گزارش فاز دوم

<u>شبیه سازی یک بلوک از میدان گازی میعانی پارس جنوبی</u>

<u>برای تعیین پتانسیل افزایش میدان استحصال</u>

<u>میعانات گازی در شرایط بازگردانی</u>

<u>(Simulation of South Pars Gas Condensate Reservoir-One Sector)</u>

Table of Contenet

Simulation of South Pars Gas Condensate Reservoir

One Sector

1 – Introduction

South Pars is an offshore gas condensate reservoir. South Pars consists of huge gas reservoir and few small oil reservoirs. The field is located in the Persian Gulf around 100 kilometers offshore in the water depth of 60 to 70 meters. The field extends into Qatar waters where it is called North dome.

The reservoir was discovered by drilling the discovery well SP-1 in 1991. Drilling operation in this field was continued up to the depth of 3522 MDD. Light oil was observed in the Dariyan, Gadvan and Fahlian formations. Heavy oil was observed in the upper Surmeh formation and huge amount of gas was discovered in the Kangan and Dalan formations. The kangan and Dalan formations were tested in detail and the test results showed that the mentioned layers are productive. Three delineation wells were also drilled in the field and all of the wells proved that the Kangan and Dalan formations (equivalent to Khuff K1, K2, K3 and K4) are productive. Based on available PVT analysis the reservoir is gas condensate with 38 barrels of condensate per each MMscf gas. The reservoir rock mainly consists of carbonate and small amount of anhydrite.

The initial gas in place is about 13300 billion cubic meters and the reserve with compressor is estimated to be about 11300 billion cubic meters. The initial condensate in place is estimated about 2.8 billion cubic meters. Different Phases are defined in the reservoir. Some of the defined phases are developed and they are under production and development of some of the phases is underway.

2-Study Objectives

The gas production from the field in Qatri side and in Iranian side was started in 1991 and 2003 respectively. Only some of the phases are developed and are under production, pressure data shows that even with the current limited gas production the decline in pressure is about 100 Psia (about 7 bars) per year. The decline in pressure can be higher after development of new phases. The result of Decline in pressure is condensate drop out in the reservoir. With the high price of condensate it can cause a noticeable loss. Recycling is one of the classic methods in gas condensate reservoirs to decrease condensate dropout. In this study one sector of reservoir similar to phase-2 was studied for different cases. In the first case the gas production from the sector continues according to current plan and in case two 10 production and 10 injection wells are added to case 1 to study the effect of recycling. In this case production wells continue their production therefore it does not change the production plan. The main objective is to find out the extra condensate production potential. In the study the gas migration and break through and alternative pattern are not taken into account and the main objective is to find condensate potential.

3-Model Construction

3-1-Geometrical Construction

Reservoir model was constructed by a network grid 25*25*11 using Grid model. Geological layers in the reservoir are K1, K2, K3 and K4. Layer-K4 is bottom and layer K1 is top. A map able Anhydrite separates sub layers K3 and K4. FIG-1 shows the 3-dimensional (3D) view of the reservoir.

The following table shows the relationship between the reservoir layers & the model layers.

Res.layer	Model layer
K1	1,2
K2	3
K2A	4
K3	5,6,7
K3A	8
K4	9,10,11

3-2-Grid block properties

Porosity, net to gross value and water saturation data are available at some well locations in sub layers K1 to K4.The result of log evaluation was reviewed and the average petrophysical properties were calculated. The average values for each sub layers were defined in the model.Table-1 shows the defined petrophysical properties in the model. The initial reservoir pressure was defined 361 Bars at reservoir datum depth of 2790 mss.

As discussed in the reservoir characterization report based on the result of DSTs and well tests the permeability of K1, K2 and K3 was defined 15 md. The permeability of K4 was defined 30 md in the model. Permeability in y direction was defined equal to permeability in x direction initially. Permeability in z direction was defined equal to Kx.

Based on model dimension and properties original gas in place was estimated in different sub layers of the reservoir. Table-2 shows some of the important reservoir data.

4-Model Regions

4-1-Saturation regions

There is no SCAL data available; therefore only one rock type region was defined in the model, using similar rock property data. Figures 2 and 3 demonstrate relative permeability and capillary pressures data respectively.

4-2- PVT regions

The PVT in well SP-13 in K4 reservoir was used to define PVT properties in the model. For this purpose first PVTi package was used to tune the equation of state using CVD, CCE and other physical properties. The generated PVT table was exported from PVT package to Eclipse. One PVT region was defined in the model. Table-3 shows reservoir fluid composition. .Figures 4 to 9 show the calculated fluid property by the model and comparison between experimental and calculated values. As the above figures show there is a good match between calculated and observed properties.

4-3-Fluid in place regions

The model has been initialized with four different sets of fluid in place regions for different sub layers.

Fluids in place values obtained after initializing the model at the above conditions are as follows:

Layers	OGIP, Bcum	OCIP, Mcum
K1	97.22	19.81
K2	73.49	14.97
K3	108.30	22.07
K4	294.16	59.94
Total	**573.17**	**116.79**

4-4- Aquifer specification

No aquifer was defined in the model.

4-5-Requested outputs

The following model derived quantities were requested in each time step:

-Field gas and condensate production rate

-Field gas and condensate production total

-Field pressure

-well production rate

-well gas production total

-well THP

-well BHP

-well block pressure

4-6-Generation of VFP tables

VFP table has been generated and used in the model. Well pressure and PVT properties were used to generate a representative VFP table.

In VFP data file, parameters like friction loss gradient multiplier and hydrostatic pressure gradient multiplier have been adjusted using the production rate, tubing head and bottom hole pressure data.

5-Available Data

The available data which was used in model construction are as follows:

-Petrophysical data: Result of log evaluation were used to define suitable petrophysical data in different sub layers of the model

-well and production data: Well and production data were used in history matching. The condensate production report is not reliable. Well specification data such as xy location and completion intervals were used in the model.

-Pressure data: the available data were used in history matching

-Other data which were used in the model are:

Initial reservoir pressure

Reservoir pressure

Dew point pressure

GWC depth

Rock Compressibility

Gas density

Water density

Condensate density

6-Model Initialization

The following results were obtained after building the model and running it for the first time.

6-1- Gas in place

As mentioned before the model has been initialized. The following values were obtained from initialized model:

Layers	ECLIPSE
1	97.22
2	73.49
3	108.30
4	294.16

6-2- Average values

Average porosity, N/G, Sw, K, Thickness values have been extracted for each geological layer.

7-History Matching

There is limited production history in this reservoir. The available pressure data shows that the decline in static pressure has been about 100 psi each year. The model does not take into account the gas migration from boundaries therefore the model pressure drop is higher than actual pressure drop in the reservoir. Figure-10 shows field pressure.

8-Prediction Scenarios

Different prediction cases were studied in the simulator. The description of each case is as follows:

Case-1: This case represents the continuation of gas production according to the plan which is production of 28.3 million cubic meters of gas per day from 10 production wells. The current reservoir condition has kept unchanged and extended to the end of year 2039. The defined VFP table was used and production wells were controlled by THP of 40 Bars. This case result shows that if we keep the current situation unchanged, the reservoir will produce at plateau rate up to year 2039. The decline in production rate starts from year 2040 and finally reservoir will be closed in 2067 due to low THP of the wells. The gas recovery in this case is about 310,384 and 485 Bscm after 25, 32 and 60 years respectively. The gas recovery factors are about 54, 67 and 84.6 percent respectively. The condensate recovery in this case is about 46, 52.5 and 59 Mscm after 25, 32 and 60 years respectively. The condensate recovery factor will be about 39.4, 44.9 and 50.5 percent respectively. Figures 11 and 12 show the result of prediction case-1.

Case-2: This case represents the continuation of gas production according to plan from 10 gas production wells and recycling. For the purpose of recycling 10 injector and 10 new producers were defined in the model. The injected gas is dry gas. In fact the condensate from 10 new gas production wells was separated and separated dry gas was injected by 10 new injectors into reservoir. The gas and condensate production was predicted in this scenario and compared with base case. Figures 13 to 21 show the result of this study. As figure-13 shows the gas plateau period in case of recycling decreases about 3 years because of well interference. Figure-14 compares the condensate production in both cases. Condensate recovery increases about 22 MMSTB after 25 years. Figures 15 to 17 show reservoir pressure, Bottom hole pressure and tubing head pressure. The tubing head pressure is in line with average measured tubing head pressure. The predicted BHP shows the effect of condensate drop out. As condensate drops out in the reservoir the pressure difference between bottom hole pressure and reservoir pressure increases. Figure-18 shows final pressure distribution in reservoir. Figures 19 to 21 show important phenomena. As figures show in the gas injected region the final remaining condensate saturation is much less than other regions, which is the effect of higher pressure and less condensate drop out.

9-Conclusion and Recommendation

9-1-Conclusions

The main conclusions of this study are as follows:

- Recycling can increase huge amount of condensate production in South Pars gas reservoir. The estimated potential for the area under study with original gas in place of 573 BScm is 22 MMSTB of condensate in 25 years. The actual recoverable condensate can be predicted in the full field simulation study with detail definition of rock properties and reservoir fracturing.

- The mentioned potential for the total field is about 3.2 MMMSTB

-The gas recovery factor (with the assumed production rates) after 25, 32 and 60 years with the final THP of 40 Bars are 54, 67 and 84.6 percent respectively.

- The condensate recovery factor in base case (with the assumed production rates) after 25, 32 and 60 years are 39.4, 44.9 and 50.5 percent. The condensate recovery factors in gas recycling case are 56, 62 and 67.6 percent respectively.

