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Application of “Virtual Pressure Gauge” for The Selection of Vertical Multiphase Flow Correlation in the Gas Lifted Well to Achieve Proper Tubing Outflow Analysis

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APPLICATION OF "VIRTUAL PRESSURE GAUGE" FOR THE SELECTION OF VERTICAL MULTIPHASE FLOW CORRELATION IN THE GAS LIFTED WELL TO ACHIEVE PROPER TUBING OUTFLOW ANALYSIS

Milla Voni[1], Judge Septopanduviyatmo[2]
Medco E&P Natuna Ltd.[1]

Abstract

Tubing outflow analyses are performed to predict pressure losses up the production tubing based on the production rate, flowing wellhead pressure, physical features of the well and produced fluids in question. An outflow/vertical lift curve is used to show how the flowing bottom hole pressure varies as function of production rate. Reliable and accurate mean to predict pressure losses in vertical multiphase flow is essential to properly design well completions and artificial-lift systems, optimize production performance, and troubleshoot well problems.

The most important vertical multiphase flow correlations today are Duns-and-Ross, Fancher-Brown, Gray, Hagedorn-Brown, Orkiszewski, and Beggs-and-Brill. Selecting the best multiphase flow correlation for a specific application is an art, as well as science. There is no universal multiphase flow correlation that works in all applications. Each correlation has its strengths and weaknesses. To determine the most suitable vertical multiphase flow correlation, it shall be compared against measured pressure survey data. Then, the selected multiphase flow correlation should be tuned to match the measured pressure drop between the deepest pressure measurement and the wellhead. The pressure survey data can be taken from permanent downhole gauge installed in the production tubing. When the permanent gauge is not available, the temporary gauge has to be run into the well by wireline to acquire pressure data at various depths in the wellbore which can add operational cost of the well and increase the risk of well failure due to wireline operation failure.

This paper describes the application of "virtual pressure gauge" to control the selection of vertical multiphase flow correlation and calibrate the selected vertical multiphase flow correlation in the gas lifted well without running the pressure gauge into the well. To check the accuracy of this technique, the comparison between common technique with actual measured pressure data and virtual gauge technique will be discussed. The comparison of those two techniques shows that virtual gauge application can be used as an alternative to select and tune vertical multiphase flow correlation under certain conditions and assumptions when running wireline gauge into the well is not possible to be performed.

Keywords: multiphase flow correlation, pressure survey, pressure gauge, gas lift.

1. Introduction

Outflow performance or vertical lift performance (VLP) has been important part of total system analysis, or widely known as nodal analysis. The nodal analysis itself is the most important tool in Production engineering field to solve well problems and optimize production.

Vertical lift performance is related to pressure drop occurred along the production tubing due to fluid flow from perforation depth up to wellhead. Nowadays, with more depleted reservoir pressure and the usage of artificial lift (especially gas lift), most of the fluid flow along the production tubing is multiphase flow.

It is critical to have the capability to predict pressure drop occurred along the production tubing to develop a vertical lift performance. Several works[1,2,3,4] have attempted to develop multiphase flow correlation to predict pressure drop along the production pipe under certain flowing condition. These works are conducted in a research and testing facility, where the flowing conditions are simulated and pressure along the pipe are measured.

Duns-and-Ross, Fancher-Brown, Gray, Hagedorn-Brown, Orkiszewski, and Beggs-and-Brill multiphase flow correlations are widely used and are considered as standard multiphase flow correlation included in nodal analysis software application such as IPM Petroleum Expert[5], Schlumberger PipeSim, Weatherford WellFlo, etc.

In real world application, a Production Engineer will run memory pressure gauge deployed by slickline to acquire pressure data at several points or depths from perforation depth up to wellhead depth. These data points are then used to match and tune the multiphase flow correlation available in the nodal analysis software application. The tuned multiphase flow correlation is then able to construct vertical lift performance as part of total system or nodal analysis. From there, Production Engineer can simulate several scenario or condition to optimize current well production.

Running memory pressure gauge into the well using slickline inherit some risks associated with tool failures. Slickline toolstring may get stuck during flowing condition and force the slickline operator to cut the wire and leave toolstring in the hole. Fishing operation could fail to retrieve wire and toolstring left in hole. The well must be shut-in and company loose production from the well.

In a gas lift well, gas passage thru an orifice valve at operating point is usually estimated with the Thornhill-Craver equation[6]. Charts such as shown in Figure 1 has been prepared using the Thornhill-Craver equation. They give the gas flow capacity for a known (upstream) gas pressure, (downstream) fluid pressure, and port size (orifice).

Therefore, if casing head pressure (CHP) and actual port size orifice are known, then the tubing pressure at orifice valve depth can be predicted using this Thornhill-Craver equation. Combining tubing head pressure (THP) and predicted downhole tubing pressure from Thornhill-Craver equation, these pressure data may be used to match and tune available multiphase flow correlation in nodal analysis software application. Running memory pressure gauge to obtain downhole tubing pressure can be avoided.

2. Basic Theory

The volumetric gas throughput of an orifice or choke is calculated on the basis of an equation for flow through a converging nozzle[7]. This equation is complex and lengthy for noncritical flow. For this reason, gas passage charts are widely used for estimating the volumetric gas flow rate. A widely used equation for calculating the gas flow rate through an orifice, choke, or full-open valve port was published by Thornhill-Craver[8]. The equation is for compressible, one-dimensional, and isentropic flow of a perfect gas through a restriction, with the addition of a correction factor (discharge coefficient) to account for deviations encountered in real cases[9].

$$q_{gsc} = \frac{155.5\, C_d\, (A) P_1 \sqrt{2\,(g)\left(\frac{k}{k-1}\right)\left[(F_{du})^{2/k} - (F_{du})^{(k+1)/k}\right]}}{\sqrt{\gamma_g (T_1)}} \qquad (1)$$

where

q_{gsc} = gas-flow rate at standard conditions (14.7 psia and 60°F), Mscf/D,

C_d = discharge coefficient (determined experimentally), dimensionless,

A = area of orifice or choke open to gas flow, in.^{2},

P_1 = gas pressure upstream of an orifice or choke, psia,

P_2 = gas pressure downstream of an orifice or choke, psia,

g = acceleration because of gravity, ft/sec^2,

k = ratio of specific heats (C_p/C_v), dimensionless,

T_1 = upstream gas temperature, °R,

F_{du} = pressure ratio, P_2/P_1, consistent absolute units,

and

$F_{cf} = \left(\frac{2}{k-1}\right)^{\frac{k}{k-1}}$ critical-flow pressure ratio, dimensionless.

