Senior Design II Final Report

Reservoir Evaluation and Simulation of CO2 Miscible Enhanced Oil Recovery on the South Willson Ranch Field

(Rampart Energy)

PREPARED FOR:

Dr. Fu

PREPARED BY:

Petroleum Engineering Senior Design Team 9:

Briana Dodson, Darya Rezaei Hariri, Jesse Stinson, Joseph Determann

DATE SUBMITTED:

May 6th, 2016

Table of Contents

Executive Summary:

The South Willson Ranch Field has been in production since 1979 with cumulative oil production of 4,632,240 bbls to date. The field underwent a water flood beginning in 1995 that significantly extended the life of the field, but sharp declines in recent production indicate that the water flood has likely recovered all of the oil it can and alternative methods of recovery must be considered to further extend the life of the field. With an estimated ROIP of 10.2 MMBBO the South Willson Ranch field is an excellent candidate for tertiary recovery efforts. Given that a water flood has already been performed, similar EOR methods using piston like displacement will likely yield the same results as a water flood.

This led us to consider the field for a miscible CO2 flood. With an ethanol plant slated to be built near the field in Banner County, Nebraska approximately 7 MMcfd of CO2 would be readily available near the field. Neuralog, Petrel, and CMG have been used to model the feasibility of this miscible CO2 oil recovery effort. Our review to date has indicated that the recovery of incremental oil via a miscible CO2 flood is technically feasible but also operationally challenging due to the required miscibility pressures of approximately 2,900 psi within the reservoir due in part to the reservoir's high temperature of 187 degrees Fahrenheit.

Introduction:

The South Willson Ranch Field Project was chosen by the group for the opportunity it provides to work with real data from a real reservoir in an effort to extend the productive life of a waterflooded oil field. Enhanced oil recovery (EOR) plays a major role in the development and improvement of existing fields today. As the price of oil fluctuates and drilling techniques improve to allow for more efficient emplacement of CO2 or chemicals, different EOR methods become economically feasible. In the case of the South Willson Ranch Field in Banner County, Nebraska the recently announced plans to build a large ethanol plant in close proximity has opened up the possibility of using miscible CO2 injection to possibly increase production in the declining field as CO2 would be readily available to transport to the field.

The main scope of this project is to determine the overall technical feasibility of using miscible CO2 injection based on simulations run in a dynamic model in CMG. Economics will play a significant role in the final analysis to determine whether or not to proceed with project implementation, but given the currently depressed oil prices and undetermined completion date for the ethanol plan, the exact prices and economics for the project should really be reviewed after completion of the plant if the field is indeed a good technical candidate for miscible CO2 flooding.

The data for this project were obtained from Rampart Energy Company, an oil and gas exploration and production company located in Denver, CO. The field has an average porosity of 20% and an average depth of 5,300ft to the J2 sand, making it a good candidate for an EOR project at first glance. The first steps towards completing this project were obtaining all the available data on the field, securing the necessary data release forms, and then familiarizing ourselves with the field data and the topic of miscible CO2 flooding. Since the idea of a miscible CO2 flood is something no one in the group was greatly familiar with, much of the first semester was spent researching the requirements for a miscible CO2 flood and finding relevant correlations to help us in our evaluation of the field. A large portion of the time spent during the first semester was determining the best way in which to technically evaluate the field as a miscible CO2 flood candidate. The ultimate conclusion was to attempt to create a dynamic model in CMG in which a miscible CO2 flood can be simulated. This process required a great

deal of research as our group's experience using Neuralog, Petrel, and CMG was quite limited so becoming familiar with the programs and obtaining access to them were significant parts of our first semester's effort.

Updated Planning: Workflow

Updated Planning: Gantt Chart

GROUP #9: Briana Dodson,Darya Rezaei Hariri, Joe Determann, Jesse Stinson

Tentative Senior Design WorkFlow - Spring 2016

Tasks	Team Members	Duration	January	February	March	April	May
Digitize Logs	Joe Jesse	2 weeks	Complete				
Static Model Petrel	All members	5 weeks		Complete			
Well Name Coordinates	Briana	1 week		Complete			
TOPS Data	Darya	1 week		Complete			
Log Data Digitze Curves	Joe Jesse	2 weeks		Complete			
Data QC	Jesse	2 weeks			Complete		
Finalize Map	All members	1 week			Complete		
CO2 Correlations	All members	7 weeks			Complete		
Dynamic Model	All members	7 weeks			Complete		
							Completed

Table 1 - Gantt Chart

Legend	
	Completed Task
	In Progress Task
	Progress Dependent Task
	Quality Check

The project was able to be completed in the time frame given and on schedule despite the obstacles involved with securing software licenses and gaining familiarity with that software.

Data Review:

The amount of data provided for this project was very thorough and complete. We received gamma ray logs, caliper logs, density porosity logs, neutron porosity logs, resistivity logs, induction logs, interval transit time, and micro logs for all six of the wells to be evaluated within the field. Field parameters such as the TOPS data, average depth, permeability, temperature, original oil in place, and partial oil composition were included in the initial data obtained as well as decline curves for the entire life of the field. This field was unitized so we have field-wide production data but we do not have individual well production decline curves. The initial decline curves for the field provided a great deal of insight on the field and were used to determine that miscible CO2 is really the only CO2 EOR method worth investigating since the field was previously waterflooded and now that it is once again near abandonment it is logical to assume that the oil able to be recovered by simple displacement (waterflood, immiscible CO2) has been produced. The performance of the waterflood ruled out an immiscible CO2 flood since using the same piston-like mechanism in an effort to enhance oil recovery would almost certainly not succeed, leading us to consider other EOR methods that do not rely on simple fluid displacement for recovery. Based on this, to improve recovery from the Willson Ranch South Field we decided to evaluate the potential of miscible CO2 to swell the oil in place, reduce its viscosity and allow it to be recovered.

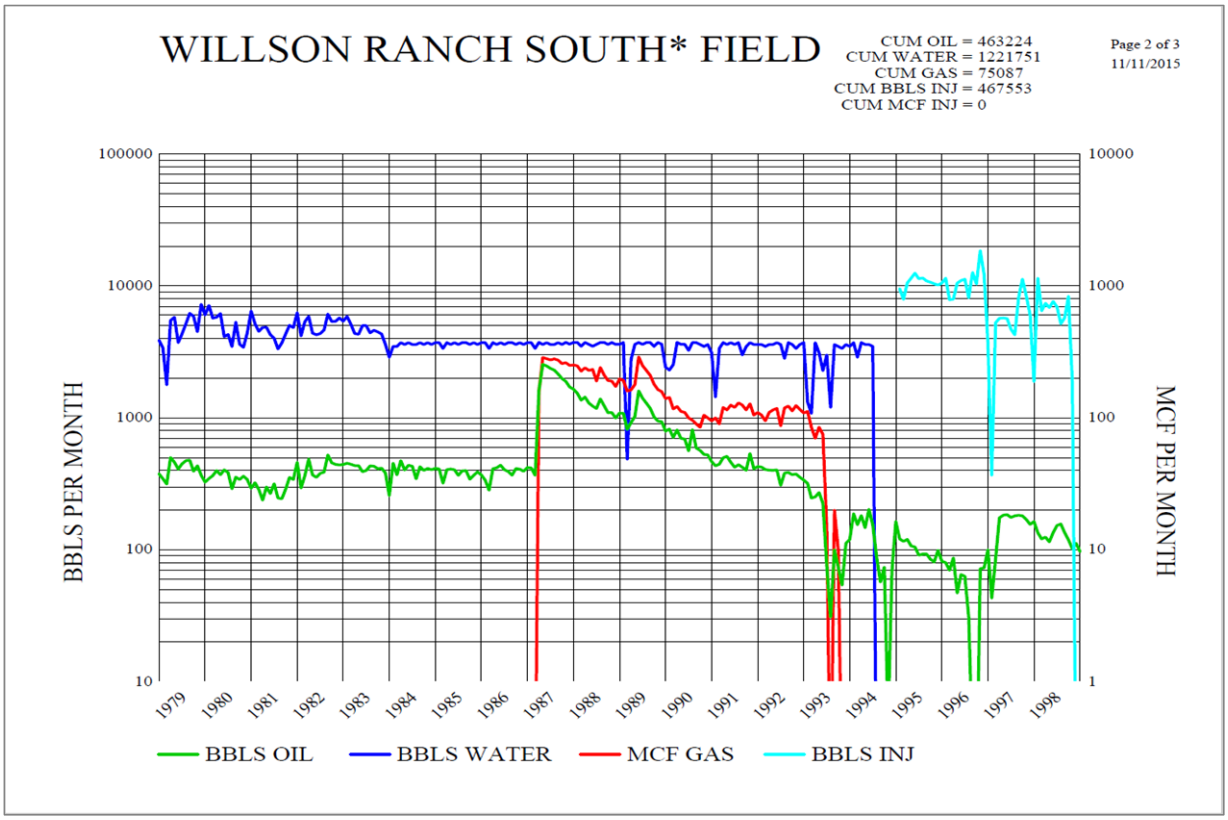
The amount of data provided has so far proven quite sufficient, and although the data were not in digital formats which would allow them to be worked with in modeling software, it was still able to be transferred into Neuralog to be digitized and uploaded into Petrel. This process required the logs to be uploaded into Neuralog and then traced by hand as the program is not able to automatically recognize the curves on logs loaded from a .pdf or any sort of picture format. This process was quite tedious and took the group an estimated 20 hours to complete. A large portion of the first weeks of the semester were dedicated to this process so that the logs would be formatted to be successfully used to create the models needed.

