
Petroleum International

Final Report

Project #1: Teapot Dome Field / Tensleep Formation

Petroleum Engineering Design – PETE 4736
Department of Petroleum Engineering
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Executive Summary

The tremendous increase in the request of hydrocarbons has been driving the oil and gas industry to utilize the most recent technology to increase the production to fulfill the requirement for hydrocarbons. One of these methods is the reservoir simulation that can anticipate the reservoir production using extremely constrained reservoir information beginning with the attributes and parameters of the reservoir rocks, such as the structure of the formation and parameters such as porosity and permeability etc. Dynamic characteristics can be then simulated using well production history and the liquid PVT properties.

This document is a project plan for a simulation/EOR project on the Teapot Dome Field / Tensleep Formation. Using supplied literature and a geologic data, a static model is developed using Petrel. With additional research on relevant literature of the field and formation a dynamic model will need to be build using the CMG/Eclipse program. After both model have been developed, the team will identify the best CO₂-based enhanced oil recovery scenario for this reservoir.

Based on the timeline of the schedule, our team has completed a static model of our reservoir. Reservoir parameter modeled are porosity and permeability, which was used to produce a dynamic model and in later weeks conduct a CO₂ simulation. A general property correlation of our porosity and permeability was carried out to develop trends such as fractures and high and low permeability zones within our reservoir. We encountered a very tight data constraint (i.e. Well logs, production data, seismic, etc.) on our area of interest within the Tensleep formation of the Teapot dome field, nobody can really cannot know exactly how the reservoir is and will perform. However, after comparing our model to numerous literature sources, as cited in the static model and dynamic model sections and the relatively simplistic inputs of a dynamic model into CMG in regards to information obtained from a static model, we have confidence our work sufficient represents the reservoir in order for the additional stages of the project to be carried out.

Our team has successfully produced a dynamic model and conducted a series of “test” CO₂ injection simulation runs, as discussed in the dynamic section of this paper. Most of the dynamic model was constructed from a master thesis by Ricardo Gaviria Garcia from Texas A&M titled *Reservoir Simulation of CO₂ Sequestration and Enhanced Oil Recovery in the Tensleep Formation, Teapot Dome Field*. Many parameters and PVT properties were used from the thesis. Water saturations, fracture trends and rock compressibility were also determined in our dynamic model. To validate the accuracy a simulation was run and the production was compared to the historical production of the formation and an error of 5.68 % was found.

The simulation tests were run using a single porosity model for simplicity with fractures including channeling modeled into the rock type as not enough data was available for a full dual permeability model because too many assumptions had to be made. The test runs include 2 hypotheses, 14 active wells and 1 injector and 13 active wells and 2 injectors. Respectively, a shut-in and producing well will be converted into a CO₂ injection well. After the simulations were run, the results were inputted into an economic model our team developed to determine the most profitable strategy.

Our results indicated that the hypothesis with 14 producers and 1 injector for a 4 year CO₂ injection strategy, at a low rate of 400 M³/d provided the most economical option at total profit of \$17.34 million. This is despite the fact that the results of higher injection rates and 2 injection wells provided a higher recovery percentage but because of the offset of cost related to CO₂ prices and well conversions, the lower injection rate was more economical.

In summary, this work shows a prospective economical CO₂ flood for the Tensleep formation in the Teapot Dome field.

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Nomenclature

API	American Petroleum Institute
BOPD	Barrels of Oil per Day
CCS	Carbon Capture Storage
CMG	Computer Modelling Group
CO ₂	Carbon Dioxide Gas
DOE	Department of Energy
EIA	Energy Information Administration
EL	Economic Limit
EOR	Enhanced Oil Recovery
EOS	Equation of State
Fm.	Formation
Ft.	Feet
H ₂ S	Hydrogen Sulfide Gas
mD	Millidarcy (measure of Permeability)
MMBO	Million Barrels of Oil
MMscf	Million Standard Cubic Feet
N ₂	Nitrogen Gas
OC	Oil Column
OOIP	Original Oil in Place
OWC	Oil/Water Contact
POWC	Producing Oil Water Contact
PVT	Pressure-Volume-Temperature
RMOTC	Rocky Mountain Oilfield Testing Center
SPM	Single Porosity Model
STBD	Stock Tank Barrel per Day
WBS	Work Breakdown Structure
WFD	Work Flow Diagram
WI	Work Interest
WOGCC	Wyoming Oil and Gas Conservation Commission

Acknowledgements & Credits

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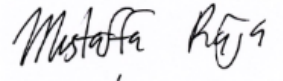
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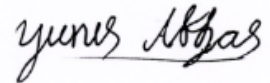


A Malaysian American from Buffalo, WY and a senior at the University of Wyoming, planning on graduating in December 2016 with a B.A in petroleum engineering. Mustaffa is concurrently a Master student in civil engineering, who's research concentration is in the utilization of coal products in highway construction.

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Turkish petroleum engineer candidate from black sea region of Turkey. My willing to be a petroleum engineer based on my father who is a field manager in Transatlantic Petroleum Co. So far, I really enjoyed what I learned and experienced in my classes, I hope I will enjoy while doing my job at oilfield.

Abdullah Hassoun

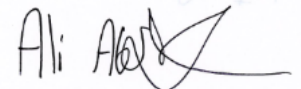
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Public data provided from:

Rocky Mountain Oilfield Testing Center (RMOTC)

Obtained from the following website: http://wiki.seg.org/wiki/Open_data

Project Objectives

The main objective of this project is to establish the best economically feasible CO₂-based enhanced oil recovery scenario for the producing wells in the Tensleep formation within the Teapot Dome field at section 10 (T38-39N R78W). More specified objectives are to research the literature, build a static model using petrel software, also build a dynamic model using the CMG/eclipse programs. Then, finally to evaluate how the reservoir hydrocarbon model and fracture permeability affects reservoir simulation and enhanced oil recovery performance using the simulation models.

Scope

Our data used in this project was obtained from a public database provided from RMOTC (Rocky Mountain Oilfield Testing Center). The data set included information of all of the Teapot Dome field, which included over 1300 wells and 9200 acres producing from all formation. Since we are specifically looking at the wells producing from the Tensleep formation within the Teapot Dome field, we are only considering 13 producing wells, located in 320 acres within section 10 of the field.

Project Background

The Teapot dome was discovered in 1915. It has been selected by the U. S. Department of Energy to implement a field- size CO₂ storage Project. With a projected storage of 2.6 million tons of carbon dioxide a year under fully operation conditions in 2006 making it the largest CO₂ storage. The first CO₂ injection done was in 2004 by the Rocky Mountain Testing Center “RMTC” producing 22 million barrels with a net of 569 million deposited into the U.S treasury. This project is an attempt of secondary/ tertiary enhancing oil recovery with the use of CO₂ injection to have economical production from the Teapot Dome. In 2014 the field was sold to Stranded Oil Resources Corporation for more than \$45 million. Thus, we can assume the field still has production potential.

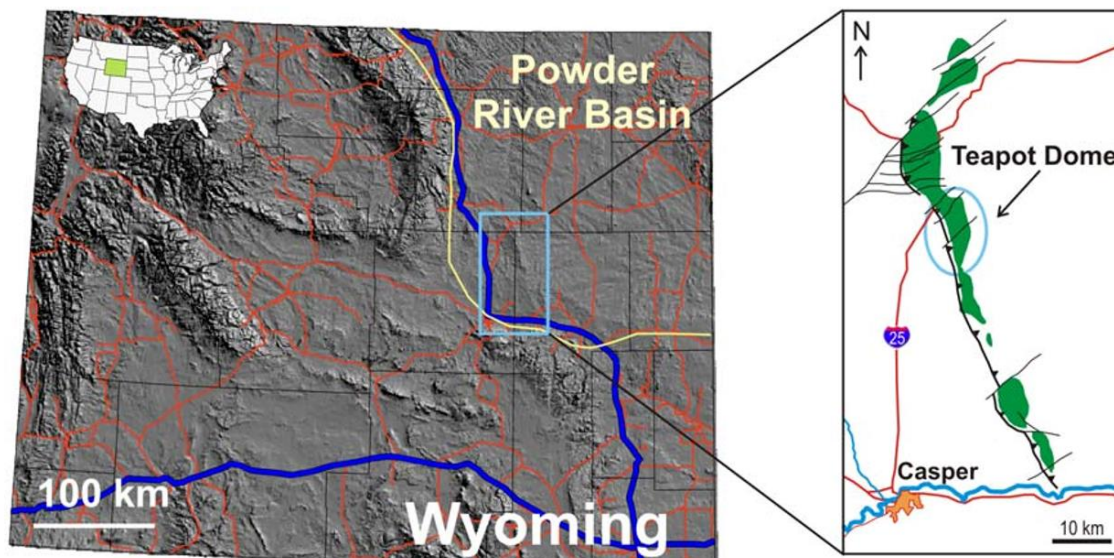


Figure 1 - Teapot Dome Location North of Casper, WY

Apart from some exploratory wells drilled in the in the 1950’s and 60’s under the Naval Petroleum Reserve, the oil field was essentially closed until full development resumed in 1976. Teapot Dome was reopened in 1976 and in 1977 became a US Department of Energy (US DOE) facility. DOE directed RMOTC to collaborate with the petroleum industry to improve domestic oil and gas production through the field testing of new technology, and in October 2003, established Teapot Dome as a national geological carbon storage test center (Friedmann et al., 2004a). Regarding the production history, Teapot Dome started its production in 1908 from the “Dutch” well (200 BOPD) at the First Wall Creek Sandstone in 1909 a few more wells were drilled to develop the Shannon sandstone. Before the reopening of the field and the development and exploration program at Teapot Dome in 1976, a total of 233 wells had been drilled in all the producing formations. In 1996, additional 1007 development wells and 90 exploratory wells were drilled. 27 of the development wells were drilled targeting the Tensleep Fm., and two of them experienced the highest initial production rates of any wells in Wyoming at that time (Gaviria, 2005).

Project Plan

Work Breakdown Structure (WBS)

The team started with data collection, as the available data were discussed, to gain more understanding about it and as soon as the team looked at the data, realized that the data was corrupted and waited three weeks to get the right public data from internet. Then second step is project plan, as team members did the WBS, Gantt chart, work flow diagram and risk analysis. Then moved on to the third part of WBS, which is data interpretation by sorting and analysing the data. Static model was then developed by learning Petrel, then importing data into Petrel and then the dynamic model was established, by first learning CMG and then imports the data into CMG. The final part is the EOR simulation, as the team had to identify the best EOR scenarios out of two scenarios as we will discuss later in the project and also do cost analysis.

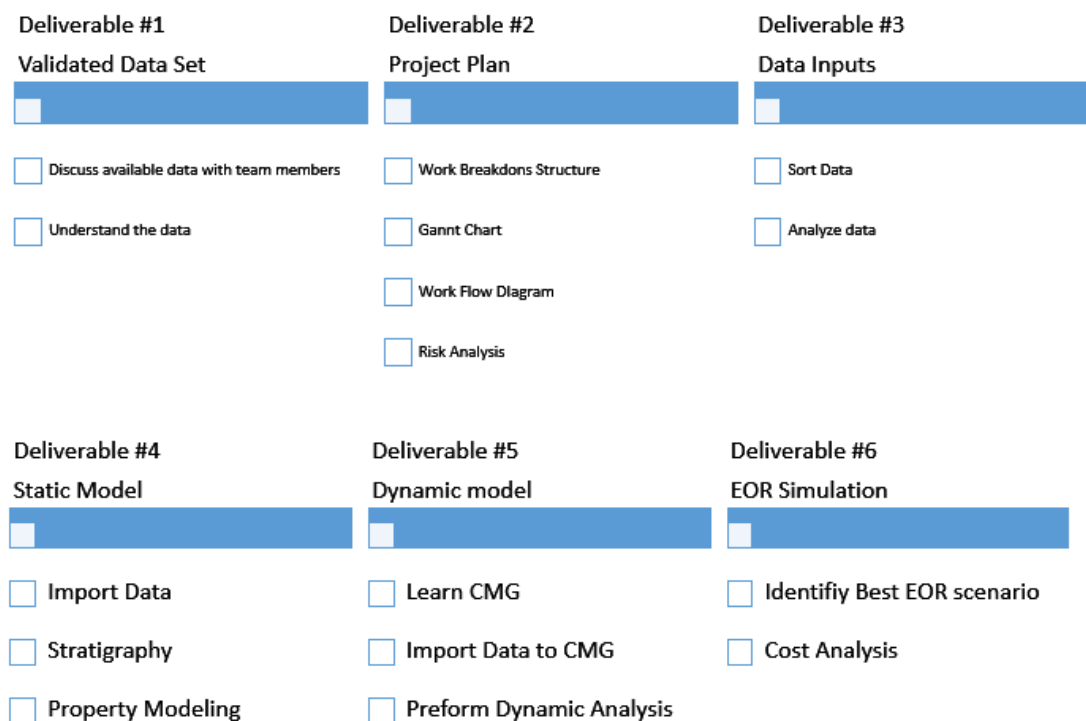


Figure 2 - Work Breakdown Structure

Work Flow Diagram

The Work Flow diagram consists of three phases planning, Execution and Delivery. The first phase is planning, as the team started with data collection then moved to project planning as well as literature research, then the plan was satisfactory so the team did the first presentation on project planning. Then the team moved to the second phase which is Execution Phase, started with data Interpretation, then learned Petrel and CMG software to build the Static and Dynamic models respectively. Those models were satisfactory, so the team moved to the last step in this phase which is EOR simulation and the analysis were satisfactory, so the team moved to the third and last Phase, Delivery phase where the team did the Final project presentation as well as Final project report.

P.I Group – Final Work Flow Diagram

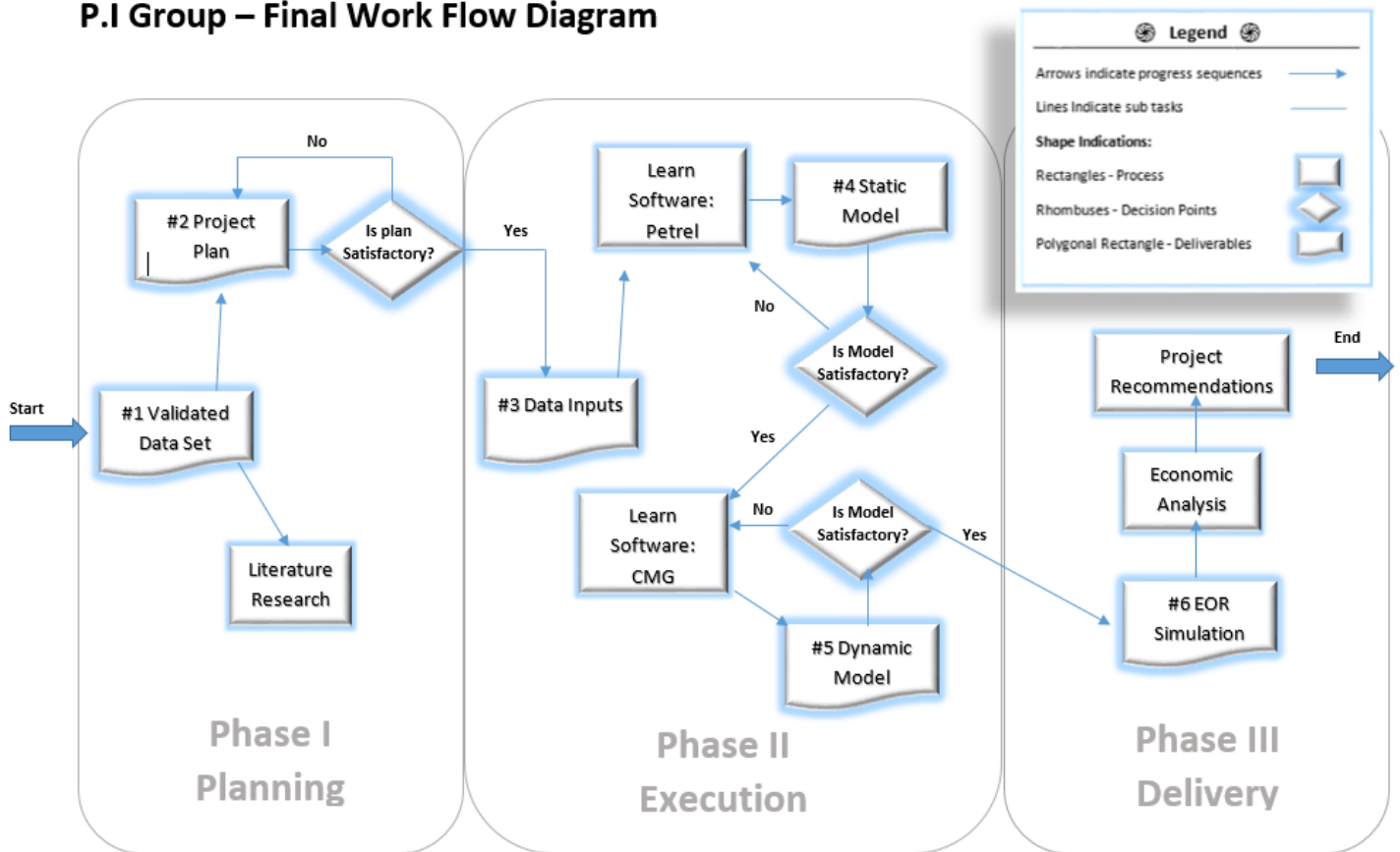


Figure 3 - Work Flow Diagram

Gantt Chart & Individual Resource chart

The team used Gantt chart to make the schedule, and Gantt chart is a chart which a series of horizontal layers show the tasks needed to be done in a certain time period and for example in the Gantt chart provided below, the static model took more time compared to the other tasks almost a month and it is shown in yellow lines. The individual task chart shows each team member tasks that need to be done during the semester.

Senior Design Gantt Chart

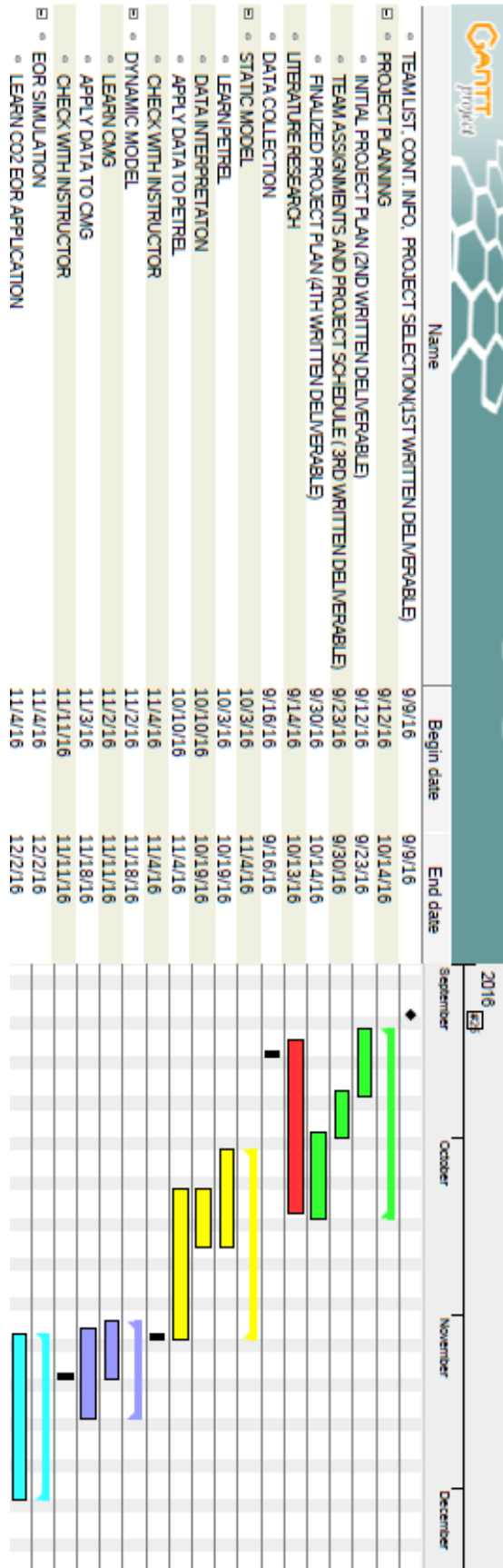


Figure 4 - Project Gantt Chart

Senior Design Gantt Chart

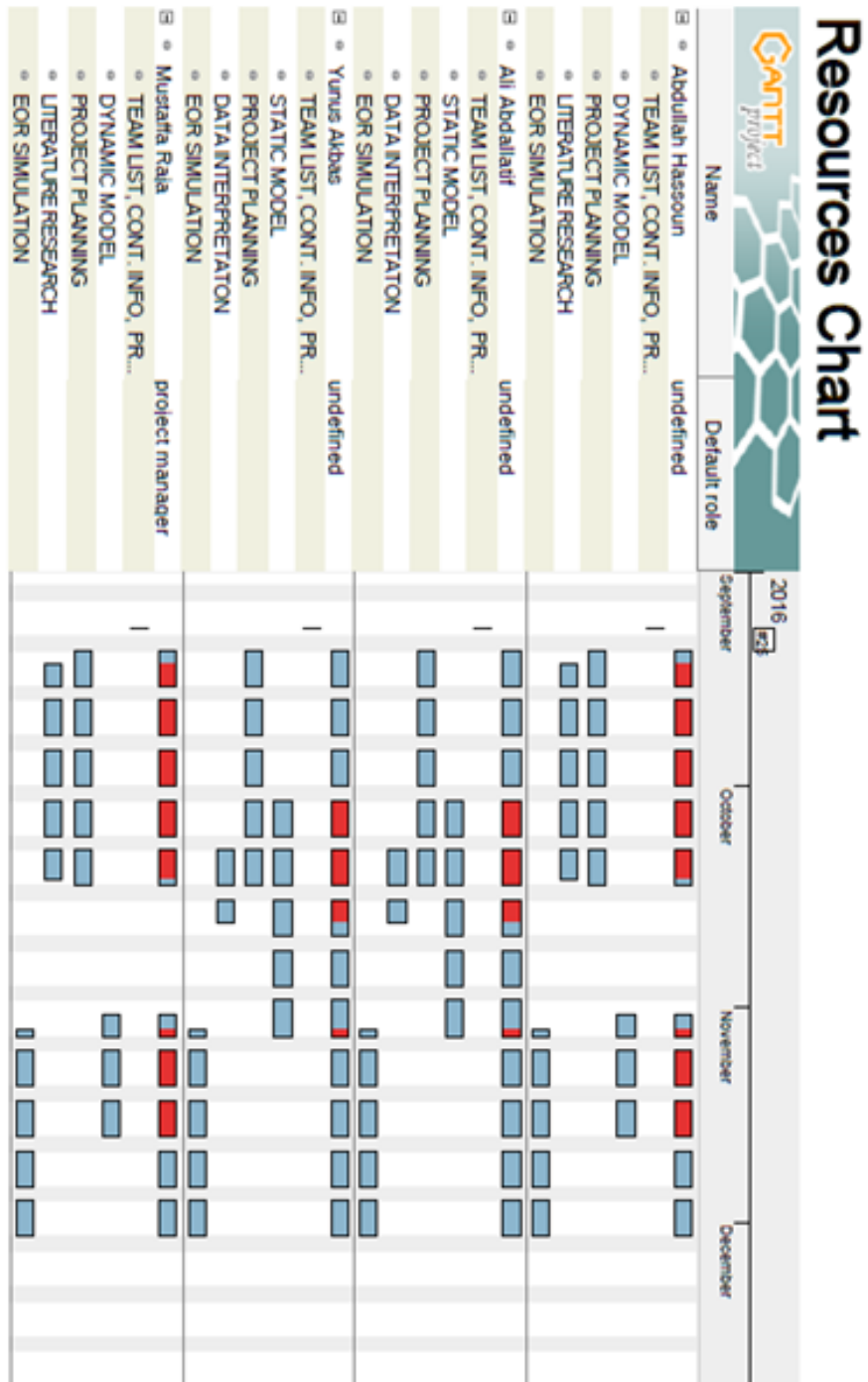


Figure 5 - Individual Resource Chart

Geological Overview

Located adjacent to the Salt Creek field and part of the Salt Creek anticline on the southwestern margin of the Powder River Basin is the Teapot Dome field. Located 30 miles North of Casper Wyoming as seen in (figure 1) with an area of 9481 acres, the Teapot Dome is now owned by Stranded Oil Resources Corporation. Stratigraphy shows that Paleozoic strata overlying Precambrian basement in the Teapot Dome field consist of relatively thin interbedded successions of sandstones, limestones, dolomites, shales and evaporates of marine, dune and inter-dune origin. The Pennsylvanian Tensleep Sandstone, which is one of the three major producing horizons in the Teapot Dome field is partially eolian in origin, and is one of several Tensleep Sandstone reservoirs producing oil in Wyoming.

