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Sensitivity Study of CO2 Huff & Puff Jatibarang Using Compositional Simulator

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Abstract

The CO_2 injection has been applied in the petroleum industry, miscible and immiscible CO_2 flooding are the processes for many EOR methods projects. Huff & Puff simulation approach has been developed to evaluate oil recovery mechanism for CO_2 injection process and to find an incremental production using this process for oil reservoir. These recovery mechanisms include CO_2 impurity effect, swelling effects, relative permeability effects, viscosity reduction, miscibility effects, and gas solubility.

Huff & Puff CO_2 consist of three steps: injected CO_2 into production well, soaking the well and the well is opened for production. A soaking time period has a different time in every projects, depends on characterization of reservoir, sensitivity of soaking time and total CO_2injected will be simulated to carry out the optimum days for soaking time period and to get optimum incremental oil from reservoir.

Jatibarang Field is chosen to apply Huff-n-Puff CO_2 injection due to its oil characteristic and having CO2 source nearby. Jatibarang field is located about 30 KM southwest of Cirebon city within the Pertamina EP concession area, discovered in November 1969. Jatibarang Layer F began to be produced in March 1975. The F layer consists of carbonate rock and shale which deposited in continental shelf platform or reefal environment, and the thickness of the reservoir is 4-5 m. Jatibarang reservoir has API 36, 0.5-0.9 cP of viscosities, 10.87-21.38 % of porosities, 3727-3937 feet of reservoir depth and permeabilities ranging from 40 to 60 mD. With these reservoir properties, the EOR screening shows that CO_2 EOR was suited to be applied in Jatibarang.

This reservoir simulation study is very useful for evaluating the effect of CO_2 injection and parametric analysis of reservoir data and injection operation.

Keywords: CO2, Huff & Puff, Simulation, Jatibarang

1. Introduction

Huff & Puff method or cyclic CO_2 process is a type of production well stimulation which involves injecting CO_2 into a well for a while based on design, shutting in the well to allow the CO_2dissolve or soaking time.

Although most of today's CO_2 EOR projects involve large-scale continuous injection of CO2 solvent, there is increasing interest in cyclic CO_2 injection into single wells. Typically, the rapid injection of CO_2 is followed by a shutin period. The well is then returned to production and the response monitored. In reservoirs with poor interwell communication, this single-well approach may afford the only means of recovering tertiary oil by a CO_2 process. In reservoirs where inter well communication is not a problem, CO2 huff 'n' puff offers a simply EOR method to produce additional recovery oil.

In this study, we design the well with Huff & Puff method by combining the history match, wizard process, sectorization model, grid sensitivity, design optimization to obtain the proper method to be implemented in the field test. Finally, these data can be used to design the proper of Huff & Puff CO_2 injection.

2. Basic Theory

The basic mechanism of CO_2 injection is the mixing of CO_2 with oil and forming a new fluid that is easier to push than the initial condition oil. This is because the physical properties of oil change due to CO_2 injection. In general there are four changes in physical properties experienced by oil due to CO_2 injection

1. Development of oil volume.
2. Decreasing viscosity.
3. Increase in Density.
4. Extraction of some oil components.

If CO_2 gas is injected into an oil reservoir under conditions of mixed pressure, it will cause miscibility or mixed. In mixed conditions, what happens between the gas injected with the oil in the porous media will reduce the surface tension between the gas and oil to form a homogeneous phase. In order to achieve mixed conditions, the minimum Miscible pressure (MMP) is needed whose magnitude is affected by reservoir pressure, reservoir temperature, reservoir oil composition and gas injection composition. In the CO_2 injection above the mixed pressure, the optimal oil recovery price will be obtained. Whereas if CO2 gas is injected into the oil reservoir under conditions under mixed pressure, it will cause immiscibility condition. It's conditions that occur between the gas injected with the oil in the porous media will cause a decrease in oil viscosity and swelling or expansion of oil volume. This causes the results of the recovery in CO_2 injection conditions under mixed pressure is lower than the oil recovery at mixed conditions of CO_2 gas injection.

3. Methodology

We could determine the proper scenario for study huff & puff in the field by studying simulation result.

3.1 History Match Black Oil Model

History of production aims to harmonize the reservoir model that has been built with the rate of production (oil and water) that has been released and the pressure of the reservoir. The parameters that are changed to obtain the expected alignment results are aquifer strength, permeability, transmisability, and relative permeability curves. History matching is a process of modifying the parameters used in making a model, so that the alignment between the model and real conditions is created, which is based on measured parameter data over a certain period of time.

This stage is very important in simulating a reservoir. This process is carried out to make the condition and performance of the reservoir model the simulation results resemble the condition and performance of the actual reservoir. Field data shows actual conditions and performance. Alignment is indicated by a graph of pressure on time and production over time. Alignment is carried out if the alignment between the model and the actual reservoir has not occurred, that is by aligning productivity and aligning the pressure.
The next step after initialization is alignment (history matching), this stage aims to align the reservoir model that has been built with the rate of production (oil, water) that has been released and the pressure of the reservoir. Keywell number determination is based on 80% of the total cumulative oil production and the existing active production wells in each layer.
The parameters that are changed to obtain the expected alignment results are aquifer strength, permeability, transmisability, and relative permeability curves. History matching is a process of modifying the parameters used in making a model, so that the alignment between the model and real conditions is created, which is based on measured parameter data over a certain period of time.

This stage is very important in simulating a reservoir. This process is carried out to make the condition and performance of the reservoir model the simulation results resemble the condition and performance of the actual reservoir. Field data shows actual conditions and performance. Alignment is indicated by a graph of pressure on time and production over time. Alignment is carried out if the alignment between the model and the actual reservoir has not occurred, that is by aligning productivity and aligning the pressure.

3.2 Convert Wizard Process

To reduce (accelerate) the calculation process in the simulator (running process), the components are combined based on the physical properties for each component in the PVP sample.

3.3 Grid Sensitivity

Numerical dispersion is particularly important in simulating multiphase flow, miscible displacement, and compositional phenomena. Detailed study be carried out on grid- and timestep-size effects. A grid-size sensitivity study is recommended when a reservoir is simulated to define the necessary grid size used. Such a study requires a series of simulation runs with increasing or decreasing grid definition. When simulators with fully implicit formulation are used, where large time steps are possible, the time truncation error also can become important. Therefore, a timestep sensitivity study for these simulators is also necessary. "Sensitivity analysis" refers to the sensitivity of the primary variables and recovery performances to grid and timestep size.

The graphic is Oil Recovery factor vs Time, it shows a LGR uniform from 10 x 10, 12.5 x 12.5, 20 x 20, 25 x 25, and the original size of the model 100 x 100. From this result, the original grid size is the top that can produce the recovery factor 20.53% compered the second is 20.31%.

From this graphic HCPV vs Time the model 25 x 25 is the higher HCPV with 394.80 ft^3.Table.1 show the summary from this analysis result.

Based on table 1 assume that LGR uniform from 20 x 20 grid size is the most applicable model for Huff & Puff method. With RF, HCPV, and pressure have a good consistency number compared from the others model.