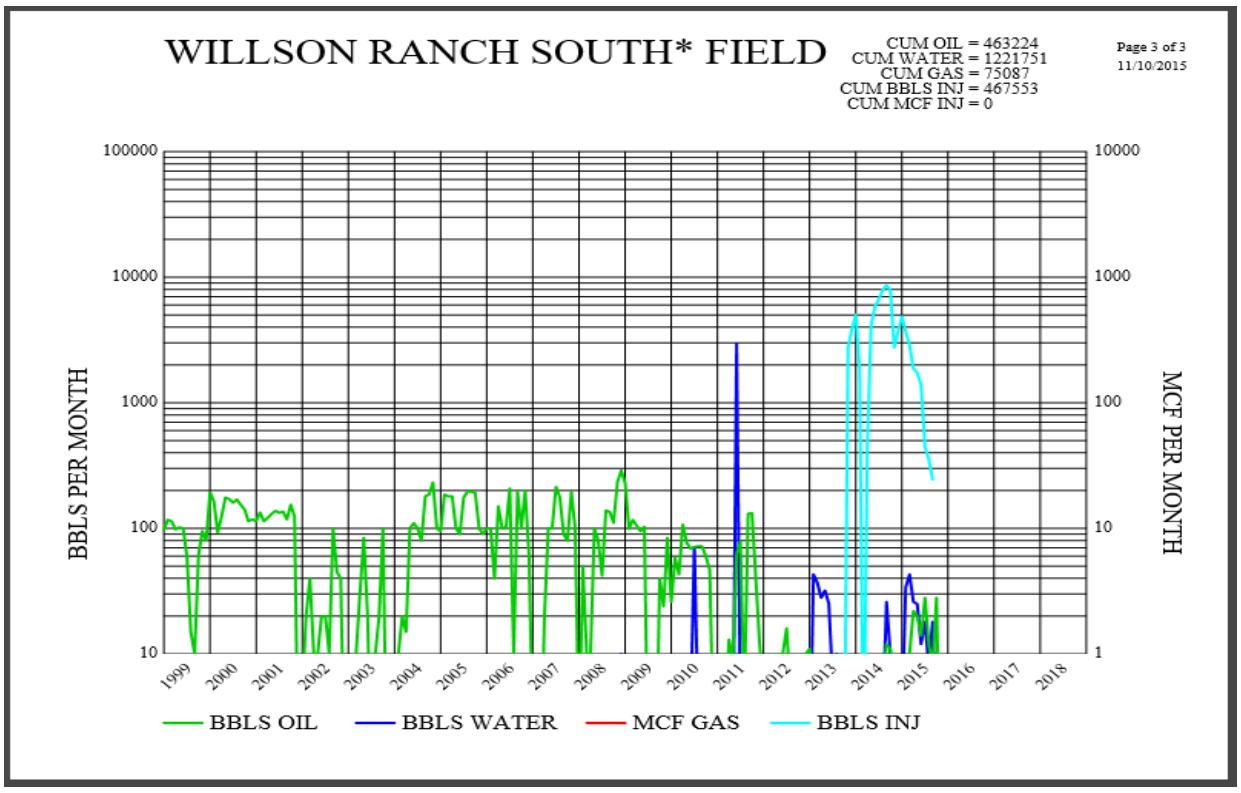
We did obtain additional location data to be input into Petrel from the Nebraska Oil and Gas Conservation Commission database. They had much of the production history for the field available in the database as well as the coordinates and an aerial map of the locations of the

wells. These data have been used to plot our wells into Petrel and set them accurately in place. So while the initial data provided have been sufficient to proceed with the project, there has been quite a bit of manipulation needed to turn the data into formats that are usable in the software. Included are the decline curves of the field which highlight the issue that we are investigating: this is a declining field that has extended its production due to water flooding and we are trying to determine if it could still possibly see improvement from miscible CO2 flooding.

Decline Curves:

Figure 1 - Initial Decline Analysis





Methods:

Our project requires three major pieces of software: Neuralog, Petrel, and CMG. Neuralog is a software program that allows traditional log files to uploaded and traced in order to digitize them. Obtaining the license to this software and getting it to run correctly using the limited trial license was quite challenging, but once the software was accessible all the given logs of each of the six wells were uploaded and traced by hand. The process of tracing was quite tedious but necessary to move forward with the project. This allowed the logs to be uploaded and used in Petrel to create our static model.

The second piece of software we are working with is Petrel. Petrel is a reservoir modeling software commonly used in the oil and gas industry and helps to generate detailed static models based upon given well parameters and various types of uploaded digitized logs. This static model really helps to show the field in detail and create a base for the dynamic model in CMG. To date most of the logs and TOPS data have been uploaded, along with basic well parameters such as permeability and formation depths. That static model was completed successfully.

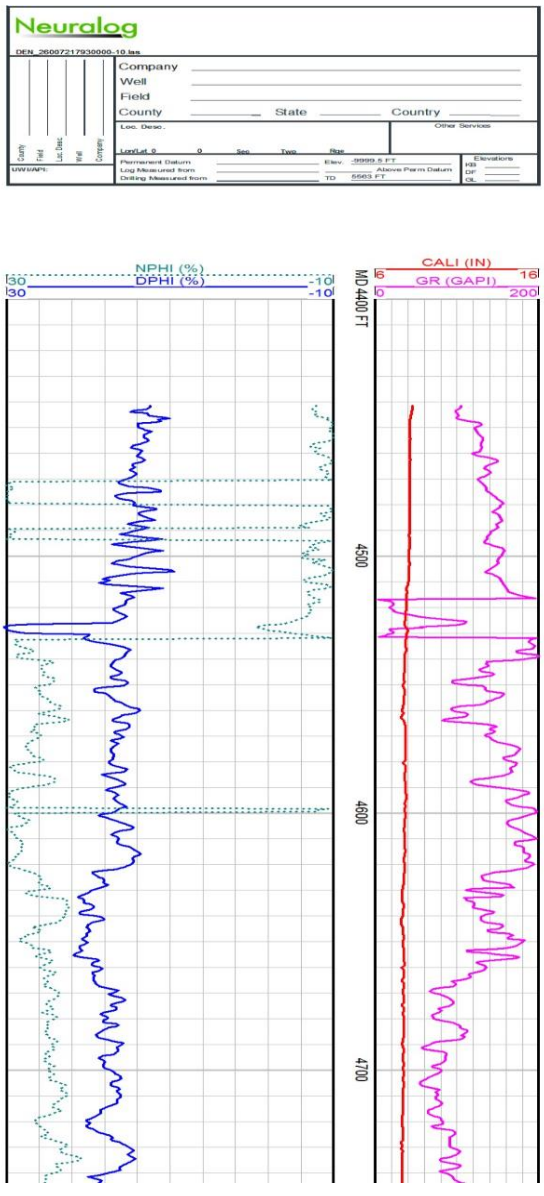
The third piece of software we plan to use is CMG. CMG is more advanced modeling software capable of running CO2 simulations. Since the project centers on using miscible CO2 to increase the production this type of simulation could really help determine just how feasible and effective this type of recovery effort would be in the South Willson Ranch Field. Of all the tasks to be completed on this project, the group allotted the most time to the creation of the dynamic model due to how unfamiliar everyone is with the software and to hopefully account for time resolving any unforeseen issues. The static model in Petrel has been uploaded into CMG to create the dynamic model from the logs and well parameters input previously. The group is currently in the process of finishing the dynamic model in CMG and then running the simulation. The dynamic model is complete and running in CMG but can still benefit from refinement of the model. The data received from the simulations regarding how much CO2 is required, whether or not miscibility can be achieved, and the expected production increase from that miscible CO2 injection will determine how technically feasible this project is.