The source of the oil is in the Permian Phosphoria formation probably supplied oil by long range migration to the Pennsylvanian Tensleep Sandstone oil reservoir (Momper and Williams, 1979). The major oil source rock for the Cretaceous sandstone reservoirs, the Dakota Sandstone, the Muddy Sandstone, the Frontier Formation (the Wall Creek Sands), and the Shannon Sandstone, is the Lower Cretaceous Mowry Shale, with minor contributions from shales in the Niobrara formation, the Frontier Formation and the Steele Shale (Momper and Williams, 1979). The geologic column of our reservoir can be seen in (figure 7) on the next page.

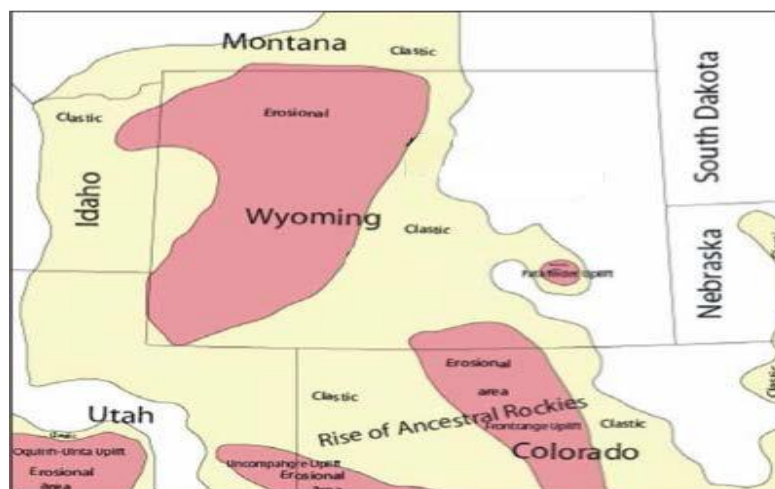


Figure 6 - Tensleep formation distribution in Mid-West Rocky Mountain region

The Tensleep Formation covers territories of Wyoming, Montana, and Colorado (Figure 6) and it reigns two thirds of Wyoming's oil (Nummedal, Towler, Mason, & Allen, 2003). Out of over 1300 wells drilled 27 of wells were drilled to evaluate on the Tensleep formation, of which only 13 are still active.

The Tensleep formation falls in the Pennsylvanian age and consists of about 300 ft. thick, of sequence of multi boundaries between sandstone and dolomite. Tensleep is mostly found at the bottom of each well and have the lowest producing formation found in Teapot Dome. It falls between dolomite units of the underlying Amsden Formation, and dolomite strata of the Goose Egg Formation. The cap rock for the Tensleep is the Goose Egg Shale, which consists of shale, carbonate, and anhydrite cap rock in the field and more than 300 ft. (97.5 m) thick.

Tensleep is the primary oil-bearing unit at fields such as Rangeley, Colorado, Lost Soldier and Wertz in Wyoming. (Nummedal et al., 2003). Where the oil is not trapped, there is a permeable sandstone aquifer which is a thick continuous porous section.

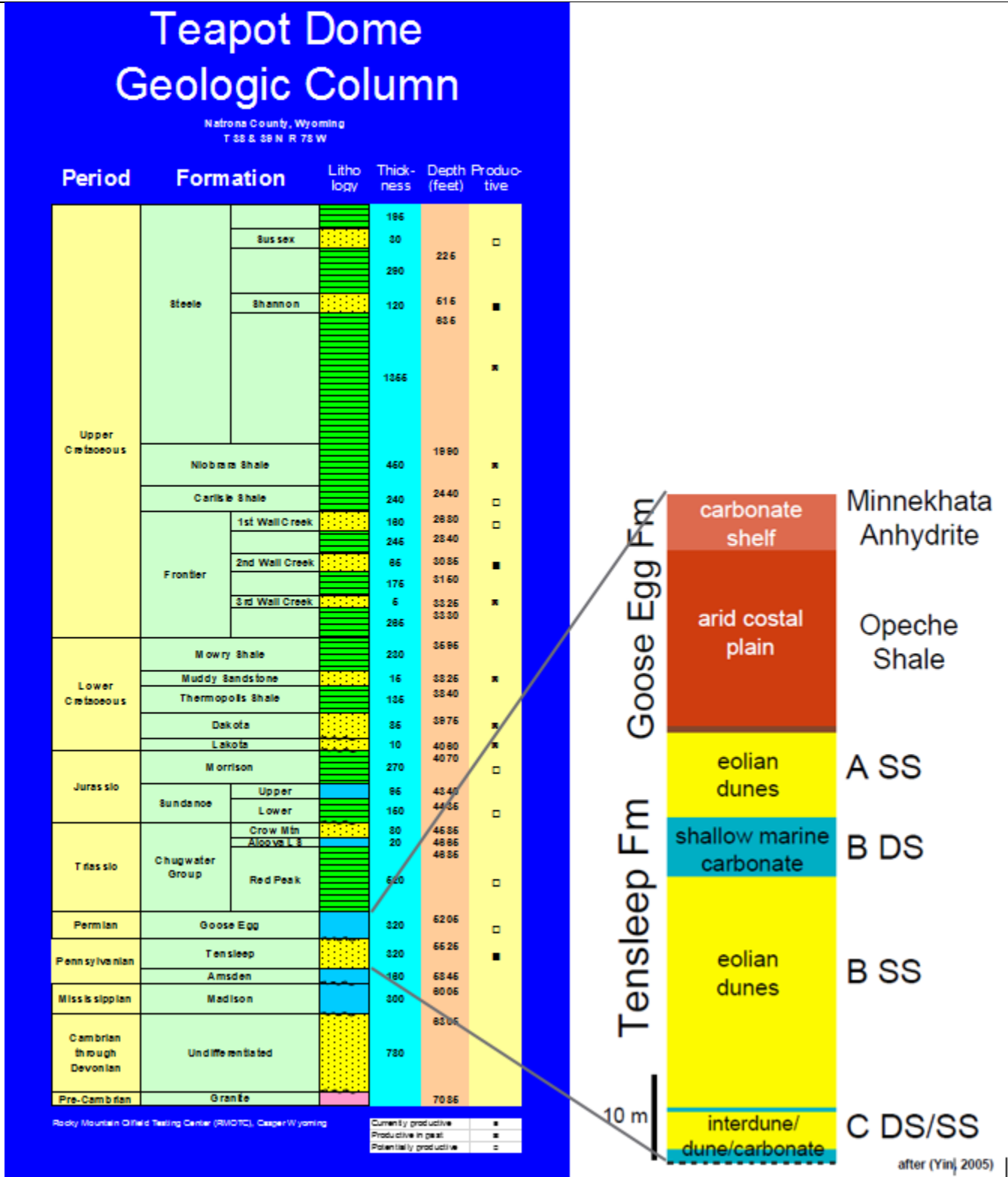


Figure 7 - Teapot Dome Geologic Column

A geologic column of the Teapot dome field is provided in (figure 7). The Permian Goose Egg and the Pennsylvanian Tensleep formations are further elaborated and the specifically the Tensleep formations is divided and characterized into different zones based on the depositional characteristics.

Teapot Dome Field

For the purposes and the time constrains of this project we will only consider oil production from a small formation, which is the Tensleep Formation and it is at section 10 (T38-39N R78W) on the map (figure 8) at the southwest region of the Teapot Dome field. The Tensleep B Sandstone found in (figure 7) produces about 60% of the oil in that section, and it's about 60 ft pay zone of the 320 ft thick Tensleep formation. Thus we will attempt to omit the above production from Shannon, Well Creek, and Dakota Sandstone formations (figure 7). 13 producing and 2 injection wells have been considered in section 10 might be considered as well, depending on the best CO₂ EOR scenario. Moreover, we noticed for the data given that most of the wells are approaching the economic limit of 5 Stb/day which indicates the necessity for the EOR we are doing. Below is a seismic map (figure 8) and a sectional map (figure 9) of the Teapot field.

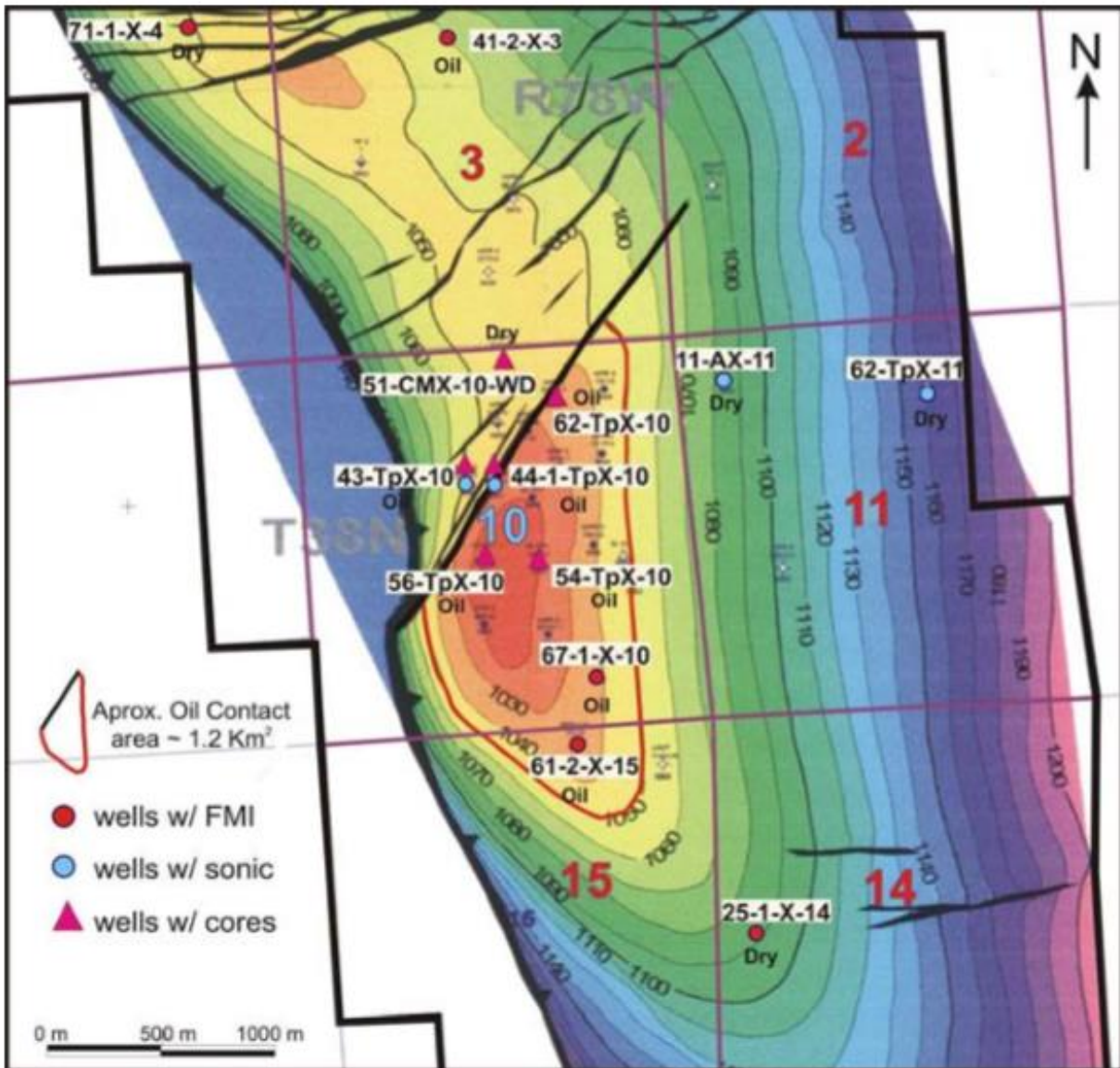


Figure 8 - Seismic Interpretation of Well Section 10 (T38-39N R78W) Tensleep Fm.

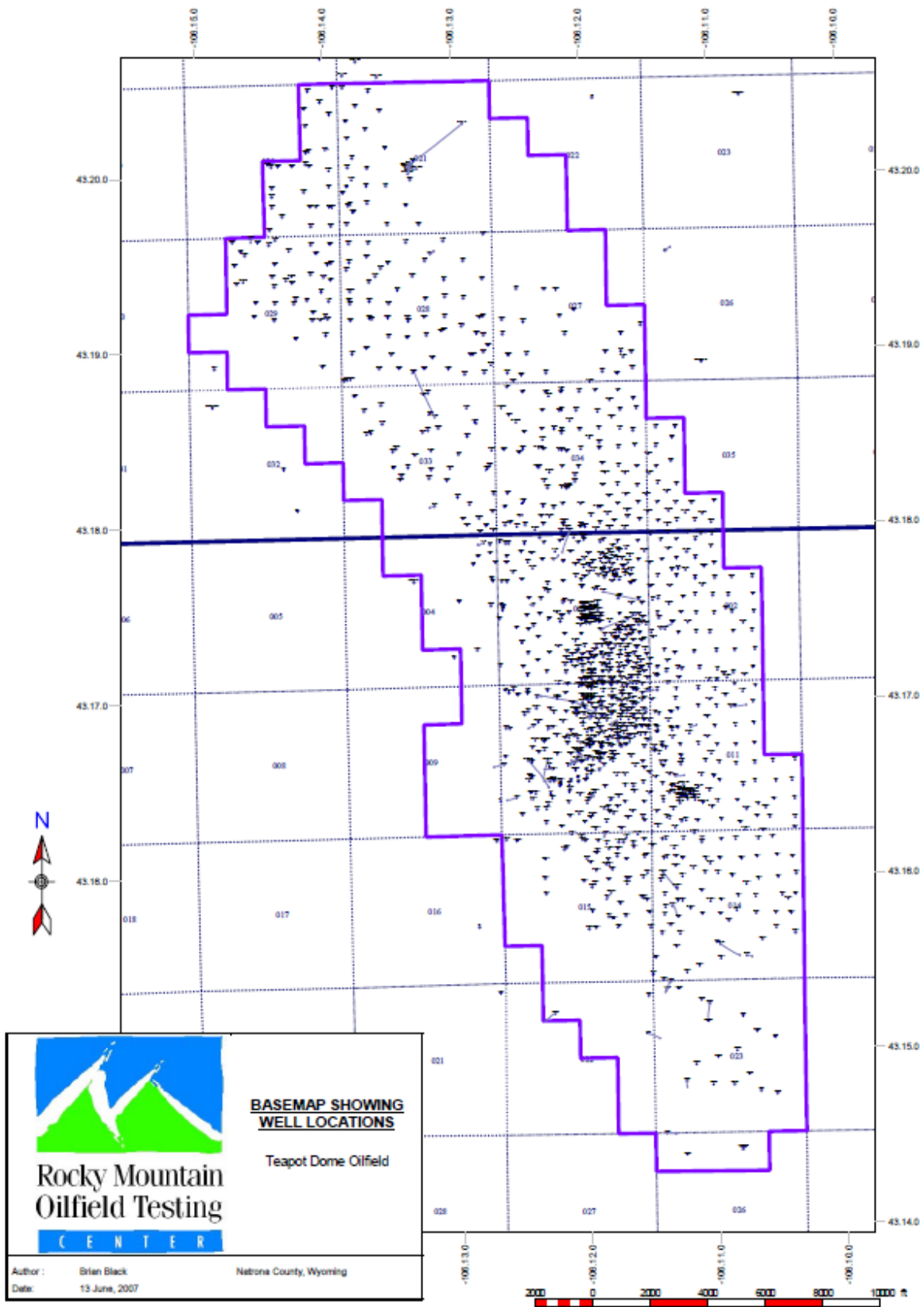


Figure 9 - Map showing coordinates and well locations in the Teapot Dome field

Reservoir Properties

We used core data to figure out reservoir properties which came from well 48-x-28. Based on this well's core data and geologist core descriptions, the summary of reservoir's layers' properties and each layers' depth can be found in (Table-1). The data found below can be correlated with a stratigraphic perspective view of each zone found within the Tensleep formation in (Figure 10).

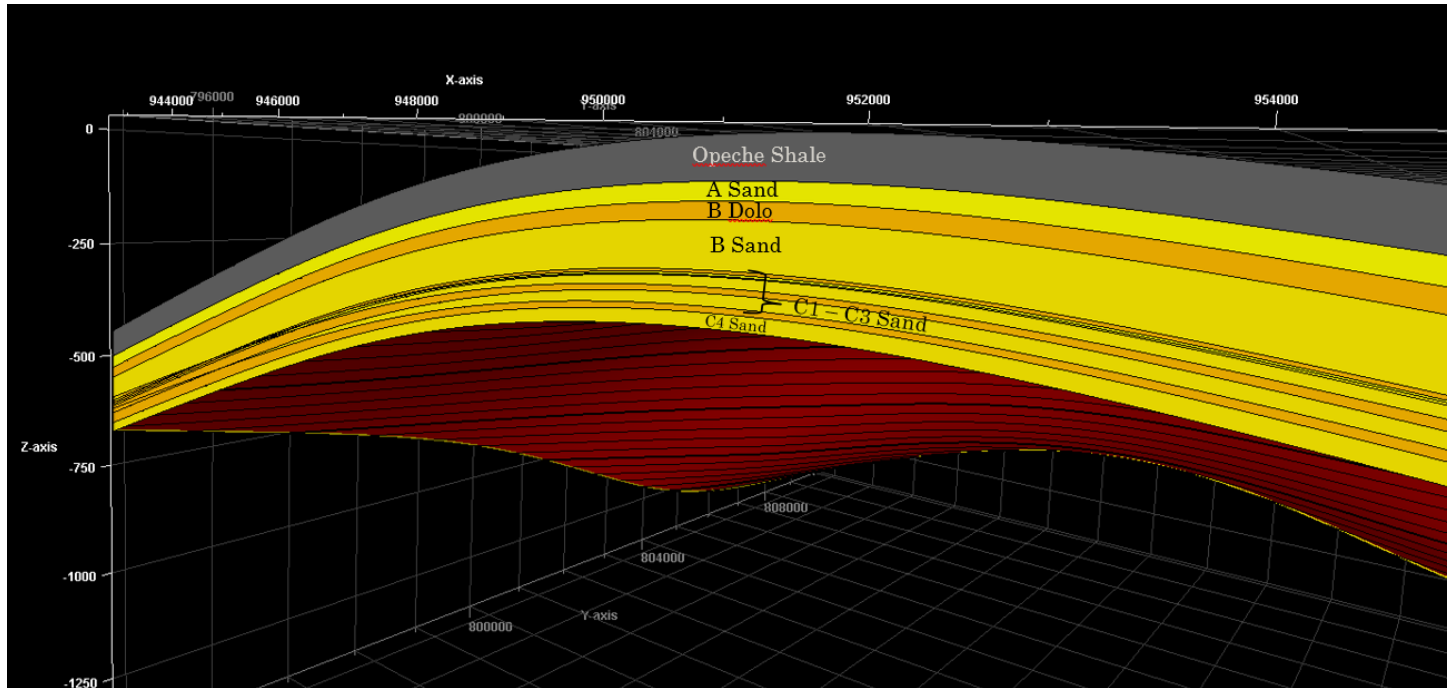


Figure 10 - Stratigraphic Perspective of Tensleep Formation

Pennsylvanian Tensleep Sandstone

(S. J. Friedmann, 2005) "The Pennsylvanian Tensleep Sandstone represents an enormous rock volume suitable for CO₂ storage, both in saline aquifers and oil-bearing zones. It covers large areas of Wyoming, Montana, and Colorado and is the primary oil-bearing unit at Rangely in Colorado and Lost Soldier and Wertz fields in Wyoming, all three of which have received continuous CO₂ injections for roughly 20 yr." It holds two thirds of Wyoming's oil and, where oil is not trapped, is a thick, continuous, porous, and permeable sandstone aquifer. Inside the Naval Petroleum Reserve No. 3 (NPR-3), in total 35 wells have penetrated the Tensleep Sandstone, including 13 cored wells. (Nummedal et al., 2003) "All have traditional well-log suites, with six recent wells having FMI (Formation Micro-Imaging) logs. Core samples and special core tests provide porosity and permeability information, petrographic samples, and petrophysical characterizations. Within the field, multiple cores have been recovered and described for both sedimentary and fracture characterizations. The longest continuous core comes from well 48-X-28 (May 2004), from which more than 150 ft (45.7 m) of core were recovered and described in detail (Figures 11A-H)." The Tensleep Sandstone consists predominantly of thick-bedded, porous, and permeable eolian sandstones."

