Sharif University of Technology
Department of Chemical and Petroleum Engineering

Course Project Report

- Multi-phase Flow Fluid Mechanics -

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1 Introduction

The objective of this project is to perform a simulation of an off-shore well using the commercial software PIPESIM, and obtain resulting IPR and TPR curves for different gas-liquid ratios to derive the optimal production rate.

PIPESIM is a steady-state multiphase flow simulator owned by Schlumberger. It is one of the major commercial software to design wells and pipelines and it relies on three core areas of science: (1) multiphase flow, (2) heat transfer, and (3) fluid behavior.

2 Model Construction

2.1 Well Design

At first, a production well is constructed using the given data. The perforation top is given to be 6865 ft, and the perforation interval is 20 ft, and therefore the inferred well depth is 6885 ft. Also pay thickness is given to be 20 ft which may imply that the total pay has been perforated. The well is consisted of a casing section with an inner diameter of 5.012 in, and an outer diameter of 5.5 in, and a tubing section with 1.867 in ID, and 2.375 in OD. The wellbore diameter is given to be 7 inches. The material used for casing and tubing is grad C90 and pipe roughness is equal to 0.001 in. The well is considered vertical with no deviation. A packer is inserted above the perforations to prevent fluid flow through annulus. The heat transfer coefficient is considered to be 2 $Btu/(h.F.ft2)$ and soil temperature is given to be equal to 50 degrees F.

2.2 Completion Data

A perforation zone is entered based on given data. The perforation mid-depth is set to 6875 ft. The IPR model is considered Darcy while below the bubble point it uses Vogel. Reservoir drainage area is considered circular with a shape factor of 31.62. Rate-dependent skin is set to zero and mechanical skin is given to be 1. A black oil fluid model is considered as the producing fluid with 30 percent watercut and varying gas-liquid ratio. The reservoir properties are set according to the problem sheet.

Perforation data are set in the Perforation design module. A sandstone type is considered for reservoir rock and reservoir pressure and porosity are only altered parameters in the Rock data tab. The gun system is set to '1-3/8" Domed Scallop, 16A Hyperdome, RDX' by default. Perforation shot density, and phasing angle were set to 4 shots/ft and 60 degrees, respectively. API penetration and entrance hole were set to 7 and .35 inches, respectively, after tunnel length, L, and tunnel diameter, D_P. Running perforation design simulation resulted in an average formation penetration and entrance hole equal to 1.82 and .47 inches, respectively. The total penetration average was equal to 2.81 inches. The productivity results subsequent to perforation design gave a mechanical skin of about 2.46 and a rate dependent skin of 2.6E-5 which were not applied to the model due to contrast with given data.

2.3 Fluid Model

Black oil model is used to describe fluid properties. The model considers 30 percent watercut and GLR equal to 175 scf/STB at first. Viscosity correlations chosen to be Beggs & Robinson for dead and live oil and Vasquez & Beggs for the undersaturated oil. Inversion watercut is 60 percent by default and is left unaltered. Other fluid properties are set according to the data in problem sheet.

The wellbore flow correlation has been set to original Beggs & Brill for vertical multiphase flow with hold-up and friction factor equal to 1. Seawater gradient/current is set to Gulf of Mexico as asked by the problem sheet.

2.4 Hydrate Formation Model

Since the fluid model is not compositional, hydrate sub-cooling checkbox cannot be checked in the Heat transfer tab. However the procedure to analyze the hydrate situation in the wellbore is in the following manner, assuming compositional fluid model:

1. Check hydrate subcooling option in Simulation settings → Heat transfer.
2. Set Report template to Flow Assurance in Simulation settings → Output variables.
3. Launch P/T profile module and run simulation
4. Set Y axis to Hydrate formation temperature to have hydrate phase diagram.

3 Results

3.1 Operating Points

The curves are derived for flow-rate based on bottom-hole pressure considering well-head pressure of 100 psig. The IPR curves for gas-liquid ratio equal to 175, 700, 1200, and 3000 are plotted in Figure 1. The IPR curves for third latter GLRs are overlapped.