3.4 Design and Optimization

Target of 1,000 tons of carbon dioxide injection with huff & Puff well stimulation technique was chosen. The huff & puff injection technique is the CO_2 injection process in a production well and then is reproduced in the same well in the hope that this will increase oil recovery. From the laboratory and correlation results obtained a minimum mixed pressure (MMP) is 2460 psi.

1000 tons of carbon dioxide will be separated into 33 tons a day for 30 days. 15 days for soaking time is the most valuable from simulation model.

4. Case Study

Jatibarang Field is chosen to apply Huff-n-Puff CO_2 injection due to its oil characteristic and having CO2 source nearby. Jatibarang field is located about 30 KM southwest of Cirebon city within the Pertamina EP concession area, discovered in November 1969. Jatibarang Layer F began to be produced in March 1975.

The Original Oil in Place (OOIP) total in the F Layer of the Jatibarang Field to be developed is 55.3 MMSTB, with cumulative oil production (Np) status in December 2011 of 9.69 MMSTB and gas of 32.105.80 MMscf, so Recovery Factor (RF) is still 17.54%. Initial oil production rate of 161 Bbl / day, initial gas rate of 44 Mcf / day, the highest oil production rate of 255 Bbl / day was achieved in June 1982, water cut 4.7% with 12 oil production wells. Water injection began in October 2003 with a water injection rate of 1535 Bbbl / day, with oil production of 471 Bbl / day from 10 production wells, 48.2% water cut.

EOR screening shows that CO2 EOR was suited to be applied in Jatibarang field.

5. Result and Discussion

The focus on the JTB-140 well which has the current NP is 1.3575 mm. Based on the simulation model, if it continues to produce until the end of 2025, it will get additional oil of 108.08 mstb or additional RF of 1.79%. Whereas with the Huff n Puff CO2 scenario by the end of 2025, it will get an additional oil of 106.21 mstb or an additional 1.77% RF. It can be said that additional oil from the Huff n Puff CO2 scenario is smaller than the base case scenario of 3.11 ms. The simulation results can be seen in table 6.

MMP result for Jatibarang field from Yellig and Metcalfe correlation method is 2.461,33 psi, and from the laboratorium experiment (slim tube) MMP is 2500 psi. CO2 injection is immicible, so the IFT reduction won't be zero, but relative permeability will increase and residual oil saturation will decrease. That effect show from the simulation study compared CO2 injection and base case.

6. Conclusion

From the discussion above, it can be concluded that understanding Huff & Puff method for CO2 injection is the most valuable tertiary method. The CO2 gas dissolved into oil in the reservoir, effected the swelling oil and dissolved into water that can be increasing viscosity of water. It caused reservoir sweep efficiency is increased, so jatibarang well can get the incremental from CO2 injection based on this simulation.

From this study jatibarang has a good respons from Huff & Puff CO2 injection, for the next plan this field should has a full scale field implementation.

7. Recommendation

The future Pilot CO2 EOR Study may be conducted to evaluate the EOR process recovery efficiency in the field, asses the sweep efficiency of the CO2 injection, obtain data to calibrate reservoir simulation models for fullfield predictions, prove efectiveness gravity stable or vertical conformance, Identify operational issues and concerns for fullfield development and to find unexpected issues, define Monitoring & Surveillance program with specific tools, and define matrix of success criteria

The continuous CO2 injection is highly recommended for Jaitbarang field, from this study shown effect from CO2 which respons the oil compared from base case simulation study.

8. Acknowledgement

We would like to thank to EOR Tertiary Team, because without Tertiary division this papper couldn't be happened.

9. References

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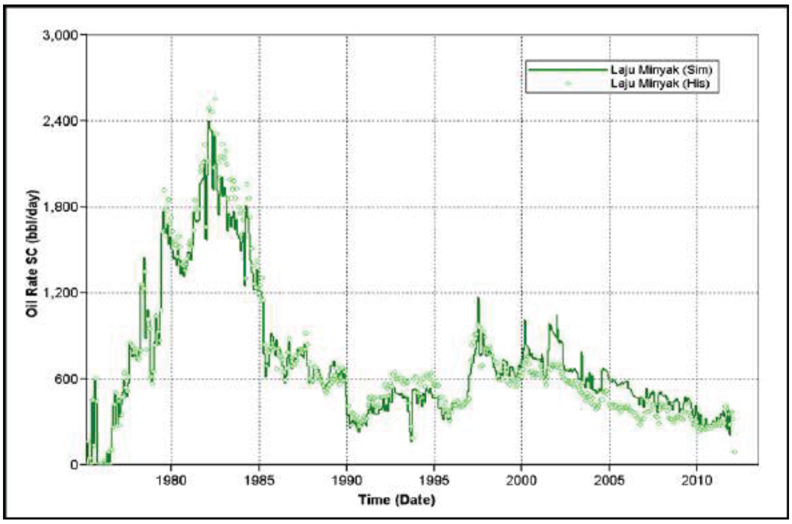

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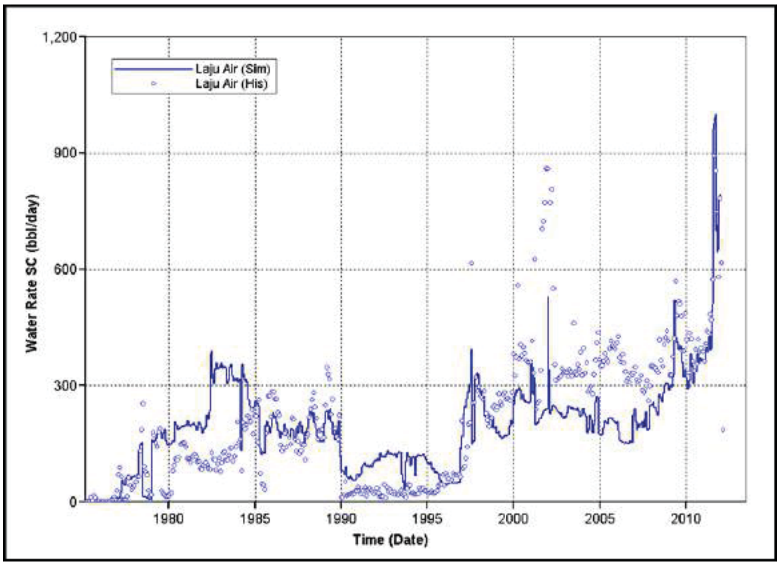

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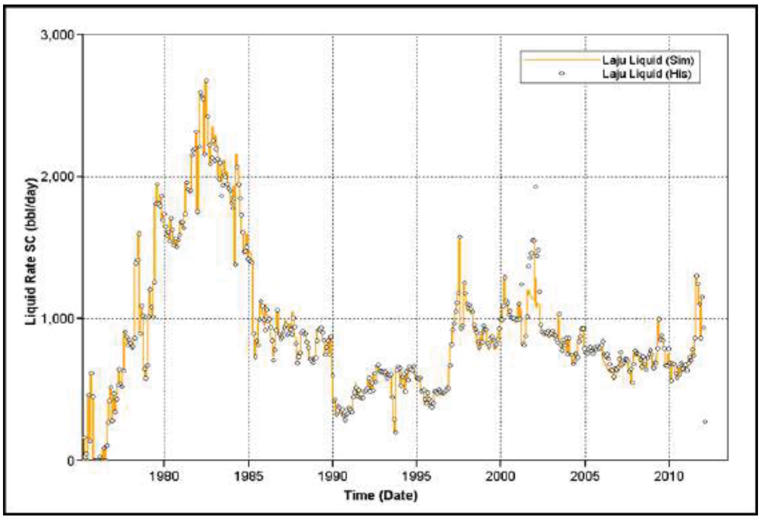