TOP (ft.)	BOTTOM (ft.)	LITHOLOGY	POROSITY	VERTICAL PERMEABILITY	HORIZONTAL PERMEABILITY
5459.6	5486.6	TENSLEEP A SANDSTONE	6.5	0.86	1.54
5486.6	5506.6	TENSLEEP B DOLOMITE	5.5	0.0047	
5506.6	5567.6	TENSLEEP B SANDSTONE	10.8	6.5	20.2
5567.6	5569.6	TENSLEEP C1 DOLOMITE	15.4	0.338	
5569.6	5581	TENSLEEP C1 SANDSTONE	NO INFO.	NO INFO.	NO INFO.
5581	5588	TENSLEEP C2 DOLOMITE	NO INFO.	NO INFO.	NO INFO.
5588	5597	TENSLEEP C2 SANDSTONE	NO INFO.	NO INFO.	NO INFO.
5597	5603	TENSLEEP C3 DOLOMITE	NO INFO.	NO INFO.	NO INFO.
5603	5614	TENSLEEP C3 SANDSTONE	NO INFO.	NO INFO.	NO INFO.
5614	5633	TENSLEEP C4 DOLOMITE	3.9	0.0033	
5633	5652	TENSLEEP C4 SANDSTONE	10.9	11.3	57.7
5652	5654	D DOLOMITE	NO INFO.	NO INFO.	NO INFO.

Table 1 - Tensleep formation zone porosity and permeability

Besides the chart above, each layer properties, dependent picture, dependent core data can be found following parts below. The zones with no info available are grouped together and described as the “Black Region” section of the core analysis.

TENSLEEP A SANDSTONE

This layer is between 5459ft to 5486 ft. Based on the core data average porosity is 5.5%, average vertical permeability is 0.86 mD, and average horizontal permeability is 1.53 mD.

TENSLEEP A SANDSTONE			
DEPTH	POROSITY	HOR K	VER K
5458.60	12.9		5.01
5464.80	6.7		0.046
5465.50	8.1		0.146
5471.30	4.6		0.0041
5478.00	3.2		0.0014
5481.10	2.9		0.0012
5458.50	13.1	9.47	
5462.80	9.7	1.06	
5464.60	6.2	0.060	
5465.40	8.1	0.168	
5471.20	3.9	0.0073	
5477.80	2.9	0.0028	
5481.50	2.1	0.0011	



Table 2A – A Sandstone

Figure 11 A - Core Photo of A Sand

TENSLEEP B DOLOMITE

This layer is between 5486ft to 5506.6 ft. Based on the core data average porosity is 6.5%, average vertical permeability is 0.0047 mD. The horizontal permeability couldn't found for this layer and only two data points were measured as found below.

TENSLEEP B DOLOMITE			
DEPTH	POROSITY	HOR K	VER K
5495.00	5.8		0.0023
5499.00	5.2		0.0071

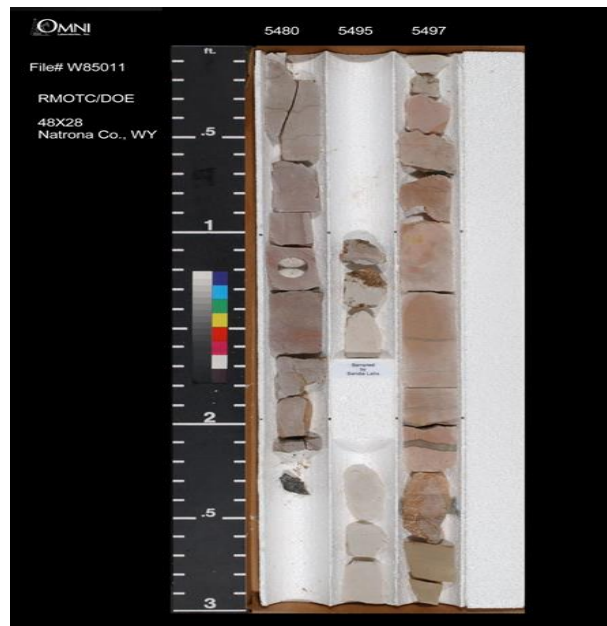


Table 2B - B Dolomite

Figure 11 B - Core Photo of B Dolomite

TENSLEEP B SANDSTONE

This layer is between 5506ft to 5567.6 ft. Based on the core data average porosity is 10.8%, average vertical permeability is 6.5 mD, and average horizontal permeability is 20.2 mD. Based on the production data, it is the most productive layer which almost produce 60% of hydrocarbon of whole formation, and this is due to its high porosity and permeability.

TENSLEEP B SS			
DEPTH	POROSITY	HOR K	VER K
5514.40	14.5		17.3
5515.60	13.9		18.2
5517.90	13.4		8.88
5518.50	13.8		23.5
5521.80	10.6		7.23
5523.00	12.0		3.46
5524.00	12.0		2.23
5525.10	11.0		0.888
5528.10	10.7		0.453
5534.00	12.8		13.4
5535.40	10.8		1.05
5536.40	11.9		10.3
5537.30	11.7		6.67
5538.30	10.7		1.01
5540.40	9.8		1.69
5542.40	12.6		7.32
5544.80	13.7		24.9
5546.80	13.8		25.1
5548.70	10.8		0.211
5550.60	9.7		1.40
5552.30	9.1		0.141
5554.50	10.4		0.512
5559.10	6.1		0.132
5560.30	3.7		0.0035
5562.30	3.9		0.0021
5564.70	5.8		0.048
5567.30	3.1		0.0059
5514.60	14.2	21.3	
5515.50	14.2	16.4	
5517.80	11.0	45.6	
5518.70	9.4	17.3	
5519.20	9.2	18.4	
5519.30	9.2	12.8	
5521.60	13.4	44.9	
5523.50	13.0	56.2	
5524.30	11.3	10.7	
5525.30	9.6	7.17	
5527.90	9.6	8.67	
5528.30	11.5	27.2	
5533.80	11.0	8.16	
5535.20	12.0	42.6	
5536.20	11.8	9.78	
5537.50	11.0	18.9	
5538.50	10.6	22.0	
5540.20	9.3	8.44	
5542.70	12.9	21.1	
5544.70	12.9	23.7	
5546.50	14.0	31.4	
5548.30	11.1	28.0	
5550.40	9.9	13.5	
5552.50	10.5	5.09	
5554.30	9.8	6.62	
5558.90	6.6	0.043	

Table 2C - B Sandstone



Figure 11 C - Core Photo from B Sand

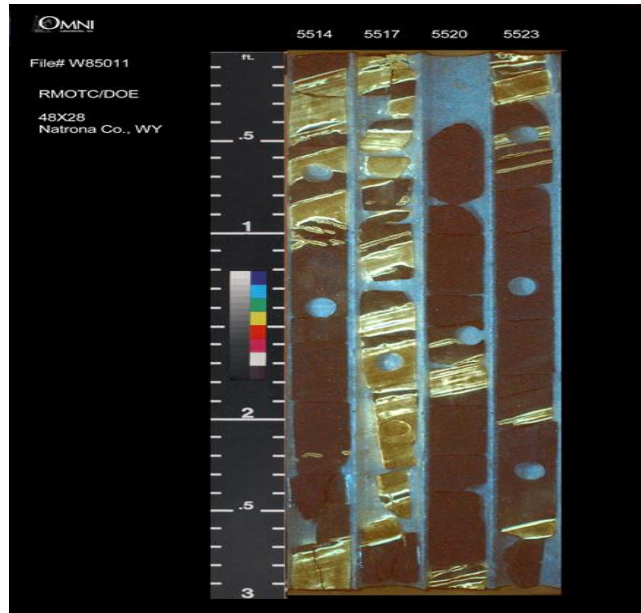


Figure 11 D - Core Photo from B Sand

TENSLEEP C1 DOLOMITE

This layer is between 5567.6 ft to 5569.6 ft. Even this layer thickness is 2ft, it is added to presentation and this report since it is different rock type and show add different properties to Tensleep formation. Even thickness is very low, only one data point gathered to calculate average porosity and permeability. Based on the core data average porosity is 15.4%, average vertical permeability is 0.338 mD. As the Tensleep B Dolomite, the horizontal permeability couldn't found for this layer.

TENSLEEP C1 DOLOMITE			
DEPTH	POROSITY	HOR K	VER K
5569.50	15.4177		0.338

Table 2D - C1 Dolomite



Figure 11 E – Core Photo from C1 Dolomite

TENSLEEP BLACK REGION

Tensleep Black Region is consisted from 5 layers Tensleep C1 sandstone, C2 dolomite, C2 sandstone, C3 dolomite, C3 sandstone, and it is between 5569.6 ft. to 5614 ft. Since data from cores and logs couldn't found, we called it black region. Even there isn't data, this layers separated by geologist descriptions related to cores. As it can be seen below, this layers mostly consisted from dolomites and dolomitic sandstones which both have very low permeability, and this is the key why engineers and geologists even didn't get core data for these layers.

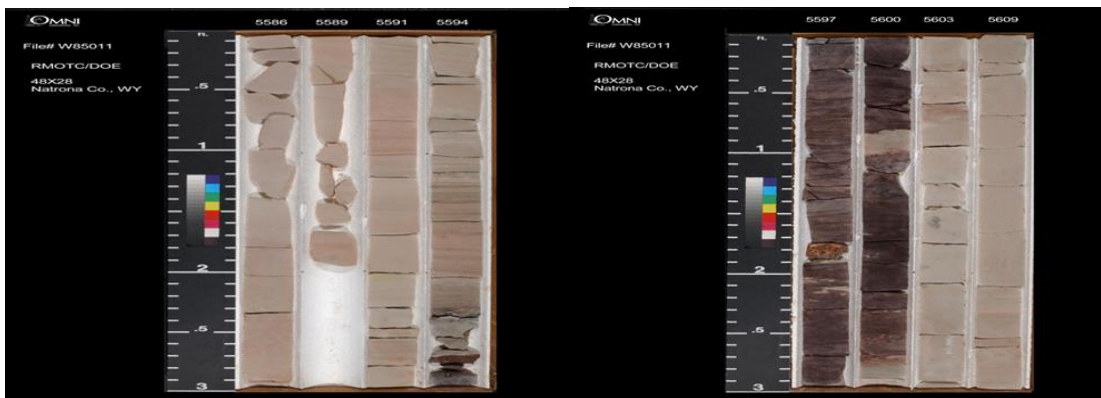


Figure 11 F - Black Region Core Photos

TENSLEEP C4 DOLOMITE

This layer is between 5614ft to 5633 ft. Based on the core data average porosity is 3.9%, average vertical permeability is 0.0033 mD. The horizontal permeability couldn't found for this layer.

TENSLEEP C4 DOLOMITE			
DEPTH	POROSITY	HOR K	VER K
5625.90	3.7		0.0025
5627.40	1.9		0.0007
5629.00	5.8		0.0061
5630.00	4.3		0.004

Table 2E - C4 Dolomite

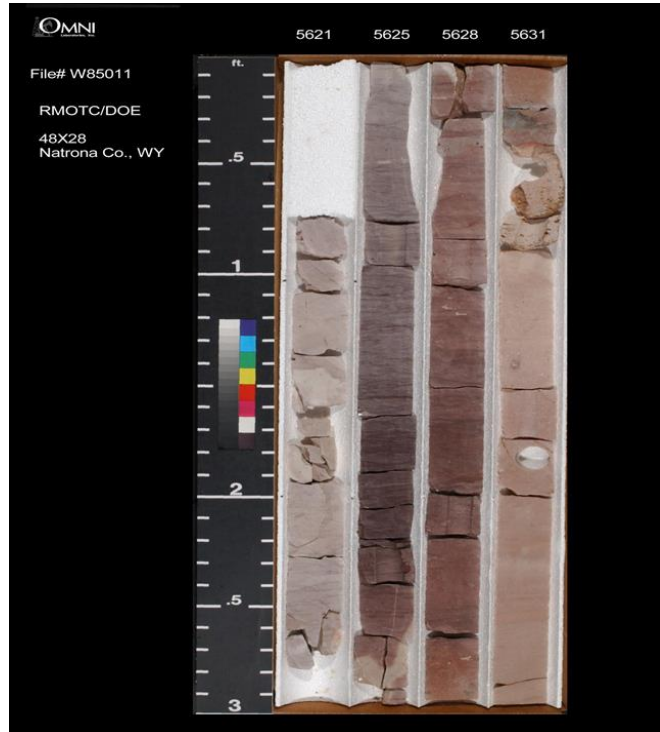


Figure 11 G – C4 Dolomite Core Photos

TENSLEEP C4 SANDSTONE

This layer is between 5633ft to 5652 ft. Based on the core data average porosity is 10.9%, average vertical permeability is 11.3 mD which is between the range of 0.007 mD to 27.4 mD, and average horizontal permeability is 57.7 mD which is between the range of 0.353 mD to 296 mD.

C4 SANDSTONE			
DEPTH	POROSITY	HOR K	VER K
5635.80	12.2		27.4
5637.30	9.8		13.2
5638.60	11.5		12.8
5640.30	11.8		19.9
5631.60	21.1	296.	
5632.90	7.2	0.353	
5635.60	12.3	33.4	
5637.50	12.0	80.7	
5638.40	13.9	154.	
5640.40	12.4	43.8	
5642.40	10.0		4.14
5644.20	9.0		0.328
5647.30	9.4		5.82
5648.60	10.1		11.1
5650.20	9.6		7.13
5642.70	8.6	2.04	
5644.40	9.6	7.76	
5647.50	8.4	6.61	
5648.70	10.1	25.6	
5648.80	10.3	39.5	
5650.30	7.4	2.85	

Table 2F - C4 Sandstone



Figure 11 H - C4 Sandstone Core Photos

TENSLEEP D DOLOMITE

This layer is between 5652 ft. to 5654 ft. Core data information and core pictures couldn't found for this layer. But it is dolomite based on the geologist's description. [2]

Further Analysis of Porosity

After accessed to Wyoming Oil and Gas Conservation Commission website, found one porosity-log, which remedied our lack of porosity information. Firstly, porosity log and porosity came from core data correlated by founding the anomalous layer which is C1 Dolomite and formation top data for that well. To check the accuracy of log, errors were calculated if there was reachable data. Based on the log-porosity, and the porosity from core data;

THICKNESS(ft)	LITHOLOGY	POROSITY FROM CORE DATA	POROSITY FROM LOG DATA	ERROR(%)
27	TENSLEEP A SS	6.5	6.371642106	1.974737
20	TENSLEEP B DOLOMITE	5.5	5.78476803	5.177601
61	TENSLEEP B SANDSTONE	10.8	9.867774774	8.631715
2	TENSLEEP C1 DOLOMITE	15.4	15.88940243	3.177938
11.4	TENSLEEP C1 SANDSTONE	NO INFO.	10.42052391	N/A
7	TENSLEEP C2 DOLOMITE	NO INFO.	4.118672601	N/A
9	TENSLEEP C2 SANDSTONE	NO INFO.	4.004078411	N/A
6	TENSLEEP C3 DOLOMITE	NO INFO.	4.413652212	N/A
11	TENSLEEP C3 SANDSTONE	NO INFO.	4.203375271	N/A
19	TENSLEEP C4 DOLOMITE	3.9	4.317354579	10.7014
19	TENSLEEP C4 SANDSTONE	10.9	10.17397807	6.660752
2	D DOLOMITE	NO INFO.	NO INFO	N/A

Table 3 – Porosity from Log Data

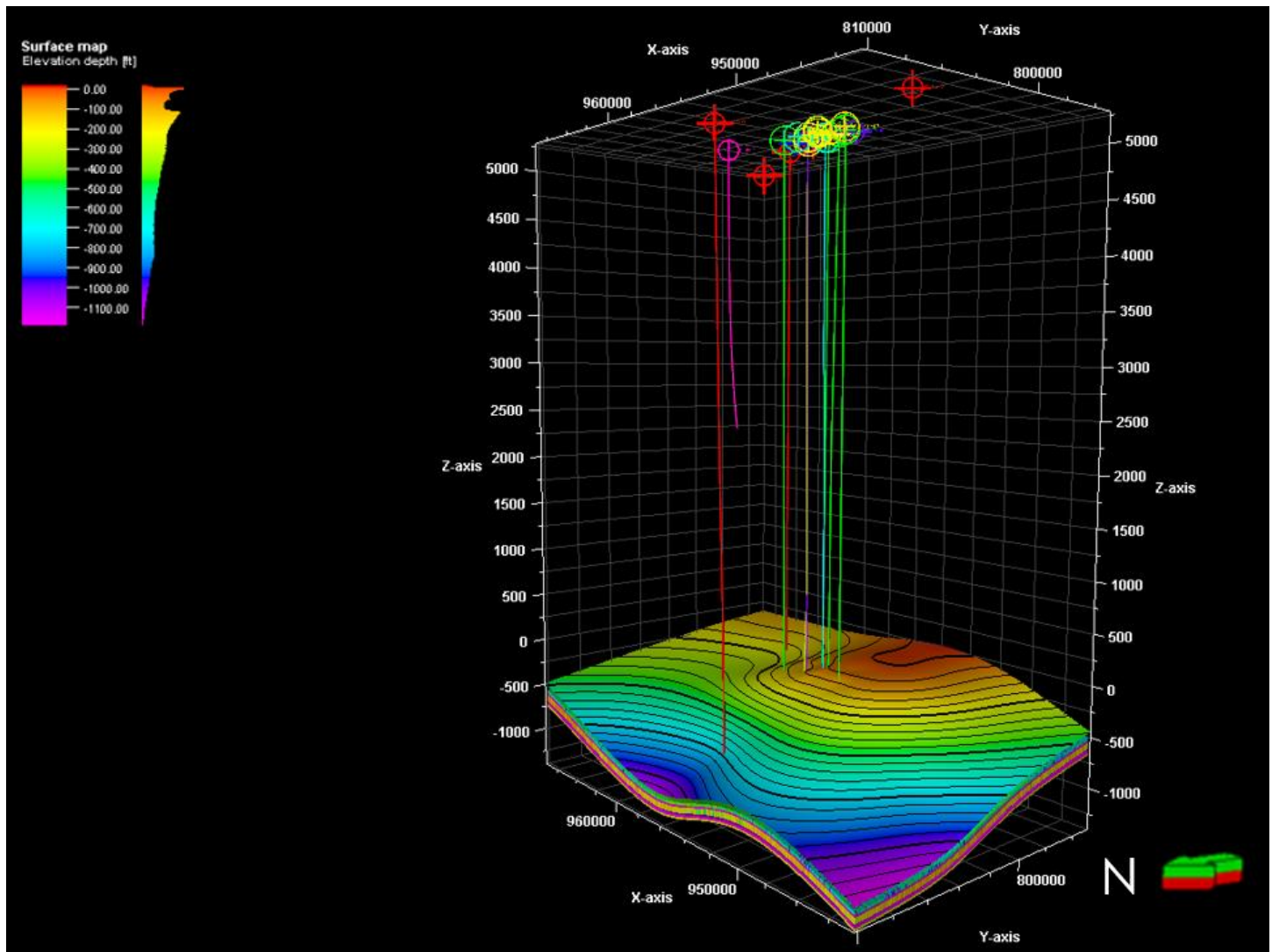


Figure 13 - Contour Perspective View of Tensleep Formation

During our static model operation, well heads, well logs, well tops & well paths data was imported. Stratigraphic horizons were then created into surfaces which we can then use to model our stratigraphy. A contour perspective view of our area of interest is shown in (figure 13). After this development, our physical properties (i.e. porosity and permeability) could then be modeled. Maps of porosity and permeability can be seen in the following (figures 14 & 15) as well as the east west cross sections (figures 16 & 17). Warmer colors (i.e red and yellows) generally indicate higher values while darker colors (i.e blues and purple) indicate lower values. Purple indicating impermeable zones. Currently, we are working to correlate our porosity and permeability better in the models.