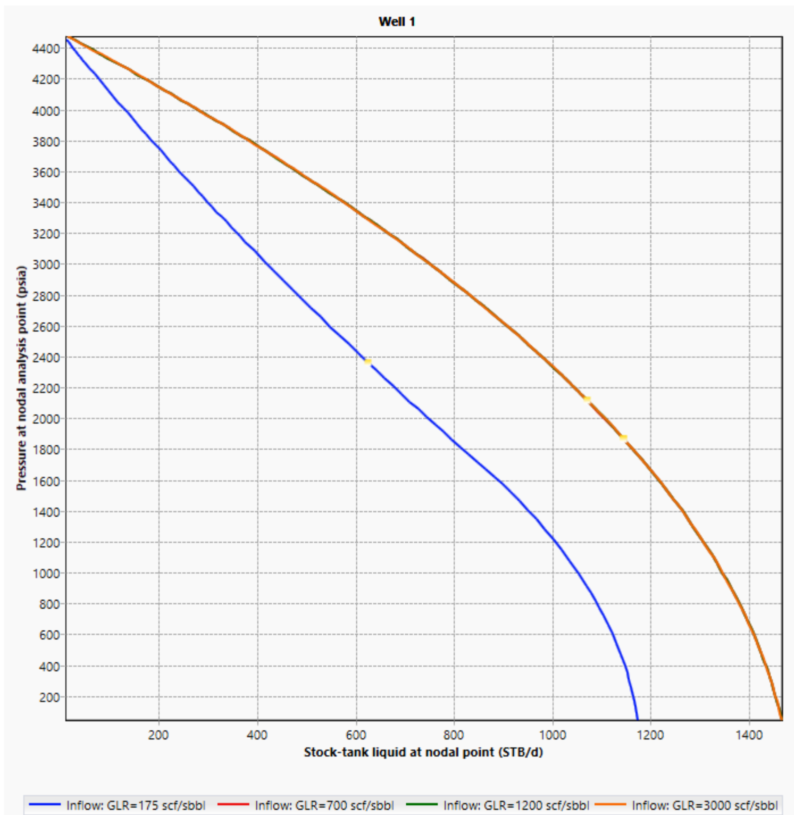

Figure 1: IPR curves for various GLRs.

Figure 2 shows TPR curves derived from original *Beggs & Brill* correlation. It is evident that by increasing gas fraction of the feed, the TPR curves are lowered since the share of hydrostatic pressure drop is reduced, except for the fourth case, i.e. GLR = 3000 scf/STB, in which pressure is raised at higher rates due to frictional pressure drop generated by high gas velocity.

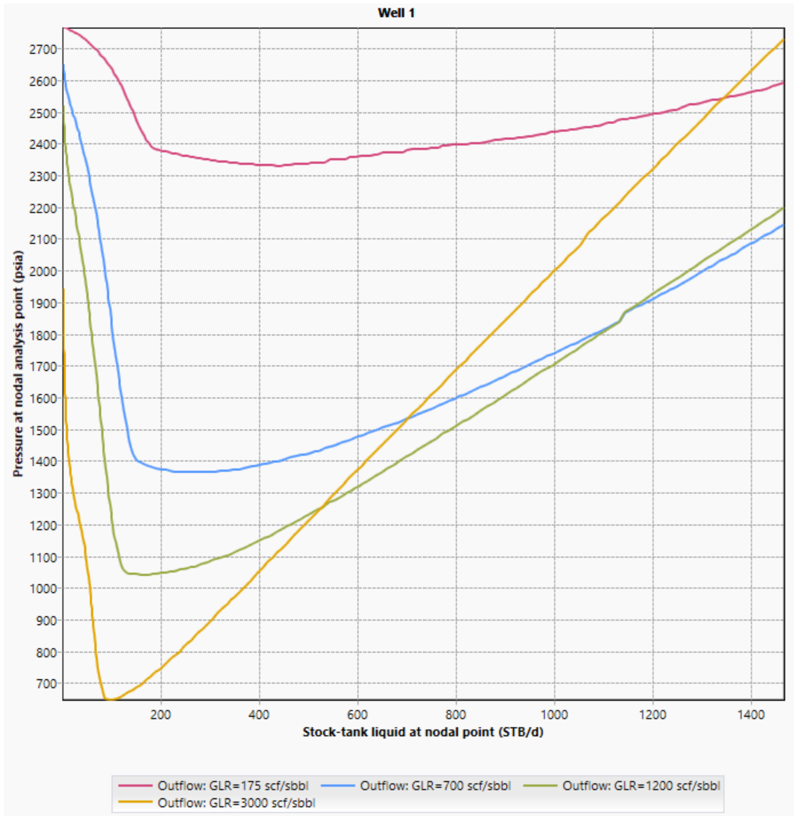

Figure 2: TPR curves for various GLRs.

Operating points are derived by intersecting IPR and TPR curves for each GLR via Nodal Analysis module of the software. The resulting points are demonstrated by Figure 3. Notice that the operational flow-rate is increasing by raising GLR until about 700 to 1200 scf/STB above which the bottom-hole flow-rate drops down. Therefore the optimal GLR should be around 1000 scf/STB. The operating flow-rates are also shown in Table 1. Maximum production rate occurs at GLR = 700 scf/STB and is equal to 1321.5 STB/d.