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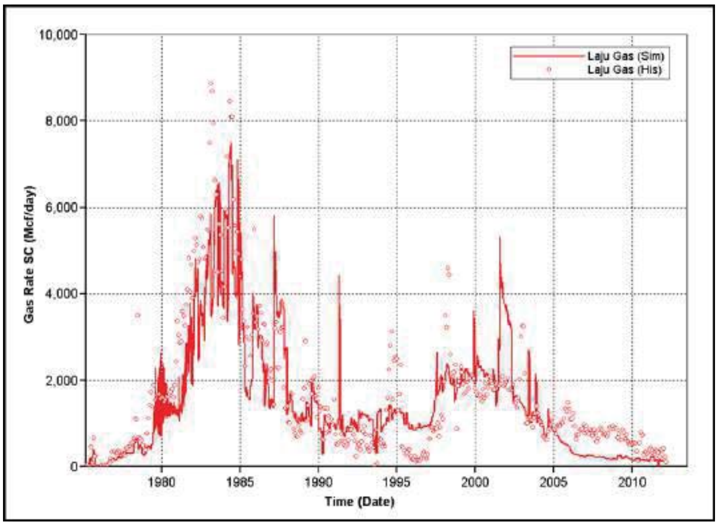
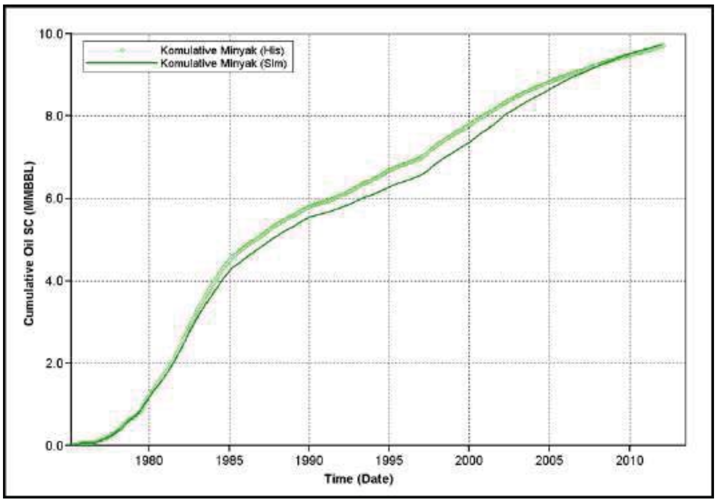


(d)

Figure 1. History Matching Black Oil Simulation Curve; (a) Oil Field Rate History Matching Curve, (b) Water Field Rate History Matching Curve, (c) Liquid Field Rate History Matching Curve, (d) Gas Field Rate History Matching Curve.



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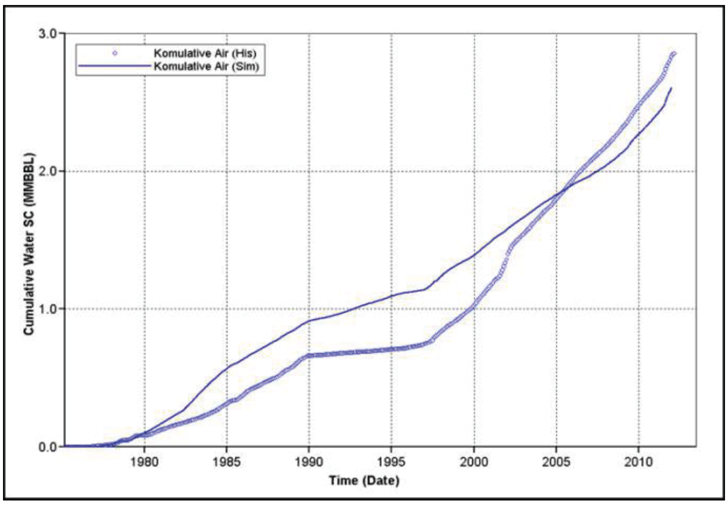

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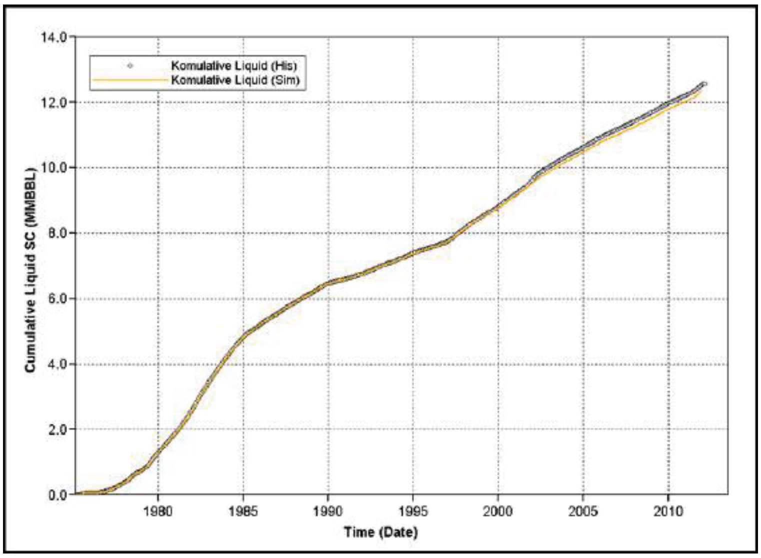

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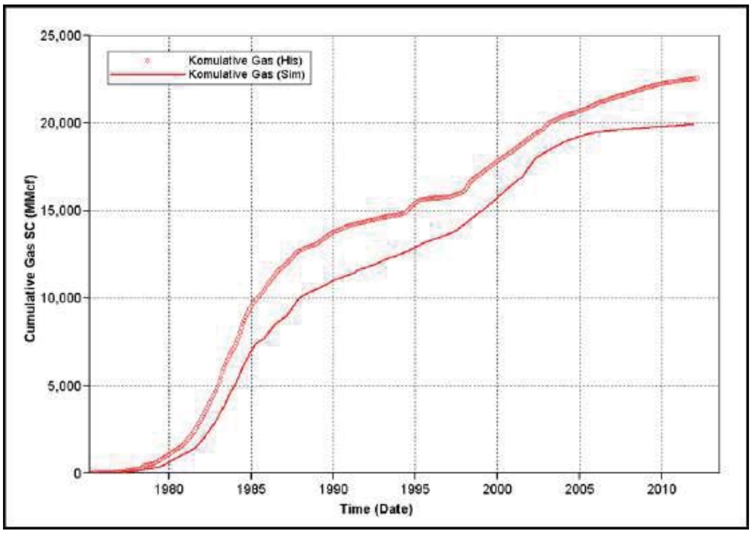


(d)

Figure 2. History Matching Black Oil Simulation Curve; (a) Oil Field Cumulative History Matching Curve, (b) Water Field Cumulative History Matching Curve, (c) Liquid Field Cumulative History Matching Curve, (d) Gas Field Cumulative History Matching Curve.

