TABLE OF CONTENTS

Technical Papers on Reservoir Engineering

ICPE (2016-005)

Well Flow Interference Study of Sylhet Gas Field by Streamline Simulation

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ABSTRACT

Sylhet Gas Field, first discovered gas field in Bangladesh operated by Sylhet Gas Fields Limited (SGFL), a company of Bangladesh Oil, Gas and Mineral Corporation (Petrobangla). Sylhet gas field is located about 230 km North-East of Dhaka and 18 km from Sylhet town and lies between the Shillong Plateau in the North and the Tripura High in the South. Commercial oil accumulation was also discovered only in this field. The gas reserve of Sylhet Field is 318.9 TCF (Petrobangla Annual Report, 2015) and oil reserve is 31 STOIIP (RPS Energy, 2009).

The main objective of this research is to investigate the flow interference between two wellsSY-3 and SY-6 using streamline simulation. Schlumberger Eclipse FrontSim streamline reservoir simulator has been used to model the dynamic streamline based fluid flow simulation within the reservoir integrating structural model, petro-physical properties, PVT and production data. Analyzing and interpreting the past flow behavior, the effect of the placement of two close vertical wells (SY-3 and SY-6) in Sylhet Field has been investigated.

Analysis of the gas flow behavior by streamline simulation model reveals that the well flow interference occurred between two wells SY-3 and SY-6 due to their close proximity that reduced the overall production of both. High permeability of the reservoir causes high flow interference. Reservoir heterogeneity leading to higher permeability around well SY-6 than SY-3 results the shifting of production rate from SY-3 to SY-6 in 24 years.

Keywords: Reservoir simulation, streamline simulation, sylhet gas field,Eclipse FrontSim streamline reservoir simulator, permeability and reservoir heterogeneity.

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INTRODUCTION

26 gas fields have so far been discovered in Bangladesh (Petrobangla Annual Report, 2015). Total gas reserve in the country is 27.12 TCF (proved plus probable, 2P) and the remaining reserve is 13.60 TCF. In 2014-15 financial year, the annual production was 893.84 BCF (Petrobangla gas production database). It is clearly evident that the countries gas reserve is declining precipitously. Priority should be given to increase the ultimate recovery factor of the existing discovered gas fields for reserve growth. In this context, proper reservoir management and development planning can play pivotal role. Streamline based flow simulation is an advanced reservoir engineering study method to study the reservoirs that can help to achieve this goal.

Althoughstreamline-based flow simulation method has been used in the oil and gas industry since 1950, significant advanceshave been made in the past 10 years. Recently streamline-based flow simulation models have offered significant potential in integrating dynamic data into high-resolution reservoir models (He et al., 2001). Faster computation, quantitative flow visualization, improved accuracy, ability to screen highly detailed geologic models and rapid history matching or production-data integration into high-resolution reservoir models are the primary advantages of streamline simulation(Datta-Gupta 2000). This paper demonstrates one of the applications of streamline simulation for the reservoirs in Bangladesh by investigating well flow interference between two wells in Sylhet Field. Streamlines offer an immediate snapshot of the flow fieldclearly showing how wells, reservoir geometry, and reservoir heterogeneity interact todictatewhere flow is coming from and where flow is going to (Thiele, 2003). Streamlines can delineate the drainage area andquantitative flow rate of individual wells. This property enables to investigate the flow interference of two adjacent wells in Sylhet Gas Field.

PROBLEM OVERVIEW

Sylhet structure was first delineated by Pakistan Petroleum Limited (PPL) after recording single fold seismic (Islam, et al, 2015).Subsequently Sylhet-1 well was drilled in 1955 with the discovery of first commercial gas accumulation in Bangladesh. Total eight wells so far have been drilled in this structure (Fig: **1**).

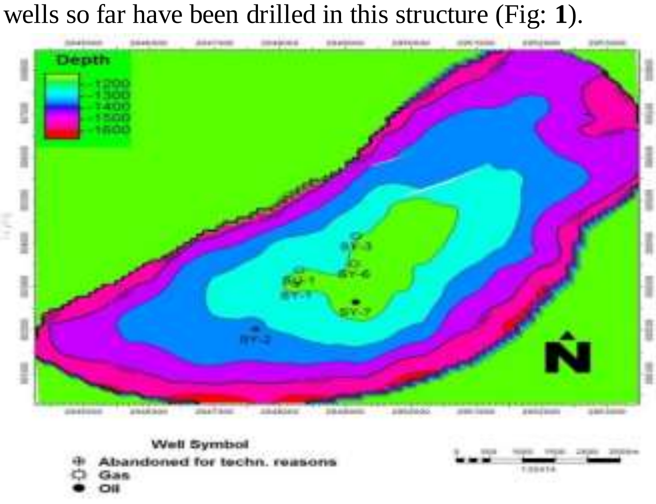
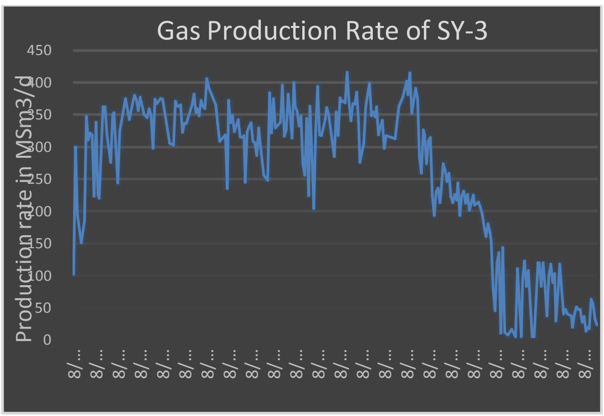


Figure 1: Position of wells drilled in Sylhet Field; (the layer shown here is the top horizon [upper Bokabil Formation] of the Sylhet Field Geomodel and color indicates depth in meter)

Among them two wells Sylhet-3 (SY-3) and Sylhet-6 (SY-6) were drilled and completed for gas production in 1957 and 1964 respectively. The distance between these two wells is only 650m. On March 1988, the production from SY-3 has been abandoned due to the low flow rate. SY-6 produced gas until March 2010. Both of them were jointly in production for 23 years (1964 to 1988). In 23 years, the production rate of this two wells was totally reversed. The Production rate of SY-3 was gradually reducing and the production rate of SY-6 was gradually increasing (fig. 3). Also, production data of this two wells indicate that neither of these two produced gas as expected. Due to their close proximity it has been speculated that flow interference may be responsible for these phenomena.
To investigate the causes behind this production behavior, streamline simulation model has been generated forentire production period (1964-1988) when these two wells were active.



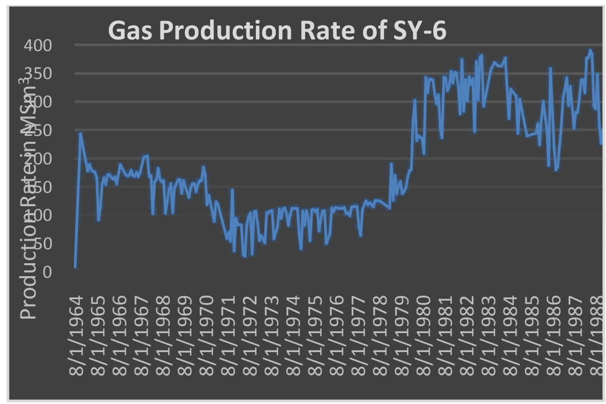


Figure 2: Gas production rate in MSm^3/d (Thousand Standard Cubic Meter per Day); (a) SY-3; (b) Sy-6

METHODOLOGY

Streamline simulation is an integrated approach. Large volume of data is required to develop streamline simulation model. First a representative reservoir model has been developed consisting primarily of structural, petrophysal and fluid model. Geological, geophysical (seismic), well log, fluid (compositional and PVT) data are used.Well completion and production data are used to make well completion design and development strategies. Streamline simulation models are developed integrating all of these models using simulator software.

The data required for developing streamline simulation model of Sylhet Field were delivered by Petrobangla in digital and hard copy formats. Schlumberger Petrel 2013.1.1 software platform is used for all kinds of modelling and visualization and Eclipse FrontSim Simulator version 2010.1 was used for simulation.

Structural model has been provided by Petrobangla. It consists of total 74 layers containing gas and oil bearing horizons of Bokalbil and Upper BhubanFromation. After structural model, wire line log data of every well were used to fill grid cells with petro-physical properties. These properties are porosity, permeability and NTG (Net to Gross Ratio). Well log data were provided in LAS (Log ASCII Standard) format with ".las" extension. Each well log data set contains caliper, gama, resistivity, neutron and Sonic log. Integrating structural and petrophysical models, representative reservoir geomodel of Sylhet Field were created that contains structural model with grid cells filled with petrophysical properties.

Then fluid models were created that describe the characteristics of fluid present in the reservoir using PVT data and fluid compositional data.Formation Volume Factor, viscosity, capillary pressure, relative permeability etc. models werecreated using PVT data. PVT data sets were provided in hard copy format by Petrobangla.

Well completion data were used to create well completion design of every well. It includes inserting of casing, perforation, tubing, gauge and packer in every well. After completing well completion design, production data of every well have been used as input. This completion and production data were also provided by Petrobangla in excel format.

After completing all of these steps and processes, simulation parameters are set to perform simulation. Eclipse FrontSim streamline reservoir simulator is used to create streamline simulation model. Simulator integrates all of the models for simulation. Then the stream simulation models were analyzed.

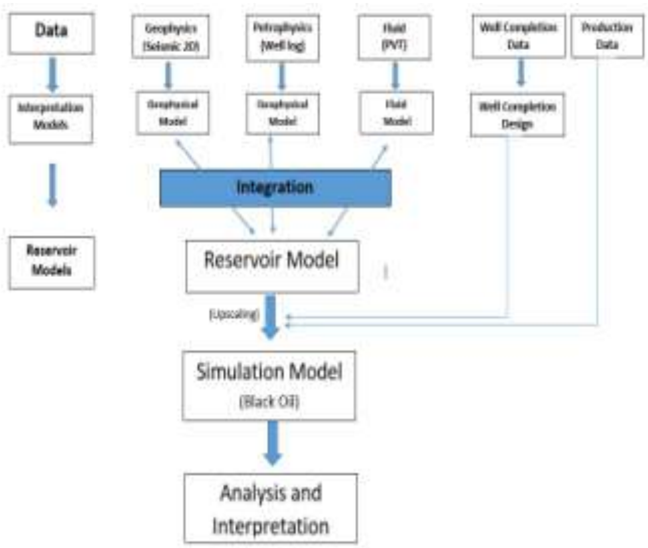


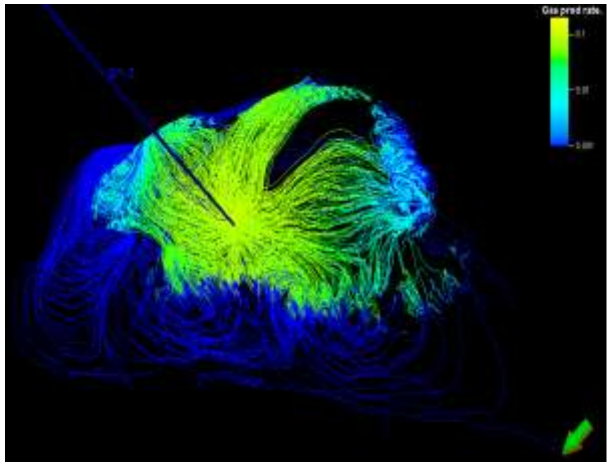
Figure 3**:** Flowchart of methodology

RESULT AND DISCUSSION

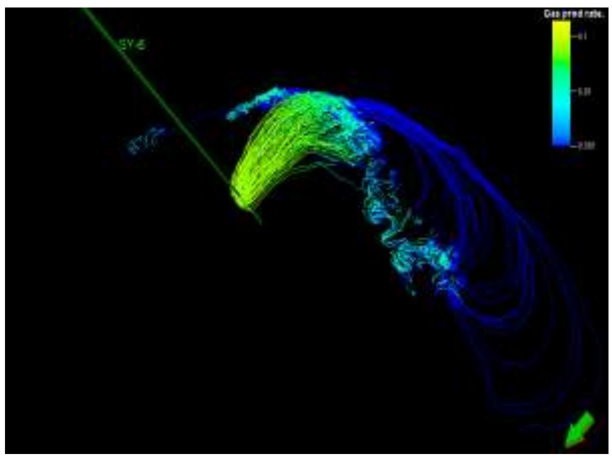
The streamline generates flow rate, fractional flow rate, saturation attributes providing a better understanding of the reservoir performance inside the porous permeable formation (Batycky, et al, 1997). Streamline Simulation attributes of gas flow rate can clearly visualize the drainage areawith associated flow rate in streamline. Temporal variations of these attributes have been used toinvestigate well flowinterference study of Sylhet Field.

At early production stage, the production rate of well Sy-3 was much higher than Sy-6 (Fig: **4**). Streamline simulation of early production period (January 1966) shows that the flow rate varies from

0.2 to 0.1 Sm^3/d for both wells (Fig.**4**). But the drainage area of well SY-3 occupied much larger area than well SY-6. Due to the coverage of larger drainage area SY-3 produced more gas than SY-6.



(a)

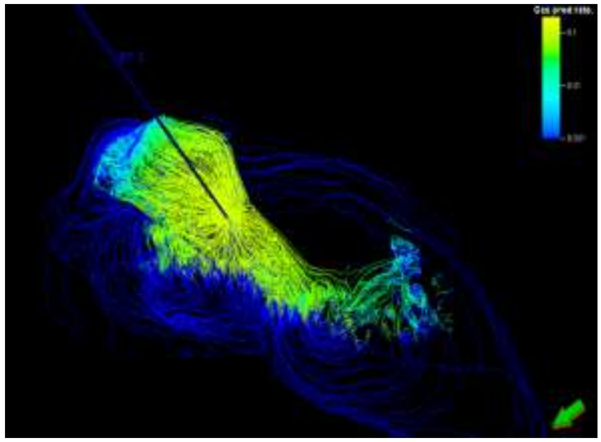


(b)

Figure 4: Drainage area associated with flow rate in streamlines in Sm^3/d; (a) well SY-3; (b) well SY-6 on January 1966

Fifteen years later when production rate of both well was roughly equal streamline simulation model shows that the drainage area of both wells also became equal (Fig.**5**). But theflow rate of individual streamline did not change. Only drainage area of SY-6 was increasing and SY-3 was decreasing with time.

Similarly, in late production period when the production rate of well SY-6 was much higher than SY-3 (Fig.**6**) streamline simulation model clearly shows that the drainage area occupied by SY-6 is much larger than SY-3. Streamlines having flow rate varies from 0.2 to 0.1 Sm^3/d for both wells as usual.



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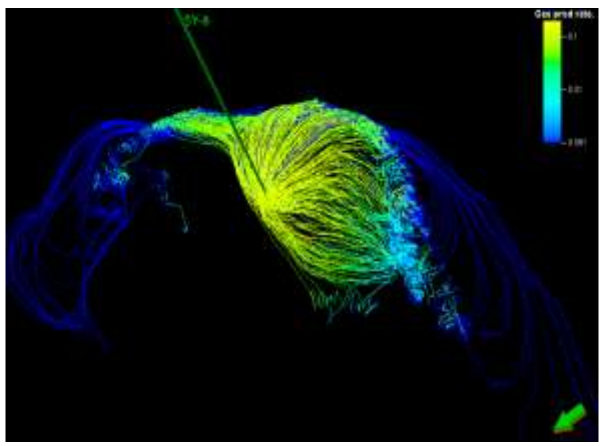
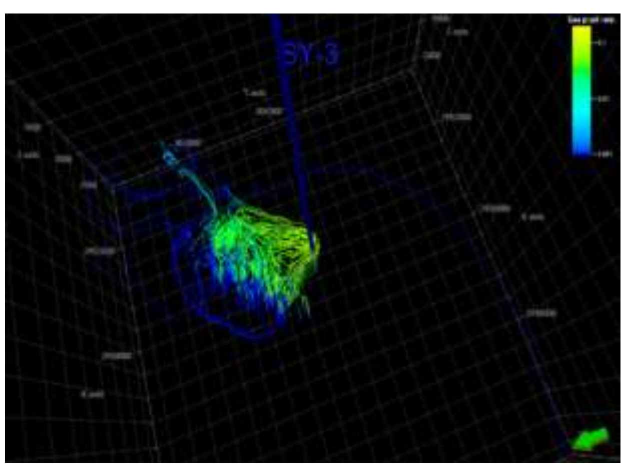
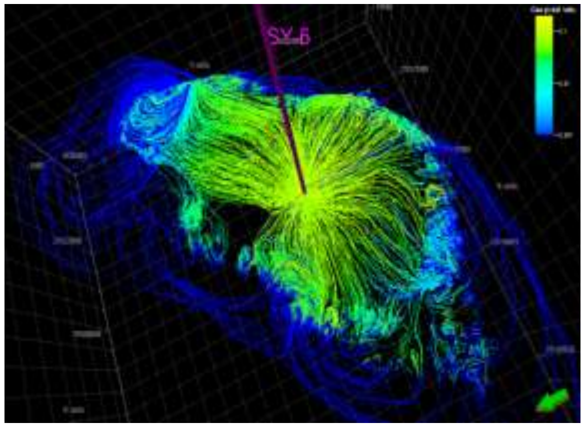


(b)

Figure 5: Drainage area associated with flow rate in streamlines in Sm^3/d; (a) well SY-3; (b) well SY-6 on July 1980



(a)

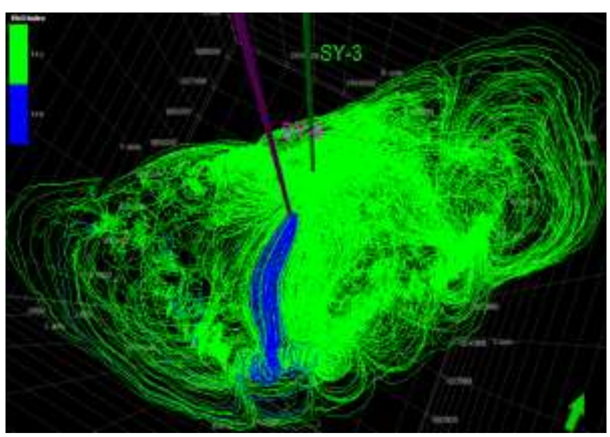


(b)

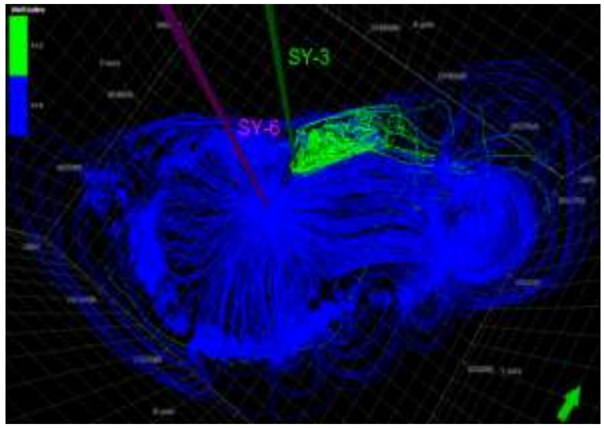
Figure 6: Drainage area associated with flow rate in streamlines in Sm^3/d; (a) well SY-3; (b) well SY-6 on March 1987

By studying streamline simulation model, it can be concluded that well SY-3 and SY-6 createdflow interference due to their close proximity to each other. Due to their interference neither of them could reach their expected production rate.Well SY-6 encroaches and graduallykill the drainage area of SY-3. As a result the production rate of SY-3 was gradually decreasing and the production rate of SY-6 was increasing.

Figure**7** shows drainage area in the form of well index attributes at early (Fig. 7a) and late (Fig. 7b) production period respectively. It clearly shows that the drainage area did not increase with time. The sharing of the drainage area of the two wells has changed with time. The flow rate of each streamline of entire production period also did not change that has been shown in previous figures (Fig. 4, 5 and 6). As a result the total production rate did not increase. It only shifted from SY-3 to SY-6 that was observed in the production data.



(a)



(b)

Figure7: Well index in streamlines; (a) September 1964; (b) March 1987

The reservoir has very high permeability. The reservoir sandstones are Late Miocene of age, with mean porosity of 26 percent and a mean permeability of approximately 221 md (RPS Energy, 2009).Permeability ranges from 100 to 900md. Some regions have even more permeability than 1000md (Fig. 8). Some areas have also relatively low permeability (100 to200md), but it is still good permeability value. Due to this overall high permeability, more distant areas of the reservoir are connected to the well. As a result both SY-3 and SY-6 had very large drainage area. Moreover, the distance between the two wells is only 650m. Therefore close proximity and high permeability cause high flow interference between SY-3 and SY-6 that has been observed. If the permeability would low, flow interference would be less in spite of their closeness.

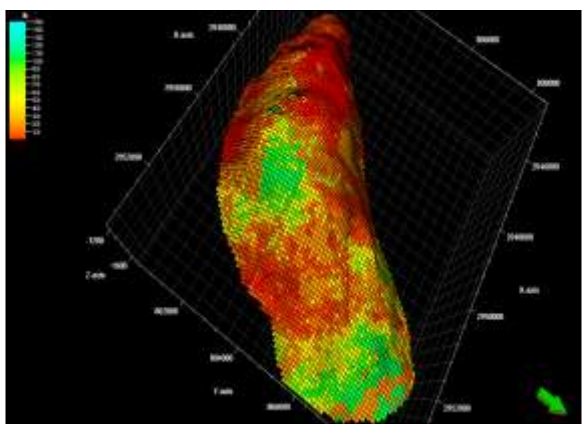
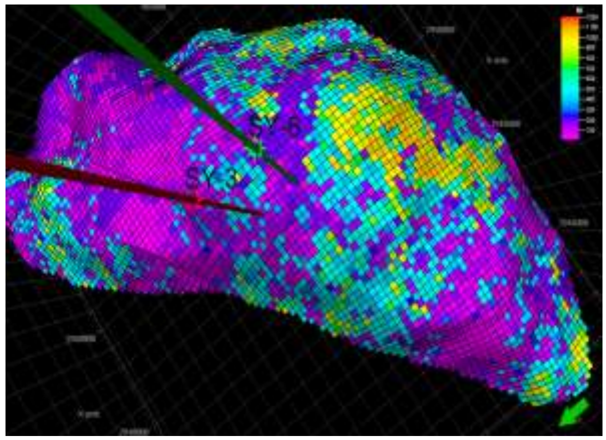


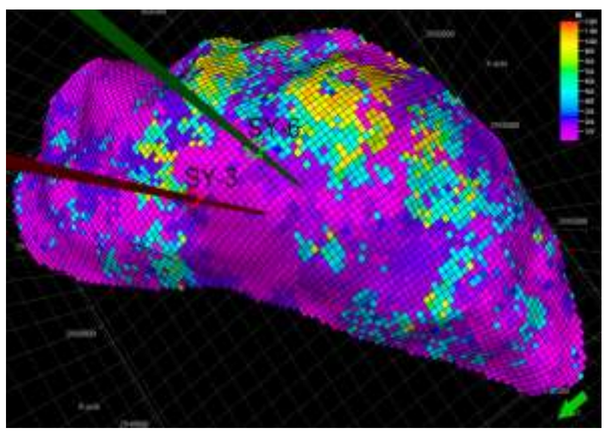
Figure **8**: Permeability model of the gas zone

Reservoir heterogeneity is the reason behind the reversal of the production rate and the gradual increase of the drainage area of well SY-6. The permeability and porosity of the reservoir is not uniform everywhere. Permeability variation affects the fluid flow greatly. Permeability model of the gas zone shows that the area around the well SY-3 is less permeable than SY-6.

Figure **9** shows permeability model of top and bottom layer of Sylhet Gas Field. The permeability value of the area around the well SY-3 varies from 200 to 400md at the top layer and 100 to 200 md at the bottom layer. For SY-6 the permeability varies from 100 to 500 md at the top layer and 300 to 600md at the bottom layer. In every layer within the gas zone the permeability around the SY-6 is more than the well SY-3. Also the regions of very high permeability as indicated by yellow color are close to the well SY-6. Due to this kind of permeability variations gas flows more easily in SY-6 than SY-3. Therefore, the drainage area SY-6 was gradually increasing with time killing the drainage area of SY-3. As a result, production shifted from SY-3 to SY-6 that observed in the production data.



(a)



(b)

Figure **9**: Permeability model of gas zones (a) top layer; (b) bottom layer

CONCLUSION

Studying streamline simulation models, it can be concluded that flow interference between the two wells occurred and reduced the production rate of both wells. The close proximity of these two wells is responsible for this flow interference. Furthermore, high permeability of the reservoir enhanced this interference. Therefore it was unjustifiable to drill well SY-6 so close to the well SY-3 in a high permeability reservoir like Sylhet Gas Field. Streamline simulation model also shows that the reservoir heterogeneity causes the shifting of production from SY-3 to SY-6.

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Analysis of DST to Detect the Oil Sand: A Real Case Study on Kailashtilla Field

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ABSTRACT

Drill Stem Test (DST) describes the dynamic characteristic of the petroleum reservoir such as wellbore storage, skin effect, permeability, average reservoir pressure, reservoir boundary. The wellbore storage effect and average reservoir pressure helps to predict the flowing phase from the reservoir. In this paper an effort has been done to analyze the DST conducted in the Kailashtilla field at the depth interval 3261 meter to 3266 meter in well KTL-7. Two sets of pressure profile have been recorded. First conditioning the well for an hour then performed drawdown following pressure buildup. The pressure signature of the buildup period and its derivative has been plotted on semi-log and log-log coordinates to develop Horner and diagnostic plots respectively. Wellbore storage, skin and transient flow effects has been observed in the DST analysis which is an indication of the hydrocarbon bearing reservoir in the zone of interest. The value of well bore storage effect is low which predicts the flow of liquid hydrocarbon into the well bore from the reservoir. Average pressure of the investigated zone has been estimated which is higher than the water column pressure. The higher average reservoir pressure also authenticates the presence oil reservoir.

Keywords: Well log, Drill Stem Test (DST), Pressure Build Up, Wellbore Storage, Average Reservoir Pressure.

INTRODUCTION

DST is one kind of well test which is performed to predict the hydrocarbon bearing zone and its characteristics (Ehlig et al. 1990). Results that can be obtained from well testing are a function of the range and the quality of the pressure and rate data available and of the approach used for their analysis. Consequently, at any given time, the extent and quality of an analysis are limited by the state-of-the-art in both data acquisition and analysis techniques (Earlougher 1977). As data improve, and better interpretation methods are developed, more and more useful information can be extracted from well test data (Ramey *et al*. 1992).

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One important ingredient of the integrated methodology was the realization, from experience, that, although reservoirs are different in terms of physical description (type of rock, depth, pressure, size, type of fluid, fluid content, etc.), the number of possible dynamic behaviors of these reservoirs during a well test was limited (Miller *et al*. 1950). This is because a reservoir acts as a low-resolution filter, so that only high contrasts in reservoir properties can appear in the output signal. Furthermore, these dynamic behaviors were obtained from the combination of three components that dominate at different times during the test, namely: (1) The basic dynamic behavior of the reservoir, during middle times, which is usually the same for all the wells in a given reservoir (2) near-wellbore effects, at early times, due to the well completion that may vary from well to well, or from test to test and (3) boundary effects, at late times, determined by the nature of the reservoir boundaries (the same for all the wells in a given reservoir) and by the distance from the well to these boundaries (which may differ from well to well) (Gringarten *et al*. 1979).

FIELD DESCRIPTION

The Kailastila field is located 13 kilometer south of Sylhet field and it is about 250 kilometer north east of Dhaka. The Kailastila field lies in the central part of the Surma Basin, and on the western margin of the Tripura high. The Kailastila structure was delineated by Shell in 1960 on the basis of single fold analog seismic data acquired in late 1950's. The structure is a four way dip closure. The KTL-1 was drilled in 1961 to a depth of 4138 m and encountered four gas sands. Subsequently five more wells, KTL-2 to KTL-6 were drilled since then. The Upper and Lower Gas Sand were tested in KTL-1 and well KTL-6. Recently well KTL-7 has been drilled at the depth 3565 meter to recover oil resources from the filed shown in Fig. 1 (http://www.sgfl.org.bd).

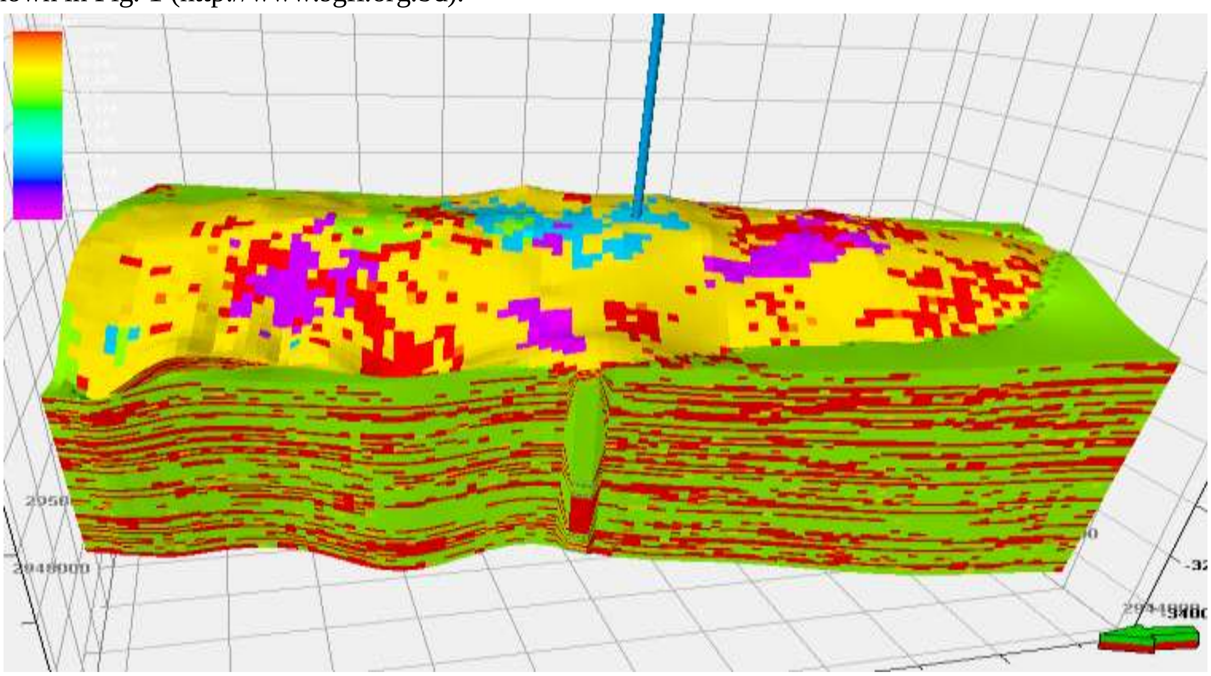

Fig.1: Location of well no. KTL-7 in the reservoir

DST interval selection

The DST interval is selected on the basis of the well log analysis. In the interval 3261 meter to 3266 meter the log analysis shows that low value of gamma log, high value of resistivity log with shallow and deep separation and high value of acoustic log indicating porous permeable formation with hydrocarbon bearing zone shown in Fig. 2.

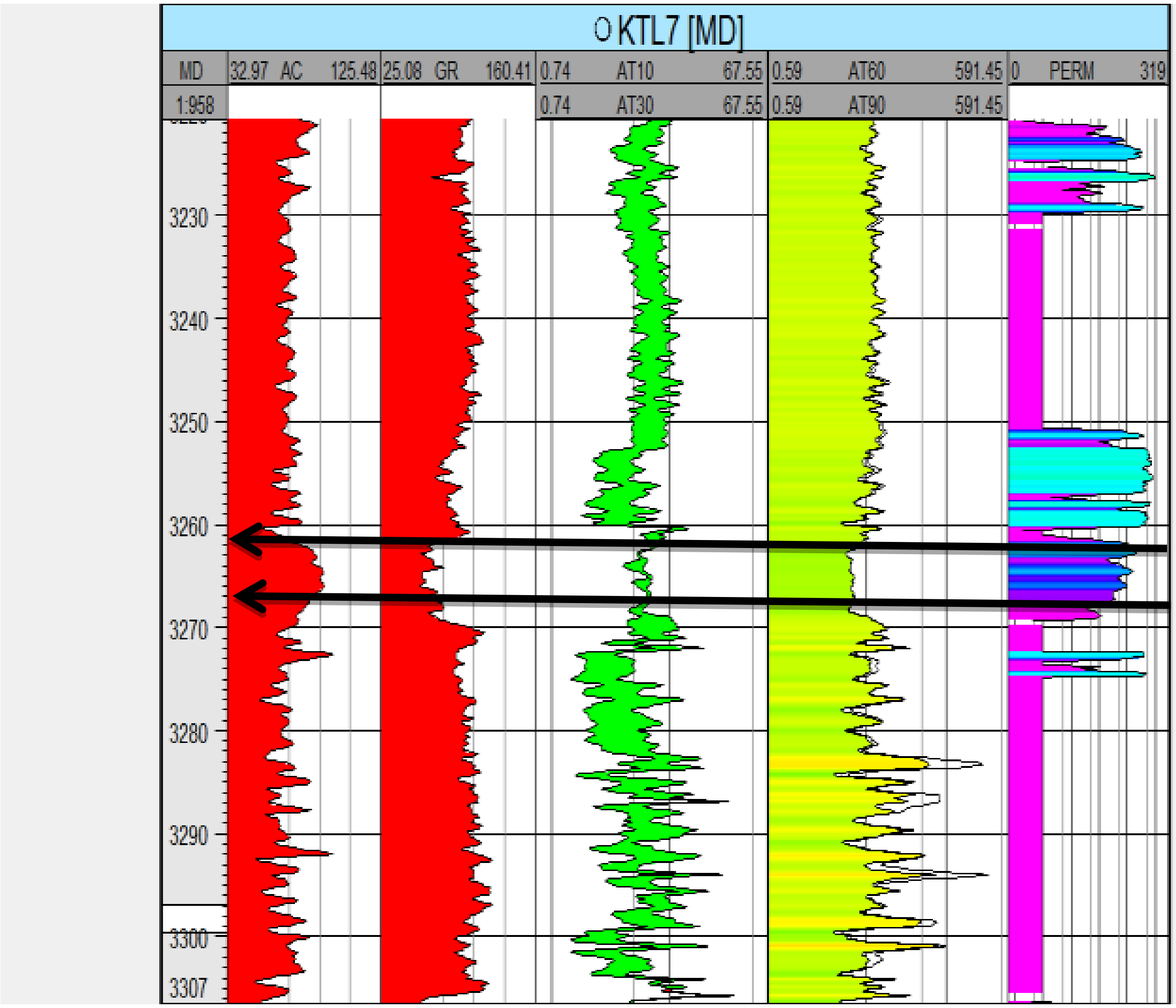

Fig.2: Well log in well KTL-7 and DST interval

Description of DST operation

To conduct the safe and proper DST operation it is very important to design the DST string and the Bottom Hole Assembly (BHA) according to the collapse load, burst load and shear failure. The DST string and the Bottom Hole Assembly (BHA) is shown in Fig. 3 where drill pipe, drill collar, crossover, pressure gauge are installed.

DESCRIPTION	SERIAL #	SUPPLIER	OD Inch	ID Inch	TOP CONN	BTM CONN	LENGTH Meter	DEPTH (m) TOP	DEPTH (m) BTM	REMARKS
10K Fixed Control Head c/w Manual plug valve on flow line.	3230-001	Northstar	N/A	2.25"						
									-1.63	STICK UP
TIW	6130BA-21	Northstar	5"	2.25"	3-1/2 IF	3-1/2 IF	0.65	-1.63	-0.98	
Head Sub XO	XO-197	Northstar	5-1/2"	2.5"	3-1/2 IF	4-1/2 IF	0.40	-0.98	-0.58	
15 ' Pup Joint for BOP spaceout		Bapex	5"	?	4 1/2 IF	4 1/2 IF	4.52	-0.58	3.94	
234 joints 5" Drillpipe 19.5# (78 stands)		Bapex	6-1/2"	3.25	4 1/2 IF	4 1/2 IF	2266.06	3.94	2270.00	Top DP tool joint is 3.94 meters below table when packer is set.
Crossover		Bapex	7	2.5"	4 1/2 IF	3-1/2 IF	0.81	2270.00	2270.81	
84 joints 3-1/2"" Drillpipe 13.3# (28 stands)		Bapex	5"	2.12	3-1/2 IF	3-1/2 IF	812.21	2270.81	3083.02	
Exit Valve with 7500 psi disk	3000AA-25	Northstar	5"	2.25"	3-1/2 IF	3-1/2 IF	1.25	3083.02	3084.27	4862 PSI at Exit. 173 F
15 joints 4-3/4 Collars 47 #/ft		Bapex	4-3/4"	2.25	3-1/2 IF	3-1/2 IF	141.60	3084.27	3225.87	
Quad Gauge Carrier	3050CA-28	Northstar	5"	2.25"	3-1/2 IF	3-1/2 IF	1.59	3225.87	3227.46	1 x fluid gauge (tubing-above valve), 1 x annulus
Multi Cycle Circulation Valve	3020AA-18	Northstar	5"	2.25"	3-1/2 IF	3-1/2 IF	2.36	3227.46	3229.82	4 x shear pins. 1000 psi to shear
DSBV (RIH closed) with 6000 psi disk to open. 7000 PSI disk to close.	3040CA-21	Northstar	5"	2.25"	3-1/2 IF	3-1/2 IF	1.63	3229.82	3231.45	5095 PSI hydrostatic at DSBV 177 F
Hydraulic Jar (Stroke .27m)	3080AA-25	Northstar	5"	2.25"	3-1/2 IF	3-1/2 IF	2.81	3231.45	3234.26	
Safety Joint (32 shear pins)	3110AA-25	Northstar	5"	2.25"	3-1/2 IF	3-1/2 IF	1.10	3234.26	3235.36	78,400 lbs shear
Crossover	XO-0012	Northstar	5"	2.5"	3-1/2 IF	2-7/8" EUE	0.34	3235.36	3235.70	
7" MR-3 35# Casing Packer **Above** (.83 m Stroke)	3120DC-027	Northstar	7"	2.25"	2-7/8" EUE	n/a	0.80	3235.70		90-70-90 elements
					Center Of Elements				3236.50	TOP OF INTERVAL
7" MR-3 35# Casing Packer **Below**		Northstar	7"	2.25"	n/a	2-7/8" EUE	1.62		3238.12	
Ported Flow Sub		Northstar	3"	2"	2-7/8" EUE	2-7/8" EUE	0.17	3238.12	3238.29	
Crossover	XO-183	Northstar	5"	2.5"	2-7/8" EUE	3-1/2 IF	0.41	3238.29	3238.70	
Quad Gauge Carrier	3050CA-30	Northstar	0.21	2.25"	3-1/2 IF	3-1/2 IF	1.59	3238.70	3240.29	2x external gauges
Crossover	XO-27	Northstar	5"	2.5"	3-1/2 IF	2-7/8" EUE	0.37	3240.29	3240.66	
Mule Shoe		Northstar	5"	N/A	2-7/8" EUE	N/A	0.12	3240.66	3240.78	
									3240.78	BOTTOM TOOLS
									3330.00	Cement Top

Rupture Disks and Temperature Correction		Low	NOMINAL	HIGH
	SSBV Open	5814	5933	6062
	PUMP	719	838	957
	SSBV Close	6928	7068	7209
	PUMP	1831	1973	2114

	Low	NOMINAL	HIGH
EXIT VALVE	7434	7586	7737
PUMP	2571	2733	2875

Fig.3: DST string and BHA for DST operation

The DST operation commenced on 9th February at 18.00 hours and terminated on 12th February at 12.00 hours. Interval & surface pressure profile and liquid height profile is plotted over the entire test period shown in Fig. 4.

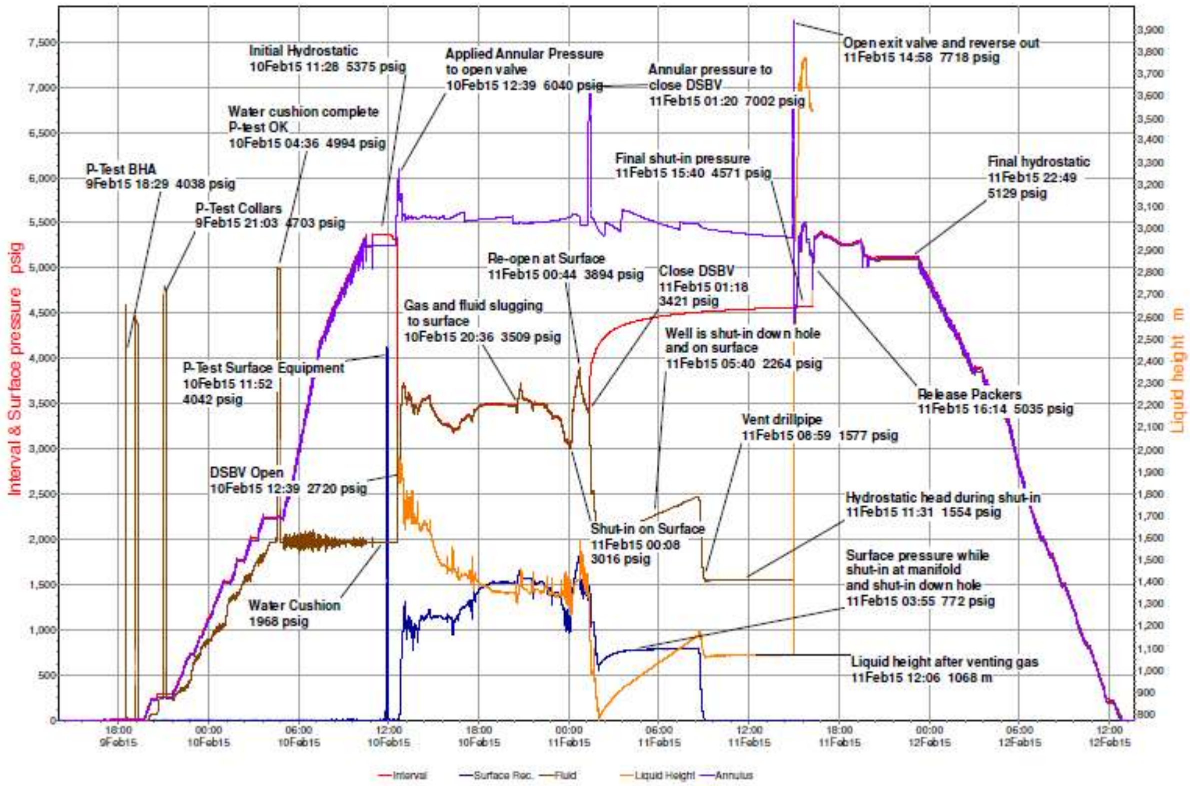

Fig.4: Summary of DST operation

During the total test period first the well bore conditioning and pressure gauge calibration operation are performed in the initial hydrostatic period then started the drawdown period for 760 minutes following buildup period for 892 minutes shown in table 1. Four pressure gauge and temperature recorder have been installed in the test stem for recording four sets of data among them two record no. 1785 and 40914 have been analyzed as these two records have shown the reservoir responses in the pressure profile.

Table 1: Summarized DST events

		Recorder # / Depth m	Surface	1787	1788	1785	40914
event	date/time mm/dd hh:mm	duration minutes		3226.67	3226.67	3239.50	3239.50
A. Init Hydrostatic	02/10 11:18				5250	5375	5377
B. Start Flow 1	02/10 12:41	760	22	1968	6094	2723	2724
B End Flow 1	02/11 01:21		1480	3411	7047	3426	3427
C. End Shut In 1	02/11 16:12	892	5	4913	4774	4574	4575
M. End Hydrostatic	02/11 22:19			5089	5109	5128	5129

The liquid flow profile is plotted during the DST operation. It has been observed that during the DST significant quantity of liquid has flown from reservoir into wellbore in form of oil and water in an average rate 1000 bbl/d shown in Fig. 5.

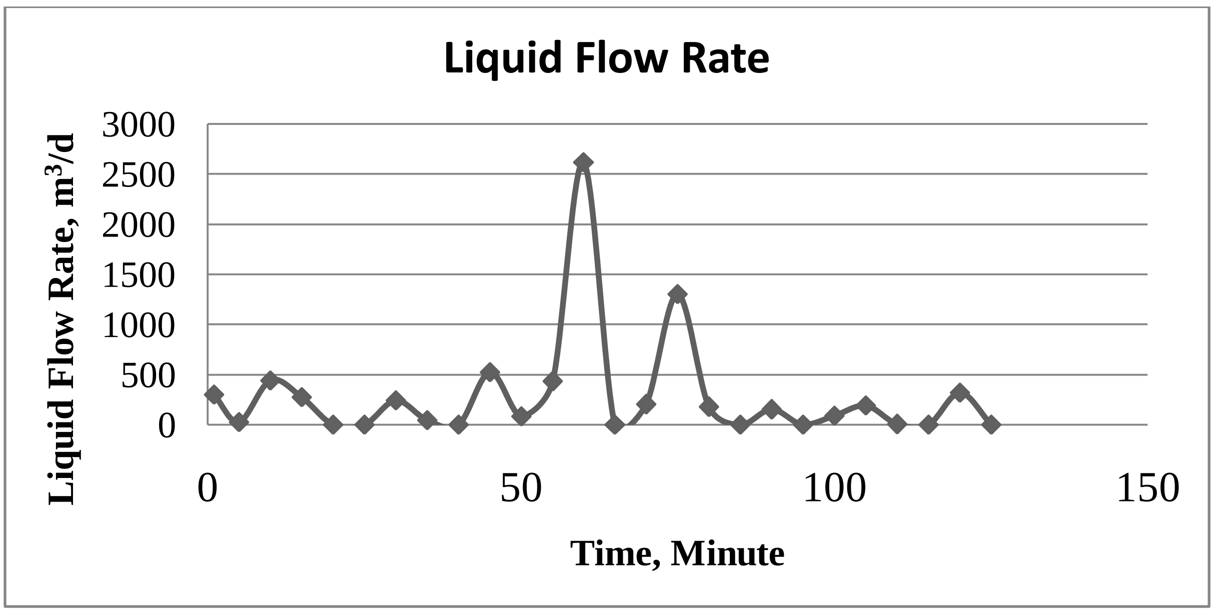

Fig.5. Liquid flow profile during DST.

Analysis of DST data for record no. 1785

A pressure gauge is set at the depth 3239.5 meter to record the flowing pressure during the DST operation and pressure signature is recorded under the record no. 1785. In the total pressure profile of the DST there is presence of drawdown following buildup pressure signature shown in Fig. 6 from 26.02 hours to 37.57 hours and from 37.57 hours to 53.68 hours respectively since the start of test.

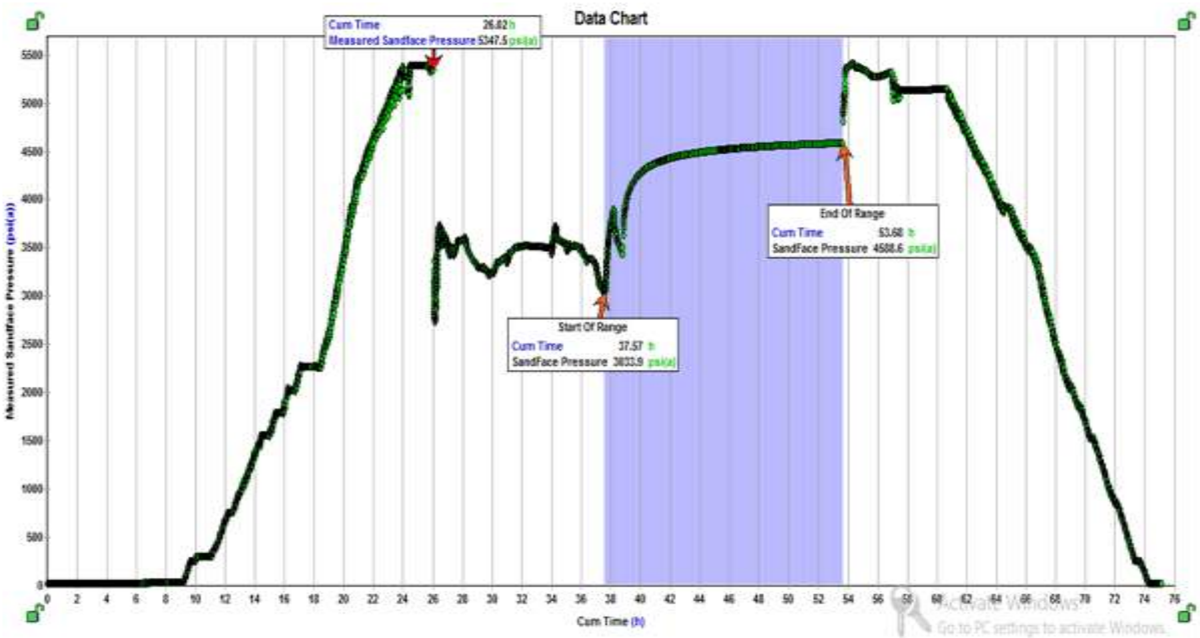

Fig.6: Recorded total pressure profile of DST

The recorded total pressure data is filtered as per 300 data per cycle to remove the noise and develop the full test model of drawdown following buildup periods shown in Fig. 7. The drawdown period (tp) exits for 11.5514 hour and pressure buildup period (Δt) exists for 16.1069 hour. The initial pressure (Pi) is 5347.53 psig and after drawdown the flowing pressure (Pwf) is 3033.92 psig following buildup period the pressure increases to 4588.57 psig.