Table 1: Operating production rates vs. GLR.

GLR (scf/STB)	Operating point (sbbl/day)
175	740.6278
700	1321.507
1200	1312.515
3000	1203.173

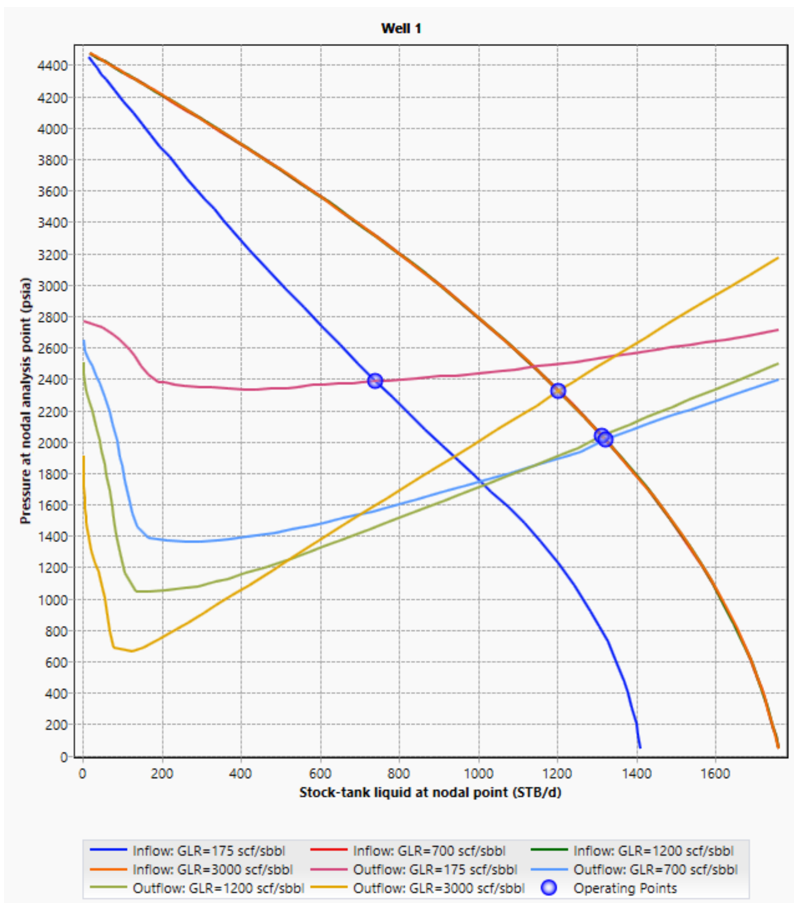

Figure 3: Operating points for various GLRs.

The resulting curves for the case in which Duns and Ros correlations were used for vertical flow are illustrated in Figure 4.

