RESERVOIR CHARACTERIZATION AND MODELING HYDRAULICALLY FRACTURED WELLS IN THE TUSCALOOSA MARINE SHALE

A Non-Thesis

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Trace B. Smith

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ABSTRACT

The objective of this study is to discuss a workflow for evaluating reservoir performance of hydraulic fractured wells in the ultra-tight Tuscaloosa Marine Shale (TMS) through production history matching utilizing Computer Modeling Group's black oil reservoir simulator. The Tuscaloosa Marine Shale is a highly potential unconventional shale reservoir located near the Gulf Coast in central Louisiana and portions of Southwest Mississippi with an estimated 7 billion barrels of recoverable oil (John et al 1997). Oil and gas companies operating in the play have reported ultimate recoveries estimated to be greater than 800,000 cumulative barrels of oil per well. Published literature and research on the shale formation and reservoir properties are limited, therefore this work is aimed to approximate formation and hydraulic fracture properties for wells drilled in the TMS through production history matching.

A non-stimulated vertical well completed in the TMS, the Winfred Blades #1, will be the control well in characterizing reservoir matrix properties through numerical simulations. Reservoir models were then constructed for five stimulated horizontal wells located in near proximity of the control well in northern Tangipahoa Parish, Louisiana. The models are comprised of a three-layered Cartesian grid with refined cell blocks representing fluid flow through a cluster of induced fractures for a multi-staged hydraulic fractured well. Formation rock properties, fracture permeability, and fracture half-length are subsequently estimated through flow simulations by matching the initial production, cumulative oil recovery, and decline curve trends to the field history. For simplicity, the complex fracture network in the model is represented as a cluster of refined grid cells (i-direction) per stimulated stage and is characterized by a series of rectangular, bi-wing fractures in which various fracture permeability and half-lengths were analyzed in the study.

Fracture azimuth and lengths can be determined from microseismic data and through industry software programs given the hydraulic fracture design parameters such as volume pumped, proppant, and pressure; however, this data is not always readily available. Therefore, the calibrated reservoir models for hydraulically fractured wells outlined in this study is to provide a proxy for estimating fracture attributes in the Tuscaloosa Marine Shale through production history matching. Production history match results from six wells drilled and completed in the Tuscaloosa Marine Shale indicates rock properties remain consistent in the regional area of interest (Northern Tangipahoa Parish, Louisiana). The estimated matrix permeability and porosity is 0.06 millidarcy and 5%, respectively. The reservoir simulation results for the five stimulated wells shows the permeability in the stimulated clusters is approximately 50-150 mD and the average modeled fracture half-length ranges between 300-800'. A detailed analysis is discussed in the following sections for five hydraulically fractured wells in the TMS, encompassing of completion design criteria, rock properties, and characterization of induced fractures (reservoir modeling), to provide further insight into the productivity of wells drilled and completed in the highly potential Tuscaloosa Marine Shale.

1. INTRODUCTION

An actively producing oil well in the eastern section of the Tuscaloosa Marine Shale, Winfred Blades #1, is the only known non-stimulated vertical well drilled in the region. Calibration of a black oil reservoir model is based on public information reported to the state, published literature on the TMS formation, and communication with the current operator regarding the well history in order to characterize formation properties through production history matching. The estimated matrix properties validated through the simulations are then input values for the stimulated reservoir models to approximate fracture attributes for surrounding hydraulically fractured wells in the shale play (John et al 1997).

1.1 TUSCALOOSA MARINE SHALE

The Tuscaloosa Marine Shale (TMS) is an unconventional shale formation spanning approximately 2.5 million acres throughout Central and Southeastern portions of Louisiana and parts of Southwestern Mississippi (Fig. 1). A study in 1997 by the Louisiana State University's Basin Research Institute estimates the TMS could contain 7 billion barrels of oil resulting in companies such as Goodrich Petroleum, Halcon Resources, Encana, and others to become significantly active in the formation.

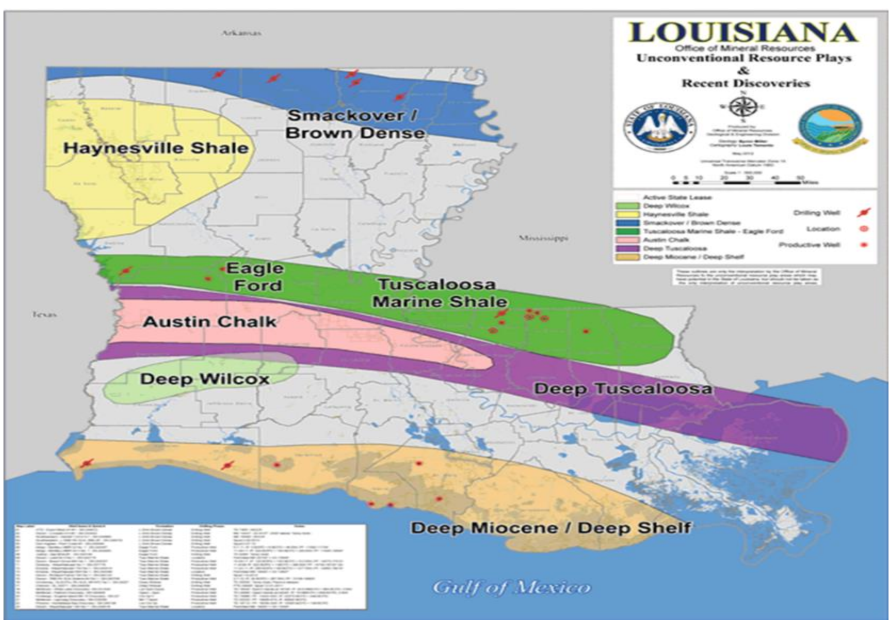


Fig. 1 - Tuscaloosa Marine Shale Geographical Map; Louisiana Office of Mineral Resources

The high pressured TMS formation consists of organic rich (total organic content: 1-4%), highly laminated shale, with thin inter-beds of silt, fine grained sand, carbonate, and limestone layers which ranges from an inch to three feet thick. The TMS thickness can range upwards to 500-800' and dips towards the Southwest with average depth interval of 10,000'-17,000' TVD (Fig. 2). Core samples from Callon Petroleum's Cutrer #2 well drilled in Tangipahoa Parish were taken from depths of 11,550' to 11,653' TVD. Measurements from the cores show permeability ranged from less than 0.01 mD to roughly 0.06 mD, porosity was 2.3-8.0%, gas saturation was 0.20-1.3% and water saturation was 31.8-88.2% (John et al 1997). Geological analysis indicates the TMS rock type to be composed of 25% calcite, 25% quartz, and 50% clay, which has slightly higher clay content compared to other unconventional formations such as the Eagle Ford. The upper portions of the TMS is comprised of higher clay content while the lower third of the rock is more brittle and encompasses more natural fracturing (Darbonne 2014).

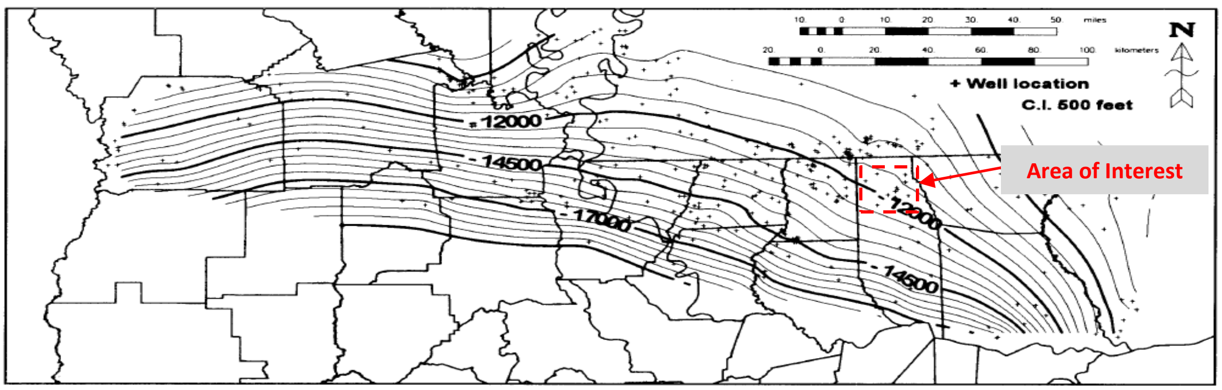


Fig. 2 - Top of Tuscaloosa Marine Shale structure map; John et al 1997

1.2 WINFRED BLADES #1

In this work, the Winfred Blades #1 well is utilized as a control in order to quantify formation rock properties. The Winfred Blades #1 well located in Northern Tangipahoa Parish (Fig. 3), is an actively producing oil well drilled and completed in the Tuscaloosa Marine Shale formation by Texas Pacific Oil Company in 1977. Located in the Little Silver Creek field, the vertical well was drilled to 12,162' (TVD) and perforated 11 different zones ranging from 11,072'-11,664'. The well has produced 26,529 barrels of oil between April 1978 and November 2014. The current operator confirmed the well is currently flowing naturally, but was placed on a pumping unit in the late 1980's in an attempt to increase production, but was returned to a flowing well shortly afterwards as the drawdown did not yield a significant increase in oil production. A detailed wellbore diagram obtained from the initial drilling and completion report (SONRIS, 2015) is shown in Appendix A.

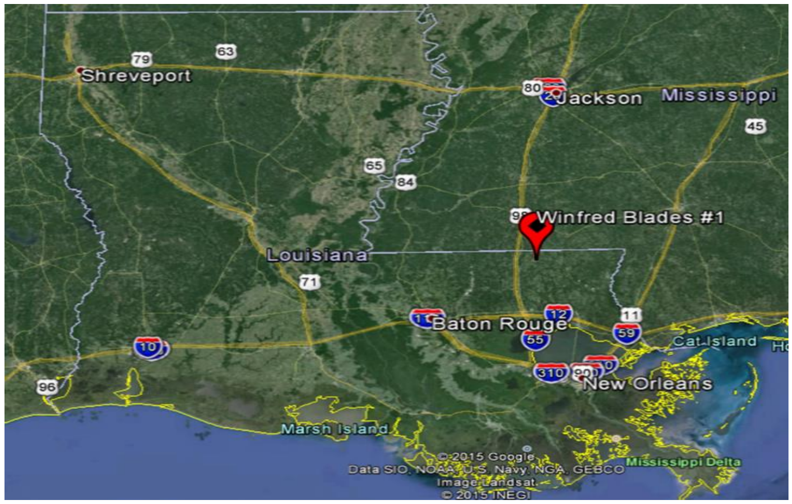


Fig. 3 - Geographical map of the Winfred Blades #1 (Google Maps)

1.3 WELL LOG ANALYSIS

The well log for the Winfred Blades #1 (Fig. 4) is public data accessible through SONRIS (Strategic Online Natural Resources Information System, June 2015). The Gamma Ray log provided by Schlumberger in 1978 shows the TMS interval is approximately 600' thick (11,072'-11,645' TVD). John et al (1997) correlated the higher resistivity section of the TMS, greater than 5 ohm-meter, for 44 different wells drilled in the formation from East to West. Thus the corresponding oil bearing zone consist of a total pay thickness for the Winfred Blades #1 of 185' (11,460'-11,645'). The perforated zones for the well are color coordinated on the well log as shown in Fig. 4.

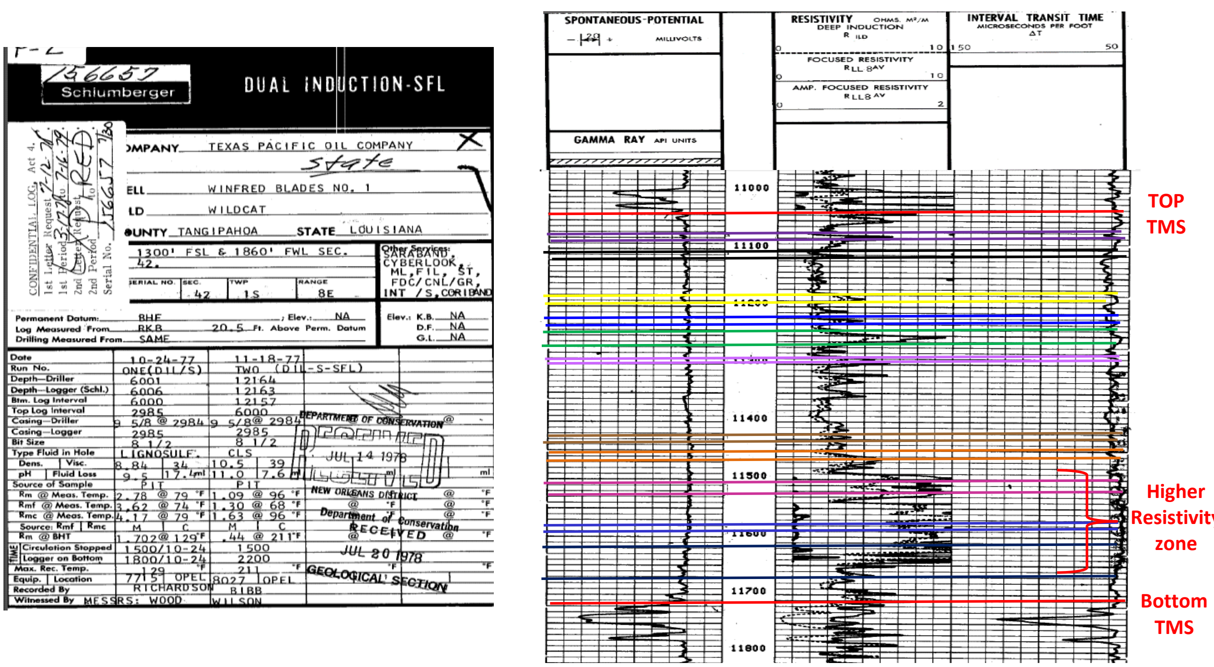


Fig. 4 - Winfred Blades #1 Well Log (SONRIS, 2015)

1.4 TMS FORMATION PRESSURE

John et al (1997) correlated the geological cross-section of the shale play and identified mud weights required to drill to the respective depths of 44 wells in the Tuscaloosa Marine Shale. Consequently, due to insufficient pressure data for the Winfred Blades #1 and surrounding wells, the mud weights were converted to hydrostatic pressure (minus 200 psi overbalance; i.e. trip margin) to estimate the formation's pore pressure (Eq.-1). Averaging the pressure for the corresponding wells yielded a pressure gradient of 0.52 psi/ft, which is slightly more conservative than Goodrich Petroleum's assessment of 0.55-0.70 psi/ft (Goodrich Petroleum Investor Report). The formation pressure calculated from the collective group of wells were plotted with respect to depth (Fig. 5). A second order polynomial trend line highly correlates the data ($R^2 = 0.90$), therefore applying Eq.-2 resulted in the reservoir pressure for the Winfred Blades #1 at 11,550' to be approximately 6,036 psi.

$P_{pore\_pressure} = 0.052\rho_{mud}gh - \text{Overbalance}$ ……………………………………………………Eq.-1

$P_{Reservoir} = -9E - 5x^2 + 2.3877x + 419.33$ ……………………………………………………Eq.-2

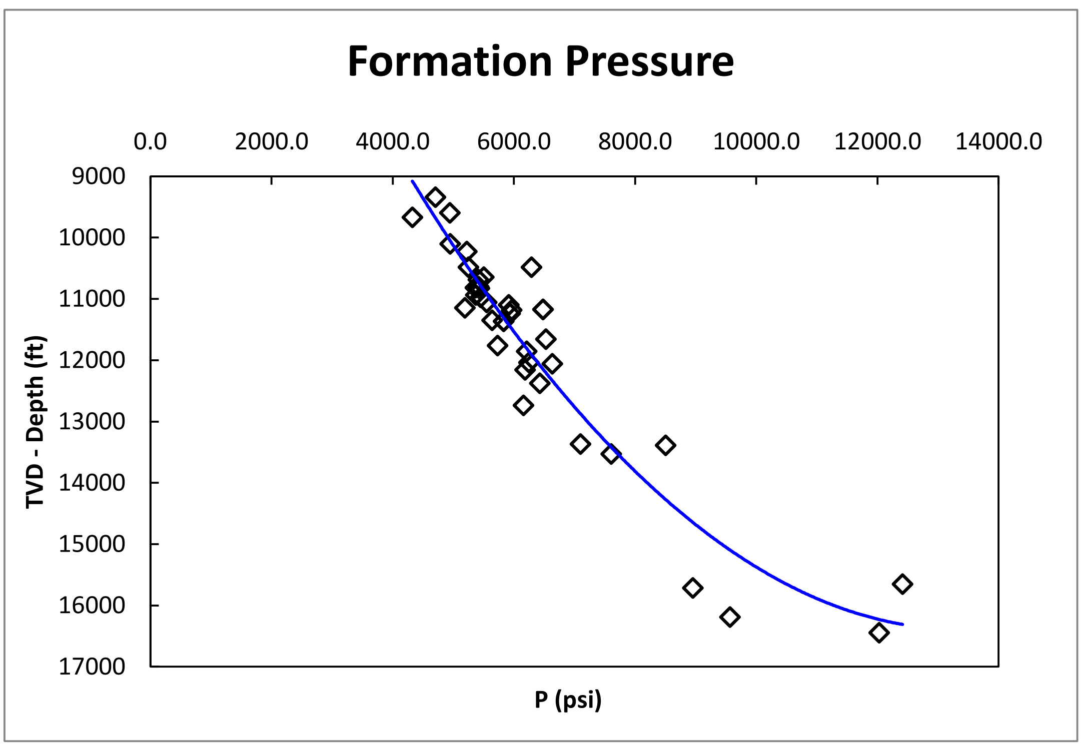


Fig. 5 – Estimated reservoir pressure from reported mud weights in the TMS

1.5 TMS FORMATION TEMPERATURE

The formation temperature gradient for Northern Tangipahoa Parish in Southeastern Louisiana is approximately 1.5 degrees per 100' with an average surface temperature of 74F, yielding an estimated formation temperature of 248F at the reference depth of 11,550' (mid-perf). According to the initial well log conducted by Schlumberger in late October and early November of 1978, the maximum temperature recorded for the Winfred Blades #1 is 211F. Recently, one of the largest producers in the TMS, Goodrich Petroleum, drilled 4 horizontal wells in the same formation within a 2 mile radius of the Winfred Blades #1 and the MWD/LWD analysis shows the average circulating temperatures are roughly 185F. Considering both climate conditions and the rate in which the horizontal wells were drilled, averaging the available temperature data resulted in a conservative estimate of formation temperature, 230F.

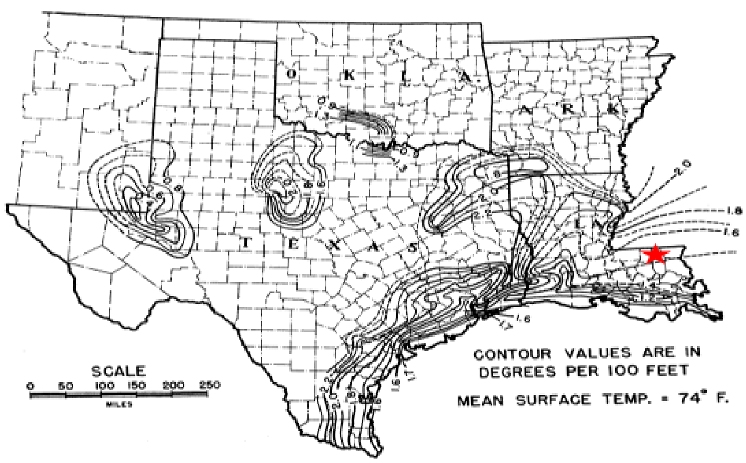


Fig. 6 – Contour map of the thermal gradients in the Southwest United States

1.6 PVT DATA

The following physical properties of a black oil were calculated from 'PVT Properties of Oil, Gas, and Water - VBA code for Microsoft Excel' (McMullan, 2003): Bubble point pressure, gas-oil ratio, oil formation volume factor, gas Z factor, oil viscosity, gas viscosity, and oil compressibility. Impurities such as H_2S, N_2, and CO_2 were not considered in the PVT computations. The fluid composition is unknown, thus the black oil reservoir simulator, IMEX, was used for the simulations as opposed to a compositional model, GEM. PVT computations are based on the initial gas-oil ratio and the API gravity reported for the Winfred Blades #1 as 167 SCF/STB and 37.2 degrees, respectively (SONRIS).

1.7 RELATIVE PERMEABILITY

Relative permeability is a measure of the ratio of effective phase permeability to the absolute permeability with respect to an independent measure of saturation variation which varies with time. While water saturation is expressed as the independent axis, it is a proxy for time. This is demonstrated in the Buckley-Leverett transport equation which is a model used to describe two-phase flow in porous media. In a consistent set of units, the Buckley-Leverett equation is expressed as:

$$\frac{\partial S}{\partial t} = U(S)\frac{\partial S}{\partial x}\ ; \quad \text{where:} \quad U(S) = \frac{Q}{\phi A}\frac{df}{dS}$$

Here S(x,t) is the water saturation, f is the fractional flow rate, Q is the total flow, ϕ is porosity and A is the area of the cross-section in the porous media. The relative permeability curve illustrated in Fig. 8 describes a drainage process, a two-phase system where a non-wetting fluid phase (oil) displaces a present wetting phase (water) in the porous media. This finishes at the end of the relative permeability curve at the initial water saturation which is also referred to as the irreducible water saturation. Thus relative permeability changes with time due to changes in saturation of one fluid phase relative to another. Without a profile of water saturation with time, typically derivable from the core/plug flooding experiment performed during Special Core Analysis (SCAL) to generate the relative permeability curves, several assumptions were considered to create oil and water permeability curves based on the available data. As the TMS is a shale formation, a large amount of surface water is associated with clay minerals, bound water, in which water molecules are not free to move and resulting in a significantly higher connate water saturation. The initial connate water saturation in the Tuscaloosa Marine Shale is estimated to range between 31.8-88.2% based on core samples obtained from Callon Petroleum's #2 Cutter well located in Tangipahoa Parish for depths ranging between 11,550'-11,653' (John et al 1997). In early 2014, Goodrich Petroleum core sample analysis indicates oil saturation values between 15-25% (Darbonne, 2014). Having no SCAL measurements, the relative permeability curves shown in Fig. 7 and Fig. 8 were generated from Eq. 3- Eq. 5, and are based on the assumed data values. The model input parameters consist of: connate water saturation: 80%, oil saturation: 20%, and irreducible oil saturation: 5%. The shale rock was assumed to be intermediate-wet.

$$\mathrm{K_{rw}} = \mathrm{K_{wr}} \mathrm{S_e^3} \quad \text{...Eq.-3}$$

$$\mathrm{K_{nrw}} = \mathrm{K_{nwr}}(1 - \mathrm{S_e})^2 \quad \text{...Eq.-4}$$

$$S_e = \frac{S_w - S_{wirr}}{1 - S_{wirr} - S_{nwr}} \text{...Eq.-5}$$

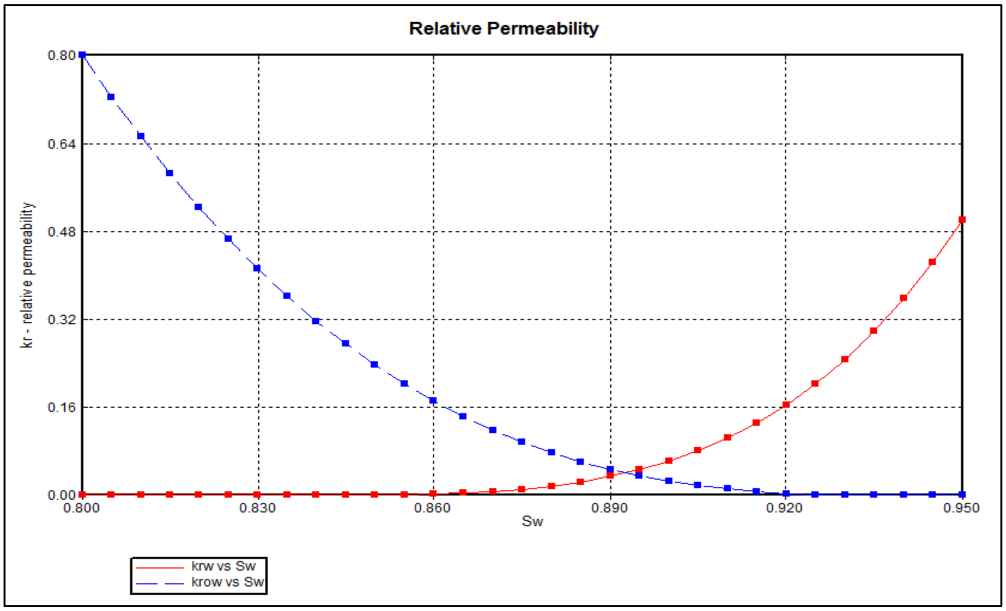


Fig. 7 - Drainage oil-water relative permeability curve for a core initially saturated with water (wetting) and is displaced by a non-wetting fluid (oil), CMG

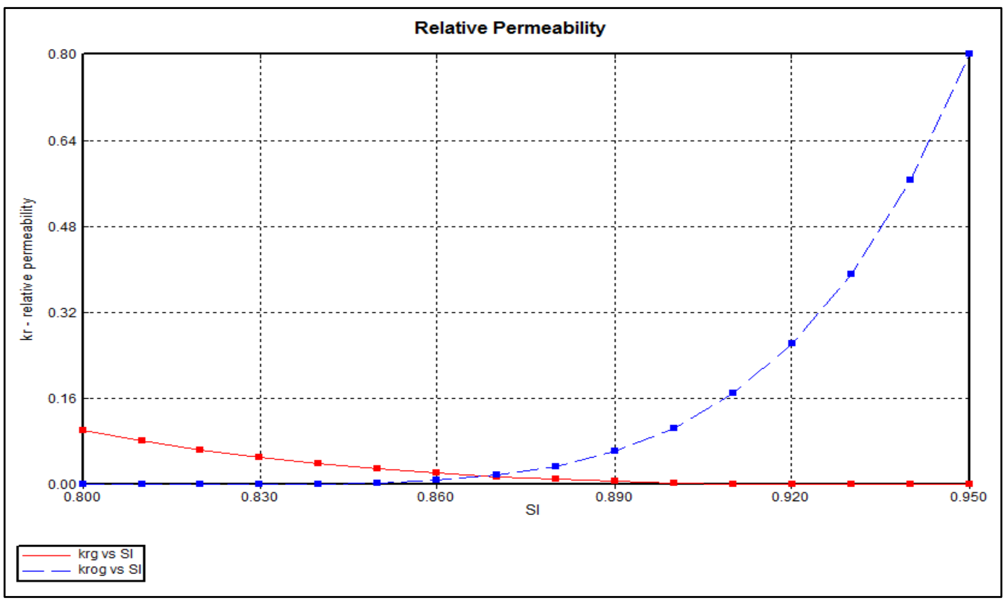


Fig. 8- Relative Oil/Gas Permeability Curves, CMG

1.8 ROCK PROPERTIES

According to core sample analysis, matrix permeability and porosity ranges from 0.01-0.06 mD and 2.3-8.0%, respectively (John et al 1997). To characterize the perforated zones of the Winfred Blades #1, the permeability and porosity (K_{perf} = 0.06 mD, ϕ_{perf} = 5.0%) was assumed to be slightly higher than the matrix (K_{matrix}= 0.03 mD, ϕ_{matrix} 3.0%) to represent a network of natural fractures. Also, the higher permeability values applied to the perforated zones in the higher resistivity section in the lower third of the TMS is representative of roughly a 10' highly fractured rock layer above the bottom 25' of the formation, termed the 'rubble zone' (Darbonne 2014). This approximation holds true for the five horizontally stimulated models (second layer) as the lateral sections of the wellbores penetrate the bottom third of the shale, near the rubble zone. Since the natural fractures were not modeled explicitly, the permeability for both the matrix and natural fractures is the effective permeability. The vertical permeability (in the k direction) is 0.01, resulting in an anisotropic permeability (K_v/K_h) of 0.2 and is a common value for shale formations. The averaged elastic properties measured from cores taken in the TMS shows the 'frackability' or Poisson's Ratio is 0.15 and the ability to maintain fractures, Young's Modulus, is $2.45 \text{x} 10^{-6}$ psi (Goodrich Petroleum, 2015).

