection pressure with different injection rate

The constraint condition for an injection well includes injection bottom hole pressure and injection rate. After Mcnamara 42-26H transforming into an injection well, it is controlled by the given injection rate first to allow the well bottom hole pressure to increase. As soon as the pressure meets the requirement, the well will automatically change to injection bottom hole pressure control, but the injection rate will start to decrease for pressure to keep at the required level, as Figure 5.2 shown. In this case, the injection pressure is set at a constant value of 8000 psia, different injection rate is set to evaluate the recovery factor of the other two wells.

Before calculating the recovery factor, it is necessary to calculate the pore volume (PV) of the field sector model.

Number of grid blocks in x direction=141 grid blocks

Number of grid blocks in y direction=141 grid blocks

Number of grid blocks in z direction=10 grid blocks

Active number of grid blocks in x and y direction=11092 grid blocks

Dimension of each grid block in x direction=100 *ft*

Dimension of each grid block in y direction=100 *ft*

Dimension of each grid block in z direction=3 *ft*

Area of field sector model=$11092 \times 100ft \times 100ft = 1.1092 \times 10^8\ ft^2$

Height of field sector model=$10 \times 3\text{ft} = 30\ ft$

Porosity=0.05

PV (ft^3) of field sector model= $\text{Area} \times \text{Height} \times \text{Porosity}$

$= 1.1092 \times 10^8\ ft^2 \times 30\ ft \times 0.06 = 2.00 \times 10^8\ ft^3$

PV (res.bbls) of field sector model=$1\ \text{res. bbl}/5.615\ \ ft^3 \times 2.00 \times 10^8\ ft^3$

$= 3.56 \times 10^7 res.bbls$

(1) <u>Scenario A-1-a: Injection rate of 5000 Mscf/day</u>

Total amount of solvent (CO_2) injected at surface conditions =$9.30 \times 10^6 Mscf$

FVF of CO_2 at reservoir conditions=0.4111 *res.bbl/Mscf* (Shoaib, 2009)

Total amount of solvent (CO_2) injected at reservoir conditions

= $9.30 \times 10^6 Mscf \times 0.4111\ res.bbl/Mscf = 3.82 \times 10^6\ res.bbl$s

PV of CO_2 injected=Amount of CO_2 injected at res. conditions/PV of field sector

= $3.82 \times 10^6\ res.bbls/3.56 \times 10^7 res.bbls = 0.107$ PV

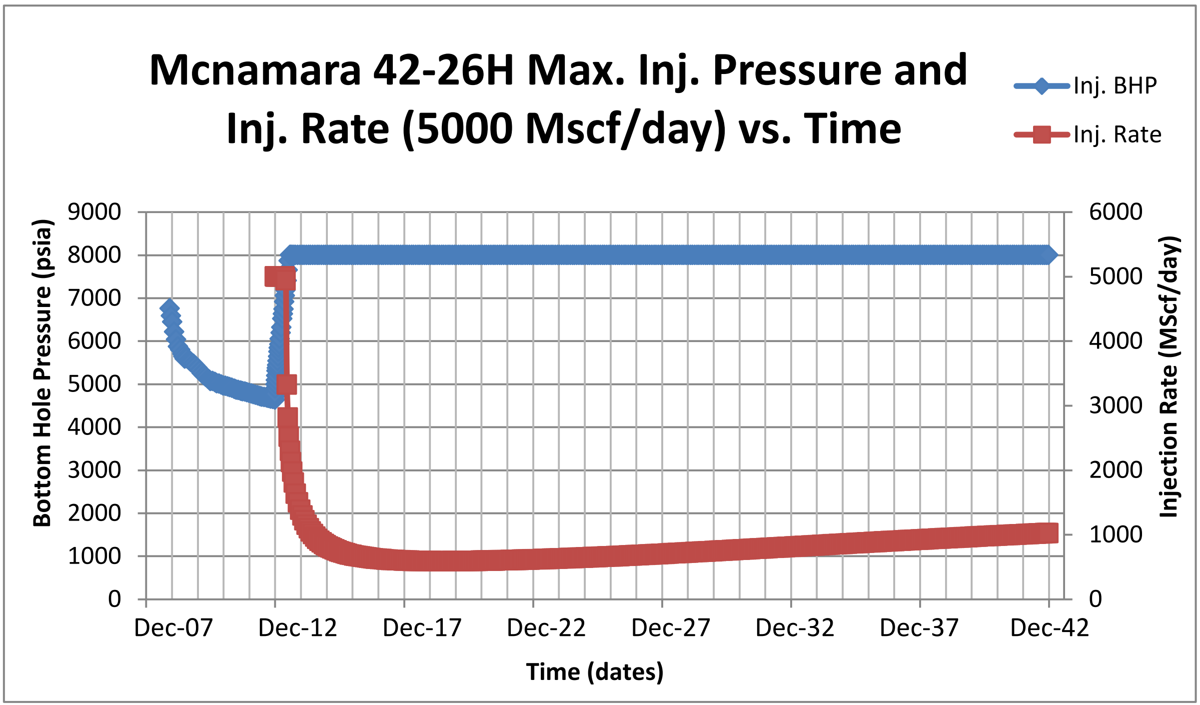


Figure 5.2 Mcnamara 42-26H BHP of 8000 psia and Inj. Rate (5000 Mscf/day) vs. Time

The oil production rate from the other two wells Locken 11-22H and Liffrig 11-27H increases after the injection (Figure 5.3 and Figure 5.4). The peak oil production rate for Locken 11-22H is 124 stb/day, occurs in September 2032, and the peak oil production rate for Liffrig 11-27H is 139 stb/day, occurs in March 2028.

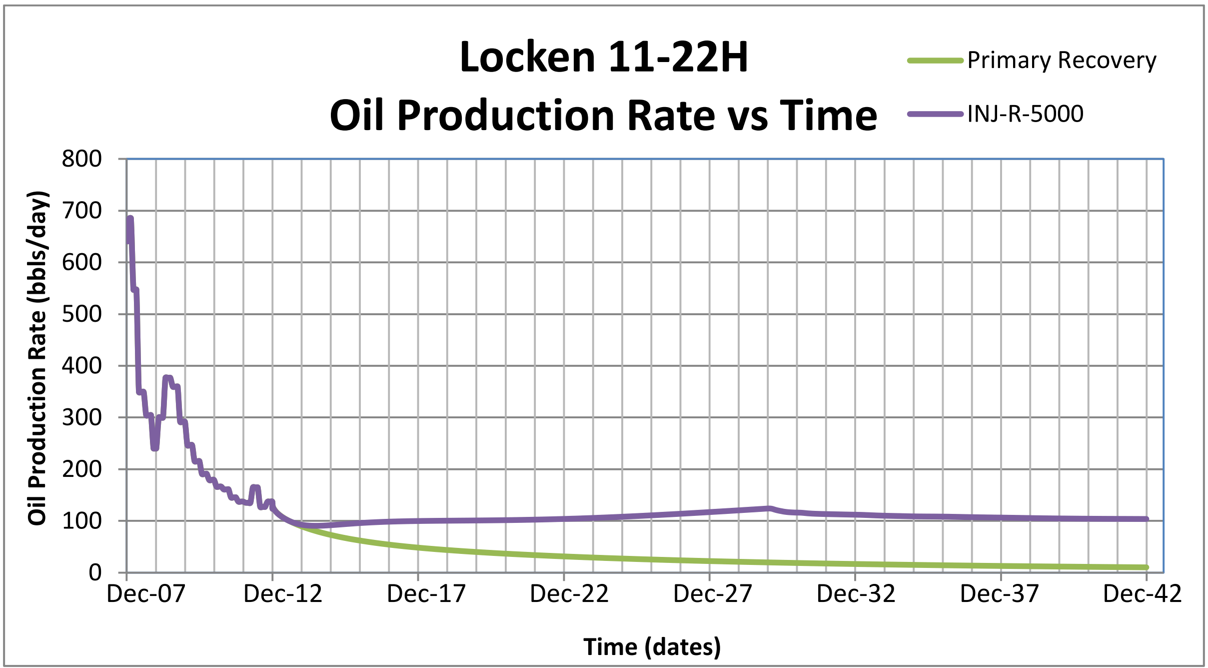


Figure 5.3 Locken 11-22H Oil Production Rate vs. Time for Injection Rate of 5000 Mscf/day

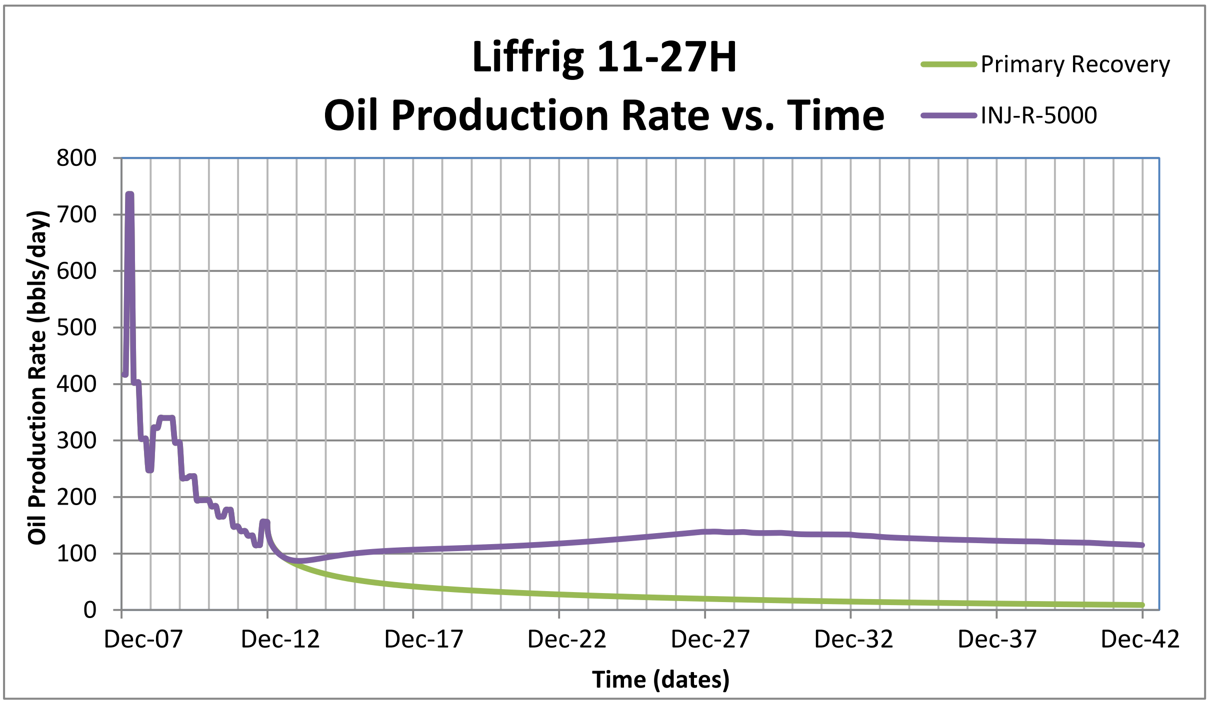


Figure 5.4 Liffrig 11-27H Oil Production Rate vs. Time for Injection Rate of 5000 Mscf/day

The increase in recovery factors of these two wells is calculated as follows:

Field sector model oil-in-place= 35.88×10^6stb

Total oil recovered on primary recovery

$= 784{,}968 + 409{,}239 + 749{,}722 = 1{,}943{,}929$ stb

Total oil recovered from Locken 11-22H and Liffrig 11-27H from Mcnamara 42-26H injected at 8000 psia and 5000 *Mscf/day*= $1{,}619{,}920 + 1{,}770{,}325 = 3{,}390{,}245$ stb

Recovery Factor (RF) of primary Recovery= $1{,}943{,}929$ stb$/35.88 \times 10^6$stb $= 5.42\%$

RF for CO_2 injection of Scenario A-1-a= $3{,}390{,}245$ stb $/35.88 \times 10^6$ stb $= 9.45\%$

The calculation above indicates the recovery factor for the CO_2 injection at an injection pressure of 8000 psia and injection rate of 5000 Mscf/day increase over nearly 4.03%. Breakthrough time in well Locken 11-22H occurs at 9.5 years and approximately at 10 years in well Liffrig 11-27H. The total amount of CO_2 produced along with the oil and gas at surface conditions is equal to 1.15 billion standard cubic feet (Bscf), which can be recycled and re-injected into the injection well to save significant purchase costs for the CO_2.

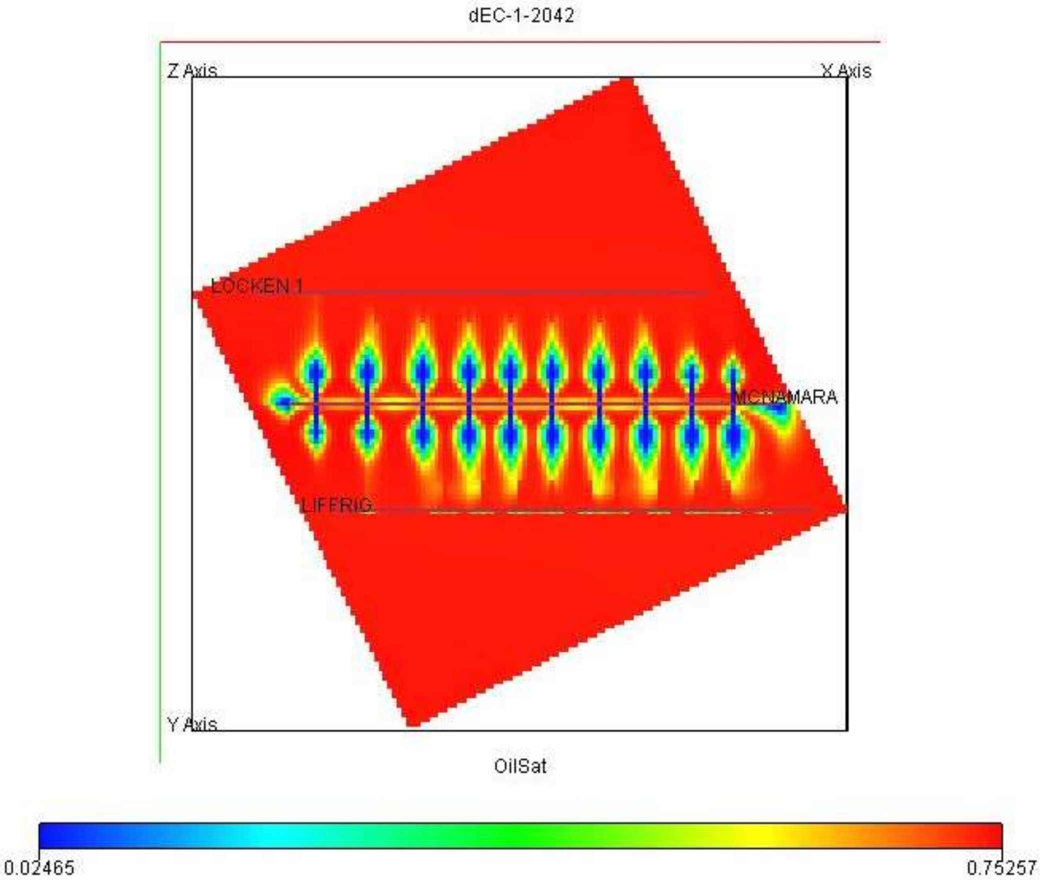


Figure 5.5 Oil Saturation for the Study Area in the Sanish Field on December 1, 2042 with Conversion of Mcnamara 42-26H into an Injection Well with Injection Rate of 5000 Mscf/day

(2) <u>Scenario A-1-b: Injection rate of 2000 Mscf/day</u>

Total amount of solvent (CO_2) injected at surface conditions = $9.17 \times 10^6 Mscf$

FVF of CO_2 at reservoir conditions= $0.4111\ res.bbl/Mscf$

Total amount of solvent (CO_2) injected at reservoir conditions

$= 9.17 \times 10^6 Mscf \times 0.4111\ res.bbl/Mscf = 3.77 \times 10^6\ res.bbls$

PV of CO_2 injected= $3.77 \times 10^6\ res.bbls/3.56 \times 10^7 res.bbls = 0.106$ PV

Similarly, the oil production rate from the other two wells Locken 11-22H and Liffrig 11-27H in this case also increases after the injection, as Figure 5.7 and Figure 5.8 shown. The peak oil production rate for Locken 11-22H is 124 stb/day, occurs in May 2030, and the peak oil production rate for Liffrig 11-27H is 138 stb/day, occurs in August 2028.

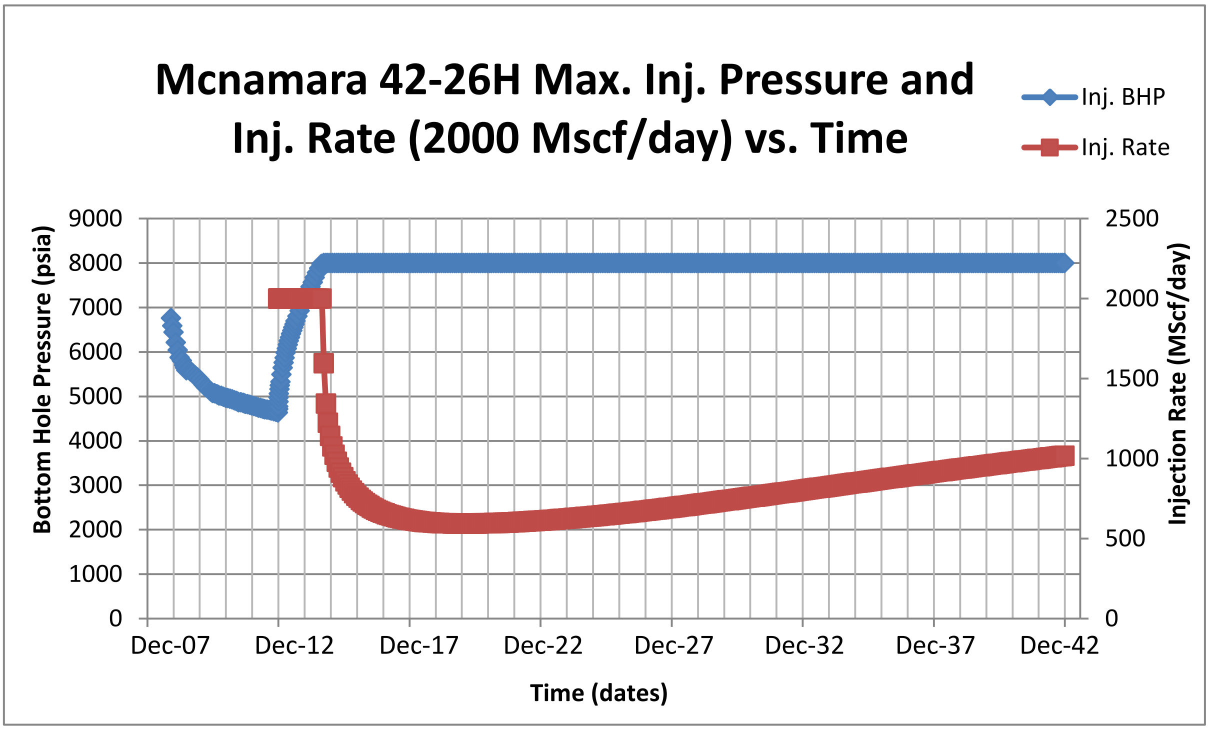


Figure 5.6 Mcnamara 42-26H BHP of 8000 psia and Inj. Rate (2000 Mscf/day) vs. Time

The increase in recovery factors of these two wells is calculated as follows:

Total oil recovered from Locken 11-22H and Liffrig 11-27H

from Mcnamara 42-26H injected at 8000 psia and 2000 *Mscf/day*

$= 1{,}607{,}564 + 1{,}756{,}260 = 3{,}363{,}824$ stb

RF for CO_2 injection of Scenario A-2-b= $3{,}363{,}824 \text{ stb } / 35.88 \times 10^6 \text{ stb} = 9.38\%$

The calculation above indicates the recovery factor for the CO_2 injection at an injection pressure of 8000 psia and injection rate of 2000 Mscf/day increase over 3.96%. Breakthrough time in well Locken 11-22H occurs at 9.9 years and approximately at 10.1 years in well

Liffrig 11-27H. The total amount of CO_2 produced along with the oil and gas at surface conditions is equal to 1.09 Bscf.

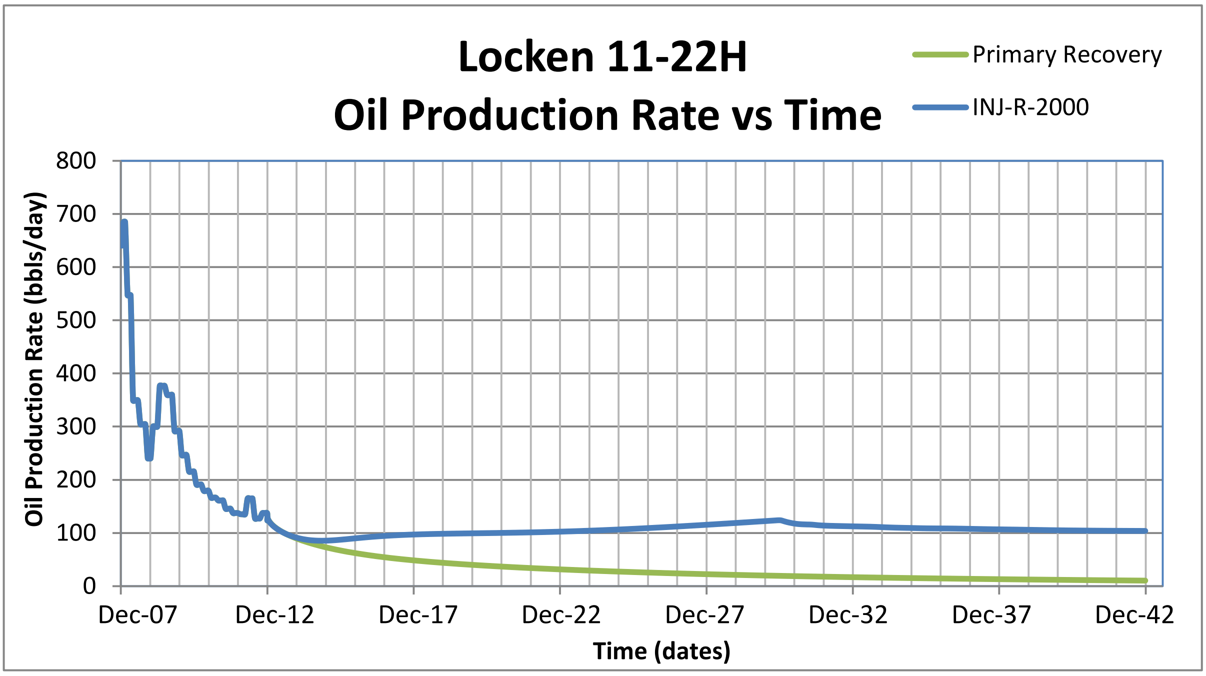


Figure 5.7 Locken 11-22H Oil Production Rate vs. Time for Injection Rate of 2000 Mscf/day

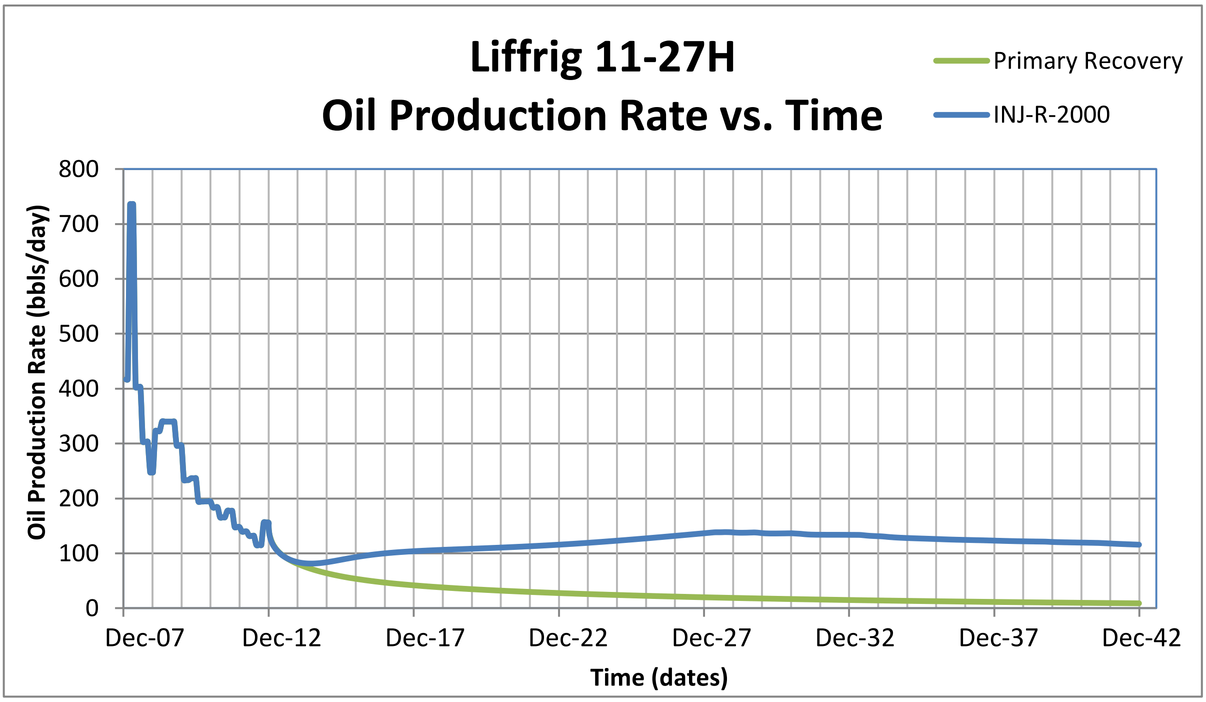


Figure 5.8 Liffrig 11-27H Oil Production Rate vs. Time for Injection Rate of 2000 Mscf/day

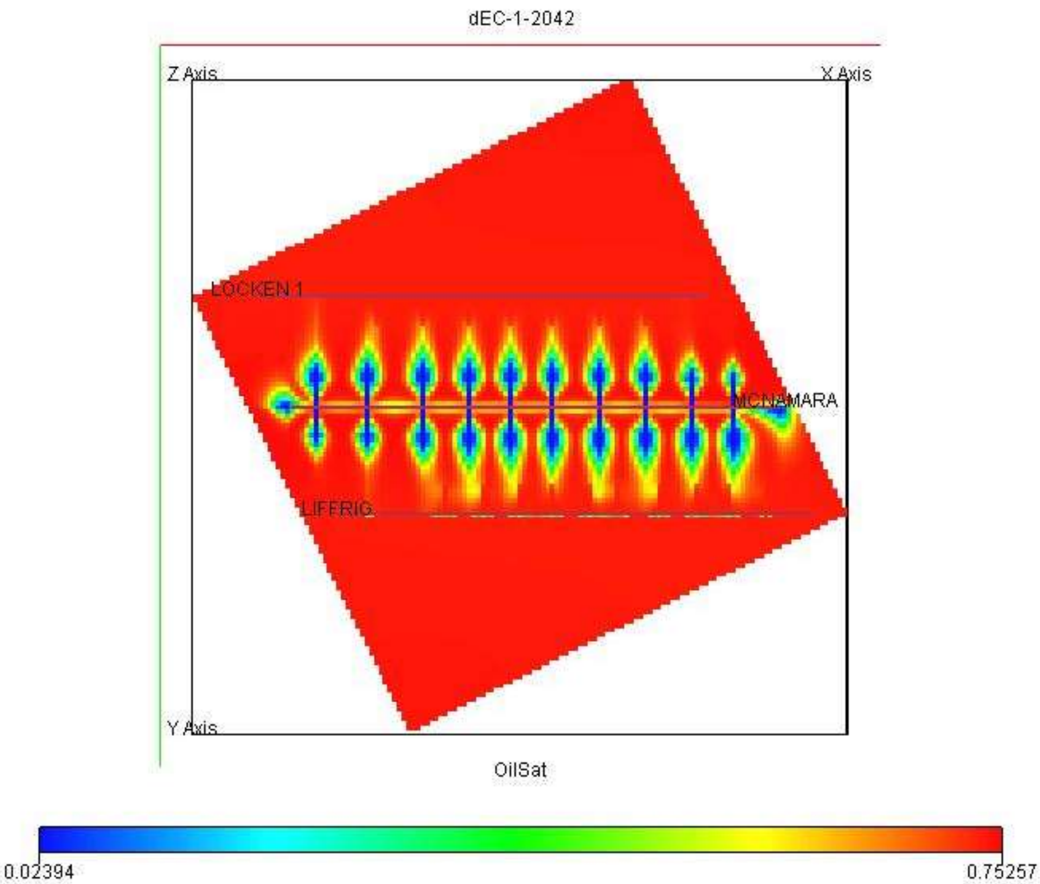


Figure 5.9 Oil Saturation for the Study Area in the Sanish Field at December 1, 2042

with Conversion of Mcnamara 42-26H into an Injection Well
with Injection Rate of 2000 Mscf/day

(3) <u>Scenario A-1-c: Injection rate of 1000 Mscf/day</u>

Total amount of solvent (CO_2) injected at surface conditions = $8.79 \times 10^6 Mscf$

FVF of CO_2 at reservoir conditions= 0.4111 $res.bbl/Mscf$

Total amount of solvent (CO_2) injected at reservoir conditions

= $9.17 \times 10^6 Mscf \times 0.4111\, res.bbl/Mscf = 3.61 \times 10^6\, res.bbls$

PV of CO_2 injected= $3.61 \times 10^6\, res.bbls/3.56 \times 10^7 res.bbls = 0.102$ PV

The oil production rate from the other two wells Locken 11-22H and Liffrig 11-27H in this case increase after the injection as Figure 5.11 and Figure 5.12 shown. The peak oil production rate for Locken 11-22H is 123 stb/day, occurs in July 2031, and the peak oil production rate for Liffrig 11-27H is 138 stb/day, occurs in October 2029.

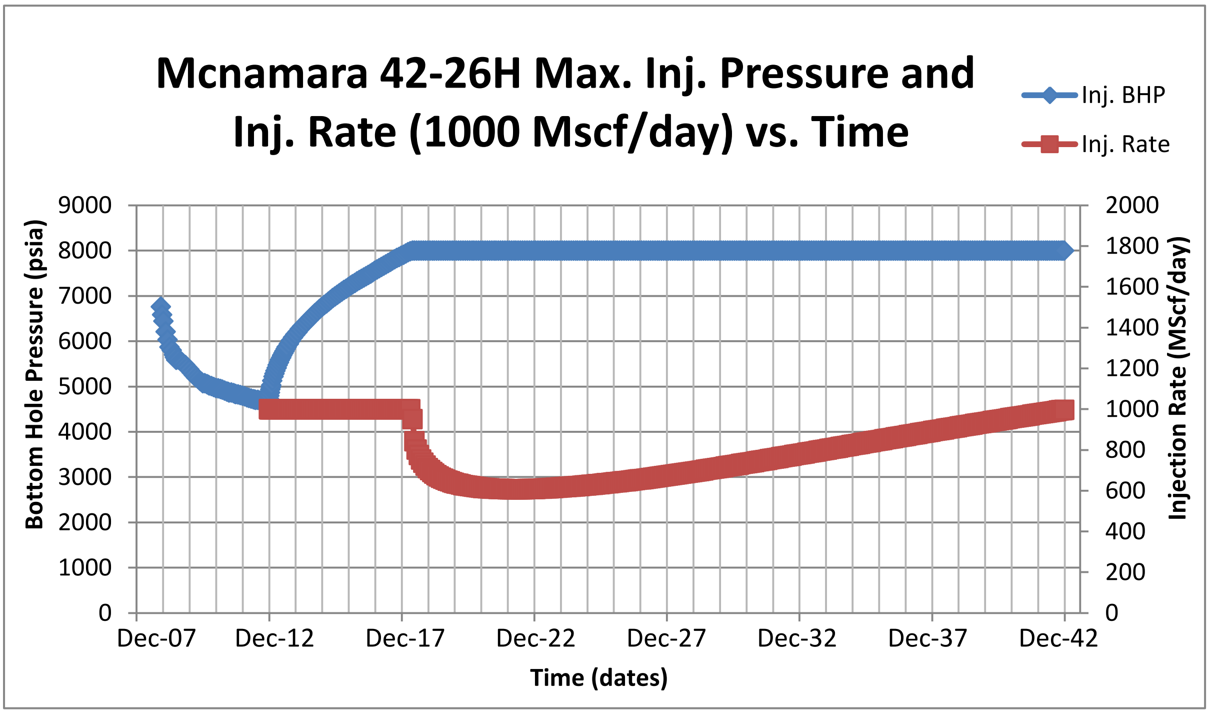


Figure 5.10 Mcnamara 42-26H BHP of 8000 psia and Inj. Rate (1000 Mscf/day) vs. Time

The increase in recovery factors of these two wells is calculated as follows:

Total oil recovered from Locken 11-22H and Liffrig 11-27H from Mcnamara 42-26H injected at 8000 psia and 1000 *Mscf/day*$= 1{,}573{,}744 + 1{,}717{,}117 = 3{,}290{,}861$ stb

RF for CO_2 injection of Scenario A-1-c= $3{,}290{,}861 \text{ stb } / 35.88 \times 10^6 \text{ stb} = 9.17\%$

The calculation above indicates the recovery factor for the CO_2 injection at an injection pressure of 8000 psia and injection rate of 1000 Mscf/day increase over 3.75%. Breakthrough time in well Locken 11-22H occurs at 11.7 years and approximately at 11.8 years in well Liffrig 11-27H. The total amount of CO_2 produced along with the oil and gas at surface conditions is equal to 0.94 Bscf.

