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Investigating a Pilot Area in the Williston Basin Three Forks Formation to Determine the Optimal Inter-Well Spacing and Hydraulic Fracture Length to Maximize Economic Recovery

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by

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Abstract

The objective of this work is to determine optimal inter-well spacing and hydraulic fracture length of the Three Forks assets in the Williston Basin operated by SM Energy. SM Energy is an independent exploration and production company with operations across North America, mainly in Texas and North Dakota. SM Energy recently switched to infill drilling development in their North Dakota assets and is interested in knowing the economically optimal number of wells that can be drilled per two-section drilling unit.

A simulation approach was taken in this research to address SM Energy's issue. For research purposes a small pilot area was chosen from the Williston Basin with twelve operating wells. The pilot area is located at Colgan Field, Williston Basin North Dakota USA. The geological and reservoir model of the pilot area was simulated in Petrel and hydraulic fracture properties were obtained from SM Energy and incorporated into the Petrel model.

After building a sound geological model the next focus was to match observed production data from the wells in the study area. After validating the model by successful history matching, the simulated model was used to answer the study question. The study question was answered by evaluating different case scenarios with symmetrical well spacing and varying well densities. Economic analysis was performed using current drilling costs, operating costs and a range of oil prices. Results from economic analysis were used to determine the most profitable situation for SM Energy.

Another focus of this thesis was on high water cuts in the operating wells. The study wells are operating around 50% water cut. In this work water influx was modelled using different aquifer models and flow geometries to match the water production data from the field. This work determined the number of wells that can be drilled economically in the Three Forks asset. In addition, SM Energy also benefits by understanding the predominant source of water influx in the study area.

Dedication

I dedicate this thesis to my parents K.S. Ravee and Nirmala Ravee who have always been so close to me and I always found them closer to my heart even though we live thousands of miles apart. Mom and Dad I always knew you believed in me and always wanted the best for me. I also like to dedicate this thesis to my brother Venkatesh Sundararajulu Ravee who has been my role model and inspiration growing up. You are the one who made me to believe nothing is impossible to a willing heart. I would like to thank Stephanie D. Brackett and Jocelyn R. Christensen for teaching me life is to explore and to be happy and always filled with full of surprises. I would never forget all the chats and beautiful moments I shared with you guys. A special thanks to my Uncle K. Padmanabhan and Aunt Prema Padmanabhan for care packages and prayers. I would like to express my gratitude for my friends Tut G. Chol and Anthony Kaah for fun filled driving classes. Now my ability driving in opposite side of the road has become a second nature as to my old way of driving. Cannot ask for a better roommate, thank you Joseph Fontana for all the fun filled moments and help and support during my stay here in Butte MT.

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I express my heart felt gratitude to Montana Tech Petroleum Engineering department for accepting me into the program. I would like to thank Leo Heath and Burt Todd for financial support and assistantship which made my Masters in Petroleum Engineering dream come true.

Thank you to my thesis chair and advisor Professor Burt J. Todd. Thanks for offering continuous advice, systematic guidance and untiring support during my research work. I owe you a debt of gratitude Burt.

I would like to thank SM Energy for providing me with this project. A special thanks to Danny Green for providing inputs and proficiency in the study area.

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1. Introduction

The main objective of this thesis is to determine optimal inter-well spacing and hydraulic fracture length for production from the Three Forks formation of Northwestern North Dakota through reservoir simulation. The purpose of this work is to better understand and provide solutions for operational problems faced by SM Energy. SM Energy focuses their drilling in the Bakken and Three Forks formations in their Gooseneck prospects in McKenzie, Williams and Divide Counties, North Dakota. As an operator, SM Energy faces challenges such as high water cut in newly drilled wells, developing effective stimulation strategies, and determining optimal well spacing.

The study area for this project is Colgan field, Gooseneck prospect (27) Divide County, North Dakota. As of January 2014, thirty-four wells have been drilled in the Colgan field to hold the lease for the acreage, but additional infill wells must be drilled to maximize recovery. In this work, twelve operating wells in the Colgan field selected to study. A geological model of the study area constructed based on data from the operator and public domain sources. Because our study area has low permeability, all twelve wells are hydraulically fractured. The hydraulic fracturing properties were obtained from the SM Energy and the results were incorporated into the reservoir simulation model. After gaining confidence in the simulation model through history matching, the model used to answer the study question.

Another important aspect of this project was to understand the water production from the study area. Currently, the field produces a range of water cuts between 25-60% with an average 50% water cut field-wide. No source of water influx has been identified so far. To better understand this problem, this study investigated the effects of various aquifer models to simulate the water production from these wells. Water production increases the operating costs because produced water must be treated for impurities and re-injected back into the ground. Identifying the source and the pattern of water influx will help the operating company to decrease the capital cost for future developments.

The desired outcome of this project is to determine the optimal combination of well density and fracture length required to produce Three Forks formation reserves most economically. If successful, this research will help SM Energy plan their future development strategies in the Williston Basin as well as advance the understanding of unconventional reservoirs.

1.1. Problem Statement

This thesis investigated a pilot area in the Williston Basin Three Forks formation to determine the optimal inter-well spacing and hydraulic fracture length to maximize economic recovery.

2. Background

The Williston Basin is a sedimentary basin as shown in Figure 1 extending across North Dakota, South Dakota and the Canadian provinces of Saskatchewan and Alberta. The Williston Basin is a prolific oil producing area, producing from many geologic formations. The Three Forks, a Devonian aged formation, is one of these oil-producing strata and is the subject of this study.

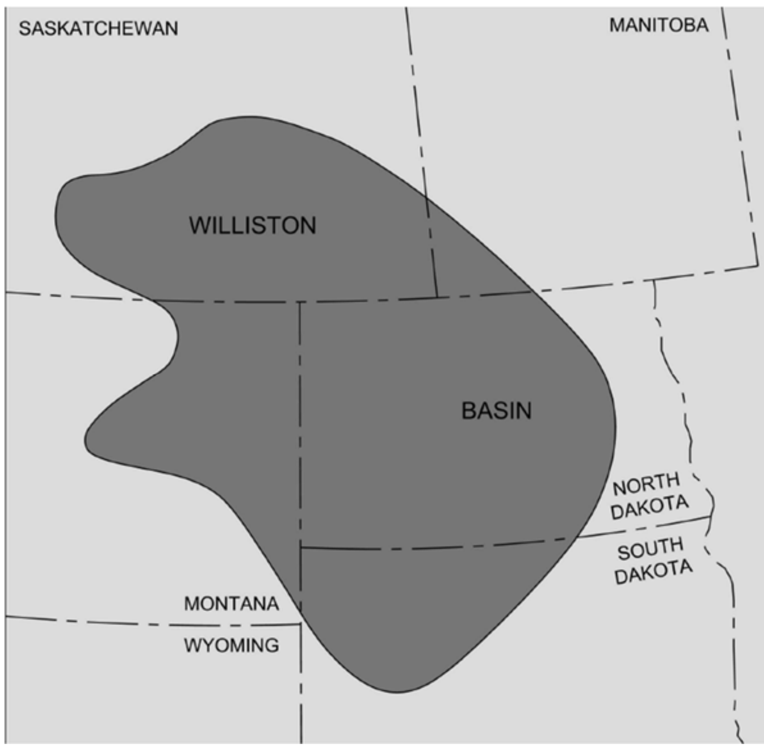

Figure 1: Extent of Williston Basin in USA and Canada

Figure 2 shows the study area, which is located in Colgan field, Divide County in North Dakota. The study area consists of twelve operating wells in sections 13, 24, 17, 18, 19 and 20 in Township 163 and Ranges 101 and 100 W, as shown in Figure 3.

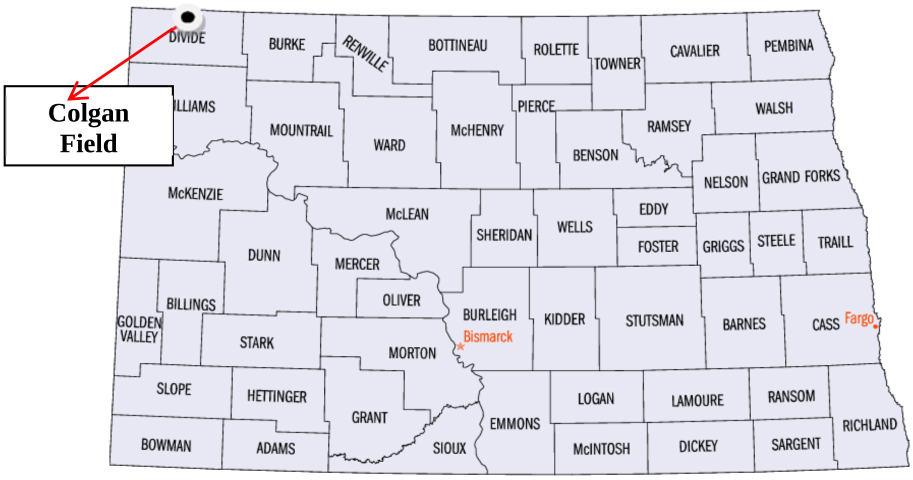

Figure 2: Colgan Field, Divide County, North Dakota

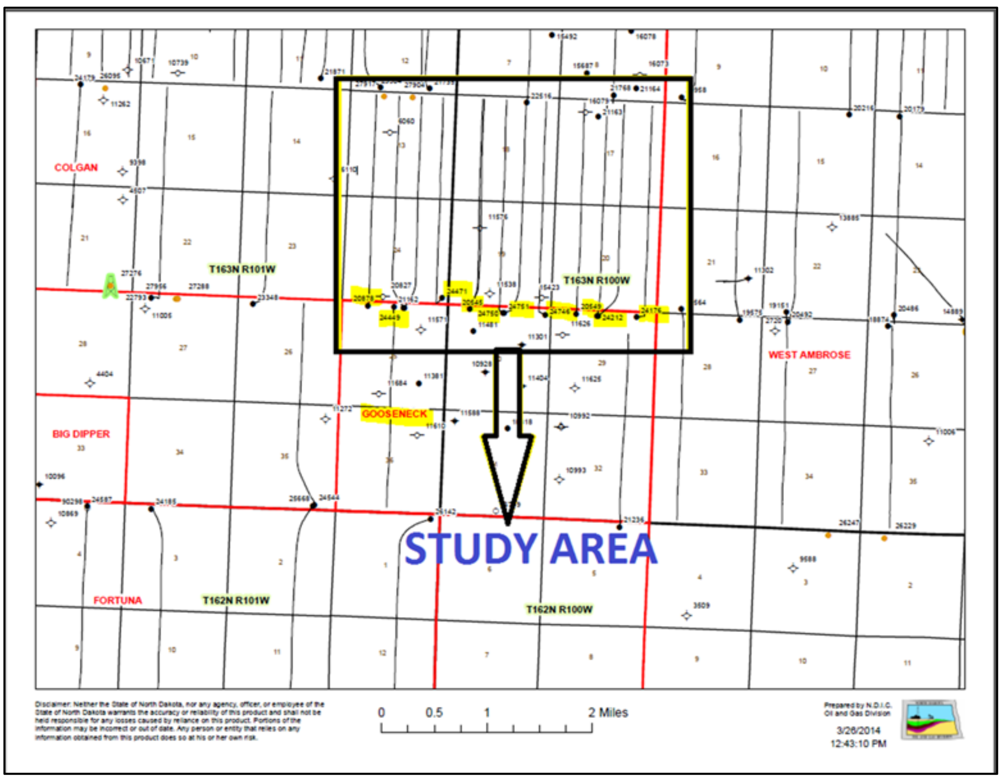

Figure 3: Map Showing Twelve Wells in Study Area

Initially little was known about the Three Forks formation and it was generally thought to be unproductive. However, in recent years the Upper Three Forks formation has developed into a significant resource play in the Williston Basin (1). Figure 4 shows the stratigraphic column of the petroleum source rocks and reservoir in the Williston Basin (4). Oil production from the Three Forks is enabled by both horizontal drilling technologies, which expose a larger amount of reservoir to the wellbore than vertical wells, and hydraulic fracturing, which stimulates movement of hydrocarbons in low permeability reservoirs.

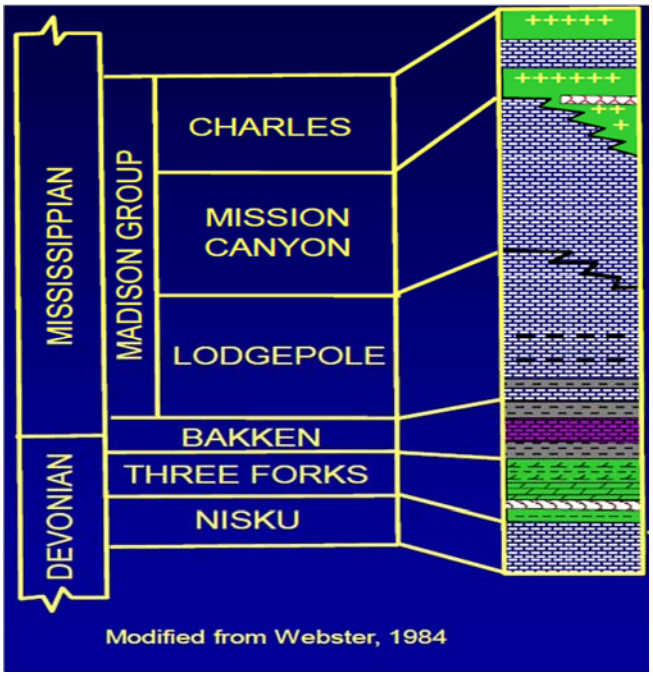

Figure 4: Stratigraphic Column of the Petroleum Source Rocks and Reservoir in Williston Basin. (Webster, 1984)

According to United States Geological Survey (USGS) assessment methodology, there are undiscovered reserves estimated at 7.4 billion barrels of oil, 6.7 trillion cubic feet of associated/dissolved natural gas, and 0.53 billion barrels of natural gas liquids in the Bakken and Three Forks formations in the United States portion of the Williston Basin (1). The USGS assessment of the Bakken formation and underlying Three Forks formation is that "oil generated in the upper and Lower Bakken shale members migrated locally into low-permeability and variable porosity reservoirs to dolomitized units of Three Forks formation" (1). This geologic sequence gives us a hint about the movement of water and pressure of natural fractures in the formation and will help to model the water influx in this basin.

The Devonian-aged Three Forks pay zone thickness ranges up to 12 feet and can be found at a depth of approximately 8,100 feet true vertical depth (TVD). Typical Three Forks wells in the Gooseneck prospect have a total measured depth of 18,000 feet that includes an approximately two-mile horizontal section. Sitchler and Cherian (4) reported that the Three Forks formation has low reservoir porosity (less than 8%) and permeability (less than 0.1md). A summary of pay zone thickness, broken down into a dolomite layer and a silty shale layer, is given in Table I. The upper bench pay zone thickness is around 7 to 8 feet in the study area (27). The total thickness of the Three Forks formation is approximately 110 feet to 260 feet basin wide. It is believed that the Three Forks zone has oil potential below our study area pay zone (1). It also could be a possibility that there is oil migration from the zones below to the upper Three Forks bench. In this work the zone below the upper Three Forks bench will be evaluated for oil potential.

Table I: Thickness of Target Zone for Twelve Operating Wells in Study Area

Well Name	NDIC File No	Dolomite Thickness (ft)	Silty Shale Thickness (ft)	Total Thickness (ft)
Bagley 4-30H	20545	3	4	7
Jeglum 3-9HNA	24211	2	4	6
Jeglum 3-9HNB	24212	2	4	6
Legaard 2-25HNA	24449	4	4	8
Legaard 2-25HNB	24448	4	4	8
Mosser 1-30HN	24746	3	4	7
Mosser 2-30HNA	24750	3	3	6
Mosser 2-30HNB	24751	3	4	7
Roese 4-29H	20549	2	2	4
Rose 16-24HN	24471	3	5	8
Simonson 1-29HN	24176	4	4	8
Legaard 4-25H	20878	3	4	7

3. Literature Review

The goal of this literature review is to understand the complex geological structure of Three Forks formation. An Independent Study course was undertaken with Professor Burt Todd, Montana Tech Petroleum Engineering Department in the Fall of 2013 to research Society of Petroleum Engineers (SPE) publications related to the Three Forks formation in the Williston Basin. The results of which are presented here. Since the Three Forks formation is a relatively new prospect, not much literature was available, so the Bakken formation in the Williston Basin was also reviewed. Key learnings gained from the literature review were used to model geological and well completion properties of the twelve operating wells in the study area.

3.1. Bakken and Three Forks Geology in Williston Basin

The Bakken formation is located in Western North Dakota, Eastern Montana, and Southern Saskatchewan Canada, as a subsurface formation within the Williston Basin. Figure 5 shows the Williston Basin and the extent of the Bakken formation within the basin.

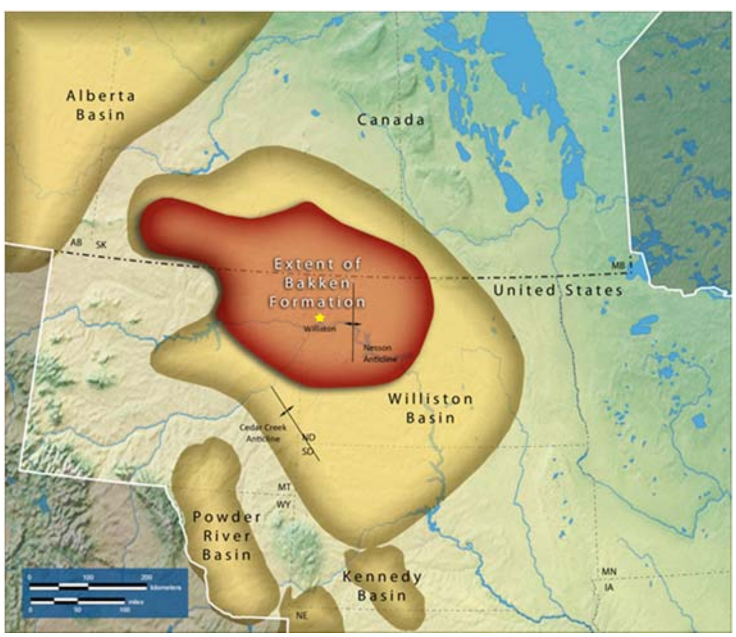

Figure 5: Bakken Shale Formation Distribution within the Williston Basin (25).

The Bakken complex is a rock unit from the late Devonian to early Mississippian age occupying 200,000 square miles of the subsurface in the Williston Basin (refer to Figure 3). The Bakken complex consists of the Bakken shale and its adjoining formations, the Three Forks or Sanish mudstone below, and Lodgepole formation above (13). Figure 6 shows the Bakken formation lying between the overlying Lodgepole formation, which is conformable in most areas, and the underlying Three Forks formation, which is unconformable. Cox and Cook (2) state that the Bakken formation is both Devonian and Mississippian in age as the contact lies within the upper portion of the Middle member. The Bakken formation is composed of three distinct members - the Upper Shale Member, a Middle Siltstone Member and a Lower Shale Member. The Upper and Lower Bakken Shales are highly organic rich and serve as the petroleum source rocks for both Bakken and Three Forks formations.

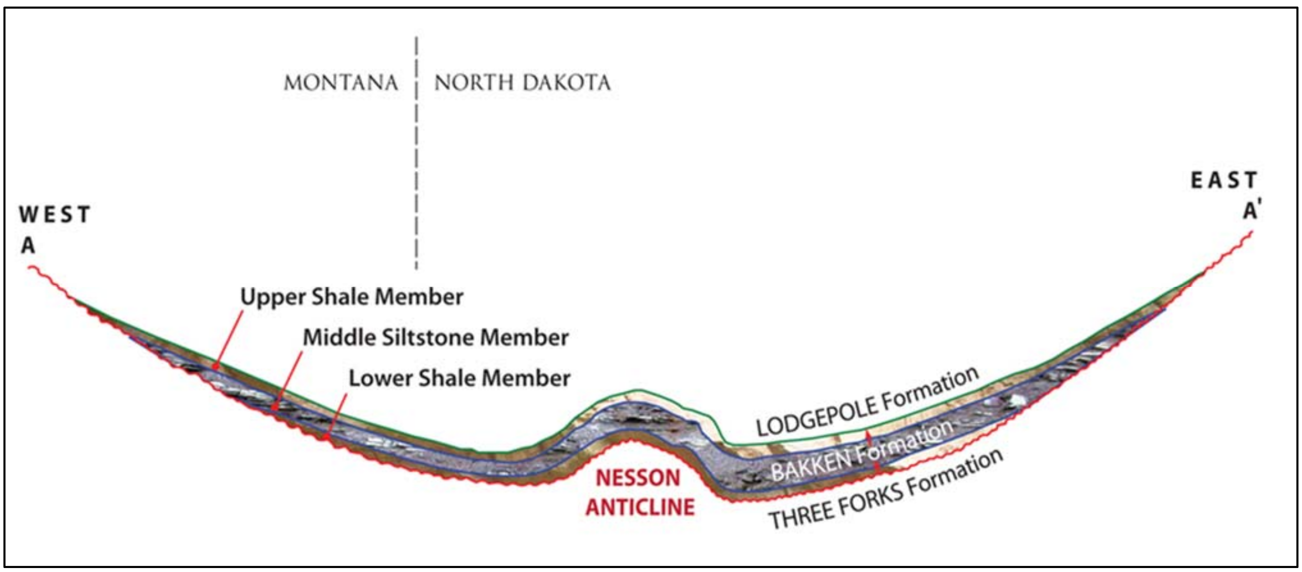

Figure 6: Schematic Cross-Section Across the Williston Basin
Showing three members of the Bakken Formation and the on lapping relationship with the Three Forks

In North Dakota, the Middle Bakken Member can reach up to 80 feet of thickness at depths approximately 9,500-10,000 feet. However, Zander and Czehura (6) said that toward the west in Montana, the Middle Bakken thins to 6 to 15 feet of pay at approximately 10,000 feet in depth. This gives us a good understanding about variation in pay zone thickness throughout Williston Basin.

Warpinski and Mayerhofer (7) reported that porosity and permeability within the middle member are generally very low. Porosity averages 5%, while permeability averages around 0.04 mD. However, the highest values of permeability are associated with naturally occurring fractures. Iwere et al., 2012, report that water cut ranges between 0-55% depending on where the wells are located and whether the initial water saturation is in equilibrium (26). The temperature of the Middle Bakken Member is about 240°F, which is often referred to as the “Bakken Kitchen” where the oil is cooked and moved to other areas in the basin.

Roth and Roth (5) observed that the Three Forks formation has been recently developed as a distinct reservoir in portions of Williston Basin. The reservoir properties were similar to that of the Middle Bakken Member, with the exception of the high water cut from the producing wells operating in the Three Forks formation.

The contact between the Bakken and Three Forks formations appears conformable in the deeper portions of the Basin and unconformable in the Basin flanks. The geology of the Three Forks can be subdivided into four units: the first, second, third and fourth benches (5).

The first and second benches of the Three Forks are widespread across the Basin, while the third bench has the presence of more shale and anhydrites, and the fourth bench is locally developed. The Upper Three Forks bench consists of a dolomite interbedded with shale and had been the primary reservoir target to date (5). The type log for the Three Forks formation is shown in Figure 7 (11). The dolomite in the upper half of the target zone is approximately three feet thick. The shale has a gamma signature of 140-160 API gamma ray units (GAPI), indicating the Upper Bench in the Three Forks formation is a shaly dolomite.

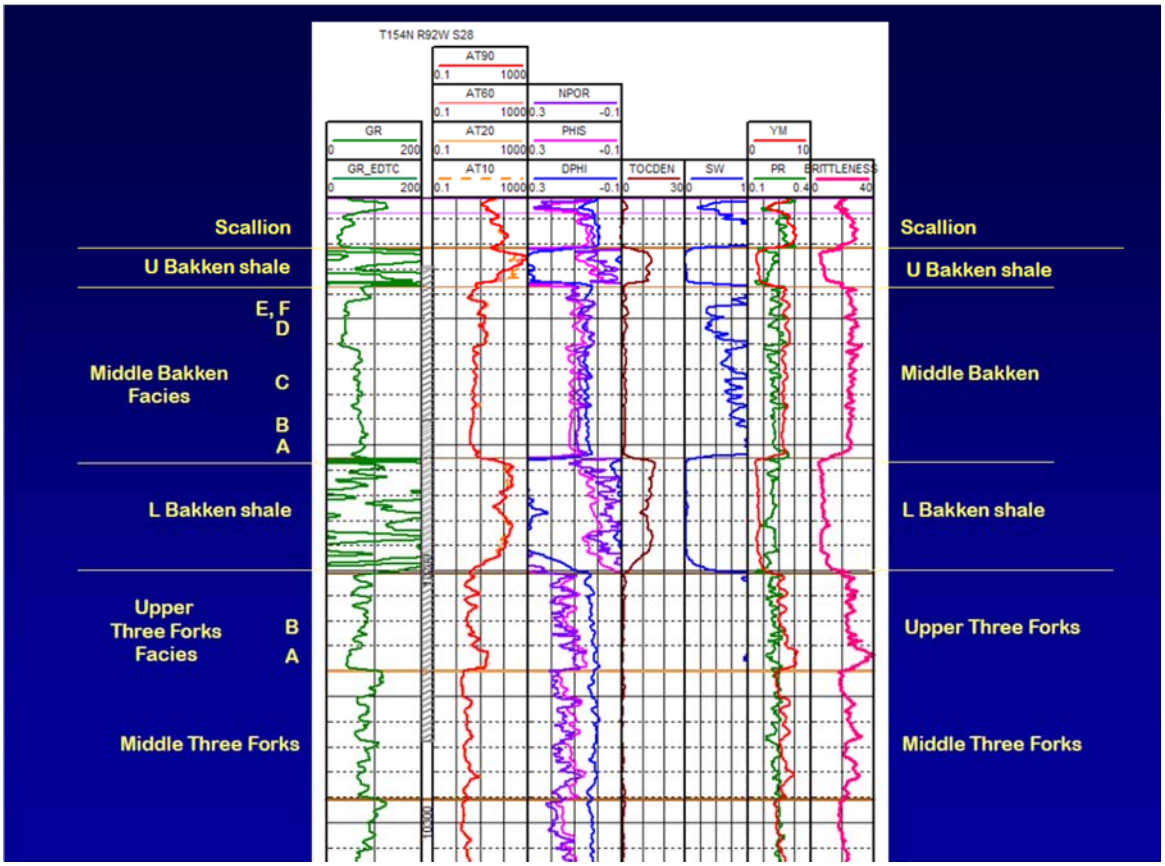

Figure 7: Type Log Showing Three Forks Formation (11)

SM Energy wells have been drilled in the 1st and 2nd benches in Three Forks formation in the Gooseneck and Colgan fields where the study area is located. The Three Forks formation in our study area ranges from approximately 8,100 to 8,200 feet TVD (2). The geologic model of the Bakken formation and underlying Three Forks formation implies that oil generated in the Upper and Lower Bakken shale members migrated locally into low-permeability and variable porosity reservoirs of the Middle Bakken member and dolomitized units of the Three Forks formation.

The Pronghorn Member of the Bakken formation, which had previously been referred to as the “Sanish” sand has recently been placed within the Bakken petroleum system (1). The

Pronghorn member of the Bakken formation, although geologically and stratigraphically defined as part of the Bakken formation, is assessed with the Three Forks formation. Where present, the Pronghorn member is in fluid communication with the underlying Three Forks reservoirs. The operator suggested the Middle Bakken Member may be supplying the Three Forks with water along with crude oil. This is a theoretical idea, but this project will test the theory by modelling water influx to understand the migration of water into the Three Forks formation.

Because of the geology of the Bakken system, a thorough analysis of log and core data is important in building the geological model. In this thesis a simulation approach was used to describe the geological structure of Three Forks formation. Too often unconventional reservoirs are considered "cookie cutter" developments where a winning formula is blindly applied with little technical analysis (2). However, achieving economic returns in a resource play can be challenging and requires careful planning and detailed evaluation. The thin net pay and the presence of water production in the Three Forks requires in-depth study to optimize recovery and economics of Three Forks production.

3.2. Effective Completion and Stimulation in Horizontal wells.

Cox et al. (2) stated that unconventional resource plays could provide a long-term supply of oil and gas for North American energy demands. Wells completed in unconventional plays typically exhibit limited drainage areas and produce a majority of recoverable reserves at low rates. Due to the limited flow capacity of these reservoirs, typical development strategies include some form of horizontal wells stimulated with hydraulic fractures. Hydraulic fracturing is performed to create greater conductivity of fluids within the formation and improved communication with the reservoir and well bore.