-Recycling is useful for the period of 25 years and after that period it has no further effect because of gas breakthrough.

-Time is very important factor. Therefore the recycling should start as soon as possible, after detailed full field simulation study.

9-2- Recommendations

The main recommendations are as follows:

-Performing Full field 3D simulation study using all of the available static and dynamic reservoir data.

-Study the effect of alternative patterns on condensate recovery

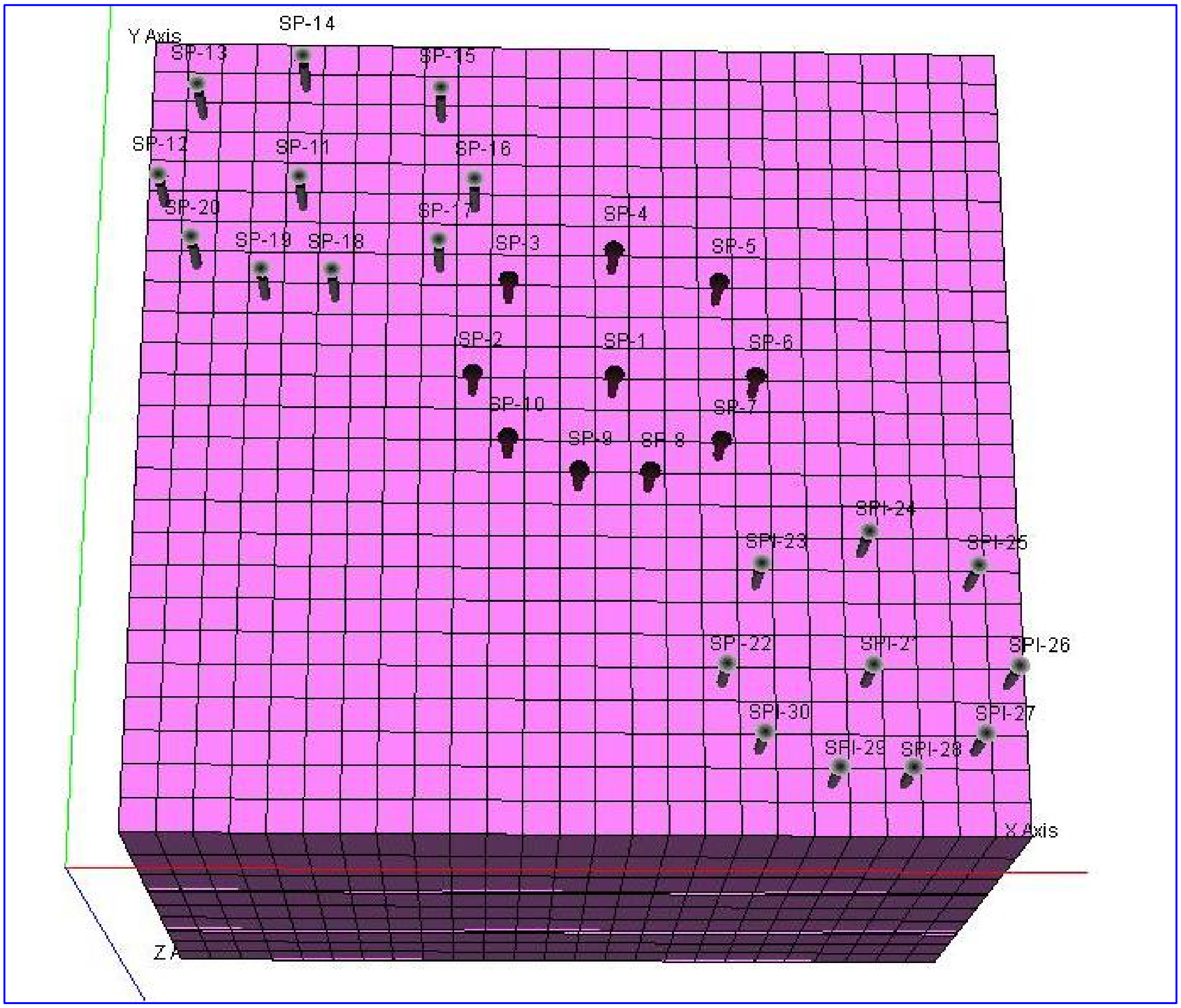
-Performing fracture study to implement its result in the simulation study to find out the effect of fracturing in gas breakthrough.

-Running FMI or FMS log.

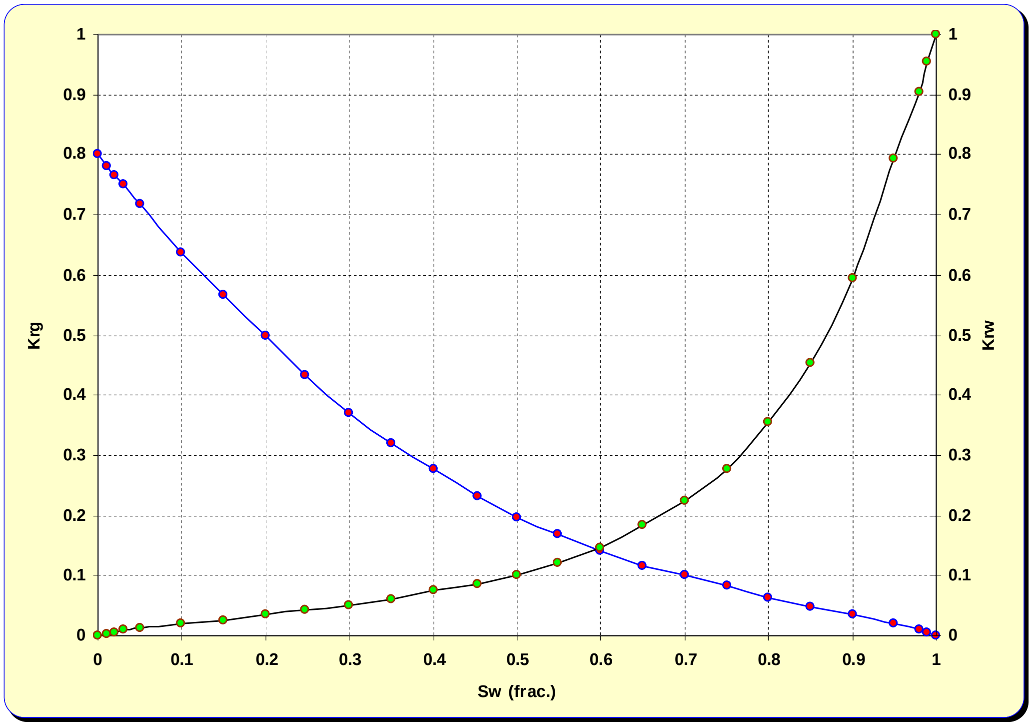
-Performing Core and SCAL tests.

-Performing Transient well tests.