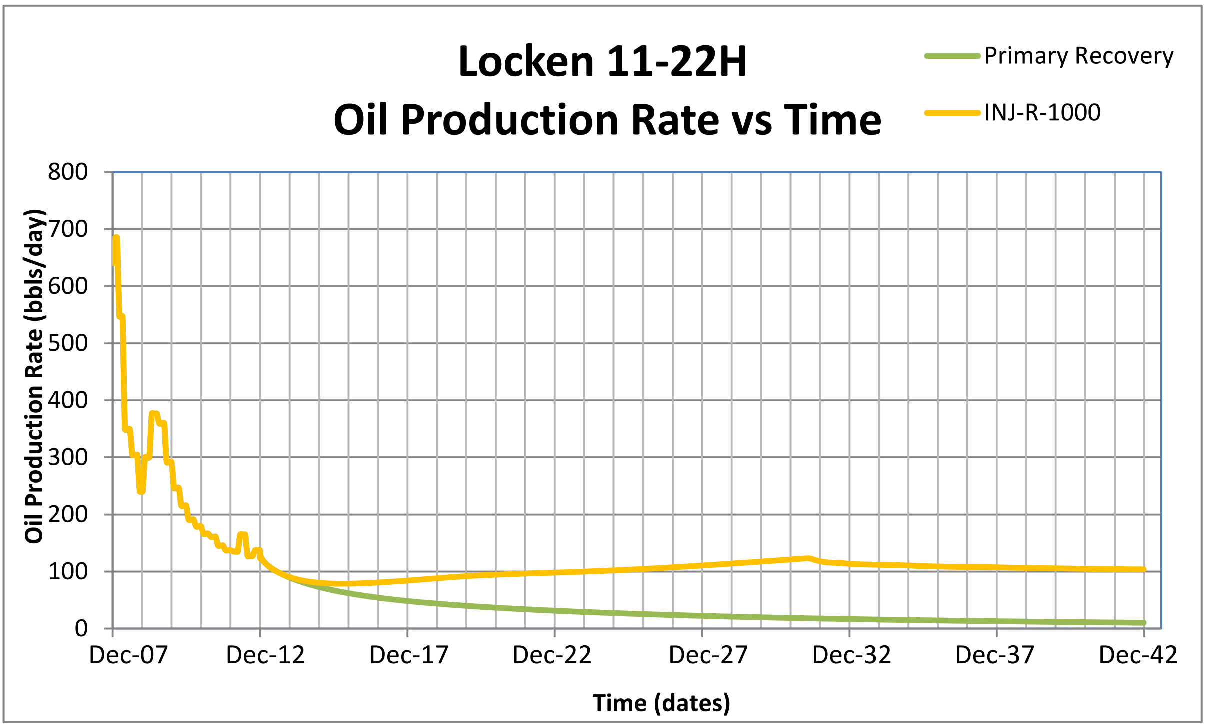


Figure 5.11 Locken 11-22H Oil Production Rate vs. Time
for Injection Rate of 1000 Mscf/day

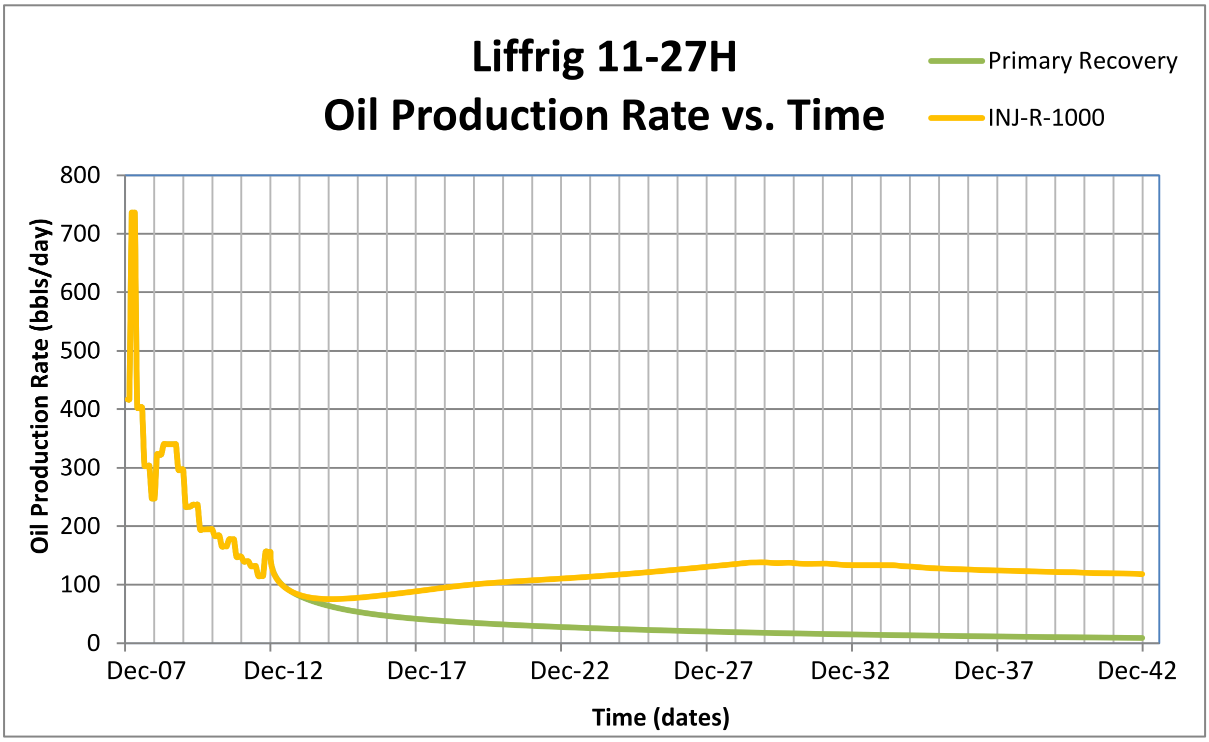


Figure 5.12 Liffrig 11-27H Oil Production Rate vs. Time
for Injection Rate of 1000 Mscf/day

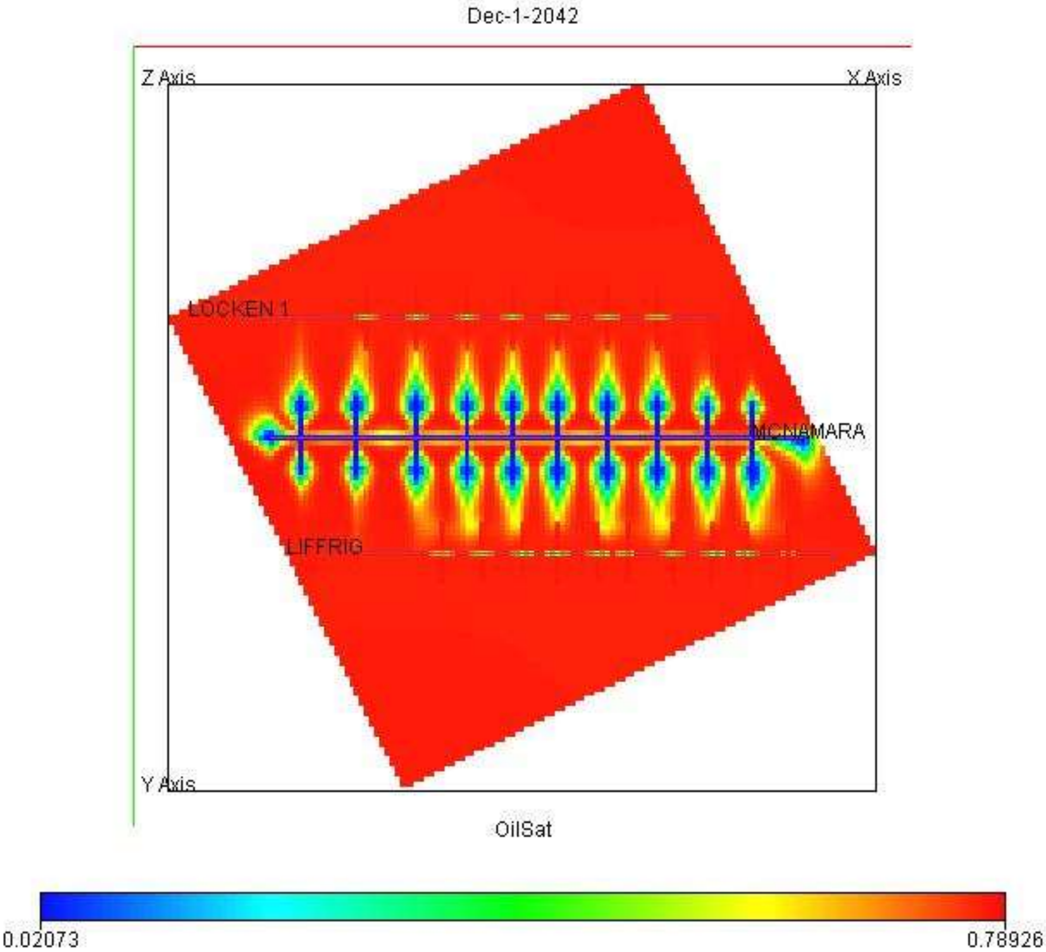


Figure 5.13 Oil Saturation for the Study Area in the Sanish Field on December 1, 2042 with Conversion of Mcnamara 42-26H into an Injection Well
with Injection Rate of 1000 Mscf/day

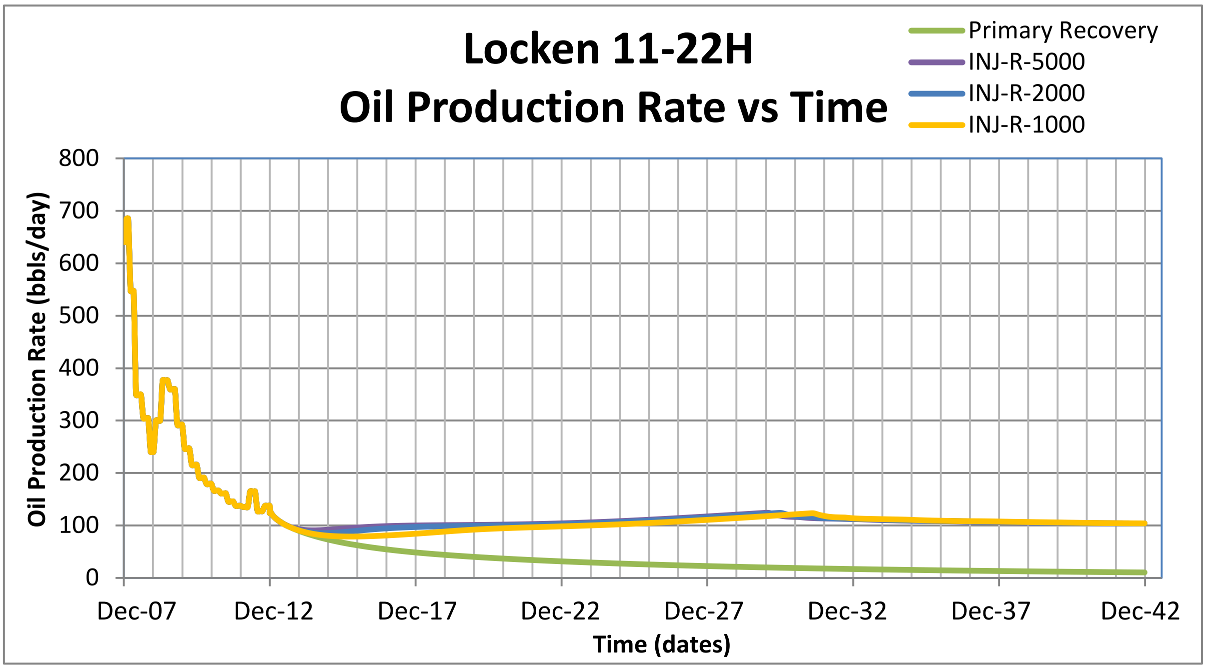


Figure 5.14 Locken 11-22H Oil Production Rate vs. Time for Injection Rate of 5000 Mscf/day,2000 Mscf/day, 1000 Mscf/day

Comparing the oil production rate for different injection rate with maximum injection pressure, as Figure 5.14 shown, the differences are not obvious. However, when focusing on the oil production rate of Locken 11-22H after the injection and zoom in the oil production rate at a range of 70 bbls/day to 130 bbls/day (Figure 5.15), the differences become bigger and obvious.

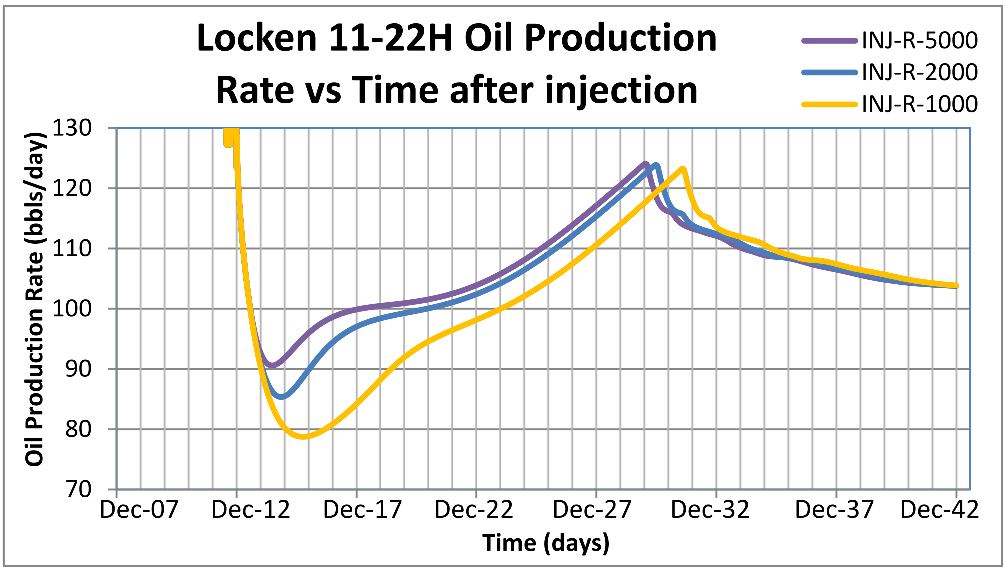


Figure 5.15 Oil Production Rate of Locken 11-22H after the Injection

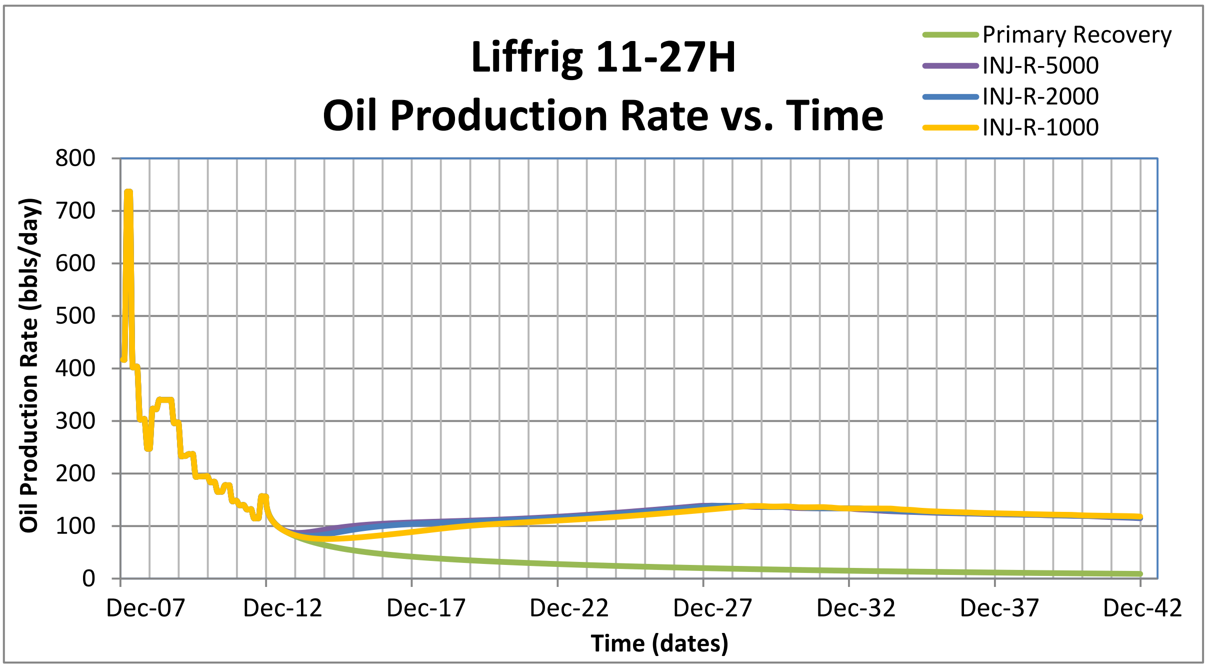


Figure 5.16 Liffrig 11-27H Oil Production Rate vs. Time for Injection Rate of 5000 Mscf/day, 2000 Mscf/day, 1000 Mscf/day

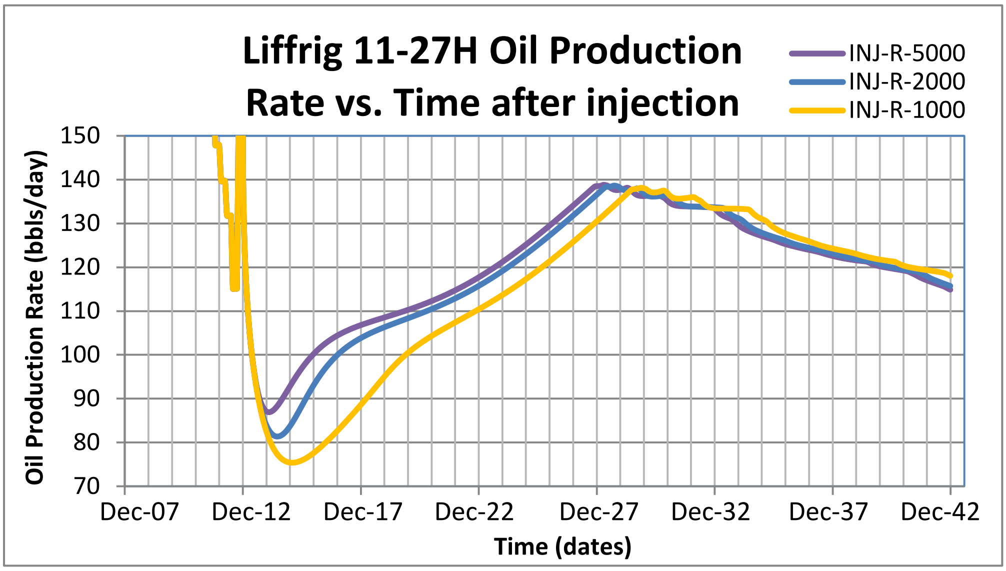


Figure 5.17 Oil Production Rate of Liffrig 11-27H after the Injection

Use the same manner to zoom in the oil production rate of Liffrig 11-27H after the injection with limit from 70 bbls/day to 150 bbls/day, the differences are enlarged. All the results from Figure 5.15 and Figure 5.17 indicate higher injection rate can yield higher oil production rate, but the amount is small, only 10 to 20 barrels per day.

5.1.2 Scenario A-2: Maximum injection rate with different injection pressure

In this case, the injection well has a constant injection rate of 5000 Mscf/day with different injection pressure of 6000, 7000, 8000 psia. The injection well is also controlled by the given injection rate at the beginning until the well bottom hole pressure increase to the demanded value. Then it will change to BHP control. The evaluation of CO_2 is analyzed for the individual wells Locken 11-22H and Liffrig 11-27H.

(1) <u>Scenario A-2-a: Injection Pressure of 6000 psia</u>

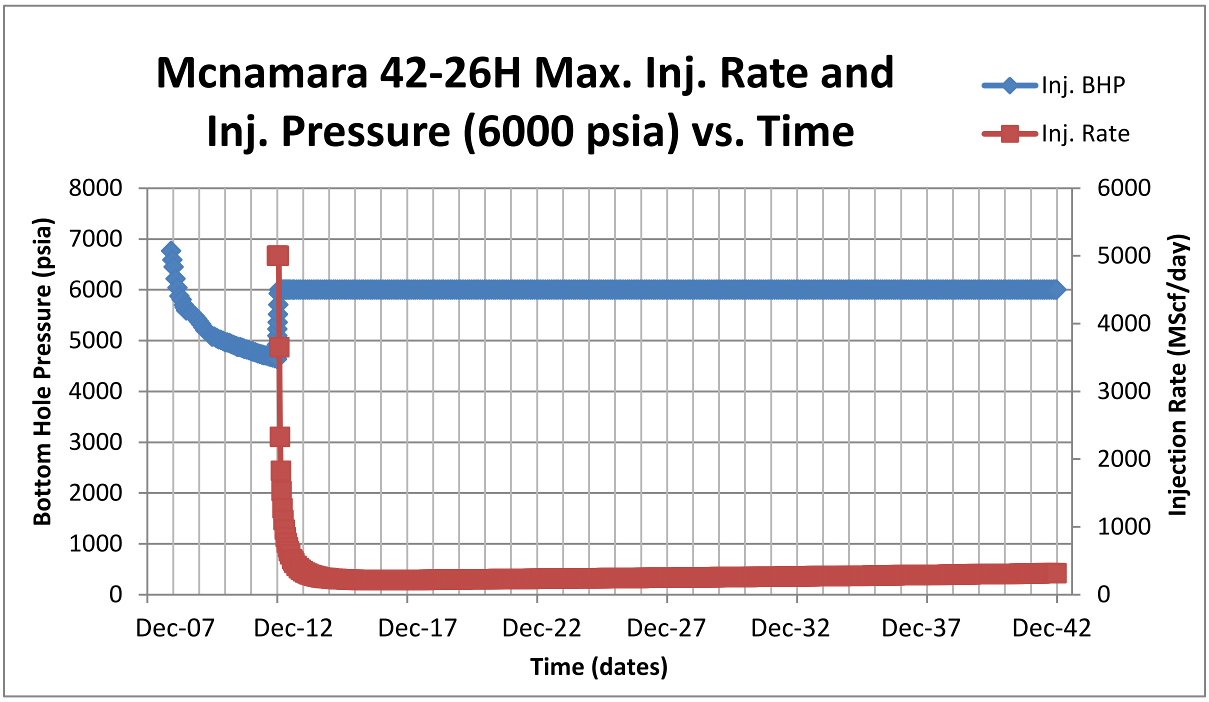


Figure 5.18 Mcnamara 42-26H Maximum Inj. Rate (5000 Mscf/day) and Inj. Pressure of 6000 psia vs. time

Total amount of solvent (CO_2) injected at surface conditions = $3.09 \times 10^6 Mscf$

FVF of CO_2 at reservoir conditions= 0.4707 $res.bbl/Mscf$

Total amount of solvent (CO_2) injected at reservoir conditions

$$= 3.09 \times 10^6 Mscf \times 0.4707\ res.bbl/Mscf = 1.45 \times 10^6\ res.bbls$$

PV of CO_2 injected= $1.45 \times 10^6\ res.bbls/3.56 \times 10^7 res.bbls = 0.041$ PV

The oil production rate from the well Locken 11-22H and Liffrig 11-27H in this case increases a few after the injection (Figure 5.19 and Figure 5.20). The peak in oil production rate during the period of 30 years of injection is 58 stb/day for Locken 11-22H and 67 stb/day for Liffrig 11-27H, and they all occur at the end of the injection December 2042.

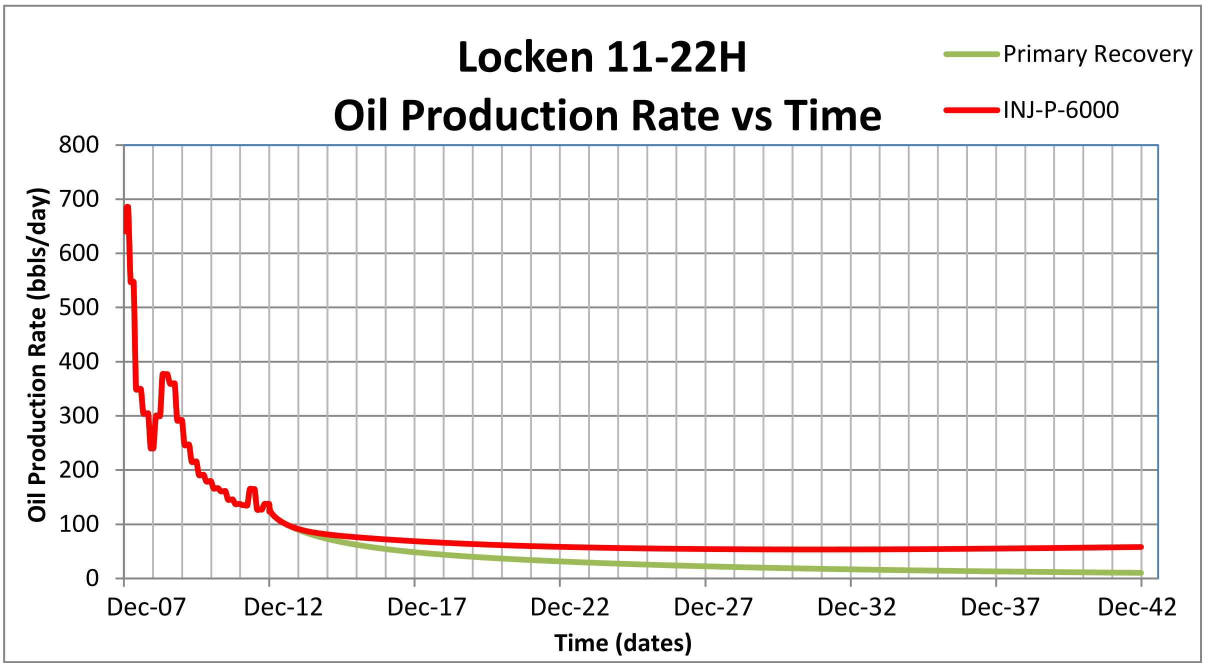


Figure 5.19 Locken 11-22H Oil Production Rate vs. Time for Injection Pressure of 6000 psia

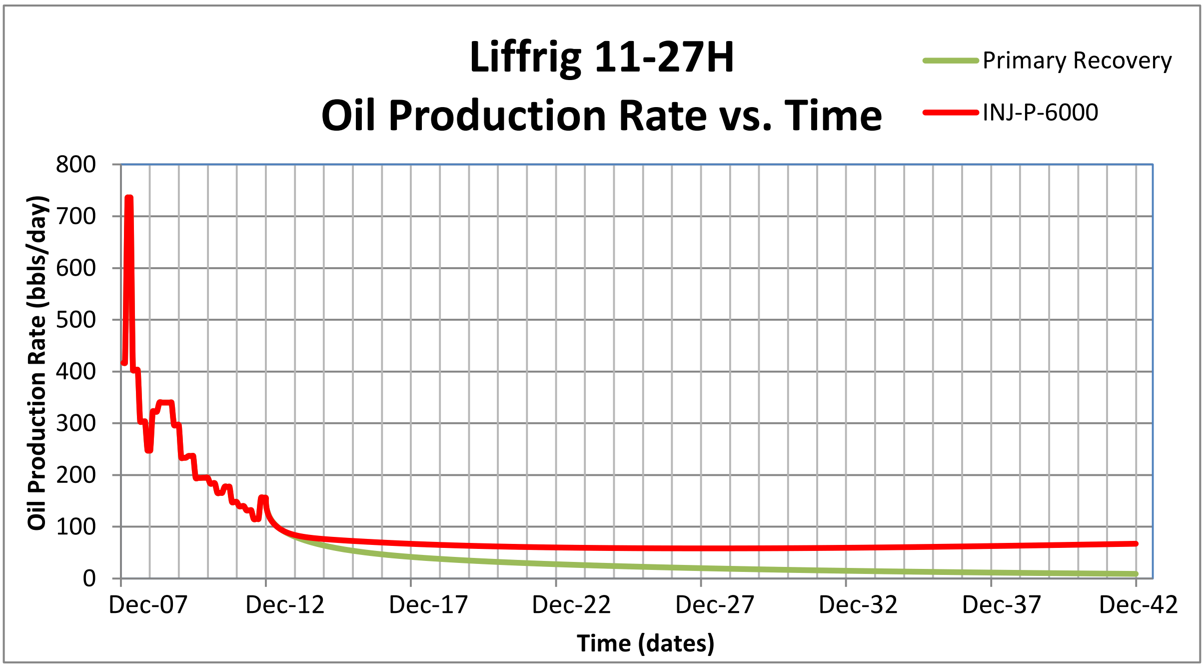


Figure 5.20 Liffrig 11-27H Oil Production Rate vs. Time for Injection Pressure of 6000 psia

The increase in recovery factors of these two wells is calculated as follows:

Total oil recovered from Locken 11-22H and Liffrig 11-27H from Mcnamara 42-26H injected at 6000 psia and 5000 *Mscf/day*$= 1{,}118{,}646 + 1{,}156{,}649 = 1{,}275{,}295$ stb

RF for CO_2 injection of Scenario A-2-a= $1{,}275{,}295 \text{ stb } / 35.88 \times 10^6 \text{ stb} = 3.55\%$

Unless the previous cases, the recovery factor of the CO_2 injection at an injection pressure of 6000 psia and injection rate of 5000 Mscf/day decreases to 3.55%. The peak oil production rate is also small. In addition, there is no breakthrough for both well Locken 11-22H and Liffrig 11-27H, probably because the modeling injection time is not long enough to see the breakthrough time.

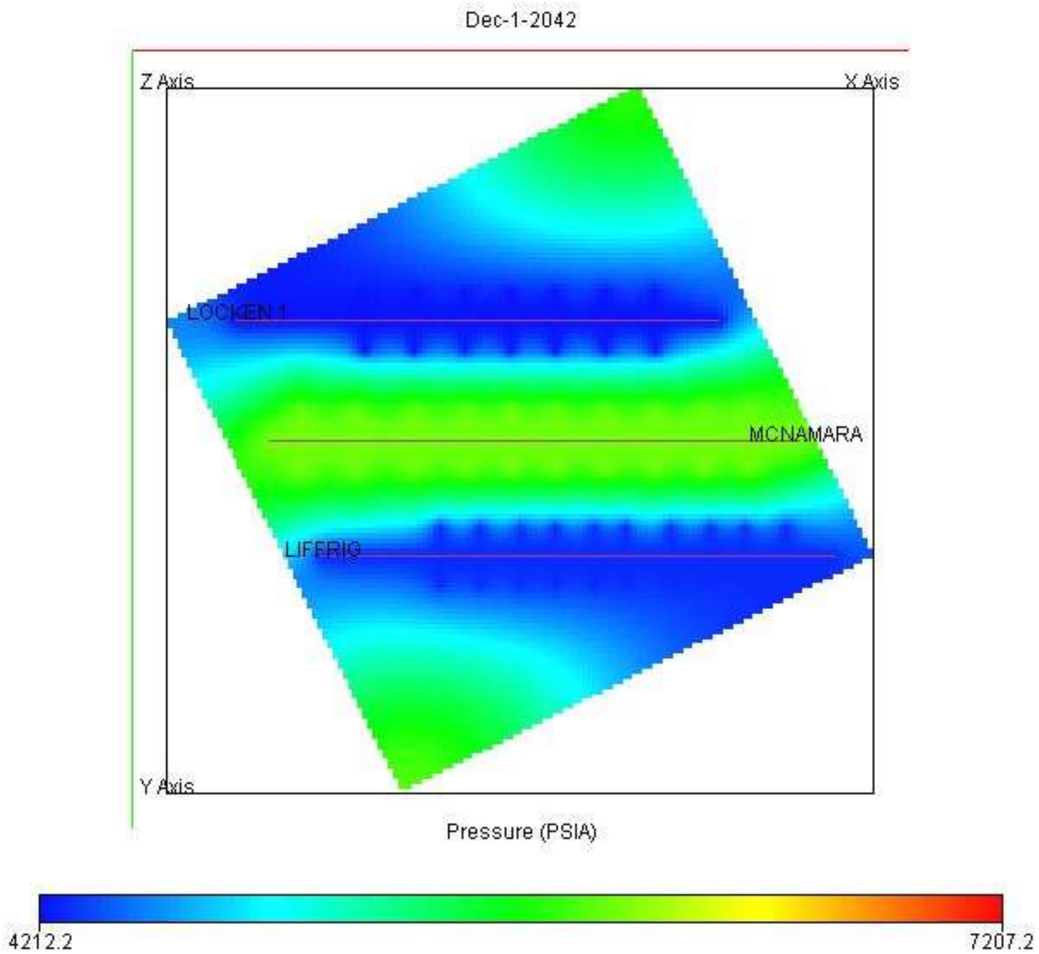


Figure 5.21 Well Pressure for the Study Area in the Sanish Field on December 1, 2042 with Conversion of Mcnamara 42-26H into an Injection Well with Injection Pressure of 6000 psia

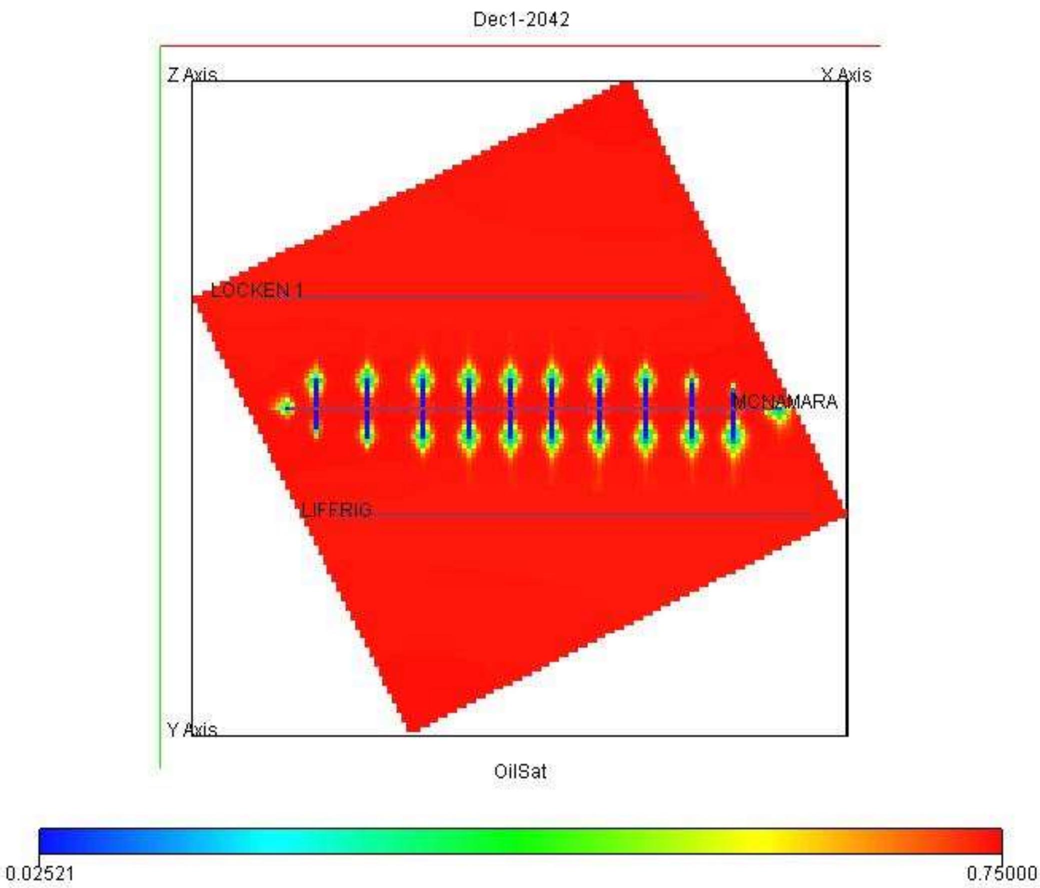


Figure 5.22 Oil Saturation for the Study Area in the Sanish Field on December 1, 2042 with Conversion of Mcnamara 42-26H into an Injection Well with Injection Pressure of 6000 psia

(2) Scenario A-2-b: Injection Pressure of 7000 psia

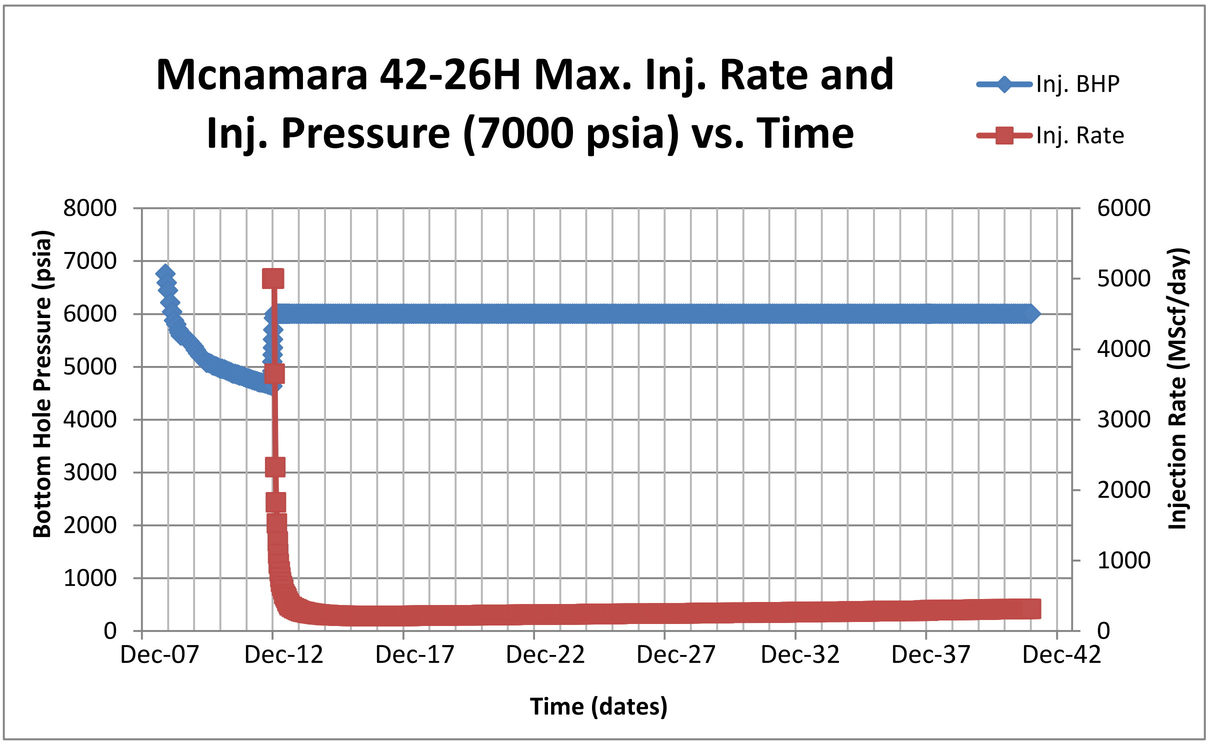


Figure 5.23 Mcnamara 42-26H Maximum Inj. Rate (5000 Mscf/day) and Inj. Pressure of 7000 psia vs. time

Total amount of solvent (CO_2) injected at surface conditions = $6.00 \times 10^6 Mscf$

FVF of CO_2 at reservoir conditions= 0.4290 $res.bbl/Mscf$

Total amount of solvent (CO_2) injected at reservoir conditions

$= 6.00 \times 10^6 Mscf \times 0.4290\ res.bbl/Mscf = 2.57 \times 10^6\ res.bbls$

PV of CO_2 injected= $2.57 \times 10^6\ res.bbls/3.56 \times 10^7 res.bbls = 0.072$ PV

The oil production rate from the other two wells Locken 11-22H and Liffrig 11-27H in this case increases after the injection (Figure 5.24 and Figure 5.25). The peak oil production rate for Locken 11-22H is 94 stb/day, occurs in September 2035, and the peak oil production rate for Liffrig 11-27H is 105 stb/day, occurs in July 2033.

