Parallel Data Generation for Efficient Data Prediction and Matching for Production Wells

Muhammad Khurram Zahoor

Department of Petroleum and Gas Engineering, University of Engineering and Technology, Lahore, Pakistan
mkzahoor@yahoo.com

Abstract: Analyzing and predicting well production behavior is one of the critical tasks during designing subsurface production facilities. As a general practice, at a time one methodology is adopted to generate the production curves and with the passage of time as the history of the well becomes available it is also plotted on the same curves to have a history match and a reliable forecast. This practice requires a lot of time, as if the selected methodology proves wrong then another method have to be adopted and need to be verified at the same time. To overcome this time consuming and tedious practice a concept of parallel data generation using different methods at a time has been discussed with further modification in the existing methodologies by introducing a correlating function/ parameter.

[Zahoor M. K. **Parallel Data Generation for Efficient Data Prediction and Matching for Production Wells.** *Academ Arena* 2018;10(1):79-84]. ISSN 1553-992X (print); ISSN 2158-771X (online). http://www.sciencepub.net/academia. 11. doi:10.7537/marsaaj100118.11.

Keywords: Parallel programming, wellhead pressure estimation, correlating parameter.

1. Introduction

Pressure drop exists between the bottom hole and wellhead of the well, due to which gas, oil and water are produced to the surface. Different correlations and methodologies are available to estimate the pressure drop along the tubing. Some correlations can be used for vertical production wells, while some can be used for any orientation of the well as well as for both flow directions, i.e., for production and injection wells.

These correlations are based on number of assumptions and at the same time different level of significance have been given to numerous parameters, which in turn leads to different pressure drop or wellhead pressure estimations. In simple form, pressure drop along the tubing can be given as [1] (equation 1):

$$\Delta P_{tubing} = P_{wf} - P_{wh} \quad (1)$$

Pressure drop through the tubing required to lift the desired amount of fluid (gas, oil, water) to the surface is dependent on number of parameters which are briefly discussed below. Pressure drop calculations can be simple if the oil is considered as incompressible, but in reality it is not true and further the production of water and gas along with it, adds to the complexity of P calculations.

2. Pressure drop through Tubing

Pressure drop while flow through tubing, is a summation of pressure losses due to potential energy, frictional losses and kinetic energy losses [1, 2]. Analyzing multiphase flow behavior is a complex phenomenon. Due to an existence of gas/liquid mixture, phenomena's like liquid hold up, slip velocities, etc., might occur [3]. Moreover, the behavior of multiphase flow through the tubing can also give arise to different flow regimes, which in turn also strongly influences the pressure drop through the tubing [2, 3].

While estimating pressure drop and/ or the resulting wellhead pressure when the bottom hole flowing pressure is known, the above mentioned parameters have been included in different multiphase flow correlations. In this study, modified Hagedorn & Brown [2, 4] (H & B) and Beggs and Brill [5, 6] (B & B) method have been used for analyzing flow through tubing.

On comparative basis, the former method is based on whether the bubble flow exists or not, if bubble flow exists then Griffith correlation has to be used for pressure drop/ gradient calculations [2]. While the later method is based on flow regimes and once the flow regime is predicted, then the liquid hold-up parameter is calculated accordingly further leading to the estimation of wellhead pressure. Furthermore, wellhead or tubing head pressure by using the above mentioned correlations can be calculated by using the following equations respectively, however further detail can also be found in the literature [2-8].

While using H & B, following equation (2) can be used for calculating wellhead pressure:

$$P_{wf} - P_{wh} = \frac{1}{144}\left[dz\left(\bar{\rho}_m + \frac{f\,w^2}{2.9652\times10^{11} D_{(ft)}^5 \bar{\rho}_m}\right) + \bar{\rho}_m \Delta\left(\frac{u_m^2}{2g_c}\right)\right] \quad (2)$$

and the following equation (3) can be used for calculating the same while using B & B method:

$$P_{wf} - P_{wh} = dZ \times \frac{\frac{1}{144}\left[\frac{g}{g_c}\rho_{tp}\sin\theta + \frac{f_{tp} G_m u_m}{2 g_c D_{(ft)}}\right]}{1 - \frac{1}{144}\left[\frac{\rho_{tp} u_m u_{sg}}{g_c \bar{P}}\right]} \quad (3)$$

3. Parallel Data Generation (PDG)

PDG, for the purpose of timely solution has been used, which is further enhanced by using a correlating parameter for efficient data matching/ history matching. Let wellbore flowing pressure as the known pressure. To increase the accuracy of the outputs generated, the entire tubing is divided into number of segments/sections, as shown in Fig.1. Furthermore, the flow chart as given in Fig.2 shows the process of executing the developed state-of-the-art algorithms, leading to data generation (wellhead pressure) by using the above mentioned approaches at the same time.