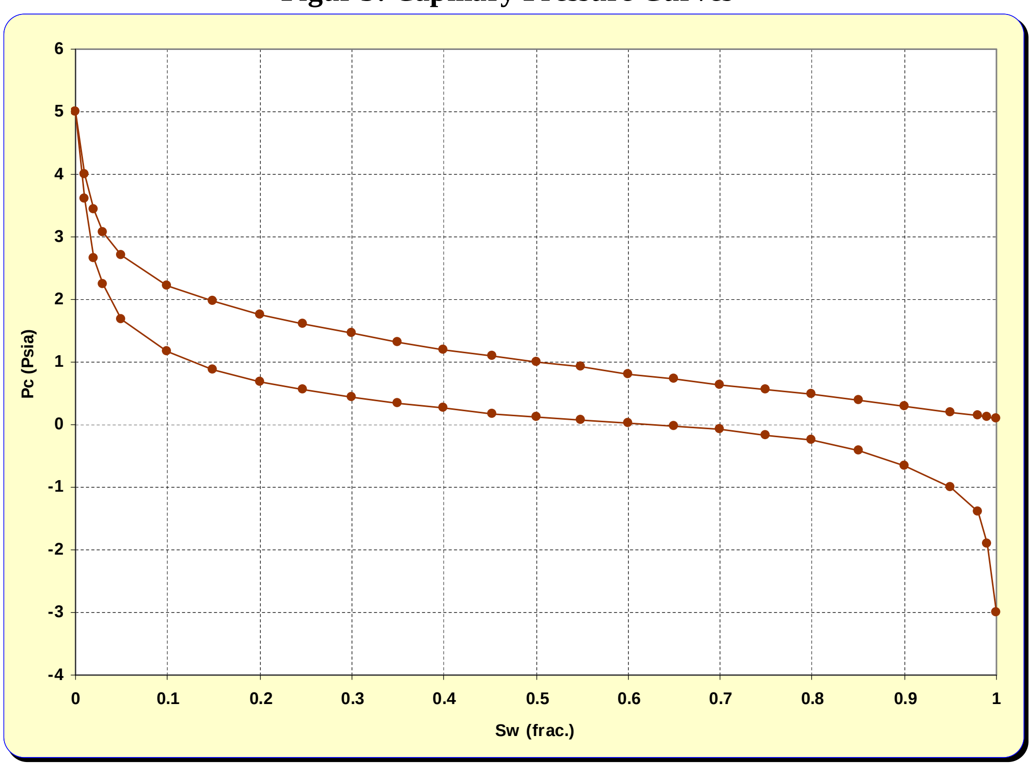
Figur 1: 3D Grid



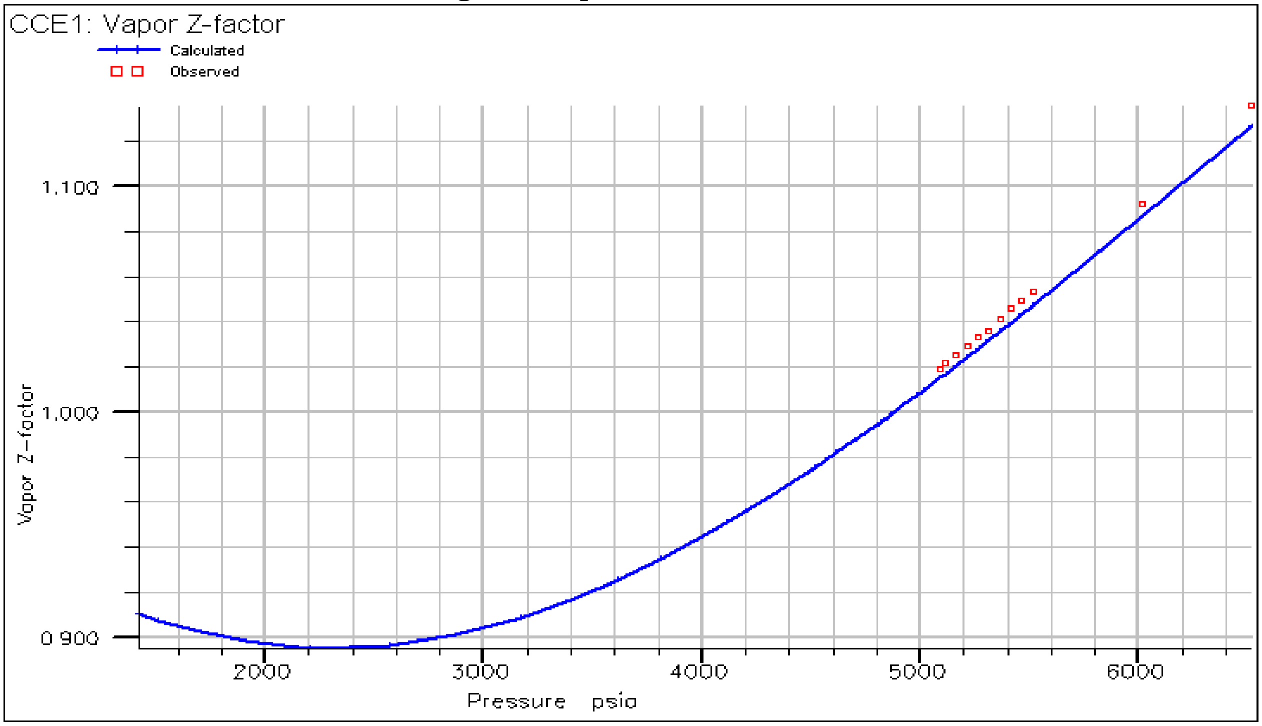
Figur 2: Relative Permeability Curves



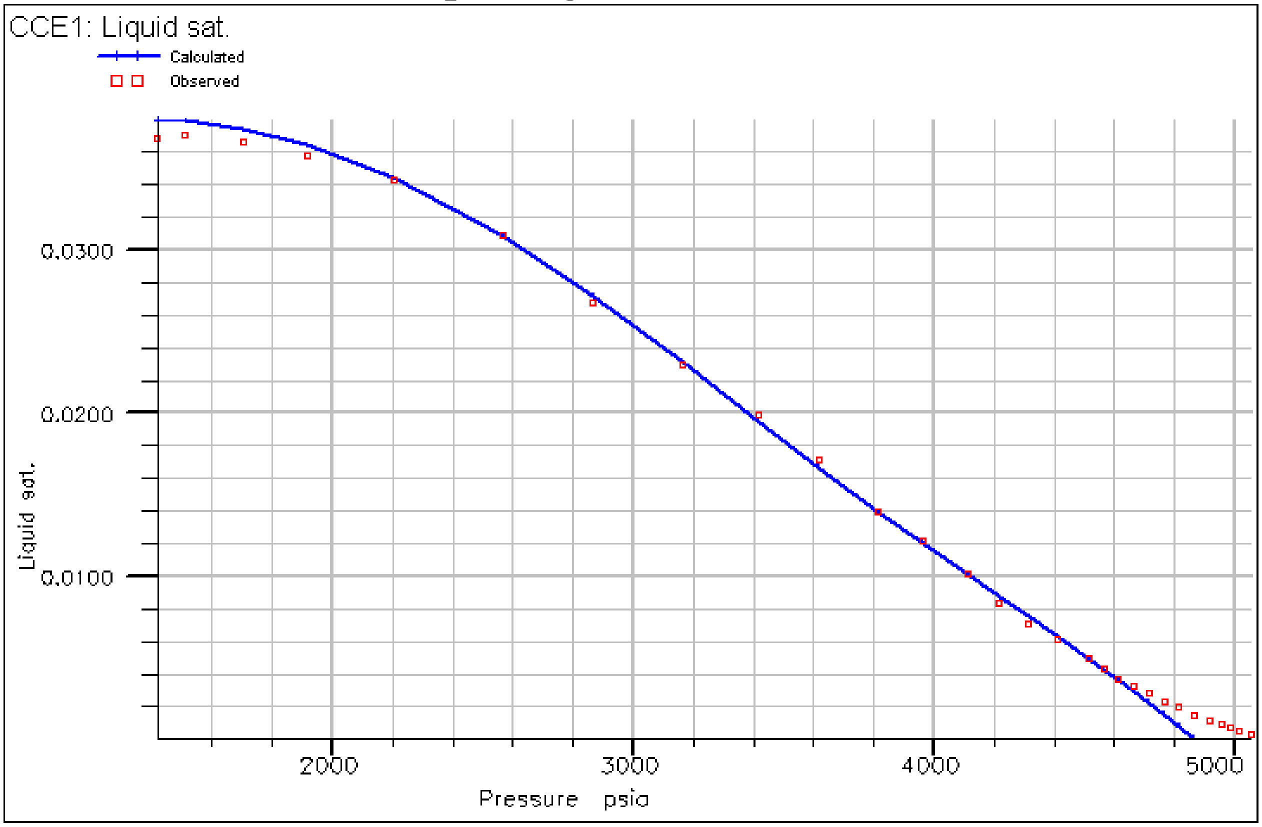
Figur 3: Capillary Pressure Curves



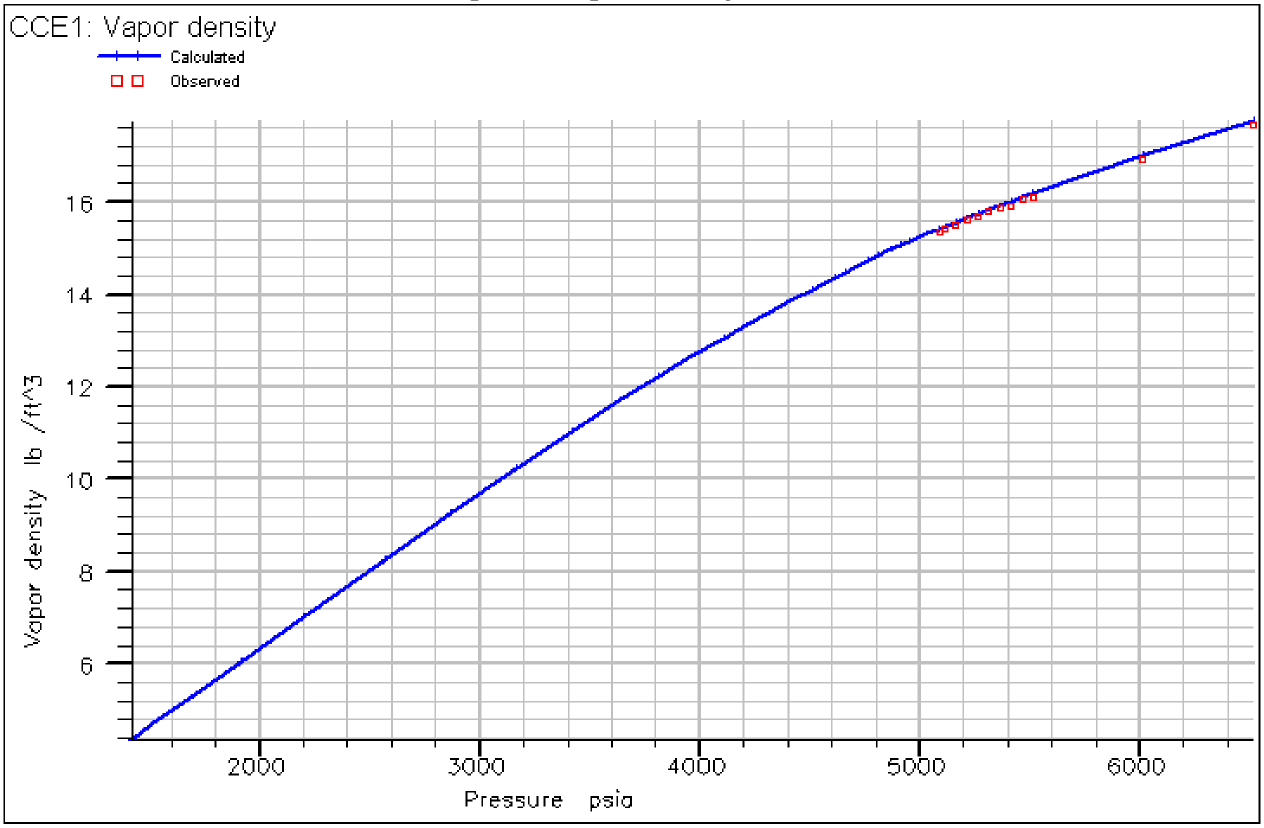