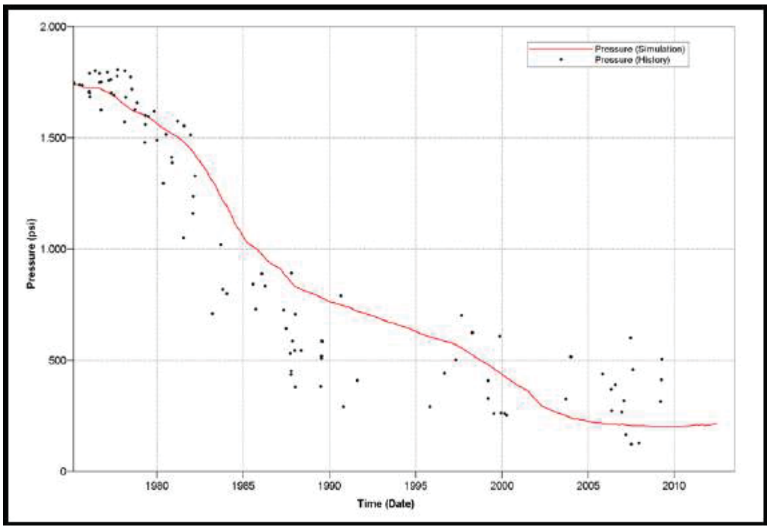


Figure 3. Field Pressure History Matching Curve

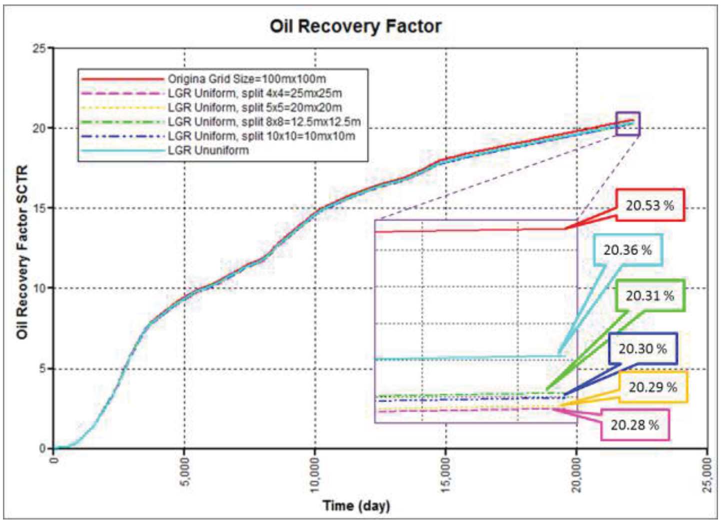


Figure 4. Recovery Factor

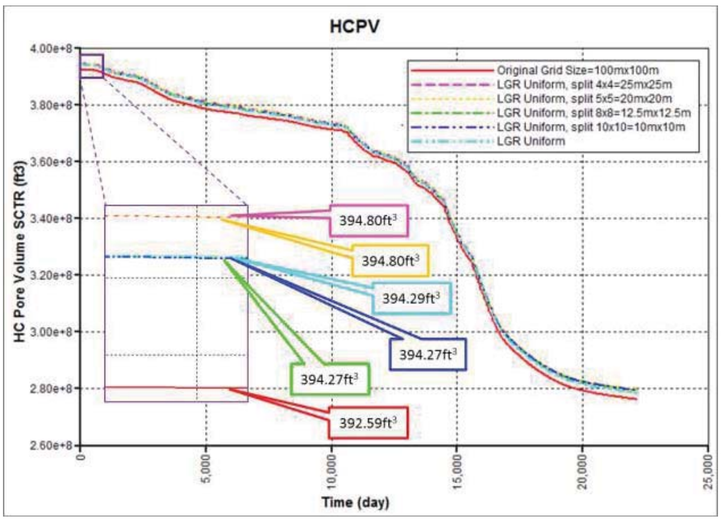
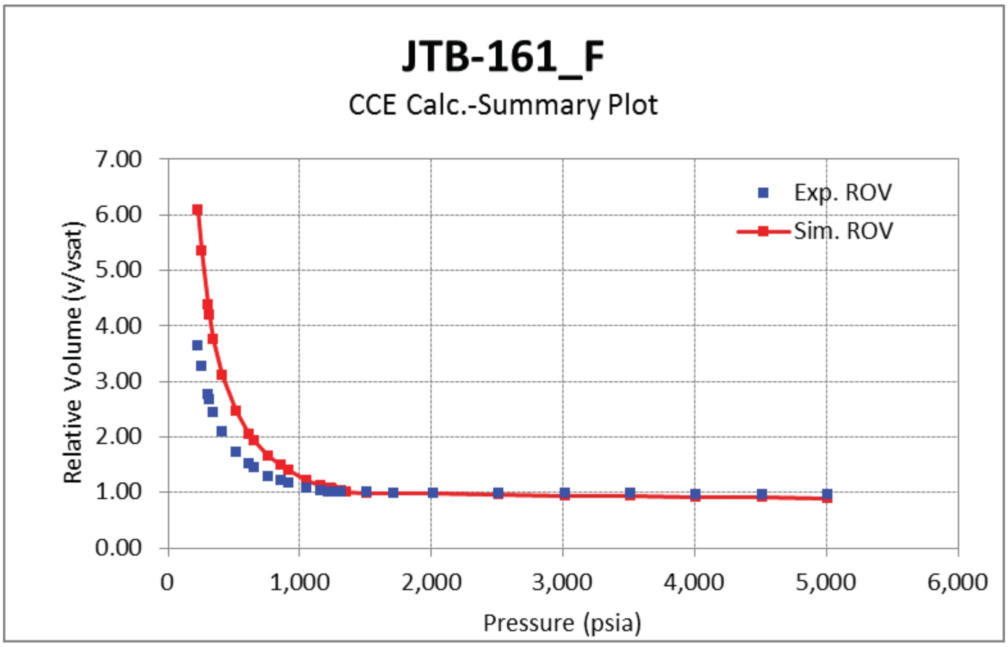
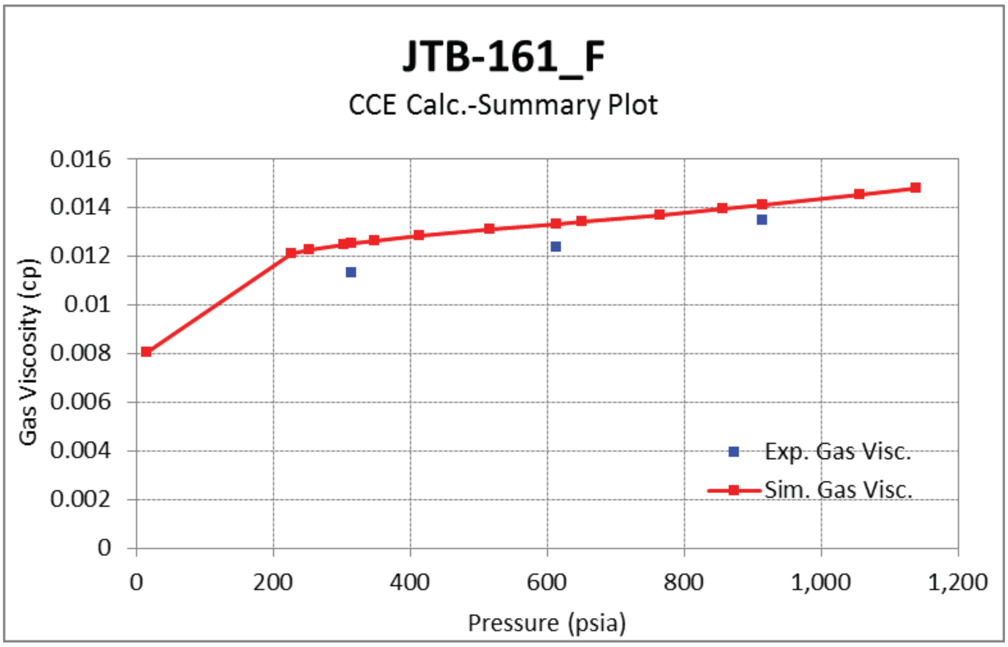