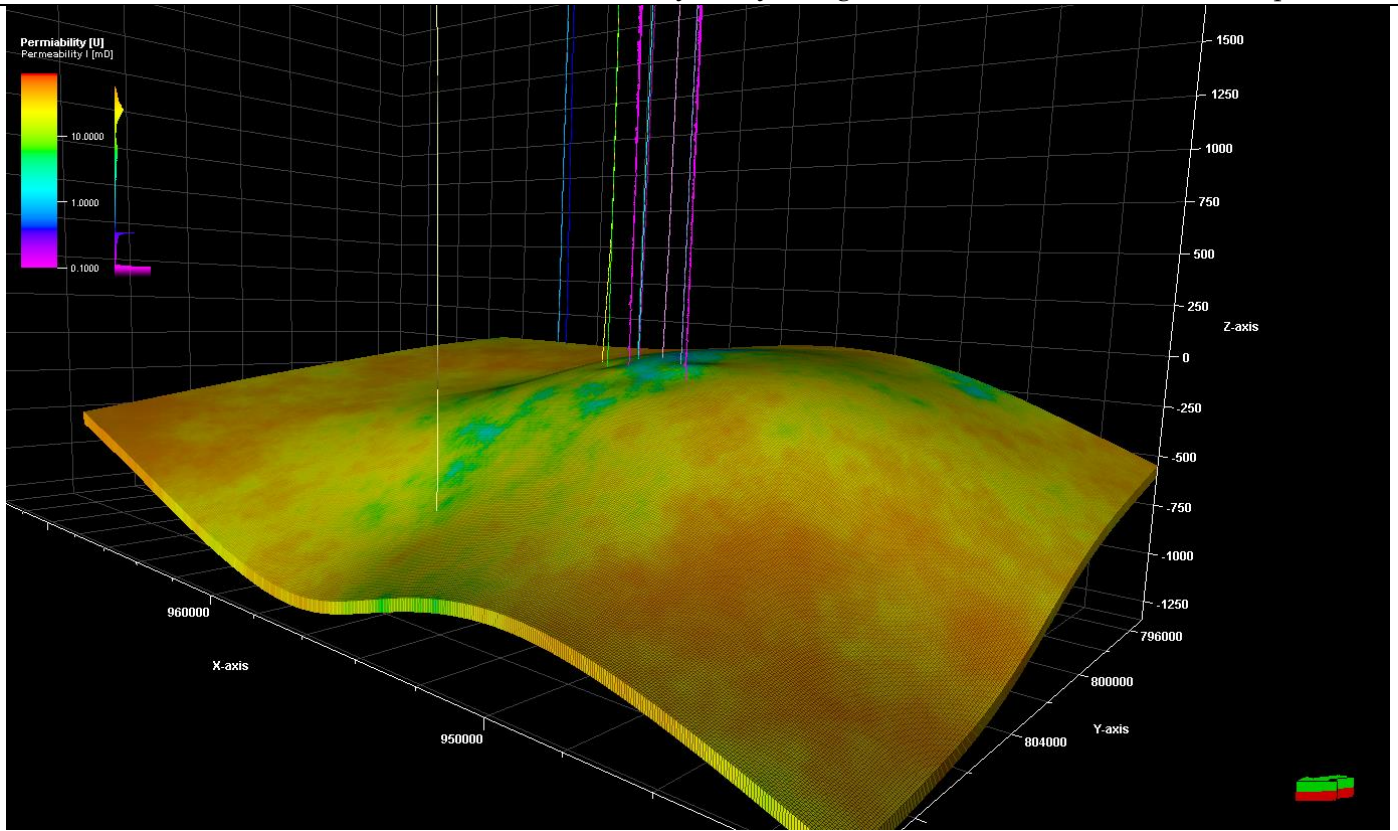


Figure 14 - Pay Zone (B sand) Permeability [mD] Model

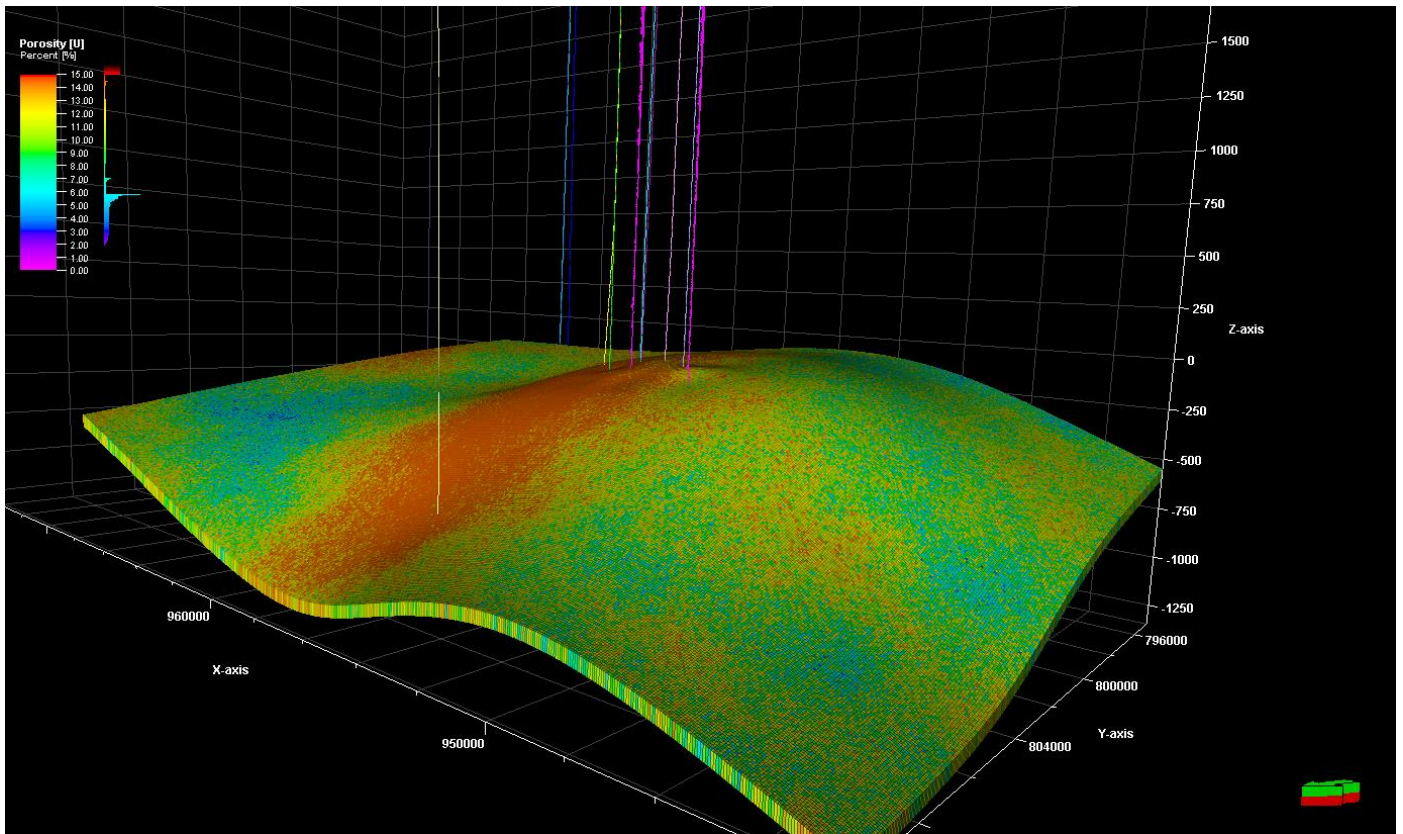


Figure 15- Pay Zone (B Sand): Porosity [%] Model

The first layer shown in purple is the Opeche shale then successively are A sand, B dolomite, B sand, C4 dolomite and sandstone

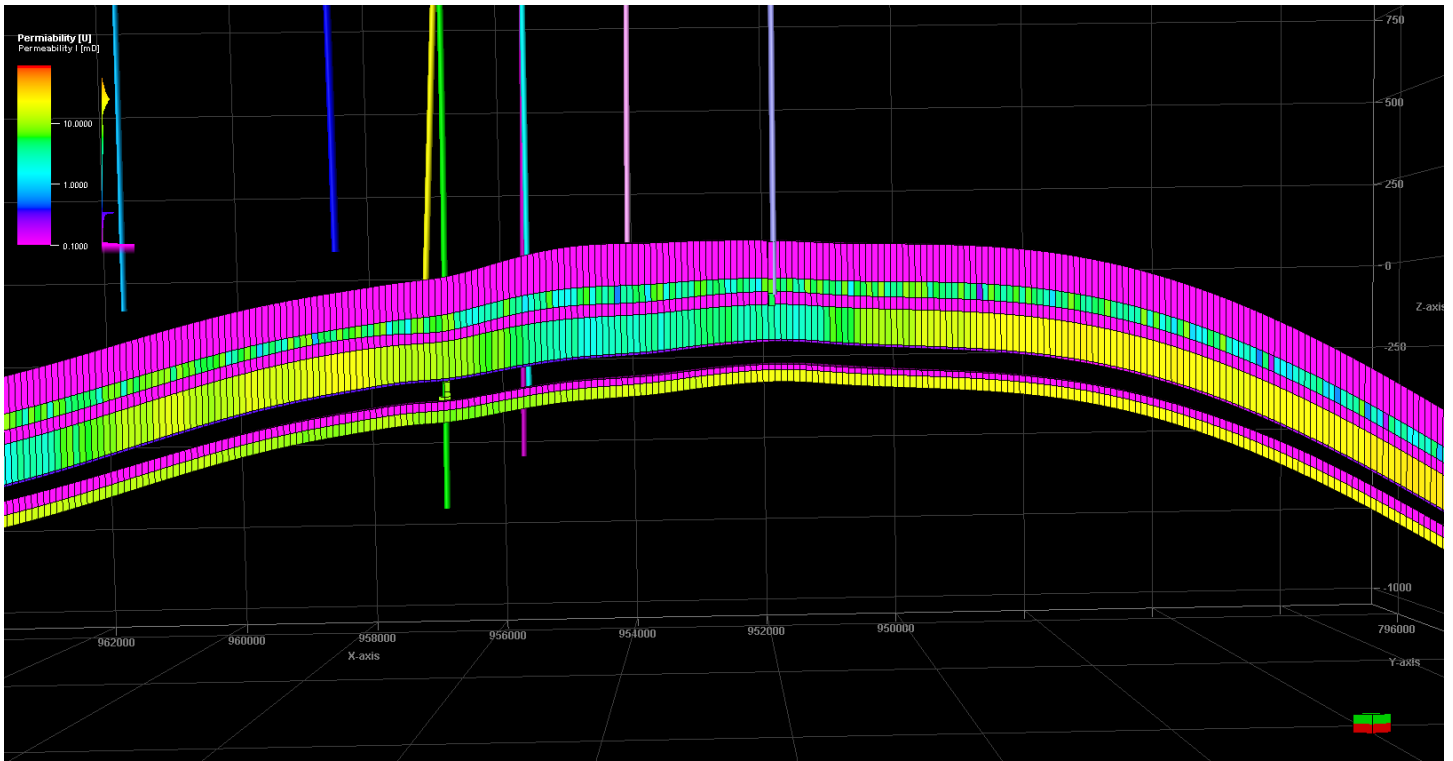


Figure 16 - East West Permeability [mD] Cross Section

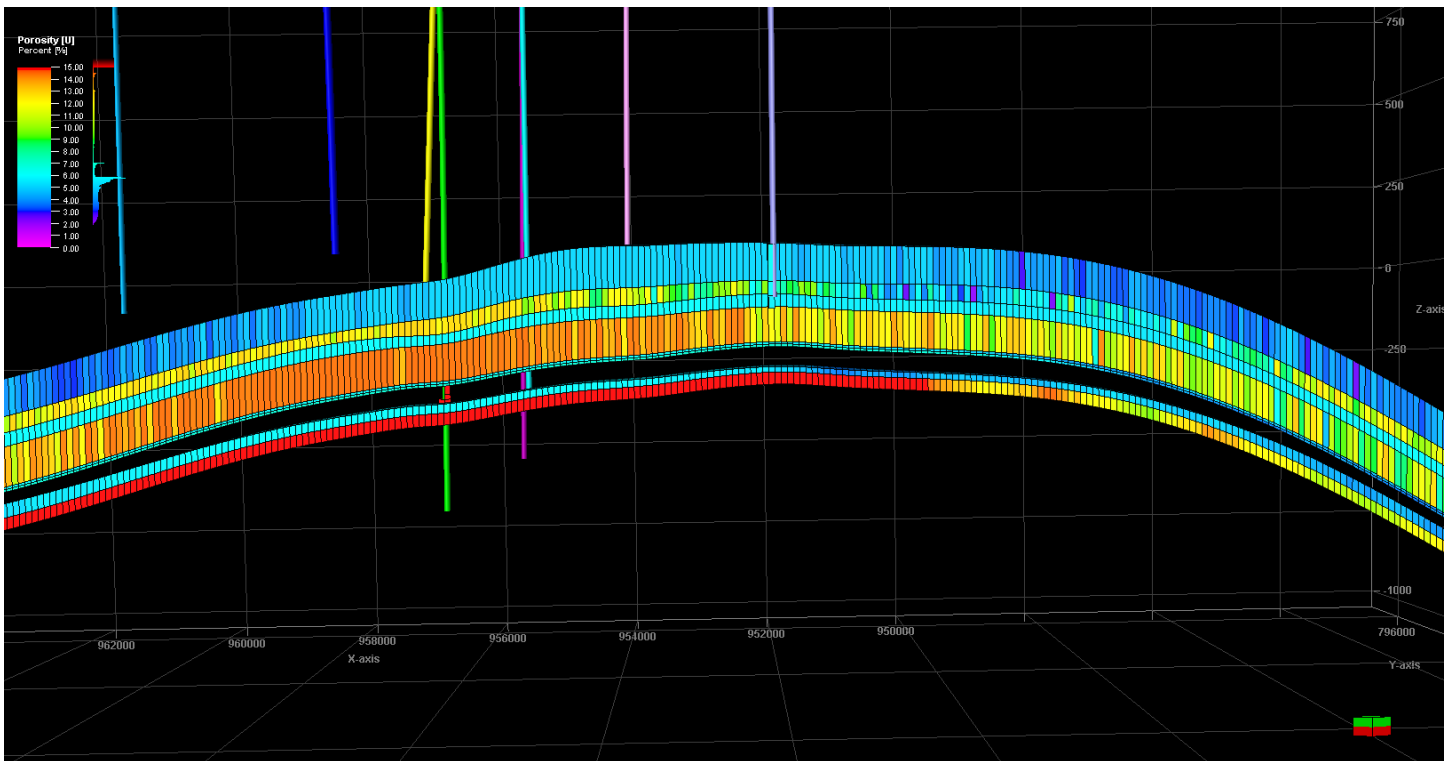


Figure 17 - East West Porosity [%] Cross Section

Dynamic Model

To properly model fluid flow in a reservoir we need an accurate account of reservoir properties including PVT relationships, critical properties of fluids and gasses. As seen in (Table - 4) many of these properties used in our dynamic model were taken from a master's thesis by Ricardo Gaviria Garcia from Texas A&M titled *Reservoir Simulation of CO2 Sequestration and Enhanced Oil Recovery in the Tensleep Formation, Teapot Dome Field* (Garcia, 2005). CMG was the selected software used in this analysis. Detailed information of the input parameters to construct the dynamic model is provided below as well as initial finding.

Reservoir Properties

Reservoir Properties	Values
Production Area	440 Acres
Average Depth	5500 ft
Gas-Oil Contact	N/A
Average Matrix Permiability	50 mD
Average Porosity	0.135
Oil Gravity	31 API
Reservoir Temperature	190 F
Primary Production Mechanism	Water Drive
Original Reservoir Pressure	2300 psi
Bubble point pressure	40-70 psi
Average pressure at start of CO2 injection	2000+-100 psi
Initial FVF	1.312 RB/BBL
GOR	4 SCF/BBL
Oil Viscosity at 60F and 42 psi	3.5 cp
Minimum miscibility pressure	1300 psi

Table 4- Reservoir Properties

IMEX CMG Model – Single Porosity

For initial simplicity and to achieve quicker results a single porosity was modeled using the IMEX Black Oil Simulator within CMG (Figure - 19). Additional model types are considered and discussed in the current status section of the report. A formation contour map (Figure - 20) exported from the static model develop in Petrel was used to create the surface used in the model. The grid layout and start date is also defined.

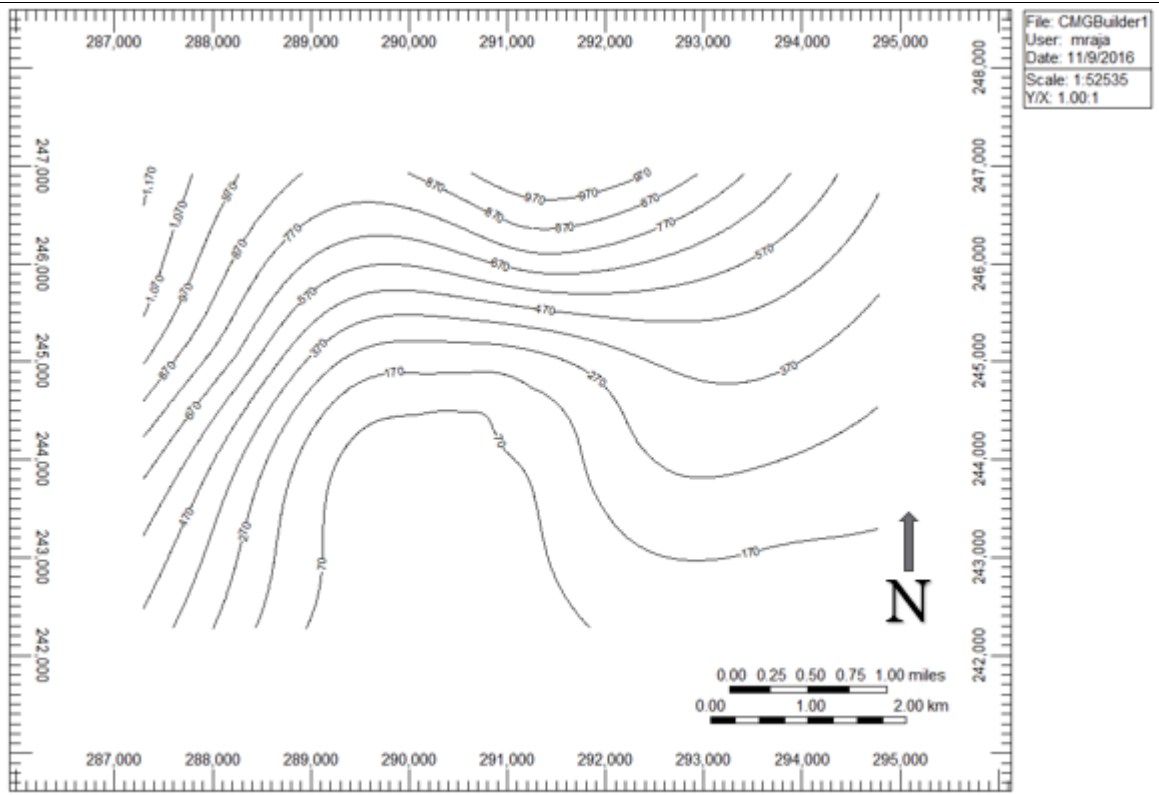


Figure 18 – Contour Map of A Sand Tensleep Formation.

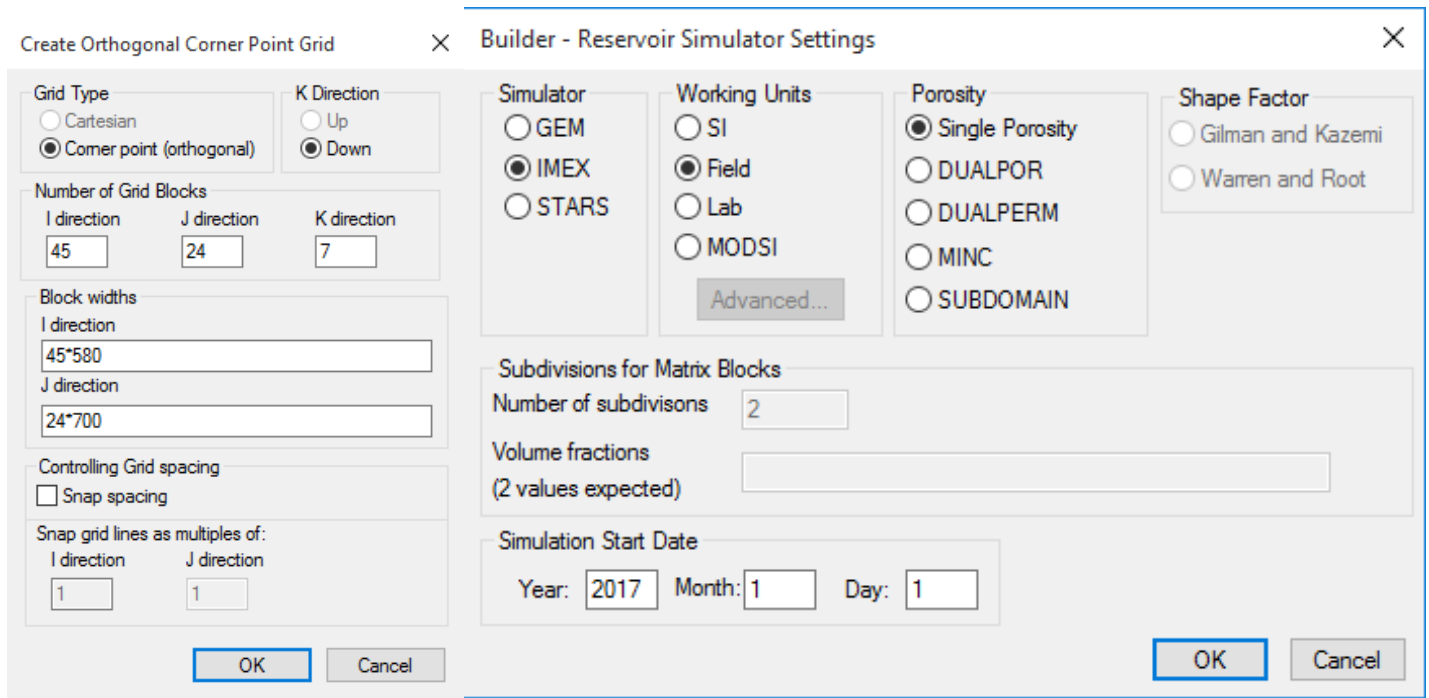


Figure 19 – IMEX Single Porosity Model and Grid Inputs.

Then, based on the imported surface from Petrel, layers which represent the different stratigraphic deposition of the Tensleep formation discussed in the reservoir properties section are created (Figure - 20). Thickness, porosity and vertical and horizontal permeability's are inserted into CMG by hand for each layer based on properties found in the petro physical analysis in Petrel. A 3D contour surface map representing the different layers is shown in (Figure - 21).

