Drill stem and Deliverability test analysis: Case study of a gas field well test analysis in Myanmar

By

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ABSTRACT

Drill-stem tests are performed to confirm or prove the presence and the producibility of oil and gas that is detected by the other services. It is usually performed on exploration wells are often the key to determining whether a well has found a commercial hydrocarbon reservoir. Reservoir parameters specifically related to productive capacity such as pressure, permeability can be determined through drill stem test. Common sequence of a drill stem test includes of a short flow period mostly five or ten minutes, which is followed by a buildup period of about an hour that is used to determine initial reservoir pressure. Afterwards, the well is allowed to flow for next four to twenty four hours to establish stable flow to the surface then the well is shut in again for final shut in or build up test which is used to determine permeability thickness and flow potential.

Drill stem tests are usually combined with deliverability tests which is referred to the testing of a well to measure its production capabilities and flow performance relationships. Most common deliverability tests are flow after flow, single-point, isochronal and modified isochronal tests. Two main applications of deliverability tests are obtaining the absolute open flow (AOF) potential and generating reservoir inflow performance relationship (IPR) or gas backpressure curve.

This paper discusses the case study of drill stem test and deliverability test done on a well in one of the gas fields located in Myanmar. Topics will cover the analyses of reservoir parameters through initial build up test, final build up test during the drill stem test and analysis of flow after flow test for Darcy and Non Darcy skin factors. In addition, it will further discusses the comparison of deliverability tests (empirical and analytical) and lastly perform production forecasting. The analyses are performed through Pansystem which is the well test analysis software developed by Weatherford Inc.

KEYWORDS: Drill stem test, Deliverability test, Analysis, Reservoir flow capabilities, Myanmar, Gas field, Pansystem

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CHAPTER-1: INTRODUCTION

1.1: BACKGROUND OF STUDY

In this case study two build up tests, and flow after flow tests in between are performed during the drill stem test on gas well. Two build up tests are used to determine the initial reservoir pressure and other parameters such as wellbore storage, permeability and kh. Flow after flow tests are used for Darcy and non-Darcy skin factors estimate then followed by performing deliverability analysis through analytical and empirical methods. Pressure build up tests are the most common well transient tests and conducted by producing a well at constant rate for some time, shutting the well in (usually at the surface), and recording the pressure (usually downhole) in the wellbore as a function of time. From which, formation permeability, current drainage area pressure, damage or simulation characterization and reservoir heterogeneities are estimated. There are many graphical methods to analyze build up tests namely, Semi Log plot analysis, Log-Log analysis and Cartesian analysis as well as type curves analysis. Semi Log and Log-Log analysis are used in this case study to analyse the build up tests.

Semi log plot analysis is also known as Hornor plot analysis and like most of other analysis, this analysis is based on assumptions that the reservoir is acting as an infinite, homogeneous, isotropic reservoir containing a slightly compressible, single-phase fluid with constant fluid properties. Wellbore damage or stimulation if there is such, is considered to be concentrated in a skin of zero thickness at the wellbore. In fact, no actual build up test can be modeled according to this description, hence, there is deviation between actual test results and this analysis result. One fundamental assumption for this analysis is that if the well has been producing, most recent rate must be maintained long enough than the second last rate. Only then, it is correct to continue plotting build up test data in Hornor pseudoproducing time vs sandface pressure to estimate formation permeability, original reservoir pressure Pi and skin factor s. Type curves analysis is used to validate the results obtained from Hornor approximation.

1.2: PROBLEM STATEMENT

All the reservoir parameters calculations are based on predictions using geophysical and geology data or certain methods. Human Error or technical error can be present in these predictions hence, consequently drawing the risk of getting inaccurate reservoir parameters. Therefore, getting the results from one particular analysis or method is not sufficient and should not be relied on unless they are validated against other analysis or method. Therefore, in this project, acquired data obtained from one analysis is validated with other methods. This project is also pursued to enhance the understanding on the area of drill stem test and the well test analysis as a whole in regard of personal interest.

1.3: OBJECTIVES

The purposes of the study are as follows,

1. To enhance understanding on drill stem test in gas wells.
2. To enhance understanding on theoretical background of build up tests, type curves, theoretical and empirical deliverability analysis.
3. To acquire and validate the important reservoir parameters.

1.4: SCOPE OF STUDY

Works of many authors on build up tests and flow after flow tests will be mainly studied. Basic theoretical background of all the analyses used will also be studied extensively. Type curves will be studied selectively. More importantly, gas well testing and significant terms and derivations are also in the scope of study. will This report will be carried out with the aid of well test software, Pansystem which is developed by Weatherford and thus, this software need to be studied during the mean time.

CHAPTER-2: LITERATURE REVIEW

Drill stem tests are widely used to determine the producible fluid content of a formation and to determine the ability of a formation to produce. Drill stem test or temporary completion can be performed in both open hole and inside casing through perforations. Drill stem tests are usually performed in potential productive interval which is predicted by logging and core data. Under this method, a test will usually made after penetrating a few feet into the prospective zone and if the results are favourable, subsequent tests may be made in search for fluid contacts (Black, W.Marshall, 1965). Three main components of a drill stem test tool are the test valve, the by-pass valve and the packer.

Drill stem tests are usually made up with initial build up period followed by multiple constant flow period and lastly the final build up. The analysis of these flows (draw-down) and shut-ins (build-up) permit the calculation of reservoir parameters such as initial reservoir pressure, permeability, skin, damage ration, radius of investigation, and estimation of absolute open flow potentials in gas wells. In fact, drill stem tests also consist of the preflow period which is the initial flow period after the test depth has been reached and the packers set. The objective of this period is mainly to release the hydrostatic pressure trapped when the packers are set and to discharge the mud contained in the rat hole between the formation and the test valve. Duration of this period can be varied from one test to another. This period is followed by initial shut in period whose purpose is to obtain the initial pressure of the reservoir, Pi. Build up test data is affected by the flow time prior to it, hence it is crucial to have a sufficient preflow to ensure a stabilized initial shut in pressure (Custer J.F & Testers Johnsten, 1975).

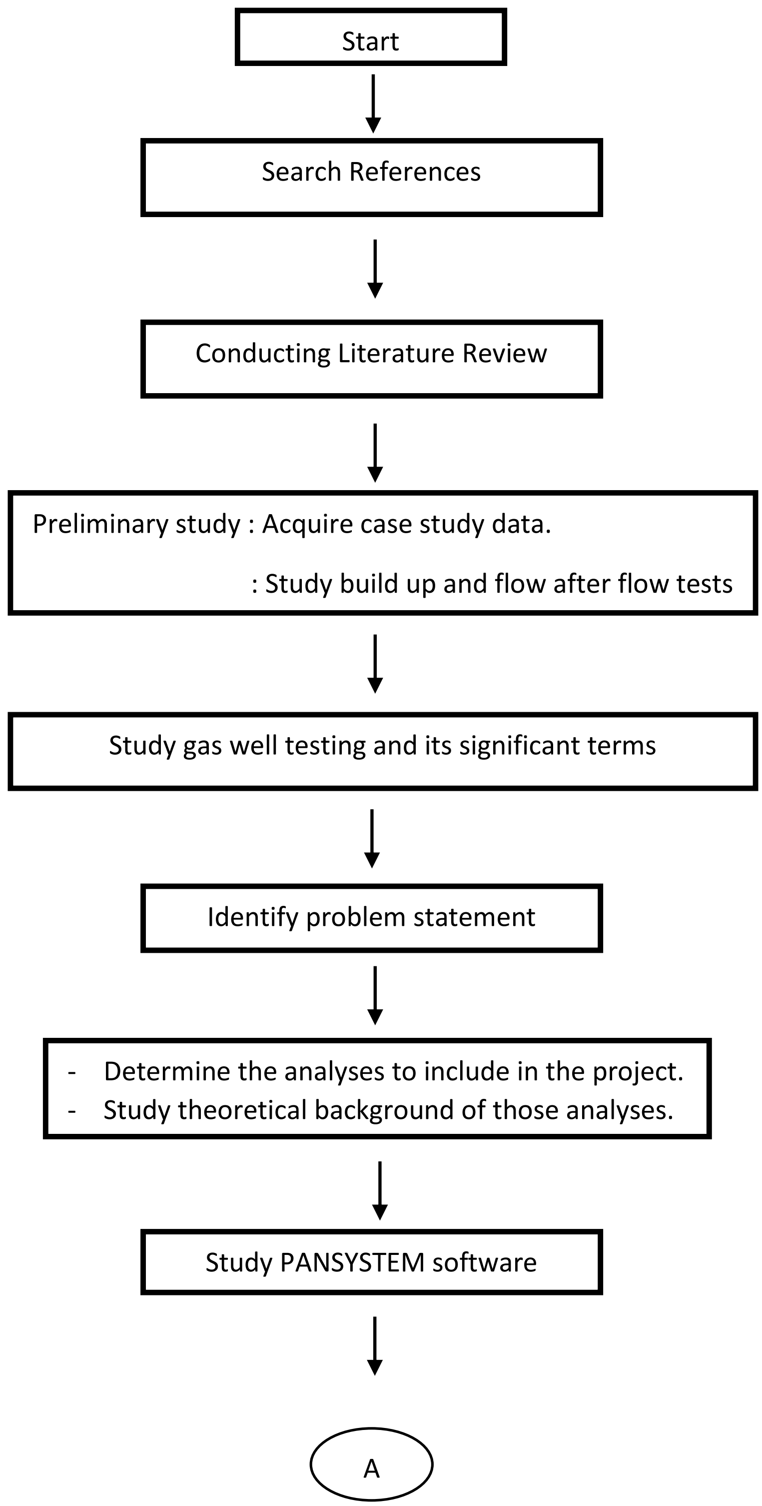
After the initial build up period, single flow period or multiple flows period is followed in the drill stem tests. Main purposes of the single flow period is to obtain a reservoir fluid sample with can be kept at reservoir conditions for later analysis, to achieve a stabilized flow rate if it is a gas well, to control the length of time to get a good value of radius of investigation. Multiple flow rate periods are also common and they are called deliverability test which is performed to measure the well's production capabilities and flow performance relationships. Many parameters relating to the flow capacity of the well and the reservoir such as non-Darcy skin coefficient, absolute open flow potential can be analysed and calculated from this period. Flow period is followed by the final shut in period and its main objective is to calculate the reservoir parameters such as permeability, skin factor (Xie Yun, Xin Young Bin, 2010) . As it was mentioned earlier, the build-up test is affected by the flow prior to it, and if the stabilized condition is not established before shut in, resulted reservoir parameters cannot be reliable.