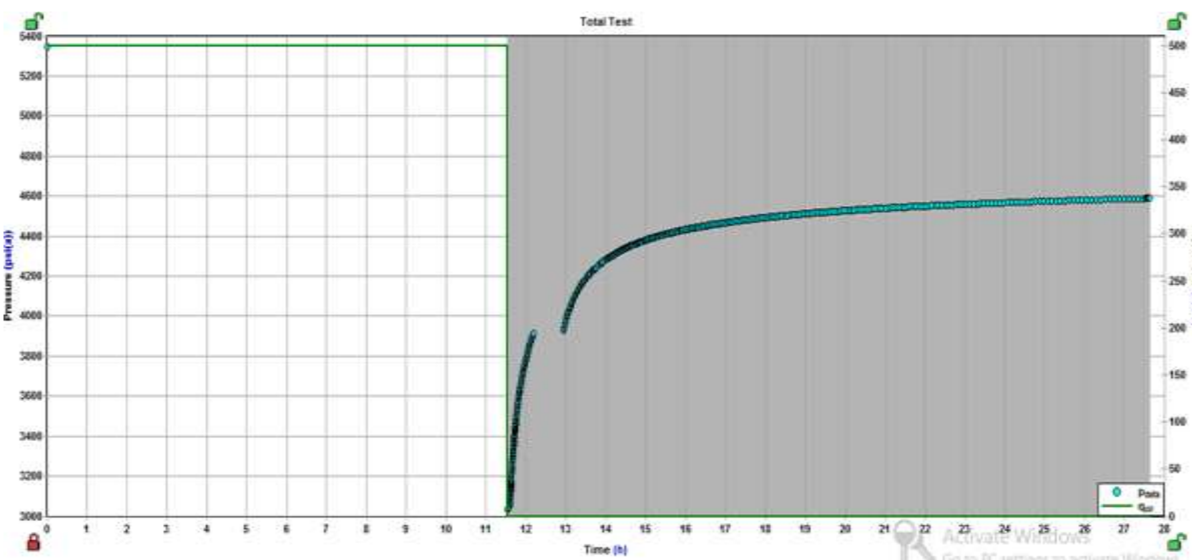

Fig.7: Full test model of drawdown following buildup period

The shut-in pressure (Pws) is plotted in Cartesian scale and the Horner time [(tp+Δt)/ Δt] is plotted in log scale to build a semi-log plot of buildup test. A best fitted straight line is drawn along the data points to estimate the slope and intersection of the straight line. From the slope of the straight line permeability (k) is calculated 6.3312 mili Darcy (md) and from the intersection the average reservoir pressure (p*) is calculated 4858.8 psia shown in Fig. 8.

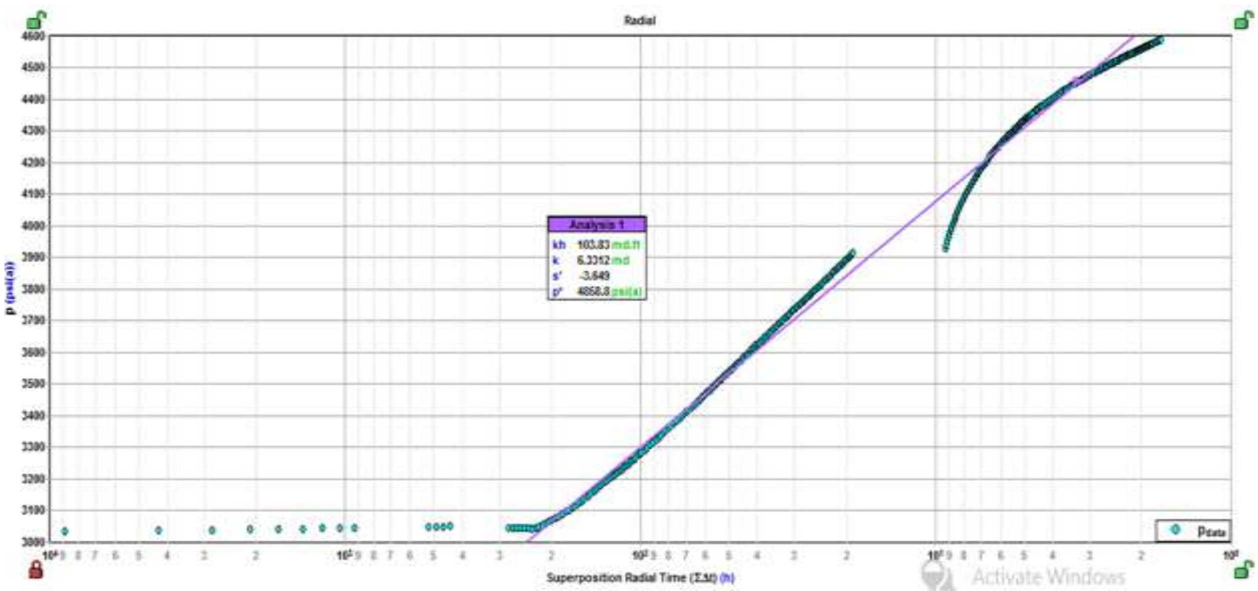

Fig.8: Semilog plot of buildup test

The buildup pressure ($\Delta Pbu=Pws-Pwf$) and its derivative [$d\Delta Pbu/d(tp+\Delta t)/\Delta t$] is plotted in log scale along the Horner time [$(tp+\Delta t)/\Delta t$] in the same scale to build the diagnostic plot shown in Fig. 9 where well bore storage effect, skin effect and infinite acting reservoir responses are visible clearly. The well bore storage is 0.21 bbl/psi and from the infinite acting line the permeability is 6.3312 md.

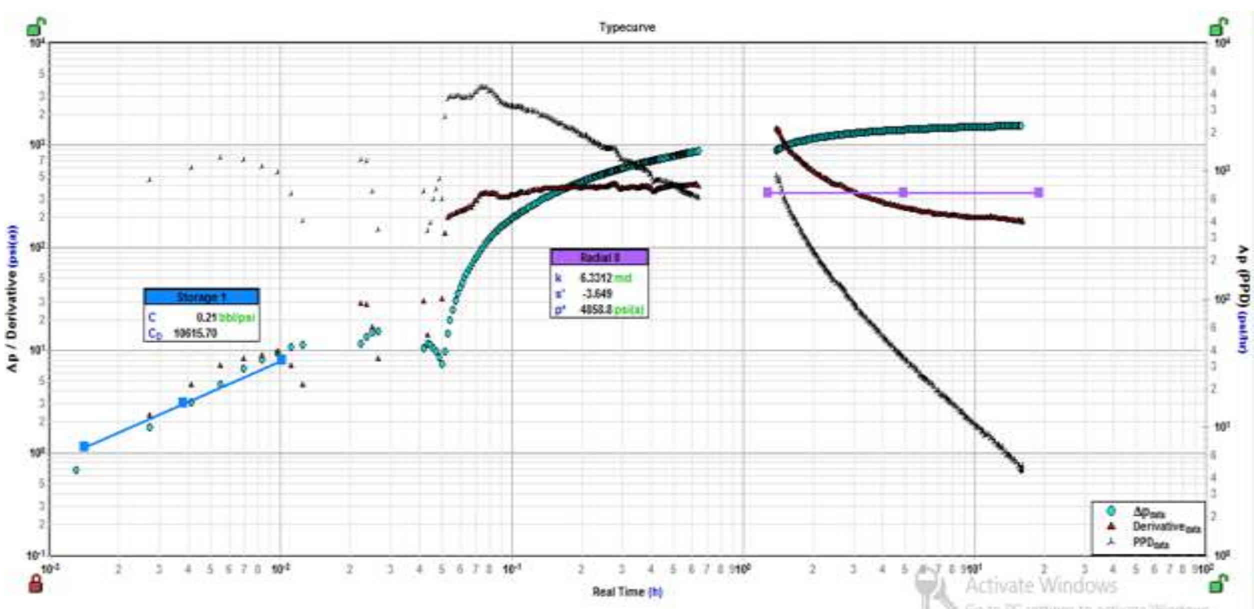

Fig.9: Diagnostic plot of buildup test

Analysis of DST data for record no. 40914

Another pressure gauge is set at the depth 3239.5 meter to record the flowing pressure during the DST operation and pressure signature is recorded under the record no. 40914. In the total pressure profile of the DST there is presence of drawdown following buildup pressure signature shown in Fig. 10 from 25.88 hours to 37.60 hours and from 37.60 hours to 53.59 hours respectively since the start of test.

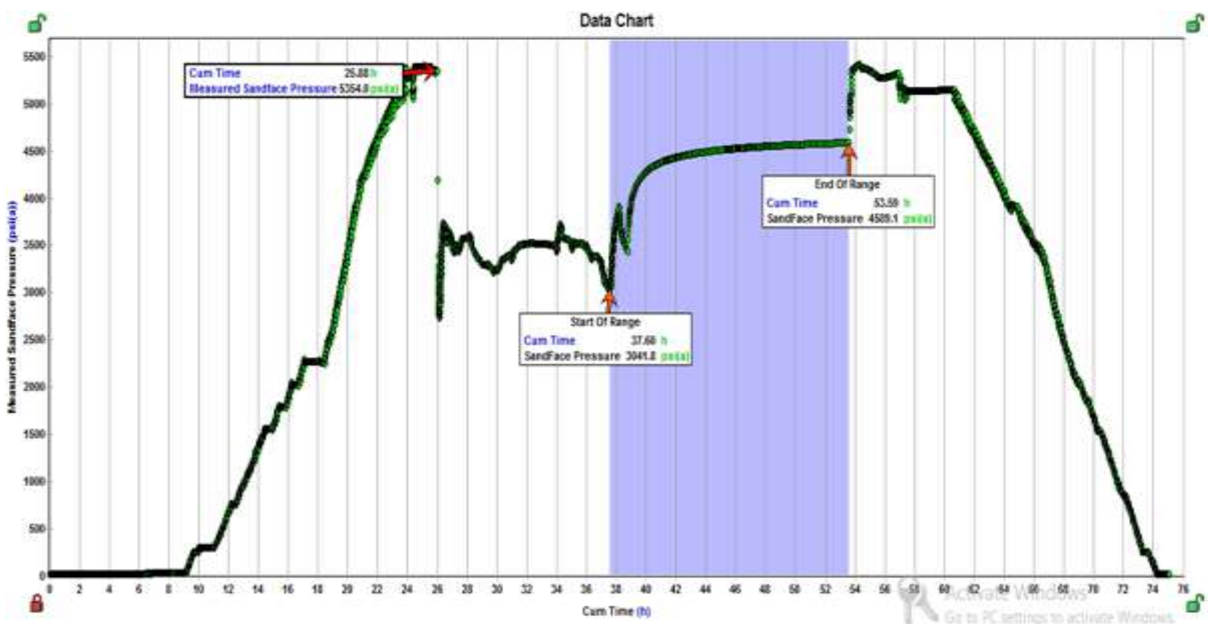

Fig.10: Recorded total pressure profile of DST

The recorded total pressure data is filtered as per 400 data per cycle to remove the noise and develop the full test model of drawdown following buildup periods shown in Fig. 11. The drawdown period (tp) exits for 11.5986 hour and pressure buildup period (Δt) exists for 15.9848 hour. The initial pressure (Pi) is 5348.83 psig and after drawdown the flowing pressure (Pwf) is 3041.79 psig following buildup period the pressure increases to 4589.14 psig.

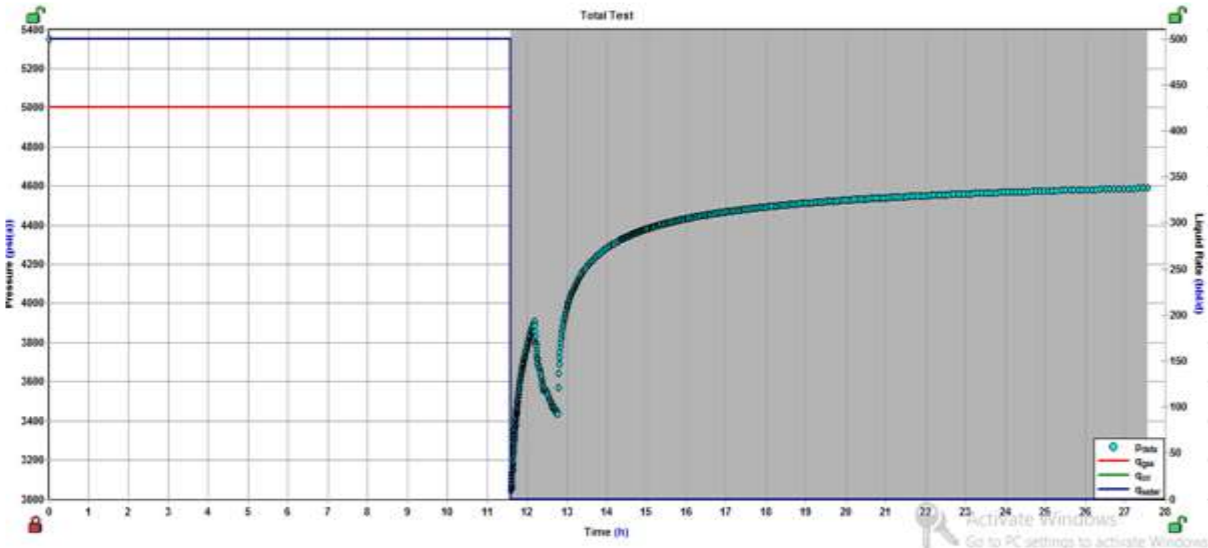

Fig.11: Full test model of drawdown following buildup period

The shut-in pressure (Pws) is plotted in Cartesian scale and the Horner time [(tp+Δt)/ Δt] is plotted in log scale to build a semi-log plot of buildup test. A best fitted straight line is drawn along the data points to estimate the slope and intersection of the straight line. From the slope of the straight line permeability (k) is calculated 12.2179 mili Darcy (md) and from the intersection the average reservoir pressure (p*) is calculated 4834.7 psia shown in Fig. 12.

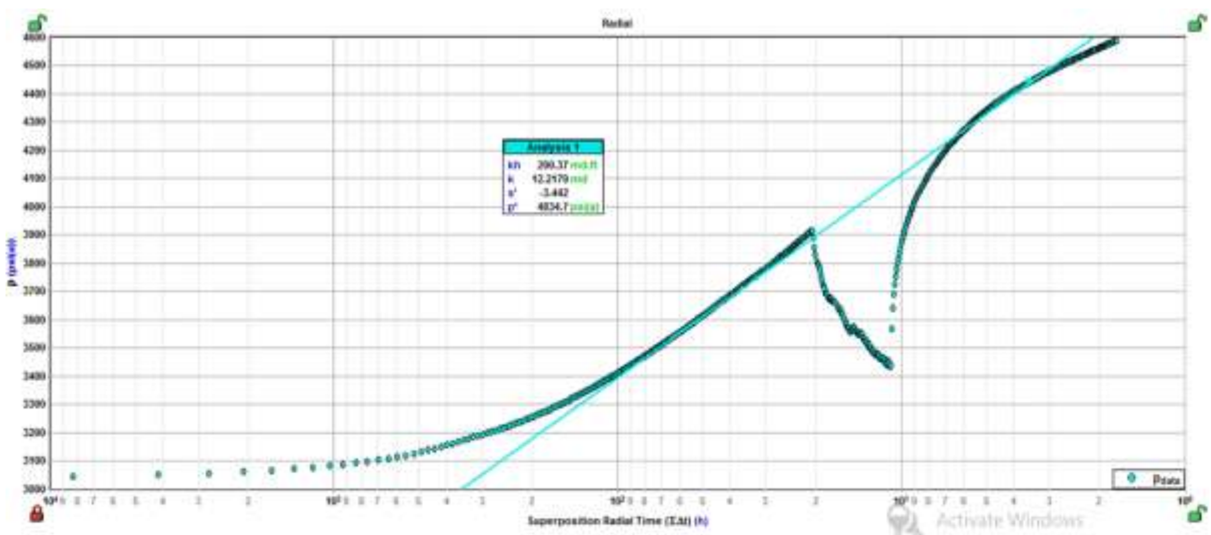

Fig.12: Semi-log plot of buildup test

The buildup pressure (ΔPbu=Pws-Pwf) and its derivative [dΔPbu/d(tp+Δt)/Δt] is plotted in log scale along the Horner time [(tp+Δt)/ Δt] in the same scale to build the diagnostic plot shown in Fig. 13 where well bore storage effect, skin effect and infinite acting reservoir responses are visible clearly. The well bore storage is 0.04bbl/psi and from the infinite acting line the permeability is 12.2179 md.

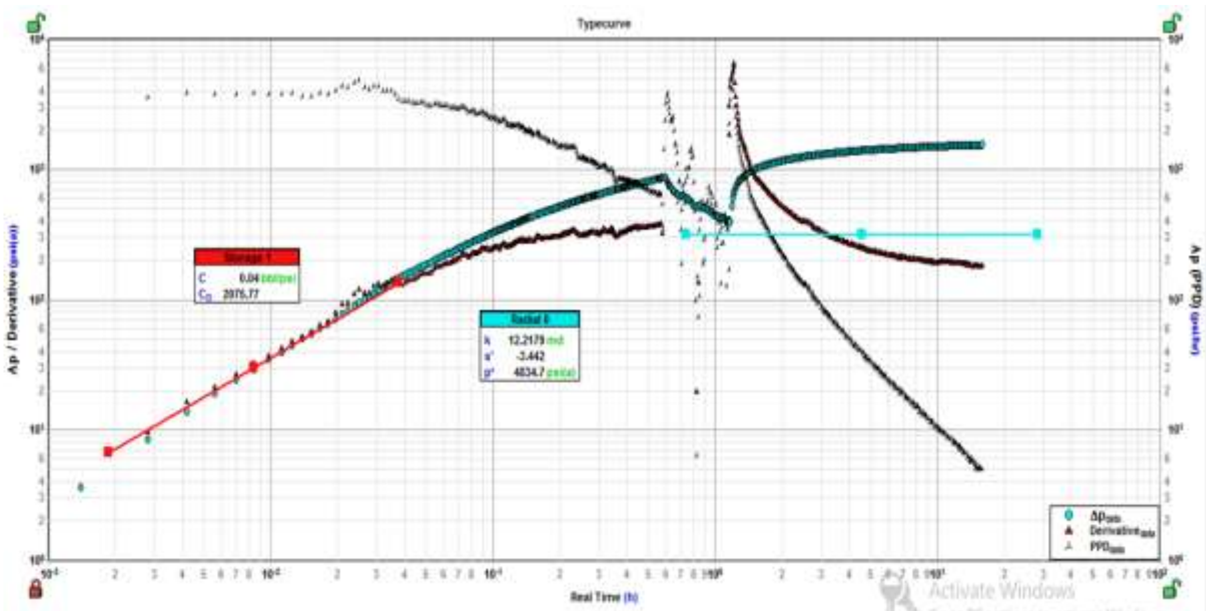

Fig.13: Diagnostic plot of buildup test

RESULTS

The well test analysis is authentic technology to detect and characterize the hydrocarbon bearing formation. In the DST there are two records which have shown the reservoir responses in the pressure signature. These two pressure profiles are analyzed as per the standard well test analysis technique such as semi-log and diagnostic plot analysis which reveals the existence of the petroleum reservoir of the following characteristics shown in table 2.

Table 2: Summary of DST interpretation

<table>
<tr><th>Parameter</th><th colspan="2">Value</th><th>Remarks</th></tr>
<tr><td>Interval</td><td colspan="2">3261 to 3266 m</td><td>According to the well log in that interval there is porous and permeable formation exists.</td></tr>
<tr><td rowspan="2">Effective Permeability (K), mD</td><td>Re. No. 1785</td><td>Re. No. 40914</td><td rowspan="2">Permeability is low.
Consistent with other DST value.</td></tr>
<tr><td>6.3312</td><td>12.2179</td></tr>
<tr><td rowspan="2">Skin Factor (S), DL</td><td>Re. No. 1785</td><td>Re. No. 40914</td><td rowspan="2">Skin Factor is Negative.

Negative skin factor indicating that there are fractures developed near the well bore during drilling operation.</td></tr>
<tr><td>-3.649</td><td>-3.442</td></tr>
<tr><td rowspan="2">Wellbore Storage, C, bbl/psi</td><td>Re. No. 1785</td><td>Re. No. 40914</td><td rowspan="2">Wellbore Storage is low.
Low Wellbore Storage indicates that liquid has flown from reservoir into well bore.</td></tr>
<tr><td>0.21</td><td>0.04</td></tr>
</table>

Average Reservoir Pressure, P*, psia	Re. No. 1785	Re. No. 40914	Average Reservoir Pressure is high. Water column pressure at depth 3266 m is 4647 psia. Approximately 200 psi overpressure exists in the zone which indicates the existence of oil.
	4858.8	**4834.7**	
Boundaries	Re. No. 1785	Re. No. 40914	No boundaries have been developed. No interference with other wells in the field. No fault in the drainage area. No channel in the drainage area. No fracture in the drainage area.
	Infinite acting	**Infinite acting**	

CONCLUSION

Form the analysis of pressure signature obtained from the DST the wellbore storage, skin factor, permeability and average reservoir pressure have been estimated and their values are analyzed to obtain the following decisions:-

1. The flowing phase during the DST is liquid on an average rate 1000 bbl/d.
2. Although the reservoir permeability is low but the negative skin factor helps the reservoir liquid to flow into the wellbore.
3. The low value of wellbore storage evident the liquid phase has flown into the well bore from the reservoir. There is no flow of gas phase into the wellbore from the reservoir.
4. Average reservoir pressure and water column pressure at depth 3266 m reveals the existence of the overpressure zone which is developed by the presence of hydrocarbon in liquid phase.
5. Well log analysis i.e. low value of gamma log and high value of resistivity log with shallow and deep resistivity separation indicates the presence of hydrocarbon as well.

From the above analysis it can be concluded that all of the investigations i.e. well log and DST analysis evident the presence of liquid hydrocarbon (oil) in the interval 3261 to 3266 meter. The decision flow chart of the analysis is shown in Fig. 14.

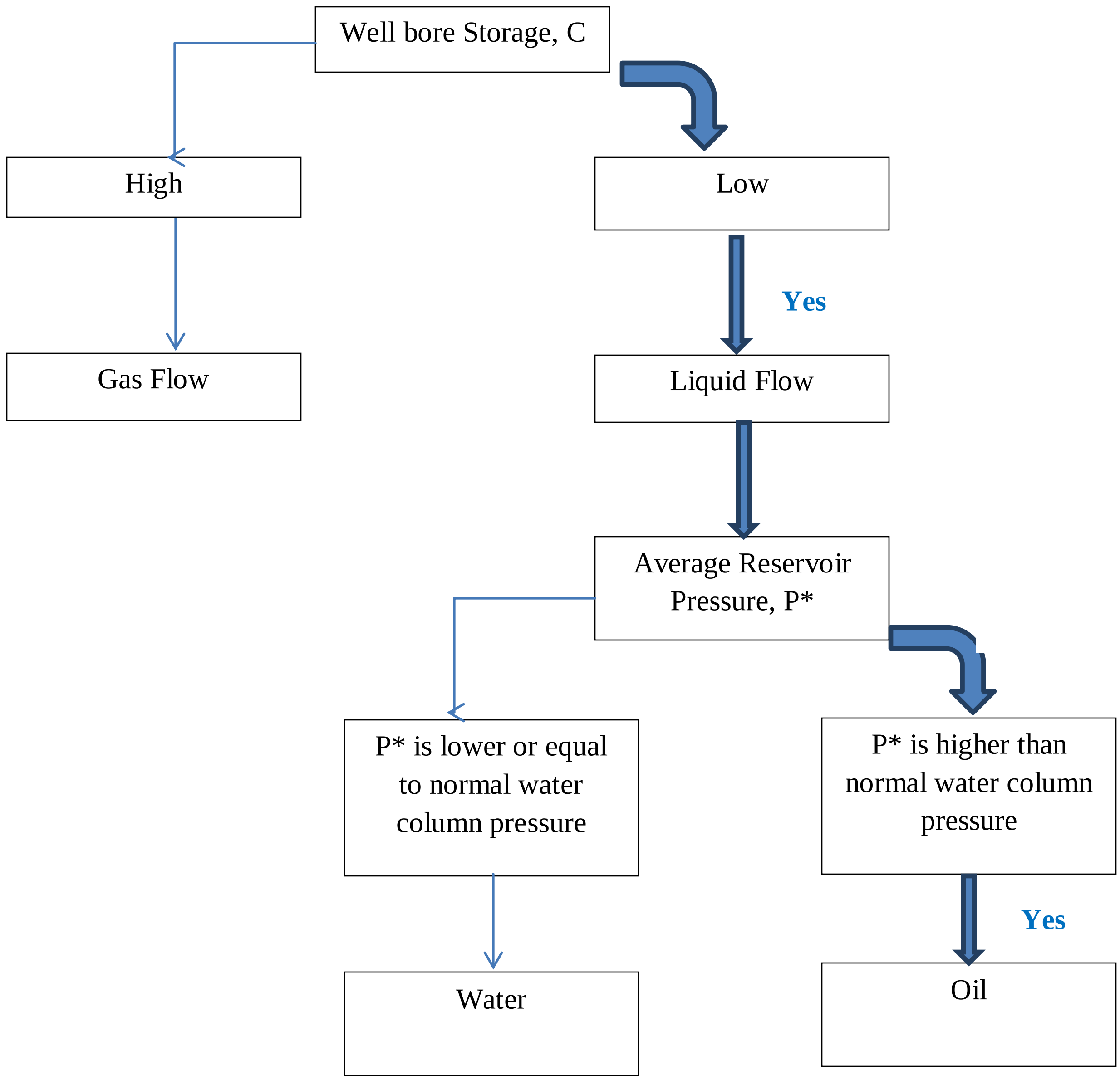

Fig.14: Decision flow chart on the basis of DST analysis

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ICPE (2016- 015)

Reserve Estimation of a Gas Field in Bengal Basin Using "Modified Material Balance" Method

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ABSTRACT

The commercial energy resource of Bangladesh is mainly comprised of natural gas significantly found in its eastern and south-eastern region. That's why; the future development of the country significantly depends on the judicial use of this valuable resource. Estimation of Gas Initially In Place (GIIP) is very crucial for the energy planning and natural gas utilization scheme. These two parameters also play very efficient role in fixing up of commercial strategies relating to natural gas. The material balance is a very important tool used by reservoir engineers in the oil and gas industry. It can provide an estimation of initial hydrocarbon stored in the specific reservoir independent of geological interpretation. For applying this method, it is almost mandatory to estimate average reservoir pressure at the required time intervals. The standard practice of estimating average pressure is to conduct pressure buildup test on individual wells in a reservoir. Pressure buildup test require Shutting off production for some time and it is not conducted on a regular interval due to the demand-supply situation prevailing in the country. Material Balance Method has been modified by different researchers to bypass the strict requirement of the average reservoir pressure as an input parameter. Instead, these techniques use Static Bottom Hole Pressure (SBHP) estimated from STHP, Shut-in Tubing Head Pressure (STHP) and Flowing Tubing Head Pressure (FTHP). Here a study has been conducted to estimate GIIP of the wells of a gas field in Bangladesh situating at the south-eastern part of the country, which is effectively contributed through four (4) wells. Here, Modified Material Balance method has been applied using SBHP, STHP and FTHP relating to three pressure data for each individual well. Data for SBHP and STHP methods were recorded during occasional Shut-in due to some emergency operational purpose or safety issues. It was found that GIIP for the wells are 166.03, 131.34, 170.78, and 240.21 BCF respectively showing the reserve of the field as 708.36 BCF or 0.708 TCF. The result found through this methodology is one of the most reliable than other reserve estimation techniques as it is subjected to real field data.

Keywords- Gas reserve, GIIP estimation, Modified Material Balance Method, Beggs and Brills correlation, SBHP, STHP, FTHP.

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INTRODUCTION

Reserve Estimation of a reservoir is a fundamental calculation in reservoir engineering. This information is of critical importance in determining production strategy, design of facilities, contracts and the value of the reserves. Reserves can be estimated in many ways -Volumetric, Production Decline, Simulation and Material Balance. The Production Decline gives an estimate of recoverable gas, whereas the other two give an estimate of gas-in-place. In the reservoir engineering literature, the word "reserve" refers to the raw gas-in-place. Whereas in the commercial world, the word "reserve" often means the recoverable sales gas. In this paper, the word "reserve" is used to denote the raw gas-in-place. [1]
In this paper, we have estimated the reserve (GIIP=Gas Initially In Place) of one of the currently producing gas fields of Bangladesh in the south-east region of the country. We used "Material Balance" method with three different pressure data like, Static Bottom Hole Pressure (SBHP), Shut-in Tubing Head pressure (STHP) and Flowing Tubing Head pressure (FTHP) of four separate wells. In reserves estimation, the real production behavior is emphasized, i.e. production decline curves or mathematical modeling are used, as well as practical experience gained from similar fields. When gas fields are in question, the material balance method has been accepted as reliable. The consequence of such an approach is a conservative estimate of reserves that results in frequent upward revisions. The result of this method adopts a comprehensive reliability than other method of hydrocarbon estimation as it uses practical production data.

DESCRIPTION OF THE FIELD

Bangladesh has occupied the major part of the Bengal basin. The Bengal Basin has included west Bengal in the west Tripura in the east. The Bengal Basin is the result of colliding between the Indian plate and the Asian plate which is explained by the universally accepted theory of Plate tectonics. The geosynclinals Basin in the southeast of Bangladesh occupies the area of Comilla and Brahmanbaria. The Basin is characterized by huge thickness of elastic sedimentary rock mostly sandstone and shale of tertiary age. The most important stratigraphic unit in Bangladesh is the Surma group since all the wells in Bangladesh are drilled in it. The Surma group is Miocene-Pliocene aged sandstone. The rock is served as excellent reservoir rocks capped by inter bed shale forming seals. Among the two formation of Surma group Bhuban formation is sandy and Bokabil formation more argillaceous.

In this paper we are addressing the wells Well# 01, Well# 02, Well# 03, and Well# 04. Here, Well# 01 and Well# 02 are exploratory wells, Well# 03 is a development well and Well# 04 is an appraisal well. All are completed as gas wells. All these four wells are equipped with an Emergency Shutdown System that shut automatically in the event of any failure or pressure variation to an unacceptable level that could be a threat to pipeline integrity or personal safety.

MATERIAL BALANCE METHOD

All reserve estimates involve some degree of uncertainty. The uncertainty chiefly depends on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. [2] But material balance is a generally recognized as comparatively more reliable method for estimating original hydrocarbon in place and the evaluation of the reservoir driving mechanisms. To evaluate the Gas Initially In Place (GIIP) of a reserve, It requires to plot a P/z vs. cumulative production "Gp", where P is the average reservoir pressure. A straight line drawing through the pressure data with their corresponding cumulative gas production gives the original gas in place. Graphical presentation of this method is shown in Figure: 1. This method of calculating the reserves of medium and high permeability reservoirs, using flowing pressure data has the potential of preventing loss of valuable production, without having to Shut-in the well. The method is suitable for all gas fields in Bangladesh where routine pressure testing cannot be conducted due to critical demand-supply situation. To get accurate results, the production rate from the reservoir should be constant. Pressure in parallel to the flowing wellhead pressure data gives the original gas in place. In this approach interference in pressure data due to production of other wells of the sand, will affect the accuracy of the results. Mattar and McNeil demonstrated that the tubing head pressure also has a similar trend of decline as the sandface pressure. [1] This is true when single-phase gas flows through the well and there is no liquid build up in the tubing the straight line has been drawn from the initial tubing head

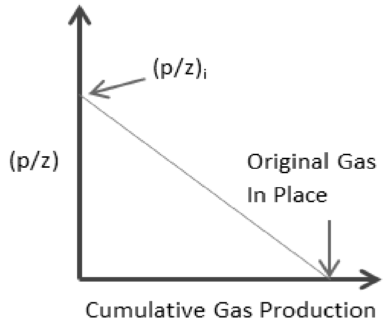

Figure 1: P/z vs. Cumulative production, Gp graph for estimating GIIP

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MODIFIED METHOD OF MATERIAL BALANCE

Three different approaches were taken to study the subject field. These were: (a) Static Bottom Hole Pressure (SBHP) estimated from Shut-in Tubing Head Pressure (b) Shut-in Tubing Head Pressure (STHP) (c) Flowing Tubing Head Pressure (FTHP). Data for approach (a) and (b) were recorded during occasional Shut-ins due to some production problems or any other reasons.

Static Bottom Hole Pressure (SBHP) estimated from Shut-in Tubing Head Pressure

Static Bottom Hole Pressure (SBHP) represents the energy available to move the fluid from the reservoir to the wellbore. [3]. The wells of a field generally suffer shut in from time to time due to production problems or any other causes which create space for recording pressure build up data at these shutting periods. The recorded Shut-in Tubing Head Pressure data was taken from monthly records of current Gas Field and corresponding Bottom Hole Shut-in Pressures were calculated. But it is to be noted that, the calculated Static Bottom Hole Pressure is not the same as the average reservoir pressure, which is generally used in the conventional material balance. A perfectly designed well test program can be beneficial for obtaining average reservoir pressure. [4]

Shut-in Tubing Head Pressure (STHP)

Shut in tubing head pressure is the pressure of well head tubing when well is in shut-in condition, i.e. there is no flow across the choke. In this approach the recorded Shut-in Tubing Head pressure are used to make a p/z vs. cumulative production plot, where p is now the Shut in Tubing Head pressure instead of the average reservoir pressure. The z factor is the most influential parameter here and out of some correlations we applied Beggs & Brill correlation to evaluate this. Since static gas gradient is very small, the plots set out for p/z using the Shut-in Tubing Head pressure vs. cumulative production for all the wells of current Gas Field, should provide quite similar results. The approach is completely based on the assumption that there is no liquid in the wellbore. If practically it is found that there is presence of liquids in the producing tube certainly erroneous results will come out of it. [4]

Flowing Tubing Head Pressure (FTHP)

Daily average flowing Tubing Head pressure data are recorded in this procedure. The z-factor is also calculated in the same way by using Beggs & Brill correlation for estimating the p/z term. The flowing Tubing Head pressure data was taken from daily records of current well. In the "flowing" material balance method that the Tubing Head pressure also has a similar trend of decline as the sand-face pressure. This is true when single phase gas flows through the well and there is no liquid build up in the tubing. While studying the plots for p/z of FTHP vs. cumulative production, it has been observed that the apparent gas in place figure of the producing sand of Current Gas Field are lower than that of obtained from static Bottom Hole Pressure and Shut-in Tubing Head Pressure methods.

This makes sense because Flowing Tubing Head Pressure decreases from the Shut-in Tubing Head Pressure because of frictional losses. The straight line drawn from the initial Tubing Head Pressure in parallel to the flowing Tubing Head Pressure data gives the original gas in place. [4]

ASSUMPTIONS

Assumptions made in this work are:
1. Constant reservoir temperature
2. Homogenous & isotropic reservoir
3. Pseudo steady-state flow.
4. Boundary dominated flow.
5. No phase change in the reservoir.
6. No water influx.
7. No rock compaction.
8. No connate water expansion

BEGGS & BRILLS CORRELATION

Estimation of gas reserves, design of oil and gas separators, and design of pipelines for the transmission of produced gas, and many other tasks in petroleum engineering are highly in need of proper estimation of z factor. The Beggs and Brill method of calculating pressure traverses requires the gas compressibility factor. This method, involving about 21 steps, is an iterative one wherein a pressure drop is obtained at the end of each iteration using, among other data, an initial assumed pressure drop. If the difference between the initial and calculated pressure drops is substantial, the iteration is repeated with the calculated pressure drop in each iteration serving as the assumed pressure drop for the next iteration. This process is continued until the difference between the assumed and calculated pressure drops is small. Arriving at a value for the final pressure drop typically requires a number of iterations.
Programming such tasks as the Beggs and Brill method for calculating pressure traverses in tubings for multiphase flow conditions cut down on the amount of time required for the calculation. Such reduction in computation time could be increased if a means was devised to incorporate the determination of gas compressibility factor into the program thus eliminating the need to manually obtain it from the chart for successive iterations. Beggs and Brill method is a new approach for determining z-factor on computer-based applications. [5]

The Beggs and Brill Correlation Equations
The correlation by Beggs and Brill for the calculation of z is given below:
$$Z = A + (1 - A)e^{-B} + CP_{pr}{}^{D}$$
Where,
$$A = 1.39\left(T_{pr} - 0.92\right)^{0.5} - 0.36T_{pr} - 0.10$$
$$B = \left(0.62 - 0.23T_{pr}\right)P_{pr} + \left[\left(\frac{0.066}{T_{pr} - 0.86}\right) - 0.037\right]P_{pr}^{2} + [\frac{0.32}{10^{9}\left(T_{pr} - 1\right)}]P_{pr}^{6}$$
$$C = 0.132 - 0.32\log T_{pr}$$
$$D = 10^{0.3106 - 0.49T_{pr} + 0.1824T_{pr}^{2}}$$

RESULT SUMMARY

The *p/z* vs. cumulative production graphs of well for SBHP, STHP and FTHP are depicted from Figure 2 to 13 and Gas in place values estimated from the plots of P/z vs. cumulative production using the Static Bottom Hole Pressure, Shut-in Tubing Head Pressure and Flowing Tubing Head Pressure for well # 1 approach are 168.2 BCF, 166.4 BCF and 163.5 BCF respectively. So, the average GIIP is 166.03 BCF here; which is 131.34 BCF, 170.78 BCF, and 240.21 BCF for well # 02, 03 and 04 respectively. So, the Gas Initally In Place (GIIP) of the reserve is 708.36 BCF or 0.708TCF.