If, the predicted wellhead pressure as a result of PDG, by using both, i.e., modified Hagedorn & Brown and Beggs & Brill method are not matching the actual wellhead pressure then the calculated P_{wh} can be multiplied by a parameter to have a well profile match within acceptable range. This methodology gives an added advantage of curve matching by using the same multiphase correlations.

4. Implementation: Results and Discussion

The developed methodology has been implemented on a number of case studies, which are described below. The data used in these cases is given in Table 1.

Table 1: Key parameters used in this study

Well Depth (m)	1053.084 (case1) 2665.47 (case2) 1019.5 (case3)
Tubing ID (m)	0.0645
Oil gravity	0.812 (case1) 0.700 (case2 & 3)
Gas gravity	0.67 (case1) 0.61 (case2 & 3)
Deviation (radians)	1.570796
Relative roughness	0.0006

4.1 Case 1: Oil Production Well

Mainly oil is produced from a well along with gas and water. The calculated wellhead pressures based on gas, oil and water flow rates and by using corresponding wellbore flowing pressure (BHP) are plotted against the actual wellhead/ tubing head pressure (THP), as shown in Figure (3), which shows that in this case, Beggs and Brill method have accurately predicted the tubing head pressures.

4.2 Case 2: Gas Production along with Condensate

In this case a gas well is analyzed, which is also producing condensate having a specific gravity of 0.70 along with water. The obtained results are presented in Fig.4 which shows that the modified Hagedorn and Brown method have given an accurate match for the well.

4.3 Case 3: Water Producing Well

The developed methodology has been implemented on a well which is producing water as a main fluid. Fig.5 shows that the estimated tubing head pressures by using the both correlations does not the match the actual THP's, so a correlating parameter has been applied on both correlations to match the predicted data with the actual data.

Fig.5 shows that Beggs and Brill (B & B) method has over estimated the actual tubing head pressure, while on the other hand modified Hagedorn and Brown (H & B) method, has under estimated the actual values. Percentage deviation for both the cases can be calculated by using the following equation (4):

$$\%\ \text{Deviation} = \frac{\text{Actual value} - \text{Predicted value}}{\text{Actual value}} \times 100 \qquad (4)$$

The under estimation of the predicted data by using H & B ranges from 2.99% to 3.98%, while the overestimation of the results based on B & B ranges from -4.9% to -5.7%. Please note that the negative sign is due to overestimation from the actual value as calculated by using above equation.

To, have a tubing head pressure profile match in this case a multiplying factor has been introduced which is multiplied by the predicted values, obtained from both methods. A profile match has been obtained, when a correlating value of 1.04 has been used in case of H & B method, while a matching has been obtained for B & B method by using a parameter of 0.99. The results obtained after incorporating these parameters a perfect match has been obtained as shown in Fig.5.

5. Conclusion

Parallel data generation for predicting wellhead pressures corresponding to the existing flowing bottom hole pressure, is one of the fastest ways to generate data, providing an opportunity to analyze the actual data with the predicted data based on two correlations, i.e., modified H & B and B & B. At the same time, this study also shows that, introducing the correlating parameter to have best fit, further strengthens the PD generation and swift pressure profile matching.

Nomenclature

A	area
D	diameter
f	friction factor
f_{tp}	two phase friction factor
g	acceleration due to gravity
g_c	constant
G_m	mixture flux rate

P_{avg}, $\overline{P}$	average pressure
P_{wh}	wellhead pressure
P_{wf}	wellbore flowing pressure
T_{avg}	average temperature
u_m	mixture velocity
u_{sg}	superficial gas velocity
w	mass flow rate
z,dZ	length
$\overline{\rho}_m$	average mixture density
$_{tp}$	two phase density
	angle of inclination

Corresponding Author:
Dr. Muhammad Khurram Zahoor
Department of Petroleum and Gas Engineering
University of Engineering and Technology, Lahore
Pakistan
E-mail: mkzahoor@yahoo.com