1.9 RESERVOIR GRID

The black oil reservoir model consists of 11x11x129 Cartesian grid (Fig. 9 and Fig. 10). As a result of low matrix permeability, the change in pressure will be affected near the wellbore and therefore, the grid is constrained to 480 feet in both i and j directions per grid block (total area: 1 mile x 1 mile). The number of layers in the vertical direction (k) is 129 (702' feet thick) and is divided into perforated and non-perforated intervals. The non-perforated interval is represented by a single layer and the thickness varies accordingly with the depth between the two adjacent perforated zones.

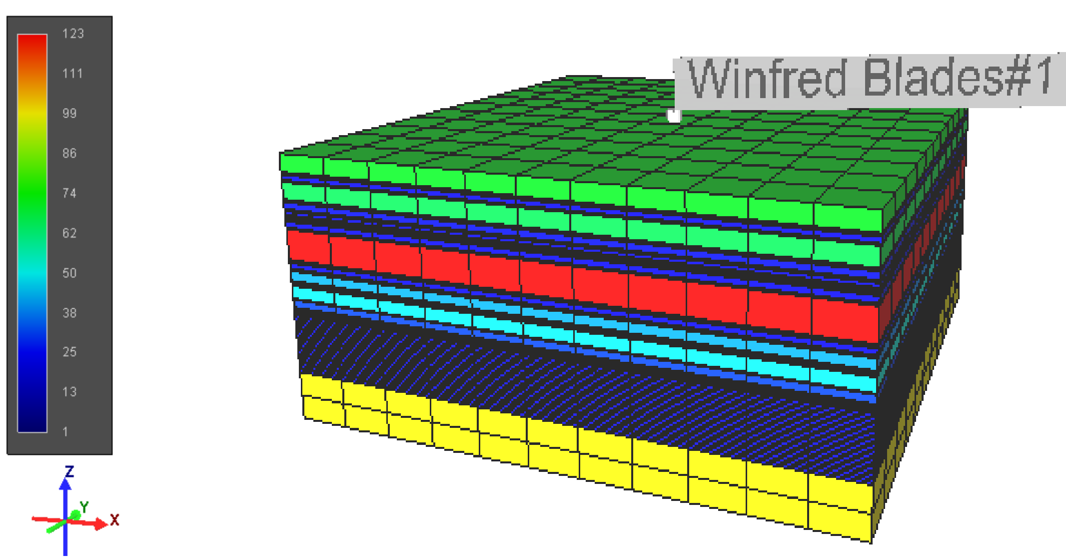


Fig. 9- Winfred Blades #1: CMG Reservoir Model 3D View (Layer Thickness)

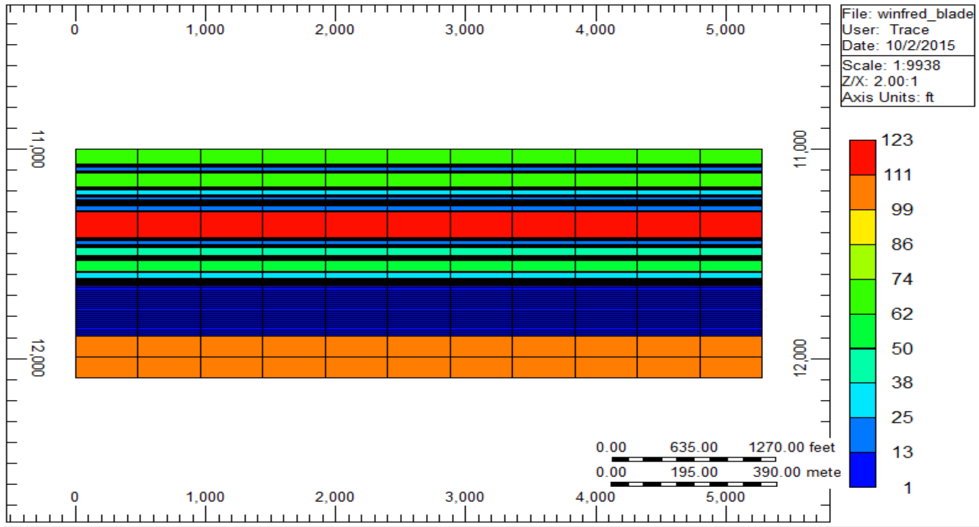


Fig. 10 - CMG Reservoir Model Cross-Sectional View

1.10 HISTORY MATCH (WINFRED BLADES #1)

A history match was obtained between simulated oil rates and measured field rates for estimating the matrix permeability and porosity. Production data was gathered for the Winfred Blades #1 from April 1, 1978 to November 1, 2014 (SONRIS, Online Natural Resource Information System; June 2015). According to the records, the well has not produced any water and thus the oil-water contact was placed significantly deeper below the producing formation to 12,000 feet in the model, signifying no aquifer support. In addition, the gas production recorded to the Louisiana Department of Natural Resources ranged between 0-1 MSCF/month. The current operator confirmed the Winfred Blades #1 does not currently produce any water and the well produces small amounts of gas but it is either flared or used at the lease site for operational purposes and is not reported for sales. In a traditional history match, static or flowing bottom-hole pressure is known from well test data; however for the Winfred Blades #1, pressure data is not available according to the present lease holder. Therefore, a minimum flowing bottom-hole pressure constraint was the primary parameter adjusted from 1978 to 2014 to match the field production. In the early1980's the Winfred Blades #1 was producing on average 5-8 barrels of oil a month as the well was placed on a pumping unit, resulting in a bottom-hole flowing pressure between 5,750-5,800 psi. Once the pumping unit was removed in 1990, rates declined to less than 2 barrels of oil per month and the bottom-hole flowing pressure fluctuated between 5,830 to 5,870 psi. The reservoir characteristics validated from the production history match resulted in the estimated matrix permeability and porosity for the perforated intervals to be 0.06 mD and 5%, respectively. Likewise, the non-perforated intervals consisted of a permeability of 0.03 mD and a porosity of 3% (Table 1). The total simulated oil recovered is 26,570 barrels

(Field Cumulative Oil: 26,529 barrels), resulting in a 6.67% recovery factor. The history match results for the Winfred Blades #1 are displayed in Fig. 11 and Fig. 12.

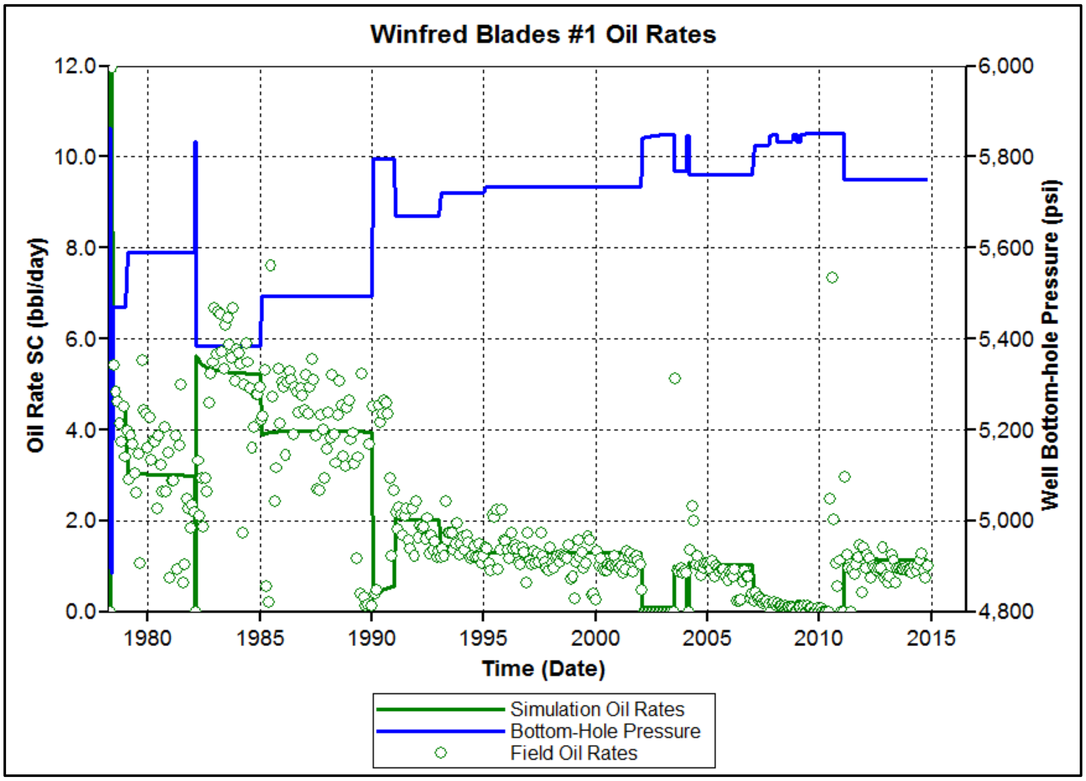


Fig. 11: Winfred Blades #1 History Match: Oil Rates and Bottom-Hole Pressure

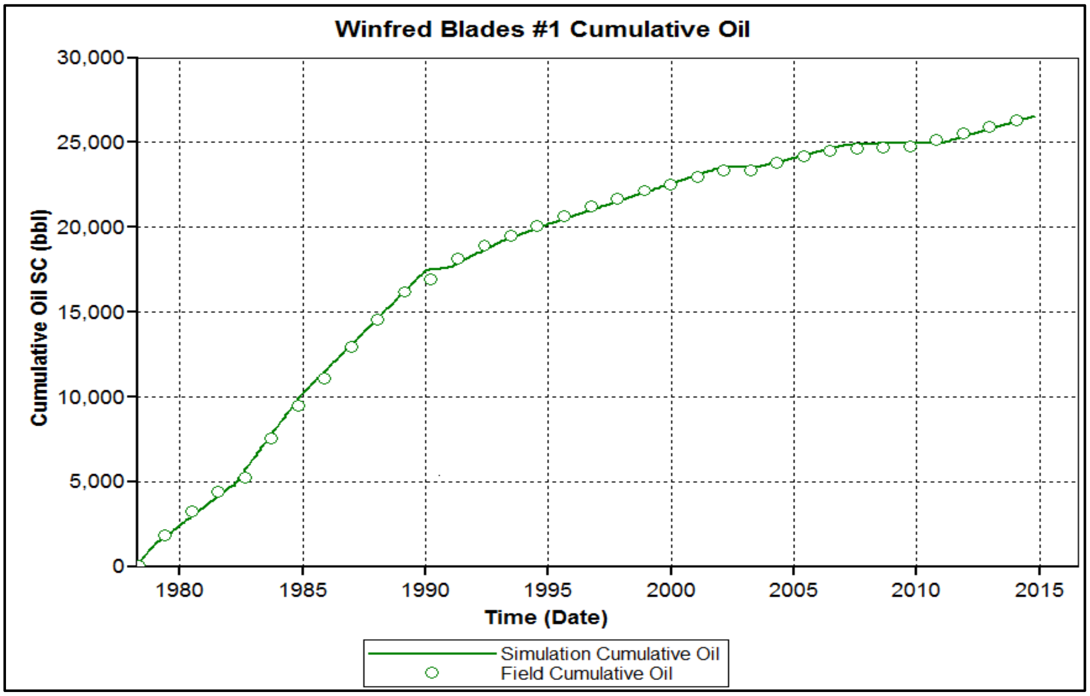


Fig. 12: Winfred Blades #1 History Match: Cumulative Oil

Reservoir Model Properties	
Matrix Permeability (i-direction) mD	0.03
Matrix Permeability (j-direction) mD	0.03
Matrix Permeability (k-direction) mD	0.01
Perforated Zone Permeability (i-direction) mD	0.06
Perforated Zone Permeability (j-direction) mD	0.06
Perforated Zone Permeability (k-direction) mD	0.01
Matrix Porosity	0.03
Perforated Zone Porosity	0.05
Reservoir Pressure (psi)	6,036
Reservoir Temperature (F)	230
Reference Depth (ft)	11,552

Table 1: Reservoir properties estimated through production history matching

2. TMS STIMULATED WELL ANALYSIS

Five actively producing hydraulically fractured horizontal wells were selected for analysis, and are located in the Tuscaloosa Marine Shale formation in northern Tangipahoa Parish (Louisiana). A black oil reservoir model was generated for each well with equivalent calibration criteria outlined in the following sections of this chapter.

2.1 WELL HISTORY:

The following stimulated wells were considered for the analysis: Blades 33-H, Soterra 6-H, Thomas 38-H, Verberne 5-H, and Williams 46-H. All of the wells are located in the Silver Creek Field, displayed in Fig. 13, with the exception of the Thomas 38-H and Soterra 6-H. Over the last year, Goodrich Petroleum has drilled several horizontal wells (Blades 33-H, Verberne 5-H, Williams 46-H) in the Silver Creek Field ranging within 2-4 miles from the control well, Winfred Blades #1. The Thomas 38-H was drilled and completed by Devon Energy in the Kentwood field, 7 miles northwest of the Winfred Blades #1 and is currently operated by Goodrich Petroleum. The Soterra 6-H was drilled and completed in the Fluker Field by Devon Energy, approximately 12.5 southwest from the control well, and is also currently operated by Goodrich Petroleum. The outlying wells are considered in the study to examine if the workflow for estimating matrix and fracture attributes modeled for three horizontal wells surrounding the Winfred Blades #1 also holds as a reasonable approximation for the Soterra 6-H and Thomas 38-H (Fig. 13).

Fig. 13 –Surface Location for TMS wells in AOI – North Tangipahoa Parish, LA (Google Earth)

Among the group of wells, both the Soterra 6-H and Thomas 38-H have been producing the longest, 3.5 and 2.5 years, respectfully. The three wells drilled by Goodrich Petroleum (Blades 33-H, Verberne 5-H, Williams 46-H) were all drilled in 2014 and resulted in significantly higher oil production compared to the two wells drilled by Devon Energy. As the wells drilled by Goodrich have only been on production less than one year, the six month cumulative oil production is used as a benchmark for comparison. The three Goodrich Petroleum drilled wells reported a six month cumulative oil production ranging between 80,000 – 91,000 barrels, while the Thomas 38-H and Soterra 6-H produced 40,000 and 14,000 barrels, respectively. Listed in Appendix D is the water production reported in the available well test information submitted to the state (SONRIS) and the total volume of water pumped during the hydraulic fracturing operation (FracFocus). The water production for the Blades 33-H is reported within the first month of production (614 barrels) and is presumed to be predominately flowback from the stimulation. Within the first 19 months of production, only 50% of the frac water is recovered. The orientation of the wellbore could possibly explain the differentiation in production amongst the wells if the trajectory of the lateral does not connect and intersect to a series of pre-existing natural fractures, resulting in poor drainage and lower recovery. The natural fractures in the Tuscaloosa Marine Shale trend from west to east resulting in operators drilling laterals north and south to achieve the maximum production. However, according to Goodrich Petroleum, the fractures have a tendency to bend on the Eastern side of the TMS, therefore the position of the wells should be orientated southwest or northeast (Darbonne, 2014). As shown in Fig. 14, the three wells drilled by Goodrich trend SW and NE roughly 60 degrees and are the highest producing among the set of wells considered in the study. The Thomas 38-H trends N-S and the Soterra 6-H trajectory is SW-NE roughly 45 degrees. Seismic attributes and borehole image logs would be required to explain whether the lower production was a direct result of the well trajectory for the two outlying wells. Table 2 list the oil and gas production data retrieved from SONRIS for the five wells.

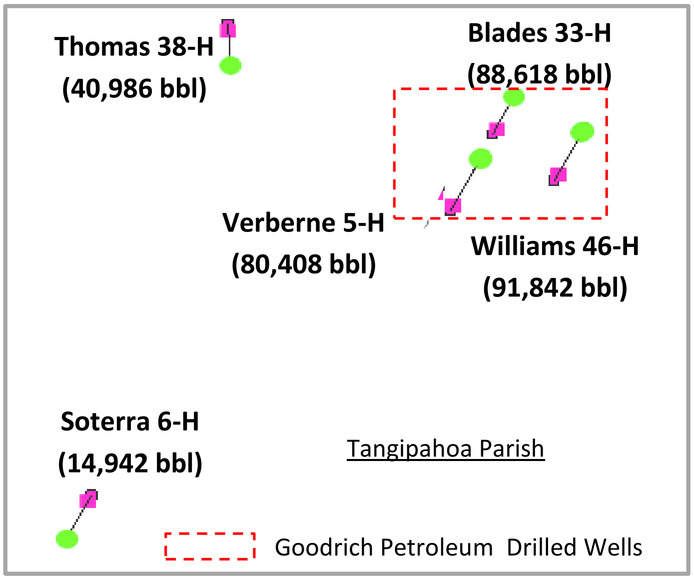


Fig. 14 –TMS Wells in Northern Tangipahoa Parish: Well trajectory and 6 month cumulative oil production (SONRIS, 2015)

From a well design and completion viewpoint, it is desirable to identify which parameters are driving the well productivity. Given the completion reports obtained from SONRIS, the horizontal lateral of the Goodrich Petroleum wells range from 5,000'-6,500', exceeding the Thomas 38-H (5,086') and the Soterra 6-H (3,929'). In early 2013, the Crosby 12-H1 drilled by Goodrich Petroleum, located in Southwestern Mississippi (Wilkinson County), is one of the company's highest producing wells (Initial Production 1,130 BOE). The company states the success of the Crosby 12-H1 is due to an increased lateral length (6,700 feet) and the number of stages (24), in addition to pumping more than 1,500 lbs/foot of proppant per stage. Similar completion designs have been applied to more recently wells drilled by Goodrich Petroleum in the TMS (Tangipahoa Parish), resulting in higher recoveries by increasing the stimulated rock volume (Darbonne, 2014). Goodrich recently reported the Blades 33-H is the companies most successful well to date on a per lateral foot basis, 17.72 bbl/ft (Goodrich Petroleum, 2015). In addition to drilling longer laterals, stage intervals between 250-380', spacing of the perf clusters, and the total proppant pumped per foot (greater than 450,000 lbs. per stage) are several alterations in the completion design Goodrich Petroleum has made in the company's more recent wells, which in return has led to higher production (Goodrich Petroleum's Investor Report, 2015). The company has also adapted a new technique, hybrid-fluid, which is highly effective by first pumping slickwater to create microseisms, followed by pumping gel to transport the sand, generating a more complex fracture system (Darbonne, 2014). Furthermore, a strong correlation is observed in the higher producing wells with an increase in the number of stages and total proppant volume pumped per stage.

	247307 Blades 33H	248323 Verberne 5H	243765 Soterra 6H	248405 Williams 46H	244870 Thomas 38H
Initial Production Date	4/1/2014	11/1/2014	2/1/2012	12/1/2014	9/1/2012
Last Reported Date	6/1/2015	6/1/2015	6/1/2015	6/1/2015	6/1/2015
Total Production Months	15	8	41	7	34
Average Oil Rate (BOPD)	338	405	34	474	99
Cumulative Oil (BBL)	154,513	97,972	41,388	101,344	102,659
1st Month Cum. Oil (BBL)	23,811	1,787	2,896	24,482	787
6th Month Cum. Oil (BBL)	88,618	80,408	14,942	91,842	40,986
1 Year Cum. Oil (BBL)	142,356	N/A	24,889	N/A	60,843
Average Gas Rate (MSCF/D)	76	96	18	101	34
Cum Gas (MSCF)	1,138	23,118	22,389	21,558	35,755
1st Month Cum. Gas (MSCF)	5,115	263	0	5,502	216
6th Month Cum. Gas (MSCF)	21,171	18,093	6,122	19,282	14,180
1 Year Cum. Gas (MSCF)	32,079	N/A	12,324	N/A	22,297

Table 2–TMS Wells Production History (SONRIS, 2015)

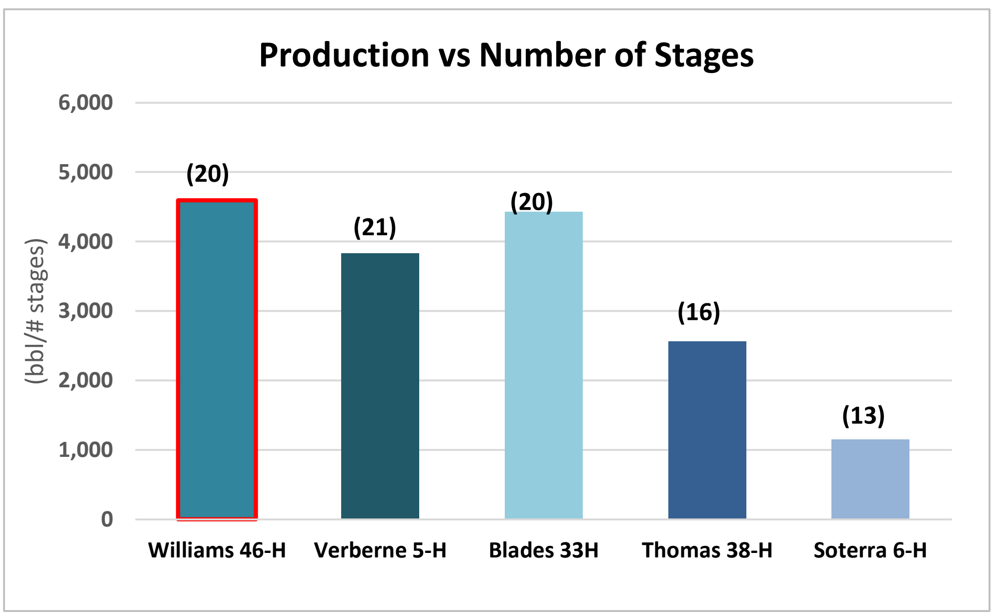


Fig. 15 –Six Month Cumulative Oil Production vs Number of Stages
(Wells are in order of oldest (top) to most recent completion date (bottom)

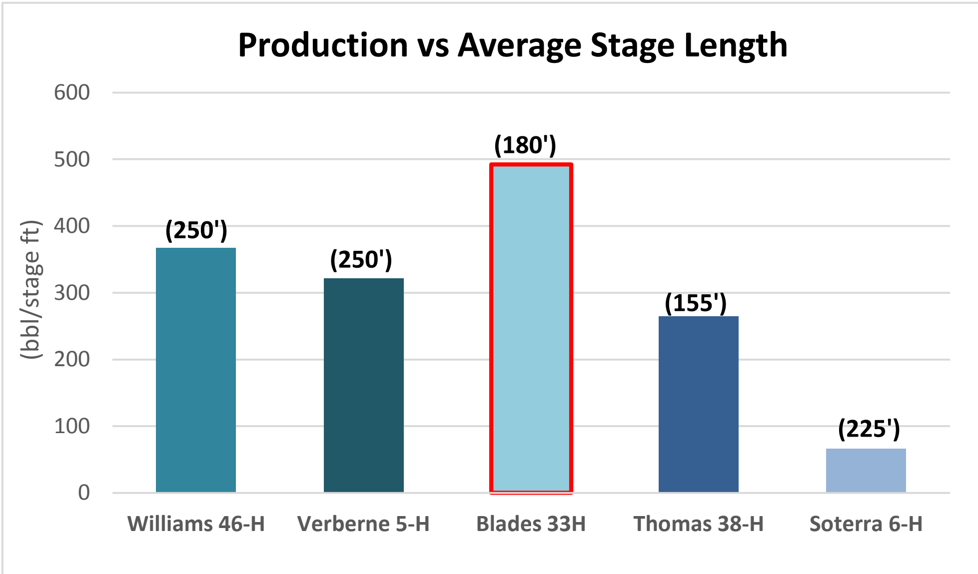


Fig. 16 - Six Month Cumulative Oil Production vs Average Stage Length (ft)
(Wells are in order of oldest (top) to most recent completion date (bottom)

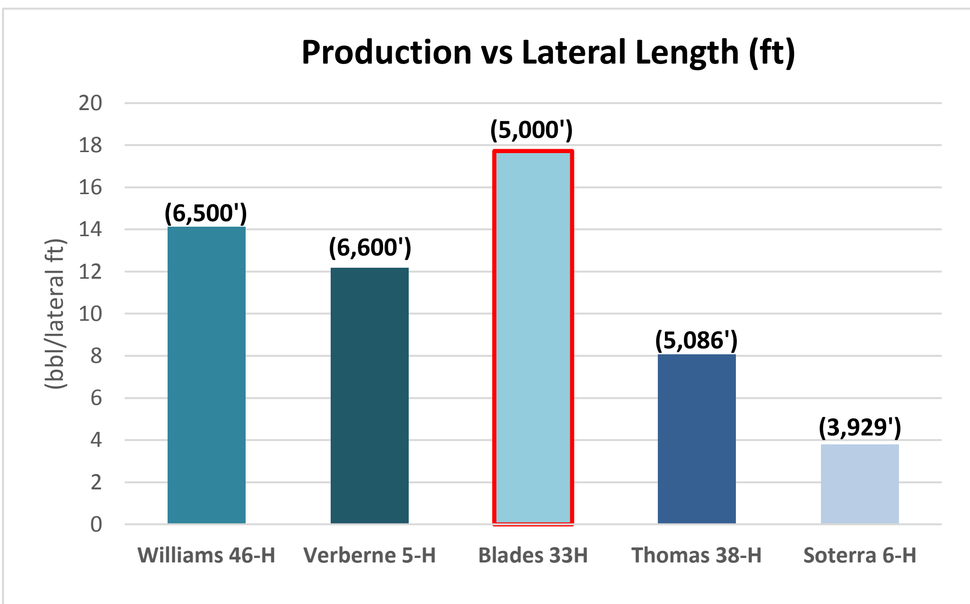


Fig. 17 - Six Month Cumulative Oil Production vs Lateral Length (ft);
(Wells are in order of oldest (top) to most recent completion date (bottom)

3. RESEVOIR MODEL CALLIBRATION

3.1 PVT

Similar to the Winfred Blades #1, the PVT properties for the Blades 33-H, Thomas 38-H, Soterra 6-H, Verberne 5-H, and Williams 46-H were computed using ‘PVT Properties of Oil, Gas, and Water - VBA code for Microsoft Excel (McMullan, 2003). The API gravity of the oil, reported to SONRIS, ranges between 36-41 degrees and the fluid composition for the five wells is unknown. The initial gas oil ratio (GOR) is obtained from the initial well test reported, however an initial GOR was not reported for the Thomas 38-H and Soterra 6-H wells. Subsequently, the gas-oil ratio was computed from the production data for the first month and is assumed to be the initial GOR. Similarly, the lower than average GOR (92 SCF/BBL) reported in the initial well test for the Blades 33-H was replaced with the calculated first month’s gas oil ratio of 214 SCF/bb.