WELL#01

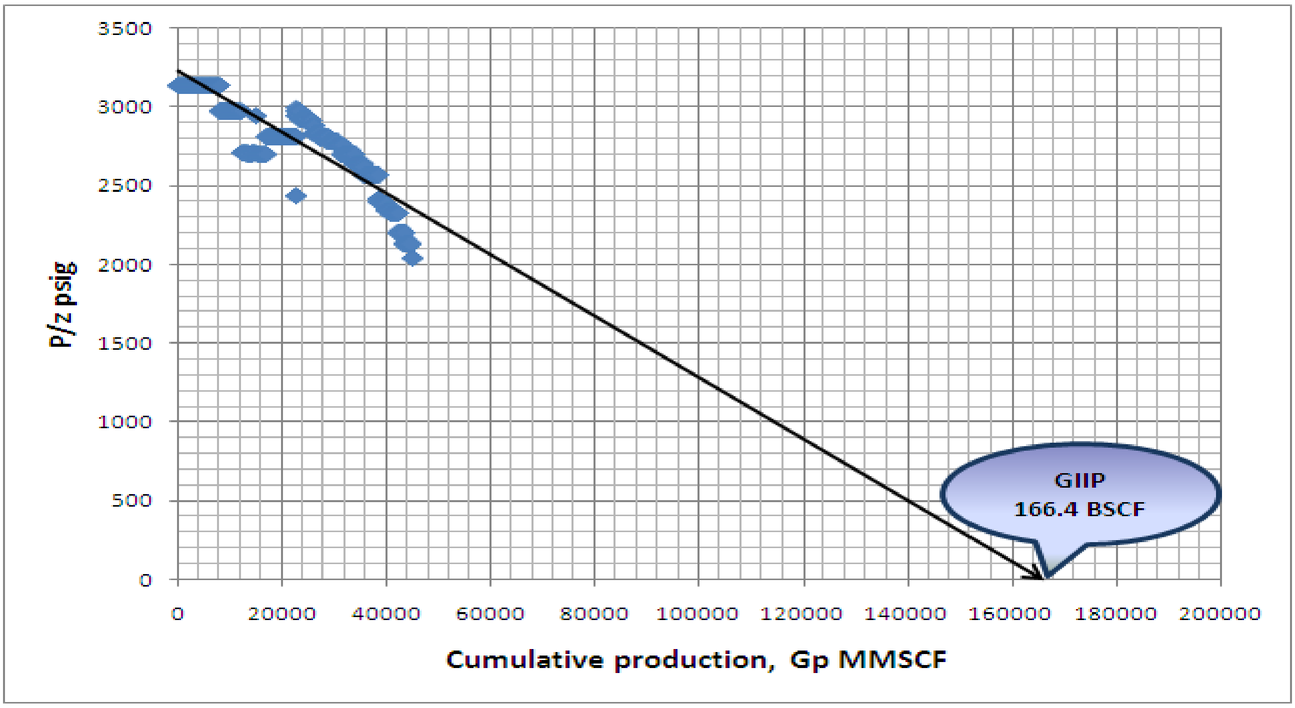

Figure 2: P/z STHP vs. Cumulative production, Gp

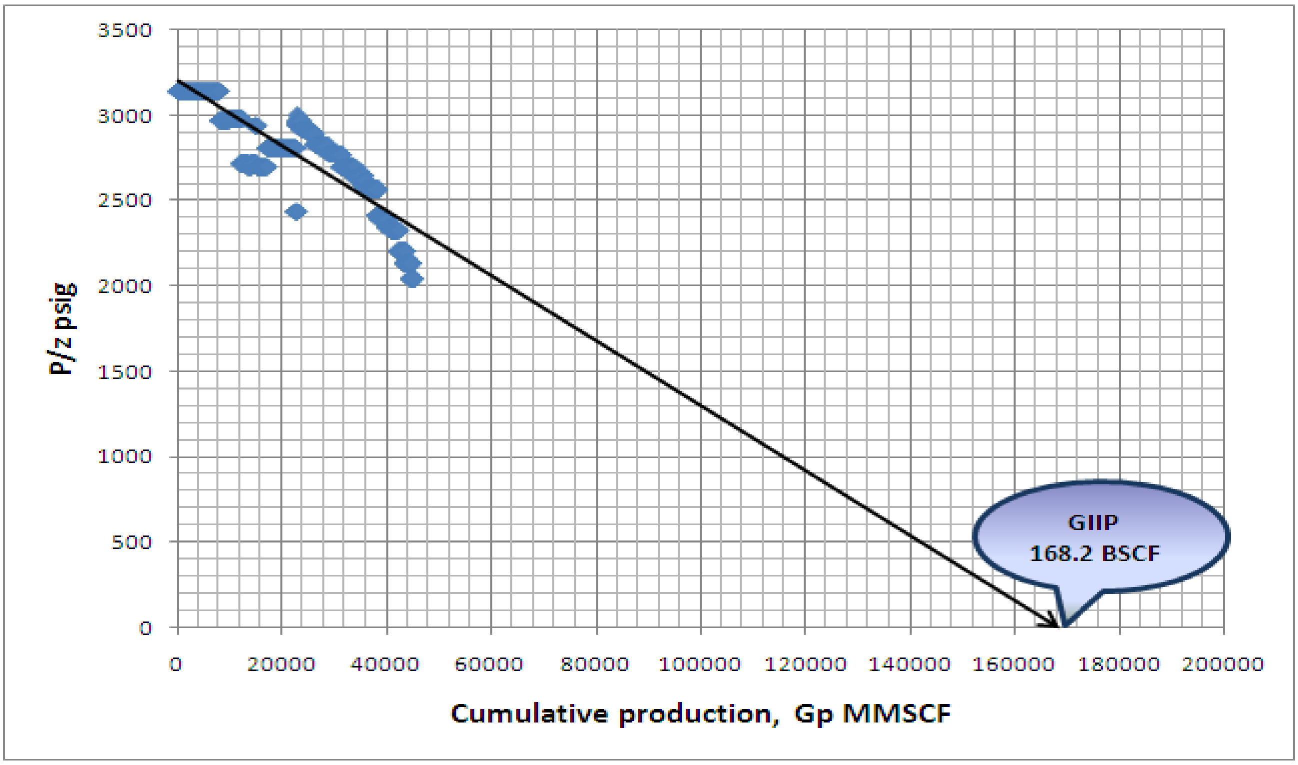

Figure 3: P/z SBHP vs. Cumulative production, Gp

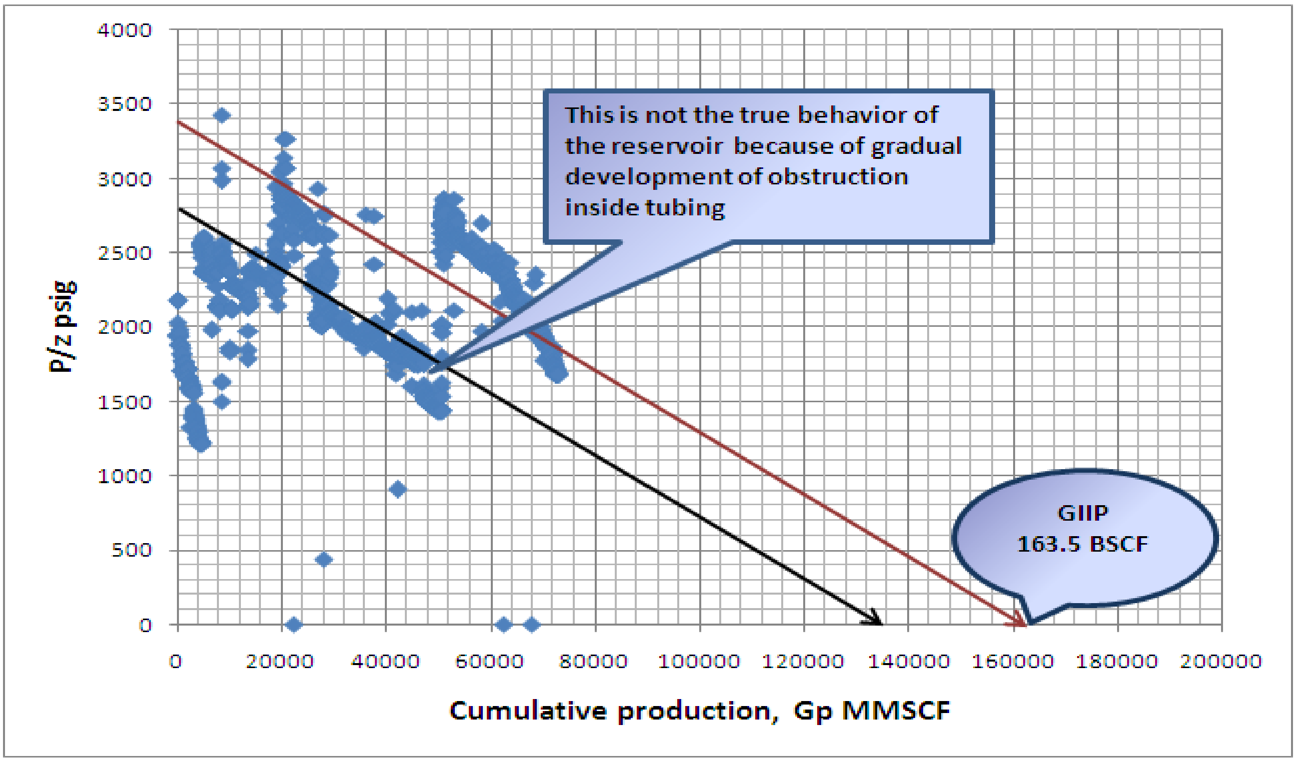

Figure 4: P/z FTHP vs. Cumulative production, Gp

WELL#02

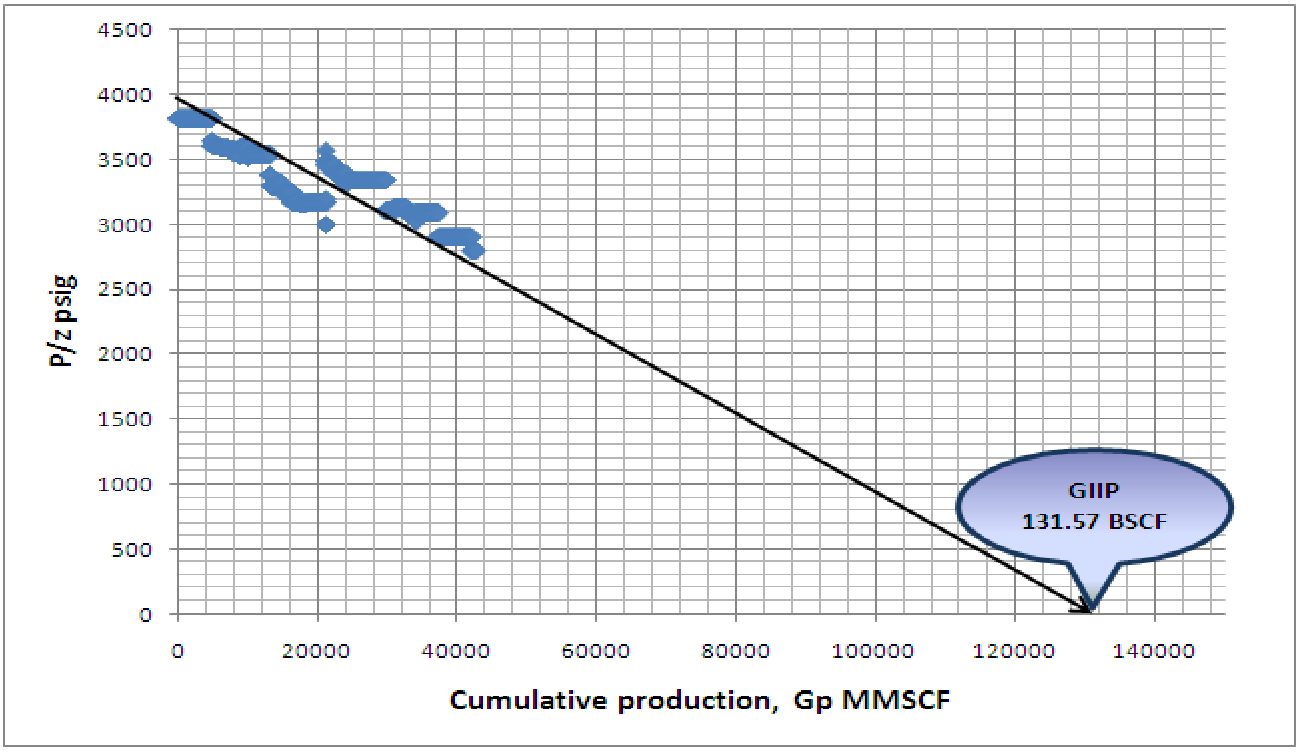

Figure 5: P/z STHP vs. Cumulative production, Gp

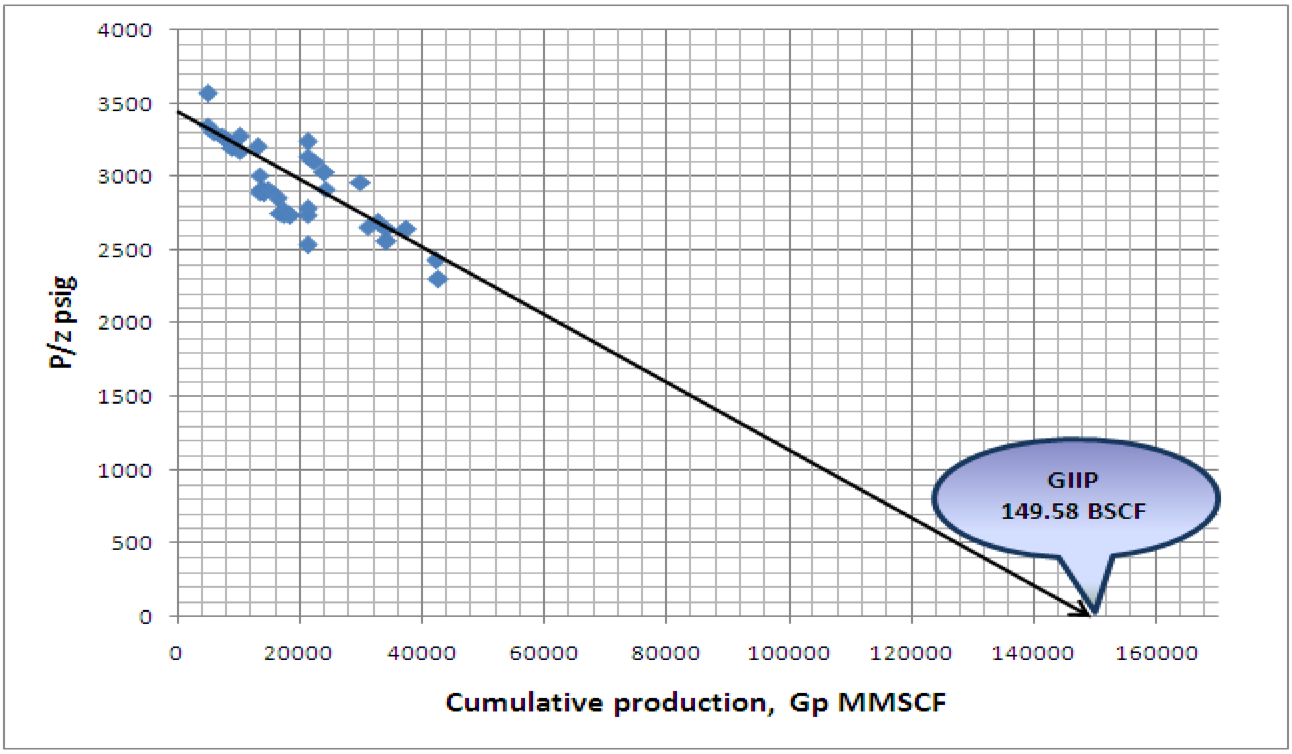

Figure 6: P/z SBHP vs. Cumulative production, Gp

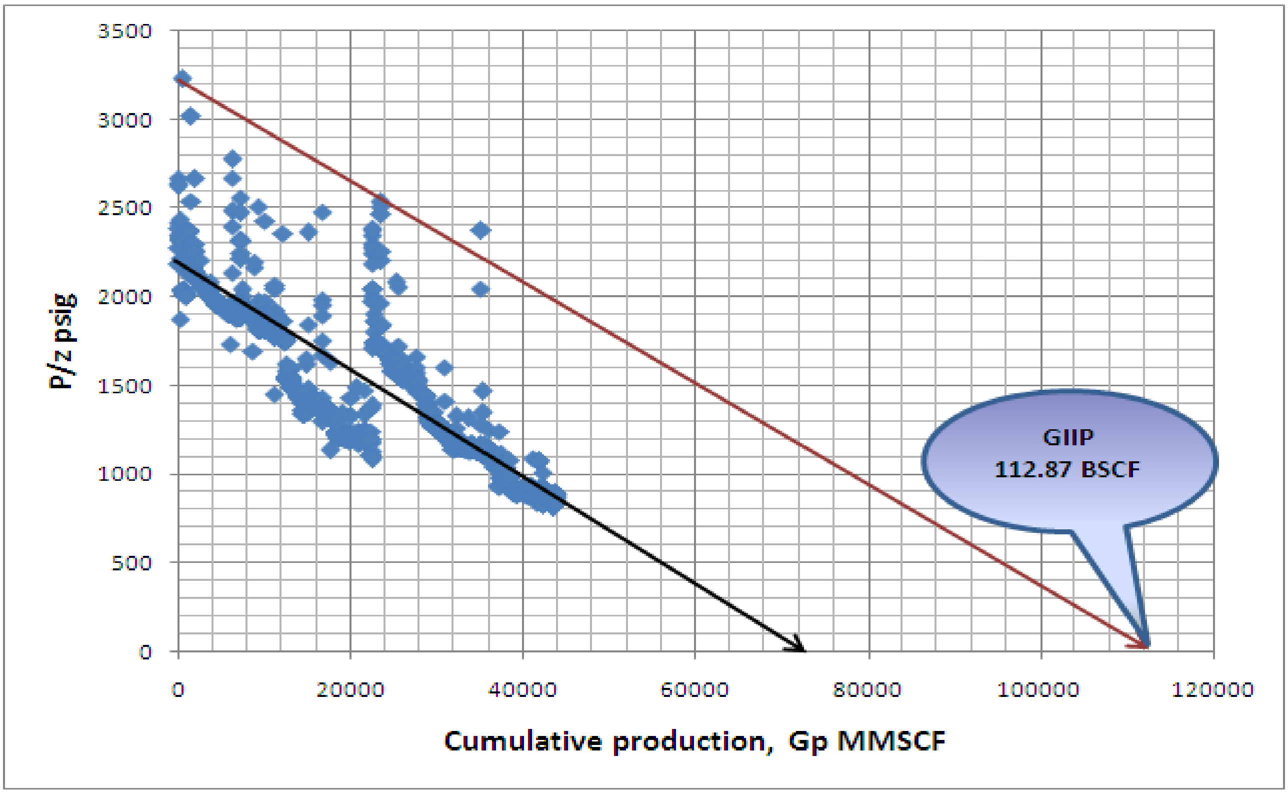

Figure 7: P/z FTHP vs. Cumulative production, Gp

WELL#03

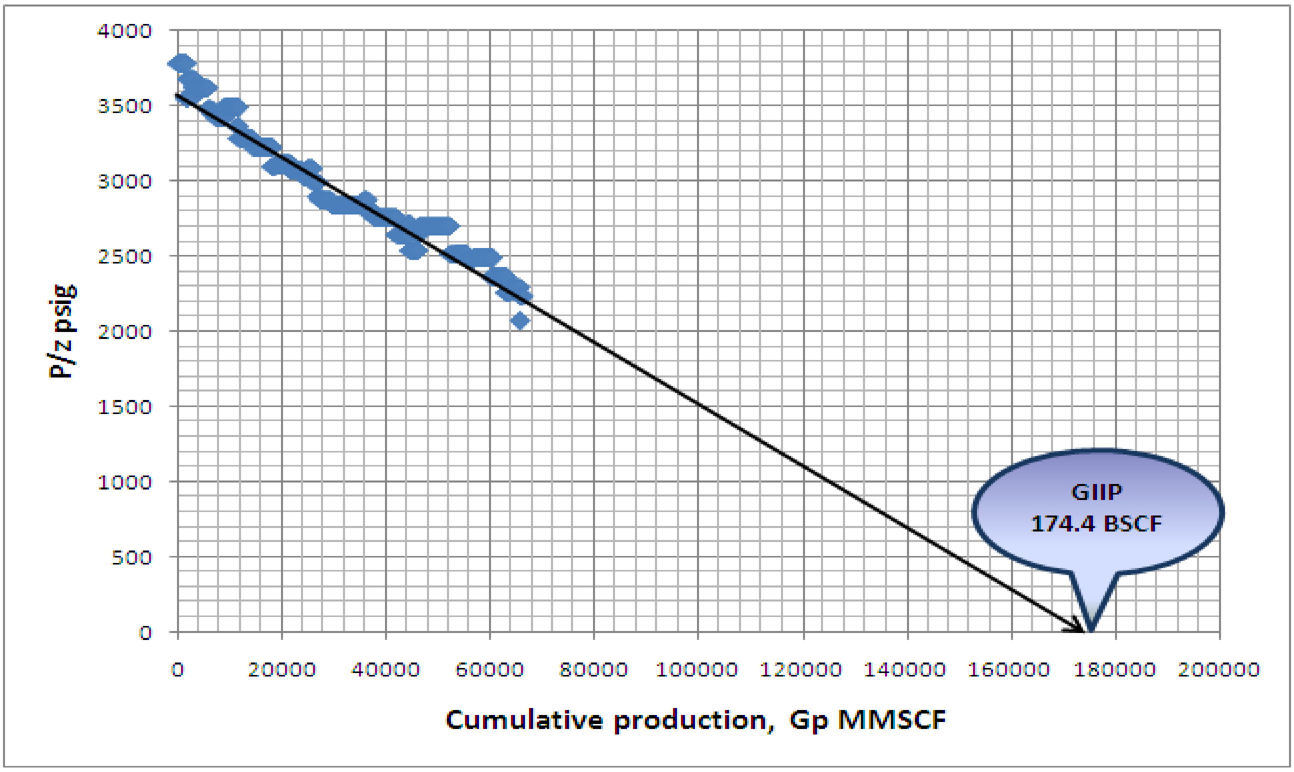

Figure 8: P/z STHP vs. Cumulative production, Gp

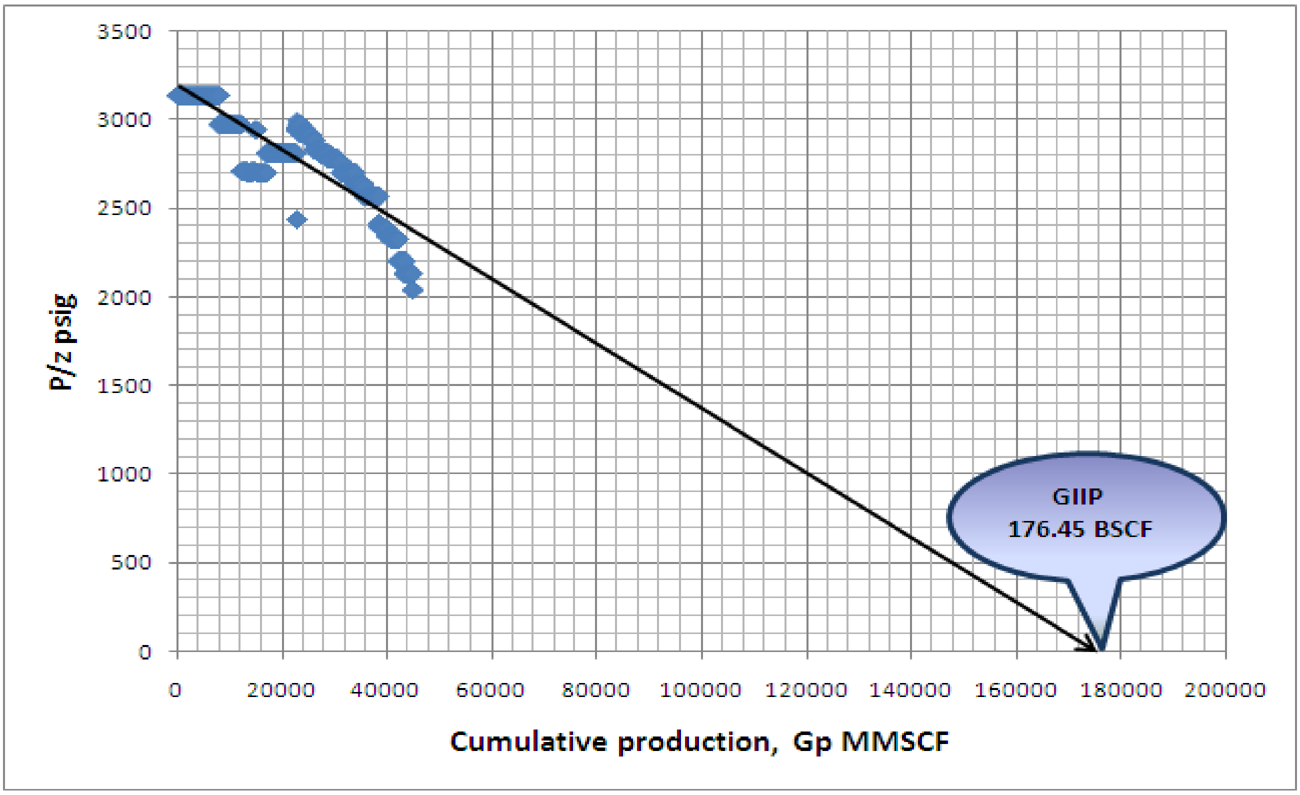

Figure 9: P/z SBHP vs. Cumulative production, Gp

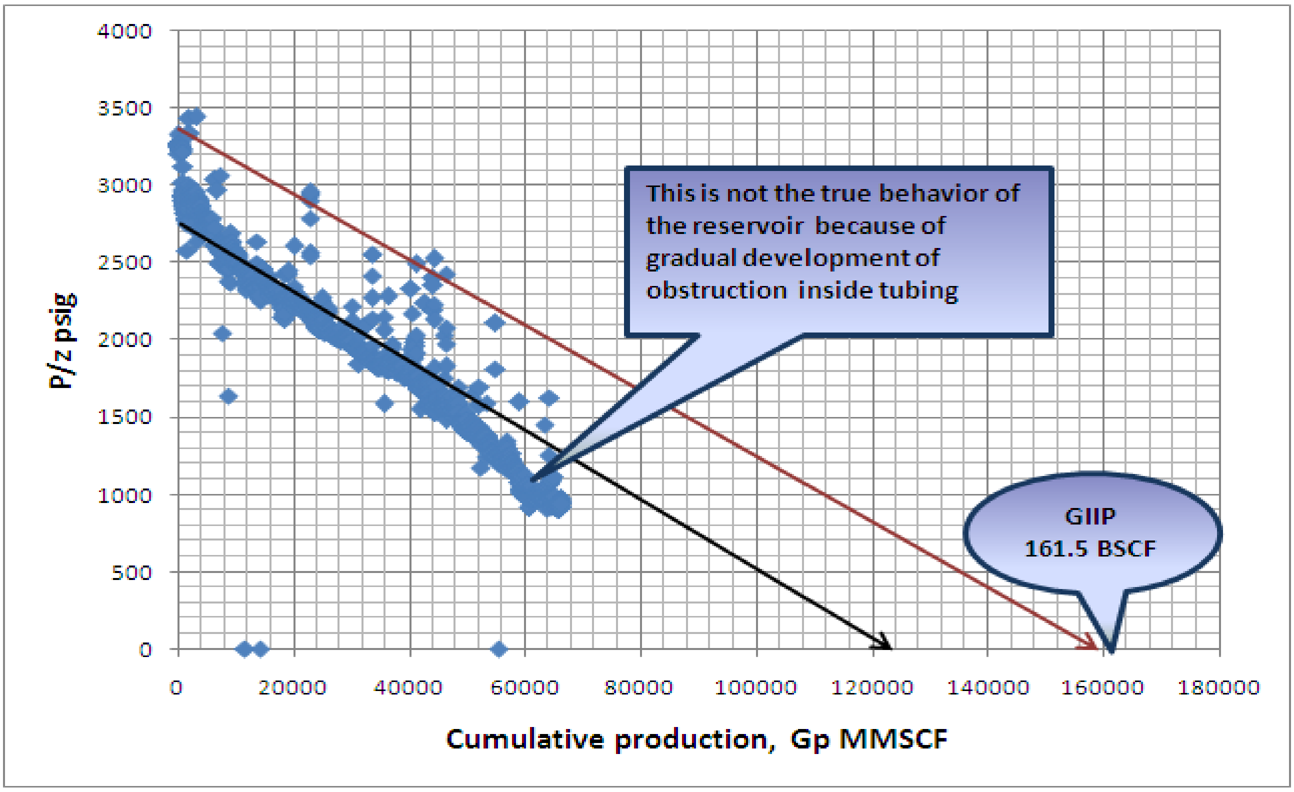

Figure 10: P/z FTHP vs. Cumulative production, Gp

WELL#04

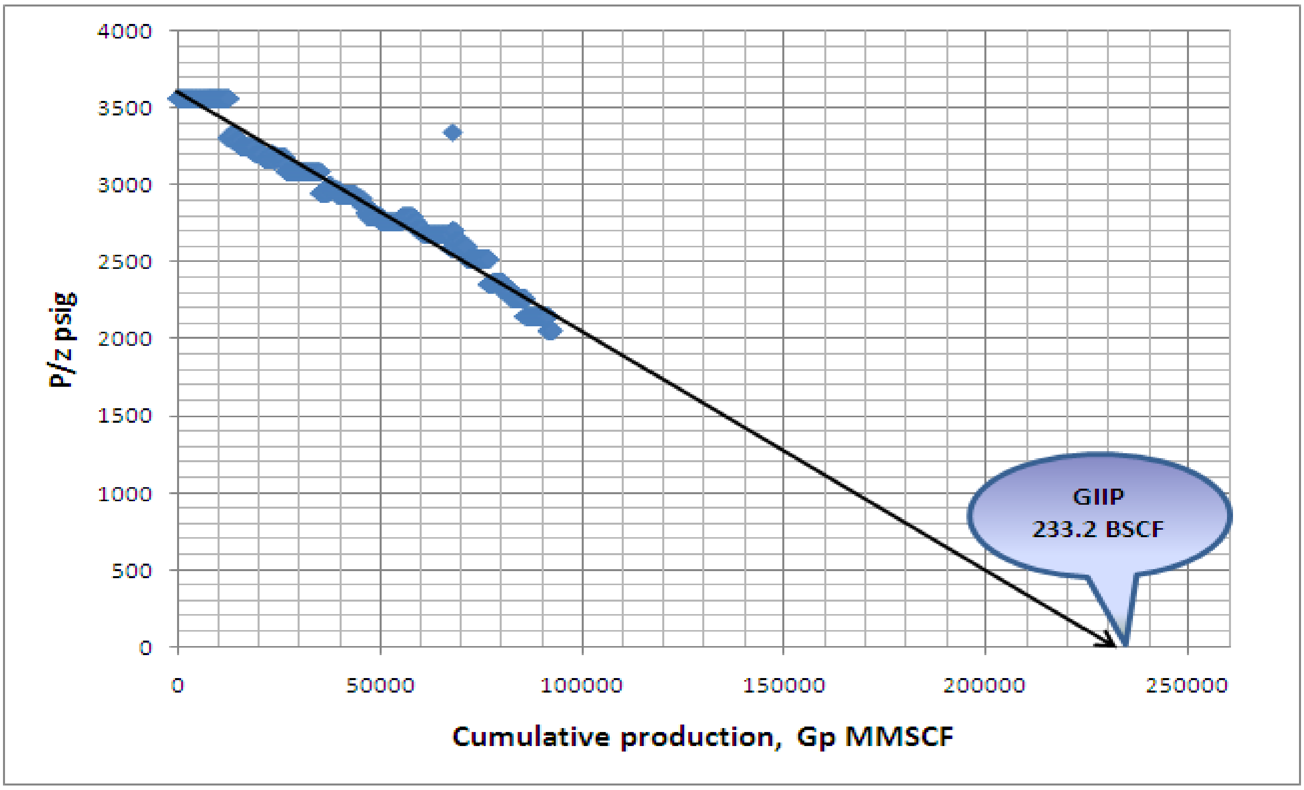

Figure 11: P/z STHP vs. Cumulative production, Gp

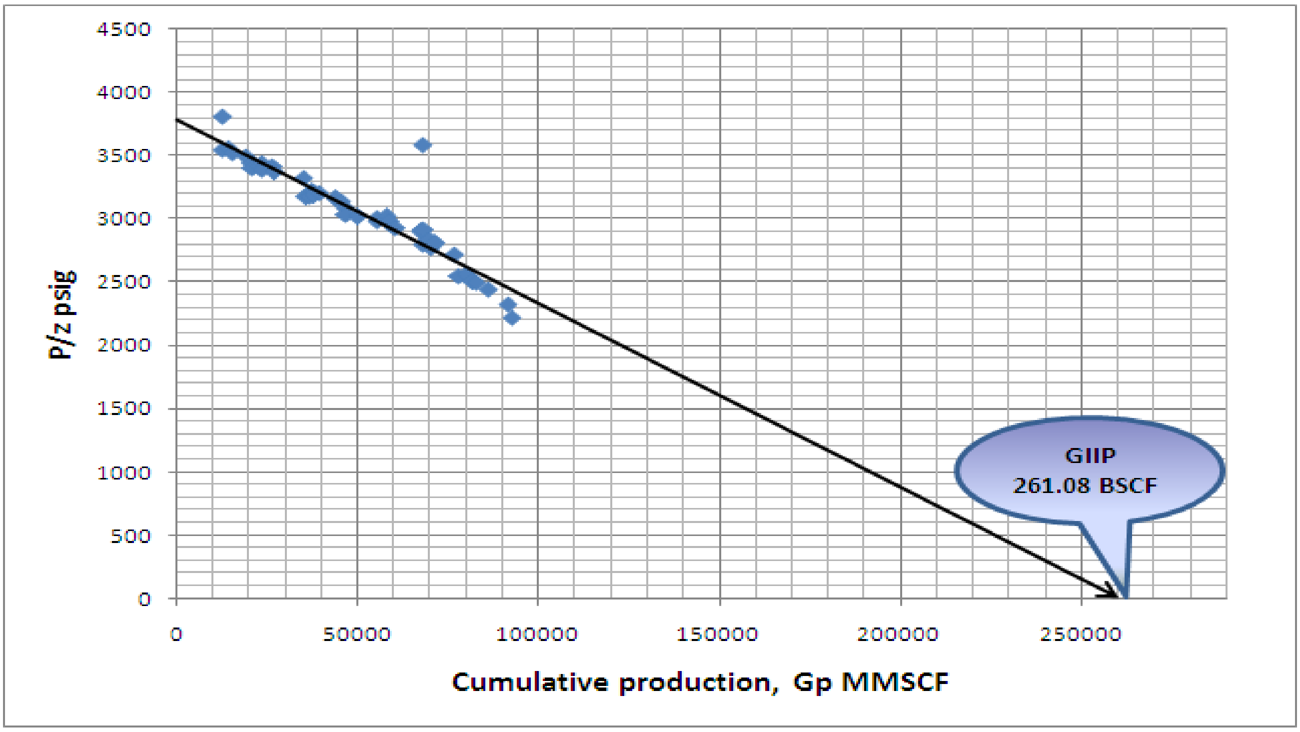

Figure 12: P/z SBHP vs. Cumulative production, Gp

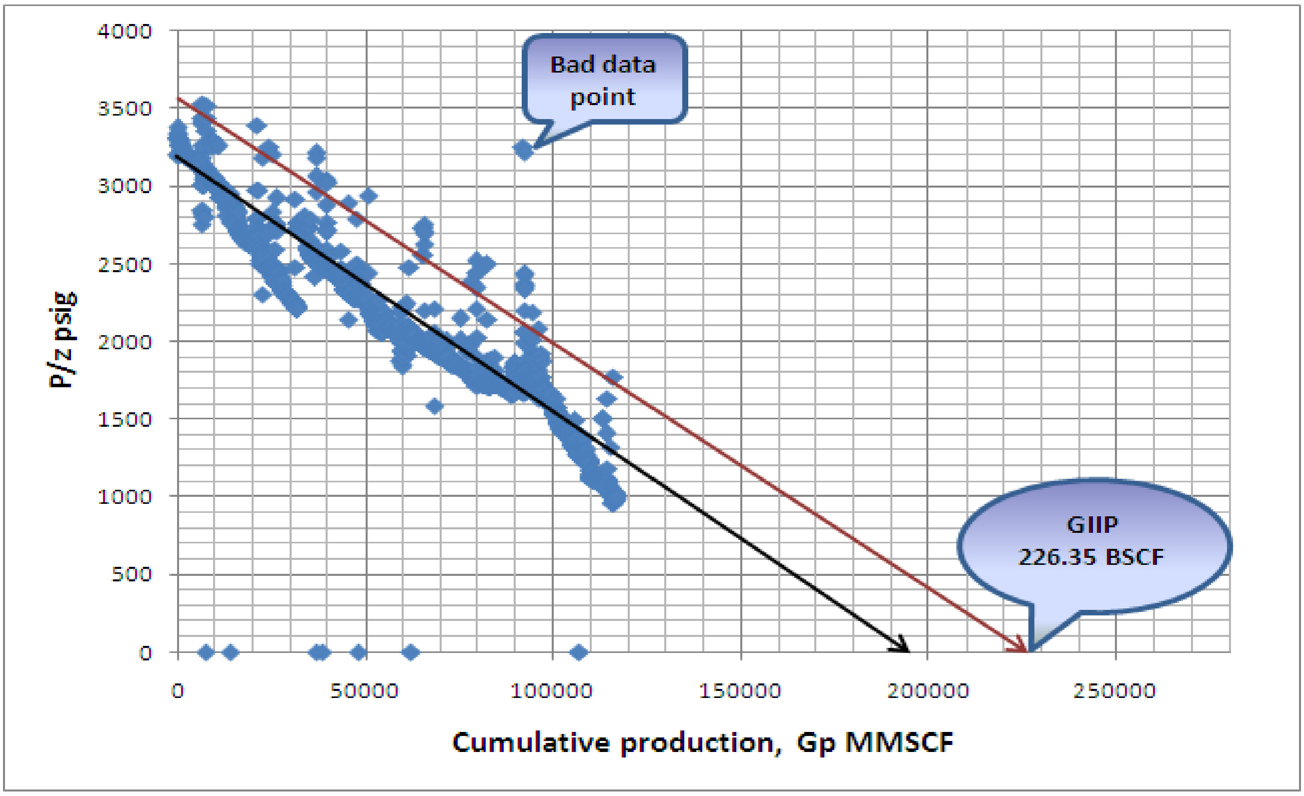

Figure 13: P/z FTHP vs. Cumulative production, Gp

Well no.	Gas Initially In Place (GIIP) [BCF]			Average GIIP [BCF]
	SBHP	STHP	FTHP	
Well#01	168.2	166.4	163.5	166.03
Well #02	149.58	131.57	112.87	131.34
Well #03	176.45	174.4	161.5	170.78
Well#04	261.082	233.2	236.35	240.21
Total				**708.36 BCF or 0.708 TCF**

Table 1: Result summary table

The results obtained from different methods are not very different. However, the SBHP method can be considered most reliable, because in this method these pressures have pressure conductivity with reservoir and it considers Pseudo-steady flow regime prevailing in the reservoir. On the other hand, conventional material balance had the least amount of data points, therefore results are less reliable. In case of Static Tubing Head Pressure methods, although may have enough data, do not conform to the requirement of the average reservoir pressure. These could be close approximations in case no other alternatives are available. When estimating with "Flowing Tubing Head Pressure (FTHP)" the GIIP shown by this method is not so reliable one. It is because of pressure loss in the tubing due to the friction in the tubing. To rectify this result, a parallel line to the EXCEL originated trendline is drawn from the initial reservoir pressure's "P/z" & where this parallel line intersects the X-axis, which is the GIIP for FTHP method.

RECOMMENDATIONS

a) If the "Flowing Bottom Hole Pressure (FBHP)" data are available the estimation can be done more precisely as these pressures have pressure conductivity with reservoir and it considers Pseudo-steady flow regime prevailing in the reservoir.
b) When plotting the "P/z vs. Gp" graph, it is better to avoid bad data points because that makes the graph trendier.

ACKOWLEDGEMENT

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NOMENCLATURE

Symbol	Meaning	Unit
BCF	Billion Cubic Feet	-
TCF	Trillion Cubic Feet	-
P	Pressure	Psig
z	Gas Compressibility Factor	-
GIIP	Gas Initially In Place	BCF
SBHP	Static Bottom Hole Pressure	Psig
STHP	Shut-in Tubing Head Pressure	Psig
FTHP	Flowing Tubing Head Pressure	Psig
Gp	Cumulative Production	MMSCF

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Evaluation of Well Performance of Titas Gas Field by Decline Curve Analysis Using Type Curves

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ABSTRACT

This paper is presented from the motivation to find and analyze the current situation of the wells of Titas Gas Field by using different decline curve methods.Production decline curve for analyzing production data of Titas gas field are used which have been developed by using decline curve and type curve analysis concept to estimate the gas in place, expected ultimate recovery, permeability, skin effect, recovery factor and remaining reserve more precisely and practically.

This paper presents analysis done with the methods established byBlasingame,Agarwal and Gardner. Normalized Pressure Integral method is also used for the more accurate process through which we can reach our goal of this paper work. As the most recent and flawless quality dataare used to perform this research work, it is assured that the result obtained, is the most updated one which can be relied on without any misinterpretation.According to Agarwal et al.These new Production decline-type curves indicates an improvement over pastday's work because difference can be made among the transient, Steady stateand boundary-dominated flow periods more accurately.These curves also contain derivative functions similar to those which are used in pressure transient literature to aid in the matching process.These also provide more direct and impeccable approach to estimate the reserve.

Keywords: Titas gas field, Well performance, Decline curve, Typecurve analysis, Production data.

1. INTRODUCTION

Titas gas field is the largest and giant gas field of Bangladesh.It is located in the district of Brahmanbaria, Bangladesh. This field was discovered by Pakistan shell Oil Company in 1962. This structure is an elongatednorthsouth asymmetric anticline measuring about 19×10 square kilometer with a vertical closure of 500m. It consists of total 23 wells among which 21 wells are producing now. Two of them (well 3 and 21) are abandoned due to gas seepage and excessive water production [3].

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The Titas gas reservoirs include multiple sandstone layers in the Bhuban and Bokabil formation of Miocene-Pliocene age.The depth of the gas reservoir is ranging from about 2616m to 3124mbelow the surface. The sands of Titas gas field is classified into three major groups and they are A sand, B sand and C sand [19].

A sand consist of A1, A2, A3 and A4 sands and Extending from a depth of 8500ft to 8900ft, these four sands represent the highest quality zones encountered by the extending wells andaccount for approximately 80% of the total field reservoir.Production from the A sand group and the Titas gas field in general began in 1968 [3].

The Distinct and separate reservoirs are identified in the B sand group which extends from a subsea depth of 9400ft to 9800ft. The reservoirs are sub classified into 3 minor and 1 major sand. The minor sand consists of the BOE, B1 and B2 sand. The reservoir classified into one major category is the B3 sand. The production was initiated from B sands at February, 1986 [3].

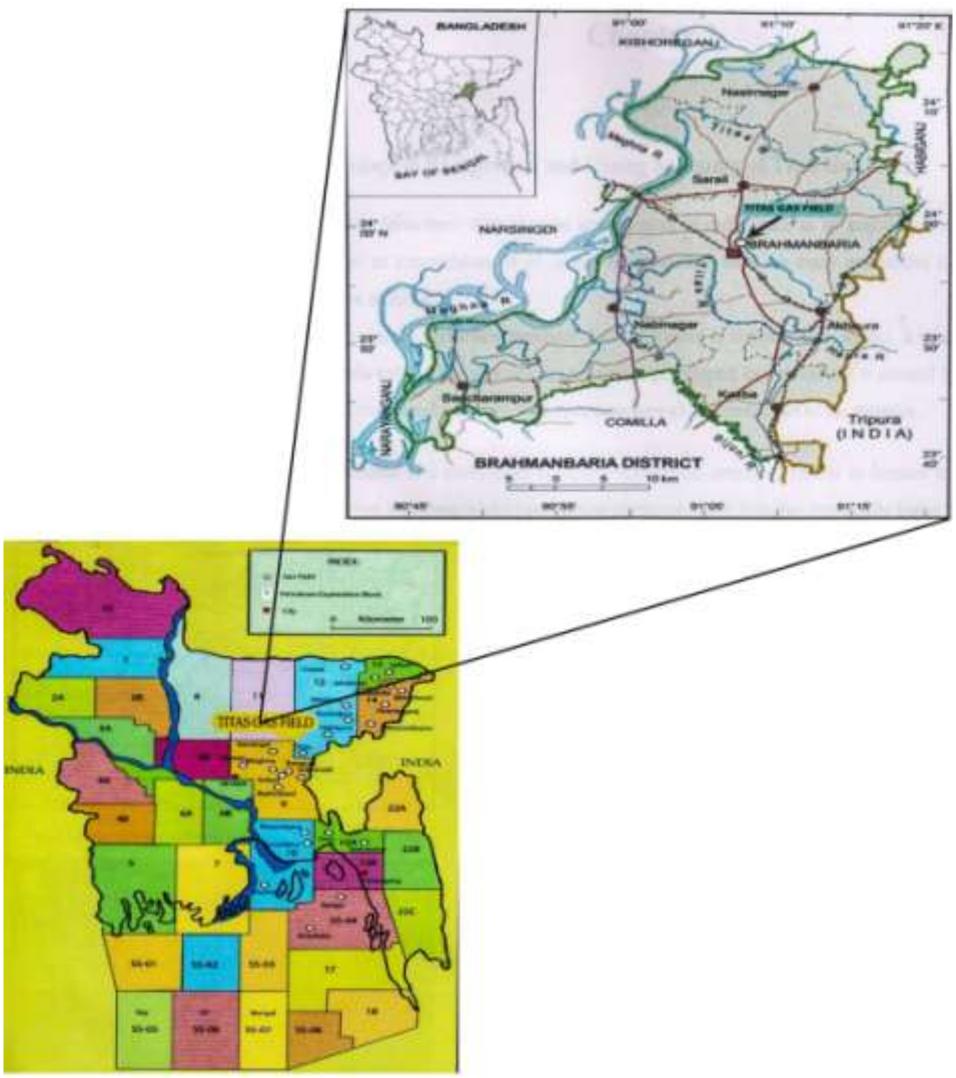

Figure - 1: Location of Titas gas field, Bangladesh [19].

The C sand group consists of 5 distinct and separate reservoir sands denoted as the COE, C1, C2, C3, and C4E sands. The only major gas accumulation in the C sand group is the C3 sand. The sands are found to extend from subsea depth of 9000ft to 10200ft and production started at February, 1986 from this sand [3].

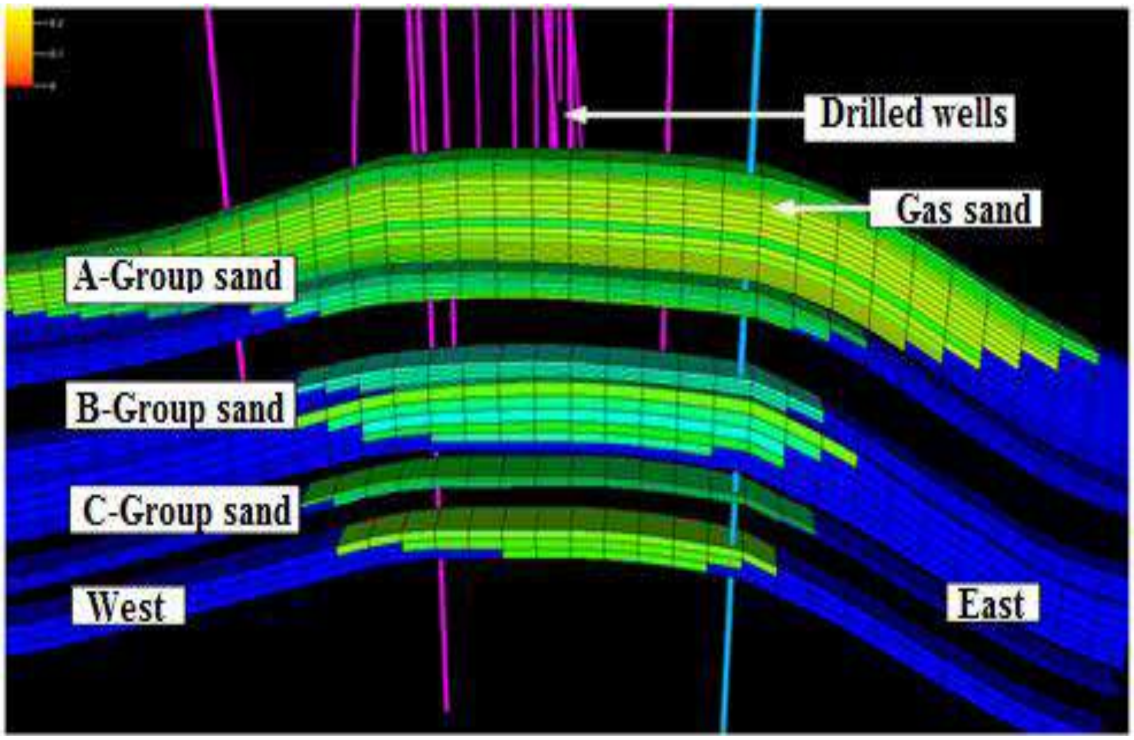

Figure - 2: Sub-surface location of Titas field and gas bearing sands [26, 27].

The quality of the reservoir sandstones are generally very good with average porosity in the range of 20% and average permeability in the range of 100-400md [19].

1.1 DECLINE CURVE ANALYSIS

Decline curve analysis (DCA) is a graphical procedure which is used to analyze falling production rates and also used for forecasting future performance of oil and gas wells. Change of oil and gas production rates is a function of time, reduction of reservoir pressure, or changing relative volumes of the produced fluids. Fitting a line through the performance history and assuming this same trend will continue in future forms the basis of DCA concept. It is a key point that in absence of stabilized production trends the technic can’t be expect to give a reliable result [28].

Decline curve analysis of production data is a technic where actual production rate and time are history matched to a theoretical model using either type curves or computer programs. The theoretical model chosen is then used to predict ultimate gas in place as well as formation properties [26].

The primary application of decline curve analysis is to forecast future production, which in turn used to estimate reserves and property values [29].

1.2 TYPECURVE ANALYSIS

According to Ley and Samaniego (1981), a considerable amount of information concerning well test analysis has been in the literature over the last several decades. Typecurve analysis consists of finding a typecurve that matches the actual response of the well and the reservoir during the test. Then the reservoir and well parameters, such aspermeability and skin, can be calculated from the dimensionless parameters defining that typecurve [14, 23]

1.3 RATE TRANSIENT ANALYSIS

Rate transient analysis (RTA) is the science of analyzing production data (both rates and flowing pressures). This method is an important tool to estimate reserve of oil and/or gas of a reservoir. Reserve estimation and development planning are the key tasks of petroleum engineers by the use of historical production (reservoir fluid production rate histories and cumulative production). Both of these fall within the domain of a quantitative production data analysis (PDA) [6, 13].

RTA can also be defined as a modern Decline Curve Analysis (DCA) method [24]. DCA method is one of the oldest and most often used tools of the petroleum engineers.This is a forecasting technique which predicts by history matching of rate-time data on an appropriate type curve. What direction to take, what type curve to choose and where the rate-time data should fit is decided based on basic reservoir engineering concepts and knowledge [10].

1.4 PERMEABILITY

Permeability (k) in a reservoir rock is its capacity to transport fluids through a system of interconnected pores. Reservoir permeability is a random-valued property of the formation [21, 34].

1.5 SKIN

The pressure drop in a well per unit rate of flow is controlled by the resistance of the formation, the viscosity of the fluid, and the additional resistance concentrated around the well bore due to drilling, completion and production practices. The pressure drop caused by this additional resistance is defined as the skin effect, denoted by the symbol S. The reservoir damage occurs because of this skin effect[9, 22].

1.6 GAS INITIAL IN PLACE

Gas initial in place (GIIP) denotes the total quantity of gas that present initially in the underground of a gas field. Fragment of the GIIP in an explored gas field can be recovered [19].

1.7 RECOVERY FACTOR

The recoverable amount of hydrocarbon initially in place, normally expressed as a percentage. The recovery factor is a function of the displacement mechanism. An important objective of enhanced oil recovery is to increase the recovery factor [31].

Generally, the recovery of gas from the GIIP in a typical gas field ranges from as low as 60% to as high as 90%.

1.8 EXPECTED ULTIMATE RECOVERY

Expected Ultimate Recovery (EUR) of a petroleum reservoir is the summation of proven reserve at a specific time and the cumulative production up to that time. Proved reserve denotes the amount of gas in a gas reservoir which can be assessed with reasonable certainty (high degree of confidence) to be commercially recoverable from known reservoir under the present economic and operating conditions [19, 25].

2. METHODOLOGY

Modern production data techniques employ the use of type curves, which enable the quantitative and qualitative evaluation of a system through identifying and matching trends in the data that are similar to the shape of the underlying type curve model.

Various types of Data (such as : reservoir properties, fluid properties, properties of Wells and production data of the Wells for the year of January, 2012- August, 2015) were collected from BGFCL,a subsidiary of Petrobangla for this study.To evaluate the performance of the wells of Titas gas field there we used the software FEKETE, F.A.S.T.RTA. We did the analysis of the production data and pressure data of total 20 wells by using production decline curves and type curves. Our total working procedure is represented by this following flow chart.

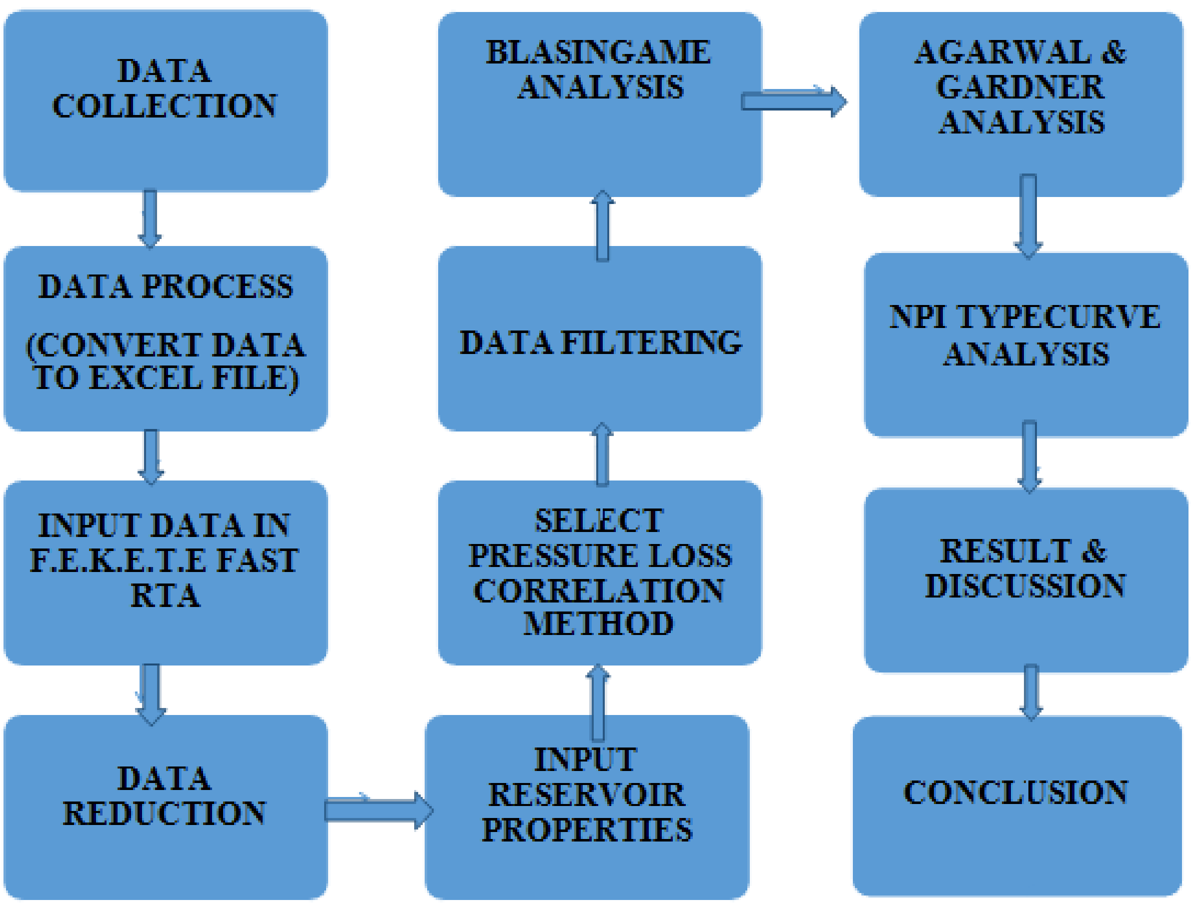

Figure - 3: flow chart of the working procedure of this program.

F.A.S.T. RTA™ is a cutting edge decline analysis tool that analyzes production rates and flowing pressures. Methods include traditional decline analysis, Fetkovich, Blasingame, Agarwal-Gardner, NPI, Transient and Wattenbarger type curves, specialized analysis and flowing material balance. Reservoir models include volumetric and water-drive. Well models include horizontal, vertical, and hydraulically fractured wells. F.A.S.T. RTA™ analyzes production data, yielding EUR, hydrocarbons-in-place, drainage area, aquifer strength, permeability, skin, and fracture half-length. It allows users to evaluate infill potential, characterize the reservoir, and estimate reserves with affluence and efficiency [12].

In this paper we performed three different methods for evaluating the well performances and these methods are BlasingameTypecurve Analysis, Agarwal– GardnerTypecurve Analysis and Normalized Pressure Integral method. We used this three analysis methods for total 20 wells of Titas gas field but we decided to represent the performance of only three wells there and these wells are well one, well five and well fourteen to represent the total work in short.

2.1 BLASINGAME TYPECURVE ANALYSIS:

At Blasingame method (FEKETE F.A.S.T RTA Help manual, 2010), the normalized rate was plotted against material-balance pseudo-time on a log–log scale.

For data plot; normalized rate $\dfrac{q}{\Delta \mathrm{p_p}} = \dfrac{q}{(p_i - p_{pwf})}$

Material Balance Time $t_c = \dfrac{Q}{q}$

Application of this concept to oil would be very straight forward. To gas, it is more complex because of varying PVT properties of gas. Accordingly simple concept $t_c = \dfrac{G_g}{q_g}$ must be defined in terms of pseudo time,

$$t_{ca} = \left\{ \frac{\left(\mu_g c_g\right)_j}{q_g} \right\} \int_o^t \left\{ \frac{q_g}{\mu_{gav} c_{gav}} \right\} dt$$

Blasingame et al. established his typecurves using dimensionless rate $\left(q_{Dd}\right)$ against dimensionless time $\left(t_{Dd}\right)$ on a log-log scale.

$$q_{Dd} = q_d \ln\left(r_{eD} - 0.5\right)$$

$$r_{eD} = \frac{r_e}{r_w}$$

$$t_{Dd} = \frac{2t_d}{\{(\ln r_{eD} - 0.5)(r_{eD}^2 - 1)\}}$$

2.2 AGARWAL-GARDNER TYPECURVE ANALYSIS

At Agarwal-Gardner method(FEKETEF.A.S.T RTA Help manual, 2010), the procedure is almost similar to the Blasingame with a few dissimilarities. As opposed to Blasingame, here for data plot,

Normalized rate, $\dfrac{q}{\Delta \mathrm{p_p}} = \dfrac{q}{(p_i - p_{pwf})}$

Material Balance Pseudo Time, $t_{ca} = \left\{\dfrac{\left(\mu_g c_g\right)_j}{q_g}\right\} \int_o^t \left\{\dfrac{q_g}{\mu_{gav} c_{gav}}\right\} dt$

Agarwal et al. established his typecurves using dimensionless rate (q_{Dd})against dimensionless time (t_{Dd}) on a log-log scale as, $q_D = \dfrac{1}{p_D} = 141.2 \dfrac{qB\mu}{\left\{kh\left(p_i - p_{wf}\right)\right\}}$

$$t_{DA} = \frac{0.00633kt}{\varphi \mu c_t A}$$

2.3 NORMALIZD PRESSURE INTEGRAL TYPECURVE ANALYSIS

In case of Normalized pressure integral (NPI)(FEKETE F.A.S.T RTA Help manual, 2010), the normalized pressure replacing normalized rate was plotted against material-balance pseudo time on a log-log scale of the same size as the type curves, which are referred as the “data plot”.

Normalized Pressure, $\dfrac{\Delta p_p}{q} = \dfrac{\left(p_{pi} - p_{wf}\right)}{q}$

Material Balance Pseudo Time, $t_{ca} = \left\{ \frac{\left(\mu_g c_g\right)_j}{q_g} \right\} \int_o^t \left\{ \frac{q_g}{\mu_{gav} c_{gav}} \right\} dt$

Normalized Pressure Integral Typecurves were developed by dimensionless pressure (p_d) against dimensionless time (t_d) on a log-log scale.

$$p_D = \frac{1}{q_D} = \frac{\left\{kh\left(p_i - p_{wf}\right)\right\}}{141.2 qB\mu}$$

$$t_{DA} = \frac{0.00633kt}{\varphi\mu c_t A}$$

2.4 RESERVOIR FLOW

To make this evaluation procedure more easier their we classified the total flowing wells into three flow categories and these are a) Transient flow condition, b) Steady state flow condition, and c) Boundary dominated flow condition

2.4.1 TRANSIENT FLOW

Pressure transient travels outward from the well deprived ofmeeting any boundaries. transient flow takes place through the early life of a well, when the reservoir boundaries have not been felt, and the reservoir is said to be infinite-acting. during this period, the size of the reservoir has no effect on the well performance, and reservoir size cannot be resoluteexcluding to deduce least contacted volume. since theboundary of the reservoir has not been contacted through the transient flow period, static pressure at the boundary remains constant [13].

2.4.2 STEADY STATE FLOW

Pressure transient has reached all of the boundaries but the static pressure at the boundary does not decline. This is often called “constant pressure boundary” [13].

2.4.3 BOUNDARY DOMINATED FLOW

Pressure transient has reached all of the boundaries and the static pressure is declining at the boundary, but not uniformly because the flow rate is not constant. This is also often called “tank-type flow” [13].

3. RESULT AND DISCUSSION

In this section we represent the performance of well one, well five, well fourteen to represent the total work in short. These three wells represent the three kinds of flow behavior which are present in Titas gas field according to this analysis & in this section we will like to represent the total research work.

3.1 WELL FIVE

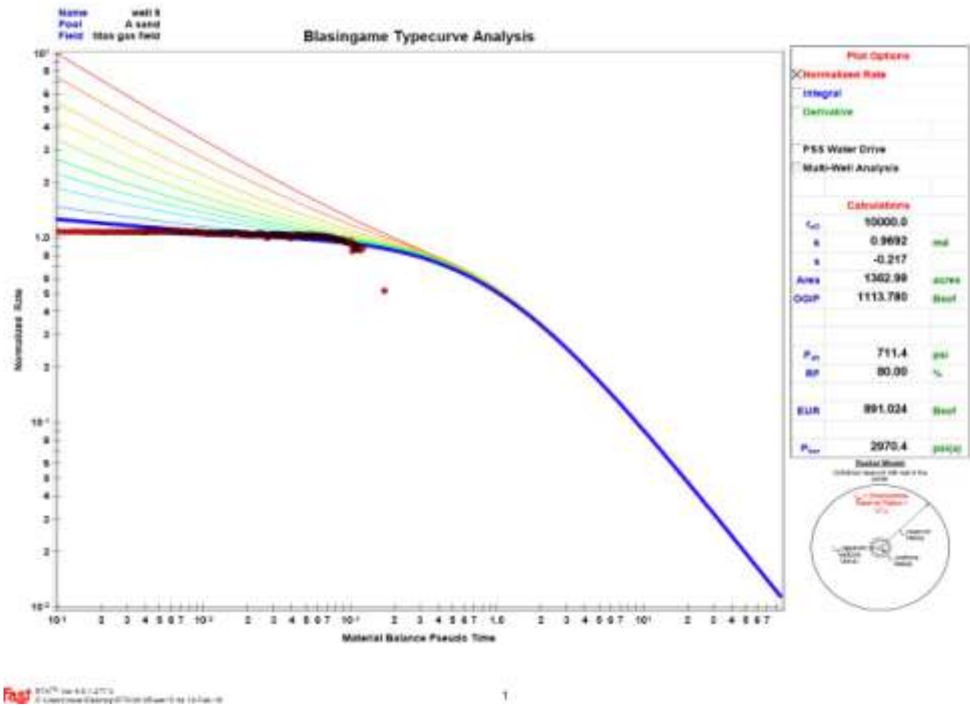

Figure - 4: Match between data plot for Well-05 and Blasingametypecurve plot.