	Grid Thickness	Porosity	Permeability I	Permeability J	Permeability K
UNITS:	ft		md	md	md
SPECIFIED:	X	X	X	X	X
HAS VALUES:	X	X	X	X	X
Whole Grid					
Layer 1	61	0	0	0	0
Layer 2	22	0.065	1.54	1.54	1
Layer 3	21	0.055	0	0	0
Layer 4	56	0.11	20.2	20.2	6.5
Layer 5	4	0.154	0	0	0
Layer 6	36	0.055	0	0	0
Layer 7	19	0.039	0	0	0
Layer 8	19	0.109	57.7	57.7	11.3
Layer 9					
Layer 10					
<					

Figure 20 – Tensleep Formation Reservoir Layer Inputs.

Grid Top (ft) 2017-01-01

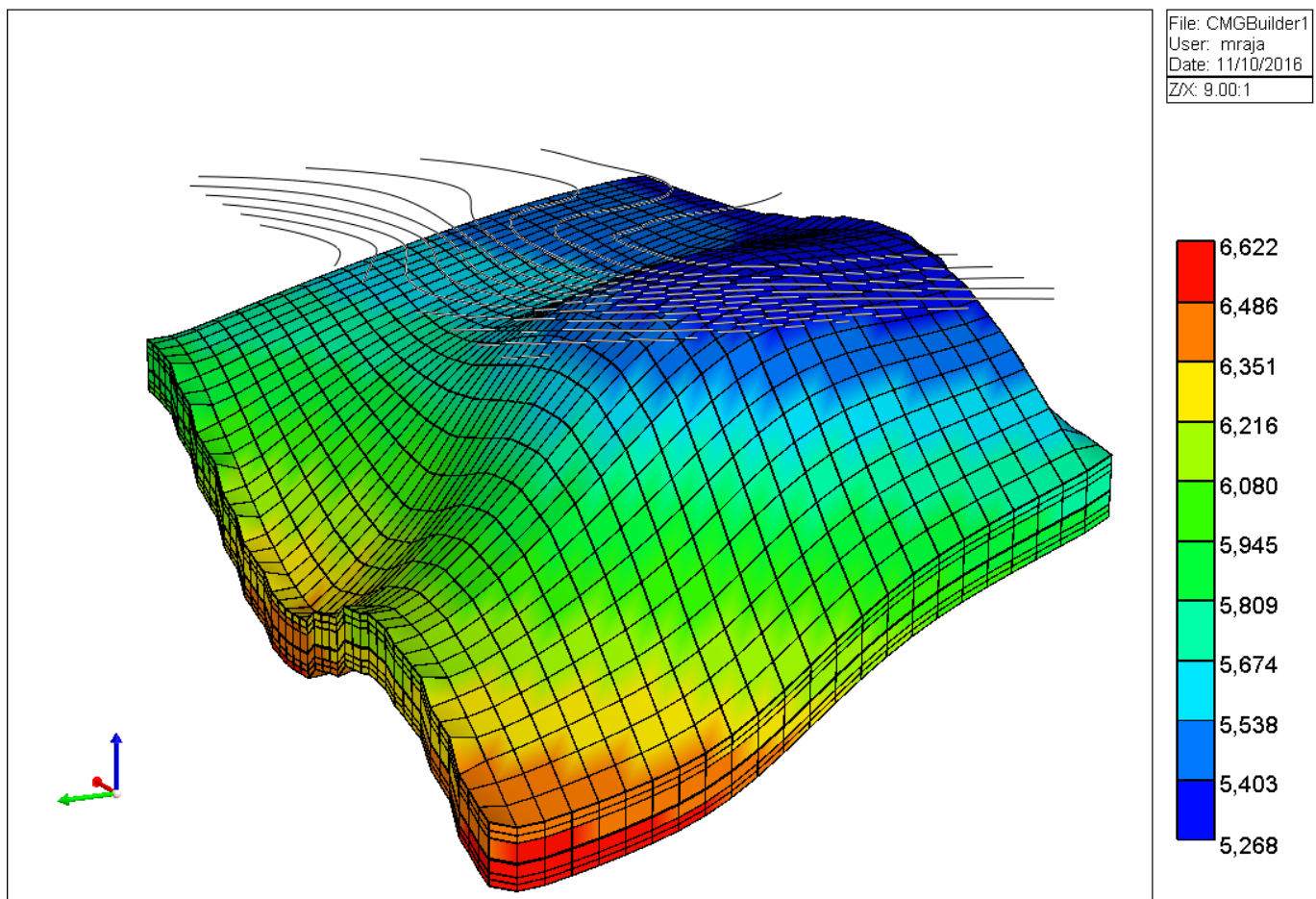


Figure 21 – 3D Contour Map of Tensleep Formation.

Rock and Formation Compressibility

Newman correlation for sandstones, this correlation was developed sandstones with porosity range $0.02 < \phi < 0.23$, and the average absolute error was found 2.6%. (Towler, 2002)

$$C_f = \frac{97.32 \times 10^{-6}}{(1 + 55.8721\phi)^{1.42859}} \tag{1.1}$$

After formation compressibility was found with the equation above, rock compressibility can be found with the equation which show relationship between formation compressibility and rock compressibility.

$$C_f = C_r \frac{1 - \phi}{\phi} \tag{1.2}$$

Based on the equations above each layer's formation compressibility and rock compressibility is;

THICKNESS(ft)	LITHOLOGY	POROSITY	FORMATION COMPRESSIBILITY (psi ⁻¹)	ROCK COMPRESSIBILITY (psi ⁻¹)
27	TENSLEEP A SS	6.435821053	1.10143E-05	7.57618E-07
20	TENSLEEP B DOLOMITE	5.642384015	1.27318E-05	7.61332E-07
61	TENSLEEP B SANDSTONE	10.33388739	6.3283E-06	7.29327E-07
2	TENSLEEP C1 DOLOMITE	15.64470121	3.7661E-06	6.98468E-07
11.4	TENSLEEP C1 SANDSTONE	10.42052	6.26425E-06	7.28702E-07
7	TENSLEEP C2 DOLOMITE	4.1186	1.76702E-05	7.59028E-07
9	TENSLEEP C2 SANDSTONE	4.004	1.81717E-05	7.57941E-07
6	TENSLEEP C3 DOLOMITE	4.413	1.64844E-05	7.61042E-07
11	TENSLEEP C3 SANDSTONE	4.203	1.73158E-05	7.59714E-07
19	TENSLEEP C4 DOLOMITE	4.108677289	1.77127E-05	7.58941E-07
19	TENSLEEP C4 SANDSTONE	10.53698904	6.17987E-06	7.27868E-07
2	D DOLOMITE	NO INFO	NO INFO	NO INFO

Table 5 - Layer Properties

Reservoir rock compressibility and reservoir formation compressibility can be found after considering each layer's volume.

RESERVOIR FORMATION COMPRESSIBILITY(psi⁻¹)	1.06422E-05
RESERVOIR ROCK COMPRESSIBILITY(psi⁻¹)	7.44192E-07

Table 6 - Rock and Formation Compressibility

In the following figures, a relative permeability correlation is constructed based on initial conditions (Figure - 23) and critical properties (Figure - 22). This information will be used to plot gas expansion [Eg] (Figure - 25), oil volume factor [Bo] and the dissolved gas oil ratio [Rs] (Figure - 24) vs pressure [P].

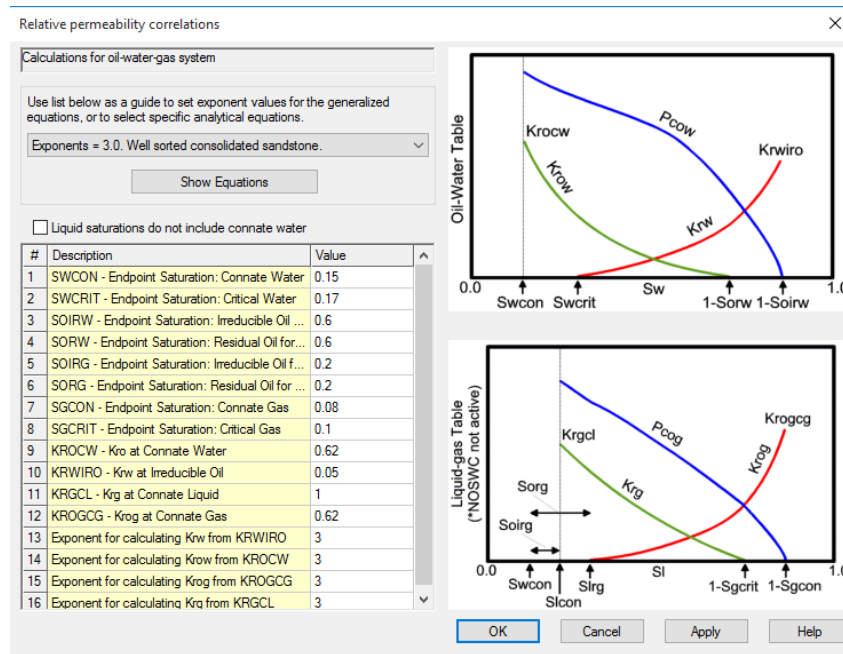


Figure 22 – Relative Permeability Correlation Inputs

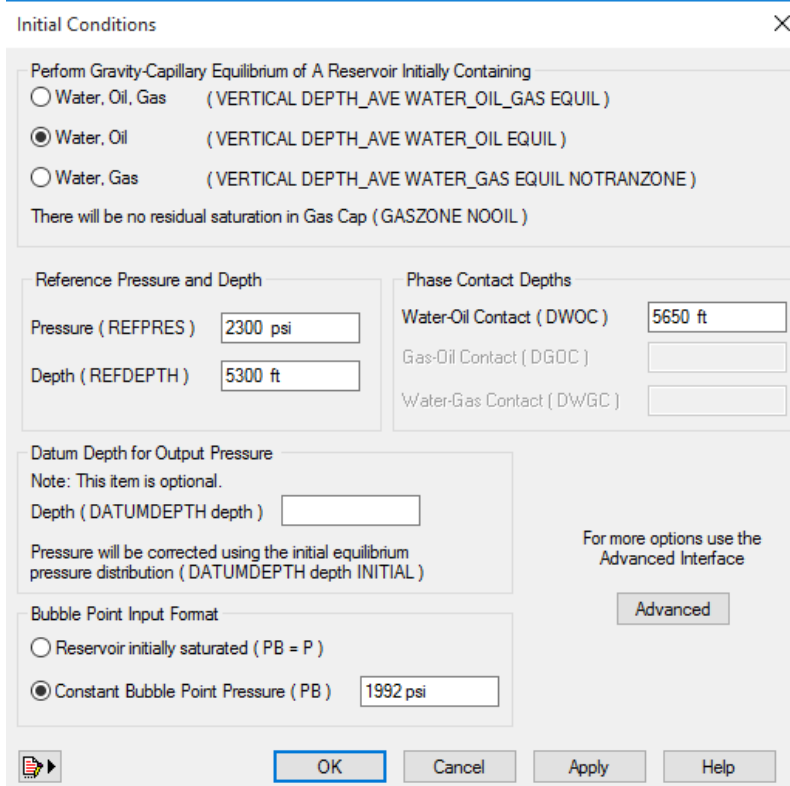


Figure 23 – Initial Conditions of Reservoir

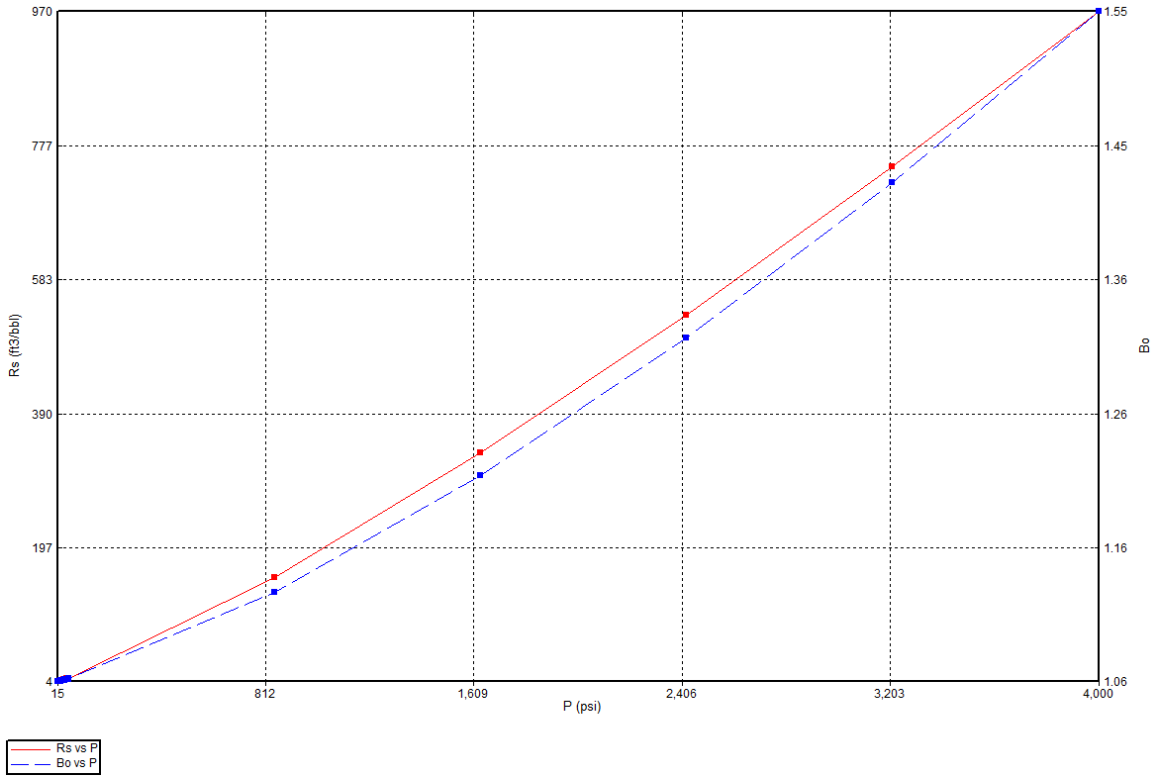


Figure 24 – Rs [ft³/bbl] Vs. P [psi]

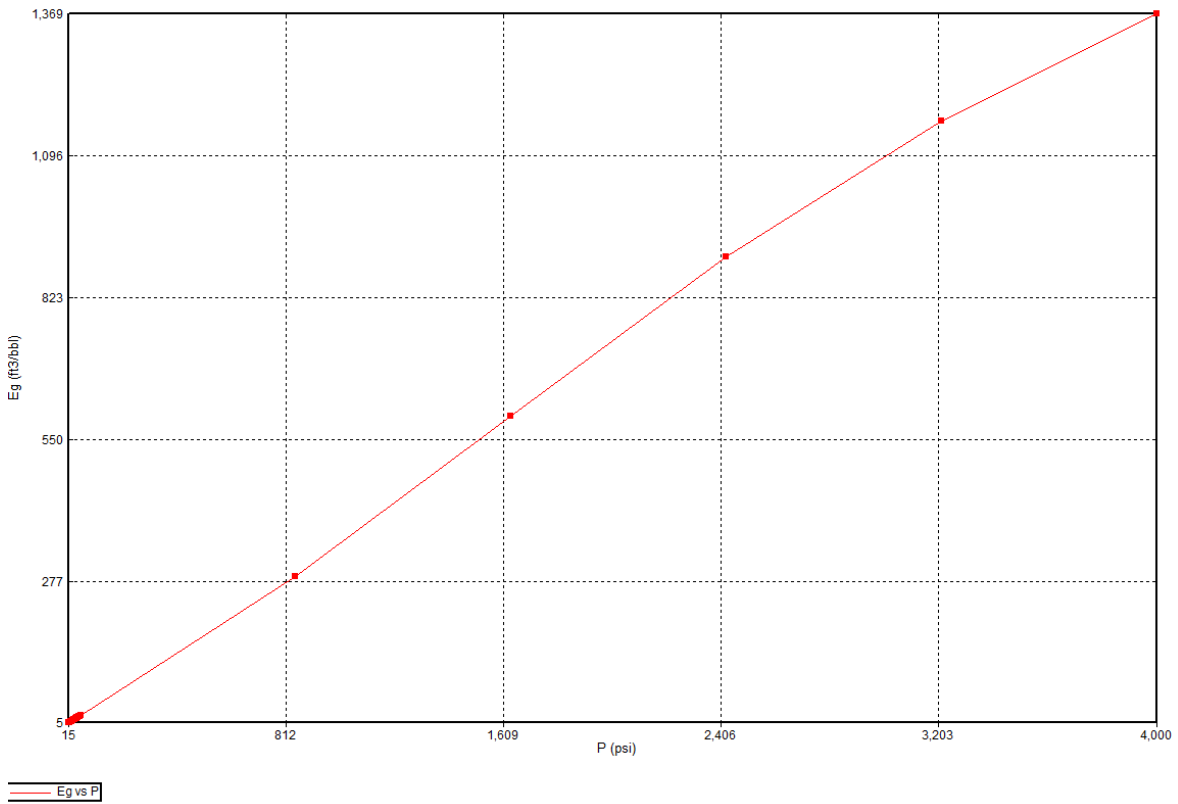


Figure 25 – Eg [ft³/bbl] Vs. P [psi]