The evolution of completion strategies includes increasing the lateral length and number of fracture stages, the method of stage isolation and proppant type and concentration. There is significant variability in the well completion methods across the Williston Basin. Zander and Czehura (6) stated that the main types of completion methods are cemented liner, open hole completion and uncemented preperforated liner. The uncemented, preperforated liner isolated with swell packers has become the most commonly employed method of completion in most Bakken wells, as shown in Figure 8. This completion method has a high degree of fracture control and excellent long term success rate (2).

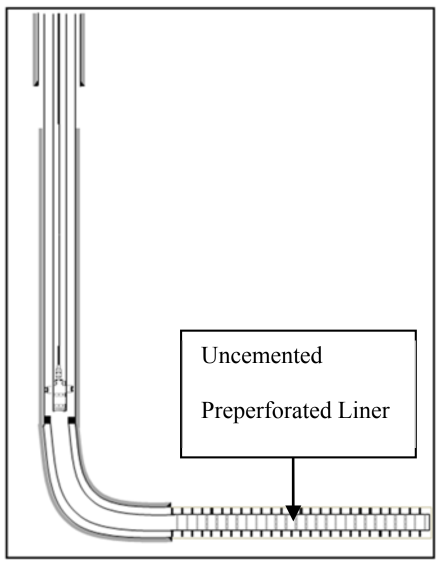

Figure 8: Wellbore with Uncemented Preperforated Liner

Roundtree and Eberhard (8) said that most wells are positioned in a north-south or northwest-southeast orientation to take advantage of induced fracture propagation in the direction of maximum horizontal stress. But there is a debate whether transverse fractures are the best way of stimulating a well. Lolon and Cipolla (9) said that both longitudinal and transverse fractures are believed to be created during the stimulation process. However, single horizontal long laterals with numerous transverse fractures are the preferred method to achieve the desired reservoir contact in Bakken completions. Transverse fractures provide a small area of intersection with a horizontal wellbore, generally necessitating the use of higher conductivity proppants and multiple stages to improve the flow capacity of the connection between the fractures and well bore.

Rankin and Thibodeau (10) stated that research by operators in the Williston Basin suggests that success in the Bakken/Three Forks can be achieved with long laterals utilizing a high number of fracturing stages placed within the formation with precise geosteering. When these goals are pursued simultaneously, production and profitability are dramatically improved. It is clear that the performance of a well is directly proportional to the contributing length of the lateral, which in turn is directly related to the effectiveness of well placement and the fracture stimulation. In this study the length of the fractures was adjusted with respect to number of wells operating in the field to optimize production and ultimate recovery.

3.3. Reservoir Modeling of Horizontal Wells in Three Forks Formation

The Bakken/Three Forks oil play is extremely active with more than 2,500 horizontal wells drilled in Montana, North Dakota, and Saskatchewan during the past decade (10). Horizontal wells are important because they offer solutions to the problem of producing oil and gas in reservoirs where vertical wells produce at uneconomic rates. Horizontal wells are appropriate for thin reservoirs, reservoirs with high water influx, reservoirs with natural fractures, reservoirs with low permeability and high anisotropy, and reservoirs with poor sweep efficiency (5).

The use of unconventional wells in the Williston Basin instrumented with downhole inflow control devices allows for even greater flexibility in production. Because unconventional wells can be very expensive to drill, complete and instrument, it is important to optimize their deployment, which requires accurate prediction of their performance (5).

Roundtree and Eberhard (8) stated that accurate modeling of flow from horizontal wells continues to pose several problems. One important aspect of horizontal well modeling is accurate representation of fine scale reservoir heterogeneity in the near-well regions. This issue arises because geological models typically include far more detail that can be accommodated in conventional reservoir simulation models. These problems can be handled with local grid refinement and by optimizing the coarse grid parameters.

The desired approach in studying the Three Forks formation is to create a reservoir model with known reservoir properties obtained from public domain sources. For unknown reservoir properties, estimates based on the literature and previous research work done by the operators in the Williston Basin were used. The successful reservoir model would incorporate individual wells with accurate near-wellbore descriptions.

Fracture design and proppant selection, economics and infill drilling potential rely on reservoir permeability; therefore it is critical to determine the permeability in this process. Core samples were obtained from SM Energy to determine the permeability and porosity of the Three Forks formation in the study area. Reservoir properties like porosity and permeability were initially modelled based on lab results, and were adjusted to achieve a better history match for the twelve operating wells in the study area.

3.4. Water Influx

Water influx is defined as replacement of produced fluids by formation water. Most petroleum reservoirs are underlain by water, and water influx into a reservoir almost always takes place at some rate when gas or oil is produced (21). Whether appreciable amounts of water are produced along with gas or oil depends on the proximity of the productive interval to the oil-water contact or gas-water contact and whether the wells are coning (vertical wells) or cresting (horizontal wells).

The first phase in understanding water influx is determining the water influx mechanism. This step includes diagnosis, classification and characterization. The second phase identifies mathematical models that effectively simulate the aquifer, especially its deliverability. This phase includes estimating or history matching aquifer model parameters. The third and the final phase requires combining aquifer and reservoir models to forecast recovery effectively and to identify optimal depletion strategies. With that said the success of the final phase depends heavily on the success of the preceding two phases (21). Recognizing the effects of expansion of the connate water with the oil and gas reservoir and calculating the water influx across a boundary can be described using any of several aquifer models available. There are five aquifer models in theory and are discussed briefly below.

The Van Everdingen Hurst (VEH) Model states that when an oil well is brought on production at a constant flow rate after a shut-in period, the pressure behavior is essentially controlled by the transient flowing condition (21). This flowing condition is defined as the time period during which the boundary has no effect on the pressure behavior. Van Everdingen and Hurst (1949) proposed solutions to the dimensionless diffusivity equation for two reservoir boundary conditions: constant terminal rate and constant terminal pressure.

For the constant terminal rate boundary condition, the rate of water influx is assumed constant for a given period, and the pressure drop at the reservoir-aquifer boundary is calculated. For the constant terminal pressure boundary condition, a boundary pressure drop is assumed constant over some finite time period, and the water influx rate is determined.

The Carter-Tracy Model was developed to reduce the complexity of the VEH water influx calculations. In 1960, Carter and Tracy proposed a calculation technique that does not require superposition and allows direct calculation of water influx (21). Using the Carter-Tracy technique the cumulative water influx at any time can be calculated directly without involving superposition.

In 1971, Fetkovich developed a method of describing the approximate water influx behavior of a finite aquifer for radial and linear geometries (21). The Fetkovich model is based on the premise that the productivity index concept will adequately describe water influx from a finite aquifer into a hydrocarbon reservoir. In other words, the water influx rate is directly proportional to the pressure drop between the average aquifer pressure and the pressure at the reservoir-aquifer boundary. This method neglects the effects of any transient period. Thus, in cases where pressures are changing rapidly at the aquifer-reservoir interface, predicted results may differ somewhat from other approaches.

The first three models are unsteady-state models and are the most realistic. These models attempt to simulate the complex pressure changes that occur within the aquifer and between the aquifer and reservoir. As pressure depletion proceeds, the pressure difference between the reservoir and aquifer grows rapidly and then attains equilibrium with the reservoir. The unsteady state models are far more successful at capturing the dynamics of water influx than other models.

In contrast, the Schilthuis steady-state model assumes aquifer pressure remains constant. Schilthuis (1936) proposed a model of an aquifer that is flowing under steady state flow regime and modeled using Darcy's equation (21). The influx constant is obtained when the reservoir pressure stabilizes. The pressure drop contributing to the influx is the cumulative pressure drop from the initial pressure. The water influx constant is calculated from the reservoir historical production data over a number of selected time intervals, provided the rate of water influx is known. Although the water influx constant can only be obtained in this manner when reservoir pressure stabilizes, once the water influx constant has been found it may be applied to both stabilized and changing reservoirs.

The VEH model is the most computationally complex of these models. To address this limitation, the Carter-Tracy and Fetkovich models were created to be free of tables and charts (21). However, these models are only approximations to and simplifications of the VEH model. The VEH charts and tables were digitized and included in Petrel. So the time constraint is removed and the need for alternative models is diminished. In this project, all three "unsteady-state" models (VEH, Fetkovich and Carter Tracy) were used to match the actual field water production data. The model most closely matching the actual field production will be determined to be the best one and will be used for this simulation study.

Once a water influx mechanism has been identified, it is important to monitor the producing wells closely and to minimize water production. Minimizing water production in edge water drives may require systematically shutting in flank wells once the advancing water reaches them. Minimizing water production in bottom water drives may require systematically cementing in lower perforations as the bottom water slowly rises. However, these strategies work best for traditional vertical wells. For long horizontal wells, as in our case, these strategies may not be applicable since the well bore is in contact with the reservoir horizontally. In this research, water influx was modelled with both edge water and bottom water drive. The most accurate water influx mechanism was selected based on how well that water influx model matched observed production performance.

4. Reservoir Model Building

Modeling the study area was a two-step process: The first step was building the reservoir model and the second was including hydraulic fracture properties. In the reservoir model building phase, the geology of the formation was modeled in Petrel. Petrel is a reservoir modelling software platform by Schlumberger and is used for making exploration and production decisions. The hydraulic fracturing properties were obtained from SM Energy for the wells in the study area and then incorporated into the reservoir model. Initial simulation results were analyzed and adjusted as necessary to improve the history match.

4.1. Reservoir Modeling

Reservoir modeling is performed to obtain accurate performance predictions for hydrocarbon reservoirs under different operating conditions. The cost associated to drill and complete a single well in the study area is estimated at about 7 million dollars (28). The need for this project arises from the huge capital investment necessary to develop the acreage, so the well density must be assessed and minimized. Various factors such as reservoir rock properties, regional variations of fluid properties, and relative permeability characteristics must be considered during model building stage.

Simulation of petroleum reservoir performance is achieved by construction and operation of a model whose behavior imitates the performance of actual reservoir behavior. The purpose of taking the simulation approach in this project is to estimate the field performance under one or more producing scenarios. Whereas the field can be produced only once at considerable expense, a model can be produced or run many times at low expense over a short time frame. Observation of model results representing different producing conditions aids selection of an optimal set of producing conditions for the reservoir, i.e., well spacing and fracture length.

In this study, a range of scenarios was evaluated to provide decision makers with insight that can help them to decide how to economically commit limited resources to activities that achieve SM Energy economic objectives. Collecting data for the reservoir flow model is a good way to ensure that every important technical variable is considered. If the model is particularly sensitive to a particular parameter, then a plan should be made to reduce the uncertainty in the parameter.

The first phase in reservoir modelling is to build a geological model of the formation. SM Energy wanted to model a pilot area in Colgan field, Divide County North Dakota. The pilot area consists of six sections and twelve operating wells. Refer to Table I and Figure 9 for the description and location of the twelve operating wells. Since the study area wells are long and horizontal, each two-section drilling unit contains four wells drilled between 2011 and 2013.

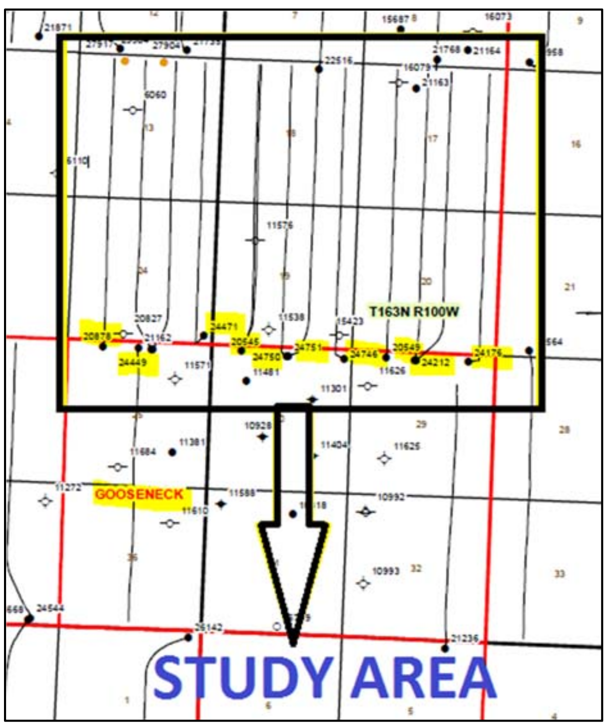

Figure 9: Six Sections of Land with Twelve Study Wells

The well locations and wellbore deviation surveys were used to place the study wells in the model. Wellbore deviation files for the twelve operating wells includes measured depth, inclination and azimuth were obtained from the North Dakota Industrial Commission (NDIC) website (24).

After locating the wells into the model the next step was building the formation structures. For this model it was decided to have four different zones-the Middle Bakken, Lower Bakken, Three Forks and base of Three Forks formation. Among these four geological structures, the Three Forks is the only oil producing zone. There were no well logs available to build formation structural relationships between each zone. The well bore deviation data were used to define the Three Forks formation. The Three Forks formation was used as the base zone and the remaining three zones were modelled by changing the elevation accordingly. The Three Forks formation was assigned a thickness of ten feet and the Middle Bakken, Lower Bakken and base of the Three Forks formations were modelled ten to twenty feet thick in order to keep the hydraulic fractures contained within the model space. To make sure that this model is accurately representing the Three Forks formation, offset wells near the study area are also considered for the Three Forks depth and thickness, as shown in Table II and Figure 10.

Table II: Off Set Wells Operating Near the Study Area

Well Name/NDIC File No	Distance From Study Area Well (Miles)	Thickness (feet)	Porosity (%)
Barstad 1-30-1	0.23	10	7.0
Rud 1-19	0.25	8	6.5
Wanda 2-25-1	0.48	7	6.8
Wolter 13-21H	0.80	8	9.0
Clegg 2-29-11	0.72	9	8.5
State Wingress 41-35-1	1.55	10	6.0

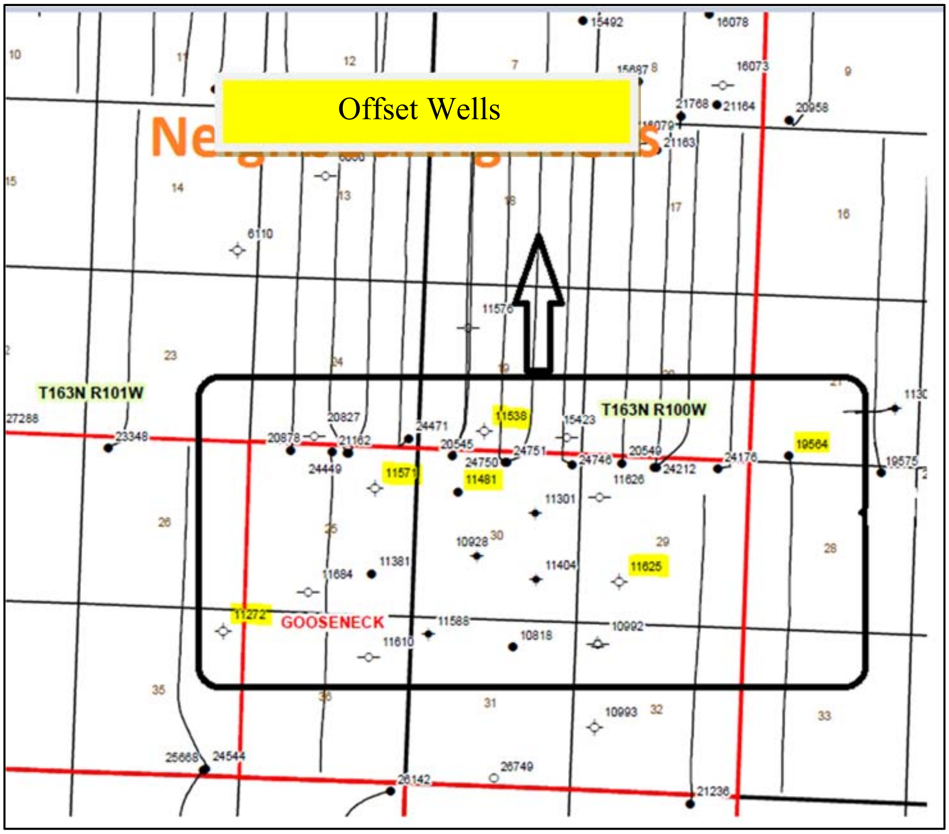

Figure 10: Map Showing Neighboring Wells from Table II

4.1.1. Geological Modelling

Once the geologic structure was developed, geological properties were modelled for the four geological layers (Middle Bakken, Lower Bakken, Three Forks and base of the Three Forks). For this project there were no core analysis reports available from public domain sources. Fortunately, SM Energy provided two core samples from the nearby wells which are representative of the Three Forks formation in Colgan Field. The two 1" core plug samples received from SM Energy were obtained from the Tomlinson 3-1HN well. The two core plugs were obtained from the same well, but at different depths along the upper bench of the Three Forks formation. The Tomlinson 3-1HN is located in Township 161N Section 100W Range 1 and it is very near to the study area. One of the core samples had higher permeability than the other core sample and was used for relative permeability tests which are discussed later in this section.

The core sample obtained from SM Energy was tested for permeability and porosity using a core Lab automated porosimeter-permeameter in Montana Tech Petroleum Engineering laboratory facilities. This advanced system can perform automated permeability and porosity tests at confining pressures up to 10,000 pounds per square inch (psi), and measure permeability ranging from 0.001 to 10 mD and porosity ranging from 0.1 to 40%. The core sample tests were performed three times to check the measurement for precision. There is also a leak check available in the system, in between each test it was mandatory to place a steel plug and to do a leak detection test. This particular step ensured integrity of the measurement.

The core sample was tested at confining pressures of 1,000, 1,500 and 2,000 psi. These tests were repeated three times. The purpose of conducting these tests at various confining pressures was to understand the pressure dependence on permeability. Before measuring porosity and permeability, the core samples were cleaned of residual fluids using solvents, then thoroughly dried. The number of cycles or amount of solvent which must be used depends on the nature of hydrocarbons being removed and the solvent used. Often more than one solvent is used, but in this case the core sample was cleaned three times using toluene as the solvent. As an initial guess for modelling purposes permeability was chosen from the table based on the highest measured values, this represents the cleanest core with the most repeatable results. Porosity was taken to be the average of the measured values. Initial modelling values of porosity and permeability of the Three Forks formation were chosen to be 6.5% and 0.075mD based on the data in Table III.

Table III: Core Sample Permeability and Porosity Results

Date	Length (inch)	Diameter (inch)	P Confining (psia)	Porosity (p.u)	K air (mD)
9/25/2014	1.01	1	1000	6.520	0.0750
9/25/2014	1.01	1	1500	6.950	0.0600
9/25/2014	1.01	1	2000	6.083	0.0500

The next step in the modelling process was assigning the permeability and porosity for the other three zones in the model. In this model the Three Forks is the oil producing zone and the remaining three zones are not productive. The permeability and porosity of the Middle Bakken and the Lower Bakken shale were set to zero. However, these layers were still included in the simulation model to enable simulation of water production from the Middle Bakken member into the Three Forks formation. Table IV shows permeability and porosity properties for the four zones used in the simulation model.

Table IV: Permeability and Porosity for Different Zones

Zone	Porosity (%)	Permeability XY (mD)	Permeability Z (mD)	Number of layers
Middle Bakken	0.00	0.0000	0.00000	3
Lower Bakken	0.00	0.0000	0.00000	2
Three Forks	6.50	0.0750	0.00750	5
Base of Three Forks	3.25	0.0375	0.00375	10

Horizontal permeability is modelled based on the core sample results from the laboratory. As a rule of thumb the permeability in Z direction is modelled to be $1/10^{th}$ of that horizontal permeability (21). For the base of Three Forks formation the permeability and porosity were set to be half the values of the Three Forks Formation, reflecting the shaly character shown on the gamma ray logs. In spite of the Three Forks being the oil producing zone in the model, storage capacity was created in the base of the Three Forks formation. This is done to simulate the water production from the base of the Three Forks formation and will be discussed in detail in the water influx modelling section.

In this project the wire line logging data were the gamma ray logs used to provide control for geo-steering while drilling the well. Gamma ray logs for the twelve operating wells in the study area were imported into the respective wells to verify the depth of the Three Forks formation.

4.1.2. Relative Permeability

The third and final step in the modelling process was to describe the relative permeability of the producing zone. Relative permeability is the ratio of effective permeability for a particular fluid to the absolute permeability. The absolute permeability is constant for a particular medium and independent of the fluid type. The ability to preferentially flow or transmit a particular fluid when other immiscible fluids are present in the reservoir is called as effective permeability (22). Typically effective permeability is lower than absolute permeability. The relative permeability of a fluid is a function of saturation.

The core sample was tested with both oil and water, and the core sample had a greater affinity to oil than water. The core sample was determined to be oil wet. In these experiments Three Forks oil sample and API brine were used for displacement.

Professor Richard Schrader (Montana Tech) and fellow student Cliff Goncalves (Montana Tech) performed relative permeability tests on two cores from the Three Forks formation that were obtained from SM Energy. The core samples were cleaned by flushing with toluene to remove dust particles from the core sample. The core plug was placed in the core holder and initially saturated with oil which was then displaced with water. Even though the displacement was successful, there was inconsistency in the measured oil effective permeability values. The inconsistency was believed to be due to viscosity changes caused by temperature changes occurring overnight.

To correct this problem, the core holder was placed in a constant temperature bath and maintained at 120 ^{o}F while the experiments were being performed with varying confining pressures. It takes approximately two months to perform experiments to calculate a single set of relative permeability curves. These experiments must be performed repeatedly to ensure consistent results. Due to time constraints in this project the relative permeability results were not included in the model. The Corey correlation available in Petrel for relative permeability curves was used for the modelling purpose as shown in Figure 11. The default end point saturations Swir is 0.2 and Sor is 0.8 were used to model relative permeability for the Three Forks Formation (13).

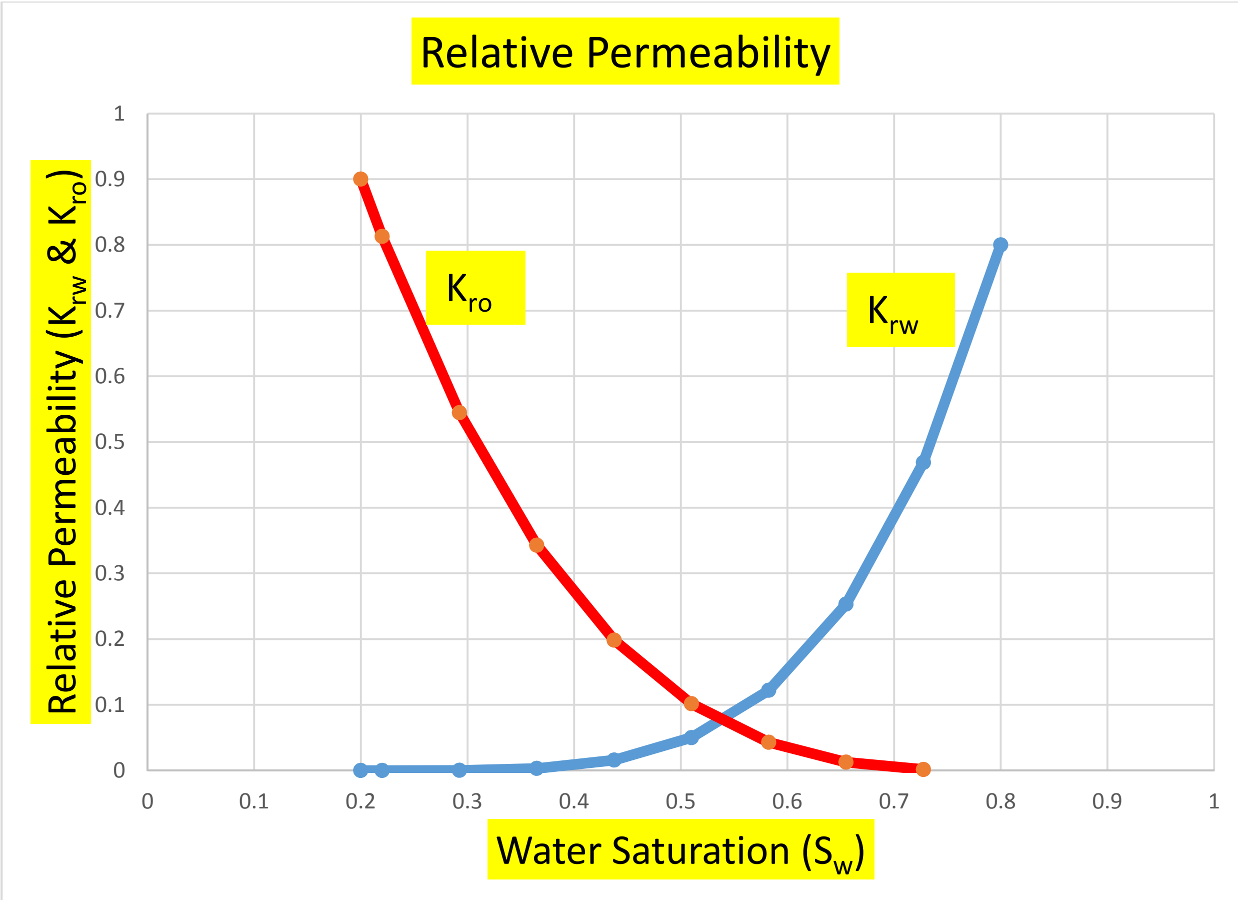

Figure 11: Relative Permeability Curve

4.1.3. Pressure Volume Temperature Properties

After describing the rock properties the focus of reservoir model construction shifted to the fluid properties. Very little fluid Pressure Volume Temperature (PVT) analysis has been performed on the fluids from the Three Forks formation. SM Energy provided a sample of oil from the Colgan field. Oil viscosity and API gravity were measured on the oil sample. The viscosity of oil was measured to be 2.6 cP with an API gravity of 40 degrees at 60 ^oF. This was compared to the oil properties from NDIC website (24) and found to be in a reasonable range. In the reservoir model building process we are often faced with analysis of processes which require the physical properties of the reservoir fluids, but in many cases little or no laboratory measurements of properties are available. In such cases empirically derived correlations are used to complete the reservoir fluid description. This work considered the correlations for light oil and gas PVT properties to identify the bubble point pressure of 1,980 Psi using the Standing-Petrosky model. The production data from the twelve study wells suggested a solution gas oil ratio of 700 SCF/STB at the saturation pressure. Figure 12 shows the bubble point pressure at 1980 psi plotted and oil formation volume factor and solution gas oil ratio is plotted as a function of pressure. Figure 13 shows the bubble point pressure plotted against oil viscosity is plotted as a function of pressure to compare the viscosity change. Figure 14 shows the gas viscosity and gas formation volume factor plotted against pressure.