Figur 4: Vapor Z -factor,CCE



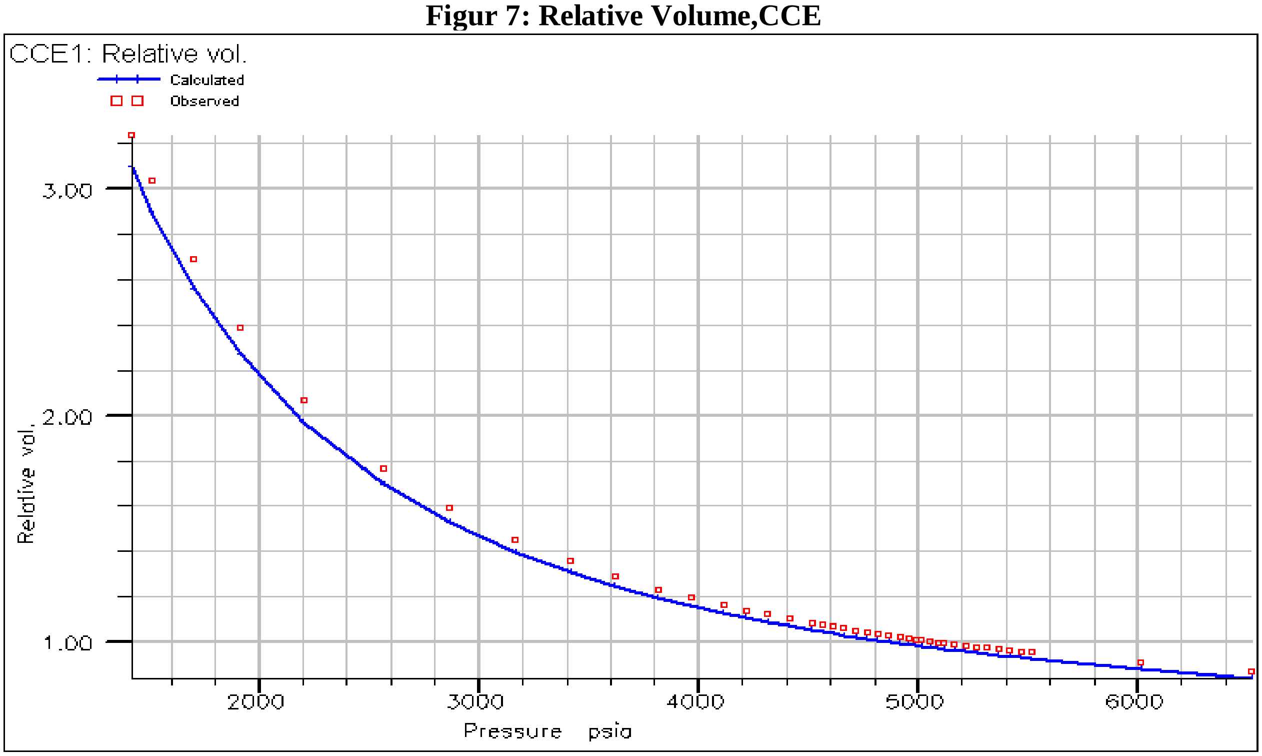
Figur 5: Liquid Saturation,CCE



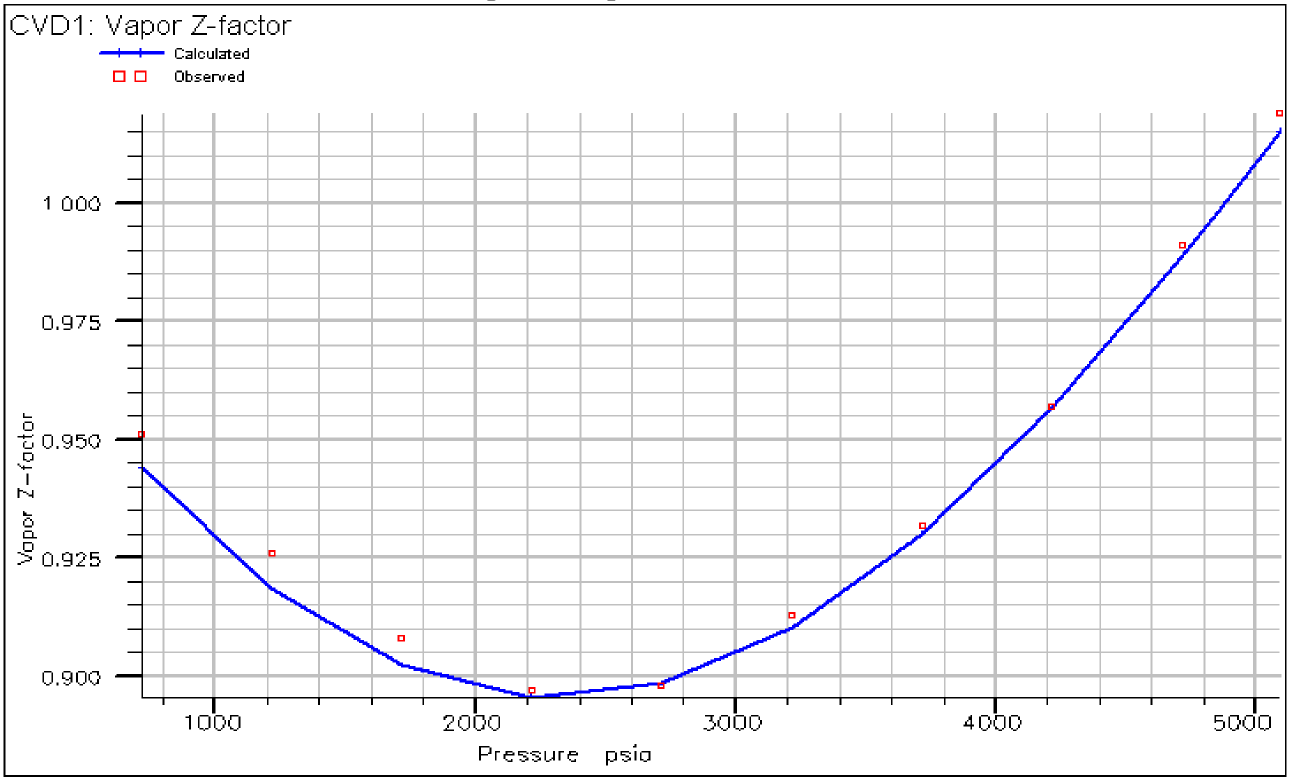
Figur 6: Vapor Density,CCE



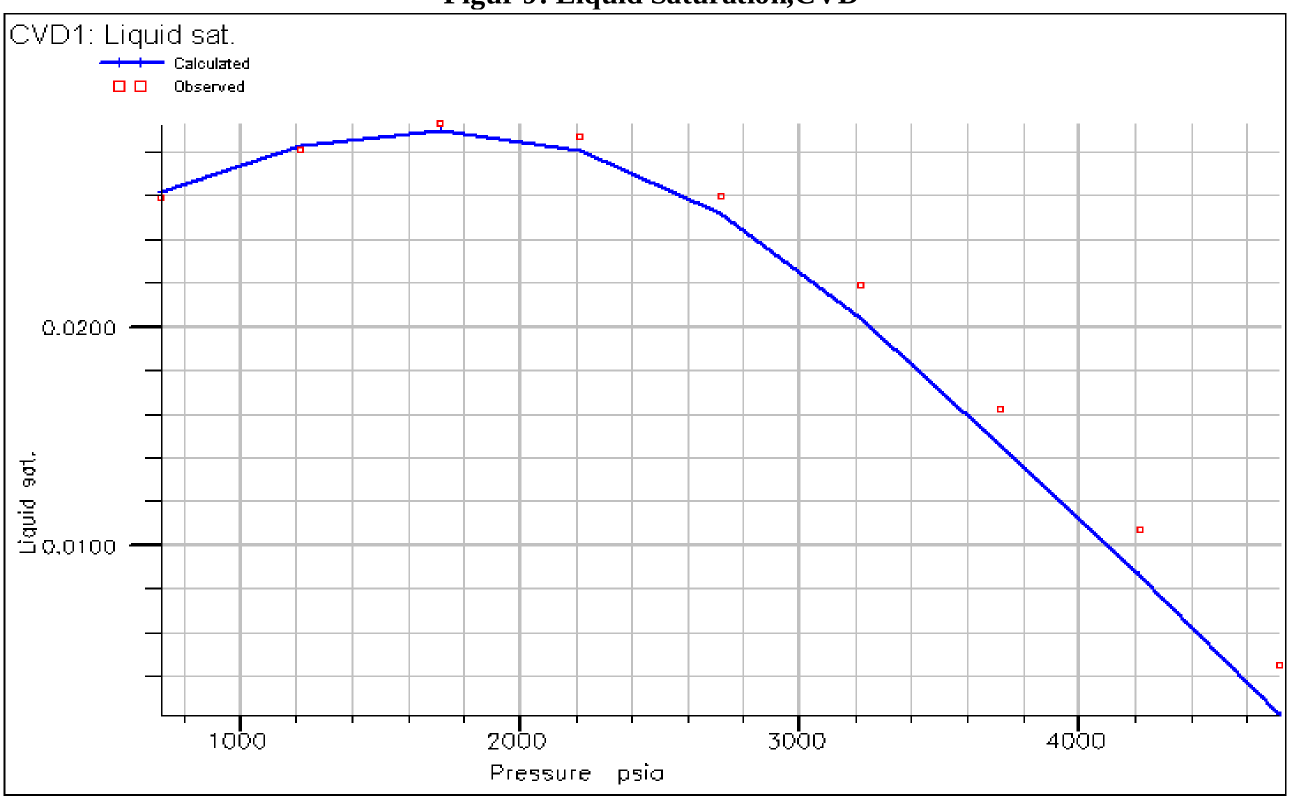
Figur 7: Relative Volume,CCE