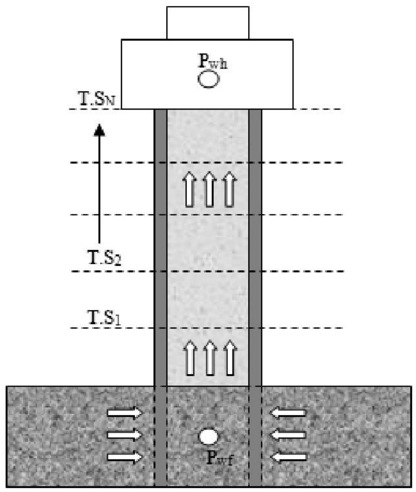

Figure1. Subsurface flow schematics

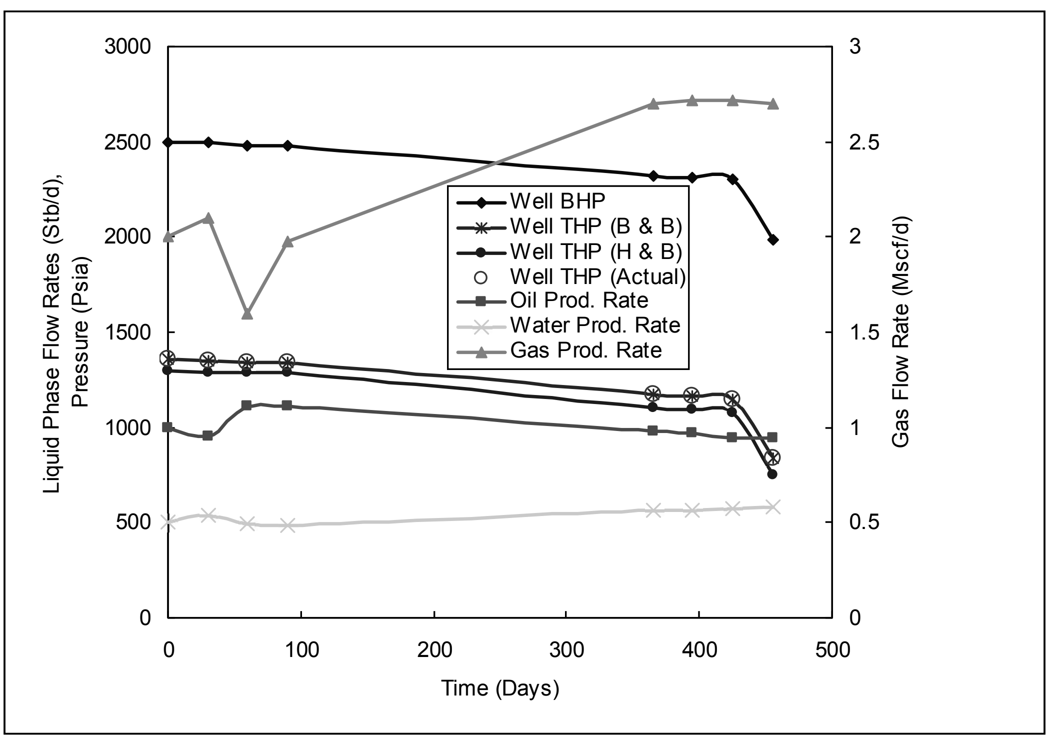

Figure 3. Well producing oil along with gas and water

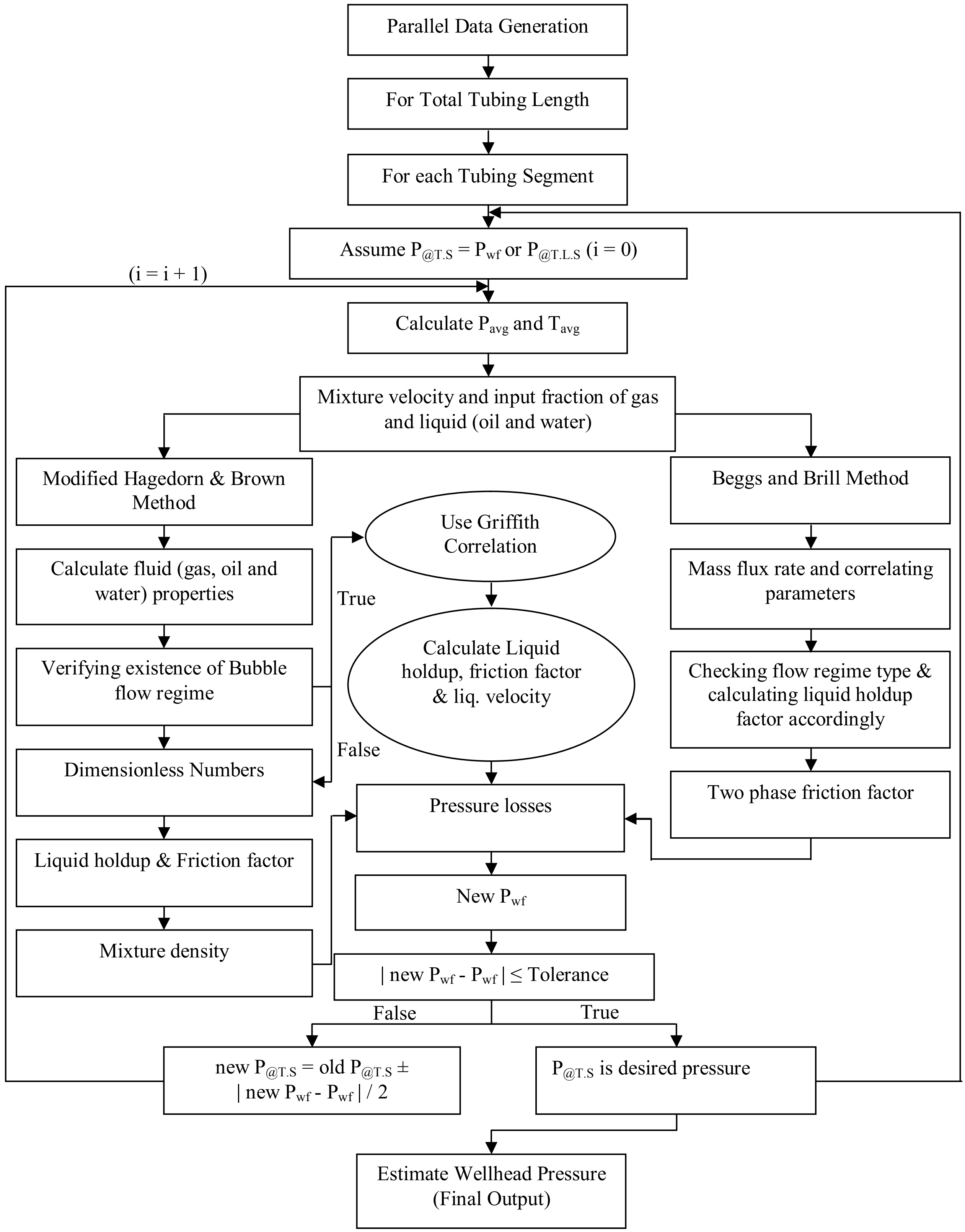

Figure 2. Algorithm for parallel data generation

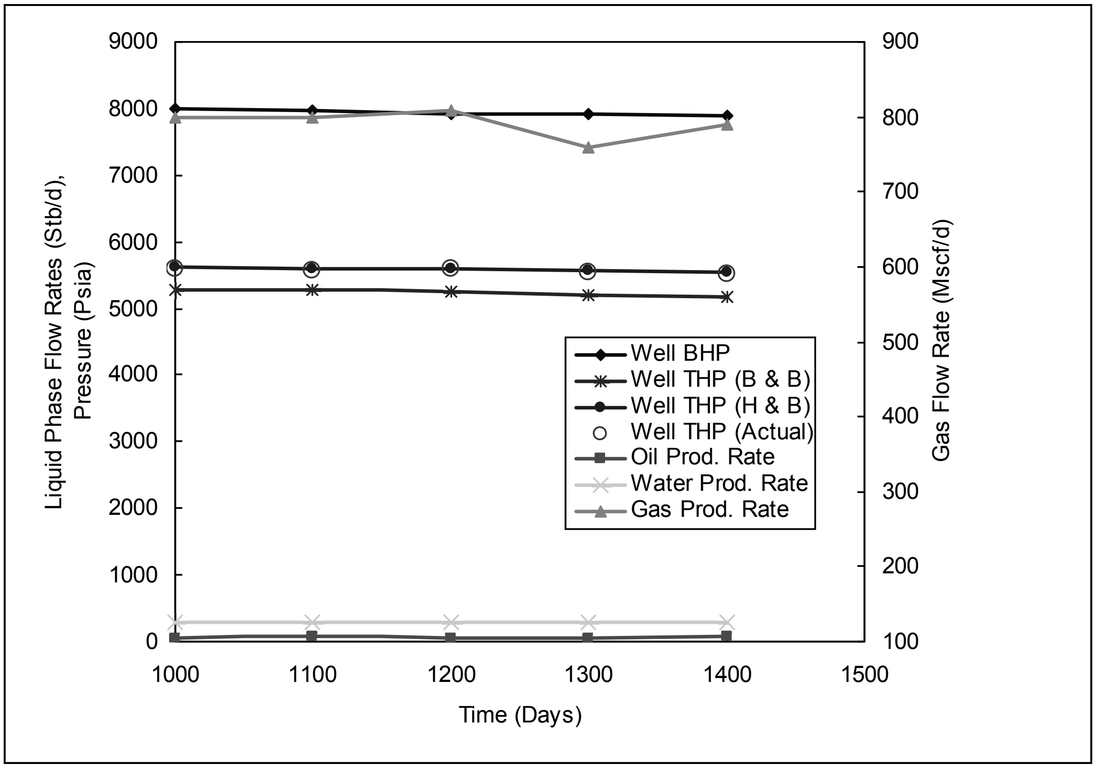

Figure 4. Gas well (also producing some condensate) production profiles

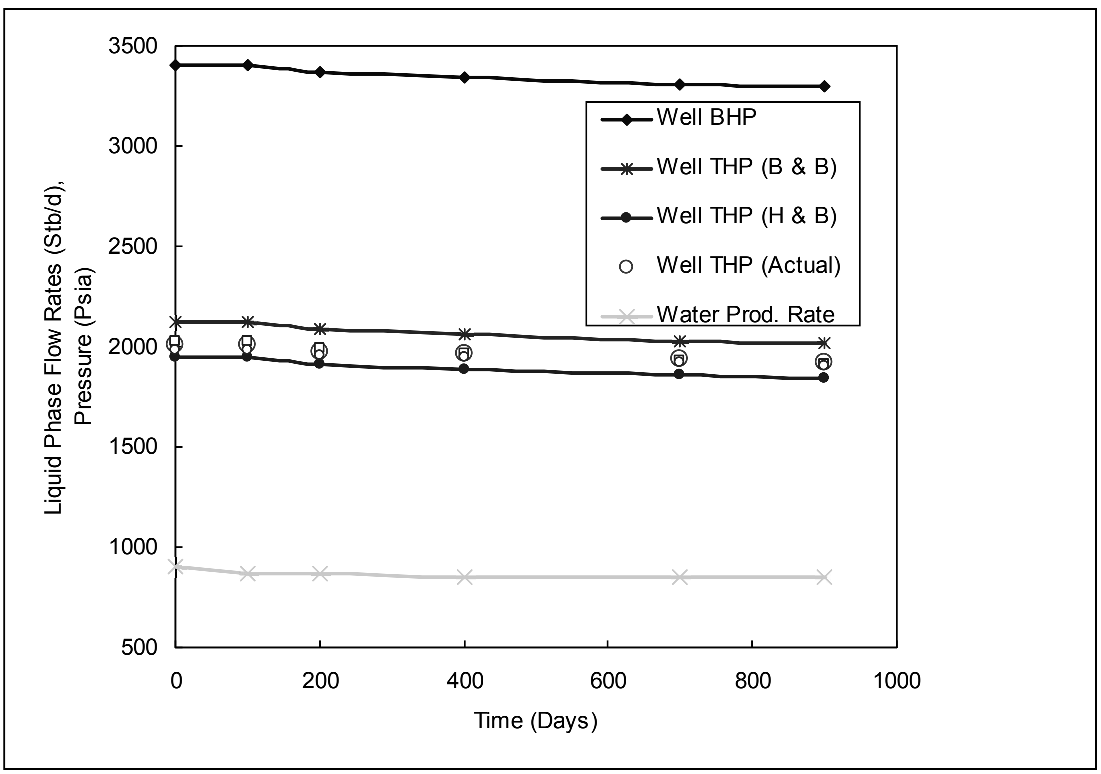

Figure 5. Water producing well production profile

References