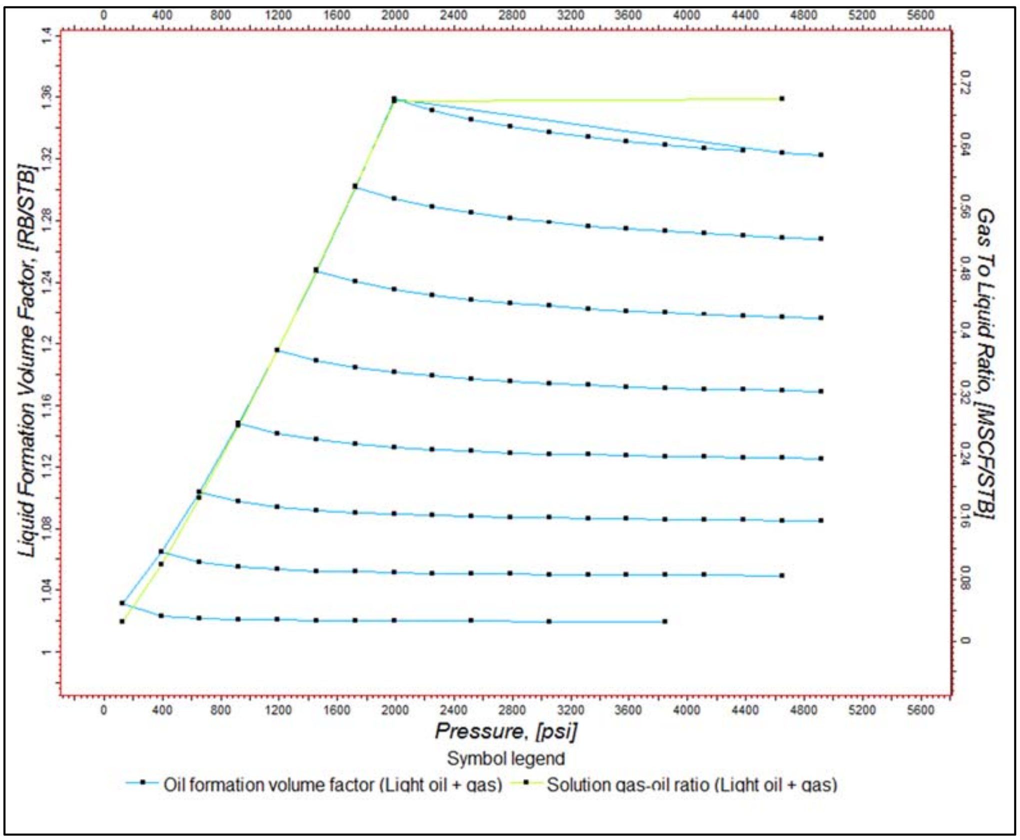

Figure 12: PVT Oil Properties Oil FVF and Gas Oil Ratio

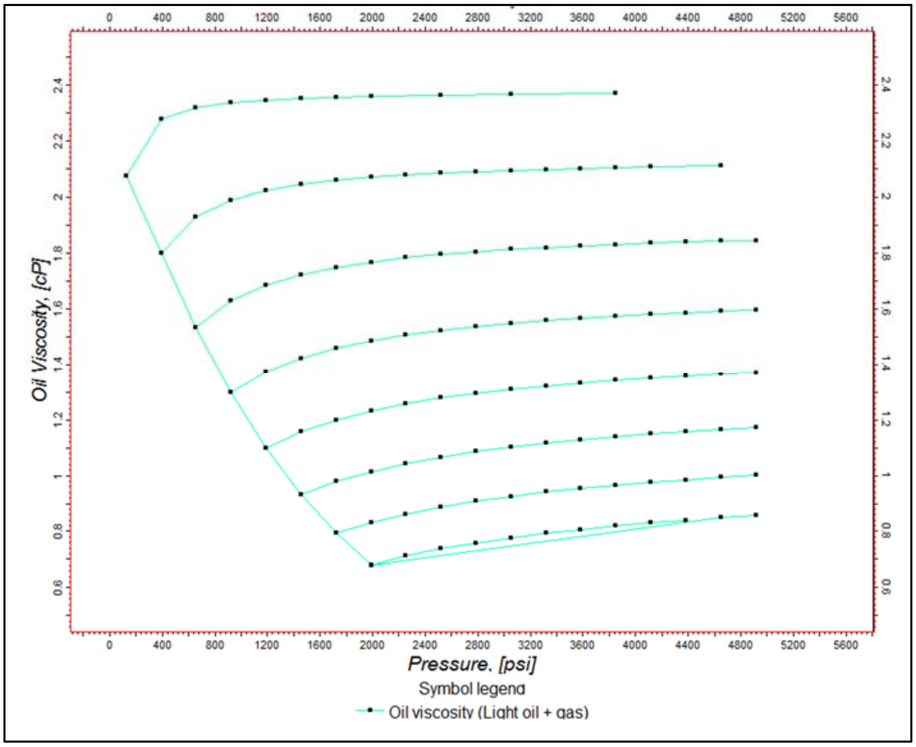

Figure 13: PVT Oil Property Viscosity

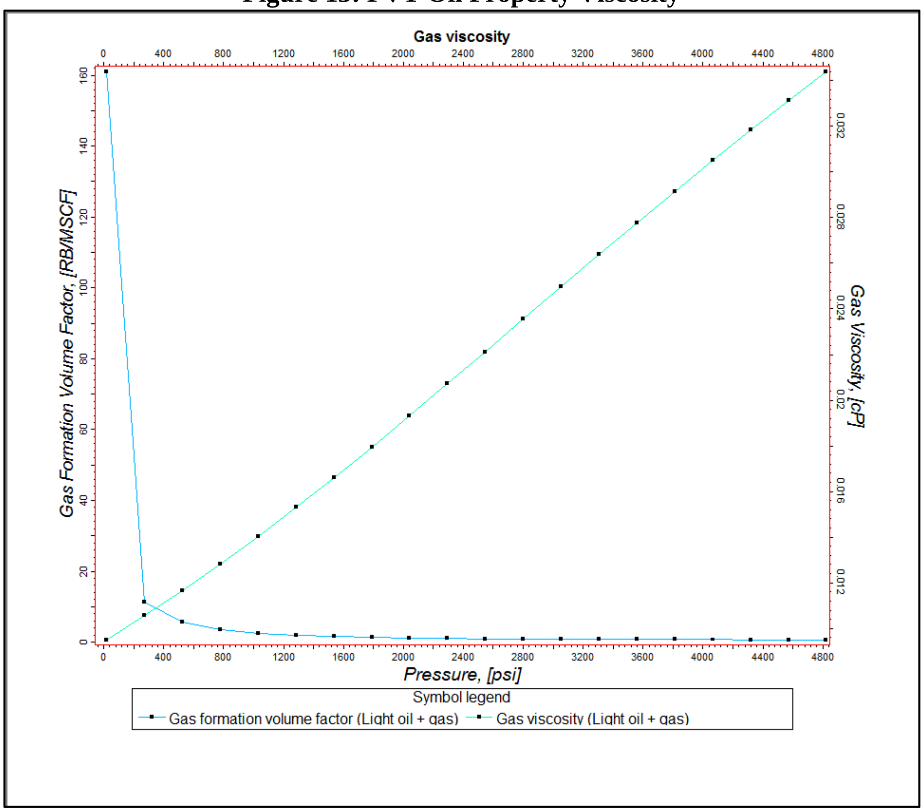

Figure 14: PVT Gas Properties

The reservoir formation temperature was 240°F from the drill stem tests reviewed from the NDIC website (24). Gas and formation water properties were taken from wells near to the study area. The well Rindel 3-9 HD had water and gas analysis reports and is located about 20 miles away from the study area. The specific gravity for the gas is determined to be 0.976 and for water is determined to be 1.17, as shown in Tables V and VI. These properties were used in the reservoir fluid description to complete the water and gas descriptions.

Table V: Water Analysis Report- Rindel 3-9 HD

Cations	Concentration (mg/L)	Anions	Concentration (mg/L)
Sodium	91600.00	Chloride	163279.80
Calcium	11112.00	Carbonate	0.00
Magnesium	1621.80	BiCarbonate	30.50
Iron	118.00	Sulfate	473.60
Potassium	3890.00	Nitrate	0.00
Barium	18.60	Specific Gravity	1.17
Chromium	0.30		
Sodium	91600.00		

Table VI: Gas Analysis Report- Rindel 3-9 HD

Component	Mole (%)	Specific Gravity
Nitrogen	1.668	0.016
Methane	53.558	0.297
Carbon di oxide	0.628	0.010
Ethane	19.857	0.206
Hydrogen Sulfide	0.001	0.000
Propane	13.719	0.209
Iso-butane	1.722	0.035
Butane	5.247	0.105
Iso-pentane	0.805	0.020
Pentane	1.006	0.025
Hexanes +	1.789	0.053
Gas Gravity	100.000	0.976

4.2. Hydraulic Fracture Modelling

Hydraulic fracturing is the process of pumping proppant-laden fluids at pressures exceeding the formation-fracturing pressure to create fractures that extend into the drainage area. During injection, the pressure in the well bore increases to a value called the breakdown pressure. Once the formation breaks down, a fracture is formed and the injected fluid flows through it.

After the fracturing pressure has been released, the formation naturally expands and traps the proppant in the fracture, leaving behind a highly-conductive channel that bypasses the damaged region surrounding the well-bore, creating a larger planar surface area for flow from the drainage area and causing linear flow patterns in the drainage area. The larger surface area and the linear flow reduce the pressure drop required to produce the well as compared to pure radial flow. Hydraulic fracturing is an important component of Bakken and Three Forks well completions (4).

The operator believes that all 12 wells in the study area have been effectively stimulated with a fracture half-length of approximately 550 feet (28). All the other properties such as fracture height, fracture width and fracture permeability were estimated based on previous knowledge and literature review done in the study area. All the study area wells are stimulated in twenty or twenty-six fracture stages.

The hydraulic fracturing model in Petrel used for this study has limitations. Increasing the number of fractures and fracture length per well did not affect the liquid production as expected. The hydraulic fracturing properties used in the simulation model are shown in Table XV in Appendix A. For these reasons, hydraulic fracture properties were not varied in this study.

4.3. Water Influx Modelling

Most oil and gas reservoirs have some amount of formation water. Modelling the encroachment of this water into oil and gas reservoirs is very important because it provides reservoir energy through pressure support. Water influx in this model was introduced not only to provide pressure support, but also to reproduce the observed water production data. In this study seven different water influx models available in Petrel were used to simulate water production. Surprisingly, all seven aquifer models predicted similar amounts of water production and pressure decline. Therefore, in this study the water influx mechanism was modeled using numerical model.

Reservoir-aquifer systems can be classified by three flow geometries: edge water drive, bottom water drive and linear water drive (21). In an edge water drive, the water moves into the flanks of the reservoir as a result of hydrocarbon production and subsequent pressure drop at the reservoir-aquifer boundary. The flow is essentially linear with negligible flow in the vertical direction. Bottom water drives occur in reservoirs with large areal extent and a gentle dip where the reservoir-water contact completely underlies the reservoir. The flow is essentially linear and, in contrast to the edge water drive, the bottom water drive has significant vertical flow. In linear-water drive, the influx is from one flank of the reservoir. The flow is strictly linear with a constant cross-sectional area.

The average water cut in the study area is about 50%, so water saturation plays an important role in the history matching process. Water saturation is defined as the fraction of pore space occupied by water. Water saturation can be determined by three methods. Water saturations can be calculated from resistivity well logs by application of an Archies law, model relating water saturation to porosity, connate water resistivity and various electrical properties. There were no resistivity logs available in the study area, so this method was not used to calculate water saturation. Water saturations can be calculated by using laboratory capillary pressure measurements by application of a model relating water saturation to various rock and fluid properties and height above the free-water level. Since there was no known available oil-water contact in this work this method was also not used. The third method is the Dean Stark water volume determination on core samples. Due to lack of core samples this experiment was not used either to calculate the water saturations. The water saturation was determined to be 50% from the history matching process and will be discussed in chapter 5.

In this study both edge water drive and bottom water drive were used to simulate water production. The operator suggested the water is produced from the edge, so edge water influx was tried first in the simulation model. Because the edge water drive did not simulate enough water production to match the field observed data, bottom water influx was tried. This was more successful in matching field observed data and will be discussed in detail in history matching section.

A summary of parameters used to build the initial reservoir model is shown in Table VII. These parameters were subject to change during the history matching process. A comparison with the parameters changed in the history matching section is given at the end of chapter 5. The initial reservoir pressure was determined to be 3,500 psi based on drill stem tests from the well nearby to the study area (24). The Original Oil in Place (OOIP) for the model was calculated to be 3,177 MSTB in the six-section study area. This translates that the oil in the Three Forks Formation in the study area is around 529 MSTB/section of land which is validated using previous literature review done in the study area (1).

Table VII: Summary Initial Model Building Parameters

Parameter	Three Forks formation	Base of Three Forks formation
Porosity (%)	6.5	-
Permeability Horizontal (mD)	0.075	-
Permeability Vertical (mD)	0.0075	-
Corey Exponent O/W	3	-
Average Thickness (ft.)	10	-
Initial Pressure (Psi)	3500	-
Solution Gas Oil Ratio (MSCF/STB)	0.7	-
Bubble Point Pressure (Psi)	1980	-
Fracture Half Length (feet)	550	-
Fracture Permeability (mD)	10	-
Number of Stages Per Well	26	-
Fracture Width (inches)	0.3	-
Fracture Height (feet)	25	-
Water Saturation (%)	50	-
Aquifer Permeability (mD)	0.075	-
Aquifer Porosity (%)	6.5	-

4.4. Economic Analysis

An Economic analysis was completed for this study. Economic analysis is a systematic approach to determine the optimum use of resources involving comparison of two or more alternatives to achieve a specific economic objective under the given assumptions and constraints. In a broader sense, economic analysis takes into account the opportunity costs of resources employed and attempts to measure in monetary terms the private and social costs and benefits of a project to the community or economy.

The oil and gas industries have been affected by technical innovations, particularity in the development of unconventional reservoirs such as the Bakken and the Three Forks formation. The objective of this economic analysis is to identify the optimal development strategy using capital and operation expenditures effectively to deplete the reserves. To efficiently deplete reserves, a reservoir must be completed with a well system that maximizes the hydrocarbon production and profitability. The main goal is to maximize the production which can be achieved through technical analysis and to minimize the cost which can be obtained by performing economic analysis.

Economic analysis takes into account the opportunity costs of resources employed and attempts to measure profitability for the benefit of the operating company. Six test cases were built for the economic analysis of the Three Forks production with one to six wells per drilling unit. The economic analysis was performed for the next thirty years. The crude oil and gas were considered as two main products from the field. Economics based on Net Present Value (NPV), Rate of Return (ROR) and Profitability Index (PI) were compared to determine the optimal well spacing.

For the oil and gas prices the past ten years of oil and gas price history were analyzed. The highest prices for oil and gas were \$110/Bbl and \$6/MMBTU respectively. The lowest prices for oil and gas in the last ten years were \$70/Bbl and \$2.8/MMBTU. Based on the historic prices low, medium and high price scenarios were developed, as shown in Table VIII.

Table VIII: Economic Input Data for Study Wells

Parameter	Data
Drilling and Completion Cost/well	$ 7,000,000
Fixed Oil Price	$70//$90/$110 per Bbl
Fixed Gas Price	$2.8/$4.4/$6 per MMBTU
Forecast	30 Years
Project Start Date	01/01/2015
Project End Date	06/01/2045
Working Interest	100%
Net Revenue Interest	87.5%

Operating costs of \$8000/month and current drilling and completion costs of \$7,000,000/well were obtained from the operator and used in the study. For this research it was assumed the prices of oil and the operating costs per barrel of oil stay constant over the life of the wells. The working and net revenue interest were assumed to be oil field standards, i.e. 87.5% and 12.5% (30). The cumulative oil and the gas production for each case were predicted using

Petrel/Eclipse. The PEEP Software was used to perform the economic analysis. Merak PEEP is a petroleum economic evaluation and decline analysis software used in upstream oil and gas projects. In this research each test case was evaluated based on well payout period NPV, ROR and PI.

5. History Matching and Forecasting

A geological model representative of the Three Forks formation was constructed, as described in Chapter 4. The next step in this research was to adjust the model until it closely reproduced the past production performance of the reservoir, a process called history matching. History matching is done to improve and validate the reservoir simulation model. History matching is also done to improve the reservoir description, and to identify and evaluate unusual operating conditions. Thus, the history matching process improves our understanding of the sensitivity of each geological parameter of the reservoir. History matching in this research was done in a sequential order and the changes were carefully analyzed before making the next change or decision. Many parameters discussed in the reservoir modelling sections were altered to improve the history match. The parameters altered to obtain a history match will be discussed in the following sections.

Once the model had been history matched, it was then used to simulate future reservoir behavior. The model was used to forecast production from hypothetical wells with symmetrical well spacing and varying well densities. The forecasted production from these hypothetical wells can be used to make economic decisions on optimal well density.

5.1. Initial History Match

The accuracy of the history matching depends on the quality and quantity of the pressure and production data available. In this work, the history match used three years of production data from wells in the study area. The study area wells are operating with artificial lift and in the model these wells will be pumped off to the lowest bottom-hole pressure i.e. 50 psi.

The initial reservoir model was run without aquifer support to create a no-influx depletion drive scenario. Figure 15 shows the well spacing and well locations.

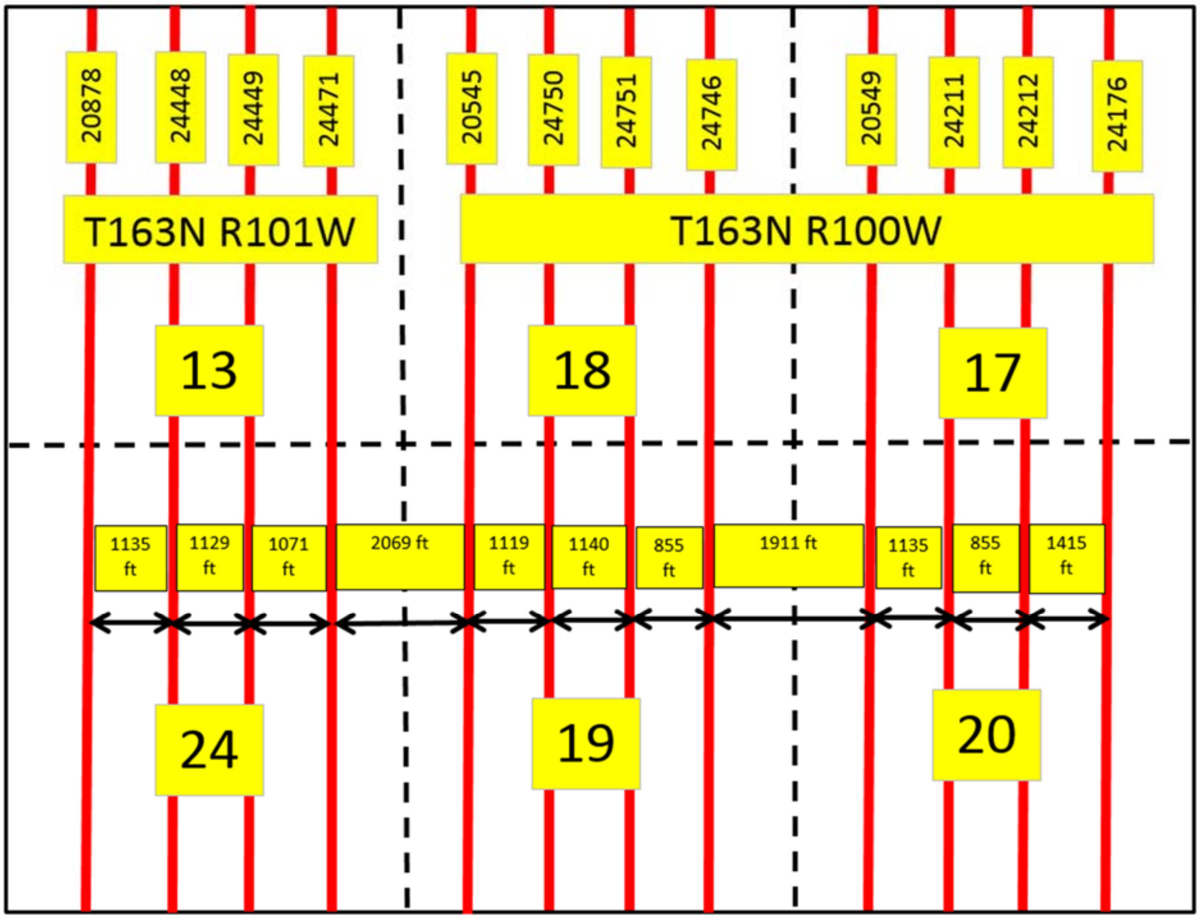

Figure 15: Study Area Well Spacing

In the history matching process, the first step is to assess the quality of data and determine the confidence level for each category of data. This in turn, influences the reservoir properties that we are willing to vary. In this study, PVT properties were modelled with good confidence because the values were either measured or derived from good correlations. The geological parameters were also modelled with good confidence, since core samples was obtained from SM Energy and porosity and permeability were measured. The relative permeability was modelled with medium degree of confidence based on the relative permeability presets i.e. light oil and gas preset values for the Corey equations (22). For the water saturation no resistivity logs were available, so there was very little confidence in our water saturation estimates. Therefore, water saturation was used as a history matching parameter. Aquifer data were also modelled with very little confidence and were also used as a history matching parameter. Hydraulic fracturing is an important completion process in unconventional reservoirs. Many parameters go into the design of hydraulic fracture treatments. But in this work hydraulic fracture properties were held constant because of a lack of fracture design properties.

Hydraulic fracturing parameters were assumed based on operator's input and literature review ofthe study area, as described in Table XV of Appendix A. The twelve study area wells were stage fractured anywhere from 20 to 26 stages. However, within Eclipse, the model was not able to handle 26 stages of fracturing and would not run. This is a known shortcoming of the Petrel software and the issue has been raised with Schlumberger helpdesk. As advised by the Schlumberger helpdesk, the number of fractures was reduced to 13 stages. The pressure depletion map suggested that 13 stages of hydraulic fracturing were enough to deplete the reserves stimulated area the model. The depths of the fractures were sequenced in such a way as to have minimum interference with the nearby wells.

Using the base reservoir model described above, the initial simulation was run. Cumulative oil production and cumulative water production from the base case are compared to three years of production in Figures 16 and 17. Clearly, the base simulation model under-predicts oil production, and water production is non-existent. This suggests that the initial geological model should be improved to match the field oil and water production.

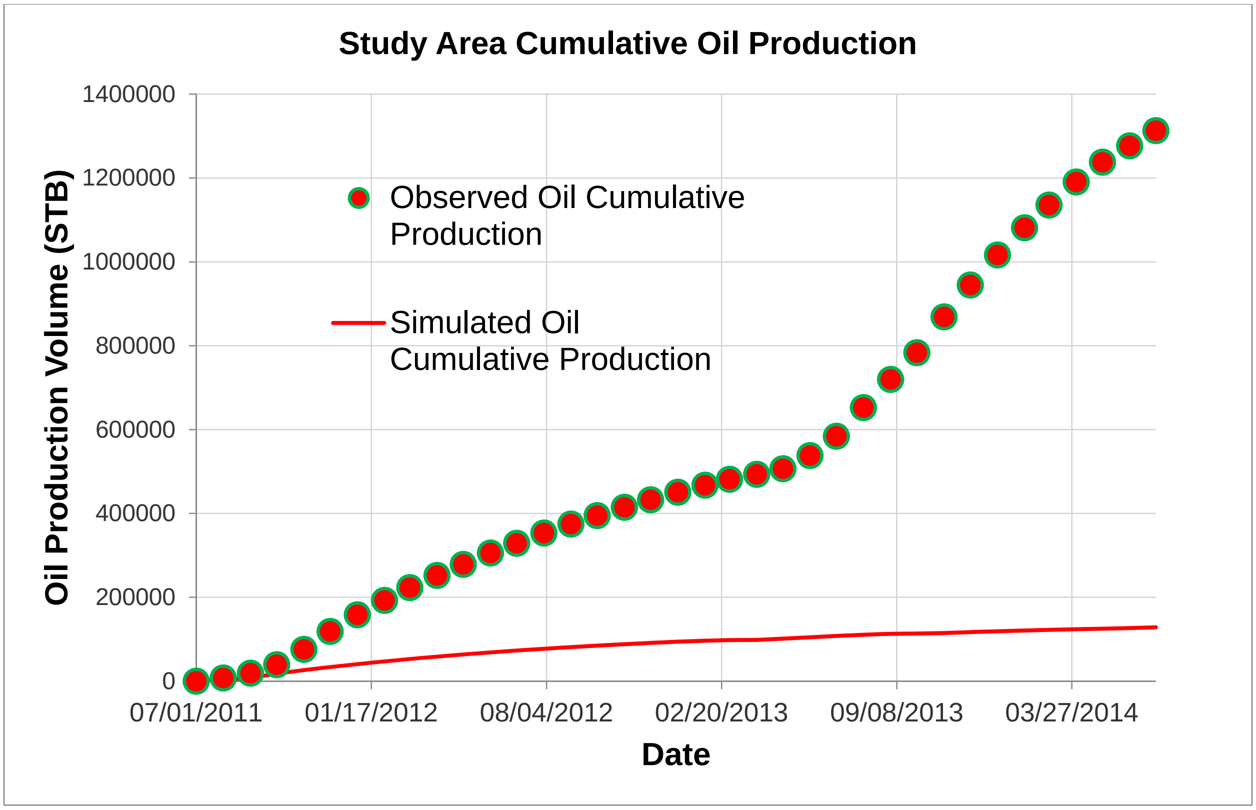

Figure 16: Base Case Cumulative Oil Production

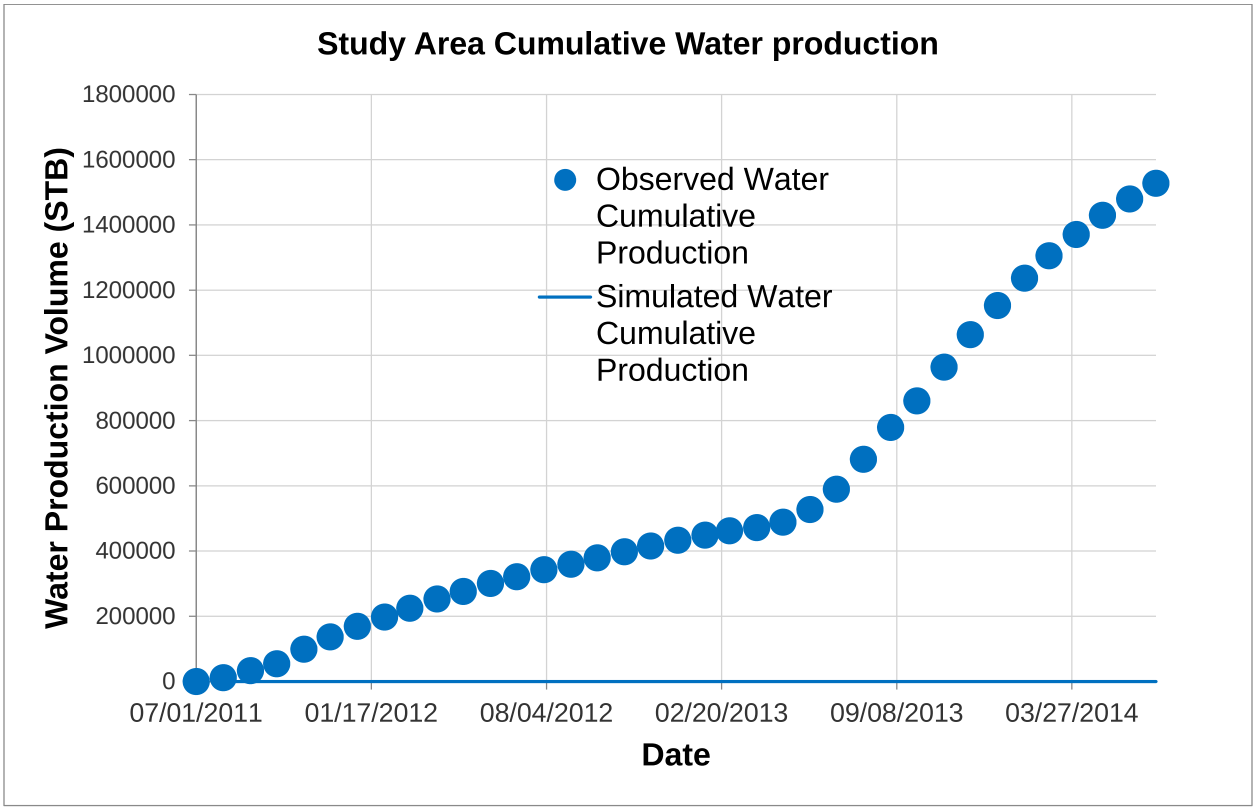

Figure 17: Base Case Cumulative Water Production

5.2. Add Lower Three Forks Reservoir Volume

The initial model contained no water influx mechanism, and no water production was observed in the initial model. Also, the oil rate was severely under-predicted. The porosity and permeability of the Three Forks formation were based on the core test results, the most representative of the Three Forks Formation data available. Because the initial model did not produce enough total fluid, the Base of the Three Forks formation was added as a productive zone and modelled as a poor quality reservoir rock. The details of geological modelling are discussed below.

The reservoir model has four zones- the Middle Bakken, Lower Bakken, Upper Three Forks Formation and Base of Three Forks Formation. Initially, only the Three Forks formation was oil productive. The other three zones were modelled with zero porosity and forced to be nonproductive. The initial simulation runs showed the model was not able to match the production data with the Three Forks as the only producing zone.

A closer look was taken at the hydraulic fracturing details and fracture height in particular. Fractures were assumed to penetrate the entire upper bench of the Three Forks formation. However, these wells probably were fractured both above and below the pay zone i.e. into the Lower Bakken member and base of the Three Forks formation. It is likely the Upper Three Forks Formation is hydraulically connected to the Lower Three Forks Formation.

Is it possible that Lower Three Forks Formation contributes to oil production in the study area? To answer this question the base of the Three Forks formation was added to the model with pore volume and initial oil saturation. Log analysis indicates the base of the Three Forks formation is a poor quality reservoir rock, so geological properties such as the porosity and the permeability were initially modelled as half that of the Three Forks formation (Table IX).