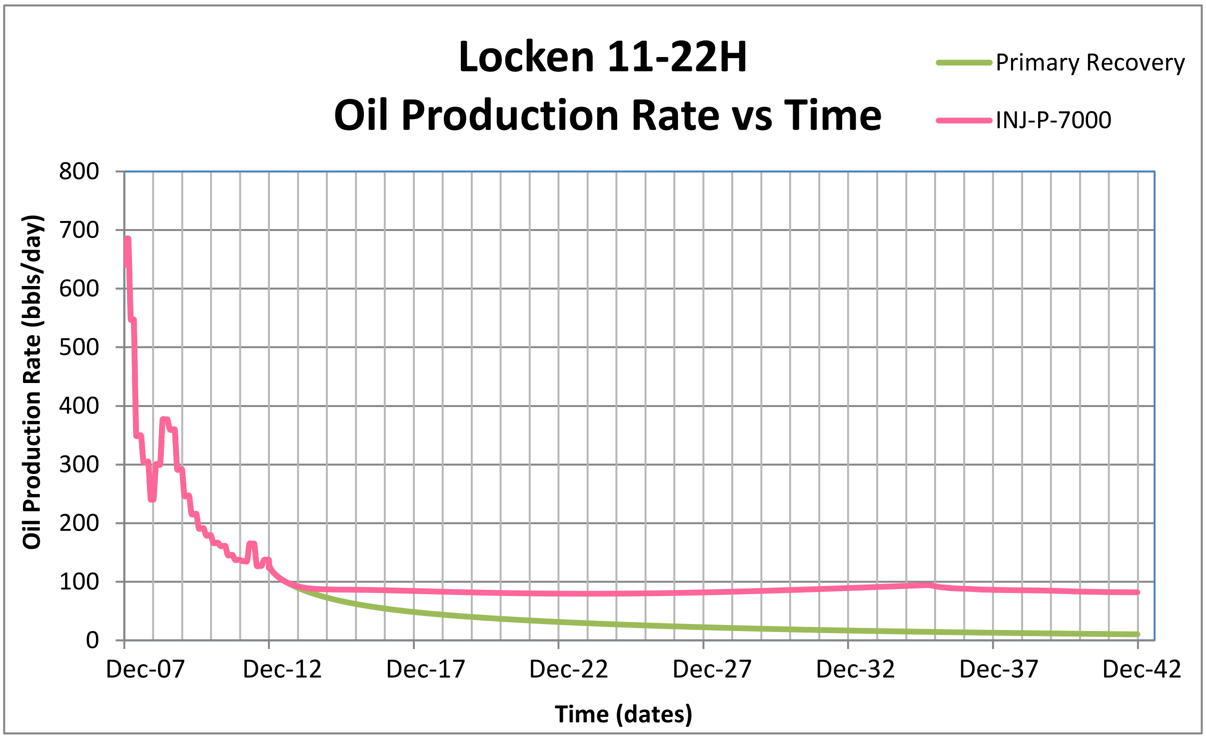


Figure 5.24 Locken 11-22H Oil Production Rate vs. Time
for Injection Pressure of 7000 psia

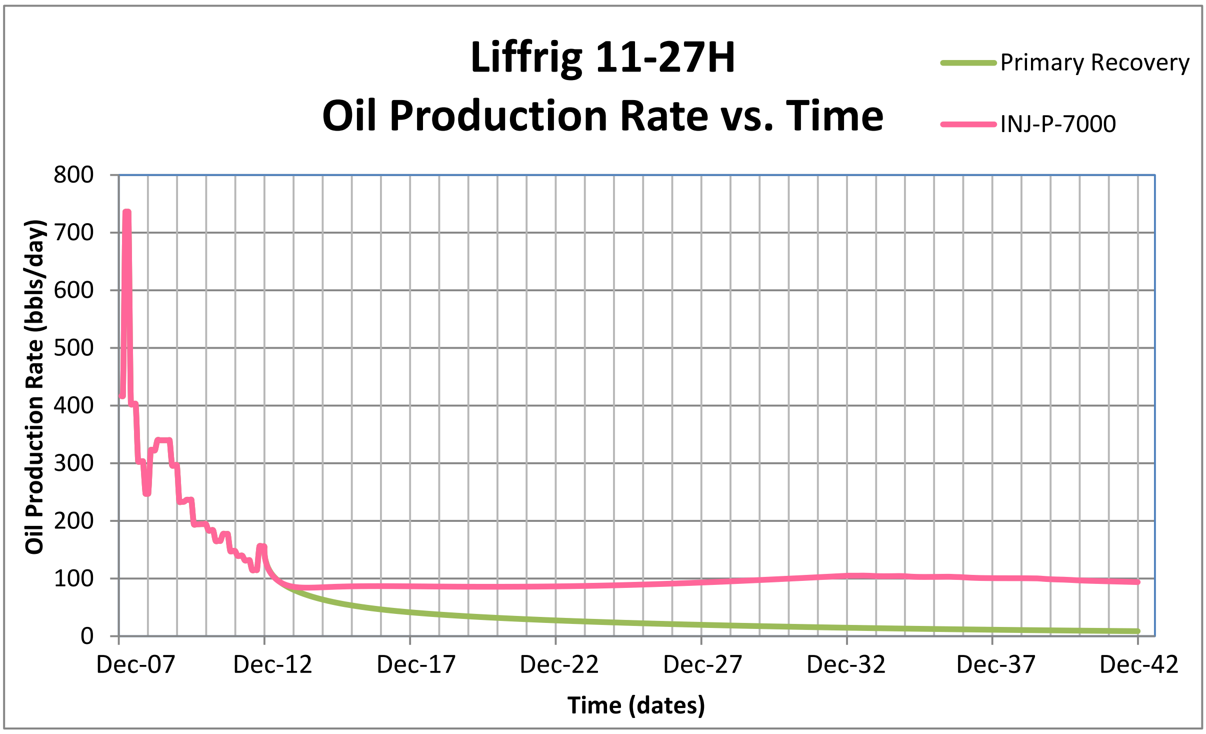


Figure 5.25 Liffrig 11-27H Oil Production Rate vs. Time
for Injection Pressure of 7000 psia

The increase in recovery factors of these two wells is calculated as follows:

Total oil recovered from Locken 11-22H and Liffrig 11-27H from Mcnamara 42-26H injected at 7000 psia and 5000 *Mscf/day*$= 1{,}385{,}733 + 1{,}486{,}334 = 2{,}872{,}067$ stb

RF for CO_2 injection of Scenario A-2-b= $2{,}872{,}067$ stb $/35.88 \times 10^6$ stb $= 8.00\%$

The calculation above indicates the recovery factor for the CO_2 injection at an injection pressure of 7000 psia and injection rate of 5000 Mscf/day increase over 2.58%. Breakthrough time in well Locken 11-22H occurs at 18.3 years and approximately at 18.5 years in well Liffrig 11-27H. The total amount of CO_2 produced along with the oil and gas at surface conditions is equal to 0.27 Bscf.

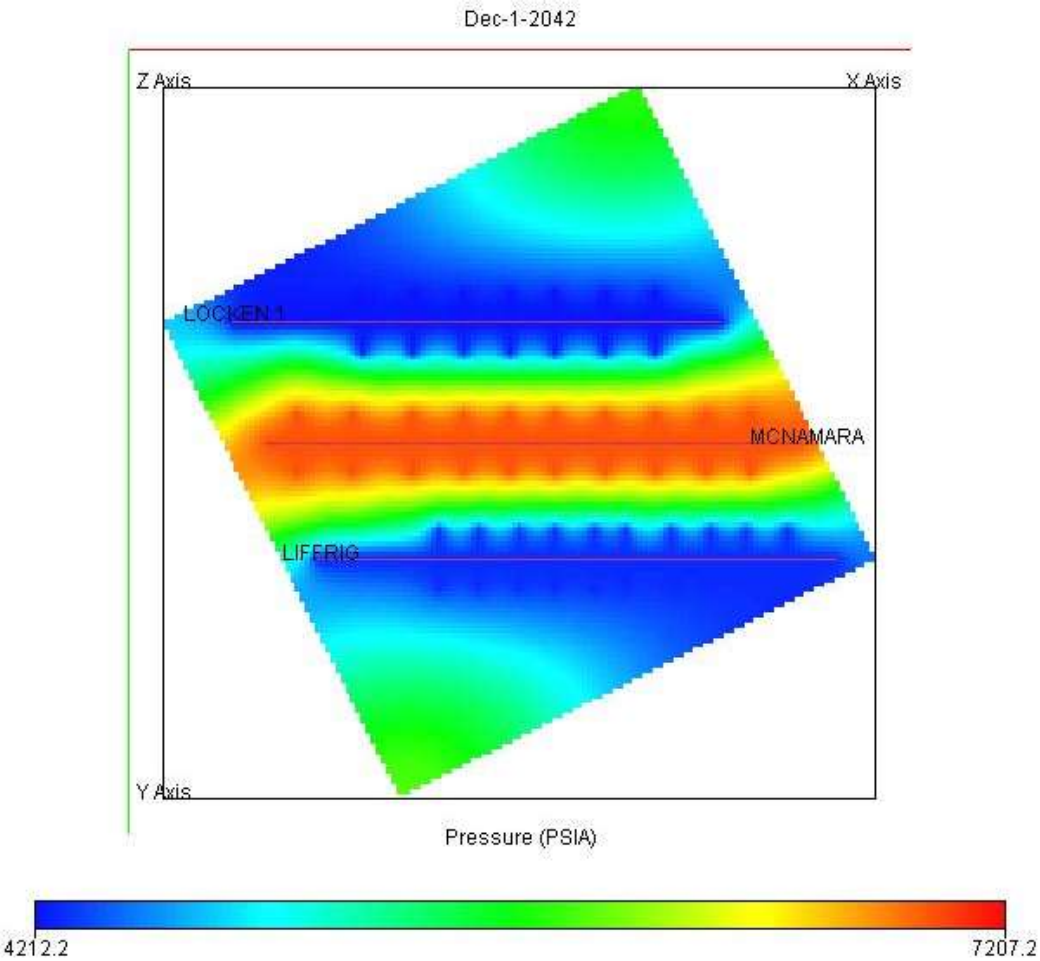


Figure 5.26 Well Pressure for the Study Area in the Sanish Field on December 1, 2042 with Conversion of Mcnamara 42-26H into an Injection Well with Injection Pressure of 7000 psia

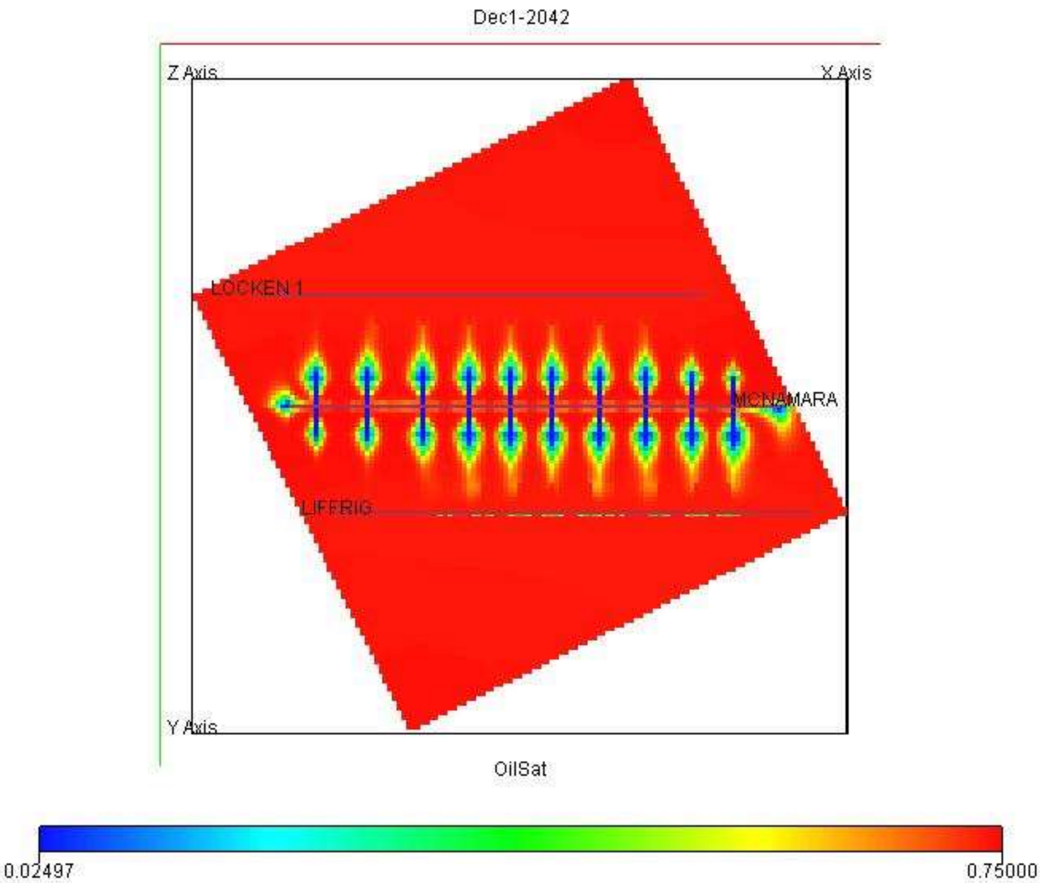


Figure 5.27 Oil Saturation for the Study Area in the Sanish Field on December 1, 2042 with Conversion of Mcnamara 42-26H into an Injection Well with Injection Pressure of 7000 psia

(3) <u>Scenario A-2-c: Injection Pressure of 8000 psia</u>

This case is exactly the same as Scenario A-1-a. The picture below is the well pressure output for an injection rate of 5000 Mscf/day and injection pressure of 8000 psia as a supplement.

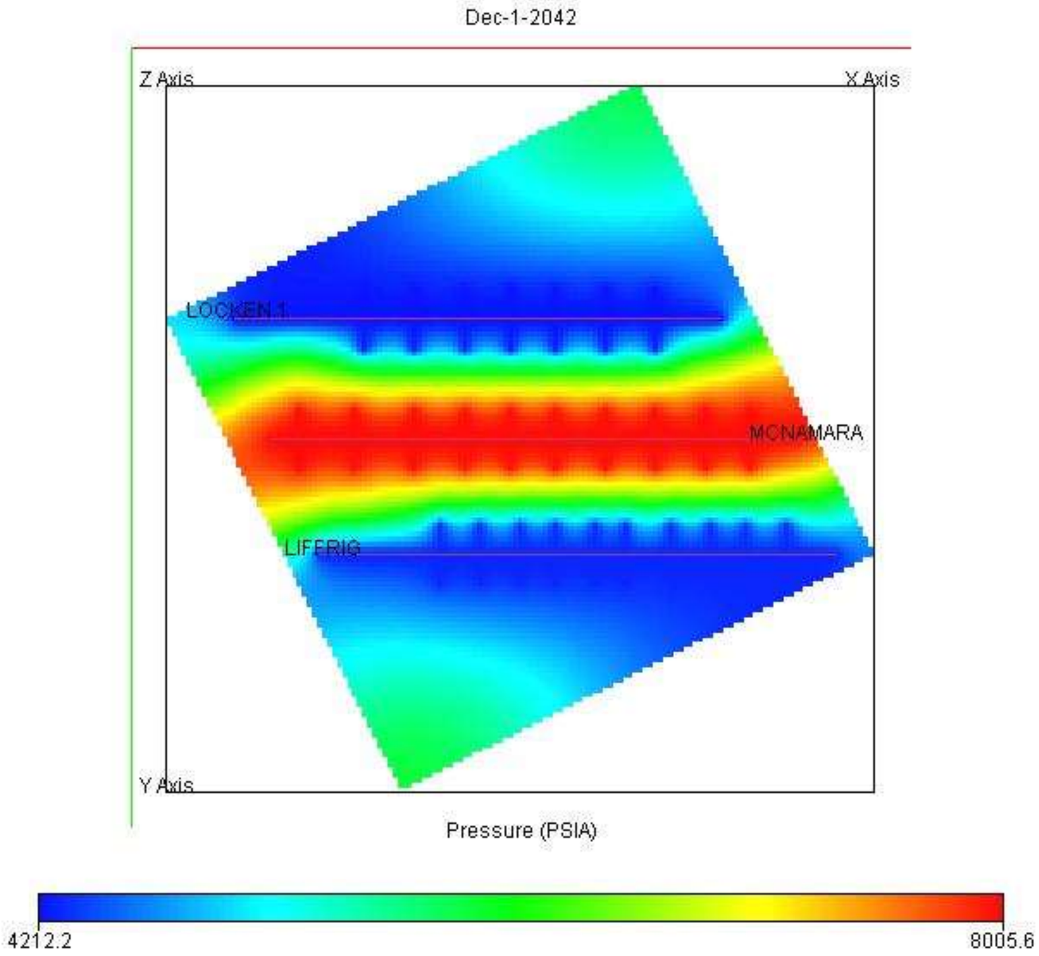


Figure 5.28 Well Pressure for the Study Area in the Sanish Field on December 1, 2042 with Conversion of Mcnamara 42-26H into an Injection Well with Injection Pressure of 8000 psia

The results from Figure 5.29 and Figure 5.30 show that higher injection pressure can have higher oil production rate.Compared to case scenario 1, the results indicate that the injection pressure has a greater effect on the oil production rate than the injection rate.

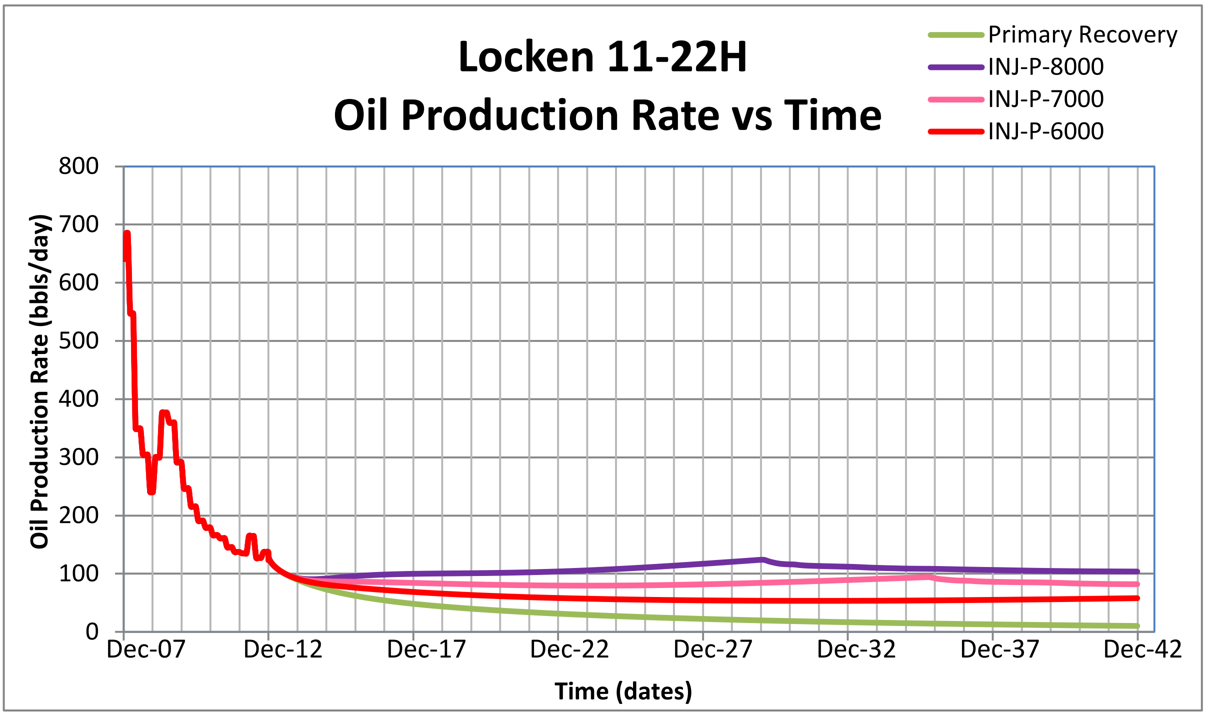


Figure 5.29 Locken 11-22H Oil Production Rate vs. Time
for Injection Pressure of 6000, 7000 and 8000 psia

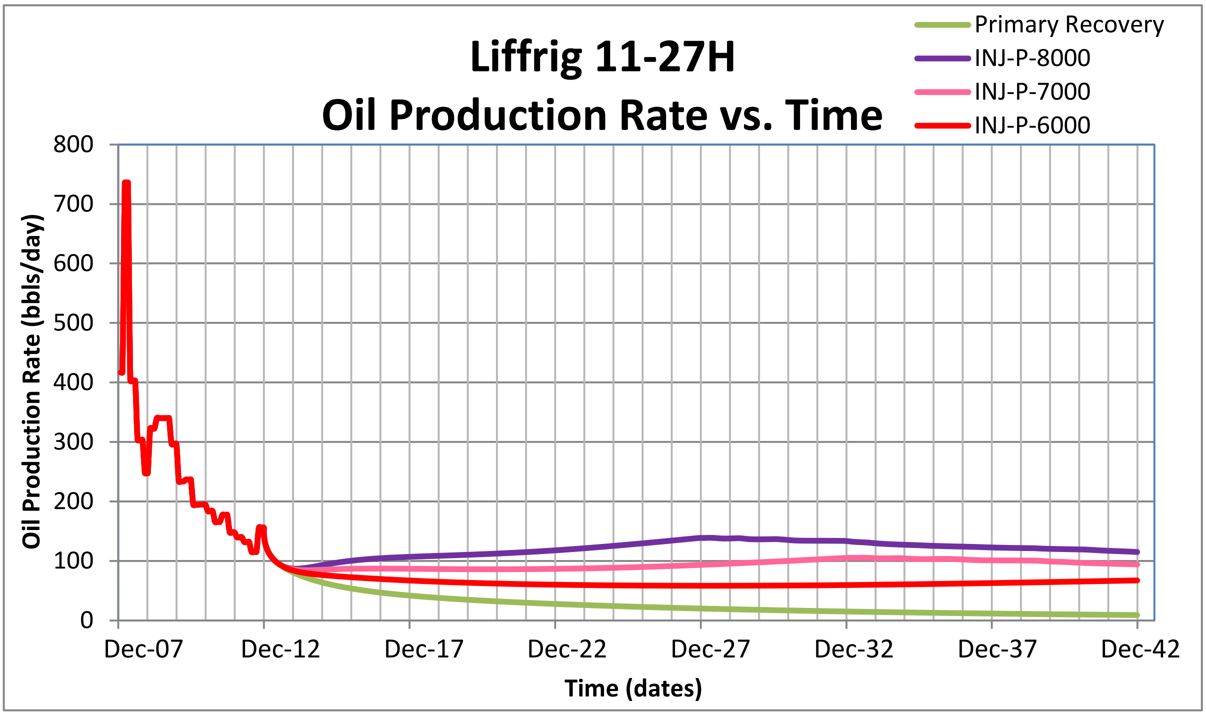


Figure 5.30 Liffrig 11-27H Oil Production Rate vs. Time
for Injection Pressure of 6000,7000, and 8000 psia

5.1.3 Scenario A-3: Different injection type

In this scenario, the effect of a water flooding on Mcnamara 42-26H is analyzed to compare results with CO_2 treatment. The injection pressure for water flooding is set as 8000 psia and injection rate is 1000 stb/day.

(1) <u>Scenario A-3-a: Water-flooding</u>

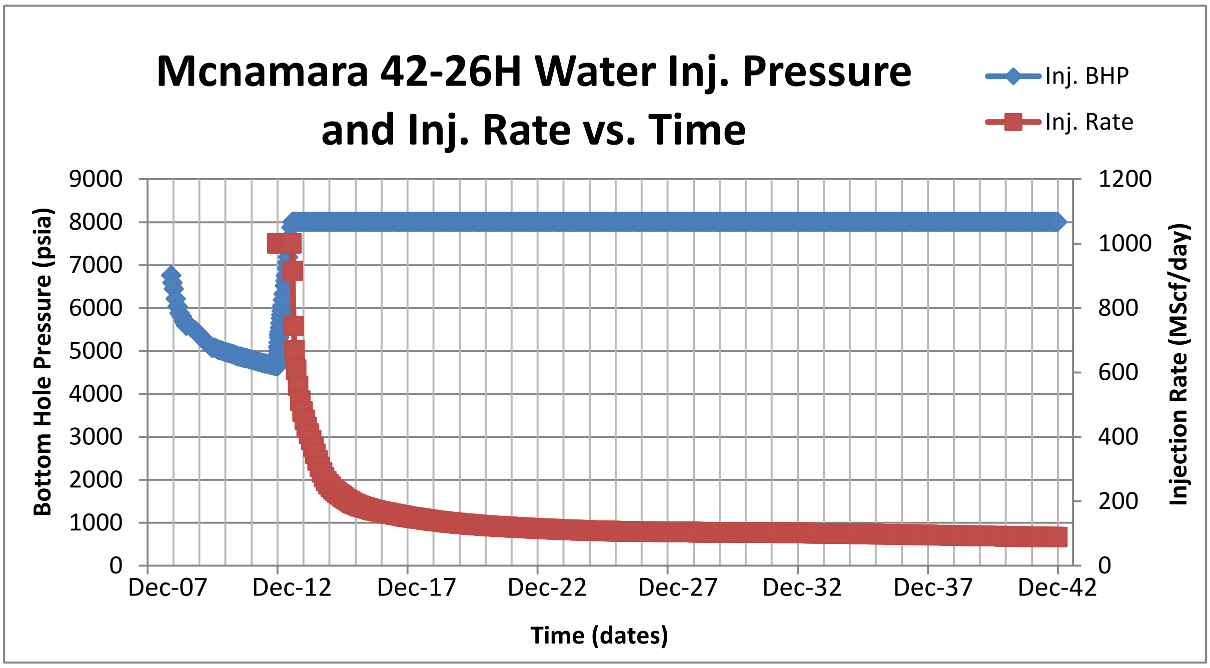


Figure 5.31 Mcnamara 42-26H Water Inj. Rate (1000 stb/day) and Inj. Pressure of 8000 psia vs. time

Total amount of water injected at surface conditions $=1.59 \times 10^6 stb$

FVF of water at reservoir conditions = 1res. bbl/stb

PV of water injected=Amount of water injected at res. conditions/PV of field sector

$$= 1.59 \times 10^6\, res.bbl/3.56 \times 10^7 res.bbls = 0.045 \text{ PV}$$

The oil production rate from the other two wells Locken 11-22H and Liffrig 11-27H in this case increases after the injection (Figure 5.32 and Figure 5.33). There is no peak oil production rate for Locken 11-22H and Liffrig 11-27H. Their oil production rates have kept decreasing after the injection till the end of the modeling time.

