STM JOURNALS

Journal of Offshore Structure and Technology

Volume 1, Issue 1
www.stmjournals.com

Integrated Production Modeling an Asset for Designing a Development Program of a Field: A Case Study

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Abstract

Current challenging scenario of environment and technologies causing Oil/Gas industry to focus on designing the development program of a field that is only possible with the help of Integrated Production modeling accurately. Managing the reservoirs through correct modeling can lead to best destinations. IPM provides key understanding of field from reservoir to separator conditions. It can provide best communication between wellbore and surface facilities Hence it can provide best economical visualization of an Oil/Gas field. The compilation is comprised of usage of IPM to design a development program of a field using real field data in order to find best way to produce well economically. Here we have focused on data obtained from a condensate field having PVT, well test, well logs and production history to design a field development program including the transfer of the size and function of the bare model sensitivity analysis, which provides a variety of media stored in the pressure distribution profiles based on both the production and its position through IPM Software. Our focusing criteria were to gather data from a field, summarized it through best methods, run different iterative methods to correct some problems in the field and summarize it. Hence this activity enabled us to come with awareness of different problems effecting overall well performance and their solutions. We have done our best to utilize our skills to design a field development program using software skills.

Keywords: *Production, reservoir simulation, sensitivity analysis*

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AIMS AND OBJECTIVES FOR CASE STUDY EVALUATION

The aim of our project was to develop a strategy for the development of a real small area of oil or gas field, which is at a very early stage of development utilizing Integrated Asset Modeling concept which includes a variety of building models from sub-surface reservoir surface. After much struggle we have been successful in getting a chance to learn one of the spaces XYZ, which is actually a newly developed gas condensate field. In this study, two models are created using the compositional fluid model and a good model modeling central analysis. The remaining chapters discuss the various steps of the models that generate their own software model checking and initial and current scenario, different results, and finally, the conclusion of all the results to come up with a better strategy is to optimize the production of field.

CHARACTERISTICS OF GAS CONDENSATE RESERVOIRS

Opening hours, click typical condensate gas reservoirs can be above or near the critical pressure. At this stage, there is only one phase of gas. However, production is carried out, is the loss of pressure and tilt the bottom hole pressure and flow falls below the dew point of the liquid hydrocarbons in the liquid phase is formed[1, 2]. The result is condensation degrades the fluid around the oil phase, reducing the efficiency of the gas permeability of the borehole. Liquid drop occurs near the well diameter and spreads radially away from the well, along with a fall in pressure [3, 4]. Understanding the multi-phase flow phenomena in reservoirs is the main characteristics of condensed drop were blocking effect. Therefore, bearing in mind that the above composition model was created to describe the changes in the composition of the fluid during the full production history of the wells. Short natural gas reservoirs generally exhibit deteriorating relations between the oil and gas 3000–50000 SCF/ STB and specific liquid between 40 and 60 API [5].

FLUID CHARACTERIZATION (PVT MODELING)

To develop any model either reservoir, well or surface, we need to feed the representative reservoir fluid data into the required software. That's why before proceeding towards any type of modeling; we need to generate the PVT properties of the reservoir fluid. This process is known as PVT modeling and is carried out in either Pvti module by Schlumberger or PVTP software by Petroleum Experts. For our study, PVTP software is being used. PVTP provides the basic of compositional model for reservoir fluids. As our fluid composition was that of condensate so it was better to go by detailed compositional model through PVTP involving each fractions weightage/percentage [6].

The PVT package can be used as a stand-alone analytical tool, or can be used to generate tables of fluid properties, reduced compositions or matched parameters (Tc, P, ω Volume Shift Parameters and Binary Interaction Coefficients) for other applications such as reservoir simulators, well analysis packages, up to production process simulator.
As the industry integrates their reservoir, production wells, surface gathering network and process models together having consistent PVT characterizations that can be used at all levels in the system is fundamental. A reservoir engineer will typically have a characterization with up to five pseudo, while the process engineer wants to model each component. PVTP enables a representative characterization to be developed for both engineering needs [10, 11].

- The ability to manipulate and predict compositional changes using two distinct methodologies.
- The Black Oil Model.
- The Equation of State Model – EoS.

First of all the composition of respective fluid was fed into software as an input which contained the name of each fraction (e.g. C1, C2, C3 N2 CO_2) and there respective molar composition in percent. Till C7+, the composition was entered as an input and then it was further splitted in the software to get the better results as shown in the Figure 1.6.

Thus, compositional model was prepared on the basis of the entered composition and properties like critical pressure, critical temperature, eccentric factor, critical volume, etc. for each component separately using the Peng-Robinson equation of state.

At initial every fluid model will not behave as the actual one and therefore there is the need of matching. This is done by entering the lab data so that model should not divert away and behave as closely as it can as a real reservoir fluid.

Two main tests performed on fluid in laboratory are constant composition expansion (CCE) test and Constant volume depletion (CVD) test.

The main purpose of constant composition test is to calculate saturation pressure of fluid at reservoir temperature. The fluid is normally flashed above the reservoir pressure and pressure is dropped at constant temperature by releasing mercury from PV cell [7,8].

The increase in gas volume is noted at each decrement of pressure till the liquid forms here it should be noted that the composition of fluid does not change because no any component is retrieved.

In the CVD test, the starting pressure is the saturation pressure. Then the pressure is constantly decreased and liquid drop-out is observed at each stage. During the test, at various stages, there is change in volume of the cell due to reduction in pressure and liquid drop-out, therefore the gas is being flashed out from the PVT cell to make the volume constant in the cell at each stage [12].