Drill stem test analysis of gas wells and oil wells are different as some of extra terms are significant and must be considered in the gas wells testing mainly due to its velocity and compressibility (Agarwal, R.G, 1979). Lin source (Ei function) solution to the diffusivity equation for slight compressible liquid with relatively constant properties is not valid for compressible gas whose properties are strong functions of pressure. Pseudo-pressure is used instead of pressure for gas flow in infinite-acting reservoirs which also takes into account of non Darcy flow pressure loss which is additional pressure loss due to high gas velocity near well bore or any other factor that will induce the non-darcy flow. and this non-darcy flow coefficient is required in theoretical analysis of deliverability tests.

Deliverability testing refers to the testing of a gas well to measure its production capabilities under specific conditions of reservoir and bottomhole flowing pressures. There are four most common type of gas well deliverability test: flow after flow, single-point, isochronal and modified isochronal tests. One main purpose of these test is to find the absolute open flow potential which is the maximum rate at which a well could flow against a theoretical atmospheric backpressure at the sandface (Riley, H.G, 1970). In practice, the well cannot produce at thist rate, AOF is often used to set maximum allowable production rates for individual wells. More importantly, reservoir inflow performance relationship (IPR) can be generated from the application of deliverability test. IPR curve can be used to evaluate gas well current deliverability potential under a variety of surface condition and also to forecast future production at any stage in the reservoir’s life. Flow after flow tests are conducted by producing the well at a series of different stabilized flow rates to measure the stabilized bottomhole pressure and each flow rate is established in succession without an intermediate shut-in period. There are theoretical and empirical method used to analyse deliverability tests. In most applications, they are usually used and compared to counter check the accuracy of the results.

CHAPTER-3: METHODOLOGY

3.1 METHOLOGY DIAGRARM



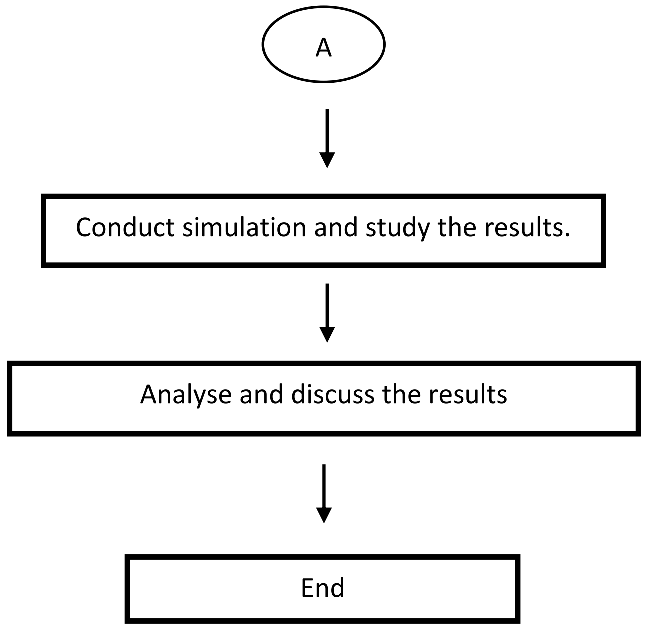


Figure 3.1: Methodology Diagram

3.2 ANALYSIS PROCESS DIAGRAM

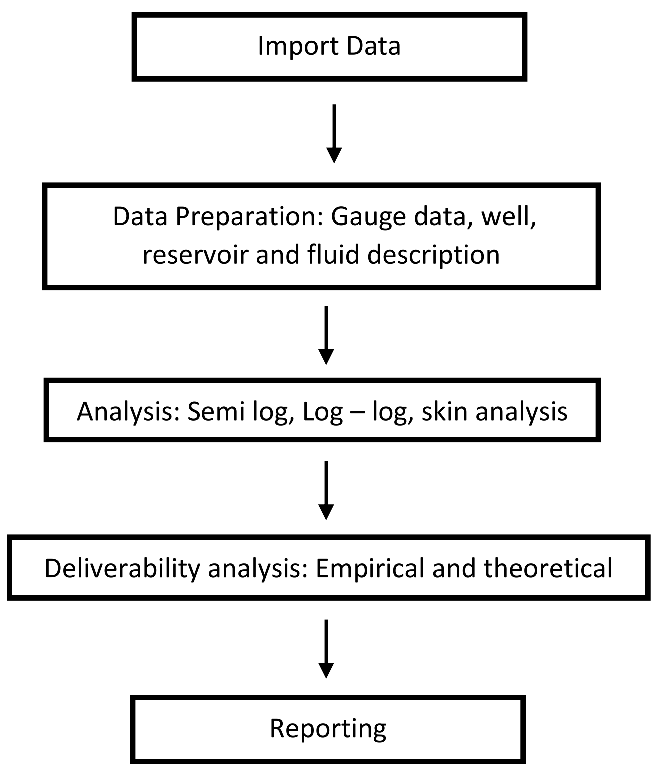


Figure 3.2: Analysis Process Diagram

3.3 PROJECT ACITIVITES

- Conducting the literature review based on previous published study on build up test, flow after flow tests and deliverability tests.
- Self-study on PANSYSTEM which are the main related software required.
- Consulting with FYPII seniors to get guideline.
- Consulting with PANSYSTEM Tutor.

3.4 TOOL REQUIRED

- As far as this project is concerned, PANSYSTEM software is the main tools required to continue with the research.

3.5 GANTT CHART

FYP ACTIVITIES	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	15	17	18	19	20	21	22	23	24	25	26
FYPI																										
FYP1 Briefing		■																								
Selection of the project topic		■																								
Discussion with SV for feasibility of the project			■																							
Conducting paper work			■	■	■	■																				
Submission of Extended proposal							■																			
Preparation of Proposal defense								■																		
Continuing project work								■	■	■	■															
Submission interim report											■															
FYPII																										
Project Work Continue												■	■	■	■	■	■	■								
Submission of progress report																			■							
Project work continue																			■	■	■	■	■			
Pre-EDX																						■				
Submission of draft report																							■			
Submission of dissertation (soft bound)																								■		
Submission of technical paper																								■		
Oral Presentation																									■	
Submission of project dissertation (hard bound)																										■

3.6 MILESTONES

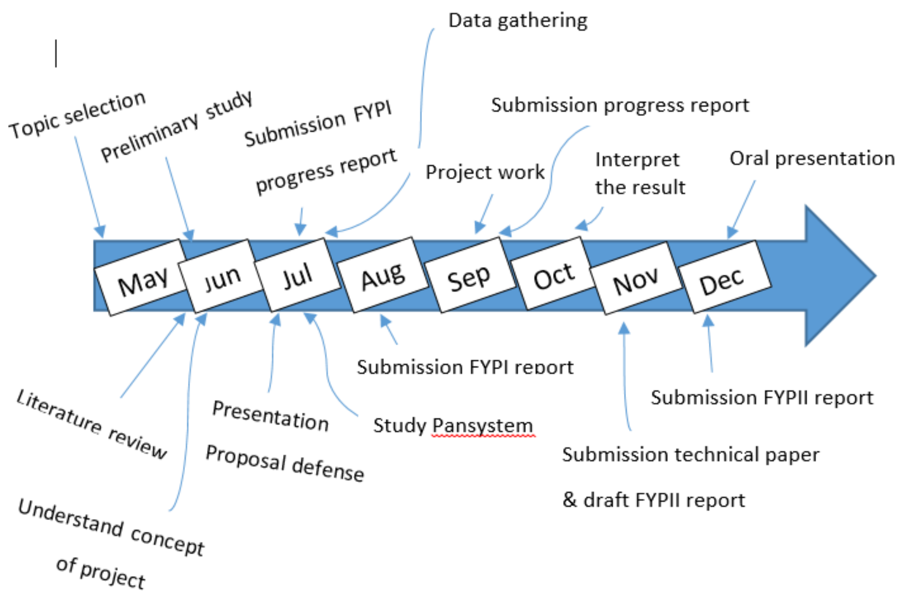


Figure 3.3: Milestones Diagram

CHAPTER 4: THEORETICAL BACKGROUND

4.1 HORNER'S APPROXIMATION

Pressure build up tests are frequently used to estimate formation permeability, current drainage area pressure, to characterize damage or stimulation and reservoir heterogeneities or boundaries. Common assumptions for all build up tests is that test is in an infinite, homogeneous, isotrpic reservoir containing a slightly compressible, single-phase fluid with constant fluid properties. More than five decades ago, Horner reported an approximation that can be applied in many cases to avoid that use of superposition that cannot be used for modeling that production history of a variable rate well. Major advantages of his approximation is that replacing the sequence of Ei functions, reflecting rate changes with a single Ei function that contains asingle producing time and a single production rate. That single rate is the most recent rate at which the well was produced. Single producing time is acquired by dividing cumulative production from the well by the most recent rate which is called pseudo-producing time. Basic two conditions for this approximation to be valid is that the most recent rate must be maintained sufficiently long enough for radius of investigation to reach the drainage radius of the tested well and that the last constant rate should be at least twice as long as the second last rate. This approximation is performed in following ways,

4.1.1 RESERVOIR PRESSURE

For a gas,

$$P_{ws}^2 = P_i^2 - \frac{1.49\ x\ 10^6\ QTZ}{\frac{kh}{\mu}} \log \frac{tp + \Delta t}{\Delta t}$$

This equation indicates that a plot of P_{ws}^2 vs $\log \frac{tp+\Delta t}{\Delta t}$ will give a curve that has for an intercept at $\log \frac{tp+\Delta t}{\Delta t}$ = 0, the value of P_2^i. Then the reservoir pressure is the square root of the extrapolated P_i^2.

