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Miscible CO_2 Flooding Using Horizontal Multi-Fractured Wells in San Andres Formation, TX – a Feasibility Study

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Abstract

The San Andres is a well-known dolomitic enhanced oil recovery target with low matrix permeabilityin the area of interest (Yoakum County, TX). A reservoir simulation study was undertaken to investigate the feasibility of using horizontal multi-fractured wells in low permeability miscible floods. A reservoir model was developed for the area of interest and was history-matched with the primary production data from the field. The model was then used to illustrate the CO_2 miscible flood potential by quantifying the incremental recovery over the primary production scenario.
Compositional modeling was used in the study to evaluate CO_2 flooding feasibility and efficiency. A holistic workflow including PVT modeling, petrophysical analysis, geomodeling, and hydraulic fracture modeling, provided integrated input into the reservoir model. Continuous CO_2 flooding was explored as an operating strategy. Furthermore, water alternating gas (WAG) cases were designed and run as a more realistic and cost-effective method of implementing miscible flooding. Based on the history-matched model, sensitivity analyses were conducted on hydraulic fracture geometry, well spacing, injection patterns and operating conditions for the primary production scenario, continuous CO_2 flooding and WAG scenarios.

Field surveillance and observations during the history-matching process showed that the wells had undergone damage from scaling. Sensitivity analysis showed that 300ft to 400ft cluster spacing resulted in the highest oil production during the first 10 years. Interdependent parameters such as well spacing and fracture half-length were studied together; this sensitivity review showed that the differential oil recovery from 128 acres to 160 acres was larger than that from 160 acres to 213 acres, leading to the recommendation that 160 acres could be the optimized well spacing. In the optimized design, the continuous CO_2 injection case showed an incremental oil recovery of 22% (compared to primary production). The CO_2 utilization factor was between 7 and 8, which was consistent with the reported value from literature. WAG sensitivity analysis showed that longer hydraulic fractures did not necessarily improve WAG efficiency, but led to earlier CO_2 breakthrough. This observation confirmed our early suspicion that smaller hydraulic fracturing treatment could be a more cost-effective design for miscible flooding in this reservoir. In addition, sweep efficiency and recovery were sensitive to WAG ratio, but not to injection slug size in each cycle.

The current study sheds light on the feasibility of conducting a CO_2 miscible flood using horizontal multi-fractured wells in low permeability reservoirs – a topic that is yet to be explored widely in petroleum engineering literature and in the industry. Incremental production that can be expected from a miscible CO_2 flood is estimated and recommendations are provided for optimal well spacing, WAG ratio and operating constraints to help determine a viable field development plan.

Introduction

San Andres formation is a carbonate reservoir in west Texas, and is well known as a CO_2 flooding target. Aside from the highly heterogenous dolomitic reservoir quality, other challenges associated with the formation include high residual oil saturation, and high water cut from primary production. Multiple publications defined this formation as a naturally water flooded residual oil zone (ROZ) (Melzer, et al., 2006; Koperna, et al., 2006; Honarpour, et al., 2010; Harouaka, et al., 2013). San Andres in the area of study, however, is believed to be the main pay zone (MPZ), and the reason is two-fold. First, due to the waterflood-like nature of the ROZ, the produced water from the San Andres ROZ typically has low TDS (10,000-50,000ppm) as it is diluted by the meteoric water recharge (Trentham, 2011), while our field data shows much higher TDS (180,000-200,000ppm). Second, oil saturation in both Chambliss and Brahaney formations is at least 50% for most of the pay zone, which is higher than what is typically observed in ROZ. (Fig 1). Rather than being a natural water flooded ROZ, it is possible that the area of interest was originally wet that was most likely partially filled from oil spillover from Wasson and Brahaney fields when the Laramide Uplift to the west/northwest caused tilting of these fields, resulting in spilling and trapping of oil due to the stratigraphic pinching out of the San Andres to the west/northwest of Wasson. Petrophysical logs in the area of interest typically show significant oil saturation, but primary production often yields higher than normal water cut. One explanation could be the extremely heterogeneous porosity distribution, with oil being trapped in the poorly connected pores (Cannon and Rossmiller, 1984). Another theory is the mixed wettability (Patel, et al., 1987; Honarpour, et al., 2010). At early time, wells produce from water-wet fractures and vuggy porosity, and later on, oil-wet matrix porosity starts contributing to the production. This is consistent with what is observed in the field, in that wells produce higher water cut initiallythat gradually decreases with time.

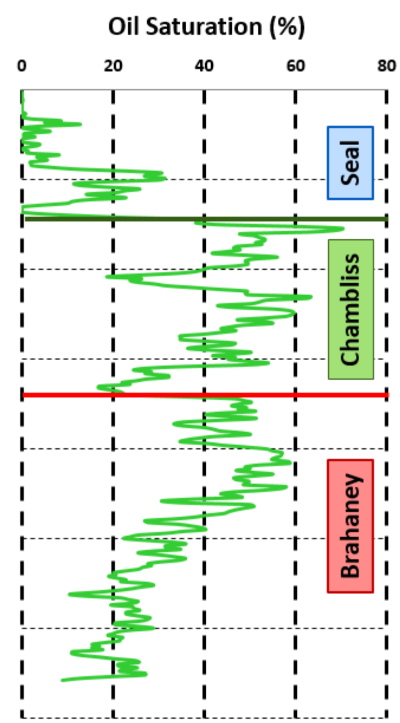

Figure 1. Oil saturation profile in San Andres Formation. The main pay zone consists of Chambliss and Brahaney formations

CO_2 miscible flooding is recognized as a possible strategy to effectively produce from the San Andres formation. The application of horizontal wells with hydraulic fractures in miscible flooding is yet to be fully understood. Numerous researchers reported results from their CO_2 miscible flooding simulation studies in Slaughter field dolomite (Guillot, 1995), west Texas carbonate (Lim et al., 1992; Lim et al., 1996), Prodhoe Bay sandstone (McGuire, et al., 1998), Bakken (Xu and Hoffman, 2013), but few have considered miscible flooding using multi-fractured horizontal wells. The objective of this study is to investigate the feasibility of CO_2 flooding using multi-fractured horizontal wells, and to optimize fracture design, well spacing, and estimate the hydrocarbon recovery from various field development strategies, such as continuous CO_2 flooding and Water Alternating Gas (WAG) processes.

The area of study is 1x1 sq. mile acerage in Yoakum County, Texas, with two producing horizontal wells at the time of the study, 1H and 4H. Due to the low permeability, all wells were hydraulically fractured with 120 ft cluster spacing to improve the productivity. About one year of historical production data is available from each well. In vertical direction, the main reservoir formations are the Chambliss and Brahaney dolomite, with an anhydrite sealing layer at the top and a water bearing layer below.

Model Development

A dynamic reservoir model was built from the upscaled geomodel. The workflow of the geomodeling was reported earlier (An et. al. 2017) indicating the variation of facies within the reservoir. The model for history matching covers an area of interest of about 1.5x1.5 mi^2 with cell size of 50ft x100ft in the horizontal planes to accommodate the hydraulic fractues (Fig 2). In the vertical direction, the model incorporated 40 layers including one for the sealing layer on top, 11 for Chambliss, 18 for Brahaney, and 10 for the bottom water bearing zone (Fig 3). Hydraulic fracture geometry was determined by numerical modeling with history matched treatment pressure, details of which are not included in this paper. Local grid refinement (LGR) was applied in the near-fracture zone to capture accurately the pressure transient and fluid flow (Fig 4). As the level of refinement could numerically affect the simulation result, LGR used in all simulation runs remain the same regardless of the HF geometry.

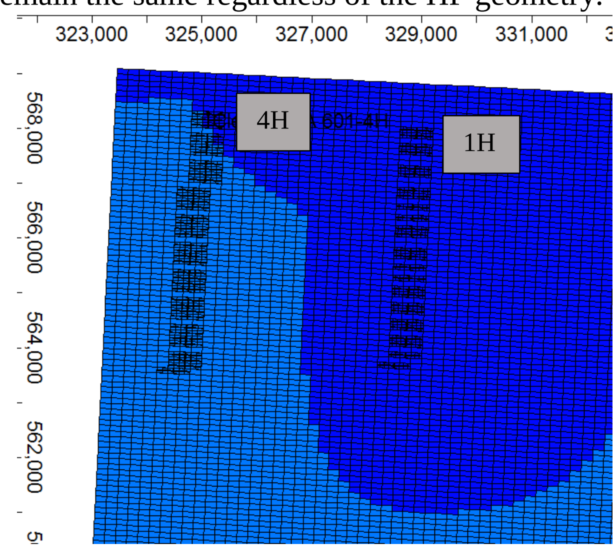

Figure 2. Map view of the reservoir model

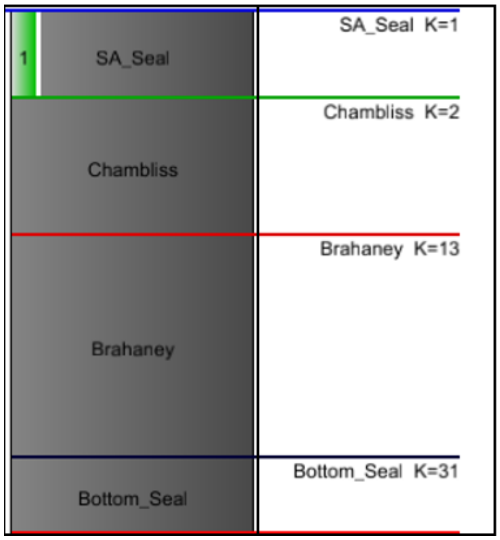

Figure 3. Stratigraphic column in the reservoir model

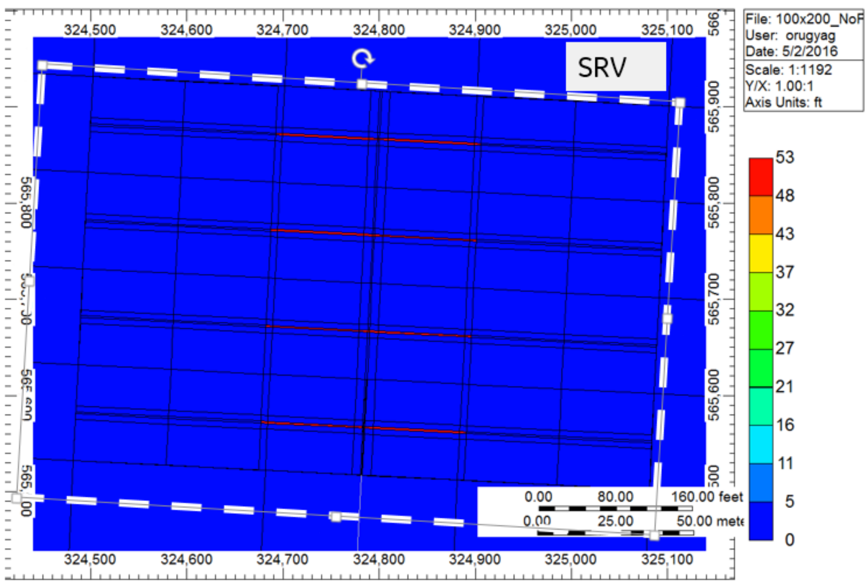

Figure 4. Zoomed-in map view to illustrate LGR and SRV. Legend displays permeability in mD

PVT lab test including Constant Composition Expansion (CCE), Differential Liberation (DL), and separator test was available from San Andres formation in an anolog field. PVT modeling was conducted by matching the lab test data. The outcome of this exercise is the compositional PVT model with eight lumped components. CO_2 and the last pseudocomponent were kept as separate components to enhance the modeling accuracy. DL data was adjusted to the separator condition before being fed into the model (Al-Marhoun, 2003).

In general, dolomite/dolostone in the Permian Basin has been widely recognized as a highly heterogenous reservoir with multi-porosity system. Additionally, natural fractures could also contribute to fluid flow in addition to matrix (Mathis and Sears 1984; Quijada, 2005; Mohamed, et al., 2012). In our study, however, neither the borehole imaging nor core data indicated pronounced evidences of natural fracturing (An et al., 2017). Therefore, a single porosity model was used in the simulation. However, to account for the possibility of other types of secondary porosity, the model consists of a near-fracture zone referred to as stimulated reservoir volume (SRV), represented by an enhanced permeability that was fine-tuned during the history matching process. The permeability in the fracture and SRV is believed to be affected by multiple mechanisms such as in-situ stress change due to depletion, proppant crashing, proppant embedment, and clay swelling (Han, el al., 2015). The model was simulated using GEM, which is CMG's finite difference compositional simulator.

Reservoir and fluid properties listed in Table 1 show a summary of the reservoir input parameters. According to historical GOR data, the reservoir was believed to be undersaturated at the time of the study, and the minimal miscible pressure (MMP) is assumed to be the same as saturation pressure. Based on the water saturation distribution from the geomodel, capillery pressure profile was computed to account for the initial equillirium in the reservoir.

Table 1. Reservoir and fluid properties

Pressure (psi)	Temperature (^oF)	Permeability (mD)	Porosity
1,800-2,000	130	0.2	0.08
Depth (ft)	MMP = P_{sat} (psi)	API (^{o})	Initial GOR (SCF/STB)
5,200+	1,500	31	800 -1,000

History Matching and Forecasting

At the time of the study, the area of interest was under primary production with two producing horizontal wells. Based on the upscaled geomodel, some reservoir and fluid properties, including matrix permeability, SRV permeability, fracture conductivity, relative permeability (curvature and end points), and skin are considered as parameters with high uncertainty and modified to match the production data. The operator experienced inorganic scaling issue from both wells, and that is why skin is considered responsible to productivity reduction.

With the consideration of all the mechanisms mentioned above, the simulation yielded a very good history match (Fig. 5 and 6). With liquid rate serving as the constraint, GOR, BHP, oil rate, water rate, and water cut matches were evaluated. Both GOR and water cut show a good match on the overall trend but missed some details in the early stages. Once a satisfying history match was achieved, the model was run under a constant BHP for 30 years to forecast the primary recovery. (Fig 7 and 8)

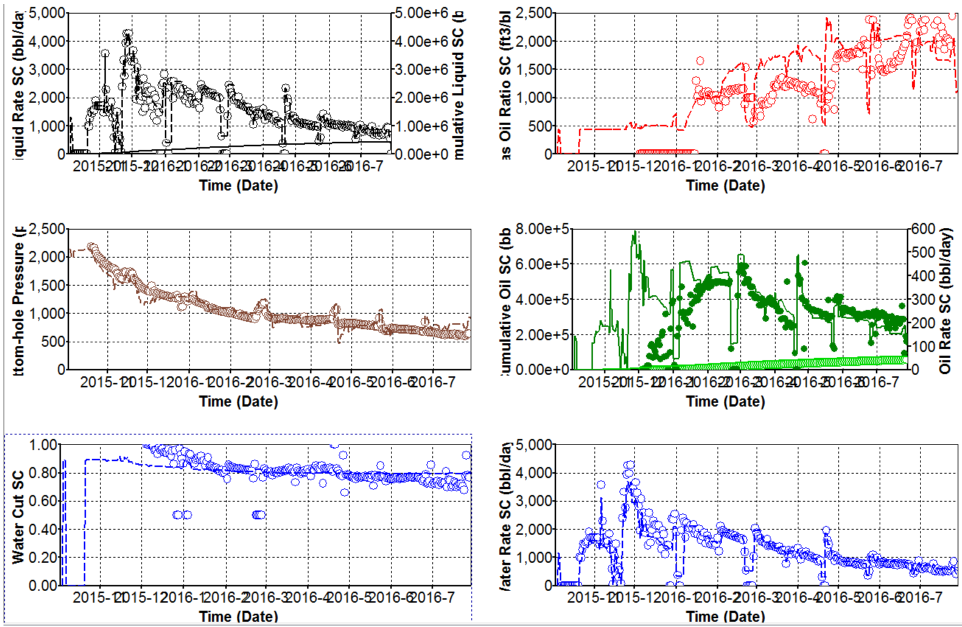

Figure 5. History match result for 1H. Dots are historical data and curves are simulation results. From left to right and top to bottom, the plots are liquid rate, GOR, bottom-hole pressure, oil rate, water cut, and water rate. The same is applicable for Fig 6-8

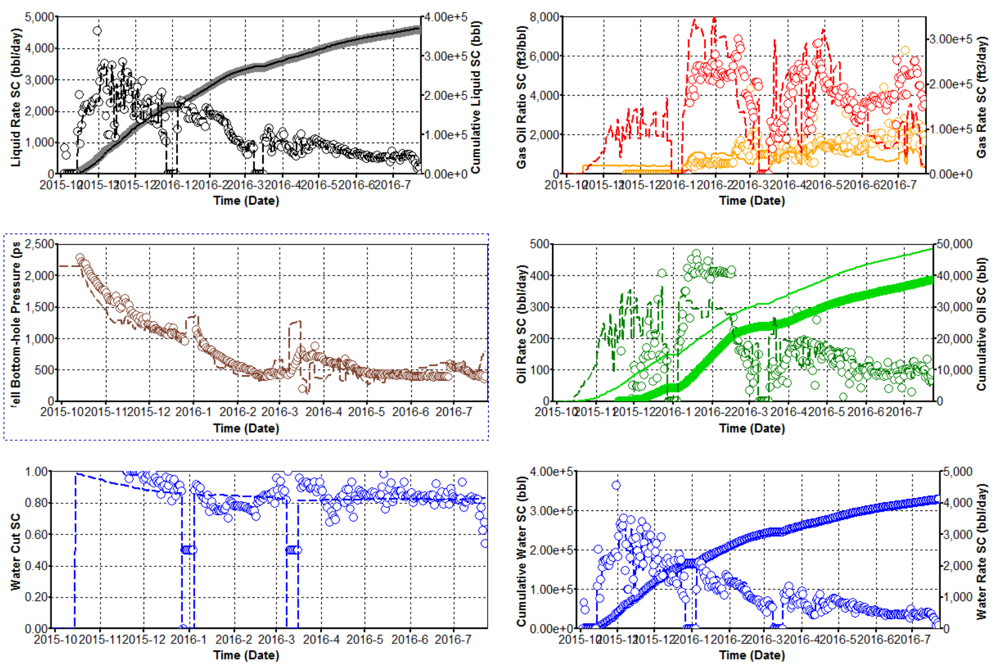

Figure 6. History match result for 4H

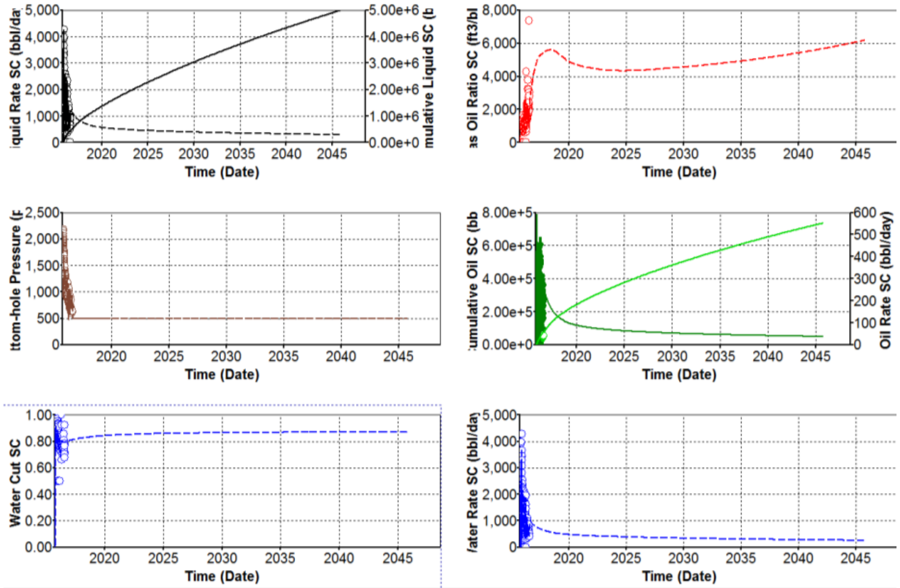

Figure 7. Forecasting for 1H

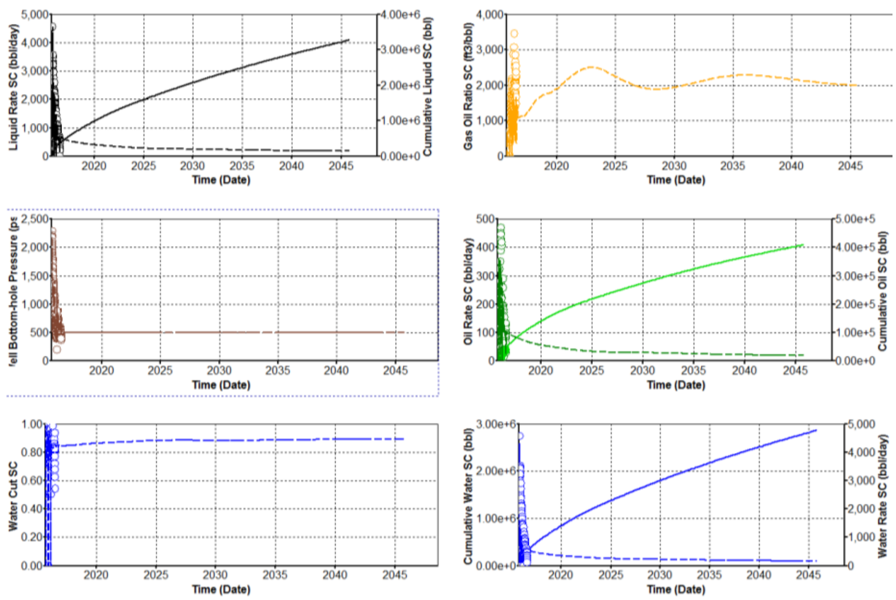

Figure 8. Forecasting for 4H

Sensitivity Analysis

One of the objectives of the simulation study is to investigate the field development strategy. Optimized well spacing is desired to effectively drain the reservoir with good sweep efficiency and without inter-well interference. Additionally, cluster spacing or hydraulic fracture spacing optimization is considered to balance the productivity and operational investment. For the current CO_2 flooding model, traditional massive fracturing treatments for primary production purpose may not be feasible, as fractures act as highly permeable conduits which could result in early CO_2 breakthrough and low sweep efficiency. Therefore, analyzing these parameters is important for a better understanding of the optimized strategy.