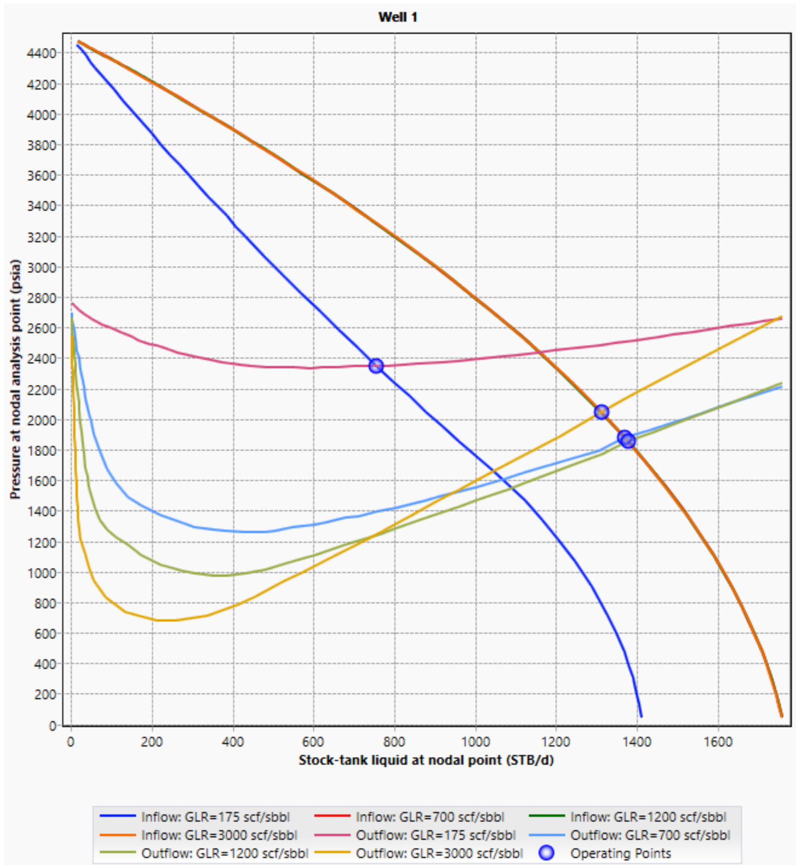

Figure 4: Operating points for various GLRs using Duns and Ros TPR correlation.

3.2 AOFP and Productivity Index

The absolute open to flow potential is defined as the flow-rate at which the bottom-hole pressure equals to atmospheric pressure. AOFP for several cases of GLR is demonstrated in Table 2. It is observed that AOFP has a general increasing trend until reaching a certain point at which it will become constant, and hence the IPR curves are similar for cases of GLR = +700 scf/STB.

The productivity index is derived from IPR slope and for the case of GLR = 175 scf/STB is around 0.369 sbbl/(psi.day).

Table 2: Absolute Open to Flow Potential.

GLR (scf/STB)	AOFP (sbbl/day)
175	1411.537
300	1675
400	1764
500	1790
600	1780
700	1760.814
1200	1760.814

3.3 Hydrate Formation

In the current work, fluid model is assumed black oil, and hydrate formation requires the Multiflash module of the software to run which needs a compositional model. Therefore, a hypothetical compositional fluid model is created based on having an IPR curve similar to that of GLR = 175 scf/STB case in Figure 1. Hydrate formation P/T diagram is subsequently drawn which is illustrated in Figure 5. It should be noted that these results may differ significantly with the ones expected while using the black oil model.

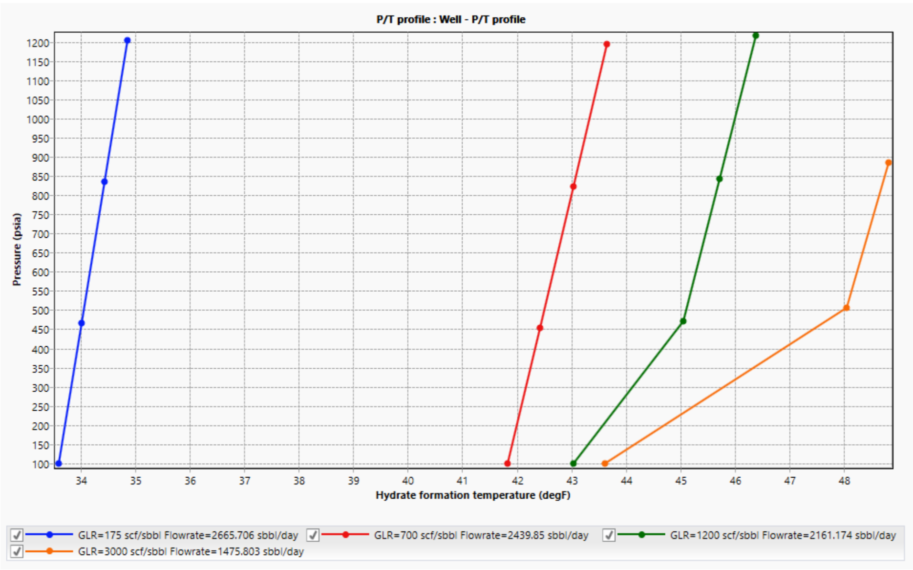

Figure 5: Hydrate formation P/T diagram.

Since reservoir and wellhead temperatures are given by 180 and 70 $^\circ F$ respectively, temperature along the tubing is expected to be within these limits. Assuming the results given by Figure 5 to be true, no hydrate will form near the surface which is at least 70 $^\circ F$ and clearly has higher temperature than 50 $^\circ F$.

4 Conclusion

An offshore well has been designed and simulated using the commercial software PIPESIM. The results have been generated and compared for various gas-liquid ratios and by two different tubing correlations. Inflow and outflow performance curves have been generated. Optimal gas-liquid ratio and operating production rates have been derived. Absolute open to flow potential is obtained for different cases of GLR, and productivity index of the original model is derived. Although hydrate formation could not be activated, the procedure to calculate hydrate formation temperature has been carried out assuming a hypothetical compositional fluid model which resulted in hydrate not forming under tubing conditions.

References

PIPESIM Online Help Version 2017.2