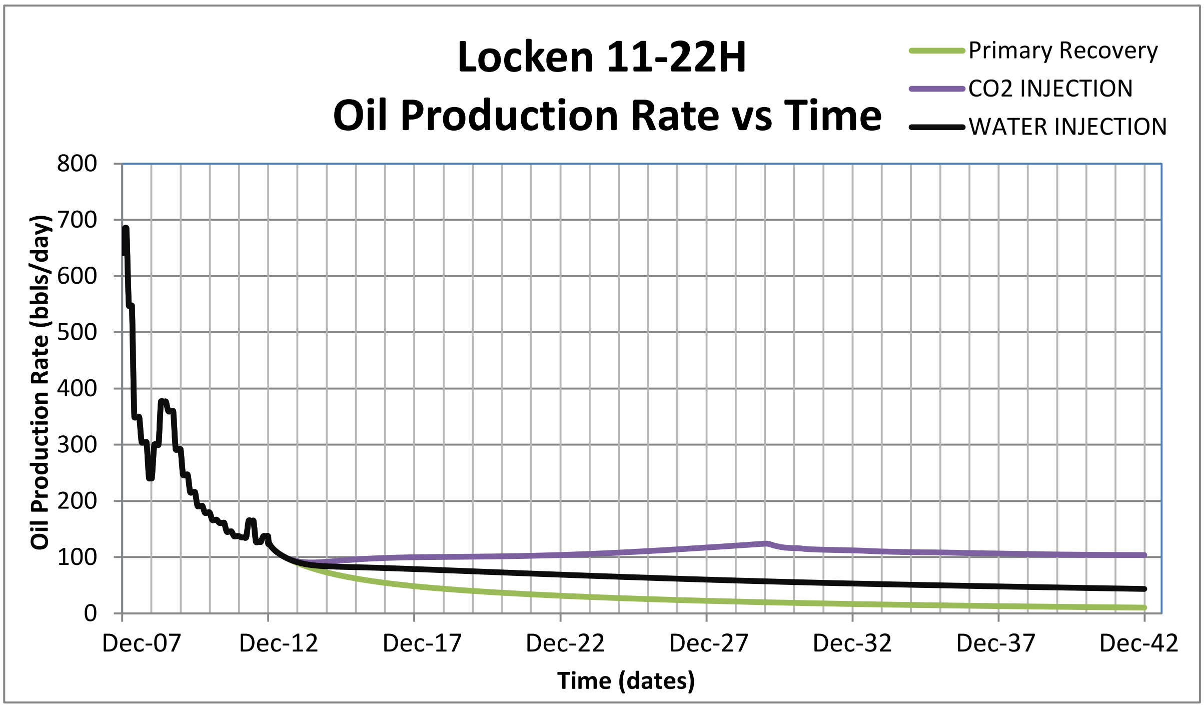


Figure 5.32 Locken 11-22H Oil Production Rate vs. Time
for Water Flooding

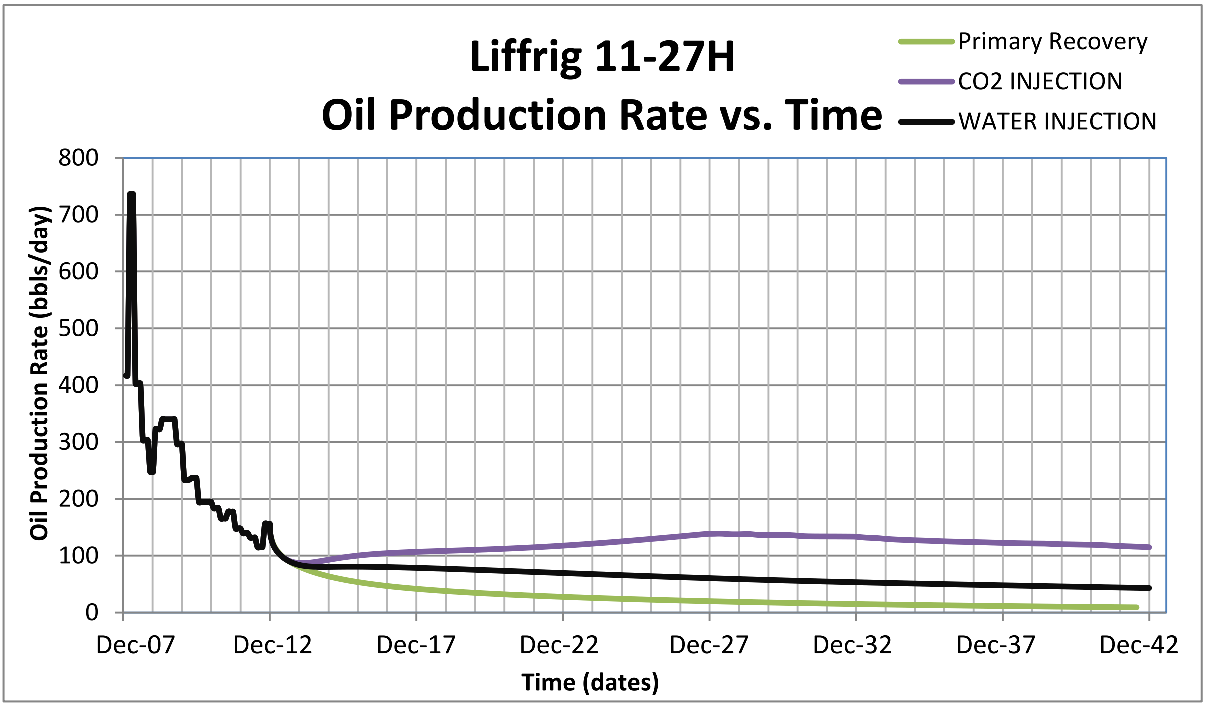


Figure 5.33 Liffrig 11-27H Oil Production Rate vs. Time
for Water Flooding

The increase in recovery factors of these two wells is calculated as follows:

Total oil recovered from Locken 11-22H and Liffrig 11-27H from Mcnamara 42-26H injected water at 8000 psia and 1000 stb/day $= 1{,}140{,}968 + 1{,}140{,}819$
$= 2{,}281{,}787$ stb

RF for Water injection of case 1= $2{,}281{,}787 \text{ stb } / 35.88 \times 10^6 \text{ stb} = 6.36\%$

The calculation above indicates the recovery factor for the water injection at an injection pressure of 8000 psia and injection rate of 1000 stb/day increases a little by 0.94%. As Figure 5.32 and Figure 5.33 shown, with same the maximum injection pressure, continuous CO_2 injection is more effective than water flooding. The recovery factor for continuous CO_2 injection increases over nearly 4.03%, but with water flooding, the recovery factor only increases nearly 1%.

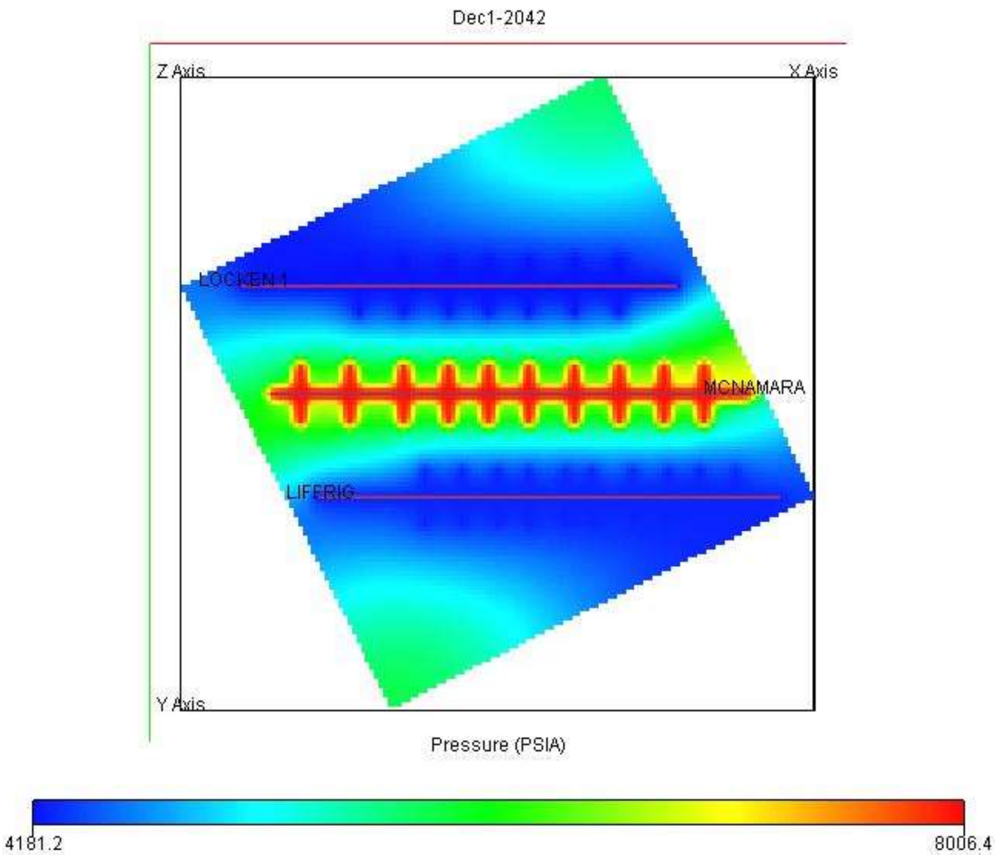


Figure 5.34 Well Pressure for the Study Area in the Sanish Field on December 1, 2042 with Conversion of Mcnamara 42-26H into an Injection Well with Water Injection Pressure of 8000 psia and Injection rate of 1000 stb/day

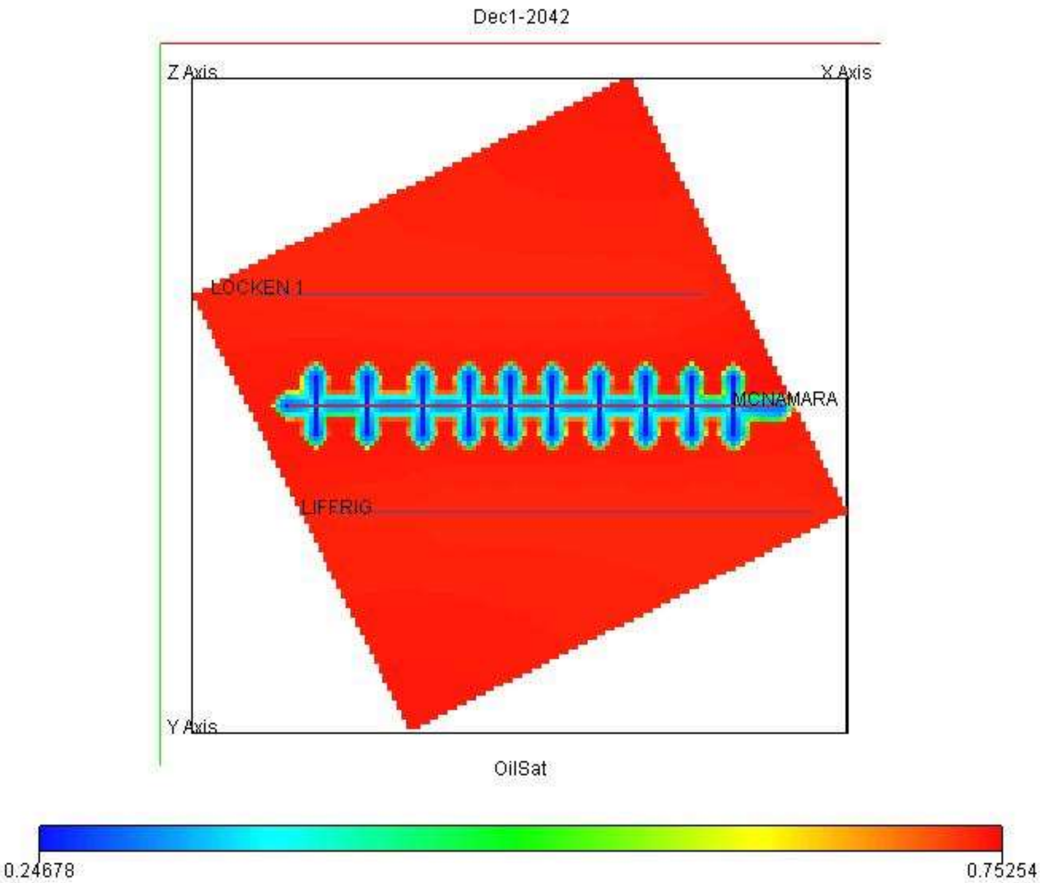


Figure 5.35 Oil Saturation for the Study Area in the Sanish Field on December 1, 2042 with Conversion of Mcnamara 42-26H into an Injection Well with Water Injection Pressure of 8000 psia and Injection rate of 1000 stb/day

5.2 Case Scenarios B: Addition of New Injection Wells

In this scenario, all initial three horizontal producers keep as production wells during the entire modeling time. On December 1, 2012, new injection wells are added into the field sector. The effect of CO_2 flooding on the recovery factor of each production well and the field is analyzed with the following scenarios: (1) two new horizontal injection wells, (2) four new horizontal injection wells, (3) four new vertical injection wells, (4) twelve new vertical injection wells using the maximum injection rate of 5000 Mscf/day and maximum injection bottom hole pressure of 8000 psia.

5.2.1 Scenario B-1: Addition of new horizontal injection wells

(1) Scenario B-1-a: Two New Horizontal Injection Wells

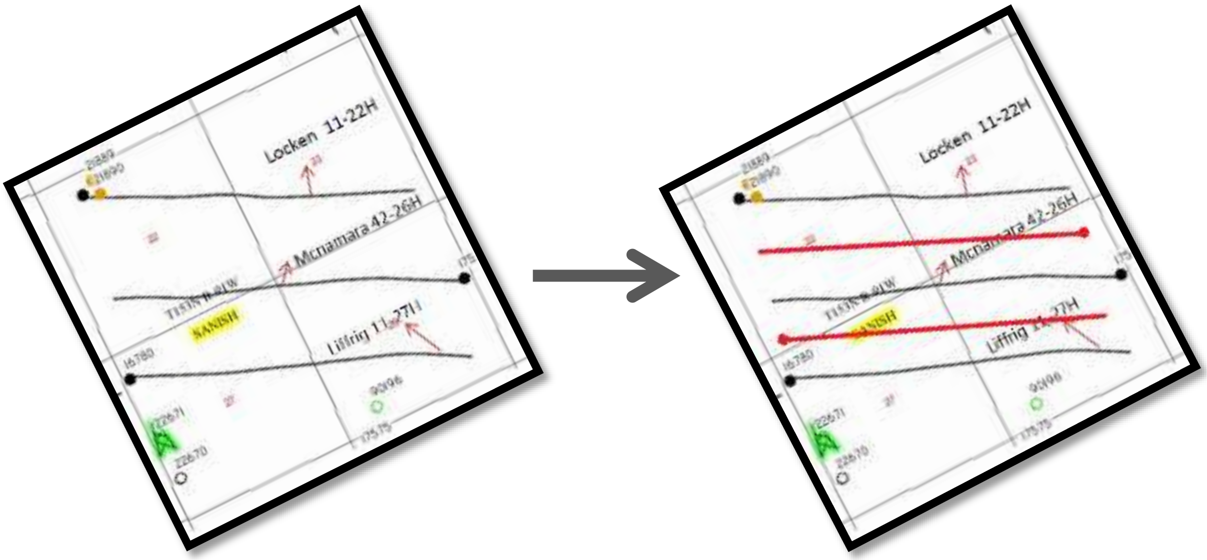


Figure 5.36 Addition of 2 New Horizontal Injection Wells in the Study Area
(Red lines on the right figure stands for new horizontal injection well)

Two new horizontal injection wells are added to the sector on December 1, 2012. The one between Locken 11-22H and Mcnamara 42-26H is called HINJ-2. The other new horizontal injection well between Mcnamara 42-26H and Liffrig 11-27H is labeled as HINJ-3.

Figure 5.37 and 5.38 show the change of injection rate and injection BHP for HINJ-2 and HINJ-3.

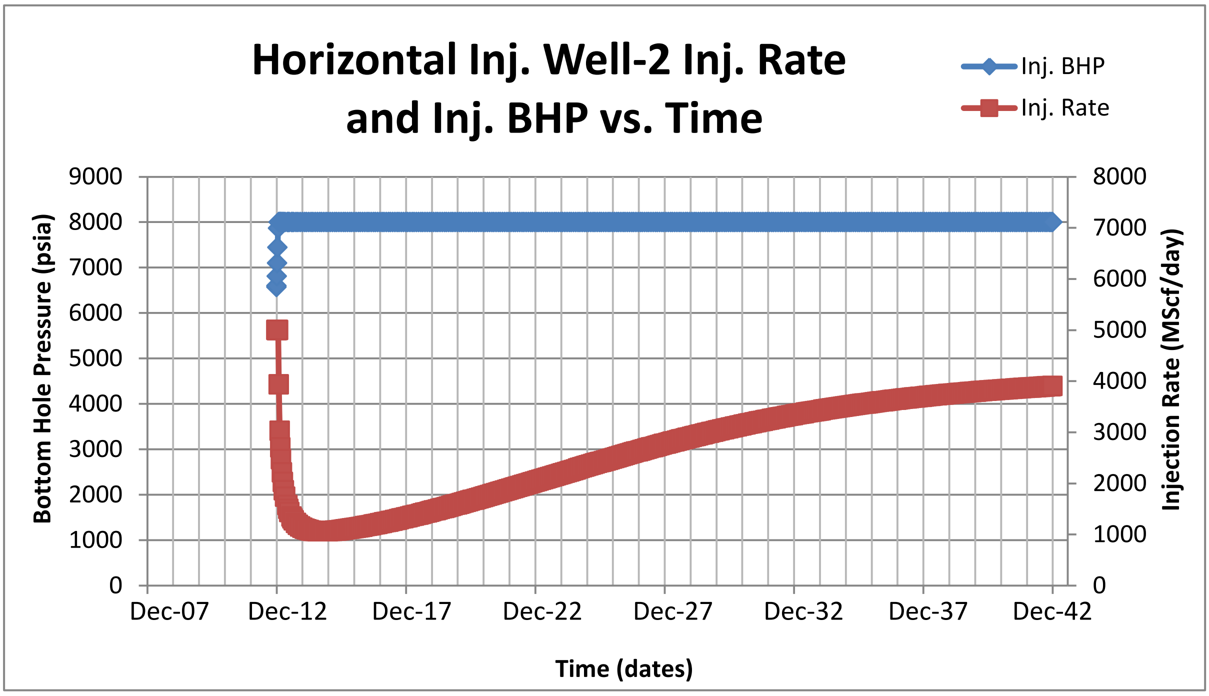


Figure 5.37 Horizontal Injection Well-2 Inj. Rate (5000 Mscf/day) and Inj. Pressure of 8000 psia vs. time

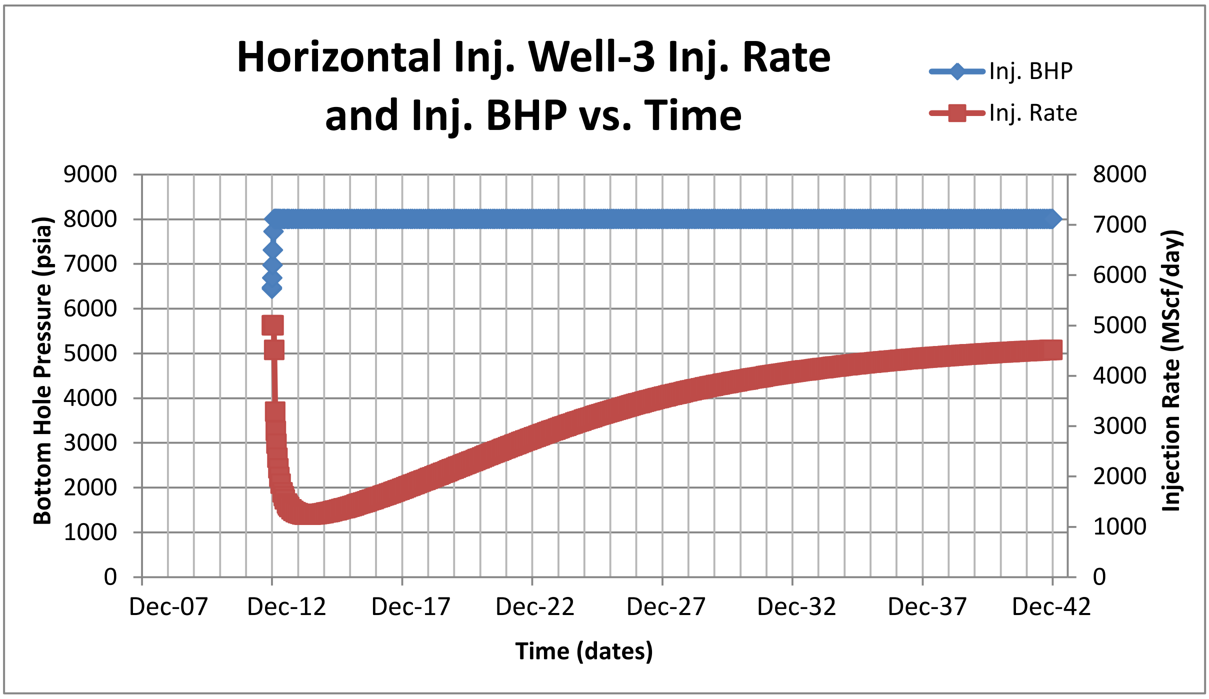


Figure 5.38 Horizontal Injection Well-3 Inj. Rate (5000 Mscf/day) and Inj. Pressure of 8000 psia vs. time

Total amount of solvent (CO_2) injected at surface conditions = $6.45 \times 10^7 Mscf$

FVF of CO_2 at reservoir conditions= 0.4079 $res.bbl/Mscf$

Total amount of solvent (CO_2) injected at reservoir conditions

$$= 6.45 \times 10^7 Mscf \times 0.4079\, res.bbl/Mscf = 2.63 \times 10^7\ res.bbls$$

PV of CO_2 injected= $2.63 \times 10^7\ res.bbls/3.56 \times 10^7 res.bbls = 0.739$ PV

The oil production rate increases for all the producer Locken 11-22H, Mcnamara 42-26H and Liffrig 11-27H in this case increases after the injection (Figure 5.39, Figure 5.40 and Figure 5.41). The peak oil production rate for Locken 11-22H is 242 stb/day and is 429 stb/day for Mcnamara 42-26H. They occur in the same day in April 2018. The peak in oil production rate of 320 stb/day for Liffrig 11-27H happens in October 2016. In addition, The field has a peak oil production rate of 951 stb/day on the same day April 2018, which Locken 11-22H and Mcnamara 42-26H occurs the peak oil production rate.

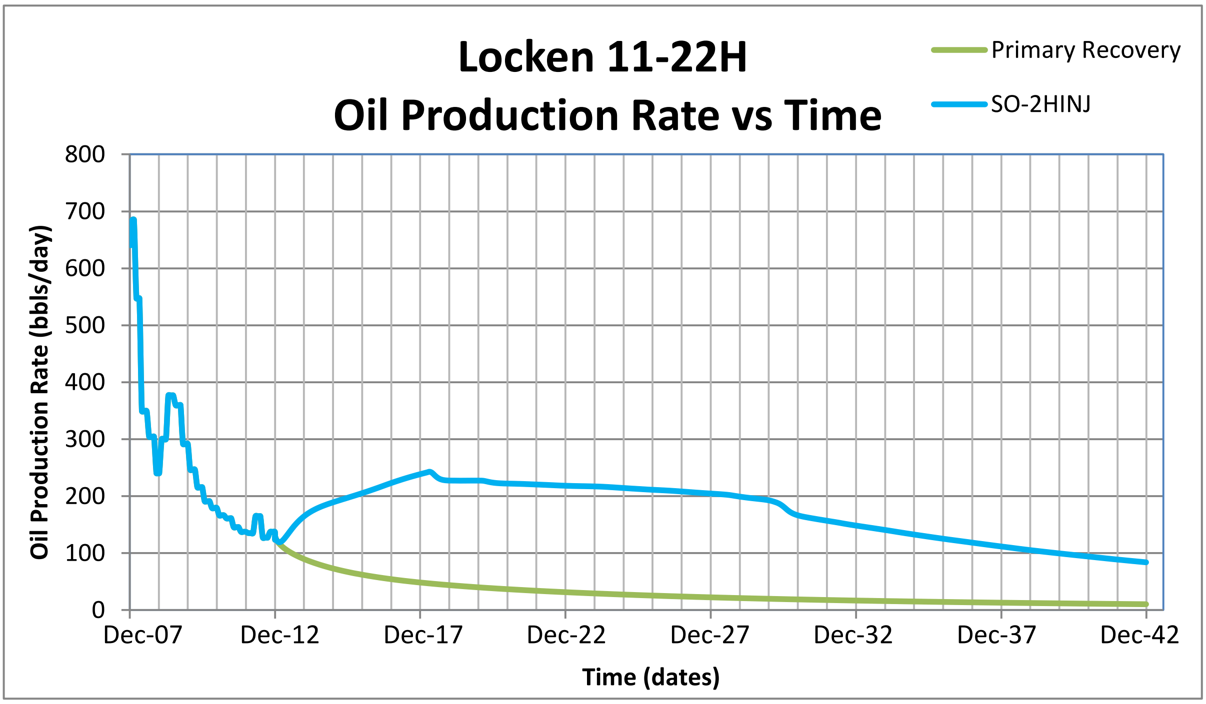


Figure 5.39 Locken 11-22H Oil Production Rate vs. Time
for 2 New Horizontal Injection Wells Case

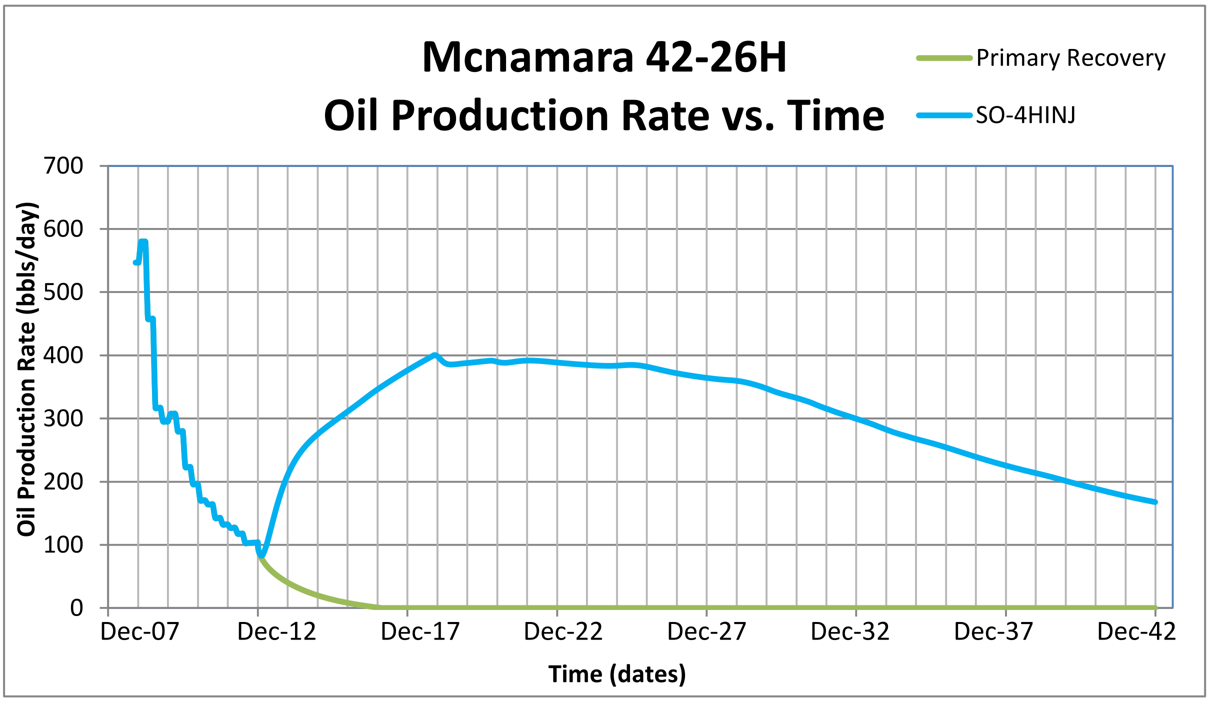


Figure 5.40 Mcnamara 42-26H Oil Production Rate vs. Time
for 2 New Horizontal Injection Wells Case

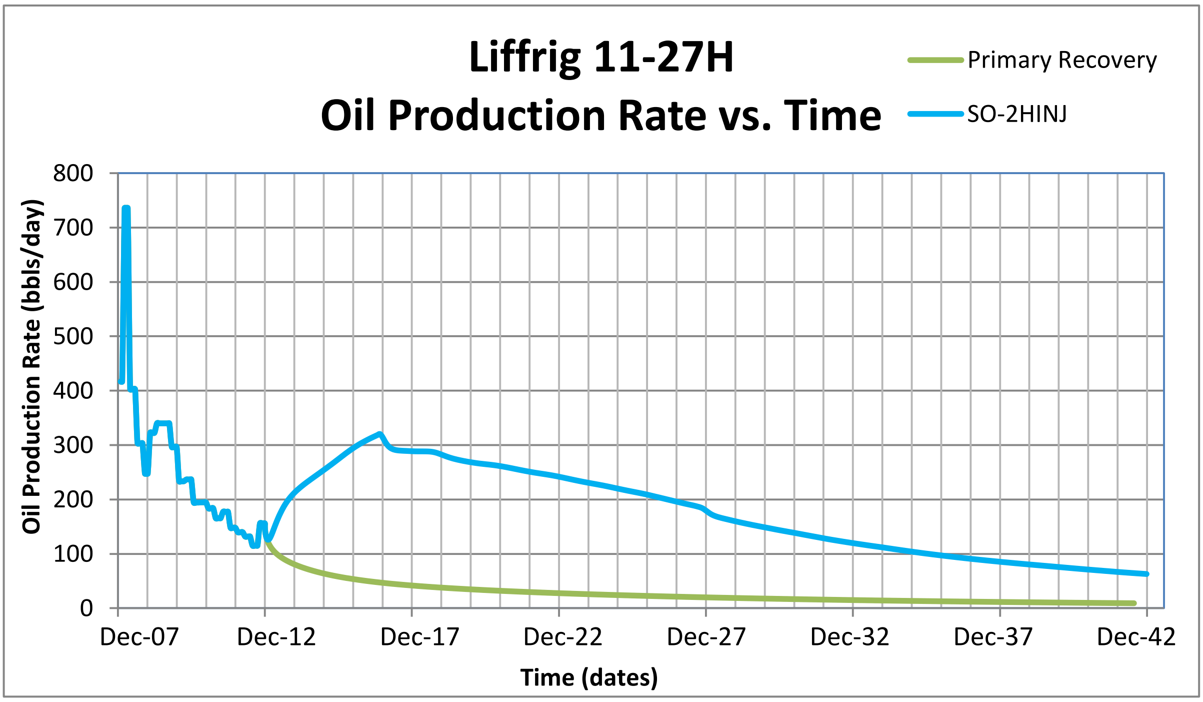


Figure 5.41 Liffrig 11-27H Oil Production Rate vs. Time
for 2 New Horizontal Injection Wells Case

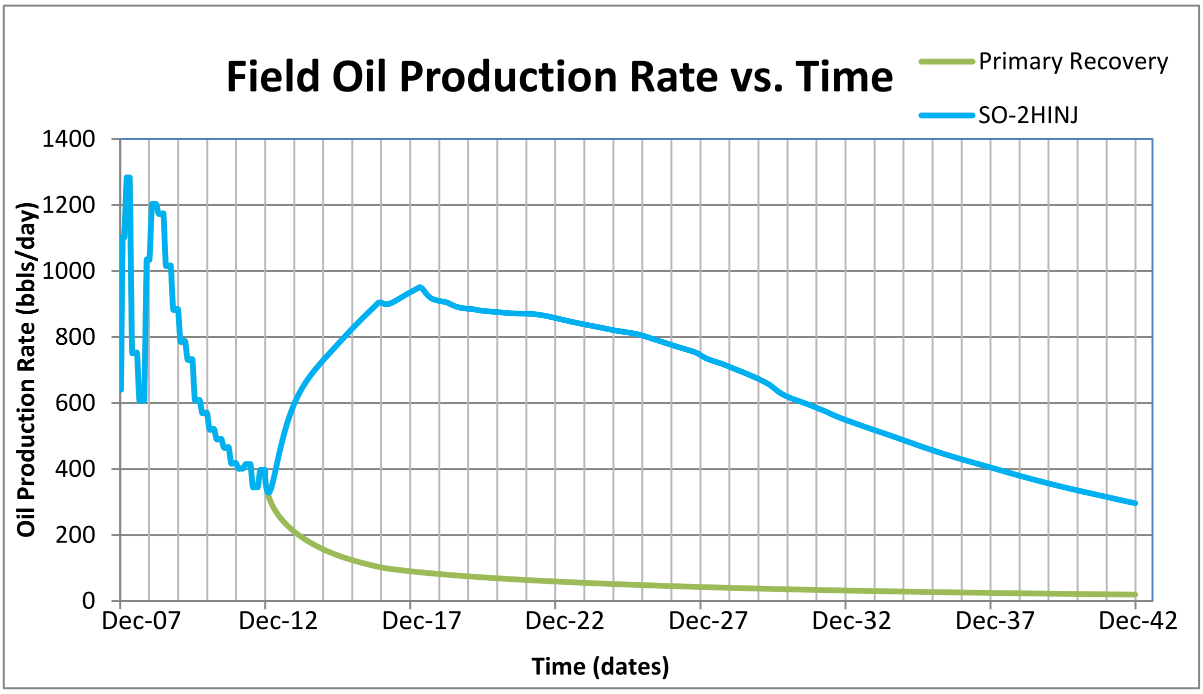


Figure 5.42 Field Oil Production Rate vs. Time for 2 New Horizontal Injection Wells Case

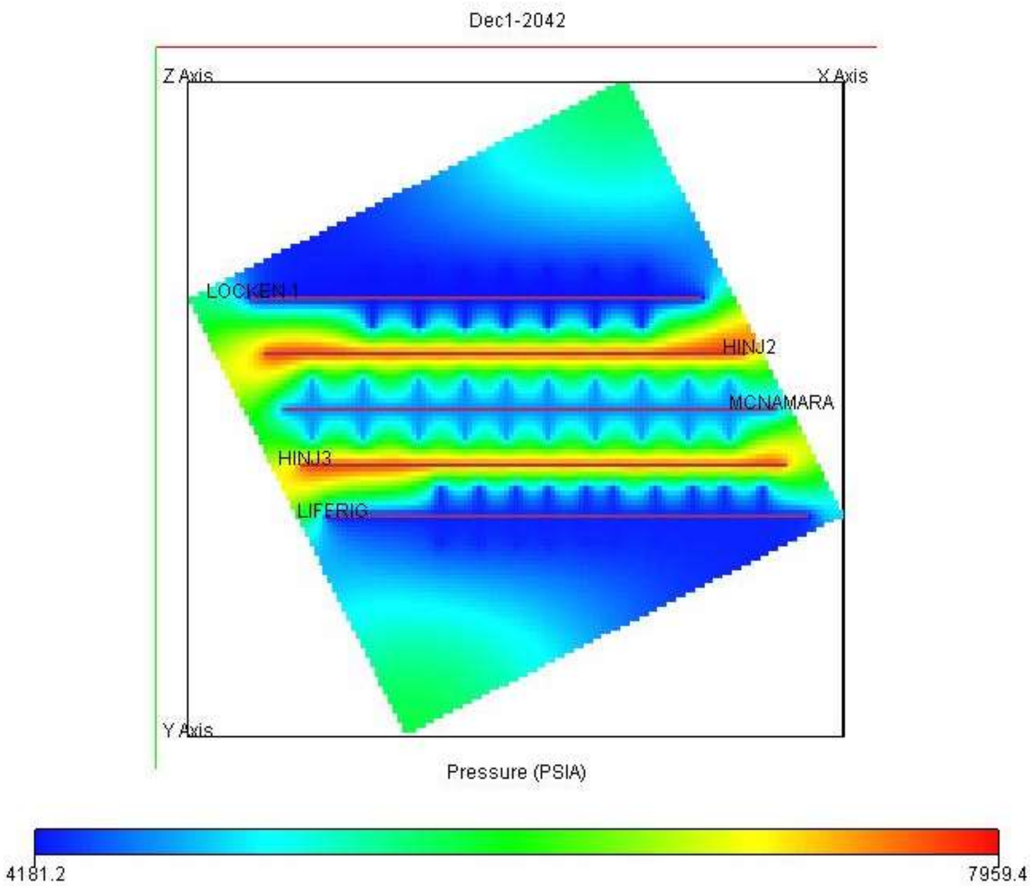


Figure 5.43 Well Pressure for the Study Area in the Sanish Field on December 1, 2042 with 2 New Horizontal Injection Wells

The increase in recovery factors of these three wells is calculated as follows:

Total oil recovered from the field with 2 new horizontal injection wells= 8,405,691 stb

RF for CO_2 injection of 2 new horizontal injection wells

$$= 8{,}405{,}691 \text{ stb } / 35.88 \times 10^6 \text{ stb} = 23.74\%$$

The calculation above indicates the recovery factor for the CO_2 injection with 2 new horizontal injection wells at an injection pressure of 8000 psia and injection rate of 5000 Mscf/day increase over 18%. The breakthrough time for the filed occurs after 7 months of injection. The total amount of CO_2 produced along with the oil and gas at surface conditions is equal to 43.49 Bscf.