1. Guo, B., W.C. Lyons, and A. Ghalambor, *Petroleum Production Engineering; A Computer Assisted Approach*. 2007: Elsevier Science & Technology Books.
2. Economides, M.J., Hill, A.D, and Ehlig-Economides, C, *Petroleum Production Systems*. 1994, Englewood Cliffs, NJ: Prentice Hall.
3. Brown, K.E., *The Technology of Artificial Lift Methods*. Vol. 1. 1977, Tulsa: PPC Books.
4. Hagedorn, A.R. and K.E. Brown, *Experimental study of Pressure gradients occuring occuring during continuous two-phase flow in Small-diameter Vertical conduits.* JPT. 1965: p.: 475-484.
5. Brill, J., and Beggs. H. D., *Two- Phase flow in pipes*. 3rd. ed. 1978, Tulsa: University of Tulsa.
6. Beggs. H. D., and Brill, J. P., *A Study of Two-Phase flow in Inclined Pipes.* Journal of Petroleum Technology, 1973. 25(5): p. 607-617.
7. Beggs, H.D. and J.R. Robinson, *Estimating the Viscosity of Crude Oil Systems.* SPE Journal of Petroleum Technology, 1975(09).
8. Beggs, H.D., *Production Optimization: Using Nodal Analysis*. 1991, Tulsa: OGCI Publications.

1/25/2018