Because gas flow in a gas lift installation occurs at the gas temperature at valve depth, a correction for temperature improves the prediction for the volumetric gas rate. If the actual gravity differs from 0.65, a second correction should be applied. An approximate correction for gas passage can be calculated using Eq.2.

$$C_{gT} = 0.0544\sqrt{\gamma_g\left(T_{gD}\right)} \qquad (2)$$

and

$$q_{ga} = \frac{q_{gc}}{C_{gT}} \qquad (3)$$

where

C_{gT} = approximate gas gravity and temperature correction factor for choke charts, dimensionless,

T_{gD} = gas temperature at valve depth, °R,

q_{ga} = actual volumetric gas rate, Mscf/D, and

q_{gc} = chart volumetric gas rate, Mscf/D.

3. Methodology

There are three methodologies used in this study, which are literature review, field data review, and simulation using nodal analysis software application.

Literature review is required to find the best method to calculate gas lift passage thru an orifice valve. Based on literature review, Thornhill-Craver equation is chosen to calculate gas lift passage thru an orifice valve and to predict tubing pressure at operating injection depth, or downstream pressure of an orifice valve.

Field data review is required to obtain pressure data from a pressure gradient survey. The data will be used in software simulation to select the best multiphase flow correlation available in nodal analysis software application to replicate downhole flowing condition from perforation depth up to surface wellhead. The selected multiphase flow correlation need to be matched and tuned to actual pressure data.

Simulation is required to match and tune available multiphase flow correlation in nodal analysis software application. In this study, Prosper from IPM Petroleum Expert is used as the nodal analysis software. Simulation is also required to determine the actual orifice port size performance against theoretical port size. The actual port size performance will be used in Thornhill-Craver equation to predict tubing pressure at operating injection depth, or downstream pressure of orifice valve.

Steps taken in this study are:

1. Gather historical pressure gradient data from field.
2. Perform QA/QC on pressure gradient data and well test data. Make sure no anomaly on the data.
3. Plug in pressure data into Prosper to select multiphase flow correlation which replicate the field data.
4. Perform multiphase flow correlation matching to tune the correlation with actual field data.
5. Perform QA/QC to matched multiphase flow correlation.
6. Perform gas lift quicklook in Prosper to determine actual orifice port size. Obtain average actual port size for 32/64 and 44/64 orifice.

7. Predict downhole tubing pressure at operating injection depth for production optimization candidate wells using Thornhill-Craver equation with actual average actual orifice port size.
8. Use predicted downhole tubing pressure at injection depth combined with actual surface wellhead pressure to select and tune multiphase flow correlation.
9. Perform nodal analysis in Prosper for various production optimization scenarios.

4. Case Study

Pressure data samples were taken from X field historical data. There are two wells which pressure survey data are used for multiphase flow correlation matching and simulation.

X-1 well is a gas lifted well which has five gas lift mandrels. Current operating injection point is at the third gas lift mandrel at depth 3,601 ft-MD. Figure 2 showed flowing pressure data at X-1 well. Matched multiphase flow correlation was Petroleum Expert with Parameter 1 (gravity term) 1.02 and Parameter 2 (friction term) 1.11. Figure 3 showed flowing temperature data which indicating single operating injection point.

X-1 well used orifice valve with port size 32/64" as operating valve. Casing head pressure (CHP) during pressure survey was 1190 psig. Using gas gradient 0.028 psi/ft, calculated casing pressure at injection point (3,601 ft-MD) was 1284 psig.

From pressure survey data, tubing pressure at injection point (3,601 ft-MD) was 1052 psig. Utilizing gas-lift quicklook feature available in Prosper, to match gas lift injection rate 2.7 MMscf/day, upstream pressure (P_{csg}) 1284 psi, and downstream pressure (P_{tbg}) 1052 psig, it required orifice valve with port size 24/64".

Therefore, the actual performance of 32/64" port size orifice valve was equivalent with 24/64" port size orifice valve in real world. Figure 4 showed gas-lift quicklook feature in Prosper for X-1 well.

If the actual performance of 32/64" port size orifice valve is plugged into Thornhill-Craver equation, along with actual casing head pressure (CHP), calculated downstream pressure (P_{tbg}) was 1100 psig. The difference with actual pressure obtained from pressure survey was 48 psi, or 4.6% from actual pressure value. Thornhill-Craver equation chart for X-1 well was shown in Figure 5.

This calculated tubing pressure and the actual tubing head pressure (THP) may be used as data point to match and tune multiphase flow correlation in Prosper. In X-1 well case, matched multiphase flow correlation was Petroleum Expert with Parameter 1 (gravity term) 1.05 and Parameter 2 (friction term) 1.17. The matched multiphase flow correlation for X-1 well obtained from pressure survey data and Thornhill-Craver calculation were shown in Figure 6.

The second case was at X-2 well which was a gas lifted well with six gas lift mandrels. Current operating injection point was at the fifth gas lift mandrel at depth 4,043 ft-MD. Figure 7 showed flowing pressure data at X-2 well. Matched multiphase flow correlation was Petroleum Expert 2 with Parameter 1 (gravity term) 1.05 and Parameter 2 (friction term) 1.1. Figure 8 showed flowing temperature data which indicating single operating injection point.

X-2 well used orifice valve with port size 44/64" as operating valve. Casing head pressure (CHP) during pressure survey was 1087 psig. Using gas gradient 0.025 psi/ft, calculated casing pressure at injection point (4,043 ft-MD) was 1170 psig.

From pressure survey data, tubing pressure at injection point (4,043 ft-MD) was 1107 psig. Utilizing gas-lift quicklook feature available in Prosper, to match gas lift injection rate 3.5 MMscf/day, upstream pressure (P_{csg}) 1170 psi, and downstream pressure (P_{tbg}) 1107 psig, it required orifice valve with port size 35/64".