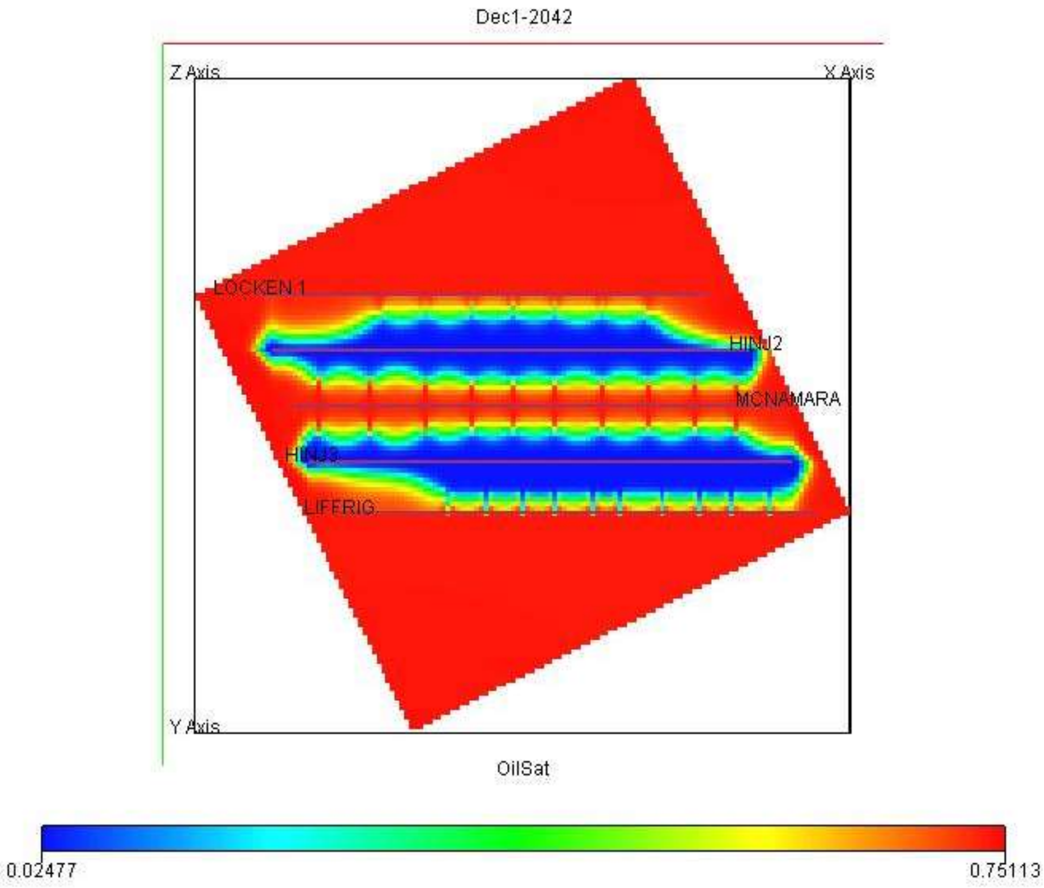


Figure 5.44 Oil Saturation for the Study Area in the Sanish Field on December 1, 2042 with 2 New Horizontal Injection Wells

(2) <u>Scenario B-1-b: Four New Horizontal Injection Wells</u>

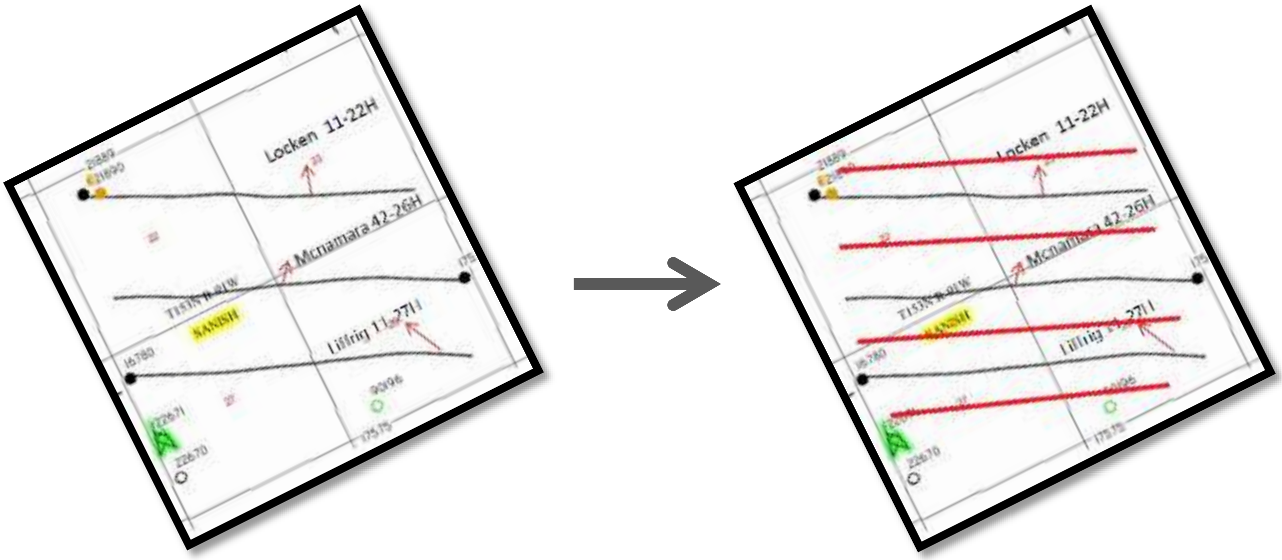


Figure 5.45 Addition of 4 New Horizontal Injection Wells in the Study Area (Red lines on the right figure stands for new horizontal injection well)

Four new horizontal injection wells are added to the sector on December 1, 2012 .Other than HINJ-2 and HIN-3, the other two injectors HIN-1 and HINJ-4, are included. HINJ-1 is the horizontal injection well above Locken 11-22H. HINJ-4 is another new horizontal injection well below Liffrig 11-27H. Figure 5.46 and 5.47 show the change of injection rate and injection BHP for HINJ-1and HINJ-4.

Total amount of solvent (CO_2) injected at surface conditions = $9.56 \times 10^7 Mscf$

FVF of CO_2 at reservoir conditions= 0.4079 $res.bbl/Mscf$

Total amount of solvent (CO_2) injected at reservoir conditions

$=9.56 \times 10^7\ Mscf \times 0.4079\ res.bbl/Mscf = 3.90 \times 10^7\ res.bbls$

PV of CO_2 injected= $3.90 \times 10^7\ res.bbls/3.56 \times 10^7 res.bbls = 1.10$ PV

The oil production rate increases for all the producer Locken 11-22H, Mcnamara 42-26H and Liffrig 11-27H in this case increases a lot after the injection (Figure 5.48, Figure 5.49 and Figure 5.50). The peak oil production rate for Locken 11-22H is 388 stb/day and occurs on

April 2021. Mcnamara 42-26H has a peak oil production rate of 401 stb/day and occurs in March 2022. The peak in oil production rate of 443 stb/day for Liffrig 11-27H happens in September 2016. The field has a peak oil production rate of 1223stb/day still in March 2018.

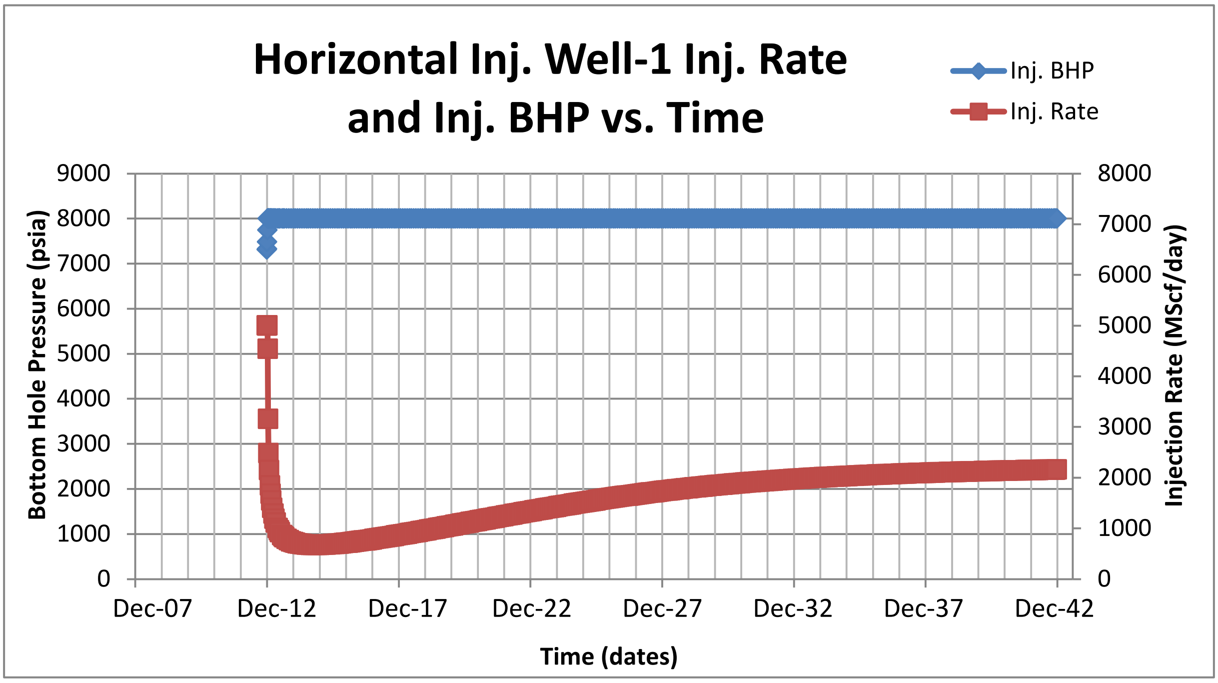


Figure 5.46 Horizontal Injection Well-1 Inj. Rate (5000 Mscf/day) and Inj. Pressure of 8000 psia vs. time

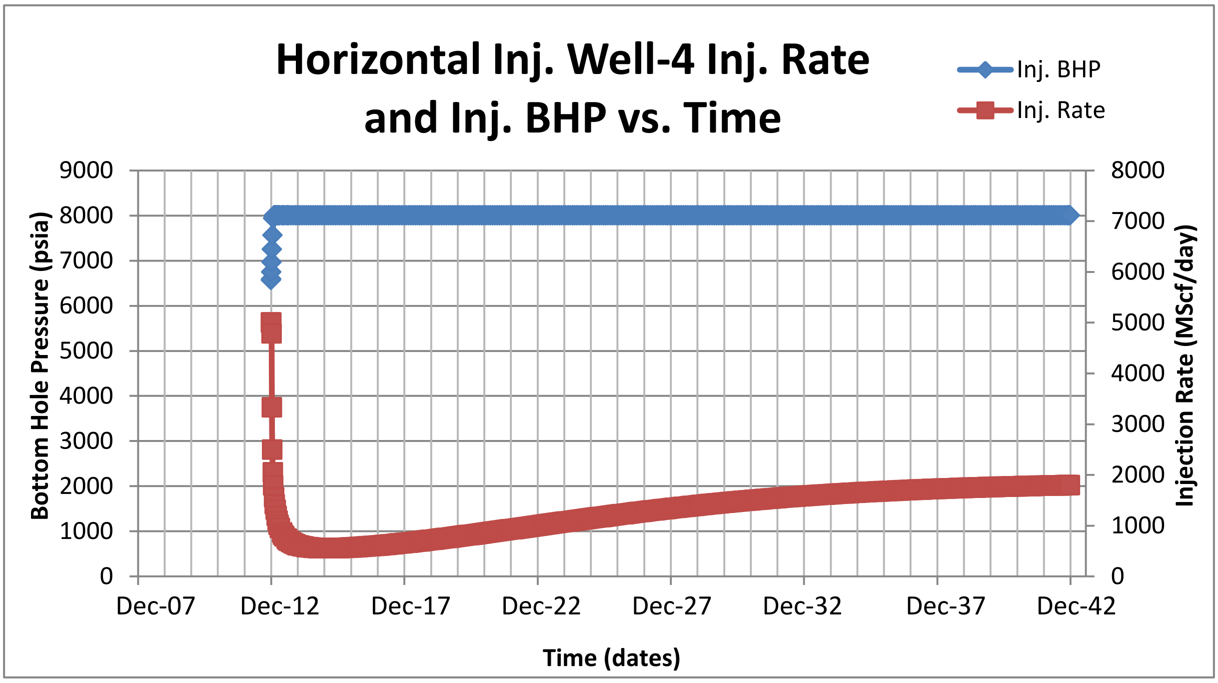


Figure 5.47 Horizontal Injection Well-4 Inj. Rate (5000 Mscf/day) and Inj. Pressure of 8000 psia vs. time

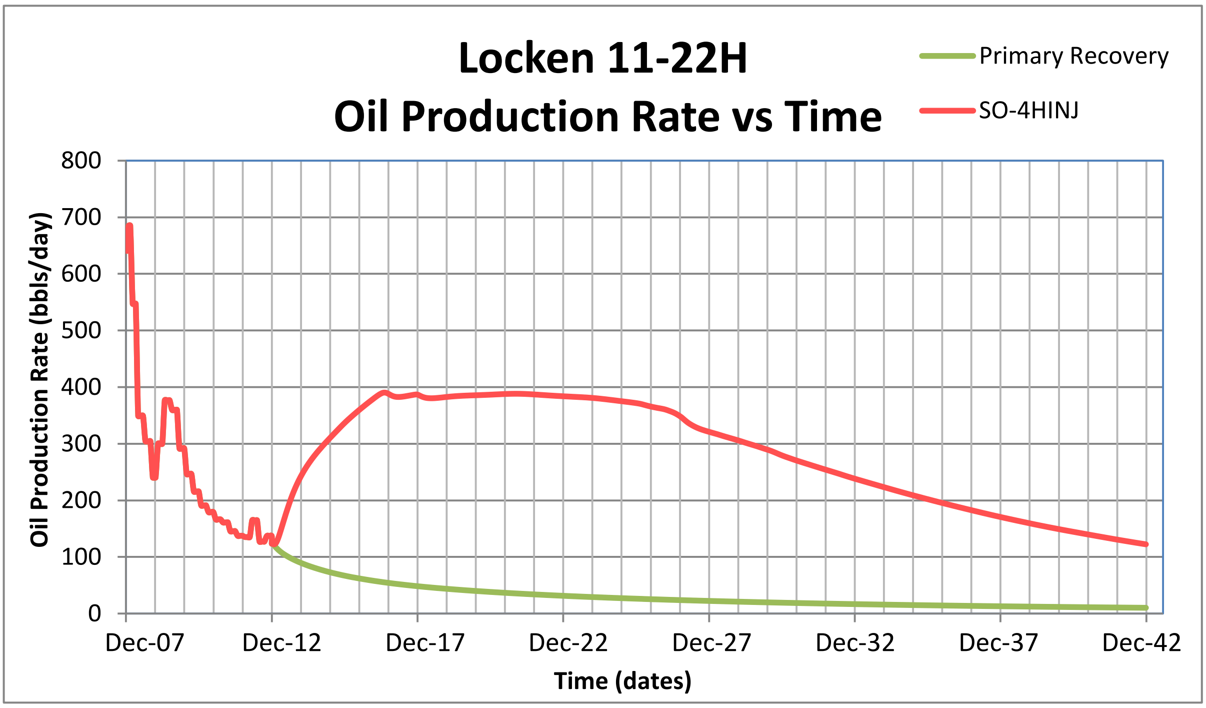


Figure 5.48 Locken 11-22H Oil Production Rate vs. Time
for 4 New Horizontal Injection Wells Case

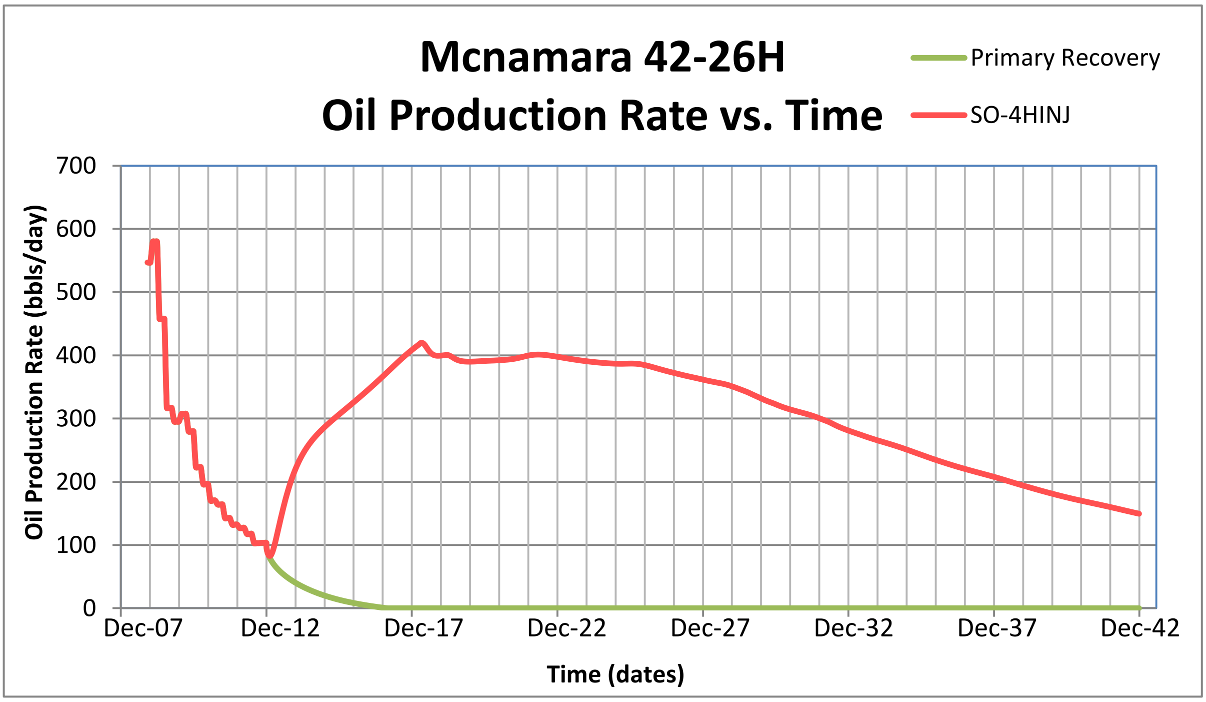


Figure 5.49 Mcnamara 42-26H Oil Production Rate vs. Time
for 4 New Horizontal Injection Wells Case

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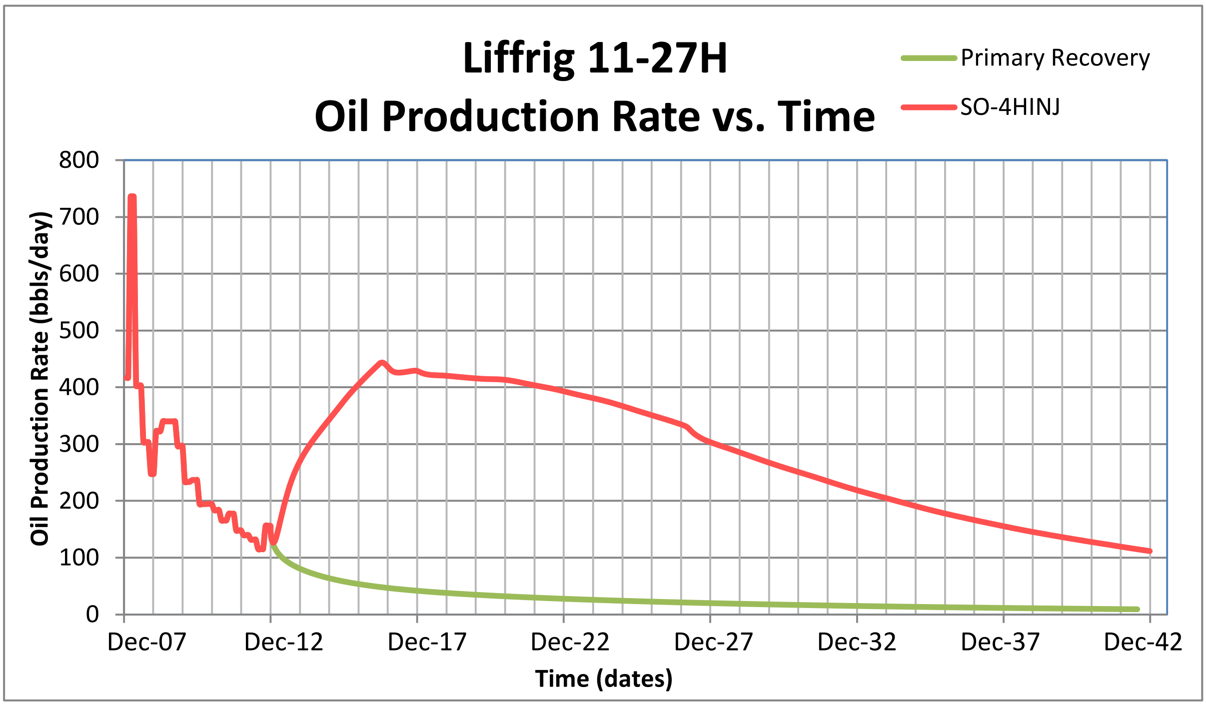

Figure 5.50 Liffrig 11-27H Oil Production Rate vs. Time
for 4 New Horizontal Injection Wells Case

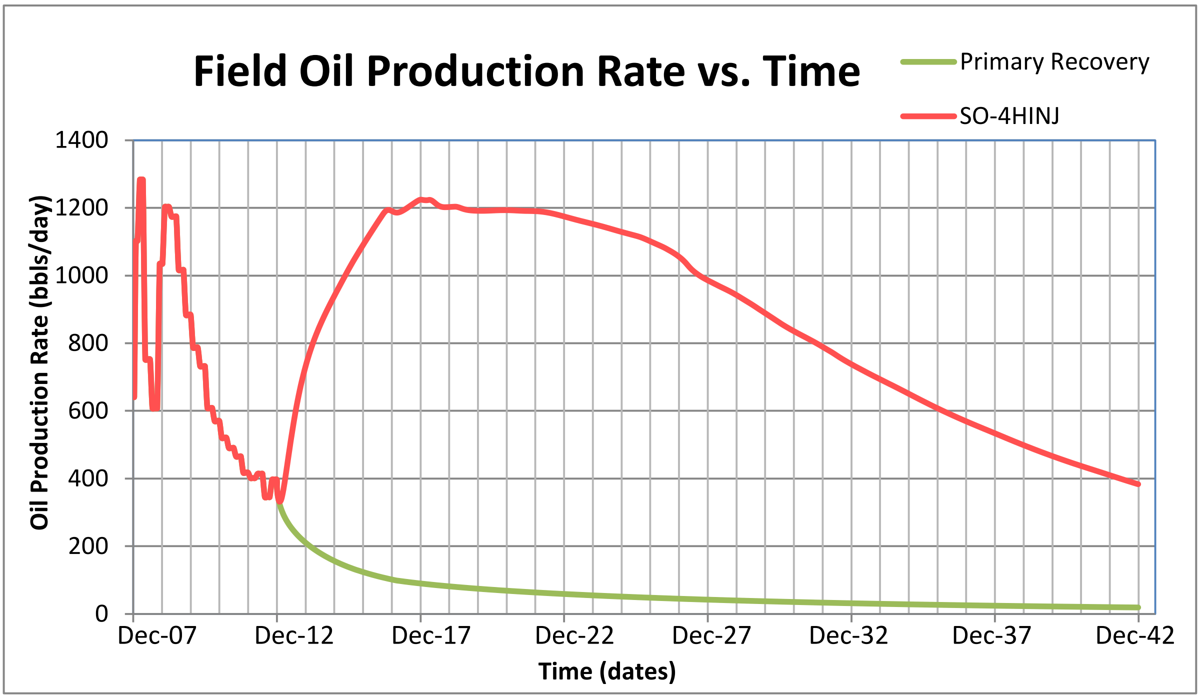

Figure 5.51 Field Oil Production Rate vs. Time for 4 New Horizontal Injection Wells Case

The increase in recovery factors of these three wells is calculated as follows:

Total oil recovered from the field with 4 new horizontal injection wells= 1.08×10^6 stb

RF for CO_2 injection of 4 new horizontal injection wells

$$= 10{,}768{,}000 \text{ stb } / 35.88 \times 10^6 \text{ stb} = 30.01\%$$

The calculation above indicates the recovery factor for the CO_2 injection with 4 new horizontal injection wells at an injection pressure of 8000 psia and injection rate of 5000 Mscf/day increase over 24.59%. The breakthrough time for the field also occurs after 7 months of injection. The total amount of CO_2 produced along with the oil and gas at surface conditions is equal to 65.23 Bscf.

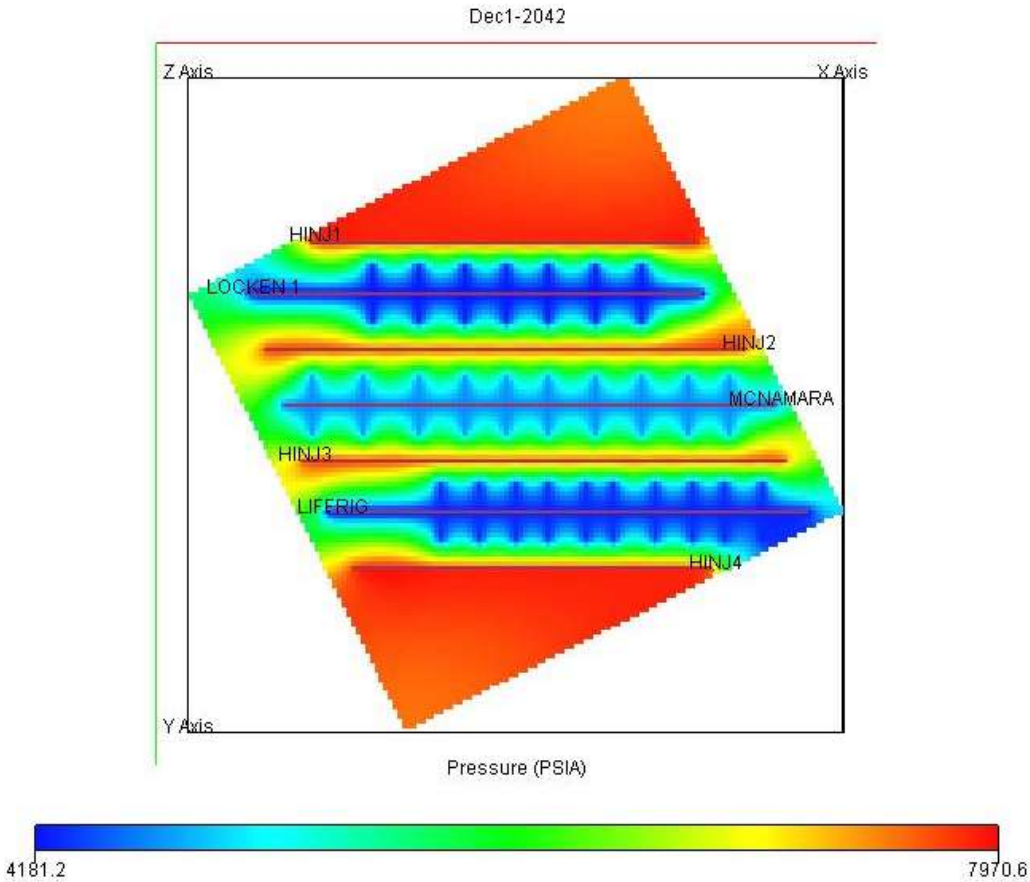

Figure 5.52 Well Pressure for the Study Area in the Sanish Field on December 1, 2042 with 4 New Horizontal Injection Wells

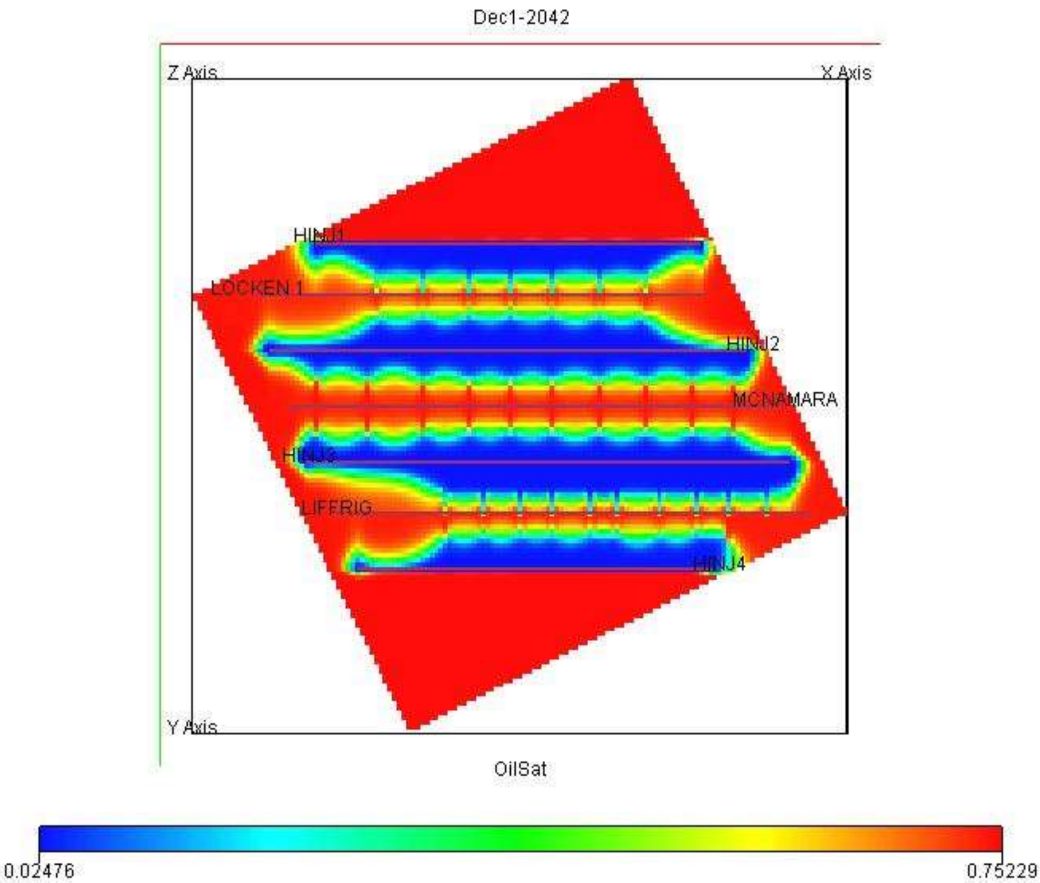

Figure 5.53 Oil Saturation for the Study Area in the Sanish Field on December 1, 2042 with 4 New Horizontal Injection Wells

5.2.1 Scenario B-2: Addition of new vertical injection wells

(1) Scenario B-2-a: Four New Vertical Injection Wells

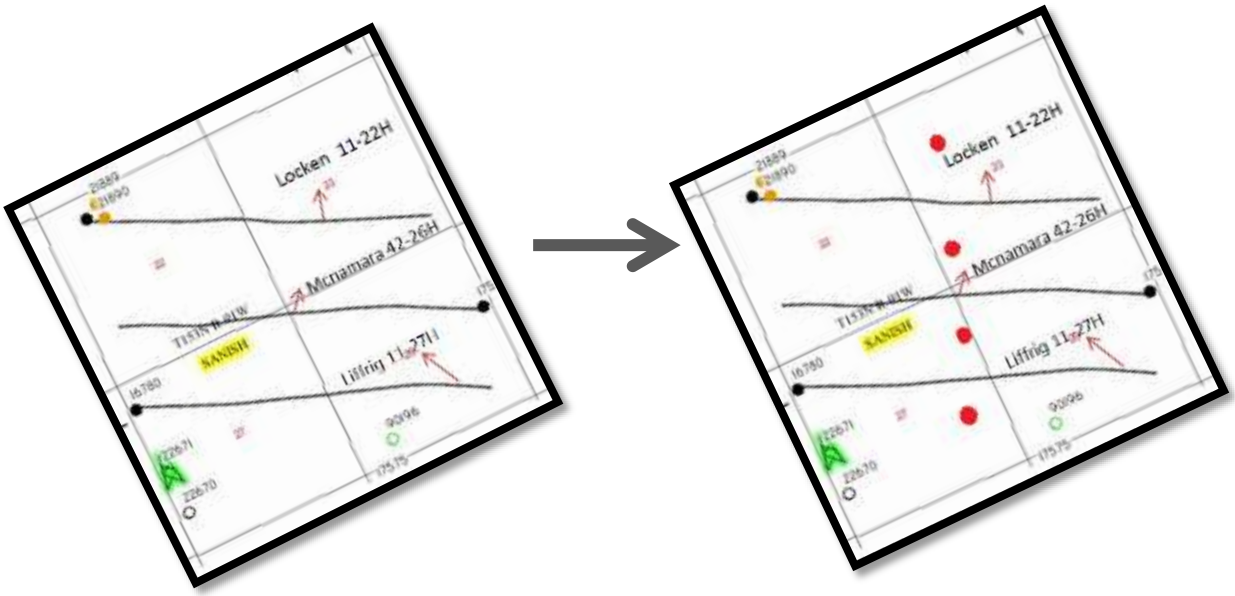

Figure 5.54 Addition of 4 New Vertical Injection Wells in the Study Area
(Red dots on the right figure stands for new vertical injection well)

Four new vertical injection wells are added to the sector on December 1, 2012. From top to bottom, four new wells are defined as VINJ-1, VINJ-2, VINJ-3, and VINJ-4. Among all the new vertical injection wells, take VINJ-1 as an example to show the change of injection rate and injection BHP in Figure 5.55. The bottom hole pressure reaches 8000 psia at the beginning of the injection, so the injection rate does not achieve 5000 psia. Instead, the injection rate ranges from 25 Mscf/day to 130 Mscf/day to allow the injection bottom hole pressure to meet the requirement of 8000 psia. The other three vertical injection wells have the similar changing trend of injection rate and injection pressure as VINJ-1 does.

Total amount of solvent (CO_2) injected at surface conditions = $4.27 \times 10^6 Mscf$

FVF of CO_2 at reservoir conditions= 0.4079 $res.bbl/Mscf$

Total amount of solvent (CO_2) injected at reservoir conditions

$$= 4.27 \times 10^6 Mscf \times 0.4079\, res.bbl/Mscf = 1.74 \times 10^6\, res.bbls$$

PV of CO_2 injected= $1.74 \times 10^6\, res.bbls/3.56 \times 10^7 res.bbls = 0.049$ PV

The oil production rate increases for all the producer Locken 11-22H, Mcnamara 42-26H and Liffrig 11-27H in this case increases only a little after the injection (Figure 5.56, Figure 5.57 and Figure 5.58). There is no peak oil production rate for all the three producers, because the oil production rates have kept decreasing since the beginning of the injection until the end of the modeling time. Compared to the oil production rate results from the additional four new horizontal injection wells, there are big differences. Even though the new injector amounts are the same, the wells and the field produce much more oil with 4 horizontal injection wells than that with 4 vertical injectors.