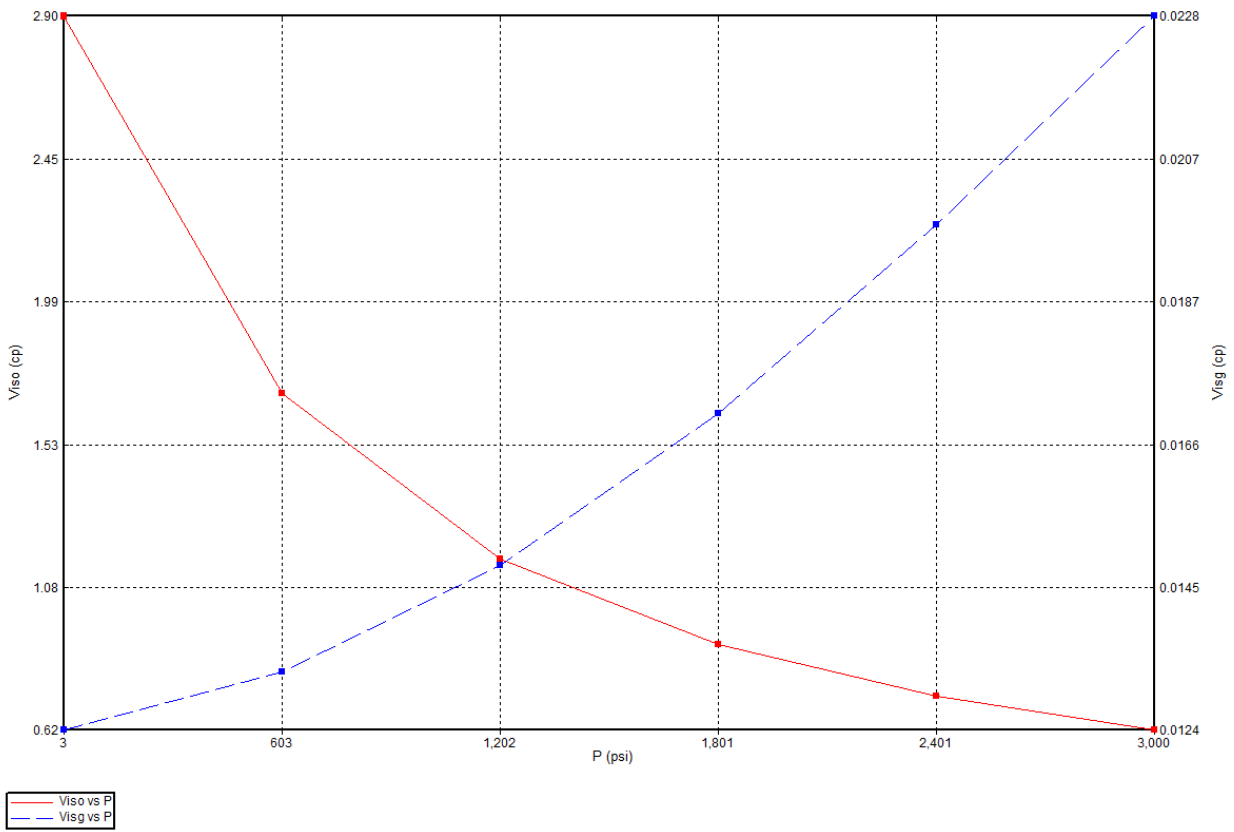


Figure 26 – Viscosity of Oil Vs. Pressure

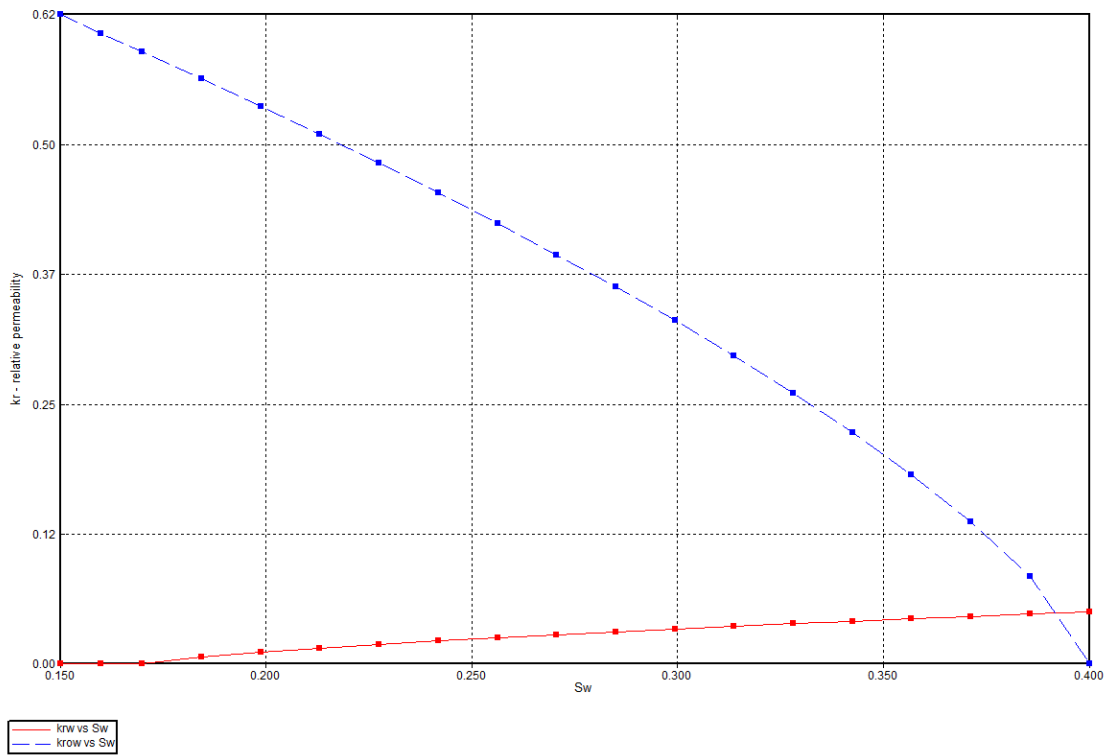


Figure 27 – Relative Permeability Vs. Water Saturation

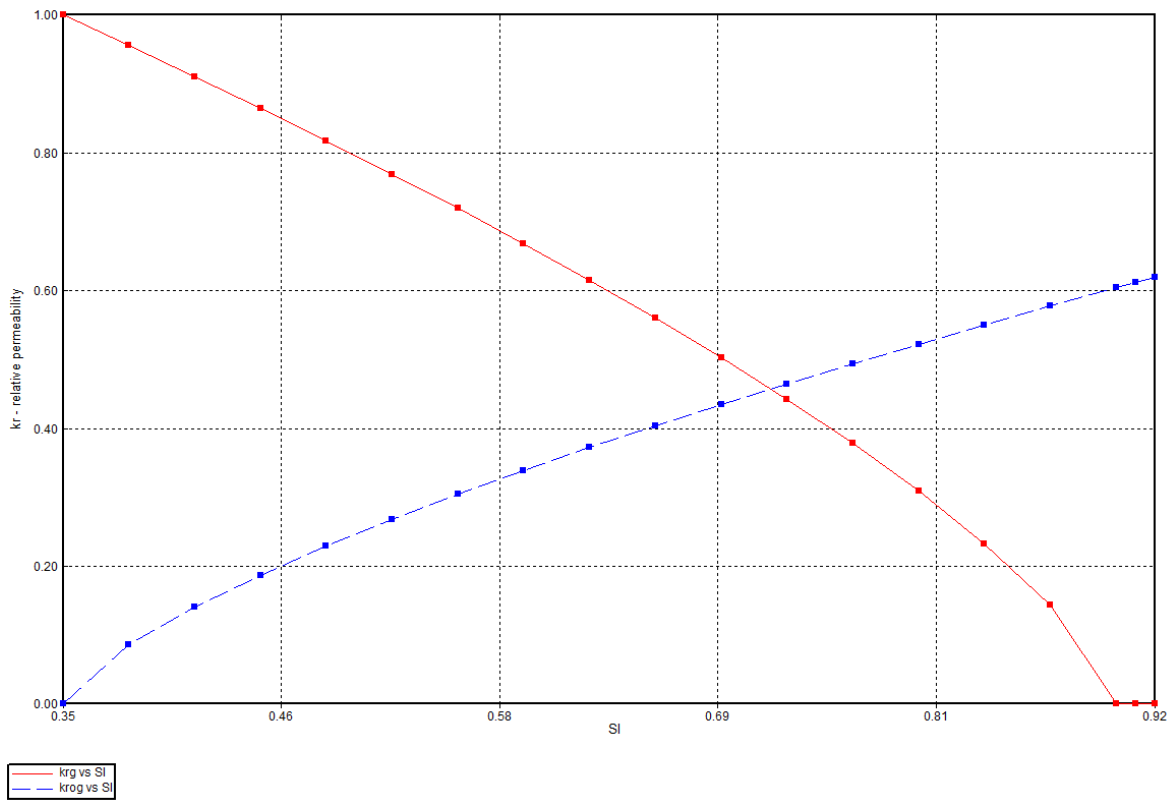


Figure 28 – Relative Permeability Vs. Initial Saturation

Kro by Stone #2 Model, SWSG

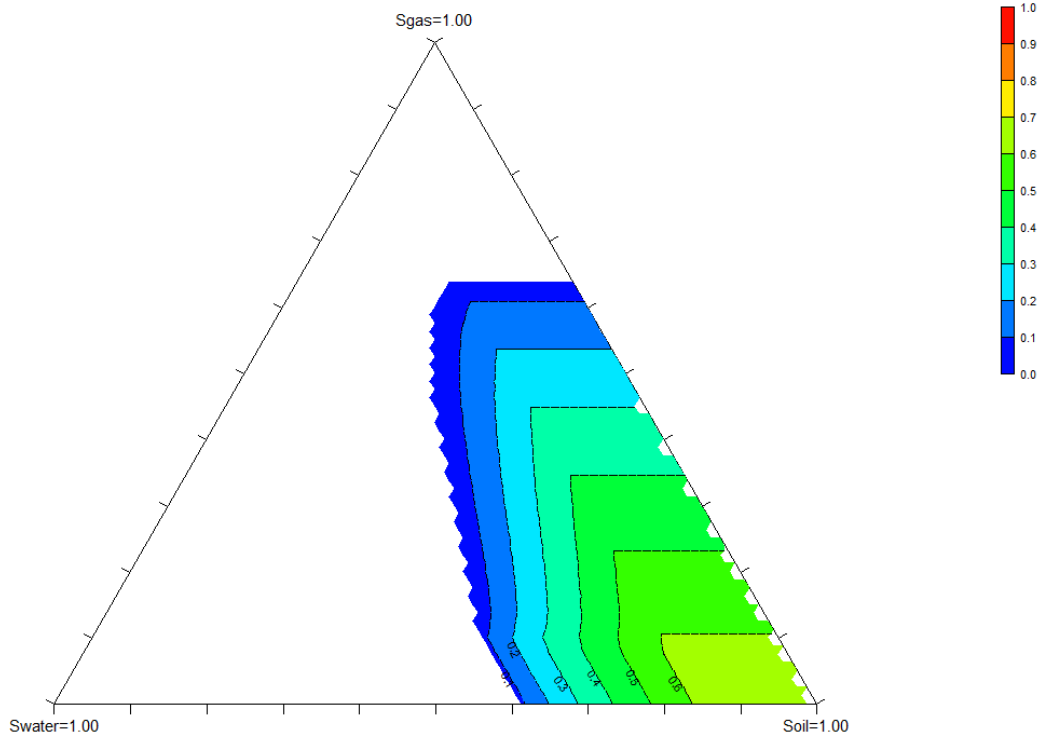


Figure 29 – Phase Diagram

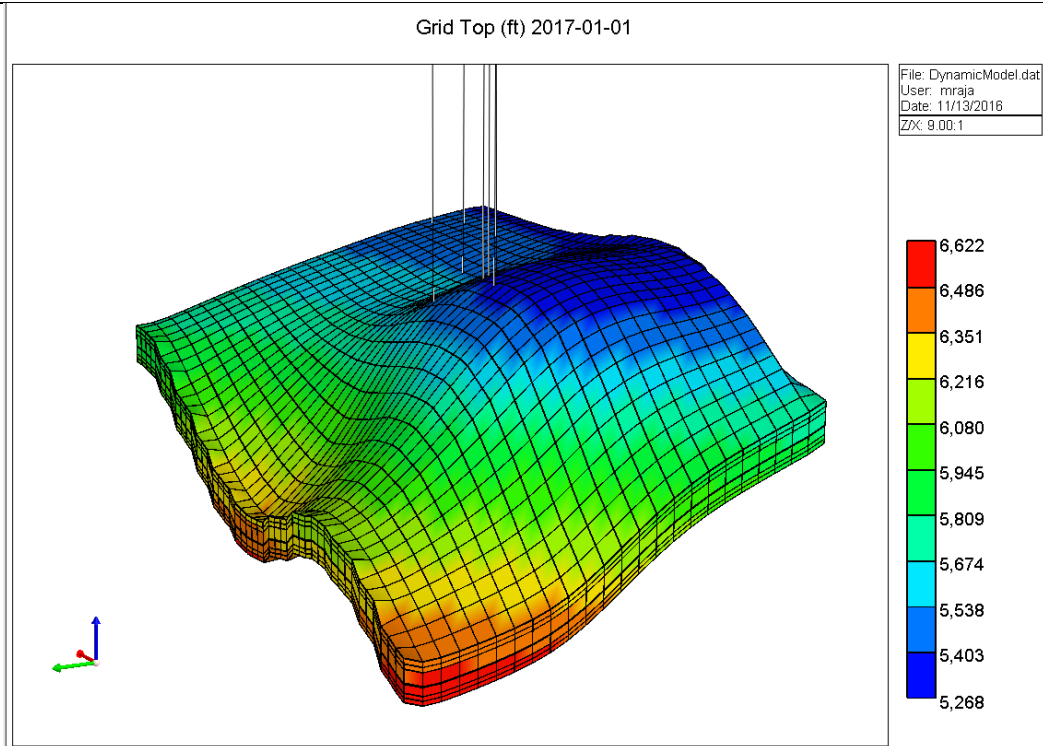


Figure 30 – 3D Contour Perspective View

Sw (Water Saturations) and So (Oil Saturation) from Resistivity Log

Since only one available resistivity log, it is used to correlate the results come from dynamic model below. While calculating the water saturation, Archie’s equation was used which is below;

$$S_w^n = \frac{R_w}{(\Phi^m \times R_t)} \tag{1.3}$$

Based on the Archie’s equation, and the values for porosity, which come from core data and porosity log, water and oil saturation table is below;

THICKNESS(ft)	LITHOLOGY	POROSITY	S _{water}	S _{oil}
27	TENSLEEP A Sandstone	6.435821053	0.228134	0.771866
20	TENSLEEP B DOLOMITE	5.642384015	0.23704	0.76296
61	TENSLEEP B SANDSTONE	10.33388739	0.191458	0.808542
2	TENSLEEP C1 DOLOMITE	15.64470121	0.188465	0.811535
11.4	TENSLEEP C1 SANDSTONE	10.42052	0.224057	0.775943
7	TENSLEEP C2 DOLOMITE	4.1186	0.56219	0.43781
9	TENSLEEP C2 SANDSTONE	4.004	0.678478	0.321522
6	TENSLEEP C3 DOLOMITE	4.413	0.248609	0.751391
11	TENSLEEP C3 SANDSTONE	4.203	0.260693	0.739307
19	TENSLEEP C4 DOLOMITE	4.108677289	0.244563	0.755437
19	TENSLEEP C4 SANDSTONE	10.53698904	0.094967	0.905033
2	D DOLOMITE	NO INFO	NO INFO	NO INFO

Table 7 - Water & Oil Saturation in Different Layers.

Oil Saturation 1978-01-01 J layer: 13

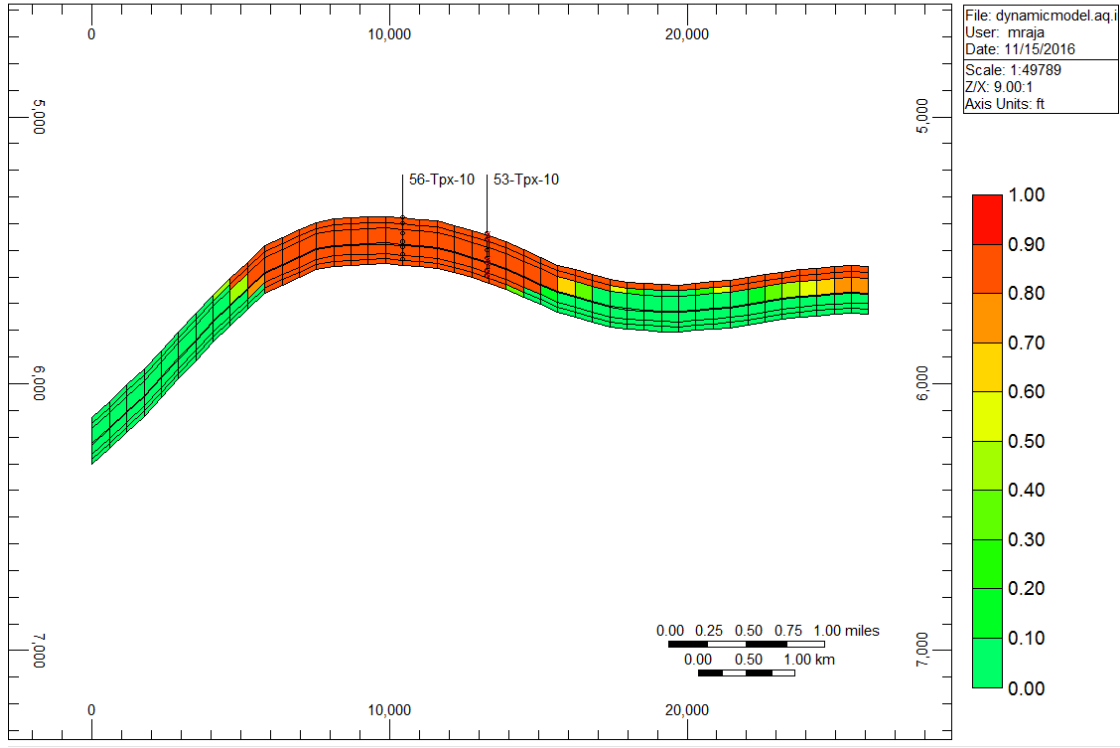


Figure 31 – East West Cut Section Showing Oil Saturation and Oil Water Contact

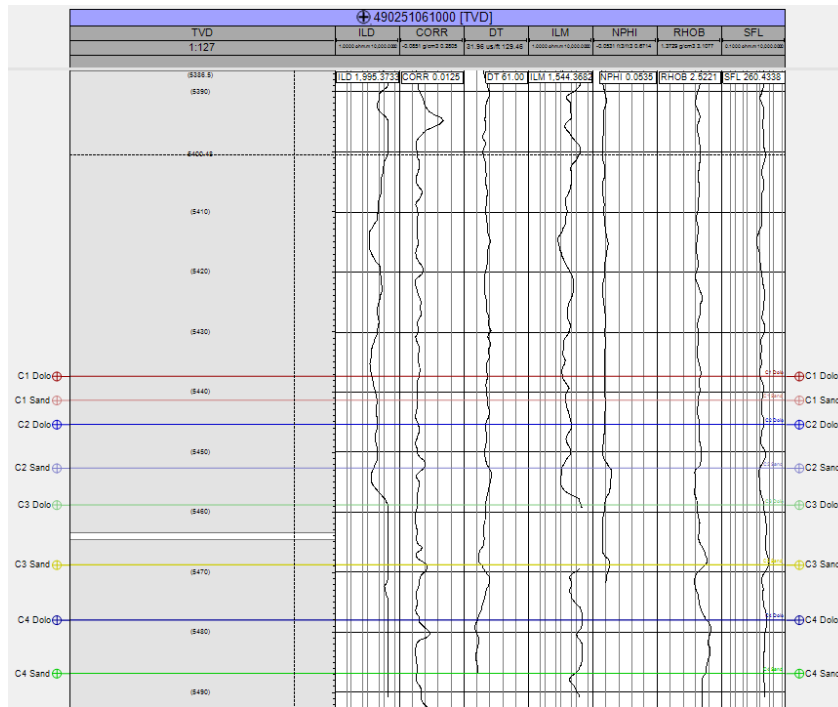


Figure 32 – Example Sw from Resistivity: Well 56-Tpx-10

History Match – Single Porosity with & w/o fractures and Channeling

We started to model our reservoir with the simplest forms and check if our real production history matches with our simulation results (figure 33). Initially, with a single porosity model without fractures we experienced a very large error with a mean of around 70 %. Through a trial and error process we were able to modify our model through bottom hole pressures, as well as fractured rock types to decrease our error with a mean around 6 %. By doing this we were able to understand reservoir production condition which will be used in further CO₂ injection analysis.

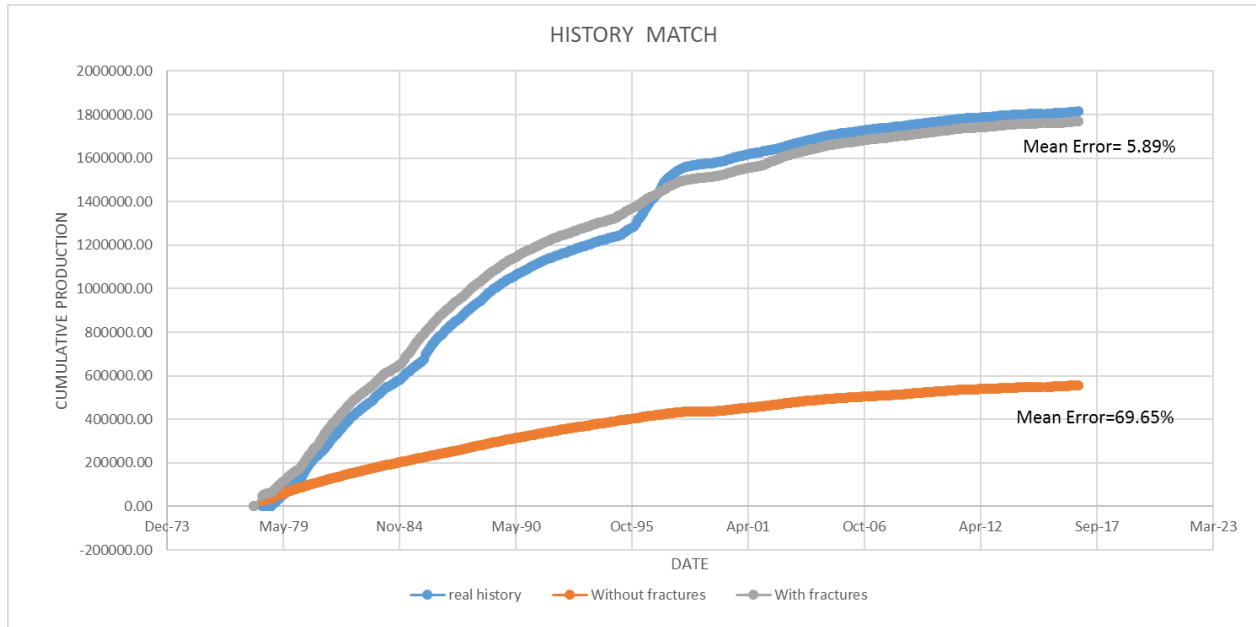


Figure 33 – Simulation production history comparison.

Natural Fractures – Dual Permeability

The simulation tests were run using a single porosity model for simplicity with fractures including channeling modeled into the rock type as not enough data was available for a full dual permeability model because too many assumptions had to be made. From the literature source (Friedmann & Stamp, 2006) we understand that our reservoir is influenced by natural fractures. We have found evidence of our natural fractures in literature and are currently trying to find trends which indicate the flow of water through fractures based on production data and fracture direction.

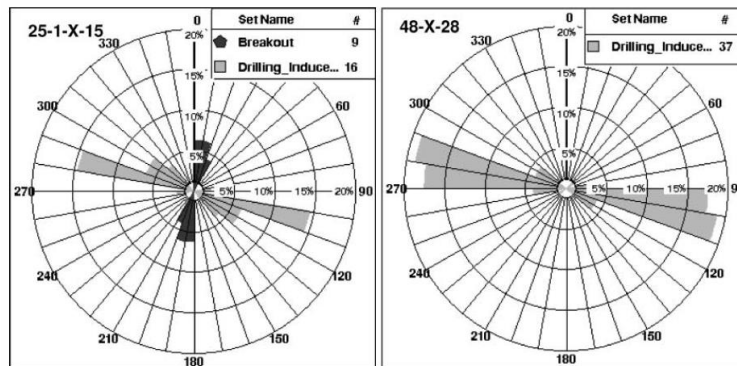


Figure 34 - Rosettes showing the similar orientation of drilling-induced fractures. (Friedmann & Stamp, 2006)

CO₂ Injection Simulations

Reservoir Production & Previous Floods

(S. J. Friedmann, 2005) “The small closure in Section 10 south of the S1 fault network originally contained 3.8 MMbbl (0.6 million m³) of 32° API oil and 11 MMscf (0.31 millionm³) of natural gas. To date, more than 1.8 MMbbl (0.29 million m³) have been produced, and more than 170 million bbl (27 million m³) of water have been produced, in large part because of the strong bottom water drive. Reservoir pressure remains high at 2350 psi (16.2 MPa), and the reservoir temperature is 190° F (88 C). The expected reservoir temperature at this depth (5500 ft. 1676 m) would be roughly 125° F (52 C), assuming a regional geothermal gradient of about 1 °F/100 ft. (2°C/100 m). Initial CO₂ swelling tests show excellent response to CO₂, including oil swelling of more than 20%, interfacial tension reduction of 90%, and fivefold viscosity reduction. This suggests that a Tensleep Sandstone CO₂ flood would be miscible or near miscible, and modeling predicts good enhanced oil recovery response.