	Blades 33-H	Thomas 38-H	Soterra 6-H	Verberne 5-H	Williams 46-H
1st Month Computed GOR (SCF/BBL)	214	275	412	147	224
Average GOR (SCF/BBL)	216	334	602	230	213
GOR Reported (SCF/BBL)	92	N/A	N/A	173	230
Estimated Reservoir Pressure (psi)	6,092	6,170	6,607	6,127	6,068
Computed Bubble Point (psi)	1,372	1,484	2,262	1,076	1,306

Table 3: PVT Properties for TMS Stimulated Wells

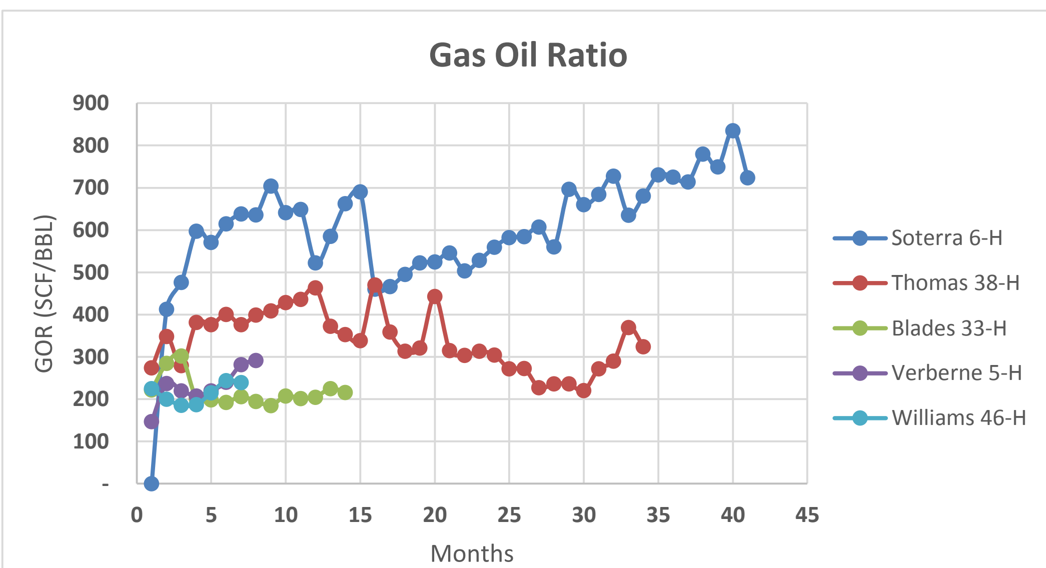


Fig. 18 - Gas Oil Ratio History

3.2 RELATIVE PERMEABILITY

The five reservoir models are calibrated with analogous relative permeability curves described for the Winfred Blades #1 (Chapter 1). However, the well test records submitted to the state document water production for each of the wells analyzed in this study (Appendix D) and therefore, the effects of adjusting relative permeability curves to account for the frac water in the stimulated zones yet to be recovered. The only well test reported during the first month of production was the Blades 33-H (Table 4), giving the most accurate insight into the total frac water recovered since initial production (April 2014 – October 2015). The total water recovered in 19 months is nearly 50% and the water cut is roughly 25% for the past three well tests. The relative water endpoint calculated using Eq.-7 required to obtain a 25% water cut is 0.24 (water viscosity: 1 cp, oil viscosity 1.2). Modifying the relative permeability curves in the Blades 33-H reservoir model to account for water in the stimulated zones resulted in a lower bottom-hole pressure required to attain the peak oil production rate, but marginal differences in the decline trend compared to the simulation results where water production was not considered in the model (Appendix E, Fig. 48).

$$f_w = \frac{1}{1+\frac{K_{ro}\ \mu_w}{\mu_o\ K_{rw}}} \qquad \text{Eq.-7}$$

Date	Water (bbl)	Oil (bbl)	Water Cut
10/16/2015	46	162	28%
3/30/2015	42	208	20%
10/7/2014	55	309	18%
4/11/2014	614	**1,136**	54%
Frac Water (gals)	**11,282,275**		
Estimated (gal) YTD	5,507,019		
% Water Recovered	49%		

Table: 4: Blades 33-H Water Production and Frac Water Data (SONRIS, FracFocus)

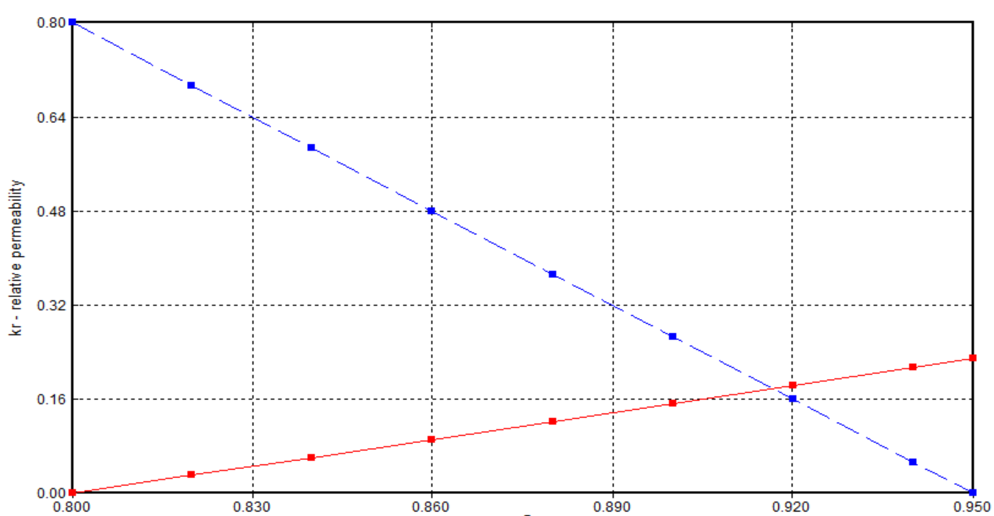


Fig. 19: Relative Oil-Water Permeability Curves

3.3 HYDRAULIC FRACTURE ATTRIBUTES:

Advancements in hydraulic fracturing create a longer production life and increased reserves, making unconventional shale formations economical if the market price of crude oil is above the break-even cost required to drill and complete the well. Slickwater or gel is pumped from the surface at very high pressures to the perforated target zone in the lateral section of the well creating microseism in the subsurface as a result of changing the stress distribution, causing shear slippage of the formation rock. According to Griffith's Theory which is based on Linear Elastic Fracture Mechanics (LEFM), rock failure occurs once the stress intensity factor exceeds the critical stress or the 'toughness' of the rock. In this study, the maximum principal stress is the overburden stress, which is a valid assumption for deeper formations such as the TMS. In this case, hydraulic fractures will open in the orientation of the minimal principal stress and propagate into the direction of the intermediate stress ($\sigma_{\text{horizontal-int.}}$). For simplicity, the reservoir grid cells are refined to characterize linear fluid flow through a 'cluster' of planar bi-wing hydraulic fractures as illustrated in Fig. 20.

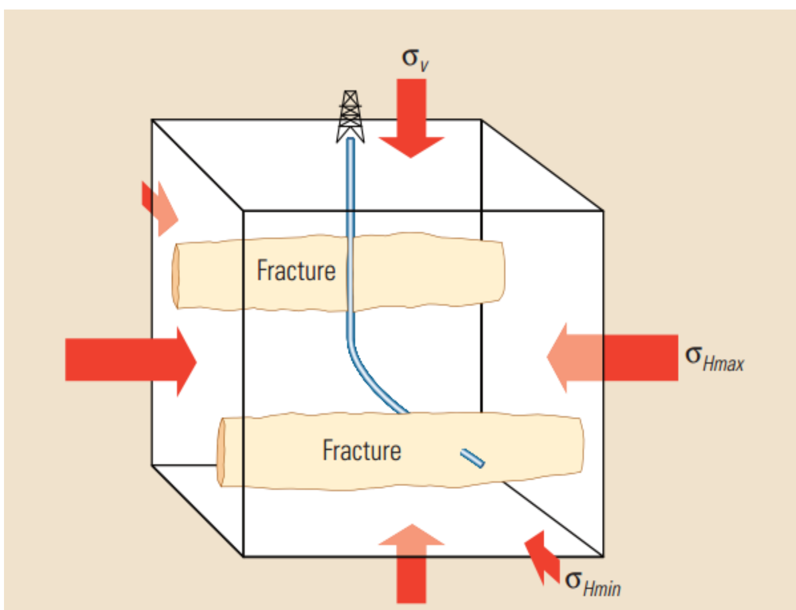


Fig. 20 - In-Situ Stress Direction (Schlumberger, 2013)

The models are comprised of an 11x11 Cartesian grid with three vertical layers (Fig. 21-23). The grid is of uniform rectangular geometric cells, however the gridding is classified as 'unstructured' in terms of assigning properties to the matrix and induced fractures separately. An array of grid refinements were applied to the model to depict a horizontal well positioned in the middle of the second layer (j-direction) and to characterize flow through the induced fractures for each stimulated stage. The hydraulic fracture stages are spaced along the lateral according to the completion descriptions obtained from SONRIS. Initial refinement consists of grid cells in the i-direction being divided into 3 additional columns, with the exception of columns 1,2,10, and 11 (i-direction), which characterizes the non-stimulated pore volume (Fig.22). Similarly, cells in rows 2 thru 10 (j-direction) are separately refined into 3 additional rows. Next, the middle column in (i-direction) and from row 2 thru 10 (j-direction), are modified into 11 additional grid columns. The 7th column of the previous refinement is then divided into 3 additional cells, representing the wellbore of approximately 1 foot diameter.

The stimulated fracture half-length is dependent up the hydraulic fracture design and the mechanical properties of the rock. In the oil rich section of the Eagle Ford, microseismic analysis indicates fracture half-lengths can extend in excess of 1,000 feet (Pinnacle, Halliburton). Therefore, the cluster of fractures in each stage are positioned symmetrically about the wellbore for fracture half-lengths ranging between 100 to 800 feet. The regionalized stress around the wellbore changes along the lateral, from heel to toe, and each stage can be comprised of a different stimulation design, creating various size fractures; therefore, the modeled half-length is the average elongation the fractures are estimated to be propagating per well. Given limited access to treatment and pressure data to simulate a propped length of the induced fractures, the fractures in the reservoir model are assumed to be propped uniformly over the specified half-length.

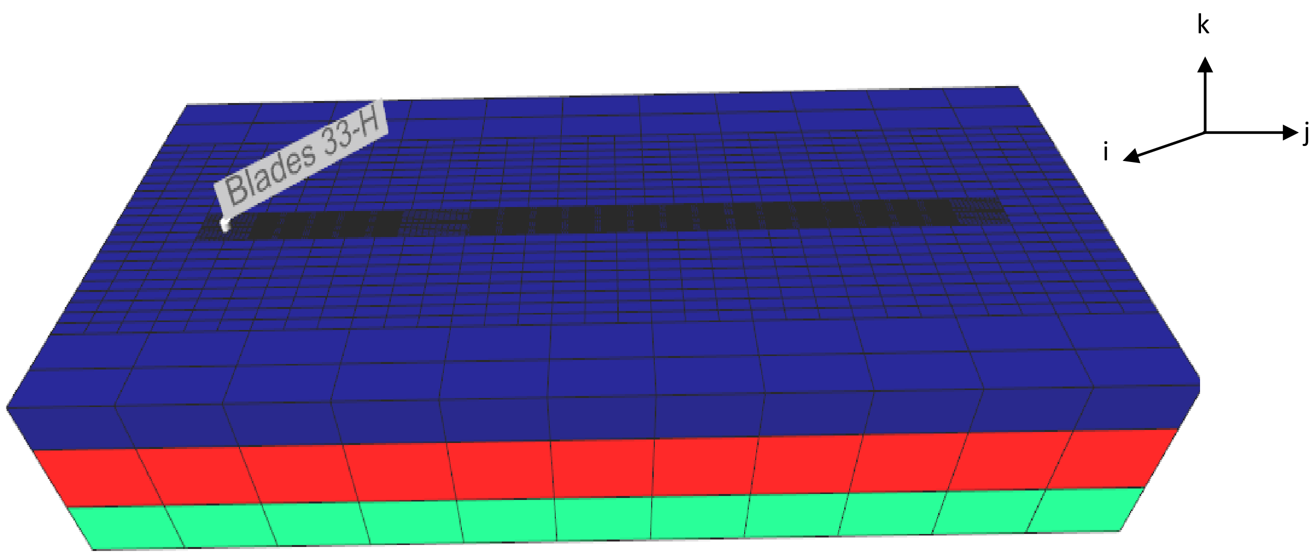


Fig. 21 – Blades 33-H Reservoir Model –CMG 3D View: Total Refinements: 6,441; Total Grid Cells: 3,542,913

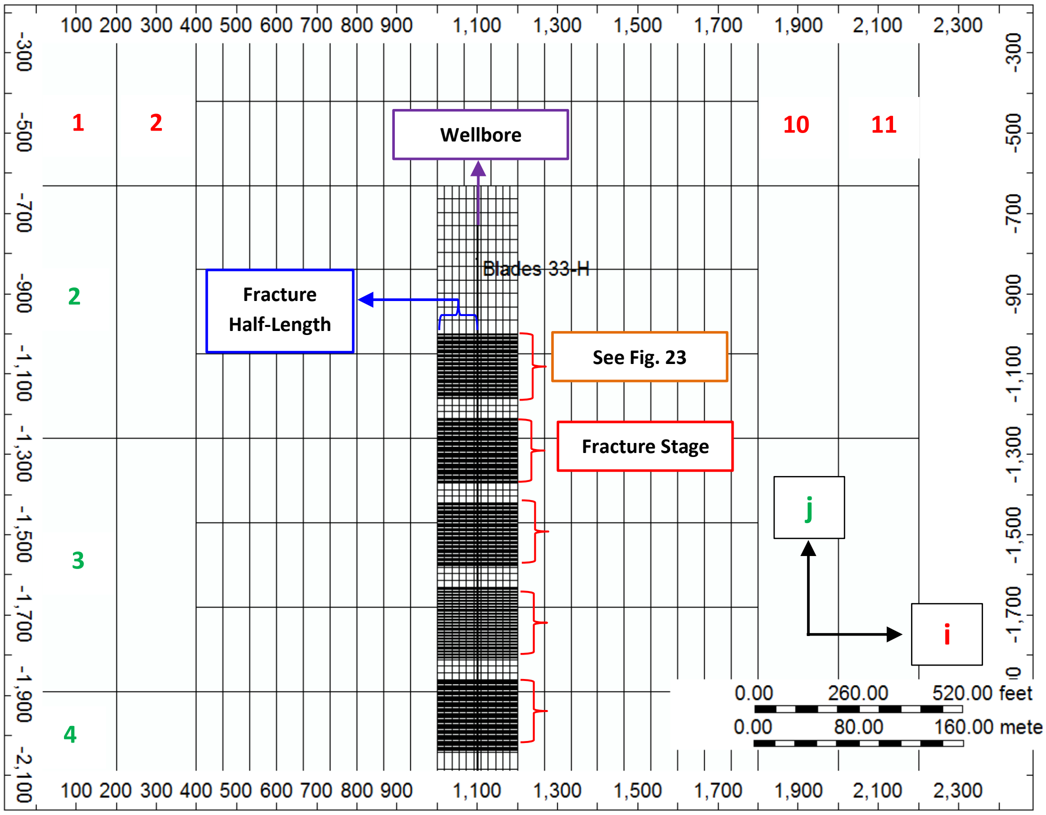


Fig. 22- Cross Section View: Horizontal Well Model Design (2nd Layer)

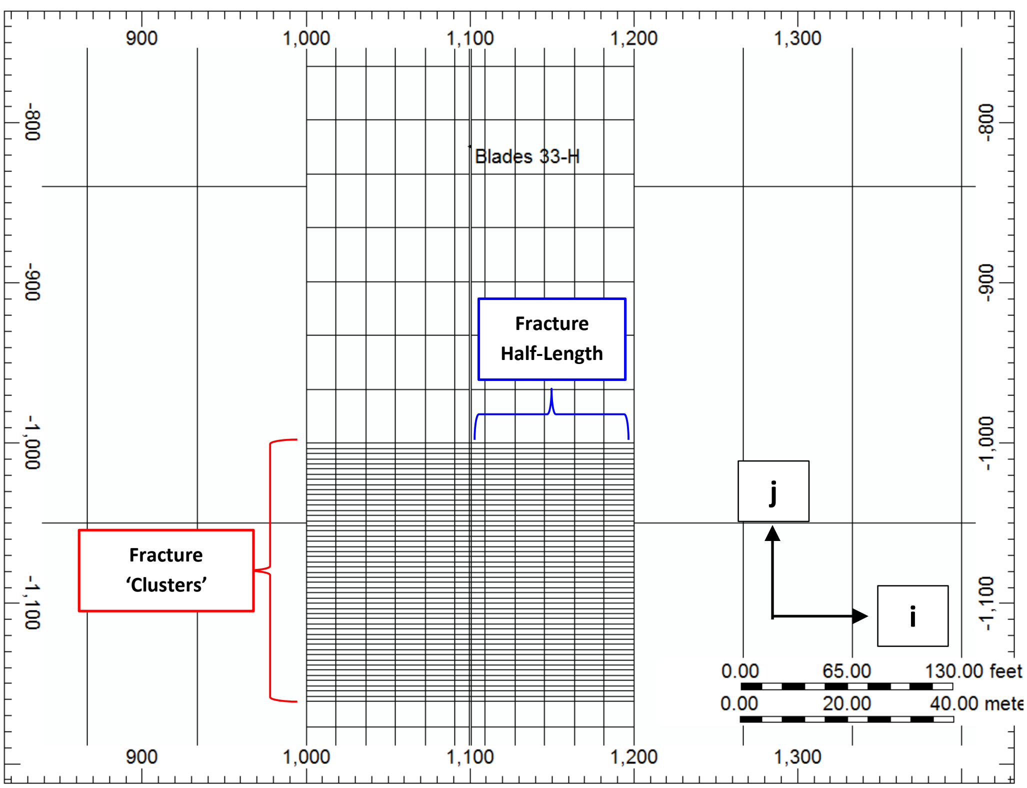


Fig. 23– Zoomed in: Cross Section View: Horizontal Well Model Design (2nd Layer)

John et all (1997) correlated the geological cross-section of the higher resistivity zone for vertical wells drilled in the TMS located in Tangipahoa Parish and the net thickness ranged between 130’-185’. According to Winfred Blades #1’s well log, the net pay thickness for the higher resistivity zone is approximately 185 ft. (Fig. 24). Given available data, the Blades 33-H, Soterra 6-H, Verberne 5-H, and Williams 46-H models assume a stimulated reservoir height of 180 feet (systemic about the wellbore; 90’ above and below). The Soterra 6-H is 7 miles to the Southwest and the three Goodrich Petroleum wells are within a 2 mile radius of the Winfred Blades #1, thus deviation in the formation thickness is expected to be minimal. The net thickness for the Thomas 38-H is validated through a near-by offset well, Franklin PST PROP H, which was drilled and completed by Halcon Resources three miles directly North and recorded the top of the TMS horizon at 10,639’ and the bottom at 11,462’. Gamma Ray and Induction logs for the Thomas 38-H, shown in Fig. 25, also indicates the pay thickness is 185’ feet, providing additional validation for the assumed stimulated height of 185’. Geomechanical modeling is not considered in the analysis (CMG: STARS), thus the above and below layers of the model are assumed to have a higher Poisson’s Ratio which will confine the fracture height growth to 185’.

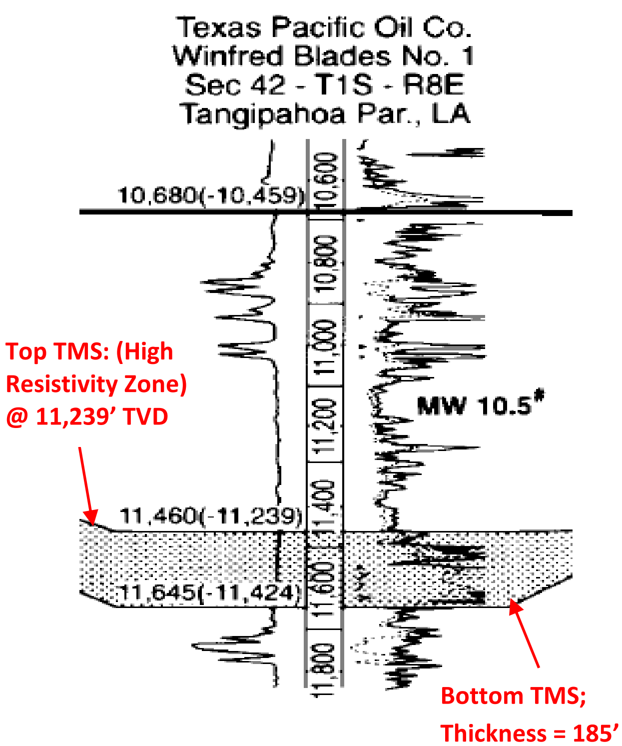


Fig. 24 - Winfred Blades #1 Well Log (John et al 1997)

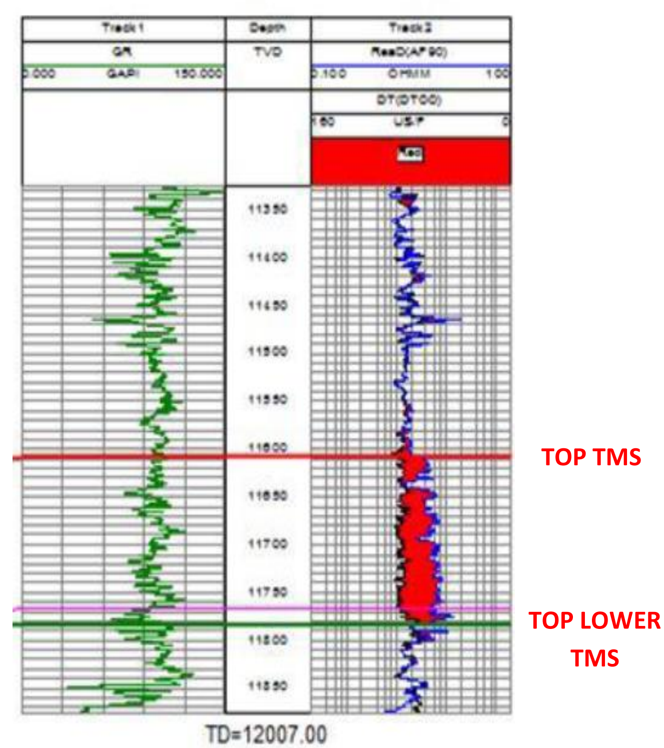
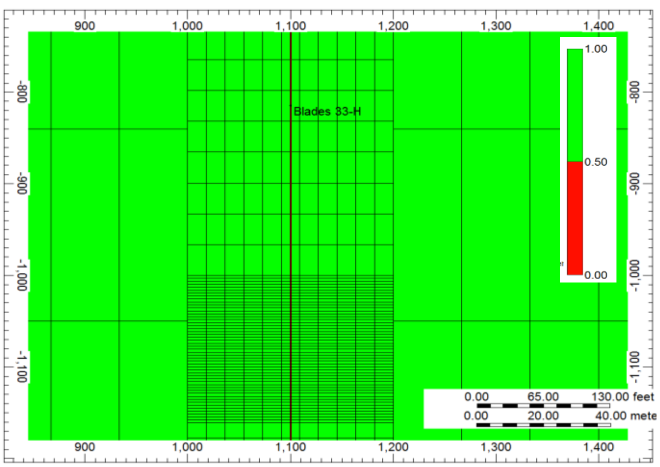
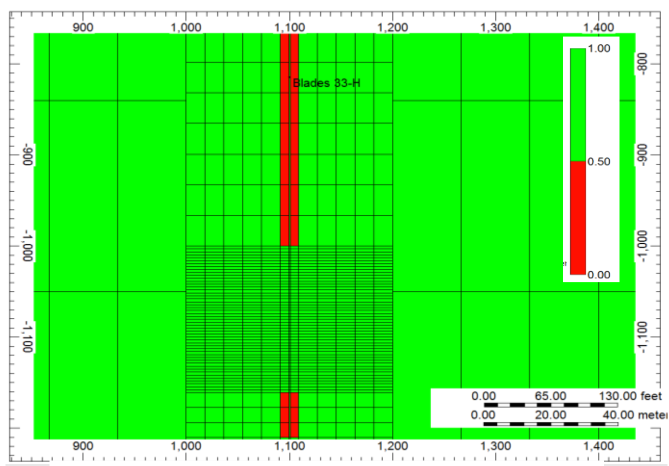


Fig. 25: Thomas 38-H Well Log: Identifying top of TMS and Lower TMS Horizons; (Goodrich Petroleum, 2015)

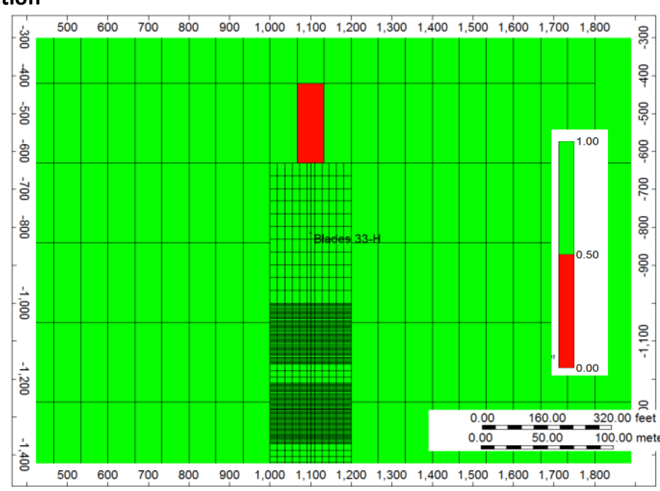
Transmissibility barriers are applied to direct flow only through the fracture stages in the i-direction and then flow is diverted through the wellbore in the j-direction. Flow through grid cells adjacent to the lateral section of the well (j-direction) is assigned a transmissibility value of zero (Fig. 26). The matrix grid cells adjacent to the wellbore have a transmissibility of 0, indicating no flow in the corresponding direction (i-direction). Transmissibility barriers for the wellbore are only applied in the vertical direction (Transmissibility k-direction = 0). The wellbore is refined such that the thickness is less than one foot (j-direction) and is assumed to be 100 percent porous. According to Darcy's law, homogeneous laminar flow in a wellbore is similar to the flow in porous medium, therefore neglecting frictional pressure loss, the wellbore is assumed highly permeable (j-direction: 1200 mD). Increasing the magnitude of the wellbore permeability translated in excessively higher rates, requiring a bottom-hole pressure beyond the average reservoir pressure, thus the wellbore is comprised of a permeability equivalent to 2 Darcy.