Then the simulation model was run multiple times, gradually increasing the porosity of the base of the Three Forks formation to increase total oil and water production. Increasing porosity increased the oil production. However, we limited porosity to a maximum value of 0.065, same as the Upper Three Forks Formation.

For modelling permeability of the Base of the Three Forks Formation, core sample laboratory permeabilities were the primary data source. It was decided to model the horizontal permeability of base of Three Forks Formation to be one half of the horizontal permeability of the Three Forks Formation i.e. 0.0375 mD. The vertical permeability was modelled as one tenth that of the vertical permeability of the Three Forks Formation i.e. 0.00375 mD. But during the history matching process these values limited the increase in the oil and gas production. So both horizontal and vertical permeability were systematically altered during the history matching process.

Initially the vertical permeability of the Base of the Three Forks Formation was 0.00375 mD, and was systematically increased to 0.0094 mD, a ratio of 1/4th the horizontal permeability. The higher vertical permeability in the Base of the Three Forks Formation model suggests that this formation may have aquifer pressure support migrating upwards through natural fractures. Due to limited permeability and porosity core data, the reservoir model is populated with a uniform porosity and permeability. The implications of this assumption are discussed in the results section. As demonstrated in Figures 18 and 19 these changes improved the oil match but did not increase the water production.

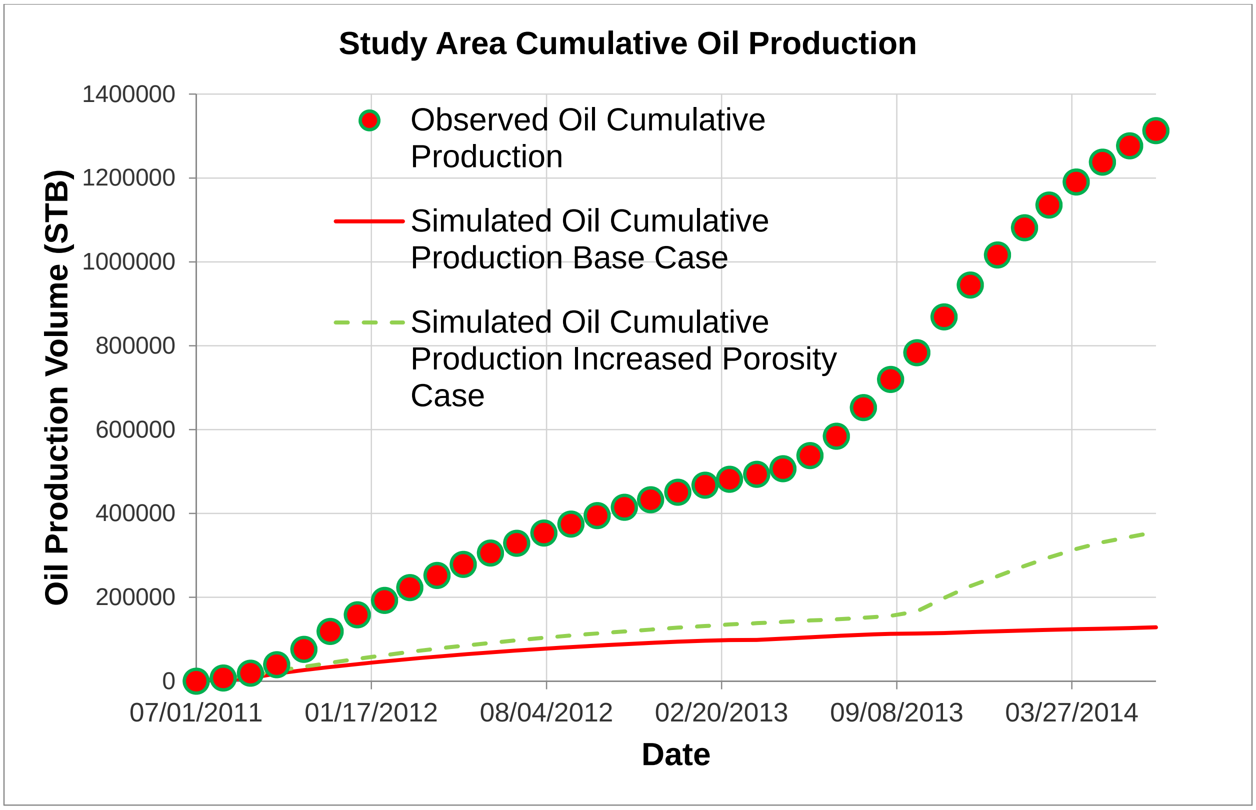

Figure 18: Increased Porosity Case Cumulative Oil Production

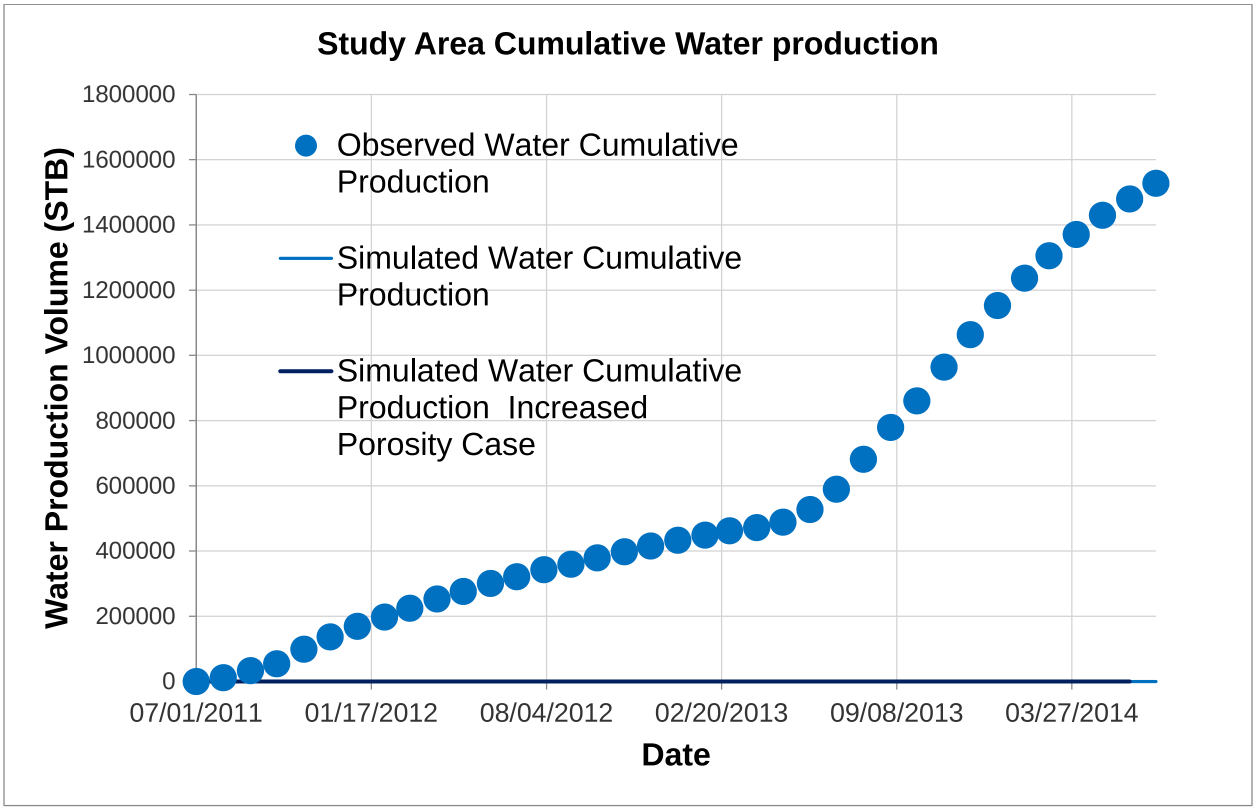

Figure 19: Increased Porosity Case Cumulative Water Production

5.3. Relative Permeability

The relative changes in production caused by increase in reservoir volume, especially the non-existent water production, suggested the reservoir model might be unrealistically limiting fluid movement in the reservoir. Since we had no measured relative permeability data, it seemed logical to maximize the relative permeability curves on reservoir productivity. The Corey exponents for the oil and gas curves were altered to increase both oil and water production from the model. The oil exponent was changed from 3 to 1, giving a straight line. The water exponent was changed from 3 to 2, decreasing the curvature and making water more mobile. The new oil-water relative permeability curve is shown in Figure 20.

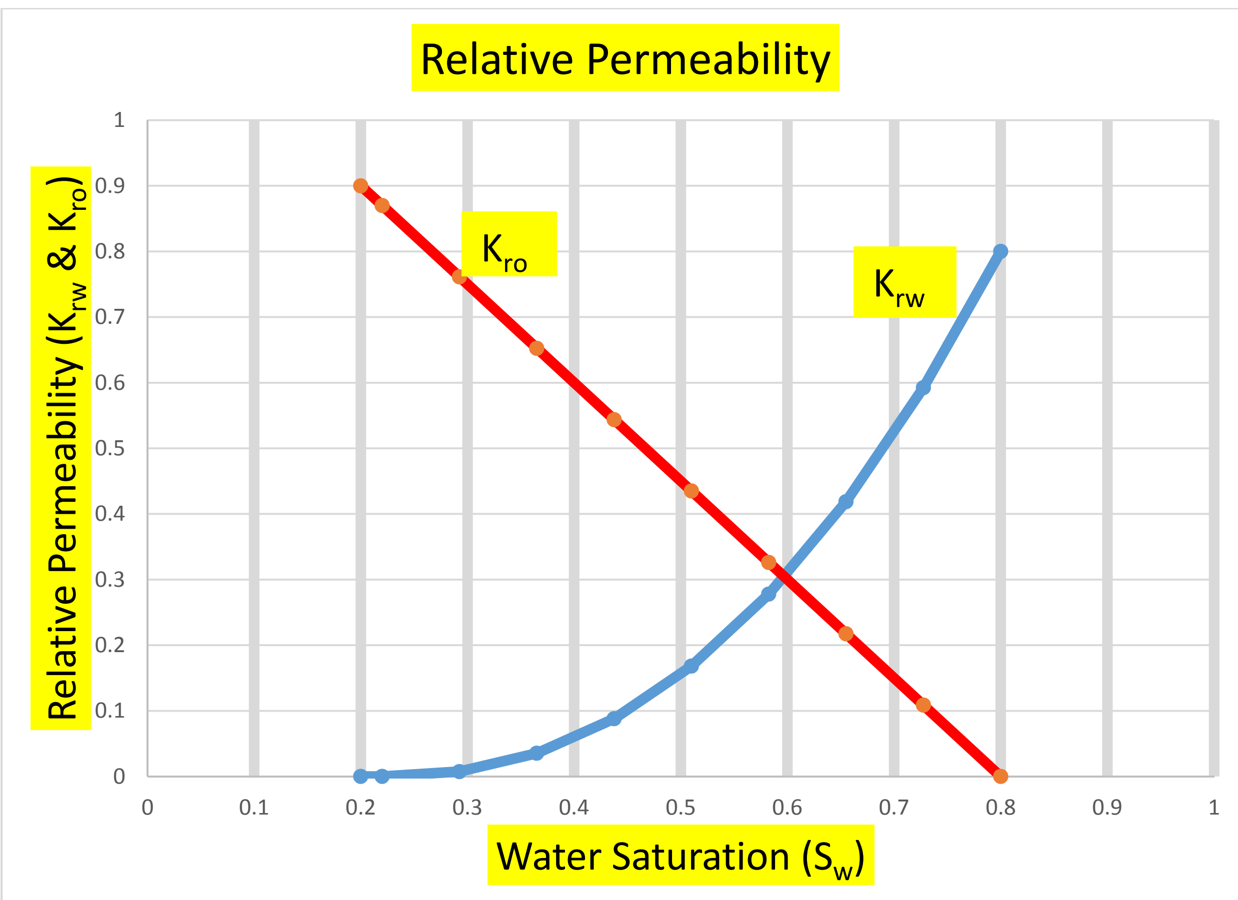

Figure 20: History Matched Relative Permeability Curve

Results from the simulation run with the altered relative permeability curves are shown in Figures 21 and 22. These changes in the simulated model did affect the produced fluid volumes. The oil production was increased significantly and the model has now started to produce water for the very first time. However, with these relative permeability curves the model recoveries are significantly less than the historic oil, water and gas production data.

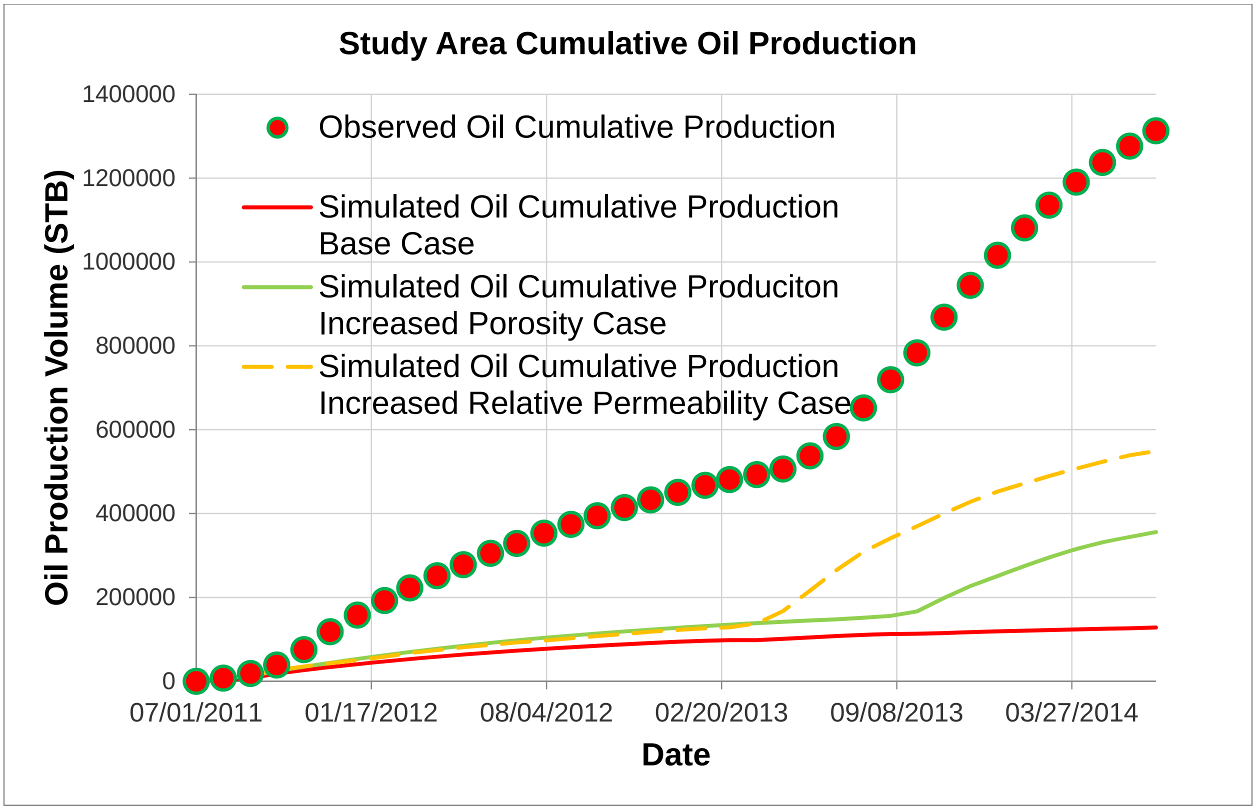

Figure 21: Altered Relative Permeability Case Cumulative Oil

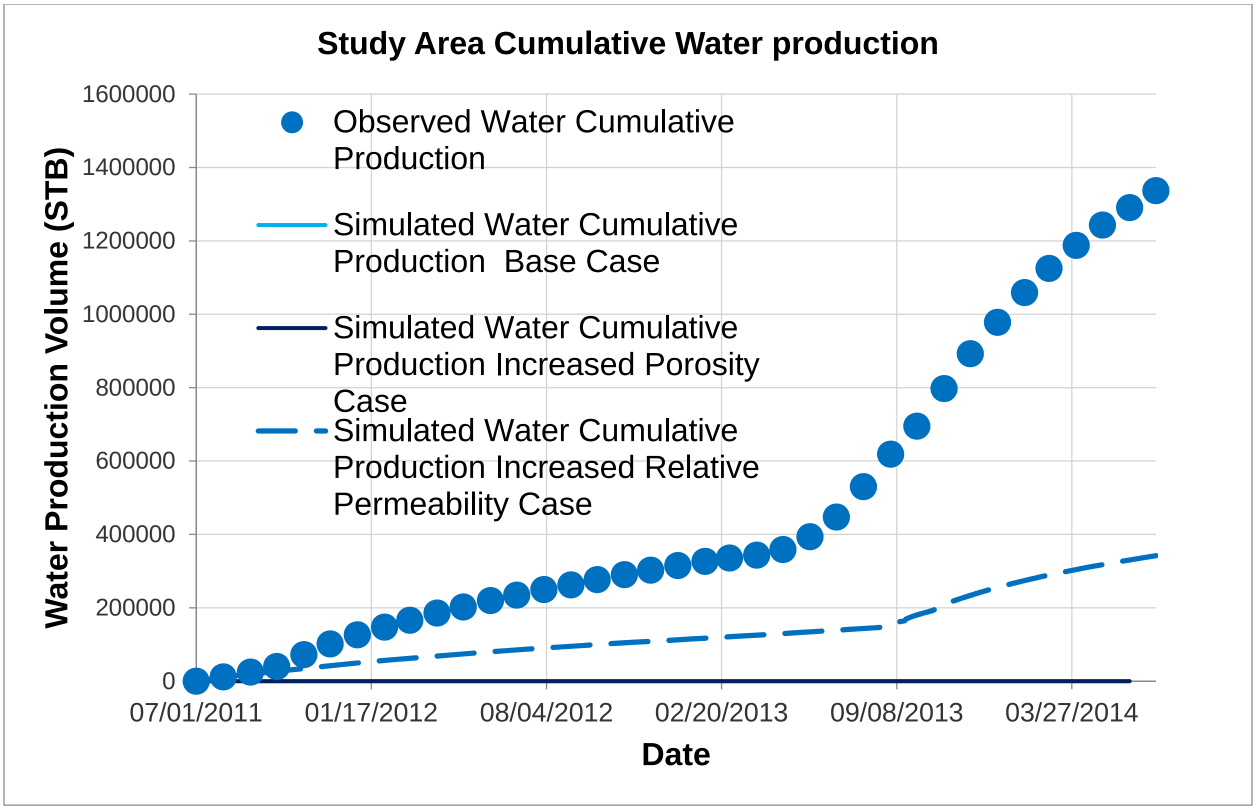

Figure 22: Altered Relative Permeability Case Cumulative Water

Changing the relative permeability curves enabled the model to generate more oil and total fluid production from the field. But still there were gaps between the observed and simulated curves as shown in Figures 21 and 22. This suggested the reservoir model lacks pressure support, which could be remedied by adding a water influx model.

5.4. Modelling Water Influx

The final strategy to match the total fluid production from the field was adding energy to the reservoir by modelling water influx. Various water influx model geometries were tested in this work to match the water cut of the study area wells. Aquifer thickness, permeability and porosity were varied to simulate water production data.

The first question that must be answered is the source of water influx i.e. from the edge or from the bottom. So, edge water drive was tried first to supply energy to the reservoir. The horizontal permeability of the model was varied to improve the water production from the study area. The initial horizontal permeability of the Three Forks formation was set to 0.075 mD, which was systematically increased to 2 mD. The horizontal permeability of 2 mD seemed to be very high and unreasonable for the Three Forks Formation. However, even with this very high permeability the model could not match production when new wells came online in July 2013, as shown in Figure 23.

Also, with edge water drive the model pressure fell below the saturation pressure, causing high simulated Gas Oil Ratios (GOR's) whenever a new well comes on production (see Figure 24). The low observed GOR's indicate the reservoir stayed above saturation pressure in the field and is a strong argument for natural pressure support in the field. However, under the edge water drive the model experienced a huge initial pressure decline within three years of production, as shown in Figure 25. For these reasons we concluded that this field is not producing water from the edge, and edge water influx was ruled out as the major water influx mechanism.

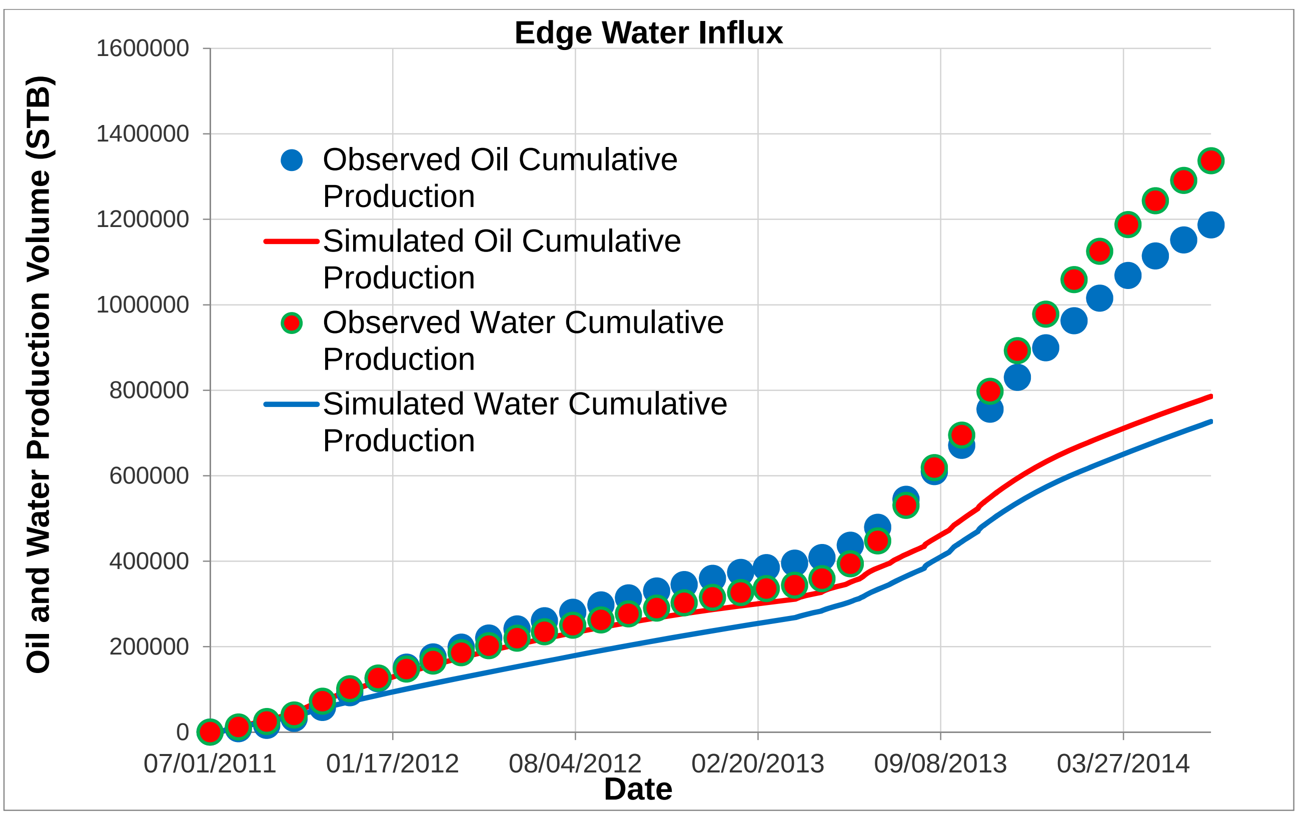

Figure 23: Edge Water Influx

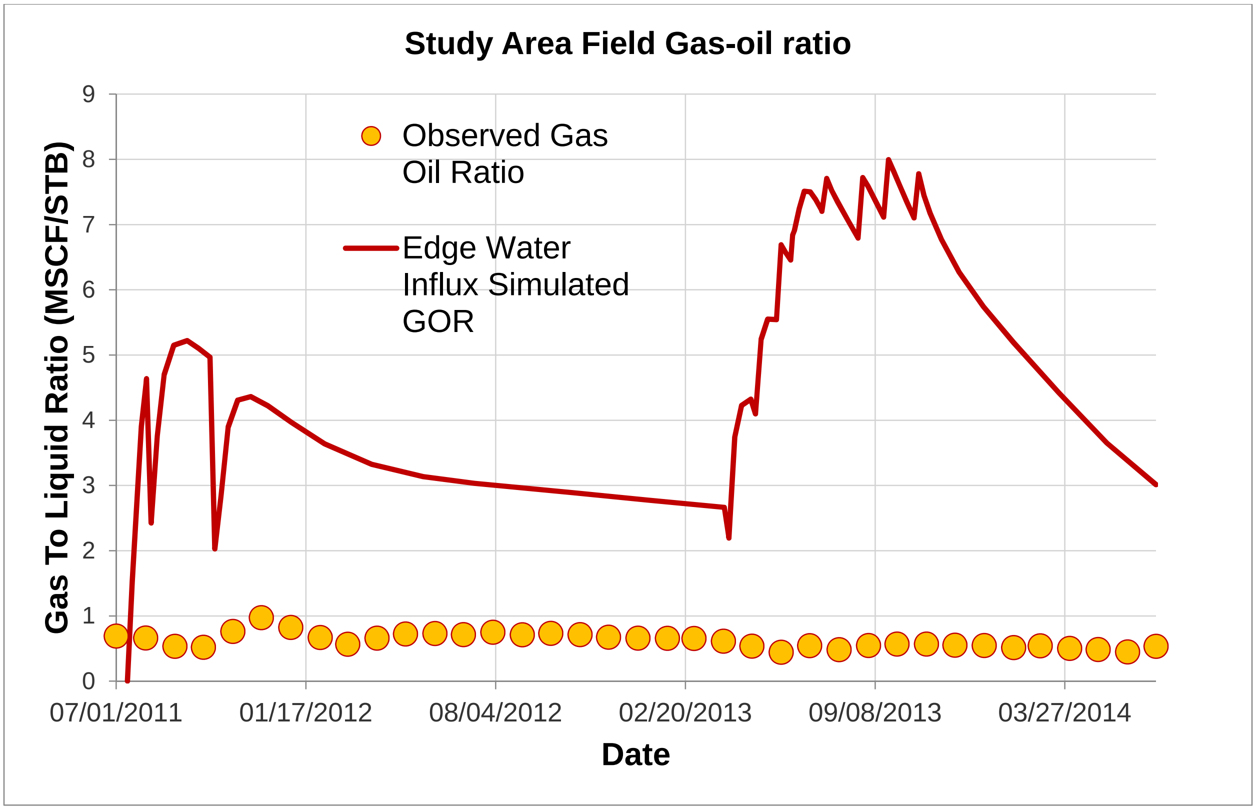

Figure 24: GOR Comparison for Edge Water and Bottom Water Influx

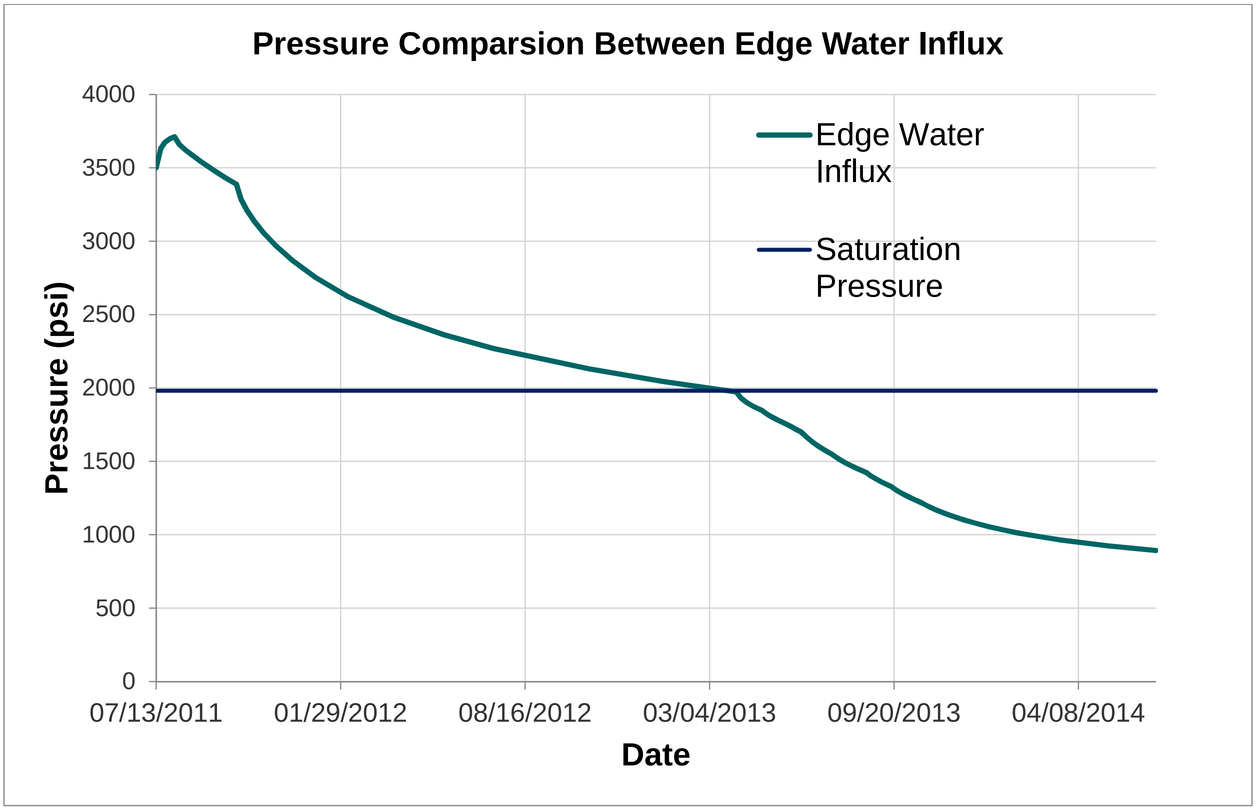

Figure 25: Edge Water Influx Pressure Depletion

Since edge water influx was unable to match the observed water production, bottom water influx was included in the model. The aquifer properties were modelled the same as that of the Base of the Three Forks Formation. The initial aquifer water saturation was modelled to be 100% and yielded high water cut. The aquifer water saturation was systematically decreased to 50% until the model produced a close match with observed data. The final history match is shown in Figure 26, with bottom water drive, enhanced relative permeability and increased upper and lower Three Forks porosity. History matching parameters are summarized in Table IX. All parameters used in the history matching process were held constant for the sensitivity analysis that will answer the study question.