Cluster Spacing

Seven scenarios of cluster spacing, varying from 100 ft to 700 ft with 100 ft increments, were tested in the study. The following assumptions were made to simplify the study.

- Green field reservoir
- Single well model with 160-acre spacing
- BHP follows the decline behavior of 1H for the first year and remains constant at 620 psi for the rest of the simulation
- Identical local grid refinement for the seven cases
- Surface fluid rate is capped to 3000 bbl/day due to facility constraints

As illustrated in Fig. 9, where the field cumulative oil production is plotted against cluster spacing, curves represent simulation results from different time steps. In the early stages, particularly for the first 2 years, tighter cluster spacing yielded higher cumulative oil, indicating negligible inter-fracture interference. However, at later stages, wider cluster spacings start outperforming the closer spacing. But too wide a cluster spacing leads to lower cumulative production (500ft, 600ft, and 700ft cases). This suggests that the optimal cluster spacing occurs at ~300ft-400ft with higher production by the 10th year. Therefore, from a longer term perspective, 300 or 400 ft cluster spacing could be a better design, as the interference between fractures is not significant enough to hinder production.

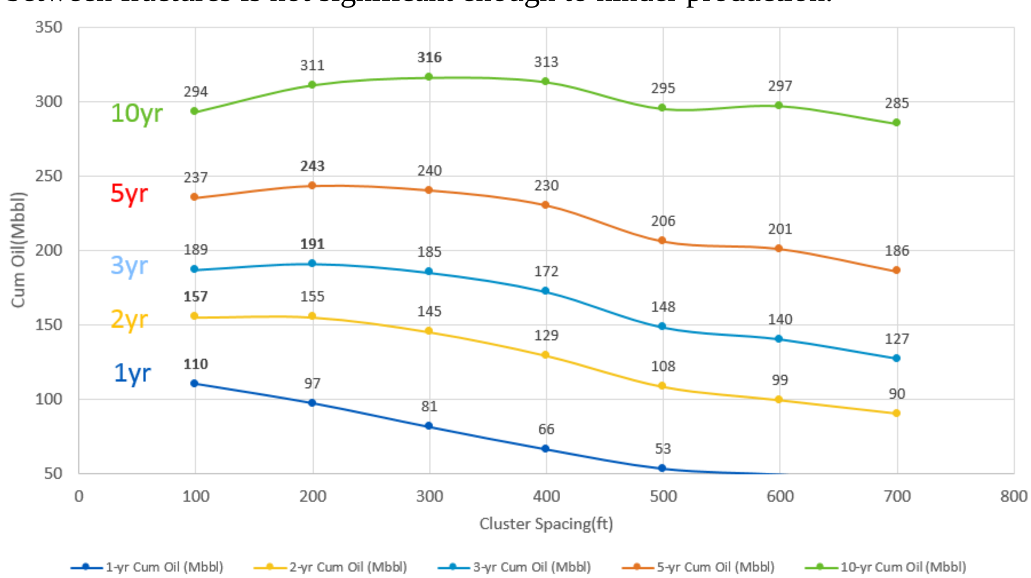

Figure 9. Sensitivity analysis on cluster spacing

In Fig 10, cumulative production per fracture, or fracture production efficiency is being considered. Ideally, the optimized case should have both high overall cumulative production and fracture efficiency.

Economic modeling (not shown here) suggests that 400 ft cluster spacing is the optimized design for this particular study.

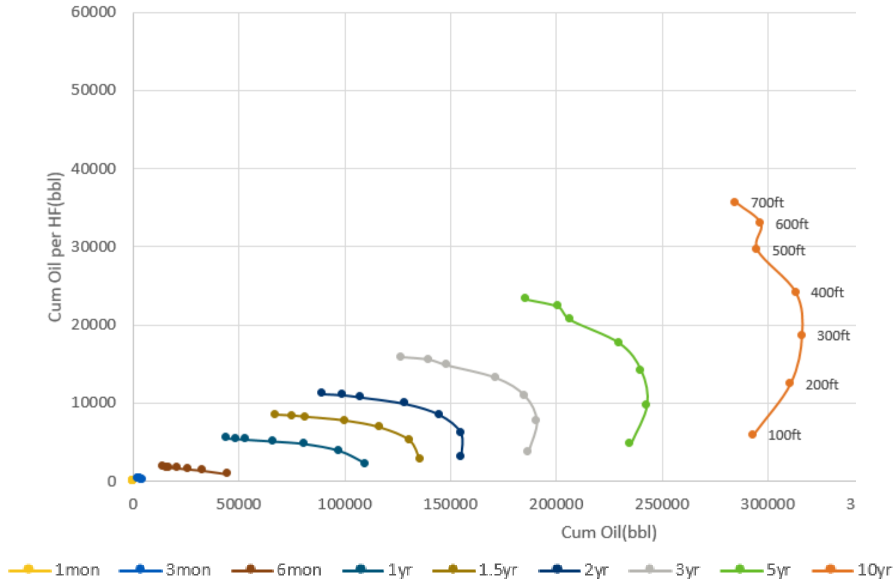

Figure 10.Sensitivity analysis on cluster spacing, considering both cum production and HF efficiency

Well Spacing and Fracture Half Length

Three well spacing cases, 213 acre (3 wells), 160 acre (4 wells), and 128 acre (5 wells), are considered in the study (Fig 11). It is noted that even after fracture modeling, fracture half length (x_f) still has high uncertainty among the fracture geometry parameters, due to the limited data available away from the wellbore. In reality, engineers have little control on the x_f from an operational point of view. As inter-dependent parameters, well spacing is coupled with half length in the sensitivity analysis. The assumptions are listed below.

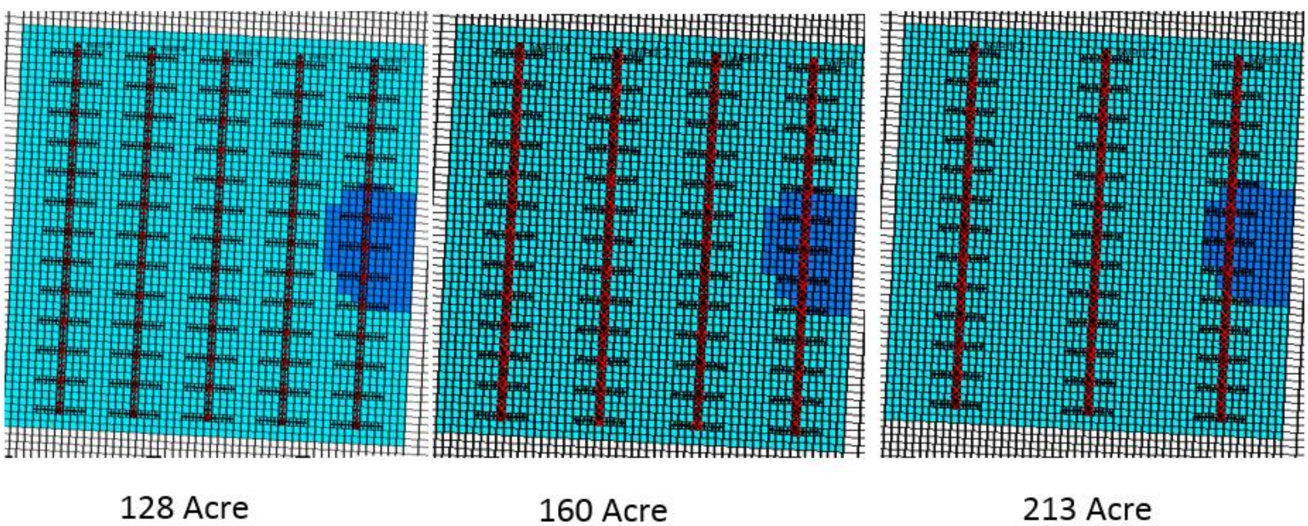

Figure 11. Model setup for well spacing and half length sensitivity analyses

- Green field reservoir
- 400ft cluster spacing

- BHP follows the decline behavior of 1H for the first year and remains constant at 620 psi for the rest of the simulation
- Fluid rate is capped to 3,000 bbl/day
- Three half length values are considered, 150ft, 250ft, 350ft. In total, there are nine simulation cases.

The simulation results for different well-spacing and hydraulic fracture half length are shown in Fig 12, 13 and 14. Focusing on later times, i.e., at the end of 10, 20, and 30 years, incremental production from 3-well spacing to 4-well spacing is higher than that from 4-well to 5-well scenario, regardless of the fracture half length. In other words, the production benefit from the 4th well is higher than that from the 5th well, which leads to the conclusion that solely based on the production, 4 wells per section, or the 160 acre spacing case is a better design. The observation was later confirmed by the economic modeling.

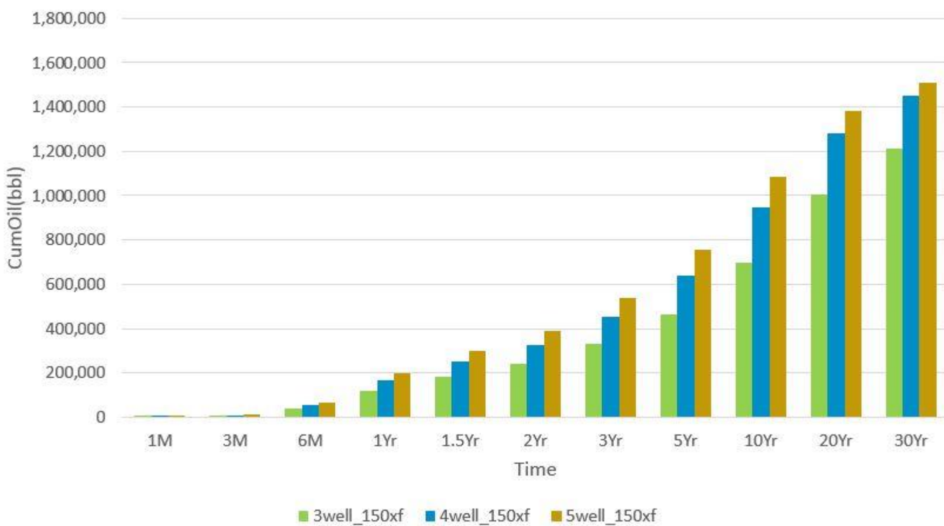

Figure 12. Sensivitity analysis on well spacing for x_f = 150 ft

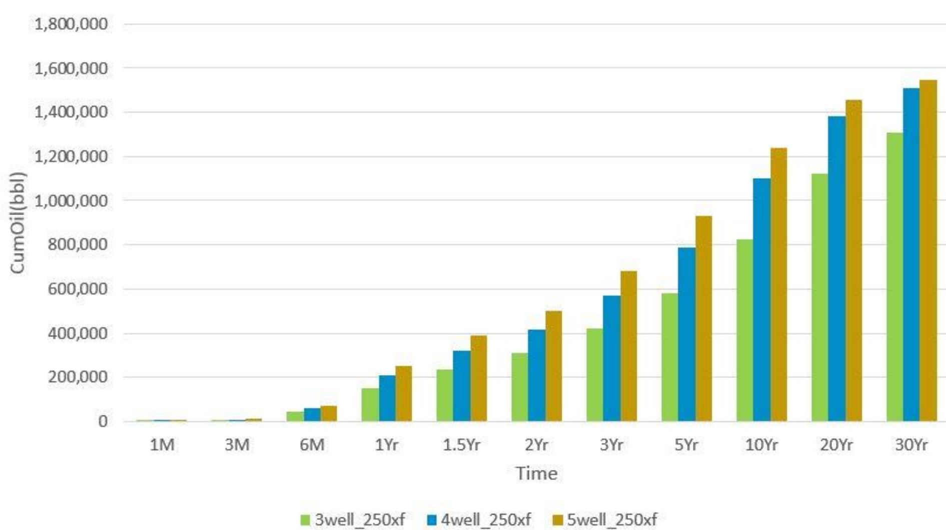

Figure 13. Sensivitity analysis on well spcacing for x_f = 250 ft

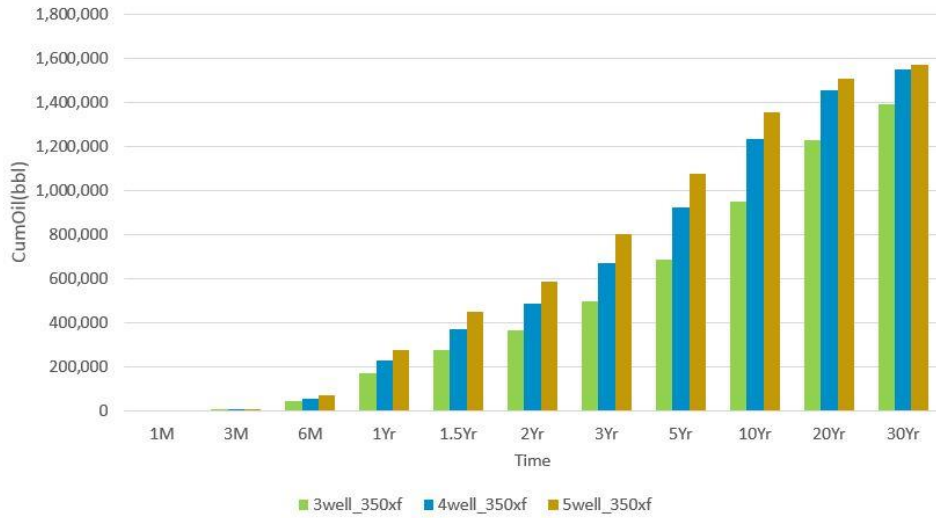

Figure 14. Sensivity analysis on well spacing for x_f = 350 ft

Continuous CO_2 Injection

Continuous CO_2 flooding feasibility analysis was conducted after a good understanding of primary production. A series of vertical injectors is placed in between horizontal producers as an analog of line drive flooding pattern. Because of symmetry, the model is further simplified as a single well model as shown in Fig 15. The simulation model consists of multiple vertical injectors, and two horizontal wells to the sides with one wing hydraulic fractures. To ensure that the 1/3rd partial model is representative of the full model, a quick validation run to compare both models was made, as shown in Fig 16. The simulation result from the 1/3rd model is multiplied by three for both injected gas and produced oil to obtain the equivalent results from the full model. As the results from both models agree with each other, the partial model is used in subsequent studies.

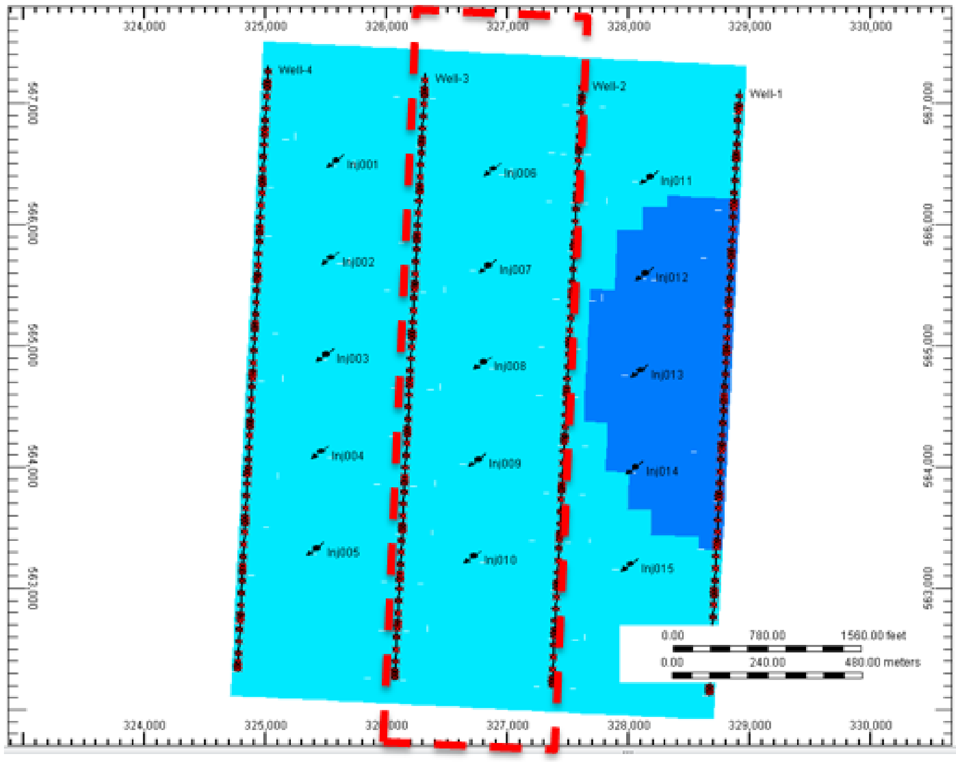

Figure 15. Map view of the model with injectors and producers. Red box indicates the partial model

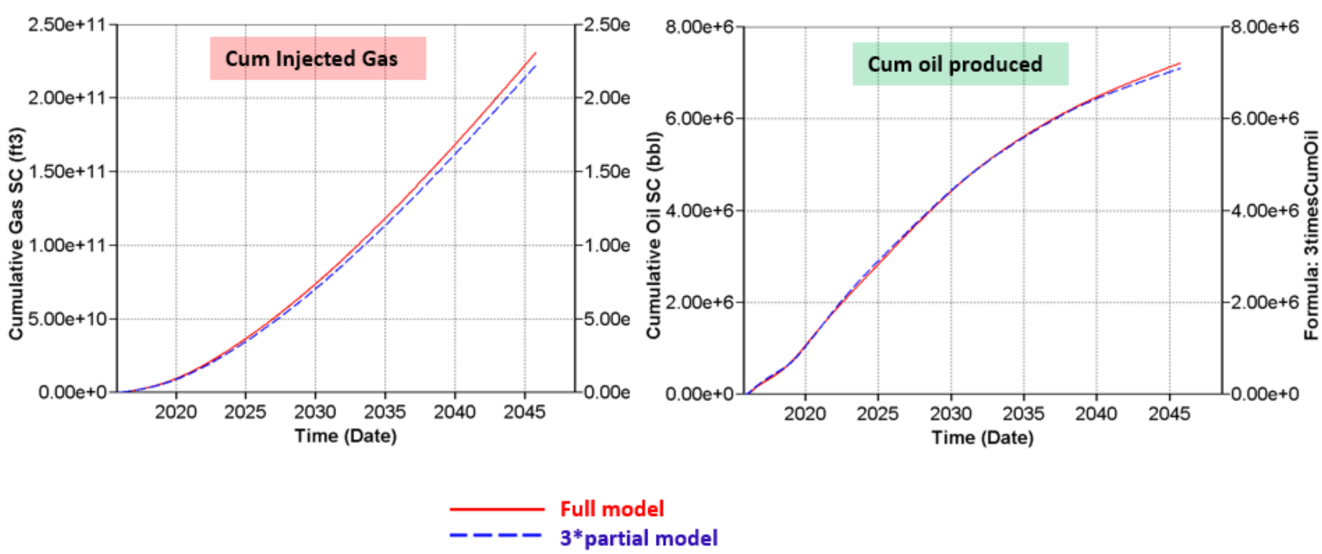

Figure 16. Validation runs to compare the full model and the 1/3rd partial model

In such tight reservoirs, a major challenge to CO_2 flooding is the injectivity. Feasibility test shows that injectors with no stimulation could barely have reasonable amount of injection. A set of sensitivity analysis were used to figure out the stimulation strategy for the injectors, as shown in Table 2. Original perforation design only covers the Brahaney interval to minimize CO_2 gravity override. Additionally, the study considers a longer perforation interval scenario that extends to the top of the Chambliss. Negative skin factor represents acidizing treatment near the wellbore. Single stage hydraulic fracturing of the vertical injectors is another alternative to increase the injectivity.