A: K-Direction



B: i-Direction



C: i-Direction

Fig. 26 – Reservoir Model: Transmissibility Multiplier

The maximum allowable refinements in CMG for a single grid cell is 50. Hence, the width of the fractures are scaled higher in the model than the actual estimated fracture aperture computed from Eq. 7-8 and assuming Perkins and Kern (PKN) fracture geometry. The PKN model assumes plastic strain is vertical and perpendicular to the fracture propagating in the horizontal plane with a constant height (Economides, 2012). The PKN fracture model assumes an elliptical shape and the fracture height remains relatively constant while the length of the fracture increases, resulting in a length to height ratio greater than unity. The PKN fracture geometry depicted in Fig. 27 is a valid assumptions for deep penetrating hydraulic fractures in low permeable formations (Economides, 2012). In this study, the PKN geometry is utilized in estimating the fracture aperture to determine a range of conductivities and permeability for the induced fractures (Table 4).

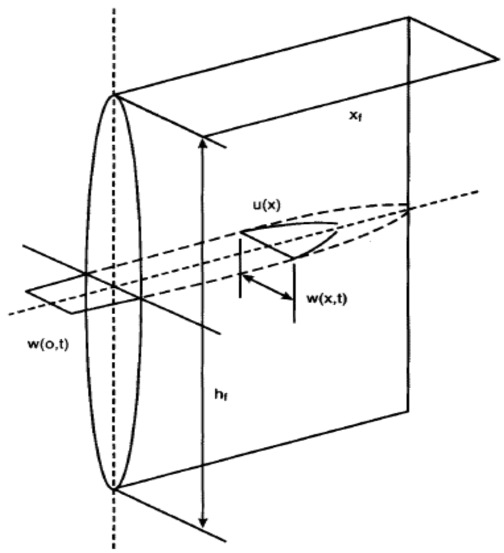


Fig. 27– Geometry of Perkins and Kern (PKN) Fracture Model – 3D Ellipsoidal Width (Economides, 2012)

For the five reservoir models, the width of the grid cells representing the hydraulic fractures range from 3 to 5 feet, depending on the length of the fracture stage which varies by well. Therefore, considering the PKN fracture geometry, the actual fracture aperture can be estimated from Eq.-7 and Eq.-8. Based on an average pumping rate of 65 BPM (SONRIS), viscosity of the fluid equaling 100 cp, and a Poisson's Ratio of 0.15 (Goodrich Petroleum, 2015), the approximated fractured width computed is listed in Table 5.

$$w = 0.19[\frac{q_i \mu x_f}{E'}]^{1/4} \quad \text{Eq.-7}$$

$$w_{max} = \frac{w}{0.628} \quad \text{Eq.-8}$$

X_f (ft)	Width (in)	Max Width (in)	Length/Height
100	0.136	0.216	0.556
200	0.161	0.257	1.111
300	0.178	0.284	1.667
400	0.192	0.305	2.222
600	0.212	0.338	3.333
800	0.228	0.363	4.444

Table 5–Estimated Fracture Parameters (PKN)

Completion details submitted to SONRIS for the Thomas 38-H well specifies the well was stimulated with 30/50 white sand. Proppant type for the remaining wells in the study were not publicly reported thus, the induced fracture conductivity and permeability in the model is based on 30/50 sand. The closure stress at depths ranging from 11,500'-12,000' is estimated to be 7,000 psi (Eq.-9) and the corresponding fracture permeability for 30/50 white sand is approximately 50 Darcy (Fig. 28). The conductivity of the fractures during production can be significantly less than lab measurements as a result of numerous down-hole conditions such as reduced proppant concentration, non-Darcy flow, or proppant embedment (Palisch, 2007). The induced fractures and matrix permeability (K_f = 50,000 mD, K_m = 0.05 mD) were averaged to estimate the permeability of a single fracture ($w_{fracture}$ = 0.20 inches) within each individual refined fracture grid cell with an overall width of 3 to 5 feet. The reservoir models were calibrated to three separate cases where permeability values of 50, 150, and 450 mD were applied to each stimulated stages. Production history match results suggest the permeability range to be a reasonable approximation (Chapter 4).

$$\sigma_{closure} = \frac{v}{1-v} * \left[\sigma_{overburdern} * Depth - P_f\right] + P_f \quad \text{.....Eq.-9}$$

$$K_{e,avg} = \frac{k_1 w_1 + k_2 w_2}{W} \quad \text{.....Eq.-10}$$

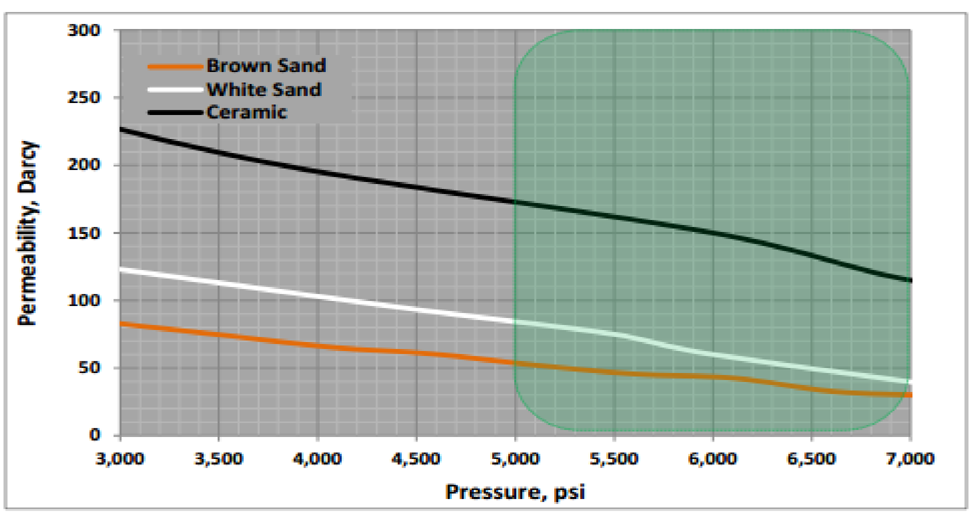


Fig. 28: 30/50 Proppant: Permeability vs Closure Stress for proppant type (Yang et al, 2012)

3.4 RESERVOIR PORE VOLUME

The volume of the reservoir rock that has been hydraulically fractures or the 'stimulated reservoir volume' (SRV) increases as the growth of induced fractures penetrate further into the formation and connects to pre-existing natural fractures, creating a complex fracture network. Contribution of the reservoir beyond the SRV for tight shale formations (micro-Darcy), such as the Tuscaloosa Marine Shale and other unconventional plays, is usually negligible (Brown et al 2004).

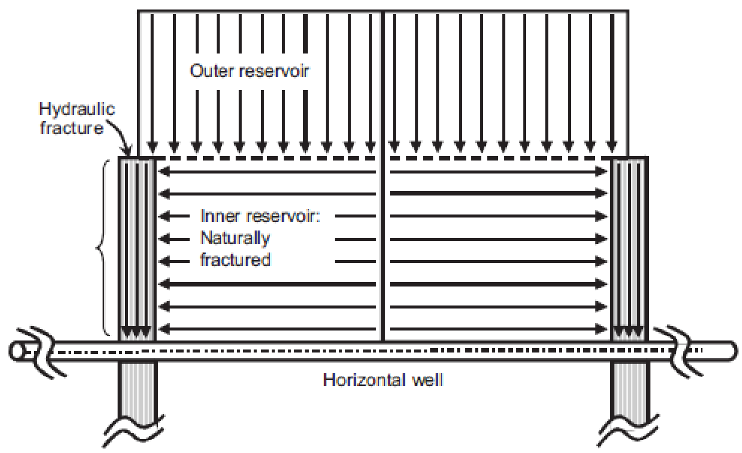


Fig. 29 - Flow regions for multi-stage horizontal fracture well

The reservoir models are designed such that increasing the fracture half-length (i-direction, column 7) translates into the remaining grid cells in the i-direction (columns 1-6 and 8-11) to be altered accordingly to the specified width. Thus, increasing the fracture half-length subsequently yields a larger pore volume, which is characterized as the outer reservoir and the non-stimulated portion of the formation. In the analysis, it is desirable to compare simulation results based on a fixed pore volume per well. To compensate for the additional pore volume by increasing the half-length, porosity in the outermost grid cells (Column 1 and 11; i-direction) are modified to obtain a consistent pore volume among the various half-length cases as show in Table 6 and illustrated in Fig. 30. The adjustment is only valid if the pressure pulse does not reach the outer grid cells. Several match attempts using the 100 and 200 foot half-length models resulted in a pressure drop in this region and were excluded in the analysis for the respected wells. The pore volumes obtained for the reservoir models are: Blades 33-H: 250.7 MMrbbl, Soterra 6-H: 202.4 MMrbbl, Thomas 38-H: 201.5 MMrbbl, Verberne 5-H: 350.5 MMrbbl, Williams 46-H: 302.4 MMrbbl.

Williams 46-H

Xf	Initial PV	Final PV	% Diff	Porosity	Columns
100	60,415	302,228	0.07%	0.99	1
300	181,283	302,493	0.02%	0.207	1
400	241,719	302,439	0.00%	0.1025	1
500	357,191	302,150	0.09%	0.03	0
600	362,592	302,303	0.04%	0.005	1
800	483,485	302,969	0.18%	0.001	2

Table 6: Pore Volume (PV) for each fracture half-length case

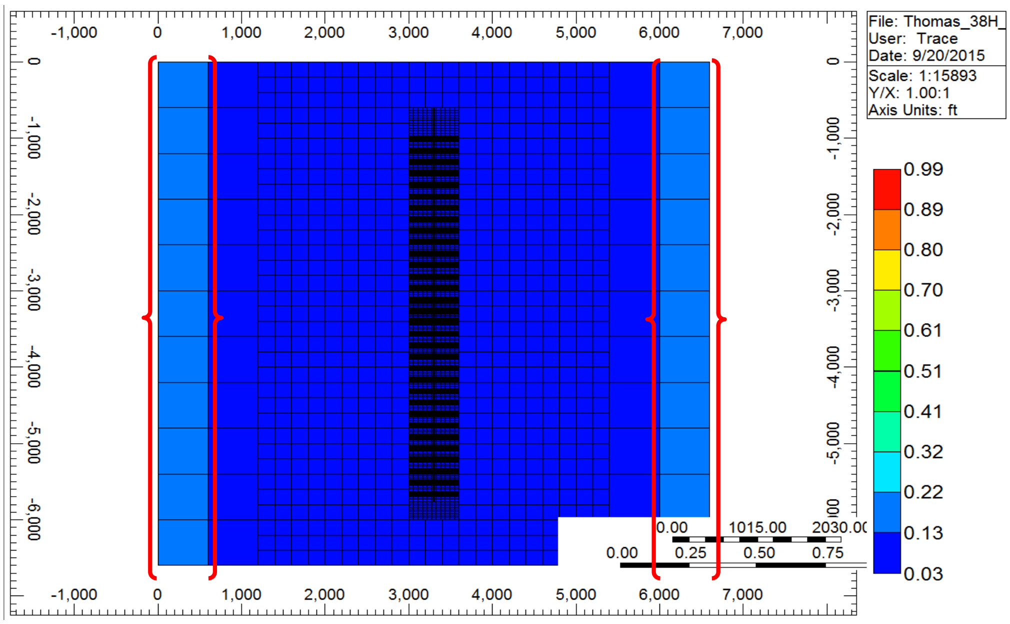


Fig. 30 - Pore Volume Model Configuration

3.5 RESERVOIR AND BOTTOM HOLE PRESSURE:

The reservoir pressure for each model is estimated using the approach outlined in Section 1.1. The models were calibrated to a bottom-hole pressure required to obtain the initial peak oil production rate and then held constant, representing a natural decline. Restricting the bottom-hole pressure and constraining the simulated oil rates to match the initial field production is a representation of choking back flow at the surface (Fig. 31). The highest rate occurs in the early stages of production and over time the propped fractures will begin to close and the decline curve becomes relatively exponential in shape. The grid refinement in each model adequately captures the high pressure depletion near the fracture-matrix boundary and the interface between the induced fractures and wellbore. For a tight shale formation, the average reservoir pressure outside the stimulated zone is expected to remain fairly constant, while the highest pressure drop occurs near the wellbore and is considered the approximated stimulated zone as shown in Fig. 32. Microseismic data would be required to provide additional validation on the volume of rock stimulated during the hydraulic fracturing operation.

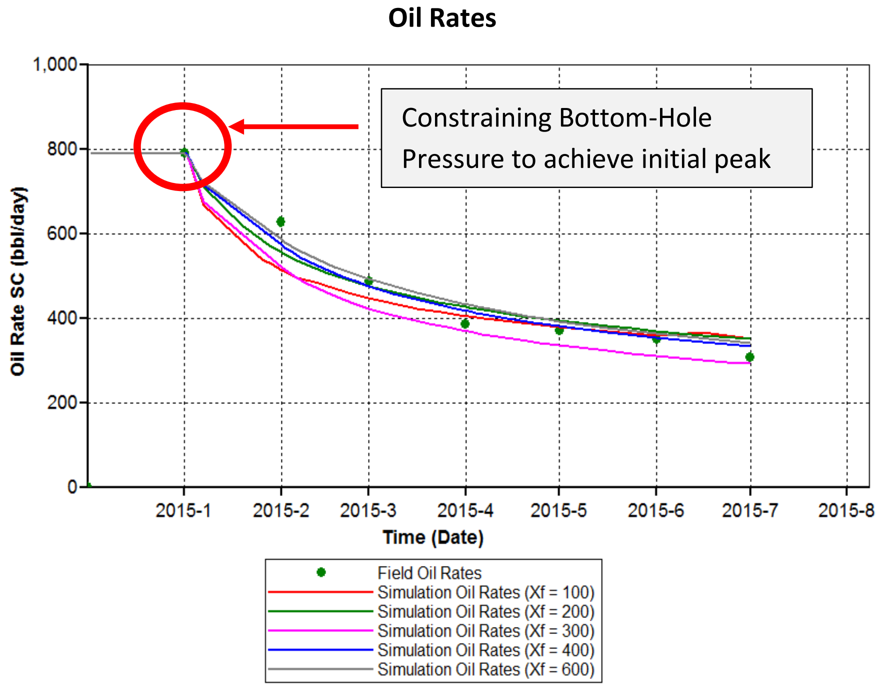


Fig. 31: Simulated oil rate constrained by bottom-hole pressure

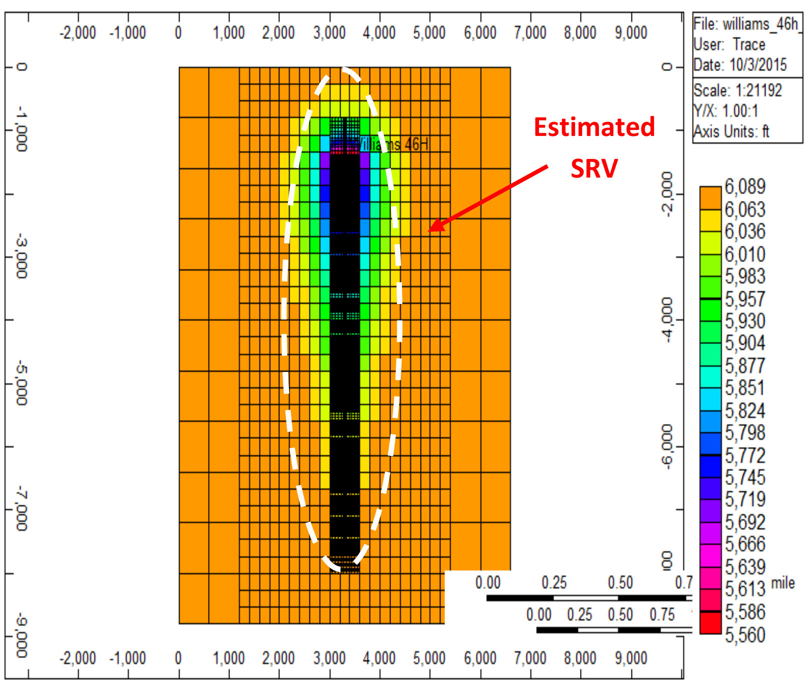


Fig. 32: Average reservoir pressure distribution after 7 months of production

4. RESERVOIR SIMULATION RESULTUS

Sensitivity analysis was performed for each of the five stimulated wells which includes simulation results for the modeled fracture half-lengths of 200', 300', 400', 500', 600', and 800' at three different hydraulic fracture permeability cases: 50, 150, and 450 millidarcy. Fracture half-length of 200' was only included in the analysis for the Verberne 5-H and Blades 33-H as the pressure pulse did not reach the outermost grid cells (Section 3.4). The simulation case which produces the best match for each wells is considered to be the average modeled fracture half-length. In the event where multiple cases provide adequate matches, the likelihood of smaller half-length is believed to be a better representation of the fracture geometry as opposed to cases with elongated, fully propped fractures. These parameters are delineated to estimate the volume of rock stimulated through matching simulated oil rate decline curves and cumulative oil production to the actual field history. Additional information from the stimulation report, such as pressure data, volume pumped, and rates would be required to do a proper evaluation and more accurately quantify the fracture characteristics; therefore the reservoir model is utilized as a guide to approximate values of K_f , X_f, and SRV. The following sections discuss the simulation cases that best matches the actual field production. Shown in Appendices E-J are snapshots of the complete production history matches and reservoir pressure depletion profile for the five stimulated wells.

4.1 WILLIAMS 46-H

The Williams 46-H is a multi-staged hydraulically fractured well consisting of uniform stage length (250') and stage spacing (71'). Goodrich Petroleum categorizes the Williams 46-H as an 'optimally completed well,' meaning a completion design entailing a 6,400' lateral length, more than 450,000 lbs of proppant per stage, and a hybrid slick water frac design (Goodrich Petroleum, 2015). The Williams 46-H is one of Goodrich Petroleum's most recently drilled well and given the stimulation description, 5,000' of the horizontal wellbore was stimulated (76% of the total lateral). The 24 hour initial production test recorded for the well is 1,240 BOE/D, however a bottom-hole pressure constraint was applied for December 2014 to obtain the first month's average oil rate (789 BOPD) and cumulative oil production. After 7 months of production data reported to the state, the percent difference among the simulation results (K_f = 150 mD) to the field data for 300-400' fracture half-length is less than 2% (Fig.33). Figure 34 shows that the pressure drainage covers a greater aerial extent for the Williams 46-H (~1200') as opposed to the Verberne 5-H (~900') in the first six months of production, suggesting a larger volume of rock was stimulated. With a 14% increase in production and similar completion design as compared to the Verberne 5-H, a slightly longer average fracture half-length (300-400’) and marginally higher induced fracture effective permeability (50-150 mD) is attributed to the well’s increase in productivity. The fracture permeability analysis between 50 and 150 mD showed negligible difference between the cases (0.30%), accordingly, K_f values between 50-150 mD is the approximated range for the Williams 46-H (Appendix J).

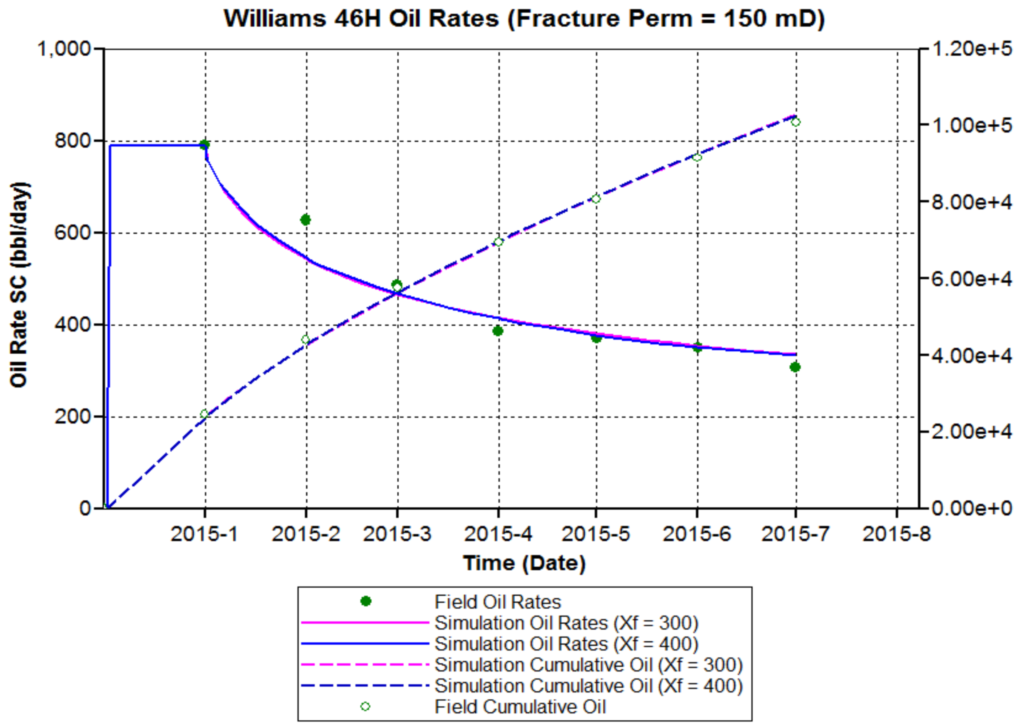


Fig. 33: Williams 46-H oil rate and cumulative oil simulation results

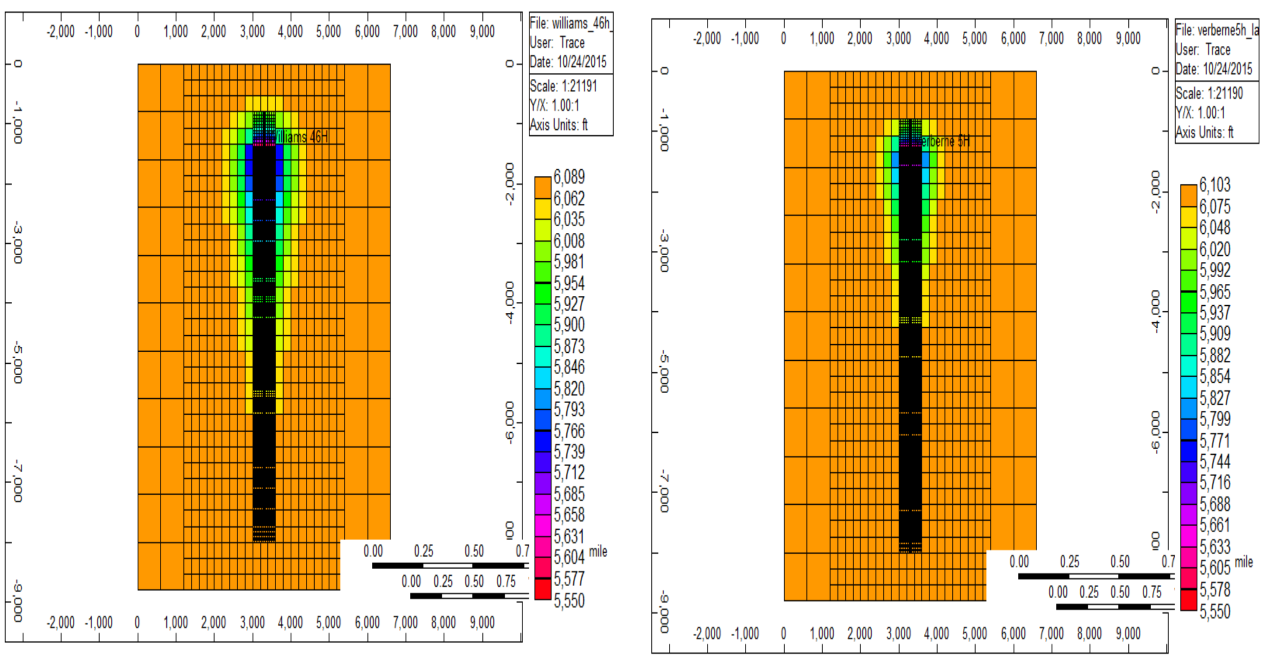


Fig. 34: Pressure depletion results after six months of production: (Top Left) Williams 46-H, Xf= 300’ (Top Right)

4.2 VERBERNE 5-H

The Verberne 5-H was completed in November 2014 and the design entails 21 stages with uniform stage spacing and length of 64' and 250' respectfully. Nearly 80% of the total lateral length (6,600') was stimulated. In contrast to the neighboring well, Williams 46-H, the Verberne 5-H consisted of an additional one stages, tallying 250' of excess rock stimulated and resulted in 11,434 bbls less produced in the first six months. The initial 24 hour production test reports the well flowed at 1,335 BOPD on a 14/64th choke (*PR Newswire*, 2015). Preliminary simulation runs consisted of setting a constraint for the first month's average oil rate (955 BOPD), but resulted in a decline curve higher than the actual field rates. When initially bringing a well on production, it is common for the choke to be adjusted during flowback at early time. An alternative approach was considered in modeling the Verberne 5-H by setting a maximum oil rate constraint equal to the initial production (1,335 BOPD) for several days to attain a cumulative recovery match and then controlling production by applying a constant bottom-hole pressure for the remaining simulation time. Modification of the well constraints provided a fracture half-length, with the lowest percent difference between the simulated and actual production, to be an average of 300' with a fracture permeability of 50 mD (Fig. 35). Figure 34 in Section 4.1 illustrates the radial drainage area is smaller for the Verberne 5-H than the Williams 46-H, and with having the lowest recorded 6 month cumulative production among the group of three Goodrich Petroleum wells, a smaller SRV is suggestive. Figure 35 depicts a sufficient match is not obtained for cases with more elongated fracture half-length as the decline curve is not steep enough to capture the effects of lower conductivity as a result of fractures closing within the first six months of production.