Therefore, the actual performance of 44/64" port size orifice valve was equivalent with

35/64” port size orifice valve in real world. Figure 9 showed gas-lift quicklook feature in Prosper for X-2 well.

If the actual performance of 44/64” port size orifice valve is plugged into Thornhill-Craver equation, along with actual casing head pressure (CHP), calculated downstream pressure (P_{tbg}) was 1100 psig. The difference with actual pressure obtained from pressure survey was -7 psi, or -0.6% from actual pressure value. Thornhill-Craver equation chart for X-2 well was shown in Figure 10.

As in X-1 well case, the calculated tubing pressure and actual tubing head pressure (THP) were reused as data point to match and tune multiphase flow correlation in Prosper. For X-2 well case, matched multiphase flow correlation was Petroleum Expert 2 with Parameter 1 (gravity term) 1.08 and Parameter 2 (friction term) 1.09. The matched multiphase flow correlation for X-2 well obtained from pressure survey data and Thornhill-Craver calculation were shown in Figure 11.

Table 1 summarized the result of multiphase flow correlation matching using data point from pressure survey and Thornhill-Craver equation.

5. Result and Discussion

From simulation and multiphase flow correlation, it was revealed that there was derating or degradation of orifice valve against theoretical port size in X field. For orifice valve with port size 32/64”, the performance behaved like 24/64” port size orifice. Meanwhile for orifice valve with port size 44/64”, the performance behaved like 35/64” port size orifice. This orifice valve performance derating is summarized in Table 2.

Given this finding, one may plug in all parameters (casing head pressure, actual orifice valve port size and gas lift injection rate) into Thornhill-Craver equation to estimate downhole flowing tubing pressure at operating injection depth, then it could be used to match and tune multiphase flow correlation. If static bottom hole pressure (SBHP) is known from last static gradient survey (SGS), then a complete nodal analysis which included inflow and outflow performance could be performed.

In X field, there were two production optimization efforts initiated using this technique. Both efforts were gas lift injection point deepening. First case was at X-3 well. Initial operating injection depth was at 5,648 ft-MD with casing injection pressure 460 psig and gas lift injection rate 2.5 MMscf/day. Orifice valve port size was 32/64”. Plugged in all available parameters into Thornhill-Craver equation, then the downhole flowing tubing pressure at depth 5,648 ft-MD was estimated 320 psig. Figure 12 showed the Thornhill-Craver equation chart for X-3 well. Then this data point were used for multiphase flow correlation matching in Prosper. Petroleum Expert 4 was the most matched correlation with Parameter 1 (gravity term) 1.01 and Parameter 2 (friction term) 1.19. The matching process was illustrated in Figure 13.

Performed nodal analysis with Prosper for gas lift injection point deepening scenario, there was additional production opportunity as much as 350 BOPD if the injection point .

6. Conclusion

Write conclusions here..

7. Recommendation

Write the recommendation here..

8. Acknowledgement

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9. References

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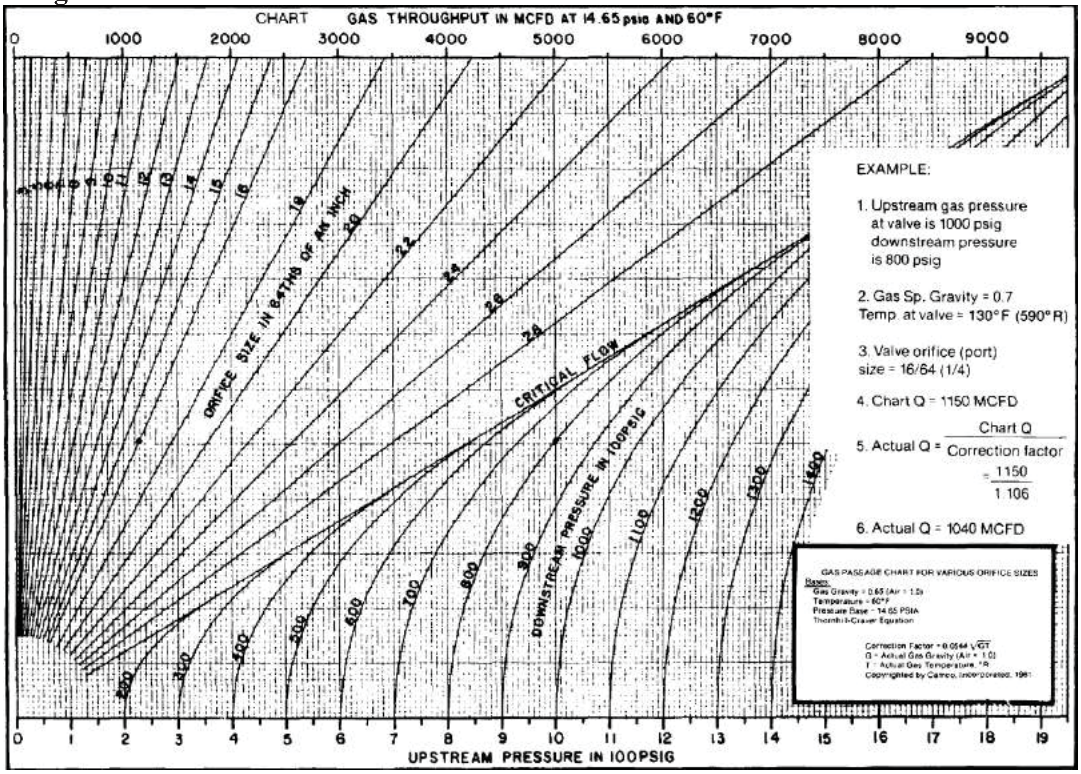

Figure 1. Gas flow capacities (0-9750 MCF/D) for known upstream pressure, downstream pressure, and orifice size. Courtesy Camco[5]