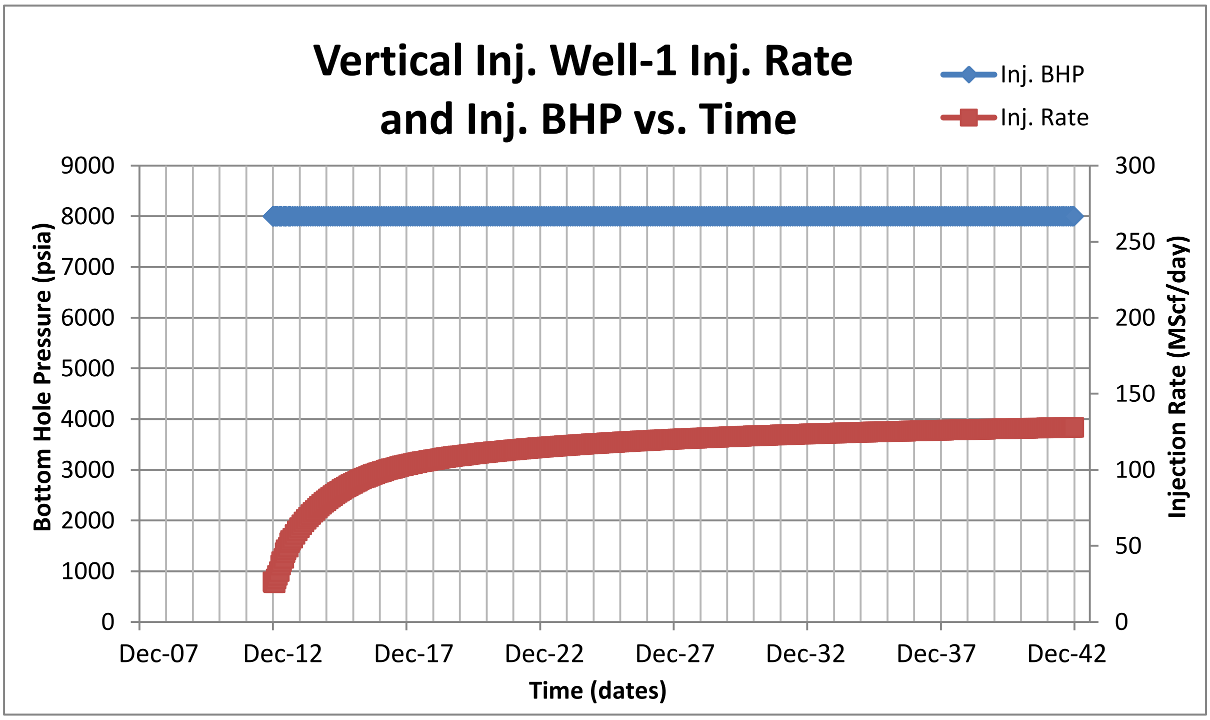

Figure 5.55 Vertical Injection Well-1 Inj. Rate (5000 Mscf/day) and Inj. Pressure of 8000 psia vs. time

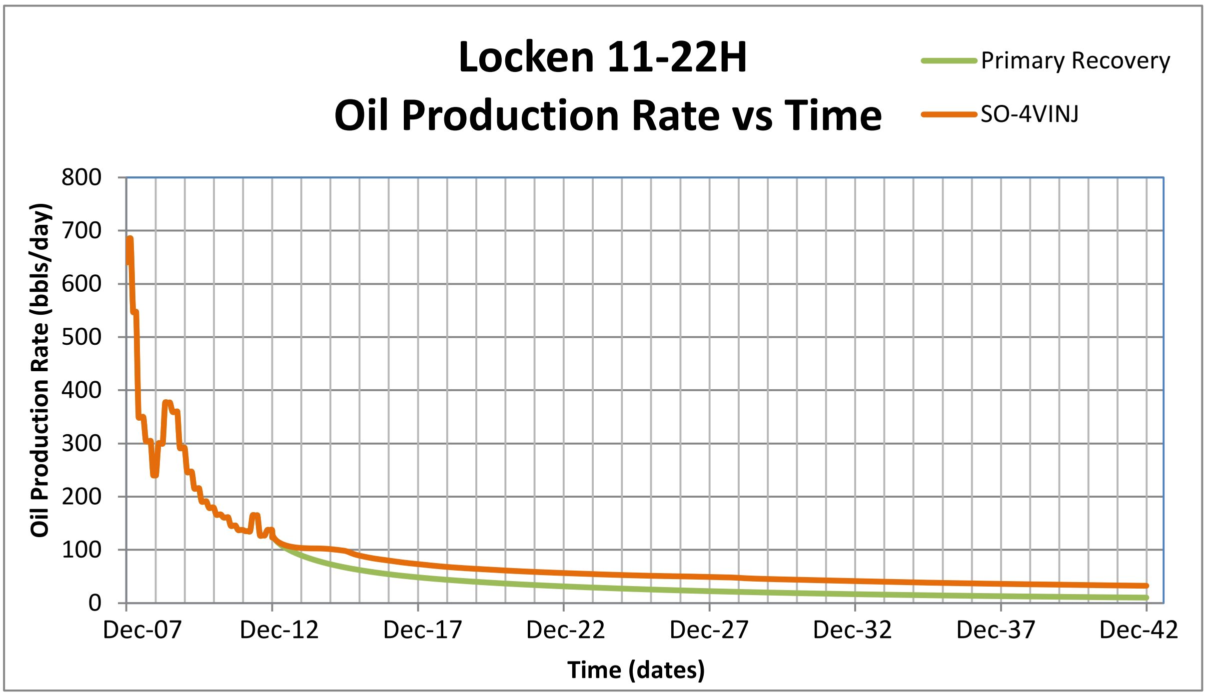

Figure 5.56 Locken 11-22H Oil Production Rate vs. Time
for 4 New Vertical Injection Wells Case

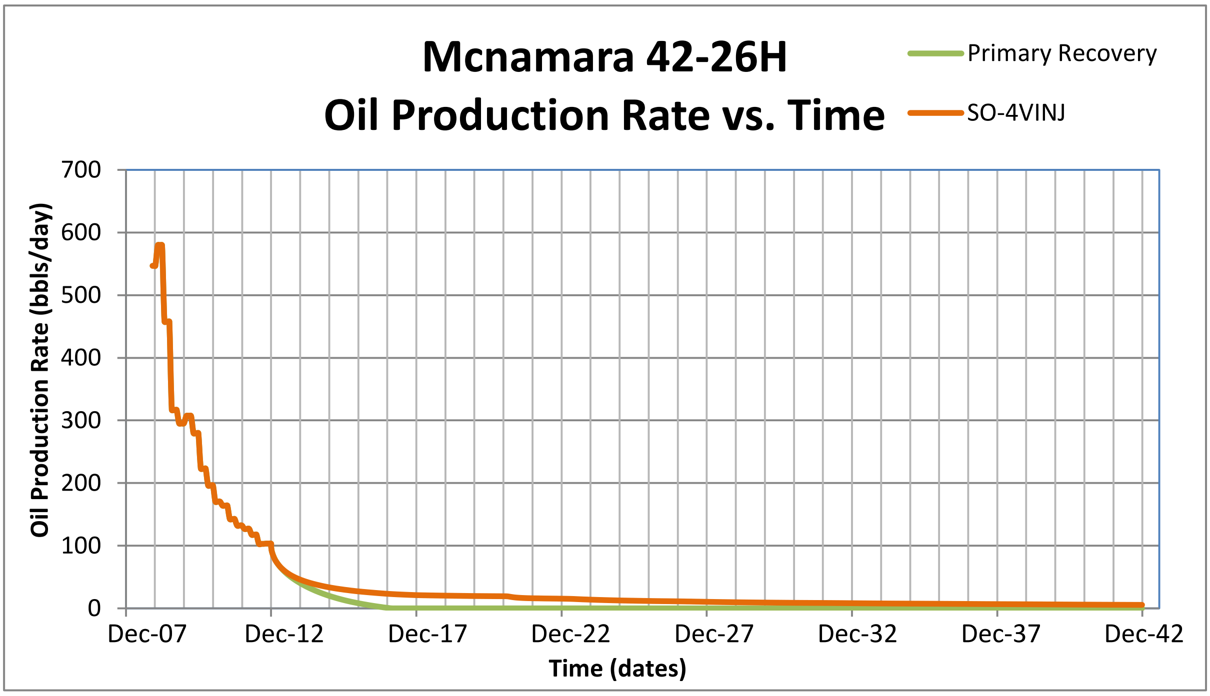

Figure 5.57 Mcnamara 42-26H Oil Production Rate vs. Time
for 4 New Vertical Injection Wells Case

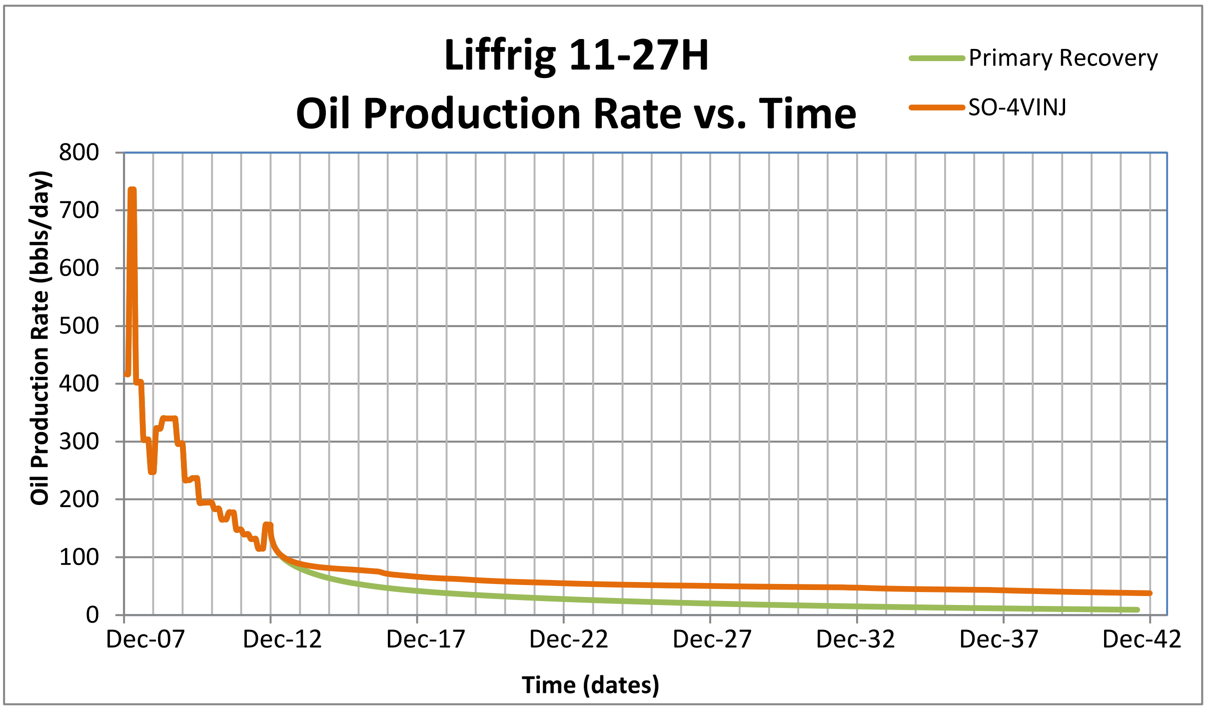

Figure 5.58 Liffrig 11-27H Oil Production Rate vs. Time
for 4 New Vertical Injection Wells Case

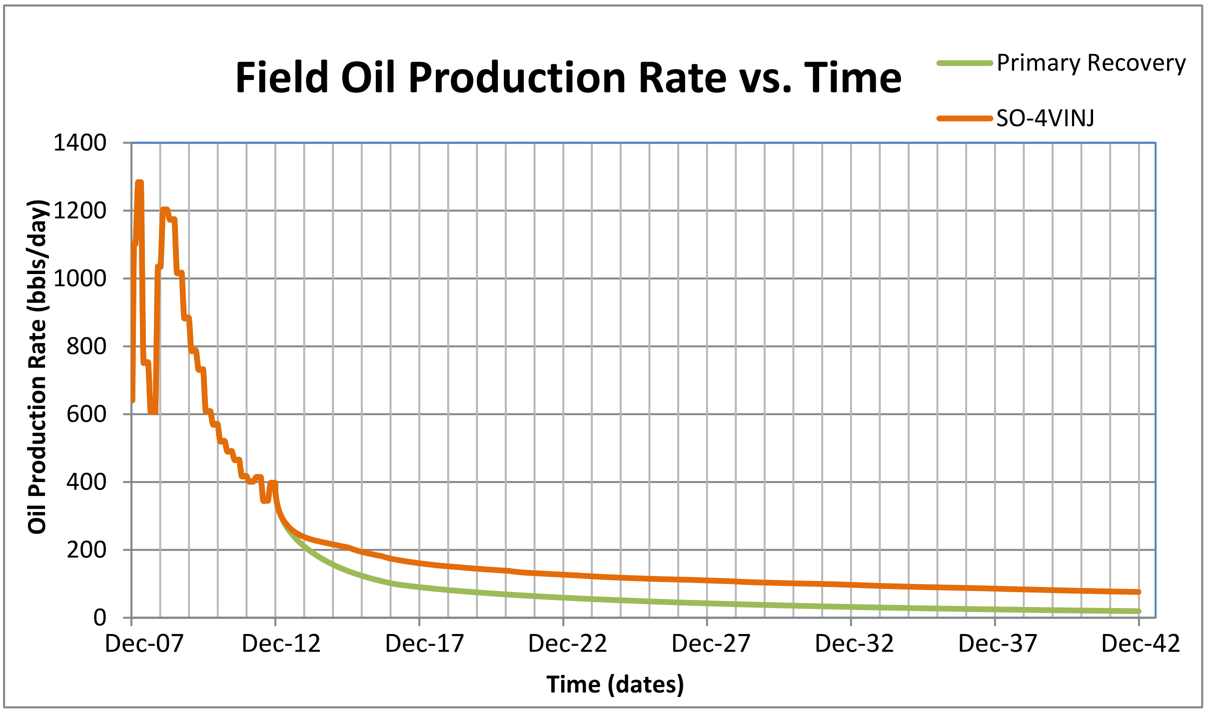

Figure 5.59 Field Oil Production Rate vs. Time
for 4 New Vertical Injection Wells Case

The increase in recovery factors of these three wells is calculated as follows:

Total oil recovered from the field with 4 new vertical injection wells$=$ 2,634,267 stb

RF for CO_2 injection of 2 new horizontal injection wells

$$= 2{,}634{,}267 \text{ stb } /35.88 \times 10^6 \text{ stb} = 7.34\%$$

The calculation above indicates the recovery factor for the CO_2 injection with 4 new vertical injection wells at an injection pressure of 8000 psia and injection rate of 5000 Mscf/day increase by 1.92%. The breakthrough time for the filed occurs after 6 months of injection. The total amount of CO_2 produced along with the oil and gas at surface conditions is equal to 1.98 Bscf.

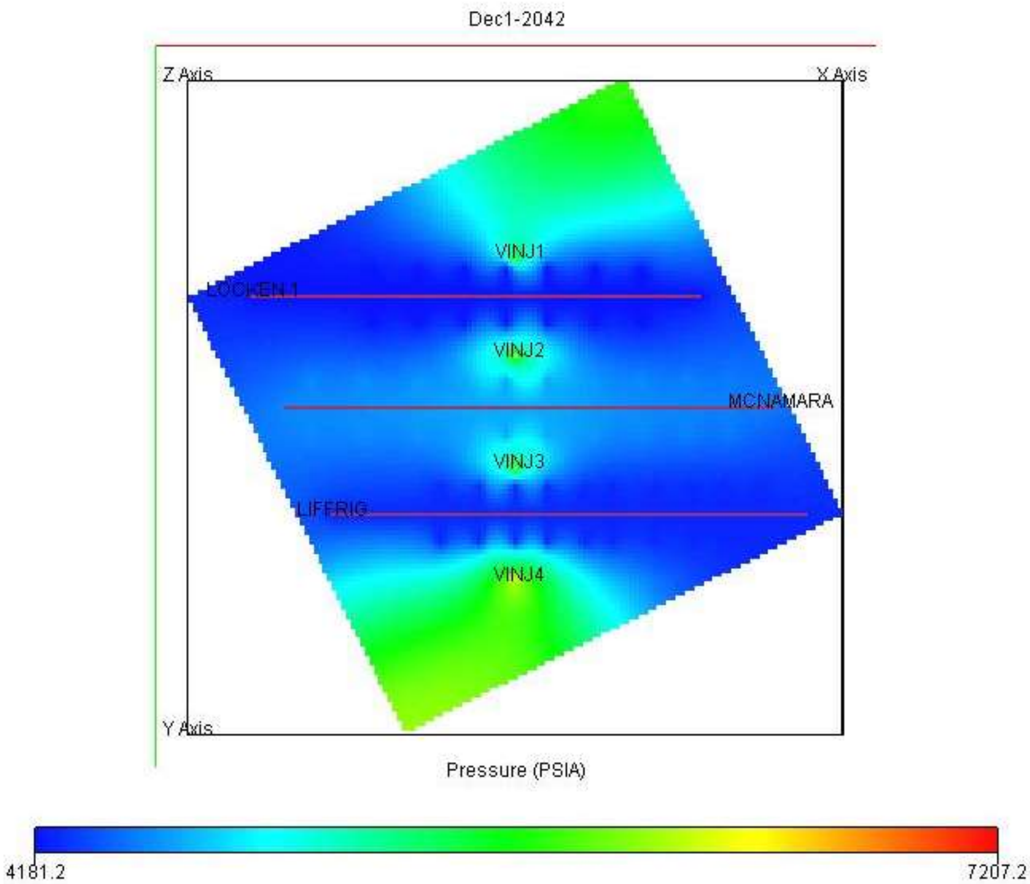

Figure 5.60 Well Pressure for the Study Area in the Sanish Field on December 1, 2042 with 4 New Vertical Injection Wells

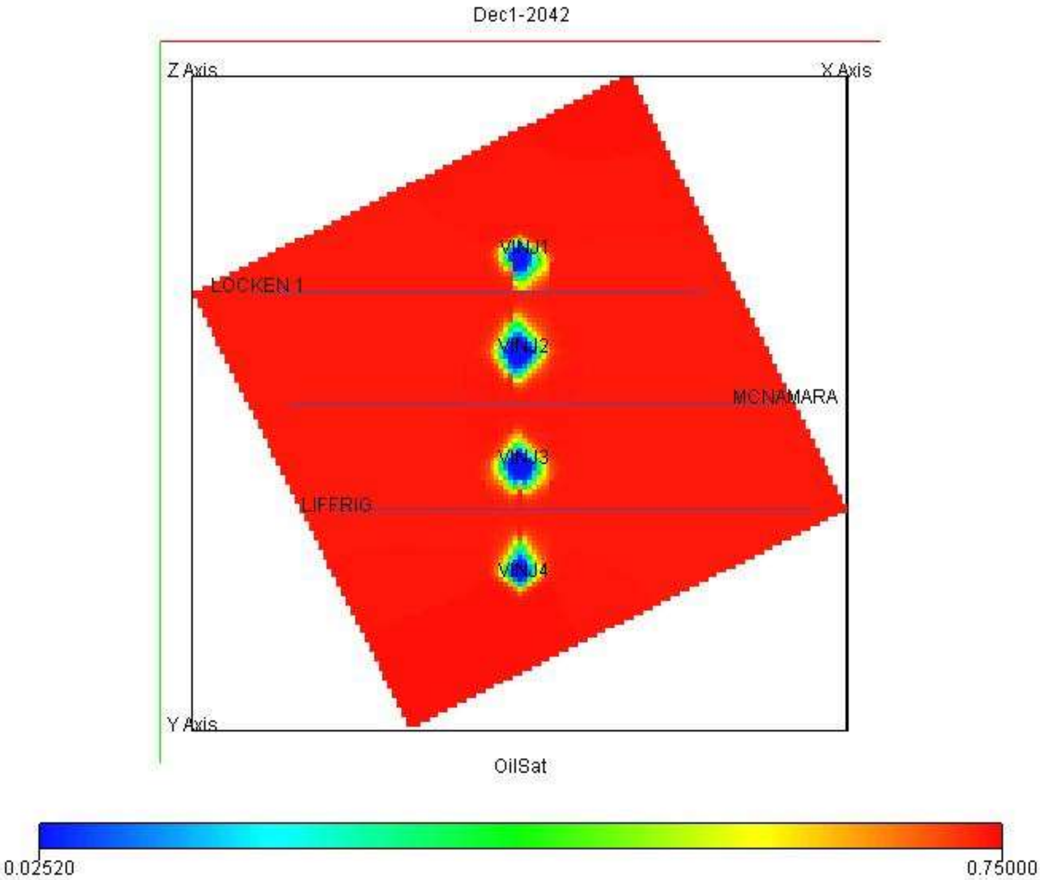

Figure 5.61 Oil Saturation for the Study Area in the Sanish Field on December 1, 2042 with 4 New Vertical Injection Wells

(1) <u>Scenario B-2-b:Twelve New Vertical Injection Wells</u>

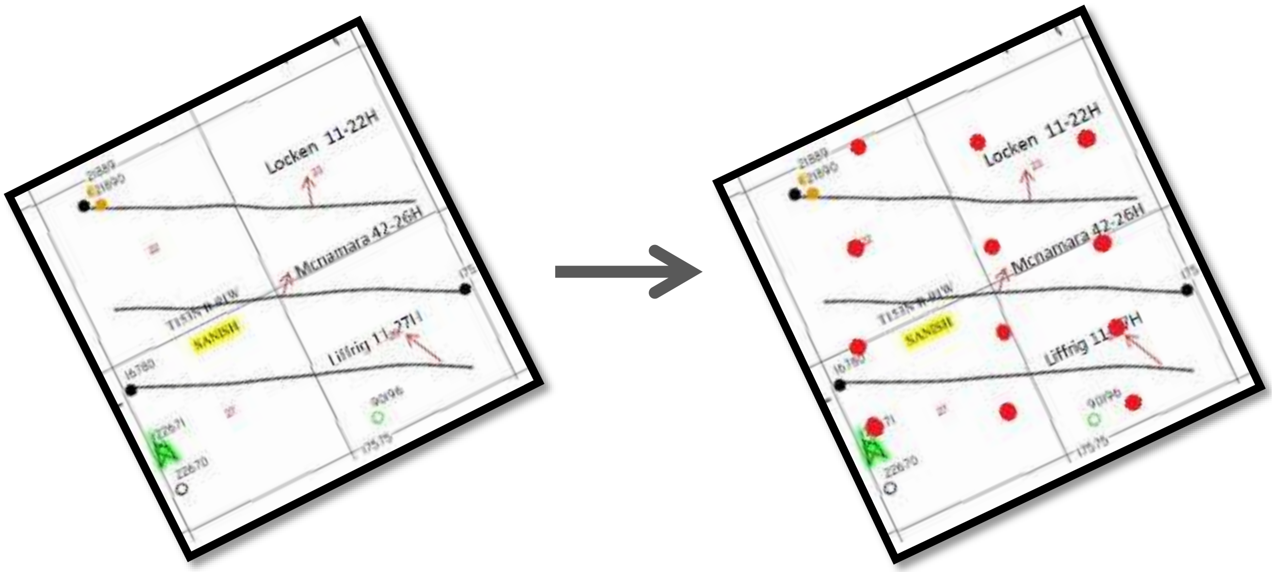

Figure 5.62 Addition of 12 New Vertical Injection Wells in the Study Area
(Red dots on the right figure stands for new vertical injection well)

Compared to the previous case, additional eight new vertical injection wells are added to the sector on December 1, 2012 .Other than VINJ-1, VIN-2, VIN-3 and VINJ-4, new wells labeled from VINJ-5 to VINJ-12 are included. Take VINJ-12 as an example to use Figure 5.63 to show the change of injection rate and injection BHP. The bottom hole pressure reaches 8000 psia at the beginning of the injection, also the injection rate does not achieve 5000 psia. Instead, the injection rate ranges from 15 Mscf/day to 90 Mscf/day to allow the injection bottom hole pressure to meet the requirement of 8000 psia. The other seven new vertical injection wells have the similar changing trend of injection rate and injection pressure as VINJ-12 does.

Total amount of solvent (CO_2) injected at surface conditions = $1.18 \times 10^7 Mscf$

FVF of CO_2 at reservoir conditions= 0.4079 $res.bbl/Mscf$

Total amount of solvent (CO_2) injected at reservoir conditions

$$= 1.18 \times 10^7 Mscf \times 0.4079\ res.bbl/Mscf = 4.81 \times 10^6\ res.bbls$$

PV of CO_2 injected= $4.81 \times 10^6\ res.bbls/3.56 \times 10^7 res.bbls = 0.135$ PV

The oil production rate increases for all the producers, Locken 11-22H, Mcnamara 42-26H, and Liffrig 11-27H in this case increases after the injection (Figure 5.64, Figure 5.65 and Figure 5.66). The peak oil production rate for Locken 11-22H is 138stb/day and occurs in May 2015. Mcnamara 42-26H has a peak oil production rate of 70 stb/day and occurs in April 2023. The peak in oil production rate of 11 stb/day for Liffrig 11-27H happens in May 2023. In addition, The field has a peak oil production rate of 306 stb/day in September 2020. Compared with the addition of four new horizontal injectors, the total field oil production of this case has less than more than six million barrels over 30 years of injection.

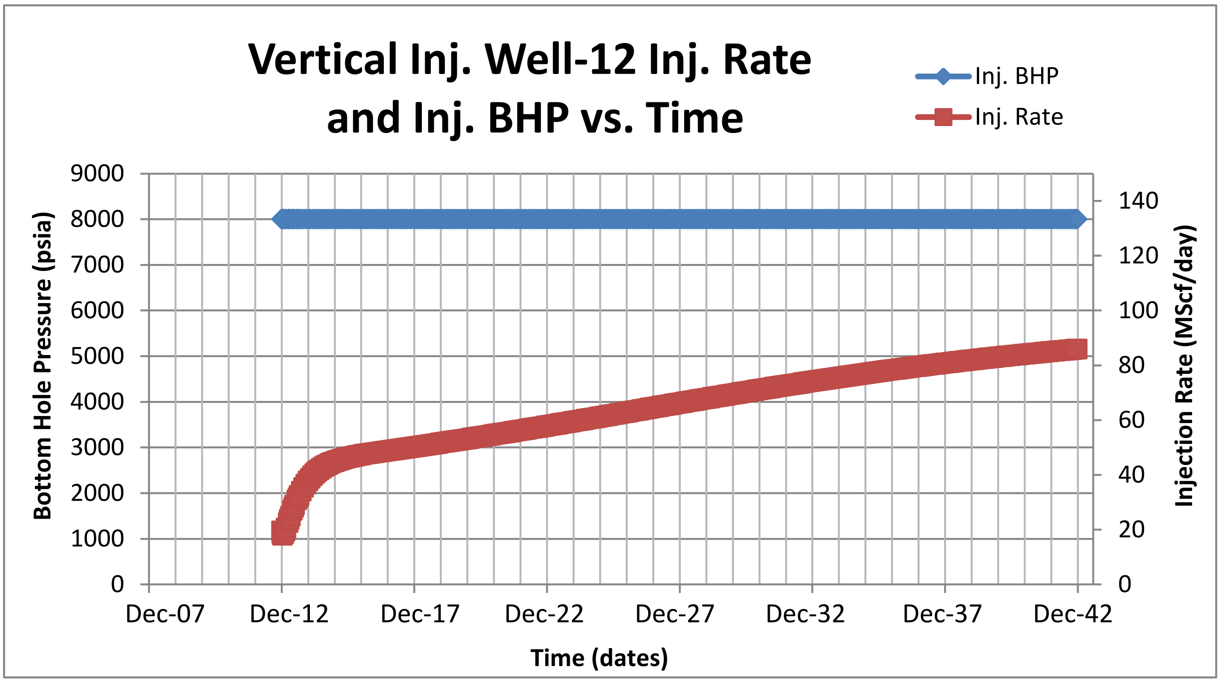

Figure 5.63 Horizontal Injection Well-12 Inj. Rate (5000 Mscf/day)
and Inj. Pressure of 8000 psia vs. time

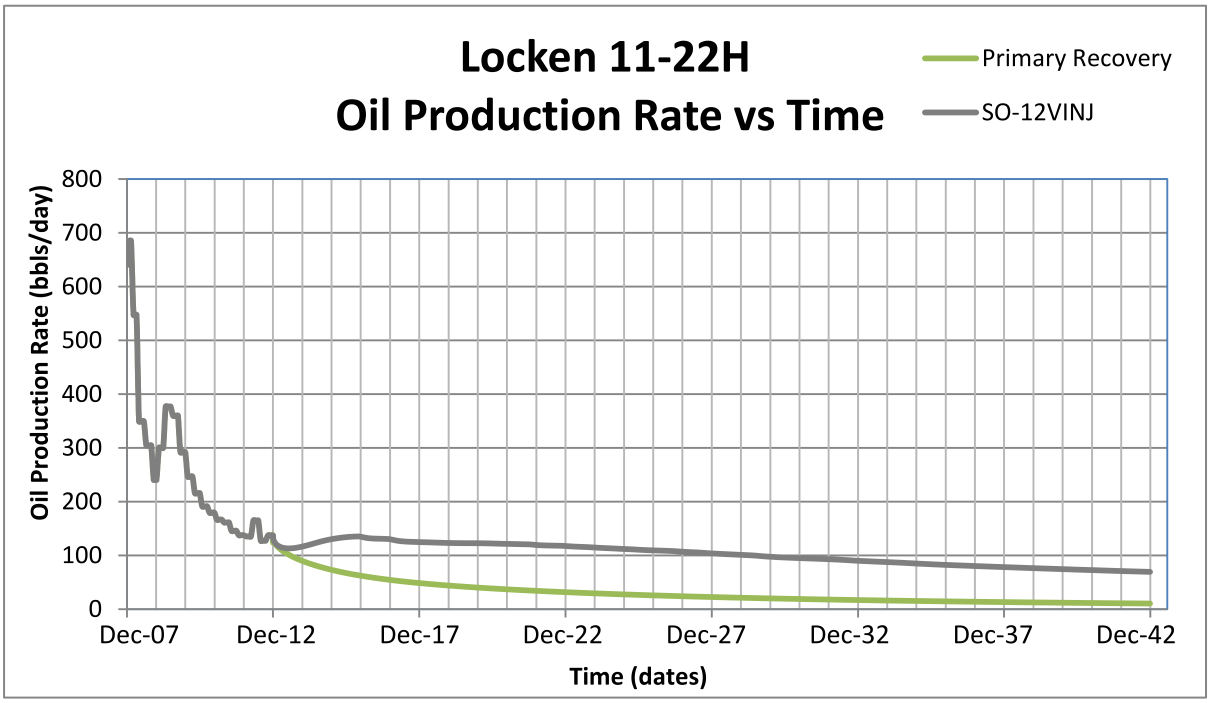

Figure 5.64 Locken 11-22H Oil Production Rate vs. Time
for 12 New Vertical Injection Wells Case

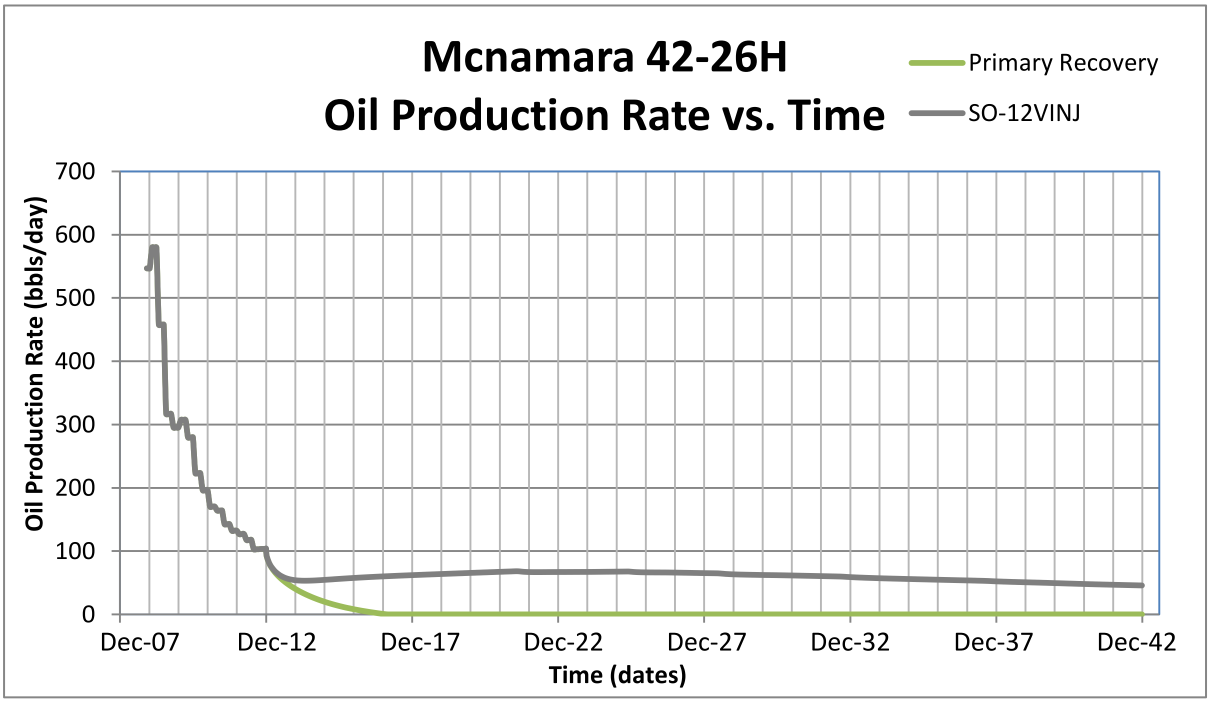

Figure 5.65 Mcnamara 42-26H Oil Production Rate vs. Time
for 12 New Vertical Injection Wells Case