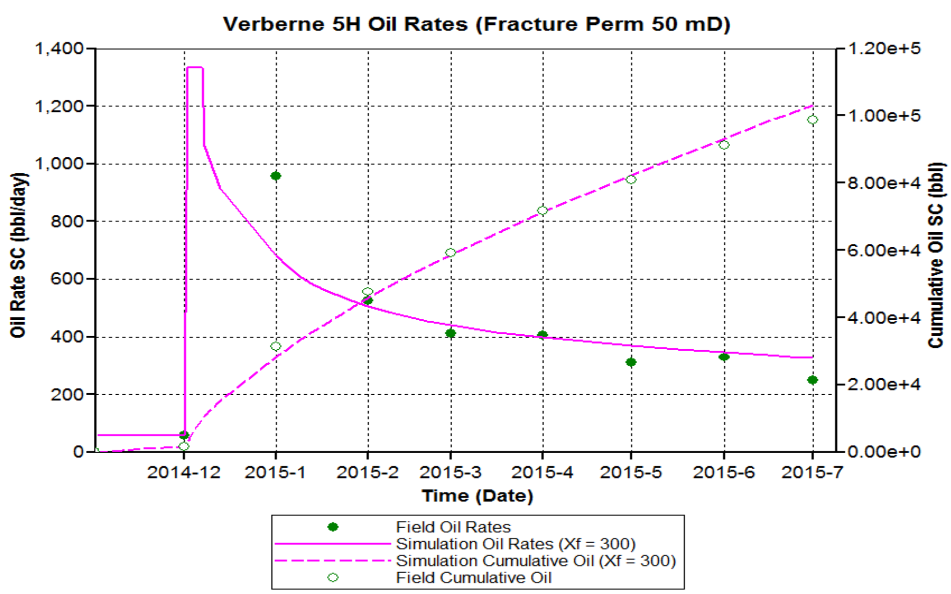


Fig. 35: Verberne 5-H oil rate and cumulative oil simulation results

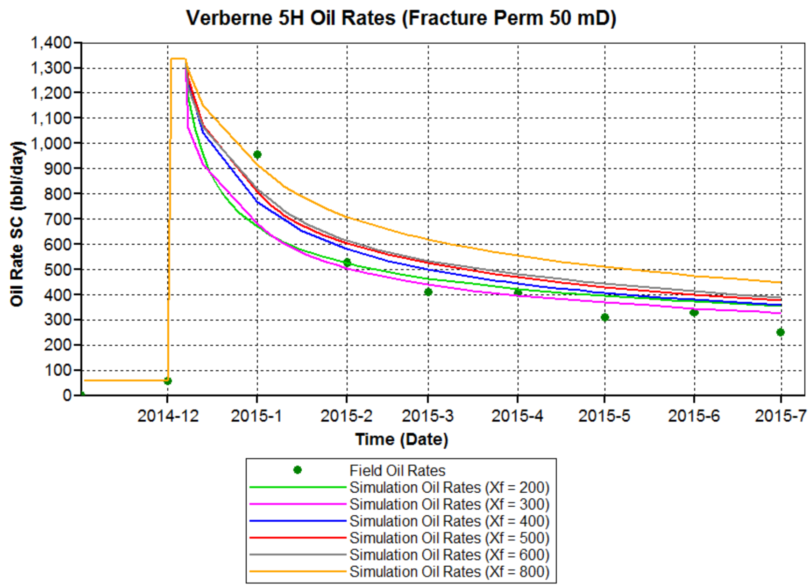


Fig. 36: Verberne 5-H oil rate and cumulative oil simulation results (all cases)

4.3 BLADES 33-H

The Blades 33-H was drilled several months prior to the Williams 46-H and is likewise classified by Goodrich Petroleum as an optimally completed well. Similar to the completion design of the nearby Williams 46-H, the Blades 33-H is comprised of a uniform stage length (180') and spacing (49'). Between stages 15 and 16, (13,105'-13,608' MD) roughly 500' of the lateral is not stimulated, thus the total stimulated area along the 5,100' lateral section is 70%. The Blades 33-H was drilled horizontally 1,500' less than the Williams 46-H, translating to 1,400' of less rock stimulated. The initial 24 hour production reported is 1,270 BOED and the six month cumulative oil is 3,224 barrels less than the highest producer among the five wells, the Williams 46-H. A maximum oil rate constraint was set to the first month's average rate of 768 BOPD, and then the corresponding bottom-hole pressure to attain the peak oil rate was held constant. After 15 months of production, the average reservoir pressure depleted nearly 30 psi, according to Fig. 37 and a modeled fracture half-length of 500' (K_f = 50 mD) producing the closest match to the decline behavior and cumulative oil production.

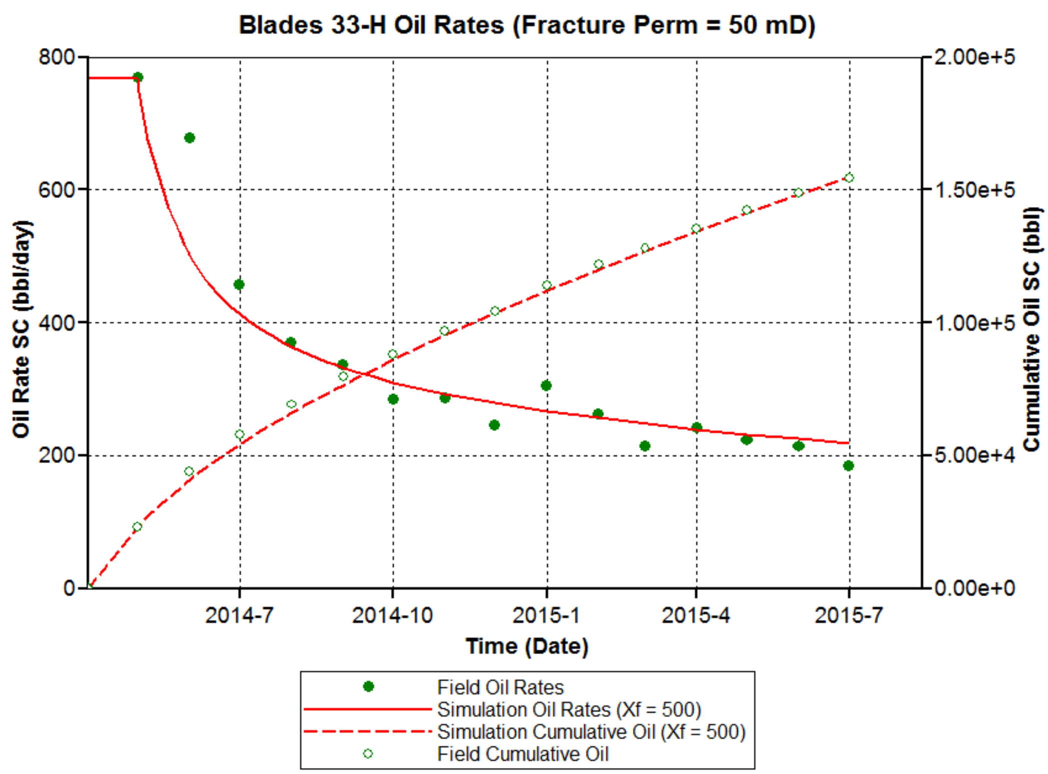


Fig. 37: Blades 33-H oil rate and cumulative oil simulation results

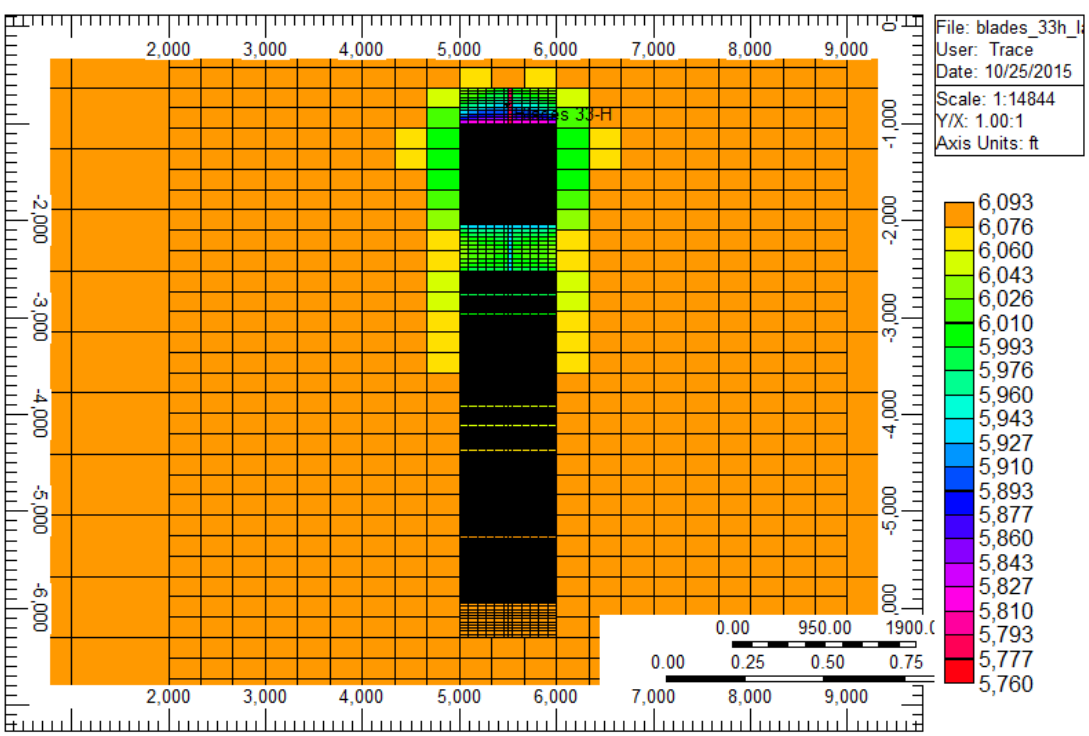


Fig. 38: Blades 33-H Pressure depletion results after six months of production: $X_f = 500'$, $K_f = 50$ mD

4.4 SOTERRA 6-H

The Soterra 6-H is an outlying well analyzed in this study and was modeled under analogous conditions as the group of wells located in the near vicinity of the Winfred Blades #1. The matrix rock properties estimated from the control well holds as a reasonable approximation in the regionalized area of the Tuscaloosa Marine Shale (Central and Northern Tangipahoa Parish, LA) given the production history match results of the Soterra 6-H (Fig. 39). After 3.5 years of producing, the cumulative oil production is 41,388 barrels, which is nearly half the production reported for each of the three Goodrich Petroleum drilled wells in the first six months. As one of the earlier wells drilled in the TMS, the optimal completion design learning curve has shown a strong correlation between higher production rates and increasing the lateral and stage length. Roughly 70% of the 3,929 horizontal lateral was stimulated for the Soterra 6-H, and in comparison is almost half the of rock volume contacted by the Verberne 5-H and Williams 46-H with laterals greater than 6,000'. The simulation result which yielded the closest match to the actual field history is the case with an average fracture half-length of 600' with K_f = 50 mD, translating into 24.9 bbl/ft in six months of production. The stimulated reservoir volume is shown to be considerably less according to the simulation results in Fig. 40. The reservoir depletes roughly 15 psi and the drainage covers an aerial extent of 1,500' contributing to production as opposed to the Thomas 38-H (X_f = 800'), where the pressure declines 45 psi and reaches 2,400' in the first six months. Alternatively, the lower productivity can also be attributable to the geographical location of the well. As shown in Fig. 41, the well is in a region with a lower percent of TOC (1.75%).

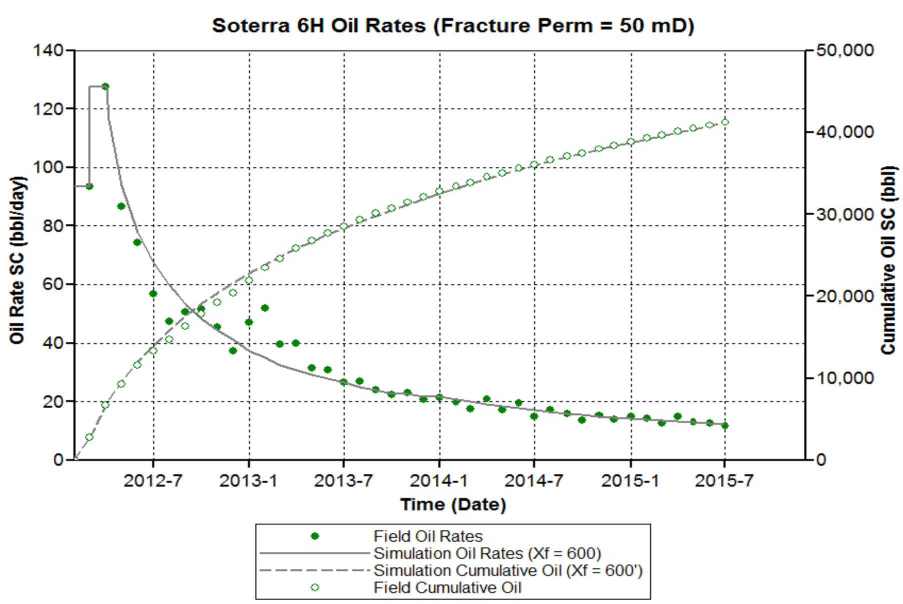


Fig. 39: Soterra 6-H oil rate and cumulative oil simulation results

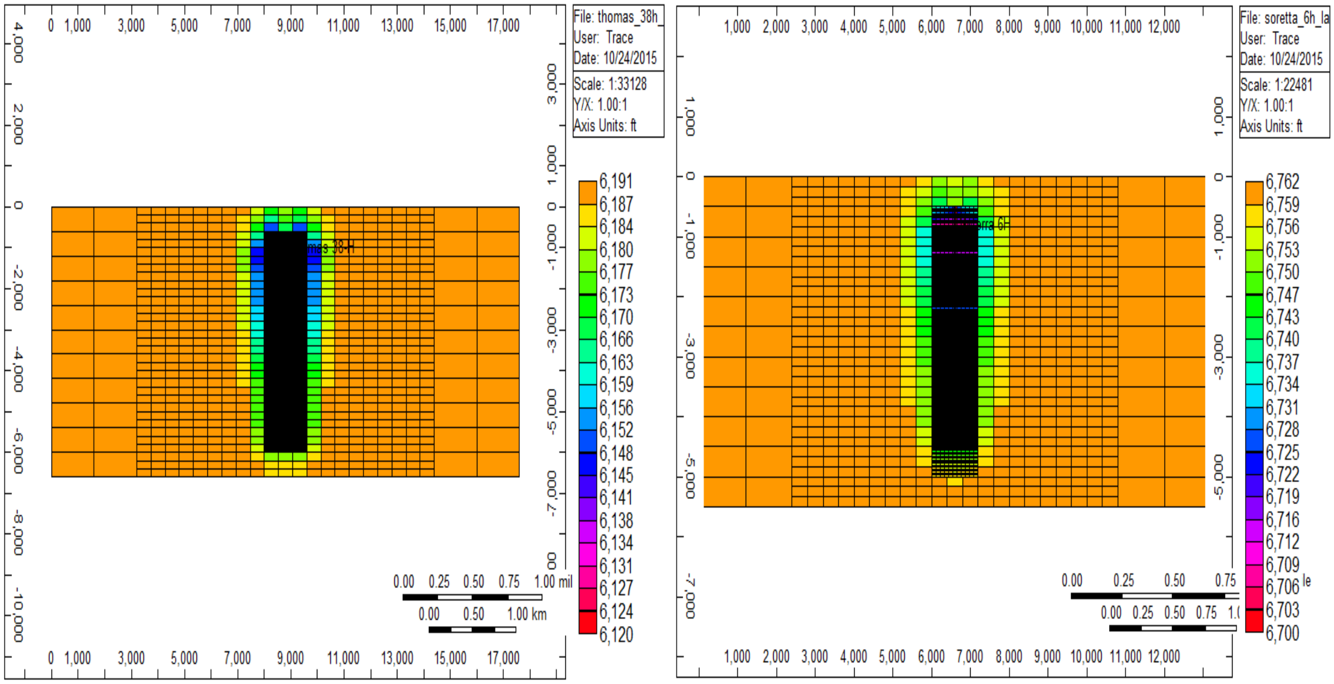


Fig. 40: Pressure depletion results after six months of production: (Left) Thomas 38-H, X_f= 800' (Right) Soterra 6-H, X_f = 600'

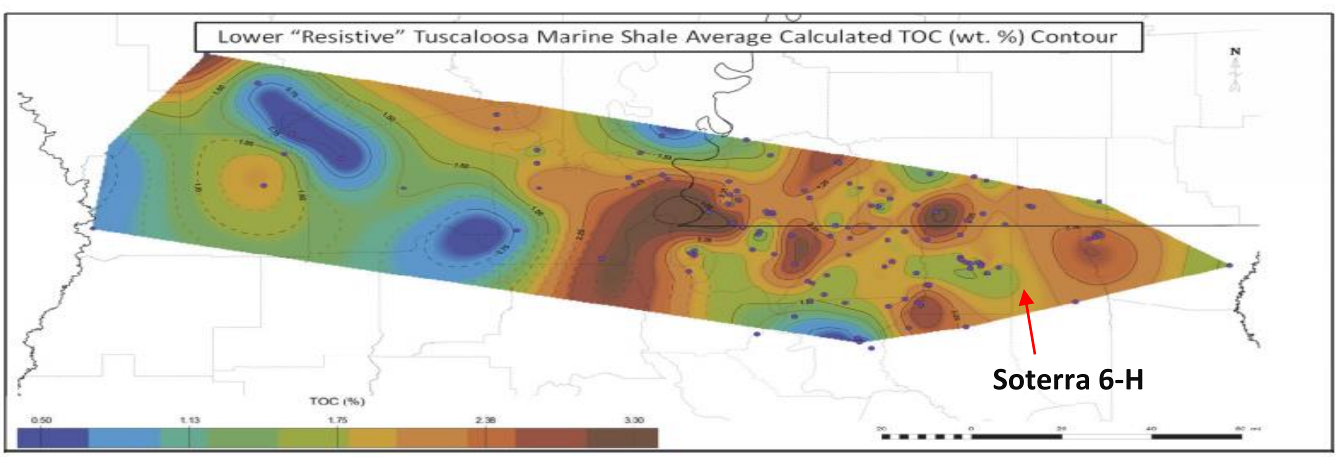


Fig. 41: Total Organic Content contour map: Higher resistivity section in the Lower TMS (Berch, 2013)

4.5 THOMAS 38-H

Drilled by Devon Energy in late 2012, the Thomas 38-H, similar to the Soterra 6-H, was a part of the TMS learning curve in which operators were attempting to delineate the optimal completion design to yield the maximum production output. With 48% of the 5,086' lateral wellbore stimulated, the initial production test records a 470 BOPD oil rate, which is an early indication of the expected well's performance. The constraints applied to the Thomas 38-H well consisted of setting a maximum production rate equal to the field rates for the first two months. Next, the bottom-hole pressure was adjusted until the pressure required to produce 470 barrels was reached. Due to the uncertainty of the choke's position and the monthly oil rates reported (November & December 2012), the bottom-hole pressure for the ensuing month, December 2012, was increased nearly 50 psi in order to reduce production rates below 200 BOPD to more closely mimic the field behavior. Goodrich Petroleum acquired Devon Energy's Soterra 6-H, but documentation on when the exchange occurred was not available. Production increased by 80 barrels in early 2014 and it appears from satellite imagery (Google Earth, 2014) the well was placed on a pumping unit (Data not available to confirm). The bottom-hole pressure was adjusted in January 2014 to achieve an oil rate of 158 barrels. Figure 45 illustrates the four BHP constraints applied to the reservoir model. Production history match results shows adequate results, vindicating marginal differentiation in the rock matrix parameters for the Thomas 38-H and thus the average fracture half-length of 800' with a fracture permeability of 50 mD (Fig. 42) best mimics the actual field behavior. The 800' averaged fracture half-length is expected to be much thinner and lower in frequency given the poor well productivity among the three Goodrich Petroleum wells examined in this work. Furthermore, Goodrich Petroleum reported the average clay content, quartz, and calcite from core samples for both the Soterra 6-H and Thomas 38-H and is listed in Table 7 (Goodrich, 2015). As the percentage of quartz and calcite increases, the Young's Modulus increases while the Poisson's Ratio is lower, resulting in a higher brittleness (Wenlong et al 2011). Comparison between the two wells suggests the region in proximity to the Thomas 38-H tends to be more brittle and is more conducive to produce from both the natural and induced fractures as opposed to the Soterra 6-H.

	Soterra 6-H	Thomas 38-H
Clay	15%	10%
Quartz	18%	23%
Calcite	23%	24%

Table 7: Mineral composition from cores taken for Soterra 6-H and Thomas 38-H (Goodrich, 2015)

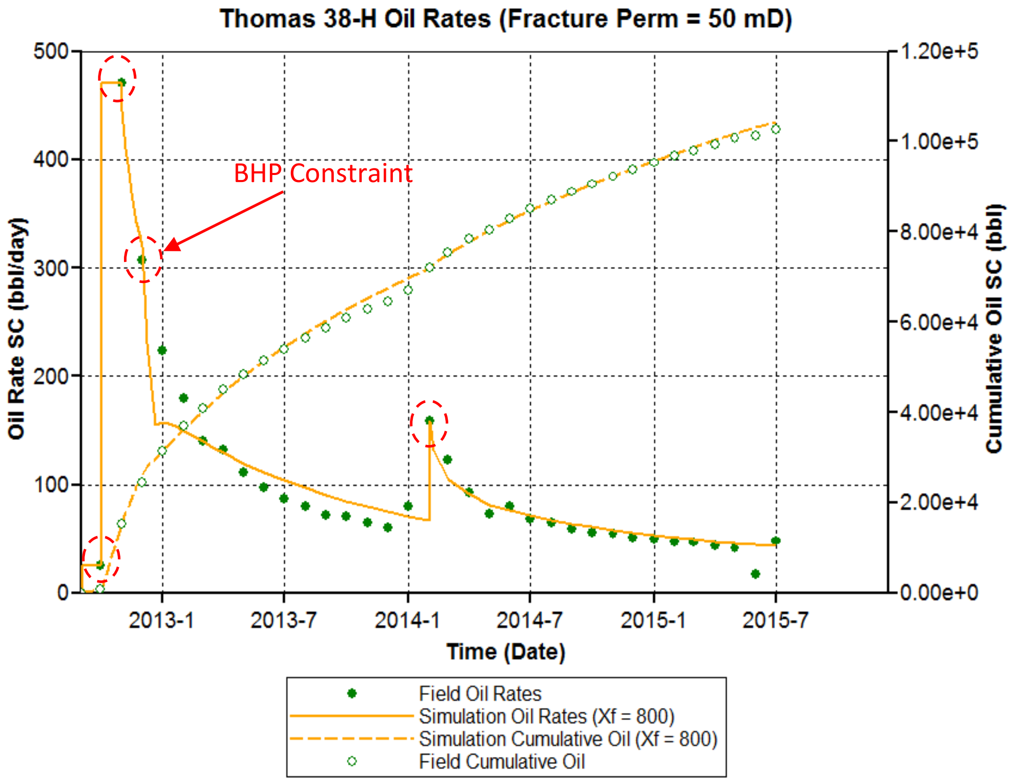


Fig. 42: Thomas 38-H oil rate and cumulative oil simulation results

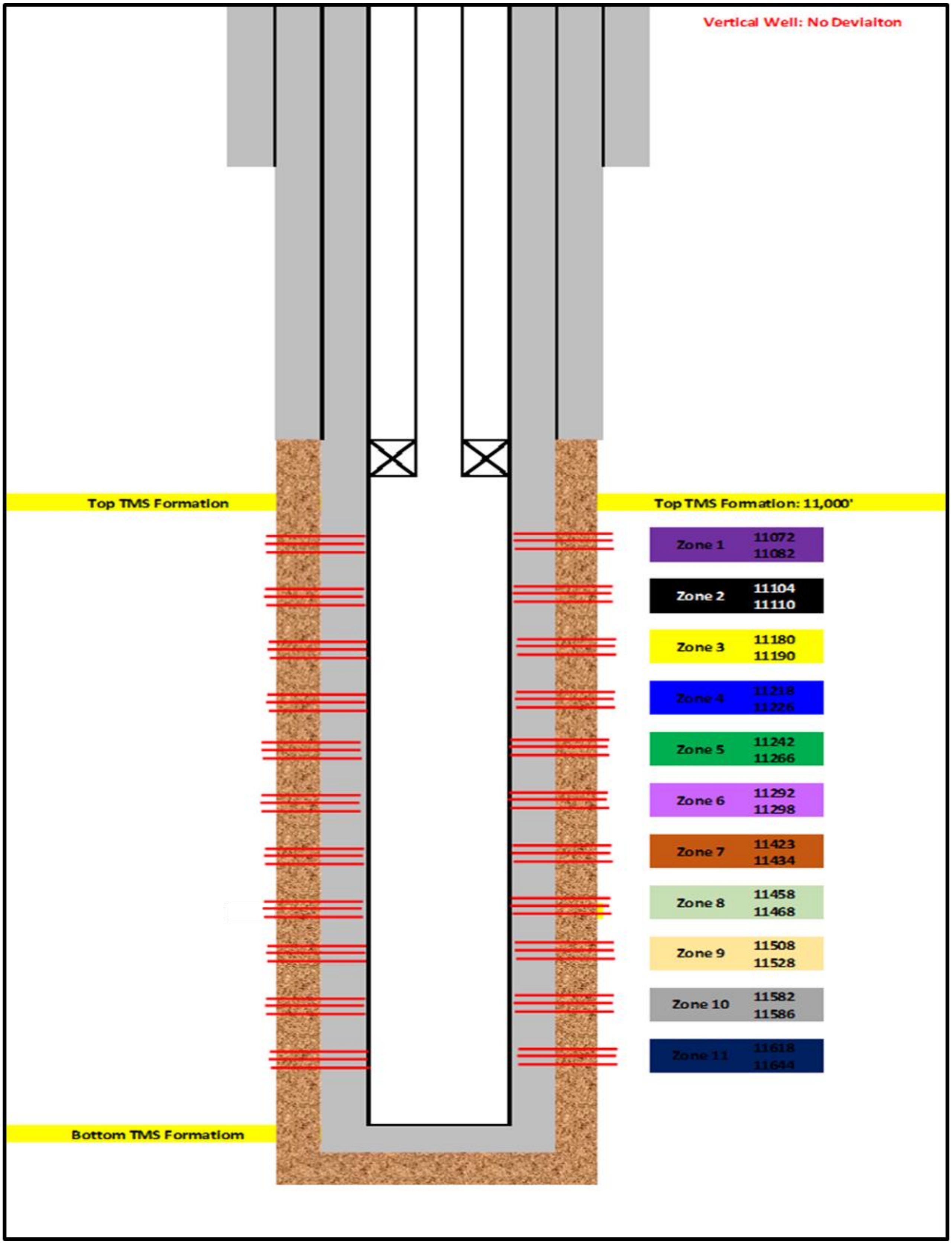
3. Conclusion

The workflow illustrated in this study provides a method for approximating rock properties and induced fracture characteristics for five hydraulically fractured wells in the Tuscaloosa Marine Shale. Through production history matching for a vertical, non-stimulated well actively producing in the TMS, the Winfred Blades #1 provided as a proxy for estimating formation rock properties in northern portions of Tangipahoa Parish. Modeling a series of near-by hydraulically fractured wells confirmed the matrix permeability ($K_m = 0.06$ mD) and porosity ($\Phi_m = 5\%$) in the stimulated zone to be a reasonable estimation. Extending the analysis roughly 10 miles to the northwest and southwest, the estimated matrix parameters are deemed to be applicable for both simulated wells, Soterra 6-H and Thomas 38-H, as the simulation results yield adequate matches to the field production data.

