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System Analytical Model to Estimate and Optimize Oil Well Performance

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***Abstract*—The use of separated flow models to specify the vertical lift performance of an oil well is usually somewhat complex- due to the many equations and correlations involved in the determination of the required variables. Consequently, coding these models in the computer presents an extent of difficulty. In this study however, with the view of developing a computer model (DOBB) to perform nodal analysis for oil wells, an efficient algorithm was established to facilitate the determination of the operating pressure and liquid flow rate of oil wells (which is the point of intersection between the VLP and IPR curve). More so, Hagedorn Brown model was incorporated into the computer model to account for liquid hold ups and various flow regimes (excluding bubble flow regime) in the tubing string. The computer model developed in this study is equipped with the ability to determine fanning friction factor of the tubing string provided that the roughness of the pipe is known. Also, when the developed computer model was tested with some ranges of data points, nodal analysis plots were obtained from the different data points. Nonetheless, DOBB (a production engineering toolkit developed in this study) was proven to be efficient on the part of performing nodal analysis for oil wells.**

***Index Terms*—Bottom-Hole, Nodal Analysis, Inflow Performance, Vertical Lift Performance.**

I. INTRODUCTION

Nodal analysis can be used for production optimization. It is used in the oil and gas industry for the determination of optimum flow rate and the recognition of wells that should be producing at flow rates higher than their current rate. Homogeneous flow models are ideal- since they neglect liquid hold-ups in the tubing [1]. On the other hand, separated flow models are very realistic because they consider liquid hold-ups in the tubing. It is imperative to know that during production of liquid hydrocarbons to the surface, the flowing pressure is expected to experience a reasonable decline because of the long vertical height taken by the fluid to the surface via the tubing [16]. Thus, the flowing pressure is likely to reduce below the bubble point pressure of the hydrocarbon fluid in the tubing during production [2]. Consequently, two phase flow usually occur in the tubing. This makes separated flow models to be most suitable for determining the VLP. Fluid properties change with location dependent on pressure and temperature in the oil and gas production system [9], [11]. To simulate the fluid flow in the system, it is necessary to break the system into discrete nodes that separate system elements (equipment sections). Fluid properties at the elements are evaluated locally. The system analysis for determination of fluid production rate and pressure at a specified node is called ‘‘Nodal analysis’’ in petroleum engineering [7]. Nodal analysis is performed on the principle of pressure continuity, that is, there is only one unique pressure value at a given node regardless of whether the pressure is evaluated from the performance of upstream equipment or downstream equipment. The performance curve (pressure–rate relation) of upstream equipment is called ‘‘inflow performance curve’’; the performance curve of downstream equipment is called ‘‘outflow performance curve’’. For the convenience of using pressure data measured normally at either the bottom-hole or the wellhead, nodal analysis is usually conducted using the bottom-hole or wellhead as the solution node [8].

The use of separated flow models is usually somewhat complex – since some of the important parameters of the models are often presented in complex charts. Second, separated flow models are usually given in the form of empirical correlations thus making it difficult to code them in computer programs. The several correlations to be used plus complex charts makes it tasking to develop an efficient algorithm that will obtain the VLP of an oil well [6]. Thus, this study developed a computer model that utilizes a separated flow model (Hagedorn-Brown) in the determination of the Vertical Lift Performance of an oil well; specify the IPR curve, locate the point of intersection between the two curves, and specifying the bottom hole flowing pressure and optimum flowrate through the development of a reliable an efficient computer algorithm that will specify the values for liquid hold-ups of the tubing string. This study provides an efficient algorithm thus, facilitating the determination of optimum pressure and flowrate. It takes into consideration liquid –hold ups in the tubing since it makes use of a separated flow model. As such, the computer model developed herein can be used to model a real oil well. The computer model developed can be used to perform complex calculations in the shortest possible time.

II. STATEMENT OF THEORY

A. *Inflow Performance Relationship (IPR) Model*

Guo et al. propounded that Inflow Performance Relationship (IPR) is used for evaluating reservoir deliverability in production engineering [13]. The IPR curve is a graphical presentation of the relation between the flowing bottom-hole pressure and liquid production rate. A typical IPR curve is shown in Fig. 2.1. The magnitude of the slope of the IPR curve is called the productivity index (PI or J), that is,

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$$J = \frac{q}{Pe - Pwf} \tag{1}$$

Where J is the productivity index. Apparently J is not a constant in the two-phase flow region.