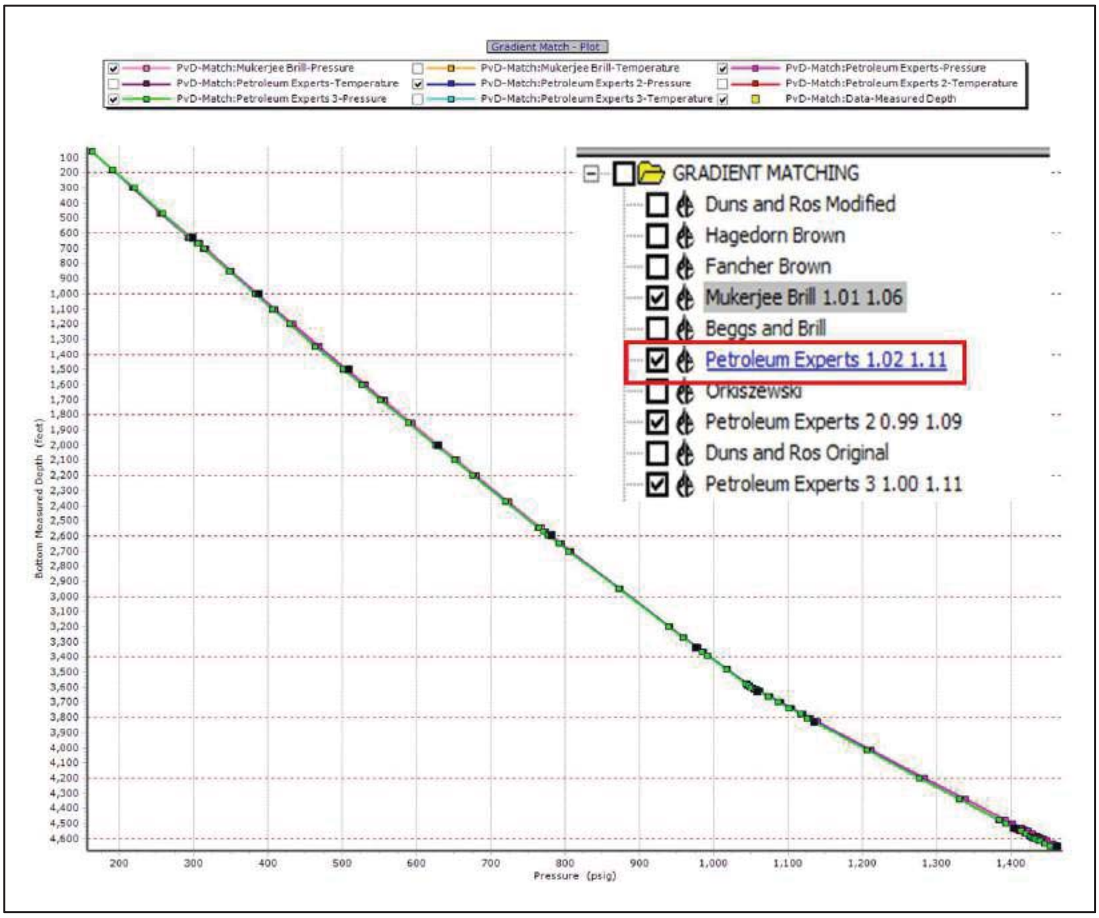

Figure 2. X-1 flowing pressure data and matched multiphase flow correlation.