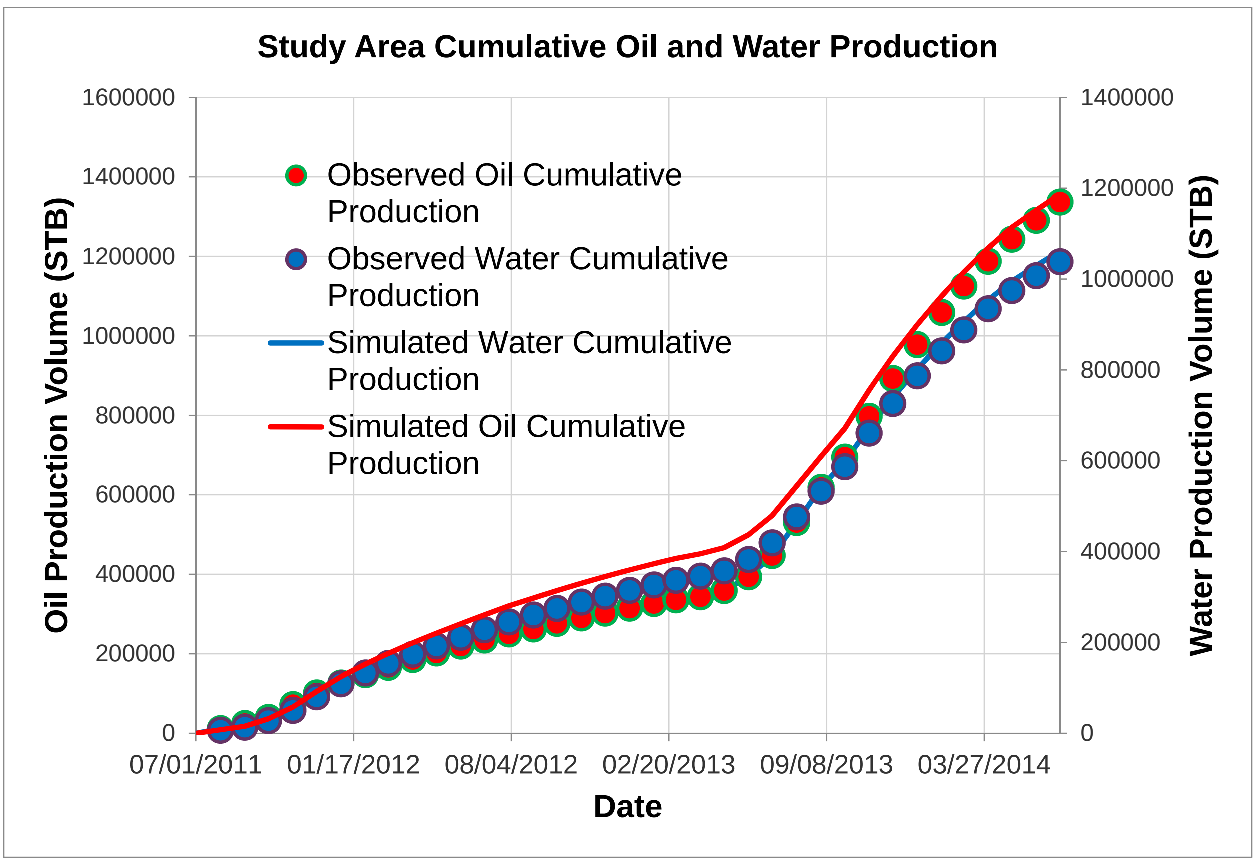

Figure 26: Bottom Water Influx

Table IX: Summary of History Matched Parameters

Parameter	Initial Properties for Three Forks Formation	Initial Properties for Base of Three Forks Formation	History Matched Three Forks Formation	History Matched Base of Three Forks Formation
Porosity (%)	6.500	-	6.5	6.5
Permeability XY (mD)	0.075	-	0.075	0.0375
Permeability Z (mD)	0.0075	-	0.0188	0.0094
Corey Exponent O/W	3.000	-	1	1
Initial Pressure (Psi)	3500.000	-	3500	3500
Solution Gas Oil Ratio (MSCF/STB)	0.700	-	0.7	0.7
Bubble Point Pressure (Psi)	1980.000	-	1980	1980
Fracture Half Length (feet)	550.000	-	550	550
Fracture Permeability (mD)	10.000	-	1000	1000
Number of Stages	26.000	-	13	13
Fracture Width (inches)	0.300	-	0.3	0.3
Fracture Height (feet)	25.000	-	25	25
Water Saturation (%)	50.000	-	50	50
Aquifer Permeability (mD)	0.075	-	0.0375	0.0375
Aquifer Porosity (%)	6.500	-	0.00325	0.00325

Under edge-water drive, the pressure falls rapidly to 800 psi after three years of production as shown in Figure 27. This resulted in a rapid decline in oil and gas production. In contrast, with bottom water influx the pressure falls more slowly with time. At the end of the third year the pressure has fallen to 2200 psi and the model is still producing well above the bubble point pressure. This caused the producing GOR to more closely approximate the saturation pressure GOR of 0.7 MSCF/BBl for the first three years as shown in Figure 28.

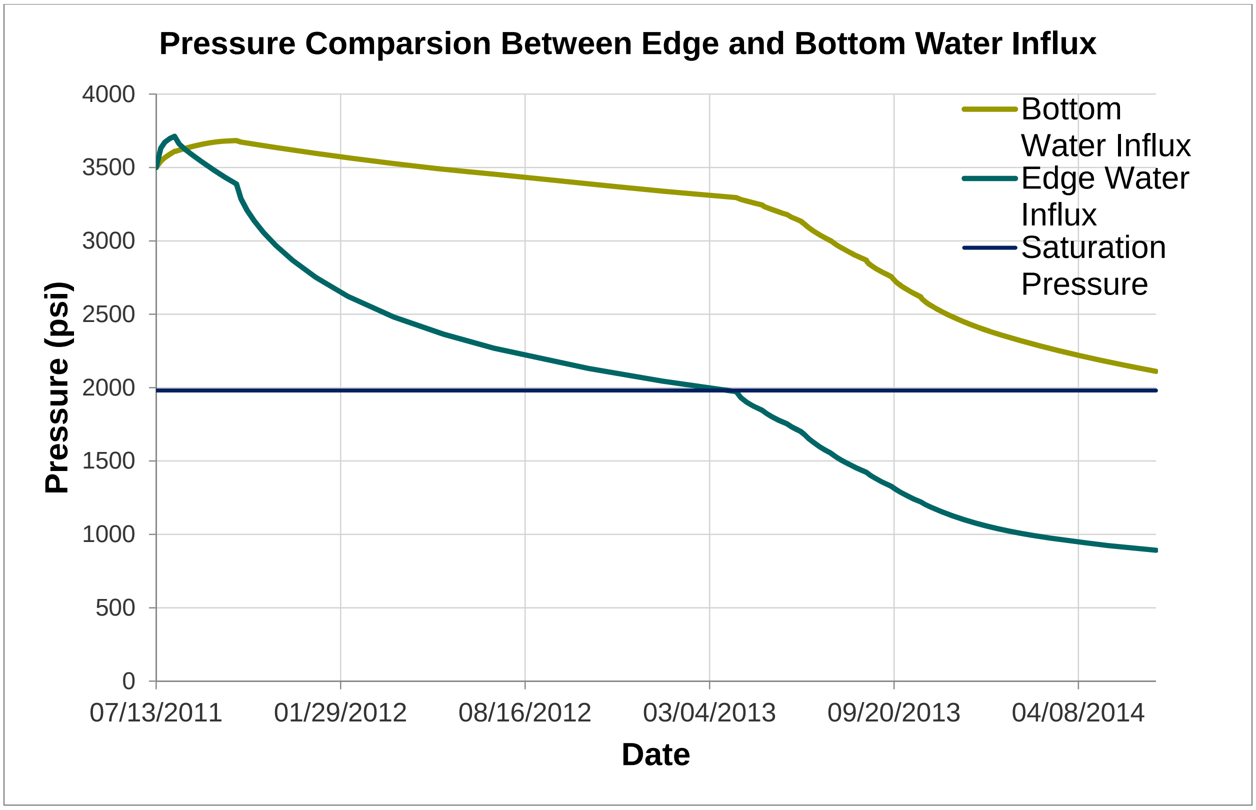

Figure 27: Pressure Depletion for Edge Water and Bottom Water Influx

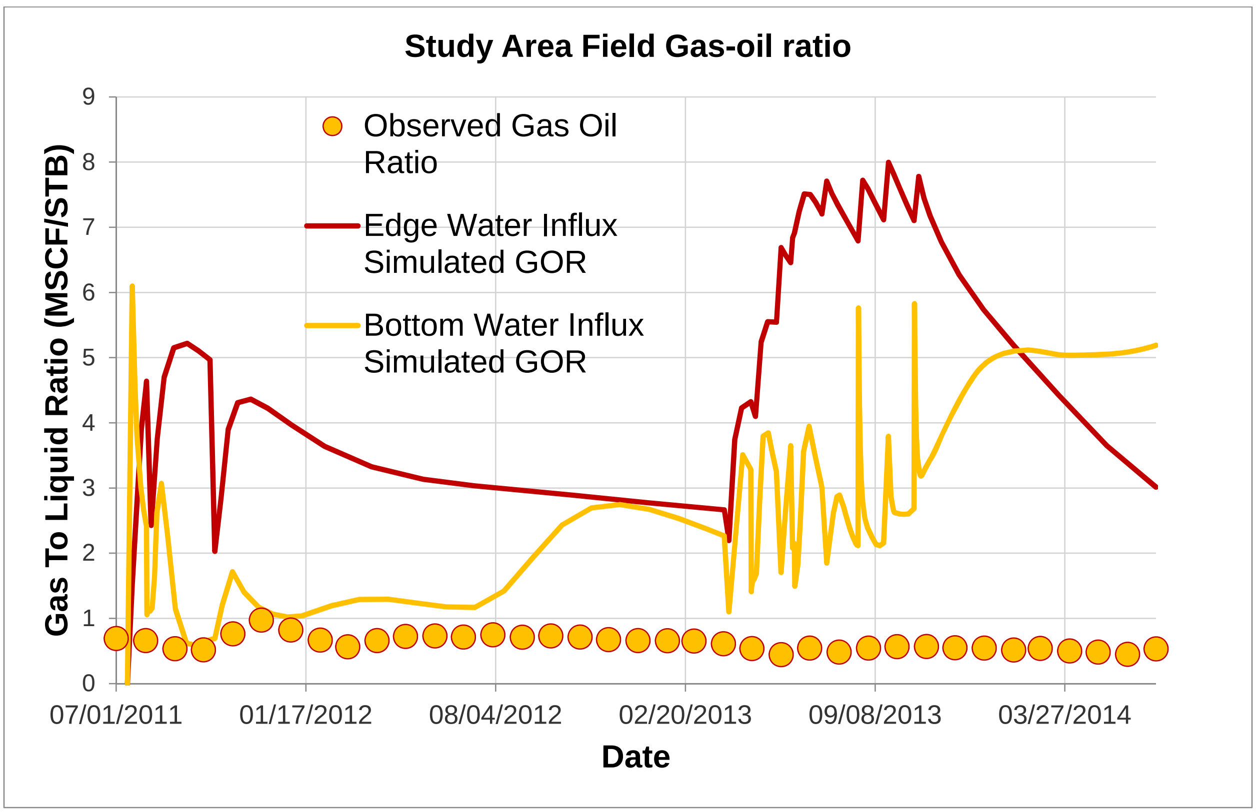

Figure 28: GOR Comparison Edge and Bottom Water Influx

Bottom water influx successfully increased total fluid production and enabled a good match on oil and water production from the study area. However, individual well water cut matches were not as accurate as the total study area match. The reservoir model consists of twelve wells, i.e. four wells per two-section drilling unit. Each of the two-section drilling units consists of an early well drilled in 2011 and three late wells drilled in 2013. These early drilled wells are most important for history matching since they have a longer period of observed data. For example the early well in section of land i.e. Bagley 4-30H (20545) had a higher water cut than other producing wells. In the history matching process, we had difficulty in history matching individual wells production and water cut. We believe this is because of uncertainty in the vertical position of wellbore i.e. their nearness to the top and bottom of the reservoir. So the total fluid production from the study area was history matched, but no attempt was made to match individual well water cut. Each individual two-section drilling unit was evaluated to find the best match for oil and water production from the study area wells. The drilling unit with the best match was used to perform sensitivity analysis on well spacing.

5.5. Group Subdivision

At this point the model matched the total production from the twelve study area wells to an acceptable level of accuracy. Since the study question was focused on identifying the optimal number of wells to be drilled per drilling unit i.e. two sections of land, it was decided to reduce the model size to one third of the study area and use the smaller two-section model for sensitivity analysis of well density.

A systematic approach was used to determine the best part of the study area for the sensitivity analysis. The total model was divided into three drilling units of four wells each and referred to Group 1, Group 2 and Group 3 (refer to Table X and Figure 29). Each group had an early well (drilled in 2011), and three late wells (drilled in 2013). The wells with the most production data (the early wells) were given more emphasis when matching the oil and water production data. Figures 30, 31 and 32 show the cumulative oil production and water cut for the three groups. By comparing the three groups, Group 2 most closely matched the oil and water production.

Table X: Group Subdivision

S.No	NDIC File No	Well Name	Group
1	20878	Legaard 4-25H	1
2	24448	Legaard 2-25HNB	1
3	24449	Legaard 2-25HNA	1
4	24471	Rose 16-24HN	1
5	20545	Bagley 4-30H	2
6	24750	Mosser 2-30HNA	2
7	24751	Mosser 2-30HNB	2
8	24746	Mosser 1-30HN	2
9	20549	Simonson 1-29HN	3
10	24211	Jeglum 3-29HNB	3
11	24212	Jeglum 3-29HNA	3
12	24176	Roese 4-29H	3

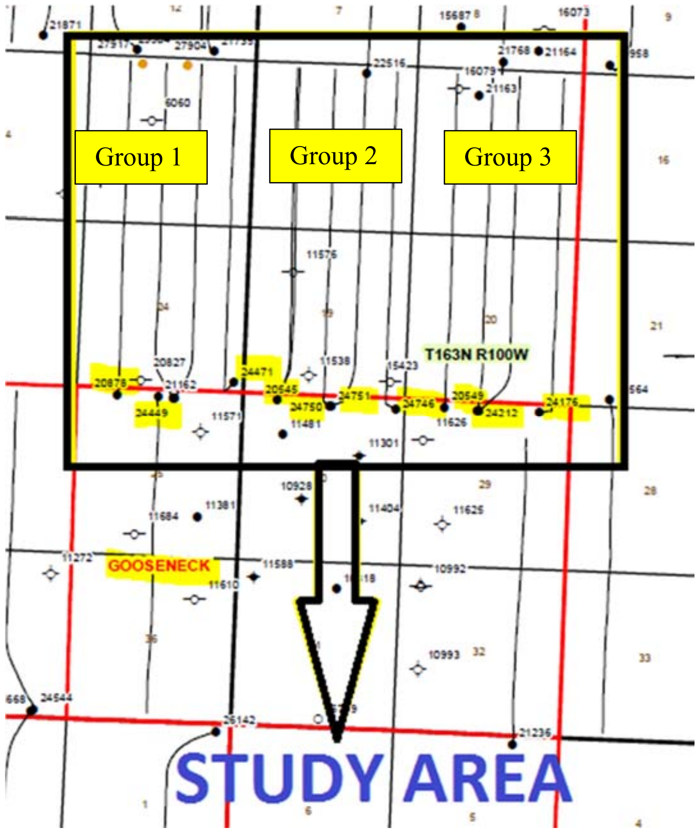

Figure 29: Map Shows Group Subdivision

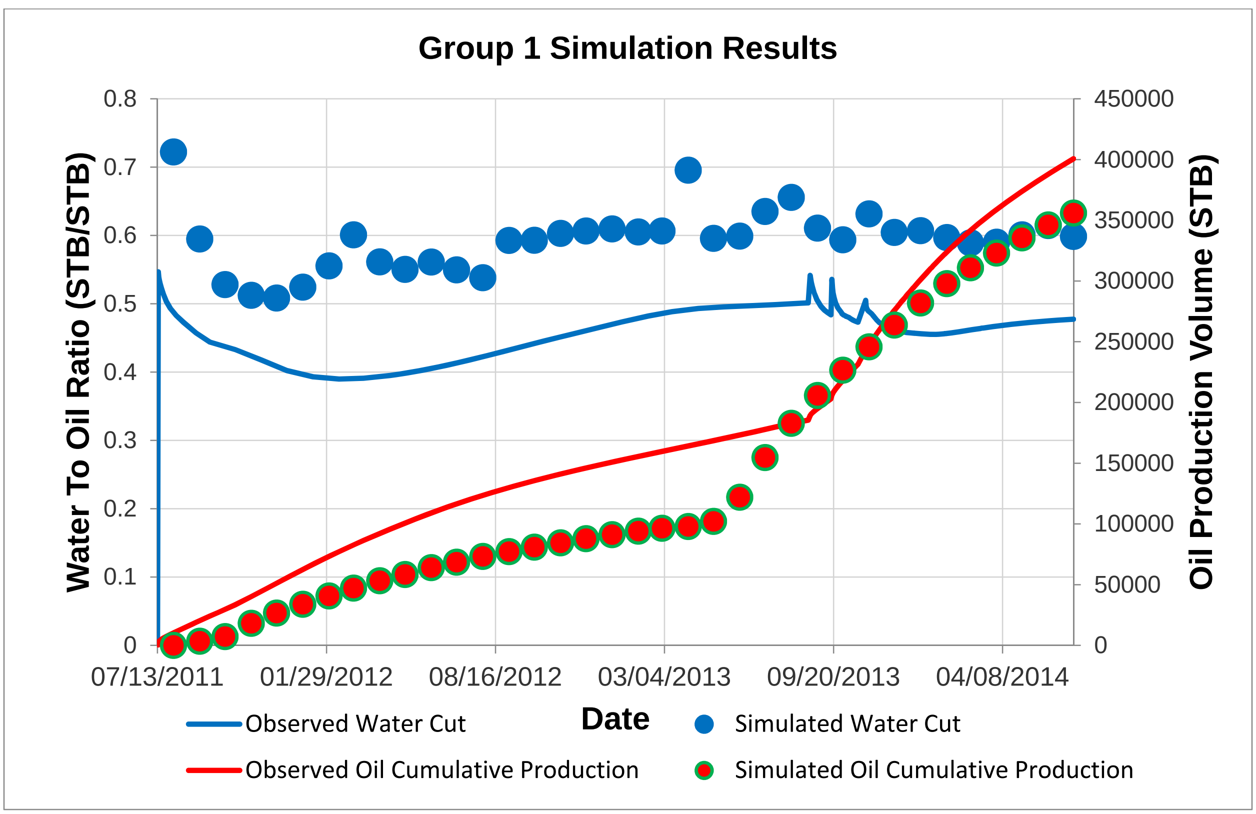

Figure 30: Group 1 Cumulative Oil Production and Water Cut

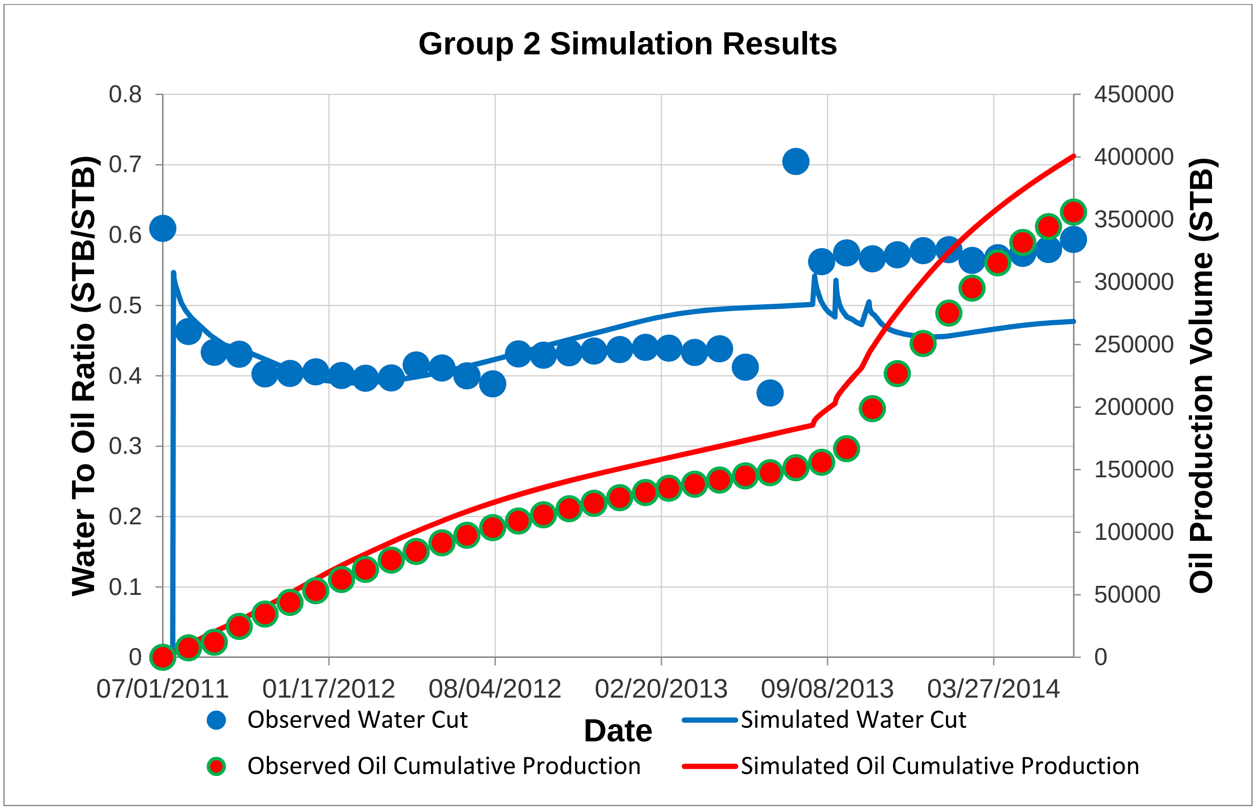

Figure 31: Group 2 Cumulative Oil Production and Water Cut

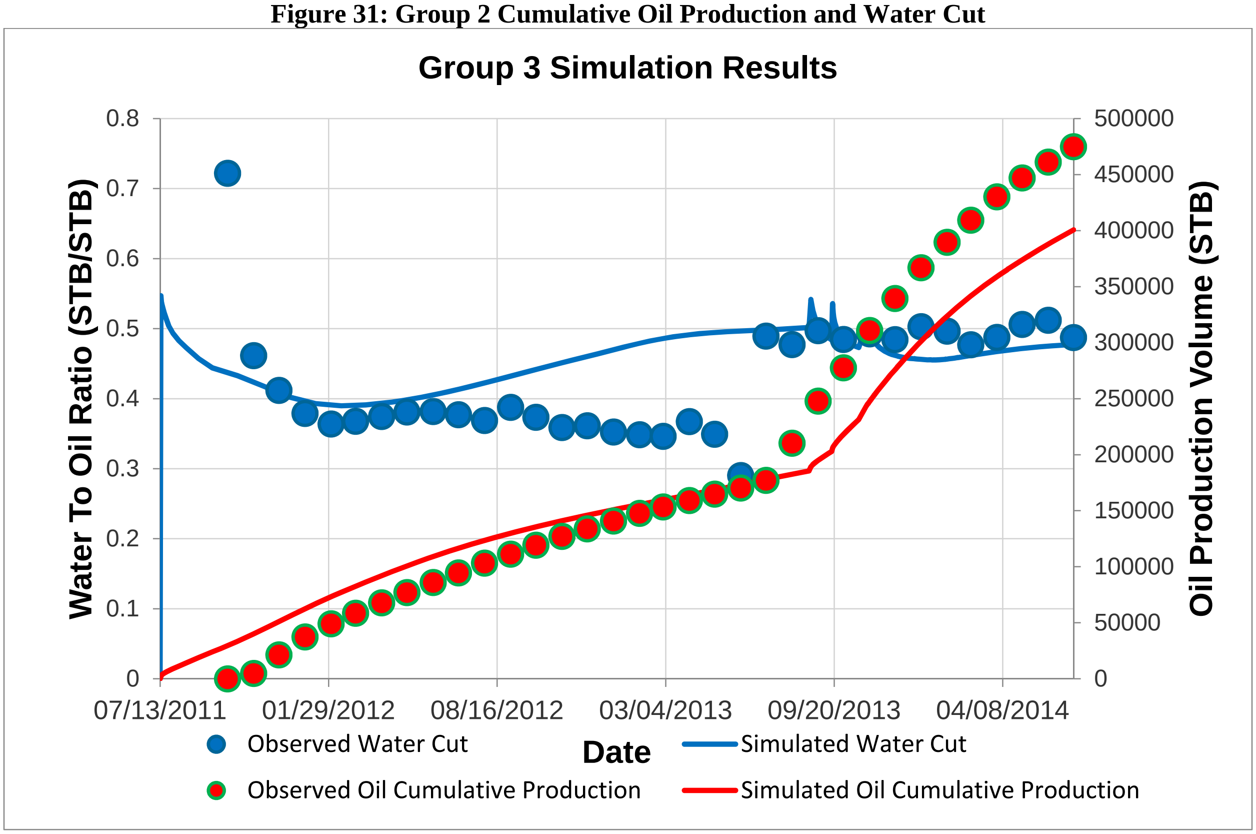

Figure 32: Group 3 Cumulative Oil Production and Water Cut

For the Group 1 wells, the model overproduced oil and under-produced the water cut compared to the observed data. In contrast, the Group 3 wells under-produced oil and over-produced the water production compared to the observed data. However, the Group 2 wells matched the oil production and water cut relatively well when compared to the observed. The well configuration of Group 2 is shown in Figure 33. The cumulative liquid production matched the observed data well, as shown in Figure 34. Therefore, it was decided to perform the sensitivity analysis with the Group 2 drilling unit, and eliminate Group 1 and Group 3 as potential candidates to perform sensitivity analysis.