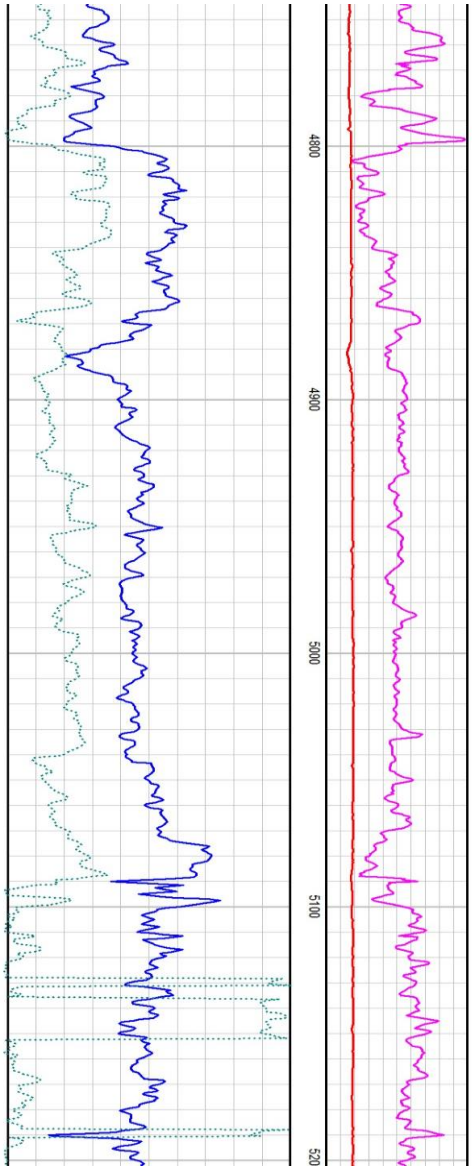
This method will be used in conjunction with the Holms and Josendal Correlation (SPE, 1982) to verify the results and help determine just how effectively CO2 would mix with the oil currently in place to increase production. We have learned that miscibility is a function of the type of oil involved, the temperature of the oil in the reservoir, and the pressures at which miscibility can be achieved at various temperatures for that particular oil. The higher the temperature, the higher our injection pressure will need to be to achieve miscibility. Miscibility is most easily achieved at low temperatures but high pressures and that creates a narrow window in which miscibility is achieved since greater depth to secure greater pressure in a reservoir usually means we have to deal with higher temperatures. Depth helps to increase pressure but can also raise temperatures so we needed to determine if our Cruise J (also called the J2) Reservoir is in a sweet spot of sufficient pressure but not too high of a temperature to allow for miscibility to be achieved.

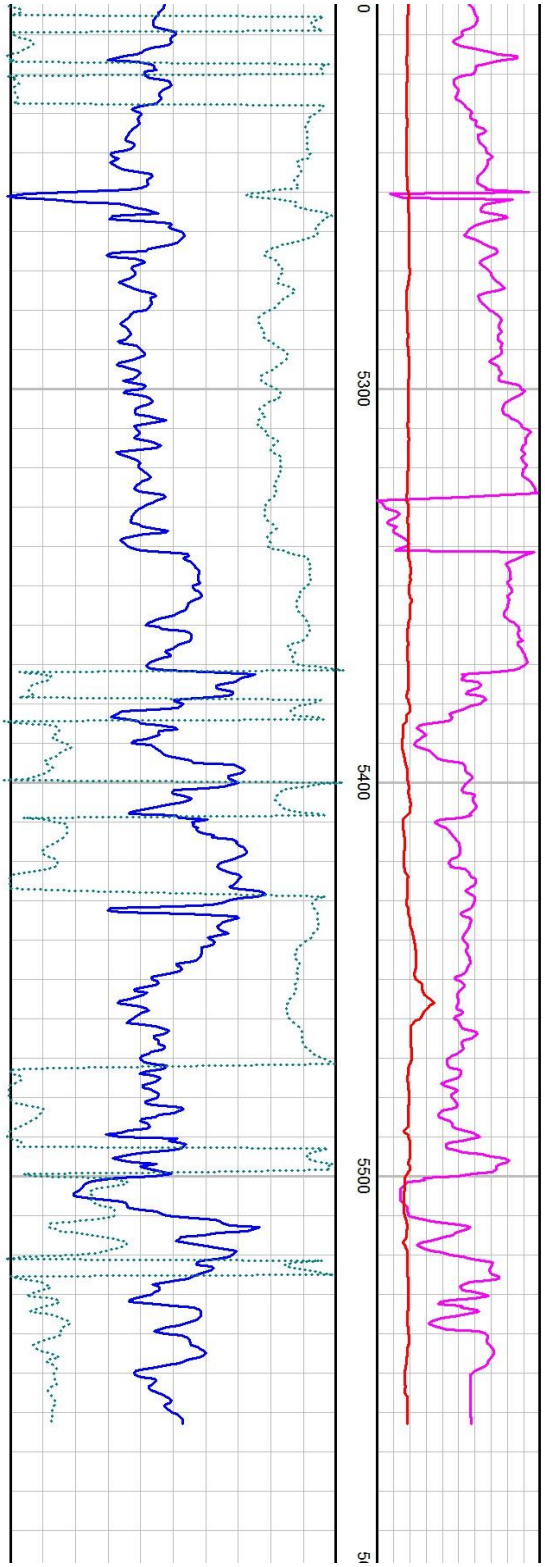
Results:

Our final results involved three different software programs: Neuralog, Petrel, and CMG. The logs received from the company were simple scans that were not digitized. The first step towards completing the project was to digitize the logs using Neuralog so that the logs could eventually be directly uploaded into the modeling software. With so many relevant logs for each of the six wells, completing the digitization was a major accomplishment as each individual log was hand traced in Neuralog. Here is an example of the output from Neuralog from one of the wells and the different strata now marked from the input logs:

***Figure 2** An example of one of the digitized logs uploaded and traced in Neuralog. This one is a gamma ray log.*



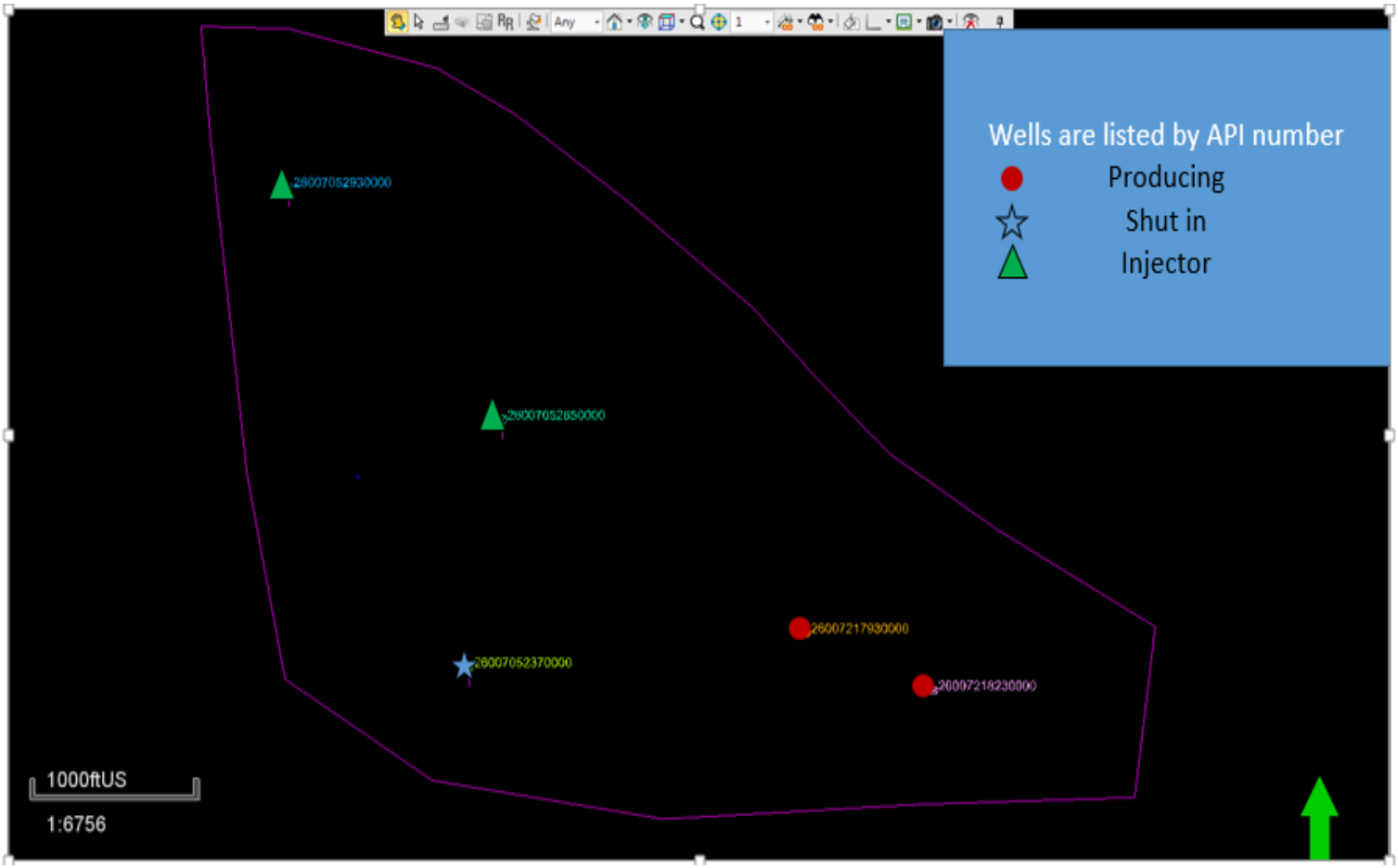




An example of one of the digitized logs uploaded and traced in Neuralog. This one is a gamma ray log.

With all of the relevant logs digitized in Neuralog, the next step was the static model in Petrel. Location data were taken from the Nebraska Oil and Gas Commission (NOGCC) to help create the 2D overview of the field. The wells are listed by API number and show whether the wells are currently producers, injectors, or shut in:

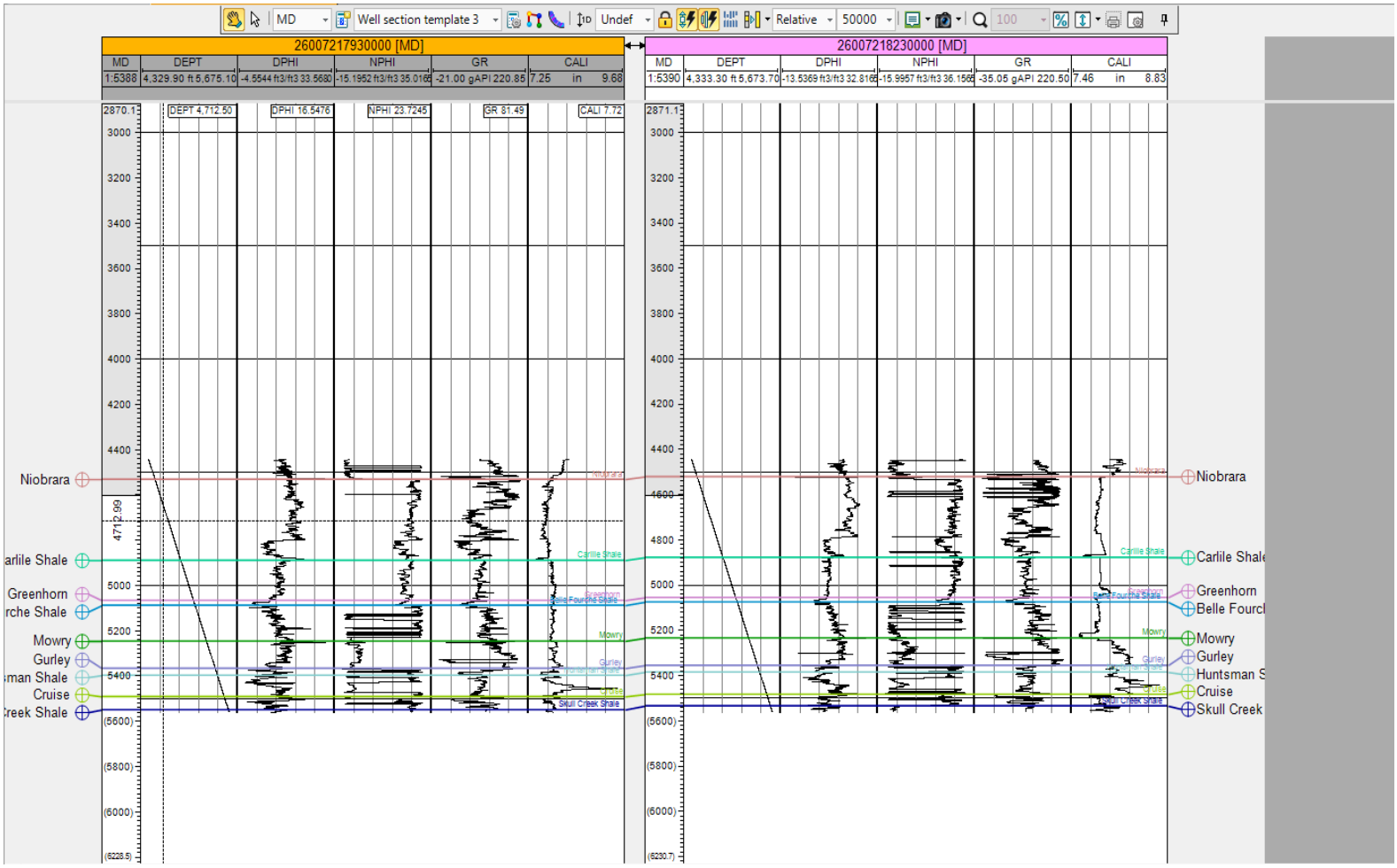
Figure 3 - static model in Petrel (2D)



2D map of the field in Petrel shows the well locations, API numbers, and which wells are producers, injectors, or shut in.

Here is an example of the different logs uploaded into Petrel. The different formation correlations are drawn in by Petrel based on the information put in about each well's location and the logs. The TOPS data is then verified across all the wells and manually adjusted as needed:

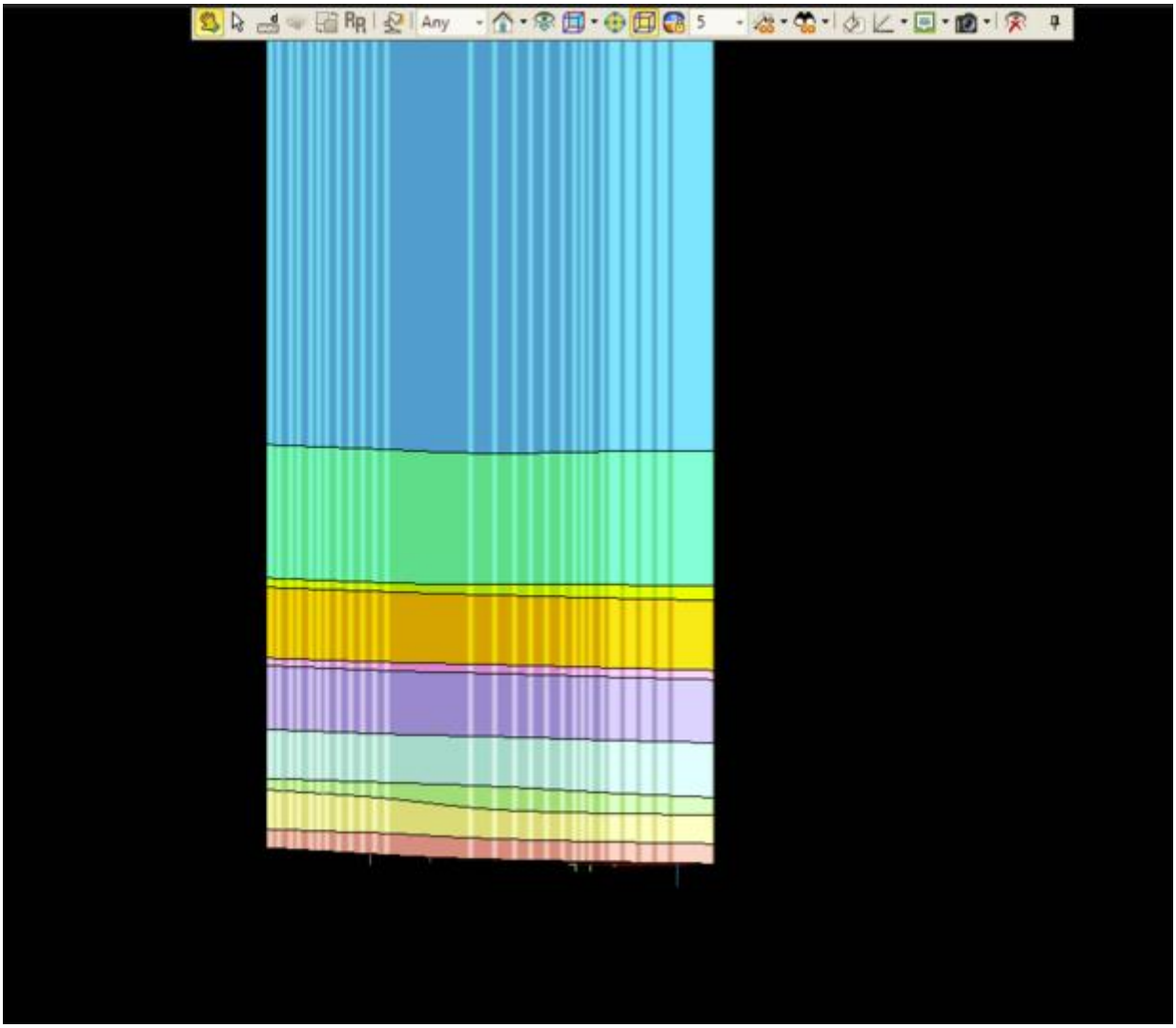
Figure 4- The TOPS data input into Petrel for two of the five wells



The TOPS data input into Petrel for two of the five wells.

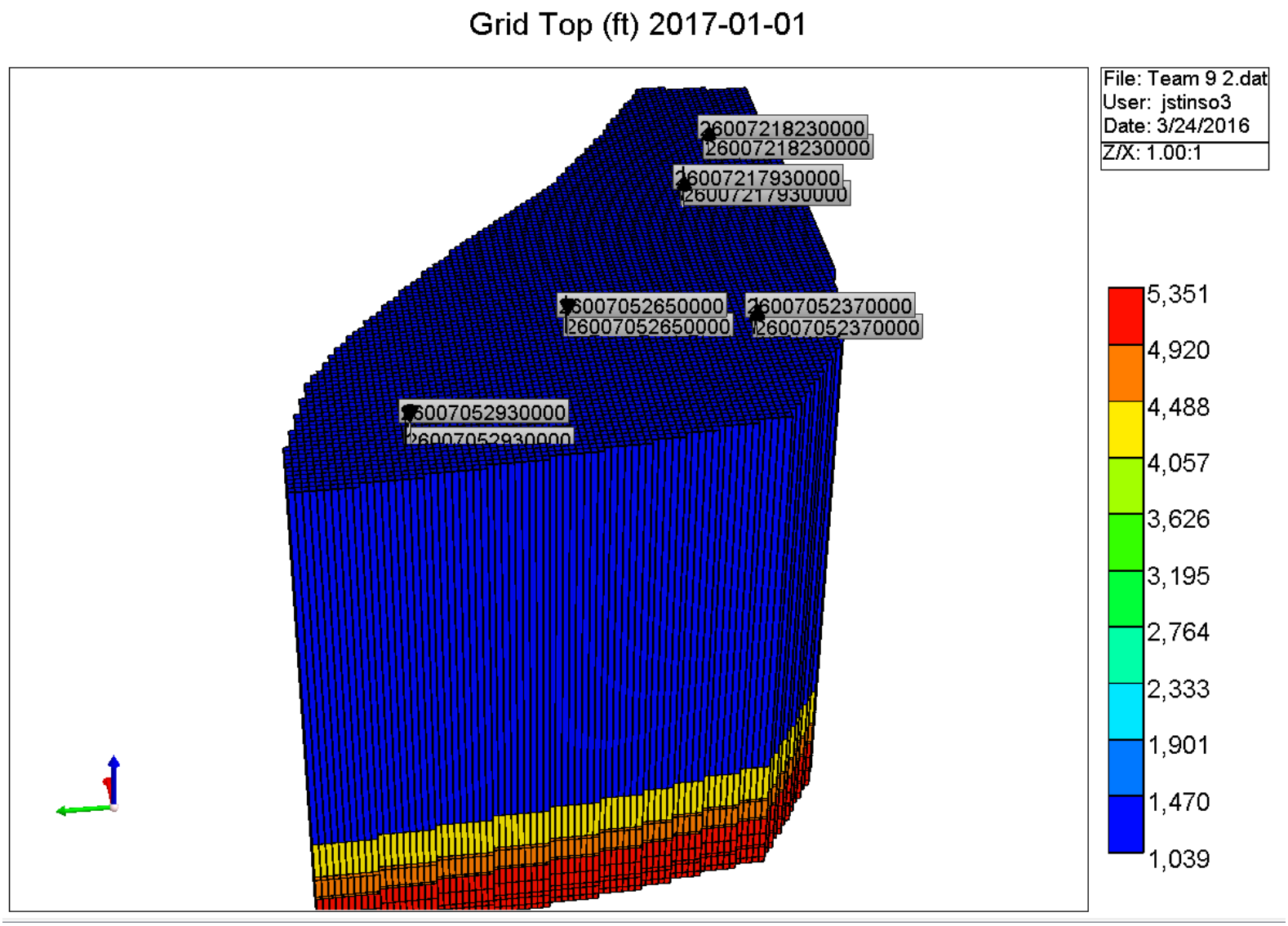
Figure 5 - Static Model - Petrel

This is an overview of the completed 3D static model in Petrel. The TOPS data were input to create a clear overview of the field. The producing zone for this field is the Huntsman Shale - Cruise "J" Sand, shown second from the bottom in pale yellow. Permeability and porosity models were not built in Petrel due to the homogeneity of the reservoir with regard to porosity and permeability. Based upon the data from drill stem tests and well logs, the permeability variance across the reservoir is ~3 md and the porosity variance is ~2%. This static model also demonstrates the type of oil trap in the South Willson Ranch Field, a stratigraphic trap with shale layered on top of sand, creating oil lenses:



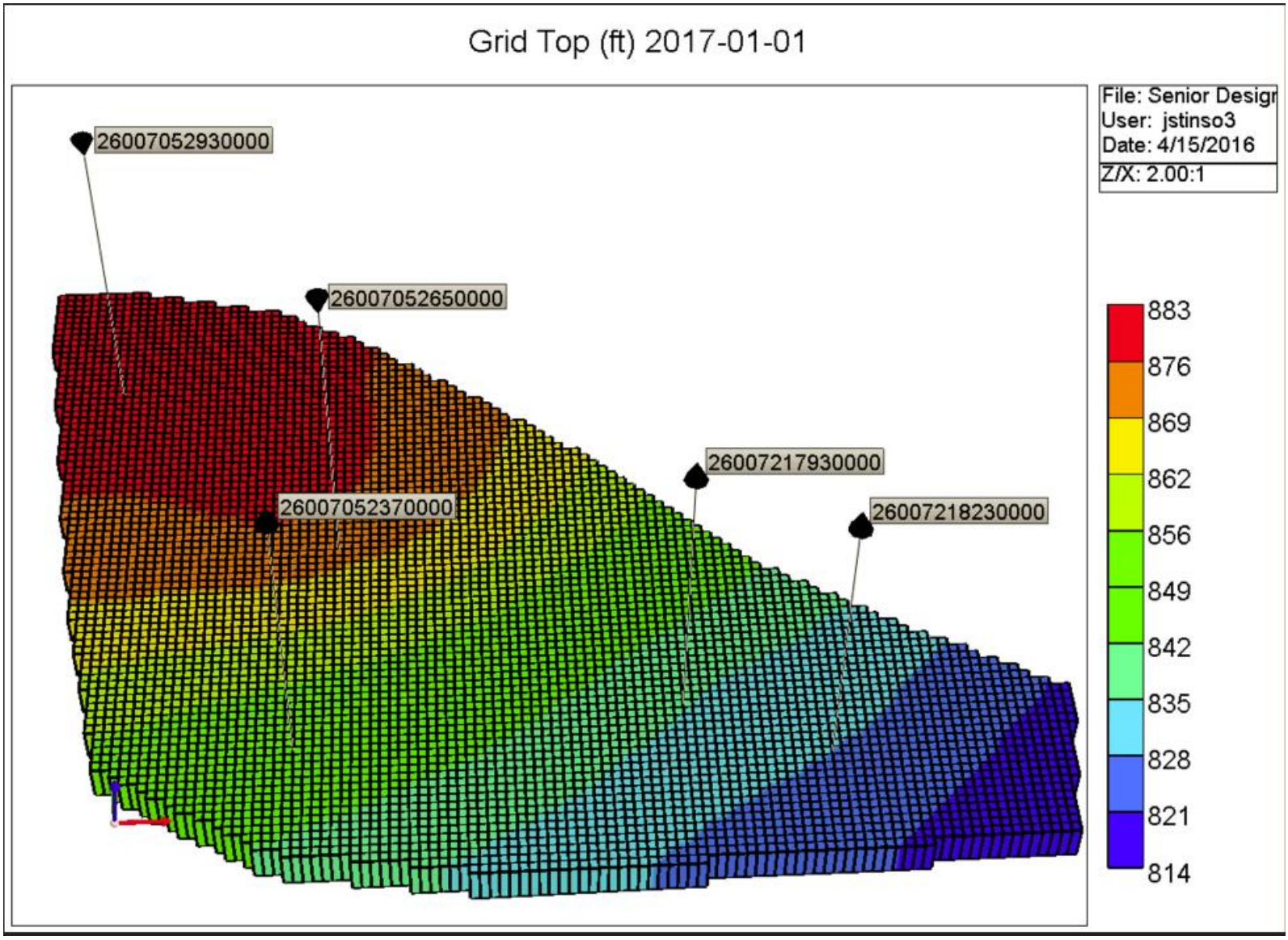
Once the 3D static model in Petrel was completed the next step was to build the dynamic model in CMG. The data from Petrel was uploaded into CMG to create the 3D model shown below. This was done by exporting a “Rescue” model from Petrel then importing said “Rescue” model into CMG. It was then necessary to input and define various properties such as porosity, permeability, components and composition, and initial region parameters (i.e. oil-water contact depth, water saturation below oil-water contact depth, reference pressure, and reference depth).

Figure 6 - CMG (3D model) - 1



Due to the license limitations we have for CMG, it was necessary to recreate our model in CMG. The current license allows for simulation of 10,000 grid blocks. The model shown above is roughly 99,000 grid blocks and is showing all of the layers of the reservoir. In order to achieve the 10,000 grid blocks we had to scale down our model. After numerous attempts it was found that we would only be able to simulate one layer, the Huntsman Shale – Cruise "J" Sandstone layer as shown in the figure below. From there the production history of each of the wells was imported to get an accurate representation of the field as it sits now, accounting for past production as well as the water flood.

Figure 7 – CMG (Huntsman Shale – Cruise "J" Sandstone stimulation)



CMG Results (Producing wells)

Table 2 - CMG Results- 3 Producing Wells

PRODUCTION GROUP SUMMARY

FILE: senior design.irf
Group: Default-Field-PRO

TIME	DATE	Oil Rate SC	Water Rate SC	Gas Rate SC	Gas Oil Ratio SC	Water Cut SC - %	Water Gas Ratio SC	Cumulative Oil SC	Cumulative Water SC
(day)		(bbl/day)	(bbl/day)	(ft3/day)	(ft3/bbl)	()	(bbl/ft3)	(bbl)	(bbl)
0.00000000	2017-01-01	3796.12	3712.45	0.00	0.00	49.44	0.00	0.00	0.00
365.00000	2018-01-01	1248.49	1189.57	0.00	0.00	48.79	0.00	519562.63	478292.66
730.00000	2019-01-01	1027.46	1103.59	0.00	0.00	51.79	0.00	930209.69	894499.13
1095.0000	2020-01-01	849.74	1070.59	0.00	0.00	55.75	0.00	1271995.25	1287518.00
1461.0000	2021-01-01	762.46	971.17	0.00	0.00	56.02	0.00	1561932.00	1665582.63
1826.0000	2022-01-01	777.03	830.79	0.00	0.00	51.67	0.00	1843718.75	1989806.38
2191.0000	2023-01-01	671.05	721.75	0.00	0.00	51.82	0.00	2132327.25	2275768.00
2556.0000	2024-01-01	621.63	680.87	554.10	0.891366	52.27	1.23	2381530.25	2527914.75
2922.0000	2025-01-01	621.29	571.28	1265.34	2.04	47.90	0.451481	2605164.50	2758879.50
3287.0000	2026-01-01	602.50	483.42	2087.05	3.46	44.52	0.231627	2827557.75	2949808.75
3652.0000	2027-01-01	628.21	416.82	3191.22	5.08	39.89	0.130616	3049099.50	3112515.75

Table 3 - CMG Results- 3 Producing Wells - Individually

Well: Ź6007217930000

TIME	DATE	On-time Fraction	Oil Rate SC	Water Rate SC	Gas Rate SC	Gas Oil Ratio SC	Water Cut SC - %	Water Gas Ratio SC	Cumulative Oil SC	Cumulative Water SC
(day)		()	(bbl/day)	(bbl/day)	(ft3/day)	(ft3/bbl)	()	(bbl/ft3)	(bbl)	(bbl)
0.00000000	2017-01-01	1.00	1457.78	988.62	0.00	0.00	40.41	0.00	0.00	0.00
365.00000	2018-01-01	1.00	441.84	345.00	0.00	0.00	43.85	0.00	188477.81	135523.36
730.00000	2019-01-01	1.00	349.33	331.00	0.00	0.00	48.65	0.00	330658.59	258776.55
1095.0000	2020-01-01	1.00	286.32	318.41	0.00	0.00	52.65	0.00	446103.75	376248.53
1461.0000	2021-01-01	1.00	237.81	311.65	0.00	0.00	56.72	0.00	541753.94	490628.38
1826.0000	2022-01-01	1.00	195.99	316.38	0.00	0.00	61.75	0.00	620504.75	605224.38
2191.0000	2023-01-01	1.00	154.05	338.91	0.00	0.00	68.75	0.00	683986.06	725363.94
2556.0000	2024-01-01	1.00	122.04	360.83	0.00	0.00	74.73	0.00	733483.75	854518.31
2922.0000	2025-01-01	1.00	186.12	262.05	0.00	0.00	58.47	0.00	787741.69	969478.75
3287.0000	2026-01-01	1.00	255.42	197.57	0.00	0.00	43.61	0.00	870551.69	1050947.00
3652.0000	2027-01-01	1.00	343.08	139.32	0.00	0.00	28.88	0.00	982078.00	1110717.50