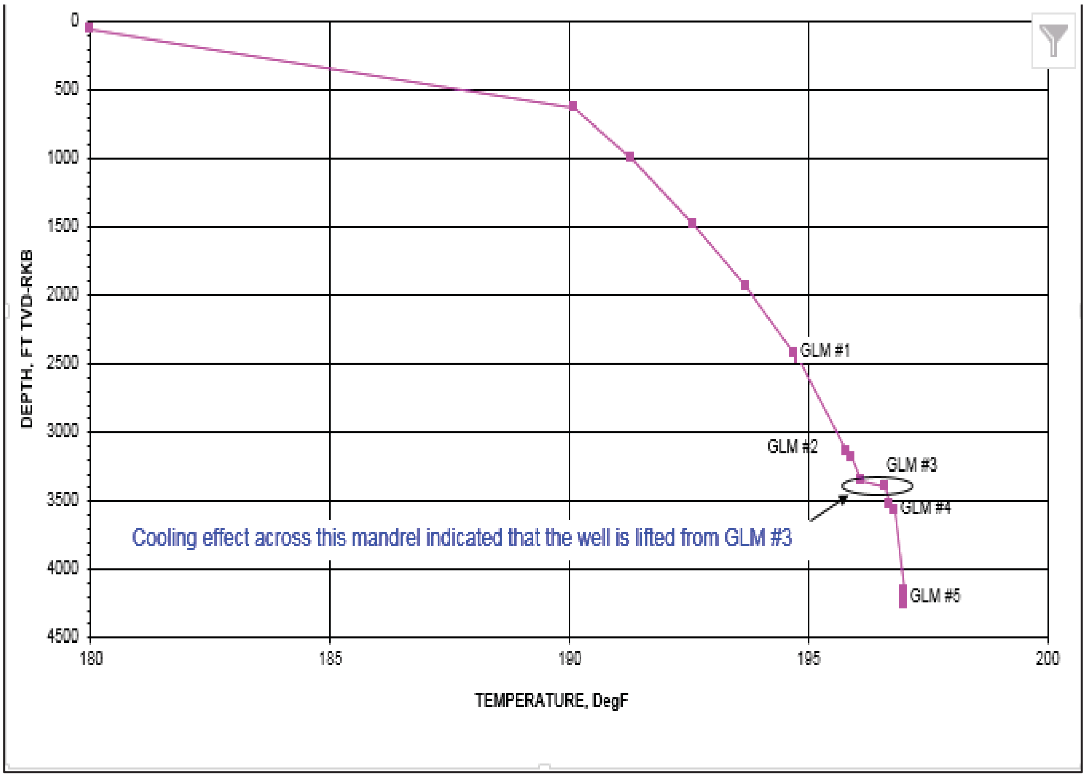

Figure 3. X-1 flowing temperature data

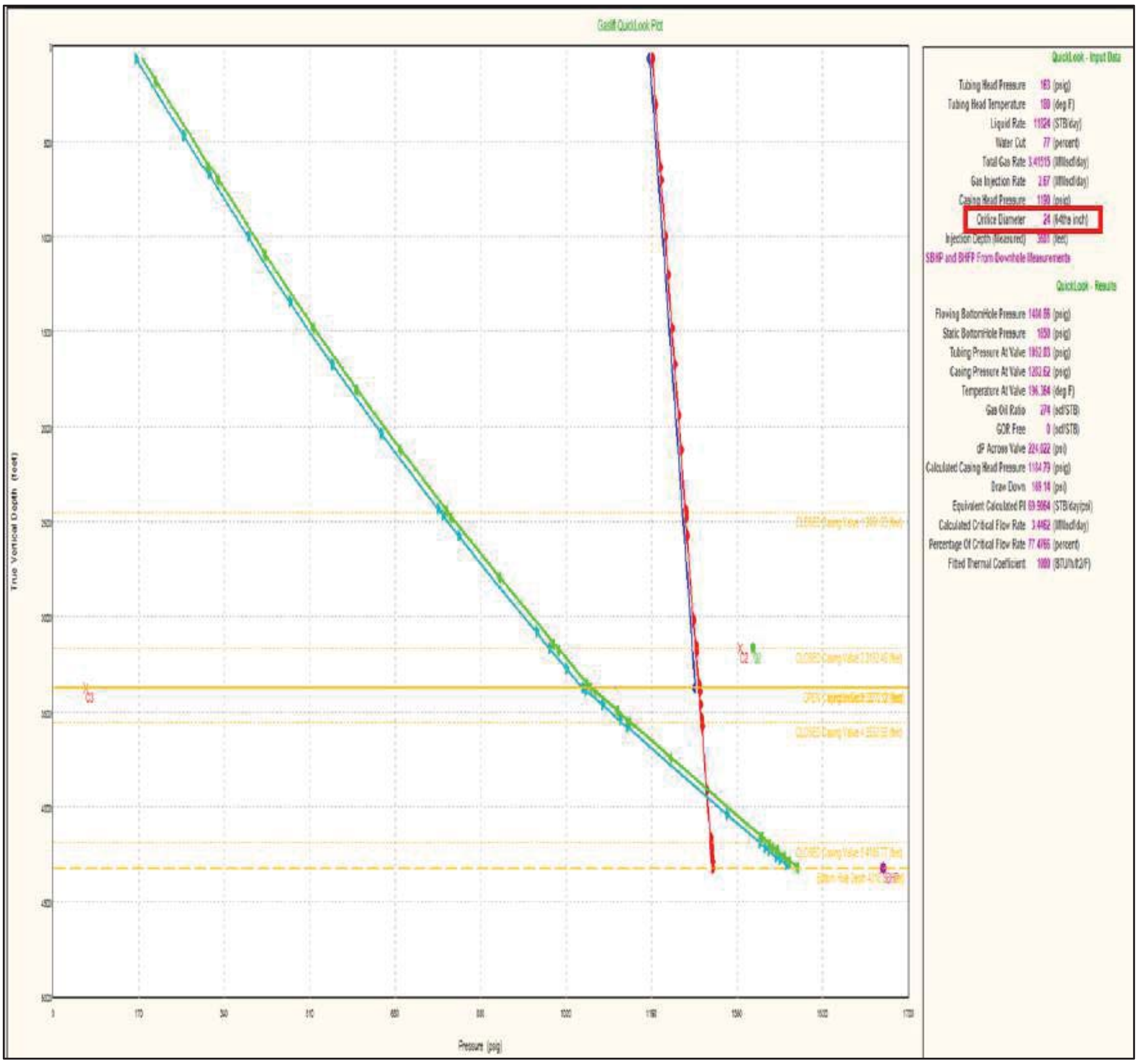

Figure 4. X-1 gas-lift quicklook

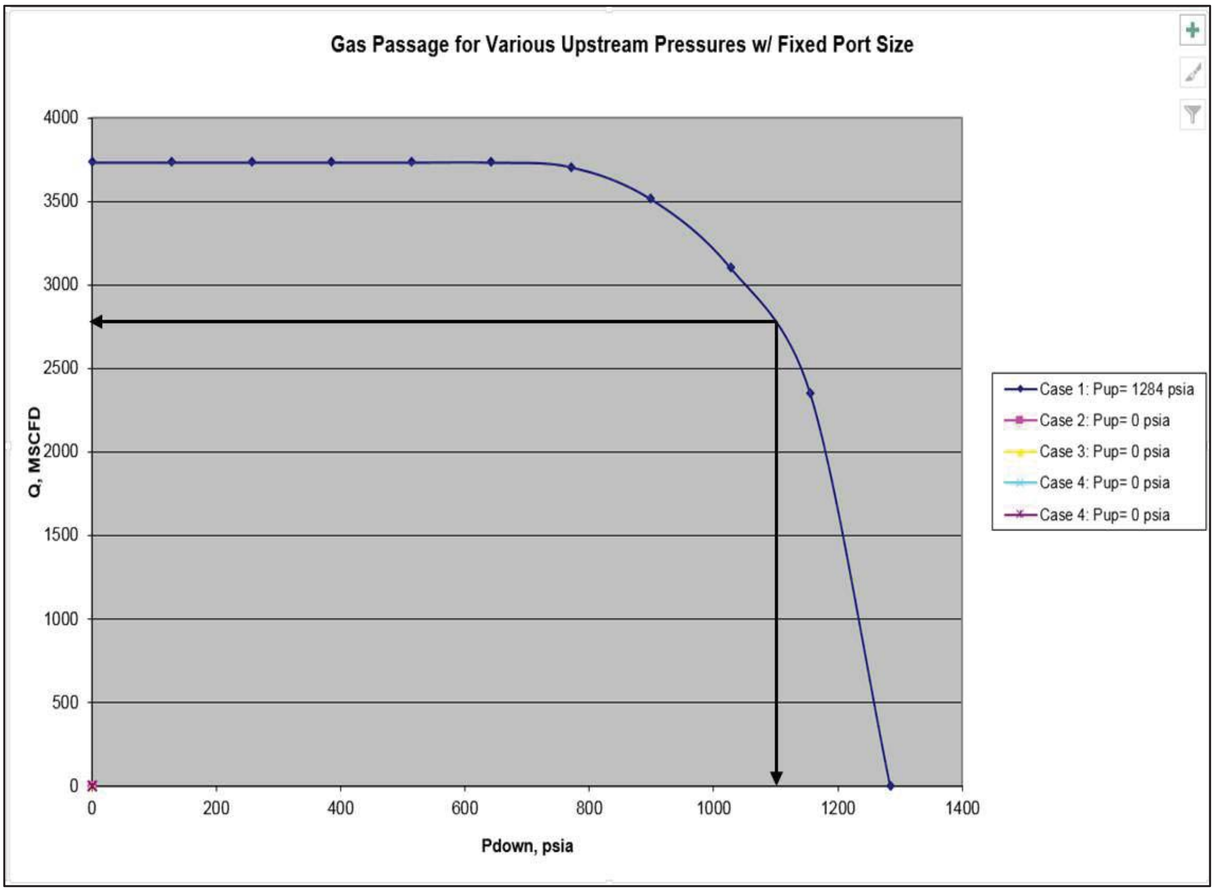

Figure 5. Thornhill-Craver equation chart for X-1 well.