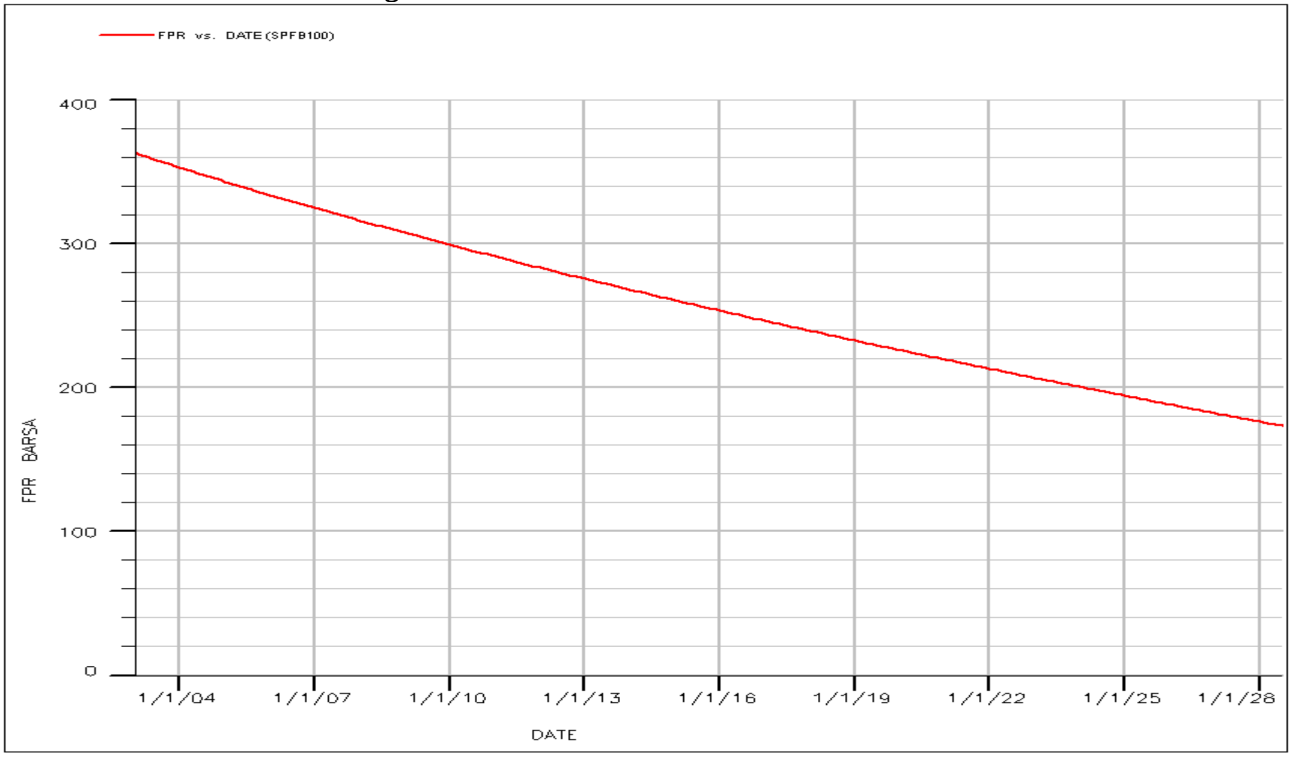
Figur 8: Vapor Z -factor,CVD



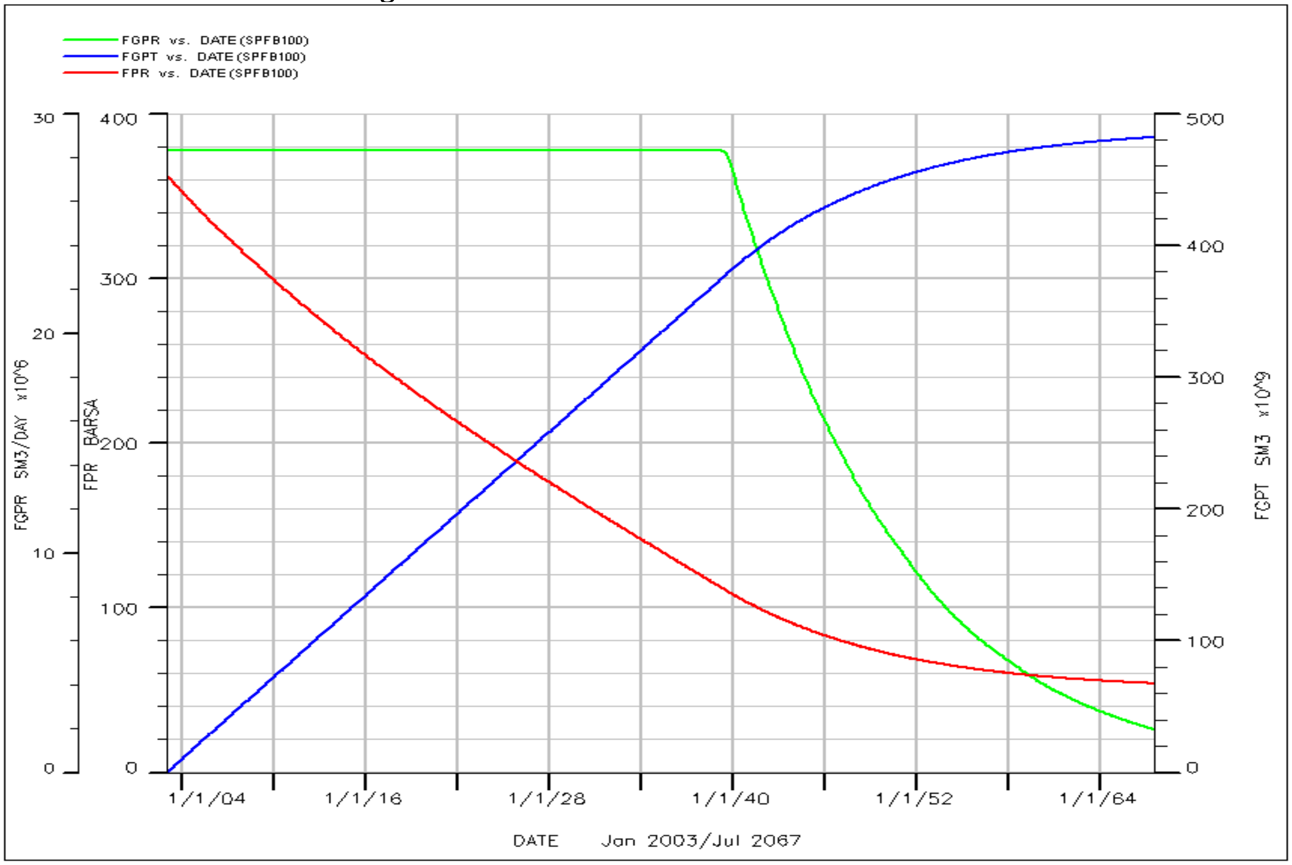
Figur 9: Liquid Saturation,CVD



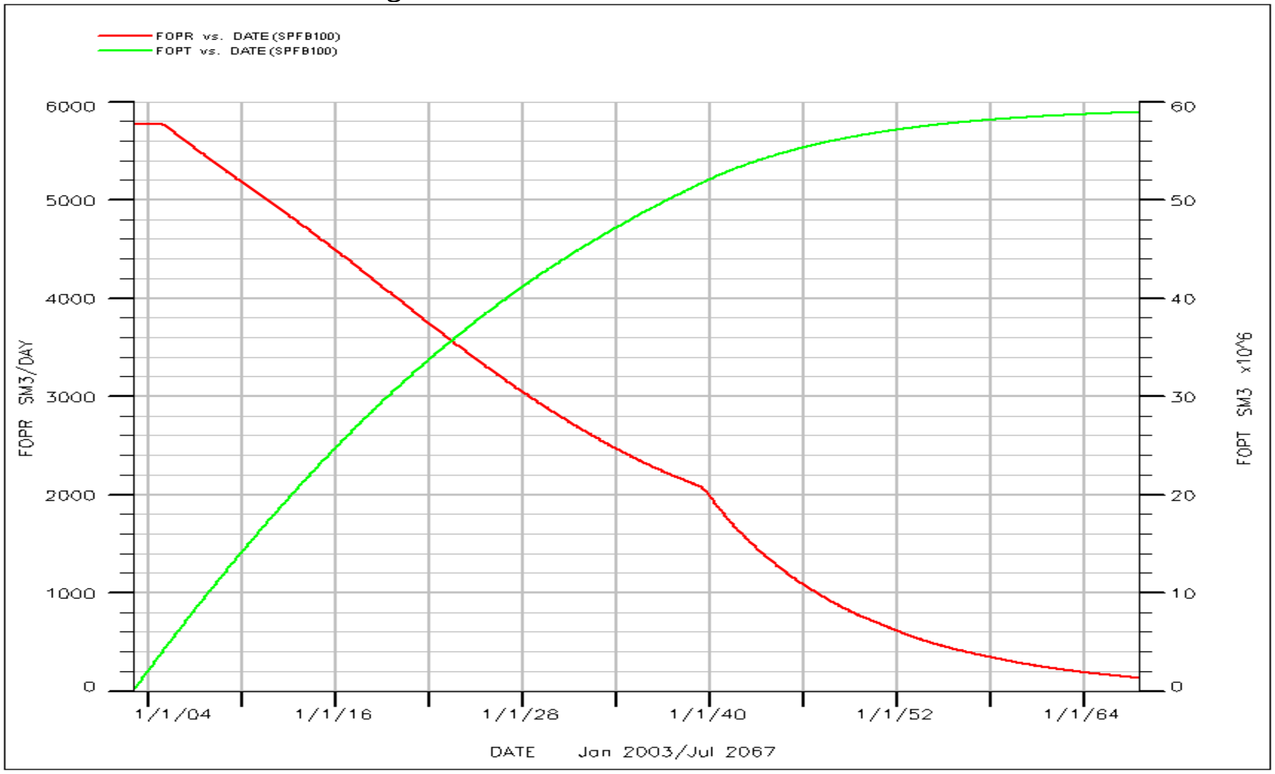
Figur 10: Base Case Field Pressure Prediction