Table 2. Sensitivities to Completion Design

Case	#injector	Skin	Perf'd K layers	HF (Y/N)?	Recovery (%)	HCPVI	Cum CO_2 injected (BCF)	CO_2 utilization factor (MCF/BBL)
Primary depletion	0	-	-	N	2.8	--	--	--
NoSkin_noHF_ShorterPerfInt	5	0	15-30 (Brahaney)	N	11	0.81	28.9	7.38
NoSkin_noHF_LongerPerfInt	5	0	2-33 (Chambliss, Brahaney)	N	13	0.91	34.1	7.77
wSkin_noHF_ShorterPerfInt	5	-3	15-30 (Brahaney)	N	14	1.18	46.5	7.51
NoSkin_wHF_ShorterPerfInt	5	0	15-30 (Brahaney)	Y	17	1.76	61.6	7.63
NoSkin_wHF_LongerPerfInt	5	0	2-33 (Chambliss, Brahaney)	Y	21	1.92	81.3	7.36

The simulations were run for 30 years and the result is shown in Fig 17. While the primary depletion scenario yields less than 3% recovery, the cases with CO_2 injection yield 11% to 21% oil recovery. The best case scenario in terms of the highest recovery and injectivity, is the case with hydraulically fractured injectors with long perforation intervals. CO_2 utilization factor is an indicator of CO_2 flooding efficiency, and is defined as follows:

$$CO_2\ utilization\ factor = \frac{Cum\ CO_2\ injected - Cum\ CO_2\ produced}{Incremental\ oil\ production\ over\ primary\ depletion}$$

where all the volumes in the equation are at reservoir conditions. The lower the CO_2 utilization factor, the higher the flooding efficiency.

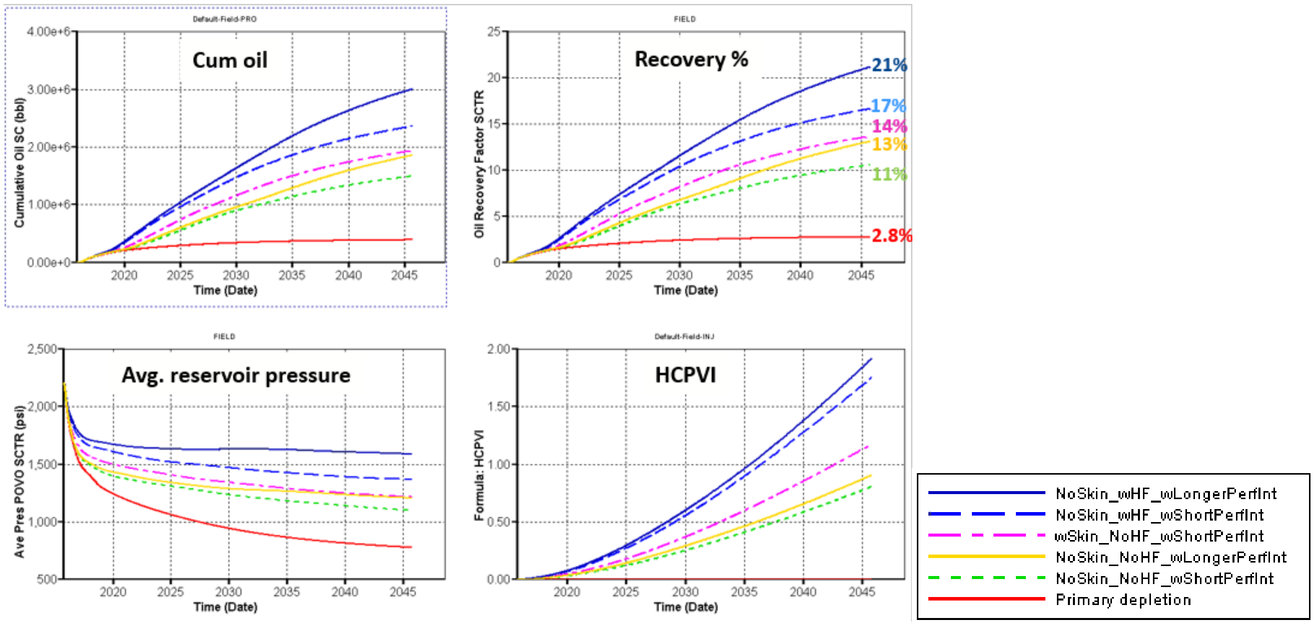

Figure 17. Simulation results for different completion strategies

Additionally, as illustrated in the 2D side view (Fig 18), significant CO_2 override is not observed until 10 years due to the low permeability. To maximize the injectivity, it is beneficial to have injectors with extended perforation length that are hydraulically fractured.

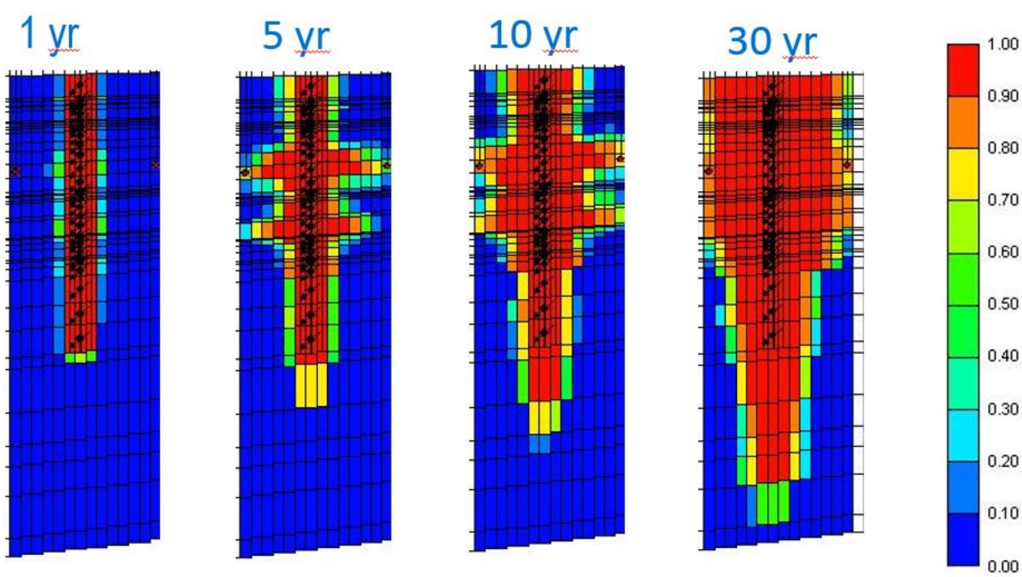

Figure 18. 2D side view of CO_2 saturations at different time steps

In addition, the number of injectors in the center of the model was also investigated. Five scenarios from 3 to 7 injectors were tested to evaluate the recovery and efficiency of the flooding. The results are in Table 3. The 7-injector scenario has both the highest recovery and efficiency, and this case was subsequently used as the base case in the following studies.

Table 3. Sensitivity to the number of injectors

Case	Cum Oil (MMSTB)	Recovery (%)	Cum CO_2 inj (BCF)	HCPVI	CO_2 utilization factor (MCF/BBL)
3 injectors	2.26	15.93	57	1.39	7.89
4 injectors	2.79	19.66	71	1.73	7.56
5 injectors	3.01	21.22	81	1.91	7.36
6 injectors	3.47	24.46	92	2.25	7.21
7 injectors	3.81	26.85	99	2.41	7.07

WAG Design

Despite the high recovery, continuous CO_2 injection has limited field application due to the constraints on CO_2 resource and high cost. Alternatively, WAG is a more cost-effective technique. To address the uncertainty in the fracture geometry, two cases with different fracture half lengths were run. The design is shown as follows.

- x_f = 150ft and 250ft
- 7 vertical injectors
- WAG cycle: 180 days of CO_2 injection followed by 180 days of water injection
- Injection constraint: max. BHP = 4,000 psi (fracture pressure = 4,500 psi)
- Production constraint: min. BHP = 620 psi

As shown in the set up of the model (Fig. 19), the injectors are staggered with the cluster locations to minimize early breakthrough. While the primary production scenario yields less than 3% recovery, both WAG scenarios reach more than 25% recovery in 30 years (Fig. 20). The Recovery vs HCPVI plot illustrates the CO_2 flooding efficiency. The curves of x_f = 250ft and x_f = 150ft on the Recovery vs. HCPVI plot are fairly close to each other. It is obvious that the CO_2 flooding efficiency is not very sensivite to the fracture half length. However, longer fracturesresulted in early CO_2 breakthrough. For these particular cases, CO_2 mole fraction from producers starts ramping up in early 2017 for xf = 250ft, while the ramp-up for the xf = 150ft case happens roughly one year later than the xf = 250ft case (Fig. 21). To avoid early breakthrough, small fracturing treatment volume, in terms of proppant and frac fluid, is recommended.

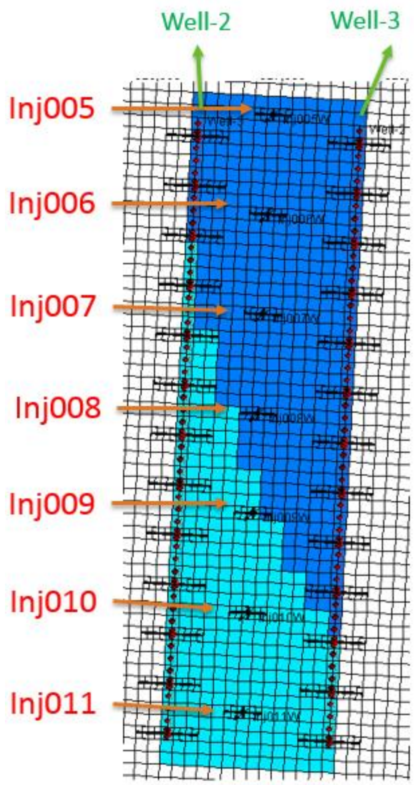

Figure 19. Model setup for WAG

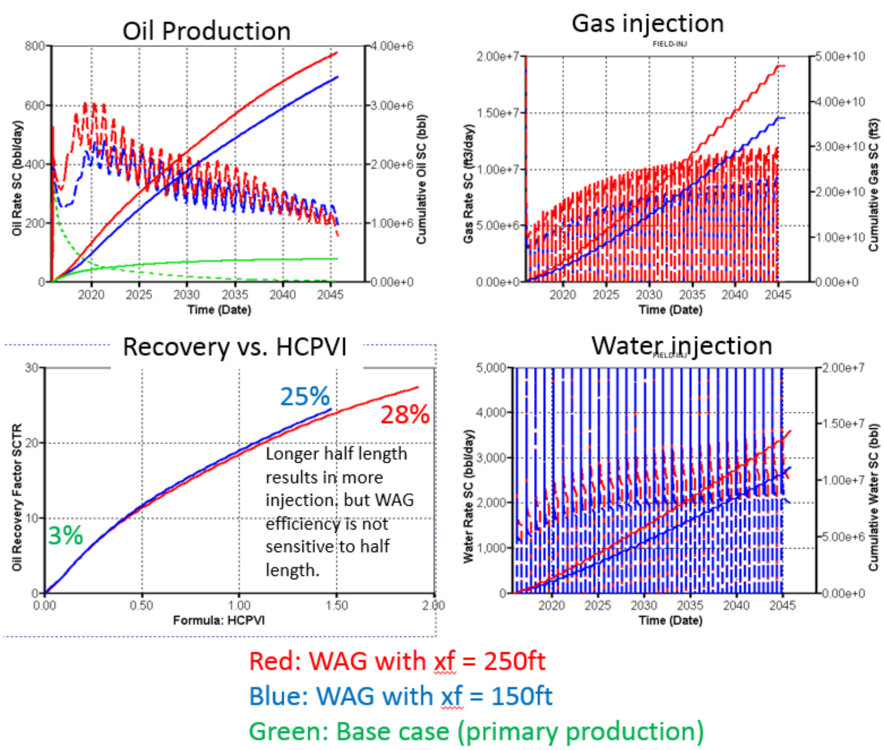

Figure 20. 1/3rd model WAG simulation results

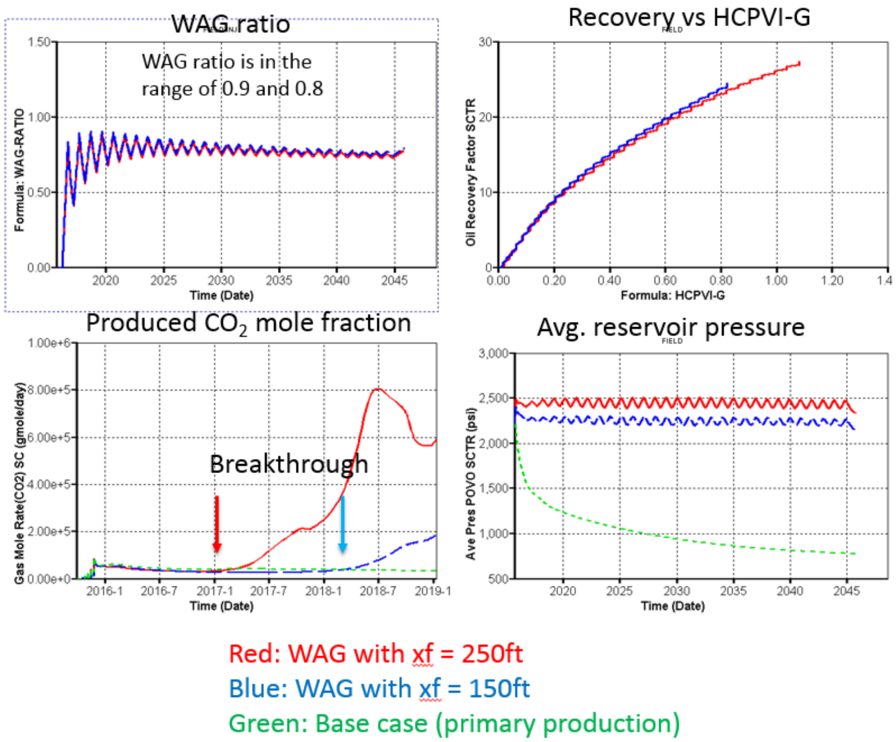

Figure 21. 1/3rd model WAG simulation results showing CO_2 breakthrough

Conclusion

The San Andres formation is a tight dolomitic reservoir with mixed wet matrix. High residual oil saturation is responsible for the high water cut from primary production, despite the large amount of immobile oil trapped underground. CO_2 miscible flooding is proved to be an effective method to enhance the oil recovery ecomically. Due to the low permeability of the matrix, horizontal wells with multi-fractures show high potential to significantly increase the oil recovery. As one of the pioneering investigations on this topic, this simulation study shows that smaller hydraulic fracture treatment volumes with larger cluster spacing than is traditionally observed in the field, and shorter half lengths could be beneficial in avoiding early CO_2 breakthrough while maintaining high flooding efficiency. The CO_2 flooding efficiency in the cases examined is not very sensitive to fracture half length. The study also demonstrates that gravity override is not pronounced in a tight reservoir such as the San Andres formation. It is encouraging that miscible CO_2 flooding is able to produce more than 20% incremental oil recovery, with CO_2 utilization factors between 7 and 8 MCF/BBL. This integrated study demonstrates that not only is it feasible to implement miscible CO_2 flooding in tight oil reservoirs using horizontal multi-fractured wells, but it can also improve recovery significantly compared to primary depletion. There are few simulation studies in literature that discuss miscible CO_2 flooding in tight reservoirs, and therefore, the findings from the current study have enormous implications in the industry for EOR applications in low permeability reservoirs.

Acknowledgments

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Miscible CO_2 Flooding Using Horizontal Multi-Fractured Wells in San Andres Formation, TX – a Feasibility Study

- Junjie Yang, Baker Hughes
- Yagna Deepika Oruganti, Baker Hughes
- Pierre Karam, Baker Hughes
- Dan Doherty, Riley Exploration
- Jim Doherty, Riley Exploration

Carbon Management Technology Conference (CMTC2017)

Outline

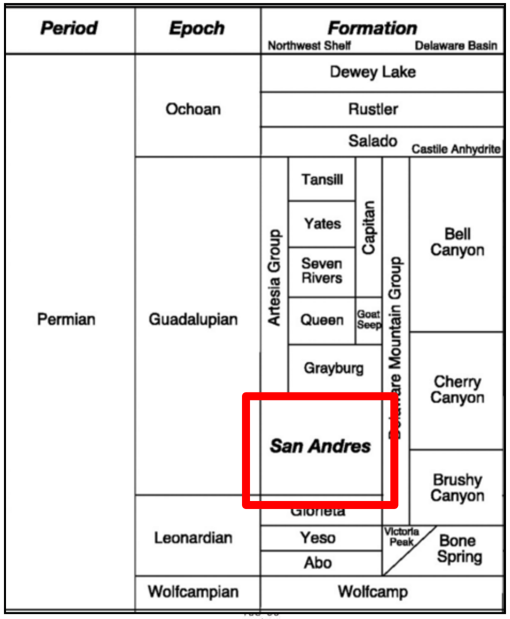
- Project objectives
- Geomodeling
- PVT modeling
- History match and forecasting
- Sensitivity analysis for primary production
- Continuous CO_2 injection scenarios
- WAG design scenarios

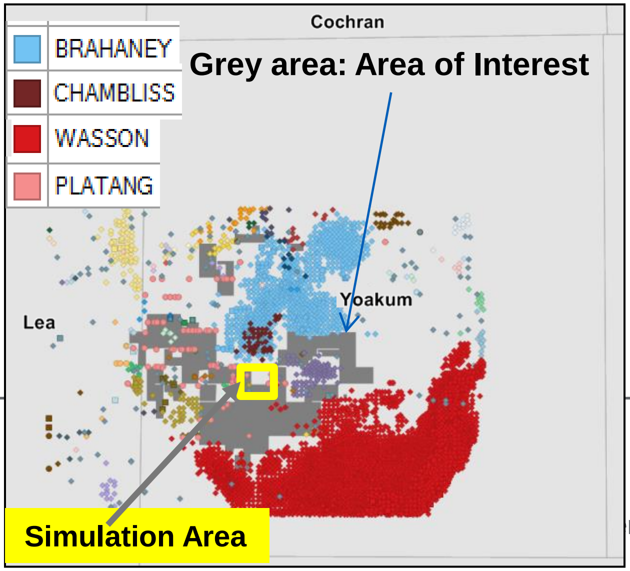
Project Objectives

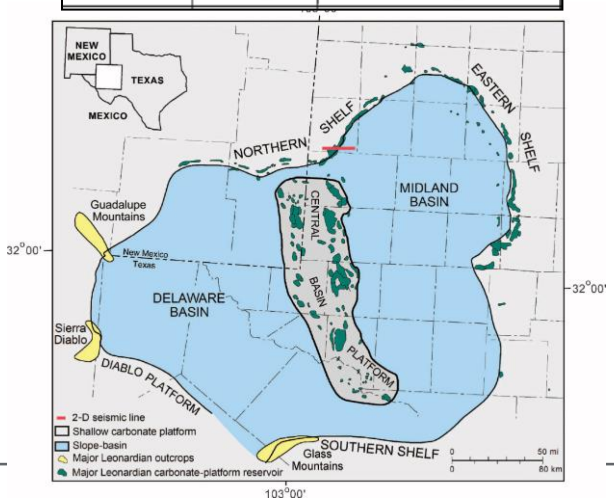
- Build a reservoir model to be used for evaluating field development scenarios, considering the effects of well spacing and frac design for both primary production and future EOR operations
- Build a section reservoir simulation model and history match the previously developed geological model
- Run sensitivity analysis for primary production and CO_2 flooding by considering well spacing and frac design combinations
- Present recommendations for primary field development and upside from future CO_2 operations