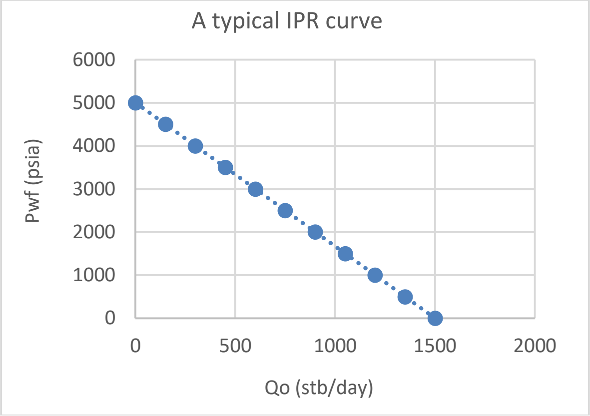


Fig. 1. Typical IPR curve

Well IPR curves are usually constructed using reservoir inflow models, which can be from either a theoretical basis or an empirical basis. your manuscript electronically for review. The equation that defines the productivity index (J) for flowing bottom-hole pressures above the bubble-point pressure is as shown in (1). Since the productivity index (J) above the bubble point pressure is independent of production rate, the IPR curve for a single (liquid)-phase reservoir is simply a straight line drawn from the reservoir pressure to the bubble-point pressure. A typical straight line IPR is as shown in Fig. 1. If the bubble-point pressure is 0 psig, the absolute open flow (AOF) is the productivity index (J) times the reservoir pressure [7].

B. Vertical Lift Performance (VLP) Model

Numerous VLP models have been developed for analysing multiphase flow in vertical pipes. Brown presents a thorough review of these models [3]. According to [13], Vertical lift Performance models for multiphase flow wells are in two categories:

1. Homogeneous flow models and
2. Separated-flow models.

Homogeneous models treat multiphase as a homogeneous mixture and do not consider the effects of liquid holdup (no-slip assumption) [13]. Therefore, these models are less accurate and are usually calibrated with local operating conditions in field applications. The major advantage of these models comes from their mechanistic nature. They can handle gas-oil water three-phase and gas-oil-water-sand four-phase systems. It is easy to code these mechanistic models in computer programs.

Separated-flow models are more realistic than the homogeneous-flow models. They are usually given in the form of empirical correlations. The effects of liquid holdup (slip) and flow regime are considered. The major disadvantage of the separated flow models is that it is difficult to code them in computer programs because most correlations are presented in graphic form.

C. IPR and VLP in Expected Flowrate (Q) and Pressure (Pwf) Prediction

Economides et al. propounded that Inflow Performance Relationship (IPR) describes the flow of reservoir fluids from the reservoir to the wellbore [7]. Once inside the wellbore, the fluid has to flow up to the production tubing string passing through various sizes of tubing and through restrictions caused by other completion string components [7]. Thus, this results in a pressure loss in the pressure of the fluid between the bottom-hole location and surface. According to [7], this pressure drop is referred to a vertical lift pressure drop. This pressure drop is attributed to three major sources:

1. Frictional pressure loss, i.e. loss associated with viscous drag
2. Hydrostatic head pressure loss due to density of the fluid column in the production tubing.
3. Kinetic energy losses due to expansion and contraction in the fluid flow area and the associated acceleration/deceleration of fluid as it flows through various restrictions.

The sum of these three pressure losses is termed vertical lift pressure loss.

III. METHODOLOGY

The computer model (DOBB) developed in this study is a production engineering toolkit that is used to perform Nodal Analysis on flowing oil wells without considering surface facilities. The computer model uses the Hagedorn Brown VLP model to specify the vertical lift performance of the well. The model can be used to provide a nodal analysis chart indicating the operating pressure and operating flowrate. More so, with the roughness of the tubing known, the model automatically calculates the fanning friction factor thus facilitating the pressure points calculations for VLP [5]. The software was developed using Microsoft Visual Studio. The splash screen of DOBB software is as shown in Fig. 2.

Fig. 2. Software splash screen

IV. ANALYTICAL EQUATIONS USED FOR THE COMPUTER MODEL DEVELOPMENT

Two main curves are required in performing a nodal analysis chart. These curves include; Inflow Performance Relationship curve and Vertical lift performance curve. The IPR model used for this study is the General combined Vogel IPR which is illustrated in (2).

$$Q = q_b + q_v * \left(1 - 0.2 * \left\{\frac{p_{wf}}{p_b}\right\} - 0.8 * \left\{\frac{p_{wf}}{p_b}\right\}^2\right) \tag{2}$$

However, the VLP variables can be estimated by the use of the Hagedorn Brown model neglecting the effect of kinetic energy. This assumption assigns a zero value to the acceleration due to gravity thus;

$$144\frac{dp}{dz} = \rho + \frac{fm^2}{(7.413\times10^5D^5)\rho} \qquad (3)$$

Equation (3) can be used to calculate the pressure gradient at any point in the tubing. To calculate the pressure drop, DP; (3) is re-arranged as follows:

$$DP = \frac{H}{144}\times\left[\rho + \frac{fm^2}{(7.413\times10^5D^5)\rho}\right] \qquad (4)$$

Thus calculating the bottom hole flowing pressures for vertical lift performance of the well, the following equation is used:

$$Pwf = Pr - \frac{H}{144}\times\left[\rho + \frac{fm^2}{(7.413\times10^5D^5)\rho}\right] \qquad (5)$$

Where Pr is the reservoir pressure.

V. Sequential Approach in Predicting the Bottom-Hole Flowing Pressure and Optimum Flowrate Using DOBB Computer Model

In this study, nodal analysis is performed for an oil well by the use of the Hagedorn Brown model. The Hagedorn Brown model takes into consideration liquid hold ups in the tubing hence enabling the specification of the Vertical Lift performance (VLP) pressure calculations. Provided that the roughness of the tubing is known, the fanning friction factor can be estimated without charts by the use of the Chen correlation.