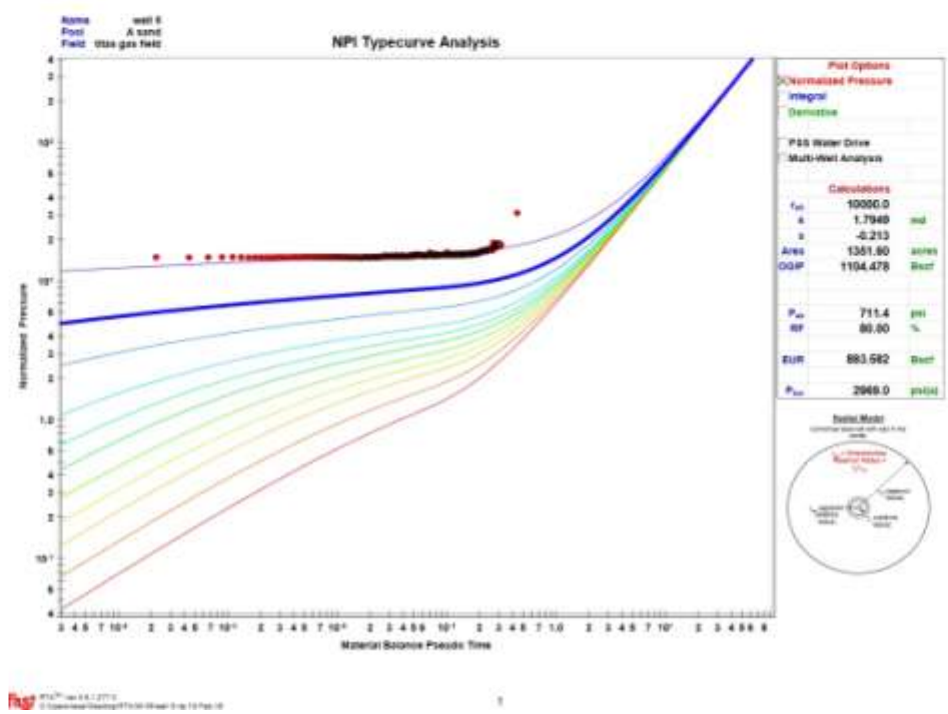

Figure - 6: Match between data plot for Well-05 and NPI typecurve plot.

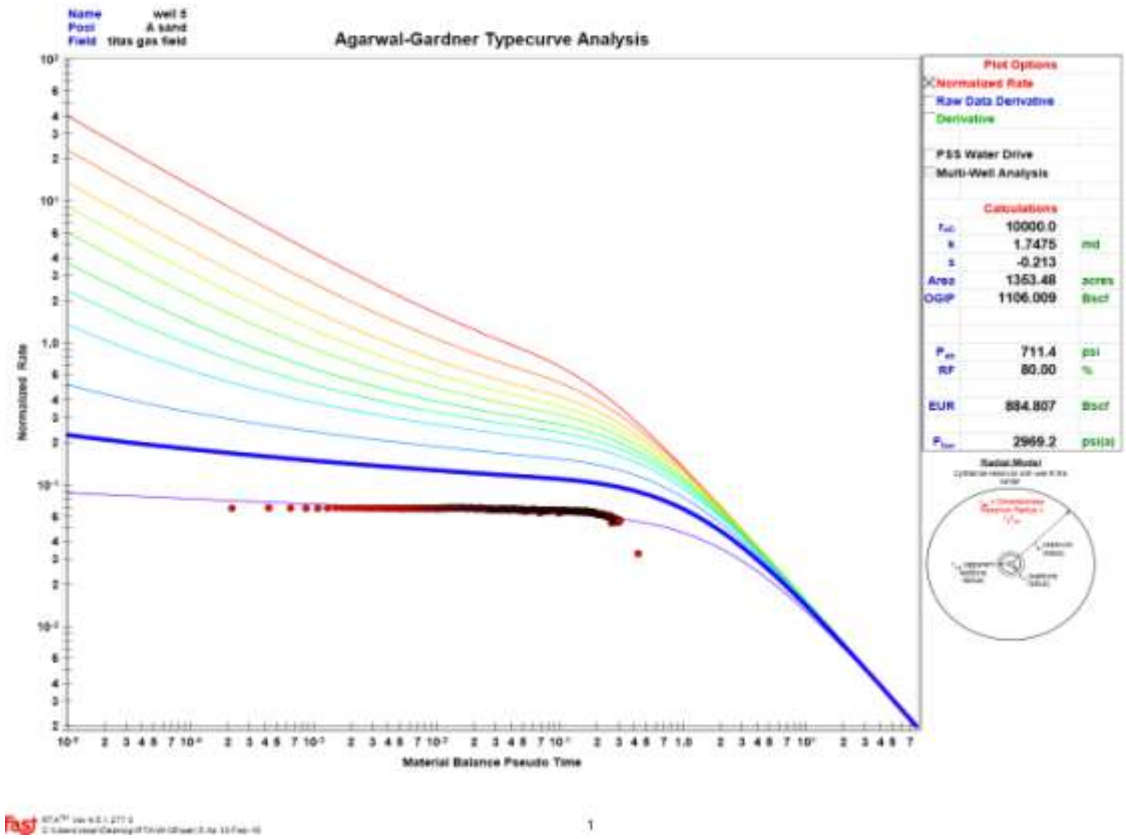

Figure - 5: Match between data plot for Well-05 and Agarwal–Gardner typecurve plot.

From the flow pattern of the above figures (Figure : 4, 5, 6) we can explain that this well exhibits steady state flow condition, the pressure and flow rate remains constant during this analysis procedure and static pressure at the boundary does not declined yet.

Well five contains a total OGIP of 1108.089 Bscf and EUR of 886.4712 Bscf, Permeability value is 1.5038 md and the value of skin is -0.214. According to the total analysis procedure we find out thatwell number 2,4,5,6,7,8,9,11 those are also at steady state flow condition similar to this well.

3.2 WELL ONE

Well one is producing since 1968, it overcomes the stages of transient flow and steady state flow period, The pattern of the flow (from figure : 7, 8, 9) indicates that the pressure and flow rate is continuously declining in a significant amount. The static pressure is declining at the boundary, but not uniformly.

So we can state that well one is now at boundary dominated flow condition.To summarize the performance of this well we use the average value of this three methods. Well one containsa total OGIP of 1064.25 Bscf, EUR of 851.4 Bscf, Permeability is 1.6715 md and the value of skin is -0.1. Well 10 is also now at boundary dominated flow condition similar to this well.

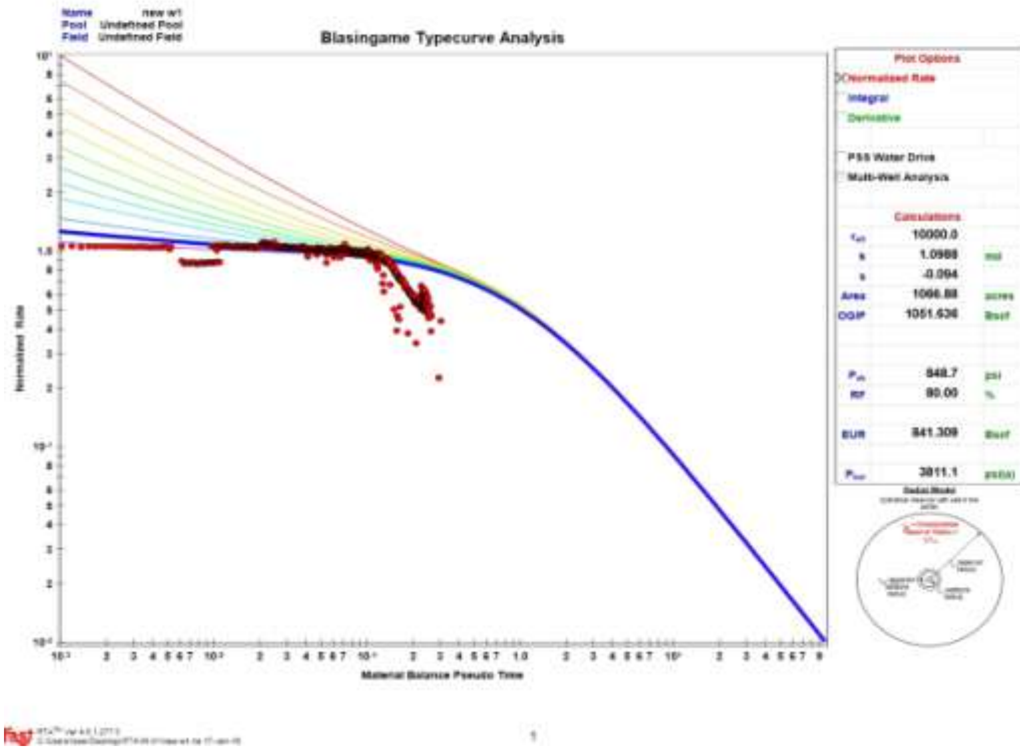

Figure - 7: Match between data plot for Well-01 and Blasingametypecurve plot.

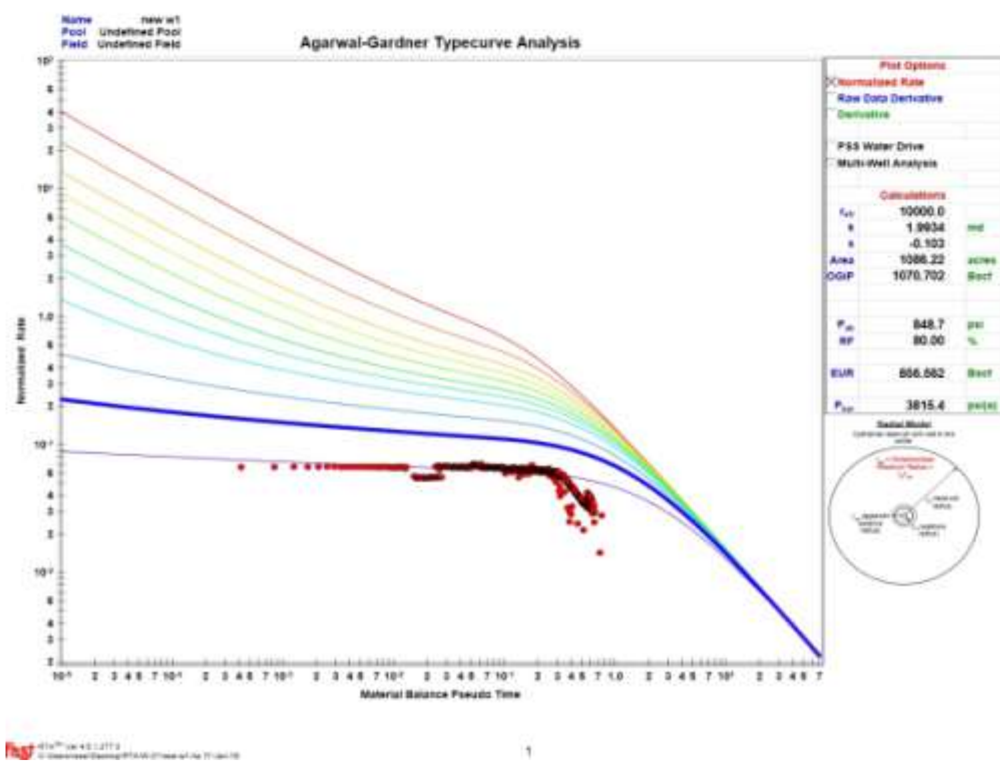

Figure - 8: Match between data plot for Well-01 and Agarwal–Gardner typecurve plot.

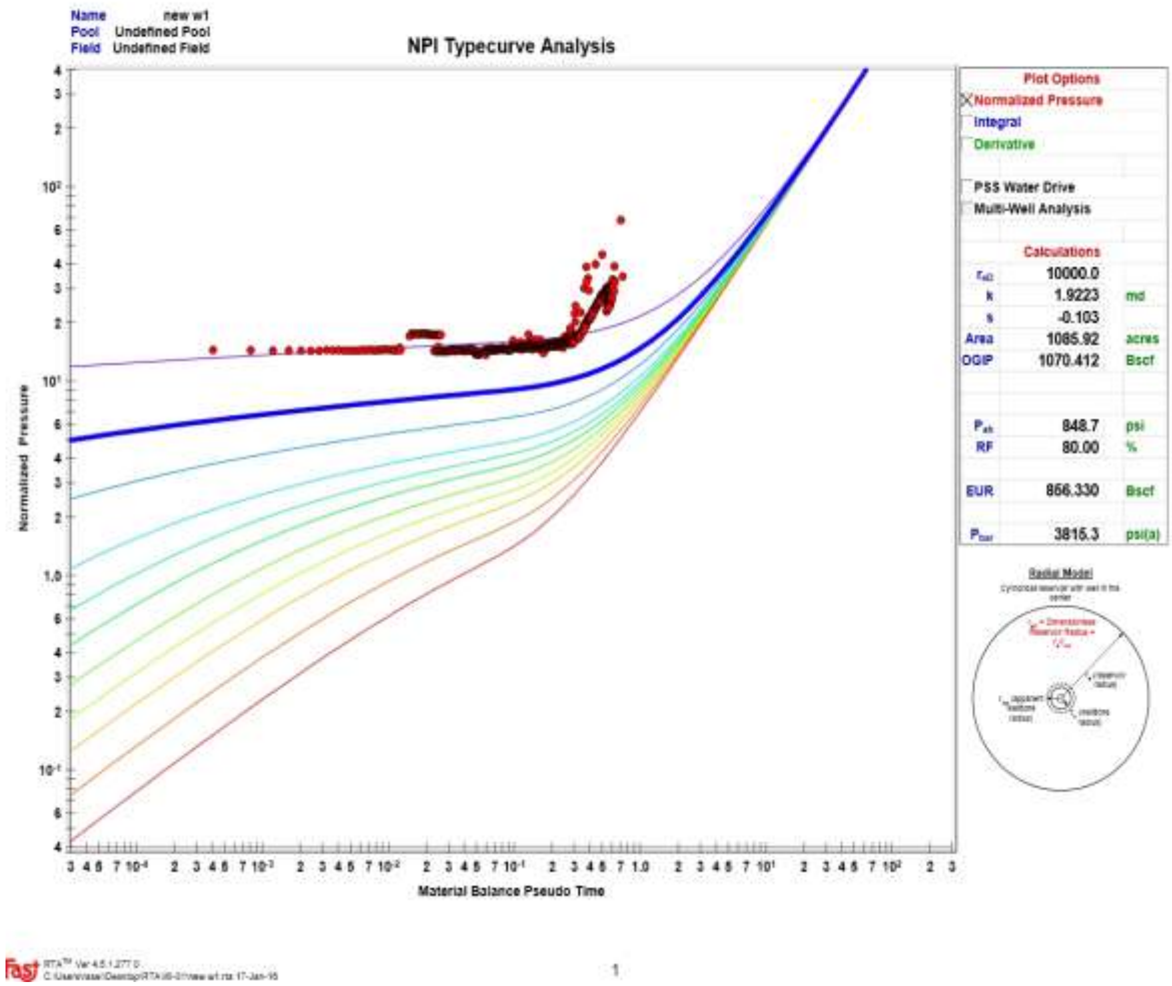

Figure - 9: Match between data plot for Well-01 and NPI typecurve plot.

3.3 WELL FOURTEEN

Transient flow takes place through the early life of a well.since the boundary of the reservoir has not been contacted through the transient flow period, static pressure at the boundary remains constant. The flow rate and the pressure is not established yet and varying with time.

From the performance of the well no 14 (Figure :10,11,12) we can make a decision that well no 14 is now at transient flow condition.Well fourteen contains a total OGIP of 800.78 Bscfand EUR of 640.624Bscf, Permeability is 1.28 md and the value of skin is -.023. Some other wells such as well no 12-18 and 20,22& 27 are also at transient flow condition.

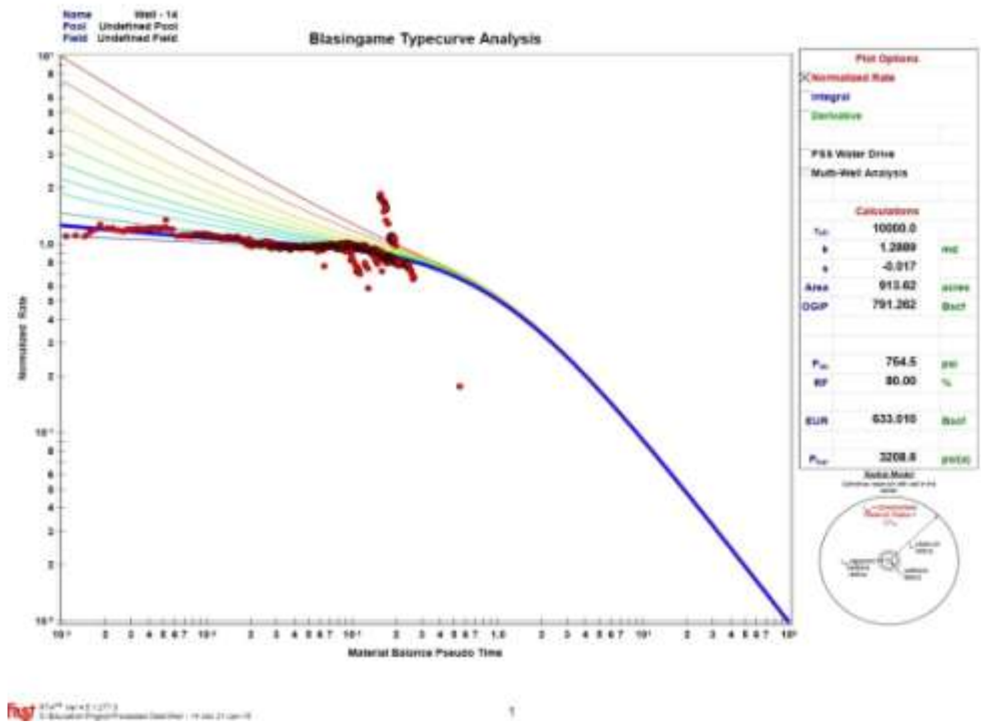

Figure -10 : Match between data plot for Well-14 and Blasingametypecurve plot.

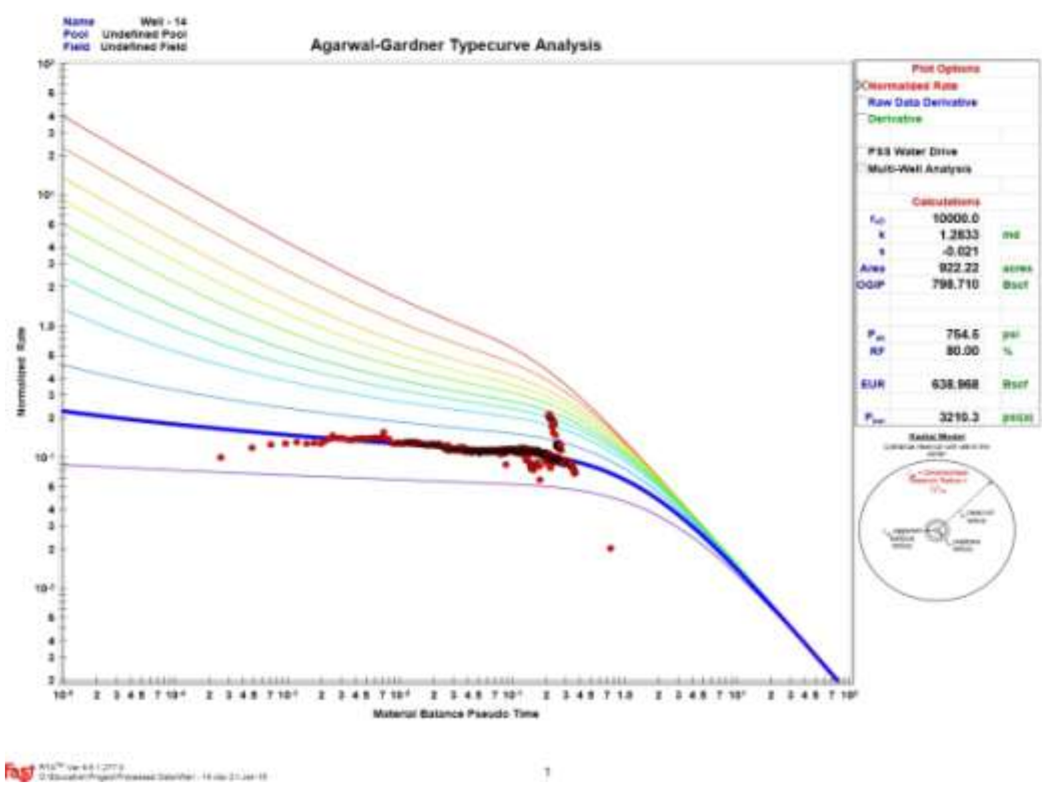

Figure - 11: Match between data plot for Well-14 and Agarwal–Gardner typecurve plot.

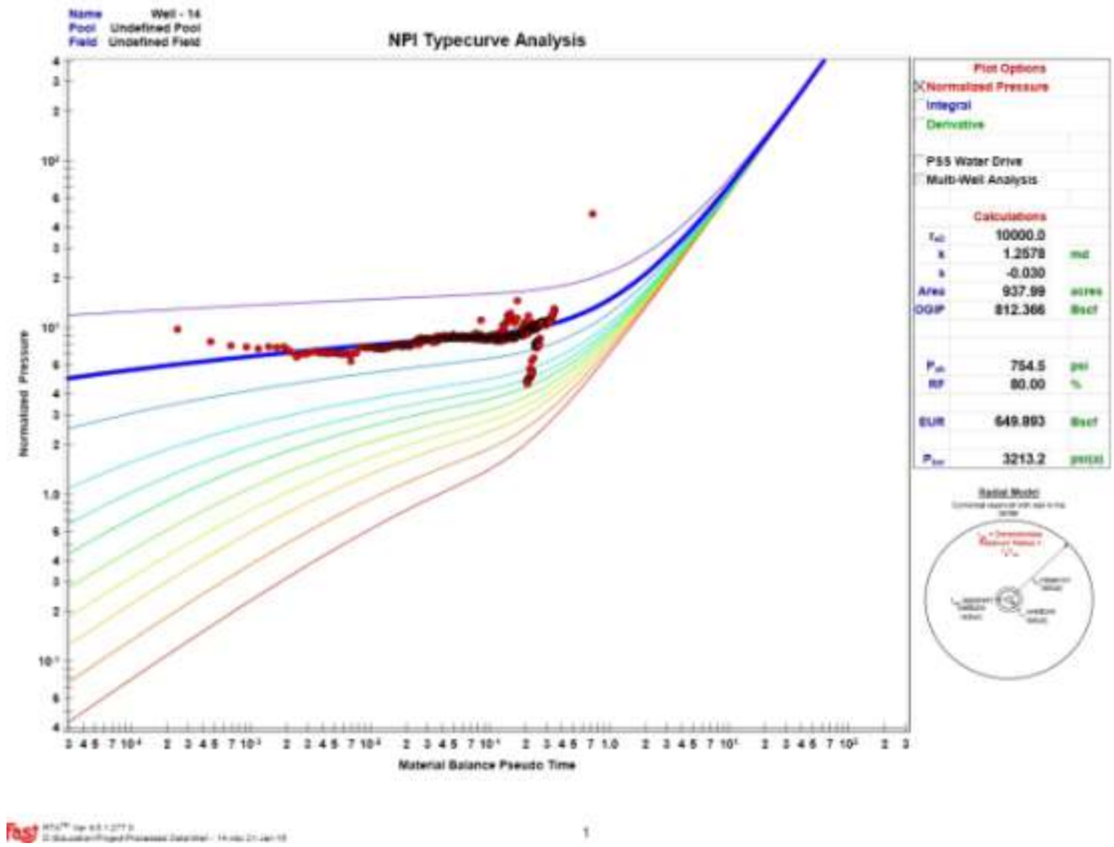

Figure -12: Match between data plot for Well-14 and NPI typecurve plot.

We have done this similar analysis for total 20 producing wells of Titas gas field. The results obtained from the total analysis of these twenty wells of Titas gas field is summarized below.

Table 1 : **Summary of the performance of the Wells of Titas gas field**.

Well no.	OGIP (Bscf)	EUR (Bscf)	K (md)	S	RF %	Sand
1	1064.25	851.4	1.6715	-0.1	80	A
2	1503.8543	1203.0833	2.6521	0.625	80	A
4	1036.72	829.381	2.0897	-0.124	80	A
5	1108.089	886.471	1.5038	-0.214	80	A
6	957.967	766.3733	1.91023	0.0666	80	A
7	788.088	630.47	3.247	0.031	80	A
8	609.383	487.50	0.754	0.361	80	B,C
9	484.96	387.96	0.442	0.555	80	B,C
10	24.88	19.91	0.388	1.679	80	B,C

11	634.158	507.327	1.61	0.131	80	A
12	27.99	182.39	3.038	0.531	80	A
13	481.97	385.573	2.97	0.0243	80	A
14	800.78	640.02	1.28	-0.023	80	A
15	491.624	393.299	8.531	0.173	80	A
16	395.519	316.415	24.38	0.235	80	A
17	140.124	112	45.62	0.237	80	A
18	296.45	236.493	1.221	0.442	80	A
20	89.814	71.824	56.31	-0.415	80	A
22	432.235	345.0761	10.187	-0.529	80	A
27	102.289	81.832	17.718	0.581	80	A

This table represent the total works that we have done to evaluate the performances of the wells of Titas gas field, there we use the average result obtained from the three analysis methods (Blasingame, Agarwal-Gardner, NPI). Those average values are shown for OGIP, EUR, Permeability, Skin, Recovery Factor.The more generalized result of this total analysisprocedure is summarized below :

Table 2 : **Accumulated result of the evaluation process.**

Parameters	**Titas Gas Field**
Original Gas in Place (OGIP)	11.4711Tcf
Expected Ultimate Recoverable Reserve (EUR)	9.1768Tcf
Remaining Reserve (RR)	5.063Tcf
Permeability (K)	0.38 to 56.31
Skin Effect (S)	-0.53 to 1.67
Recovery Factor (RF)	80%

In this table we use the total accumulated result of 20 wells to estimate the total OGIP, EUR. We use the range of permeability values and skin factor. The recovery factor remains same for this twenty wells. According to this work Sand A contains 10.3519 Tcf gas and sand B, C contains 1.1192 Tcf gas. Total reserve is 11.4711TcfRecovery Factor (RF) 80% and total Expected Ultimate Recoverable Reserve (EUR) 9.4296 Tcf respectively.

The permeability value ranges from 0.38 to 56.31. The skin effect remains between -0.53 to 1.67, here the negative valued wells are stimulated wells and the positive value of skin represent damaged wells.

According to (BGFCL, 2016) 4.206253 TCF gas has been recovered, so according to our analysis the Remaining Reserve (RR) of Titas gas field is5.063 TCF.

3.4 COMPARISON WITH THE PREVIOUS ANALYSIS :

A better comparisonwill ensure the quality of the work& it will increase the possibility of acceptance of our evaluation program. Here the comparison is given below.

Table 3 : Comparison between the results of previous programs and recent evaluation program.

Reserve Estimation Agency	Year	Initial GIIP (Tcf)	Initial Reserve (Tcf)	EUR (Tcf)
IKM	1991	4.14	3.67	
HCU-NPD	2001	7.32	5.14	
RPS ENERGY	2010	8.14	6.34	
Choudhury	2007	10.59		
Present Analysis	2016	11.4711		9.1768

The compassion reveals recent analysis results are compatible with the previous work of Chowdhury Z. The reserve is 8.32 % higher than Chowdhury Z's estimation.

4. CONCLUSION

Titas gas field is an example of significant reserve growth. Although this gas field started production in 1968, the field is however yet to enter into a mature state of development (Imam B, 2013).From this evaluation and the comparison of this work with previous analysis it is clear that the reserve is expanding.

Averaging from three methods of RTA, Original Gas in Place (OGIP) is 11.4711 Tcf which is the highest estimation than the previous research programs and the Expected Ultimate Recoverable Reserve (EUR) is 9.4296 Tcf respectively. The permeability value ranges from 0.38 to 56.31 and the skin effect range is between -0.53 to 1.67. The recovery factor is 80%.

Well 1 and 10 is at Boundary dominated flow condition where well 2, 4, 5 6, 7, 8, 9 and 11 are at steady state flow condition. Well 12-18 and 20,22& 27 are at the transient flow condition. According to this work 45.83 % of reserve have been recovered.

NOMENCLATURES

F = Fahrenheit

S = Skin factor

k = Permeability of the reservoir (md)

r_w = Wellbore radius

Δp_s = Additional pressure drop due to skin effect

μ = Viscosity

q = Production rate (MMScfd)

Δp_p = Pseudo pressure difference (psi)

P_{pwf}= Bottomhole pseudo pressure (psi)

Q = G = Cumulative production (Bcf)

Q_G =Cumulative gas production (Bcf)

t_c = Material balance time

t_{ca} = Material balance pseudo time

μ_g = Viscosity of gas

c_g = Compressibility of gas (psi^{-1})

q_g = Gas production rate (mmcfd)

t = Time (day)

r_{ed} = Dimensionless radius of the reservoir

t_{Dd} = Dimensionless time

q_{Dd} = Dimensionless rate

h = Net pay thickness of the reservoir (ft)

C_t = Total compressibility (psi^{-1})

P_i = Initial pressure (psi)

P_{pi} = Initial pseudo pressure (psi)

P_{wf} = Wellbore flowing pressure (psi)

P_{pwf} = Wellbore flowing pseudo pressure (psi)

t_{dA} = Dimemsionless radius

A = Area (ft^2)

B = Formation volume factor

ABBREVIATIONS

A-G = Agarwal-Gardner

Bcf = Billion Cubic Feet

BGFCL = Bangladesh Gas Field Company Limited

DCA = Decline Curve Analysis

EUR = Expected Ultimate Recovery

FWHP = Flowing well head pressure

GIIP = Gas Initially In Place/ Gas Initial In Place

GWC = Gas Water Contact

IKM = Intercomp-Kanata Management Limited

md = millidarcy

NPI = Normalized Pressure Integral

PDA = Production data analysis

PTA = Pressure Transient Analysis

RTA = Rate Transient Analysis

RR = Remaining Reserve

RF = Recovery Factor

SPE = Society of Petroleum Engineers

Tcf = Trillion Cubic Feet

Well-01 = Production well no. 01 in A sand

Well-04 = Production well no. 04 in A sand

Well-14 = Production well no. 14 in A sand

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Pressure Data Analysis using Derivative Type Curve for Multilayered Gas Reservoir

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ABSTRACT

Well testing is regarded as one of the tools for formation evaluation and also reservoir management. Well test analysis is performed assuming that the reservoir is homogeneous and isotropic. However, many reservoirs can be found that they are composed of a number of layers and are not homogeneous. The pressure data analysis of a vertically heterogeneous reservoir is different than a single layered reservoir. Thus, it is necessary to know the multilayered reservoir parameters. The objectives of this study are to: i) analyze well test and pressure data, and ii) determine the formation properties such as permeability, skin factor, absolute open flow (AOFP) potential, average reservoir pressure, dimensionless wellbore storage coefficient and reservoir areal extent, etc. Subsequently, vertical and multilayered model parameters are estimated using pressure, semi log plot, pressure derivative, and dimensionless type curves. Fekete Software is used to perform this study. Diagnostic analysis is performed using derivative type curve and compared the results of diagnostic analysis with vertical model parameters and Al-Mansoori Wireline Services model analysis of the Kailastila gas field. It is observed that diagnostic results are well matched with vertical model parameters. The multilayered reservoir is considered as a commingled system where three independent layers are commingled at the wellbore. Each layer has an independent skin factor, permeability, and other parameters. The reservoir geometry is rectangular. All pressure data analyses are presented here in a graphical sequence. This paper will provide a better understanding of the multilayered modelling using the pressure data analysis, which can characterize the whole reservoir in a better way.

Keywords: well testing, pressure transient test analysis, type curve, permeability, skin factor.

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INTRODUCTION

Well testing is a technique that is used to evaluate well conditions and to characterize the reservoir. The response in reservoir pressure is monitored with the change of production condition during a well test. Whether the pressure response is lesser or greater, it is possible in many cases to infer the characteristics of the formation properties. A reservoir engineer utilizes pressure transient test as a resource of information to estimate the reservoir properties and make well development decision. It occurs due to changes in production or injection of fluids with respect to time. The flow rate is treated as an input parameter and the pressure response is acted as output parameter. Pressure transient testing is a method to characterize reservoir properties and also known as the ability of the formation to produce fluid which has been studied since many years. It is used to compare with different techniques in determining reservoir properties. In addition, many types of test, e.g., DST, wireline formation tests, drawdown tests, build up tests, step rate tests, fall off tests, interference and pulse tests, layered reservoir tests, etc. are also available depending on the parameters to be analyzed. For analysis purposes, pressure buildup test data are usually separated into three regions. The "early time" region which is typically affected by wellbore storage, the "middle time" region is the indicative of the characteristics of the reservoir model (i.e., undistorted, transient flow) and finally, the "late time" region pertains to data affected by reservoir boundaries (Likitsupin, 1994). A typical pressure test may not contain all three regions. There are several methods available to estimate reservoir parameters from pressure transient test data and production data. The accuracy of these methods depends on data source and type available. In this paper, the reservoir parameters are estimated by using the deliverability (flow after flow test) and build up test based on collecting data. Mainly the applications of these methods are performed by using “FEKETE” well test software for more accuracy of estimated parameters

Type curve analysis, though relatively new to petroleum engineers has historically been used successfully by groundwater hydrologists. The art of type curve analysis consists of developing the ability to identify the right type curve for the right test. In a sense, type curve matching represents the most general approach to transient pressure analysis as the procedure does not depend on the presence of specific flow periods in the measured test data. Generally, type curves are presented in dimensionless terms, such as dimensionless pressure vs. dimensionless time. Type curve analysis can help to identify the appropriate reservoir model, the appropriate flow regimes for analysis, and estimate reservoir properties (Fetkovich et al., 1987).

A recent development in the transient pressure analysis is the use of the pressure derivative function as a diagnostic tool to identify the appropriate model for analyzing the measured pressure data. The derivative function, which is related to but is not identical to the derivative function of differential calculus, has been found to have characteristic shapes for the most commonly used mathematical models for transient pressure analysis. Another branch of well testing is known as deliverability testing, is done to measure the production capabilities under specific conditions of reservoir and bottomhole flowing pressures of gas wells (Lee and Wattenbarger, 1996). There are four types of deliverability test analysis, e.g., flow after flow test, isochronal test, modified isochronal test, single point test. Chase and Hassan (1993) described a method for predicting the deliverability of a gas well that requires only pressure buildup or drawdown test data. Shandrygin *et al*. (2010) proposed a model for IPR curve analysis for estimation of the parameters and evaluate it using synthetic IPR curves for the multi-layered reservoir of the gas condensate well during multi rate testing.

In well testing, the interpretation of pressure data is done by assuming that the petroleum reservoir is isotropic, homogeneous, and consists of a single layer. In practice, there can be found many reservoirs, which are composed of a number of layers due to sedimentary deposition processes and diagenetic history. Their characteristics are different from one layer to other layer and may produce from more than one layer. Thus, layer properties are critical information for multilayer reservoir development, especially during secondary recovery. Many studies have focused on testing and analyzing the pressure transient behavior of a multilayer system to understand and quantify formation properties (Larsen 1981; Larsen 1982; Kuchuk et al. 1986; Ehlig-Economides and Joseph 1987; Shah et al. 1988; Spath et al. 1994). Aly and Lee (1996) presented a method for modeling multilayer reservoirs with unequal an initial layer pressures by monitoring pressure data caused by cross-flow between the layers during pre-production well testing.
In this study, the vertical model and the multilayered model are selected for representing best pressure response. Table 1 shows the assumptions behind vertical and multilayer modelling to estimate reservoir properties for this study.

Table 1: The assumptions behind vertical and multilayer modelling

Assumptions for estimating reservoir properties	
Vertical Modelling	Multilayer Modelling
Homogeneous, single layer, and isotropic reservoir	Multilayer rectangular reservoir
Elongated rectangular shape reservoir	The fluids flow is horizontal in each layer.
Well located in any location within the reservoir	The flow condition is pseudo-steady state.
No flow and constant pressure boundaries	The fluid flows within three layers

In this study, two zones (layers) were selected for Kailastila gas field for testing. It is located at Sylhet, Bangladesh. First, DST has done at 10,260ft (3127M) to 10,274ft (3131M) and then, production test done at 9882ft (3012M) to 9932ft (3027M). Gas production started from 1996 and continued till 2006.The gas production stopped due to small amount of gas production and excessive saline water production was noted. To overcome the problem as well as to resume a more gas production decision was taken to retrieve an existing completion string from the well and to produce gas from the interval 2930M-2949M & 2956M-1958M. (AL-MANSOORI wireline services, 2007).

SCOPE OF THE PAPER

The objectives of this study to perform well testing and analyze the pressure data of Kailastila gas field, in order to determine the ability of a formation to produce reservoir fluids. The multilayer model parameters are estimated along with vertical model parameters using pressure and their semi log derivative on a set of dimensionless type curves. Finally, we have compared the results of diagnostic analysis with vertical modeling and the previous study performed by Al-Mansoori wireline services. The following reservoir parameters are determined in this study:

- Formation permeability (k)

- Average reservoir pressure (p_{avg})
- Permeability thickness product (kh)
- Skin factor (s)
- Wellbore storage effects (C)
- Reservoir areal extent
- Absolute Open Flow Potential (AOFP) of the well
- Productivity of the formation and well deliverability's

METHODOLOGY

The main emphasis on interpretation of this paper is on the pressure buildup and the flow after flow test. The reservoir fluid can be considered to be a wet gas. Based on an analysis of the pressure response, it is chosen a homogeneous model to analyze the build-up response to changing wellbore storage in an elongated rectangular reservoir. The flow regime is assumed as radial flow.

Several methods have been used to estimate reservoir properties in this study, e.g., pressure build up test, type curve analysis, Dietz-MBH method, vertical model analysis and multilayer model analysis, and flow after flow test. "Fekete software" has been used to complete this study. The general input parameters are obtained from Al. The parameters are presented in the Table 2.

Data Preparation

At first, all raw pressure data are taken into Microsoft Excel Document as a "CSV "file.

Table 2: Input data for KTL-04 for all analysis purposes. These values are taken from the report of AL MANSOORI Wireline Services (Al-Mansoori wire line services, 2007)**.**

Parameters	Values	Parameters	Values
Wellbore Radius (inches)	3.5	Water Salinity (ppm)	10000
Net Drainage Thickness (ft)	69	Initial Reservoir Pressure (Psia)	3491
Effective Porosity (%)	0.1	Initial Reservoir Temp (^{o}F)	162.7
Gas Gravity	0.586	Gas Saturation (%)	64
Primary Separator Pressure (Psia)	1000	Gas Viscosity(μ_g)	0.0198
Primary Separator Temp (^{0}F)	70	Gas compressibility factor(z)	0.911
CO2 Component (mol %)	0.1432	Connate water saturation (%)	36
H2S Component (mol %)	Nil		

Data Input

Temperature column is not marked. The markers of pressure, time and date column and also their units are selected. After removing and filtering, data management occurs. Then shut-in and flowing points are selected and values are entered manually. Primary fluid type is selected after determining phase situation. Then pressure adjustment and gauge depth are valued. PVT properties such as initial reservoir pressure, temperature, gas gravity, compressibility factor, gas compressibility, viscosity, critical temperature and pressure values are entered.

Data Analysis

The diagnostic analysis is done for vertical wellbore. Formation thickness, total porosity, gas and water saturation are valued. So the parameters formation permeability, skin due to damage, extrapolated pressure is estimated from radial and derivative type curve analysis. After putting the value of radial analysis outputs, drainage area, reservoir length and width ratio, average reservoir pressure, synthetic initial pressure is estimated. Then the vertical model and the multilayer model are created. Permeability, skin due to damage, drainage area, and wellbore storage constant are valued in such a way that model type curve and pressure values are matched with estimated radial analysis and derivative analysis plot. Then model and estimated values are compared. At last AOF plot is created by using values of wellhead and sand face pressure and production rate at various end flow and shut-in, extend or stabilized points. So AOF can be estimated from sand face and wellhead in terms of pseudo-pressure and pressure-squared curves. Gas IPR and OPR curves are created and production potential is calculated at different deliverability pressure.

RESULTS AND DISCUSSION

This section presents the summary of the results obtained from diagnostic analysis, vertical model analysis, multilayer model analysis and Al Mansoori Wireline Services model analysis for KTL-04.

Build Up Test Analysis (Diagnostic Analysis)

Figure 1 represents the semi-log plot of radial flow analysis for KTL-04. The radial flow analysis is usually done with the semi log plot of Pseudo-pressure versus Superposition Radial Pseudo. The purpose of analyzing radial flow data is to determine permeability (k) and apparent or total skin (s').

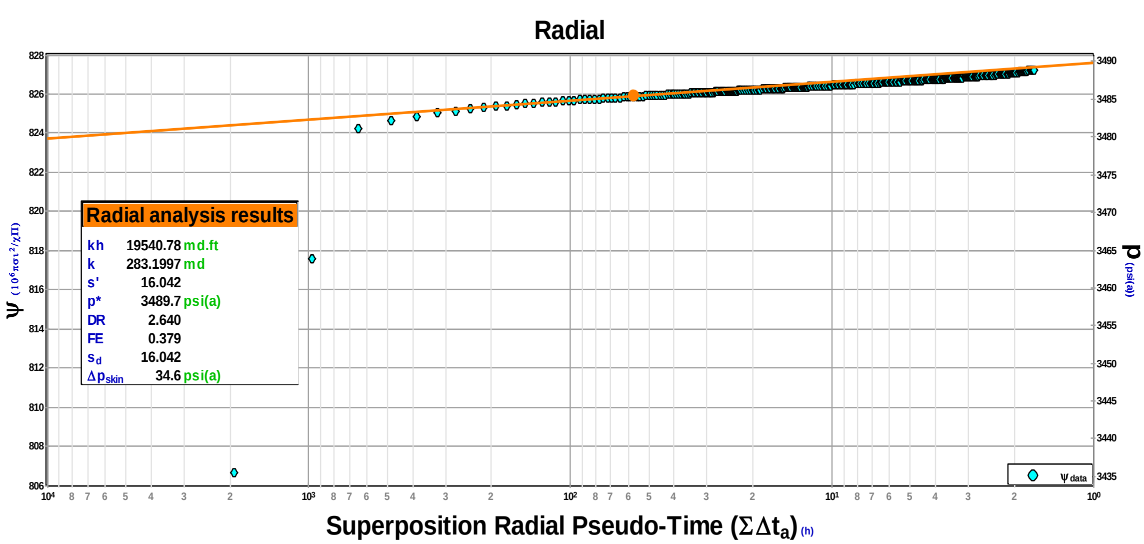

Figure 1: Semi log plot of radial flow analysis for KTL-04

From figure (Figure 1) it is seen that permeability (k) = 283.1997 mD, total skin effect s'= 16.042 and linear extrapolated pressure of actual buildup, (P*) `= 3489.7 psia for KTL-04. The positive skin factor indicates the well KTL-04 is damaged, however, it cannot give us clear information, because all the skin components in total skin factor have not been analyzed. The straight line is generated based on correlation (Equation 1).

$$P_{ws} = P_i - \frac{162.6\, qB\mu}{kh}\left[\log\left(\frac{t_p + \Delta t}{\Delta t}\right)\right] \tag{1}$$

All data points cannot fall on the straight line, because the practical field the data cannot be found as a standard form. Figure 2 represents the Dietz_MBH semi-log plot of radial flow analysis for KTL-04.

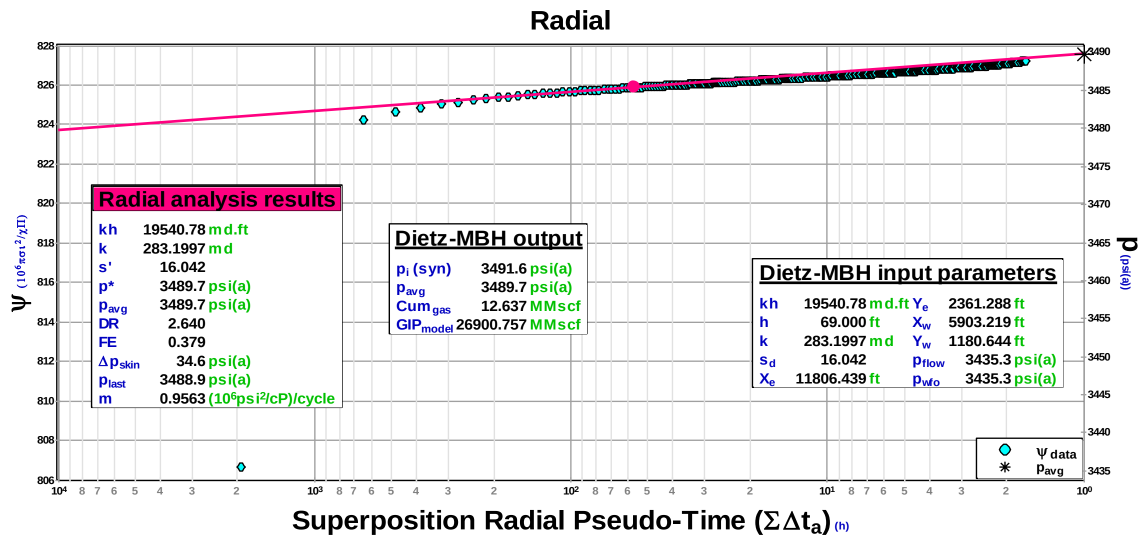

Figure 2: Dietz_MBH Semi log plot of radial flow analysis for KTL-04

The Dietz_MBH semi log plot (Figure 2) represents the average reservoir pressure (P_{avg}) is 3489.7 psia for well KTL-04 which is close to the initial reservoir pressure (P_i), 3491 psia (Table 2) and similar to extrapolated pressure 3489.7 psia from the analytical radial flow analysis. It indicates that the reservoir is at an early stage of production. The areal extents from radial flow analysis (Table 3) show the reservoir is rectangular in shape which is consistent with the assumption. Table 3 summarizes the results from diagnostic analysis of pressure buildup test for KTL-04 and the values are also mentioned in figure 1 and 2.

Table 3: Results from diagnostic analysis of pressure buildup test for KTL-04

Main Parameters	Value	Remarks
K (mD)	283.1997	Average permeability
Kh (mD. ft)	19540.78	Total permeability-thickness product
S^*	16.042	Total skin
P^*(psia)	3489.7	Extrapolated pressure
$P_{(avg.)}$ (psia)	3489.7	Average reservoir pressure

$P_{(syn)}$ (psia)	3491.6	Synthetic pressure
X_e (ft)	11806.439	Reservoir length
Y_e (ft)	2361.288	Reservoir width
X_w (ft)	5903.219	Well location in X-direction measured from boundary
Y_w (ft)	1180.644	Well location in Y-direction measured from boundary
Cum_{gas} (MMSCF)	12.637	Cumulative Gas Production

Derivative Type Curve Analysis

Figure 3 represents the derivative type curve for KTL-04. Derivative analyses are used to identify all flow regimes present in pressure transient data and to estimate values of parameters (e.g. K and S*) that can be determined by the analysis of each of these flow regimes. Diagnostic analysis lines are matched to various regions of the derivative response, and various parameters are calculated based on the analysis type and line position.

Due to the fact that the derivative is often noisy and that information can be lost from over smoothing. There are several numerical techniques available to calculate a derivative. Two methods, standard and Bourdet, are available within the software. Both methods incorporate a smoothing algorithm to reduce noise in the derivative. In this study, Bourdet derivative method is used. All analysis works are presented graphically.

This Derivative type curve shows the parameters permeability (k) = 283.1997 md, total skin effect s' = 16.042 and extrapolated pressure (P*) `= 3489.7 psia. All of these parameters are well matched with the parameters obtained from semi log plot (Figure 1). In this figure, few distorted data points are existing for all pressure, pressure derivative and dimensionless type curve which indicate the smaller effect of after flow.