For a liquid,

$$P_{ws} = P_i - \frac{2.121 \, x \, 10^6 \, QB}{\frac{kh}{\mu}} \log \frac{tp + \Delta t}{\Delta t}$$

From this equation, the plot of Pws vs log $\frac{tp+ \Delta t}{\Delta t}$ will have for intercept Pi directly.

4.1.2 PERMEABILITY

Final shut in build-up plot of P_{ws}^2 vs log $\frac{tp+ \Delta t}{\Delta t}$ will have a straight line, the slope equation for the straight line in this case is,

$$m = \frac{1.49 \, x \, 10^6 \, QTZ}{\frac{kh}{\mu}}$$

Therefore, $\frac{kh}{\mu} = \frac{1.49 \, x \, 10^6 \, QTZ}{m} \frac{mD.m}{Pa.s}$

If the gas viscosity is known, then $kh = \frac{kh}{\mu} \, x \, \mu \, mD.m$

4.1.3 FORMATION DAMAGE

Pressure drop due to the skin is expressed as,

$$\Delta P_{D \, well} = \frac{1}{2} (\ln t_D + 0.809) + S$$

Formation damage for a gas well is expressed as,

$$S = 1.1512 \left[\frac{P_i^2 - P_{wf}^2}{m} - \lg \frac{ktp}{\emptyset \mu c r_w^2} + 0.87 \right]$$

If S = 0, no drop in pressure exists near the wellbore.

If S > 0, a drop in pressure will be present near the wellbore, a damaged wellbore.

If S < 0, an enlarged wellbore either by stimulation or fracturing.

4.2 TYPE CURVES

Type curves are qualitative analysis of theoretical solutions to diffusivity equation and they can be generated virtually for any reservoir model for which a general solution describing the flow behavior is available. They are always presented in terms of dimensionless variables. Bourdet derivate type carves were developed from pressure derivatives of the analytical solutions of the same flow equations used in the generation for the Gringarten type curves. Its purpose is to identify the flow regimes during the wellbore storage-dominated period and infinite-acting radial flow and it is also able to estimate the reservoir properties and wellbore condition. Its advantages over conventional plot of well testing is that it can amplify the hardly visible heterogeneities on the derivative plot. Dimensionless variables used in Bourdet + Gringarten analysis are as follows,

$$p_D = \frac{kh(p_i - p)}{141.2qB\mu} \quad t_D = \frac{0.0002637kt}{\phi\mu c_t r_w^2} \quad C_D = \frac{0.894C}{\phi c_t h r_w^2}$$

$$p_D = \frac{t_D}{C_D}$$

$$\frac{dp_D}{d(t_D/C_D)} = p'_D = 1$$

Since P'D = 1, Multiplying P'D by TD/CD gives:

$$\left(\frac{t_D}{C_D}\right)p'_D = \frac{t_D}{C_D}$$

Type curve matching procedure for this analysis is as follows,

1. Prepare the test data for analysis by tabulating pressure change versus time. For drawdown test data, tabulate pressure change as $\Delta p = (p_i \text{ or } \overline{p}) - p_{wf}$ versus flowing time, Δt. For buildup test data, tabulate pressure change as $\Delta p = (p_{ws} - p_{wf@\Delta t=0})$ versus equivalent shut-in time, Δt_e, calculated from Eq. (12.16). Plot Δp vs. Δt or Δt_e.

2. If a unit slope line is present on the plot of the test data, select any point $(\Delta p, \Delta t \text{ or } \Delta t_e)_{USL}$ on the unit slope line. Calculate dimensionless wellbore storage coefficient

$$C_D = \frac{0.03723qB}{\phi c_t h r_w^2}\left(\frac{\Delta t \text{ or } \Delta t_e}{\Delta p}\right)_{USL}$$

calculate wellbore storage coefficient as:

$$C = 0.04165qB\left(\frac{\Delta t \text{ or } \Delta t_e}{\Delta p}\right)_{USL}$$

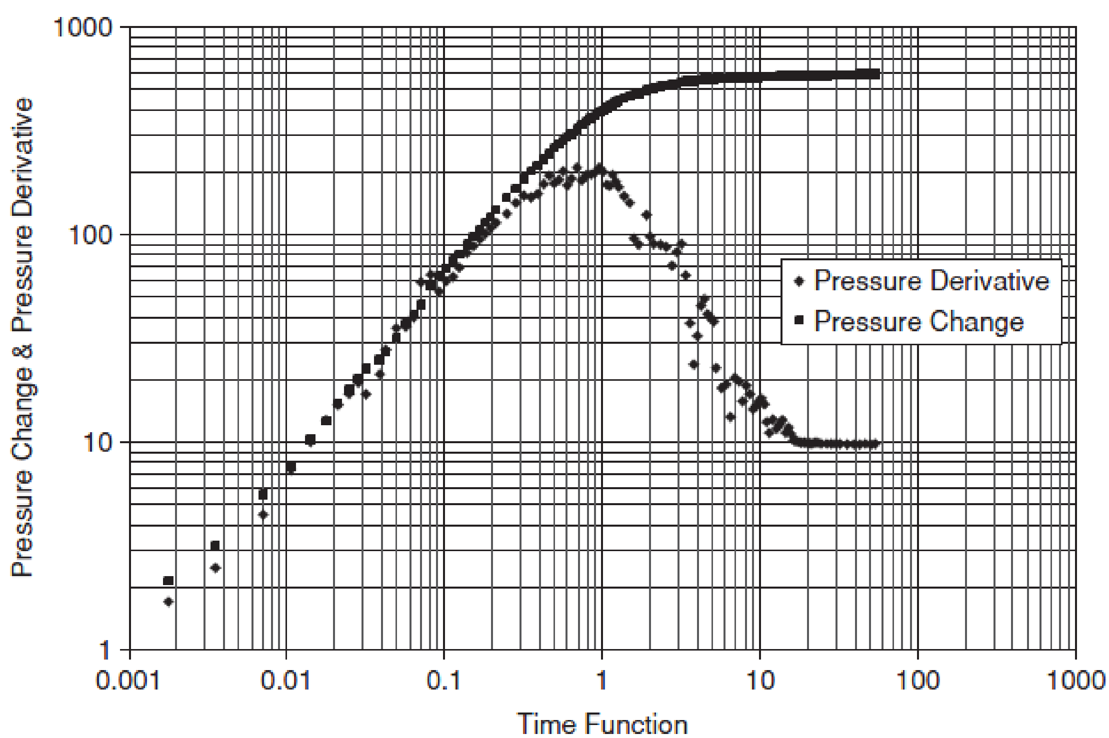


Figure 4.1: Pressure Derivative, Pressure Change Vs Time

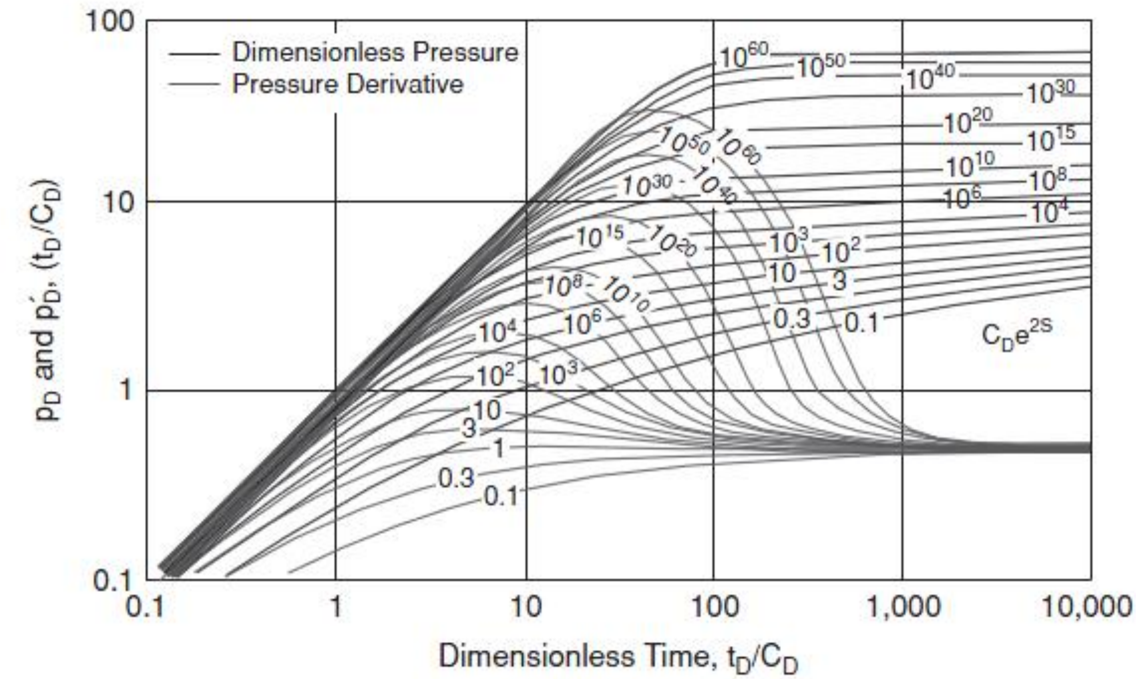


Figure 4.2: Bourdet + Gringarten type curve

3. For the derivative curve, calculate derivative of pressure with respect to natural logarithm of time. For drawdown test data, calculate the derivative as:

$$-\frac{dp_{wf}}{d(\ln t)} = -t\left[\frac{dp_{wf}}{dt}\right] = t\Delta p'$$

For buildup test data, calculate the derivative as:

$$\frac{dp_{ws}}{d(\ln \Delta t_e)} = \Delta t_e\left[\frac{dp_{ws}}{d(\Delta t_e)}\right] = \Delta t_e\Delta p'$$

Plot $t\Delta p'$(or $\Delta t_e\Delta p'$) versus Δt (or Δt_e) on the same graph plotted in Step 1.

4. Select a set of Gringarten-Bourdet type curves on the same scale as the graph plotted in Steps 1 and 2. Note that it is important that the two graphs are on the same scale.

5. Superimpose the plot of the test data on the Gringarten-Bourdet type curves. Achieve a match in the vertical direction by aligning the IARF stabilization line of the test data with similar line on the type curve indicated by $p_D'(t_D/C_D) = 0.5$.

6. If a unit slope line is present on the plot of the test data, achieve a match in the horizontal direction by aligning the unit-slope line of the test data with the unit slope line of the type curve.

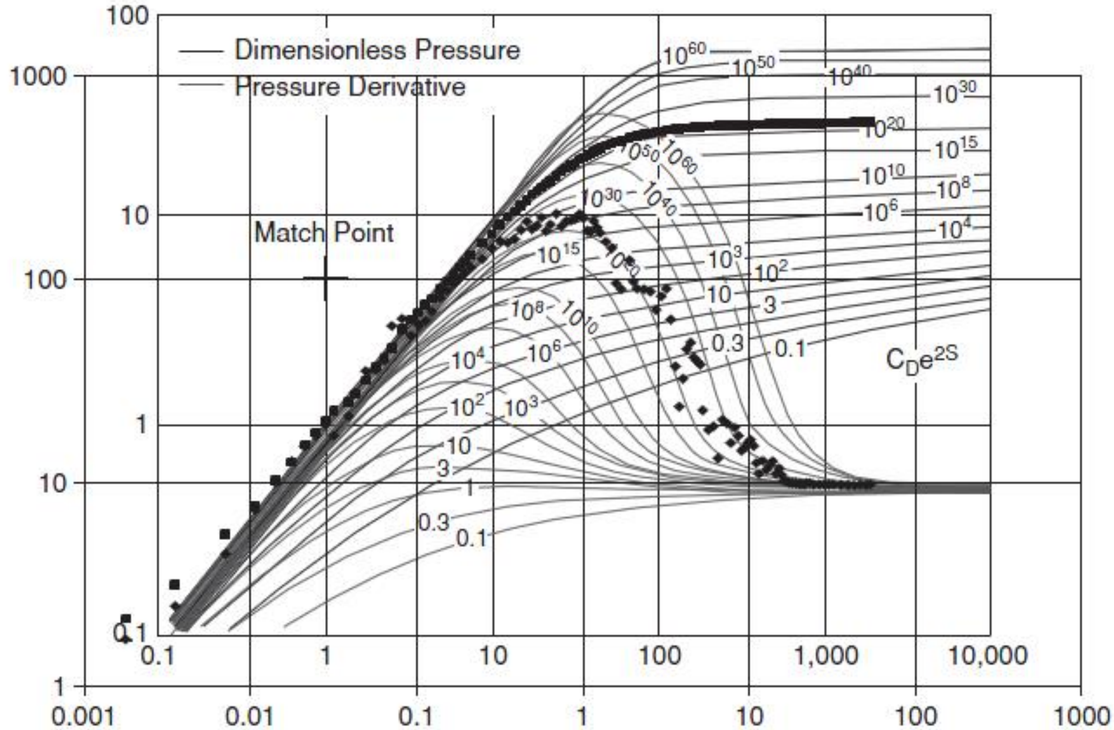


Figure 4.3: Type curve analysis using Bourdet + Gringarten type curve

7. From the pressure match point $(p_D, \Delta p)_{PMP}$ in Step 5, calculate formation permeability

$$k = \frac{141.2qB\mu}{h}\left[\frac{p_D}{\Delta p}\right]_{PMP}$$

8. From the time match point in Step 6, use the match point $(t_D/C_D,\ \Delta t \text{ or } \Delta t_e)_{TMP}$ to calculate dimensionless wellbore storage coefficient

$$C_D = \frac{0.0002637k}{\phi\mu c_t r_w^2}\left[\frac{\Delta t \text{ or } \Delta t_e}{t_D/C_D}\right]_{TMP}$$

Compare the values of C_D calculated from Steps 2 and 8. If inconsistent, repeat match and re-calculate.

9. Using the correlating parameter, C_De^{2s}, of the match type curve and value for C_D from Step 8, calculate skin factor for the test data

$$s = 0.5\ln\left(\frac{C_De^{2s}}{C_D}\right)$$

10. For validation, calculate permeability and skin factor using straight-line methods.

4.3 THEORETICAL DELIVERABILITY EQUATIONS

Generalized diffusivity equation for radial flow of a real gas assuming homogeneous and isotropic porous medium is,

4-1

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{P}{\mu_g z}\frac{\partial p}{\partial r}\right)\frac{1}{0.0002637} = \frac{\emptyset p c_t}{k_g z}\frac{\partial p}{\partial t}$$

Assuming $\frac{P}{\mu g z}$ is constant with respect to pressure and that $\mu_g z c_t$ can be constant at average reservoir pressure, eq 4.1 can be linearized as follows,

4-2

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial p}{\partial r}\right) = \frac{\emptyset \mu c_t}{0.002637kg}\frac{\partial p}{\partial t}$$

which is the same linear differential equation which we use for slightly compressible liquid flow. However, this equation is only valid for high temperature and pressure situation. Therefore, real psedopressure transformation which was introduced by Al-Hussainy et atl., to linearize equation 1 further to be more rigorous.

4-3

$$\Psi_p = 2\int_{p_0}^{p}\frac{P}{\mu_g z}\,dp$$

Then, Eq-1 can be solved without limiting assumptions and can be rewritten as,

4.4

$$\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial \Psi_p}{\partial r}\right) = \frac{\emptyset \mu_g(p) c_t(p)}{0.002637kg}\frac{\partial \Psi_p}{\partial t}$$

Eq 4.4 is not completely linear yet as $\mu_g(p)c_t(p)$ depends on pressure and pseudopressure but acceptable approximation to rule out this case is that $\mu_g c_t$ can be evaluated at average reservoir pressure. Then, we can use E-function solutions with this transformation as follows,

4.5

$$\Psi_p\left(P_R\right)^2 - \Psi_p\left(P_{wf}\right)^2 = \frac{1.422\ x\ 10^6\ qT}{k_g h}\left[1.151\ \lg(\frac{k_g t}{1688\phi\mu_g c_t\, r_w^2})\right] + \ s + Dq$$

Note that $\mu_g c_t$ is now constant at average reservoir pressure.

For convenience, Houpeurt transformed eq 4.5 to simpler quadratic equation,

4.6

$$\Delta\Psi_p = \Psi_p\left(P_R\right)^2 - \Psi_p\left(P_{wf}\right)^2 = aq + bq^2$$

Where 4.7

$$a = \frac{1.422\ x\ 10^6\ T}{k_g h}\left[1.151\ \lg(\frac{k_g t}{1688\phi\mu_g c_t\, r_w^2})\right] + \ s$$

4.8

$$b = \frac{1.422\ x\ 10^6\ TD}{k_g h}$$

Now, let's take a moment to understand D further, it is commonly known as non-darcy effects, the inertial and turbulent flow effects result normally from high gas velocities near the wellbore and cannot be modeled with Darcy's law. It is defined in terms of a turbulence factor and it can be correlated with reservoir properties as follows,

4.9

$$D = \frac{2.715\ x\ 10^{-12}\ \beta k_g M\rho_{sc}}{\mu_g h\left(P_{wf}\right) r_w T_{sc}}$$

Where $= 1.88\ x\ 10^{10}\ k^{1.47}\ \emptyset^{-0.53}$, note that it can change with different BHFP.

4.4 EMPIRICAL DELIVERABILITY EQUATIONS

Rawlins, Schellhard (1935) came out with an empirical relationship for deliverability test analysis as follows,

4.10

$$q = C\left[\Psi_p\left(P_R\right)^2 - \Psi_p\left(P_{wf}\right)^2\right]^n$$

4.5 STABILIZATION TIME

Stabilization time can be defined as the time when the flowing pressure is no longer changing significantly, and it can be interpreted as the time when the pressure transient is affected by a no flow boundary either natural or artificial. This situation occurs when the radius of investigation equals or exceeds the distance to the no-flow boundary of the well i.e., ri >= re, consequently following equation can be developed to estimate the stabilization time, ts.