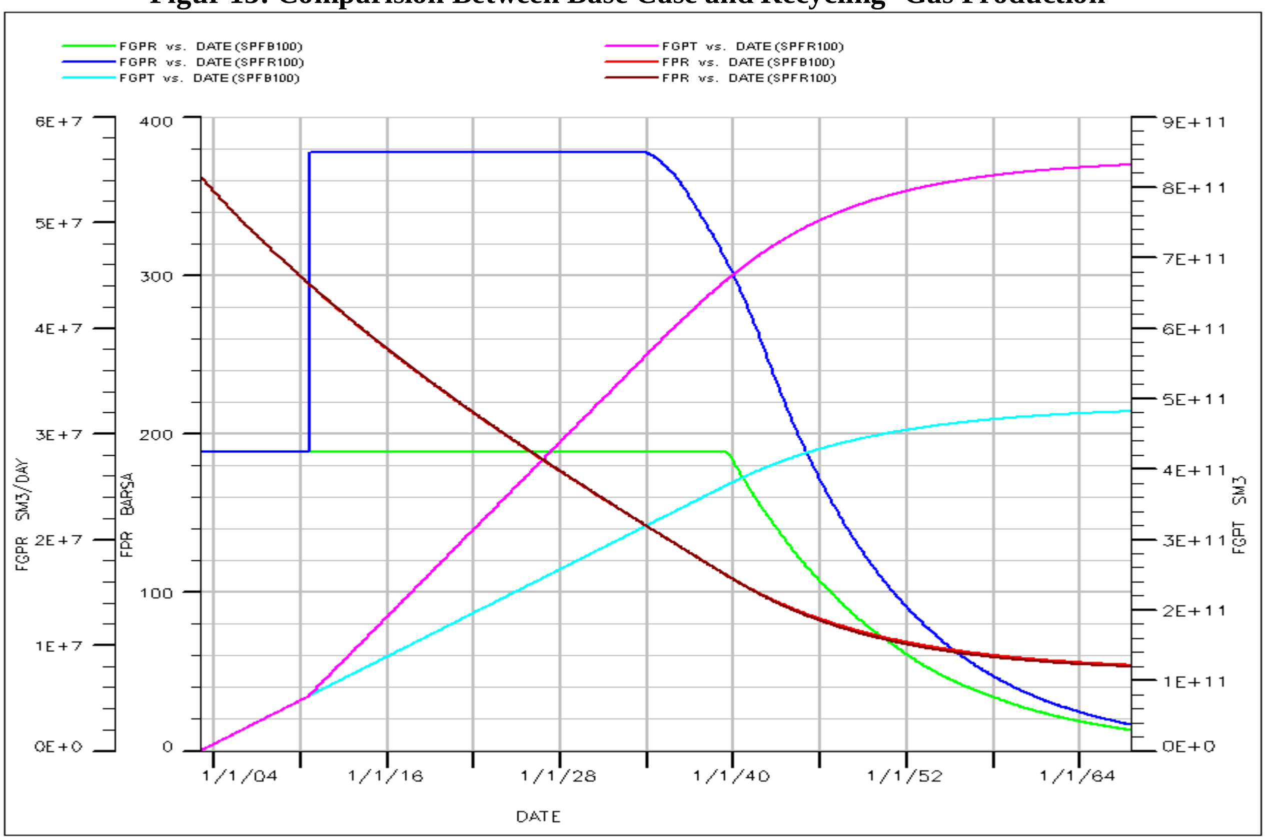
Figur 11: Base Case Gas ProductionPrediction



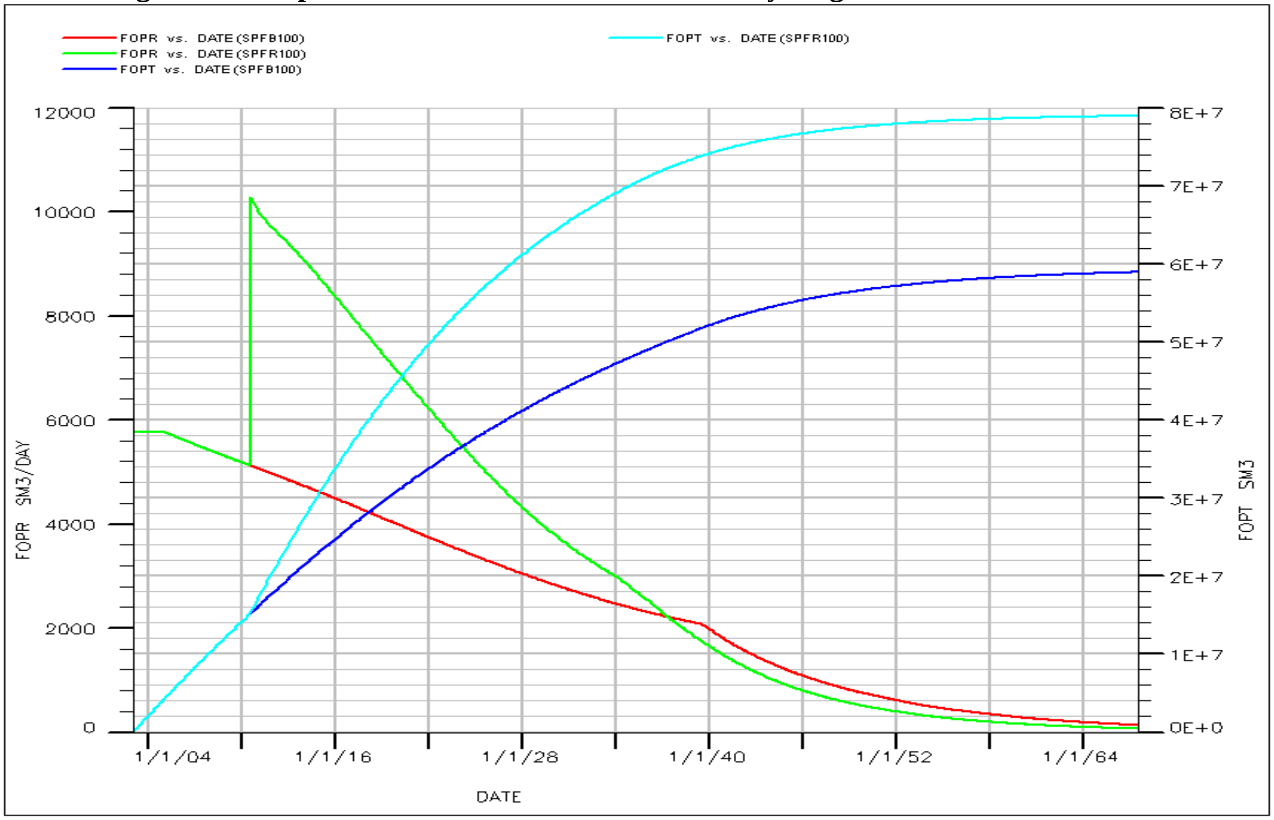
Figur 12: Base Case Condensate Prediction