Introduction – San Andres Formation

- Our area of interest is in Platang field, southwest Yoakum Co, TX
- Permian age carbonate formation (Upper Leonardian/Lower Guadalupian)
- Formation consists of interbedded dolomites with layers of siltstones
- The sequence stratigraphic interpretation was guided by key facies indicator based on lithology and sedimentary structures







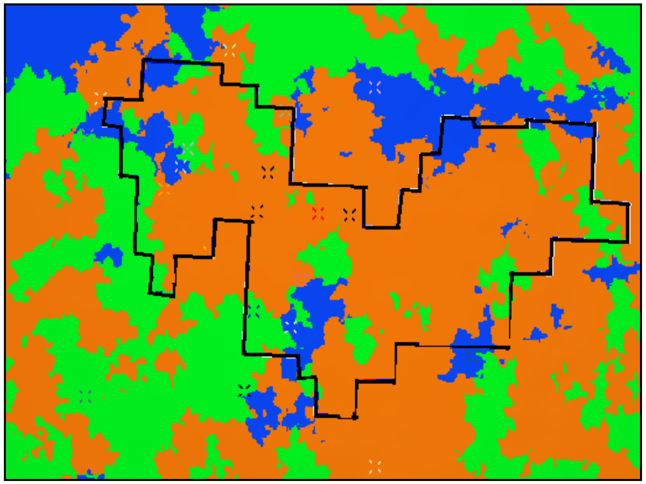
Geomodeling

- Available data:
  - Structure map
  - Well tops from offset wells (~450 well tops were included in the model)
  - Geosteering report for horizontal wells
  - Petrophysical logs, borehole imaging

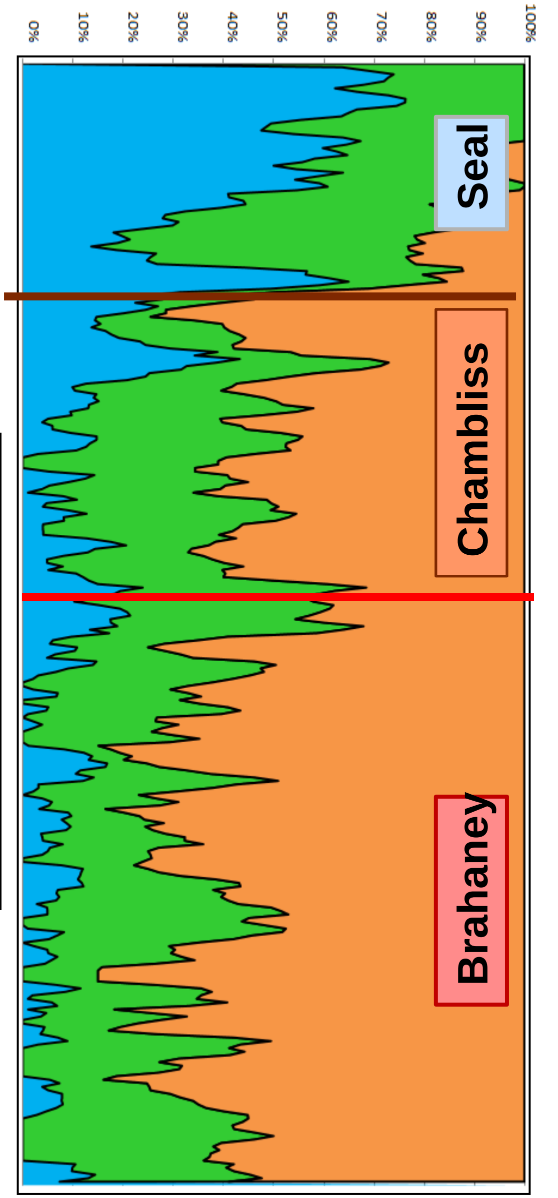
- Three main zones were modeled:
  - San Andres Seal Layer
  - Chambliss
  - Brahaney

- Reservoir properties are populated by facies modeling

Facies
- Evaporite
- Supratidal
- Intertidal

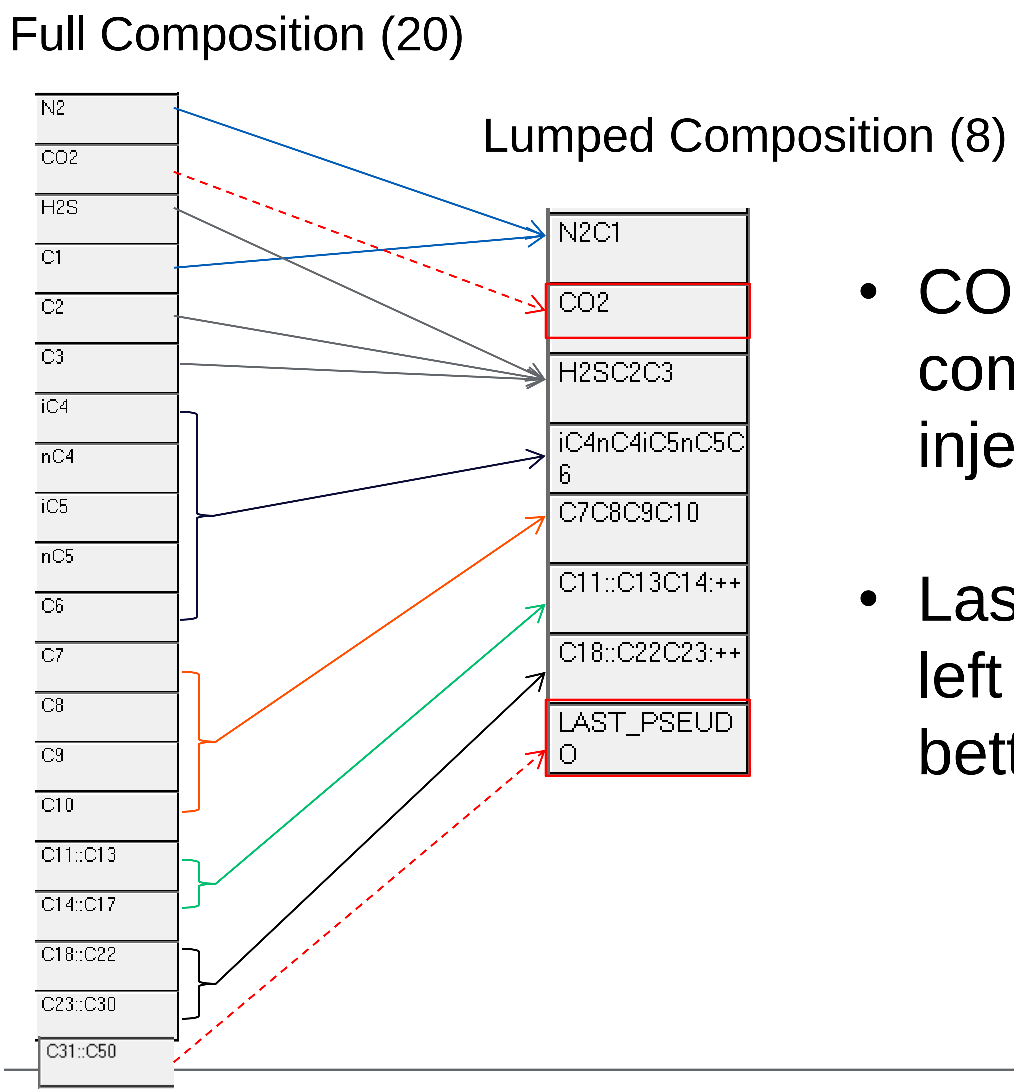


Geostatistical model



Vertical Stacking Profile

PVT Modeling

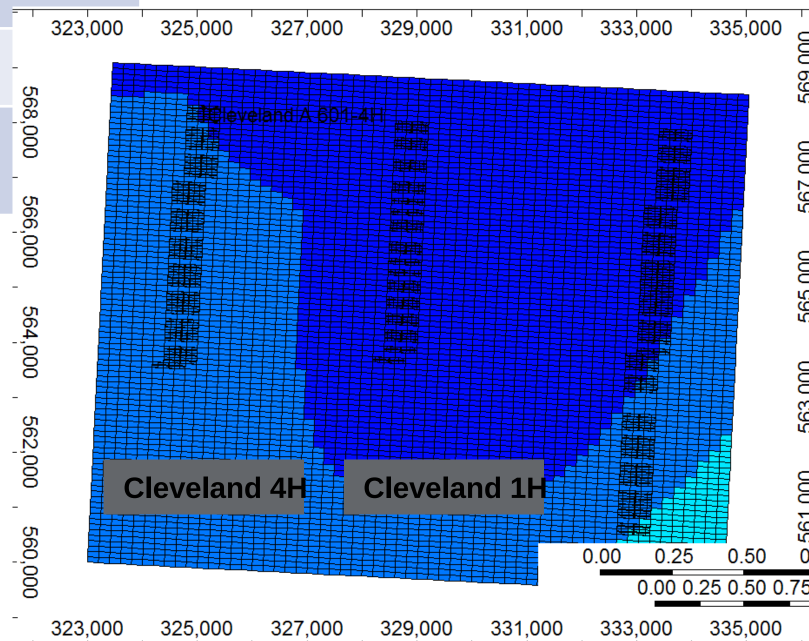


- CO_2 is left as independent component for the following injection simulation
- Last pseudo component is left separately to get a better match

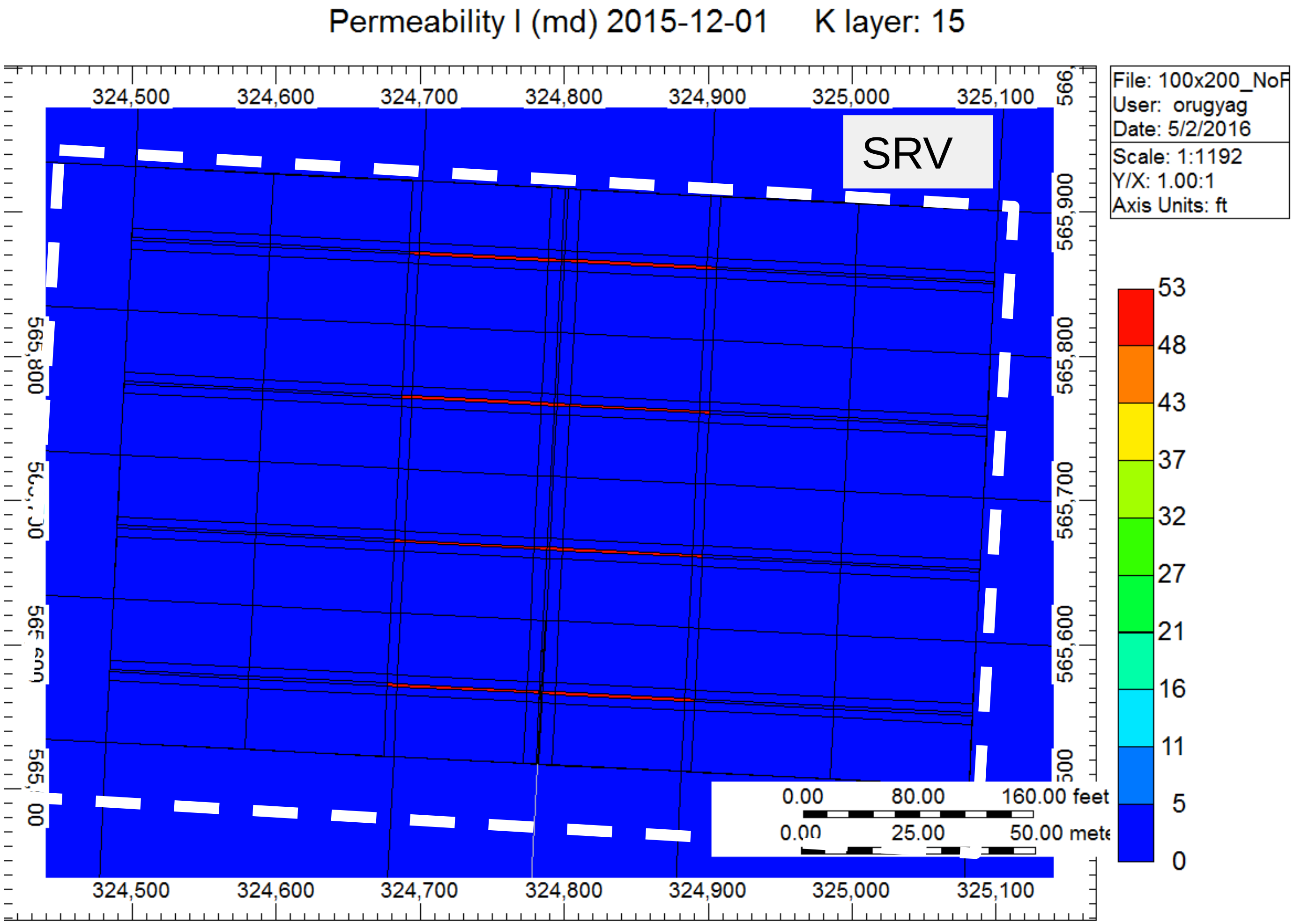
Reservoir Simulation

Reservoir Overview

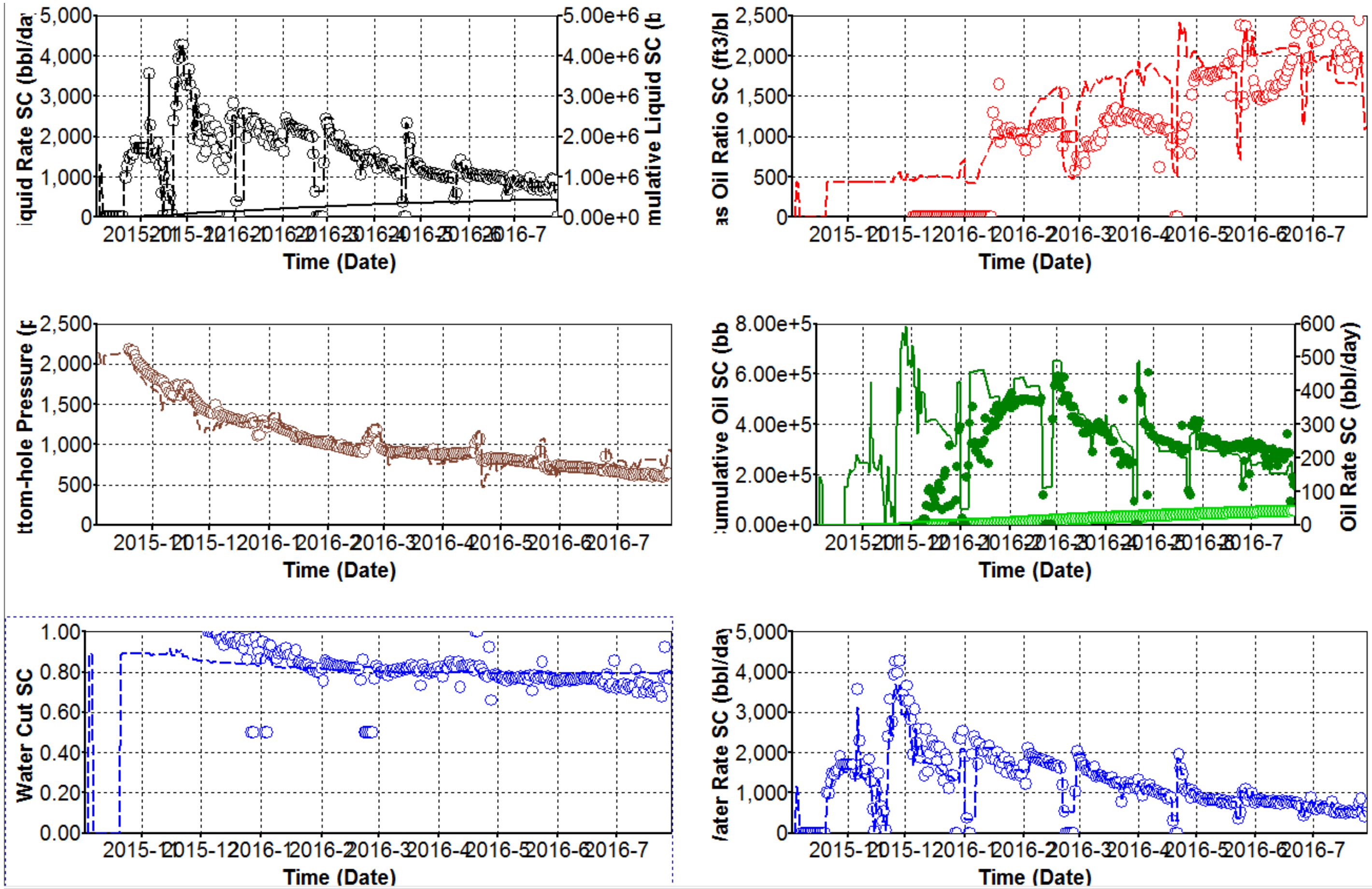
Properties	AOI
Pressure (psia)	1,800- 2,000
Temperature (°F)	~130
Depth (ft)	5,200+
MMP = P_{sat} (psia)	1,500
API (°)	~31
Production status	Primary
Initial produced GOR (SCF/STB)	800 -1,000



Hydraulic Fractures Modeled Using LGR – IJ Plane (Top View)



Cleveland 1H – History Match



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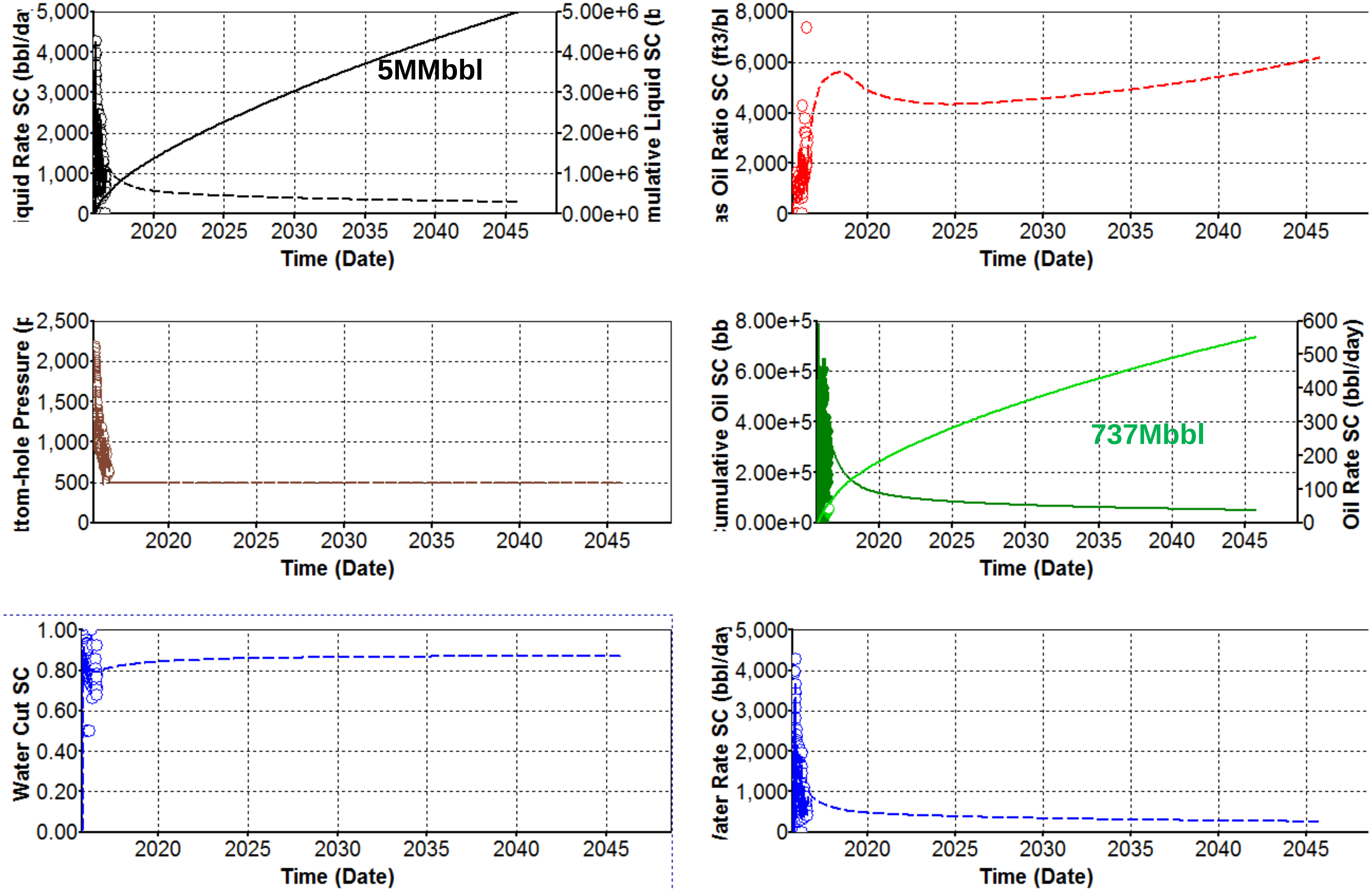
Cleveland 1H - Forecast