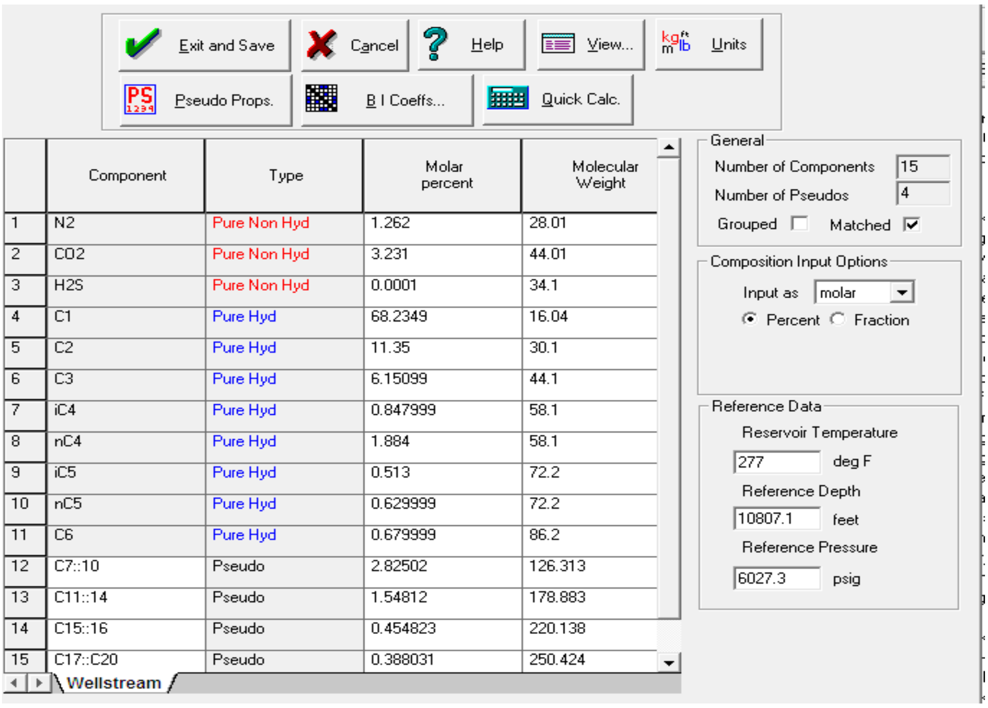
The test data from laboratory analysis was fed into PVTP software to observe physical changes of volume of fluid at various conditions of pressure and temperature and to match the fluid model. Various parameters like liquid drop-out during the CCE and CVD tests, Vapor Z-factor during both tests and relative volume during CCE test were fed as the lab data into the software.

As we suspected, there was an error between the calculated compositional model and laboratory analysis.

Regression was then performed several times to compensate for errors and matching the compositional model. Some of the output charts after the regression from the PVTP are shown in the Figures (1.2–1.6) respectively:

Several graphs are generated with the help of software modelling and those graphs are represented over here in order to evaluate the capability of a well either it is producible or not. These graphs after sensitivity also suggest the major helpful points to improve the methods to recover the reservoir economically.

The results after the regression were quite satisfactory as shown in the above figures and the overall error was found to be less than 10% which is the basic requirement of a valid.



	Component	Type	Molar percent	Molecular Weight
1	N2	Pure Non Hyd	1.262	28.01
2	CO2	Pure Non Hyd	3.231	44.01
3	H2S	Pure Non Hyd	0.0001	34.1
4	C1	Pure Hyd	68.2349	16.04
5	C2	Pure Hyd	11.35	30.1
6	C3	Pure Hyd	6.15099	44.1
7	iC4	Pure Hyd	0.847999	58.1
8	nC4	Pure Hyd	1.884	58.1
9	iC5	Pure Hyd	0.513	72.2
10	nC5	Pure Hyd	0.629999	72.2
11	C6	Pure Hyd	0.679999	86.2
12	C7::10	Pseudo	2.82502	126.313
13	C11::14	Pseudo	1.54812	178.883
14	C15::16	Pseudo	0.454823	220.138
15	C17::C20	Pseudo	0.388031	250.424