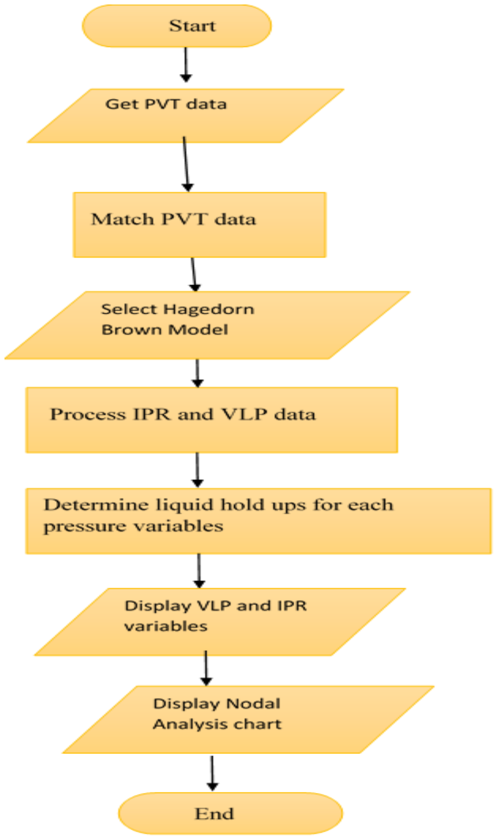
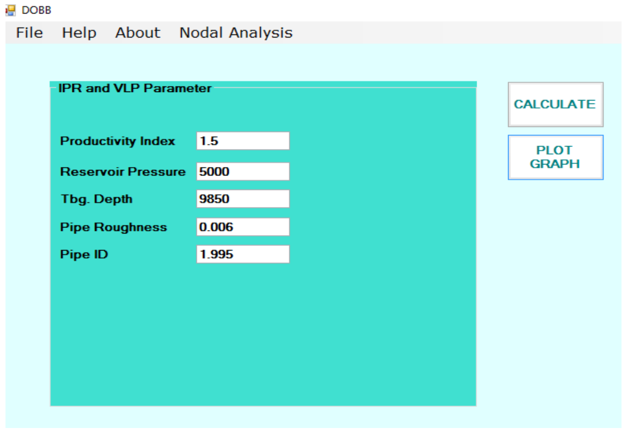


Fig. 3. Nodal Analysis flowchart for the computer model (DOBB)

However, the input data for Well-X20 and Well-Y25 are represented in Table 1. The input parameters for Well-X20 and Well-Y25 in the developed computer model (DOBB) are as shown in Fig. 4, Fig. 5, Fig. 6 and Fig. 7 respectively.

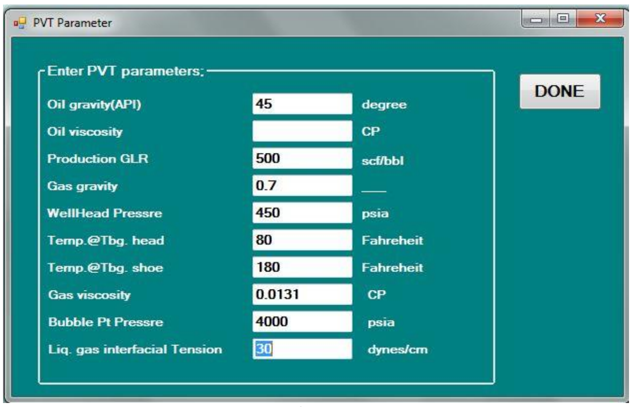
TABLE I: Input Data [13]

Parameters	**Well-X20**	**Well-Y25**
Tubing shoe depth	9850ft	5000ft
Tubing roughness	0.006	0.005
Tubing internal diameter	1.995in	2.259in
Production GLR	500scf/bbl	450scf/bbl
Wellhead Pressure	450psi	400psi
Gas specific gravity	0.7	0.7
Bubble point pressure	4000psi	3000psi
Oil gravity	45	40
Liq. Interfacial tension	30dynes/cm	30dynes/cm
Tubing head temp.	80ºF	70ºF
Bottomhole Temp.	180ºF	150ºF
Gas viscosity	0.0131CP	0.0131CP
Reservoir pressure	5000psi	4000psi
PI above bubble pnt.	1.5bbl/d-psi	0.99bbl/d-psi



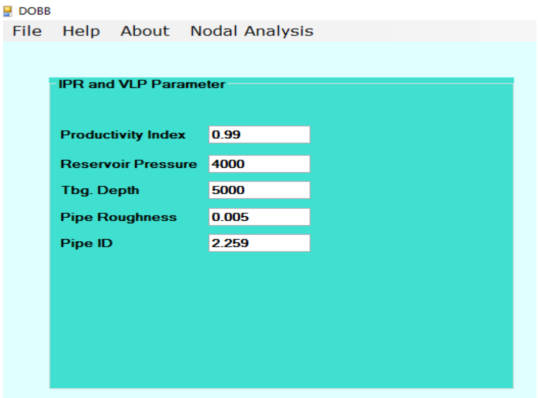
Productivity Index 1.5
Reservoir Pressure 5000
Tbg. Depth 9850
Pipe Roughness 0.006
Pipe ID 1.995