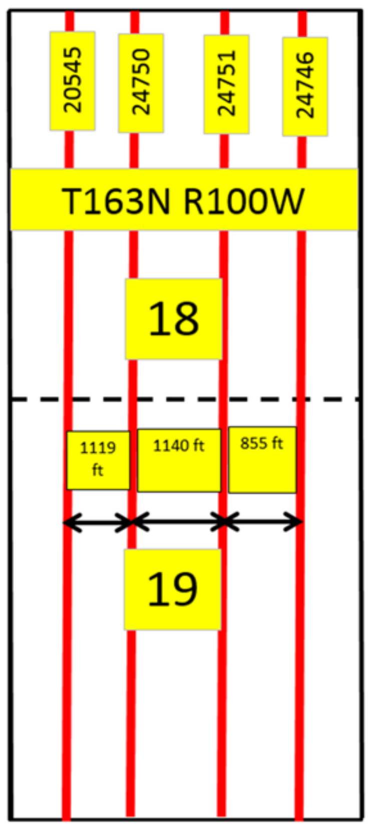

Figure 33: Group 2 Wells in the Model

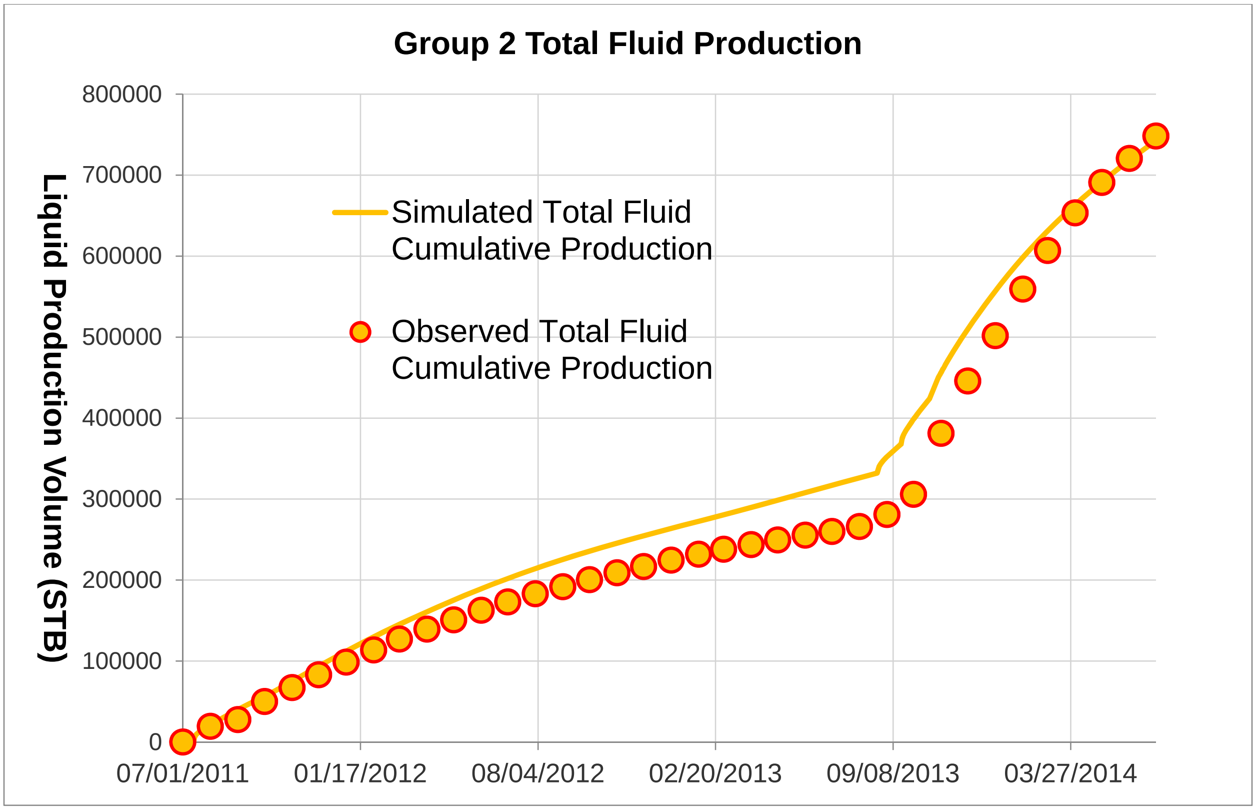

Figure 34: Group 2 Total Fluid Production

6. Results and Analysis

Prediction of production rates and ultimate recovery of oil are needed for development planning and timely action. As discussed in chapter 5, a history matched reservoir model was constructed and was available for oil forecasting. In this stage of the research the existing wells were removed from the trimmed model and hypothetical wells were placed with symmetrical well spacing in the history matched reservoir model.

To answer the study question methodically, this research systematically placed one to six wells per drilling unit and simulated production for each scenario. This was done to understand the increase in oil production developed by each new well in the model. For each simulation the model was run for thirty years to determine the amount of oil and gas produced from the field. The oil and gas production predictions were then used for economic analysis. Each test case was compared based on the capital expenditures and net profits earned.

The operator wants to maximize recovery and optimize development of the Colgan field, which will be developed with multi-stage fractured horizontal wells. The current well spacing is approximately 1500 feet with four wells drilled per drilling unit (28). The goal of this study is to alter the well spacing symmetrically in the simulation model to evaluate the following questions:

- Are the closer spaced wells more likely to share reserves?
- Is it profitable to drill more wells to extract the available reserves?
- Will water influx support more wells in the formation?

A two-section area (T163N R100W sections 18&19 from the study area) was used to perform the sensitivity analysis. The hypothetical wells would be drilled with symmetrical well spacing, beginning with one per drilling unit and increased one per case until a maximum of six wells drilled per unit. The nomenclature for these hypothetical wells are denoted as WXCX, the first two letters represent well number and second two letters represents case number. For example, W3C3 is the third hypothetical well in case three. Each well was placed vertically in the center of the Three Forks formation, given a completion length of 10,000 feet and stimulated with thirteen stages of hydraulic fracturing treatments with half fracture length of 550 feet.

Each simulation forecast was run for thirty years i.e. from 01/01/2015 to 06/01/2045. The hypothetical wells were scheduled to come online at the rate of one per month. The last well in case 6, (W6C6) started producing at 06/01/2015, so for a uniform end date all the wells were produced until 06/01/2045. The simulations were run until the economic limit of 10 Bbl/day/well was reached or until 06/2045, whichever came first. Results from these test cases are presented in the sections that follow.

6.1. Case 1

In the first test case scenario, the hypothetical well W1C1 was drilled in the center of the drilling unit, 2640 feet away from the section lines as shown in Figure 35. Since only one well is operating in this case, the offset well spacing for this case would be 5240 feet.

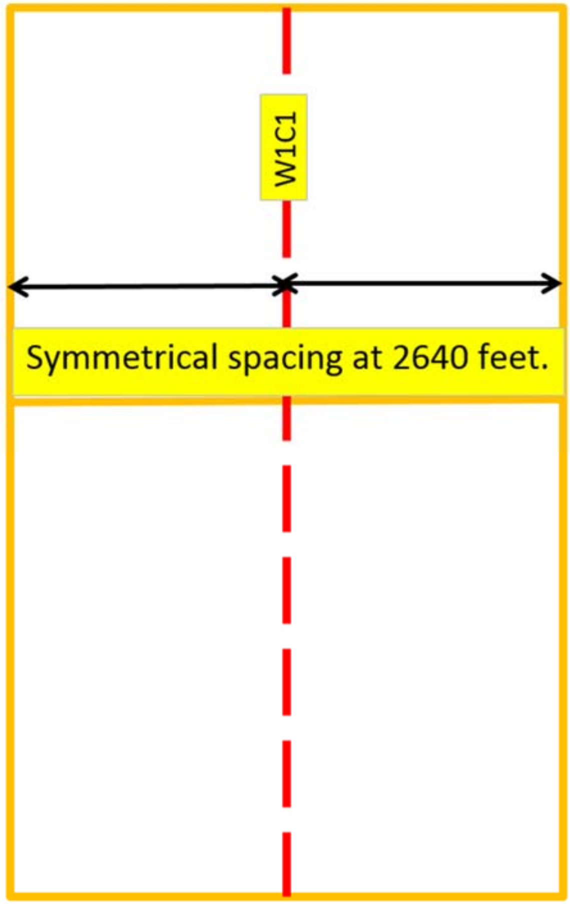

Figure 35: Single Well Spacing for Test Case I

The simulation was run until 06/2045 and oil and gas production were recorded. The model produced oil until the end of simulation period and did not reach the economic limit at 10 Bbl/day. The simulation pressure depletion map showed significant reservoir pressure left at end of thirty years, as shown in Figure 36. The cumulative production for this case was 426,000 Bbl of oil and 1,692,000 MSCF of gas. The total recovery of oil was 3.8% of the original oil in place.

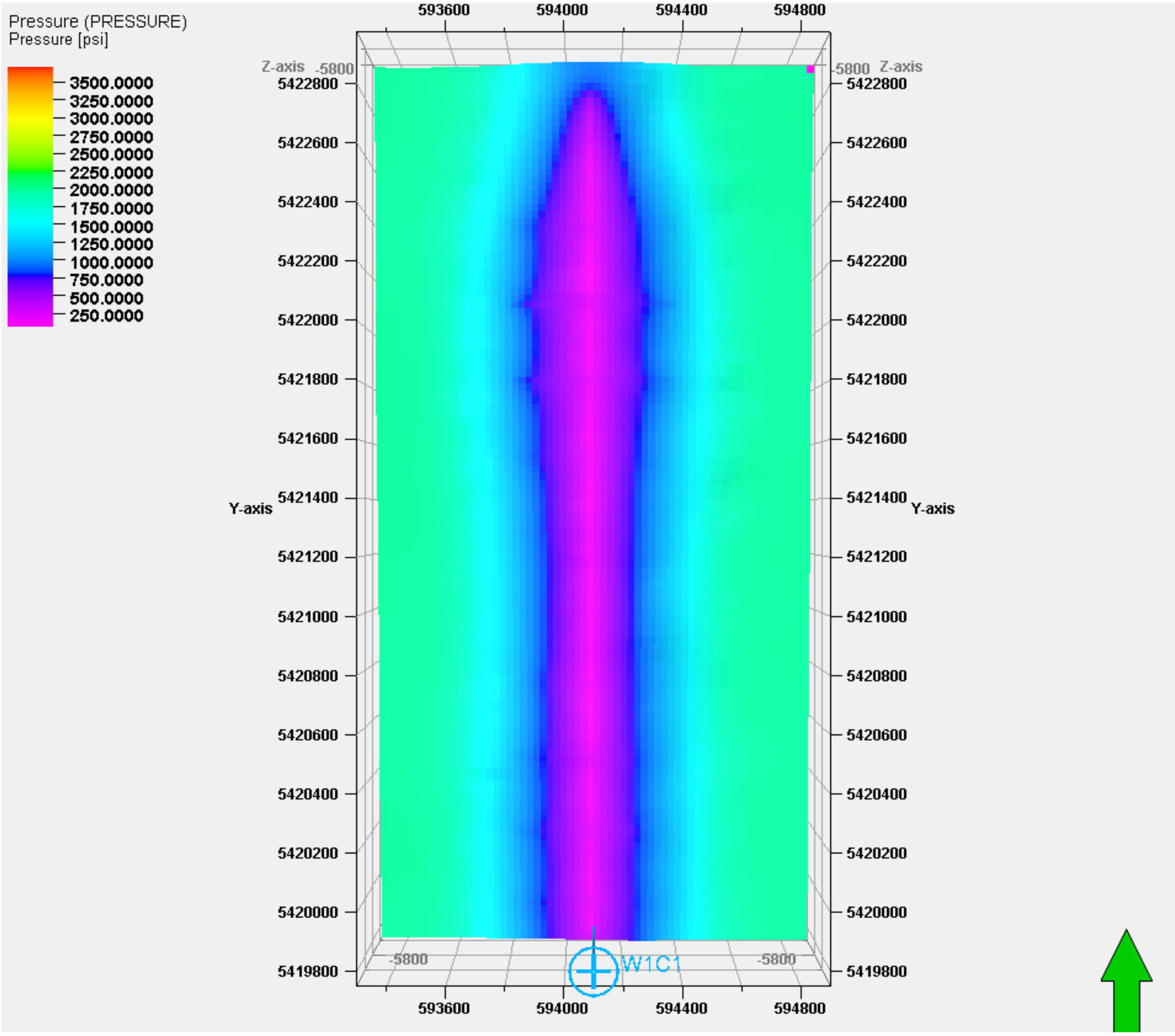

Figure 36: Case 1 Pressure Map

6.2. Case 2

In the second test case scenario, two hypothetical wells W1C2 and W2C2 were placed in the drilling unit approximately 2640 feet away from the center of the section lines as shown in Figure 37. The offset well spacing for this case is 1320 feet. The reason for reducing offset well spacing into half regular well spacing is because it is assumed the wells drilled in the adjacent drilling units will also have the same offset well spacing. When combined the spacing of these offset wells is 2640 feet which is same as the other wells in the section. The simulation reached the economic limit in 2042. The cumulative oil production for this case is 673,000 Bbl and gas production is 3,522,000 MSCF. The total recovery of oil is 6.1% of original oil in place, an incremental improvement of 2.3% over case 1.

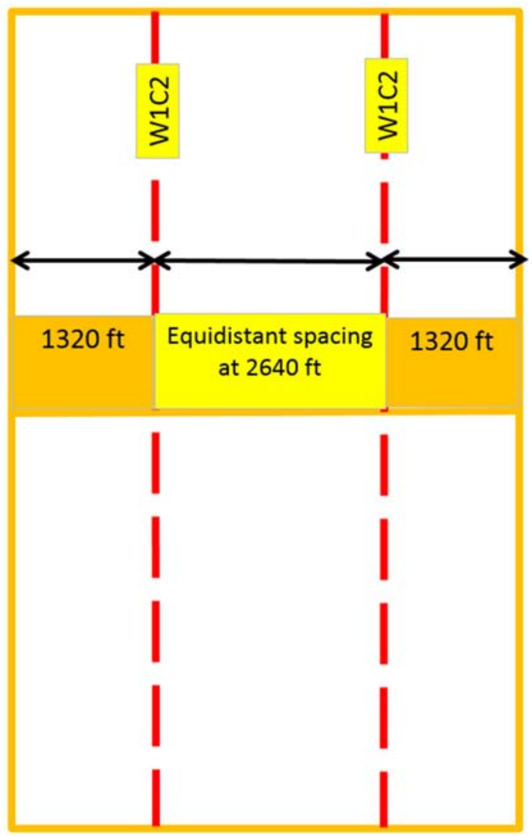

Figure 37: Double Well Spacing for Test Case II

The final pressure depletion map from case 2 is shown in Figure 38. Placing two wells in the model left areas of un-depleted pressure in the reservoir, and presumably was not enough to deplete the reserves from the model. This case suggests that the untouched reservoir area can be produced by adding a new well in the model with a reduced well spacing.

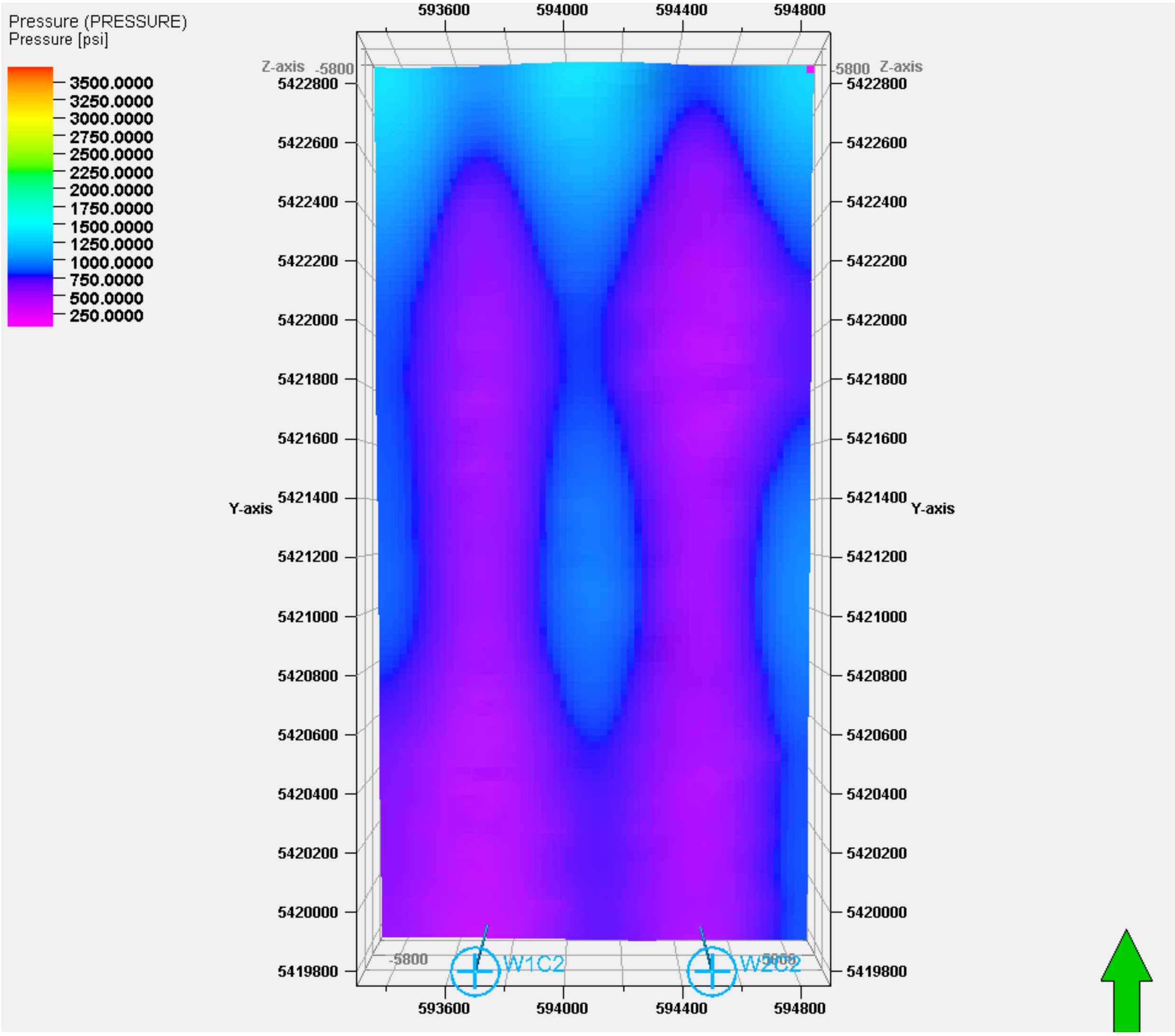

Figure 38: Case 2 Pressure Map

6.3. **Case 3**

In the third test case scenario, three hypothetical wells W1C3, W2C3 and W3C3 were located in the drilling unit approximately 1760 feet away from the center of the section lines as shown in Figure 39. The offset well spacing for this case is 880 feet.

The simulation reached its economic limit in 2034, and oil and gas production values were recorded. The cumulative oil production for this case is 776,000 Bbl and gas production is 4,506,000 MSCF. The total recovery of oil with respect to original oil in place was 6.9%, an increase of 0.8% over the two-well case.

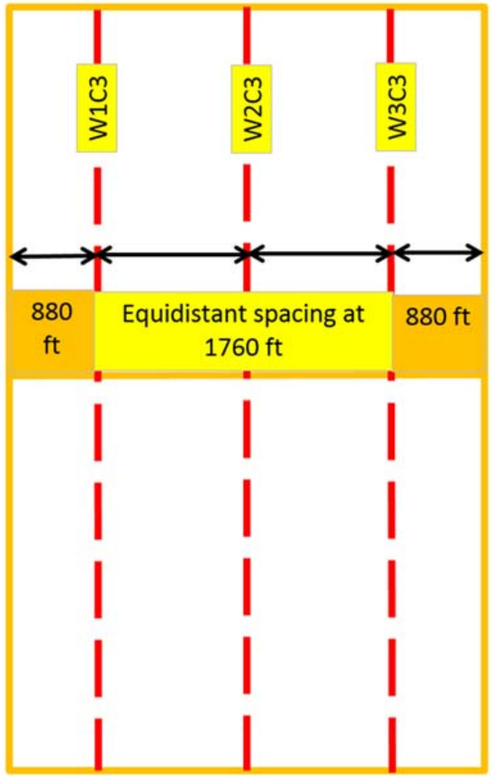

Figure 39: Triple Well Spacing for Test Case III

The pressure map from case 3 is shown in Figure 40. The model reached the economic limit in May 2033. This is reflected in the pressure depletion map which shows a maximum pressure of 750 psi at the end of the simulation. This case inspired us to study the incremental change in the oil production by adding a new well in the drilling unit, which leads to case 4.

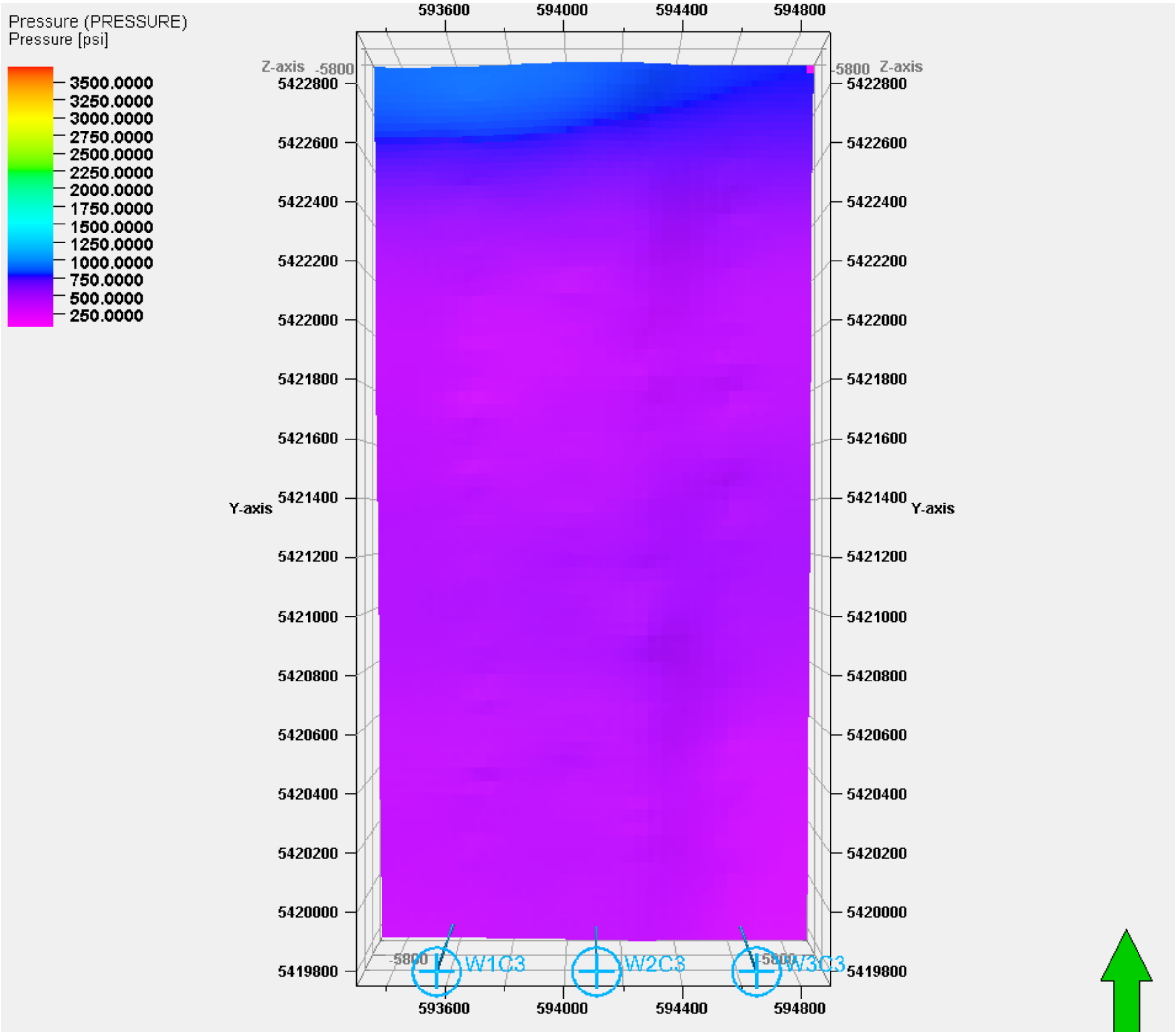

Figure 40: Case 3 Pressure Map

6.4. Case 4

In the fourth test case scenario, four hypothetical wells W1C4, W2C4, W3C4 and W4C4 were placed in the drilling unit approximately 1320 feet apart, as shown in Figure 41. The offset well spacing for this case is 660 feet.

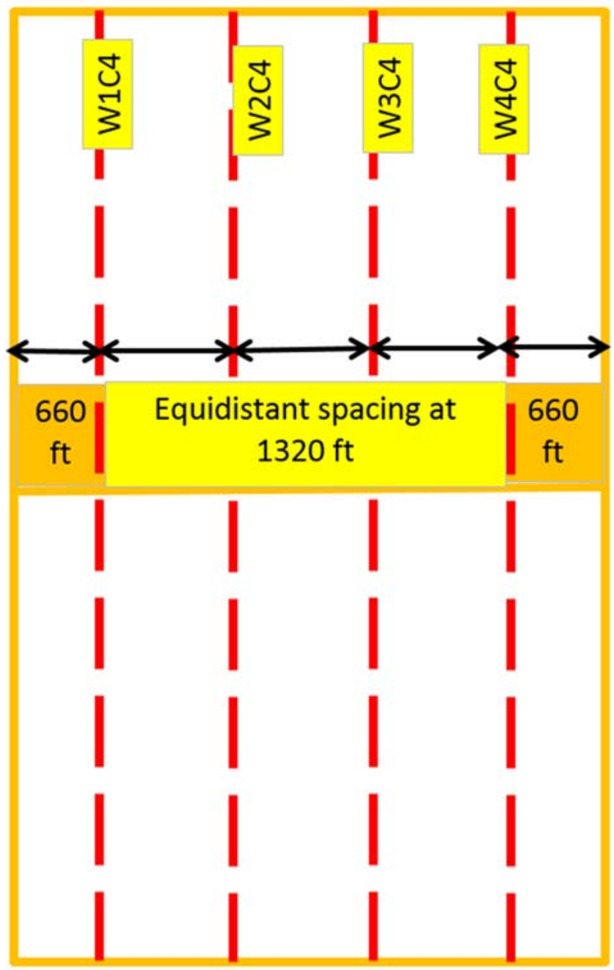

Figure 41: Quadruple Well Spacing for Test Case IV

The simulation was run until the economic limit was reached in 2029 and oil and gas production were recorded. The cumulative oil production for this case is 875,000 Bbl and gas production is 4,436,000 MSCF. The total recovery of oil was 7.8% of the original oil in place, an improvement of 0.9% over case 3.