Fig. 1.1: *The Composition of the Reservoir Fluid.*

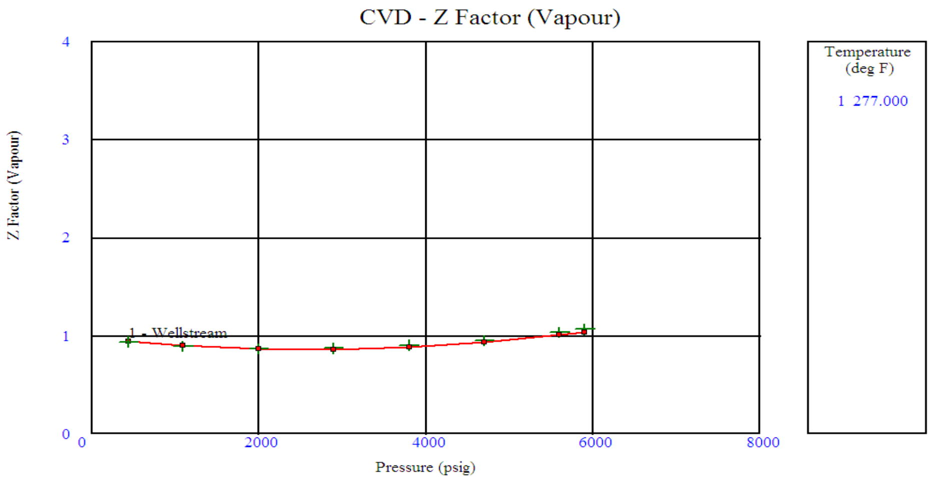


Fig. 1.2: *Match of Cvd Vapor Z-Factor after Regression (Pvtp Plot).*

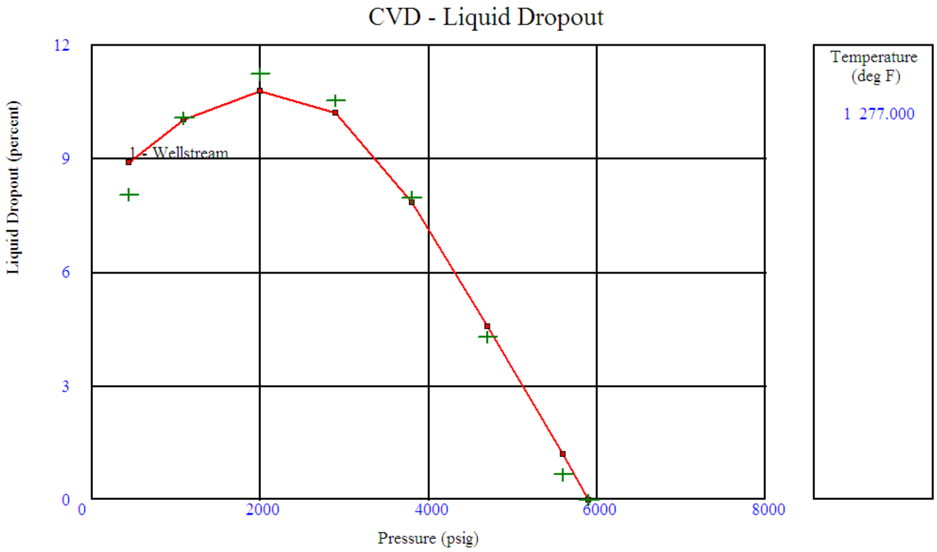


Fig. 1.3: *Match of Cvd Liquid Drop-out after Regression (Pvtp Plot).*

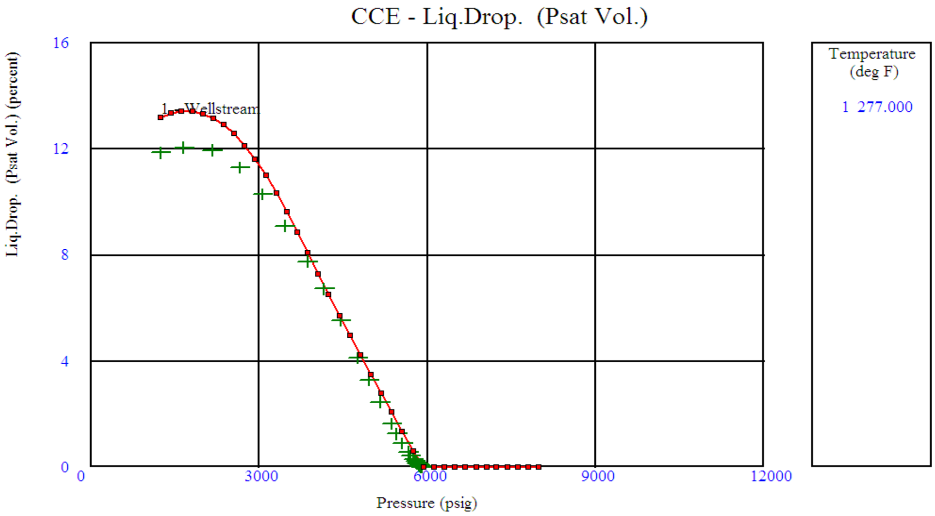


Fig. 1.4: *Showing the Match of Cce Liquid Drop-Out after Regression (Pvtp Plot).*

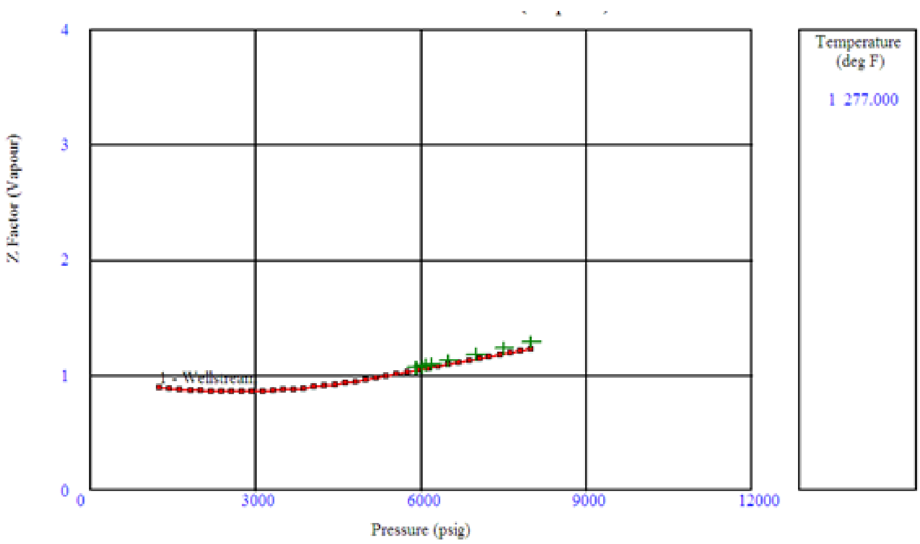


Fig. 1.5: *Match of Cce Relative Volume after Regression (Pvtp Plot).*

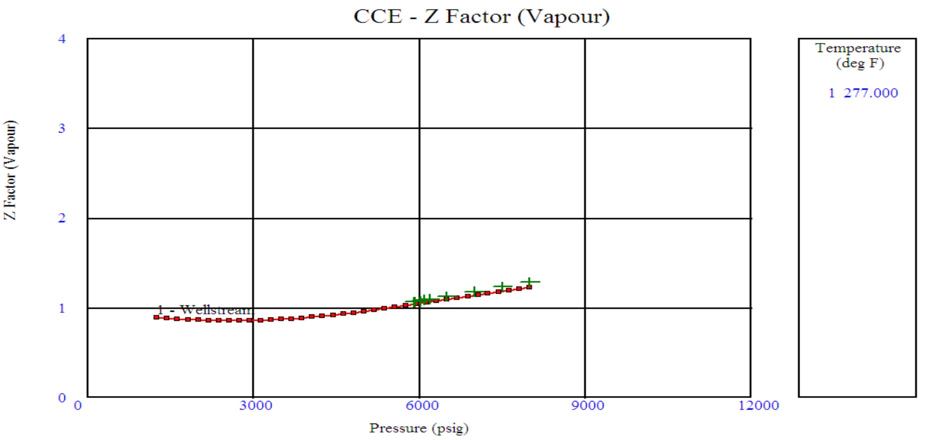


__Fig. 1.6:__ Match of Cce Vapor Z-Factor after Regression (Pvtp Plot).

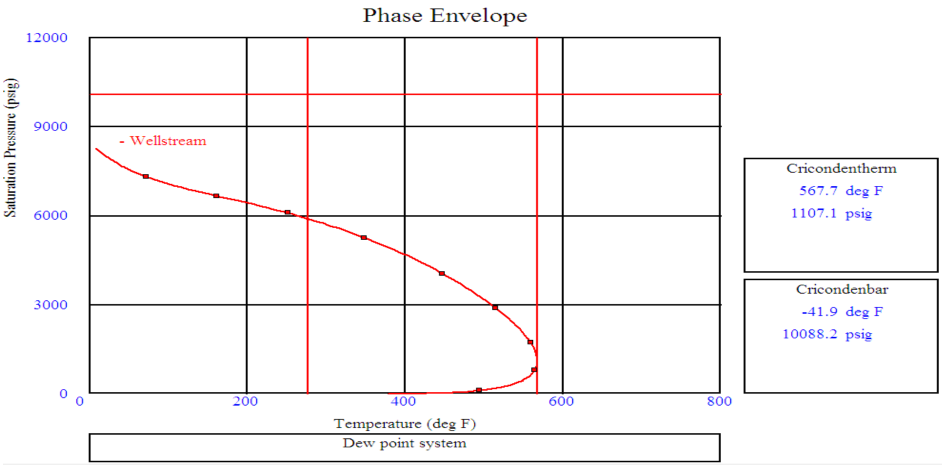


__Fig. 1.7:__ Phase Envelop of the Fluid System.

A STEP TO WELLBORE SCENARIO AND ITS MODELING

The major step of modeling a wellbore is done using prosper software which is a common tool used in oil industry which models naturally flowing oil, gas, condensate and artificial wells. This chapter shows our approach towards building a model of a natural flowing condensate well X1.