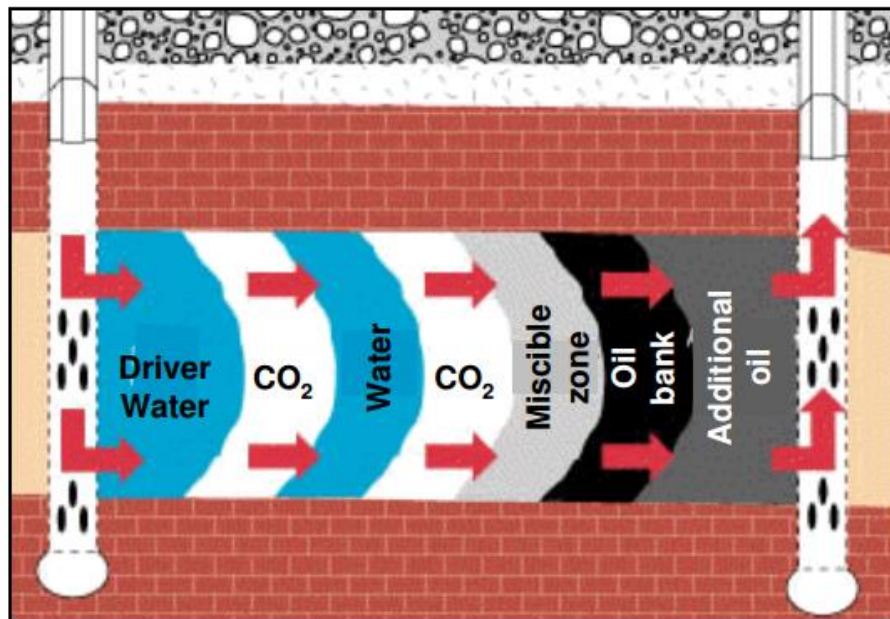


Figure 35 – CO₂ Flood Concept

In Friedmann’s paper he also discusses that “Tensleep has been selected by the project team as the first and most promising reservoir target for specific proposed CO₂-injection experiments. The Tensleep was chosen for several reasons, including depth, relatively small number of wells penetrating the zone, regional extent and oil production significance, excellent cap rock, and local enhanced oil recovery potential. Thus, the Tensleep and the Goose Egg cap rock have been the primary focus of recent characterization and pre-CO₂ baseline studies. A preliminary CO₂-enhanced oil recovery screening study performed by RMOTC laid the groundwork for additional, more thorough review of both of these reservoirs. Other zones at Teapot Dome are also being considered for possible future injection, but will not be covered in this study.” (S. J. Friedmann, 2005)

EOR Strategy of CO₂ Injection

For our EOR model, to determine the best possible CO₂ injection scenario, we considered 2 hypotheses. Each scenario will have a varied CO₂ injection rate range of 300, 400 & 500 M³/d. A cost vs revenue analysis was used to determine which hypothesis will be suggested as the best EOR scenario. Well locations of the producing wells and converted injection well are located in (figure 36).

1st Hypothesis: 14 active wells & 1 Converted shut in well.

- There are 4 prospective shut in wells that can be converted into injection wells based on location. The most suitable one due to its position is 63-Tpx-10.
- This test will determine whether a CO₂ injection is economically feasible.

2nd Hypothesis: 13 active wells & 2 Converted shut in well.

- A test will be conducted to determine whether 2 injection wells can increase production enough to warrant a second injection well.
- The second injection well that will be considered is 55-Tpx-10.

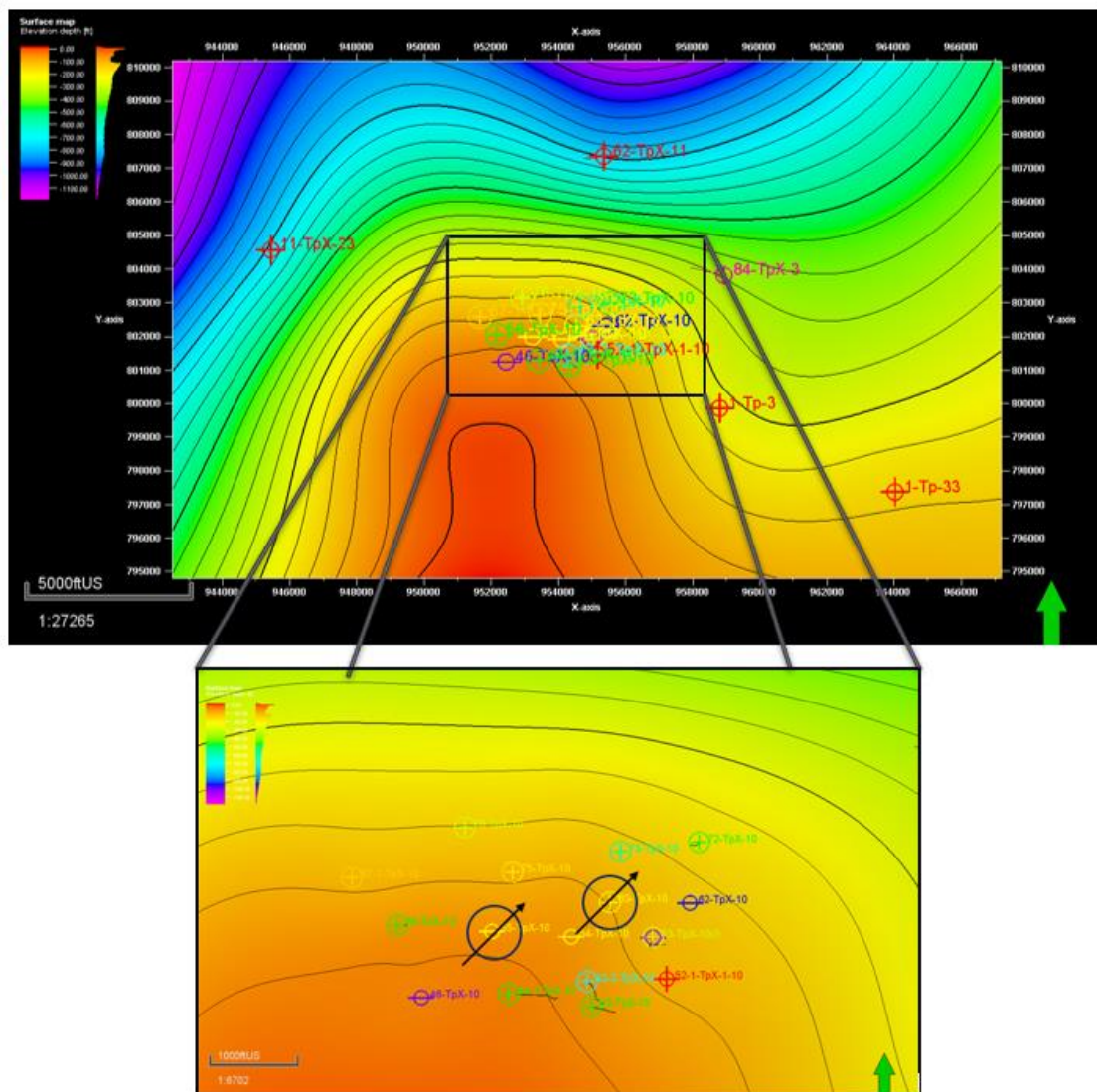


Figure 36 – Contour Map showing Well Locations and converted CO₂ injection wells.

EOR Simulation Results

Based on our simulation results, as we increase the total amount of injected CO₂, the total production also increases. Total production This is shown on the graphs (figure 37 & 38) below as well as (table 8).



Figure 37 – Graphs showing total production vs. injection rates for scenario 1.

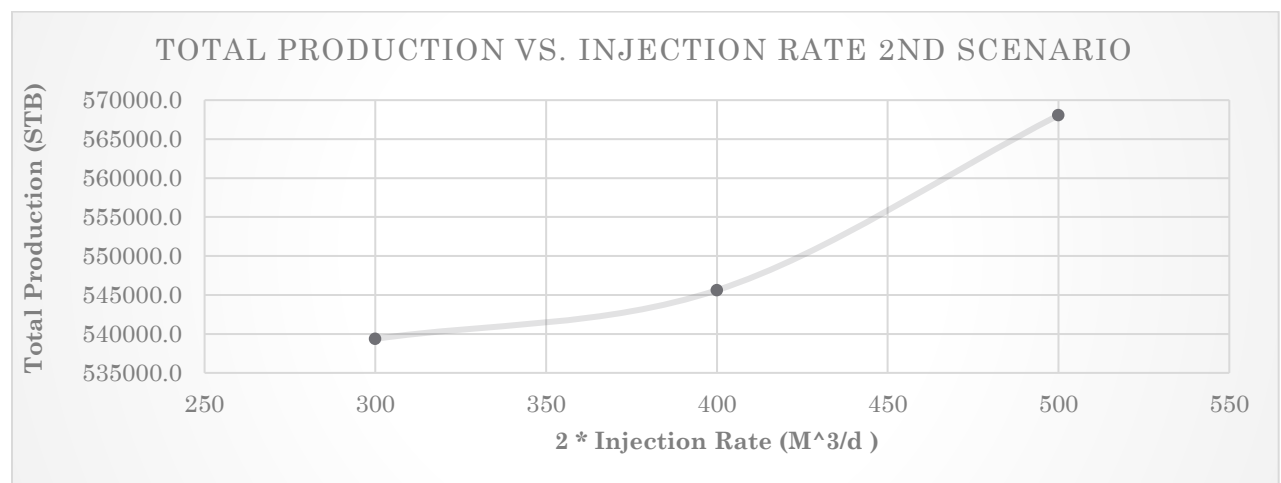


Figure 38 – Graphs showing total production vs. injection rates for scenario 2.

INJECTION RATE(M ³ /D)	EOR	TOTAL PRODUCTION(STB)
500	10.467	523339.0
400	10.337	516829.5
300	9.904	495198.2
2*500	11.361	568064.5
2*400	10.912	545610.6
2*300	10.787	539366.4

Table 8 – Injection rate, EOR percentage and total production relationships

As can be seen from (figure 39) below, increasing injection rates give a higher EOR percentage. Higher injection rates doesn't necessarily mean the EOR percentages increases linearly. Because of this reason, the most profitable case is not the highest injection rate and or EOR percentage as we will describe in the economic analysis section.

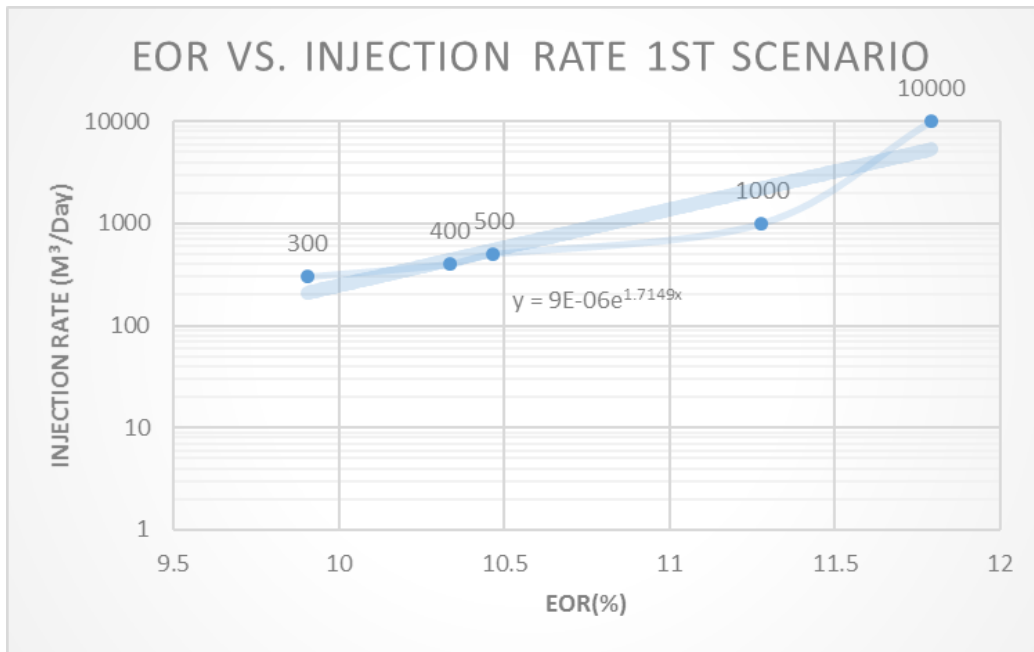


Figure 39 – Graph indicating EOR percentage vs. injection rate.

A cumulative production rate of the most profitable simulation of 400M³/d is plotted against the simulation without any EOR (figure 40). The result shows a 10.34 % EOR rate for a duration of 4 years. The start of the simulation begins at 2017 and ends at the beginning of 2021. The slope of the line starts to decline at the beginning of 2019.

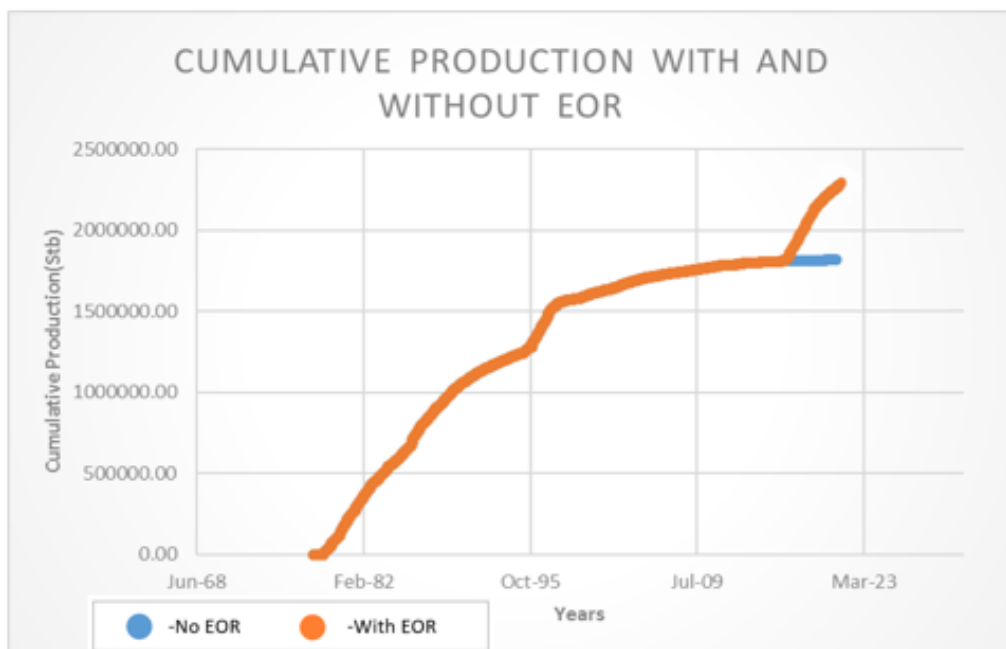


Figure 40 – Cumulative production of 400M³/d injection rate compared with no EOR.

Economic Analysis

Economic Model Analysis

Oil and natural gas industry in 2004 recorded an estimated \$56.2 billion on drilling alone, the most ever spent, compared to \$36.9 billion spent during the previous year, according to results from the 2004 Joint Association Survey on Drilling Costs (JAS) released. The economic model is the main decision making tool that oil companies use to make a call on a project based on profitability with considerations to such costs. In this project we attempt to make reflections and assumptions to have an idea of whether or not it might be profitable to pursue CO₂ EOR operations in Teapot dome. Oil and CO₂ prices are one of the major components in our economic model. The more important part for our economic model is costs associated with CO₂ injection that we would like discuss as well.

Opex Parameters

CO₂ Transportation

(Garcia, 2005) “Anadarko Petroleum Corporation recently completed a new CO₂ pipeline to their Salt Creek field, immediately adjacent to Teapot Dome’s northern field boundary. The pipeline configuration provides for 250 mmcf /day (7.1MMm³/day) of anthropogenic CO₂, which originates at the Shute Creek gas processing facility (owned by ExxonMobil) located in western Wyoming.”

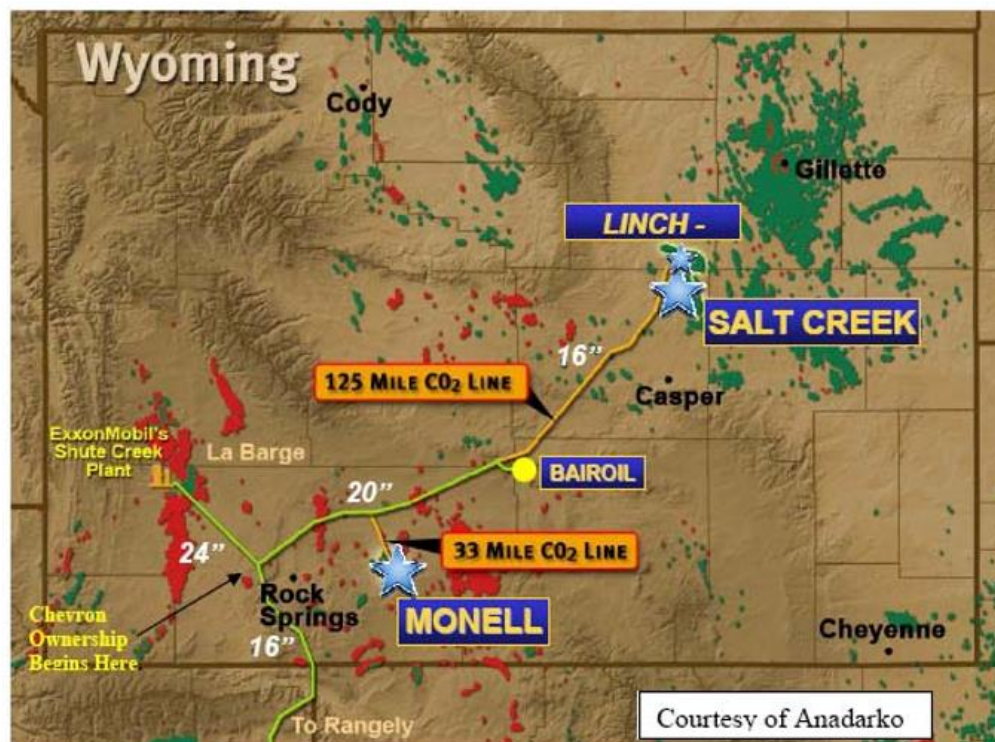


Figure 41 - CO₂ Transportation to Teapot Dome (Garcia, 2005).

CO₂ Transportation Cost:

The optimum flow rate is determined on daily basis based on CO₂ requirements, which is provide from the simulation model and the project revenue. Before the transportation of the CO₂, CO₂ change from gas to liquid state by getting compressed, to determine which the most suitable economic condition for transportation.

$$C_{pump} = \left[(1.11 \times 10^6) \times \left(\frac{W_p}{1000} \right) \right] + 0.07 \times 10^6 \quad (2.1)$$

Where:

C_{comp} : Capital cost of compressor (\$)

C_{pump} : Capital cost of Pump (\$)

M_{train} : CO₂ mass flow rate through each compressor train (kg/s)

N_{train} : Number of parallel compressor trains

$P_{initial}$: Initial pressure of CO₂ (MPa)

$P_{cut-off}$: Pressure at which compression switches to pumping (MPa)

W_p : Pumping power (KW)

The cost of transportation for CO₂ depends on two factors, CO₂ mass flow rate (m) and pipe length (L, as it flows through pipelines). Transported CO₂ is also scaled by terrain factor (F_T) equal 2.7 and Location Factor (F_L) equal 0.1

$$C_{cap} = 9970 \times (m^{0.35}) \times (L)^{0.13} \quad (2.2)$$

$$C_{total} = F_L \times F_T \times C_{cap} \times L \quad (2.3)$$

Where:

C_{cap} : Capital cost

C_{total} : Total cost

Operating and Maintenance Cost

Operating and maintenance costs of our wells in our field can be calculated by using the equation (2.5). This equation and the following Capex parameters were obtained from an EPA journal. (EPA, 2008)

$$\text{Operating and Maintenance Cost} = \left(\$25,000 + \frac{\$3}{ft} \right) / \text{well} \quad (2.4)$$

Capex Parameters

The equations below were used to calculate the total capital expenditure in our economic analysis. Since our EOR strategy involved converting previously active producing well into CO₂ injection wells, the converting cost were taken into account as well as other facility upgrades, well head control equipment and compressor and pipe costs.

$$\text{Injection Well Converting Cost} = \left(\frac{\$280}{ft} \right) / \text{well} \quad (2.5)$$

$$\text{Facilities Upgrades} = \left(\frac{\$20,000}{\text{Well}} \right) \quad (2.6)$$

$$\text{Well Head Control Equipment} = \$500 * (\text{Ton CO}_2)^{0.6} \quad (2.7)$$

$$\text{Compressor and Pipe Cost} = \frac{\$1,500}{hp} + \frac{\$60,000}{\text{inch mile}} \quad (2.8)$$

Most Profitable Scenario 1: 14 producers & 1 injectors at 400M³/d.

An example of our most profitable economic model is shown in (figure 42) at 400M³/d. The cumulative oil production was produced by the simulation and the corresponding well conversion parameters were run through the equations in the CAPEX and OPEX parameters to produce the economic models. The models for all the scenarios are located in Appendix III.

ECONOMIC MODEL FOR 400

	2017	2018	2019	2020
Oil Barrel prices	51.6	52.4256	53.2644096	54.11664015
Oil production (Stb/day)	461.7058085	382.9145186	318.9220658	252.4288211
Total oil Production (Stb)	168522.6201	139763.7993	116406.554	92136.51969
Total Gross Revenue	8695767.197	7327201.036	6200326.373	4986118.881
ROYALTY BURDEN	-1086970.9	-915900.1295	-775040.7967	-623264.8601
CAPEX				
INJECTION WELL COST(\$280/FT)	-1540000			
FACILITIES UPGRADE(\$20000/WELL)	-280000			
COMPRESSOR AND PIPE COST(\$1500/HP+\$60000/inch-mile)	-1180000			
WELL HEAD CONTROL EQUIPMENT(\$500*TON^0.6)	-43875.19583			
OPEX				
OPERATING AND MAINTANACE COSTS (\$25000+3\$/FT PER WELL)	-622500	-632460	-642579.36	-652860.6298
TOTAL CO2 COST(TRANSPORTATION, STORAGE, CO2)	-115248.528	-117092.5044	-118965.9845	-120869.4403
PROFIT(PRETAX)	\$ 3,827,173	\$ 5,661,748	\$ 4,663,740	\$ 3,589,124
TOTAL PROFIT	\$ 17,339,982.31			

Figure 42 – Economic model used in calculating total profit for the most profitable case.

Profit

The profits for each year of the injection ranges in scenarios 1 and 2 were plotted in (figures 43 & 44). In the first year we expect a lower profit value because of the high capital expenditure costs. We also experienced the most profit in the second year for all cases of both scenarios. Due to decline rate of production we started to get lower profits for subsequent years.