Fig. 4. IPR/VLP input data for Well-X20(DOBB)



Oil gravity(API) 45 degree
Oil viscosity CP
Production GLR 500 scf/bbl
Gas gravity 0.7 ——
WellHead Pressre 450 psia
Temp.@Tbg. head 80 Fahreheit
Temp.@Tbg. shoe 180 Fahreheit
Gas viscosity 0.0131 CP
Bubble Pt Pressre 4000 psia
Liq. gas interfacial Tension 30 dynes/cm

Fig. 5. PVT data for Well-X20(DOBB)



Productivity Index 0.99
Reservoir Pressure 4000
Tbg. Depth 5000
Pipe Roughness 0.005
Pipe ID 2.259

Fig. 6. IPR/VLP input data for Well-Y25 (DOBB)

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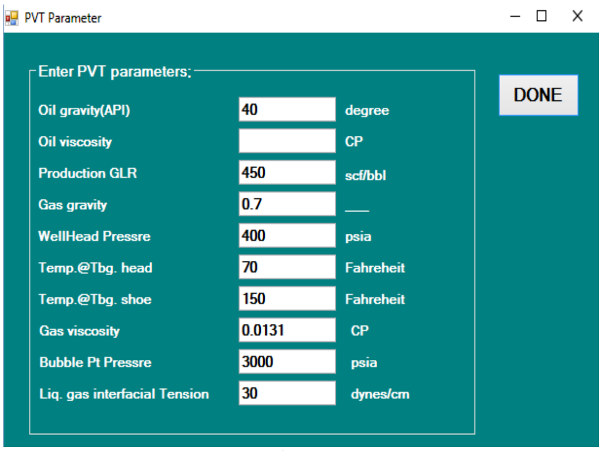


Enter PVT parameters:

Oil gravity(API)	40	degree
Oil viscosity		CP
Production GLR	450	scf/bbl
Gas gravity	0.7	___
WellHead Pressre	400	psia
Temp.@Tbg. head	70	Fahreheit
Temp.@Tbg. shoe	150	Fahreheit
Gas viscosity	0.0131	CP
Bubble Pt Pressre	3000	psia
Liq. gas interfacial Tension	30	dynes/cm

Fig. 7. PVT data for Well-Y25 (DOBB)

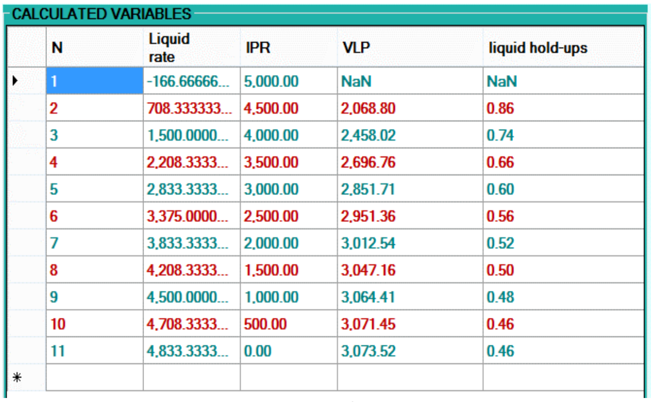
Nonetheless, for the sake of adequately verifying the computer model developed in this study, it was paramount to make use of some modified data – so as to adequately put to test the efficiency of the developed model. The modified data used are as illustrated in Table 2. The results of these input parameters are be discussed in the next section.

TABLE II: MODIFIED DATA POINTS

Parameters	Mod-data 1	Mod-data 2
Tubing shoe depth	7000 ft	5000ft
Tubing roughness	0.0059	0.005
Tubing internal diameter	1.995in	2.259in
Production GLR	550scf/bbl	450scf/bbl
Wellhead Pressure	450psi	400psi
Gas specific gravity	0.7	0.7
Bubble point pressure	1500psi	1850Psi
Oil gravity	39	40
Liq. Interfacial tension	30dynes/cm	25dynes/cm
Tubing head temperature	60ºF	70ºF
Bottomhole Temperature	150ºF	145ºF
Gas viscosity	0.0122CP	0.0122CP
Reservoir pressure	3500psi	3000psi
PI above bubble point	1.1bbl/day-psi	1.212bbl/day-psi

VI. RESULTS AND DISCUSSION

The results obtained from using the DOBB software are as shown in the figures below:



CALCULATED VARIABLES

N	Liquid rate	IPR	VLP	liquid hold-ups
1	-166.66666...	5,000.00	NaN	NaN
2	708.333333...	4,500.00	2,068.80	0.86
3	1,500.0000...	4,000.00	2,458.02	0.74
4	2,208.3333...	3,500.00	2,696.76	0.66
5	2,833.3333...	3,000.00	2,851.71	0.60
6	3,375.0000...	2,500.00	2,951.36	0.56
7	3,833.3333...	2,000.00	3,012.54	0.52
8	4,208.3333...	1,500.00	3,047.16	0.50
9	4,500.0000...	1,000.00	3,064.41	0.48
10	4,708.3333...	500.00	3,071.45	0.46
11	4,833.3333...	0.00	3,073.52	0.46