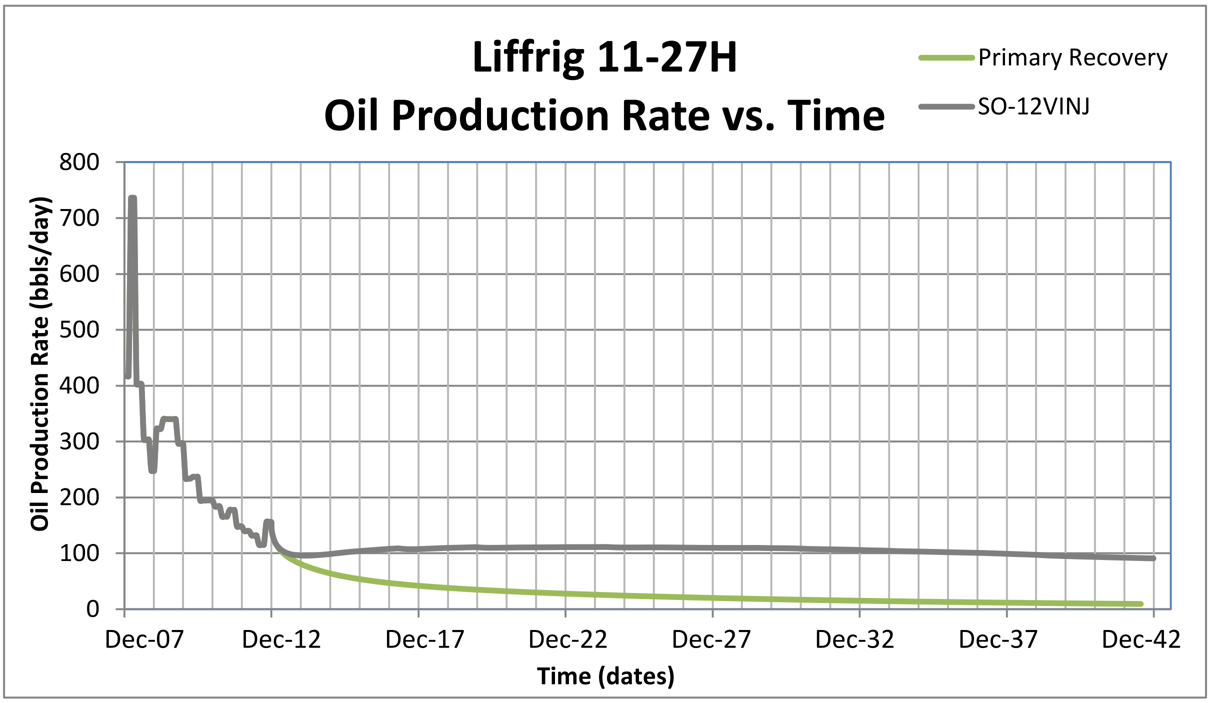

Figure 5.66 Liffrig 11-27H Oil Production Rate vs. Time
for 12 New Vetical Injection Wells Case

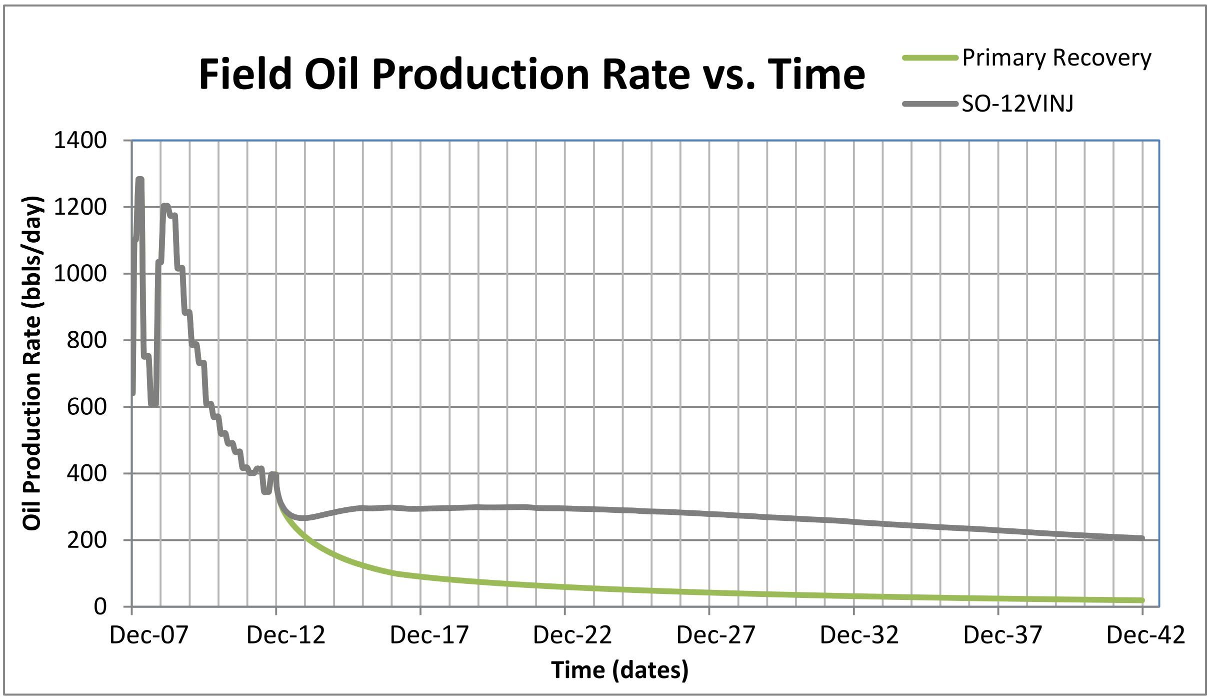

Figure 5.67 Field Oil Production Rate vs. Time
for 12 New Vertical Injection Wells Case

The increase in recovery factors of these three wells is calculated as follows:

Total oil recovered from Scenario B-2-b= $4{,}205{,}048$ stb

RF for CO_2 injection of 2 new horizontal injection wells

$$= 4{,}205{,}048 \text{ stb } / 35.88 \times 10^6 \text{ stb} = 11.72\%$$

The calculation above indicates the recovery factor for the CO_2 injection with 2 new horizontal injection wells at an injection pressure of 8000 psia and injection rate of 5000 Mscf/day increase by 6.3%. The breakthrough time for the filed occurs after 6 months of injection. The total amount of CO_2 produced along with the oil and gas at surface conditions is equal to 4.55 Bscf.

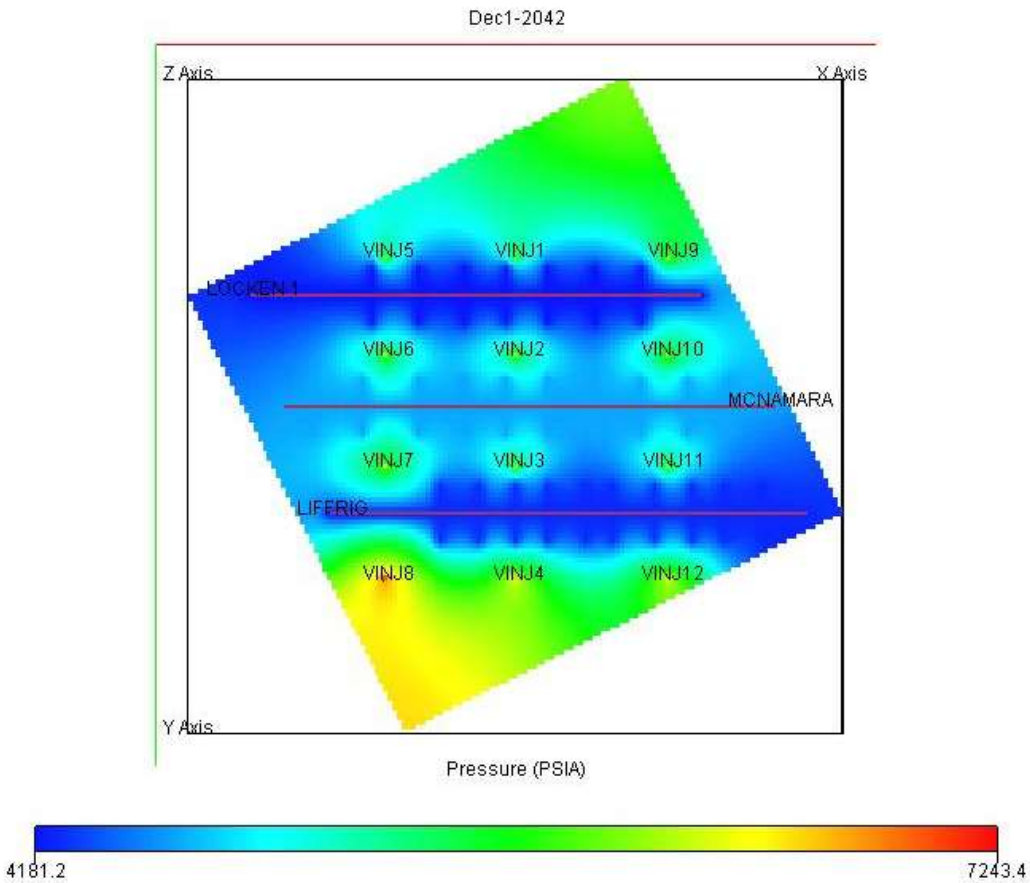

Figure 5.68 Well Pressure for the Study Area in the Sanish Field on December 1, 2042 with 12 New Vertical Injection Wells

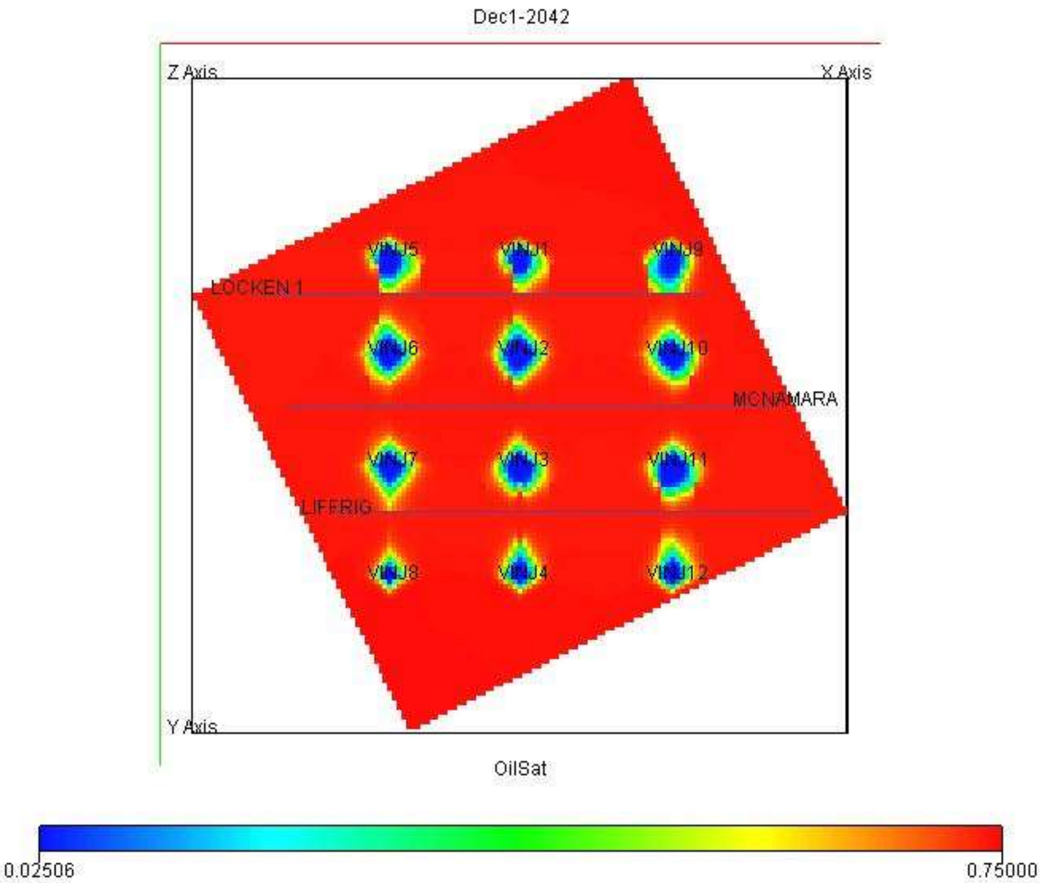

Figure 5.69 Oil Saturation for the Study Area in the Sanish Field on December 1, 2042 with 12 New Vertical Injection Wells

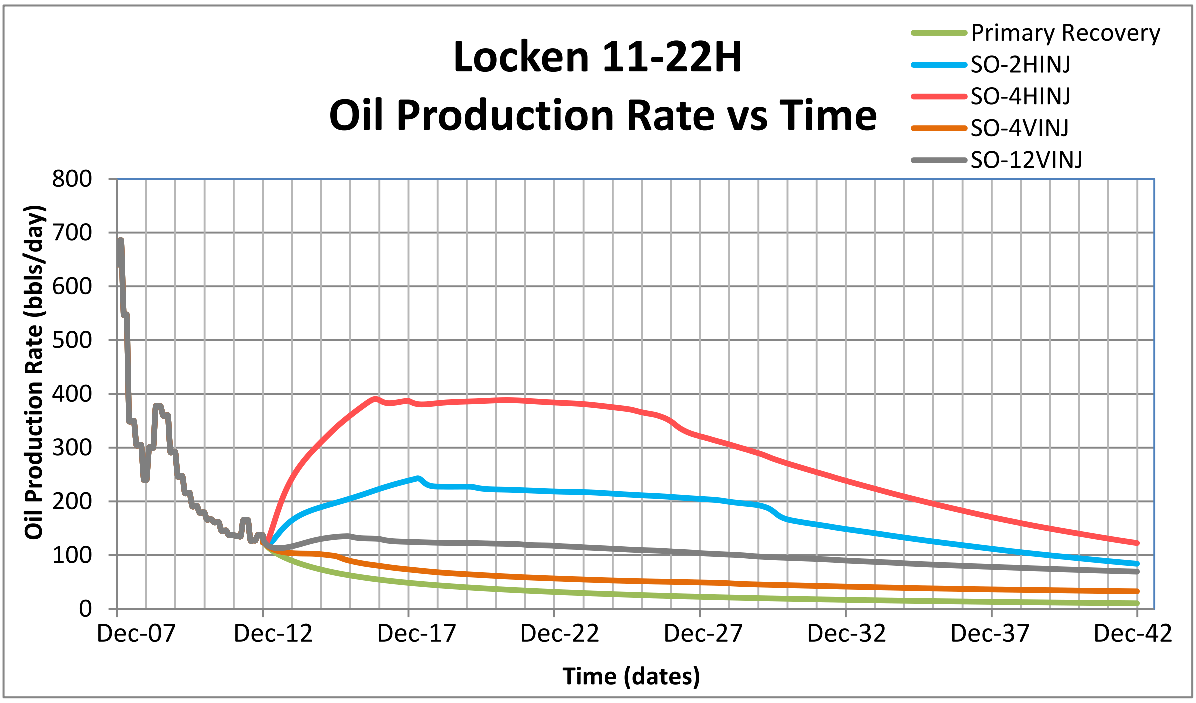

Figure 5.70 Locken 11-22H Oil Production Rate vs. Time
for All Additional New Injection Wells Cases

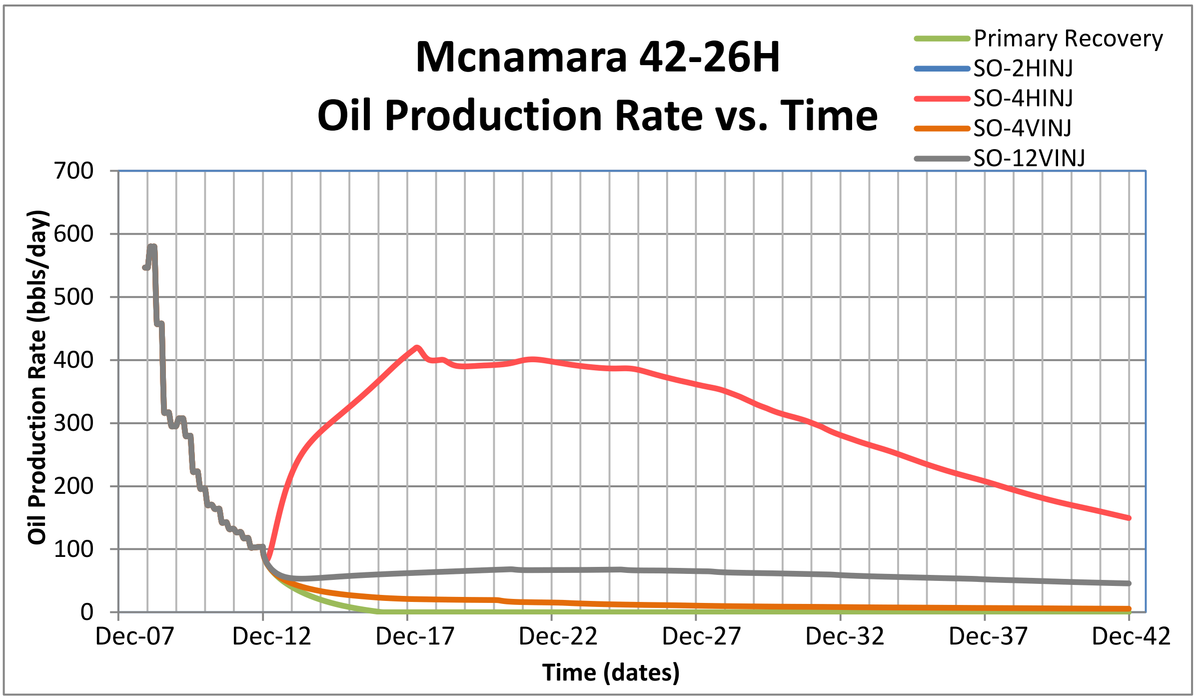

Figure 5.71 Mcnamara 42-26H Oil Production Rate vs. Time
for All Additional New Injection Wells Cases

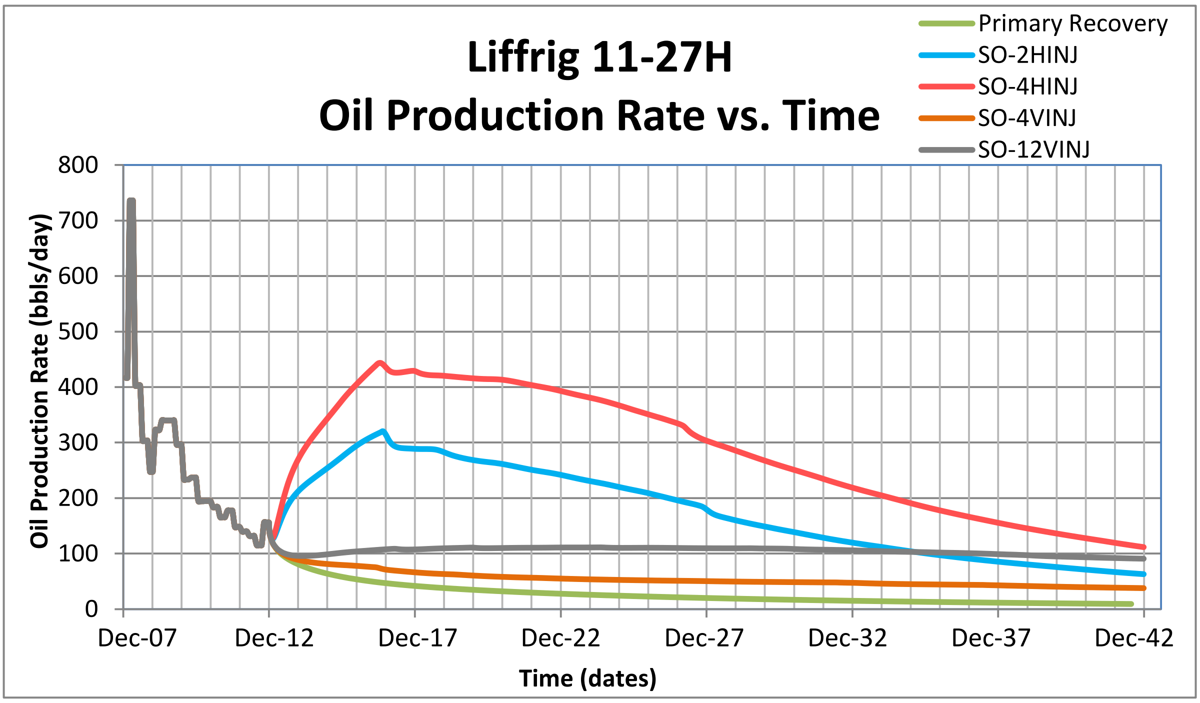

Figure 5.72 Liffrig 11-27H Oil Production Rate vs. Time
for All Additional New Injection Wells Cases

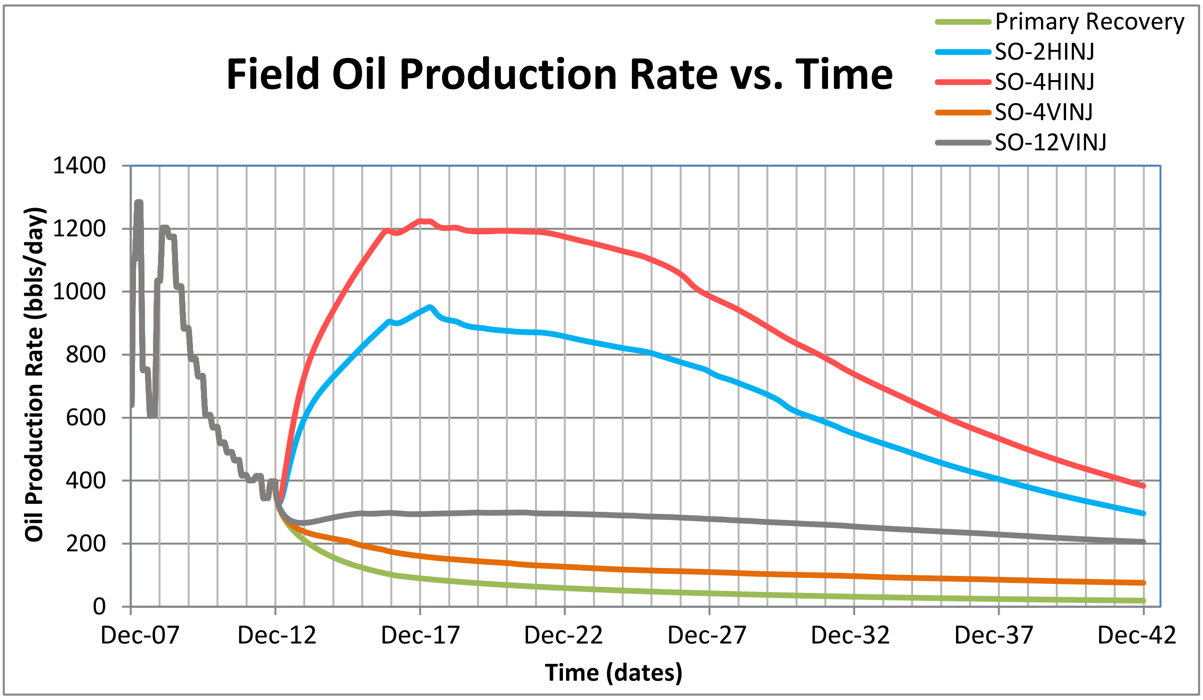

Figure 5.73 Field Oil Production Rate vs. Time
for All Additional New Injection Wells Cases

From Figure 5.70, Figure 5.71, Figure 5.72, when comparing the case with 4 horizontal injection wells and the one with 4 vertical injection wells, the results indicate that for the study area of the Sanish Field, CO_2 injection with horizontal injection wells works better than it with vertical injection wells. Because all the producers in the area are horizontal wells, horizontal injection wells would have more contact area. When comparing the case with 2 horizontal injection wells and 4 horizontal injection wells or comparing the case with 4 vertical injection wells and 12 vertical injection wells, the results from Figure 5.70 show that with more injection wells in the sector, the field would have higher oil production rate. For Mcnamara 42-26H, the differences in oil production rate between 2 horizontal injection wells case and 4 horizontal injection wells case are almost invisible. The reason is Mcnamara 42-26H is in the middle of the field sector, for 4 horizontal injection wells case, additional of well HINJ-1 and HINJ-4 is far from Mcnamara 42-26H. The effect of these two injection wells on Mcnamara 42-26H is slight.

5.3 **Summary of Different Case Scenario**

All the case scenarios are summarized through Table 5.1 to Table 5.5, including the amount of CO_2 injected, the estimated increase in recovery factor, breakthrough time after the injection, and field total solvent production. In the black oil model, well production forecasting performance on the primary recovery show a declining trend with a sector recovery factor of 5.42%. Through gas injection into the area, recovery factor increases between 5-15%.

Table 5.1: Scenario results of maximum inj. pressure with different inj. rate

Cases Scenario	Inj. Rate (Mscf/day)	Amount of CO_2 Injected	Estimated Increase in RF	Time for BT after Injection	Solvent Production (Bscf)
A-1-a	5000	0.107 PV	4.03 %	9.5 years	1.15
A-1-b	2000	0.106 PV	3.96 %	9.9 years	1.09
A-1-c	1000	0.102 PV	3.75 %	11.7 years	0.94

Table 5.2: Scenario results of maximum inj. rate with different inj. pressure

Case Scenario	Inj. Pressure (psia)	Amount of CO2 Injected	Estimated Increase in RF	Time for BT after Injection	Solvent Production (Bscf)
A-2-a	6000	0.041 PV	- 1.87 %	-	-
A-2-b	7000	0.072 PV	2.58 %	18.3 years	0.27
A-2-c	8000	0.107 PV	4.03 %	9.5 years	1.15

Table 5.3: Scenario results of different injection type

Case Scenario	Injection Type	Amount of CO_2 Injected	Estimated Increase in RF	Time for BT after Injection	Solvent Production (Bscf)
A-3-a	Water	0.045 PV	0.94 %	-	-
A-3-b	CO_2	0.107 PV	4.03 %	9.5 years	1.15

Table 5.4: Scenario results of new horizontal injection wells

Case Scenario	Horizontal Inj. Well Amount	Amount of CO_2 Injected	Estimated Increase in RF	Time for BT after Injection	Solvent Production (Bscf)
B-1-a	2	0.739 PV	18.0 %	7 months	43.49
B-1-b	4	1.10 PV	24.59 %	7 months	65.23

Table 5.5: Scenario results of new vertical injection wells

Case Scenario	Vertical Inj. Well Amount	Amount of CO_2 Injected	Estimated Increase in RF	Time for BT after Injection	Solvent Production (Bscf)
B-2-a	4	0.049 PV	1.92 %	6 months	1.98
B-2-b	12	0.135 PV	6.30 %	6 months	4.55

Scenario 1 involves CO_2 injection in Mcnamara 42-26H with maximum injection pressure 8000 psia. The impact of gas injection is analyzed by changing the injection rate fro 1000 Mscf/day to 5000 Mscf/day. The total outputs of this case are summed up in Table 5.1.

Scenario 2 is a similar case to scenario 1, which also involves CO_2 injection in Mcnamara 42-26H. But the injection rate becomes constant this time with varying injection pressure of 6000 psia, 7000 psia, and 8000 psia. All results are shown in Table 5.2.

Scenario 3 is to use maximum injection pressure of 8000 psia and injection rate of 1000 stb/day to inject water instead of CO_2. Outcomes are provided in Table 5.3.

Different than Scenario 1, 2, and 3, Scenario 4 and 5 include new injection wells. Two and four new horizontal wells with an injection pressure of 8000 psia and injection rate of 5000 Mscf/day are tested in scenario 4 and output in Table 5.4. Then with same injection pressure and rate being used in four and twelve new vertical injection are also evaluated in scenario 5, shown in Table 5.5.

These five cases allow comparing the different injection rate, different injection pressure, different injection type, vertical and horizontal injection wells. They are also used to evaluate the effect of drilling new wells along with conversion of existing producers.

1) Analyzing CO_2 injection with different injection rate and different injection pressure, the results indicate higher injection rates and higher injection pressure generate higher oil production rate. From Table 5.1 and Table 5.2, the best case is using an injection pressure of 8000 psia and injection rate of 5000 Mscf/day, and the recovery factor is estimated an increased by 4.03%.

2) Comparing continuous CO_2 injection with water flooding, the results from Table 5.3 show CO_2 injection is more effective than the water flooding with more recovery factor increase of 3.09%.

3) Evaluating the CO_2 injection using vertical and horizontal injection techniques indicates horizontal producers are able to produce much more oil produced along with horizontal injectors. More injection wells in the field can increase the recovery factor. Comparing with total amount of 2 and 4 horizontal injection wells, the recovery factor increases from 18% to 24.59%. The same result can be seen from a comparison of the total amount of 4 and 12 vertical injection wells, the recovery factor increase from 1.92% to 6.3%.

4) Among all the cases, continuous CO_2 injection associated with 4 new horizontal injection wells yield a greater maximum recovery factor of 30.01%.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

The key conclusions of this study are drawn based on the results and analyses from Chapter 5. Moreover, the recommendations for future projected related to North Dakota Bakken are suggested in the last section of this chapter.

6.1 Conclusions

- The black oil model is built first to simulate the primary recovery of the study area. A primary recovery factor of 5.42% is obtained from the model, which is consistent with the expectation. In addition, declining trends of oil production rates of all three wells are observed from the black oil model. After nearly five years of bottom hole pressure control, all oil production rates would drop under 50 bbls/day. So with a big amount of oil reserves, low primary recovery, and declining oil production rate, gas injection might be considered to apply in this area to maximize the field potential development.
- The solvent model is built according to the extension of the fluid properties and modification of the well arrangement from the black oil model. The first case scenario simulated in the solvent model is to convert existing producer Mcnamara 42-26H into an injector. Results indicate that the higher injection rate can yield higher oil production rate and greater recovery factor. But the increase amount of oil production is small, and breakthrough time is shorter along with more CO_2 need to be bought for higher injection rate.

- Analogously, oil production rate and recovery factor are proportional to injection pressure, more oil will be produced from higher injection pressure. However, when the injection pressure of Mcnamara 42-26H is 6000 psia, the recovery factor becomes lower than the primary recovery. One probable reason is that the injection time is only simulated for 30-year period, the breakthrough does not occur during the 30 years. The oil production rate might be continuing to increase afterwards, so does the recovery factor.
- Since the injection well is controlled by the injection rate first for a short time to allow the well pressure to raise, and then change to injection pressure control as soon as the well bottom hole pressure meets the requirement, injection pressure has greater impact on the recovery factor than the injection rate.
- Continuous CO_2 injection provides a higher increase of 3.09% in oil recovery as compared to water flooding. As a result, the continuous gas injection should be taken into account to use for maximizing the recovery from this tight oil reservoir.
- When simulated additional injection wells in the field sector in the solvent model, recovery factor is enhanced more than that from the conversion of an existing well. Among all the case scenarios, the addition of four new horizontal injector case has the highest recovery factor increase by 24.59%. The second best case is the one with the addition of two new horizontal injection wells, increase the recovery factor by 18.0%. However, the breakthrough time shortens from years to months or even could be days in fact. If CO_2 flooding would be applied in the Sanish Field, more horizontal injection wells should be drilled than originally in this 4 sector area.

- Additional of four vertical wells only increases the recovery factor by 1.92%. Comparing to the same injection well amount, horizontal injection wells work much better than vertical injection wells with the original three horizontal producer. Though adding twelve vertical injection wells in the region can raise the recovery factor of 6.3%, the economic factors of drilling so many new wells should be considered as well.

6.2 Recommendations for Future Work

Some aspects of this research can be examined in the future for modeling gas injection in a reservoir similar to the Sanish Field. The following recommendations are made for future projects to improve the evaluation of the effect of CO_2 injection into a shale oil reservoir and allow a more effective planning of a field potential development.

- A water-alternating-gas (WAG) injection option can be tested in this shale oil reservoir along with defining the hysteresis. In WAG system, the relative permeability of a phase is not only a function of its saturation and history, but also dependent on the history of the solvent (Schlumberger, 2009).
- Due to lack of the well pressure historical data and assumption of homogeneity, the accuracy of the model needs to be further improved. If the well pressure historical data are available, the historical matching should be conducted.
- Describe the network of natural fractures and hydraulic fractures present in the middle Bakken member more precisely and define the simulated reservoir volume more accurately.

- A dual porosity and dual permeability model or a composition model can be built by converting the solvent model with more data. The compositional model uses an equation-of-state (EOS) to calculate phase equilibrium and mass transfer of components during the multi-contact miscibility process (Jarrell, et. Al, 2002). It can provide a more accurate description of the miscibility process in this tight formation and obtain a better evaluation of impact on oil recovery.

- Conduct an economic analysis project to estimate the costs associated with conversion of existing producers for injection operation, spending on drilling new wells and the costs related to the gas. These expenses should consider the expenditure differences between using horizontal or vertical drilling technique, transportation of CO_2, the amount of CO_s needs to be bought, installation of injection facilities, and other factors that would affect the costs. The comparison results should be taken into account for the field development plan.