4.11

$$t_s = \frac{948\emptyset\mu_g c_t r_e^2}{k_g}$$

CHAPTER-5: INPUT DATA

5.1 RESERVOIR DESCRIPTION

Fluid type : Gas

Well orientation : Vertical

Number of wells : 1

Number of layers : 1

5.2 LAYER PARAMETERS DATA

	Layer 1
Formation thickness (ft)	16
Average formation porosity	0.2
Water saturation	0.45
Gas saturation	0.55
Formation compressibility (psi-1)	3.6468E-006
Total system compressibility (psi-1)	4.2076E-005
Layer pressure (psia)	7280
Temperature (deg F)	283

5.3 WELL PARAMETERS DATA

	Well 1
Well radius (ft)	0.35
Distance from observation to active well (ft)	0
Wellbore storage coefficient (bbl/psi)	3.2108E-003
Storage Amplitude (psi)	0
Storage Time Constant (hr)	0
Second Wellbore Storage (bbl/psi)	0
Time Change for Second Storage (hr)	0
Well offset - x direction (ft)	0
Well offset - y direction (ft)	0

5.4 FLUID PARAMETERS DATA

	Layer 1
Gas gravity (sp grav)	0.856
Water-Gas ratio (STB/MMscf)	0
Water salinity (ppm)	0
Check Pressure (psia)	7149
Check Temperature (deg F)	283
Gas density (lb/ft3)	18.66
Initial gas viscosity (cp)	0.033
Gas formation volume factor (ft3/scf)	0.004
Water density (lb/ft3)	58.518
Water viscosity (cp)	0.174
Water formation volume factor (RB/STB)	1.066
Initial Z-factor ()	1.191
Initial Gas compressibility (psi-1)	6.6986E-005
Water compressibility (psi-1)	3.5255E-06

5.5 GAS COMPOSITION DATA

Gas Composition	Layer 1
Nitrogen	1.54
CO2	0
H2S	76.8
Methane	8.82
Ethane	3.2
Propane	0.49
Iso-Butane	1.14
n-Butane	0.42
Iso-Pentane	0.57
n-Pentane	0.74
Hexanes	5.11
C7+	100.2

5.6 LAYER BOUNDARIES DATA

Layer 1 Boundary Type : Infinitely acting

	Layer 1
L1 (ft)	0
L2 (ft)	0
L3 (ft)	0
L4 (ft)	0
Drainage area (acres)	0
Dietz shape factor ()	0

5.7 MODEL PARAMETERS

Layer 1 Model Type : Radial homogeneous

5.8 RATE CHANGES DATA

Time Hours	**Pressure psia**	**Rate MMscf/day**
5.661	7149	0
8.667	2365.2	12.25
11.727	6925.5	0
18.852	5974.04	3.95
26.31	4966.99	6.6
32.342	3894.03	9.015
37.767	2224.1	12.11
47.833	6619.3	0

CHAPTER 6: RESULTS AND DISCUSSIONS

6.1 TEST OVERVIEW PLOT

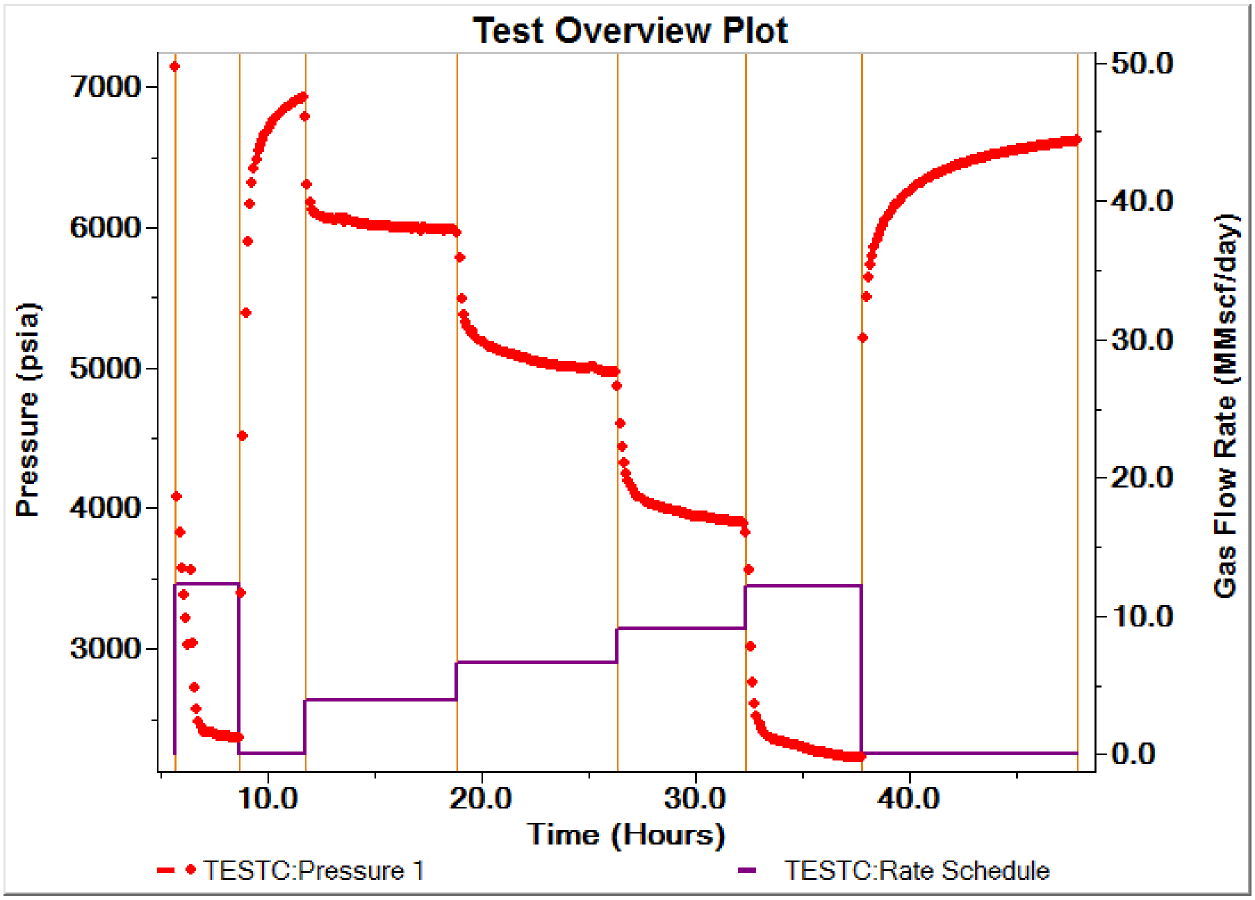


Figure 6.1: Test Overview Plot

Overview of the whole drill stem test conducted can be seen in Figure 6.1. The test is run for almost 60 hours which is a very long test compared to the normal drill stem tests. It is started with preflow period for about 3.5 hours to achieve the stabilized condition before shut in the. After that, the well is shut in for about 2.5 hours before starting the flow after flow test for next 30 hours achieving four stabilized flow rates. It ended with final build up period where the well is shut in for about 20 hours.