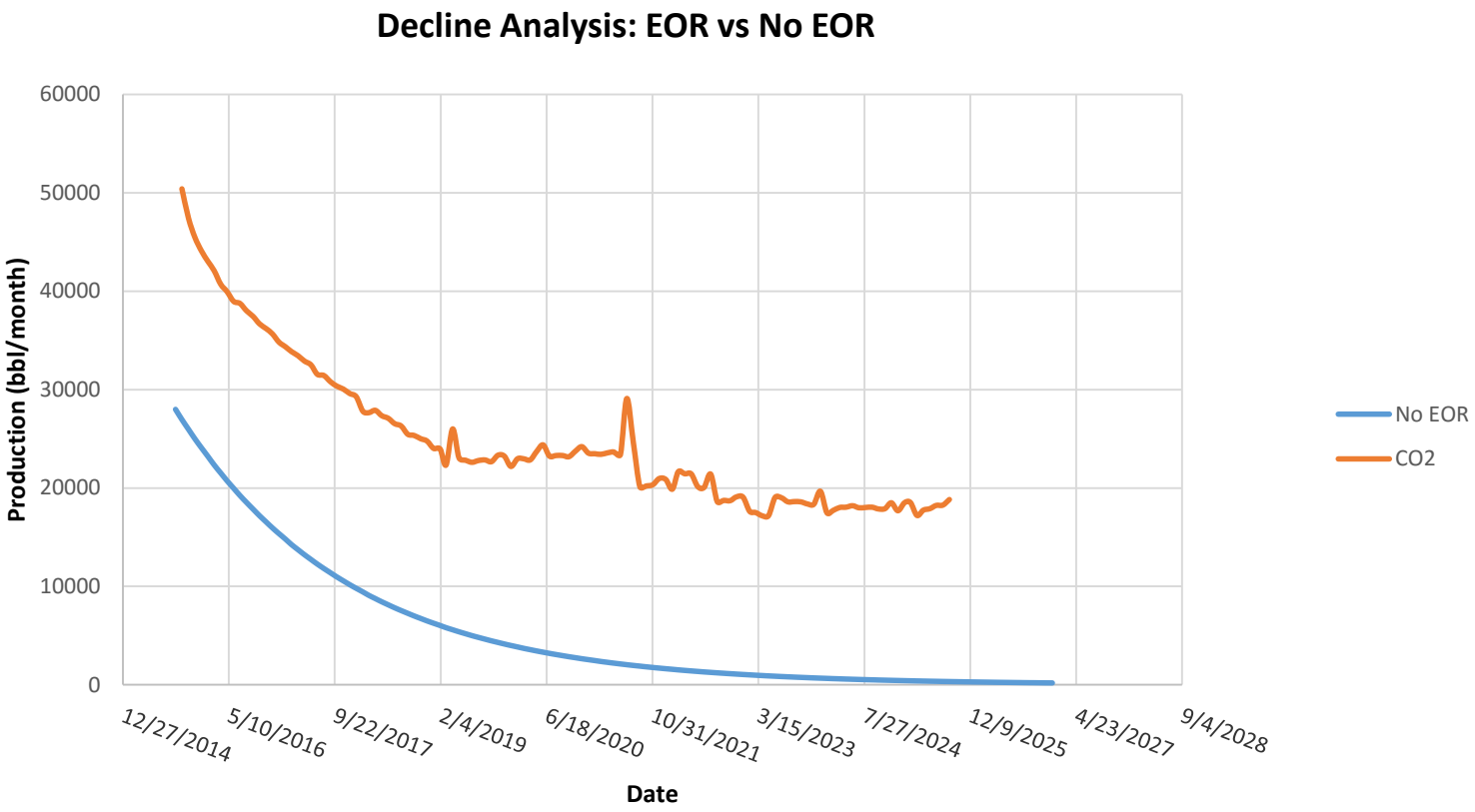
Well: Ź6007218230000

TIME	DATE	On-time Fraction	Oil Rate SC	Water Rate SC	Gas Rate SC	Gas Oil Ratio SC	Water Cut SC - %	Water Gas Ratio SC	Cumulative Oil SC	Cumulative Water SC
(day)		()	(bbl/day)	(bbl/day)	(ft3/day)	(ft3/bbl)	()	(bbl/ft3)	(bbl)	(bbl)
0.00000000	2017-01-01	1.00	1786.89	726.53	0.00	0.00	28.91	0.00	0.00	0.00
365.00000	2018-01-01	1.00	560.31	239.15	0.00	0.00	29.91	0.00	232840.30	99906.90
730.00000	2019-01-01	1.00	464.22	204.22	0.00	0.00	30.55	0.00	417824.63	179839.56
1095.0000	2020-01-01	1.00	389.94	180.58	0.00	0.00	31.65	0.00	572455.75	249381.67
1461.0000	2021-01-01	1.00	332.32	162.81	0.00	0.00	32.88	0.00	703627.38	311729.69
1826.0000	2022-01-01	1.00	286.97	150.09	0.00	0.00	34.34	0.00	815769.31	368548.50
2191.0000	2023-01-01	1.00	248.34	143.80	0.00	0.00	36.67	0.00	912719.19	422016.63
2556.0000	2024-01-01	1.00	216.58	142.21	0.00	0.00	39.64	0.00	997086.00	473970.06
2922.0000	2025-01-01	1.00	190.30	145.53	0.00	0.00	43.33	0.00	1071156.88	526405.00
3287.0000	2026-01-01	1.00	170.20	154.04	0.00	0.00	47.51	0.00	1136393.50	581221.69
3652.0000	2027-01-01	1.00	144.80	175.74	0.00	0.00	54.83	0.00	1193425.88	641536.75

Well: Ź6007052370000

TIME	DATE	On-time Fraction	Oil Rate SC	Water Rate SC	Gas Rate SC	Gas Oil Ratio SC	Water Cut SC - %	Water Gas Ratio SC	Cumulative Oil SC	Cumulative Water SC
(day)		()	(bbl/day)	(bbl/day)	(ft3/day)	(ft3/bbl)	()	(bbl/ft3)	(bbl)	(bbl)
0.00000000	2017-01-01	1.00	551.45	1997.30	0.00	0.00	78.36	0.00	0.00	0.00
365.00000	2018-01-01	1.00	246.34	605.43	0.00	0.00	71.08	0.00	98244.54	242862.38
730.00000	2019-01-01	1.00	213.90	568.37	0.00	0.00	72.66	0.00	181726.44	455882.97
1095.0000	2020-01-01	1.00	173.48	571.60	0.00	0.00	76.72	0.00	253435.73	661887.81
1461.0000	2021-01-01	1.00	192.34	496.71	0.00	0.00	72.09	0.00	316550.78	863224.50
1826.0000	2022-01-01	1.00	294.07	364.33	0.00	0.00	55.34	0.00	407444.78	1016033.50
2191.0000	2023-01-01	1.00	268.66	239.05	0.00	0.00	47.08	0.00	535622.13	1128387.50
2556.0000	2024-01-01	1.00	283.02	177.84	554.10	1.96	38.59	0.320947	650960.56	1199426.50
2922.0000	2025-01-01	1.00	244.87	163.70	1265.34	5.17	40.07	0.129375	746266.13	1262995.50
3287.0000	2026-01-01	1.00	176.88	131.81	2087.05	11.80	42.70	0.0631540	820612.69	1317640.00
3652.0000	2027-01-01	1.00	140.33	101.76	3191.22	22.74	42.03	0.0318881	873595.44	1360261.50

Decline Curve



This decline curve shows the estimated production from the field over a period of 10 years if the field undergoes a miscible CO2 flood versus the production without any sort of enhanced oil recovery effort. The timeframe of 10 years was chosen to be modeled and evaluated based upon a reasonable timeframe for a CO2 flood and the likely effects of a carbonic acid build up in the reservoir causing significant damage to casing, tubing and production equipment after such a long period of continuous injection of CO2.

Discussion:

The South Willson Ranch Field is a smaller part of the larger Willson Ranch Field. The entire field area has been in production for approximately 40 years and a great deal of production data is available for the field as a whole. The field was likely developed because oil prices in the late 1970's in the $40 per barrel range would have yielded about $8 Million of revenue per well with a per well EUR of 200,000 barrels and drilling and completion costs for such a well were probably under $800,000 per well, giving a potential 10 to 1 return on investment. This field has very little productive life left but still has significant oil in place with an estimated OOIP of 14.8 million barrels and ROIP of approximately 10.2 MMBO, which makes it a candidate for various EOR methods. The field has cumulative production to date of 4,632,240 bbls of oil, 750,870 Mcf of gas and 12,217,510 bbls of water. The water volume includes produced water which was injected and re-injected during the years of waterflooding.

As shown by the decline curves, this field is interesting because primary production and water flooding were already attempted and yielded a significant increase in production, but the incremental production from the water flood has been all but completely exhausted. To get another increment of production from this field will require a change in chemistry of the oil remaining in place in order to make that oil less viscous and easier to recover. Miscible CO2 flooding is unique because the CO2 is mixed directly with the oil in place to decrease the viscosity of the oil and help to increase its flow and movement through the reservoir and up and out of the wellbores. This effort may prove to be successful given that the oil in the South Willson Ranch Field is trapped inside of oil lenses. If the viscosity of that oil can be reduced in situ through the achievement of miscibility with CO2 a great deal more of that oil can be recovered.