The basic task of the study is to find out the decision to be taken to enhance the production of a well when reservoir pressure has been declined. Before coming on to the task, let's have a look at the initial and the existing scenario of the well.

Initial Well Scenario

At initial condition, the pressure buildup and flow after flow tests were conducted on the well X1 whose results are shown in the Figures 1.8 and 1.9 respectively and the reservoir properties are shown in Figure 1.10.

At initial conditions using the above mentioned well test data an IPR model has been generated in prosper which is shown in the Figure 1.11. All the three test points fall on the IPR curve which indicates its validity.

After the IPR there is a need to generate the vertical lift performance (VLP) curve for the well. For this we need to select the appropriate VLP correlation so that the testing point can be matched in the VLP/IPR system. This is done in the VLP/IPR matching section where various VLP correlations are matched to select the best one [13–15]. The results of the VLP correlation comparison is shown in the Figure 1.12

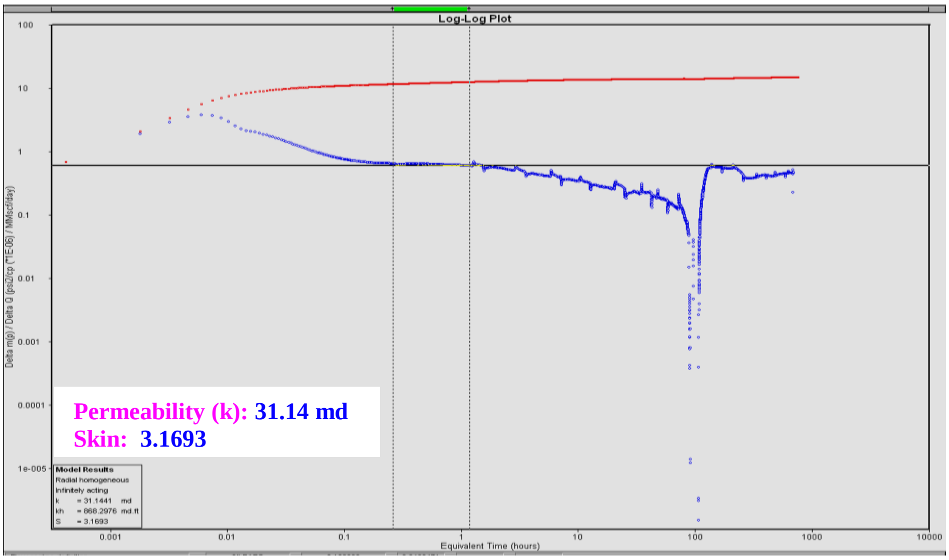


Fig. 1.8: *Initial PBU Test.*

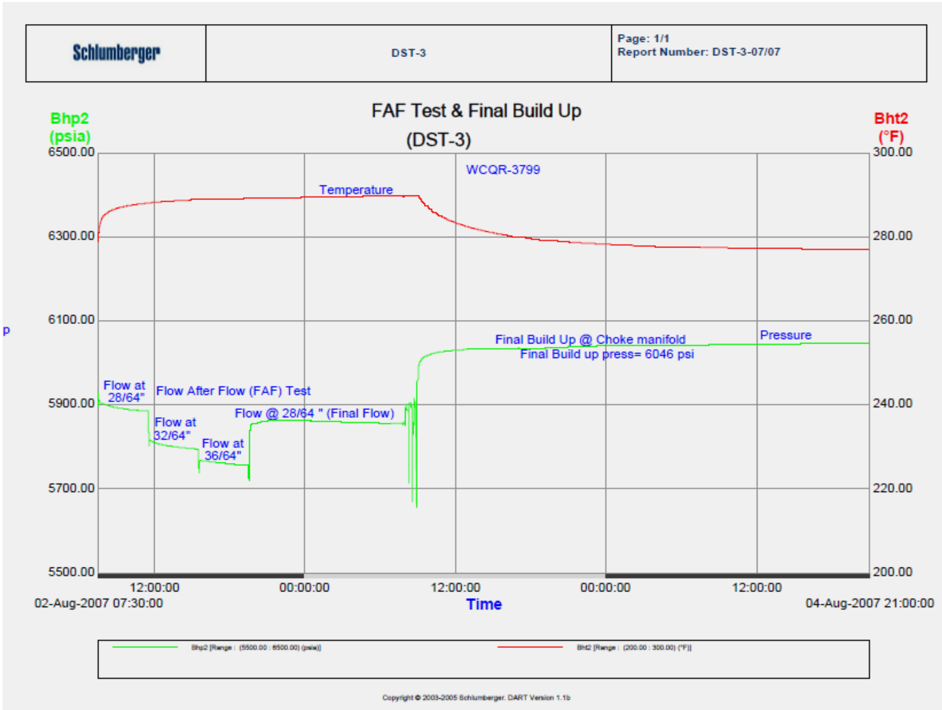


Fig. 1.9: *Initial Flow After Flow Test.*

Parameters	**Values**	**Units**
Permeability	31.14	md
Skin	3.17	
P*	6070.0	Psia
Final Build Up Pr	6042.0	Psia
C	0.00007914	MMscfd/Psi^2
n	0.8053	
AOF	98.16	MMscfd