6.2 INITIAL BUILD UP ANALYSIS USING SEMI LOG PLOT

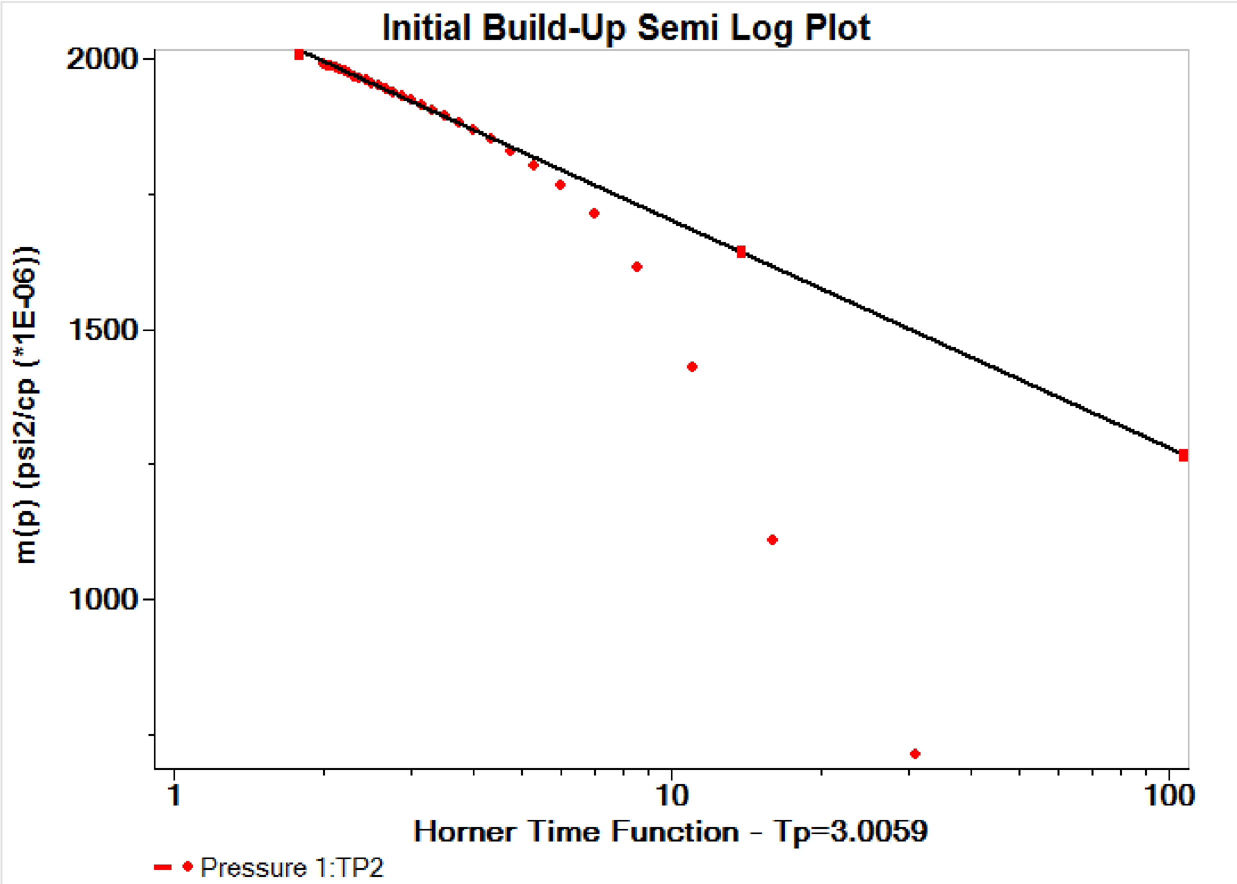


Figure 6.2: Initial Build-Up Semi Log Plot

Results

	Value		Value
Permeability (md)	2.213	Extrapolated m(p) (psi2/cp (*1E-06))	2121.665
Permeability-thickness (md.ft)	35.401	Extrapolated pressure (psia)	7280.572
Extrapolated pressure (psia)	7280.572	m(p) at dt = 1 hr (psi2/cp (*1E-06)	1868.18
Radius of investigation (ft)	142.357	Pressure at dt = 1 hour (psia)	6589.874
Flow efficiency	1.226		
dP skin (constant rate) (psi)	-2365.2		
Skin factor	-1.99		

Figure 6.2 depicts the Semi log analysis of the initial build up test. The X axis is Horner time function and Y-axis is pseudopressure. Straight line region which is supposedly the middle time region is chosen to analyse. Aim of this analysis of this region is only to find initial reservoir pressure and analysis of other reservoir parameters can be incorrect as the test duration is relatively short compared to the last build up analysis from which those parameters will be analysed and validated with type curve analysis. According to this analysis, extrapolated initial reservoir pressure is 7280.572 psi.

6.3 LAST BUILD UP ANALYSIS USING SEMI LOG PLOT

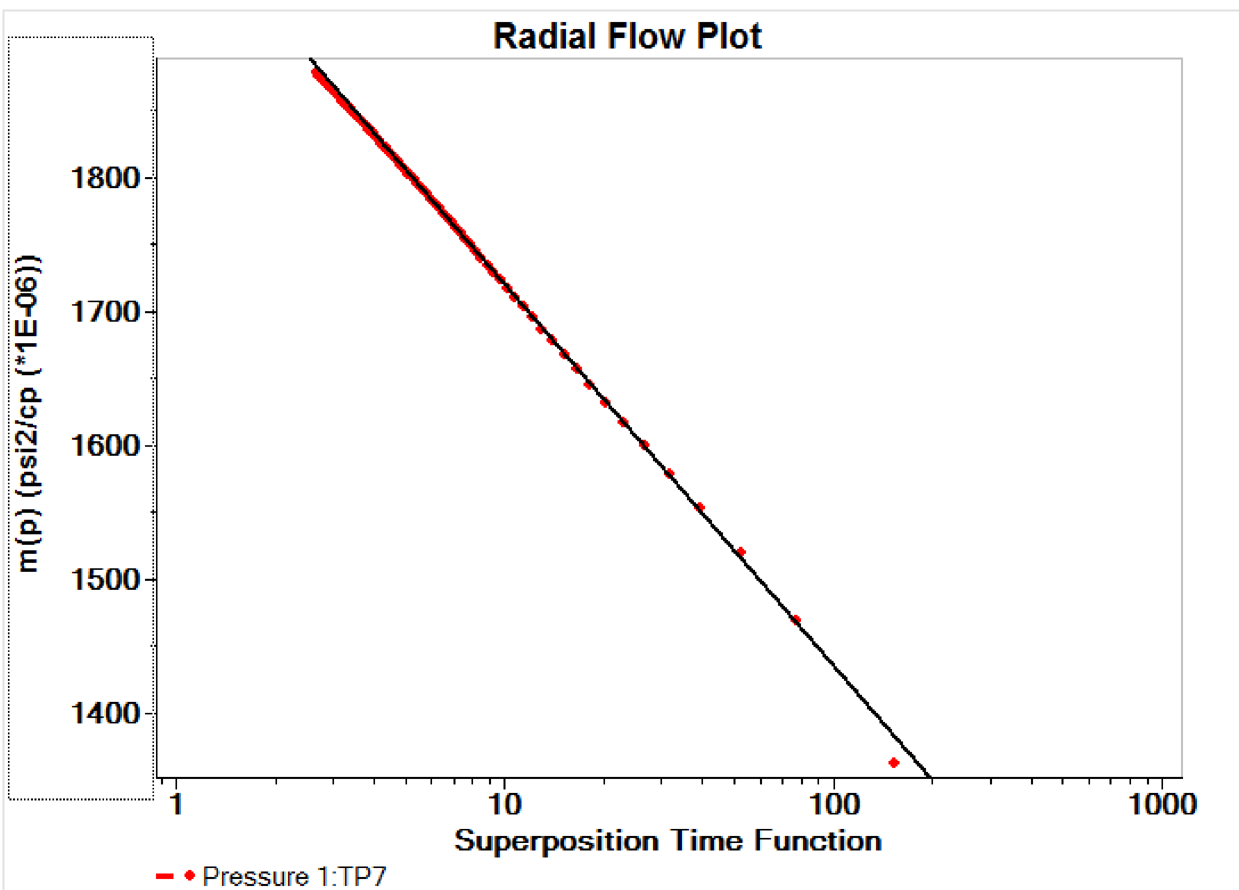


Figure 5.3 : Last build-up Semi Log Plot

Results

	Value		Value
Permeability (md)	3.235	Extrapolated m(p) (psi2/cp (*1E-06))	2004.544
Permeability-thickness (md.ft)	51.765	Extrapolated pressure (psia)	6961.322
Extrapolated pressure (psia)	6961.322	m(p) at dt = 1 hr (psi2/cp (*1E-06))	1660.262
Radius of investigation (ft)	315.33	Pressure at dt = 1 hour (psia)	6024.011
Flow efficiency	1.016	Skin factor	-2.78
dP skin (constant rate) (psi)	-97.514		

Figure 6.3 shows the last build up semi log analysis with X axis superposition time function and Y axis is pseudopressure. The last build up test period is much longer than the initial build up test, hence, results obtained from this period is assumed more accurate. Permeability obtained from this analysis is 3.235 md and the skin factor is -2.78 which means that the wellbore is enlarged. To validate this assumption, Bourdet + Gringarten type curve analysis is used as follows,