Figure 5. HCPV



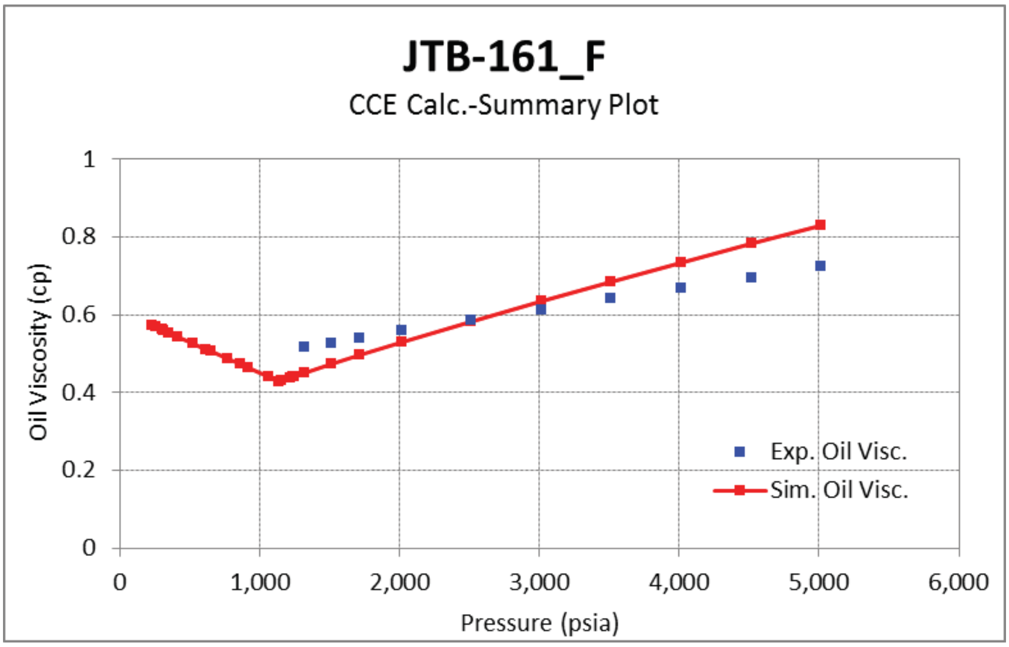
JTB-161_F
CCE Calc.-Summary Plot
Relative Volume (v/vsat)
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0
1,000
2,000
3,000
4,000
5,000
6,000
Pressure (psia)
Exp. ROV
Sim. ROV

(a)



JTB-161_F
CCE Calc.-Summary Plot
Gas Viscosity (cp)
0.016
0.014
0.012
0.01
0.008
0.006
0.004
0.002
0
0
200
400
600
800
1,000
1,200
Pressure (psia)
Exp. Gas Visc.
Sim. Gas Visc.

(b)