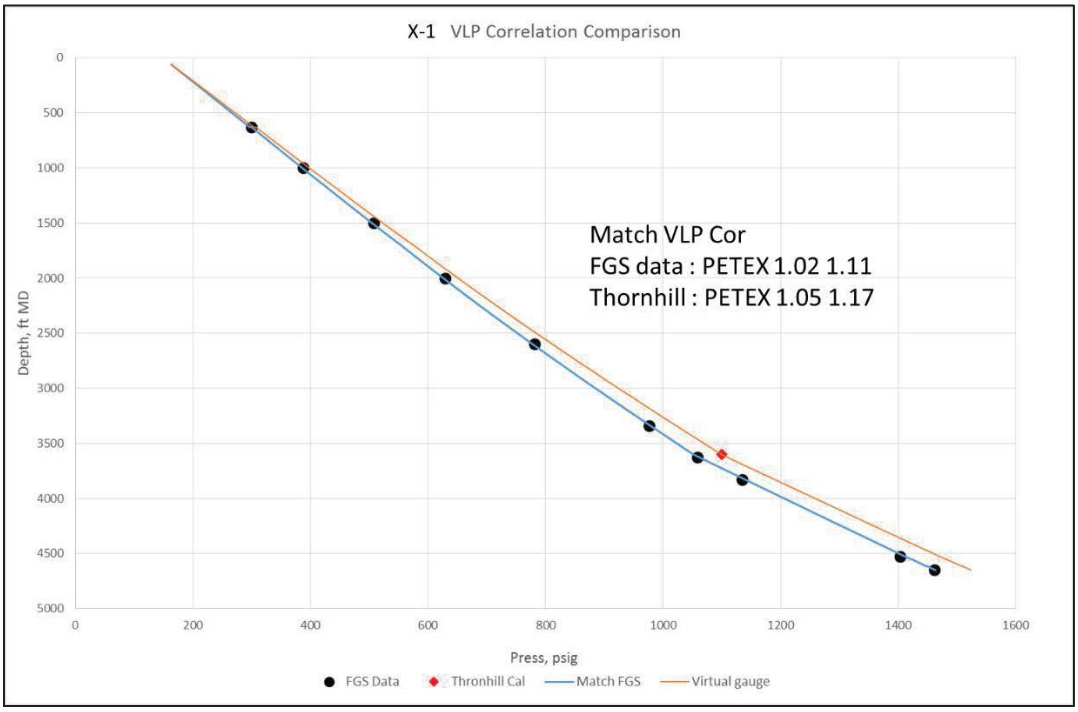

Figure 6. Multiphase flow correlation comparison for X-1 well.

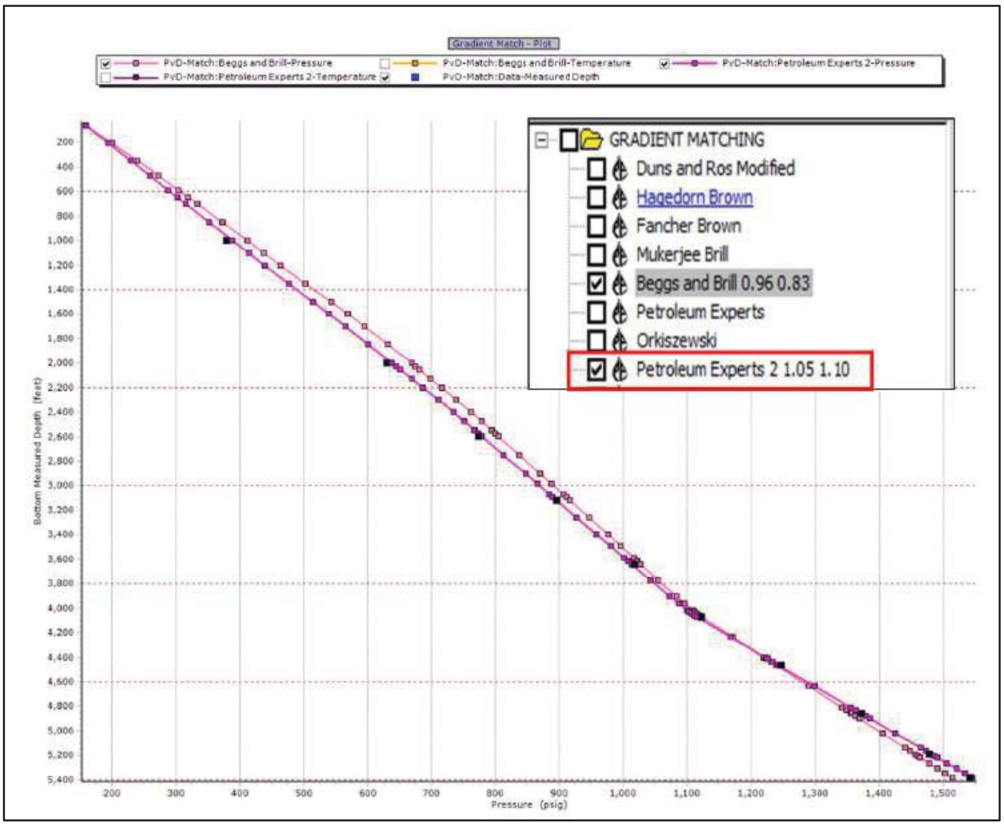

Figure 7. X-2 flowing pressure data and matched multiphase flow correlation.