Fig. 8. Calculated variables for Well X-20 (DOBB)

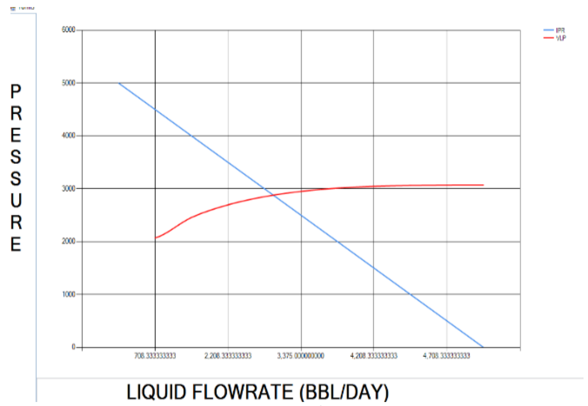
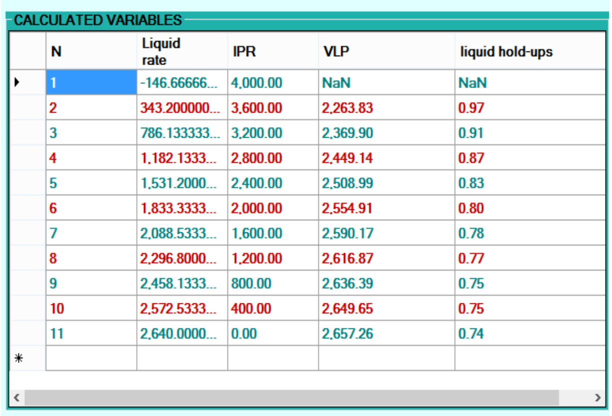


Fig. 9. Nodal Analysis plot for Well X-20 (DOBB)



CALCULATED VARIABLES

N	Liquid rate	IPR	VLP	liquid hold-ups
1	-146.66666...	4,000.00	NaN	NaN
2	343.200000...	3,600.00	2,263.83	0.97
3	786.133333...	3,200.00	2,369.90	0.91
4	1,182.1333...	2,800.00	2,449.14	0.87
5	1,531.2000...	2,400.00	2,508.99	0.83
6	1,833.3333...	2,000.00	2,554.91	0.80
7	2,088.5333...	1,600.00	2,590.17	0.78
8	2,296.8000...	1,200.00	2,616.87	0.77
9	2,458.1333...	800.00	2,636.39	0.75
10	2,572.5333...	400.00	2,649.65	0.75
11	2,640.0000...	0.00	2,657.26	0.74

Fig. 10. Calculated variables for Well X-25 (DOBB)

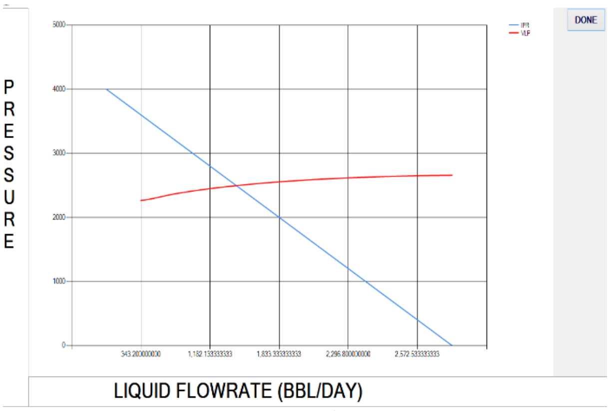
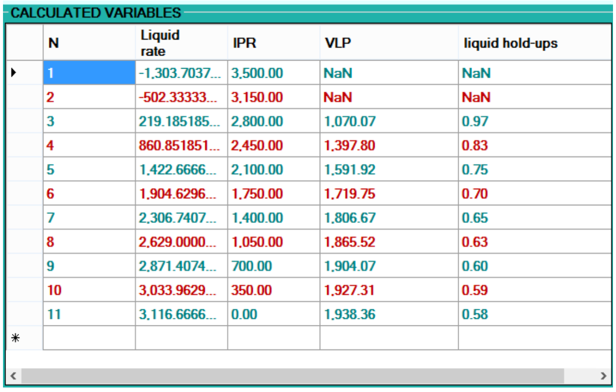


Fig. 11. Nodal Analysis plot for Well X-25 (DOBB)



CALCULATED VARIABLES

N	Liquid rate	IPR	VLP	liquid hold-ups
1	-1,303.7037...	3,500.00	NaN	NaN
2	-502.33333...	3,150.00	NaN	NaN
3	219.185185...	2,800.00	1,070.07	0.97
4	860.851851...	2,450.00	1,397.80	0.83
5	1,422.6666...	2,100.00	1,591.92	0.75
6	1,904.6296...	1,750.00	1,719.75	0.70
7	2,306.7407...	1,400.00	1,806.67	0.65
8	2,629.0000...	1,050.00	1,865.52	0.63
9	2,871.4074...	700.00	1,904.07	0.60
10	3,033.9629...	350.00	1,927.31	0.59
11	3,116.6666...	0.00	1,938.36	0.58