The permeability of hydraulic fractures are shown to be approximately 50 to 150 millidarcy as the production history matches among the five stimulated wells modeled provide consistent matches under these conditions. The half-length of the stimulated zone for the Verberne 5-H is 300’ and the Williams 46-H averages between 300’ to 400’, providing the best matches with the field production. The Blades 33-H is Goodrich Petroleum’s top performing well on a bbl/1000’ lateral basis and the corresponding modeled induced half-length for the well is estimated to be 500’, slightly longer than the other two wells the company drilled in the same vicinity. The Soterra 6-H and Thomas 38-H simulation results indicate a stimulated zone half-length of 600’ and 800’ (K_f = 50 md), respectively and is suggesting of thinner, elongated fractures given the lower well productivity. Moreover, if microseismic monitoring was conducted for the Soterra 6-H and Thomas 38-H, this information should be incorporated in the analysis to determine whether the vertical fracture height growth is significantly less, translating to a lower stimulated reservoir volume than the models account for. The Soterra 6-H production is almost 65% less than the Thomas 38-H in the first six months and stimulated an additional 1700’ of pay, suggesting the differential in production may be related to location of the well, where the estimated total organic content is much less, around 1.75% on the central-western flank of Tangipahoa Parish (Fig. 41).

Future work should consider additional horizontal wells sampled throughout the TMS as the area of interest this work focuses on is yet an active section of the formation, but only a small portion of the unconventional play. Finally, an impending analysis should be conducted to provide additional insight into the lower performing wells by examining the direction of continuity for the regional minimum principle stress and whether the induced fractures are connecting to a high density natural fracture network. Better understanding of the principle stress directions and fracture attributes can ultimately maximize the total hydrocarbon recoveries by allowing operators to optimize stage spacing, well trajectory, and well planning.

APPENDIX A: WINFRED BLADES #1 WELLBORE SCHEMATIC



APPENDIX B: WINFRED BLADES #1 PVT DATA

INPUTS	
Temperature (F)	230
Temperature [R]	690
Oil Specific Gravity	0.839
API (Degrees)	37.2
Gas Gravity	0.65
Separator Temp (F)	100
Separator Pressure (psi)	100
GOR (ft3/BBL)	167
Bubble Point Pressure (PSI)	1088
N2	0
CO2	0
H2S	0
Reservoir Pressure	6036

Table 8: Winfred Blades #1 PVT Input Parameters

Pressure (psi)	GOR (scf/stb)	Bo (rbbl/stb)	Z Factor	Visc. Oil (cp)	Visc. Gas (cp)	Compressibility (psi^{-1})
14.7	1.01	1.1087	0.9989	1.1913	0.01409	0.0015192
200	22.37	1.1189	0.9853	1.0708	0.01419	0.0001170
400	50.92	1.1326	0.9715	0.9528	0.01435	0.0000621
600	82.40	1.1477	0.9587	0.8575	0.01456	0.0000440
807	117.14	1.1644	0.9467	0.7782	0.01482	0.0000349
900	133.34	1.1722	0.9417	0.7477	0.01494	0.0000322
1000	151.10	1.1807	0.9366	0.7179	0.01509	0.0000298
1200	187.61	1.1947	0.9276	0.6727	0.01541	0.0000264
1400	225.27	1.2073	0.9200	0.6417	0.01575	0.0000240
1600	263.97	1.2210	0.9140	0.6176	0.01613	0.0000222
1800	303.58	1.2355	0.9096	0.5988	0.01654	0.0000208
2000	344.02	1.2506	0.9069	0.5843	0.01697	0.0000197
2500	448.35	1.2905	0.9072	0.5618	0.01814	0.0000179
3000	556.67	1.3322	0.9167	0.5531	0.01941	0.0000167
3500	668.45	1.3753	0.9338	0.5536	0.02072	0.0000159
4000	783.26	1.4193	0.9569	0.5606	0.02206	0.0000154
4500	900.79	1.4640	0.9847	0.5723	0.02339	0.0000150
5000	1020.79	1.5092	1.0159	0.5873	0.02470	0.0000147
5500	1143.06	1.5547	1.0497	0.6048	0.02598	0.0000144
6000	1267.43	1.6005	1.0854	0.6238	0.02722	0.0000143
6500	1393.76	1.6464	1.1227	0.6439	0.02842	0.0000141
7000	1521.91	1.6923	1.1612	0.6645	0.02959	0.0000141

Table 9: Winfred Blades #1 PVT

APPENDIX C: WINFRED BLADES #1 PRODUCTION DATA

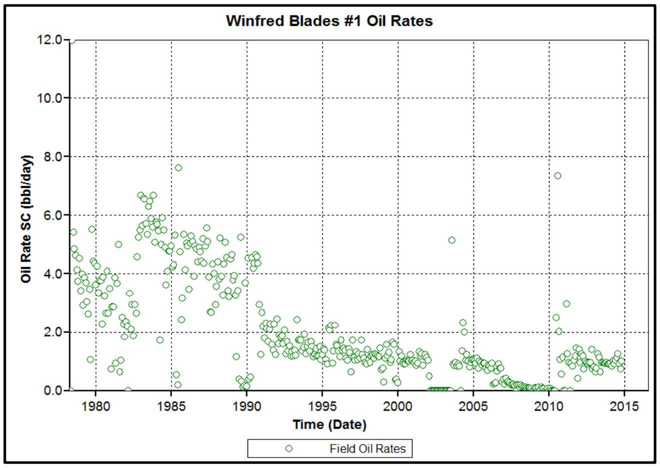


Fig. 43 – Field Oil Rate

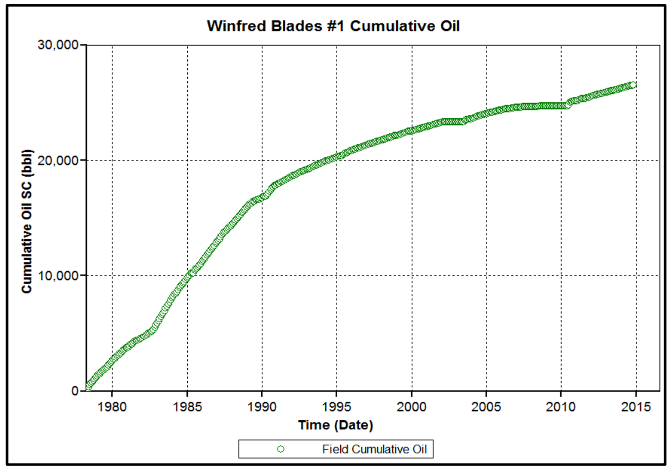


Fig. 44– Field Cumulative Oil

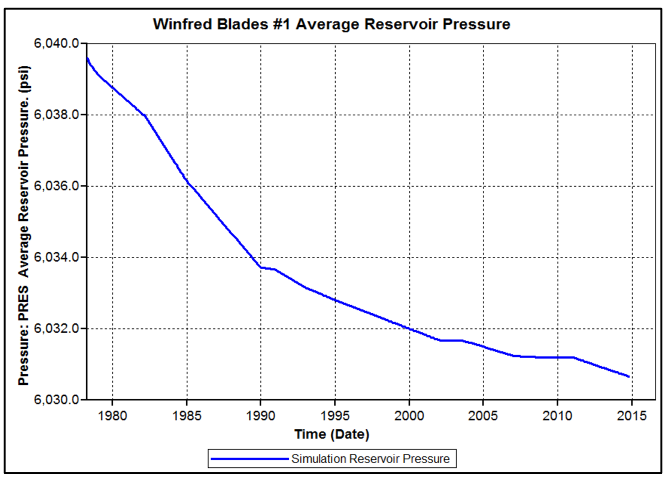


Fig. 45 – Reservoir Pressure

APPENDIX D: TMS WELL PARAMETERS:

	Blades 33H	Verberne 5H	Soterra 6H	Williams 46H	Thomas 38H
Serial Number	247207	248323	243765	248405	244870
Operator	Goodrich Petroleum	Goodrich Petroleum	Devon Energy	Goodrich Petroleum	Devon Energy
Field Name	Little Silver Creek	Little Silver Creek	Fluker	Little Silver Creek	Kentwood
Parish	Tangipahoa	Tangipahoa	Tangipahoa	Tangipahoa	Tangipahoa
Production Type	Oil Well	Oil Well	Devon Energy	Goodrich Petroleum	Devon
API Number	1710520046	1710520046	17105200390000	17105200500000	17105200420000
Spud Date	41658	41658	40826	41893	41052
Status	Actively Producing	Actively Producing	Producing	Producing	Producing
TVD	11660	11660	12646	11614	11809
MD	17,136'	17,136'	16936	18650	17225
Perfs (MD)	12'064-17,009'	12'064-17,009'	13,108-16,829	12,172-18,501	12,383-17,113
Reference Depth	11,660'	11,660'	12646	11614	0
Stimulation	Hydraulic Fracturing	Hydraulic Fracturing	Hydraulic Fracturing	Hydraulic Fracturing	Hydraulic Fracturing
Artificial Lift	No	No	0	No	None
Surface Longitude	90-24-43	90-24-43	0	90-23-36	90-29-30
Surface Latitude	30-55-20	30-55-20	0	30-54-29	30-57-28
Ground Elevation	324	324	0	289.5	203.6
Kelly Elevation	26	26	0	0	232

Table 10: TMS Well Details

Blades 33-H

Date	Water (bbl)	Oil (bbl)	Water Cut
10/16/2015	46	162	28%
3/30/2015	42	208	20%
10/7/2014	55	309	18%
4/11/2014	614	**1,136**	54%
Frac Water (gals)	**11,282,275**		
Estimated (gal) YTD	5,507,019		
% Water Recovered	49%		

Verberne 5-H

Date	Water (bbl)	Oil (bbl)	Water Cut
11/1/2015	26	**195**	13%
5/1/2015	92	353	26%
Frac Water (gals)	**N/A**		
Estimated (gal) YTD	789,096		
% Water Recovered	N/A		

Williams 46-H

Date	Water (bbl)	Oil (bbl)	Water Cut
10/1/2015	34	**251**	14%
5/1/2015	70	371	19%
Frac Water (gals)	**7,880,215**		
Estimated (gal) YTD	940,254		
% Water Recovered	12%		

Soterra 6-H

Date	Water (bbl)	Oil (bbl)	Water Cut
11/1/2015	12	15	80%
5/1/2015	18	10	180%
11/1/2014	7	20	35%
5/1/2014	9	22	41%
11/1/2013	15	27	56%
5/1/2013	20	30	67%
11/1/2012	17	49	35%
5/1/2012	23	97	24%
Frac Water (gals)	**3,823,858**		
Estimated (gal) YTD	918,477		
% Water Recovered	24%		

Table 11a: Water Production and Frac Water Data (SONRIS, FracFocus)

Thomas 38-H			
Date	**Water (bbl)**	**Oil (bbl)**	**Water Cut**
10/17/2015	56	23	2.434782609
3/30/2015	77	55	1.4
10/21/2014	105	65	1.615384615
3/11/2014	126	99	1.272727273
9/10/2013	30	80	0.375
4/15/2013	25	102	0.245098039
10/24/2012	92	394	0.233502538
Frac Water (gals)	**4,938,584**		
Estimated (gal) YTD	3,681,594		
% Water Recovered	75%		

Table 11b: Water Production and Frac Water Data (SONRIS, FracFocus)

APPENDIX E: BLADES 33-H SIMULATION RESULTS

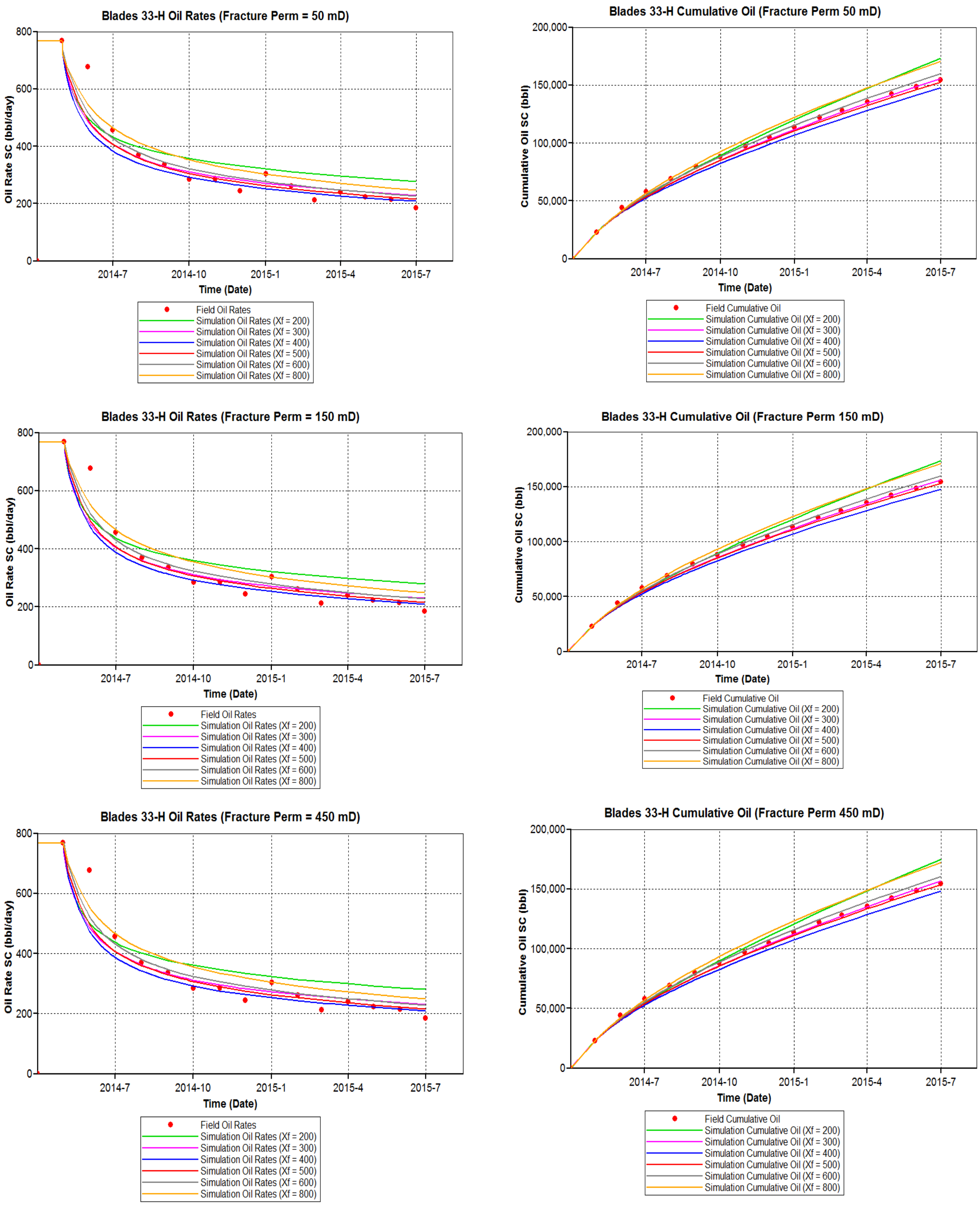
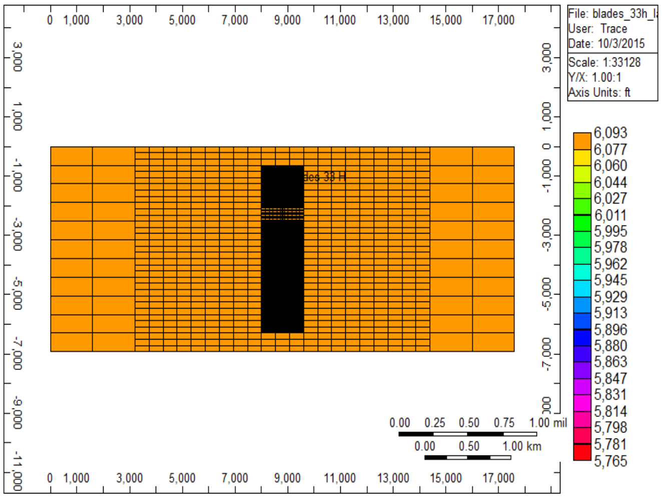
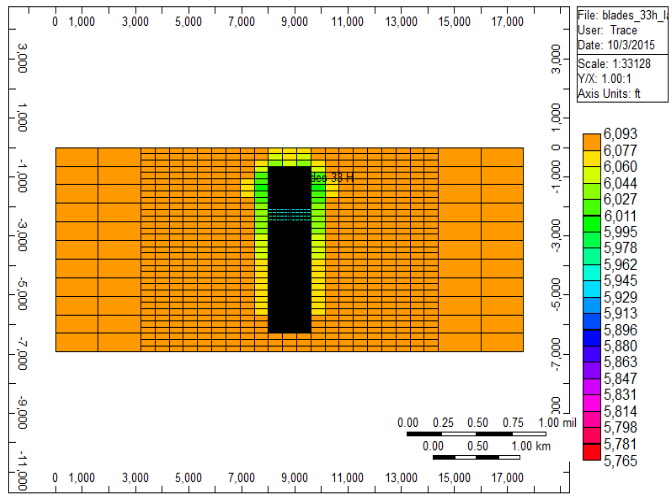


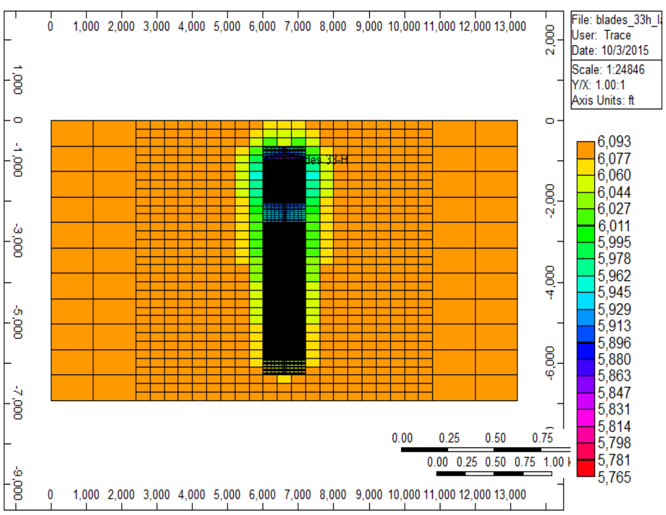
Fig. 46: Blades 33-H Simulation Results: Rates and Cumulative Oil



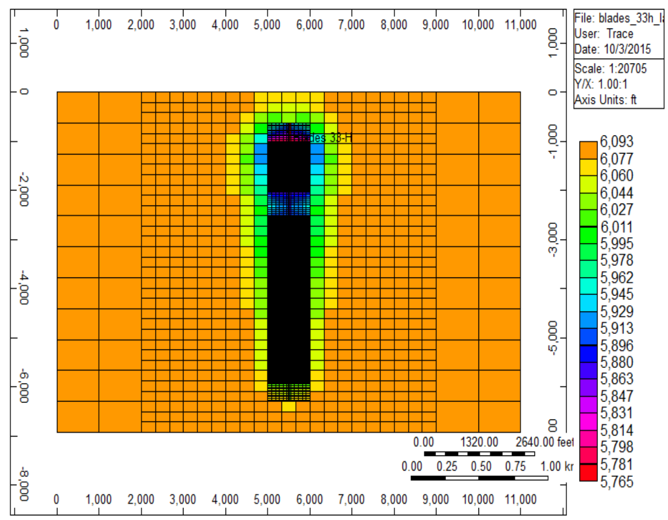
A. Initial Pressure Distribution ; K_f = 150mD



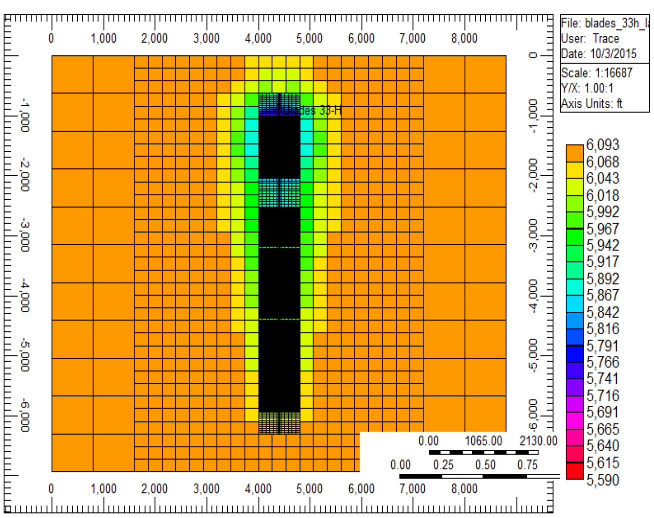
B. Pressure Distribution Xf = 800'



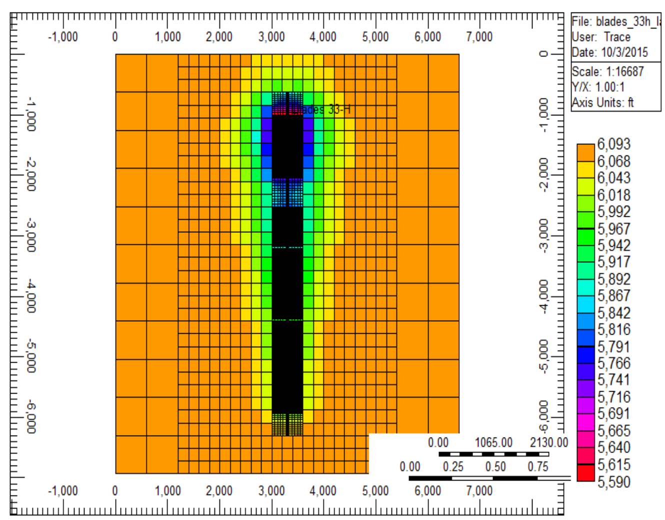
C. Pressure Distribution Xf = 600'