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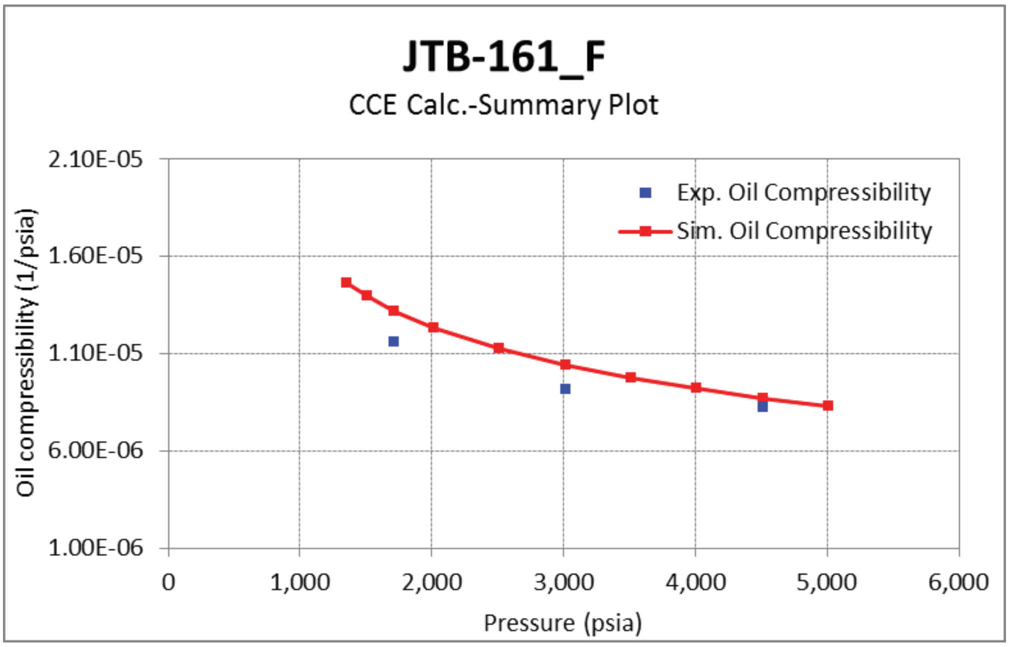
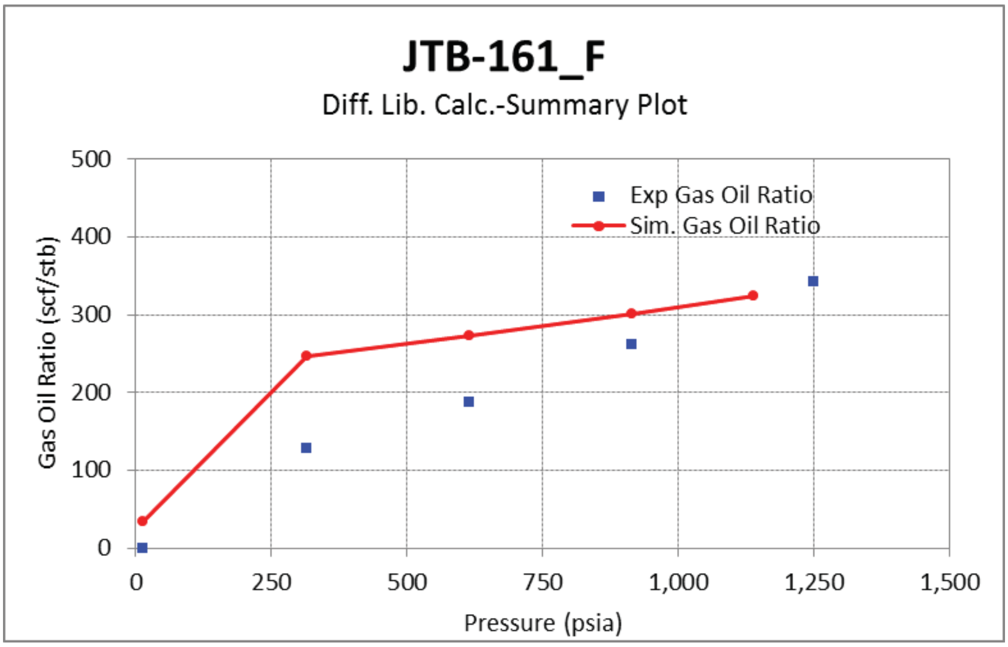
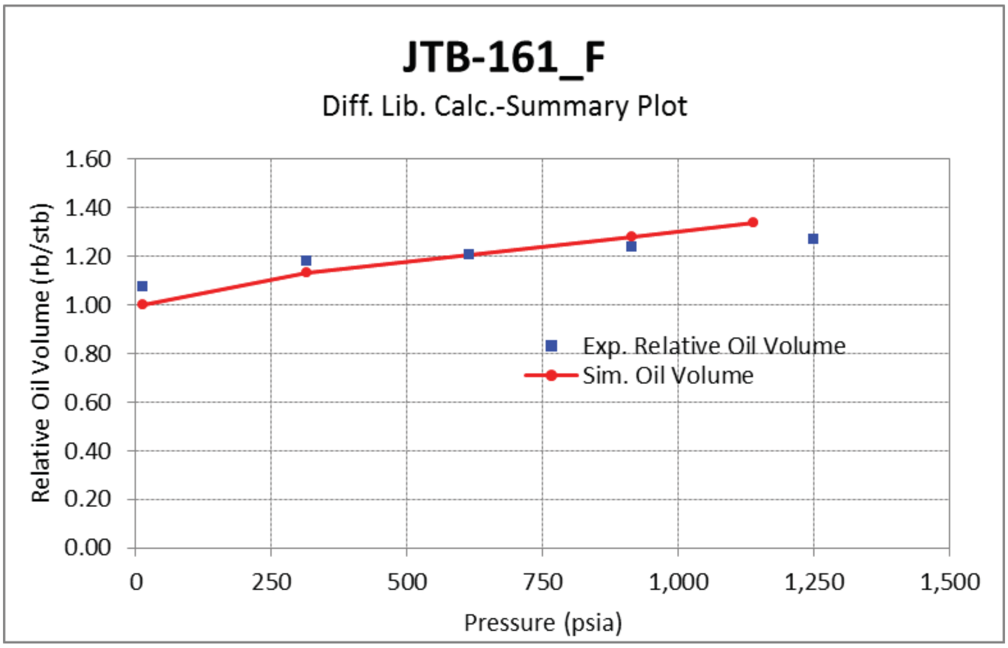


(d)

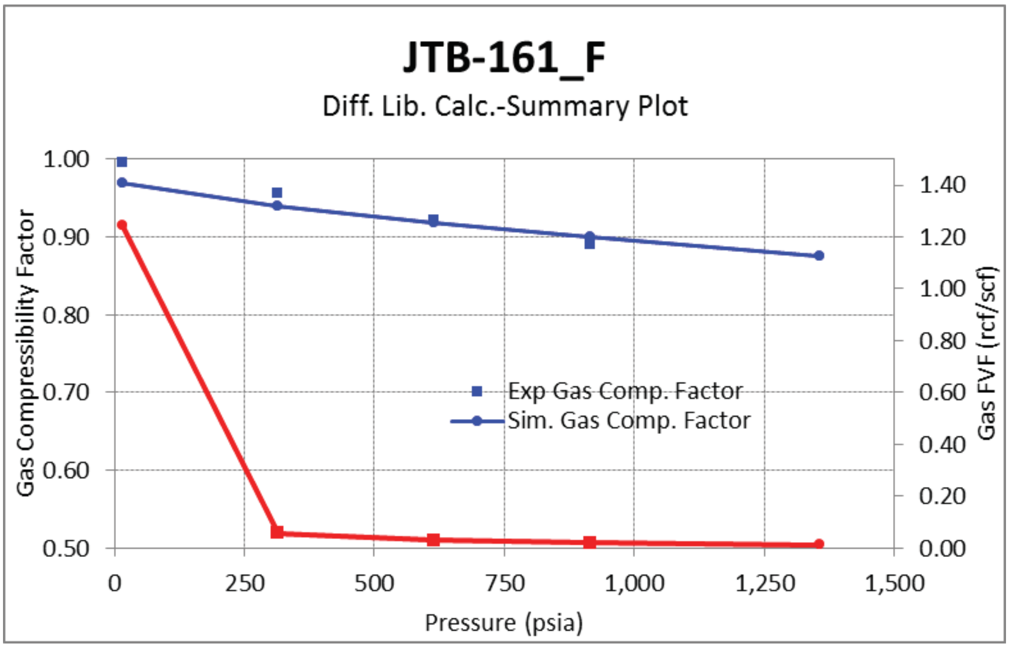
Figure 6. CCE Simulation JTB-161 F Zone Curve; (a) Relative Volume (ROV) versus pressure, (b) Gas Viscosity versus Pressure, (c) Oil Viscosity versus Pressure, (d) Oil Compressibility versus Pressure


JTB-161_F
Diff. Lib. Calc.-Summary Plot
Gas Oil Ratio (scf/stb)
500
400
300
200
100
0
0
250
500
750
1,000
1,250
1,500
Pressure (psia)
Exp Gas Oil Ratio
Sim. Gas Oil Ratio

(a)