6.4 TYPE CURVE ANALYSIS FOR LAST BUILD UP

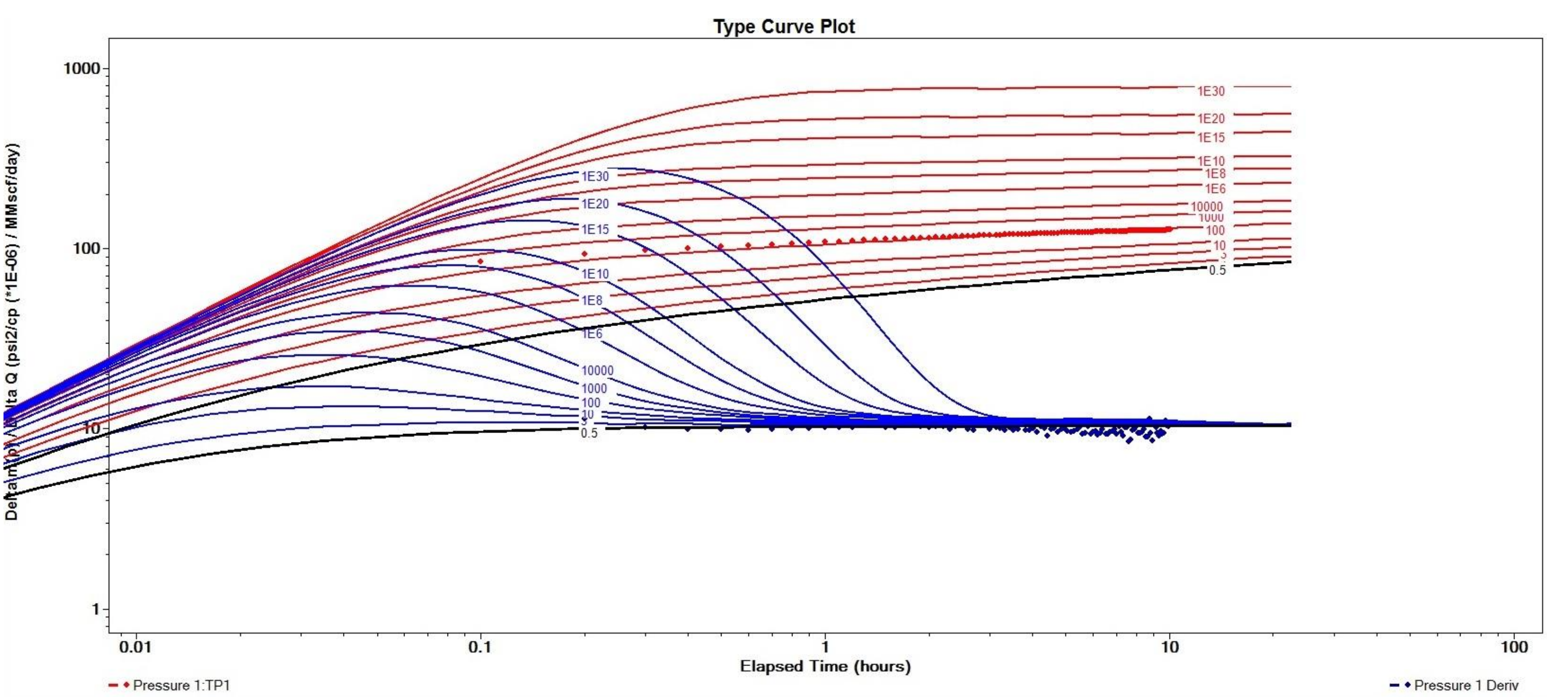


Figure 6.4: Type curve analysis for last build up

Results

	Value
Permeability (md)	3.317
Wellbore storage coefficient (bbl/psi)	3.5266E-003
Dimensionless wellbore storage	191.062
Apparent wellbore volume (bbl)	52.646
Permeability-thickness (md.ft)	53.077
Skin factor	-2.973

According to the best match point from this type curve analysis, the parameters calculated such as permeability (3.317 md) and skin factor (-2.973) are close to the parameters obtained from the last build up test analysis so it is safe to say that the results achieved are correct. Dimensionless wellbore storage (C_D) is also calculated as 191.062.

6.5 THEORETICAL DELIVERABILITY ANALYSIS

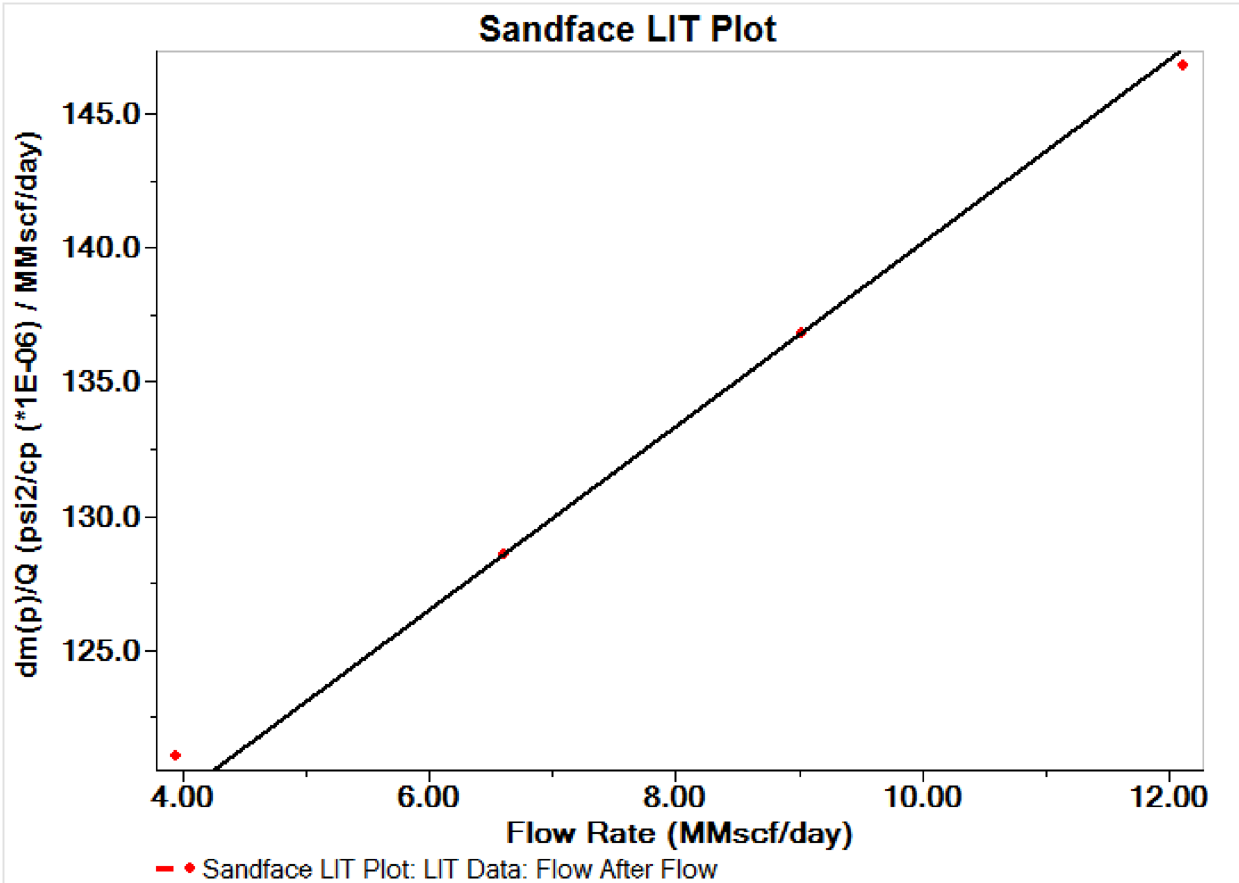


Figure 6.5: Theoretical deliverability analysis (LIT analysis)

Results

	Value
Darcy flow coefficient (B) (psi2/cp/(Mscf/day))	1.0596E+005
Non-Darcy flow coefficient (D) (psi2/cp/(Mscf/day)2)	3.425
Absolute open flow potential (Gas) (MMscf/day)	13.834

Figure 6.5 illustrates theoretical analysis for deliverability tests and Non-Darcy flow coefficient and AOF is obtained from this analysis. AOF is 13.834 MMscf/day and the result is compared with empirical analysis as follows,

6.6 EMPIRICAL DELIVERABILITY ANALYSIS

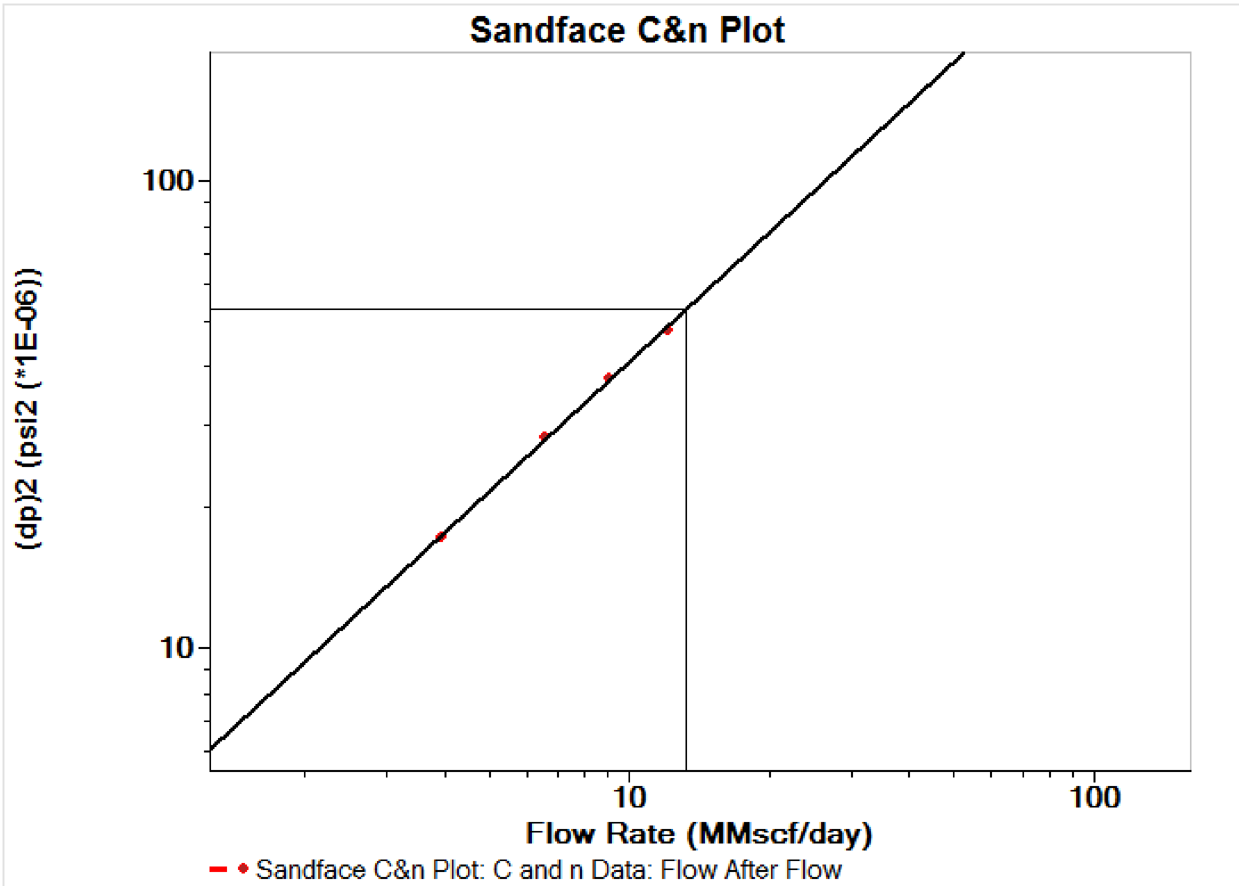


Figure 6.6: Empirical deliverability analysis

Results

	Value
n-coefficient	1.088
C-coefficient (MMscf/day/psi2n)	5.2146E-008
Absolute open flow potential (Gas) (MMscf/day)	13.23

Figure 6.6 is empirical analysis plot using coefficient C and n and AOF obtained is 13.23 which is close the result from theoretical analysis hence we can assume that they are accurate.