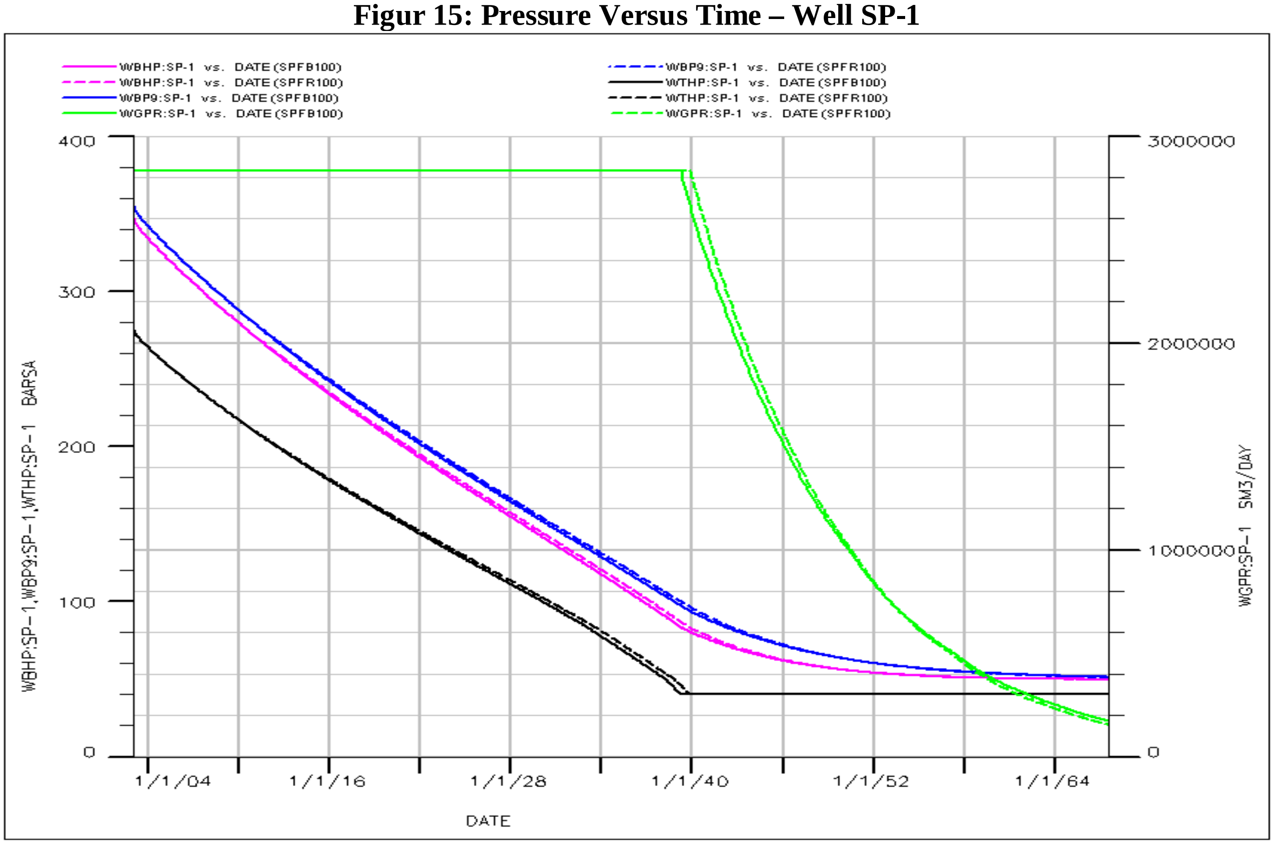
Figur 13: Comparision Between Base Case and Recycling- Gas Production



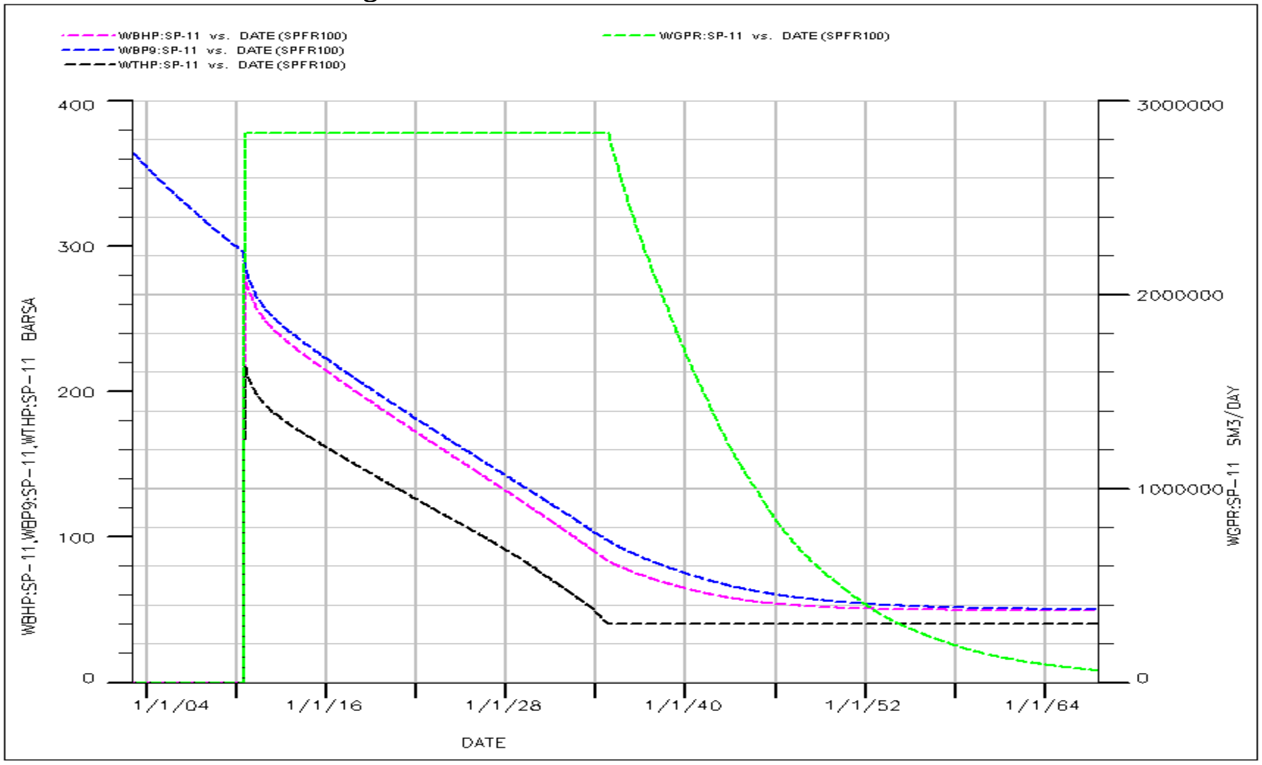
Figur 14: Comparision Between Base Case and Recycling- Condensate Production



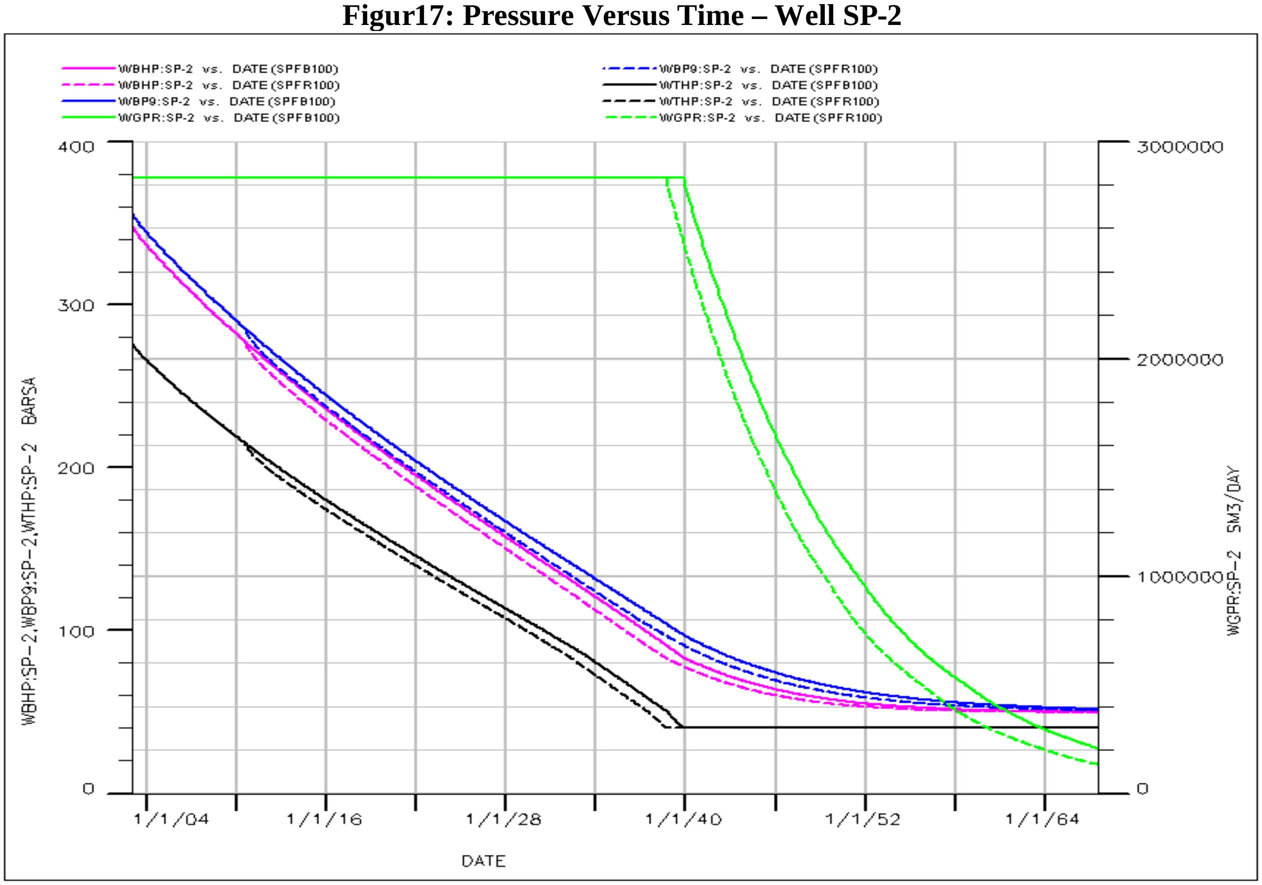
Figur 15: Pressure Versus Time – Well SP-1