Fig. 1.10: *Initial Reservoir Properties.*

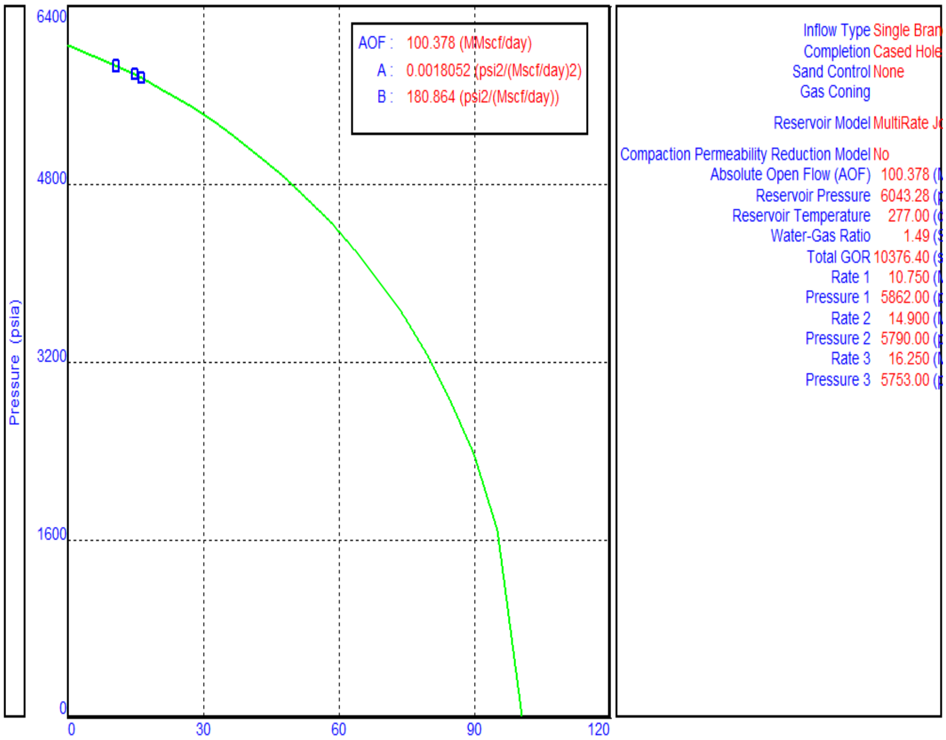


Fig 1.11: *Initial IPR (IPR Plot Multi-Rate Jones).*

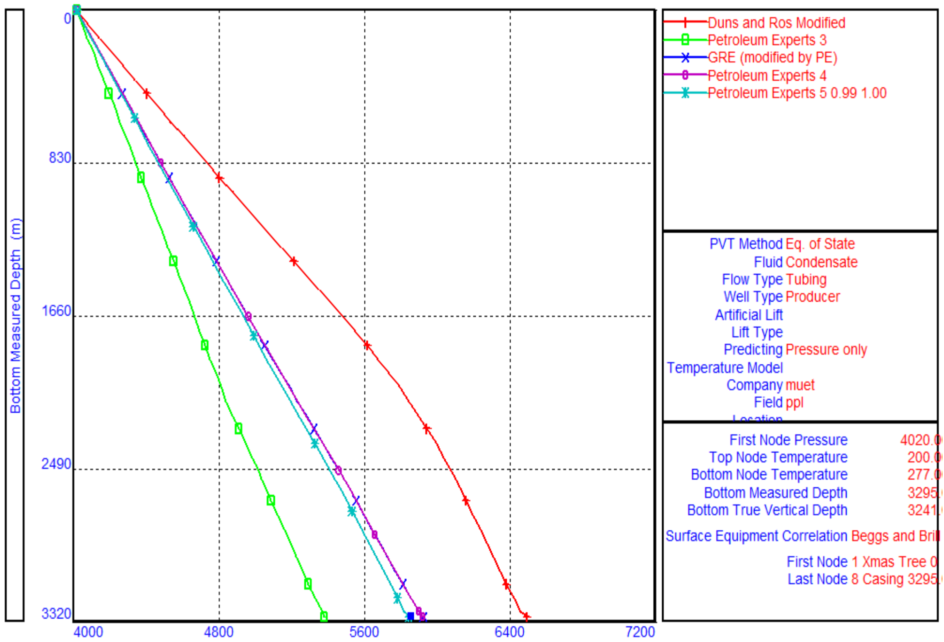


Fig 1.12: *Tubing Correlation Comparisons (Pressure Vs Measured Depth).*

The above figure shows that the Petroleum Experts (PE) 5 correlation is the best one which matches the required bottom hole flowing pressure. Using the PE 5 tubing correlation the VLP is generated and is being matched with the generated IPR and the intersection point is matched the entered test point as shown in the Figure 1.13. This matching shows the validity of our prosper model [16, 17].

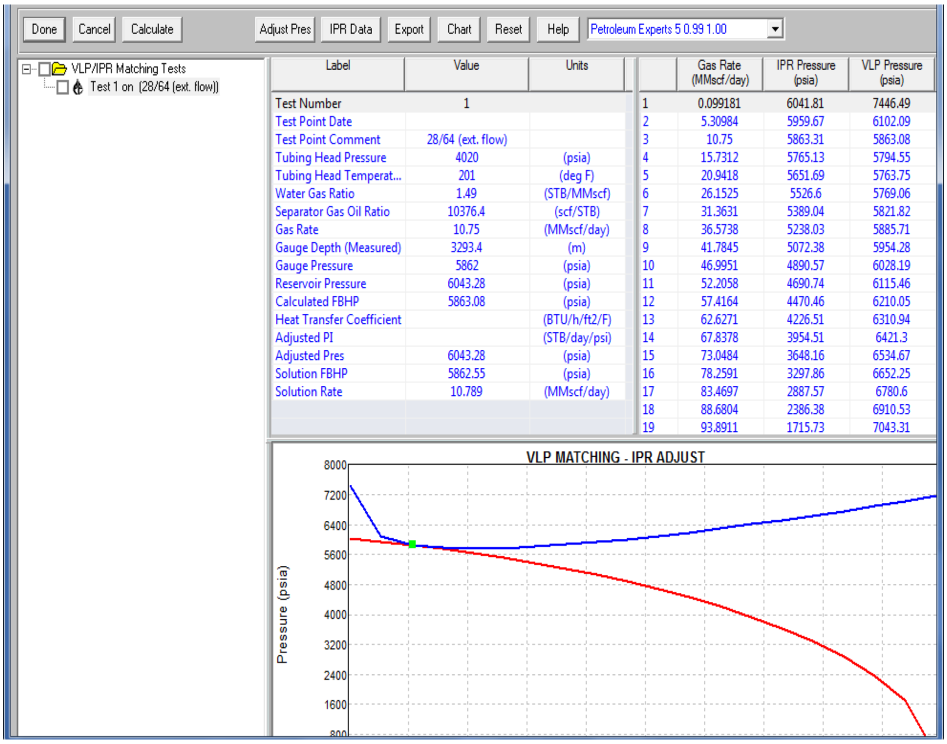


Fig. 1.13: *VLP / IPR System Match.*

Well Scenario (Latest PBU Match)

The well is actually gas condensate well and is producing the gas along with condensate and very little amount of water as shown in the production performance history in the figure below.