D. Pressure Distribution Xf = 500'

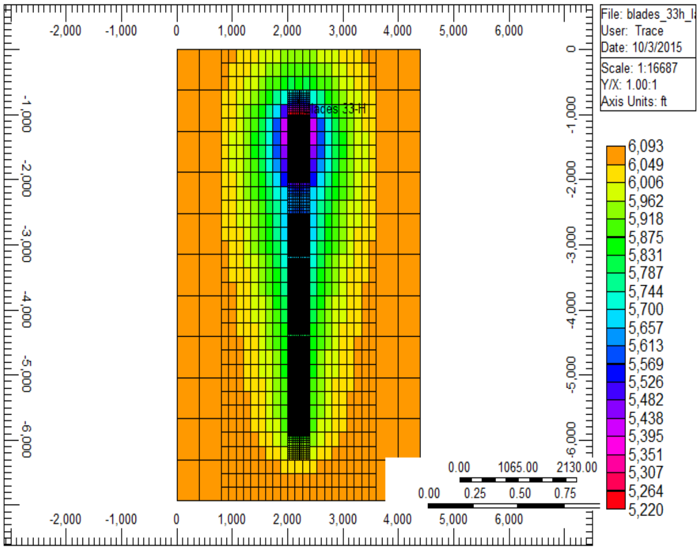


E. Pressure Distribution Xf = 400'



F. Pressure Distribution Xf = 300'

Fig. 47a – Blades 33-H Pressure Profile



F. Pressure Distribution Xf = 200’

Fig. 47b – Blades 33-H Pressure Profile

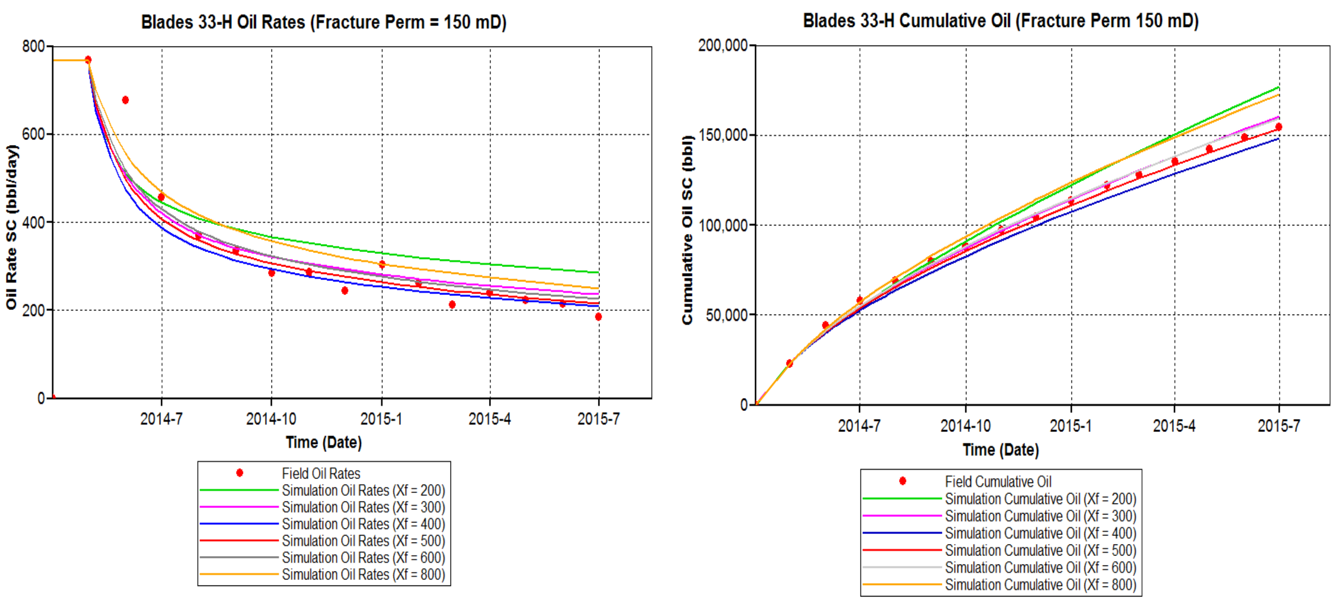
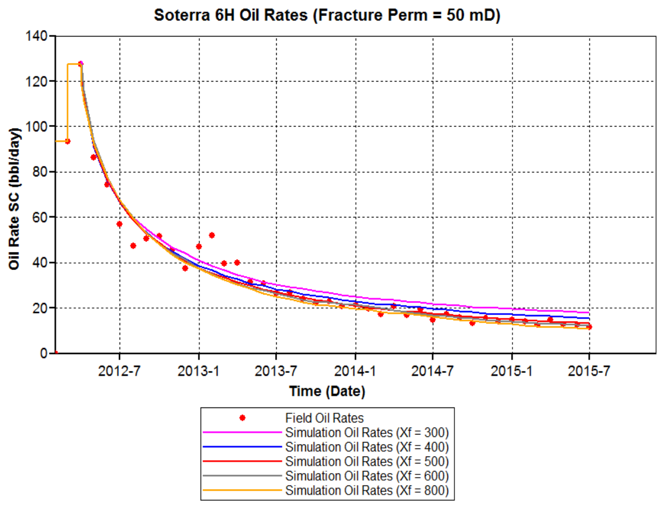
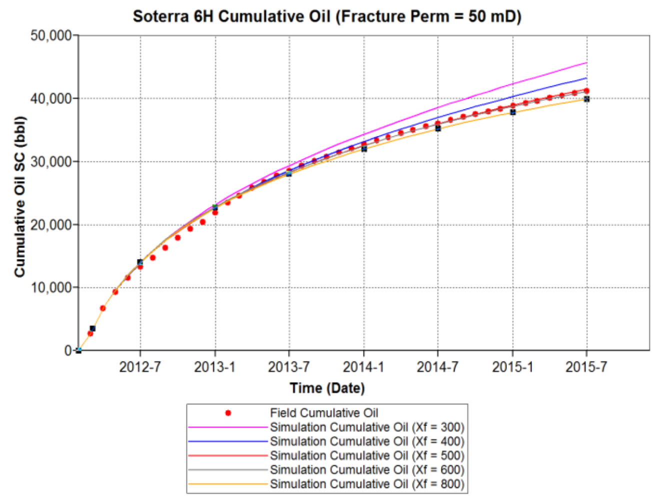
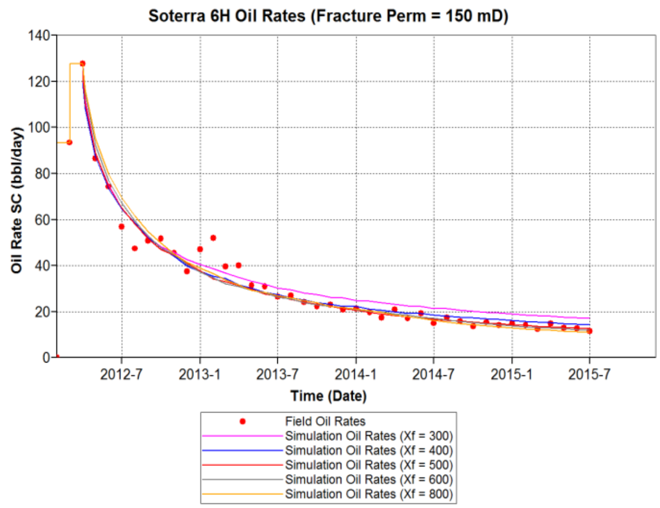


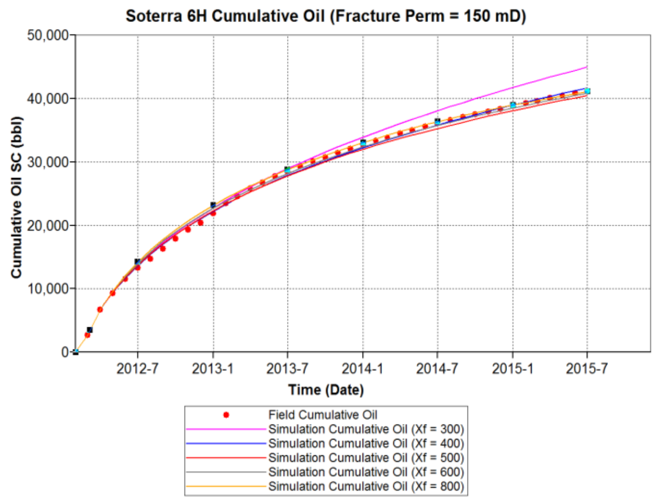
Fig. 48 – Blades 33-H History match results (Adjusting relative permeability curves to account for water production)

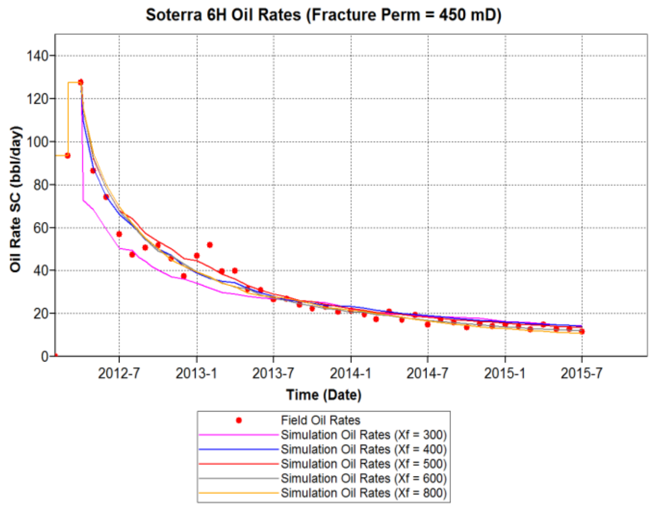
APPENDIX F: SOTERRA 6-H SIMULATION RESULTS











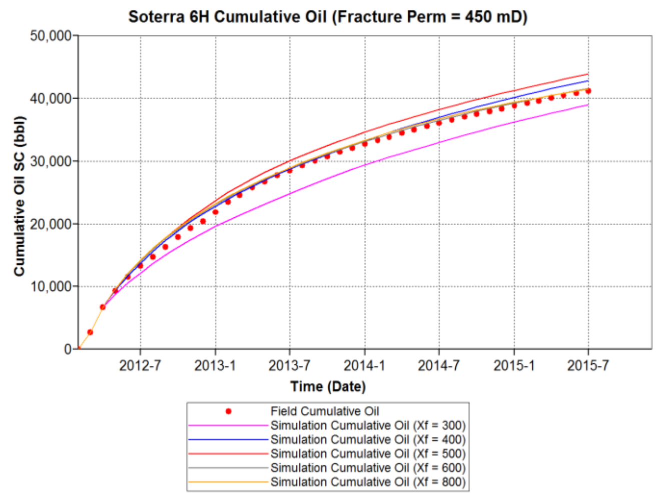
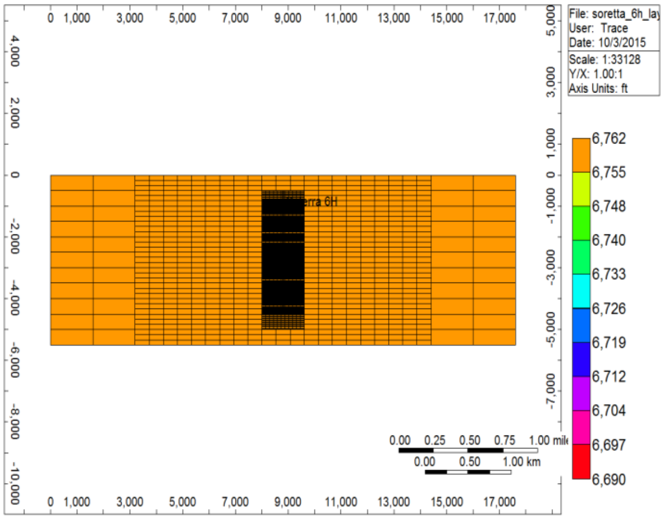
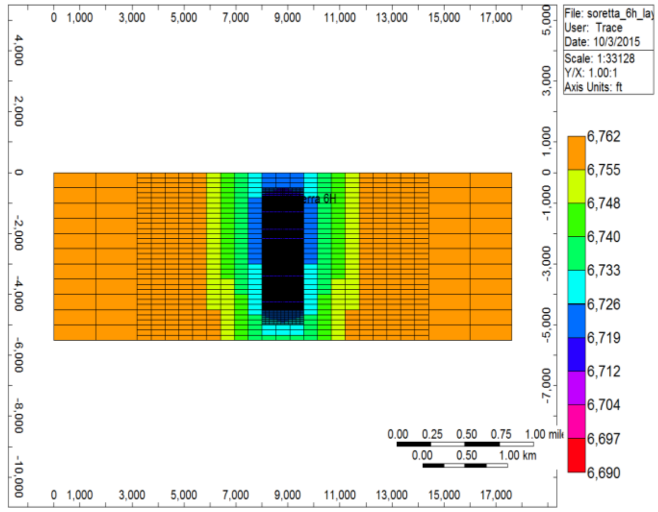


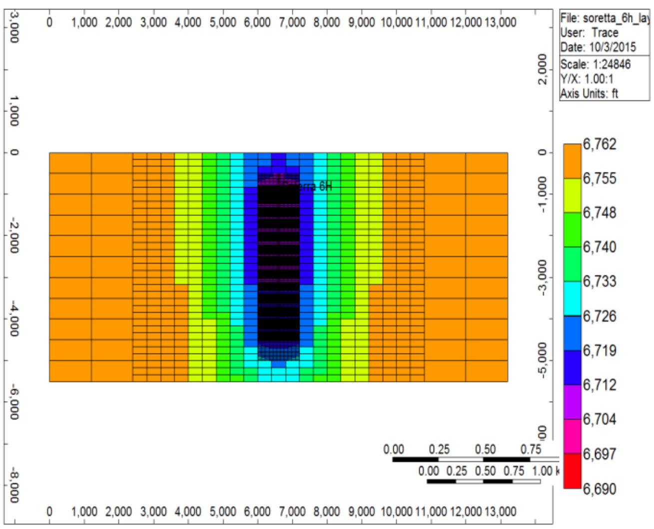
Fig. 49: Soterra 6-H Simulation Results: Rates and Cumulative Oil



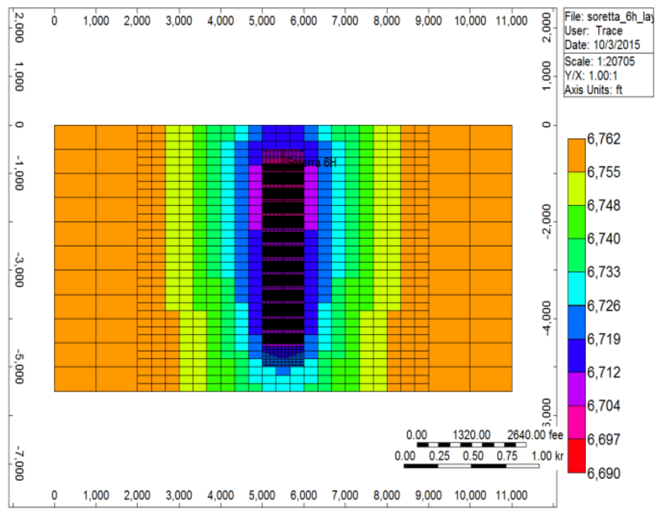
A. Initial Pressure Distribution ; K_f = 150mD



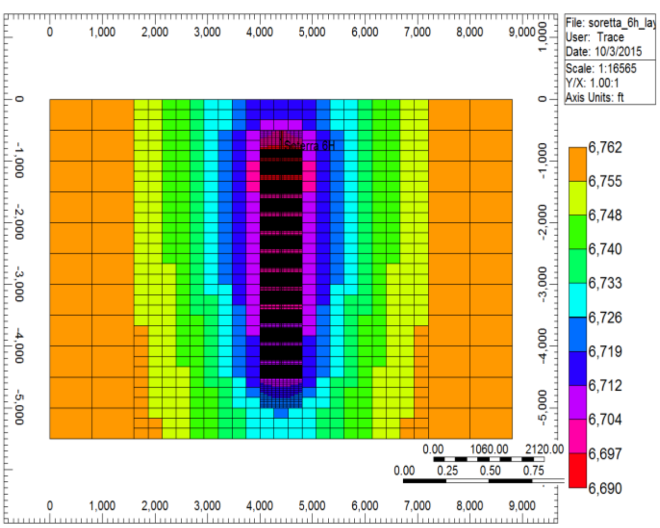
B. Pressure Distribution Xf = 800’



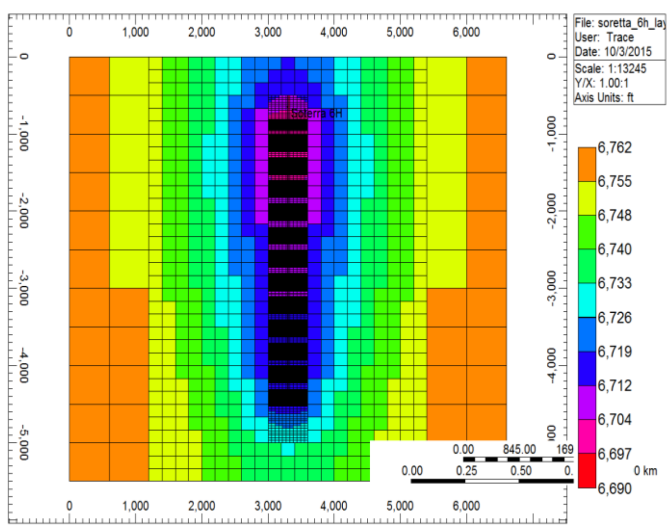
C. Pressure Distribution Xf = 600’



D. Pressure Distribution Xf = 500’



E. Pressure Distribution Xf = 400’



F. Pressure Distribution Xf = 300’

Fig. 50: – Soterra 6-H Pressure Profile

APPENDIX G: THOMAS 38-H SIMUL ATION RESULTS

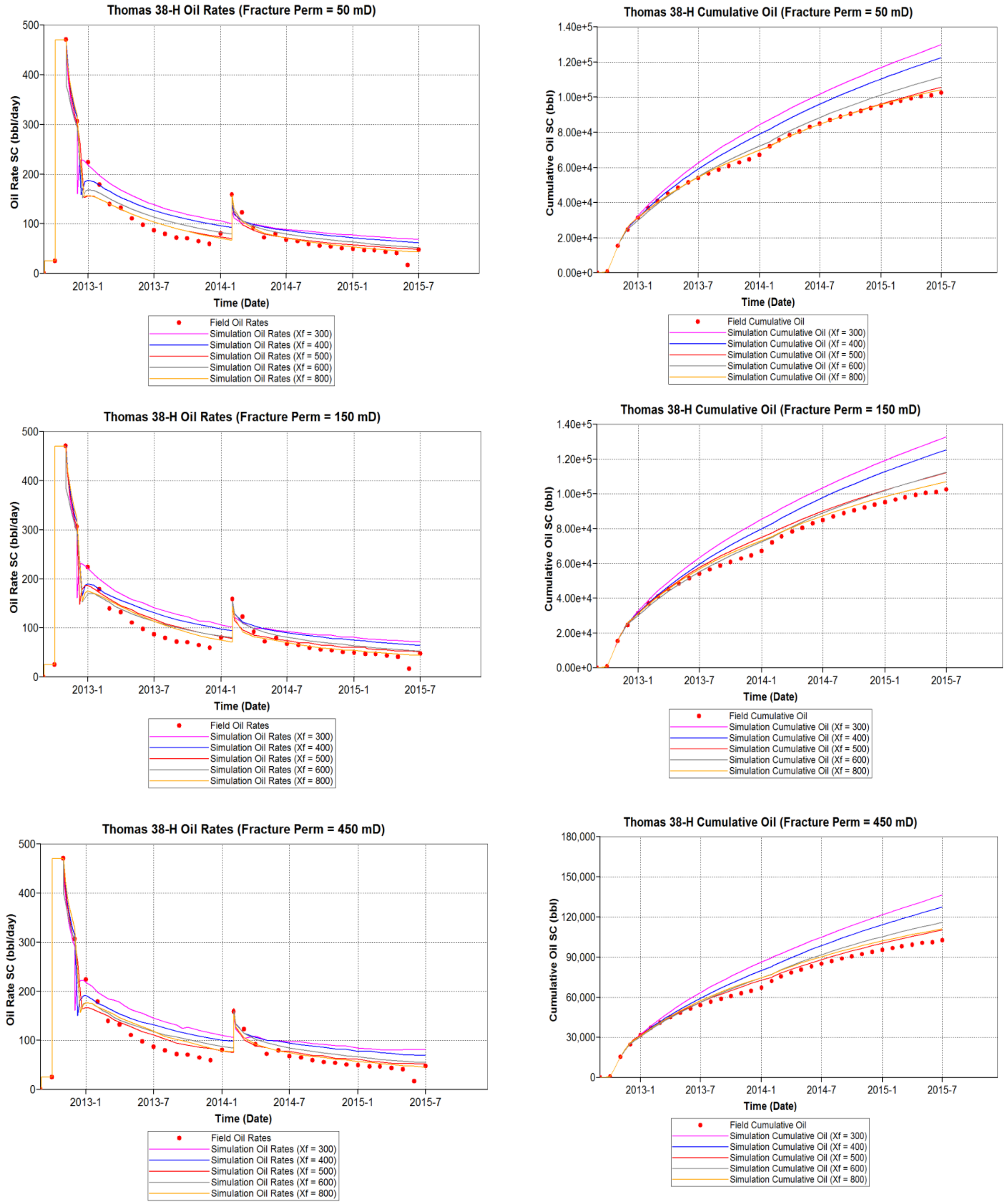
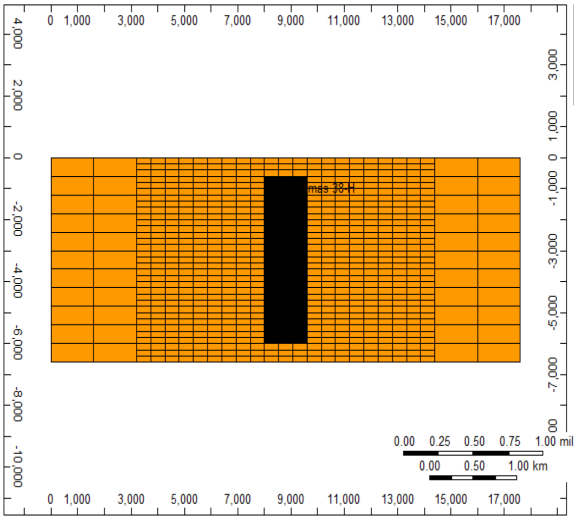
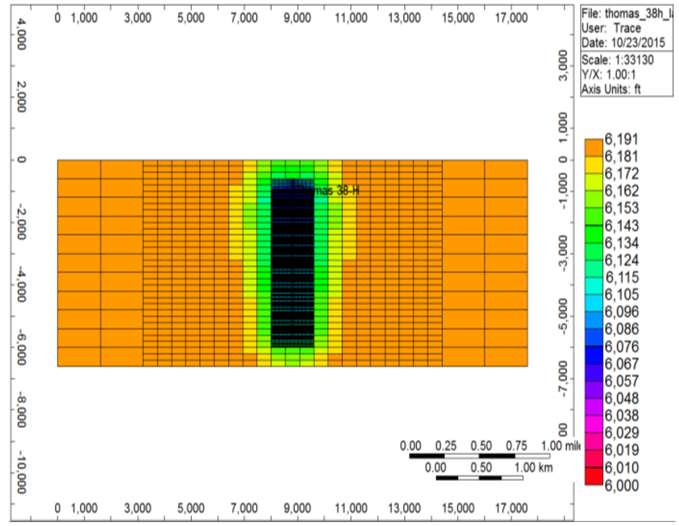


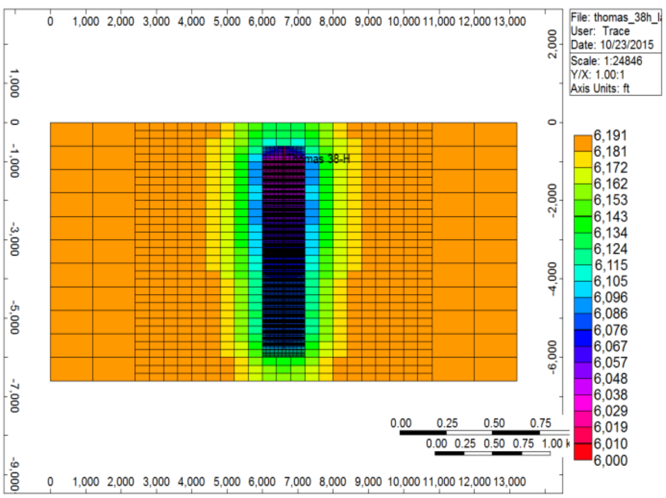
Fig. 51: Thomas 38-H Simulation Results: Rates and Cumulative Oil



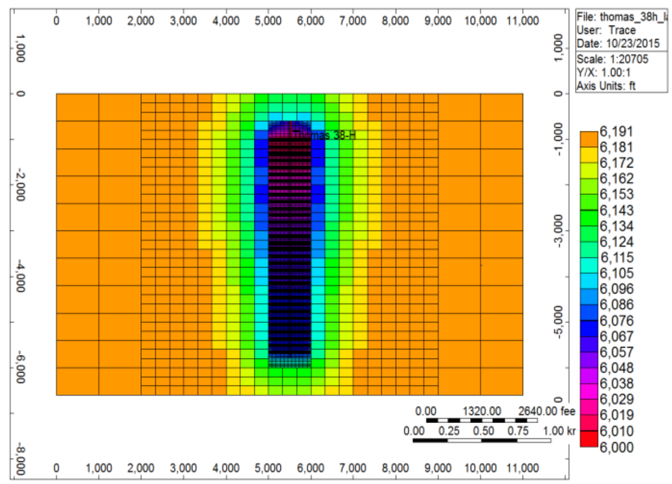
A. Initial Pressure Distribution ; K_f = 150mD



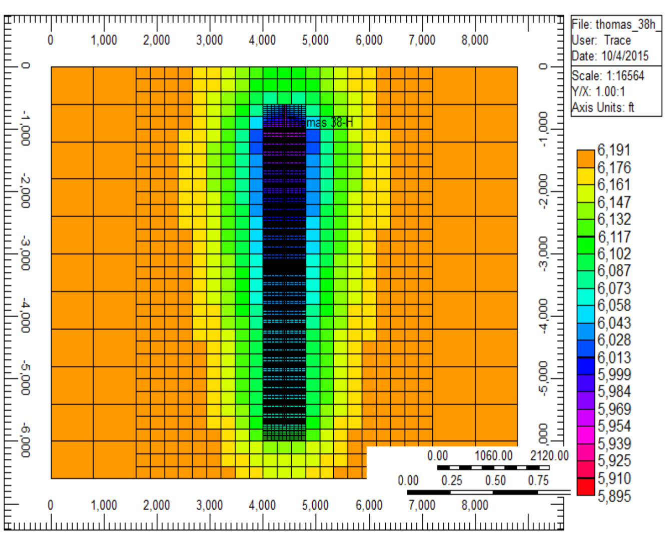
B. Pressure Distribution Xf =800’