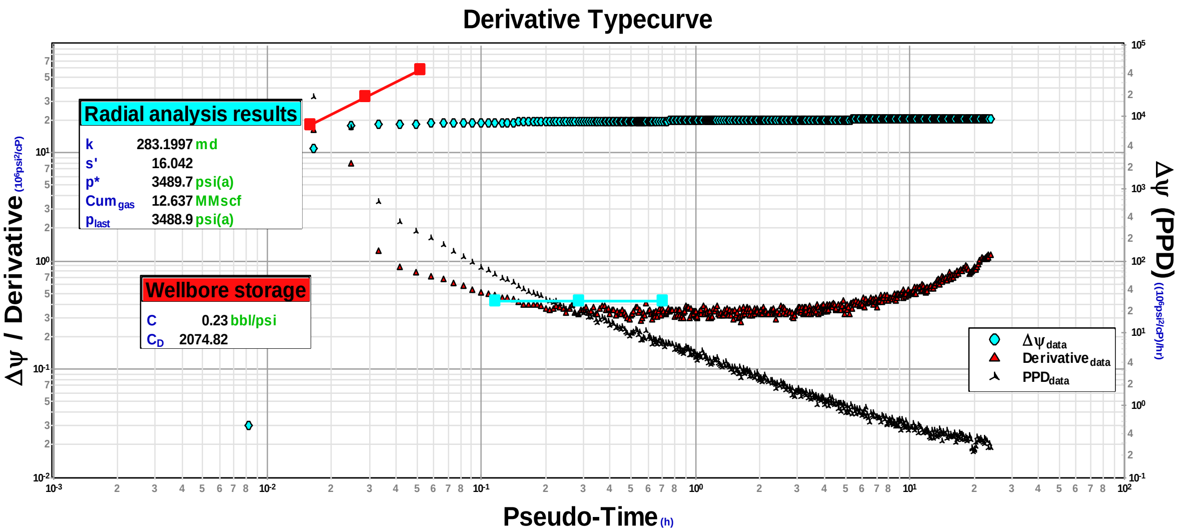

Figure 3: Derivative type curve for KTL-04

The Dietz_MBH derivative type curve for KTL-04 (Figure 4) represents the average reservoir pressure (Pavg) is 3489.7.8 psia for Well KTL-04 which is well matched with the average reservoir pressure obtained from the Dietz_MBH semi log plot (Figure 2). This average reservoir pressure is also greater than the initial reservoir pressure (Pi), 3491 psia. Figure 4 also shows that the plots of derivative and dimensionless pressure of actual build-up do not well matched with Dietz_MBH plots. This may due loss of some information for noisy effect of derivative**.**

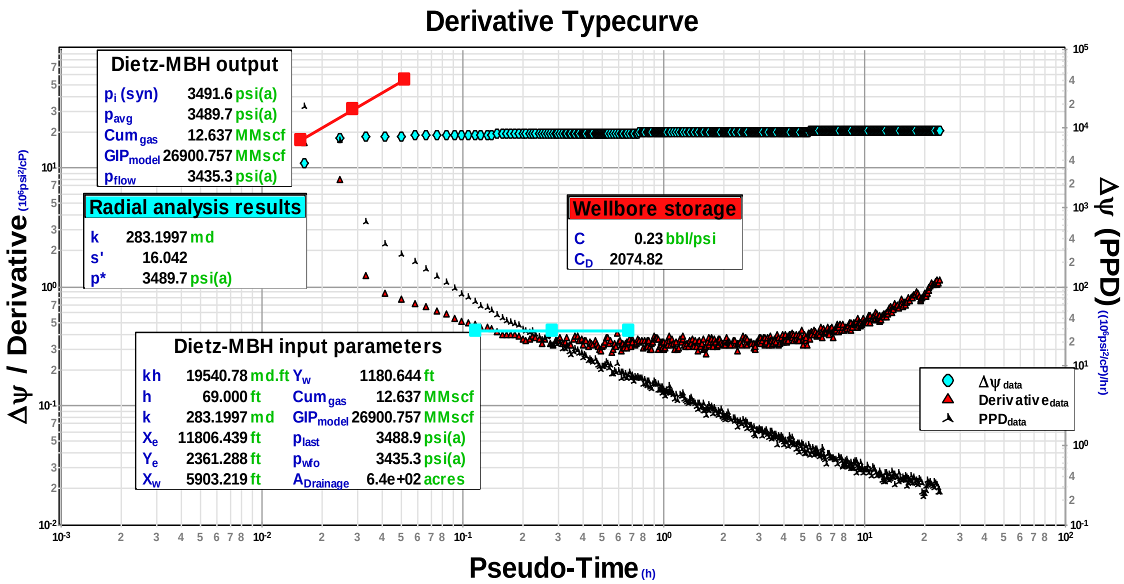

Figure 4: Dietz_MBH derivative type curve for KTL-04

Vertical Model analysis

Figures 5 and 6 illustrate the results from vertical model analysis for the KTL-04 graphically. Figure 5 represents that the model pressure data line is well fitted with reservoir pressure data points. A slight deviation is seen in the tail segment. Figure 6 shows the plot of pressure, pressure derivative and dimensionless pressure during the buildup and the vertical model analysis for KTL-04. The derivative type curves show all these three model curves are well matched with corresponding reservoir data points.

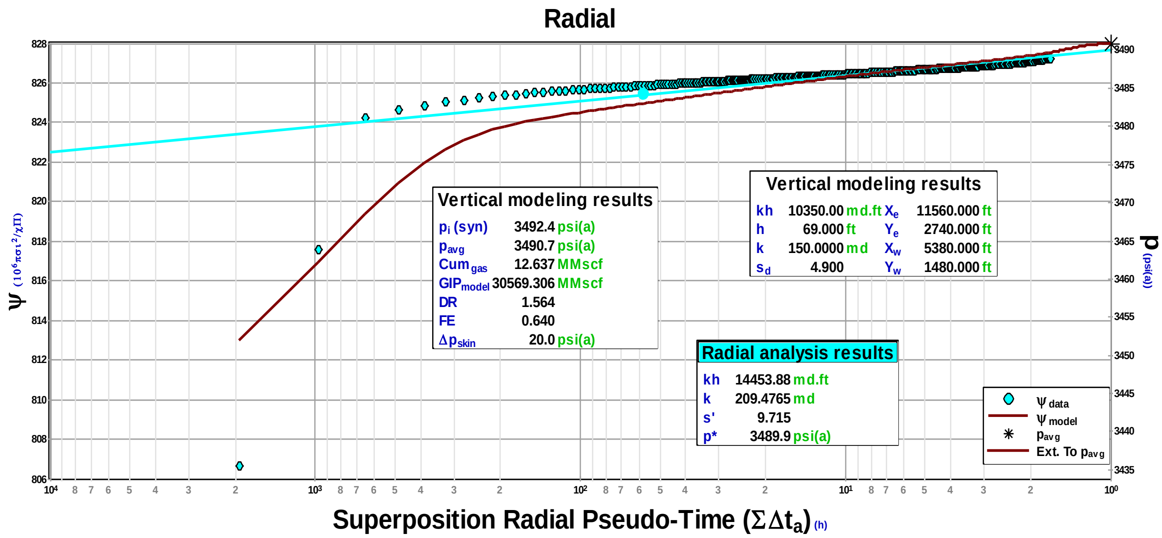

Figure 5: Semi log plot of vertical model analysis for KTL-04

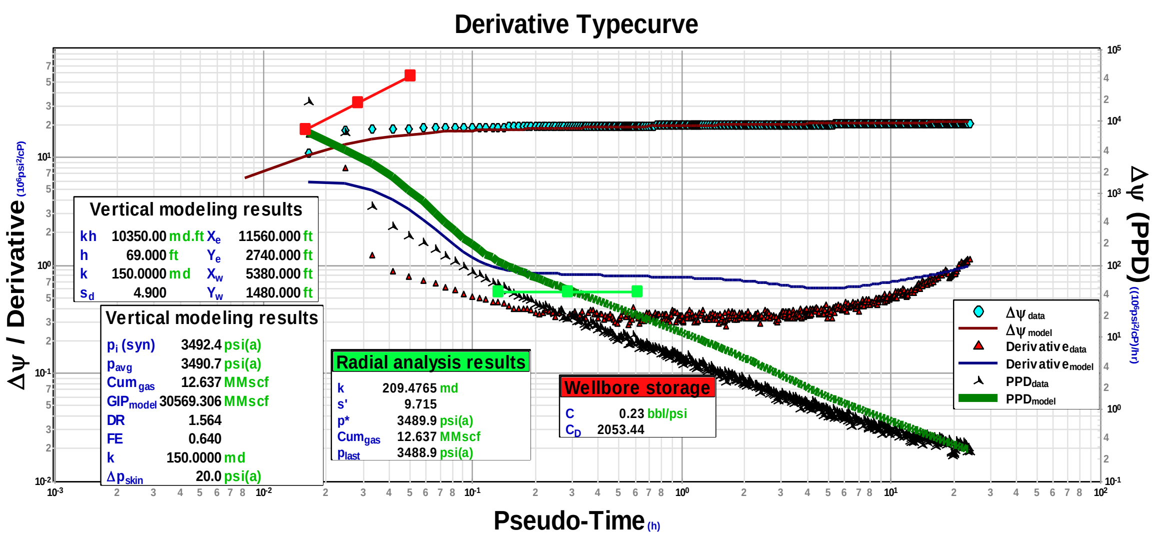

Figure 6: Log-log plot of pressure, pressure derivative and dimensionless pressure type curve in vertical model analysis for KTL-04

Table 4 shows the results from vertical model analysis of pressure buildup test in KTL-04. The results are divided into three categories, e.g., main model parameters, well and wellbore storage parameters, and reservoir parameters. The reservoir parameters such as permeability, skin, average reservoir pressure, reservoir length and width etc. are summarized in the table.

Multilayer Model Analysis

Figures 7 and 8 illustrate the multilayer model analysis results for the KTL-04 graphically. Figure 7 shows that the model pressure line is well matched with original reservoir pressure data points at a certain point. The solid red, blue, and the green line represents the model line. There is a slight deviation in the tail segment. Figure 8, it is seen that the derivative type curves of all three pressures, pressure derivative and dimensionless pressure derivative model curves are well fitted with corresponding original reservoir pressure data points.

Table 4: Results from vertical model analysis of pressure buildup test in KTL-04

Description	Parameters	Value	Remarks
Main Model Parameters	k (mD)	209.4765	Average permeability
	kh (mD. ft)	14453.88	Total permeability-thickness product
	C_D	2053.44	Dimensionless storage coefficient
	S_d	9.715	Skin due to damage
	P_i (psia)	3491	Initial reservoir pressure
	P^* (psia)	3489.9	Extrapolated pressure
	$P_{(avg.)}$ (psia)	3490.7	Average reservoir pressure
	$P_{(syn)}$(psia)	3492.4	Synthetic pressure
Well and Wellbore storage parameters	C_D	2053.44	Dimensionless storage coefficient
	S_d	4.9	Skin due to damage
Reservoir parameters	k (mD)	209.4765	Average permeability
	kh (mD. ft)	14453.88	Total permeability-thickness product
	s'	9.715	Total skin effect
	P_i (psia)	3491	Initial reservoir pressure
	P^* (psia)	3489.9	Extrapolated pressure
	$P_{(avg.)}$ (psia)	3490.7	Average reservoir pressure
	$P_{(syn)}$ (psia)	3492.4	Synthetic pressure
	X_e (ft)	11560	Reservoir length
	Y_e (ft)	2740	Reservoir width
	X_w (ft)	5380	Well location in X-direction measured from boundary
	Y_w (ft)	1480	Well location in Y-direction measured from boundary

From multilayer model analysis, it is seen that the skin distribution through the layers are not equal. The permeability of layer 1 is 110 mD. The permeability value of Layer 1 is higher than layer 2 and layer 3. On the other hand, the skin effect of layer 1 is smaller than layer 2 and layer 2 is smaller than layer 3. The average reservoir pressure is same for all three layers. Table 5 summarizes the results from multilayer model analysis of pressure buildup test in KTL-04. The value of permeability (k) and reservoir thickness (h) varies through three layers. The average reservoir pressure is 3490.0 psia and the average permeability is 89.8872 mD.

Deliverability Test Analysis

Simplified analysis and laminar-inertial turbulent (LIT) analysis are used to determine AOFP for deliverability test analysis. Pressure squared and pseudo-pressure methods can be used in both simplified and LIT analysises. However, simplified analysis is used in most of the cases.

In this study, AOFP is obtained by simplified analysis using both pressure squared and pseudo-pressure methods for KTL-04. IPR and OPR curve, deliverability test, and flow after flow test are done in terms of pressure squared and pseudo-pressure methods in sand face and well head. A flow after flow survey was conducted in Well KTL-04 of Kailastila Gas field on 16th Nov 2007 to 18th Nov 2007. The survey was conducted by Al Mansoori Wireline Services using quartz memory gauges S/No. 20468 lower and 20389 upper and the sample rate for each gauge was 30sec. The gauges were calibrated to 10K Psi pressure and 350^0F temperature. The pressure accuracy is 0.02% of full scale and resolution is 0.00006% of full scale.

Table 5: Results from multilayer model analysis of pressure buildup test in KTL-04

Description	Parameters	Value	Remarks
Main Model Parameters	k (mD)	89.8872	Average permeability
	kh (mD. ft)	18516.77	Total permeability-thickness product
	C_D	2074.818	Dimensionless storage coefficient
	S_d	14.855	Skin due to damage
	P_i (psia)	3491	Initial reservoir pressure
	P^* (psia)	3488.7	Extrapolated pressure
	$P_{(avg.)}$ (psia)	3490.0	Average reservoir pressure
	$P_{(syn)}$ (psia)	3490.7	Synthetic pressure
Well and Wellbore storage parameters	C_D	2074.818	Dimensionless storage coefficient
	S_d	14.855	Skin due to damage
Layer 1 parameters	k_1 (mD)	110	Average permeability
	h_1 (ft)	69	Reservoir thickness
	k_1h_1 (mD. ft)	7590	Total permeability-thickness product
	S_d	3	Skin due to damage
	ω	0.1	Capacity between layers
	λ	1.00e-06	Exchange term between layers
Layer 2 parameters	k_2 (mD)	100	Average permeability
	h_2 (ft)	67	Reservoir thickness
	k_2h_2 (mD. ft)	6700	Total permeability-thickness product
	S_d	4	Skin due to damage
	ω	0.8	Capacity between layers
	λ	1.5e-06	Exchange term between layers
Layer 3 parameters	k_3 (mD)	90	Average permeability
	h_3 (ft)	70	Reservoir thickness
	k_3h_3 (mD. ft)	6300	Total permeability-thickness product
	S_d	5	Skin due to damage
	ω	0.9	Capacity between layers
	λ	2.00e-06	Exchange term between layers

The temperature accuracy is 0.45 ^{0}F and resolution is <0.009 ^{0}F. The gauges were hanged at a depth of 8750 ft wzl. The gauge recorded complete survey data successfully and the data quality is excellent. The flow-after-flow test involved 2 periods of increasing draw-down followed by a build-up. The production test was carried out by Al Mansoori Production services. The well was flowed for approximately 9 hours in different chokes and shut in for approximately 24 hours. The test utilized a surface shut-in.

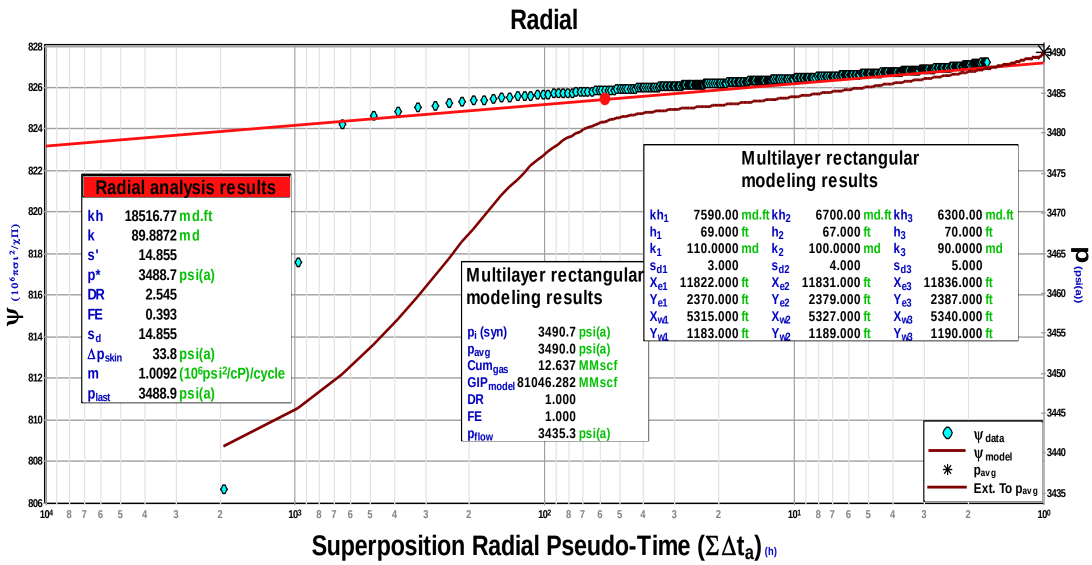

Figure 7: Semi log plot of multilayer model analysis for KTL-04

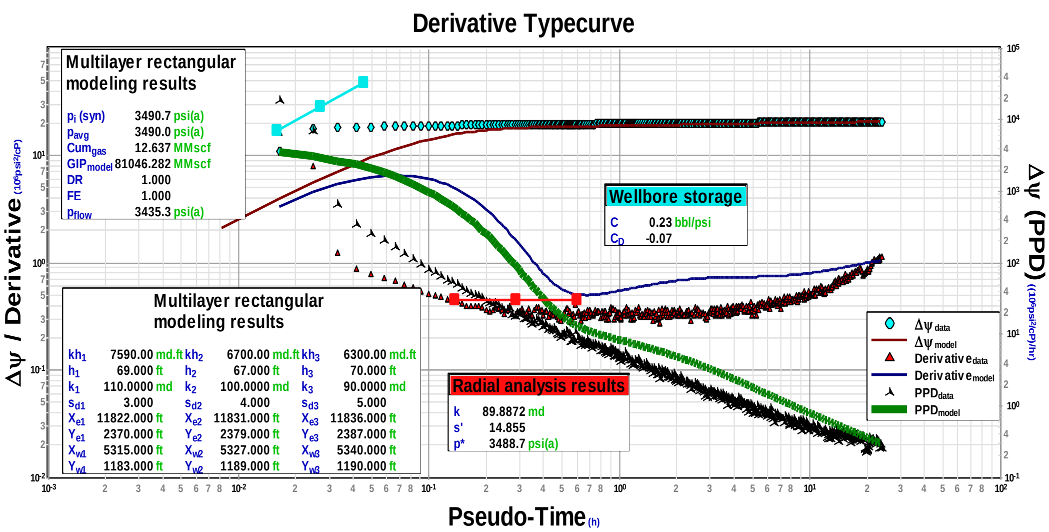

Figure 8: Log-log plot of derivative type curve of pressure, pressure derivative and dimensionless in multilayer model analysis for KTL-04

Figures 9 and 10 shows the sand face flow after flow test results and IPR curve in terms of pseudo-pressure method for KTL-04 and Figure 11 and 12 shows the sand face flow after flow test results and IPR curve in terms of pressure squared method for KTL-04. Subsequently, Figure 13 and 14 shows the well head flow after flow test results and OPR curve in terms of pseudo-pressure method for KTL-04 and

Figures 15 and 16 shows the well head flow after flow test results and OPR curve in terms of pressure squared method for KTL-04

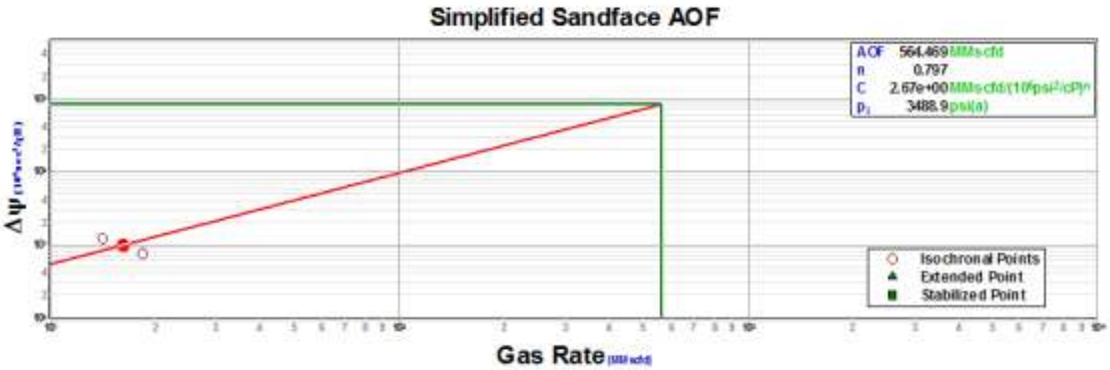

Figure 9: Sand face flow after flow test analysis curve in terms of Pseudo-pressure for KTL-04

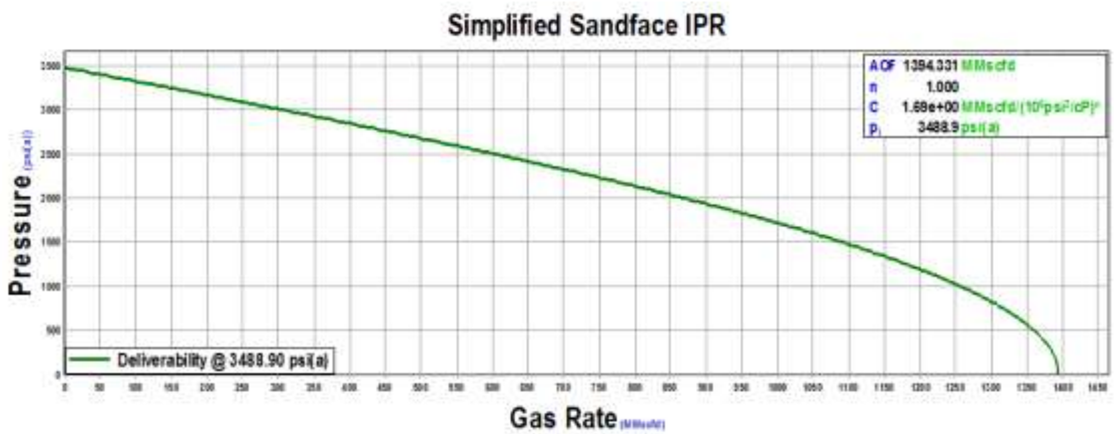

Figure 10: Sand face IPR curve for KTL-04

Figure 9 represents sand face deliverability test results in terms of pseudo-pressure method with AOFP 564.469 mmscfd, n = 0.797 and stabilized performance coefficient, C = 2.67 mmscfd/[106psia2/cP] ^{n} for KTL-04. Here the value of 'n' indicates the Darcy's flow, which is compatible with the assumption. This sand face inflow performance curve for KTL-04 represents the results of AOFP, 1394.331 mmscfd, the stabilized performance coefficient, C=1.69mmscfd/[106psia2/cP] ^{n} and n = 1, which are totally consistent with results obtained from the flow-after-flow test curve. The shape of IPR curve is similar like a standard IPR curve for gas reservoir.

Figure 13 represents well head deliverability test results in terms of Pseudo-pressure method with AOFP 169.419 mmscfd, n = 0.666 and stabilized performance coefficient, C = 2.42 mmscfd/[106psia2/cP] ^{n} for KTL-04. Here the value of 'n' indicates the non-Darcy's flow, which is not reasonable with the assumption. The value of AOFP is less than the value obtained from sand face deliverability curve (Figure 9) which is reliable because at well head the pressure difference is normally lower than the sand face pressure difference.

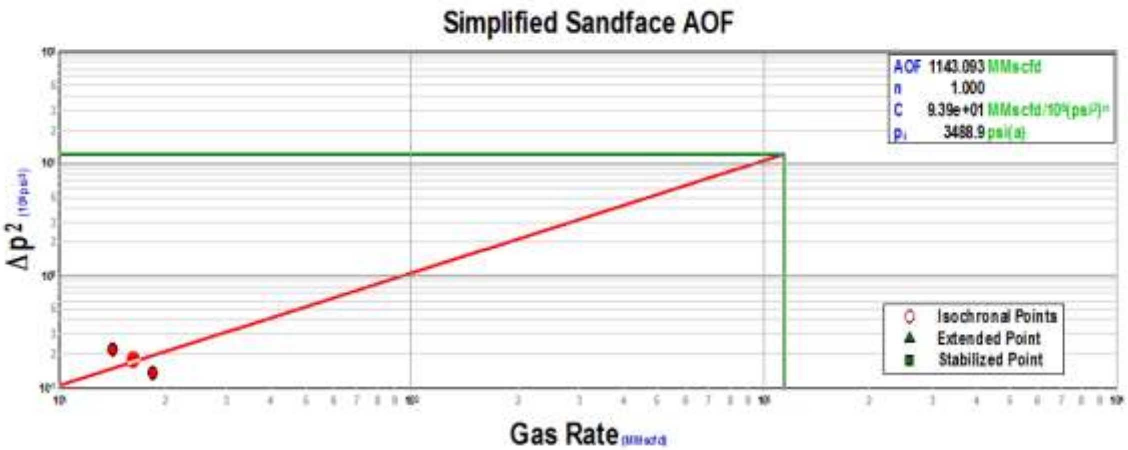

Figure 11: Sand face flow after flow test analysis curve in terms of pressure-squared for KTL-04

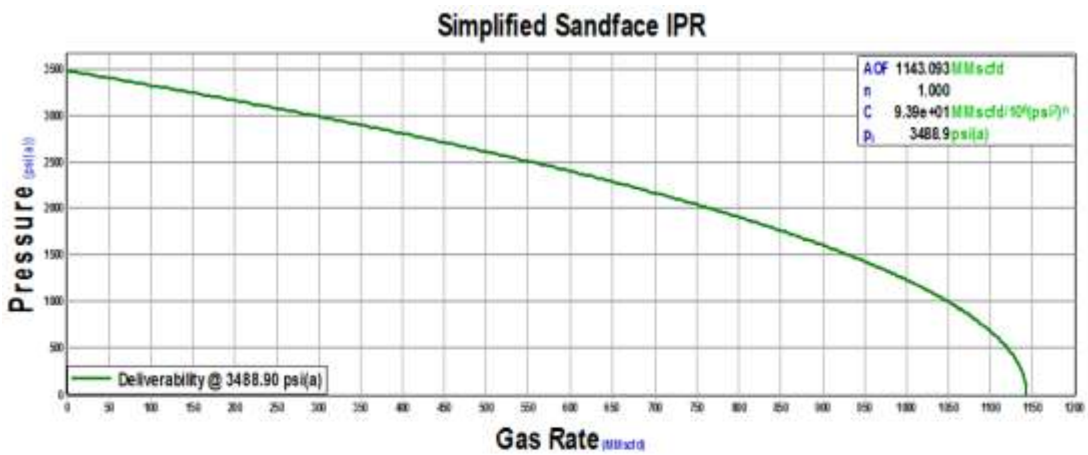

Figure 12: Sand face IPR curve for KTL-04

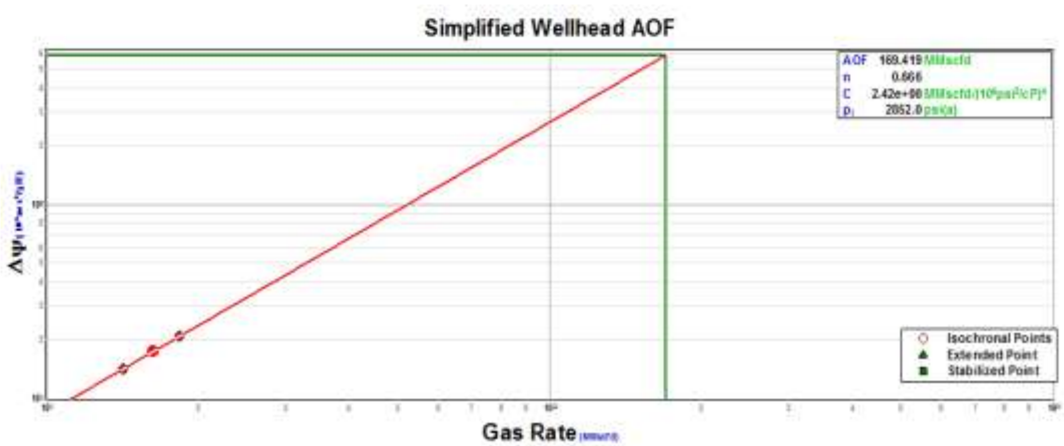

Figure 13: Well head flow after flow test analysis curve in terms of Pseudo-pressure for KTL-04

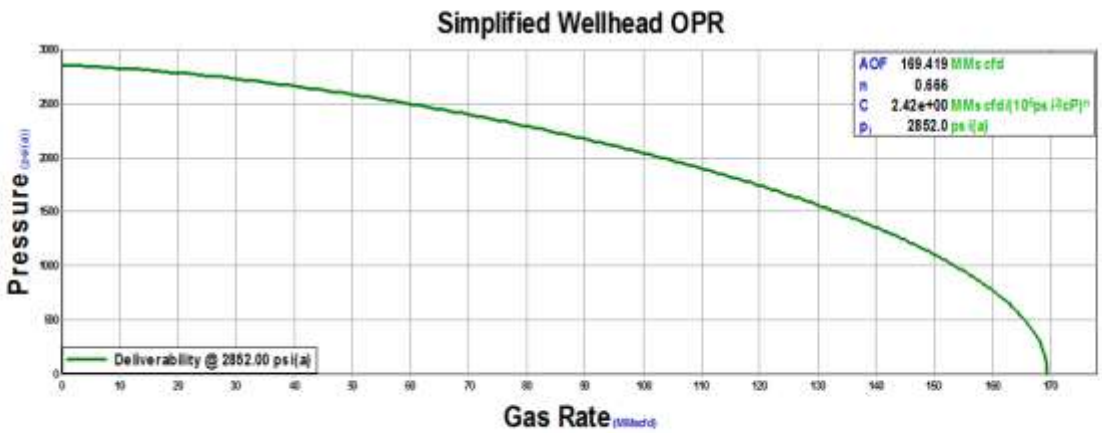

Figure 14: Well head OPR curve for KTL-04

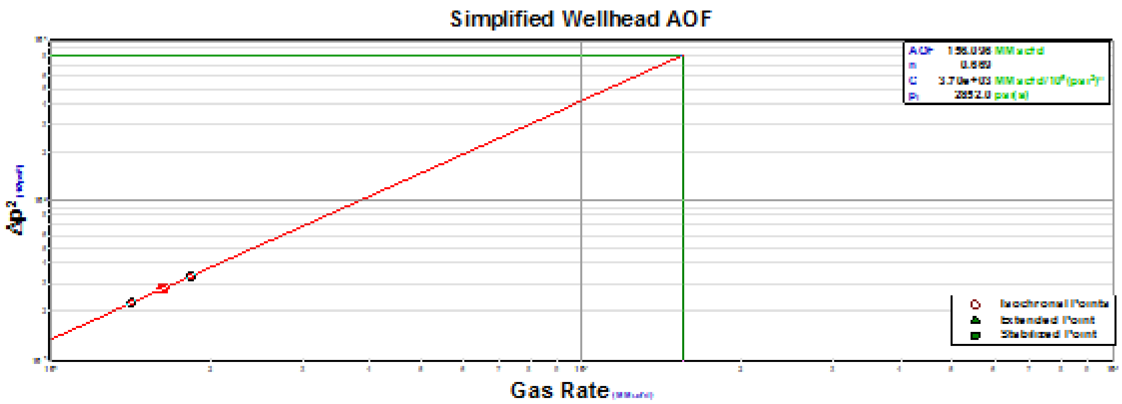

Figure 15: Well head flow after flow test analysis curve in terms of pressure-squared for KTL-04

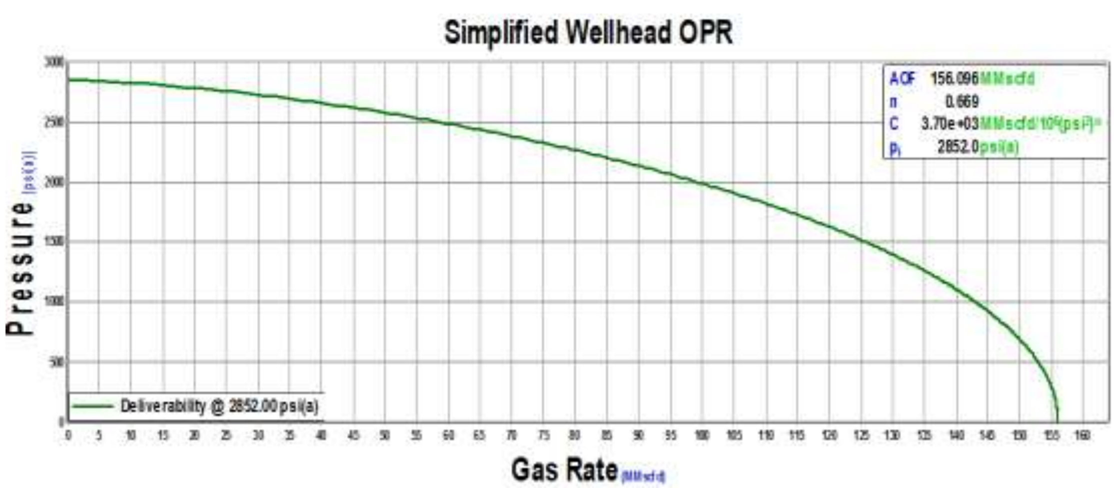

Figure 16: Well head OPR curve for KTL-04

Table 6 shows the deliverability test results for KTL-04 in terms of Pseudo-pressure and pressure squared. The values of absolute open flow potential in terms of pseudo pressure and pressure squared method are closely matched. The deliverability exponent, n at sandface is 1, which indicates the Darcy's flow.

Table 6: Deliverability test results for KTL-04 in terms of Pseudo-pressure and pressure squared method

Parameters	Pseudo Pressure Method		Pressure Squared Method	
	Sandface Value	Well head Value	Sandface Value	Well head Value
P_i (psia)	3488.9	2852	3488.9	2852
AOF(mmscfd)	1394.331	169.419	1143.093	156.096
C [mmscfd/($10^6 psi^2/cP)^n$]	2.67	2.42	$9.39e^{01}$	$3.70e^{03}$
n	1.0	0.666	1.0	0.669

Comparison among diagnostic analysis parameters, vertical model parameters and Al Mansoori Wireline Services model parameters

Table 7 summarizes the comparison among diagnostic analysis parameters, vertical model parameters and Al Mansoori Wireline Services model parameters) it is obtained that, the estimated pressure response and reservoir extends of radial analysis vary from the vertical model. This is because, most of the time all the models are developed based on the theoretical background. Therefore, the vertical model shows the actual trends of reservoir and cannot extract the reservoir parameters in the conventional manner.

Table 7: Comparison among diagnostic analysis parameters, vertical model parameters and Al Mansoori Wireline Services model parameters of KTL-04.

Parameters	**Diagnostic Analysis Value**	**Vertical Model value**	**Al Mansoori Wireline Services model value**
k(mD)	283.1997	209.4765	342
kh (mD ft)	19540.78	14453.88	23600
s'	16.042	9.715	20.6
S_d	Not found	4.9	Not available
P^*(psia)	3489.7	3489.9	Not available
$P_{(avg.)}$ (psia)	3489.7	3489.3	Not available
$P_{(syn)}$(psia)	3491.6	3491	Not available
X_e(ft)	11806.439	11560	10000
Y_e(ft)	2361.288	2740	1250
X_w(ft)	5903.219	5380	Not available
Y_w(ft)	1180.644	1480	Not available

Comparison the flow-after-flow test results and Al Mansoori Wireline Services

This section compares the flow-after-flow test results found from this study and Al Mansoori Wireline Services model study for KTL-04.

The results obtained from the flow-after-flow test analysis and Al Mansoori Wireline Services model analysis for KTL-04 are discussed here. For both analyses of Pseudo-pressure method and Pressure squared method in case of sandface flow for KTL-04 it indicates a non-Darcy flow, which is not consistent with assumption and for well head value. The flow-after-flow test analysis results obtained from this study are so many dissimilar with the results obtained from Al Mansoori Wire Lines Services. This may happen for performing analysis through the theoretical model. This value of ‘n’ indicates that, Al Mansoori Wire Lines Services study was also erroneous. Al Mansoori Wire Lines Services acknowledged this erroneous result and did not give an explanation of this error. Table 8 shows the Comparison of sand face flow-after-flow test results in terms of Pseudo-pressure with Al Mansoori Wireline Services model for KTL-04.

Table 8: Comparison of sand face flow-after-flow test results in terms of Pseudo-pressure with Al Mansoori Wireline Services model for KTL-04

Parameters	**Analysis Value**	**Al Mansoori value**
AOF (mmscfd)	564.469	2490
C [mmscfd/(10^6psi^2/cP)^n]	2.67	1.03e^{-04}
n	0.797	0.720

RECOMMENDATION

1. In this study, it is considered that reservoir is multilayered rectangular. Though at first it is considered that reservoir model is vertical, it is considered that the reservoir as a multilayered reservoir. Because it is not possible to estimate all of the reservoir properties accurately from a single layer. Besides, if we consider the reservoir as a multilayered we will be able to know the whole reservoir characteristics.
2. It is also recommended that the reservoir can also be considered as any other shape such as multilayer cylindrical.
3. Down-hole shut-in and down-hole flow measurements are recommended for the accuracy of the analysis. With down-hole flow measurements, it will be possible to deconvolve the pressure response and analyze even the draw-down periods.
4. The wellbore storage effect is 2074. This result is very high. The wellbore storage effect may also be minimized to provide better formation characteristics which are now being masked by the wellbore storage.
5. It is recommended that the build-up test can be performed for a longer period to properly analyze the boundary effects. The flow rate should be measured accurately with a flow measurement device.

CONCLUSION

The objective of this study was to estimate reservoir properties of KTL-04. According to this study, it is observed that the permeability value that is obtained from diagnostic analysis of KTL-04 is 283.1997 mD for vertical modeling these values are well-matched with diagnostic analysis. The total skin effect is positive, that means reservoir is stimulated or damaged as all the skin components has not been analyzed. From Dietz_MBH analysis, it is seen that the average reservoir pressure is closer to the initial reservoir pressure indicate that the reservoir is at its early stage of production. From this study, it is analyzed that Kailastila gas field is a good reservoir due to its good permeability value and good flow capacity. Reservoir model parameters are compared with the parameters obtained from Al Mansoori wireline service report. There are many differences between diagnostic analysis and model value. Thus, it is recommended that diagnostic analysis must be performed along with vertical modeling. However, it is not possible to acquire the whole reservoir characteristics by investigating only one layer. Multilayer model parameters can be a good tool to characterize the reservoir.

ACKNOWLEDGEMENT

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NOMENCLATURE

B	=	Formation Volume Factor (rb/stb)
k	=	Permeability (mD)
P_i	=	Initial Reservoir Pressure (psia)
$P_{i(syn)}$	=	Synthetic initial reservoir pressure (psia)
P^*	=	Extrapolated pressure (psia)
$P_{R(avg)}$	=	Average reservoir pressure (psia)
P_b	=	Base pressure (14.696psia)
ΔP_{skin}	=	Pressure drop due to skin (psia)
P_w	=	Wellbore pressure (psia)
P_{wD}	=	Dimensionless wellbore pressure
P_{wf}	=	Flowing pressure (psia)
P_{wfo}	=	Final flowing pressure(psia)
P_{ws}	=	Shut-in pressure (psia)
t_p	=	Producing time (hr)
Δt	=	Shut in Time (hr)
q	=	Volumetric Flow Rate (stb/d)
n	=	Deliverability exponent
c	=	Flow coefficient, [mmscfd/$(10^6 psi^2/cP)^n$]
s	=	Skin factor
μ	=	Viscosity (cP)

$\Psi = P_p$	=	Pseudo-pressure (psi^2/cP)
$\Psi^* = P_p{}^*$	=	Extrapolated pseudo-pressure (psi^2/cP)
$\Delta\Psi = \Delta P_p$	=	Delta pseudo-pressure (psi^2/cP)
$\Psi_{ws} = P_{ws}$	=	Shut-in pseudo-pressure (psi^2/cP)
$\Psi_{ws}{}^* = P_{ws}{}^*$	=	Extrapolated shut-in pseudo-pressure (psi^2 /cP)

ABBREVIATIONS

AOFP	=	Absolute Open Flow Potential
KTL-04	=	Kailastila Well-04
PVT	=	Pressure Volume Temperature
IPR	=	Inflow-Performance-Relationship
OPR	=	Outflow-Performance-Relationship
MBH	=	Matthews, Brons and Hazebroek
LIT	=	Laminar-Inertial-Turbulent
MP	=	Match Point
PPD	=	Primary Pressure Derivative

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ICPE (2016-031)

Quantification of Reserve and Skin Index of Well-02 of Habiganj Gas Field, Bangladesh Using Typecurve Analysis

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ABSTRACT

It is an important task of petroleum engineers to estimate reserve and measure skin index of a well to make proper development planning. There are various methods to quantify reserve and skin index of a well. In this research, reserve and skin index of Well-02 of Habiganj gas field, Bangladesh were estimated by analyzing daily Production (production/day) data of Well-02 for the whole year of 2007. There are two gas zones in the Habiganj gas field: Upper Gas Sand (UGS) and Lower Gas Sand (LGS). The Well-02 was a gas producing well from UGS. This was a software based research and software FEKETE, F.A.S.T.RTATM (version 4.5.1.277), IHS Inc. was used for this purpose. Typecurve analysis by using software FEKETE, F.A.S.T.RTATM is one kind Decline Curve Analysis (DCA). Reservoir properties and properties of Well-02 were also used to do this research. The objectives were to estimate reserve (Gas initially in place and Expected ultimate recovery) of Well-02 and to measure damage due to the skin surrounding this producing well. After completing this research, the Gas initially in place (GIIP) and Expected ultimate recovery (EUR) values of Well-02 of Habiganj gas field, Bangladesh were estimated to 329.253 Billion cubic feet (Bcf) and 230.477 Bcf, respectively. Skin effect in the surrounding of this producing well was amounted to 7.047 by the end of the year of 2007. Due to this amount of skin effect, the Well-02 was damaged. For this reason, permeability surrounding the near wellbore region of Well-02 was reduced than the average permeability value of the UGS of Habiganj gas field and this reduced permeability value was measured to 2.1898 millidarcy (md) in this research.

Keywords: Habiganj Gas Field, Typecurve analysis, Decline curve analysis, Reserve, Skin, Permeability.

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LIST OF NOMENCLATURES

S = Skin factor

S_d = Skin effect due to well drilling and completion

S_{PT} = Pseudo-skin factor resulted from reservoir open level

S_{PF} = Pseudo-skin factor due to perforation

r_s = Radius of the alteed zone due to skin

k_s = Permeability of the altered zone due to skin

k = Permeability of the reservoir (md)

r_w = Wellbore radius

r_e = Radius of the reservoir

Δp_s = Additional pressure drop due to skin effect

μ = Viscosity

q = Production rate (MMScfd)

Δp_p = Pseudo pressure difference (psi)

P_{pwf} = Bottomhole pseudo pressure (psi)

Q = G = Cumulative production (Bcf)

Q_G =Cumulative gas production (Bcf)

t_c = Material balance time

t_{ca} = Material balance pseudo time

μ_g = Viscosity of gas

c_g = Compressibility of gas (psi^{-1})

q_g = Gas production rate (mmcfd)

t = Time (day)

r_{ed} = Dimensionless radius of the reservoir

t_{Dd} = Dimensionless time

q_{Dd} = Dimensionless rate

h = Net pay thickness of the reservoir (ft)

C_t = Total compressibility (psi^{-1})

P_i = Initial pressure (psi)

P_{pi} = Initial pseudo pressure (psi)

P_{wf} = Wellbore flowing pressure (psi)

P_{pwf} = Wellbore flowing pseudo pressure (psi)

t_{dA} = Dimemsionless radius

A = Area (ft^2)

B = Formation volume factor

ABBREVIATION OF UNITS

Bbl = Barrel

Bcf = Billion cubic feet

D = Darcy

F = Fahrenheit

ft = Feet

in = inch

km = Kilo meter

md = millidarcy

MMScf = Million standard cubic feet

INTRODUCTION

Habiganj Gas Field lies at northeastern part of Bangladesh about 100 Kilo meter (km) away from Dhaka (capital city of Bangladesh). This gas field was discovered by shell Oil Company in 1963 and still now operated by Bangladesh Gas Field Company Ltd (BGFCL), a subsidiary of Bangladesh Oil, Gas and Mineral Corporation (known as petrobangla) (Imam, 2013; Bangladesh Gas Fields Company Limited [BGFCL], 2014; Imam, 2005; Islam et al., 2016; Shofiqul and Nusrat, 2013). Figure 1 illustrates the location of Habiganj gas field in Bangladesh.

Habiganj gas field has two gas zones of sandstone formations, upper gas sand (UGS) and lower gas sand (LGS). The UGS is the primary reservoir lies at a depth of 1320 meter below the surface with maximum gross pay thickness of 230 meter. It has an average porosity of 0.30 and average permeability of 2-4 D (Imam, 2013; Islam et al., 2016). Figure 2 demonstrates the cross- section of the subsurface of Habiganj gas field, Bangladesh. The recovery from UGS in the Habiganj Gas Field is dominated by the water drive mechanism and the aquifer adjacent to UGS is ten times greater than the reservoir (Islam et al., 2016; Haq and Gomes, 2001).

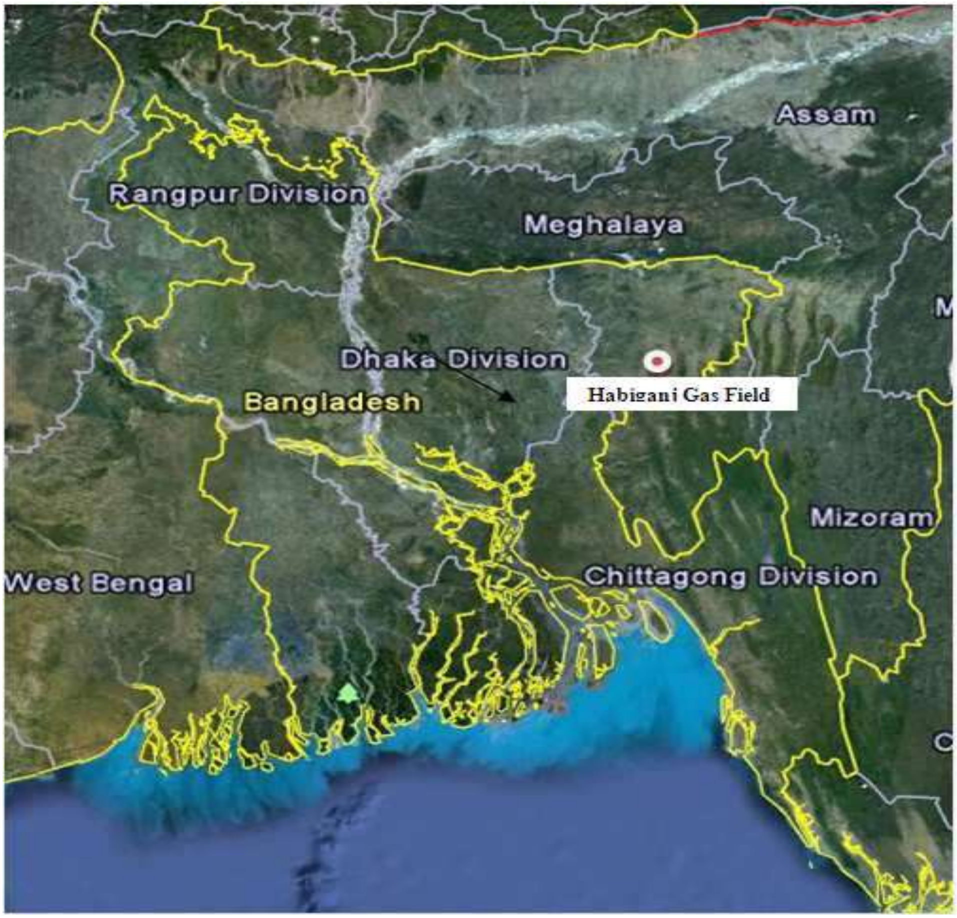

Figure 1: Location of Habiganj gas field, Bangladesh (Shofiqul and Nusrat, 2013)

Typecurve analysis: A considerable amount of information concerning well test analysis has been in the literature. Typecurve analysis consists of finding a type curve that matches the actual response of the well and the reservoir during the test. Then the reservoir and well parameters, such as permeability and skin can be calculated from the dimensionless parameters defining that type curve [Ley and Fernando, 1981; Gringarten, 1987].

Typecurve analysis can also be defined as a Decline Curve Analysis (DCA). DCA is a forecasting technique which predicts by history matching of rate-time data on an appropriate typecurve. What direction to take, what typecurve/ typecurves to choose and where the rate-time data should fit is decided based on basic reservoir engineering concepts and knowledge (Fetkovich, 1980; Fetkovich et al., 1987).

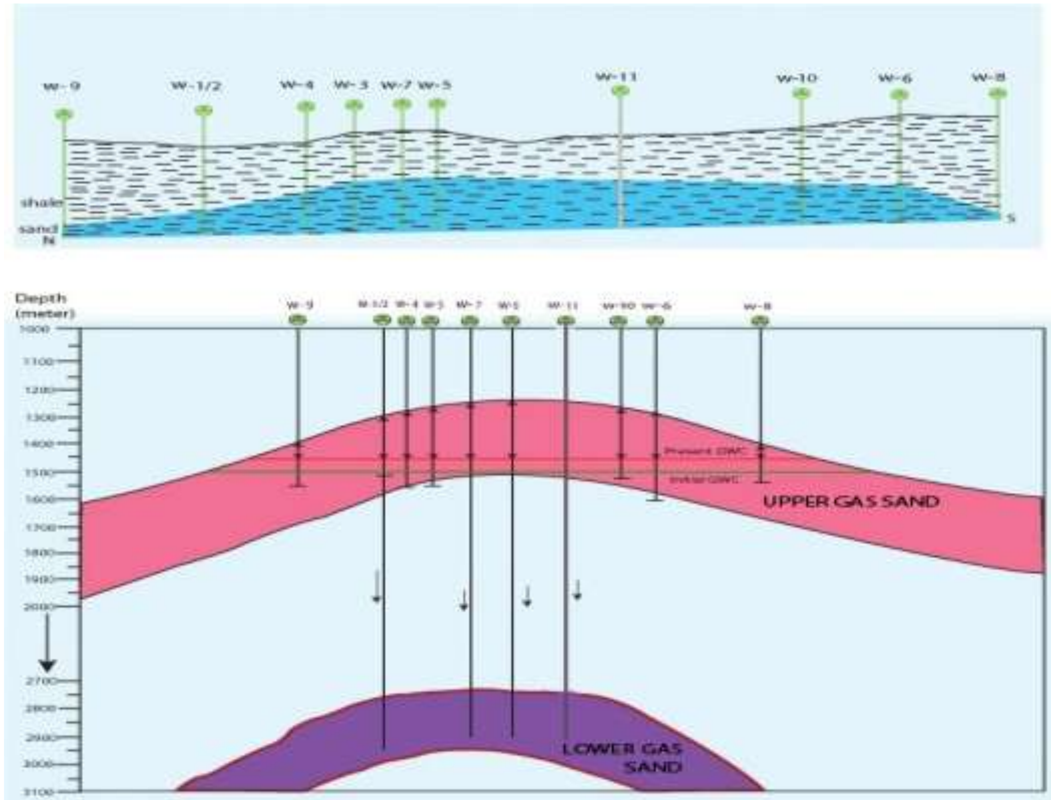

Figure 2: Cross-section of the subsurface of Habiganj gas field, Bangladesh (Imam, 2013; Islam et al., 2016).