Fig. 12. Calculated variables using Mod-data 1 (DOBB)

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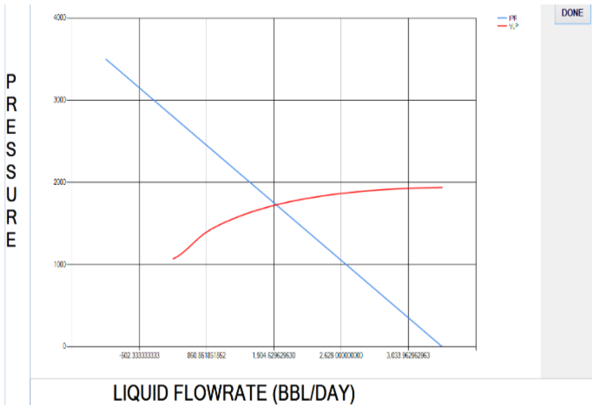
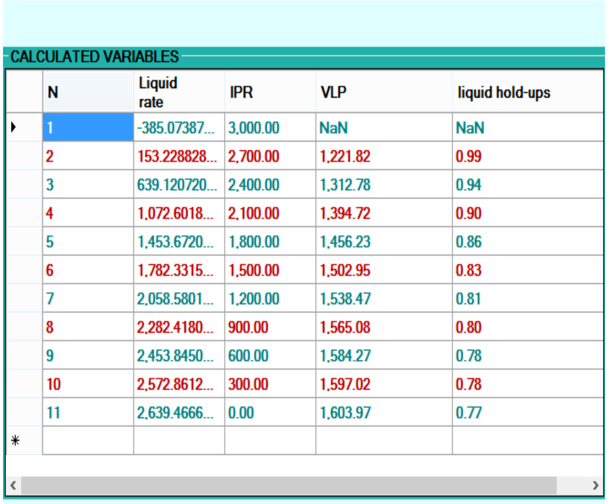


Fig. 13. DOBB Nodal Analysis plot using Mod-data 1



CALCULATED VARIABLES

N	Liquid rate	IPR	VLP	liquid hold-ups
1	-385.07387...	3,000.00	NaN	NaN
2	153.228828...	2,700.00	1,221.82	0.99
3	639.120720...	2,400.00	1,312.78	0.94
4	1,072.6018...	2,100.00	1,394.72	0.90
5	1,453.6720...	1,800.00	1,456.23	0.86
6	1,782.3315...	1,500.00	1,502.95	0.83
7	2,058.5801...	1,200.00	1,538.47	0.81
8	2,282.4180...	900.00	1,565.08	0.80
9	2,453.8450...	600.00	1,584.27	0.78
10	2,572.8612...	300.00	1,597.02	0.78
11	2,639.4666...	0.00	1,603.97	0.77

Fig. 14. Calculated variables using Mod-data 2 (DOBB)

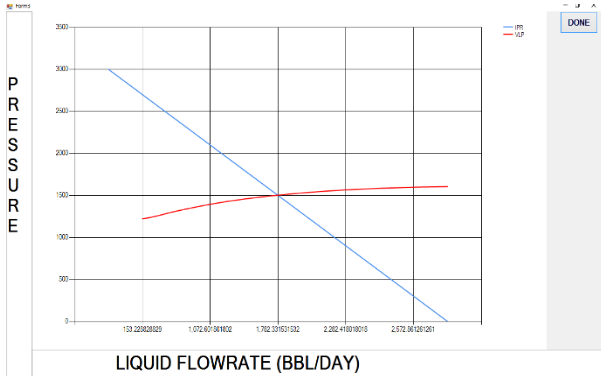


Fig. 15. DOBB Nodal Analysis plot using Mod-data 2

VII. DISCUSSION

A. *Discussion of results obtained from Well– X20 and Well-Y25*

The results obtained for Well X-20 and Well Y25 are as shown in Fig. 9 and Fig. 11 respectively. However, the calculated variables for Well-X20 and Well-Y25 are represented in Fig. 8 and Fig. 10 respectively. The variables revealed that from the point when the average reservoir pressure is at its apex (that is the reservoir pressure), there were no values for the VLP and liquid hold up column. But as soon as pressure began to decline, values were returned for the VLP and liquid hold up column. From the Nodal analysis plot conducted by the DOBB computer model, it was observed that the point of intersection between the Vertical Lift Performance (VLP) Curve and the Inflow Performance Relationship (IPR) curve for Well–X20 gave an operating pressure of 2800 psi and operating flowrate of 3000 bbl/day. Similarly, for Well-Y25 the operating pressure and flowrate were determined as 2500 psi and 1432 bbl/day respectively.