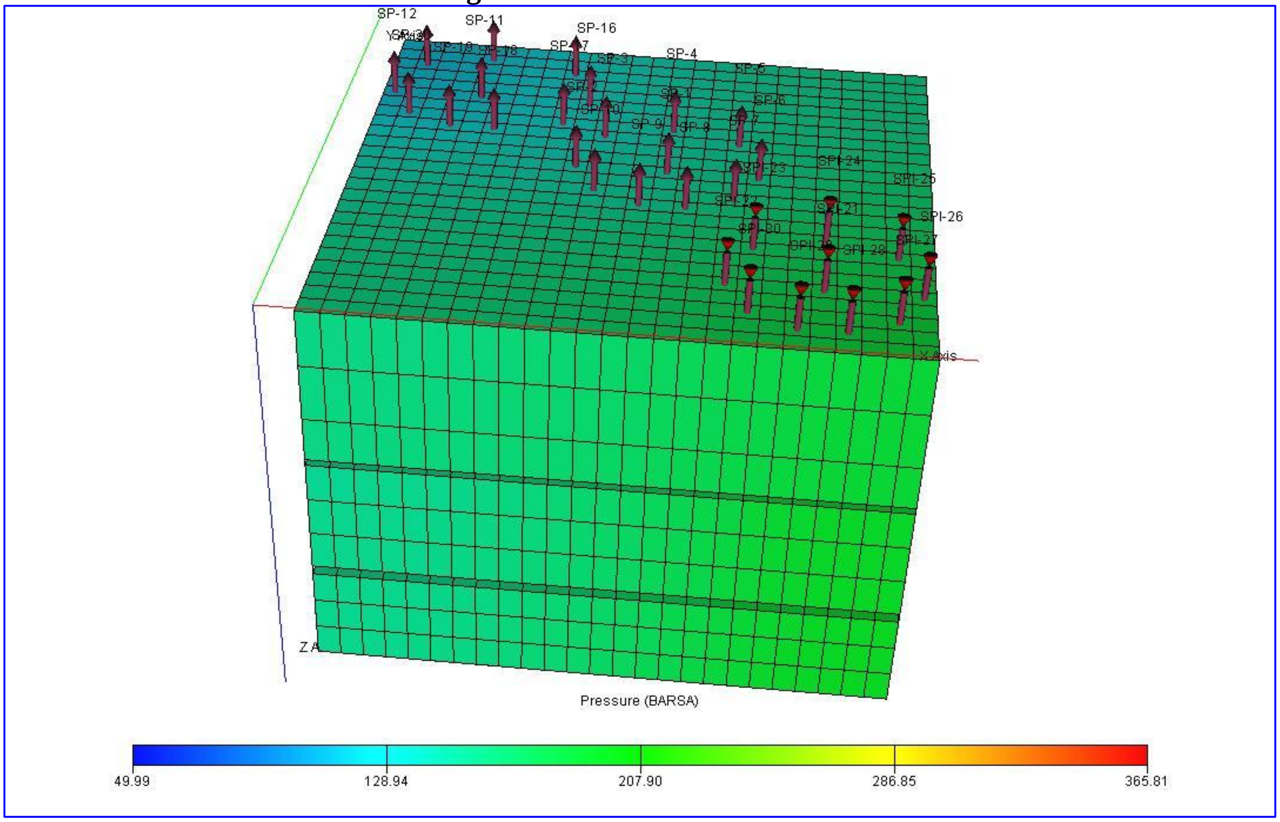
Figur16: Pressure Versus Time – Well SP-11



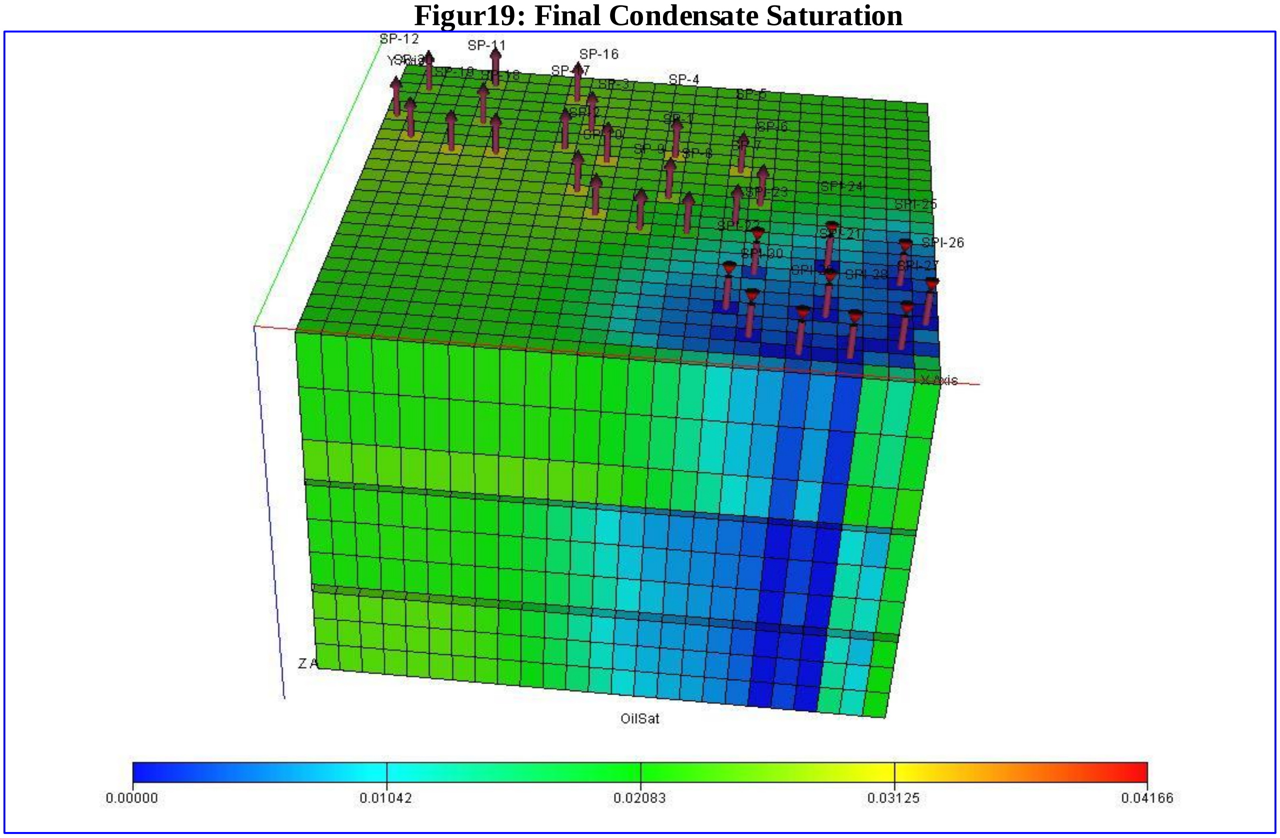
Figur17: Pressure Versus Time – Well SP-2



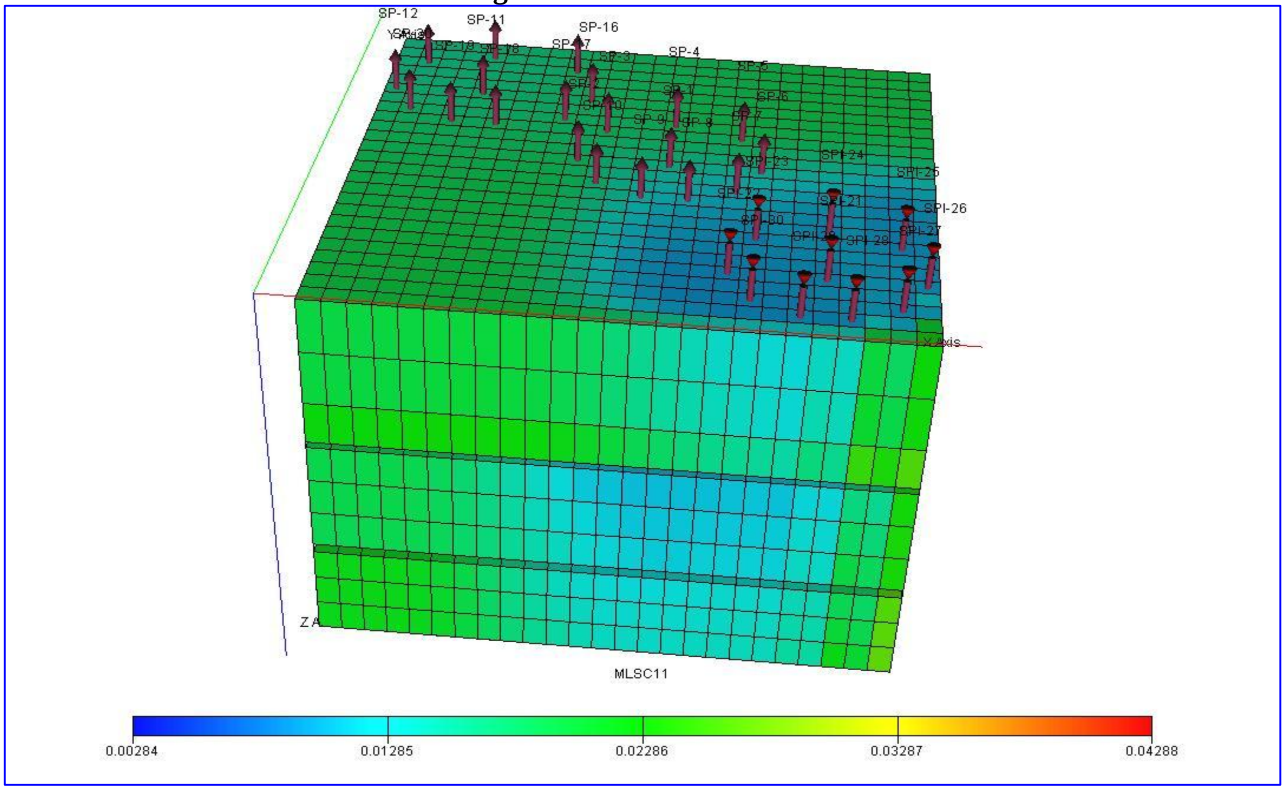
Figur18: Final Reservoir Pressure



Figur19: Final Condensate Saturation



Figur20: Final C6 Distribution



Figur21: Final C7 Distribution