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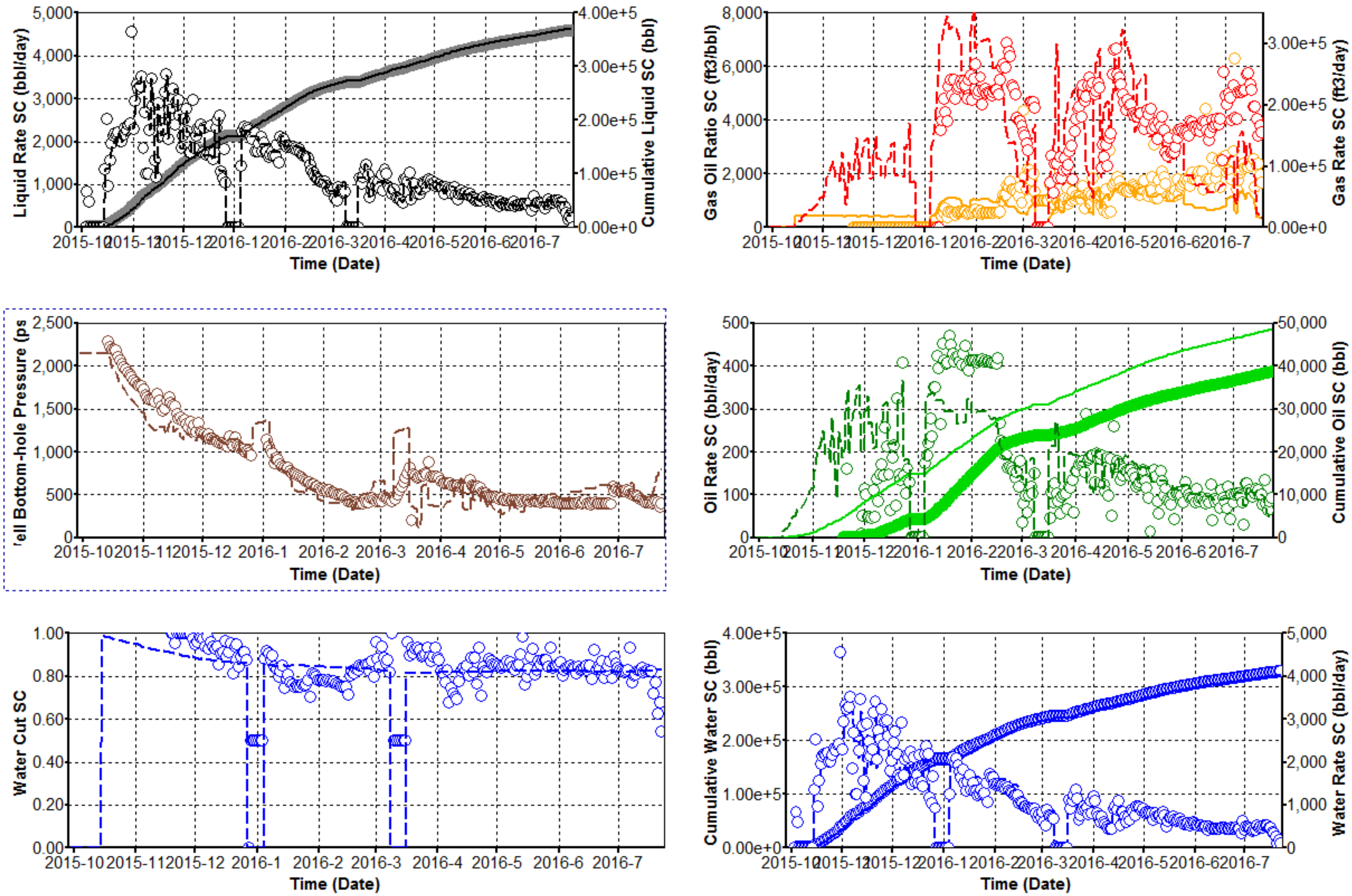
Cleveland 4H – History Match



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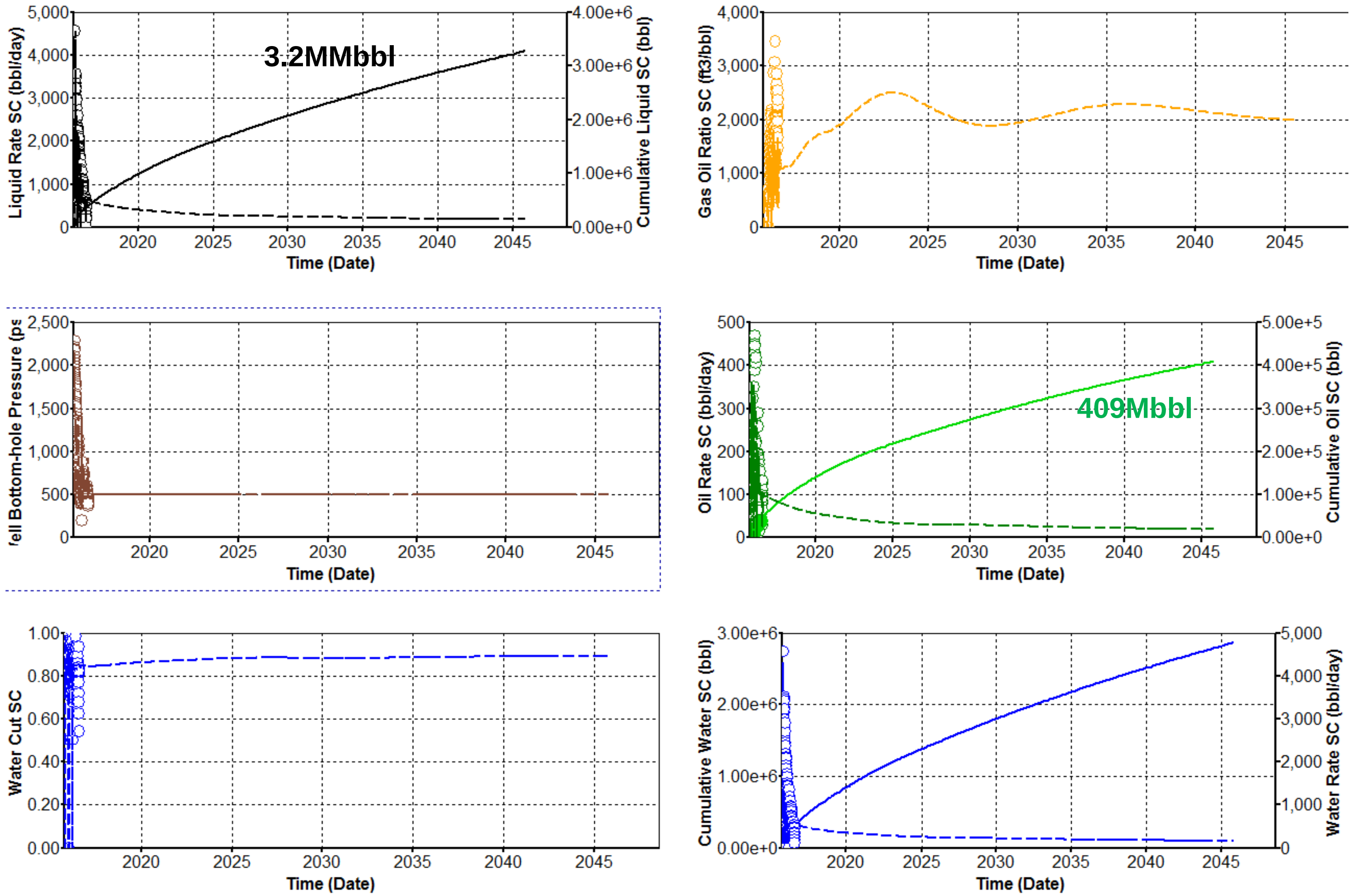
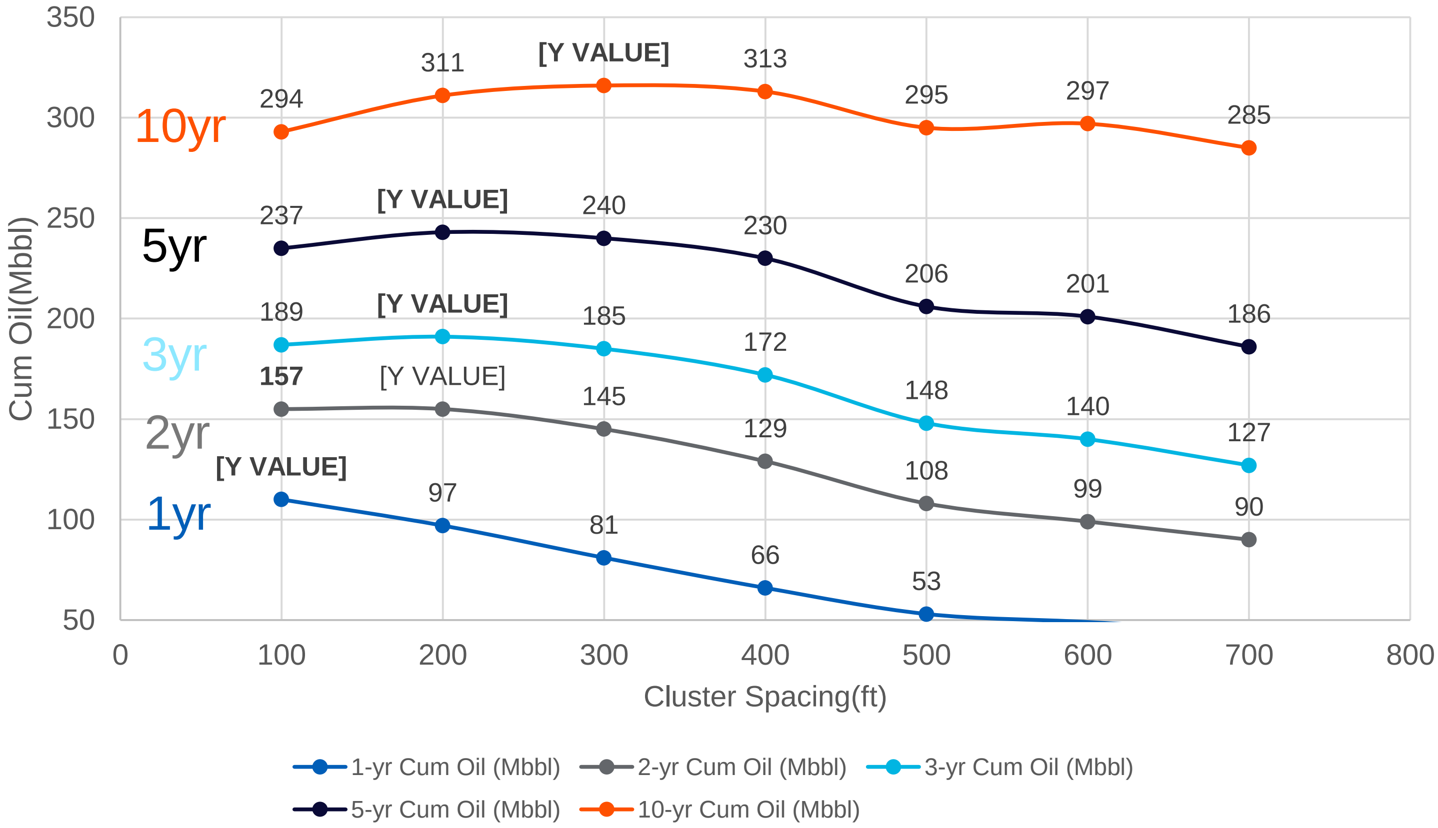
Cleveland 4H - Forecast



Sensitivity Analysis – Cluster Spacing

- Simulation assumes the model is a green field reservoir
- Single well model (160 acre spacing) is run with various cluster spacings to determine the optimal value
- Bottom hole pressure follows the decline behavior of Cleveland 1H for the first year and remains constant at 620 psi for the rest of the simulation period
- Seven scenarios of cluster spacing were simulated: 100 ft, 200 ft, 300 ft, 400 ft, 500 ft, 600 ft, 700 ft
- To eliminate the effect of grid refinement on production, all runs have the same level of refinement
- No skin
- Fluid rate is capped at 3,000 bbl/day

Cum Oil vs. Cluster Spacing



- Difference on production is more pronounced on the early stage
- 300 ~ 400 ft cluster spacing give the optimal production in 10 yrs

Sensitivity Analysis – Well Spacing and Fracture Half Length

- Simulation assumes the model is a green field reservoir
- Simulation model is a 1x1 sq. mi area
- Based on previous study, 400ft cluster spacing (13 fractures) is used for all scenarios
- Bottom hole pressure follows the decline behavior of Cleveland 1H for the first year and remains constant at 620 psi for the rest of the simulation period
- No skin
- Fluid rate is capped at 3,000 bbl/day
- Well spacing and half length are interdependent. In total, nine cases are simulated and compared.

Well Spacing
213 Acre – 3 wells/section
160 Acre – 4 wells/section
128 Acre – 5 wells/section

✖

Half Length
150 ft
250 ft
350 ft

=

9 scenarios

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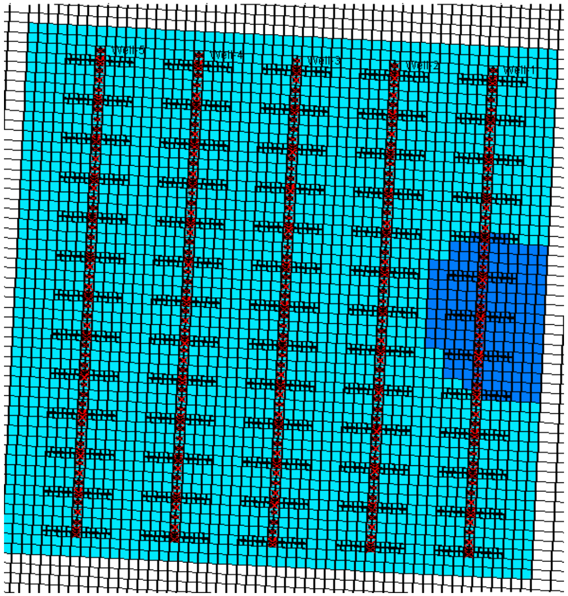
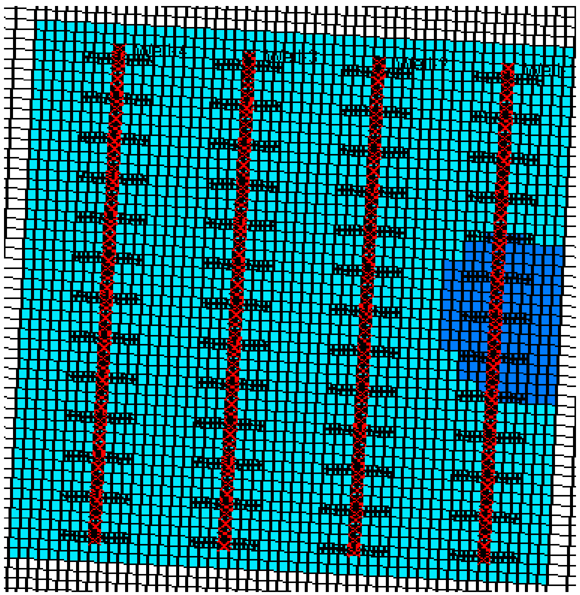
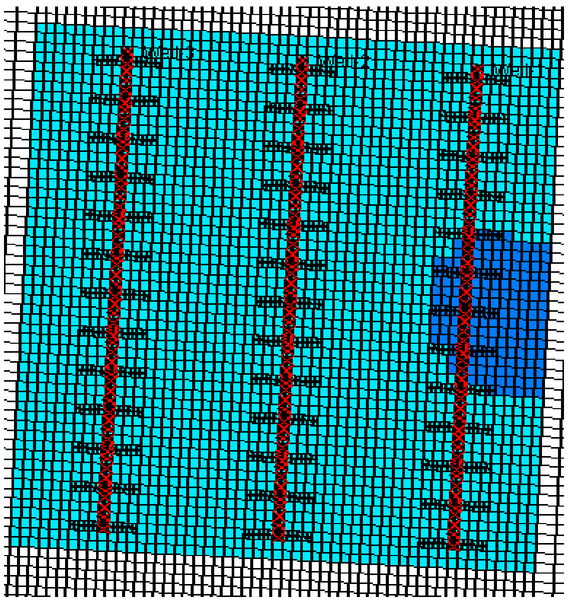
Grid & Refinement



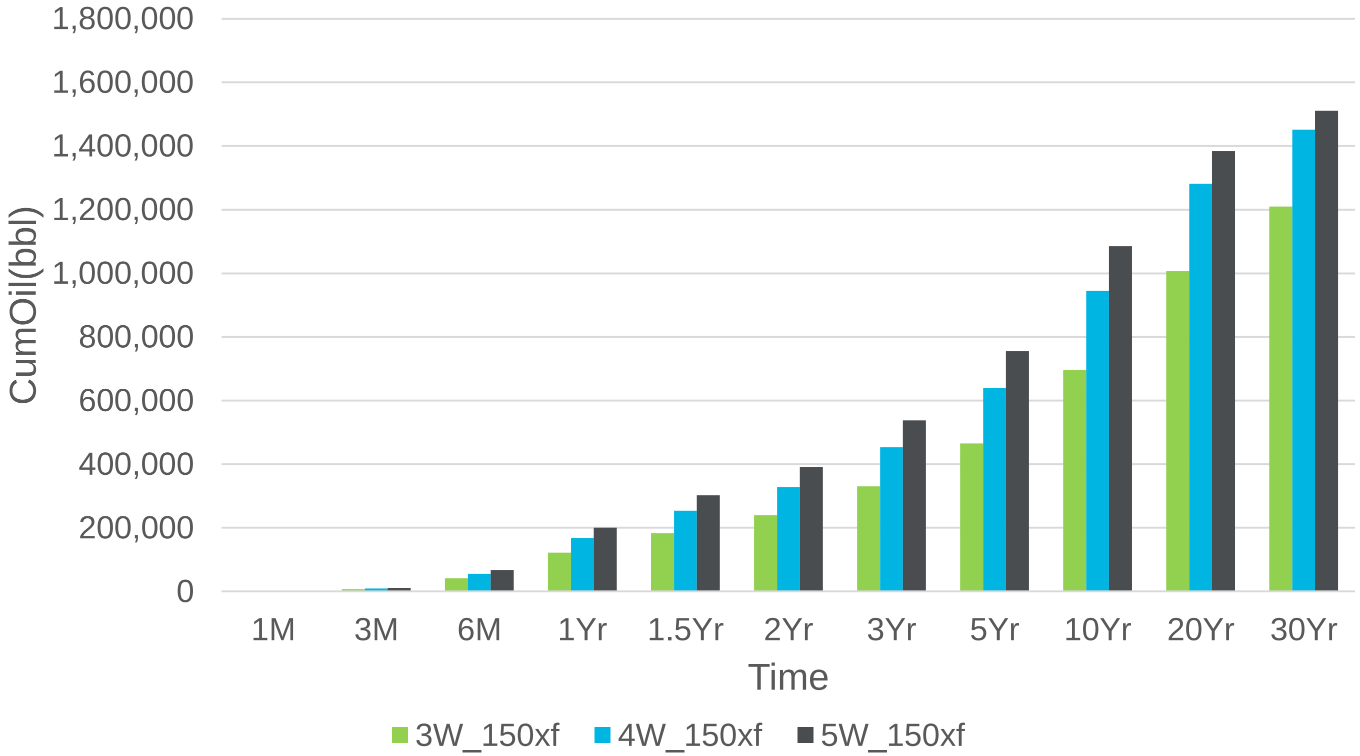




128 Acre	160 Acre	213 Acre

- Simulation area is 1x1 sq. mile
- As the incremental in each parameter (xf, cluster spacing) is 100 ft, reservoir block size is 100x100 ft
- Cells hosting hydraulic fractures have refinement of 5/5/1 in i/j/k directions