B. *Discussion of results obtained from using modified data points*

The nodal analysis plot for Mod-data 1 and Mod-data 2 as provided by the DOBB computer model are as shown in Fig. 13 and Fig. 15. The nodal analysis plot for Mod-data 1 reveals that, the point of intersection between the VLP and IPR gave a bottom hole flowing pressure of 1,700psi and an optimum liquid flowrate of 1,910 bbl/day. Similarly, the bottomhole flowing pressure and optimum flowrate for Mod-data 2 gave 1500 psi and 1782.33 bbl/day respectively. The display of estimated variables for both modified data points are well illustrated in Fig.12 and Fig. 14. The results inferred from the modified data reveals that the liquid flowrate of Mod-data 1 is higher than that of Mod-data 2 despite the fact that the former has lesser productivity index (1.1 bbl/day-psi) than the latter (1.2.2 bbl/day-psi). This is due to the fact that Mod- data 1 possesses a lower internal tubing diameter (1.995 inches) than Mod- data 2 (2.259 inches). This is reflective of the fact that wells with lesser tubing diameter often have a better vertical lift performance than wells with high tubing diameter.

VIII. CONCLUSION

The computer model, DOBB: a production engineering toolkit, has beyond reasonable doubt proved its competence in the determination of the operating pressure and flowrate of oil wells. The model utilized the Chen’s correlation in the determination of the fanning friction factor of the tubing string. Hagedorn Brown model was incorporated into the model thus enabling it to compute the liquid hold ups and subsequently specifying the Vertical Lift Performance of a well. Though the use of Hagedorn Brown model presented a slight difficulty due to the multiple correlations and equations required for the calculation of liquid hold up, DOBB tool through the development of an efficient algorithm is able to use the model to perform nodal analysis.