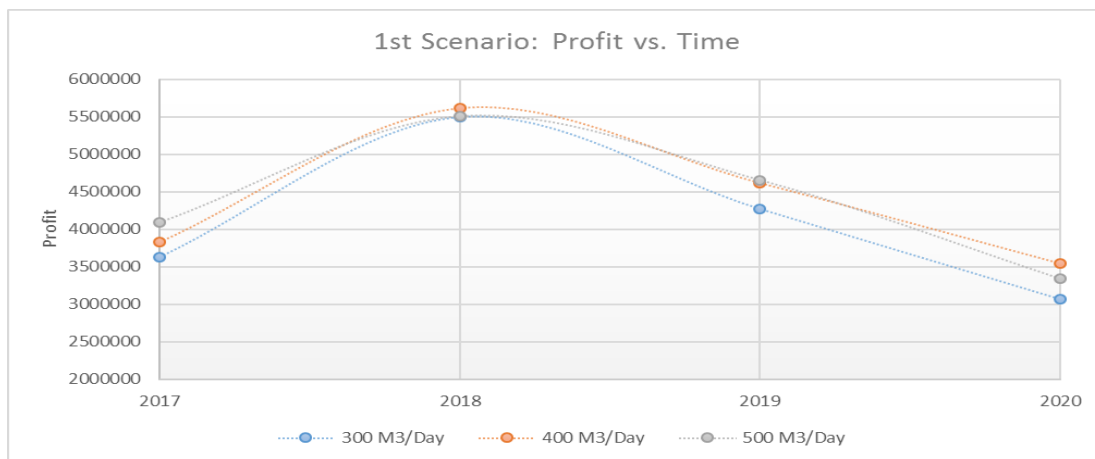


Figure 43 – Scenario 1: Profit vs. Time at variable injection rates.

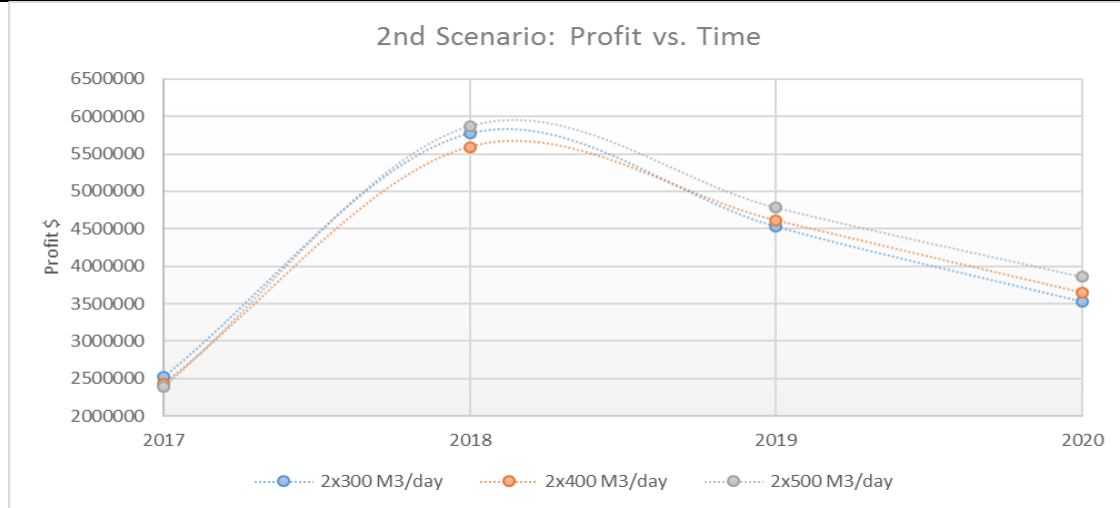


Figure 44 – Scenario 2: Profit vs. Time at variable injection rates.

Summary

The project is a CO₂ injection enhanced oil recovery of the Tensleep formation located in Wyoming's Teapot Dome field at section 10 (T38-39N R78W). This section briefly summarizes and reviews the sequence of events and their significant.

- An in-depth literature review of the field and formation was conducted to familiarize the team with the relevant geologic information.
- A comprehensive geological evaluation was conducted on this field, to determine the characteristics of the reservoir.
- A static model was produced detailing the shape and properties, such as the porosity, permeability trends of the reservoir.
- The dynamic model was used to simulate production history of the field by using the properties which was gathered during the computational analysis of the static model.
 - Properties calculated to perform the dynamic model include water and oil saturation, bottom hole pressures, oil water contact, fracture properties and trends, compressibility factors, and PVT and critical properties.
- After the dynamic model performed within a 6% error range of the preexisting production of the reservoir on a well by well basis as well as on a field wide scale, we started to test different EOR simulation hypothesis with variable injection rates as well as increasing the number of injection wells.
 - This was done to run prediction test in order to gather data on how the reservoir will supposedly produce in the future with EOR and without EOR
- An Economic model was produced in order to compare the results of each scenario and determine the most profitable case.
- Conclusion and recommendations were then made based on the assessment of the economic model as well as general observation seen during the process of completing the project.

Conclusions & Recommendations

Based on the results from the simulations and conclusions derived from them, our team has suggested a few recommendations. Some are applicable through our testing and others are suggestions that came about through our testing but were not part of the scope of our project and should be looked at in more detail before any action is taken.

EOR Strategy

- Based on our economic analysis, we suggest a four-year strategy with a low rate CO₂ Injection of 400 M³/d. This will produce a profit of \$17.3 Million.
- A low rate is recommended partly because the producing formation is not a large area. The scatter of active wells is within a 1 mile by 1 1/2-mile rectangular area, which is strongly affected by the water drive of the aquifer below.
- Oil and CO₂ prices could change the economic situation of the proposed CO₂ injection strategy. Meaning if oil prices increase or CO₂ prices decrease, it could be more economical to increase the rate of CO₂ to ultimately recover more oil which will increase profit revenues as well as extend the economic life of the wells producing from the Tensleep formation within the Teapot Dome field.

Solving the Water Coning Issue.

- It's clear through the production data that the wells in the Tensleep formation are producing extremely large amounts of water (95% water cut). This production is mostly due to water coning through fractures since logs do indicate very low initial water saturations.
- The lower producing formations such as C4 sand are very close to the aquifer below and some wells are possibly even producing in submerged zones. The wells that are possible producing from the aquifer are the northern perimeter wells that include 72-Tpx-10, 73-Tpx-10, 75-Tpx-10, 76-Tpx-10, and 67-Tpx-10. We understand this because of the severely large water cut in these well over the wells producing higher up on the formation.
- To mitigate this, we suggest well completion methods to seal off the lower perforations such as spacers. The zone C4 sand could be plugged from most wells producing larger than average water levels. As we suspect this formation to be flooded with water due to production and pressure differential causing coning.
- Another possible solution would be to lower production rates while simultaneously injecting CO₂, this would stabilize the bottom hole pressures and reduce the coning effect of water. Reducing the water cut from (95%) could increase the economic limit of the formation.

Appendix I - Risk Analysis

In our risk analysis our team listed the risk which are known and unknown to us that can affect the outcomes of our project. The risk management of this project will help We also made several risk matrices that reflect these risks.

Known Risks

There are some know risks associated with our project listed below that can cause minor variations in productivity as well as the consequences related to the problem. These problems have a high probability to occur or have already. They include:

1. Apparently the data we originally received is missing some documents and in its current state cannot be opened.
 - a. This will affect our teams' ability to produce the static model at our scheduled time.
 - b. It also may delay and push back other deadlines.
 - c. Data had to be occurred from (RMOTC).
2. Having difficulties learning new programs
 - a. This can substantially delay our project deliverables such as our static and dynamic models
 - b. Both models are created using different software that the results are dependent on each other.
3. Trouble with communication since most of our members are international students
 - a. Instructor and classmates may not understand when we are trying to communicate.
 - b. Effect on project grading outcomes.
4. Attendance of team members in meetings and class. (figure 45).
 - a. Important information delivered in class may be missed.
 - b. Could result in missed information in deliverables,
5. Accuracy of static model showing satisfactory results. (figure 46)
 - a. The accuracy of our static model will affect our dynamic model and CO₂ injection simulations.

Mitigation Strategy

1. Due to time constraints of the semester, we just had to put in the extra effort and time to produce the deliverables. Our schedule changed throughout the semester to reflect the current progress of each deliverable.
2. To learn the new programs our team met with several Ph. D student to help us understand petrel and CMG.
3. In effect, the team had to increase our communication skills to be able to adequately get our point across and produce correct deliverables.
4. The team had to encourage and communicate with each other so that important information could be delivered and conveyed to absent team members.
5. A close observation is made to insure accuracy of our models by referencing other sources and comparing the results. Some inaccuracies such formation depth is unknown but is modeled based on a trend of other more well-known surfaces.

Known Unknown Risks

Some foreseeable risks possibilities are listed below as well as possible consequences. Their probability, occurrence and or effect is not known.

1. Team Member illness, injury or forced absence.
 - a. Any missing group members can reduce manpower to complete tasks.
 - b. This will also increase the amount of work other member need to accomplish.
2. Loss of Project data
 - a. If we complete a project task and it is lost and needs to be redone this can take precious time away from completing other tasks.
3. Cooperation and communication problem within group
 - a. It's possible that our group will argue about which direction to take
4. Data Shortage
 - a. The shortage of log data and core data will affect the outcome of the static model.
 - b. Correlations are hard to make between core and log.
5. Scope Creep
 - a. When working on our project we may come across additional obstacles that can lead to scope creep which will take more of our time.

Mitigation Strategy

1. Our team was divided into two groups that focused on different task as mentioned in the project planning section.
2. Data was backed up on multiple devices as well as saved in cloud storage systems. Multiple version of each deliverable were saved after progress had been made. Also, screenshots were taken of data inputs so that they could be easily reproduced.
3. Meeting were held frequently in order to discuss each direction. The advantages and disadvantages of the different directions were also discussed and decisions were made as group.
4. Certain decisions were made to either spend time to collect the necessary data or to make good assumption and validate them later with results.
5. Advantages and disadvantages of various scope creep as they appeared throughout the project were discussed as a group and decisions were made on whether the scope is beneficial or not.

Risk Matrixes

The risk matrix reflect points made in the known risk portion of the risk analysis and a more thorough discussion can be found there.

Team members not showing up to Class

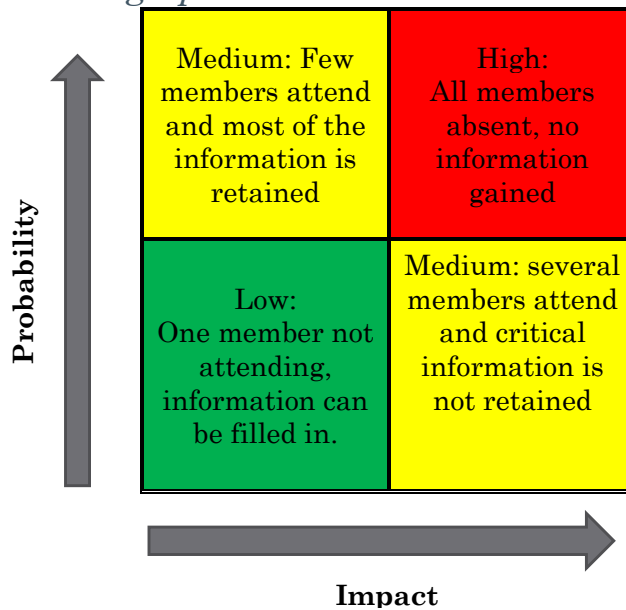


Figure 45 – Risk Matrix associated with team members not showing up to class

Static model not showing satisfactory results

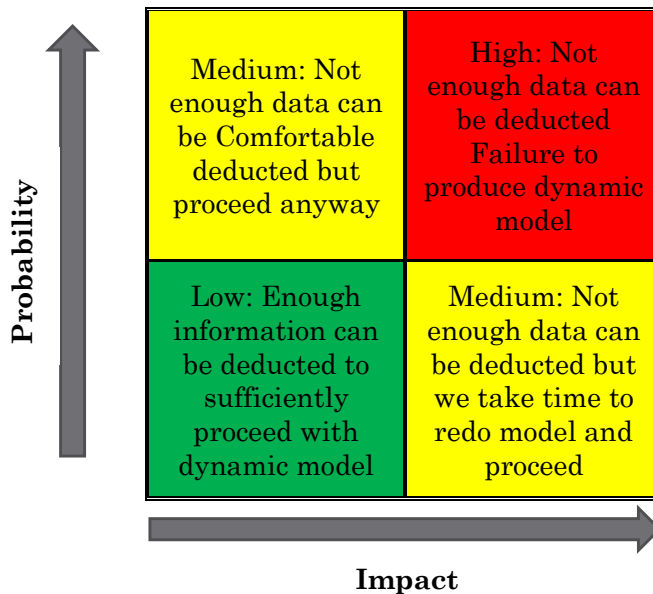


Figure 46 - Risk Matrix of satisfactory static model implications

Appendix II - Data Quality Control & Review

While conducting the project we had to continually check and analyze the data we were using in order to insure accuracy. Some of the measures are detailed below:

- Initially, the data we received was corrupted and had to see further sources. We received public data from the Rocky Mountain Oilfield Testing Center (RMOTC). Obtained from the following website: http://wiki.seg.org/wiki/Open_data
- To determine porosity, we correlated and compared the errors from core analysis and log data. (Table - 3)
- Within water saturation calculations, we checked our findings with results from literature and the CMG water oil contact figure (Figure - 31)
- Production data was obtained from Wyoming Gas Oil Commission and compared it to the production data we received, as well as included new data for well we did not have historical production data.
- Wells penetrating into the Tensleep formation were selected from the Teapot Dome field and compared to literature.

Appendix III – Economic Models

RATE(M3/D)	MASS(TON)	RATE(TON/DAY)	TOTAL CO2 COST	RATE(FT3/D)
500	2888	7.912	192080.9	17657
400	2310.4	6.330	153664.7	14125.6
300	1732.8	4.747	115248.5	10594.2

Table 9 – Conversion of CO₂ to different variables and its costs.

ECONOMIC MODEL FOR 300

	2017	2018	2019	2020
Oil Barrel prices	51.6	52.4256	53.2644096	54.11664015
Oil production (Stb/day)	451.6589673	377.6564096	300.5107323	226.8811694
Total oil Production (Stb)	164855.5231	137844.5895	109686.4173	82811.62683
Total Gross Revenue	8506544.99	7226585.312	5842382.257	4481487.01
ROYALTY BURDEN	-1063318.124	-903323.1639	-730297.7822	-560185.8762
CAPEX				
INJECTION WELL COST(\$280/FT)	-1540000			
FACILITIES UPGRADE(\$20000/WELL)	-280000			
COMPRESSOR AND PIPE COST(\$1500/HP+\$60000/inch-mile)	-1180000			
WELL HEAD CONTROL EQUIPMENT(\$500*TON^0.6)	-43875.19583			
OPEX				
OPERATING AND MAINTANACE COSTS ((\$25000+3\$/FT PER WELL)	-622500	-632460	-642579.36	-652860.6298
TOTAL CO2 COST(TRANSPORTATION, STORAGE, CO2)	-153664.704	-156123.3393	-158621.3127	-161159.2537
PROFIT(PRETAX)	\$ 3,667,062	\$ 5,534,679	\$ 4,310,884	\$ 3,107,281
TOTAL PROFIT	\$ 16,253,537.96			

Figure 47-A – Economic model of 1st scenario at 300M³/d

ECONOMIC MODEL FOR 400

	2017	2018	2019	2020
Oil Barrel prices	51.6	52.4256	53.2644096	54.11664015
Oil production (Stb/day)	461.7058085	382.9145186	318.9220658	252.4288211
Total oil Production (Stb)	168522.6201	139763.7993	116406.554	92136.51969
Total Gross Revenue	8695767.197	7327201.036	6200326.373	4986118.881
ROYALTY BURDEN	-1086970.9	-915900.1295	-775040.7967	-623264.8601
CAPEX				
INJECTION WELL COST(\$280/FT)	-1540000			
FACILITIES UPGRADE(\$20000/WELL)	-280000			
COMPRESSOR AND PIPE COST(\$1500/HP+\$60000/inch-mile)	-1180000			
WELL HEAD CONTROL EQUIPMENT(\$500*TON^0.6)	-43875.19583			
OPEX				
OPERATING AND MAINTANACE COSTS (\$25000+3\$/FT PER WELL)	-622500	-632460	-642579.36	-652860.6298
TOTAL CO2 COST(TRANSPORTATION, STORAGE, CO2)	-115248.528	-117092.5044	-118965.9845	-120869.4403
PROFIT(PRETAX)	\$ 3,827,173	\$ 5,661,748	\$ 4,663,740	\$ 3,589,124
TOTAL PROFIT	\$ 17,339,982.31			

Figure 47-B – Economic model of 1st scenario at 400M³/d

ECONOMIC MODEL 1 INJECTORS FOR 500

	2017	2018	2019	2020
Oil Barrel prices	51.6	52.4256	53.2644096	54.11664015
Oil production (Stb/day)	482.1917808	380.8219178	325.5863014	245.2054795
Total oil Production (Stb)	176000	139000	118839	89500
Total Gross Revenue	9081600	7287158.4	6329889.172	4843439.294
ROYALTY BURDEN	-1135200	-910894.8	-791236.1466	-605429.9117
CAPEX				
INJECTION WELL COST(\$280/FT)	-1540000			
FACILITIES UPGRADE(\$20000/WELL)	-280000			
COMPRESSOR AND PIPE COST(\$1500/HP+\$60000/inch-mile)	-1180000			
WELL HEAD CONTROL EQUIPMENT(\$500*TON^0.6)	-43875.19583			
OPEX				
OPERATING AND MAINTANACE COSTS (\$25000+3\$/FT PER WELL)	-622500	-632460	-642579.36	-652860.6298
TOTAL CO2 COST(TRANSPORTATION, STORAGE, CO2)	-192080.88	-195154.1741	-198276.6409	-201449.0671
PROFIT(PRETAX)	\$ 4,087,944	\$ 5,548,649	\$ 4,697,797	\$ 3,383,700
TOTAL PROFIT	\$ 17,326,557.13			

Figure 47-C – Economic model of 1st scenario at 500M³/d

ECONOMIC MODEL FOR 2*300

	2017	2018	2019	2020
Oil Barrel prices	51.6	52.4256	53.2644096	54.11664015
Oil production (Stb/day)	495.0478631	400.9311148	322.0330239	259.7040515
Total oil Production (Stb)	180692.47	146339.8569	117542.0537	94791.97881
Total Gross Revenue	9323731.453	7671954.801	6260808.095	5129823.407
ROYALTY BURDEN	-1165466.43	-958994.35	-782601.01	-641227.93
CAPEX				
INJECTION WELL COST(\$280/FT)	-3080000			
FACILITIES UPGRADE(\$20000/WELL)	-260000			
COMPRESSOR AND PIPE COST(\$1500/HP)	-1380000			
WELL HEAD CONTROL EQUIPMENT(\$500*TON^0.6)	-66483.93777			
OPEX				
OPERATING AND MAINTANACE COSTS	-622500	-632460	-642579.36	-652860.6298
TOTAL CO2 COST(TRANSPORTATION, STORAGE, CO2)	-230500	-234188	-237935.008	-241741.9681
PROFIT(PRETAX)	2518781.08	5846312.45	4597692.72	3593992.88
TOTAL PROFIT	16153907.19			

Figure 47-D – Economic model of 2nd scenario at 300M³/d

ECONOMIC MODEL FOR 2*400

	2017	2018	2019	2020
Oil Barrel prices	51.6	52.4256	53.2644096	54.11664015
Oil production (Stb/day)	495.0610585	395.2973516	332.1826484	272.2808593
Total oil Production (Stb)	180697.2863	144283.5333	121246.6667	99382.51366
Total Gross Revenue	9323979.975	7564150.805	6458132.116	5378247.729
ROYALTY BURDEN	-1165497.50	-945518.85	-807266.51	-672280.97
CAPEX				
INJECTION WELL COST(\$280/FT)	-3080000			
FACILITIES UPGRADE(\$20000/WELL)	-260000			
COMPRESSOR AND PIPE COST(\$1500/HP)	-1380000			
WELL HEAD CONTROL EQUIPMENT(\$500*TON^0.6)	-79031.515			
OPEX				
OPERATING AND MAINTANACE COSTS	-622500	-632460	-642579.36	-652860.6298
TOTAL CO2 COST(TRANSPORTATION, STORAGE, CO2)	-307328	-312245.248	-317241.172	-322317.0307
PROFIT(PRETAX)	2508654.48	5673926.71	4691045.07	3730789.10
TOTAL PROFIT	16194979.5			

Figure 47-E – Economic model of 2nd scenario at 400M³/d

ECONOMIC MODEL FOR 2*500

	2017	2018	2019	2020
Oil Barrel prices	51.6	52.4256	53.2644096	54.11664015
Oil production (Stb/day)	498.2578609	417.4979891	347.9149909	289.9291591
Total oil Production (Stb)	181864.1192	152386.766	126988.9717	105824.1431
Total Gross Revenue	9384188.552	7988967.641	6763992.602	5726847.07
ROYALTY BURDEN	-1173023.57	-998620.96	-845499.08	-715855.88
CAPEX				
INJECTION WELL COST(\$280/FT)	-3080000			
FACILITIES UPGRADE(\$20000/WELL)	-260000			
COMPRESSOR AND PIPE COST(\$1500/HP)	-1380000			
WELL HEAD CONTROL EQUIPMENT(\$500*TON^0.6)	-90353.77768			
OPEX				
OPERATING AND MAINTANACE COSTS	-622500	-632460	-642579.36	-652860.6298
TOTAL CO2 COST(TRANSPORTATION, STORAGE, CO2)	-384161.76	-390308.3482	-396553.2817	-402898.1342
PROFIT(PRETAX)	2394149.45	5967578.34	4879360.89	3955232.42
TOTAL PROFIT		16315529.89		

Figure 47-F – Economic model of 2nd scenario at 500M³/d

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