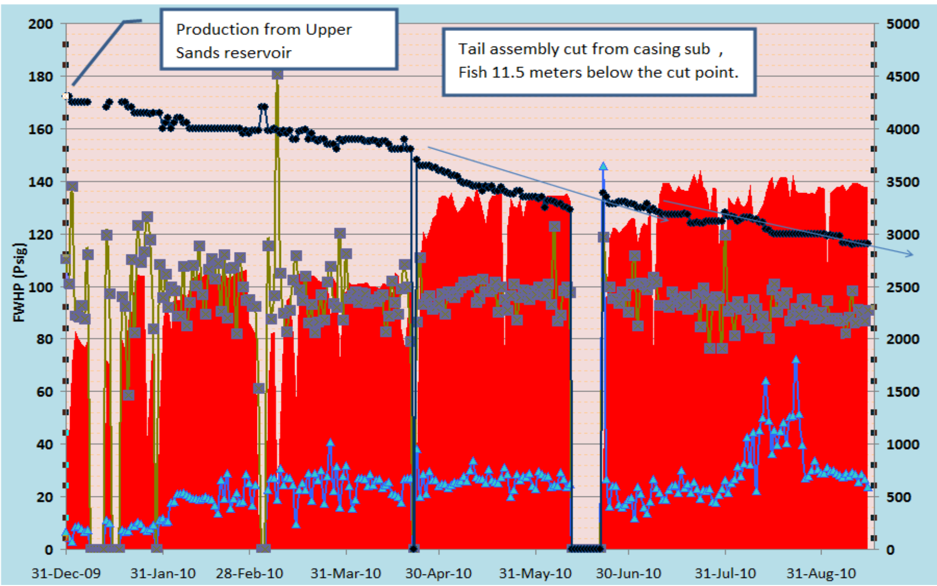


Fig. 1.14: *Production Performance History.*

The above figure shows the various types of parameters which are received as output from well. The water cut and GOR has remained fairly constant but wellhead pressure has been decreasing due to decrease in reservoir pressure during the well's life. The last PBU test conducted on the well shows that reservoir pressure has declined from the initial pressure of 6042 psia to 5414.7 psia. According to the current reservoir conditions, the existing VLP/IPR system has been generated using the same procedure as mentioned in the initial well scenario section and the result is shown in the Figure 1.15

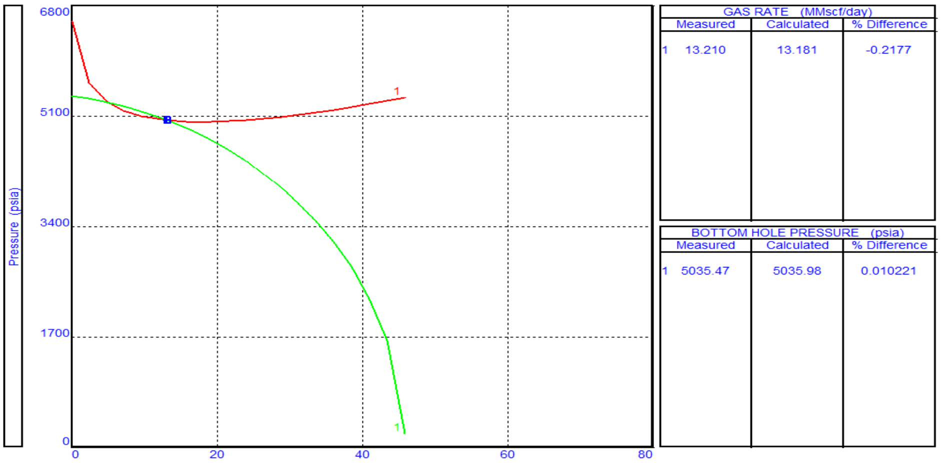


Fig. 1.15: *Existing VLP/IPR Match.*

AIM OF PROJECT AND DECISION TASK

What decision should be taken from available options to optimize the production of the well when reservoir pressure has been declined?

Based on the latest build up match we have to choose the best decision out of various available options to enhance the productivity by the help of Prosper. It is therefore different parameters need to be changed to measure their effect on productivity which we normally call sensitivity analysis. Some of these parameters are discussed below:

- Change in wellhead flowing pressure.
- Change of tubing size through work over job.
- Change in water gas ratio.
- Change in condensate gas ratio
- Scaling problem in the tubing

Sensitivity Analysis of Wellhead Flowing Pressure (FWHP)

The results for various sensitivities of "Top node pressure" or FWHP are shown in Figure 1.16 and the values are tabulated in the Table 1.1.

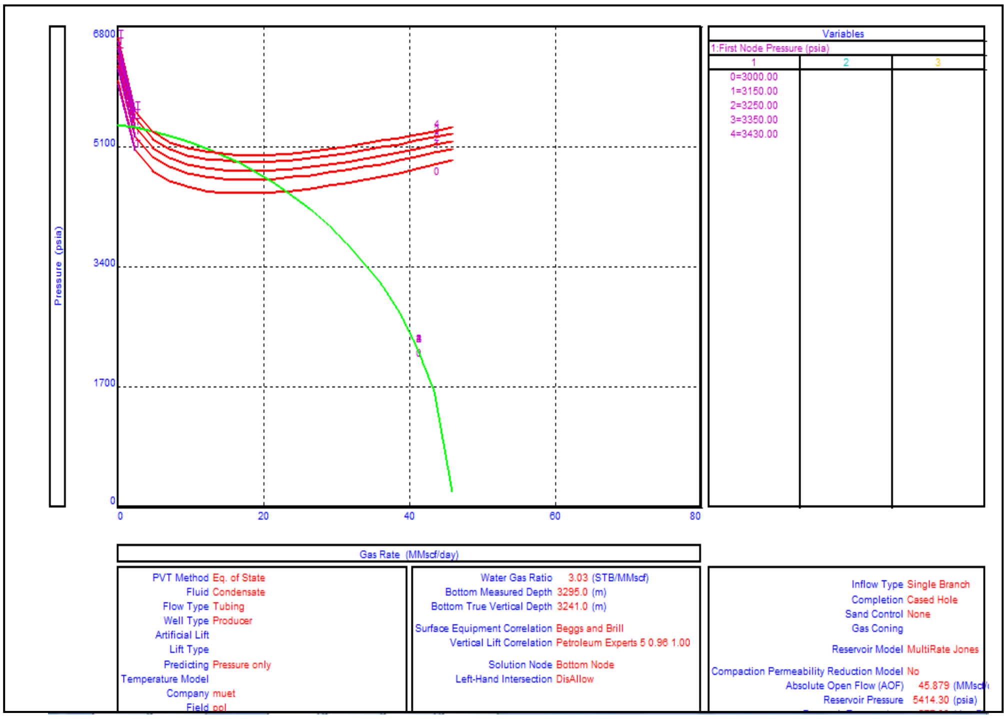


Fig. 1.16: *Sensitivity Analysis of Wellhead Flowing Pressure (System Plot).*

Table 1.1: *Iterative Results of Wellhead Flowing Pressure.*

S.No	FWHP	GAS RATE (MMSCFD)
0	3000	23.154
1	3150	20.643
2	3250	18.712
3	3350	16.443
4	3430	13.828

As the FWHP decreases, the Gas rate is increasing and the maximum rate is obtained at the lowest FWHP which is 23.154 MMSCFD.