Field Cumulative Production vs. Time for 3/4/5 Wells Per Section with x_f = 150ft



The 4-well scenario is the optimal well spacing

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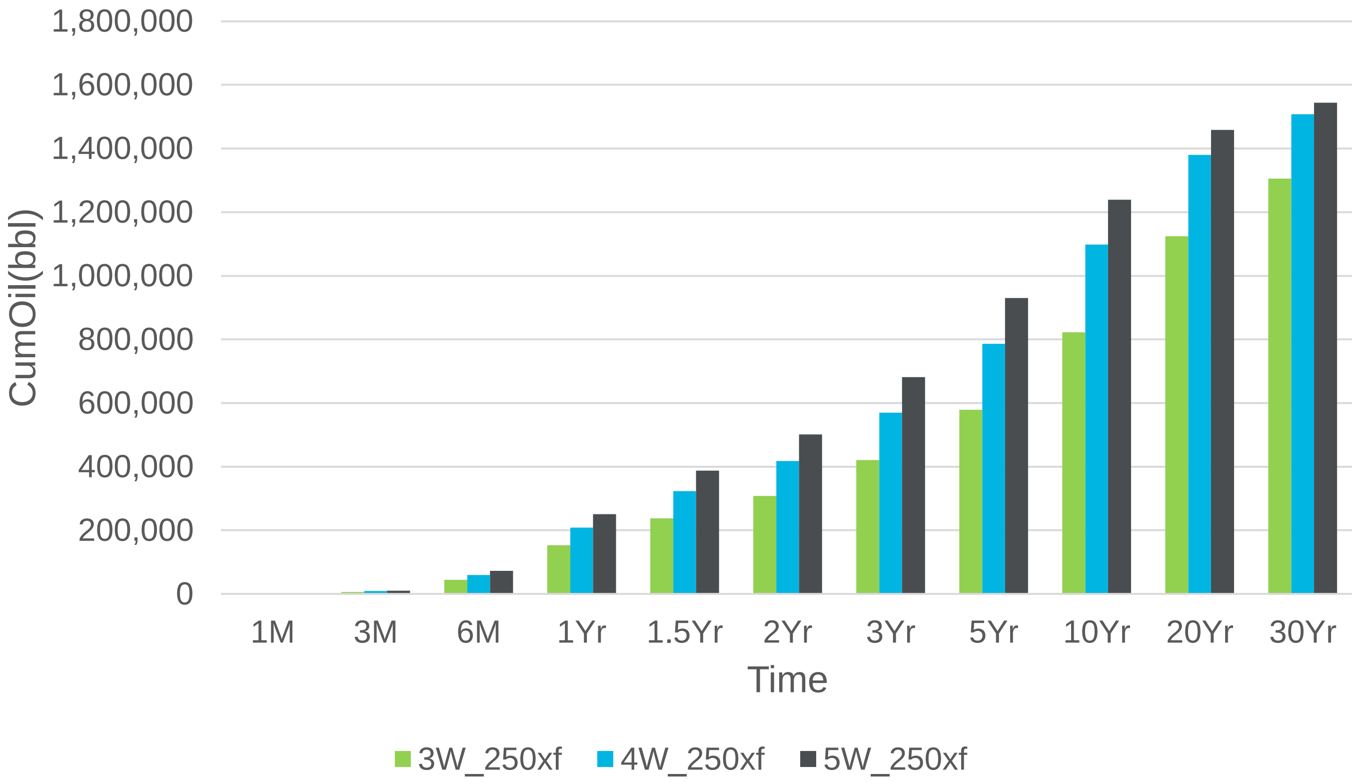
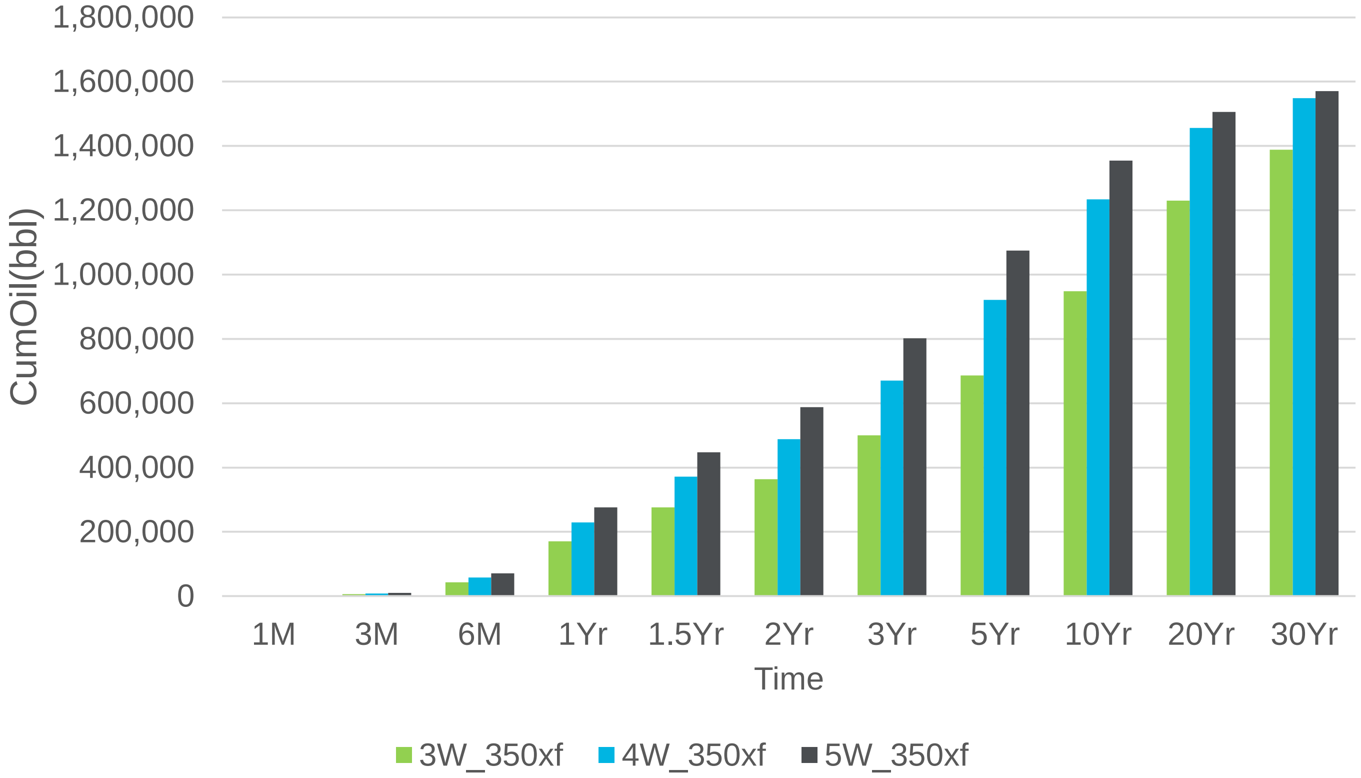
Field Cumulative Production vs. Time for 3/4/5 Wells Per Section with x_f = 250ft



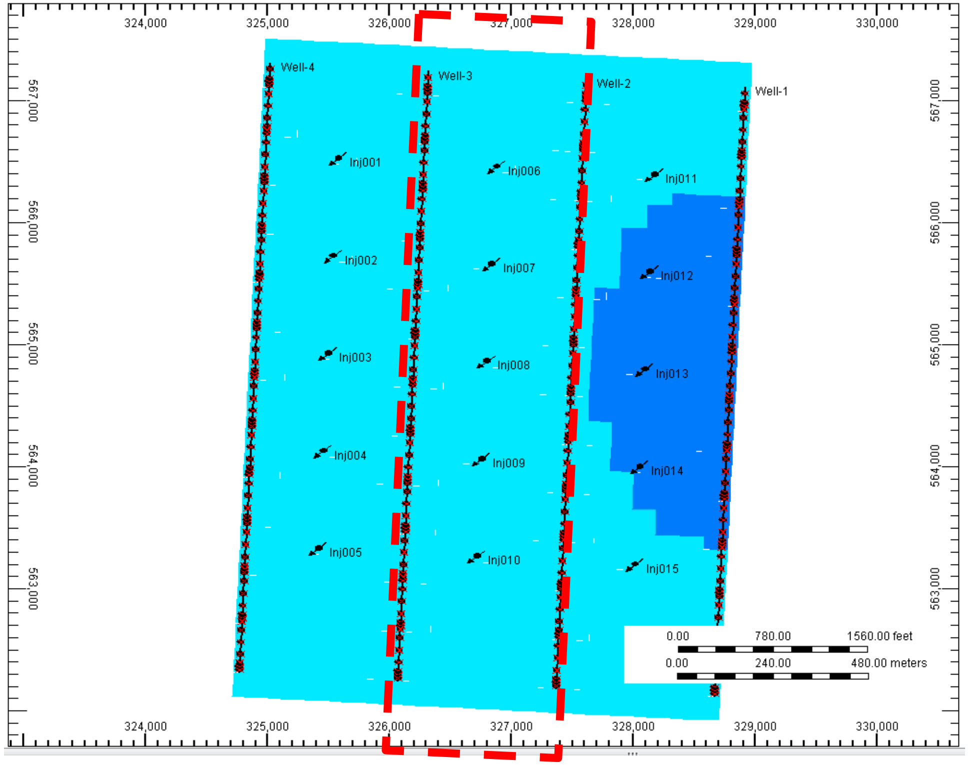
The 4-well scenario is the optimal well spacing

Field Cumulative Production vs. Time for 3/4/5 Wells Per Section with x_f = 350ft



The 4-well scenario is the optimal well spacing

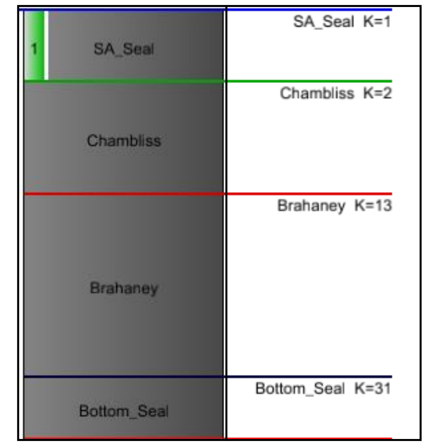
CO_2 Injection Model Setup



1/3rd model

- The full model has 4 horizontal producers with multi-stage hydraulic fractures and vertical injectors in between
- In order to save computational time, a smaller model is used for the sensitivity analysis, which consists of the two horizontal producers in the middle and the injectors in between them.
- Geometrically, it is one third of the full model.

Scenario Setup



- Base case is the scenario with primary depletion (no injection)
- Injectors with different completion strategies, including skin, perf layers, hydraulic fractures, are tested
- The following hydraulic fracture geometry is assumed for all injectors:

  Fracture half length x_f = 150 ft

  Fracture perm: k_f = 10,000 md

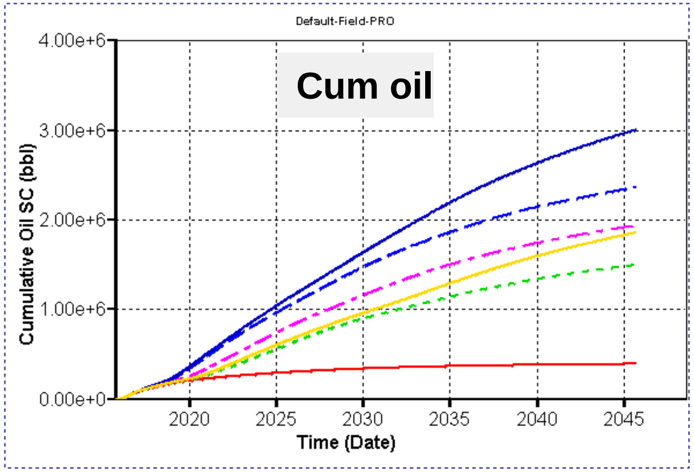
  Fracture height h_f = perforation interval height (see table below)

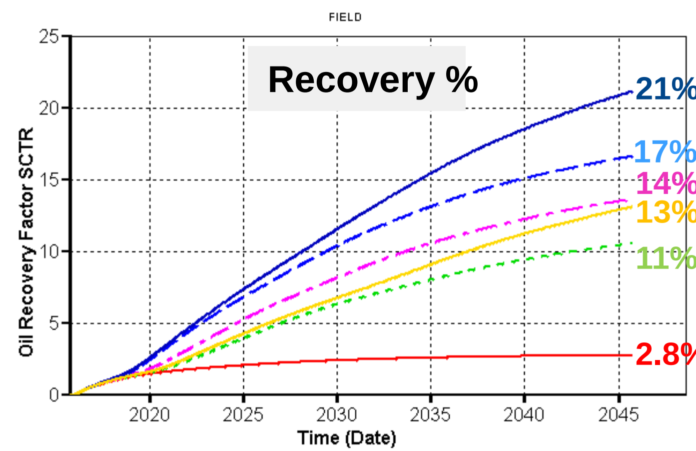
$$CO_2\text{utilization factor}\left(\frac{\text{Mcf}}{\text{bbl}}\right) = \frac{Cum.CO_2\ injected - Cum.CO_2\ produced}{Incremental\ oil\ production\ over\ primary\ depletion\ case}$$

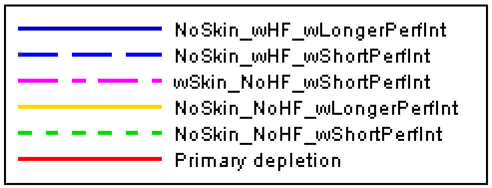
Case	#injectors	skin	Perf'd K layers	HF (Y/N)?	Recovery (%)	HCPVI	Cum CO2 injected (BCF)	CO_2 utilization factor
Primary depletion	0	-	-	N	2.8	--	--	--
NoSkin_noHF_ShorterPerfInt	5	0	15-30	N	11	0.81	28.9	7.38
NoSkin_noHF_LongerPerfInt	5	0	2-33	N	13	0.91	34.1	7.77
wSkin_noHF_ShorterPerfInt	5	-3	15-30	N	14	1.18	46.5	7.51
NoSkin_wHF_ShorterPerfInt	5	0	15-30	Y	17	1.76	61.6	7.63
NoSkin_wHF_LongerPerfInt	5	0	2-33	Y	21	1.92	81.3	7.36

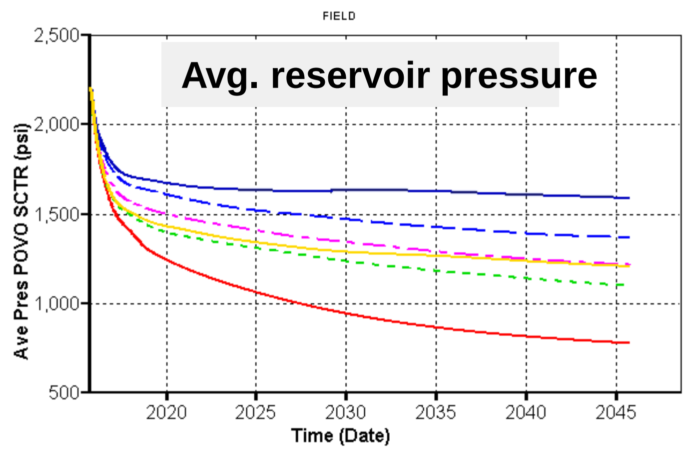
Most efficient process. Chosen as base case for continuous CO_2 flooding, going forward

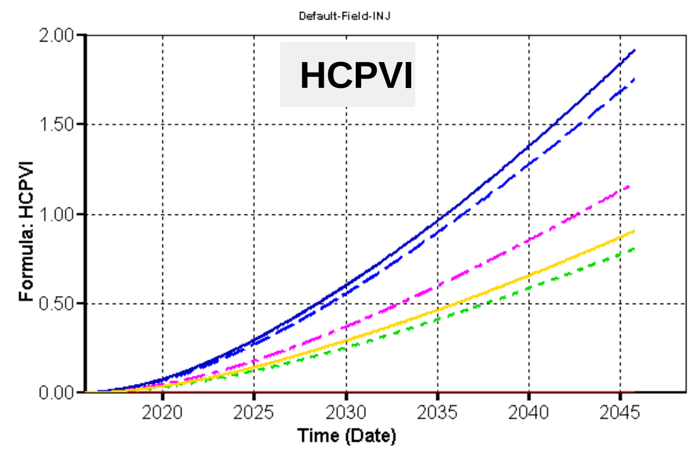
Sensitivities to Injector Completion Strategies (1/3rd Model)





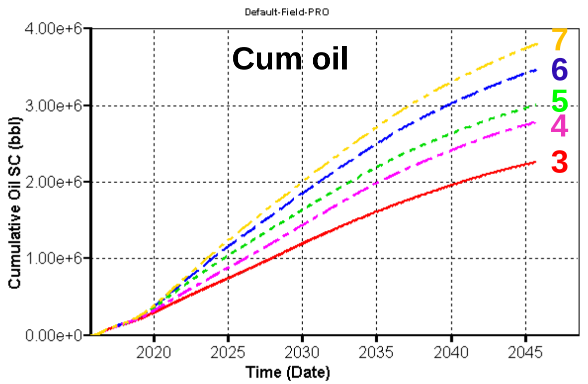


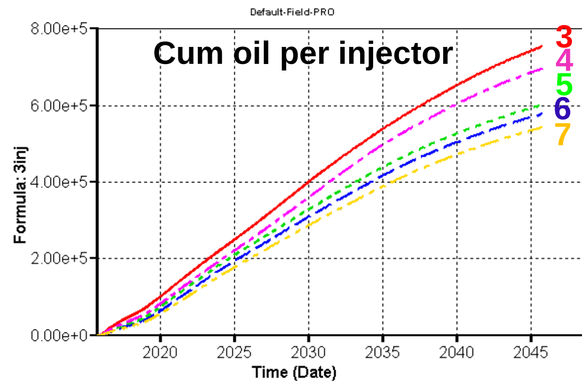


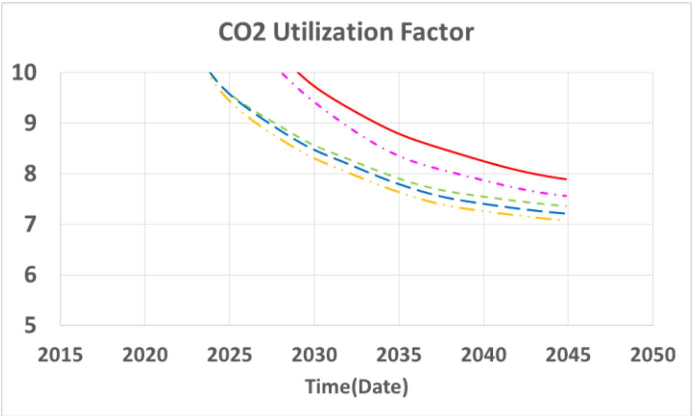


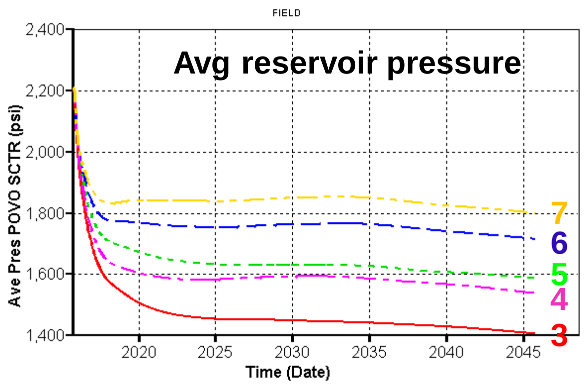
Case	#injectors	skin	Perf'd layers	HF (Y/N)?	Recovery (%)	HCPVI	CO_2 utilization factor
Primary depletion	0	-	-	N	2.8	--	--
NoSkin_noHF_ShorterPerfInt	5	0	15-30	N	11	0.81	7.38
NoSkin_noHF_LongerPerfInt	5	0	2-33	N	13	0.91	7.77
wSkin_noHF_ShorterPerfInt	5	-3	15-30	N	14	1.18	7.51
NoSkin_wHF_ShorterPerfInt	5	0	15-30	Y	17	1.76	7.63
NoSkin_wHF_LongerPerfInt	5	0	2-33	Y	21	1.92	7.36