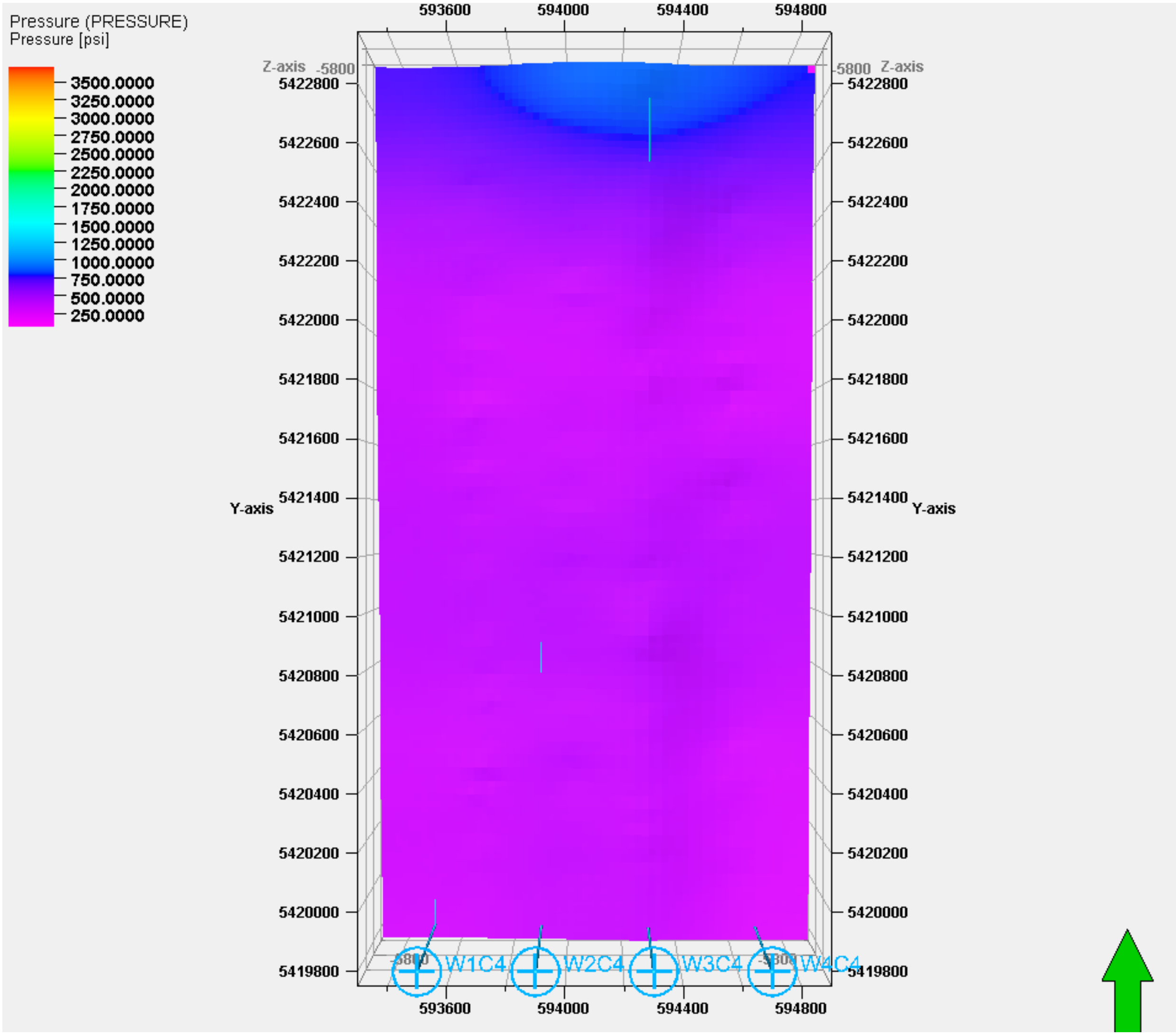

Figure 42: Case 4 Pressure Map

The pressure map at the end of the simulation is shown in Figure 42. The pressure depletion map shows a maximum pressure of 750 psi at the end of the simulation which suggests that the economic limit is reached earlier with four wells in the field without significant increase in oil production.

Currently the operator is drilling four wells per drilling unit and our test case with four wells produced only marginally more oil than the three-well case. The entire reservoir pressure has been depleted with four wells, so there is little point in increasing the number of wells to drain the reserves. However, the decision was made to run two additional cases to fully evaluate the effect of accelerating the study area reserves recovery. This improves our understanding of the relationship between capital cost invested, the amount of oil recovered and rate of return.

6.5. Case 5 and Case 6

In the fifth test case scenario, five hypothetical wells (W1C5, W2C5, W3C5, W4C5 and W5C5) were placed in the drilling unit approximately 1056 feet away from each other as shown in Figure 43. The offset well spacing for this case is 528 feet.

The simulation was run until the economic limit was reached in 2026 and oil and gas production were recorded. The cumulative oil production for this case is 932,000 Bbl and gas production is 4,625,000 MSCF. The total recovery of oil with respect to original oil in place was around 8.3%, an increase of 0.5% from case 4. The pressure map from the five-well simulation is showing Figure 44.

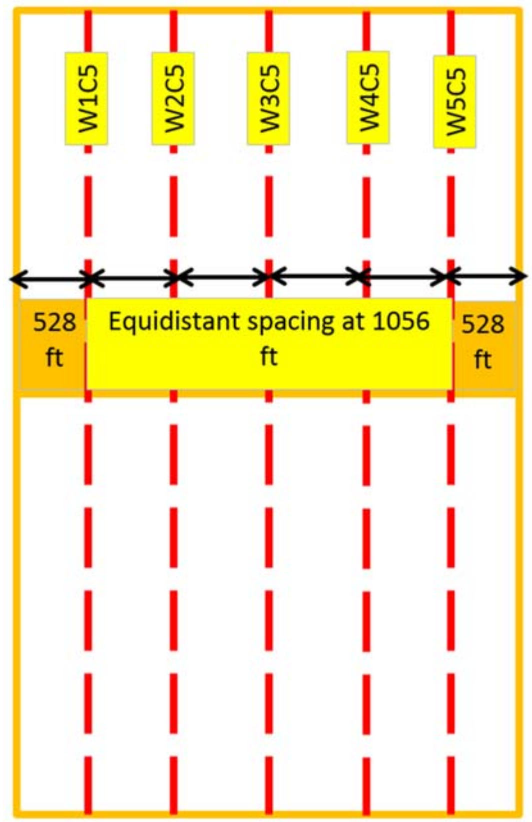

Figure 43: Quintuple Well Spacing for Test Case V

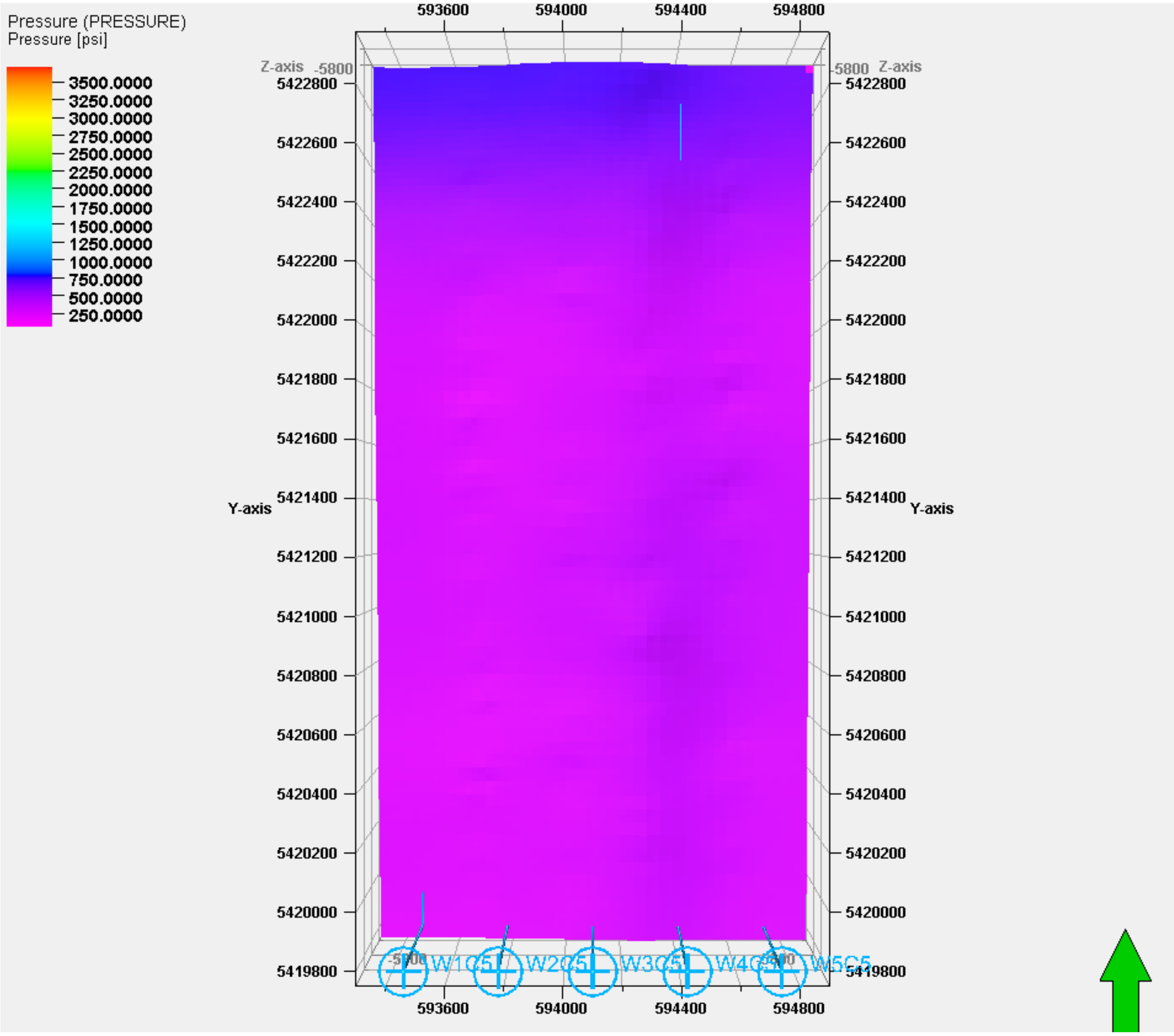

Figure 44: Case 5 Pressure Map

In the sixth test case scenario, six hypothetical wells (W1C6, W2C6, W3C6, W4C6, W5C6 and W6C6) were placed in the drilling unit approximately 880 feet apart as shown in Figure 45. The offset well spacing for this case would be 440 feet. This is the maximum number of wells than can be placed in a drilling unit, because with six wells per drilling unit the hydraulic fractures between neighboring wells already overlap.

The simulation was run until the economic limit was reached in 2023 and oil and gas production were recorded. The cumulative oil production for this case is 956,000 Bbl and gas production is 4,850,000 MSCF. The total recovery of original oil in place was around 8.6%, an increase of 0.3% over case 5. The pressure depletion map from this simulation is shown Figure 46.

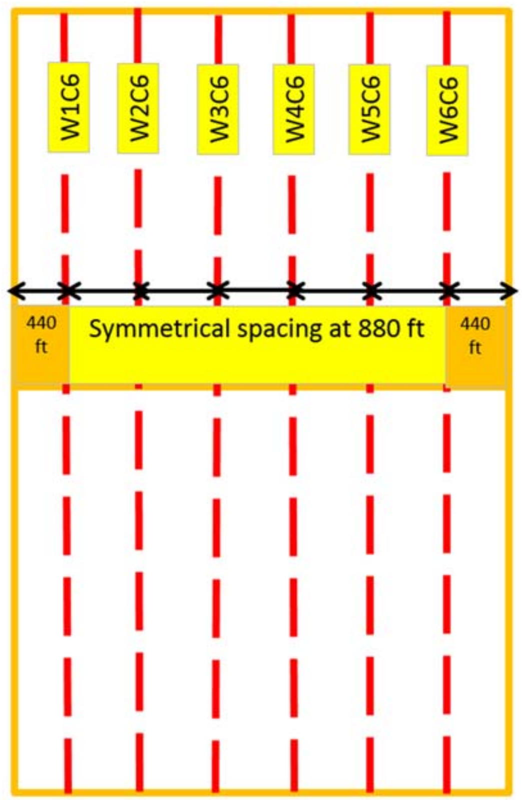

Figure 45: Sextuple Well Spacing for Test Case VI

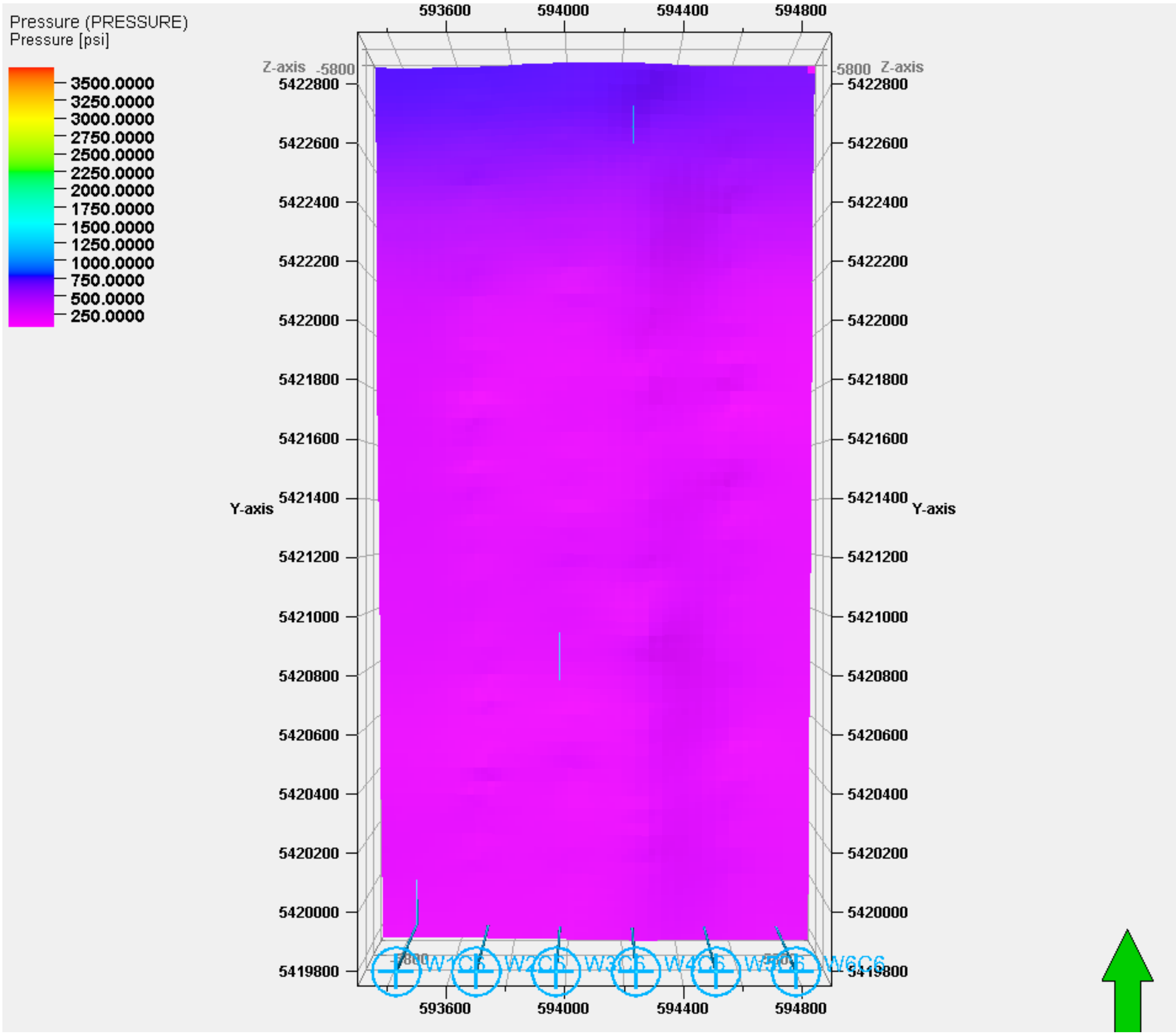

Figure 46: Case 6 Pressure Map

6.6. Comparison of Results

Simulation results comparing the six cases are plotted in Figures 47 through 50. Each individual test case scenario reached the economic limit except for case 1. The oil and gas economic production limit is achieved sooner with more operating wells. In terms of water cut the simulation results suggests this field was producing a steady water cut of 0.5-0.6 throughout the simulation period. The water influx was observed to be very steady and constant throughout this process.

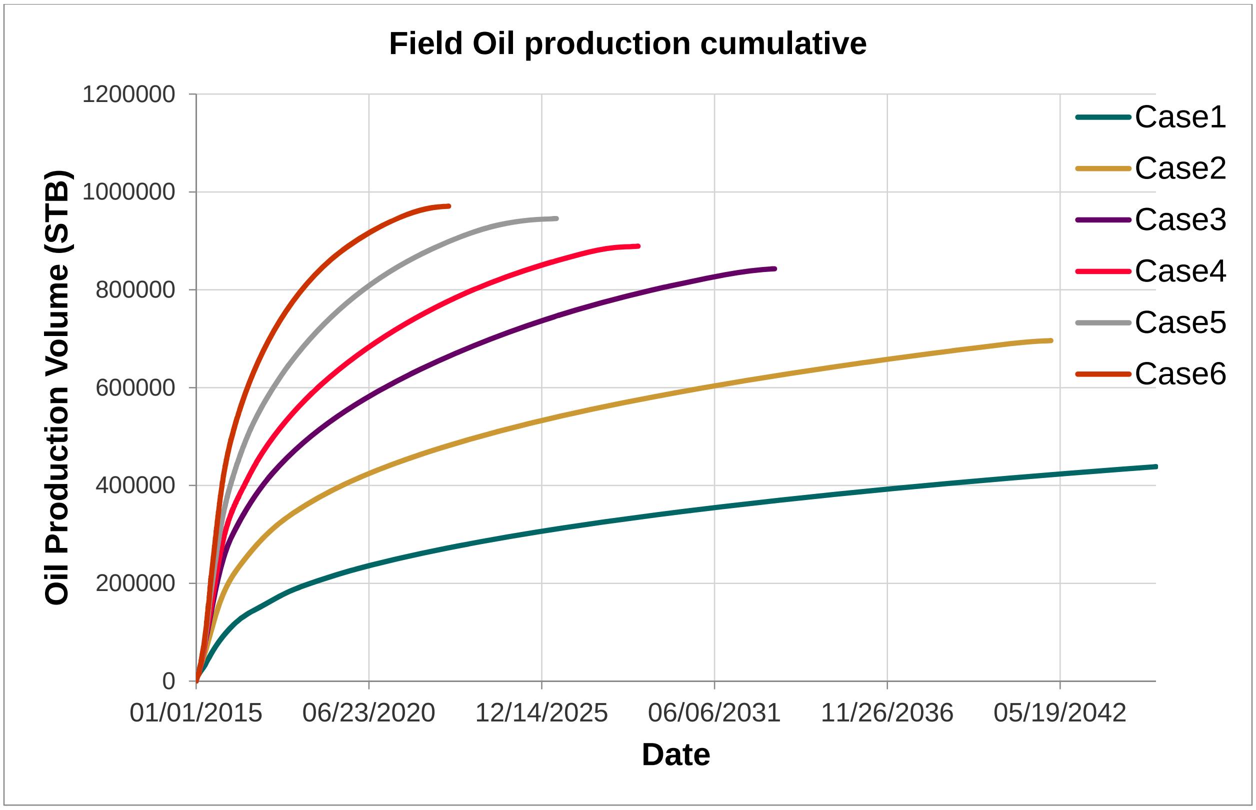

Figure 47: Cumulative Oil Production for Six Test Cases

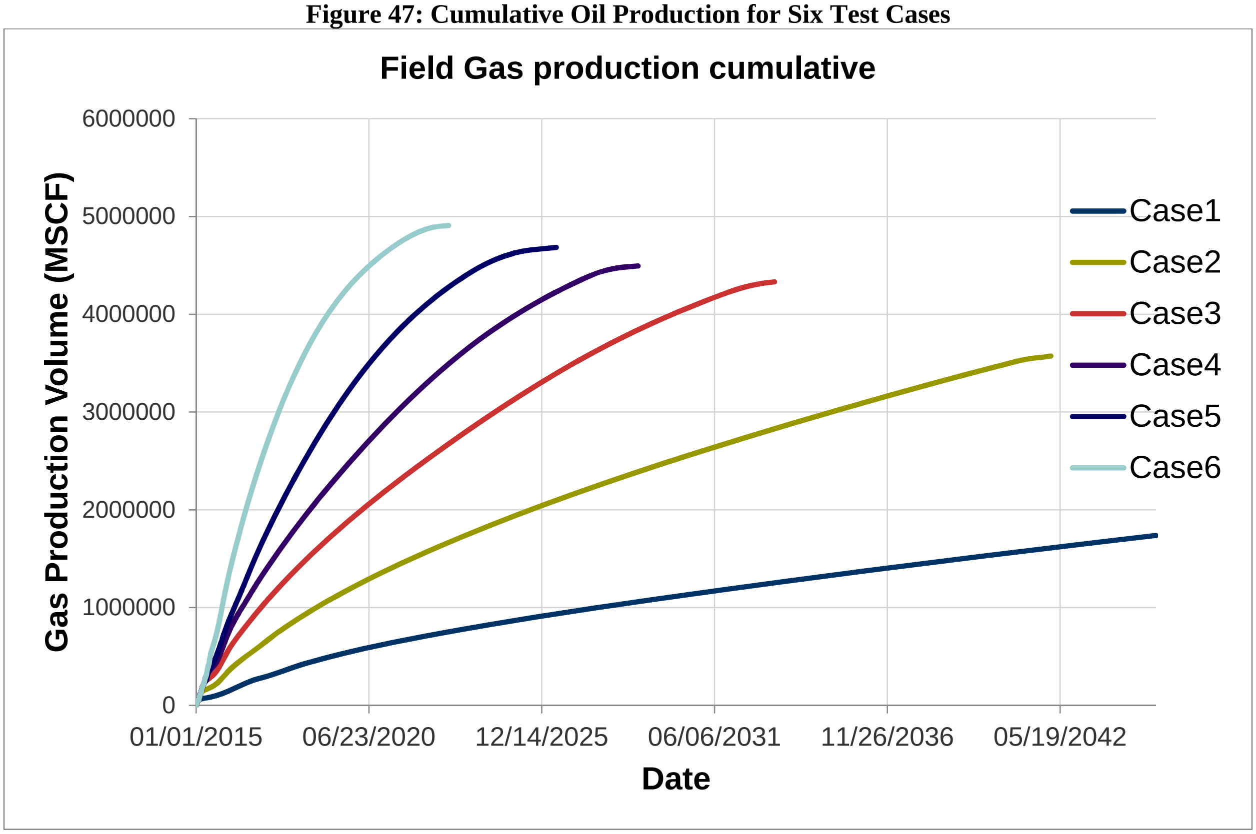

Figure 48: Cumulative Gas Production Rate for Six Test Cases

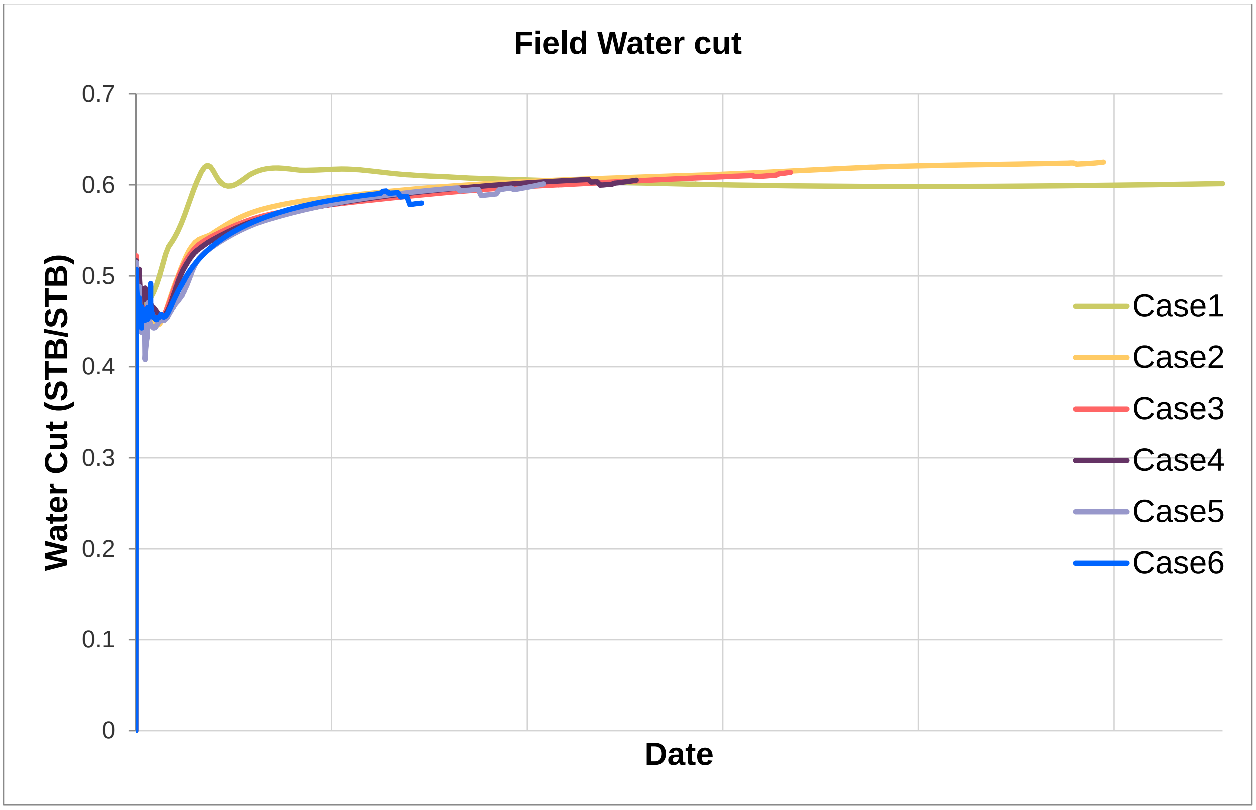

Figure 49: Field Water Cut Production for Six Test Cases

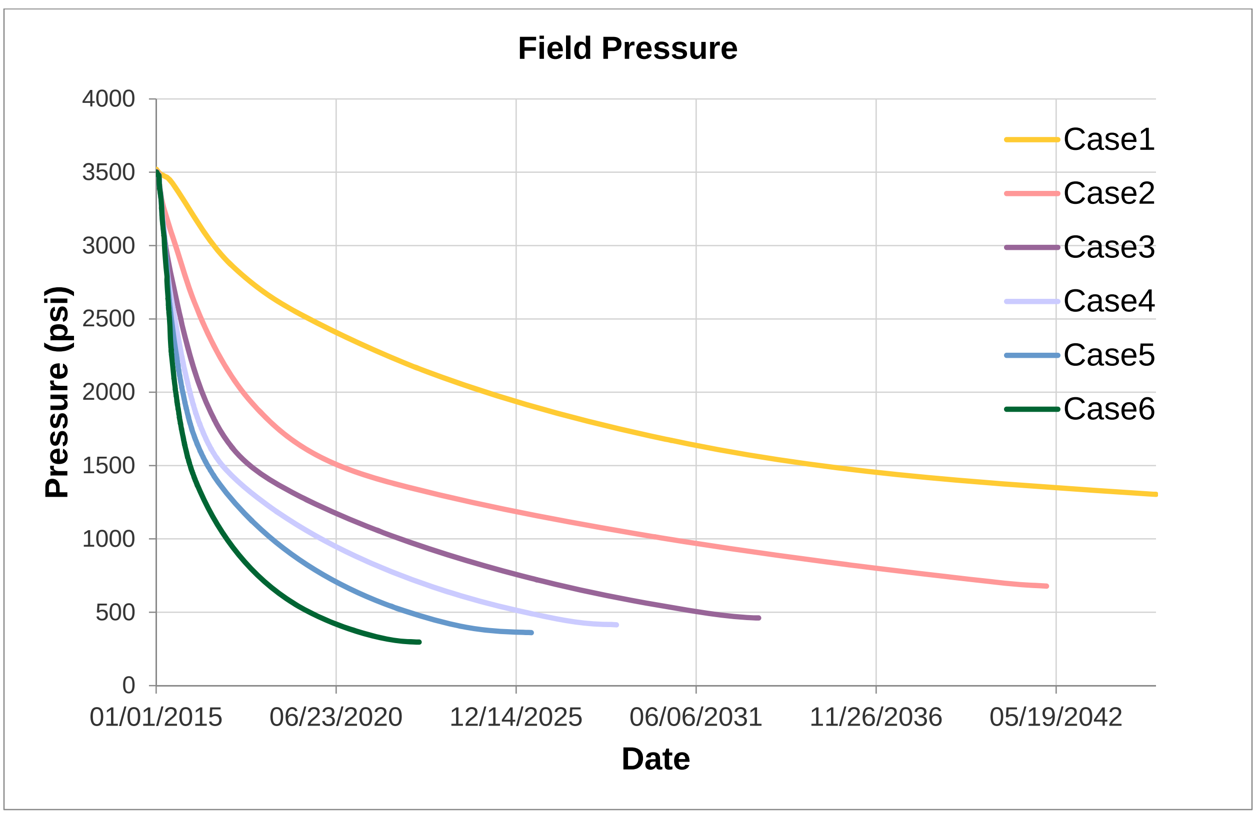

Figure 50: Field Pressure Depletion Map for Six Test Cases

Table XI gives a summary of the six test case scenarios. The oil and gas recovery from each case with the economic limits are listed below. Table XI suggests the reservoir is depleted either with 2 to 3 wells. After three wells the incremental recovery is only marginal with the addition of each new well and the test cases are reaching the point of diminishing returns.