6.7 IPR CURVE

Layer 1 Deliverability Data

	Layer 1
Layer pressure (psia)	7280
Dietz shape factor	31.62
Drainage area (acres)	100
Permeability (md)	3.238
Skin factor	-2.926
C-coefficient (MMscf/day/psi2n)	5.2146E-08
n-coefficient	1.088
Absolute open flow potential (Gas) (MMscf/day)	13.23
Damage Ratio	522.806
Radius of investigation (ft)	110.291

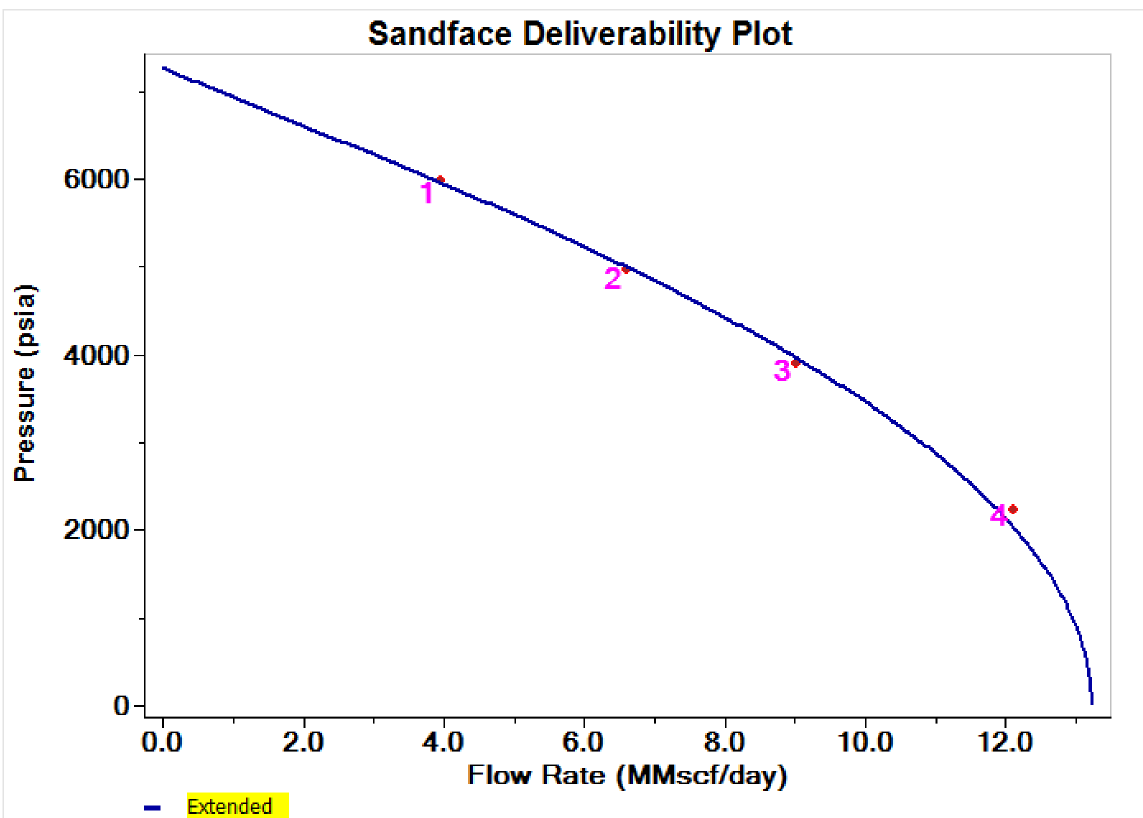


Figure 6.7: IPR Curve

6.8 PRODUCTION FORECASTING

	Value
Permeability (md)	3.238
Permeability-thickness (md.ft)	51.807
Skin factor	-2.926
Layer pressure (psia)	7280
Drainage area (acres)	100
Formation thickness (ft)	16
Average formation porosity	0.2
Water saturation	0.45

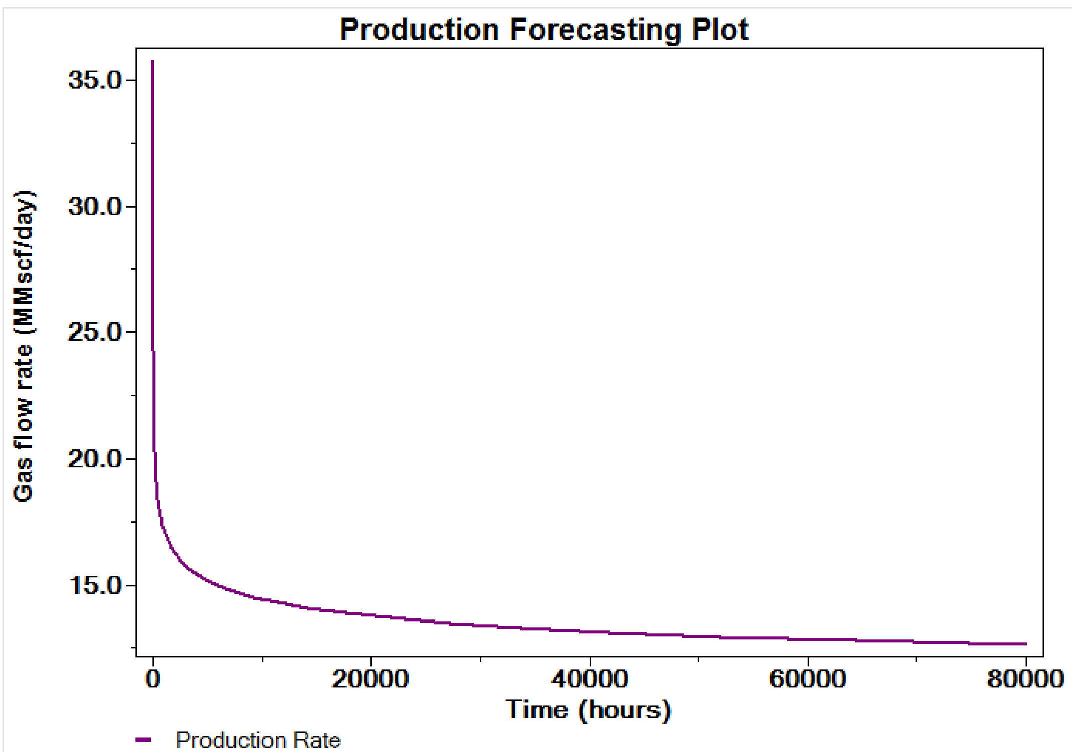


Figure 6.8: Production Forecasting Plot

Production Forecasting Results

	Value
Cumulative production at 80000hours (bscf)	45.013
Reservoir pressure at 80000hours (psia)	7280

CHAPTER-7: CONCLUSION AND RECOMMENDATION

CONCLUSION

In conclusion, this case study was about a fairly standard drill stem test conducted in one of the gas fields in Myanmar. Two build-up regions and five flow regions including preflow period are run during the test which lasts for about 60 hours, sufficient time for an average drill stem test. First build up test was analysed using Hornor's approximation and the initial reservoir pressure is determined from this analysis. Other important reservoir parameters are determined from the last build up analysis and validated using Bourdet + Gingertan type curve from which the parameters obtained are confirmed the accuracy. Four flow regions are run for long period to achieve stabilized flow rate as a fundamental requirement for flow after flow test. Using theoretical and empirical analysis, the value of AOF is achieved and found that values are very close for both analysis. IPR curve is obtained through the data acquired from deliverability test and production forecast for next 80000 hours is performed. Last but not least, objectives are achieved through extensive study of theoretical background of all the analyses as well as Pansystem software.

RECOMMENDATION

Due to limitations of the data acquired, this study is based on assumptions that the reservoir is homogeneous, isotropic with relatively constant fluid and reservoir properties which is in fact, often not the case in real reservoirs. Numerical analysis can be used to analyze the heterogeneous reservoirs however it takes time to understand how to use numerical analysis in Pansystem. If it was possible, the analytical and numerical analysis can be also compared so that there would be more confidence on the obtained results. Therefore, as an area of interest, I will do further study on Pansystem numerical analysis and also hope to experience real drill stem test in the field in future so that more important aspects of this test can be understood.

ABBREVIATIONS AND NORMENCLUTURES

Ps	=	shut in pressure
Pi	=	initial reservoir pressure
Pwf	=	bottomhole flowing pressure (BWHP)
Ct	=	formation compressibility
k	=	formation permeability
r_w	=	wellbore radius
r_e	=	reservoir radius
h	=	pay thickness
tp	=	production time
q_g	=	gas flow rate
T	=	temperature
Z	=	gas deviation factor
B	=	reservoir volume factor
m	=	Horner slope
μ	=	viscosity
C_D	=	dimensionless wellbore storage constant
t_D	=	dimensionless time
s	=	skin factor
C	=	stabilization constant
n	=	inverse slope

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