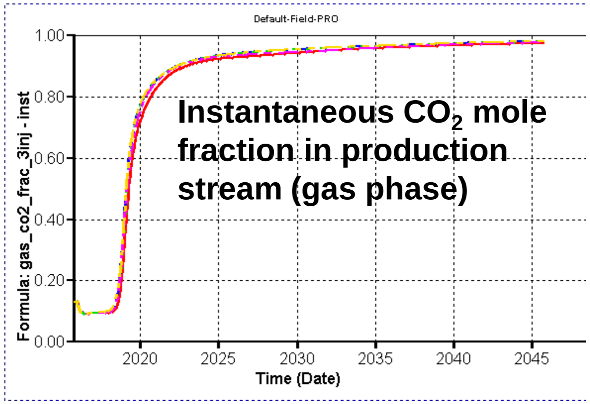
Sensitivity to Number of Injectors (1/3rd Model)

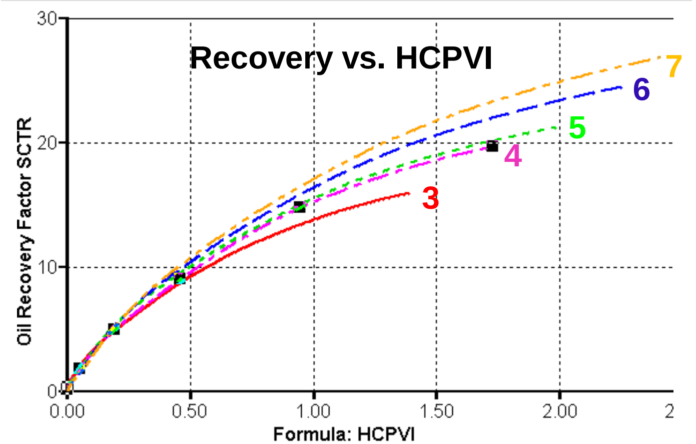




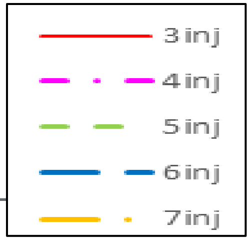




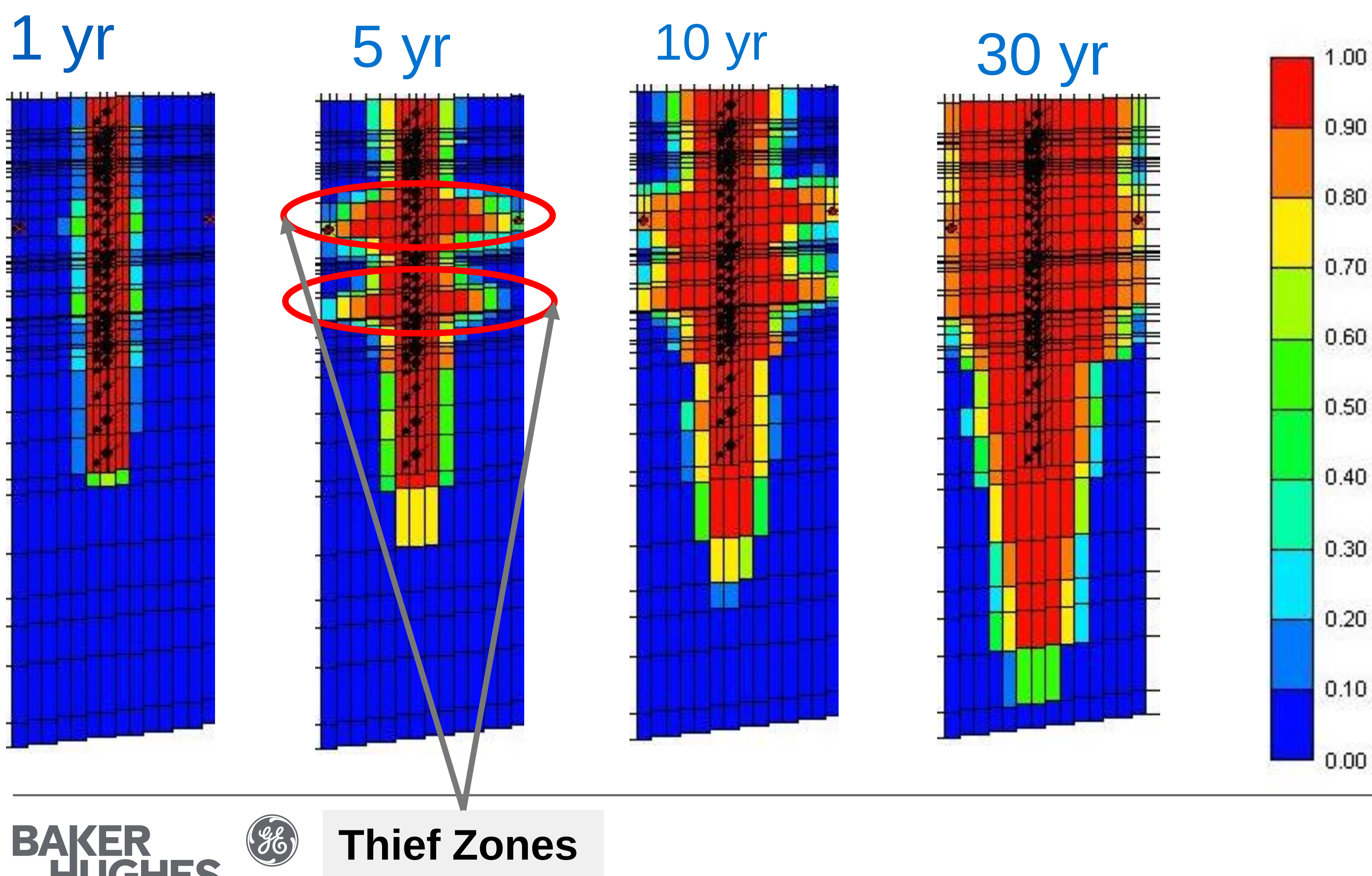




Case	Cum Oil (MMSTB)	Recovery (%)	Cum CO2 inj (BCF)	HCPVI	CO_2 utilization factor
3 injectors	2.26	15.93	57	1.39	7.89
4 injectors	2.79	19.66	71	1.73	7.56
5 injectors	3.01	21.22	81	1.91	7.36
6 injectors	3.47	24.46	92	2.25	7.21
7 injectors	3.81	26.85	99	2.41	7.07



Global CO_2 Mole Fraction (Injector IK X-Section)



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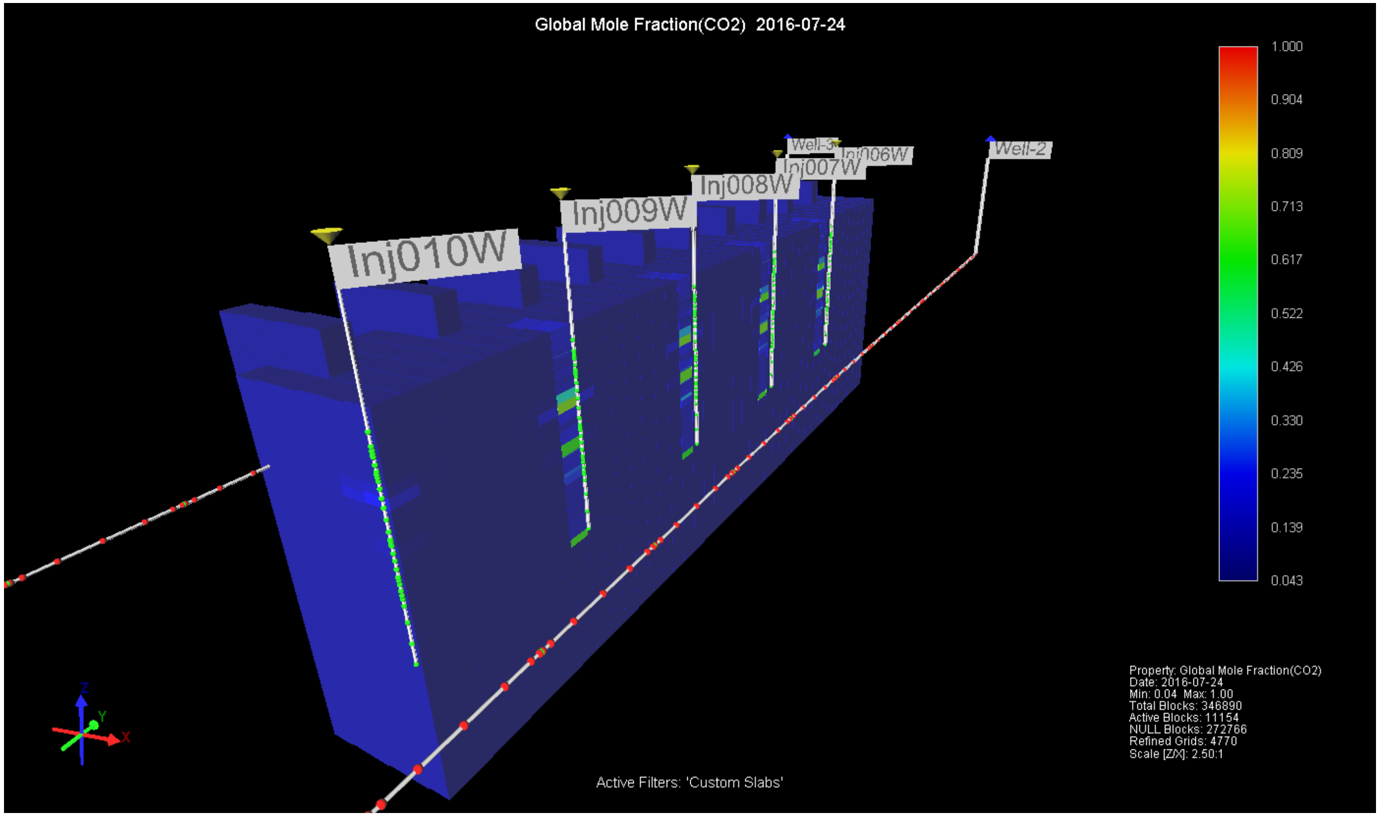
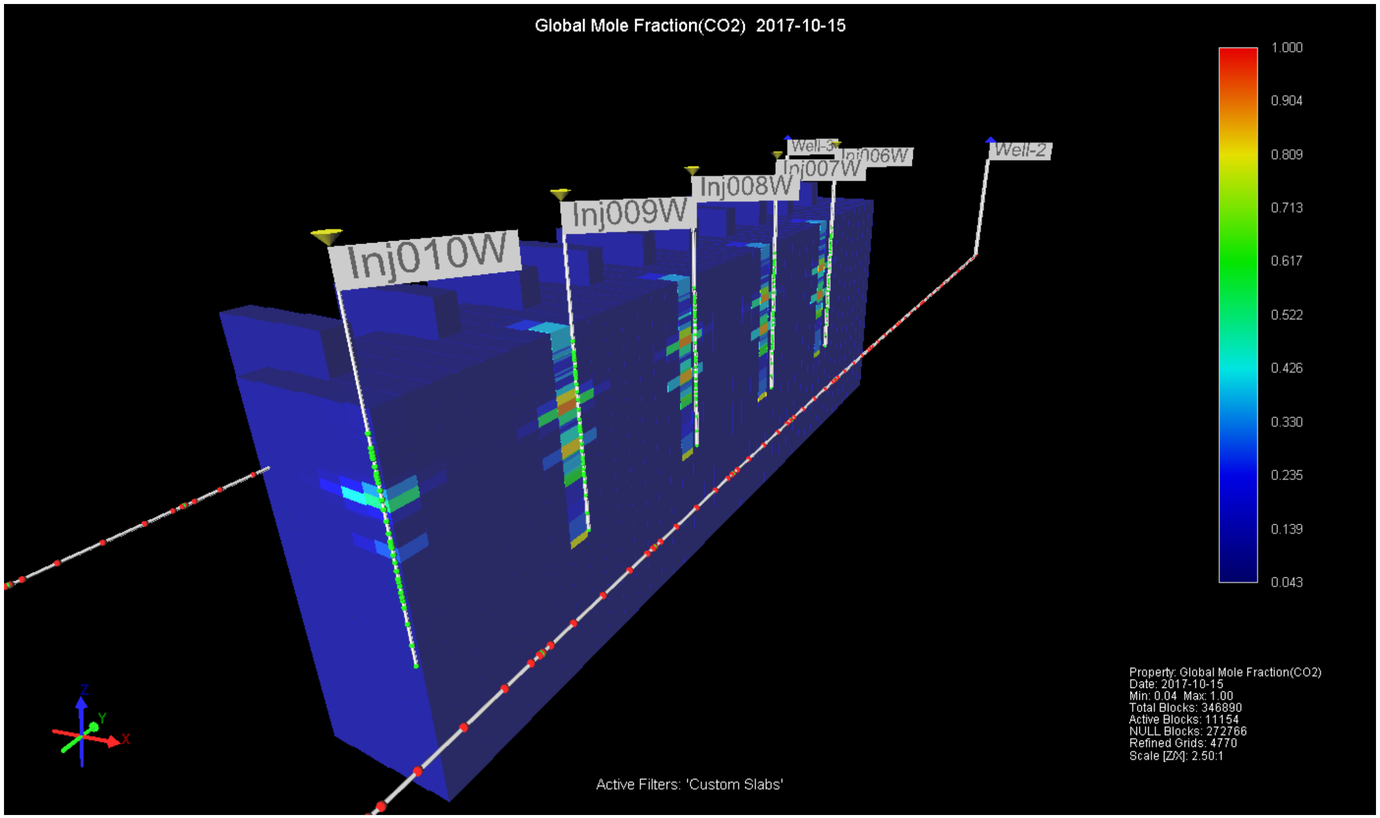
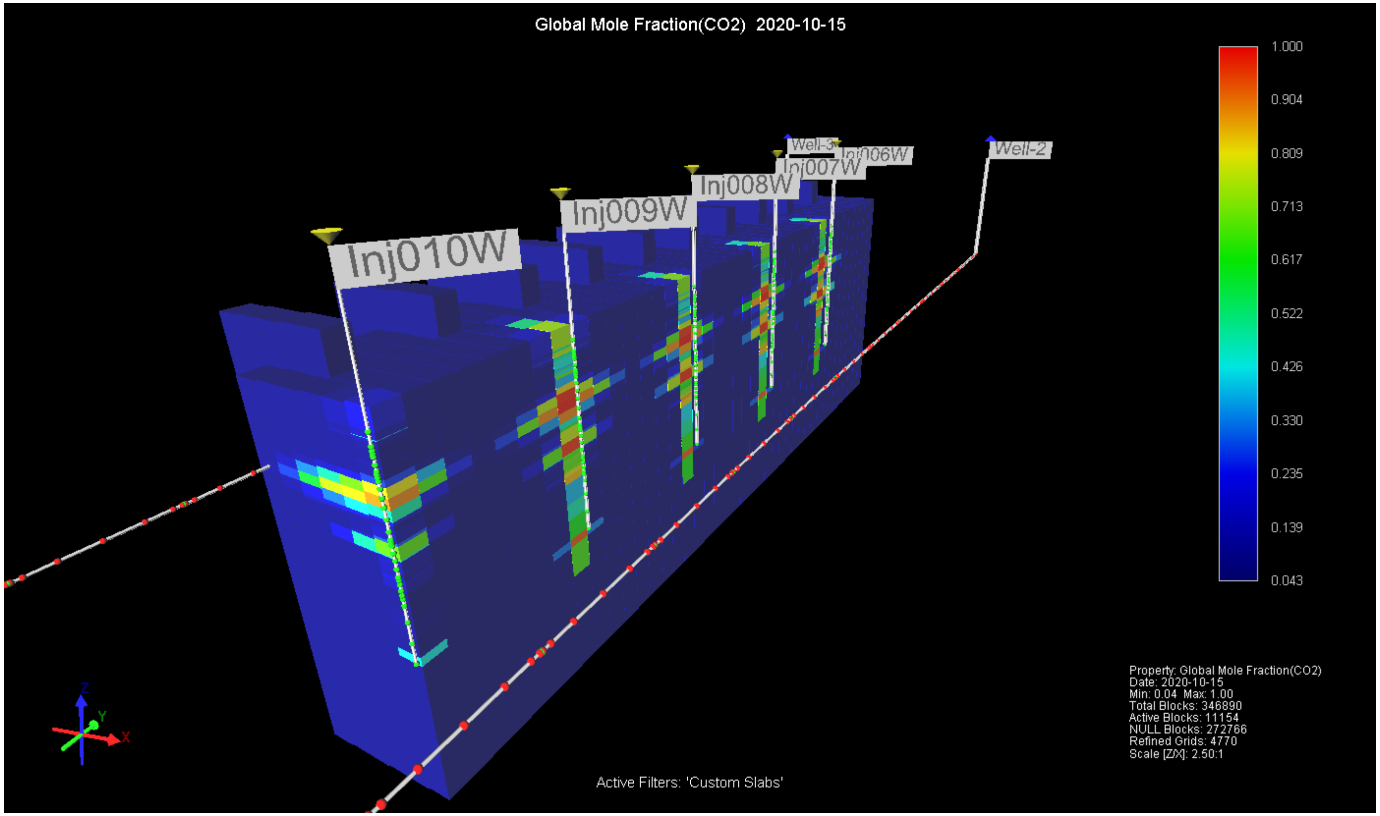
1 yr – CO_2 Global Mole Fraction (Injectors JK X-Section)



2 yr – CO_2 Global Mole Fraction (Injectors JK X-Section)



5 yr – CO_2 Global Mole Fraction (Injectors JK X-Section)