Table XI: Oil and Gas Recovery from simulation results

Number of Wells Operated	Oil Recovery Bbl	OOIP Bbl	OOIP Recovered (%)	Gas Recovery MSCF	Economic Limit Achieved
1	426,000	11,119,000	3.8	1,692,000	-
2	673,000	11,119,000	6.1	3,522,000	2/1/2042
3	777,000	11,119,000	6.9	4,506,000	5/1/2033
4	875,000	11,119,000	7.8	4,436,000	1/1/2029
5	932,000	11,119,000	8.3	4,625,000	6/1/2026
6	956,300	11,119,000	8.6	4,850,000	1/1/2023

The simulation results and pressure depletion maps suggests that total potential of this reservoir can be tapped with either 2 to 3 wells per drilling unit. Addition of more than three wells seems to deplete the pressure rapidly with only marginal increases in oil production. Results from the simulation runs will be further analyzed using economic analysis, and will be discussed in the following section.

6.7. Economic Analysis:

In this work economic analysis was performed using three different product price scenarios, cases A, B and C with fixed oil prices of \$70, \$90, and \$110/Bbl and fixed gas prices of \$2.8, \$4.4 and \$6/MMBTU. Results are presented in the sections that follow.

The Net Present Value (NPV) is the difference between the present value of cash inflows and the present value of cash outflow (30). NPV is used in capital budgeting to analyze the profitability of an investment in a project. NPV of the expected cash flows is computed by discounting them at the required rate of return. For this research the NPV is discounted at a rate of 10% to make a comparison with other economic analysis cases. Surprisingly the effect of the oil and the gas price did not make a significant difference in Net Present Value. Increasing the well density above 3 shows the situation is not profitable to the operating company. As shown in the summary Table XII, the NPV is maximum for the two well case for all the economic scenarios. For the three well case the NPV is still profitable but not as profitable as the two-well case. These results are presented graphically in Figure 51.

Table XII: NPV Results from Economic Analysis

Number of Wells	NPV BT @10% ($) Case A	NPV BT @10% ($) Case B	NPV BT @10% ($) Case C
1	6,649,340	11,309,000	15,969,516
2	9,427,604	17,675,000	25,922,619
3	3,025,861	11,697,000	20,368,235
4	(13,632,443)	(8,275,000)	(2,918,213)
5	(21,450,676)	(16,355,000)	(11,261,082)
6	(34,475,177)	(31,349,000)	(28,223,269)

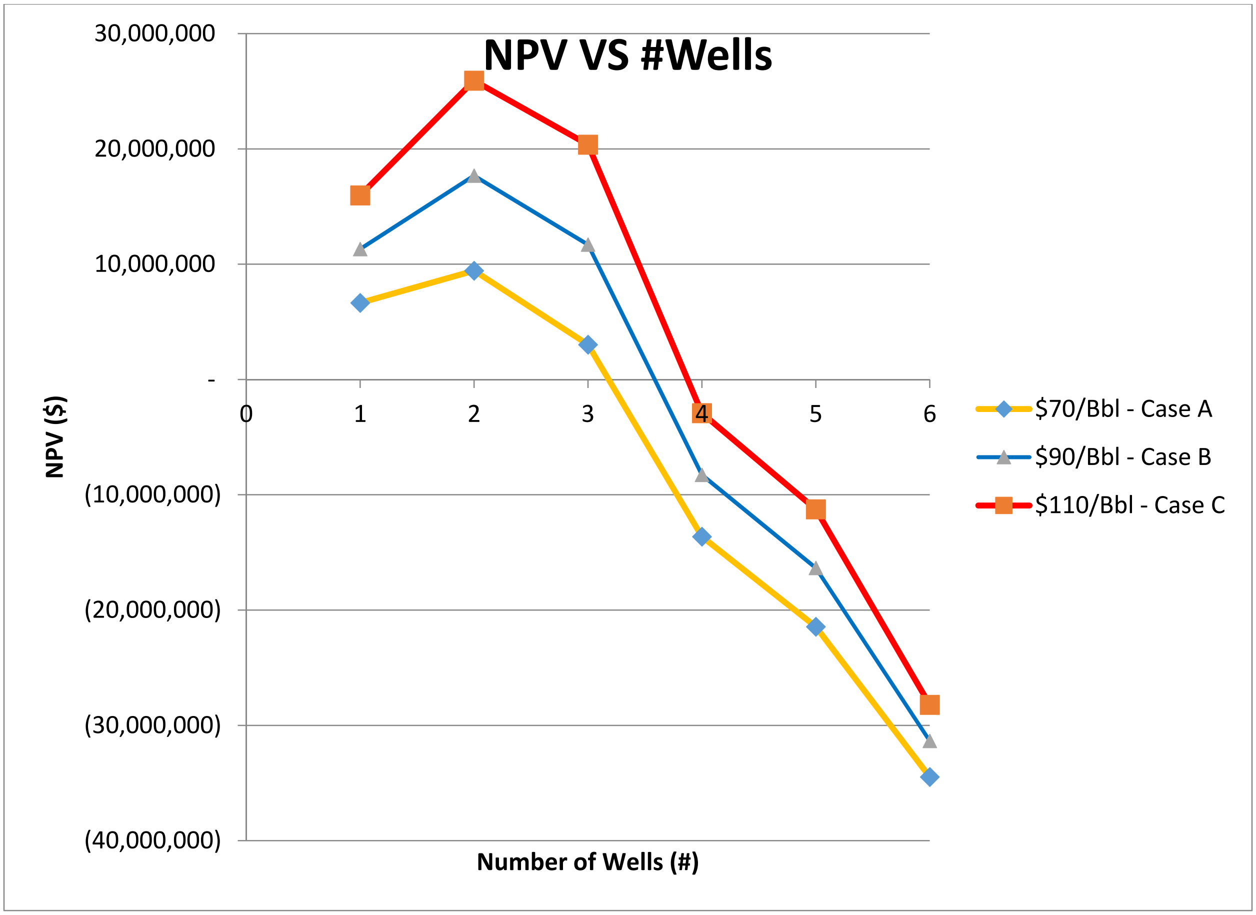

Figure 51: NPV for Three Different Price Scenarios

Rate of return (ROR) is defined as gain or loss on an investment over a specific period, expressed as percentage increase over the initial investment cost (30). Gains on investment are considered to be any income received from the security plus real capital gains. ROR is a ratio of the yearly income from the investment to the original investment. For this research the investment period is considered to be the next thirty years and the simulation results for the oil and gas production were used to compare against original investment. The rate of return peaks for the two well case and it is profitable until the three-well case scenario. After that the rate of return goes negative when we place more than three wells in per drilling unit are considered as shown in Table XIII and Figure 52.

Table XIII: ROR Results from Economic Analysis

Number of Wells	ROR (%) Case A	ROR (%) Case B	ROR (%) Case C
1	41.4	67.5	96.3
2	29.1	46.3	63.9
3	12.6	19.1	24.9
4	-	1.3	7.0
5	-	-	-
6	-	-	-

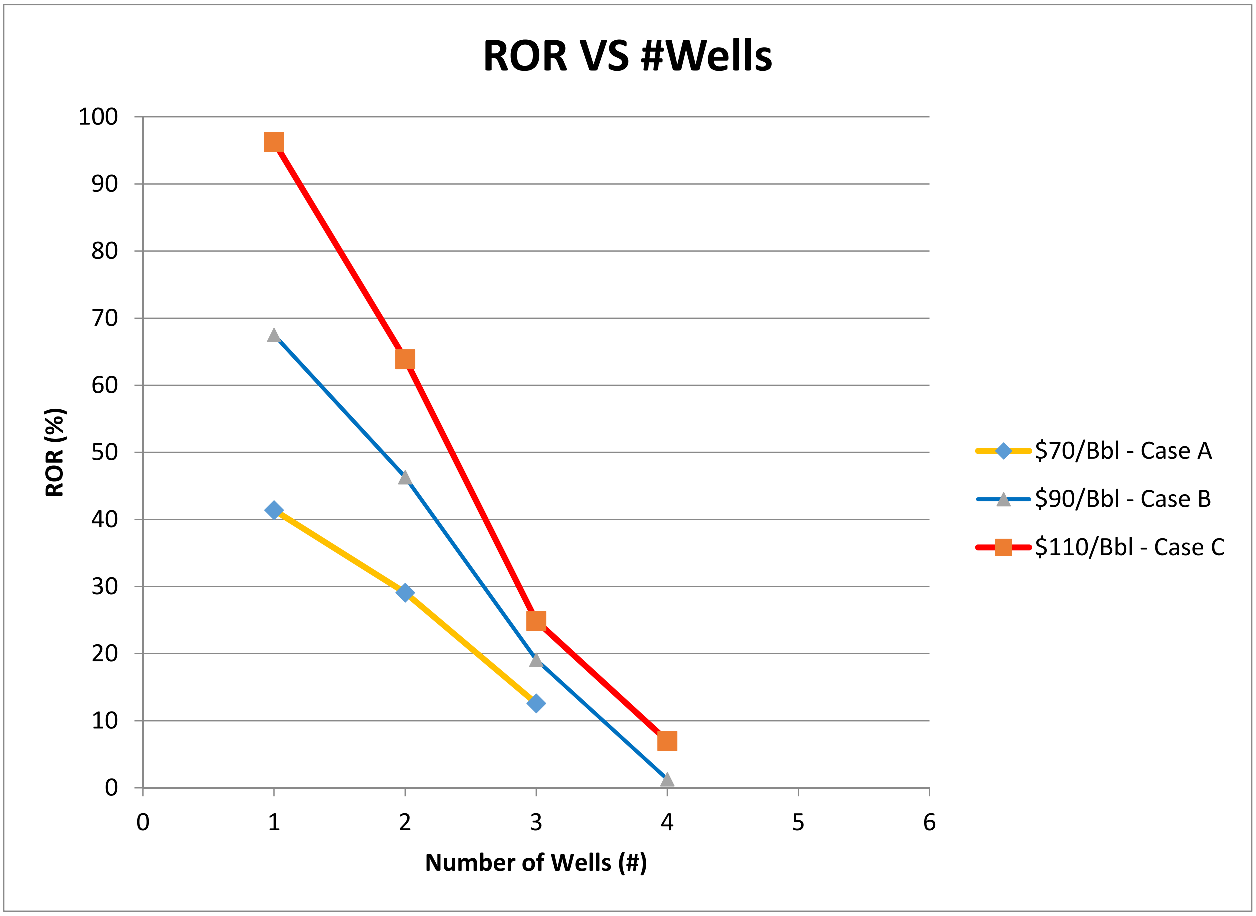

Figure 52: Rate of Return

Payout is the time period during which the withdrawals from an account or annuity are paid (30). Payout period may be expressed on an overall or periodic basis as either percentage of the investment's costs or in real dollar amounts. Payout period can also refer to the period of time in which an investment or a project is expected to recoup its initial capital investment and become minimally profitable. The payout periods for the economic analysis in cases A, B and C are summarized in Table XIV. Case C is profitable up to the five well case scenario, case B is profitable for four well case scenario. Case A it is only profitable until three well case scenario, after which the payout period hits a negative value and the project is no longer profitable. In Figure 53 the payout period for the three economic analysis cases are shown. The payout period analysis also suggests the three well case scenario is profitable at three wells per section of land regardless of the oil price.

Table XIV: Payout Period Results from Economic Analysis

Number of Wells	Payout Period (Months) Case A	Payout Period (Months) Case B	Payout Period (Months) Case C
1	24.3	18.0	15.2
2	33.1	25.5	22.6
3	73.2	58.3	53.7
4	-	161.0	85.4
5	-	-	137.8
6	-	-	-

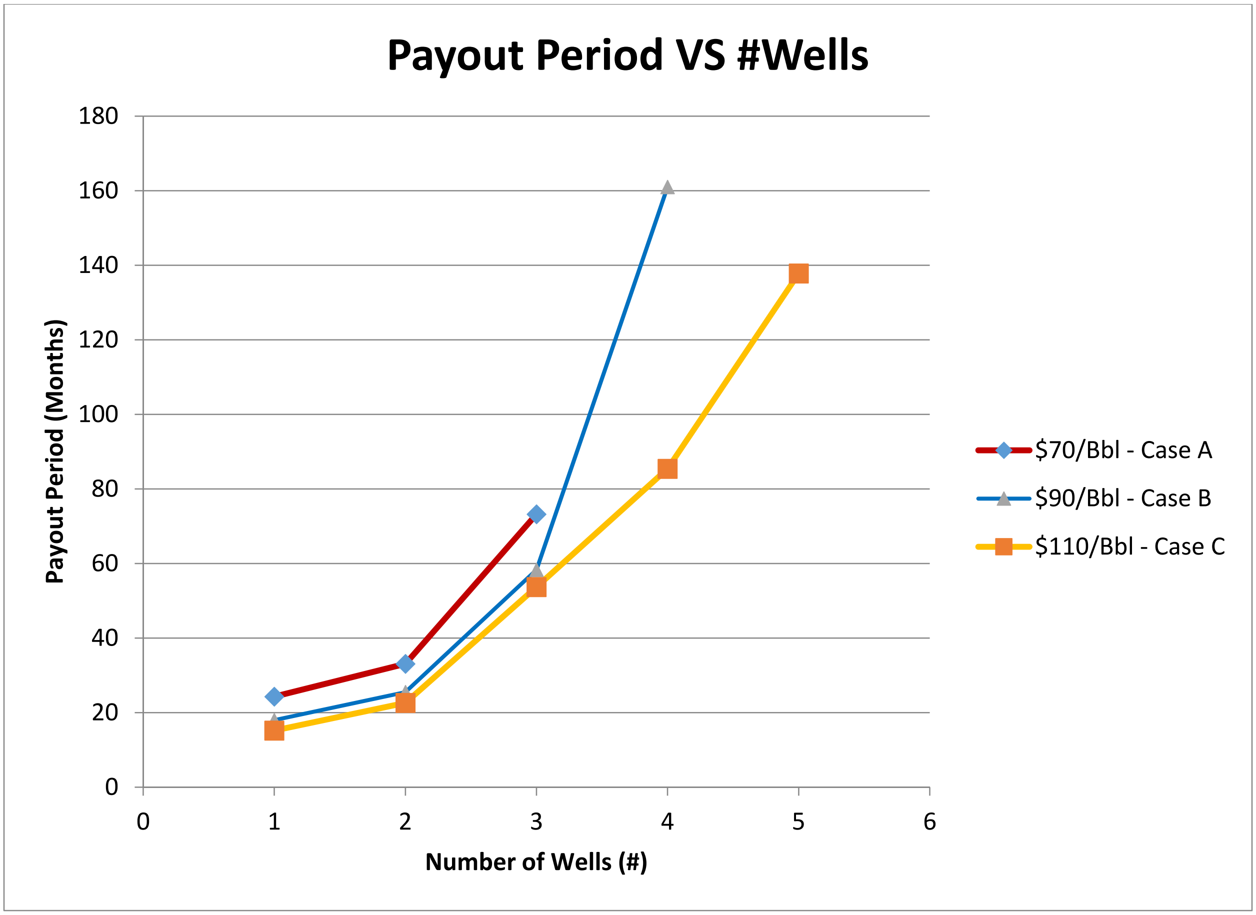

Figure 53: Payout Period

The oil and the gas recovery were plotted against number of wells in Figures 54 and 55. These two figures show the majority of oil and gas can be extracted using three wells per drilling unit. Drilling additional wells will marginally increase production and accelerate reserves recovery. But acceleration of reserves by adding more wells is not profitable to pay off well capital and operating costs.

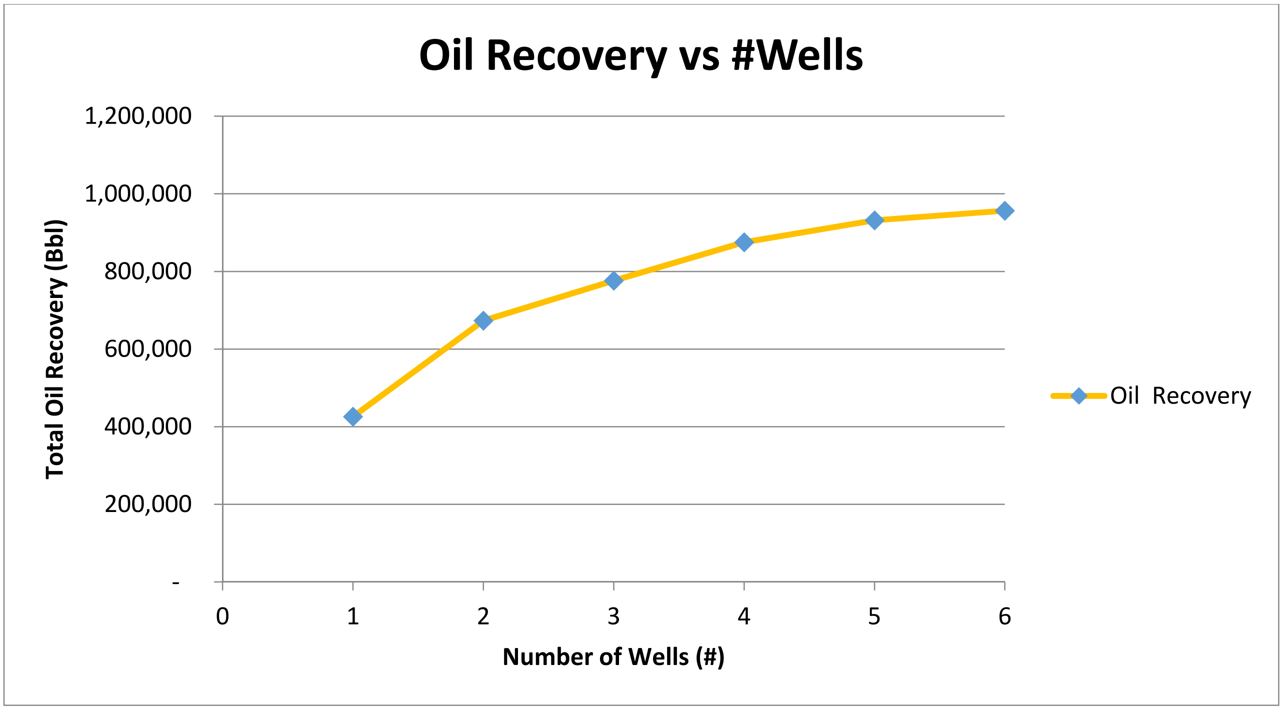

Figure 54: Oil Recovery from Field

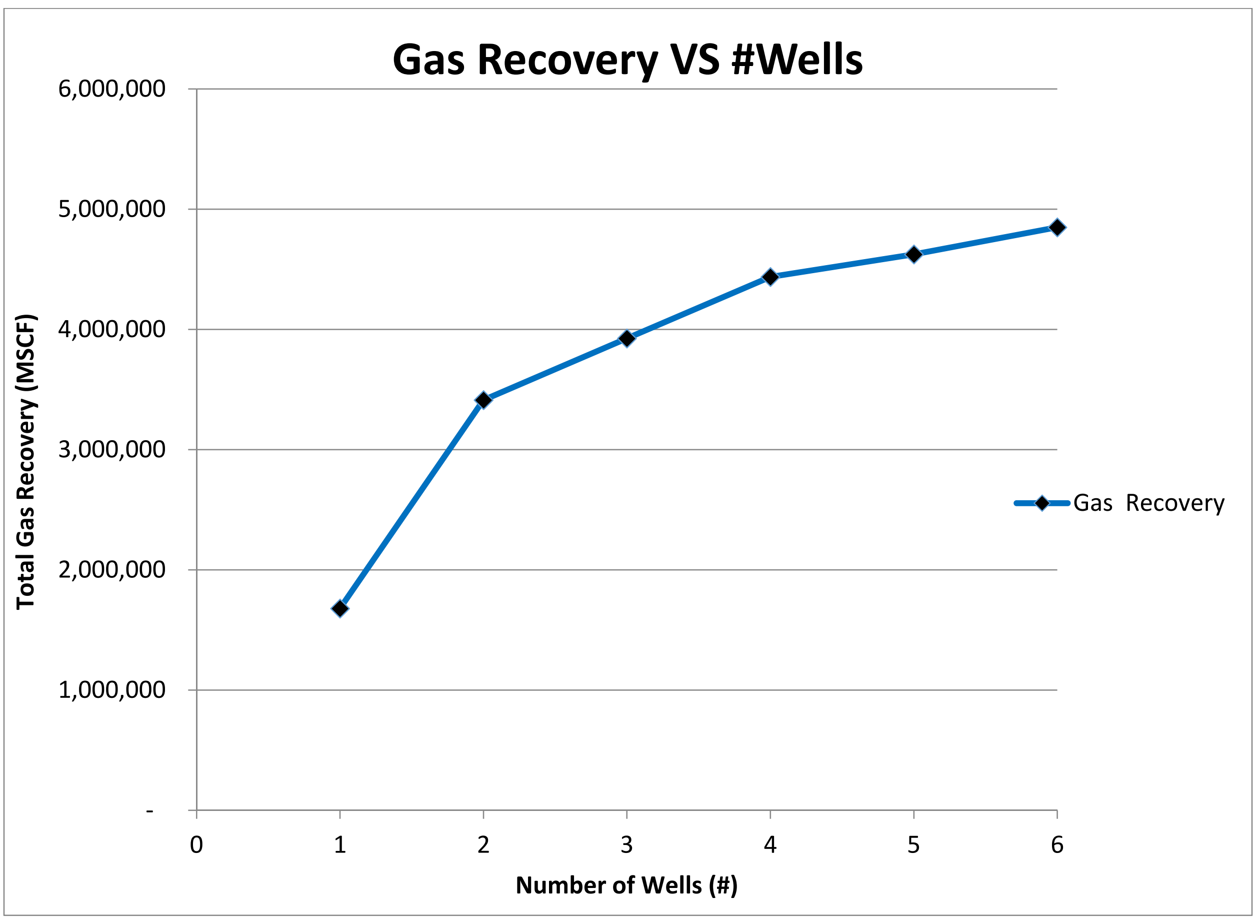

Figure 55: Total Gas Recovery from Field

The highest recovery of oil of the original oil in place was 9%. The economic analysis based on NPV, ROR and Payout period suggests it is highly profitable for the operator to place two-wells per section of land. But considering the reservoir heterogeneity and the oil recovered and economic analysis the three well case scenario it is still profitable.

This research recommends operator to drill three wells per section of land to deplete the reserves. The well spacing for this case is 1760 feet with an offset well spacing of 880 feet. The ideal case for the operator would be case B, with a rate of return was 19.1% and payout period of 58.3 months.

6.8. Discussion of Results

A model was built which gave an acceptable history match. The model was constructed with homogenous properties were used to construct the geology of the model. The model was history matched to historic oil and water production by varying water influx, relative permeability and upper and lower Three Forks porosity. Significant assumptions were made and were discussed in the previous chapters. Limitations in the model are discussed below.

The first concern is the production data were available only for the first three years of production for three of the twelve study area wells. The remaining nine wells had less than a year of production data. Since the time period of the production data available was only three years, the time for the water breakthrough could not be evaluated in this research. The water cut plateaued around 0.6 for the entire time of production for the hypothetical wells (see Figure 47). This could be analyzed and understood better if more production data were available.

The second concern is the geological model was constructed with uniform porosity and permeability based on the core and the lab results. This is unlikely be true in the real life situation. If more core samples and log data were available, a better understanding of porosity and permeability values would be modelled. A cross plot relationship between porosity and permeability could be developed, which would enhance our confidence in the geological model.

The third concern of the homogenous geological model is that there are no natural fractures considered in this research due to lack empirical evidence. If present, natural fractures may affect the water influx mechanism and also support oil production more efficiently.

The fourth concern experienced during the model building process was well placement. There was poor depth control for the reservoir top and bottom, due to a scarcity of offset well logs. It was very difficult to place the study area wells in the Three Forks formation pay zone, with a pay zone thickness less than 10 feet. We believed these wells are located in the Three Forks Formation, so we forced them into middle of the Three Forks Formation. However, the dynamics of water cut behavior are influenced by proximity to the water influx. Our inability to accurately locate our study wells vertically in the pay zone prevented accurate water cut matching on a well by well basis.

In spite of these limitations, we believe the model honors the study area's because the model was described faithfully with all the available data. During the model building stage, we had a very good well bore deviation survey which was used to represent the study area wells in three dimensional co-ordinate system. Core samples were obtained from SM Energy and was used to test for porosity and permeability values. The core lab porosity and permeability values were used in the model. The field production data was obtained from NDIC website and used for the history matching purpose. Various water influx models were tried, and the bottom water influx was determine the reservoir behavior accurately. For all the above reasons we believe this is the best possible model that could have been built with the available data. Therefore, we believe the model is a valid basis of the conclusions proposed herein.

The optimal inter-well spacing is determined to be 1760 feet with three wells operating in the study area at oil price of \$90/Bbl and gas price of \$4.4/MMBTU. The economic analysis suggests that it is not advisable to drill more than three wells in the study area based on forecasted recovery and economic analysis.

7. Conclusions and Recommendations

Conclusions based on this research work are listed below:

1) The optimal inter-well spacing is determined to be 1760 feet with three wells operating in the study area at oil price of $90/Bbl and gas price of $4.4/MMBTU. The economic analysis suggests that it is not advisable to drill more than three wells in the study area based on forecasted recovery and economic analysis.
2) A reservoir simulation model was built to study production over a twelve-well study area in Colgan Field, Divide County, North Dakota. The model was history matched to observed production data varying reservoir pore volume, vertical perm and water influx parameters.
3) A vertical to horizontal permeability of 0.25 value gave a good oil and water production match. This relatively high Kv/Kh was a result from natural fractures, or may be an artifact of depositional environment.
4) Water influx plays a major significant role in supporting the oil production in this formation. Bottom water influx is determined to be the predominant source of water influx in this formation.
5) With only the Upper Three Forks as the producing zone we were unable to match the field observed data. Therefore, reservoir performance suggests there may be additional Three Forks productive zones contributing to Three Forks production.
6) Based on the analysis of Three Forks core, the Three Forks formation is determined to be oil wet.
7) Software limitations in Petrel prevented the full exploitation of hydraulic fracture modelling in this work.
8) The maximum recovery for six well case scenario was about 8.6% of the original oil in place.

The following recommendations derive from the study conclusions:

1) Further evaluate the base of the Three Forks for oil potential. Analyze wells logs from wells drilled past the base of the Three Forks formation for oil saturation and water contact.
2) Update the history match periodically to track the progression of water influx, focusing on matching the overall water cut.
3) Investigate natural fractures in base of the Three Forks formation for their effect on aquifer influx and overall production.
4) Investigate opportunities for waterflooding the Colgan Field.
5) Obtain additional core samples to perform capillary pressure/relative permeability tests.
6) Explore other hydraulic fracture modelling software and or approaches to more accurately model hydraulic fractures in the reservoir model.
7) Continue research on wettability tests by performing Amott wettability test to confirm the Three Forks Formation is oil wet.

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Appendix A: Tables

Table XV: Initial Hydraulic Fracturing Properties Bagley 4-30H

Center MD (feet)	Fracture height (feet)	Fracture Half Length (feet)	Fracture Permeability (mD)	Width (inches)
18457	25	550	10	0.3
17906	25	550	10	0.3
17511	25	550	10	0.3
16988	25	550	10	0.3
16468	25	550	10	0.3
15948	25	550	10	0.3
15430	25	550	10	0.3
14900	25	550	10	0.3
14354	25	550	10	0.3
13809	25	550	10	0.3
13294	25	550	10	0.3
12813	25	550	10	0.3
12337	25	550	10	0.3
11861	25	550	10	0.3
11383	25	550	10	0.3
10904	25	550	10	0.3
10424	25	550	10	0.3
9944	25	550	10	0.3
9457	25	550	10	0.3
8961	25	550	10	0.3

Table XVI: Modified Hydraulic Fracture Properties

Center MD (feet)	Fracture height (feet)	Fracture Half Length (feet)	Fracture Permeability (mD)	Width (inches)
18457	25	550	1000	0.3
17511	25	550	1000	0.3
16468	25	550	1000	0.3
15430	25	550	1000	0.3
14354	25	550	1000	0.3
13809	25	550	1000	0.3
12813	25	550	1000	0.3
12337	25	550	1000	0.3
11383	25	550	1000	0.3
10904	25	550	1000	0.3
9944	25	550	1000	0.3
9457	25	550	1000	0.3
8961	25	550	1000	0.3

SIGNATURE PAGE

This is to certify that the thesis prepared by Adhikeshavan Ravee entitled "Investigating a Pilot Area in the Williston Basin Three Forks Formation to Determine the Optimal Inter-well Spacing and Hydraulic Fracture Length to Maximize Economic Recovery" has been examined and approved for acceptance by the Department of Petroleum Engineering, Montana Tech of The University of Montana, on this 1st day of May, 2015.

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