Sensitivity Analysis of Tubing Size

Various sensitivities have been run using various tubing sizes and their results are summarized in the Figure 1.17 and the Table 1.2, respectively.

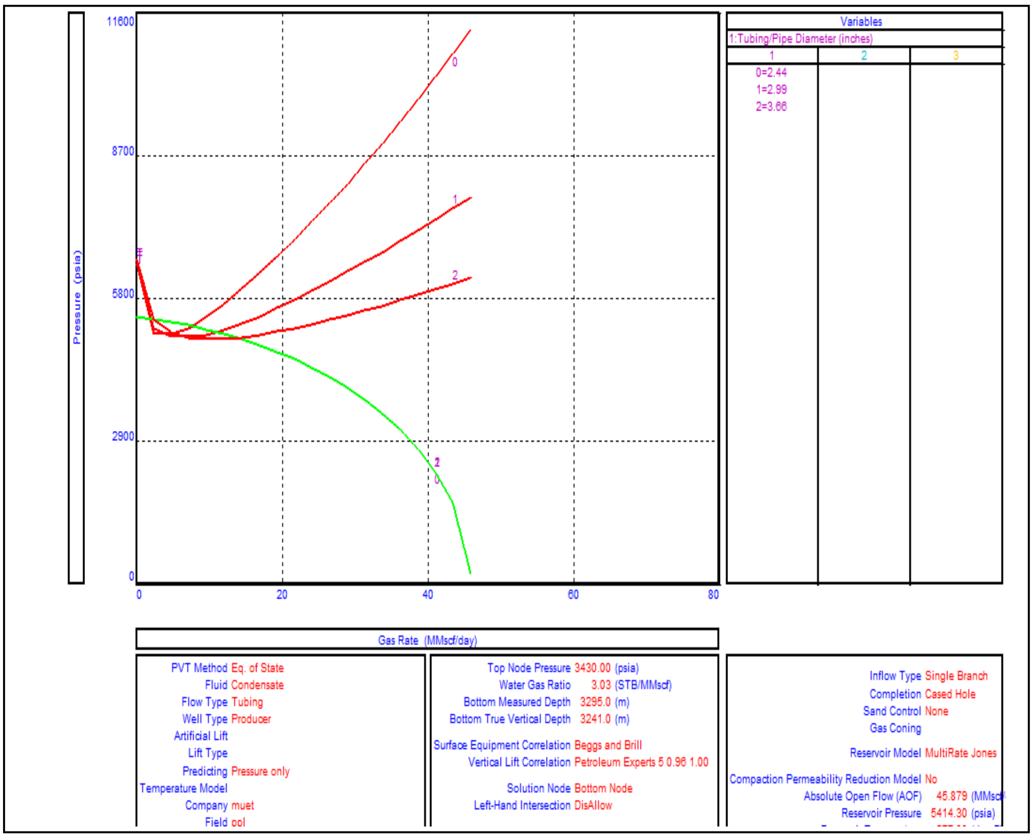


Fig. 1.17: *Sensitivity Analysis of Tubing Size (System Plot).*

Table 1.2: *Iterative Results of Tubing Size.*

S.No	Tubing Size (inches)	Gas Rate (MMSCFD)
0	2.441	7.848
1	2.992	11.165
2	3.661	14.045

The above results show that as the tubing size is increasing, more gas is produced at the surface. This is due to the fact that the larger tubing size has fewer pressure losses.

Sensitivity Analysis on Water Gas Ratio

Various sensitivities have been run at different WGR and their results are summarized in the Figure 1.18 and the Table 1.3 respectively:

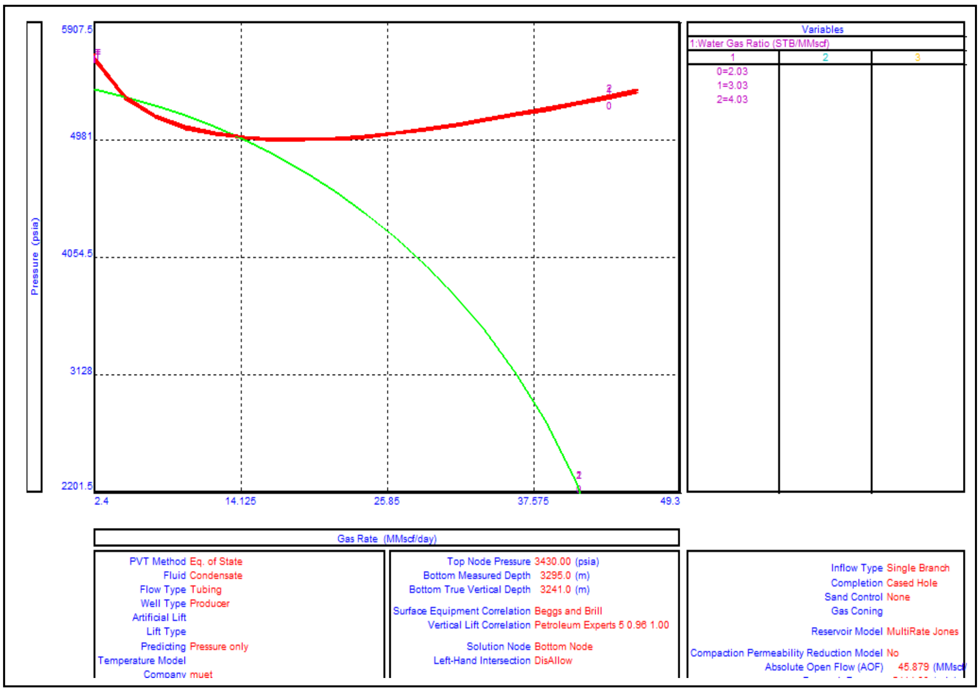


Fig. 1.18: *Sensitivity Analysis on Water Gas Ratio (System Plot).*

Table 1.3: *Iterative Results on Water Gas Ratio.*

S.No	WGR (STB/MMSCF)	Gas Rate (MMSCFD)
0	2.03	14.081
1	3.03	13.829
2	4.03	13.643

It can be clearly observed from the above results that there is not such significant effect of WGR on production rate which is also clear from the production history performance shown in the Figure 1.14

Sensitivity Analysis on GOR:

Various sensitivities have been run at different GOR and their results are summarized in the Figure 1.19 and the Table 1.4 respectively:

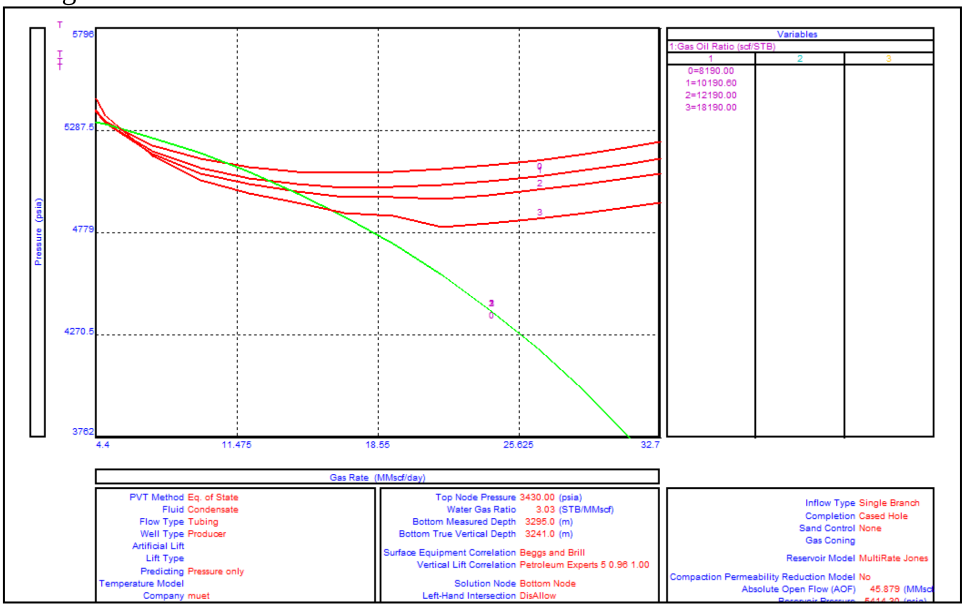


Fig. 1.19: *Sensitivity Analysis on GOR (System Plot).*

Table 1.4: Iterative Results on GOR.

S.No	GOR (SCF/STB)	Gas Rate (MMSCFD)
0	8190	11.093
1	10190.6	13.065
2	12190	14.229
3	18190	16.307

The above results show that with increasing GOR the production rate is also increasing.

Sensitivity Analysis on Tubing Roughness: Various sensitivities have been run at different GOR and their results are summarized in the Figure 1.20 and the Table 1.5, respectively:

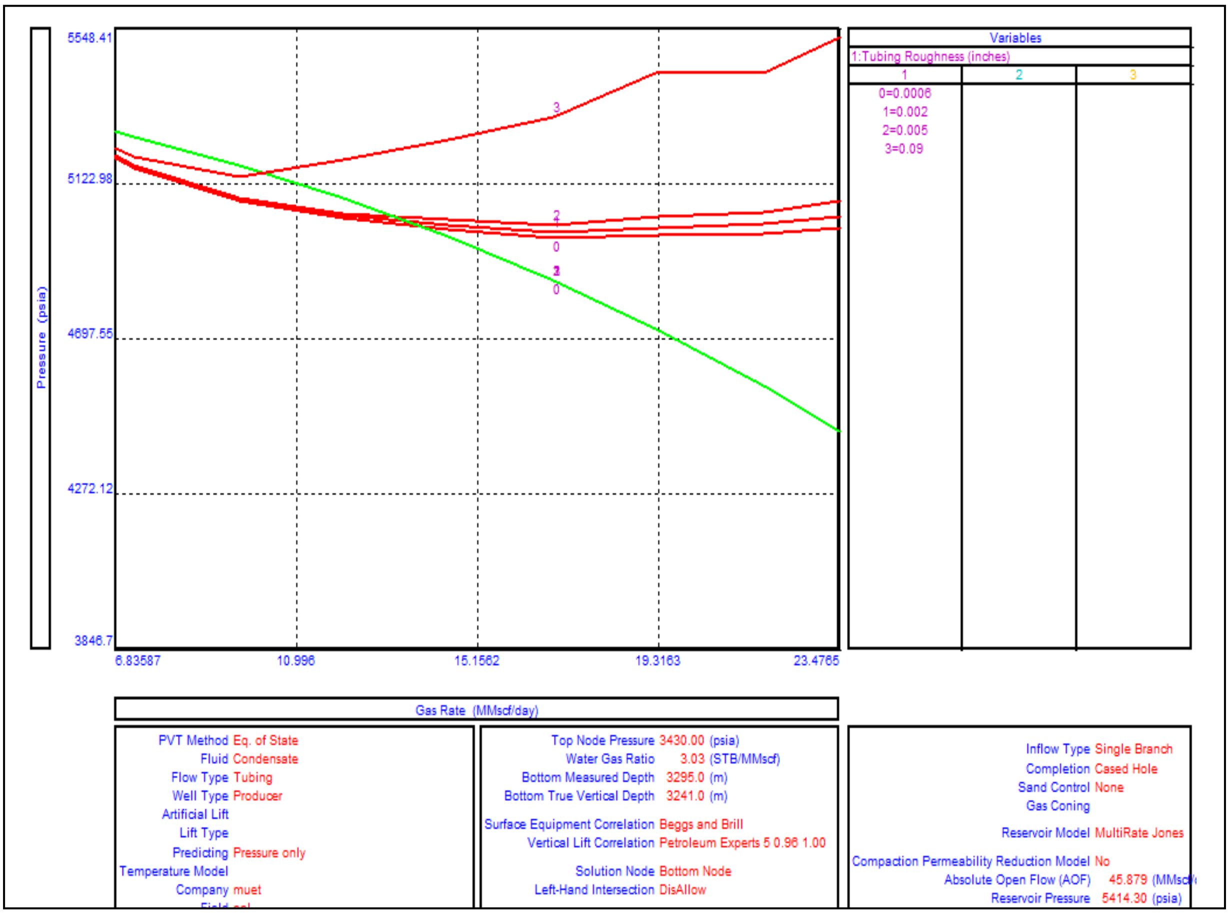


***Fig. 1.20:** Sensitivity Analyses on Tubing Roughness (System Plot).*

Table 1.5: Iterative Results on Tubing Roughness.

S.No	**Tubing roughness (inches)**	**Gas Rate (MMSCFD)**
0	0.0006	13.829
1	0.002	13.518
2	0.005	13.215
3	0.09	10.228

The above result shows the significance of scaling in the tubing. If there is too much scaling then the rate is reduced dramatically.

CONCLUSION

Keeping the all above study in view, it is concluded that current well has less potential of productivity. GOR and water cut has no effect on the well because its liquid drop out is less than 12%, due to that it is not possible to change the reservoir pressure by alternative energy. Ultimate option is to change the wellhead pressure. Changing tubing size can be best option too but it is not economical feasible. Corrosion would be effective if and only if scaling is too high.

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