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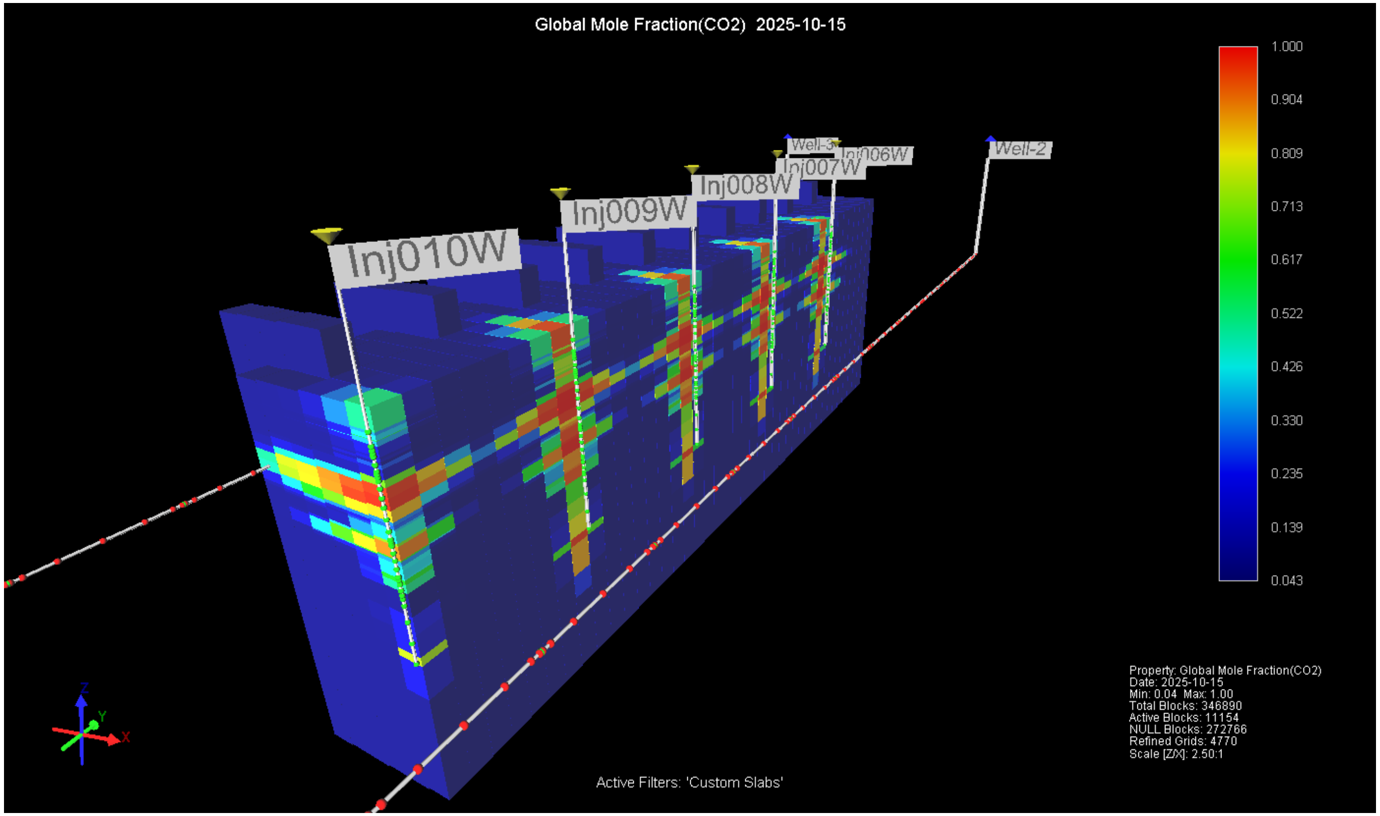
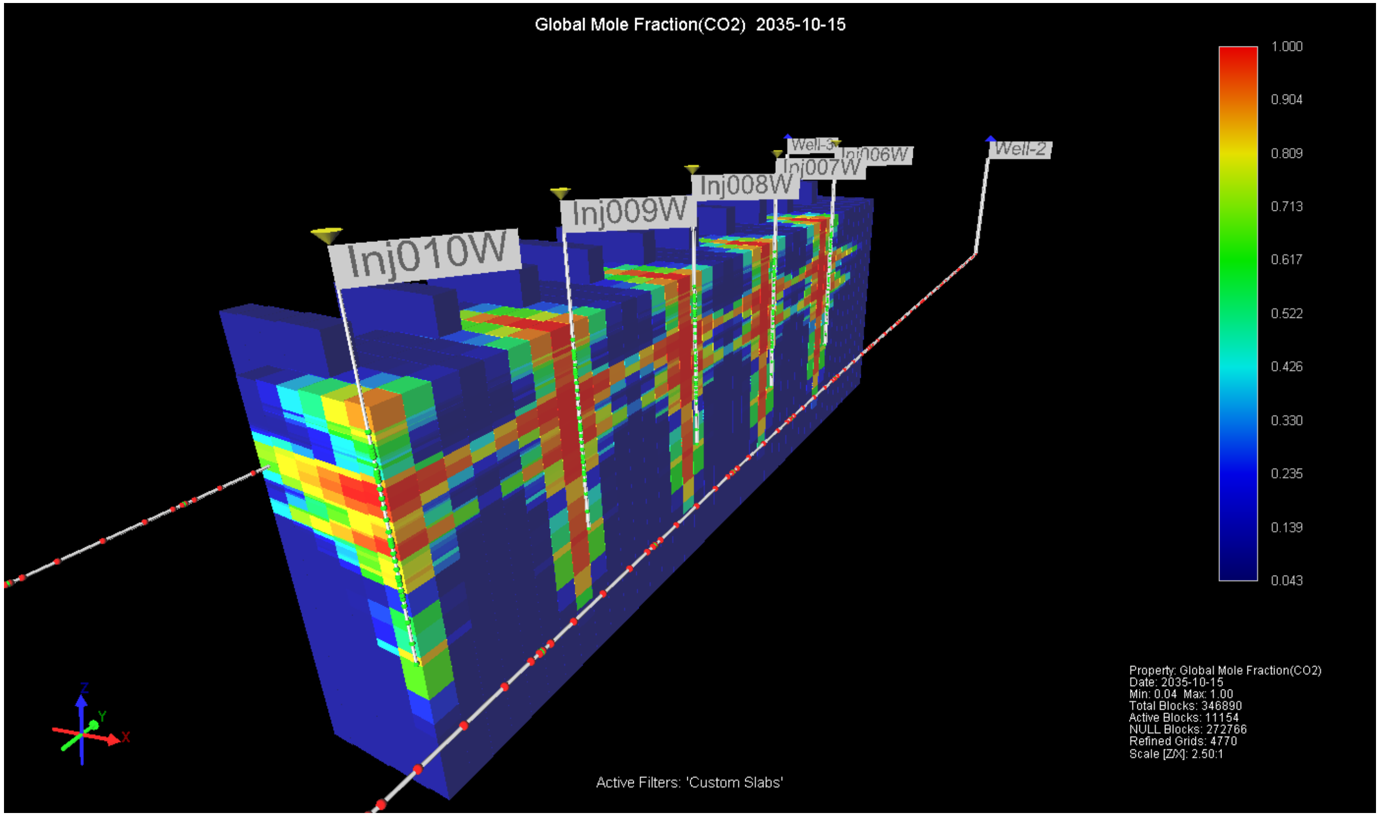
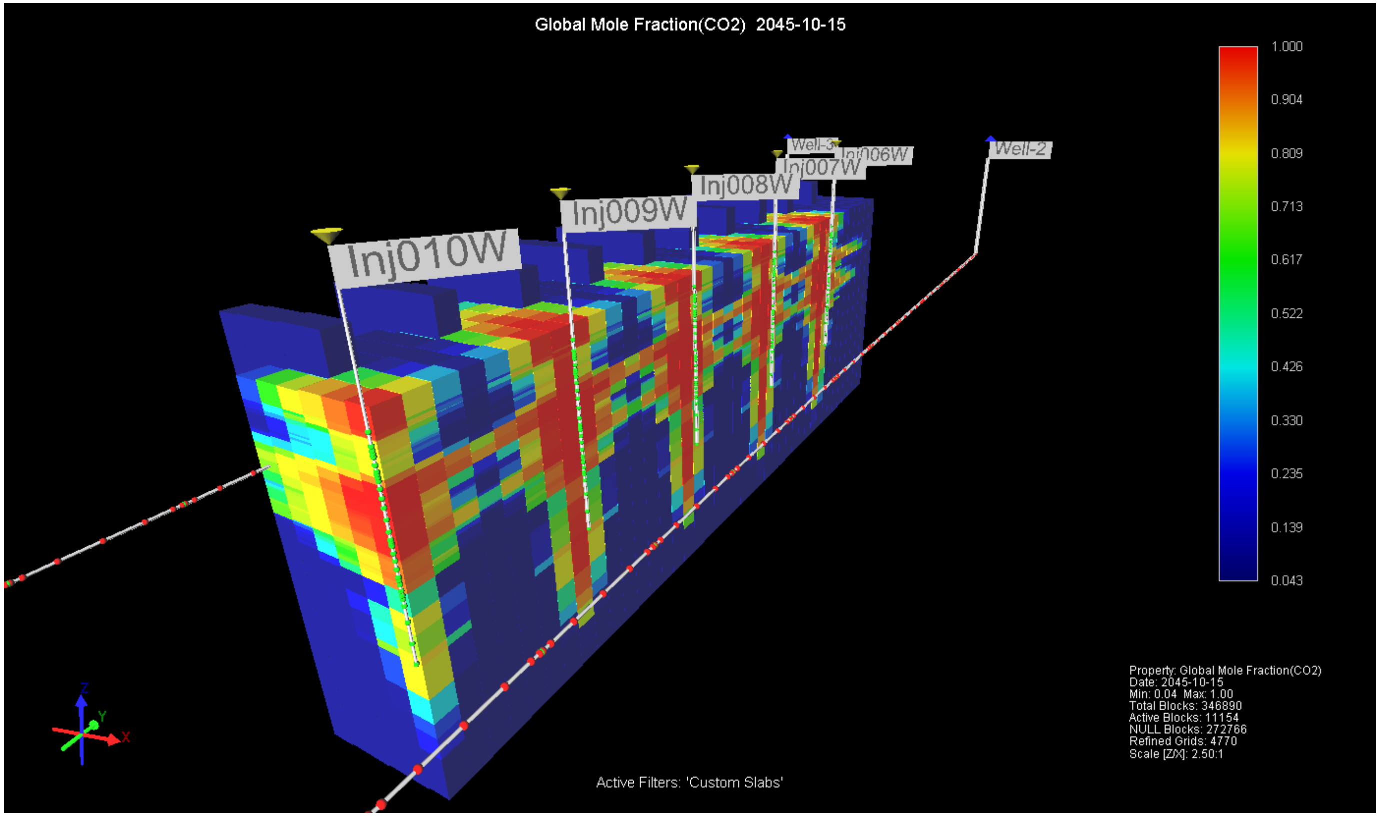
10 yr – CO_2 Global Mole Fraction (Injectors JK X-Section)



20 yr – CO_2 Global Mole Fraction (Injectors JK X-Section)

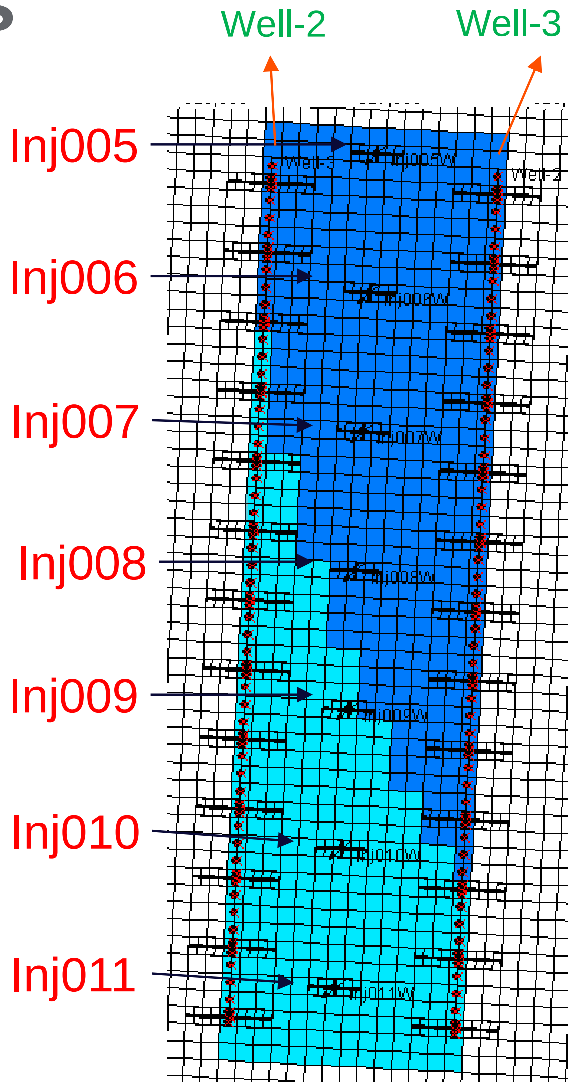


30 yr – CO_2 Global Mole Fraction (Injectors JK X-Section)



Recommended WAG Designs

- Two WAG simulation cases are recommended here and are compared with the primary production case. The design of the WAG case is:
- 7 injectors (Inj005 – Inj011) with perforations in layers 2-33, no skin, hydraulically fractured
- xf = 150ft and 250ft, NFZ transmissibility multiplier = 20
- One WAG cycle: 180 days of CO_2 and 180 days of water
- WAG ratio: 0.9-0.8 (Rsvr vol of water/Rsvr vol of gas)
- Injection constraint: max. BHP = 4,000 psi
- Production constraint: min BHP = 620 psi. (Fast initial drawdown to a value of 620psi from reservoir pressure)



Pattern (1/3rd of the full model)

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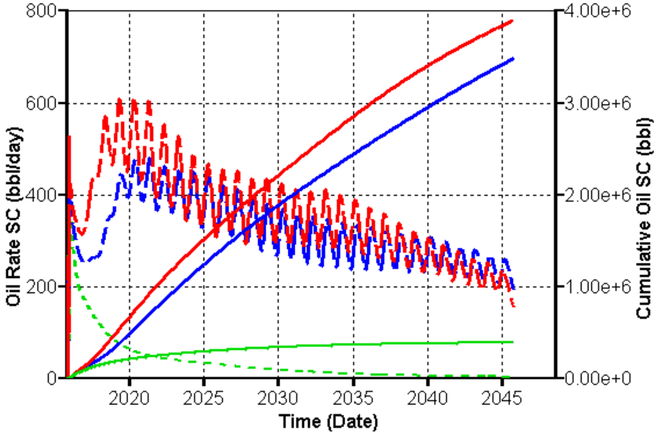
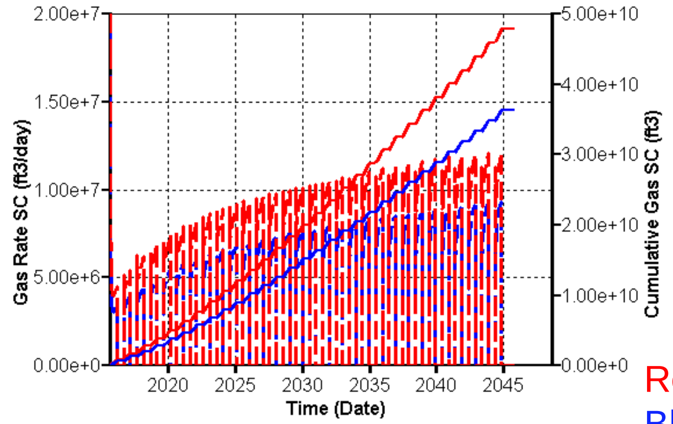
Recommended WAG Designs

Oil Production



Gas injection

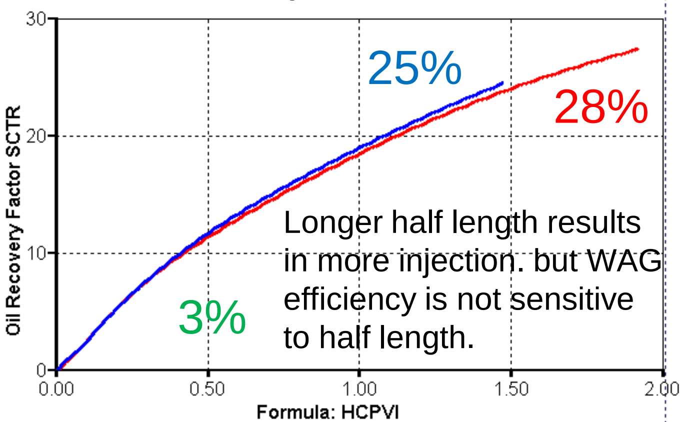


Red: WAG with xf = 250ft

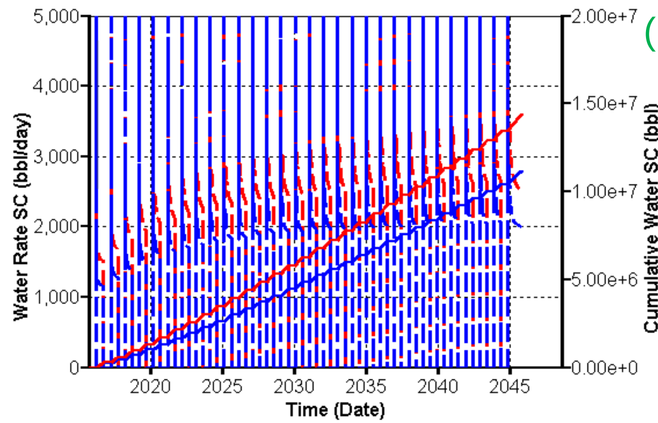
Blue: WAG with xf = 150ft

Green: Base case (primary production)

Recovery vs. HCPVI



Water injection



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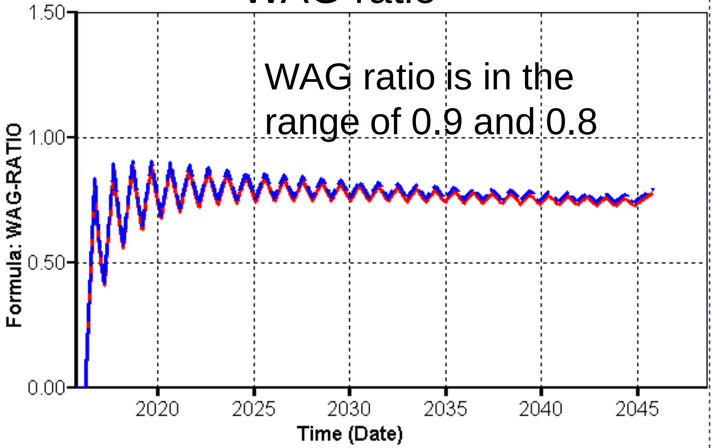
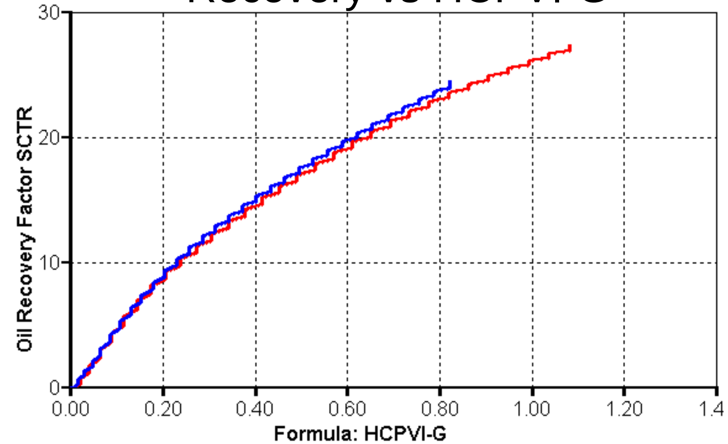
Recommended WAG Designs

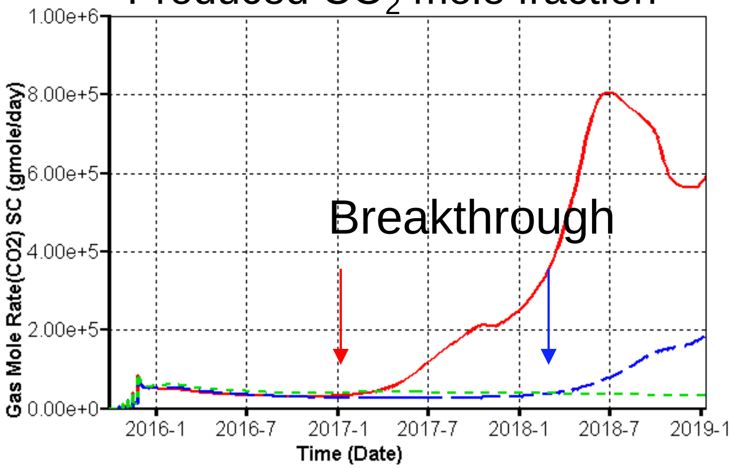
WAG ratio



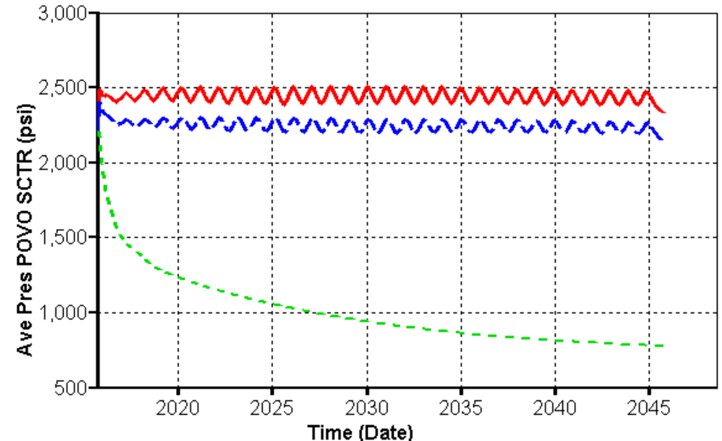
Recovery vs HCPVI-G



Produced CO_2 mole fraction



Avg. reservoir pressure



Red: WAG with xf = 250ft

Blue: WAG with xf = 150ft

Green: Base case (primary production)

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