Permeability and skin: Permeability (k) in a reservoir rock is equivalent to the ability to transmit fluids through interconnected pores of the reservoir rock. It's a random-valued property of the reservoir (Zolotukhin and Ursin, 2000; Jensen et al., 1987)

The pressure drop around the well bore is defined as the skin effect (S). This pressure drop is occurred by the resistance of the formation, the viscosity of the fluid, and the additional resistance around the well bore due to drilling, completion of and production from the well. The reservoir damage is occurred due to this skin effect (Everdingen, 1953; Jianchun et al., 2014). The permeability around the damaged well is always deviated from the reservoir formation due to this skin effect (Figure 3). From figure 3, The altered zone around the wellbore has uniform permeability k_s out to a radius r_s, beyond which the formation permeability, k, is unaltered (Islam et al., 2016; Altered zone and skin effect, 2016).

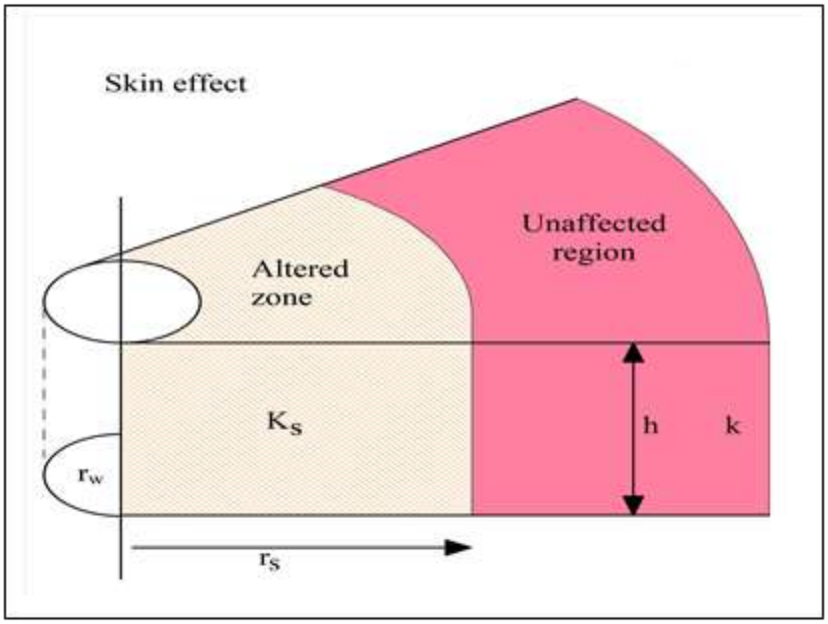

Figure 3: Deviation of permeability around the well bore (Islam et al., 2016; Altered zone and skin effect, 2016)

Reserve: All the gas in a reservoir of a gas field cannot be recovered. Total amount of gas present initially in a gas reservoir is known as Gas initially in place (GIIP). Part of this GIIP can be extracted, which ranges from 60%-90% in a typical gas reservoir. This amount of gas which is commercially recoverable from GIIP is known as the reserve, which can be also be termed as Expected ultimate recovery (EUR) (Imam, 2013).

MATERIALS AND METHODS

A set of basic data is needed for typecurve analysis of gas wells. This data includes production data and it is established that typecurve analysis is the best approach to use production data. The additional data are reservoir, fluid and well properties (Chen and Teufel, 2000; Agarwal, 1999).

This data (reservoir properties, fluid properties, properties of Well-02 and production data of Well-02 for the year of 2007 of Habiganj gas field) were collected from BGFCL, a subsidiary of Petrobangla. Typecurve analysis methods such as Blasingame typecurve analysis, Agarwal-Gardner typecurve analysis and Normalized Pressure Integral (NPI) typecurve analysis were followed by using software FEKETE, F.A.S.T.RTA™. Data utilized to make graph of these methods in the software were filtered to minimize scattered data and to clean up ‘noise’. It was done to obtain a good match between typecurves and data plot in the graph of the software (Islam et al., 2016; Help Manual, 2010).

Typecurves and Dataplots: According to Help manual (2010) Blasingame, Agarwal-Gardner and NPI typecurves are produced by using dimension variables. Blasingame and Agarwal-Gardner typecurves are made on log-log scale by using dimensionless rate against dimensionless time. NPI typecurve is made on a log-log scale by using dimensionless pressure against dimensionless time.

Dimensionless rate and dimensionless time for Blasingame typecurve can be defined as respectively,

$$q_{Dd} = q_d \ln\left(r_{eD} - 0.5\right)$$

$$t_{Dd} = \frac{2t_d}{\left\{(\ln r_{eD} - 0.5)(r_{eD}^2 - 1)\right\}}$$

Here, dimensionless radius $r_{eD} = \dfrac{r_e}{r_w}$

In case of Agarwal-Gardner typecurve, Dimensionless rate and dimensionless time are expressed respectively as,

$$q_D = \frac{1}{p_D} = 141.2 \frac{qB\mu}{\left\{kh\left(p_i - p_{wf}\right)\right\}}$$

$$t_{DA} = \frac{0.00633kt}{\varphi\mu c_t A}$$

For NPI typecurve, dimensionless pressure and dimensionless time are respectively as,

$$p_D = \frac{1}{q_D} = \frac{\left\{kh\left(p_i - p_{wf}\right)\right\}}{141.2qB\mu}$$

$$t_{DA} = \frac{0.00633kt}{\varphi\mu c_t A}$$

When the required data are entered into the software, data points of the same co-ordinates as typecurves were plotted in the log-log graph of the typecurves. These are defined as ‘Data plot’.

In the Blasingame and Agarwal-Gardner typecurves, data points are the plotting of normalized rate against material balance pseudo time and in the NPI typecurve, data points are the plotting of normalized pressure against material balance pseudo time.

For data plot in the Blasingame and Agarwal-Gardner typecurve, normalized rate and material balance pseudo time can be defined as,

Normalized rate, $\dfrac{q}{\Delta \mathrm{p_p}} = \dfrac{q}{(p_i - p_{pwf})}$

Material balance pseudo time $t_{ca} = \left\{ \frac{\left(\mu_g c_g\right)_j}{q_g} \right\} \int_o^t \left\{ \frac{q_g}{\mu_{gav} c_{gav}} \right\} dt$

For data plot in the NPI typecurve, material balance pseudo time is identical to the material balance pseudo time in the Blasingame and Agarwal-Gardner typecurve mentioned above. Normalized pressure can be expressed as,

$$\frac{q}{\Delta \mathrm{p_p}} = \frac{q}{(p_i - p_{pwf})}$$

Analysis between typecurve and data plot: In this study, after entering the data in the software FEKETE, F.A.S.T.RTA™, typecurve analysis was done by selecting a match point between data plot and typecurve plot and reading its co-ordinates. The axis of the two plots was kept parallel and data plot was moved over the typecurve plot to get the best match. Certain position of a certain typecurve was selected which fitted the data plot best among several typecurves. From a curve match, the following reservoir parameters were found from the output of the software: GIIP, EUR, permeability and skin (Islam et al., 2016, Help Manual, 2010).

Data set: The basic necessary data set for this study including reservoir, fluid and well properties are listed below. Data consisting of daily production of gas and water and daily flowing well head pressure (FWHP) for the year of 2007 are presented in the appendix section.

Reservoiur Properties
Producing Zone: Upper Gas Sand
Porosity: 30%
Reservoir Temperature: 178 degree F

Fluid properties
Fluid Type: Gas
Fluid used for static calculation: Gas

Properties of Well-02
Well Type: Vertical
Perforation Interval: 4646-4853 ft
Mid-Point Perforation: 4749.5 ft
Tubing Size: 4.5 in
R_w: 0.350 ft
Casing (ID): 7 in
Static Well head Temperature: 75 degree F (avg)
Flowing Well Head Temperature: 95 degree F (avg)

RESULTS AND DISCUSSIONS

Results of the study: Graph of the match through analysis between data plot and Agarwal-Gardner, Blasingame and NPI typecurves are presented in Figures 4-6 for well-02, respectively. To get the optimum value, results from three methods were averaged.

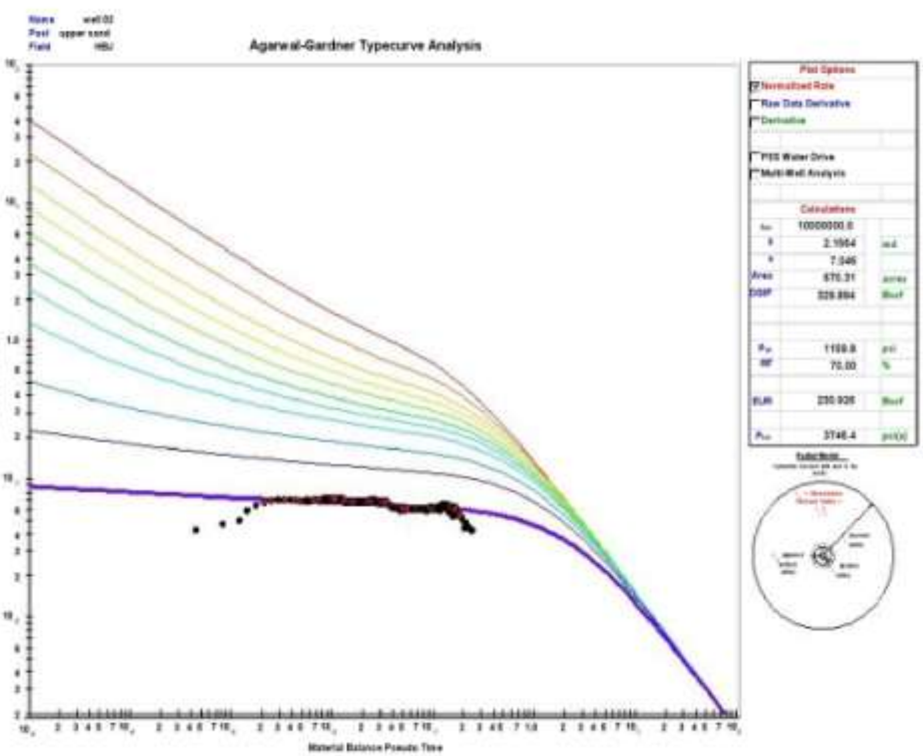

Figure 4: Analysis between data plot for well-02 and Agarwal-Gardner Typecurve plot.

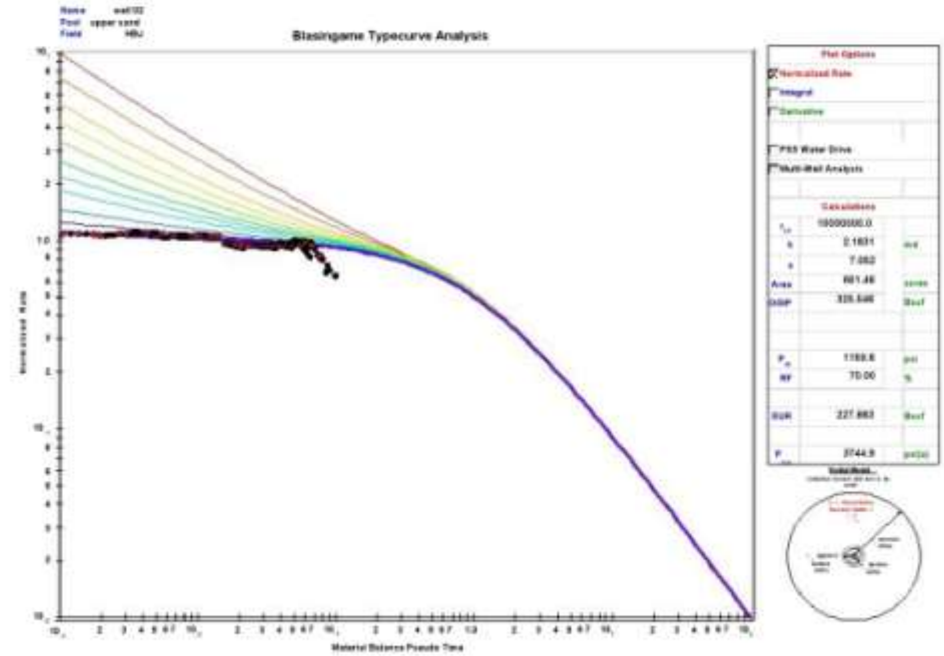

Figure 5: Analysis between data plot for well-02 and Blasingame Typecurve plot.

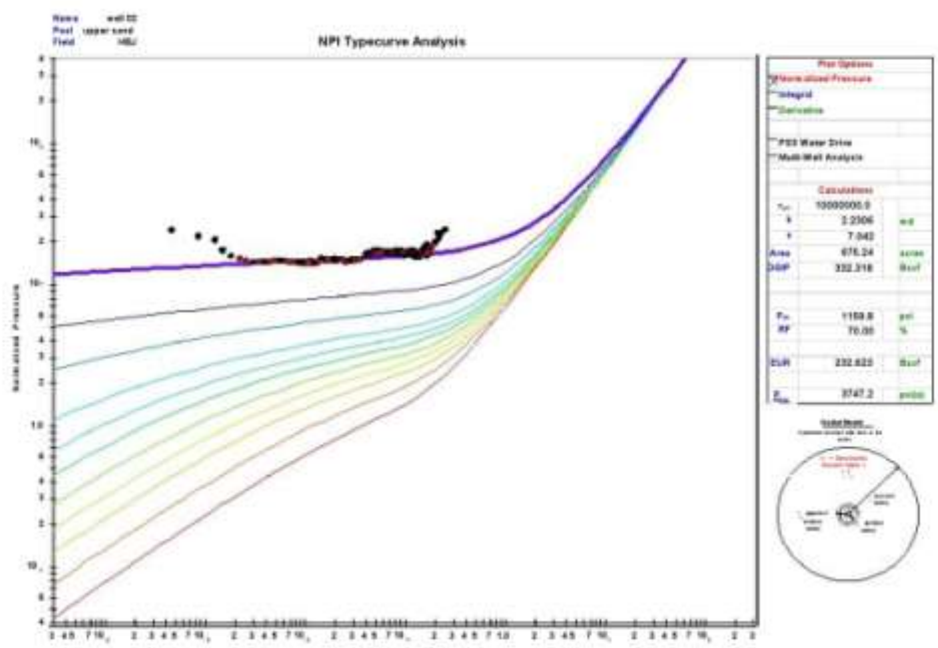

Figure 6: Analysis between data plot for well-02 and NPI Typecurve plot.

GIIP and EUR of Well-02 were obtained in Figures 4-6. Table 1 below shows the findings of GIIP and EUR values of Well-02 to be 329.253 Bcf and 230.477 Bcf, respectively obtained from FEKETE, F.A.S.T.RTA^{TM}. So, only 230.477 Bcf gas from 329.253 Bcf would be recovered from Well-02 by primary recovery.

The value of skin (s) and permeability (k) surrounding the wellbore of the Well-02 were also illustrated in Figures 4-6. From table 1, permeability and skin at the end of the year of 2007 were amounted to 2.1897 md and 7.047 respectively in the wellbore region of Well-02.

Table 1: Results of the study

Analysis Method	GIIP (Bcf)	EUR (Bcf)	Skin	Permeability (md)
Agarwal-Gardner	329.894	230.926	7.046	2.1554
Blasingame	325.548	227.883	7.052	2.1831
Normalized Pressure Integral	332.318	232.623	7.042	2.2306
Average	329.253	230.477	7.047	2.1897

Comparative discussion with other studies : According to Imam B (2013), the average permeability (k) value of UGS of Habiganj gas field was estimated as 2-4 D. In this study the permeability (k) value of UGS of Habiganj gas field was obtained as 2.1897 md surrounding Well-02. So, permeability near the wellbore region was minimized. Here it can also be seen that the skin factor (s) was estimated surrounding the well-02 as 7.047, which is huge in the value. So, suggested by Everdingen V (Hawkins Jr., 1956) permeability near the wellbore region of Well-02 was lowered due to this highly valued skin effect.

CONCLUSIONS

Using three different typecurves from FEKETE, F.A.S.T.RTA^{TM}, this study shows the estimated GIIP and EUR value of Well-02 of Habiganj gas field was found to be 329.253 Bcf and 230.477 Bcf, respectively. It is also illustrated in this study that the Well-02 was greatly damaged which caused too high skin factor as to be 7.047 that altered reservoir permeability from 2-4 darcy to 2.1897 md around Well-02.

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APPENDIX:

Production data of Well-02 for the year of 2007.

Table A. 1: January, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
1/1/2007	14.068	1681	8.461
1/2/2007	15.599	1681	9.36
1/3/2007	16.624	1681	8.297
1/4/2007	19.662	1681	9.851
1/5/2007	21.490	1681	10.75
1/6/2007	22.169	1681	19.978
1/7/2007	22.932	1681	19.462
1/8/2007	23.141	1681	23.098
1/9/2007	23.078	1681	23.098
1/10/2007	23.144	1681	23.098
1/11/2007	23.050	1681	22.997
1/12/2007	22.951	1681	17.248
1/13/2007	22.853	1681	17.173
1/14/2007	23.144	1681	17.324
1/15/2007	23.070	1681	17.324
1/16/2007	23.122	1681	23.098
1/17/2007	23.136	1681	23.098
1/18/2007	23.117	1681	23.098
1/19/2007	23.122	1681	23.098
1/20/2007	23.086	1681	30.03
1/21/2007	23.052	1681	30.03
1/22/2007	23.085	1681	30.03
1/23/2007	23.052	1681	30.03
1/24/2007	23.118	1681	30.03
1/25/2007	23.116	1681	30.03
1/26/2007	23.114	1681	17.324
1/27/2007	23.091	1681	36.962
1/28/2007	23.090	1681	36.962
1/29/2007	23.065	1681	36.962
1/30/2007	23.132	1681	23.098
1/31/2007	23.075	1681	23.098

Table A. 2: February, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
2/1/2007	23.078	1612	19.632
2/2/2007	23.128	1610	19.632
2/3/2007	23.139	1609	23.098
2/4/2007	23.054	1609	23.098
2/5/2007	23.095	1609	30.03
2/6/2007	23.092	1609	30.03
2/7/2007	23.112	1609	30.03
2/8/2007	23.060	1607	30.03
2/9/2007	23.180	1605	28.998
2/10/2007	23.130	1607	28.873
2/11/2007	23.062	1607	34.647
2/12/2007	23.144	1607	34.647
2/13/2007	23.070	1607	23.098
2/14/2007	23.082	1607	23.098
2/15/2007	23.070	1607	34.647
2/16/2007	23.117	1607	23.098
2/17/2007	23.113	1607	23.098
2/18/2007	23.120	1606	23.098
2/19/2007	23.135	1606	27.722
2/20/2007	23.053	1606	26.564
2/21/2007	23.113	1606	26.564
2/22/2007	23.135	1606	26.564
2/23/2007	23.107	1606	36.962
2/24/2007	23.142	1606	46.203
2/25/2007	23.149	1606	46.203
2/26/2007	23.118	1606	46.203
2/27/2007	23.102	1606	46.203
2/28/2007	23.064	1606	46.203

Table A. 3: March, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
3/1/2007	23.119	1601	46.203
3/2/2007	23.137	1599	46.203
3/3/2007	23.150	1596	46.203
3/4/2007	23.132	1593	36.962
3/5/2007	23.111	1591	36.962
3/6/2007	23.104	1590	36.962
3/7/2007	23.113	1589	36.962
3/8/2007	23.118	1589	36.962
3/9/2007	23.084	1589	30.03
3/10/2007	23.119	1589	36.962
3/11/2007	23.118	1589	36.962
3/12/2007	23.119	1589	28.873
3/13/2007	23.075	1589	28.873
3/14/2007	23.102	1589	28.873
3/15/2007	23.050	1589	34.647
3/16/2007	23.130	1589	34.647
3/17/2007	23.149	1589	34.647
3/18/2007	23.056	1589	34.647
3/19/2007	23.148	1589	32.339
3/20/2007	20.998	1611	25.199
3/21/2007	21.101	1616	21.098
3/22/2007	21.125	1617	31.653
3/23/2007	20.955	1618	31.502
3/24/2007	21.016	1619	18.902
3/25/2007	21.044	1620	15.751
3/26/2007	21.043	1620	12.6
3/27/2007	21.073	1619	16.877
3/28/2007	21.100	1619	21.098
3/29/2007	21.077	1619	21.098

Table A. 4: April, 2007

3/30/2007	21.039	1620	20.997
3/31/2007	21.088	1619	10.549

Table A. 6: June, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
5/1/2007	20.961	1617	10.49801
5/2/2007	21.030	1620	10.49801
5/3/2007	21.108	1619	10.54833
5/4/2007	21.036	1621	12.59887
5/5/2007	21.070	1621	6.32774
5/6/2007	21.010	1623	6.30258
5/7/2007	21.116	1622	8.44118
5/8/2007	20.968	1623	7.34672
5/9/2007	21.070	1622	12.66177
5/10/2007	20.983	1623	6.30258
5/11/2007	21.002	1623	6.30258
5/12/2007	21.142	1622	8.44118
5/13/2007	20.999	1623	8.39715
5/14/2007	21.068	1622	8.44118
5/15/2007	21.061	1622	6.32774
5/16/2007	20.963	1623	8.39715
5/17/2007	21.124	1622	8.44118
5/18/2007	20.972	1623	8.39715
5/19/2007	20.991	1623	8.39715
5/20/2007	20.959	1623	9.44758
5/21/2007	21.047	1623	8.39715
5/22/2007	21.008	1623	8.39715
5/23/2007	20.887	1624	8.35941
5/24/2007	20.797	1625	8.32167
5/25/2007	21.068	1622	8.44118
5/26/2007	20.754	1625	6.23968
5/27/2007	20.838	1625	8.32167
5/28/2007	20.730	1626	8.27764
5/29/2007	20.968	1623	8.39715

Table A. 5: May, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
4/1/2007	21.075	1617	14.77
4/2/2007	21.069	1616	13.713
4/3/2007	21.124	1616	13.713
4/4/2007	21.150	1616	14.77
4/5/2007	21.075	1616	14.77
4/6/2007	20.546	1619	10.247
4/7/2007	21.108	1616	10.549
4/8/2007	20.985	1617	10.499
4/9/2007	21.148	1616	12.662
4/10/2007	21.061	1616	12.662
4/11/2007	21.017	1617	12.6
4/12/2007	21.027	1617	15.751
4/13/2007	21.023	1617	15.751
4/14/2007	20.012	1627	14.002
4/15/2007	21.068	1616	12.662
4/16/2007	21.151	1615	12.719
4/17/2007	21.080	1616	12.662
4/18/2007	21.183	1616	12.719
4/19/2007	21.103	1616	14.77
4/20/2007	21.007	1616	8.398
4/21/2007	21.016	1617	10.499
4/22/2007	20.985	1617	10.499
4/23/2007	21.016	1617	10.499
4/24/2007	21.089	1616	10.549
4/25/2007	21.035	1616	10.499
4/26/2007	20.950	1617	12.6
4/27/2007	21.086	1616	15.826
4/28/2007	20.988	1617	10.499
4/29/2007	20.977	1617	10.499
4/30/2007	21.044	1617	10.499

5/30/2007	20.924	1624	10.44769
5/31/2007	20.653	1625	10.34705

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
6/1/2007	20.817	1621	10.39737
6/2/2007	21.078	1616	12.66177
6/3/2007	21.091	1613	10.54833
6/4/2007	21.024	1614	10.49801
6/5/2007	20.975	1614	12.59887
6/6/2007	21.027	1614	12.59887
6/7/2007	20.862	1615	10.44769
6/8/2007	20.942	1615	12.54226
6/9/2007	21.031	1614	11.54844
6/10/2007	21.091	1613	11.60505
6/11/2007	21.061	1613	12.66177
6/12/2007	21.148	1613	12.66177
6/13/2007	21.072	1613	12.66177
6/14/2007	20.610	1618	10.29673
6/15/2007	21.014	1614	11.96987
6/16/2007	20.949	1615	11.91326
6/17/2007	21.042	1614	10.49801
6/18/2007	20.954	1614	11.96987
6/19/2007	20.883	1615	10.44769
6/20/2007	20.689	1616	10.34705
6/21/2007	20.754	1615	16.63705
6/22/2007	20.604	1618	14.41668
6/23/2007	20.768	1616	16.63705
6/24/2007	20.710	1617	14.49216
6/25/2007	20.753	1616	14.56135
6/26/2007	20.526	1619	14.34749
6/27/2007	20.858	1615	16.71882
6/28/2007	20.871	1615	10.44769
6/29/2007	20.656	1617	11.3849
6/30/2007	20.740	1617	11.3849

Table A. 7: July, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
7/1/2007	20.517	1616	11.27168
7/2/2007	20.507	1616	11.27168
7/3/2007	20.482	1616	11.27168
7/4/2007	20.518	1616	10.24641
7/5/2007	20.562	1616	12.35985
7/6/2007	20.477	1615	12.29695
7/7/2007	20.977	1616	12.59887
7/8/2007	20.495	1611	12.29695
7/9/2007	21.041	1616	14.69973
7/10/2007	20.795	1611	14.56135
7/11/2007	21.027	1613	14.69973
7/12/2007	20.970	1611	10.49801
7/13/2007	20.995	1611	10.49801
7/14/2007	21.012	1611	10.49801
7/15/2007	21.128	1611	10.54833
7/16/2007	21.120	1610	10.54833
7/17/2007	21.049	1610	10.49801
7/18/2007	21.025	1611	11.54844
7/19/2007	21.140	1611	11.60505
7/20/2007	21.258	1610	11.71198
7/21/2007	21.282	1609	11.71198
7/22/2007	21.073	1608	11.60505
7/23/2007	21.030	1610	11.54844
7/24/2007	21.036	1611	11.54844
7/25/2007	20.970	1611	10.49801
7/26/2007	21.060	1611	8.44118
7/27/2007	20.963	1610	9.44758
7/28/2007	21.021	1611	9.44758
7/29/2007	20.982	1611	9.44758
7/30/2007	21.054	1611	15.75016
7/31/2007	21.088	1611	15.82564

Table A. 8: August, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
8/1/2007	20.979	1615	14.69973
8/2/2007	21.000	1615	14.69973
8/3/2007	21.090	1614	14.76892
8/4/2007	21.747	1608	15.19035
8/5/2007	21.346	1612	14.9073
8/6/2007	21.010	1615	14.69973
8/7/2007	20.987	1615	14.69973
8/8/2007	21.072	1614	14.76892
8/9/2007	21.044	1615	14.69973
8/10/2007	21.051	1614	14.76892
8/11/2007	21.296	1610	14.9073
8/12/2007	20.991	1615	14.69973
8/13/2007	21.016	1615	14.69973
8/14/2007	20.778	1617	12.47936
8/15/2007	20.740	1618	8.27764
8/16/2007	21.048	1615	10.49801
8/17/2007	21.023	1615	10.49801
8/18/2007	21.014	1615	10.49801
8/19/2007	21.131	1614	10.96976
8/20/2007	21.076	1614	10.96976
8/21/2007	21.212	1613	11.02637
8/22/2007	20.986	1615	10.49801
8/23/2007	20.686	1618	8.27764
8/24/2007	20.946	1616	12.54226
8/25/2007	21.308	1612	12.78128
8/26/2007	21.142	1614	10.54833
8/27/2007	21.173	1613	13.78139
8/28/2007	21.225	1613	12.71838
8/29/2007	21.194	1613	19.07757
8/30/2007	20.897	1616	10.44769
8/31/2007	20.789	1617	10.39737

Table A. 9: September, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
9/1/2007	21.130	1616	10.54833
9/2/2007	21.303	1614	14.9073
9/3/2007	21.139	1616	14.76892
9/4/2007	20.973	1617	8.39715
9/5/2007	21.039	1617	8.39715
9/6/2007	20.972	1617	12.59887
9/7/2007	20.572	1621	8.2399
9/8/2007	21.047	1617	20.99602
9/9/2007	21.043	1617	15.75016
9/10/2007	21.095	1616	16.87607
9/11/2007	21.077	1616	15.82564
9/12/2007	20.991	1617	16.80059
9/13/2007	20.874	1618	15.67468
9/14/2007	20.213	1625	24.24166
9/15/2007	21.014	1617	26.24817
9/16/2007	20.973	1617	27.2986
9/17/2007	20.650	1620	37.25567
9/18/2007	20.653	1620	39.32508
9/19/2007	20.980	1617	41.99833
9/20/2007	21.077	1616	52.74794
9/21/2007	20.804	1619	51.99943
9/22/2007	21.135	1617	52.74794
9/23/2007	20.980	1617	41.99833
9/24/2007	20.996	1617	52.49634
9/25/2007	21.029	1617	57.74849
9/26/2007	20.674	1620	55.88665
9/27/2007	21.053	1614	56.96853
9/28/2007	21.086	1614	56.96853
9/29/2007	21.126	1614	59.07568
9/30/2007	21.055	1616	59.07568

Table A. 10: October, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
10/1/2007	21.024	1616	58.79892
10/2/2007	20.833	1618	58.23911
10/3/2007	21.244	1614	59.35873
10/4/2007	20.970	1616	58.79892
10/5/2007	20.993	1616	60.89349
10/6/2007	21.142	1615	59.07568
10/7/2007	20.977	1616	60.89349
10/8/2007	21.151	1614	61.47846
10/9/2007	21.136	1615	61.18912
10/10/2007	20.981	1616	60.89349
10/11/2007	20.898	1617	62.69872
10/12/2007	18.948	1629	54.80477
10/13/2007	19.394	1626	58.19508
10/14/2007	20.074	1624	56.27663
10/15/2007	17.230	1636	51.59687
10/16/2007	17.481	1635	52.49634
10/17/2007	18.378	1626	55.19475
10/18/2007	21.111	1615	63.29627
10/19/2007	20.962	1616	62.99435
10/20/2007	20.978	1616	62.99435
10/21/2007	20.975	1616	62.99435
10/22/2007	21.020	1616	62.99435
10/23/2007	21.085	1615	63.29627
10/24/2007	20.982	1616	62.99435
10/25/2007	21.118	1615	63.29627
10/26/2007	20.500	1621	51.24463
10/27/2007	20.978	1616	52.49634
10/28/2007	21.033	1616	52.49634
10/29/2007	20.963	1616	52.49634
10/30/2007	20.633	1620	51.49623

10/31/2007	20.970	1616	52.49634

Table A. 11: November, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
11/1/2007	20.903	1609	52.24474
11/2/2007	20.964	1608	52.49634
11/3/2007	20.990	1608	52.49634
11/4/2007	21.010	1608	52.49634
11/5/2007	20.864	1609	52.24474
11/6/2007	21.142	1607	52.74794
11/7/2007	20.998	1608	50.39548
11/8/2007	20.973	1608	49.34505
11/9/2007	20.564	1612	48.40784
11/10/2007	21.035	1608	48.29462
11/11/2007	20.952	1608	48.29462
11/12/2007	21.014	1608	48.29462
11/13/2007	21.049	1608	48.29462
11/14/2007	21.036	1608	48.29462
11/15/2007	19.652	1621	45.30687
11/16/2007	14.768	1629	19.10902
11/17/2007	20.691	1611	32.08529
11/18/2007	20.982	1608	31.50032
11/19/2007	20.926	1609	44.92947
11/20/2007	20.822	1610	44.71561
11/21/2007	21.009	1608	45.14962
11/22/2007	21.145	1607	42.19961
11/23/2007	21.115	1607	42.19961
11/24/2007	20.998	1608	41.99833
11/25/2007	21.261	1605	42.59588
11/26/2007	21.287	1605	42.59588
11/27/2007	21.221	1606	42.3946
11/28/2007	21.191	1606	45.57734
11/29/2007	19.953	1614	41.99833
11/30/2007	20.247	1613	39.58926

Table A. 12: December, 2007

Date (M/D/Y)	Gas (MMScf)	FWHP (psig)	Water (Bbl)
12/1/2007	20.344	1614	39.78425
12/2/2007	20.214	1613	39.58926
12/3/2007	20.126	1614	36.18008
12/4/2007	20.130	1614	36.18008
12/5/2007	20.164	1613	38.37529
12/6/2007	20.213	1613	37.36889
12/7/2007	19.985	1615	36.99778
12/8/2007	20.547	1611	37.92241
12/9/2007	20.209	1613	37.36889
12/10/2007	20.502	1611	37.92241
12/11/2007	20.142	1614	35.17368
12/12/2007	20.345	1612	35.52592
12/13/2007	20.439	1611	35.69575
12/14/2007	20.205	1613	36.3562
12/15/2007	20.528	1610	36.89714
12/16/2007	20.203	1613	36.3562
12/17/2007	20.291	1612	36.53861
12/18/2007	20.187	1613	35.3498
12/19/2007	20.043	1615	34.99756
12/20/2007	18.422	1619	14.7186
12/21/2007	17.791	1621	16.02063
12/22/2007	15.237	1626	13.68075
12/23/2007	17.377	1623	17.39814
12/24/2007	17.314	1624	17.2975
12/25/2007	18.245	1619	18.19697
12/26/2007	19.774	1617	19.80092
12/27/2007	17.495	1625	17.49878
12/28/2007	16.095	1629	16.09611
12/29/2007	14.097	1641	14.10218
12/30/2007	20.310	1612	20.29783

12/31/2007	21.010	1606	41.99833

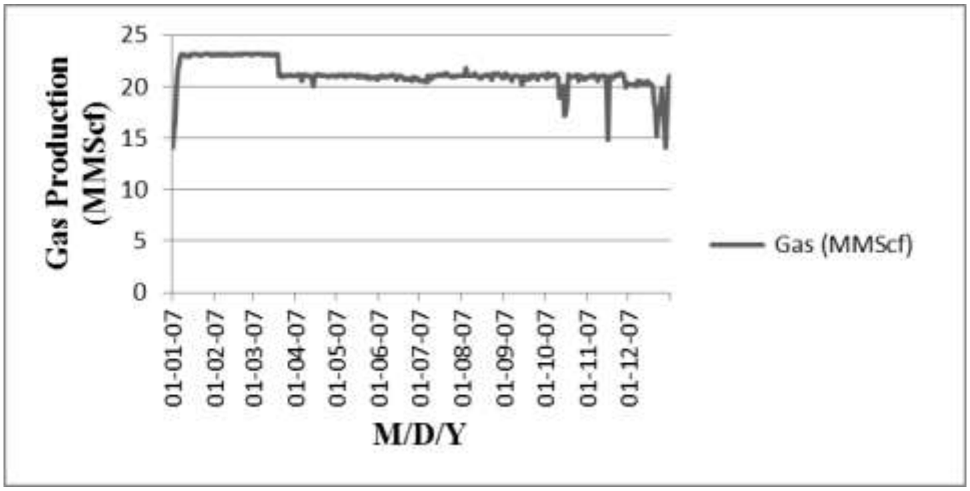

Figure A. 1: Gas production per day of Well-02 for the year of 2007

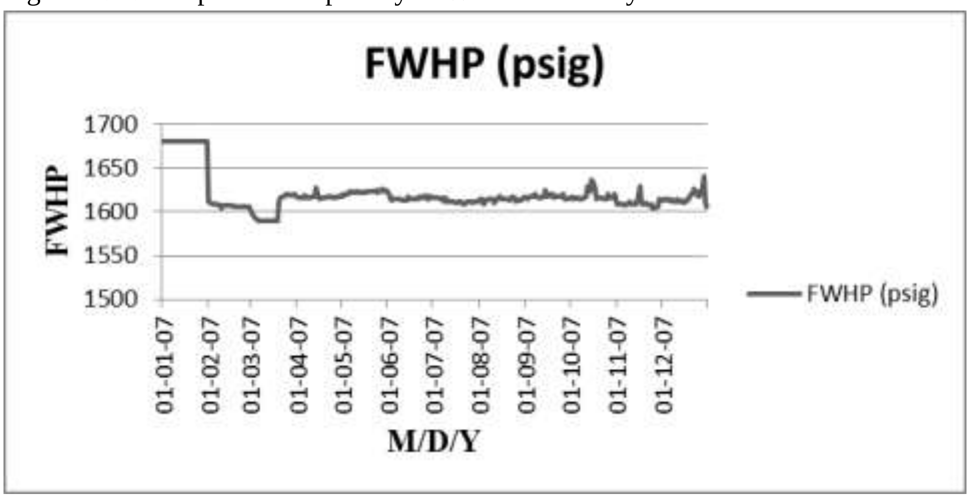

Figure A. 1: Flowing well head pressure (FWHP) per day of Well-02 for the year of 2007

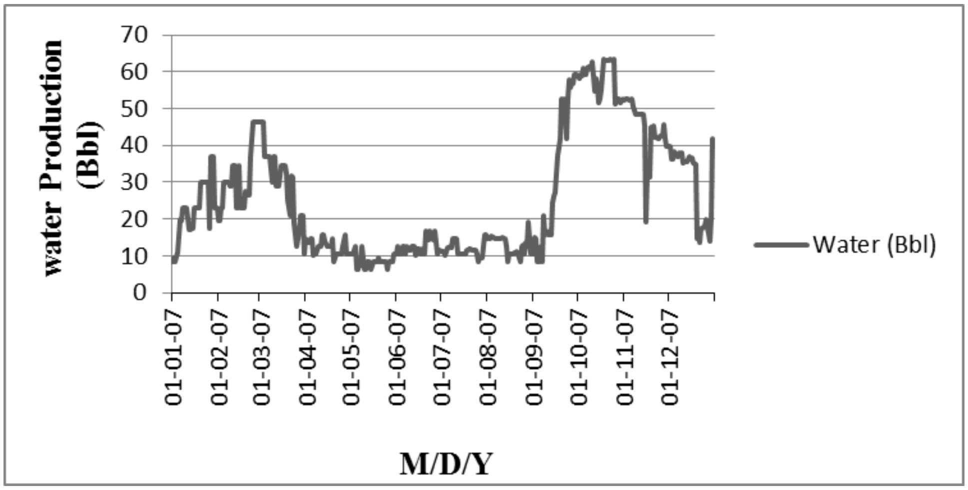

Figure A. 1: Water production per day of Well-02 for the year of 2007

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PVT Properties of Heavy Oil – A Critical Review

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ABSTRACT

Pressure-volume-temperature (PVT) properties of crude is necessary for reservoir engineering calculations and pipe line flow calculations. In order to improve oil field development strategies, an accurate prediction of PVT properties is one of the most important tasks. For several hydrocarbon systems, a large number of PVT correlations have been eshtablished. In most cases, overall accuracy of these correlations are often limited due to compositional variation, impurities, etc. PVT properties of crude oil can also be determined through experimental analyses. However, it is time-consuming and expensive. In this paper the classifying criteria of PVT properties of heavy oil is based on region. This paper reviews the existing PVT models around the world as per their region, addressing the shortcomings of these models, and explores new ways that can be added in this regards. And It will also show better way in future to get PVT properties more accurately with less error.

Keywords: PVT properties; empirical equations; bubble point pressure; oil formation volume factor.

INTRODUCTION

There are mainly two types of energy souces in this earth. One is renewable and another one is non-renewable energy. From the beginning of human life human need energy to survive in this world. Most of the natural energy souces are non-renewable. Those energy souces are around the whole world from begining of man kind. But it is true those enegry souces are changing all the time. They change from one type to another. Those resourses are not last for all time. All non-renwable energies will finish one day. Human are trying to use those resourses in the best way it possible. Those non-renewable energies are-Oil, Gas, Coal etc. Among them crude oil is the most valuable. From very early stage of civilization human are trying to produce crude oil. It is the one of the best source of energy till now. And world economy and growth is mostly depend on oil. Many countries have oil reserve and they are producing

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crude oil. As it is one of the main source of energy. Many researches are on going to make the good use of crude oil. Overall oil production of the world can be divided into several regions. Those are- Middle East, Central and South America, North America, Africa, Euroasia, Asia and Ocenia, Europe. Those region are included both onshore and offshore reserve. U.S. Energy Information Administration published a estimated reserve of crude oil of the world. World oil reserve senario is shown through a pi chart [64].

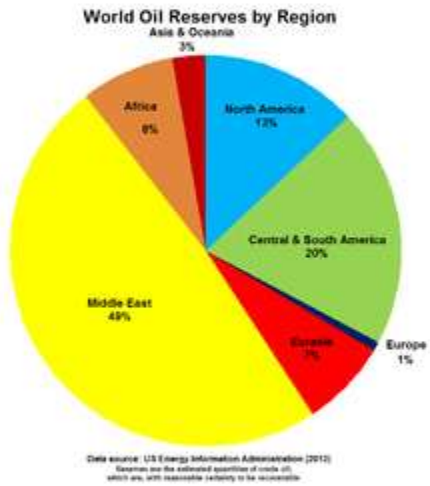

Figure: World Oil Reserves by region [Collected from U.S. EIA]

U.S. Energy Information Administration also published top 10 countries in those region who are producing oil in 2016 as a measure of (bbl/day). Those are- 1.Soudia Arabia, 2.Russia, 3.United States, 4.Iraq, 5.People's Rebublic of China, 6.Iran, 7. Canada, 8.United Arab Emirates, 9.Kuwait, 10.Venezuela [64].

Oil and gas is one of the main resource of energy of the world. But the production process is not always easy. There are lot of challenges in the process of oil productuon. From survey to production and also distribution lot of things to overcome. Many researchers are working to make those process smooth and apply more efficient way of production. In consideration of crude oil production reservoir fluid properties, behavior and PVT properties are most important. Several study is going to regionaly and also overall to find good approach for PVT properties correlationas and analysis.

PVT properties of reservoir fluids are the most important parameters for reservoir engineering calculations, such as inflow performance and well test data analysis, material balance calculation, reserve estimation, formation evaluation for potential field development, fluid flow through porous media, reservoir simulations, production equipment design, and future projects for enhanced oil recovery [1-9]. PVT properties for reservoir oils include oil formation volume factor (OFVF), and bubble point pressure (P_b). OFVF is defined as the ratio of the volume of oil at reservoir (in-situ) conditions to that at stock tank (surface) conditions[10]. P_b is the pressure at which the first bubble of gas comes out of solution in oil reservior at a specific temperature. Both OFVF and P_b are important for determination of recoverable reserves, enhanced oil recovery, oil production capacity, and many other aspects of oil and gas engineering [11-14]. Nonetheless, errors in prediction of the PVT properties are caused by errorneous calculation of other fluid properties [4-5, 11,15-18]. These properties can be estimated either by experimental measurements or by using equations or models. Measurements in the laboratory are often costly,. time consuming. Moreover, test results in most cases are dependent on the quality of the reservoir fluid sample [5,19-20]. If there is no laboratory data, PVT values and other fluid properties are estimated either by empirical correlations or by other modeling approaches [3].

The long list of correlations established for estimating P_b and OFVF since the early 1940's confirms the importance of PVT properties from industrial point of view. Most of the developed correlations, however, have some drawbacks and cannot be used universally due to different properties of fluids in each belt or area [3,18,21]. Almost all correlations have been established based on small range of data points, and very narrow specifications. For that reason, the purpose of this study is to compare novel models and choose which models are more reliable for the prediction of P_b and OFVF of heavy oil systems. In order to obtain rapid solution, software, are used; Matlab, LINGO, Origin and Excel are mainly used for statistical data processing. Emperical correlations are established by monitoring several dependent parameters. Those dependent variables are allied to several disticnt variables. Models remain same as it was eshtablished. At present, use of machine learning algorithms is a common practice in the oil and gas industry. It is mainly used to model infinitesimal properties through learning physical patterns including experimentally measured data [22-26]. At first, these models were found at the universal databank to have significant correlation between input and output variables. After that it is generalized to adequate unseen data [27]. Most of these models have different identical errors at the time of predicting PVT values. There are some models based on different types of algorithms which could be an impressive technique to get more definte model solutions. In order to justify the simulation right we should look over the process with a specific way [25,26,28-30]. This paper reviews existing PVT correlations and models for heavy oil, addresses the problem of those models, and identifies the impact of considering some new models based on different types of software and algorithms to get more accurate PVT properties.

This critical review will help to understand the PVT properties of heavy oil and empirical equations related to observe those properties. It focuses all the PVT correlations for bubble point pressure and oil formation volume factor as per region. Addresses variation of correlation with regional difference. And a clearer approach will provide here to get PVT properties of reservoir crude oils more accurately.

LITERATURE REVIEW

Establishment of PVT correlations to get properties of reservoir fluids has been an important research area for many years. Over the last 70 years, various correlations have been developed in order to predict PVT properties.

Middle East Crude Oil:

Establishment of empirical correlations began in the 1950's, when Katz [31] established a graphical correlation for calculation of OFVF. He considered temperature, oil gravity, specific gravity of gas, solution gas-oil ratio (R_s), and P_b of reservoir for his correlation.

Saleh et al. [36] conducted an extensive study on empirical correlations for Egyptian heavy oils. The test results show that Glaso's [34] correlations for solution gas-oil ratio and Pb work best for the studied data. He concluded that Standing's [32] model was the optimum for OFVF, and Vazquez and Beggs [13] correlation was the finest for oil viscosity estimations

Al-Marhoun [38] took 160 data sets for his correlation. Those data sets were gathered from 69 fields around the Middle Eastern region. Correlations for OFVF and P_b by applying various regression calculations.

Al-Marhoun [42] developed another updated correlation for OFVF using 700 bottom whole samples collected from the region of Middle East and North America.

Al-Fattah and Al-Marhoun [43] evaluated several empirical correlations for OFVF. They worked with 647 experimentally gathered PVT data from published literature. Al-Marhoun's [42] is one of the best correlations for predictive results in terms of accuracy of calculations of OFVF, while Glaso's [34] correlation gave quiet less accurate results compared to the other models. Those observations indicate that none of the studied correlations show good performance at high solution gas-oil ratio and high temperatures.

Elsharkawy et al. [45] tested PVT correlations with 44 samples of Kuwaiti heavy oils. They investigated that Standing's [32] correlation gives the best results for P_b. It gives minimum error of 10.85%. Al-Marhoun's [38] OFVF correlation produced the least error of 2.72% within all studied OFVF correlations.

Mahmood and Al-Marhoun [47] gave an empirical correlation for Pakistan regional heavy oil. They took their datas from 166 different hydrocarbon systems. Al-Marhoun's [38] correlation gave most efficient results for P_b. And it gave a minimum average error of 31.5%. Al-Marhoun's [42] correlation for OFVF also provided the minimum error and average error for this correlation was 1.23%.

Almehaideb [48] evaluated correlations for Pb, oil viscosity and compressibility based on 62 data sets. Those data sets were collected from numerous UAE oil reservoirs. This correlation is quite similar to Omar and Todd's correlation [49]. In their study P_b was presented as a function of OFVF, gravity of oil and gas, Rs and also reservoir temperature.

Al-Shammasi [52] presented a comparative analysis of the P_b correlations proposed by Standing [32], Al-Marhoun [38,42], Vasquez and Beggs [13], Glaso [34], Kartoat modjo and Schmidt [44], Farshad [40], Almehaideb [48], Lasater [33], Macary and El Batanoeney [51], and Petrosky and Farshad [14]. A total of 1243 data samples were used from 13 published papers and various reservoirs of Kuwait.

Al-Marhoun [53] evaluated Standing [32], Vasquez and Beggs [13] and Al-Marhoun [38, 42] bubble point correlations using 530 data samples taken from the Middle East reservoirs. He found that Al-Marhoun [38, 42] correlation for P_b has the minimum average error of 7.81%. Also OFVF at bubble point pressure has the least mean absolute relative error of 0.72.

Ahmed et al. [57] used 35 bottom hole fluid samples from different locations in Egypt and provided guidelines for each PVT Property and the reservoir input data for black oils. They investigated correlations from Vasquez and Begg's [13], Al-Marhoun's [47], Petrosky and Farshad's [14], Laster [33], and Standing's [32]. It was summarized that the Lasater correlation provided the best result for P_b calculations with an average error of 7.9%.

Hemmati and Kharrat [55] used 287 laboratory PVT analyses from 30 Iranian oilfields to develop new correlations. All those used data sets were from black crude oil. The correlations used in their paper are Standing [32], Glaso [34], Al-Marhoun [47], Hanafy [50], and Petrosky [14]. They concluded that the minimum Average Relative Error (ARE) was 0.06% by Petrosky's correlation, and the maximum ARE was 8.77% by Hanafy's correlation.

Mansour [58] modified Soave–Redlich–Kowng equation of state to be applicable for Egyptian crude oils. He used data of 43 black oil samples representing active oil producing areas of Egypt. The equation enables to predict the OFVF and other PVT properties of black oil with average relative errors ranging from 0.01% to 10.713%.

Shokrollahi et al. [62] focused on accurate determination of PVT properties of reservoir oil using committee machine intelligent system (CMIS). They used Iranian crude oil as their sample data. Overall comparisons were also executed between a variety of PVT prediction models and committee machine intelligent system model developed in this study. Also applied statistical method to detect and identify some predictable output points from the gathered data system.

Naseri et al. [63] used Iranian oil PVT data. They established new correlations to get saturation pressure and oil formation volume factor at bubble point pressure. These correlations were validated by comparing results of these correlations with experimental data. Checking the results provides that results for Iranian oil properties in this work are in same relation with experimental data respect to other correlations.

In Table-1a and Table-1b presents all the PVT correlations based on Middle East crude oil. It shows PVT correlations for OFVF and Bubble point pressure.

Table-1a shows the available correlations of oil formation volume factor (B_o) for Middle East crude.