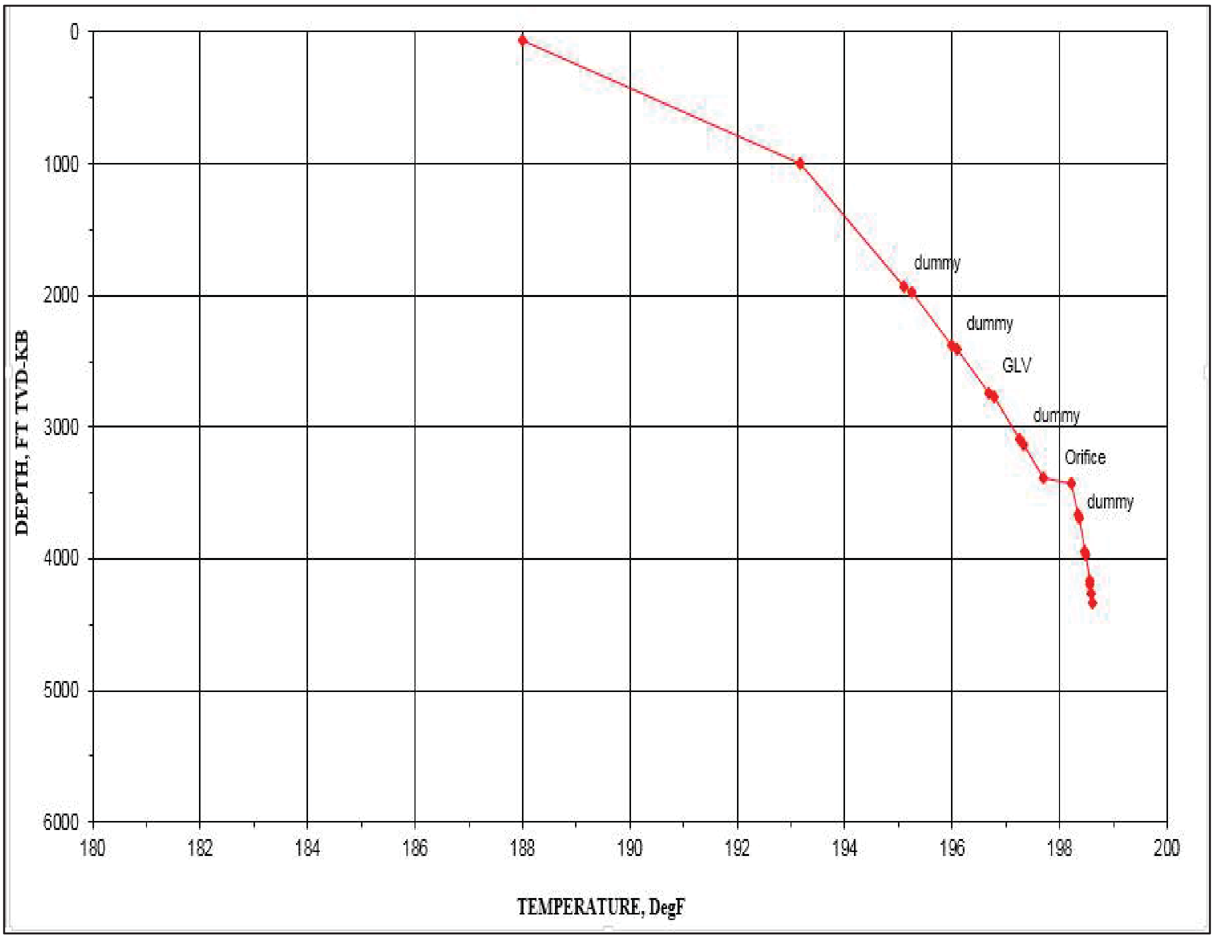

Figure 8. X-2 flowing temperature data

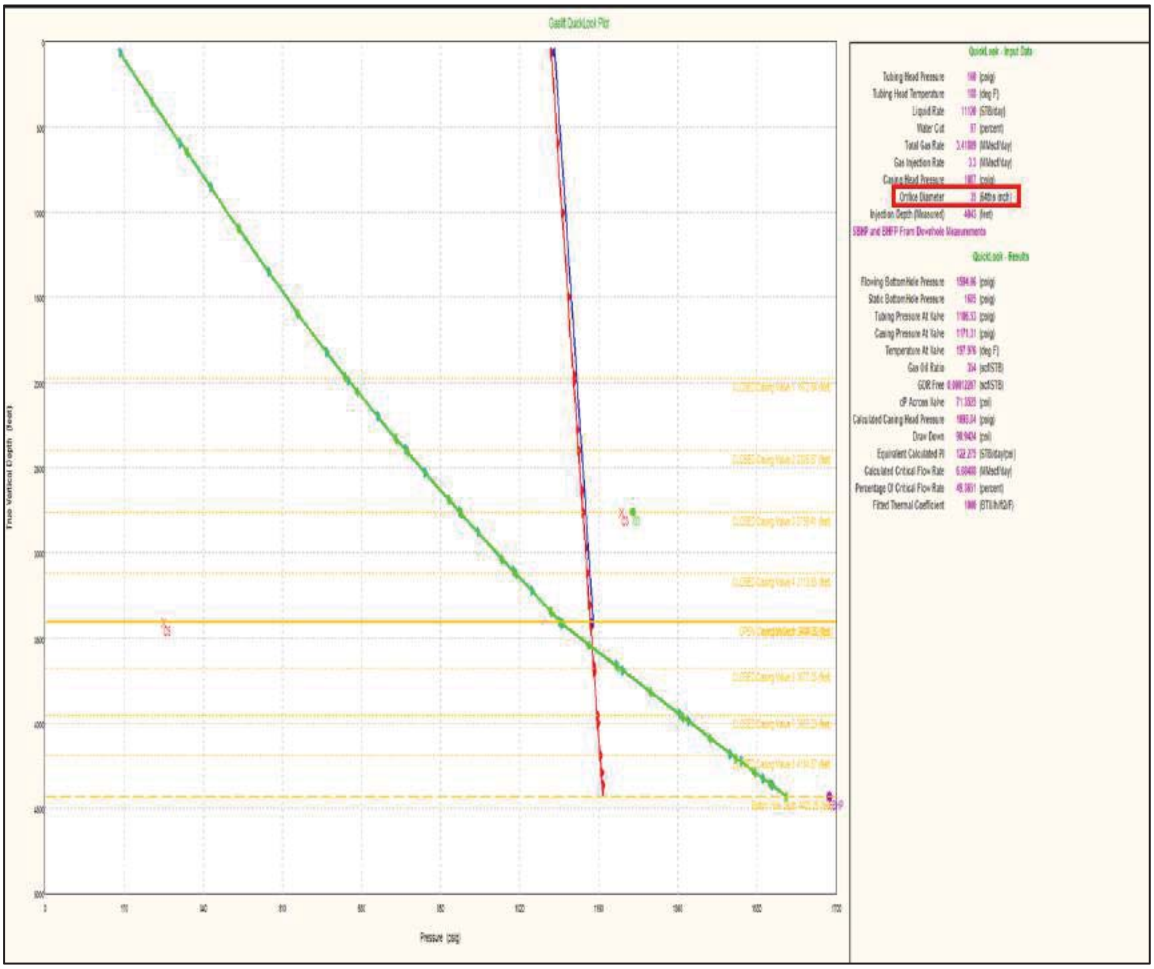

Figure 9. X-2 gas-lift quicklook

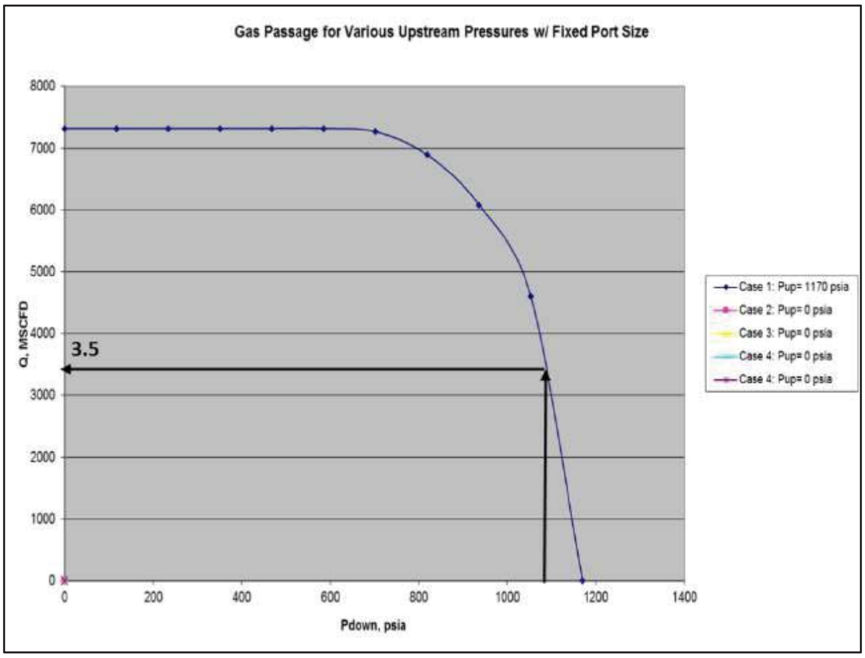

Figure 10. Thornhill-Craver equation chart for X-2 well.

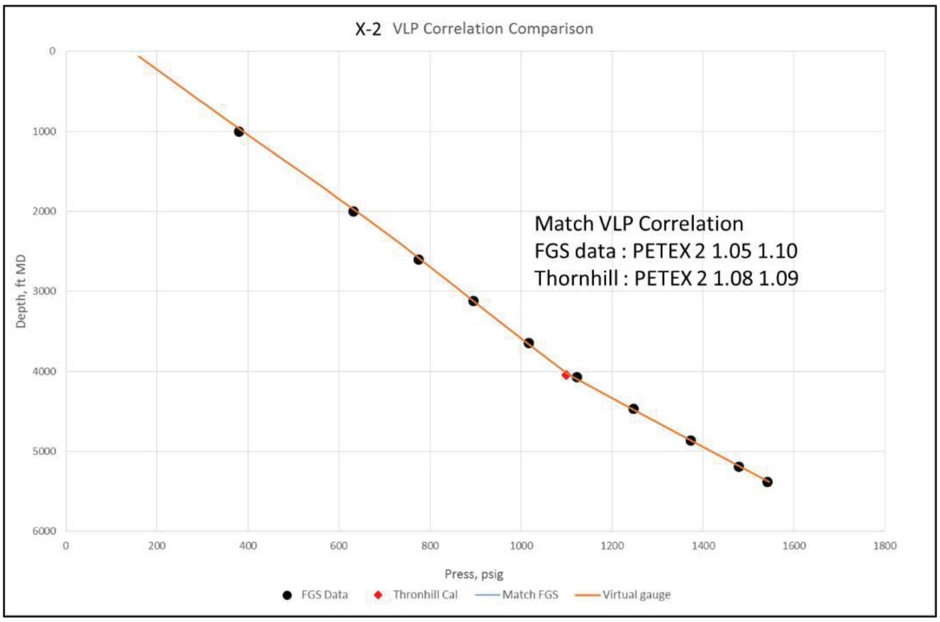

Figure 11. Multiphase flow correlation comparison for X-2 well.

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Table 1. Multiphase flow correlation from pressure survey and Thornhill-Craver equation.

Well	Actual P_{tbg} from Pressure Survey	Calculated P_{tbg} from Thornhill-Craver	Difference
X-1	1052 psig	1100 psig	4.6%
X-2	1107 psig	1100 psig	-0.6%

Table 2. Orifice valve performance derating in X field.

Theoretical Port Size	Actual Port Size Performance	Derating
32/64”	24/64”	75%
44/64”	35/64”	80%