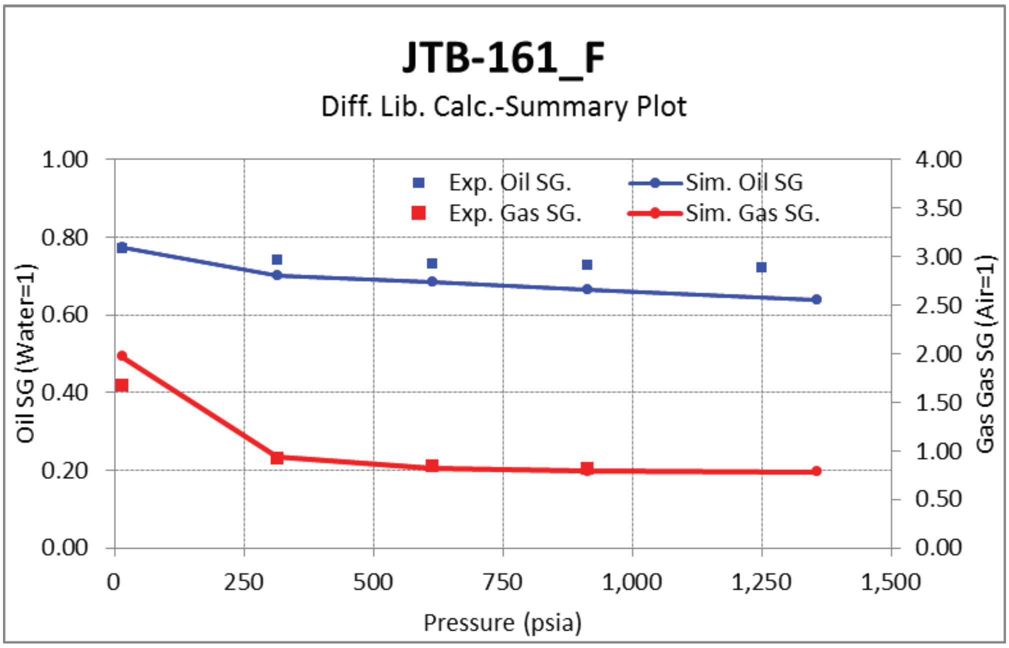

JTB-161_F
Diff. Lib. Calc.-Summary Plot
Relative Oil Volume (rb/stb)
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0
250
500
750
1,000
1,250
1,500
Pressure (psia)
Exp. Relative Oil Volume
Sim. Oil Volume

(b)



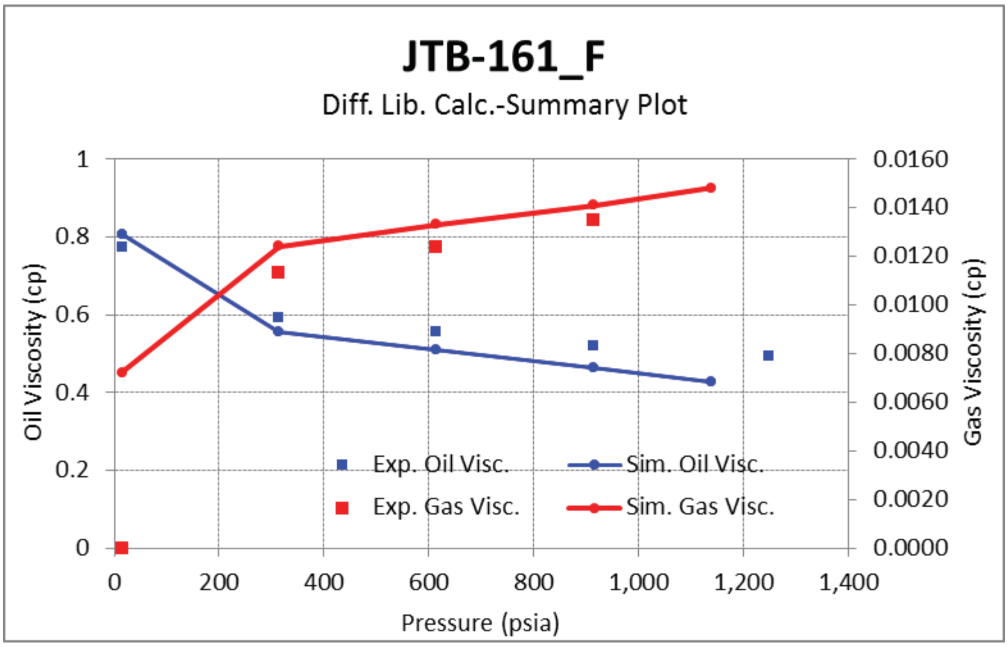
JTB-161_F
Diff. Lib. Calc.-Summary Plot
Gas Compressibility Factor
Gas FVF (rcf/scf)
Exp Gas Comp. Factor
Sim. Gas Comp. Factor
Pressure (psia)
1.00
0.90
0.80
0.70
0.60
0.50
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0
250
500
750
1,000
1,250
1,500

(c)



JTB-161_F
Diff. Lib. Calc.-Summary Plot
Oil SG (Water=1)
Gas Gas SG (Air=1)
Exp. Oil SG.
Exp. Gas SG.
Sim. Oil SG
Sim. Gas SG.
Pressure (psia)
1.00
0.80
0.60
0.40
0.20
0.00
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
0
250
500
750
1,000
1,250
1,500

(d)



(e)

Figure 7. Dif. Lib. Simulation JTB-161 F Zone Curve; (a) Gas Oil Ratio versus pressure, (b) Relative Oil Volume versus Pressure, (c) Gas Compressibility – Gas FVF versus Pressure, (d) Oil SG – Gas SG versus Pressure, (e) Oil Viscosity – Gas Viscosity versus Pressure.

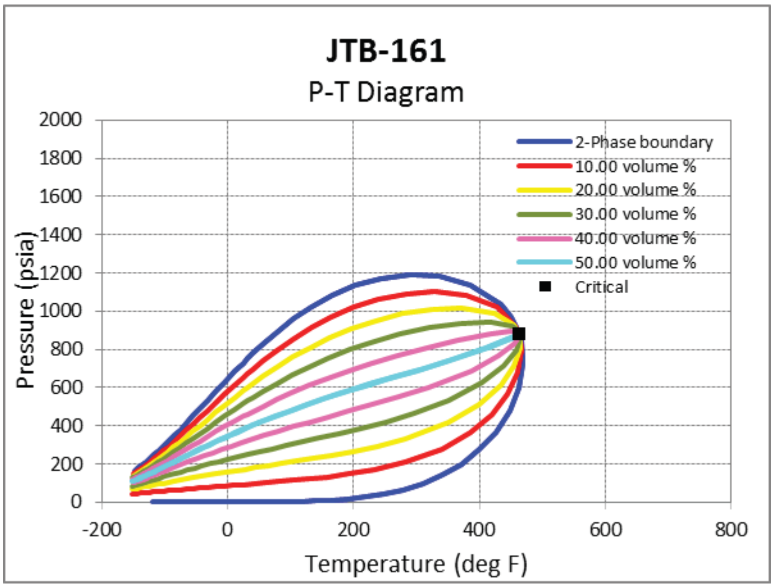


Figure 8. P – T Diagram Reservoir Fluid Simulation JTB-161 F Zone
Well JTB-161 (F Zone)

Figure 9. P – T Diagram Reservoir Fluid Simulation JTB-161 F Zone
Well JTB-161 (F Zone)