Authors	Year	Samples Origin (region)	No. of Data points	Correlation
Al-Marhoun	1988	Middle East	160	$B_o = a_1 + a_2 * (T + 460) + a_3 * M + a_4 * M^2$ $M = R_s^{a_5} * \gamma_g^{a_6} * \gamma_o^{a_7}$ a_1=0.497069, a_2=0.862963E-03, a_3=0.18259E-02, a_4=0.318099E-05, a_5=0.74239, a_6=0.323294, a_7=-1.20204
Dokla & Osman	1991	U.A.E (Middle East)	51	Al-Marhoun (1988), Recalculated $B_o = a_1 + a_2 * (T + 460) + a_3 * M + a_4 * M^2$ $M = R_s^{a_5} * \gamma_g^{a_6} * \gamma_o^{a_7}$ a_1=0.0431935, a_2=0.156667E-02, a_3=0.139775E-02, a_4=0.380525E-05, a_5=0.773572, a_6=0.404020, a_7=-0.882605
Almehaideb	1997	UAE (Middle East	62	$B_o = a_1 + a_2 * \frac{R_s * T}{\gamma_o^2}$ a_1=1.122018, a_2=1.41E-06
Bolondarzadeh, Hashemi & Soltani	2006	Iran (Middle East)	166	$B_o = a_1 + a_2 * \Big((a_3 * R_s^{a_4}) *$ $a5*\gamma ga6a7*APIa8+a9*Ta10*Pba11$ a_1= 0.930471, a_2= -0.973481, a_3= 0.080264, a_4= 1.140597, a_5= -0.01037, a_6= 0.146902, a_7= 5.59574, a_8= -0.05807 a_9= -0.02428, a_{10}= 8.291315, a_{11}= 0.140489
Mehran, Movagharnejad and Didanloo	2006	Iran (Middle East)	387	Glaso (1980), Recalculated constants $B_o = 1 + 10^A$ $A = a_1 + a_2 * log(B_{ob}^*) + a_3 * \log(B_{ob}^*)^2$ $B_{ob}^* = R_s * \left(\frac{\gamma_g}{\gamma_o}\right)^{a_4} + a_5 * T$ a_1= -4.7486, a_2= 1.587, a_3= -0.0495,

				a_4= 0.4211, a_5= 2.035
Hemmati & Kharrat	2007	Iran (Middle East)	287	Glaso (1980), Recalculated constants $B_o = 1 + 10^{(a_1+a_2*\log(M)+a_3*(\log(M))^2)}$ $M = R_s * \left(\left(\frac{\gamma_g}{\gamma_o}\right)^{a_4}\right) + a_5 * T$ a_1= -4.6862, a_2= 1.5959, a_3= -0.0566, a_4= 0.5946, a_5= 1.7439
B. Moradi, Malekzadeh, Amin Shoushtari, Awang & P. Moradi	2013	Middle East	581	$B_o = a_1 + a_2 * API^{a_3} * \gamma_g^{a_4} * \left(R_s * \left(\frac{\gamma_g}{\gamma_o}\right)^{a_5} + a_6 * T\right)^{a_7}$ a_1= 0.965278, a_2= 0.000100512, a_3= 0.0672605, a_4= -0.465317, a_5= 0.643141, a_6= 2.27448, a_7= 1.15416

Table-1b shows the available correlations of Bubble Point Pressure (P_b) for Middle East crude.

Authors	**Year**	**Samples Origin (region)**	**No. of Data points**	**Correlation**
Al-Marhoun	1985	Saudi Arabia (Middle East)	647	$P_b = -64.13891 + 7.02362 \times 10^{-3} * X - 2.278475 \times 10^{-9} * X^2$ $X = R_s^{0..722569} \frac{\gamma_o{}^{3.046590}}{\gamma_g{}^{1.879109}} (T + 459.671.302347$
Al-Marhoun	1988	Saudi Arabia (Middle East)	160	$P_b = \frac{5.38088 \times 10^{-3} * R_s^{0.715082}\ \gamma_o{}^{3.1437}}{\gamma_g{}^{1.87784}} (T + 459.671.302347$
Al-Najjar, Al-Soof and Al-Khalisy	1988	Iraq (Middle East)	145	$P_b = a_1 \left(\frac{R_s}{\gamma_g}\right)^{a_2} e^{[a_3 \frac{\gamma_{API}}{(T+459.67)}]}$ If γ_{API}<=30 a_1= 7.920, a_2= 1.025, a_3= -24.244 If γ_{API}>30 a_1= 30.910, a_2= 0.816, a_3= -19.748
Dokla and Osman	1990	U.A.E. (Middle East)	105	$P_b = \frac{8.363.86 * R_s^{0.724047}\ \gamma_o{}^{0.107991}}{\gamma_g{}^{1.01049}\ (T+459.67)^{0.952584}}$

Kartoatmodjo and Schmidt	1991	Indonesia, North America, Middle East, Latin America	1567	$P_b = \left[\frac{R_s}{A\gamma_{gc}^{B}\, 10^{\left[C\frac{\gamma_{API}}{(T+459.67)}\right]}}\right]^{D}$ If γ_{API}<=30 A= 0.05958, B= 0.7972, C= 13.1405, D=0.998602 If γ_{API}>30 A= 0.03150, B= 0.7587, C= 11.289, D=0.914328
Almehaideb	1997	U.A.E. (Middle East)	62	$P_b = -620.592 + 6.23087 R_s \frac{\gamma_{API}}{\gamma_g B_o^{1.38559}} + 2.89868T$
Elsharkawy	1997	Kuwait (Middle East)	44	For γ_{API} >30 $P_b = \left[\frac{R_s}{\gamma_g^{0.0.4439}\gamma_{API}^{1.1394}\, 10^{[8.392\times 10-4*T-2.188]}}\right]^{1.0551194}$ For γ_{API} <=30 $P_b = \left[\frac{R_s}{\gamma_g\, 10^{\left[0.4636\frac{\gamma_{API}}{(T-1.2179)}\right]}}\right]^{0.847271}$

North and Latin America Crude Oil:

Standing's [32] graphical correlations for OFVF, P_b and total OFVF, were developed with the help of experiments performed on 105 samples from 22 different crude oil fields around California. The parameters considered in the correlations are reservoir temperature, R_s, oil and gas gravities. Most of the non-linear regression correlations were generally based on these four parameters.

Lasater [33] established a correlation based on 158 samples. These crude oil samples were collected from 137 fields within Canada, US, and South America.

Glaso [34] used data from 45 oil samples collected from the North Sea area. Both graphical and regression models for OFVF and P_b were proposed with average errors of 20.43% for the Pb and 1.28% for OFVF.

Ostermann and Owolabi [12] presented PVT correlations based on sample data sets from several Alaskan oil fields. The experimental outcomes recommended Glaso's [34] correlation for saturation pressure computing and Standing's [32] correlation for OFVF based on errors for Alaska region oil specimens. They also figured out the presence of several non-hydrocarbon elements such as nitrogen and carbon dioxide on assumption of P_b. However, no nitrogen improvement is required for OFVF determination.

Sutton and Farshad [40] used calculated PVT correlations for Gulf of Mexico heavy oil data. The test results showed that Glaso's [34] eshtablished correlation for P_b, OFVF, and solution gas-oil ratio works best for the studied data. They also showed that Vazquez and Beggs [13] correlations gives much better performance than Glaso's [34] correlation for gas-oil ratios above 1400 SCF/STB and P_b greater than 7,000 psia. It gave an average plenary error of 25.34% and 27.05% for P_b and solution gas-oil ratio, respectively, for Glaso's [34] correlation models.

Petrosky and Farshad [14] established empirical correlations for heavy oil from the Gulf of Mexico area. They used over 90 PVT data samples for P_b, under-saturated isothermal oil compressibility, OFVF and R_s. They established correlations for P_b and OFVF with minimum error of 3.28% and 0.64%, respectively.

In Table-2a and Table-2b presents all the PVT correlations based on Middle East crude oil. It shows PVT correlations for OFVF and Bubble point pressure.

Table-2a shows the available correlations of oil formation volume factor (B_o) for North and Latin American crude.

Authors	Year	Samples Origin (region)	No. of Data points	Correlation
Standing	1947	California (North America)	105	$B_o = a_1 + a_2 * \left(R_s * \left(\frac{\gamma_g}{\gamma_o}\right)^{a_3} + a_4 * T a5\right.$ a_1=0.972, a_2=1.472E-4, a_3=0.5, a_4=1.25, a_5=1.175
Glaso	1980	North Sea (North America)	45	$B_o = 1 + 10^{\left(a_1 + a_2 * \log\left(B_{ob}^*\right) + a_3 * \left(\log\left(B_{ob}^*\right)\right)^2\right)}$ $B_{ob}^* = R_s * \left(\frac{\gamma_g}{\gamma_o}\right) + a_5 * T$ a_1=-6.58511, a_2=2.91329, a_3=-0.27683, a_4=0.526, a_5=0.968
Petrosky & Farshad	1993	Gulf of Mexico, Texas, Louisiana (North America)	81	Standing (1947), Recalculated constants $B_o = a_1 + a_2 * \left(R_s^{a_3} * \left(\frac{\gamma_g{}^{a_4}}{\gamma_o{}^{a_5}}\right)^1 + a_6 * T a7a8\right.$ a_1=1.0113, a_2=7.2046E-05, a_3=0.3738, a_4=0.2914, a_5=0.6265, a_6=0.24626, a_7=0.5371, a_8=3.0936

Farshad, Leblance, Garber & Osorio	1996	Colombia (LatinAmerica)	98	Glaso (1980), Recalculated constants $B_o = 1 + 10^{(a_1 + a_2 * log\,(M) + a_3 * (log\,(M))^2)}$ $M = R_s^{a_4} * \gamma_g^{a_5} * \gamma_o^{a_6} + a_7 * T$ For single stage separation: a_1= -2.6541, a_2=0.5576, a_3= 0.3311, a_4= 0.5956, a_5= 0.2369, a_6= -1.3282, a_7= 0.0976 For two stage separation: a_1= -4.7477, a_2= 2.1197, a_3= -0.1223, a_4= 0.7584, a_5= -0.10436, a_6= -1.017, a_7= 0.33127
Dindoruk & Christman	2001	Gulf of Mexico (North America)	99	$B_o = a_{11} + a_{12} * A + a_{13} * A^2 + a_{14} * (T - 60) * \frac{API}{\gamma_g}$ a_{11}=9.871766E-01, a_{12}=7.865146E-04, a_{13}=2.689173E-06, a_{14}=1.100001E-05

Table-2b shows the available correlations of Bubble Point Pressure (P_b) for North and Latin American crude.

Authors	Year	Samples Origin (region)	No. of Data points	Correlation
Standing	1947	California (North America)	105	$P_b = 18.2[\left(\frac{R_s}{\gamma_g}\right)^{0.83} * 10^{0.00091T - 0.0125\gamma_{API}} - 1.4$
Lasater	1958	Canada west and Midcontinent U.S (North America)	158	$P_b = \frac{P_f(T+495.67)}{\gamma_g}$ $P_f = e^{\left(\frac{x_g - 0.15649}{0.33705}\right)} - 0.59162$
Glaso	1980	North Sea (North America)	45	Nonvolatile Oils $X = \left(\frac{R_s}{\gamma_g}\right)^{0.816} \left(\frac{T^{0.172}}{\gamma_{API}^{0.989}}\right)$ Volatile Oils $X = \left(\frac{R_s}{\gamma_g}\right)^{0.816} \left(\frac{T^{0.130}}{\gamma_{API}^{0.989}}\right)$ $P_b = 1.7669 + 1.7447 logX -$

				$0.30218(logX)^2$
Owolabi	1984	Alaska and Cook Inlet (North America)	225	$P_b = 55.0 + 0.8643[\left(\frac{R_s}{\gamma_g}\right)^{1.255} \frac{T^{0.172}}{\gamma_{API}^{0.178}}]$
Kartoatmodjo and Schmidt	1991	Indonesia, North America, Middle East, Latin America	1567	$P_b = \left[\frac{R_s}{A\gamma_{gc}^{B}10^{\left[C\frac{\gamma_{API}}{(T+459.67)}\right]}}\right]^D$ If γ_{API}<=30 A= 0.05958, B= 0.7972, C= 13.1405, D=0.998602 If γ_{API}>30 A= 0.03150, B= 0.7587, C= 11.289, D=0.914328
Farshad	1992	Columbia (Latin America)	90	$P_b =$ $64.14\left[\frac{R_s^{0.6343}}{\gamma_g{}^{1.15036} * 10^{7.97\times10-3\gamma_{API}-3.35\times10-4T}}\right. -$ 7.2818
De Ghetto	1994	Mediterranean Basin, Africa, Persian Gulf and North Sea	195	For Extra Heavy oil (API<=10) $P_b = 10.7025[\left(\frac{R_s}{\gamma_g}\right)^{0.8986} *$ $10^{(0.00091T-0.0125\gamma_{API})}$ For Heavy oil (10<API<=22.3) $P_b = \left[\frac{56.434R_s}{\gamma_{gc}10^{\left[10.9267\frac{\gamma_{API}}{(T+459.67)}\right]}}\right]^{0.8294}$ For Medium oil (22.3<API<=31.1) $P_b = \left[\frac{R_s}{0.10084\gamma_{gc}10^{\left[7.4576\frac{\gamma_{API}}{(T+459.67)}\right]}}\right]^{1.0134}$ For Light oil (API>31.1) $P_b = \left[\frac{R_s}{0.0.1347\gamma_{gc}10^{\left[12.153\frac{\gamma_{API}}{(T+459.67)}\right]}}\right]^{0.8669}$
Dindoruk and Christman	2001	Gulf of Mexico (North America)	107	$P_b = 1.86997927\left(\frac{R_s^{1.221486524}10^A}{\gamma_g{}^{1.370508349}}\right. +$ 0.011688308

Africa, Asia and Worldwide Crude Oil:

Vazquez and Beggs [13] developed correlations in order to estimate R_s, oil viscosity, and OFVF under saturation conditions. It was an experimental study of 600 samples collected from all over the world. The oil mixtures were classified into two groups: one is above 30 ^{0}API and another one is below 30 ^{0}API gravity. Correlations for both P_b and OFVF were presented.

Obomanu and Okpobori [37] suggested a correlation for OFVF, Pb and R_s. For this correlation they took data samples from 100 Nigerian oil reservoirs.

Labedi [39] designed new correlations for P_b, density and fluid compressibility for African heavy oils.

McCain [41] published a PVT correlation which is dependent on large datasets collected from worldwide. It is considered one of the best correlations in this field of study for P_b, R_s and OFVF.

Kartoat Modjo and Schmidt [44] used heavy oil specimens collected from around the world. They established new correlations for different PVT properties. For their correlation, they took Standing's [32] and Vazquez and Begg's [13] models as standard for OFVF and Pb respectively.

Ghetto et al. [46] continued reliability analysis for the most common empirical correlations based on 195 datasets from all over the world, including a huge range of hydrocarbon mixtures. The evaluated results show that Standing's [32] correlation gives error for Pb calculations with a minimum average error of 16.1% which is the least one. For the OFVF, Vazquez and Beggs' [13] correlation was one of the best with minimum average error of less than 3%. They also reevaluated new coefficients for Standing's [32] correlation and found some developments in Pb calculations.

Ikiensikimama et al. [54] published a study of fifteen correlations using 237 datasets for Pb to validate their applicability to Niger delta heavy oil. It was concluded that Lasater [33] empirical correlation is one of the best with maximum error of 10.3 and correlation coefficient of 0.943. Eighteen correlations for OFVF at bubble point using 237 datasets were also studied in the study [54]. It was concluded that, Glaso's [34] empirical correlation is the best among all published correlations for OFVF at bubble point.
Hosein and Singh [56] performed a comparative study of the correlations by Standing's [32], Vasquez and Begg's [13], Glaso's [34], Al-Marhoun's [47], and Petrosky-Farshad's [14] using data from 12 laboratory PVT reports. It was concluded that the minimum average absolute deviation (AAD) was 4.2% by Al-Marhoun correlations, and the maximum AAD was 18.8% by Glaso correlation for P_b. As for OFVF, they found the minimum average absolute error (AAE) at 0.9% by Petrosky-Farshad's correlations, and the maximum average absolute error (AAE) at 2.7% by Al-Marhoun's correlation.

Omole et al. [59] established a new approach for PVT properties. Their neural network model was developed to predict the crude oil viscosity using 32 data sets collected from the Niger Delta Region of Nigeria. About 17 data sets were used to train the model, 10 sets were used to test the accuracy of the model, and remaining 5sets to validate the relationships established during the training process. They found that the back propagation neural network model (BPNN) were better than the empirical correlations in terms of average absolute relative error and correlation coefficient.

Bello et al. [61] presented a lack of formal analysis process to predict PVT properties for Nigeria delta crude oil. They used five correlations for OFVF and P_b for large number of niger delta data bank. They showed model predictions can be varied upto 42% and 56%. They suggested to setup new model urgently.

Gharbi et al. [60] presented a universal neural-network-based model for predicting PVT properties of crude oil samples obtained from all over the world. In their network datasets were trained, contains 5200 experimentally obtained PVT data of different crude oil and gas mixtures from all over the world. A comparison between the results predicted by the neural-network models and also predicted by other correlations is presented for these crude oil samples. This study shows that artificial neural networks provide excellent reliable tool for estimating any crude oil PVT properties better than available empirical correlations.

From the very beginning till today all the correlations of oil formation volume factor (B_o) and bubble point pressure (P_b) are listed respectively in Tables1 and 2. Those tables are classified on the basis of according year, number of data sets and most importantly origin of the samples.

In Table-3a and Table-3b presents all the PVT correlations based on Middle East crude oil. It shows PVT correlations for OFVF and Bubble point pressure.

Table-3a shows the available correlations of oil formation volume factor (B_o) for African, Asian and Worldwide crude.

Authors	**Year**	**Samples Origin (region)**	**No. of Data points**	**Correlation**
Vazquez & Beggs	1980	World Wide	6000	$B_o = 1 + a_1 * R_s + a_2 * \left(\frac{API}{\gamma_{gs}}\right) * (T-60) + a_3 * R_s * \left(\frac{API}{\gamma_{gs}}\right) * (T-60)$ If API <=30 a_1=4.677E-04, a_2=1.751E-05, a_3=-1.811E-08 If API >30 a_1=4.670E-04, a_2=1.100E-05, a_3=1.337E-09

Kartoatmodjo & Schmidt	1991	World wide	5392	Standing (1947), New calculated $B_o = a_1 + a_2 * \left(R_s^{a_3} * \gamma_{g100}^{a_4} *\right.$ $\gamma oa5+a6*T+460a7$ a_1=0.98496, a_2=0.0001, a_3=0.755, a_4=0.25, a_5=-1.5, a_6=0.45, a_7=1.5
Al-Marhoun	1992	World Wide	4005	$B_o = 1 + a_1 * R_s + a_2 * R_s\left(\frac{\gamma_g}{\gamma_o}\right) + a_3 * R_s * (1-\gamma_o) * (T-60) + a_4 * (T-60)$ a_1=0.177342E-03, a_2=0.220163E-3, a_3=4.292580E-06, a_4=0.528707E-03

Table-3b shows the available correlations of Bubble Point Pressure (P_b) for African, Asian and Worldwide crude.

Authors	**Year**	**Samples Origin (region)**	**No. of Data points**	**Correlation**
Vazquez & Beggs	1976	World Wide	6000	$P_b = \left[A\left(\frac{R_s}{\gamma_{gc}}\right)10^{\left(\frac{B\gamma_{API}}{T+459.67}\right)}\right]^C$ If γ_{API}<=30 A= 27.64, B= -11.172, C= 0.9143 If γ_{API}>30 A= 56.06, B= -10.393, C= 0.8425
Labedi	1982	Libya, Nigeria and Angola (Africa)	145	$P_b = \frac{6.0001}{\gamma_{gsp}}\left[\frac{R_s^{0.6714}\left(\frac{T}{\gamma_{API}}\right)^{0.7097} * T_{sp}^{0.08929}}{10^{7.995\times10^{-5} * R_s}}\right]$
Obomanu and Okpobiri	1987	Nigeria (Africa)	100	$P_b = \left(\frac{R_s T^{0.497}\, 10^{0.811}}{1.01136371\, \gamma_g{}^{2.15} \gamma_{API}^{1.27}}\right)^{1.0787}$

Kartoatmodjo and Schmidt	1991	Indonesia, North America, Middle East, Latin America	1567	$P_b = \left[\frac{R_s}{A\gamma_{gc}^{B}10^{\left[C\frac{\gamma_{API}}{(T+459.67)}\right]}}\right]^D$ If γ_{API}<=30 A= 0.05958, B= 0.7972, C= 13.1405, D=0.998602 If γ_{API}>30 A= 0.03150, B= 0.7587, C= 11.289, D=0.914328
Omar and Todd	1993	Malaysia (Asia)	58	Standing (1947), Recalculated constants $P_b = 18.2[\left(\frac{R_s}{\gamma_g}\right)^X * 10^{0.00091T-0.0125\gamma_{API}} - 1.4$
Hasan	1993	Indonesia (Asia)	47	Standing (1947), Recalculated constants $P_b = 18.2[\left(\frac{R_s}{\gamma_g}\right)^{0.83} * 10^{0.00091T-0.0125\gamma_{API}} + 2.2$
De Ghetto	1994	Mediterranean Basin, Africa, Persian Gulf and North Sea	195	For Extra Heavy oil (API<=10) $P_b = 10.7025[\left(\frac{R_s}{\gamma_g}\right)^{0.8986} * 10^{(0.00091T-0.0125\gamma_{API})}$ For Heavy oil (10<API<=22.3) $P_b = \left[\frac{56.434R_s}{\gamma_{gc}10^{\left[10.9267\frac{\gamma_{API}}{(T+459.67)}\right]}}\right]^{0.8294}$ For Medium oil (22.3<API<=31.1) $P_b = \left[\frac{R_s}{0.10084\gamma_{gc}10^{\left[7.4576\frac{\gamma_{API}}{(T+459.67)}\right]}}\right]^{1.0134}$ For Light oil (API>31.1) $P_b = \left[\frac{R_s}{0.0.1347\gamma_{gc}10^{\left[12.153\frac{\gamma_{API}}{(T+459.67)}\right]}}\right]^{0.8669}$
Al-Shammasi	1999	World Wide	1243	$P_b = \frac{\gamma_o^{5.527215}\left[\gamma_g R_s(T+459.67)\right]^{0.783716}}{e^{(1.841408\gamma_g\gamma_o)}}$

OVERVIEW OF CORRELATIONS

Both P_b and B_o is very important parameters in term of PVT properties. Many of these correlations are established considering regional data and parameters. Those region are- Middle East, Central and South America, North America, Africa, Euroasia, Asia and Ocenia, Europe. If we see most of the correlation focused on mainly Middle East and North America. Few developed regarding African region. Asian and Europian regional are not considered most of the cases.

Middle East has largest reserve of crude among the world. But their research about crude oil characterization is later then other part of the world. Al-Marhoun [38] is the first who work on PVT properties in Middle East. He provides model both for OFVF and $P_{b.}$ Though his model didn't cover all crude sample of Middle East, still he is the pioneer in Middle East region. All the researches till today are mostly depended on his model. Some other researchers in Middle East flow Glaso's [34] model both for OFVF and P_b. They recalculated constants of Glaso's [34] model and provide more accurate model for Middle East region. In recent times some researchers applied Artificial Neural Network system to develop more accurate PVT correlations with less error.

After Middle East North and Latin America have maximum crude oil reserve. They started their research about 70 years back. Standing's correlation for both oil formation volume factor and bubble point pressure was the first established correlation. After that many correlations for PVT properties flow this correlation. Some researchers tried to change the constant use by Standing to get more accurate result. Glaso's correlation was also based on North American crude. This correlation also used as a base for several new research on PVT properties. Some researchers around the world follow these two models as base for further development.

Few researhers established their correlations based on African crude. They focused specially on Nigerian delta. Rather than these three region very small amount of research done based on Asian and Europian region crude. But some researchers developed correlations beyond any regional crude. They took their samples around the world. Vazquez & Beggs [13] considered World Wide scenario for both P_b and $B_{o.}$ But he considered very less number of data sets. Though he didn't take a lot of samples till it was the first approach of establishing correlations regarding worldwide data. Al-Mahroun [42] also considered World wide data sets for only B_o. Al-Shammasi [52] considered Worldwide scenario for $P_{b.}$ Now many researchers are focusing to come with new correlation beyond region. They are taking more samples and also from around the world.

For all of this correlation they used some statistical functions to justify and make difference from every model. Those statistical calculations really help to identify which model is more efficient. Those statistical parameters are:

1. AM (Arithmetic Mean
2. SD (Standard Deviation)
3. RE (Relative Error)
4. ARE (Absolute Relative Error)
5. *ARE (Average Relative Error)
6. AARE (Average Absolute Relative Error)

Among all the correlations Standind's [32], Glaso [32] and Al-Mahroun [38] correlations are more efficeient for oil formation volume factor (B_o). Many reserchers take those three model as the reference to develop new corretions with more regional data. Many researchers also develop some new correlations considering those three correlation but varying constants. They got more efficient models for B_o.

For bubble point pressure Standind's [32] and Vazquez & Beggs [13] correlations are more exact. Vazquez & Beggs [13] also used World wide data set that makes his correlations more distinct from others. Many reserchers take those two model as the reference to develop new corretions with more regional data. Some researchers also develop some new correlations considering those three correlation but varying constants. They got more efficient models for P_b.

FUTURE RESEARCH SCOPE

World depend on petroleum industry for energy resouces. In petroleum industry for oil and gas production ; there are some important issues. PVT properties is the most important one. For this reason many researchers are focusing their research on this topic. In last 70 years there are a lot of work went to develop accurate correlation. Those primary researchers showed a path to solve problem regarding pvt properties. Most of those correlations are regional based. But now many new researchers focusing on developing correlation that will work beyond regional barries. There are lot of scopes to develop a new correlation that will satisfy for all region. In order to predict pvt properties Artificial Intelligence (AI) are used by some researchers. Many new researchers focusing AI to make more accurate PVT correlation that will applicable for all regions.

CONCLUSION

The literature to date has yet to conceptualize artificial intelligence in a comprehensive way with respect to PVT properties. Distinct search of heavy oil PVT properties puts up an indisputable and exceptional role in reservoir calculation, both quantitative and qualitativeassumption of reservoir fluid production, optimum oil recovery plans. Preliminary goal of this research was to have an overview of all PVT correlations and discuss how can develop more efficient PVT correlations for crude oil. In this process PVT properties were determined as Bo and Pb. This review gives a clear view of limitions for pvt correlations. Most of them are based on regional consideration. All most all B_o and P_b correlations developed for certain region. Those are not justifying for world wide fields. But lot of research is going on to develop more efficient correlation. Some new techniques and approach are also applying like AI and CIMS network. From previous correlations and adding new techniques may be a comprehensive well supported correlation for both P_b and B_o can be developed sooner. And hopefully those correlations will help ECLIPSE™, and CMG to develop their efficiency and more fruitful results while decreasing the uneasiness related in reservoir simulation and modeling.

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NOMENCLATURE

OFVF	Oil formation volume factor
B_o	OFVF at P_b
P_b	Bubble point pressure, psi
GOR	Gas-oil ration, SCF/STB
SCF	Standard cubic feet
STB	Stoke tank barrel
AI	Artificial intelligence
CMIS	Committee machine intelligent system
RE	Relative error
ARE	Average relative error
*ARE	Absolute relative error
AARE	Average absolute relative error

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Quantifying Expected Recovery and Production Forecasting of Kailashtila Gas Field (Well-5) Using Rate Transient Analysis

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ABSTRACT

Production decline analysis has been an important technique for reservoir properties estimation, controlled production operation and finding most efficient production technique. In conventional well testing, we have to shut in the well to analyze the well and stop production operation for determining the important reservoir parameters. But to keep pace with the ever increasing demand of oil & gas and rapid advancement of technology, it is important to keep our production going and also estimate reservoir properties accurately. Keeping these problems in mind, we have demonstrated the most reliable way to find these important properties using Material Balance Equation, Pseudo Steady-State Equation & Combination of these equations and plotting them in different empirical standard type curves of modified pseudo rate vs. modified pseudo time related to pressure without shutting-in the well. We can estimate Expected Ultimate Recovery (EUR), Permeability, Skin Factor, Drainage, Volume, Initial gas in place, and so forth on the basis of production rate and pressure data using Traditional Decline Analysis, Fetkovich Analysis, Blasingame Analysis, Agarwal-Gardner Type Curve Analysis, Flowing Material Balance, NPI Type Curve, Transient Analysis, Flowing Material Balance, and Wattenbarger Type Curve Analysis. We used these analyses for estimating expected ultimate recovery and production forecasting reservoir just about Kailastila Gas Field Well No 5.

Keywords: Expected Ultimate Recovery, Typecurve, OGIP, Skin.

INTRODUCTION

The analysis of production data to determine reservoir characteristics, completion effectiveness, and hydrocarbons-inplace has become very popular in recent years. Evaluating the important characteristics of the reservoir and its future production reliability are considered very important. Keeping that in mind, we used many analysis and techniques that have shown the dynamic behavior of the field in terms of production rate and fluid recovery. We are required to find EUR, OGIP, permeability, skin, drainage area

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etc. to know about the reservoir. Advanced decline analysis gives us the benefit of evaluating necessary parameters and helps to forecast about the field. Rate transient analysis is the most advanced and widely recognized technique of evaluating EUR, permeability, skin etc. only using the production and flow data without shut-in. The most important benefit of using this technique is that it uses the data that we already have, we do not have to shut – in the well and most importantly, we can do the analysis with minimal cost.

RATE TRANSIENT ANALYSIS

Rate transient analysis enables us to analyze on both production and flowing pressure data at the same time. It allows us to determine expected ultimate recovery, gas-in-place, permeability, and skin and to perform material balance analysis without having to shut-in a well.

All analyses (typecurves, analytical models) can be used in RTA if the fluid system in the reservoir is single phase. For oil, that means it must be undersaturated or the pressure above the bubble point. Multiphase oil systems can be analyzed using the Numerical Model. In oil reservoirs, PVT properties and relative permeability data are extremely important: These include Formation Volume Factor (FVF), viscosity, compressibility and bubble point pressure. For multiphase oil systems, user defined relative permeability and PVT properties (if available) should be entered into the Advanced Properties section in RTA. When analyzing oil reservoirs, it is important to have good flowing pressure data.

Rate transient analysis helps to determine more correctly the following:

- Reservoir characterization (permeability, skin, fracture half-length)
- Diagnose changing skin or permeability conditions
- Monitor well performance in competitive drainage situations
- Monitor productivity to ensure proper production allocation
- Analytical and numerical production modeling – single-zone vertical to multi-frac horizontal wells
- Determination of stimulated reservoir volume, optimal well spacing and EUR/well for unconventional reservoirs
- Graphical techniques are used to analyze the production data that includes many Cartesian, log-log, semi log graphs of production and rate functions. Most of the graphs are used in history matching and evaluating the desired parameter. The analysis and interpretation of the rate transient data requires an expert reservoir engineer who will make the data input and matching of the data.

TYPES OF ANALYSIS

In decline curve analysis, two methods which are commonly used among the practicing engineers are the statistical or least-square approach and the log-log type curve analysis [8]. There are many types of analysis available in RTA, such as Traditional Decline Analysis, Fetkovich Analysis, Blasingame Analysis, Agarwal-Gardner Type Curve Analysis, Flowing Material Balance, NPI Type Curve, Transient Analysis, Flowing Material Balance, and Wattenbarger Type Curve Analysis. In most cases modified pressure vs modified rate is used and fitted in type curves to determine EOR, OIP/GIP, Permeability, Skin etc. Some analysis does not fit in any wells because of the limitations of the analysis. As natural gas is produced from depletion drive reservoirs, the energy available to transport the produced fluids to the surface declines. This transport energy eventually becomes low enough that flow rates are reduced and fluids produced with the gas are no longer carried to the surface but are held up in the wellbore. Considering this basic concept the analysis has been conducted. Here these analyses are used to determine expected recovery from this well.

METHODOLOGY

The desired parameters are calculated in different methods that help us pointing out the problems and increasing reliability. To make the analysis, first we have to convert the production data into CSV or Excel file. Then we have to import those data using import option on FEKETE FAST RTA. Then, to make desirable amount of data we use the data reduction option to reduce data points. As it is recommended to use 1000 or less data points, the data reduction plot will pop up if it have more than the selected amount of data. Then, we input the reservoir properties that already documented. The initial wellhead pressure, net pay thickness, porosity etc. are required data that needs to be delivered to the software. Then we check the data for any unexpected problems. As RTA calculation are based on sandface pressures, the correlation of wellhead pressures to bottomhole pressures are needed if importing surface pressures. Then we choose the pressure loss correlation method. Beggs and Brill method is vastly used for this analysis. Then we go to the analysis option and resume analysis starting with Traditional Analysis. By making a proper matching of the data with the referred plot we will get EUR plus other parameters for this.

Then we perform Fetkovich analysis and try to match the data with the graph. This will provide the transient behavior of the system (k, s) on the left side and boundary dominated behavior of the reservoir (OGIP, Area) on the right side of the graph. We can use the data filtering option to to clean up the data that is noisy or difficult to interpret. Then we start the Basingame Analysis. We have to input abandonment pressure (Pab) or recovery factor (RF). This will allow us to calculate the EUR. Then we analyze with A-G rate vs Time, NPI, and Transient Analysis. K, Xf, Area and OGIP are calculated and displayed in the parameter grid. Flowing Material Balance is then started; when the analysis line is straight, we will get original gas in place. After all this analysis we will model them for history matching and create a forecast using those curves.

TRADITIONAL DECLINE ANALYSIS

In this analysis of the KTL – 5, we find EUR 7.522 Bscf. This analysis primary concerns about that declining trend of the well production data. This analysis also shows that this well will end production in 10/07/2015.

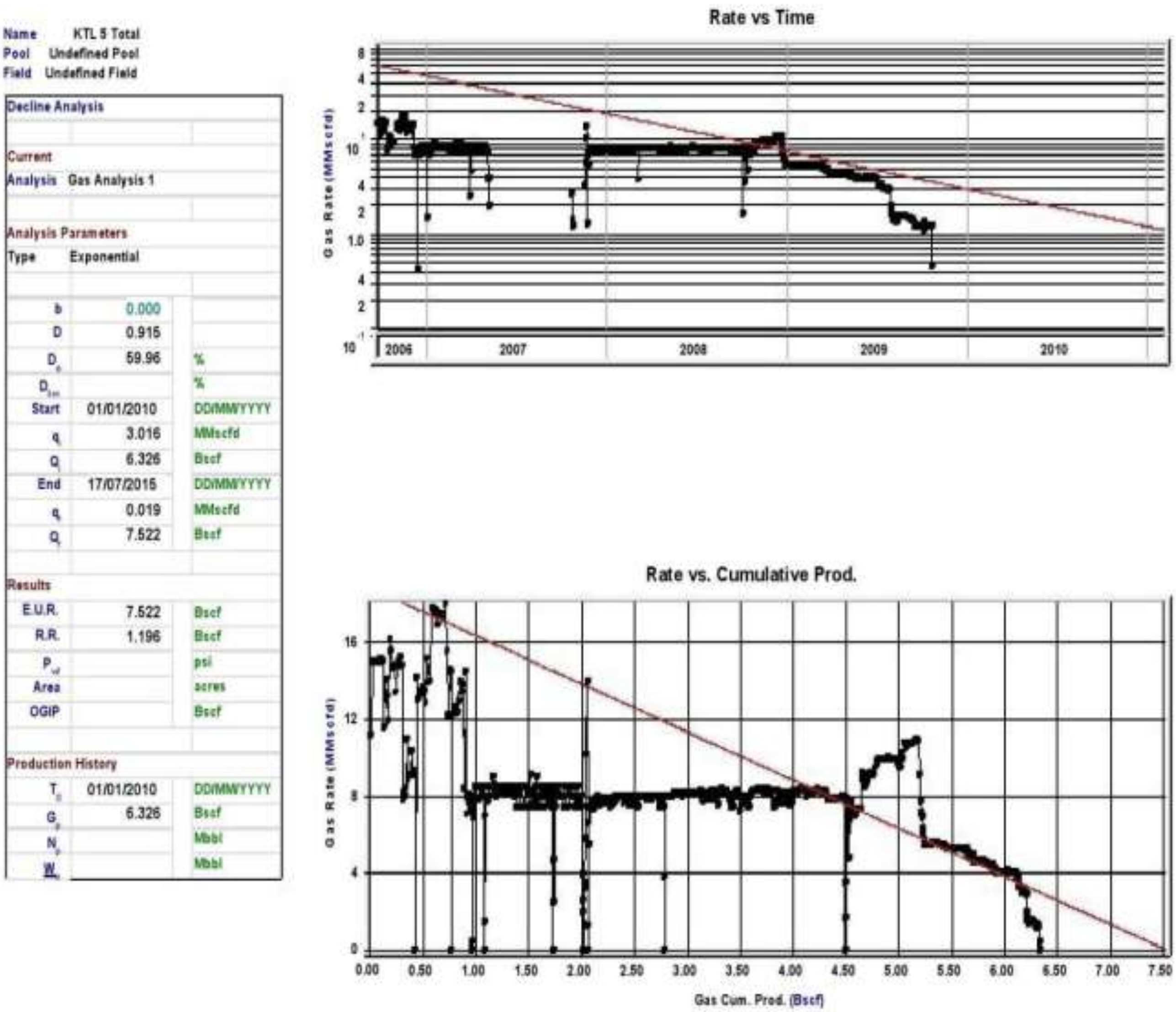

Figure 01: Rate vs Time, Rate vs Cumulative Production.

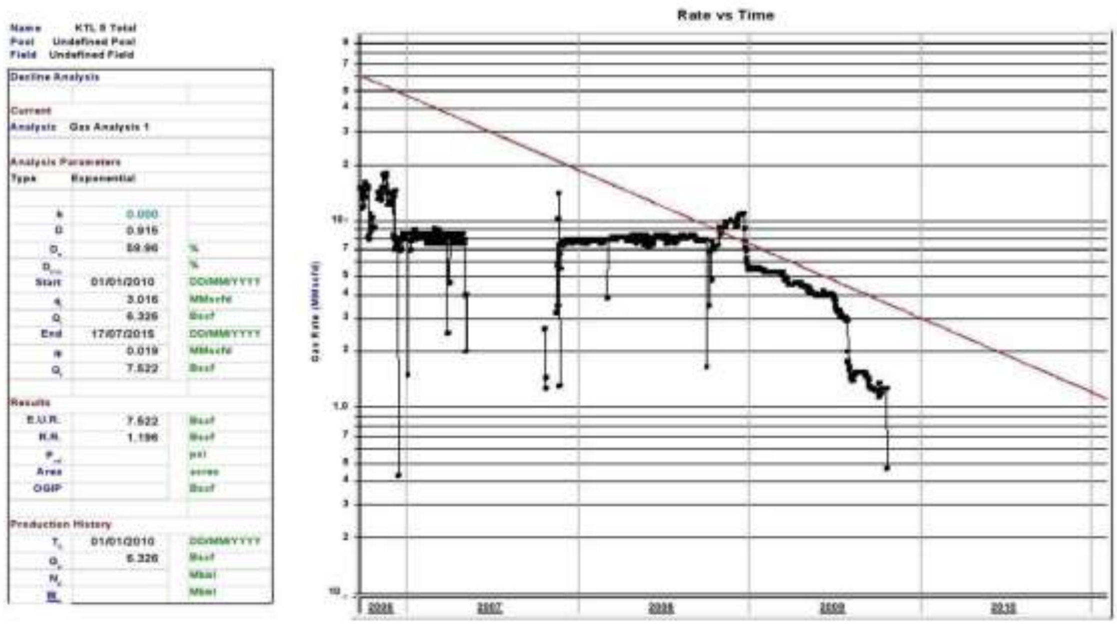

Figure 02: Rate Vs Cumulative Prod.

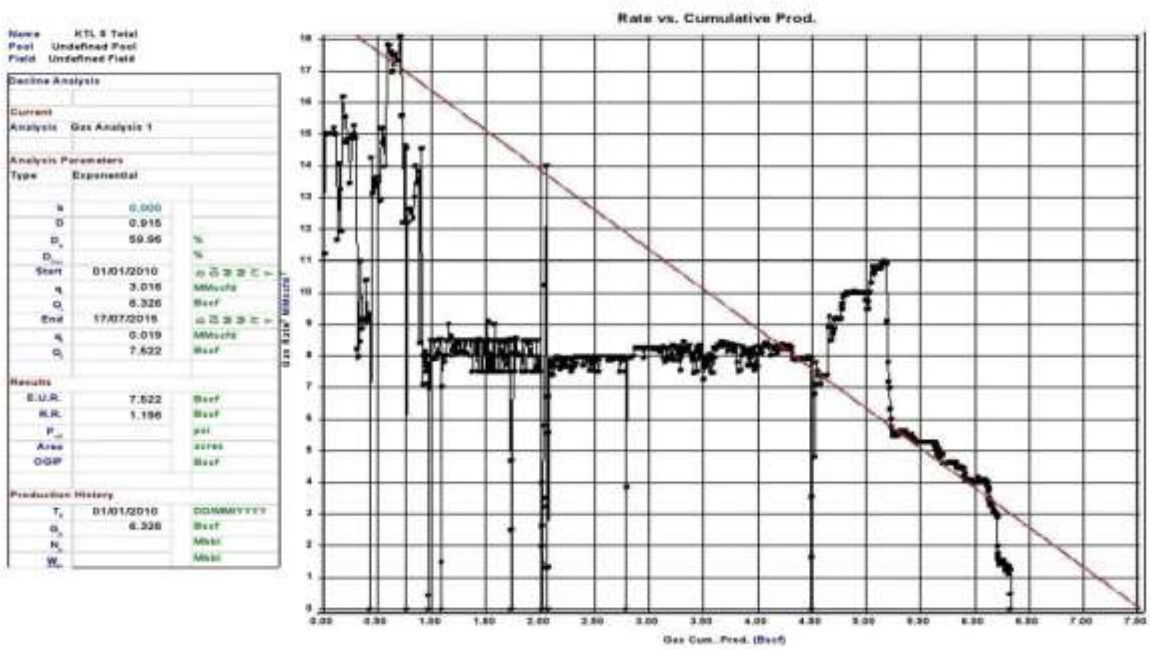

Figure 03: Rate vs. Time

FETKOVICH ANALYSIS

This analysis does not consider the change in bottom flowing pressure is transient regime. Since we have included the whole production history of the well (including transient and boundary dominated regime) this analysis did not considered the change in bottom flowing pressure in one regime. We can also observe that this well is strongly deviating (in rate) from the type curve in.

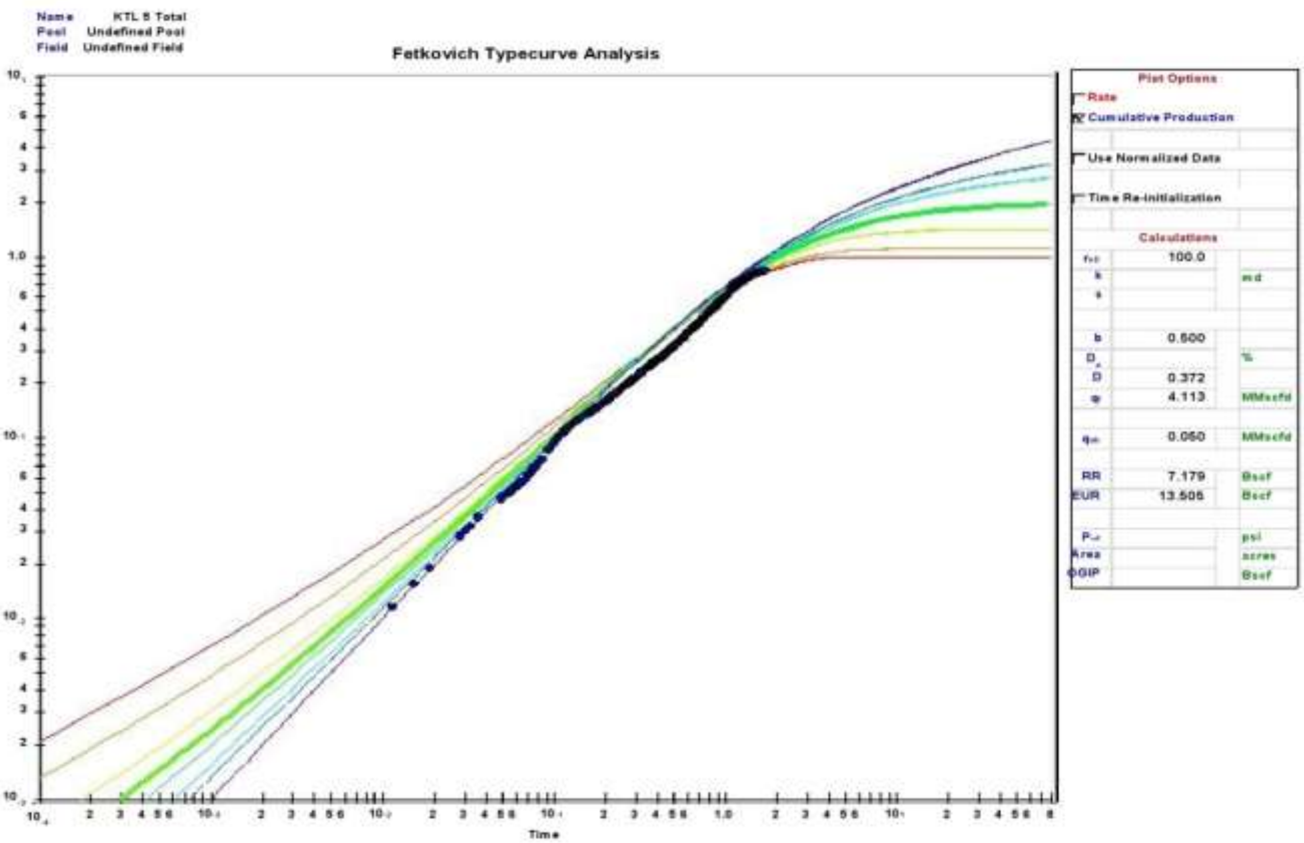

Figure 04: Fetkovich Typecurve Analysis(Cumulative Prod.)

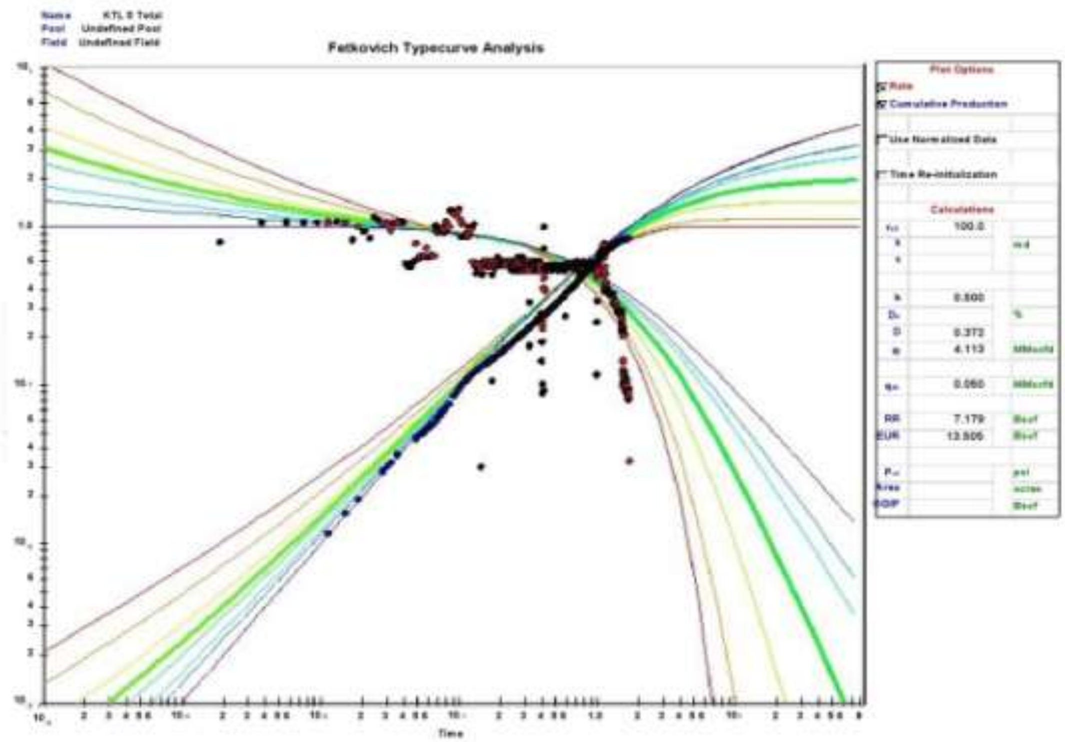

Figure 05: Fetkovich Typecurve Analysis(Rate and Cumulative Prod.)

BLASINGAME ANALYSIS

Blasingame Analysis of KTL – 5 shows that, the calculated points of the well has gone below the reference curve. After conducting multi-well testing with KTL – 1 we get the result of EUR 30.642 Bscf, OGIP 38.303 Bscf, Permeability .5950 md.

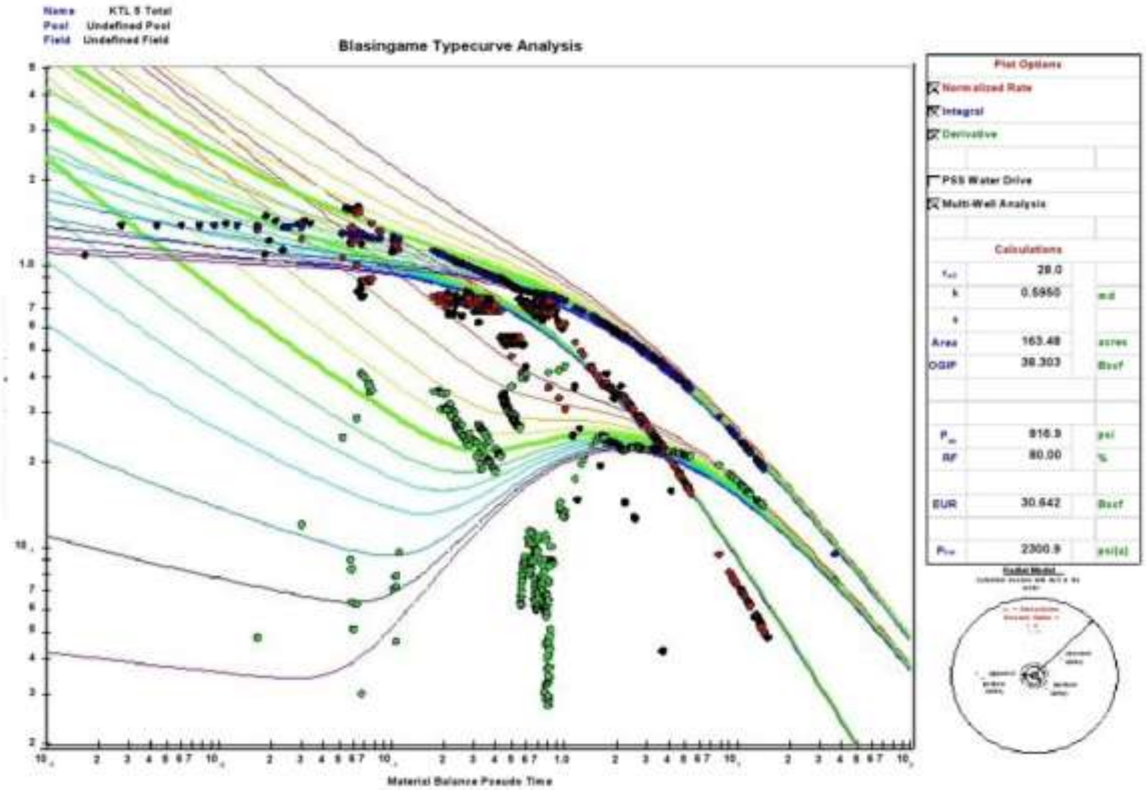

Figure 06: Blasingame Analysis(Normalized Rate, Integral & Derivative)

AGARWAL-GARDNER TYPE CURVE ANALYSIS

In Agarwal-Gardner Typecurve Analysis we find EUP 28.021 Bscf, OGIP 35.026 Bscf, Permeability 1.4126 md. In this analysis, like Blasingame, we have to conduct a multi-well analysis.