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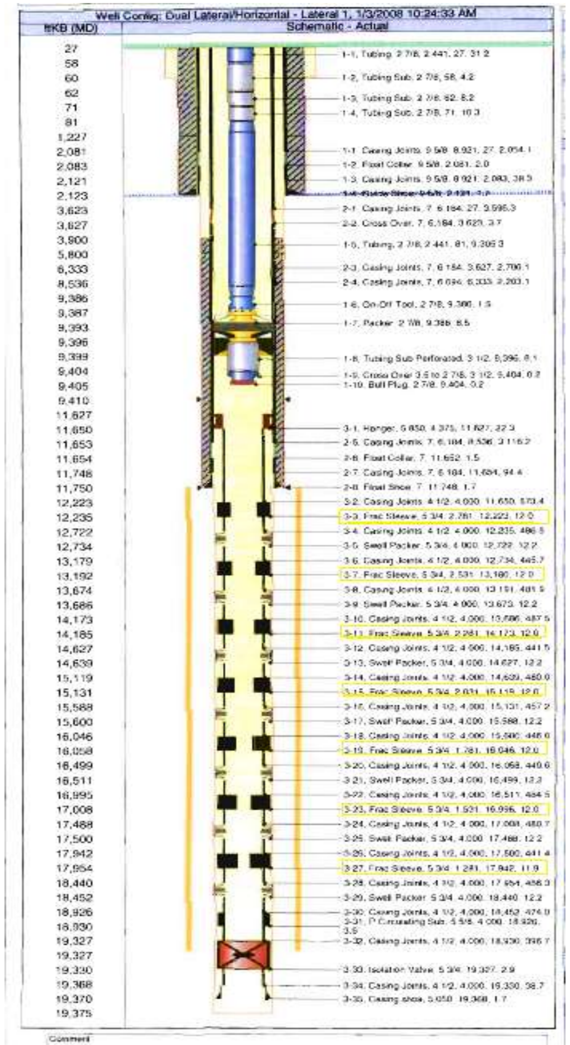
APPENDIX A-HYDRAULIC FRACTURE INFORMATION

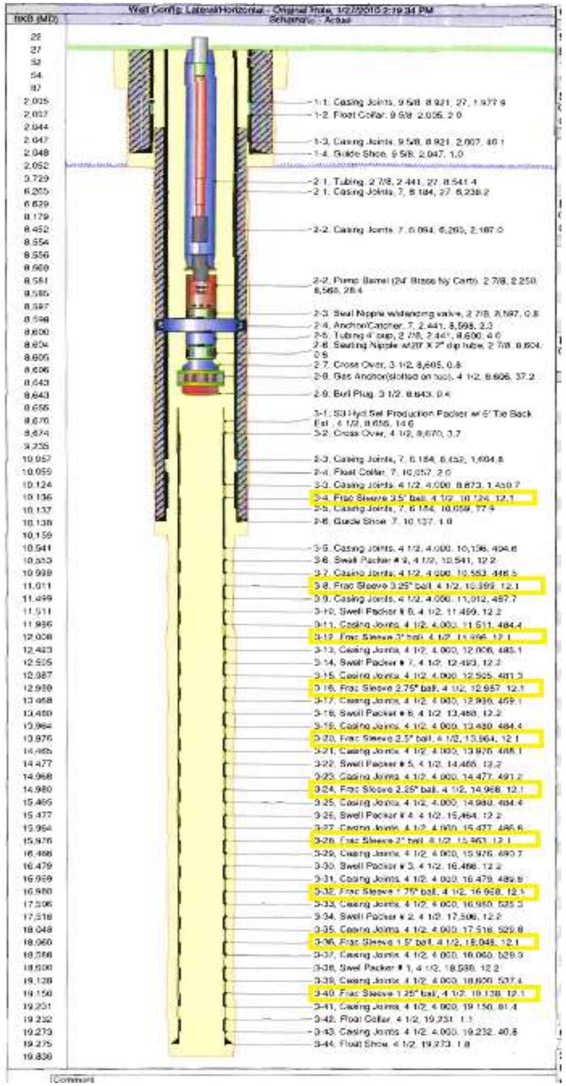
APPENDIX A includes hydraulic fracture information of each well in the study area from official well files, including the number of hydraulic fracture stages, position of fractures, the perforation interval of each fracture and so on. Because all the hydraulic fractures are being defined in the models, these information is included as a supplemental description in the form of figures and tables. Appendix A-1 is the hydraulic fracture information for well Locken 11-22H. Appendix A-2 is the hydraulic fracture information for well Mcnamara 42-26H. Appendix A-3 is the hydraulic fracture information for well Liffrig 11-27H.

APPENDIX A-1: Fractures Information of well LOCKEN 11-22H (NDIC, 2012)



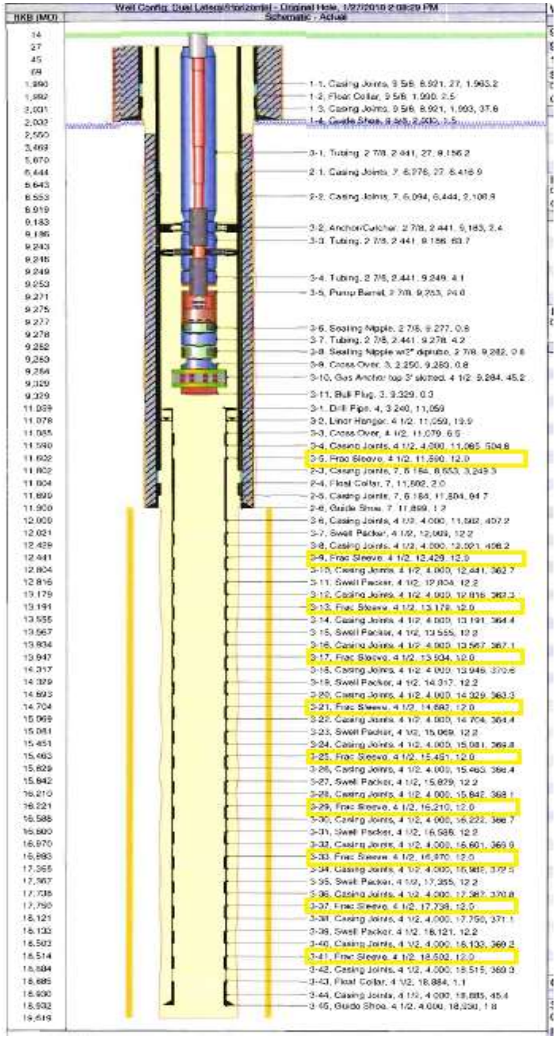
OD (in)	Wt (lbs/ft)	Grade	Top (ftKB)	Btm (ftKB)	Len (ft)	Item Description	Stages	Frac thickness (ftKB)
5.85			11627.40	11649.80	22.35	Hanger		
4 1/2	11.60	HCL-80	11649.80	12223.20	573.38	Casing Joints		
5 3/4			12223.20	12235.10	11.98	Frac Sleeve	1	11.90
4 1/2	11.60	HCL-80	12235.10	12721.60	486.48	Casing Joints		
5 3/4			12721.60	12733.80	12.21	Swell Packe		
4 1/2	11.60	HCL-80	12733.80	13179.50	445.70	Casing Joints		
5 3/4			13179.50	13191.50	11.96	Frac Sleeve	2	12.00
4 1/2	11.60	HCL-80	13191.50	13673.40	481.94	Casing Joints		
5 3/4			13673.40	13685.70	12.23	Swell Packe		
4 1/2	11.60	HCL-80	13685.70	14173.20	487.50	Casing Joints		
5 3/4			14173.20	14185.10	11.96	Frac Sleeve	3	11.90
4 1/2	11.60	HCL-80	14185.10	14626.60	441.48	Casing Joints		
5 3/4			14626.60	14638.80	12.22	Swell Packe		
4 1/2	11.60	HCL-80	14638.80	15118.80	479.98	Casing Joints		
5 3/4			15118.80	15130.80	11.99	Frac Sleeve	4	12.00
4 1/2	11.60	HCL-80	15130.80	15588.00	457.16	Casing Joints		
5 3/4			15588.00	15600.20	12.23	Swell Packe		
4 1/2	11.60	HCL-80	15600.20	16046.20	446.02	Casing Joints		
5 3/4			16046.20	16058.20	11.97	Frac Sleeve	5	12.00
4 1/2	11.60	HCL-80	16058.20	16498.80	440.58	Casing Joints		
5 3/4			16498.80	16511.00	12.22	Swell Packe		
4 1/2	11.60	HCL-80	16511.00	16995.50	484.55	Casing Joints		
5 3/4			16995.50	17007.50	11.98	Frac Sleeve	6	12.00
4 1/2	11.60	HCL-80	17007.50	17488.20	480.72	Casing Joints		
5 3/4			17488.20	17500.40	12.21	Swell Packe		
4 1/2	11.60	HCL-80	17500.40	17941.80	441.41	Casing Joints		
5 3/4			17941.80	17953.80	11.93	Frac Sleeve	7	12.00
4 1/2	11.60	HCL-80	17953.80	18440.10	486.34	Casing Joints		
5 3/4			18440.10	18452.30	12.21	Swell Packe		
4 1/2	11.60	HCL-80	18452.30	18926.30	474.01	Casing Joints		
5 5/8			18926.30	18930.00	3.65	P Circulating Sub		
4 1/2	11.60	HCL-80	18930.00	19326.70	396.74	Casing Joints		
5 3/4			19326.70	19329.60	2.88	Isolation Valve		
4 1/2	11.60	HCL-80	19329.60	19368.30	38.65	Casing Joints		
5.05			19368.30	19370.00	1.74	Casing Shoe		

Appendix A-2: Fractures Information of well MCNAMARA 42-26H (NDIC, 2012)



OD (in)	Wt (lbs/ft)	Grade	Top (ftKB)	Btm (ftKB)	Len (ft)	Item Description	Stages	Frac thickness (ftKB)
4 1/2			8655.10	8669.8	14.62	S3 Hyd. Set Production Packer w/6' Tie Back Ext.		
4 1/2			8669.80	8673.40	3.67	Cross Over		
4 1/2	11.6	L-80	8673.40	10124.10	1450.67	Casing Joints		
4 1/2			10124.10	10136.20	12.08	Frac Sleeve 3.5'' Ball	1	12.10
4 1/2	11.6	L-80	10136.20	10540.80	404.61	Casing Joints		
4 1/2			10540.80	10553.00	12.22	Swell Packer #9		
4 1/2	11.6	L-80	10553.00	10999.50	446.47	Casing Joints		
4 1/2			10999.50	11011.60	12.13	Frac Sleeve 3.25'' Ball	2	12.10
4 1/2	11.6	L-80	11011.60	11499.30	487.65	Casing Joints		
4 1/2			11499.30	11511.50	12.22	Swell Packer #8		
4 1/2	11.6	L-80	11511.50	11995.90	484.39	Casing Joints		
4 1/2			11995.90	12008.00	12.08	Frac Sleeve 3'' Ball	3	12.10
4 1/2	11.6	L-80	12008.00	12493.10	485.09	Casing Joints		
4 1/2			12493.10	12505.30	12.24	Swell Packer #7		
4 1/2	11.6	L-80	12505.30	12986.60	481.28	Casing Joints		
4 1/2			12986.60	12998.70	12.08	Frac Sleeve 2.75'' Ball	4	12.10
4 1/2	11.6	L-80	12998.70	13467.70	469.05	Casing Joints		
4 1/2			13467.70	13479.90	12.22	Swell Packer #6		
4 1/2	11.6	L-80	13479.90	13964.30	484.4	Casing Joints		
4 1/2			13964.30	13976.40	12.08	Frac Sleeve 2.5'' Ball	5	12.10
4 1/2	11.6	L-80	13976.40	14464.50	488.14	Casing Joints		
4 1/2			14464.50	14476.80	12.25	Swell Packer #5		
4 1/2	11.6	L-80	14476.80	14968.00	491.18	Casing Joints		
4 1/2			14968.00	14980.10	12.08	Frac Sleeve 2.25'' Ball	6	12.10
4 1/2	11.6	L-80	14980.10	15464.50	484.44	Casing Joints		
4 1/2			15464.50	15476.70	12.23	Swell Packer #4		
4 1/2	11.6	L-80	15476.70	15963.50	486.77	Casing Joints		
4 1/2			15963.50	15975.60	12.09	Frac Sleeve 2'' Ball	7	12.10
4 1/2	11.6	L-80	15975.60	16466.30	490.71	Casing Joints		
4 1/2			16466.30	16478.50	12.24	Swell Packer #3		
4 1/2	11.6	L-80	16478.50	16968.40	489.83	Casing Joints		
4 1/2			16968.40	16980.40	12.08	Frac Sleeve 1.75'' Ball	8	12.00
4 1/2	11.6	L-80	16980.40	17505.80	525.31	Casing Joints		
4 1/2			17505.80	17518.00	12.24	Swell Packer #2		
4 1/2	11.6	L-80	17518.00	18047.80	529.77	Casing Joints		
4 1/2			18047.80	18059.90	12.09	Frac Sleeve 1.5'' Ball	9	12.10
4 1/2	11.6	L-80	18059.90	18588.10	528.29	Casing Joints		
4 1/2			18588.10	18600.40	12.24	Swell Packer #1		
4 1/2	11.6	L-80	18600.40	19137.80	537.45	Casing Joints		
4 1/2			19137.80	19149.90	12.07	Frac Sleeve 1.25'' Ball	10	12.10
4 1/2	11.6	L-80	19149.90	19231.30	81.39	Casing Joints		
4 1/2			19231.30	19232.40	1.1	Float Collar		
4 1/2	11.6	L-80	19232.40	19273.20	40.81	Casing Joints		
4 1/2			19273.20	19275.00	1.8	Float shoe		

Appendix A-3: Fractures Information of Well LIFFRIG 11-27H (NDIC, 2012)



OD (in)	Wt (lbs/ft)	Grade	Top (ftKB)	Btm (ftKB)	Len (ft)	Item Description	Stages	Frac thickness (ftKB)
4	15.7	X95	11058.60	11058.60	0.00	Drill Pipe		
4 1/2			11058.60	11078.50	19.92	Liner Hanger		
4 1/2			11078.50	11085.00	6.54	Cross Over		
4 1/2	11.6	N-80	11085.00	11589.80	504.85	Casing Joints		
4 1/2			11589.80	11601.90	12.03	Frac Sleeve	1	12.10
4 1/2	11.6	N-80	11601.90	12009.00	407.18	Casing Joints		
4 1/2			12009.00	12021.20	12.21	Swell Packer		
4 1/2	11.6	N-80	12021.20	12429.40	408.16	Casing Joints		
4 1/2			12429.40	12441.40	12.01	Frac Sleeve	2	12.00
4 1/2	11.6	N-80	12441.40	12804.10	362.73	Casing Joints		
4 1/2			12804.10	12816.30	12.20	Swell Packer		
4 1/2	11.6	N-80	12816.30	13178.70	362.34	Casing Joints		
4 1/2			13178.70	13190.70	11.99	Frac Sleeve	3	12.00
4 1/2	11.6	N-80	13190.70	13555.10	364.41	Casing Joints		
4 1/2			13555.10	13567.30	12.19	Swell Packer		
4 1/2	11.6	N-80	13567.30	13934.40	367.12	Casing Joints		
4 1/2			13934.40	13946.40	11.98	Frac Sleeve	4	12.00
4 1/2	11.6	N-80	13946.40	14316.90	370.56	Casing Joints		
4 1/2			14316.90	14329.10	12.20	Swell Packer		
4 1/2	11.6	N-80	14329.10	14692.50	363.34	Casing Joints		
4 1/2			14692.50	14704.50	12.01	Frac Sleeve	5	12.00
4 1/2	11.6	N-80	14704.50	15068.90	364.44	Casing Joints		
4 1/2			15068.90	15081.10	12.21	Swell Packer		
4 1/2	11.6	N-80	15081.10	15451.00	369.82	Casing Joints		
4 1/2			15451.00	15463.00	12.00	Frac Sleeve	6	12.00
4 1/2	11.6	N-80	15463.00	15829.30	366.37	Casing Joints		
4 1/2			15829.30	15841.50	12.22	Swell Packer		
4 1/2	11.6	N-80	15841.50	16209.60	368.08	Casing Joints		
4 1/2			16209.60	16221.60	12.00	Frac Sleeve	7	12.00
4 1/2	11.6	N-80	16221.60	16588.30	366.70	Casing Joints		
4 1/2			16588.30	16600.50	12.21	Swell Packer		
4 1/2	11.6	N-80	16600.50	16970.40	369.89	Casing Joints		
4 1/2			16970.40	16982.50	12.03	Frac Sleeve	8	12.10
4 1/2	11.6	N-80	16982.50	17355.00	372.53	Casing Joints		
4 1/2			17355.00	17367.20	12.19	Swell Packer		
4 1/2	11.6	N-80	17367.20	17738.00	370.80	Casing Joints		
4 1/2			17738.00	17750.00	12.01	Frac Sleeve	9	12.00
4 1/2	11.6	N-80	17750.00	18121.10	371.11	Casing Joints		
4 1/2			18121.10	18133.30	12.20	Swell Packer		
4 1/2	11.6	N-80	18133.30	18502.50	369.19	Casing Joints		
4 1/2			18502.50	18514.50	12.02	Frac Sleeve	10	12.00
4 1/2	11.6	N-80	18514.50	18883.80	369.27	Casing Joints		
4 1/2			18883.80	18884.80	1.06	Float Collar		
4 1/2	11.6	N-80	18884.80	18930.20	45.39	Casing Joints		
4 1/2			18930.20	18932.00	1.78	Guide Shoe		

APPENDIX B-MODELING CODE

The modeling code for solvent model executed up to December 1, 2042

```
--********************NEW RUNSPEC SECTION*********************
RUNSPEC
TITLE
Solvent Sanish Field:
DIMENS
   141       141     10    /

OIL
GAS
DISGAS
WATER

SOLVENT

FIELD

MISCIBLE
1      20    'NONE'    /

TABDIMS
      1        1      30      30       1        20 /

WELLDIMS
      30      200       1        40 /

START
     1 'DEC' 2007    /

UNIFOUT

--FMTOUT

NSTACK
80/

--============================================================
GRID
INIT
```

```
INCLUDE
ACTNUM.dat
/

DX
198810*100.0 /

DY
198810*100.0 /

DZ
198810*3.0/

BOX
1 141 1 141    1    1 /

TOPS
19881*10100 /
ENDBOX

BOX
1    141    1    141    1    10 /

PORO
198810*0.06 /

PERMX
198810*0.04
/

COPY
        'PERMX' 'PERMY' /
        'PERMY' 'PERMZ'/
/

ENDBOX

--Adding fracture permeability
--LOCKEN 11-22H
BOX
40    40    41    53    1    10    /
PERMX
130*10 /
```

```
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
50    50    41    53    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
60    60    41    53    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
69    69    41    53    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
78    78    41    53    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
```

```
ENDBOX

BOX
88    88    41    53    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
98    98    41    53    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
14    111    47    47    1    10    /
PERMX
980*10 /
PERMY
980*10 /
PERMZ
980*10 /
ENDBOX

--LIFFRIG 11-27H
BOX
55    55    88    100    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
```

```
63    63    88    100    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
71    71    88    100    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
78    78    88    100    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
86    86    88    100    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
92    92    88    100    1    10    /
PERMX
130*10 /
PERMY
```

```
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
101    101    88    100    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
109    109    88    100    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
116    116    88    100    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
124    124    88    100     1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX
```

```
BOX
31    134    94    94     1    10    /
PERMX
1040*10 /
PERMY
1040*10 /
PERMZ
1040*10 /
ENDBOX

--MCNAMARA 42-26H
BOX
117    117    65    77    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
108    108    65    77    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
98    98    65    77     1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
88    88    65    77    1    10    /
```

```
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
78    78    65    77    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
69    69    65    77     1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
60    60    65    77    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
50    50    65    77    1    10    /
PERMX
130*10 /
PERMY
130*10 /
```

```
PERMZ
130*10 /
ENDBOX

BOX
38    38    65    77    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
27    27    65    77    1    10    /
PERMX
130*10 /
PERMY
130*10 /
PERMZ
130*10 /
ENDBOX

BOX
21    127    71    71    1    10    /
PERMX
1070*10 /
PERMY
1070*10 /
PERMZ
1070*10 /
ENDBOX

--==============================================================

PROPS

ROCK
3256.00 1E-05/


SWFN
--Sw          krw                    Pc
```

```
0.250       0.00000    0.000
0.300       0.00000    0.000
0.400       9.7546E-04    0.000
0.500       0.01561    0.000
0.600       0.07901    0.000
0.700       0.24972    0.000
0.750       0.40000    0.000
/

SGFN
--Sg        krg             Pc
0.000       0.0000     0.000
0.050       0.0000     0.000
0.100       6.8587E-04    0.000
0.200       0.01852    0.000
0.300       0.08573    0.000
0.400       0.23525    0.000
0.500       0.50000    0.000
/

SOF2
--So        kro
0.250       0.00000
0.300       0.00110
0.400       0.02963
0.500       0.13717
0.600       0.37641
0.700       0.80000
0.750       1.00000
/

SOF3
--So        krow            krog
0.250       0.00000    0.0000
0.300       0.00110    0.0000
0.400       0.02963    0.0000
0.500       0.13717    0.0000
0.600       0.37641    0.0064
0.700       0.80000    0.0512
0.750       1.00000    1.0000

/

SORWMIS
```

```
--Sw       misSor
0.00       0.00
0.50       0.05
1.00       0.15
/

SSFN
--         krg*       krs*
0           0.0         0.0
1.0        1.0         1.0
/

MISC
--solfrac    misc
0.0               0.0
0.1               1.0
1.0               1.0
/

PMISC
--oil phase pr.        misc
1000                    0.0
1500                          0.0
2000                    0.0
2500                    0.0
3000                    0.0
3100                          1.0
3500                    1.0
4000                    1.0
4500                    1.0
5000                    1.0
5500                    1.0
6000                    1.0
7000                    1.0
8000                    1.0
9000                    1.0
/

PVTW
-- ref-pr.    bwi         cw                 uw
3256        1.015              3.00D-6            1             0      / ( psi rb/stb    1/psi    CP )
```

```
DENSITY
42.0    65.48    0.059    /


SDENSITY
--lb/ft3
0.123628        /

TLMIXPAR
0.5          /

PVDG
--pr(psia)      Bg(rb/Mscf)          vis(cP)
216      16.400 0.0138
376      9.256    0.0140
536      6.381    0.0142
696      4.832    0.0145
856      3.866    0.0148
1016     3.207    0.0151
1176     2.732    0.0155
1336     2.374    0.0159
1496     2.097    0.0164
1656     1.877    0.0169
1816     1.699    0.0174
1976     1.553    0.0180
2136     1.431    0.0186
2296     1.330    0.0193
2456     1.244    0.0199
2616     1.171    0.0206
2776     1.108    0.0213
2936     1.053    0.0219
3096     1.006    0.0226
3256     0.964    0.0233
/

PVDS
--pr(psia)        Bg(rb/Mscf)        vis(cP)
150.00              23.1161           0.013
500.00                6.6489          0.018
1500.0                1.9065          0.023
2000.0                1.3137          0.025
2500.0                1.0009          0.030
2800.0                0.8617          0.033
```

```
3000.0          0.7983      0.035
3200.0          0.7429      0.036
3500.0          0.6741      0.040
3800.0          0.6256       0.042
4000.0          0.5988      0.045
4500.0          0.5561      0.048
4815.0          0.5308      0.049
5000.0          0.5148      0.051
5200.0          0.5053       0.053
5500.0          0.4907      0.055
6000.0          0.4707      0.060
6500.0          0.4455      0.064
7000.0          0.4290      0.067
7500.0          0.4147      0.072
8000.0          0.4111      0.075
8500.0          0.4079      0.078
9000.0          0.3873      0.080
/

PVTO
--Rs     RefPr      Bo     vis
0.062     300     1.129   0.586 /
0.136     600     1.166   0.496 /
0.218     900     1.208   0.435 /
0.305     1200    1.255   0.390 /
0.397     1500    1.305   0.355 /
0.493     1800    1.359   0.328 /
0.593     2100    1.416   0.306 /
0.695     2400    1.476   0.287 /
0.800     2700    1.539   0.271 /
0.907     3000    1.604   0.258 /
1.000     3256    1.662   0.247
          3600    1.649   0.255
          3900    1.637   0.263
          4200    1.626   0.271
          4500    1.615   0.279
          4800    1.604   0.288
          5100    1.594   0.298
          5400    1.583   0.308
          5700    1.573   0.318
          6000    1.562   0.328
          6300    1.552   0.338
          6600    1.541   0.348
          6900    1.53    0.358
```

```
            7200    1.519    0.368 /
/

SOLUTION
==============================================================

EQUIL
-- 1       2    3       4    5       6          7          8            9
10100    7200    10500    0.0    5000    0.0    1 /

RSVD
10100      0.800
10130      0.800
/

SUMMARY
==============================================================
RUNSUM
SEPARATE

-- Variables to output are greatly flexible.
-- Summary variables influence little on simulation.
-- Summary output influences only disk capacity.

FOIP

FOPR

FOPT

WOPR
'LOCKEN 11-22H'
'MCNAMARA 42-26H'
'LIFFRIG 11-27H'
  /

WOPT
'LOCKEN 11-22H'
'MCNAMARA 42-26H'
'LIFFRIG 11-27H'
/
WBHP
'LOCKEN 11-22H'
'MCNAMARA 42-26H'
```

```
'LIFFRIG 11-27H'
/

WNIR
'MCNAMARA 42-26H'
/

FNIT

WNPR
'LOCKEN 11-22H'
'LIFFRIG 11-27H'
/

WNPT
'LOCKEN 11-22H'
'LIFFRIG 11-27H'
/

FNPT

FNPR

SCHEDULE
==========================================================

RPTRST
BASIC=2 /

TUNING
0.1 30.4    /
/
30 1 90 /

------1
WELSPECS
'LOCKEN 11-22H'       'G'      14      47      -1 'OIL' 3*    N/
/

COMPDAT
-- 1                       2        3      4    5           6    7    8         9        10     11
'LOCKEN 11-22H' 14      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LOCKEN 11-22H' 15      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LOCKEN 11-22H' 16      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
```

'LOCKEN 11-22H'	17	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	18	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	19	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	20	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	21	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	22	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	23	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	24	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	25	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	26	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	27	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	28	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	29	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	30	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	31	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	32	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	33	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	34	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	35	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	36	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	37	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	38	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	39	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	40	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	41	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	42	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	43	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	44	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	45	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	46	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	47	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	48	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	49	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	50	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	51	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	52	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	53	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	54	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	55	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	56	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	57	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	58	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	59	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LOCKEN 11-22H'	60	47	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/

'LOCKEN 11-22H' 61	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 62	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 63	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 64	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 65	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 66	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 67	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 68	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 69	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 70	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 71	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 72	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 73	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 74	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 75	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 76	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 77	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 78	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 79	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 80	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 81	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 82	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 83	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 84	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 85	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 86	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 87	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 88	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 89	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 90	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 91	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 92	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 93	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 94	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 95	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 96	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 97	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 98	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 99	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 100	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 101	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 102	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 103	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/
'LOCKEN 11-22H' 104	47	5	5	'OPEN' 1* 1*	0.729	1*	0	1* x/

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'LOCKEN 11-22H' 105      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LOCKEN 11-22H' 106      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LOCKEN 11-22H' 107      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LOCKEN 11-22H' 108      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LOCKEN 11-22H' 109      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LOCKEN 11-22H' 110      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LOCKEN 11-22H' 111      47      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
/

WCONPROD
-- 1                       2           3         4     [5    6    7      8]      9
'LOCKEN 11-22H' 'OPEN' 'ORAT' 640.73    4*      100      /
/

DATES
13 'DEC' 2007/
/

------2
WELSPECS
'LIFFRIG 11-27H'       'G'      31      94      -1 'OIL'    3*    N/
/

COMPDAT
-- 1                       2        3        4    5          6    7    8         9       10    11
'LIFFRIG 11-27H'     31      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     32      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     33      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     34      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     35      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     36      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     37      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     38      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     39      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     40      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     41      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     42      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     43      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     44      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     45      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     46      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     47      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     48      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
'LIFFRIG 11-27H'     49      94      5    5    'OPEN' 1* 1*       0.729       1*    0    1* x/
```

'LIFFRIG 11-27H'	50	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	51	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	52	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	53	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	54	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	55	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	56	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	57	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	58	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	59	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	60	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	61	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	62	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	63	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	64	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	65	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	66	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	67	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	68	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	69	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	70	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	71	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	72	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	73	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	74	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	75	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	76	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	77	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	78	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	79	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	80	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	81	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	82	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	83	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	84	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	85	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	86	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	87	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	88	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	89	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	90	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	91	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	92	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/
'LIFFRIG 11-27H'	93	94	5	5	'OPEN'	1*	1*	0.729	1*	0	1* x/

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'LIFFRIG 11-27H' 94 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 95 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 96 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 97 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 98 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 99 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 100 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 101 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 102 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 103 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 104 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 105 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 106 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 107 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 108 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 109 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 110 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 111 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 112 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 113 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 114 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 115 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 116 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 117 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 118 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 119 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 120 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 121 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 122 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 123 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 124 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 125 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 126 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 127 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 128 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 129 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 130 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 131 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 132 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 133 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
'LIFFRIG 11-27H' 134 94 5 5 'OPEN' 1* 1* 0.729 1* 0 1* x/
/
```

```
WCONPROD
-- 1                              2           3         4      [5    6    7      8]      9
'LOCKEN 11-22H'        'OPEN' 'ORAT' 685.2      4*      100      /
'LIFFRIG 11-27H'      'OPEN' 'ORAT' 416.77    4*      100      /
/

DATES
23 'JAN' 2008/
/

WCONPROD
-- 1           2           3    4    [5    6    7      8]      9
'LOCKEN 11-22H'        'OPEN' 'ORAT' 547.21    4*      100      /
'LIFFRIG 11-27H'      'OPEN' 'ORAT' 735.90    4*      100      /
/

DATES
1 'APR' 2008/
/

WCONPROD
-- 1           2           3    4    [5    6    7      8]      9
'LOCKEN 11-22H'        'OPEN' 'ORAT' 349.21    4*      100      /
'LIFFRIG 11-27H'      'OPEN' 'ORAT' 402.73    4*      100      /
/

DATES
1 'JUL' 2008/
/

WCONPROD
-- 1           2           3    4    [5    6    7      8]      9
'LOCKEN 11-22H'        'OPEN' 'ORAT' 304.49    4*      100      /
'LIFFRIG 11-27H'      'OPEN' 'ORAT' 303.38    4*      100      /
/

DATES
1 'OCT' 2008/
/
------3
WELSPECS
'MCNAMARA 42-26H'        'G'      127      71      -1 'OIL'    3*    N/
/
```

```
COMPDAT
-- 1                    2       3    4   5        6   7   8       9      10   11
'MCNAMARA 42-26H' 127   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 126   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 125   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 124   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 123   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 122   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 121   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 120   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 119   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 118   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 117   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 116   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 115   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 114   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 113   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 112   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 111   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 110   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 109   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 108   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 107   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 106   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 105   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 104   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 103   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 102   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 101   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 100   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 99   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 98   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 97   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 96   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 95   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 94   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 93   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 92   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 91   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 90   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 89   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 88   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 87   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
'MCNAMARA 42-26H' 86   71   5   5   'OPEN' 1* 1*   0.5     1*   0   1* x/
```

'MCNAMARA 42-26H' 85	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 84	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 83	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 82	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 81	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 80	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 79	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 78	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 77	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 76	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 75	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 74	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 73	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 72	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 71	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 70	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 69	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 68	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 67	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 66	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 65	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 64	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 63	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 62	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 61	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 60	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 59	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 58	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 57	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 56	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 55	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 54	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 53	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 52	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 51	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 50	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 49	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 48	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 47	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 46	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 45	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 44	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 43	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/
'MCNAMARA 42-26H' 42	71	5	5	'OPEN'	1*	1*	0.5	1*	0	1* x/

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'MCNAMARA 42-26H' 41     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 40     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 39     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 38     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 37     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 36     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 35     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 34     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 33     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 32     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 31     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 30     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 29     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 28     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 27     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 26     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 25     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 24     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 23     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 22     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
'MCNAMARA 42-26H' 21     71     5    5    'OPEN' 1* 1*    0.5       1*    0    1* x/
/

WCONPROD
-- 1                     2          3        4     [5    6    7     8]     9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 240.37    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 546.77    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 247.57    4*      100      /
/

DATES
06 'DEC' 2008/
/

WCONPROD
-- 1           2          3    4    [5    6    7     8]     9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 300.08    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 579.64    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 322.78    4*      100      /
/

DATES
28 'FEB' 2009/
/
```

```
WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'       'OPEN' 'ORAT' 376.70    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 457.73    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 339.97    4*      100      /
/

DATES
31 'MAY' 2009/
/

WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'       'OPEN' 'ORAT' 359.80    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 316.79    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 339.97    4*      100      /
/

DATES
31 'AUG' 2009/
/

WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'       'OPEN' 'ORAT' 291.73    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 295.40    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 296.53    4*      100      /
/

DATES
30 'NOV' 2009/
/

WCONPROD
-- 1                              2              3          4    [5    6    7      8]      9
'LOCKEN 11-22H'       'OPEN' 'ORAT' 246.42    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 307.06    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 233.50    4*      100      /
/

DATES
28 'FEB' 2010/
/
```

```
WCONPROD
-- 1           2           3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 215.57    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 279.72    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 236.72    4*      100      /
/

DATES
31 'MAY' 2010/
/

WCONPROD
-- 1           2           3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 191.05    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 223.10    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 194.34    4*      100      /
/

DATES
31 'AUG' 2010/
/

WCONPROD
-- 1           2           3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 179.20    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 196.18    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 194.63    4*      100      /
/

DATES
30 'NOV' 2010/
/

WCONPROD
-- 1           2           3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 166.36    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 170.31    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 183.68    4*      100      /
/


DATES
28 'FEB' 2011/
/
```

```
WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 161.02    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 164.03    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 165.60    4*      100      /
/

DATES
31 'MAY' 2011/
/

WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 145.58    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 142.58    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 177.29    4*      100      /
/

DATES
31 'AUG' 2011/
/

WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 137.40    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 132.22    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 147.88    4*      100      /
/

DATES
30 'NOV' 2011/
/

WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 135.23    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 126.84    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 139.68    4*      100      /
/
DATES
29 'FEB' 2012/
/
```

```
WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 164.72    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 117.65    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 131.80    4*      100      /
/

DATES
31 'MAY' 2012/
/

WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 127.25    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 102.98    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 115.12    4*      100      /
/

DATES
31 'AUG' 2012/
/

WCONPROD
-- 1            2            3    4    [5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'ORAT' 137.11    4*      100      /
'MCNAMARA 42-26H' 'OPEN' 'ORAT' 103.43    4*      100      /
'LIFFRIG 11-27H'    'OPEN' 'ORAT' 156.03    4*      100      /
/

DATES
30 'NOV' 2012/
/

WCONINJE
'MCNAMARA 42-26H'       GAS      OPEN      RATE      5000      1*      8000 /
/

WSOLVENT
'MCNAMARA 42-26H'       1.0    /
/

WCONPROD
-- 1            2            3    [4    5    6    7      8]      9
'LOCKEN 11-22H'      'OPEN' 'BHP' 5*      4185      /
```

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'LIFFRIG 11-27H'    'OPEN' 'BHP' 5*      4250      /
/

DATES
1 'DEC' 2012/
/
DATES
1 'JAN' 2013/
/
DATES
1 'FEB' 2013/
/
DATES
1 'MAR' 2013/
/
DATES
1 'APR' 2013/
/
DATES
1 'MAY' 2013/
/
DATES
1 'JUN' 2013/
/
DATES
1 'JUL' 2013/
/
DATES
1 'AUG' 2013/
/
DATES
1 'DEC' 2042/
/



END
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