List of Tables

Table 1 Consistency Simulation Result

No	File	Grid size	Σ Grid	Consistency		
				RF	HCPV	Pressure
1	Original Grid Size =100mx100m	100x100	43,520	20.5292	392.594	2839.59
2	LGR Uniform, split 4x4=25mx25m	25x25	50,720	20.2845	394.801	2772.88
3	LGR Uniform, split 5x5=20mx20m	20x20	54,770	20.3058	394.8	2784.12
4	LGR Uniform, split 8x8=12.5mx12.5m	12.5x12.5	74,240	20.3058	394.274	2746.86
5	LGR Uniform, split 10x10=10mx10m	10x10	91,520	20.2991	394.274	2763.71
6	LGR Ununiform	-	44,858	20.3557	394.288	2853.69

Table 2 Run Time Simulation

No	File	Grid size	Σ Grid	Run Time (Hours)	
				1 lic	8 lic
1	Original Grid Size =100mx100m	100x100	43,520	0.84	0.11
2	LGR Uniform, split 4x4=25mx25m	25x25	50,720	2.01	0.26
3	LGR Uniform, split 5x5=20mx20m	20x20	54,770	3.14	0.41
4	LGR Uniform, split 8x8=12.5mx12.5m	12.5x12.5	74,240	10.35	1.33
5	LGR Uniform, split 10x10=10mx10m	10x10	91,520	16.11	2.06
6	LGR Ununiform	-	44,858	1.49	0.19

Table 3 Near wellbore condition of JTB-161

No.	Reservoir Parameter	Value	Unit
1	Existing injection rate	1,200	bbl/day
2	Perforated layer thickness	49.85	ft
3	Average pattern porosity	0.189	fraction
4	Average pattern permeability	1,120	mD
5	Fracture pressure	2,604	psi
6	Average pattern pressure before polymer injection	1,000	psi

Table 4 Near wellbore condition of JTB-137

No.	Reservoir Parameter	Value	Unit
1	Existing injection rate	1,800	bbl/day
2	Perforated layer thickness	49.21	ft
3	Average pattern porosity	0.197	fraction
4	Average pattern permeability	192	mD
5	Fracture pressure	2,572	psi
6	Average pattern pressure before polymer injection	1,028	psi

Table 5 Near wellbore condition of T-140

No.	Reservoir Parameter	Value	Unit
1	Existing injection rate	1,800	bbl/day
2	Perforated layer thickness	49.21	ft
3	Average pattern porosity	0.197	fraction
4	Average pattern permeability	192	mD
5	Fracture pressure	2,572	psi
6	Average pattern pressure before polymer injection	1,028	psi

Table 6 Simulation Result T-140

Scenario	NP mmstb	RF %	Add.Oil mbbl	Add. RF %	Incre. RF mmbbl	Incre. Oil %
BC	1.4656	24.37	108.08	1.80	-	-
Huff n Puff	1.46373	24.34	106.21	1.77	-0.03109	-0.03

Table 7 MMP Estimation

Emperical Method	**MMP (psi)**	**MMP (bar)**
Jhonson, Polin, Alston	1,675.60	115.53
Emera Samar	1,867.88	128.79
Yellig & Metcalfe	2,461.33	169.70
Standing & Khazam	2,294.80	158.22

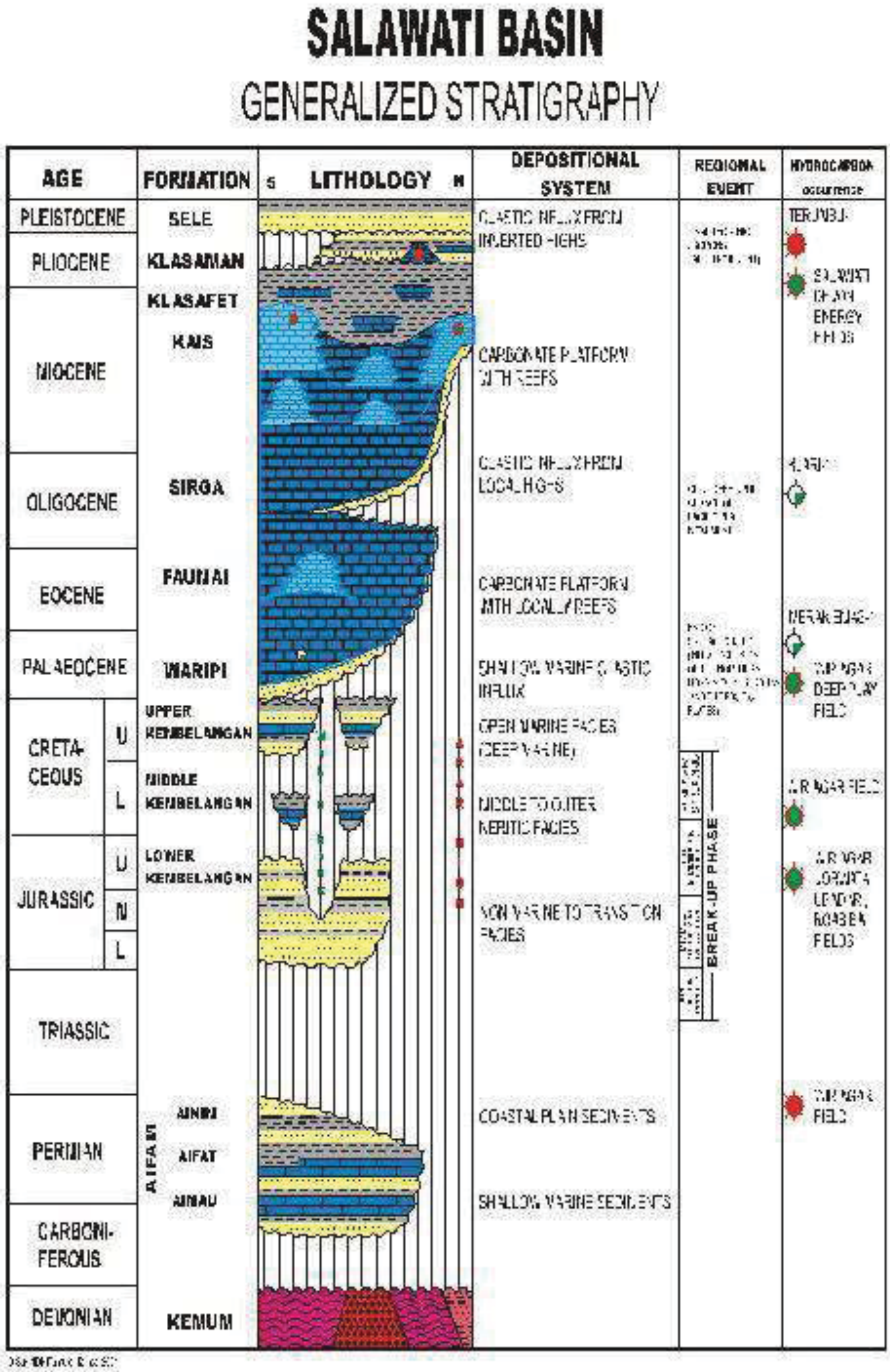


Figure 4 Well X-25 Stratigraphy