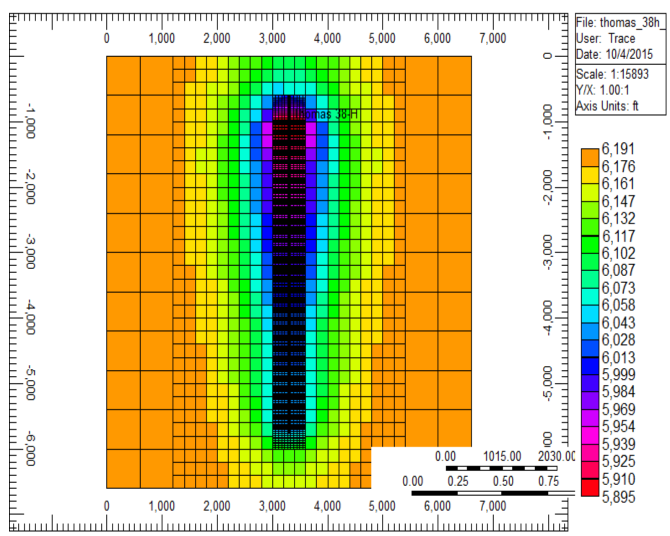
C. Pressure Distribution Xf =600’



D. Pressure Distribution Xf =500’



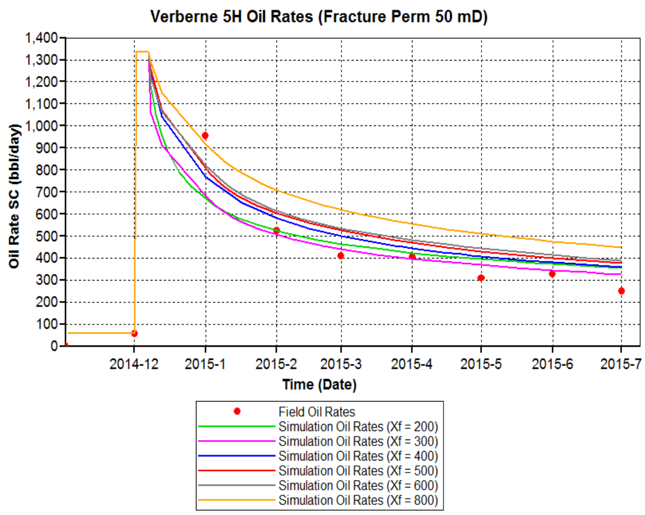
E. Pressure Distribution Xf =400’

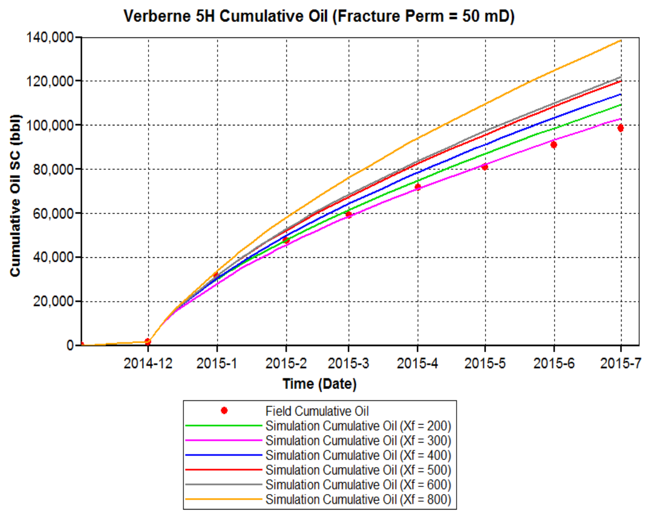


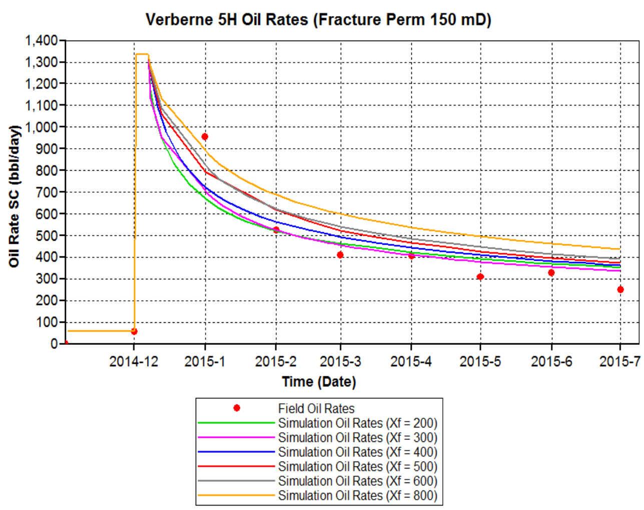
F. Pressure Distribution Xf =300’

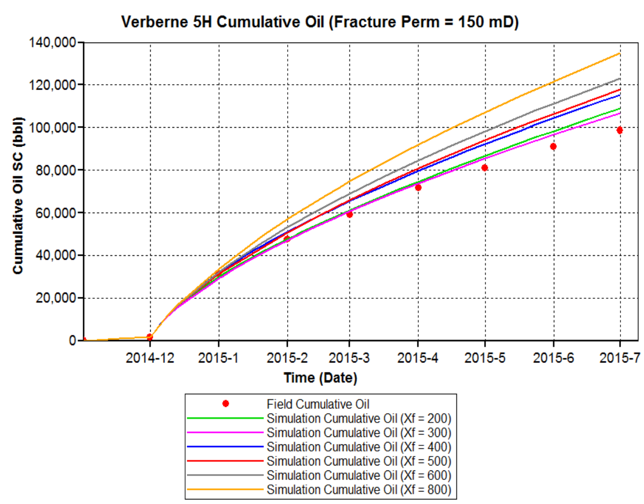
Fig. 52: Thomas 38-H Pressure Profile

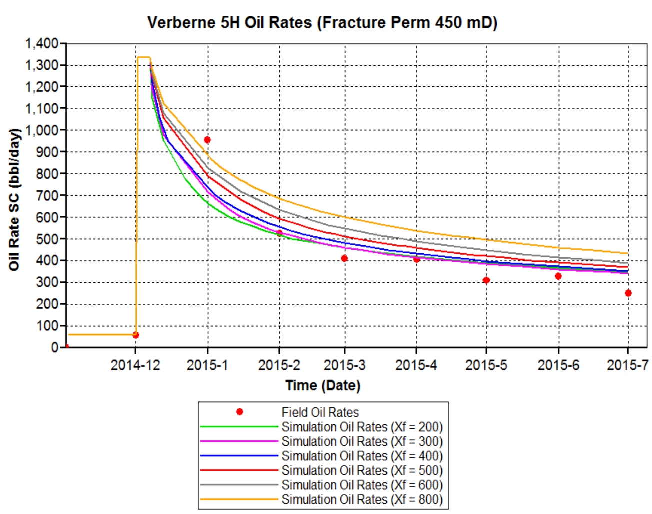
APPENDIX H: VERBERNE 5-H SIMULATION RESULTS











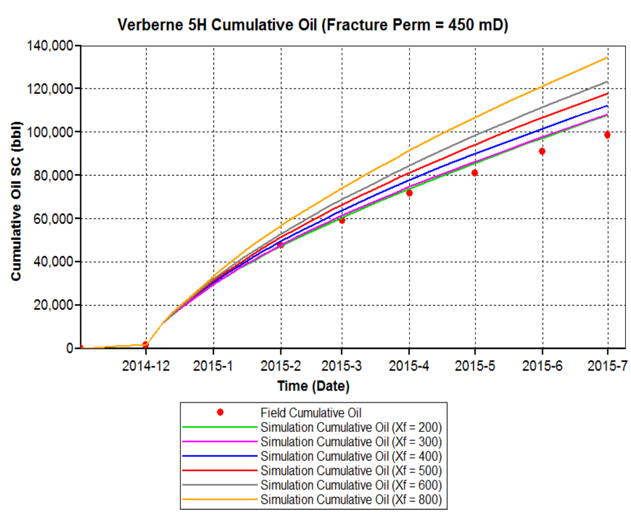
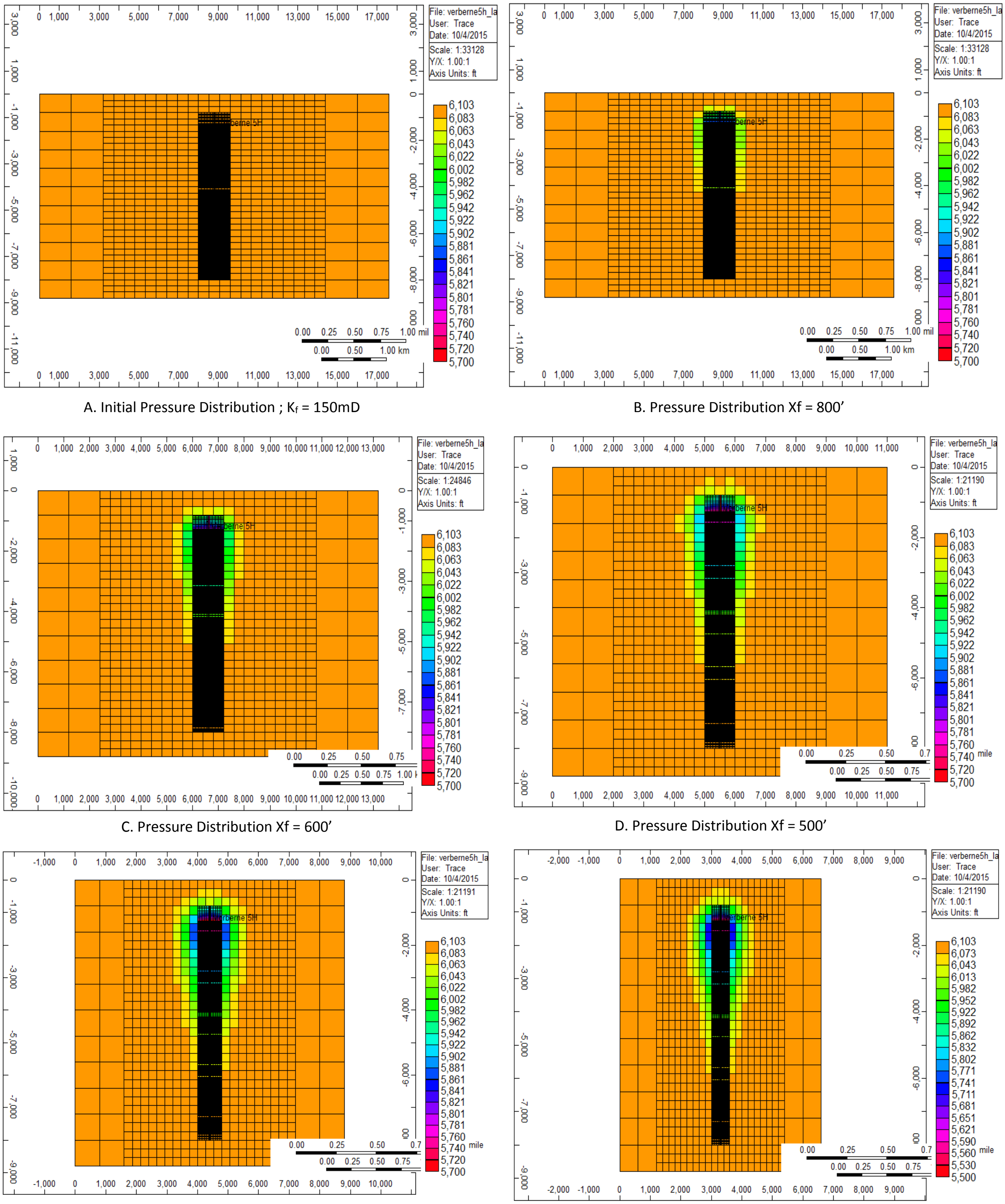


Fig. 53: Verberne 5-H Simulation Results: Rates and Cumulative Oil



A. Initial Pressure Distribution ; K_f = 150mD

B. Pressure Distribution Xf = 800’

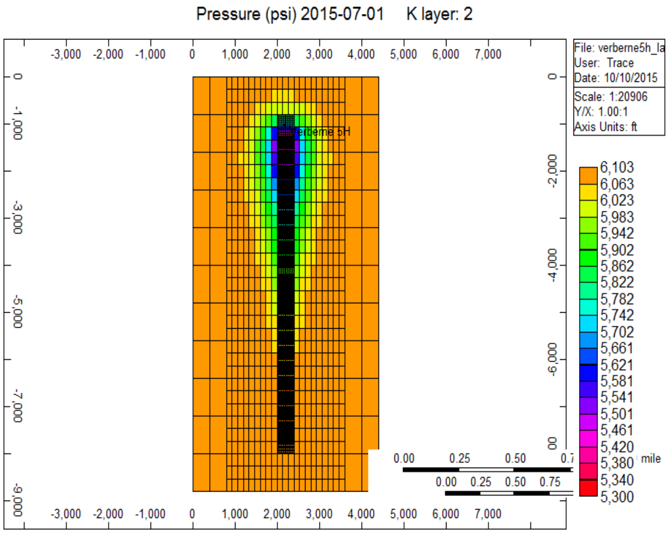
C. Pressure Distribution Xf = 600’

D. Pressure Distribution Xf = 500’

E. Pressure Distribution Xf = 400’

F. Pressure Distribution Xf = 300’

Fig. 54a – Verberne 5-H Pressure Profile



G. Pressure Distribution Xf = 200’

Fig. 54b– Verberne 5-H Pressure Profile

APPENDIX I: WILLLIAMS 46-H SIMULATION RESULTS

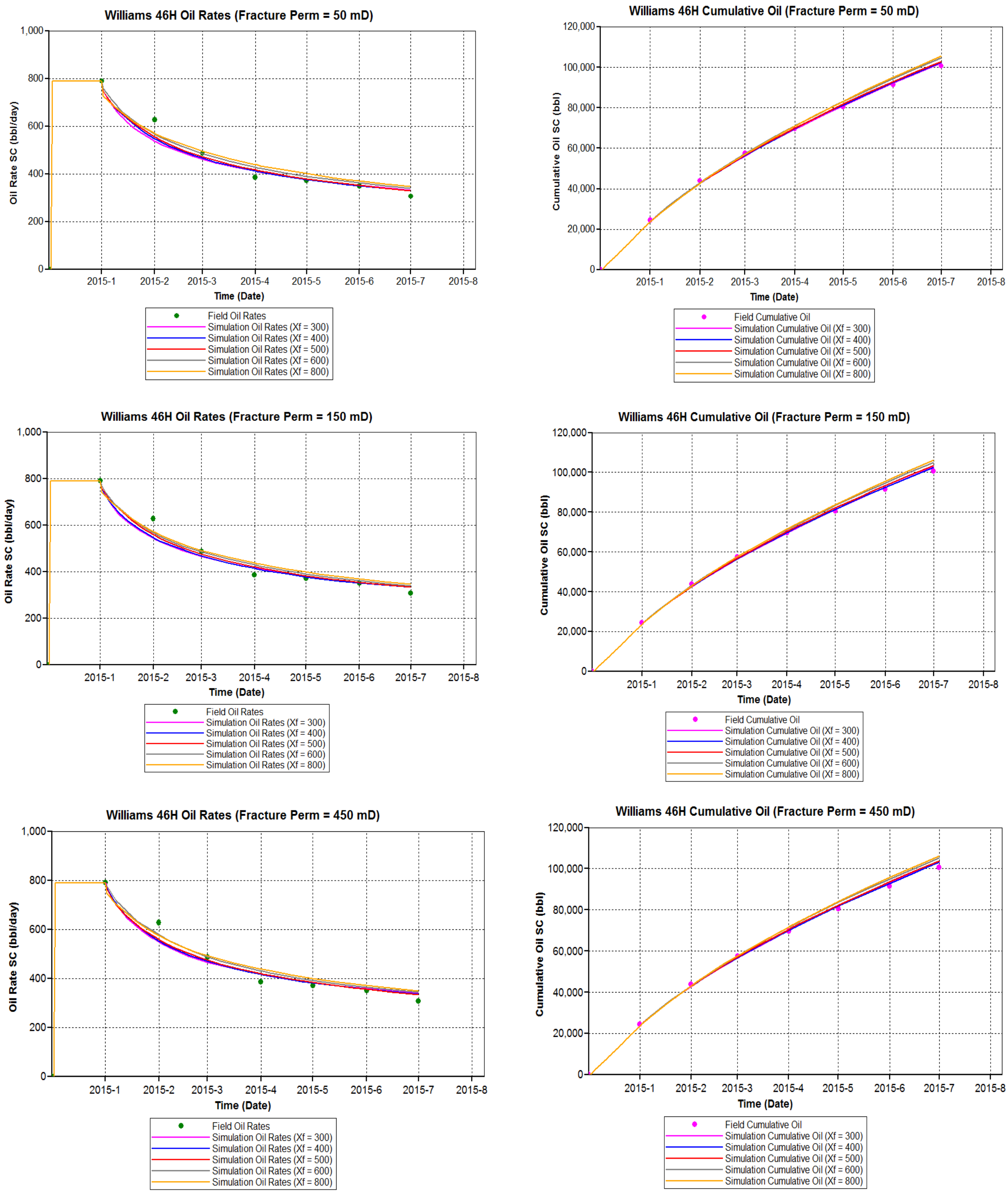
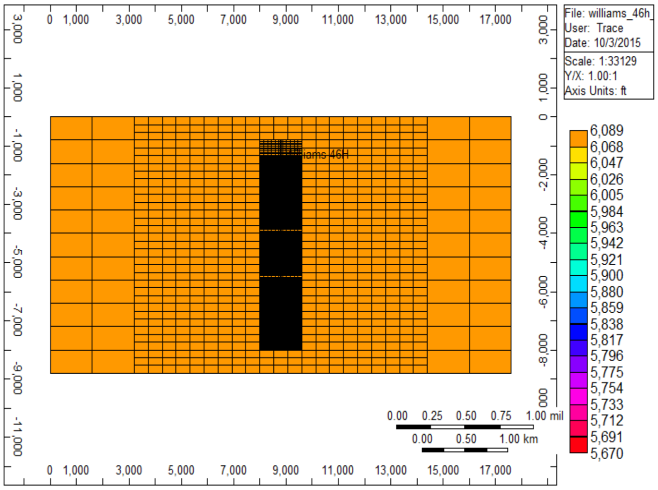
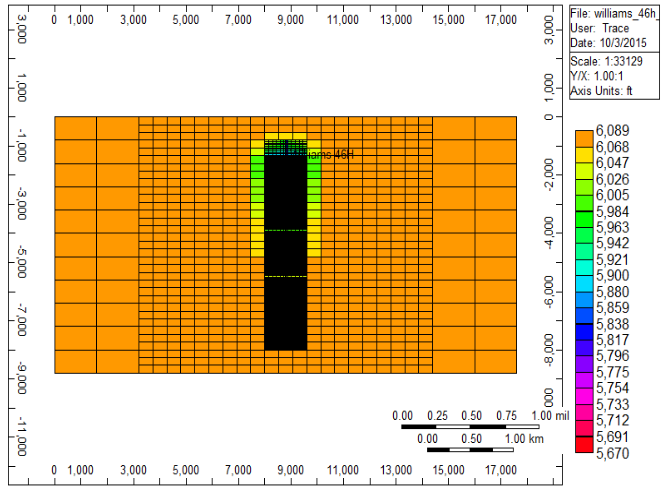


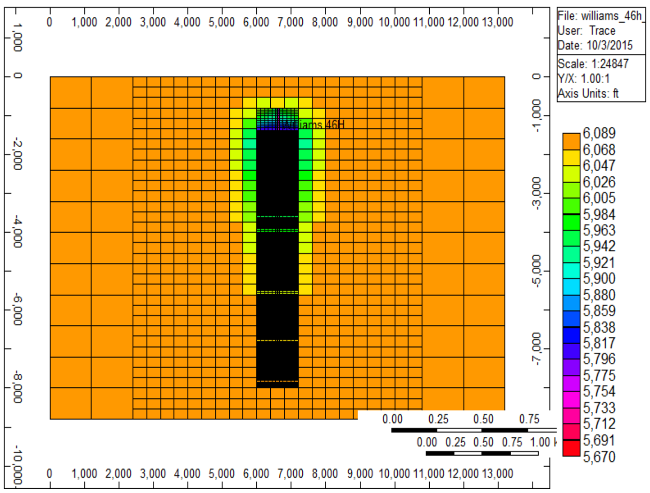
Fig. 55: Williams 46-H Simulation Results: Rates and Cumulative Oil



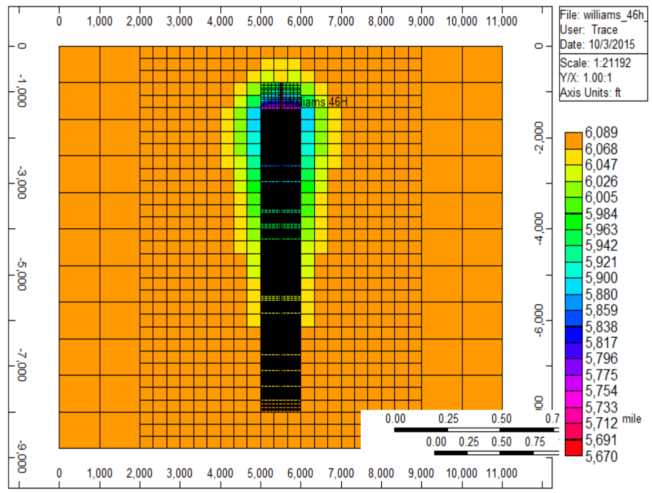
A. Initial Pressure Distribution ; K_f = 150mD



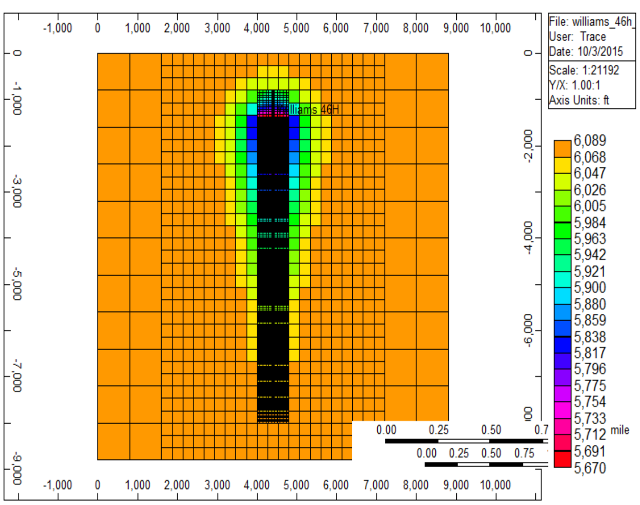
B. Pressure Distribution Xf = 800’



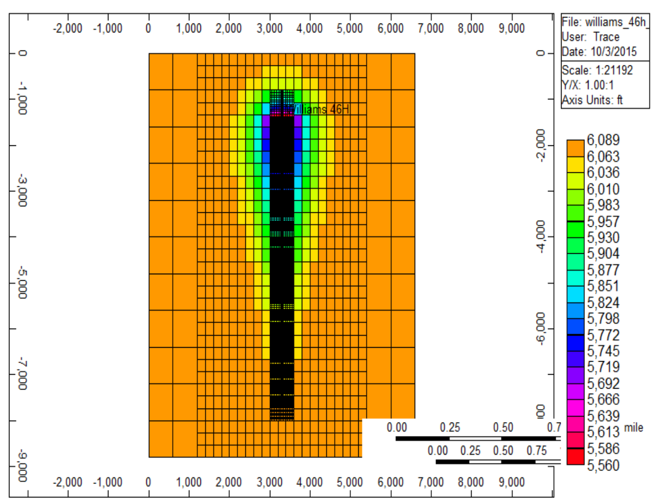
C. Pressure Distribution Xf = 600’



D. Pressure Distribution Xf = 500’



E. Pressure Distribution Xf = 400’



F. Pressure Distribution Xf = 300’

Fig. 56– Williams 46-H Pressure Profile

APPENDIX J: SIMULATION RESULTS - SUMMARY

Blades 33-H												
Fracture	Xf = 200		Xf = 300		Xf = 400		Xf = 500		Xf = 600		Xf = 600	
Perm (mD)	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff
50	173.13	12.21%	157.14	1.85%	147.61	4.33%	154.80	0.33%	159.80	3.57%	170.76	10.68%
150	173.82	12.66%	156.25	1.27%	147.87	4.16%	153.12	0.76%	160.15	3.80%	171.41	11.10%
450	174.67	13.21%	156.63	1.52%	148.19	3.95%	153.05	0.80%	160.57	4.07%	172.04	11.51%

Soterra 6-H										
Fracture	Xf = 300		Xf = 400		Xf = 500		Xf = 600		Xf = 800	
Perm (mD)	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff
50	45.71	10.95%	43.26	5.01%	40.66	1.30%	41.12	0.19%	41.30	0.25%
150	44.98	9.18%	41.69	1.19%	40.50	1.68%	40.84	0.86%	41.10	0.25%
450	38.99	5.36%	42.87	4.07%	43.89	6.54%	41.59	0.94%	41.49	0.71%

Thomas 38-H										
Fracture	Xf = 300		Xf = 400		Xf = 500		Xf = 600		Xf = 800	
Perm (mD)	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff
50	129.92	26.75%	122.44	19.45%	105.80	3.22%	111.48	8.76%	104.32	1.78%
150	132.86	29.62%	125.35	22.29%	112.15	9.41%	112.40	9.66%	107.13	4.52%
450	136.49	33.16%	127.44	24.33%	110.27	7.58%	116.04	13.21%	111.24	8.53%

Verberne 5-H												
Fracture	Xf = 200		Xf = 300		Xf = 400		Xf = 500		Xf = 600		Xf = 800	
Perm (mD)	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff
50	109.44	10.97%	103.26	4.70%	114.34	15.94%	120.09	21.77%	122.04	23.75%	138.56	40.50%
150	109.15	10.68%	106.85	8.35%	115.50	17.12%	117.80	19.45%	123.18	24.90%	134.85	36.74%
450	109.44	10.97%	106.05	7.53%	114.34	15.94%	120.09	21.77%	122.04	23.75%	138.56	40.50%

Williams 46-H												
Fracture	Xf = 100		Xf = 300		Xf = 400		Xf = 500		Xf = 600		Xf = 800	
Perm (mD)	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff	Simulation	% Diff
50	0.00	0.00%	102.43	1.76%	102.54	1.87%	102.99	2.31%	104.78	4.09%	105.64	4.95%
150	0.00	0.00%	102.73	2.06%	102.55	1.88%	103.48	2.80%	105.09	4.40%	106.09	5.39%
450	0.00	0.00%	103.35	2.67%	103.19	2.51%	103.78	3.10%	105.41	4.72%	106.23	5.53%

Table 12: Summary of Simulation Results

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