APPENDIX

Source Codes for DOBB Tool

```
Imports System.Math
Public Class Form1
    Inherits Windows.Forms.Form
    Public Function Nvl(ByRef usl As Double) As Double
        Dim API, Ts, Th, Uo, Ug, Pb, Pw, Sg, lgt, ID, So, Dto As Double
        API = Val(Form2.txtAPI.Text)
        Ts = Val(Form2.txtTs.Text) + 460
        Th = Val(Form2.txtTh.Text) + 460
        Uo = Val(Form2.txtUo.Text)
        Ug = Val(Form2.txtUg.Text)
        Pb = Val(Form2.txtPb.Text)
        Pw = Val(Form2.txtPw.Text)
        Sg = Val(Form2.txtSg.Text)
        lgt = Val(Form2.TxtLgt.Text)
        ID = Val(txtid.Text) * 1 / 12
        So = 141.5 / (131.5 + API)
        Dto = 62.4 * So
```

```
        Return 1.938 * usl * (Dto / lgt) ^ 0.25
    End Function
    Public Function Nvg(ByRef usg As Double) As Double
        Dim API, Ts, Th, Uo, Ug, Pb, Pw, Sg, lgt, ID, So, Dto, dtg, H, Pr As Double
        API = Val(Form2.txtAPI.Text)
        Ts = Val(Form2.txtTs.Text) + 460
        Th = Val(Form2.txtTh.Text) + 460
        Uo = Val(Form2.txtUo.Text)
        Ug = Val(Form2.txtUg.Text)
        Pb = Val(Form2.txtPb.Text)
        Pw = Val(Form2.txtPw.Text)
        Sg = Val(Form2.txtSg.Text)
        lgt = Val(Form2.TxtLgt.Text)
        ID = Val(txtid.Text) * 1 / 12
        H = Val(txtD.Text)
        Pr = Val(txtpr.Text)
        So = 141.5 / (131.5 + API)
        dtg = Sg * 0.07967
        Dto = 62.4 * So
        Return 1.938 * usg * (Dto / lgt) ^ 0.25
    End Function
    Public Function Mav(ByRef usg As Double, ByRef usl As Double) As Double
        Dim API, Ts, Th, Uo, Ug, Pb, Pw, Sg, lgt, ID, So, Dto, dtg, A As Double
        API = Val(Form2.txtAPI.Text)
        Ts = Val(Form2.txtTs.Text) + 460
        Th = Val(Form2.txtTh.Text) + 460
        Uo = Val(Form2.txtUo.Text)
        Ug = Val(Form2.txtUg.Text)
        Pb = Val(Form2.txtPb.Text)
        Pw = Val(Form2.txtPw.Text)
        Sg = Val(Form2.txtSg.Text)
        lgt = Val(Form2.TxtLgt.Text)
        ID = Val(txtid.Text) * 1 / 12
        So = 141.5 / (131.5 + API)
        Dto = 62.4 * So
        dtg = Sg * 0.07967
        A = PI * ID ^ 2 / 4
        Return A * (usl * Dto + usg * dtg)
    End Function

    Private Sub ExitToolStripMenuItem_Click(ByVal sender As System.Object, ByVal e As System.EventArgs) Handles ExitToolStripMenuItem.Click
        End
    End Sub

    Private Sub MatchPVTDataToolStripMenuItem_Click(ByVal sender As System.Object, ByVal e As System.EventArgs) Handles MatchPVTDataToolStripMenuItem.Click
        Form2.Show()
    End Sub

    Private Sub HagedornBrownmodelToolStripMenuItem_Click(ByVal sender As System.Object, ByVal e As System.EventArgs) Handles HagedornBrownModelToolStripMenuItem.Click
        Dim FORM2 As New Form2
        Try
            If Val(FORM2.txtTs.Text) <> 0 Or (FORM2.txtAPI.Text) <> 0 Then
                GroupBox1.Visible = True
                Button1.Visible = True
                Button2.Visible = True
            Else
                GroupBox1.Visible = False
                Button1.Visible = False
                MsgBox("Match PVT data first", MsgBoxStyle.Exclamation)
                Exit Sub
            End If
        Catch ex As Exception
            MsgBox("Match PVT data first", MsgBoxStyle.Exclamation)
        End Try
    End Sub
```

```
    Private Sub Button1_Click(ByVal sender As System.Object, ByVal e As System.EventArgs) Handles Button1.Click
        GroupBox2.Visible = True
        Dim P_i, Pr, gt, dat, L, Pb, Ug, Ul, qg, ql, GLR, id, Ep, Nvvl, Nvvg, Nd, Nl, Y, CNL, X1, X2, Y_V, yl, dtav, Mavv, Nre, Ff, H, LB, Rt, Tt, ml As Double
        Dim Pipr As Decimal
        Dim API, Ts, Th, Uo, Pw, Sg, lgt, So, Dto, A, dtg, pwf, pav, phf As Double
        Dim r, i As Integer
        DGV.DataSource = Nothing
        DGV.Rows.Clear()
        Pr = Val(txtpr.Text)
        P_i = Val(txtPI.Text)
        phf = Val(Form2.txtPw.Text)
        i = 1
        r = 1
        gt = Pr / 10
        Pipr = Pr - gt

        pav = Pr
        Pb = Val(Form2.txtPb.Text)
        L = P_i * (Pr - Pb)
        dat = P_i * Pb / 1.8
        GLR = Val(Form2.TxtGLR.Text)
        id = Val(txtid.Text) * 1 / 12
        API = Val(Form2.txtAPI.Text)
        Ts = Val(Form2.txtTs.Text) + 460
        Th = Val(Form2.txtTh.Text) + 460
        Uo = Val(Form2.txtUo.Text)
        Ug = Val(Form2.txtUg.Text)
        Pb = Val(Form2.txtPb.Text)
        Pw = Val(Form2.txtPw.Text)
        Sg = Val(Form2.txtSg.Text)
        lgt = Val(Form2.TxtLgt.Text)
        Ep = Val(txtE.Text)
        H = Val(txtD.Text)
        Pr = Val(txtpr.Text)
        So = 141.5 / (131.5 + API)
        dtg = Sg * 0.07967
        Dto = 62.4 * So
        A = PI * id ^ 2 / 4
        Do Until i > 11
            r = DGV.RowCount - 1
            DGV.Rows.Add()
            Pipr = Pr
  ql = L + dat * (1 - 0.2 * (Pipr / Pb) - 0.8 * (Pipr / Pb) ^ 2)
            qg = GLR * ql
            Ug = (4 * qg) / (PI * id ^ 2)
            Ul = (4 * ql) / (PI * id ^ 2)
            Tt = Ug + Ul
            Rt = Ug / Tt
            Nvvl = Nvl(Ul)
            Nvvg = Nvl(Ug)
            ml = A * Ul * Dto
            LB = 1.071 - 0.2218 * ((Tt ^ 2) / id)
            Rt = Ug / Tt
            'If Rt > LB Then
            Nd = 120.872 * id * (Dto / lgt) ^ 0.5
            Nl = 0.15726 * Uo * (Dto * (lgt) ^ 3) ^ -0.25
            X1 = Log10(Nl + 3)
            Y = -2.69851 + 0.15841 * X1 - 0.551 * X1 ^ 2 + 0.54785 * X1 ^ 3 - 0.12195 * X1 ^ 4
            CNL = 10 ^ Y
            X2 = Nvvl * Phf ^ 0.1 * CNL / (Nvvl ^ 0.575 * 14.7 ^ 0.1 * Nd)
            Y_V = -0.10307 + 0.6177 * (Log10(X2) + 6) - 0.63295 * (Log10(X2) + 6) ^ 2 + 0.29598 * (Log10(X2) + 6) ^ 3 - 0.0401 * (Log10(X2) + 6) ^ 4
            yl = Y_V
            Mavv = Mav(Ug, Ul)
            dtav = yl * Dto + (1 - yl) * dtg

            Nre = 0.022 * Mavv / (id * Uo ^ yl * Ug ^ (1 - yl))
            Ff = (-4 * Log10(Ep / 3.7065 - (5.0452 / Nre) * Log10(Ep ^ 1.1098 / 2.8257 + (7.149 / Nre) ^ 0.8981))) ^ -2
            pwf = pav - (H / 144 * (dtav + (Ff * Mavv ^ 2 / (74130000000.0
```

```
* id ^ 5 * dtav))))
            DGV(2, r).Value = Pipr.ToString("n2")
            DGV(1, r).Value = ql.ToString("n9")
            DGV(3, r).Value = pwf.ToString("n2")
            DGV(0, r).Value = i.ToString
            DGV(4, r).Value = yl.ToString("n2")
            i += 1
            r += 1
            Pr = Pr - gt
        Loop
    End Sub
    Private Sub Button2_Click(ByVal sender As System.Object, ByVal e
As System.EventArgs) Handles Button2.Click
        Form3.Show()
    End Sub
  End Class
```

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