The plan to use a miscible CO2 flood, while relatively expensive, if technically feasible may prove to increase the productive life of the field significantly. The South Willson Ranch Field is a stratigraphic trap in which the oil is trapped in lenses and with a water flood already implemented the water surrounding the remaining oil left in place may prove to be a significant obstacle. Since there has been previous water flooding it can be expected that there will be a relatively high water saturation within the reservoir. This increased water saturation will lead to

some problems when injecting CO2. One of the problems that is of concern is that the CO2 will have a hard time actually contacting the oil. When doing a miscible CO2 flood, the goal is for the CO2 to mix with the oil to reduce the density and viscosity, allowing the oil to more readily flow through the reservoir. With the increased water saturation, it is more likely that the CO2 will mix with the water and possibly won't mix with the oil. This could then lead to the water "sweeping" the CO2 over the oil. If this phenomenon occurs, the CO2 will not become miscible with the oil, therefore rendering a miscible CO2 flood ineffective. One possible solution to this problem is to inject larger quantities of CO2 at greater pressures. We must determine if the CO2 miscibility would alter the chemistry of the fluids in the reservoir sufficiently to allow for more oil recovery. The miscibility of the oil in place must be considered when trying to use this method as some oil is much more miscible than others at different temperatures and pressures. Since the field has good porosity and permeability if the oil in place is conducive to imbibing CO2 it is likely that a miscible CO2 would prove to be very successful for a number of years based on the results of the previous water flood. The models we created will help verify this prediction and give a much clearer picture of the exact increase in production and the lifespan of that production.

To date the initial data from the decline curves and well parameters would seem to make this field a promising technical candidate for a miscible CO2 flood. After completion of the static model we determined that only five of the six wells contained in the field are viable for a tertiary recovery effort as one of the wells (API#: 26007219980000, Well #6) was shut in after a three month test period in which there was no production. It was completed 12/6/12 and shut in on 2/20/13, which also coincides with a decline in the price of oil. This well was abandoned likely due to a lack of oil productivity near that wellbore due to that part of the reservoir watering out, severely limiting the production potential. Due to the lack of production and the expense involved in converting the well back into a producer the well was removed from our analysis.

After completing and running the dynamic model in CMG the results show that over a 10 year time frame of miscible CO2 injection at a rate of 7 MMcfd per day the South Willson Ranch field would be able to recover 3.05 MMbbl of the 10.2 MMbbl of remaining oil in place.

The 7 MMcfd CO2 injection constraint comes from the estimated future daily CO2 availability of the nearby ethanol plant. This would be hugely successful recovery effort, recovering an additional 30% of the remaining ROIP. This model however was limited by the software in that only a single strata of the Cruise J sand, was able to be used as a productive formation due to constraints on the number of blocks able to be uploaded into the version of the software we received. The second issue with the software is that it was unable to fully take into account the parameters required for miscibility. While it effectively demonstrates that a miscible CO2 flood is technical feasible, it does not adequately show how high of a pressure base the CO2 would have to reach via compression from atmospheric pressure in order to be able to achieve miscibility with the oil in place in the reservoir. For this aspect of performing a miscible CO2 we chose to look at the Holms & Josendal (1982 SPE) correlation.

From reviewing the results from the remaining five wells from the dynamic model in CMG, and taking into account the mole weight of C5+ in the Willson Ranch oil and its high reservoir temperature of 187 degrees Fahrenheit it appears that the miscible CO2 flood is technically possible, but it would require extensive compression of the CO2. Unfortunately the high temperature of the reservoir drives up the pressure required to achieve miscibility. Using the Holms & Josendal correlation:

Figure 8- Holms & Josendal correlation

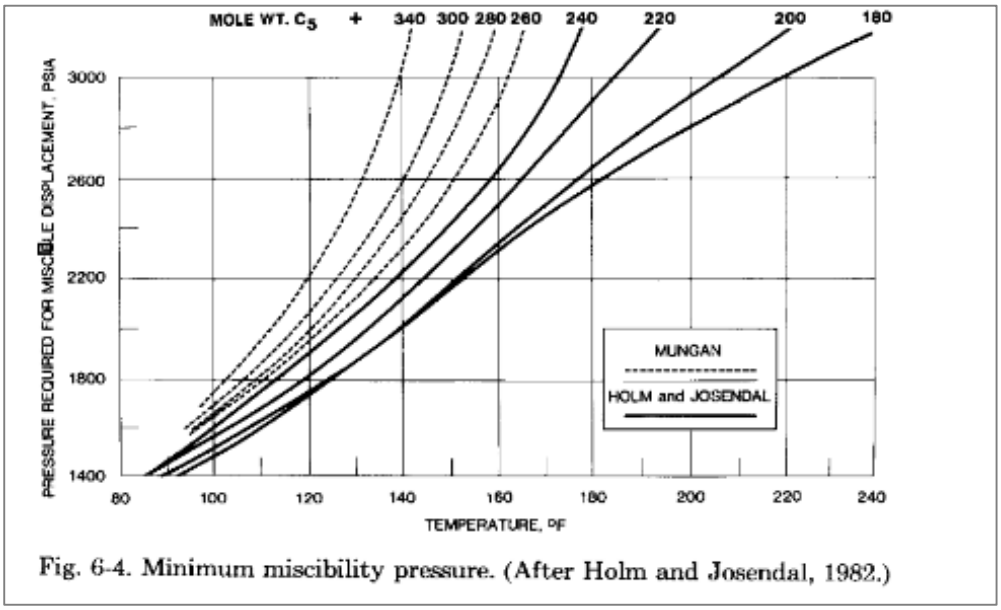


Fig. 6-4. Minimum miscibility pressure. (After Holm and Josendal, 1982.)

Table 4 - Oil Analysis of South Willson Ranch

	WRU 14 Oil Analysis				
	Wt %	Mol %	rho 60	API	MW
Carbon Dioxide	0.07	0.3			44.01
Methane	0.68	7.44			16.04
Ethane	0.21	1.2			30.07
Propane	1.3	5.17			44.1
Iso-butane	0.45	1.34			58.12
n-butane	1.86	5.59			58.12
Iso-Pentane	1	2.43			72.15
N-Pentane	1.71	4.14			72.15
Hexanes	2.53	5.15			86.18
Heavier	90.19	67.24	0.857	33.5	235

The oil analysis was used to calculate the C5+ value needed for the correlation, adding together the percentages for Iso-Pentane, N-Pentane, Hexanes, and Heavier for a C5+ value of 95.43 Wt% or 78.96 Mol%. So using the correlation above the pressure needed to obtain miscibility with the oil in the South Willson Ranch Field is estimated to be around 2900 psia. With the bottomhole pressure of the Willson Ranch Field currently being at 530 psia the amount of compression needed to achieve this pressure with the CO2 would be quite high and would require several stages of compression since the CO2 would be delivered at atmospheric pressure.

So while a miscible CO2 flood is technically feasible and could recover a significant amount of the ROIP for the South Willson Ranch field as demonstrated by the CMG model, the economics of this project would have to be extensively analyzed prior to going forward. Since the project would not even be considered for a few more years when the ethanol plant is built, it would certainly be worth revisiting this project at that time to calculate the miscible CO2 implementation expenses, expected results and potential payoff.

Conclusion:

The South Willson Ranch field has a significant amount of remaining oil in place at 10.2 MMbbl even after several years of waterflooding, which making it a good candidate for consideration as a miscible CO2 flood. As shown by the dynamic model run in CMG a miscible CO2 flood is technically feasible for the field given the reservoirs parameters and predicts a 30% recovery rate from the ROIP at 3.05 MMbbl. The major technical hurdle to overcome in achieving CO2 miscibility will be the high pressure at which CO2 will need to emplace in the reservoir in order to make it invade the oil in place and mix with it to swell that oil to reduce its viscosity. The composition of the oil present in the South Willson Ranch Field is one of the parameters used in determining the miscibility of CO2 but a parameter that is of far greater significance to miscibility is reservoir temperature. Because of the high reservoir temperature of 187 degrees Fahrenheit at South Willson Ranch, which mitigates against miscibility, injection pressures in the reservoir will need to approach 3,000 psi in order to effect the desired miscibility. So, as long as the required compression can be employed to boost the CO2 pressure from atmospheric to 2,900 psi in the reservoir CO2 miscibility can be achieved.

References:

1. Van Spence. Rampart Energy. Denver, CO. Data release 2015-2016.
2. Figure [8] – Donaldson, E.C. Chilingarian G.V, Yen, T.F. “Enhanced Oil Recovery II: Process and Operations”, 1989, Developments *in Petroleum Science*, Volume 7, Part B p. 134 ISBN - 978-0-444-42933-9.