This analysis also shows that this well is producing with interference with KTL – 1. Result is quite similar to Blasingame Analysis.

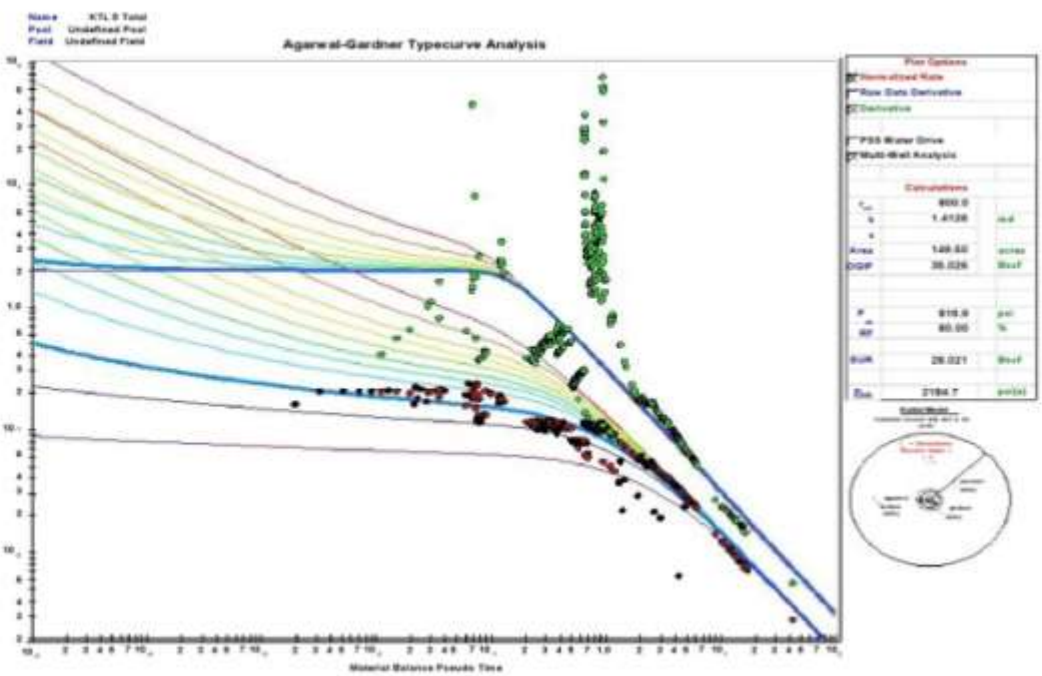

Figure 07: Agarwal Gardner Typecurve Analysis (Normalized Rate & Derivative)

FLOWING MATERIAL BALANCE

Flowing Material Balance of KTL – 5 gives us EUR 33.595 Bscf, OGIP 41.994 Bscf. The flowing material balance uses the concept of boundary-dominated flow or pseudo-steady state flow, as well as flowing pressures and rates to calculate original hydrocarbons-in-place. From the analysis, it uses two graphs to indicate the results which give more suitability and relativity of the results.

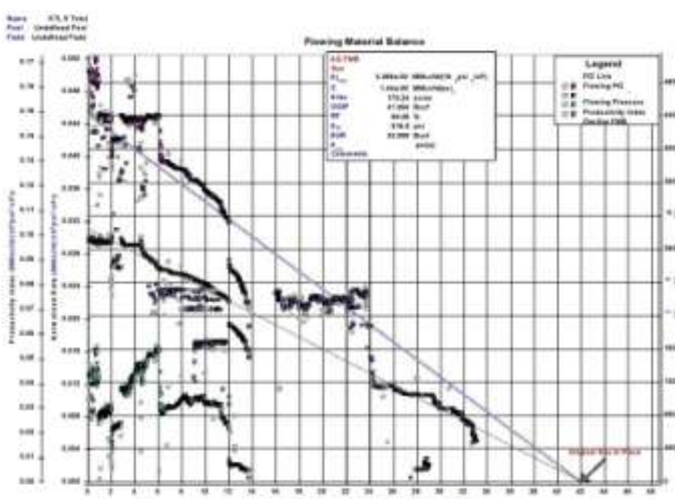

Figure 08: Flowing Material Balance

NPI TYPE CURVE

NPI Typecurve analysis of KTL – 5 gives EUR 28.634 Bscf, OGIP 35.792 Bscf, Permeability 2.5108 md. NPI type curve analysis shows that this well has interference with KTL – 1 and the estimation of EUR and OGIP is similar to other analysis.

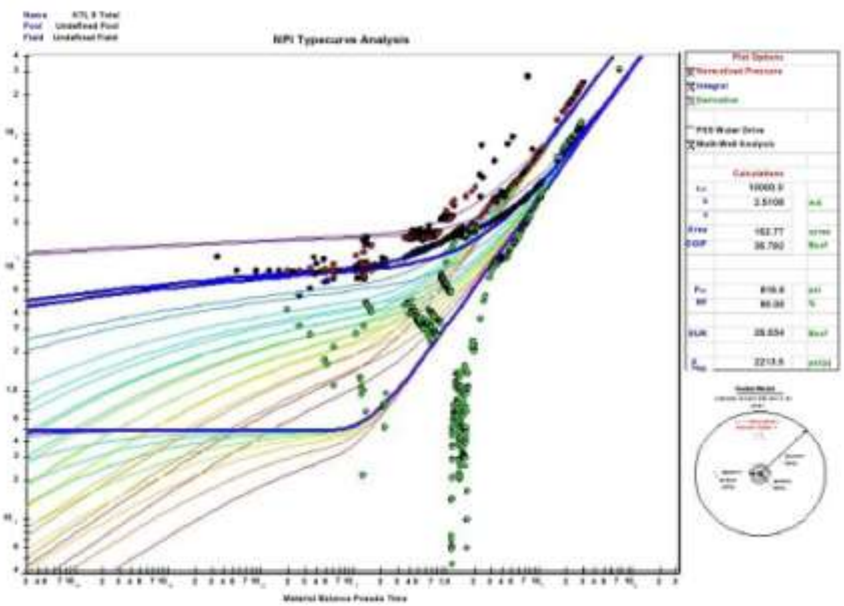

Figure 09: NPI Typecurve Analysis

TRANSIENT ANALYSIS

From Transient Analysis of KTL – 5 we find EUR 27.661 Bscf, OGIP 34.576 Bscf, Permeability .5489 md, Skin -4.983.

The evaluation of transient parameters is accomplished using the transient stems of the dimensionless typecurve model. Unlike the boundary-dominated flow case, the definition of the characteristic dimensionless variables changes according to the chosen transient model.

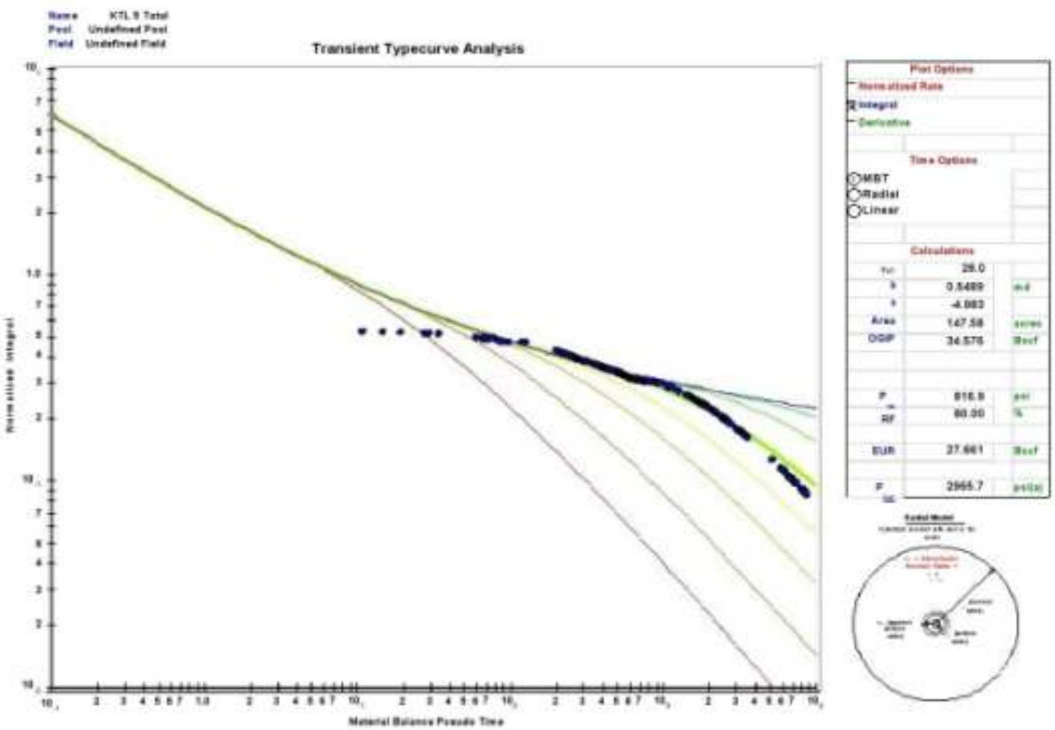

Figure 10: Transient Typecurve Analysis (Integral)

WATTENBARGER TYPE CURVE ANALYSIS

Wattenbarger Type Curve Analysis of KTL – 5 gives EUR 26.893 Bscf, OGIP 33.616 Bscf. Long linear flow has been observed in many gas wells. Sometimes decline curves for tight gas wells indicate that linear flow may last for over 10 or 20 years. These wells are usually in very tight gas reservoirs with hydraulic fractures designed to extend to or nearly to the drainage boundary of the well.

They assumed a hydraulically fractured well in the center of a rectangular reservoir. The fracture is assumed to be extended to the boundaries of the reservoir. Since KTL – 5 does not have such characteristics, this analysis is not favorable for this well, although it gave results similar to other analysis.

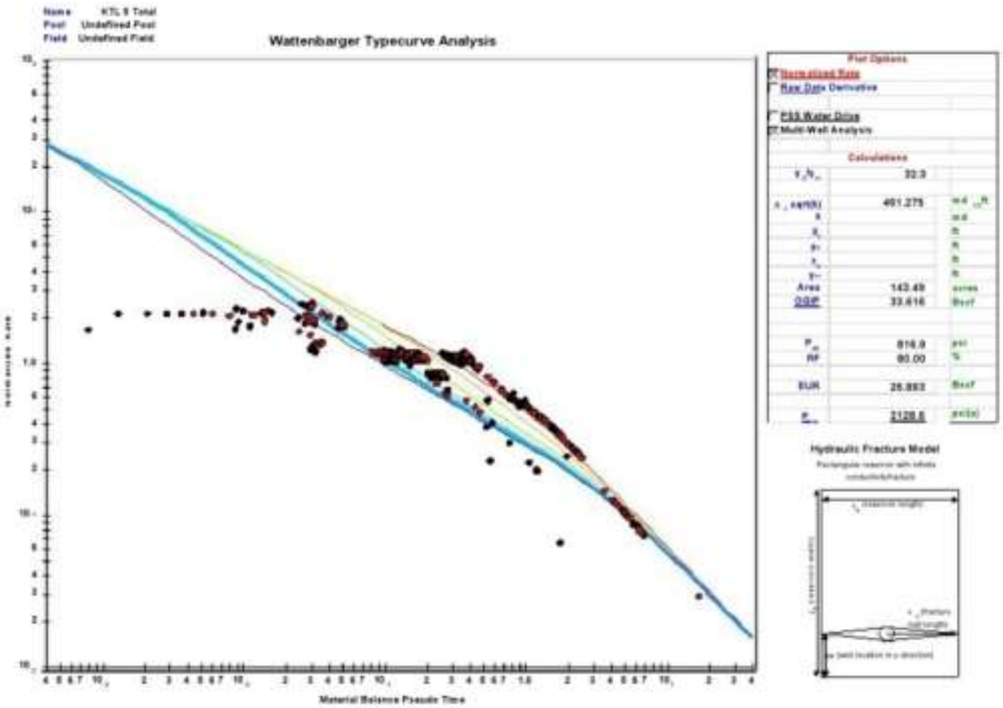

Figure 11: Wattenbarger Typecurve Analysis (Normalized Rate)

CONCLUSION

From analysis results and type curve fitting, we can come to the following decisions.

1. Kailastila Gas Field Well No. 05 is producing gas, having interference with Kailastila Gas Field Well No. 01.
2. Most of the analysis shows very close value of Expected Ultimate Recovery, we can quantify EUR as 29.288 Bscf by averaging the accepted analysis values.
3. Skin of Kailastila Gas Field Well No. 5 is negative. This indicate a flow enhancement in near wellbore.
4. Original Gas in Place measured by averaging accepted analysis values is 36.61 Bscf.
5. Most of the analysis results are close to one another that validate the analysis procedures.
6. Though skin is negative, we cannot conclude that reservoir is fractured as it also depends on other factors.

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Revisiviting Reservoir Fluid Properties with Memory Concept

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ABSTRACT

The actual effect of continuous time function (i.e. memory) on fluid flow through porous media comes out when we predict oil flow. In order to make predictions, several Newtonian flow equations have been considered. In addition, some non-Newtonian flow models are also considered to represent any fluid properties. This paper summarizes the fluid flow models where memory formalism was taken into consideration. Literature shows that fluid memory is the most crucial but most ignored portion in studying any fluid flow model. The strength of the memory underlays that it presents almost all the previous history of the fluid and also predicts how it will act in the future time. So far, there is no non-Newtonian flow model which is established by memory. This paper reviews most of the existing fluid models with memory, focuses the hypothetical problems of time function, and describes the actual benefit of having memory for fluid properties such as temperature, surface tension, stress, strain, viscosity etc. It also critically reviews all the existing models, and shows a relation of fluid viscosity, time function, and permeability of fluid media with stress-strain. This study will help in describing the exact behavior of a fluid flow in porous media. This concept can be used in considering fluid flow behavior in a special reservoir condition.

Keywords: real time function, porous media, non-Newtonian fluid, reservoir simulation, stress-strain, memory of fluid.

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INTRODUCTION

Both rock and fluid properties play a vital part in the time of fluid flow through porous media. Most of these properties are functions of both temperature, and pressure. It varies with time. Rock properties such as permeability, porosity, pore volume, wettability depend on fluid properties [1, 2]. Nevertheless, it is too important to present permeability, porosity and also viscosity as a real time function. The general flow equations such as Darcy's law does not allow to change criteria for both rock and fluid in a systematic manner.

In general, fluids will not be able to move as a result of shear forces. It will also skew the structure without measuring exact amount of force. Its structure will change automatically because of applied force. The shear stress and rate of strain relationship indicates the category of fluid. Viscosity works here as a measuring tool [1, 3].

Newton's law of viscosity is defined that there is always a simple linear relation between the rate of strain and stress. Any fluid which converges this law is known as Newtonian fluid [1, 2]. Viscosity is considered as coefficient of proportionality which differs with pressure and temperature. Sometimes it also varies with the chemical formation of the fluid if it is not a plain substance. Viscosity does not rely on the forces acting upon it in the case of Newtonian fluid [1, 4, and 5]. Researchers have been considering water, few light-hydrocarbon oils, air, and other gases as Newtonian fluids [1, 2]. On the other hand, fluid which does not have a distinct viscosity is known as non-Newtonian fluid. Viscosity of those fluids varies with both applied forces and rate of strain.

Concept of using fluid characterization can be easily modeled adding the idea of continuous time function. The process can be defined as a changing permeability, and viscosity with the help of media and time. Therefore, permeability change can be modeled with respect to memory function of fluid. It is also applicable for viscosity and other fluid properties at the same time. If we consider polymer flooding with shear-thinning fluid [6], even permeability and viscosity can easily be applied with the alteration of time concept.

In literature, it is always found that human thoughts are accompanied with the usual flow of time cycle. Flow of gas, oil, water and other fluids grow upward and downward by all aspect of different coditions and processes. Almost all established processes in oil and gas engineering have concentrated on the permeability [1]. Those are applicable for both solid and semi-solid formations with the help of fluid flow through it. The concept of memory for fluid is an excellent process to make this happen by altering the structure of reference from the outer flow to within the flow [1,7]. Very few nonlinear, viscous and incompressible fluids provide some abnormal behavior. There are some more viscous fluids properties. The mechanism that defines these special and peculiar natures with respect to continuous time is known as memory or fluid memory [1, 7]. Till now few researches clearly explain and applied the issue. Some non-Newtonian fluids act indistinctly in period of flow through any porous media. With flow period, turbulent character outcomes in few condensations of some minerals in the pore space compress the fluid flow lane in the reservoir. Very few fluids may also react chemically with the porous structure that causes changing the pore sizes [1]. Sometimes fluids transport solid particles which can create ostraca for few pores. Sometimes pore structure can be reformed by mineral particles flow through fluids and also as a result of temperature variations that generated by flux. These observations create permeability change locally within the representative elementary volume (REV). The changes in local permeability is a very important topic in almost all geothermal studies of any reservoir. So, it can be assumed; reservoir permeability reduces with span of time, and the fluid flow takes place as if the fluid medium can remember its state as well. For fluid memory, the refining characteristics of diffusion equation is modified according to the analogous equation which depends mainly on Darcy's law [1, 8]. Fluid properties with the span of time works as a for the spectral properties of mass flow through any fluid. The process filter may increase low-frequency or decrees high frequency. The overall importance of the filter is progressively much more serious with higher amounts of loosening time. As there are not many theories regarding this topic, few authors also tried to develop non-local flow theories employing fundamental principles of statistical physics [1, 8]. Original Darcy's law can be derived for saturated flow by employing these studies. This paper reviews the existing fluid models, discuss some drawbacks of memory and finally, analyzes the importance of time function on fluid stress-strain relationship. This critical review will help to understand reservoir fluid behavior and also the importance of incorporation of time function. Memory concept will introduce a new outlook to overall reservoir simulation process. In addition, it will provide a clear assessment of rock and fluid properties.

LITERATURE REVIEW

This review is depended on how the real time function of a fluid correlates to any fluid property and how that fluid property is related with other properties. It also shows the addition of fluid media for any porous media. And also include time function in it. Table 1 summarizes researches that have already done assuming the concept of memory in fluid flow. It presents all the fluid models that incorporate memory concept, their assumptions and also their drawbacks.

Slattery [9] presented visco-elastic fluid characteristics using Buckingham-Pi theorem. He also combined the Ellis model, Newtonian, Noll simple and power model fluid. He found the memory effects on normal stress. For porous media, memory effect presents in the form of permeability change which itself a function of characteristics length. He only studied these parameters in the form of permeability. Material parameters are considered only for regional thermodynamic state. Those are generally fluid viscosity, diffusivity and stress of any reservoir. However, he was unable to provide any model which shows the overall view of the fluid characteristic.

Mifflin and Schowalter [10] represented a way to a solution for three dimensional steady state fluid flows in an enclosed or wide open flow systems incorporating the memory. They also assumed that the flow is laminar as well as force and torque free. They partitioned the elemental part of time function into gradient of velocity. But that does not recognize the actual time function concept. They neglected the rest of the integral part and assumed a small constant value. Their model shows the relation between stress and fluid viscosity only with time function.

Ciarletta and Edoarda [11] presented their study about general linear progression related to incompressible fluid flow. They also concerned about fluid viscosity which displays an unclear memory of previous motions. So, they over looked the non-linear portion of the model. Finally, they considered the fluid viscosity which presents as a time function of stress.

Eringen [12] established a theory for fluids with micro polar property; that has effect of orientation and incorporate memory effect on it. Both nonlocal and orientation effects close to boundary change fluid viscosity extensively. All surfaces are consumed with layers that contain polymer. Fluid viscosity represents as a function of the channel gap. He found that all most all fluids have their own formations with some own properties in micro scale. It becomes proportionate with the outer characteristic to the concept of a memory. He concluded that memory effects become efficient at the time of outer length when it becomes short enough to make a comparison with the radius of molecular particles of fluids. In the condition of thin film lubricants, this thing can come up. He incorporated memory concept only with viscosity and stress of fluid.

Nibbi [13] generated a new way to make a relation with free space energies to viscous fluid incorporating real time function concept. In this study, he figured out most recent findings for linear viscoelastic fluid that have free energies. Representations of viscoelastic fluid models with memory concept are undefined till today. However, he fails to mention anything about fluid media and also the real feature of time function.

Broszeit [14] produced a numerical simulated model for steady state of isothermal flow type in a Newtonian fluid and also incorporates memory. He only used single-integral law and also predicted fluid motion kinematics. He showed deformable pathway of any fluid that plays an important part in simulation. He showed memory correlation of fluid with stress only.

Caputo [15] defined the memory of fluid as a fractional order derivative and also effect of permeability decreasing with time. He gave an over view of all the outcomes of various researchers in order to study diffusivity of fluid in porous media. All the above described flow shows that permeability of the fluid medium changes with time. M. Caputo [15] reviewed few geothermal regions. In those regions, fluids may generate minerals in the pore spaces, thus tempering their structure and size. He failed to relate the fluid time function with other characteristics of fluid. He also failed to show how this property plays an important part in reservoir porous media. Nonetheless, M. Caputo [15] admitted time function of fluid flow in porous media which can be presented more broadly and precisely. Darcy’s law should be recouped engaging with other models defining fluid media exactly.

Li et al. [16] reviewed non-Newtonian fluid properties. They showed how reciprocal action and cluster can occur as a result of stress and also their recreation due to time function. Their findings show very clearly that a new approach should be invented both for reciprocal action and cluster in non-Newtonian fluids. The real time function effect of enduring stresses helps to grip the shear-thinning process as a result the regional viscosity decreases. Their model does not define or show the actual feature of time function in fluid flow. They failed to incorporate the characteristics of both fluid flow and fluid media with real time function.

Arenzon et al. [17] presented a model under the condition of thermal variation and gravity; which describes recreation of hugely dense particles. They discovered a congest conversion line between a low and high densely fluid phase. They showed both irreversible and quasi-reversible cycle and also memory effects. They also said that memory function is a history dependent incident. They figured out that memory is very similar to commotion at early times. They only showed fluid density to define the actual concept of memory based on a quasi-static flow system. Still, this model does not show the overall picture of memory.

Shin et al. [18] reviewed the non-equilibrium characteristics for inertia influenced components. They tried to explain the issue of component impeachment in turbulent layer boundary. They figured out that a boundary layer (turbulent) is hugely damaged by a non-equilibrium memory effect. It occurs because inertia attraction between components and minimum shearing stress of the flows. This is known as memory effect of the non-equilibrium. Their model describes only homogeneous encompassing media effect and is not enough to represent the overall outcome of fluid flow behavior and media with corresponding time.

Zhang [19] reviewed traffic flow behavior of fluid. It represents micro and macroscopic fluid flow together. The flow of traffic is entrenched as he established a viscosity model in terms of second order with time function. This model shows traffic viscosity and is related to driver memory. Memory is a functional presentation of both space and time. In memory concept, previous time events depend on forward time events. Traffic system of road is the main base of his model.

Lu and Hanyga [20] presented wave field simulation of a heterogeneous porous medium with the help of the Johnson–Koplik–Dashen dynamic permeability model including Biot's theory. They came up with first-order differential equations for pore pressure, stresses, velocities, and quadrature variables. They tried to make a correlation between memory with seismic and ultrasound wave multiplication with drag force. They drew a conclusion that the fluid memory for the drag force should be presented in terms of a time complexity with a singularity $21-t$ for $0\rightarrow t$. Nonetheless, they tried to show some evidences of theoretical and experimental studies at $0\rightarrow t$ that is not true.

Chen et al. [21] introduced memory concept for store and successive flow in a porous medium considering stress. To show dynamic effects of viscous friction of store, they represented the idea of invasion percolation with memory (IPM). The basic concept of this expression is that, all local thresholds must be over a given pore throat. Nonetheless, it unaccounted for viscous fluid flow. They used open path for their calculations which didn't affect pressure distribution. As a result, recognition of higher-energy paths was mostly a quasi-thermodynamic process. For Bingham fluids, this model would compare to vanishing plastic viscosity. They also tried to explain how IPM works. But they failed to construct a model representing the idea of fluid flow memory.

Gatti and Vuk [22] established of the gesture of a linear model for visco-elastic fluid in a 2-D domain considering periodic boundary terms. They assumed that fluid behavior is incompressible of Jeffrey's nature where Reynolds dimensionless number is equal to unity and condition is isotropic homogeneous. They considered density is time independent. They measured fluid memory effect by considering both pressure and velocity are time independent. Those considerations maintain only the conventional models.
Hossain et al. [1, 3] presented a new approach of fluid memory for reservoir characterization. They established a stress-strain model and made viscous stress as probable property. They also considered temperature, the surface tension, pressure variations during modeling. They made a precision value of α from $0 \leq \alpha < 1$. They showed 0 values for memory effect and unity for extreme effect of memory. But they didn't show any significant relation of pressure gradient and memory. In addition, they didn't clarify the fluid flow; whether it is Newtonian or non-Newtonian. Though their model has come short comings, it provides a new view of dealing reservoir fluid with memory.

Hossain et al. [1, 2] presented a behavior of both rock and fluid, and incorporate fluid memory with it. Their main aim was to model permiabilty and viscosity over time. They established a model for the fluid flow inside porous media. The model also introduced momentum balance and continuity equation. They also said that it can be used for crude oil flow in any porous media. But, they did not show the model for non-Newtonian fluid in general condition. This model only can be applicable during enhanced oil recovery (EOR) process for non-Newtonian fluids.

Hossain et al. [23] introduced a new engineering approach that has been bypass linearization during model equation. They proposed a model where they involve not only discretization but also formulation to get the flow equations in the integral form. The equations are written for a set grid block in space at a given time period. The model equations that they presented reflect the flow equations in an algebraic form. The most important aspect of this model is the consideration of fluid and rock properties as a time dependent variable without making any linearization. In reservoir simulation and also in well testing, this model can be used easily. However, the shortcoming of this model is that they didn't show anything regarding non-Newtonian fluid and didn't observe the total overview of fluid behavior and media.
Hossain et al. [6] presented mathematical model incorporating memory concept in order to show rheological behavior with shear rate and bulk rheology. They solved this model numerically and made a comparison with established experimental results that are available in literature. They tried to show many excellent agreements with experiment results. But they didn't show any clear view for non-Newtonian fluids. It can be easily say that this group shows a lot of new view and findings regarding memory. They

provided new technics to incorporate memory concept in fluid and also offered a relationship between fluid memory and media.

Kodama and Koide [24] discussed the roles of fluid viscosity in terms of fluid dynamics from the of view of memory concept. Memory effect is applied so several terms are appeared in higher order corrections. They showed that when the memory effect applied on the extensively, the hydrodynamic equations of motion became non-singular. They also discussed the question of memory effect in the derivation of transport coefficients from a microscopic theory. They applied the Green–Kubo–Nakano (GKN) formula to calculate transport coefficients. They also derived the general formula when the fluid flow is non-Newtonian. But in their study they failed to show the overall scenario of memory and media.

Yu and Fan [25] developed a multi-relaxation time lattice Boltzmann model using the interaction potential approach. This model is able to enhance the numerical stability at low viscosities so significantly, without appreciable increase in computation time or memory use. It will also reduce the lowest stable viscosity by magnitude compared to the single relaxation time lap. They validated for multi-relaxation-time & lattice Boltzmann model for two phase flow. In their model they didn't consider the non-Newtonian fluid. Also didn't show the relation of media and memory.

Zia and Brady [26] described the motion of a single Brownian particle in a complex fluid situation. They also described material behavior both at and away from equilibrium. They studied both theoretical and dynamic simulation of the transient character of a colloidal dispersion which undergo through nonlinear micro rheological forcing with respect of time. Their study showed that in case of very short times, the time scale for relaxation is set by a boundary layer of thickness. Almost all stress relaxation occurs during this time. For longer times, the Brownian diffusion of the bath particles acts to close the wake on a time scale set by how long it takes a bath particle to diffuse all together. They tried to show fluid media and memory which is not exact.

Daitche and Tél [27] investigated the effect of the history force on particle which carried out for both heavy and light particles. They showed general relations are given to identify parameter regions where the history force is predicted to be similar with the Stokes drag. They discussed Lyapunov exponent of transients become larger with memory. They found periodic attractors are very slow, t^−1/2 type convergence towards the asymptotic form. They presented the concept of snapshot attractors is useful to understand this slow convergence. And showed ensemble of particles converges exponentially fast towards a snapshot attractor, which undergoes a slow shift for long times. Though they showed memory of fluid but they didn't consider non-Newtonian fluid. And also failed to show fluid media.

Table 1 presents the available various critically reviewed existing models along with all ssumption.

Memory Model	References	Assumptions
$\overline{K} = f(L, \overline{v}, t, \mu_o, P, \overline{\tau}, \alpha)$ $\overline{K}$= Premiability of the system $\overline{v}$= Velocity t= Time μ_o= Viscosity P= Pressure $\overline{\tau}$= Stress tensor α= Diffusivity	Slattery [9]	1) Incompressible flow with steady state 2) Porous media (Isotropic) 3) Inertia effects are neglected 4) Only local thermodynamic state considered for all parameters
$\tau = \int \frac{2\eta_o}{\lambda_1}\left[\left(1-\frac{\lambda_2}{\lambda_1}\right)e^{-\frac{(t-t')}{\lambda_1}} + \right.$ $\lambda 2\delta t \times \Gamma t, t' dt'$ τ= Stress η_o = Zero shear rate viscosity t = Present time t' = Some past time λ_1 = Relaxation time λ_2 = Retardation time	Mifflin and Schowalter [10]	1) Incompressible flow with steady state 2) Fluid particles are homogeneous 3) Spherical particles shape
$\overline{T}(x,t) = -p(x,t)I +$ $\int_R 2\mu(\tau)\overline{D}(x,t-\tau)d\tau, (x,t) \in$ $\Omega_T \equiv \Omega \times (0.T)$ $\overline{T}$= Stress $\overline{D}$ = Velocity gradient t = Time Ω = Domain of physical space (i.e. $\equiv R^3$) filled by moving fluid T= Fixed positive number, ($\leq +\infty$) P = Pressure μ=μ(τ)= Relaxation modulus of the viscosity	Ciarletta and Scarpetta [11]	1) Viscous fluid flow 2) Non-linear term is Neglected 3) Incompressible and homogeneous fluid flow 3) Physical space is smooth and domain is bounded 4) Soild material is based of this model

$t_{kl} = -\pi\delta_{kl} + T_{kl}, T_{kl} = 2\int_{-\infty}^{t} d\tau \int_{\vartheta-\sigma} dv' \sum_{klmn}^{1} (s = t)\frac{\delta C'_{mn}}{\delta\tau}, \frac{\delta C_{mn}}{\delta\tau} = 2d_{ij}(\tau)\frac{\delta x_i(\tau)\delta x_j(\tau)}{\delta x_m(t)\delta x_m(t)} 2\sum(s = t) = (\lambda_0 + \lambda_1 j)\delta_{kl}\delta_{mn} + (\mu_0 + \mu_1) \times (\delta_{kl}\delta_{lm} + \delta_{kn}\delta_{lm}$ k_{lt} = Stress tensor λ_0, λ_1, μ_o, μ_1 = Viscosity moduli t = Time σ = Spin density δ = Orthogonal tensor τ = Dummy time variable	Eringen [12]	1) Negligible nonlocal effect 2) Fluid not conducting heat 3) Molecules are homogeneous 4) Spherical molecules shape
$\bar{T}(t) = -p(t)I + \int_{R}^{+\infty} 2\,\mu(s)\overline{D^t}(s)ds,$ $\bar{T}$ = Symmetric stress tensor $\bar{D}$ = Infinitesimal rate strain tensor t = Time $\overline{D^t}$ = History of $\bar{D}$ up to time, t = $\overline{D^t}(s) = \bar{D}(t-s)$ P = Pressure μ= μ(τ) = Relaxation modulus of the viscosity	Nibbi [13]	1) Viscous fluid flow 2) Incompressible and homogeneous flow 3) Linear and isotropic flow 4) The function of relaxation has to be satisfy; $\mu \in L^1(0, +\infty)$, $\mu \in L^1(0, +\infty) \cap L^2(0, +\infty)$
$q = -\frac{\eta\rho_o\left(\frac{\delta^\alpha}{\delta t^\alpha}\right)\left(\frac{\delta p}{\delta y}\right)\delta^\alpha p(y,t)}{\delta t^\alpha} = [\frac{1}{\Gamma(1-\alpha)}]\int_0^t (t - u)^{-\alpha}\,[\delta p(y, where\ 0 \le\ \alpha \le 1$ p(y,t) = Fluid pressure with time	Caputo [15]	1) Viscous fluid flow 2) Incompressible and homogeneous flow 3) Linear and isotropic flow 4) Permeability declines with time only

ρ_o = Density of the fluid in the undisturbed condition η = Ratio of the pseudo-permeability of the medium with memory to fluid viscosity α = Fractional order of differentiation t = Time u = Fluid velocity in the plane of the integral z = (1-α Definition to simplify the computations K = Permeability of the system P = Pressure q = Fluid mass flow rate per unit area		
$$\frac{d\tau_m}{dt} = -\alpha\tau_m + \beta\gamma_B$$ τ_m = Mean stress in a cell, pa γ_m= Shear rate due to residual stresses, 1/s γ_B = Shear rate due to passage of bubble, 1/s α, β = Constant determined by the rheological simulation under different conditions of fluid and bubble volume	Li et al. [16]	1) Bubble shape is sperical 2) Bubble is homogeneous 3) Stresses and composition homogeneous 4) Frequency is constant for the formation

${v^+}_t = {v^+}_{t,eq} + \Delta {v^+}_t$ ${v^+}_{t,eq} = -\frac{24}{R_{ep}}\frac{1}{C_D}\tau_p \frac{d}{dy}\Big(\zeta_{yy} -$ $Dyydvydy1u*$ ${v^+}_t = -\frac{24}{R_{ep}}\frac{1}{C_D}\tau_p \frac{d}{dy}\left(\tau_\beta \frac{d\zeta_{yy}}{dy}\right)\frac{1}{u^*}$ ${v^+}_{t,eq}$ = Equilibrium turbophoretic velocity ${v^+}_t$ = Non equilibrium turbophoretic velocity R_{ep} = Reynolds number C_D = Drag force τ = Relaxation time τ_β = Relaxation time scale required to reach a local equilibrium state of the particle Reynolds stress ζ_{yy} = Maxwell distribution parameter D_{yy} = Coefficient u^* = Friction velocity	Shin et al. [18]	1) Medium is homogeneous 2) Particle motion with drag force 3) Mean shear rates variation is unrelated 4) Gaussian fluctuating velocities of particles 5) Turbulent particle is independent of mean shearing 6) The shear rate of the flow is independent.
$\mu(\rho) = 2\beta\tau_\varepsilon c^2(\rho)$ $= 2\beta\tau(\rho V'(\rho)_*)^2$ $v_t + \{v + c(\rho)\}v_x = \mu(\rho)v_{xx}$ ρ = Traffic density β = Parameter that describe memory τ = Relaxation time v = Traffic velocity μ = Viscosity of traffic fluid c = Concentration of fluid	Zhang [19]	1) Media is isotropic 2) Considerd taylor expansion 3) Basis is traffic road model 4) G_* (Monotonic, Generic function) is assumed as linear function.

$\tau_T = \frac{k^2 \Delta p A_{xz} \Gamma(1-\alpha)}{\mu_o \eta \rho_o \varphi y c \int_0^t (t-\zeta)^{-\alpha}\left(\frac{\delta^2 p}{\delta \zeta^2}\right) d\zeta} \times$ $\left[\left(\frac{\delta\sigma}{\delta T}\frac{\Delta T}{\alpha_D M_a}\right) \times e^{\left(\frac{E}{RT}\right)}\right]\frac{du_x}{dy}$ Let, $I = \int_0^t (t-\zeta)^{-\alpha}\left(\frac{\delta^2 p}{\delta \zeta^2}\right) d\zeta$ $\tau_T = \frac{k^2 \Delta p A_{xz} \Gamma(1-\alpha)}{\mu_o \eta \rho_o \varphi y c I} \times$ $\left[\left(\frac{\delta\sigma}{\delta T}\frac{\Delta T}{\alpha_D M_a}\right) \times e^{\left(\frac{E}{RT}\right)}\right]\frac{du_x}{dy}$ A_{xz} = Cross sectional area of rock perpendicular to the flow of heat *c* = Total compressibility of the system E = Activation energy for viscous flow *Ma* = Marangoni number *k* = Permeability of the system R = Universal gas constant *t* = Time σ = Surface tension α = Fractional order of differentiation φ = Porosity of fluid media ξ = Dummy variable for time η = Ratio of the pseudo-permeability of the medium with memory to fluid viscosity.	Hossain et al. [3]	1) Heterogeneous and isentropic formation 2) Fluid memory considered for viscosity, density, diffusivity and compressibility 3) Media properties are also considered 4) Newtonian fluid 5) Incorporate temperature and pressure effect.
$\gamma_{pm} = \frac{\alpha_{SF}}{\sqrt{k\varphi}} \frac{\eta}{(1-)} \int_0^t (t -$ $\zeta - \alpha \delta 2 p \delta \zeta \delta x d\zeta$ $\mu_{eff} =$ $\mu_\infty +$ $\frac{\mu_0 - \mu_\infty}{\left[1+\left(\frac{\alpha_{SF}}{\sqrt{k\varphi}}\frac{\lambda\eta}{(1-)}\int_0^t (t-\zeta)^{-\alpha}\frac{\delta^2 p}{\delta\zeta\delta x} d\zeta\right)^{\alpha}\right]^{\frac{n}{\alpha}}}$ γ_{pm} = Apparent shear rate within the porous medium α_{SF} = Shape factor which is medium-dependent	Hossain et al. [6]	1) Heterogeneous and isentropic formation 2) Depend on space, time, pressure and dummy variable 3) Presented for one dimension 4) Considered polymer fluid; Newtonian.

k = Initial reservoir permeability φ = Porosity of fluid media t = Time λ = Time constant in Carreau–Yasuda model a = Parameter in Carreau–Yasuda model n = Power-law exponent for Carreau–Yasuda model, η = Ratio of the pseudopermeability of the medium with memory to fluid viscosity ζ = Dummy variable for time		
$\pi(\tau) = \int_{-\propto}^{\tau} G(\tau - s)\delta_{\mu}\mu^{\mu}(s)$ τ = Proper time μ^{μ} = Fluid velocity $\delta_{\mu}\mu^{\mu}$ = Bulk viscosity $J(t) = \int_{t0}^{t} ds\, G(t - s)F(s)$ $J(t)$ = Current density $\partial_t J(t) = \frac{\psi(0)}{D_{GKN}} J(t) + \int_{0}^{\propto} ds\delta_s \psi(s)F(t)$ D_{GKN} = Transport coefficient	Kodama and Koide [24]	1) Considered a diffusion process, 2) Infinite speed volatile the causality, 3) Considered fluid cell of proper volume, 4) Assumed non-Newtonian fluid.
$\frac{\eta^{micro}\ (t; Pe)}{\eta} = -\frac{3}{4\pi} Pe^{-1} \left(1 + \frac{a}{b}\right)^2 \varphi_b u. \int ng(r, t; Pe)) d\Omega$ t = Time u =Uunit vector antiparallel to the line of the externally applied force g (r, t; Pe) = Function of time r~(a+b) = Dimesionless length $\frac{\eta^{micro}}{\eta}$ = Microviscosity	Zia and Brady [26]	1) Heterogeneous and isentropic formation 2) Assumed steady state 3) Considered the microstructural perturbation

OVER VIEW OF FLUID MEMORY

Fluid memory is one of the important phenomena for reservoir engineering. Till now lots of study has done for this topic. Till today al most all the models are failed to show the real picture of fluid memory. Most of the cases for simplicity, considered fluid as Newtonian. But in real field no fluid is Newtonian. Even now we also know that even water is non-Newtonian fluid. Most of the models developed for one dimensional flow. Their is no fluid memory model for two or three dimension. Hossain et al [7] in their review tried to show the fluid properties and memory till that time. And after that they developedal sever fluid memory model varrying their assumption. Those model are most accepted model for fluiid memory. But there are some limitations also. They assumed fluid is non-Newtonian and also developed all of their models for one dimension.

FUTURE RESEARCH SCOPE

Reservoir engineering plays an important role in petroleum production. And fluid property is one of the most integrated part of reservoir engineering. Till now there is no such fluid model; specialty for stress-stain which describe the real picture of reservoir fluid property. Hosaain et al [3] established a model but till it is not totally appropriate. A comprehensive stress- strain model can be developed considering fluid as non-Newtonian, thixotropic behavior, more than one dimension and mostly fluid memory and media. For comprehensive model also should be consider compressibility, pH, density etc. So there are a lot of space to come up a comprehensive fluid (stress-strain) model incorporating memory concept.

CONCLUSION

The study presents a survey on existing fluid flow models that are related to memory concept. The most uniqueness of memory depends on its definition and it varies with a particular fluid medium and also with various combinations of any given fluid. It is one of the greatest difficulties of fluid memory. Memory itself is a continuous function of all available properties of a given fluid and its medium over time. A big challenge is the understanding, incorporating effects, and behavior of a fluid memory in reservoir fluid accumulated with porous media. Preliminary, some complex phenomena of the fluid and some relative relation to fluid viscosity and density may be assumed. Time function is much more important for reservoir porous media, as it has large effects on permeability of a formation. A compact explanation of fluid behavior awaits overall elaboration and addition of new sets of relations between fluid density, viscosity, stress and strain as well as all other fluid and media properties with memory. This paper reveals that memory function helps in interpreting the reservoir intentionality till now and some additional consideration to generate a more efficient and comprehensive fluid memory model.

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NOMENCLATURE

$\lvert\delta\sigma/\delta T\rvert$	the derivative of surface tension σ with temperature and can be positive or negative depending on the substance
η	ratio of the pseudo-permeability of the medium with memory to fluid viscosity
ξ	dummy variable for time
φ	porosity of fluid media
ρ_o	density of the fluid, kg/m^3
du_x/dy	velocity gradient along y-direction, m/s/m
τ_T	shear stress at temperature T, ^0K
μ_o	fluid dynamic viscosity, cp
α_D	thermal diffusivity, m^2/s
α	fractional order of differentiation
σ	surface tension
y	distance from the boundary plan, m
u_x,	fluid velocity in the direction of x, m/s
t	time, sec
ΔT	T_T-$T_{o,}$ °K
T	temperature, °K
R	universal gas constant, kJ/ mol-K
ΔP	P_T-P_o = Pressure difference, N/m^2
P (y, t)	fluid pressure, N/m^2
Ma	marangoni number
k	permeability of the system, mD
h	length in temperature gradient, m
E	activation energy for viscous flow of 30 API gravity oils, KJ/mol
c	total compressibility of the system, 1/pa
A_{xz}	cross sectional area of rock perpendicular to the flow of heat, m^2
2-D	two dimensional

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Comparison of Reservoir Parameters from Pressure Transient and Production Data Analysis: A Case Study

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ABSTRACT

This paper studies the applicability of Pressure Transient Analysis (PTA) and Production Data Analysis (PDA) in estimating reservoir and well parameters. The motivation for the work arose from a need to assess the reliability of PDA as a substitute for PTA, and to corroborate results obtained from PTA with those obtained from PDA. Pressure-Time data and Rate-Time data obtained from a real producing well, aliased as Well A, were analyzed. The scope of analysis was limited to estimating the reservoir permeability and skin factor. It was found that these two independent methods yielded reasonably close estimation of permeability and skin for the given case study.

Keywords: Pressure Transient Analysis, Rate Transient Analysis, Decline Curve Analysis, Production Data Analysis, Fetkovich method, Blasingame method

INTRODUCTION

Estimating reservoir parameters such as permeability, skin, reservoir pressure, drainage area, fracture length, distance to boundary, etc., are very important task for the reservoir engineer. Pressure Transient Analysis (PTA) is well established method and widely applied in the oil and gas industry for estimating these parameters. The basic idea of PTA is to manipulate the flow rate of a well and interpret the corresponding bottom hole pressure response. Rate manipulation may be achieved by production or injection at a constant rate, or more than one constant rates, including a zero-rate or shut in period. PTA

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is usually costly and involves disruption of production. PTA is mathematically rigorous and derived from the diffusivity equation, which is the fundamental equation to describe fluid flow through porous medium.

Production Data Analysis (PDA) on the other hand, has its roots in the traditional decline curve analysis (DCA). DCA evolved from empirical observations, and involved study of rate versus time, ignoring pressure data. The purpose of DCA was to predict future performance of a well, and to estimate ultimate recovery. It did not yield any reservoir parameter. Modern PDA techniques, however, take into account the pressure data as well. Most importantly, these methods are not empirical, rather mathematically rigorous. Modern PDA techniques are able to predict future rates, original oil/gas in place, and reservoir properties such as permeability, drainage area etc. In this regard PDA is comparable to traditional pressure transient analysis (PTA). To emphasize this point, PDA is also sometimes called rate transient analysis (RTA).

For PTA, special procedures, or well tests are performed to collect the data. The duration of these tests range from hours to days, and require elaborate testing equipment setup. For PDA, the readily available rate and flowing pressure data from the field are used. The data may be for months to years.

PTA and PDA represent two independent techniques for estimating reservoir parameters. Ideally both techniques should yield reasonably close results. Considerable amount of literature is published on both of the subjects, addressing theoretical developments. Comparative study with actual field data, however, is not so prolific. This paper therefore investigates this concept by applying both PTA and RTA to analyze the data obtained from the same well.

LITERATURE REVIEW

i) Pressure Transient Analysis (PTA)

PTA is widely applied in petroleum industry to investigate reservoir parameters. Gringarten (2008) provided an excellent overview of well test analysis, covering the historical and theoretical developments of the subject. The theory lies in the solution of the diffusivity equation (van Everdingen and Hurst, 1949). The welltest interpretation techniques prevailing in the 50's and 60's were covered in the two SPE monographs (Matthews and Russell, 1967, Earlougher, 1977). These techniques involved locating the middle time straight line on a semi-log plot of pressure versus time. The reservoir, well, and flow models covered from simple homogenous reservoir to dual porosity reservoirs, from vertical unfractured to hydraulically fractured wells, and from radial flow to linear/bi-linear flow.

Typecurves became popular in the late 70's with the works of Gringarten et.al (1979), Gringarten (1984, 1987) etc. Type curves are graphical representation of the solutions of diffusivity equation, where for the sake of generality dimensionless variables for pressure, time, wellbore storage, etc are used. Addition of pressure-derivative added more power to the analyst (Bourdet et. al, 1989). Type curve analysis involved plotting the pressure change and pressure derivative versus time, or some suitable transform of time, on a log log paper. Then the plot is overlaid on the appropriate type curve to obtain a match. Reservoir parameters are estimated from match point relations. With type curves, It became possible to analyse more complex boundary effects as wel as early time behaviours. Different type curves have been

developed for different reservoir and well configurations such as homogeneous and dual porosity reservoirs, vertical, horizontal and fractured wells, etc.
Computers became an indispensible tool for well test analysis during the 90's. With that development came a new era where it became possible to match the observed data with computer generated or simulated data, which gave more confidence to the interpretation results. The challenge was to select the correct reservoir, well and boundary models. Convolution/deconvolution (von Schroeter et al 2001, Kucchuk et. al 2010) technique came in the new millenia, which greatly improved interpretation.
With the techniques available now, one can estimate the reservoir permeability, skin, average reservoir pressure, wellbore storage coefficient, drainage volume, fracture length, double porosity parameters such as storativity and inter porosity flow coefficient, etc.

ii) Production Data Analysis (PDA)

PDA or RTA is an advanced approach to conventional decline curve analysis. Ilk et. al (2007) and Mattar and Anderson (2003) provided excellent overviews on the evolution of PDA. The concept of conventional decline curve analysis was to fit past production data to a curve using empirically derived exponential, hyperbolic or harmonic functions, and use the curve to predict future performances of the well (Arps, 1944). The objective of conventional decline curve analysis was to predict future oil rate and to estimate the ultimate recovery of the well. It did not provide information on reservoir or well parameters.
An advanced approach of decline curve analysis is established when Fetkovich (1980) introduced the concept of using type curve to analyze rate-time data. Fetkovich introduced two dimensionless variables-dimensionless flow rate and dimensionless time and applied constant pressure at inner boundary. Fetkovich then demonstrated that this analytical solution and the empirical solutions from Arps can be combined into a log-log plot to generate a set of type curves. Fetkovich type curve is able to match production data from both transient and boundary dominated periods, and provides reservoir parameters such as permeability, skin and drainage area.
Blasingame et. al (1986, 1991) overcame the limitation of Fetkovich's work and developed a technique where the flowing bottomhole pressure varied. The authors proposed functions that could transform the production data for a system with changing rate or changing pressure drop into an equivalent system produced at a constant bottomhole pressure.
Blasingame Type Curve have identical format with Fetkovich type Curve, but contains three curves and modified dimensionless variables. The x-axis is changed to modified dimensionless decline time function, and the y axis is changed to 3 types of plotting functions: i) Normalized rate curve, ii) Rate-Integral function, and iii) Derivative of the Rate-Integral function. Similar to PTA type curve techniques, the real data are plotted on log-log paper after appropriate transforms and matched with the type curve. The reservoir parameters can then be estimated from match point relations. Computer applications are now available which can aid the matching process, as well as performing simulation using the estimated parameters.

METHODOLOGY

Proper well testing data were not available, only the rate and pressure history of about six years were provided by the company. Following steps were taken to complete this work:

1) The data were screened and filtered for abnormalities.
2) From the rate and pressure history plot, the periods with clear buildup and/or drawdown in pressure response were identified. The corresponding rates were noted. These were treated as well test data and used for PTA.
3) PTA was performed using type curve matching, and simulation. The software Saphir by KAPPA Engineering was used for this purpose.
4) The period where the production rate of the well undergo natural decline was identified. These were used for PDA.
5) PDA was performed using Fetkovich and Blasingame type curve matching methods. The software Topaze by KAPPA Engineering was used for this purpose.

RESULTS AND DISCUSSIONS

Table 1 show the well and reservoir information used in this case study.

Table 1. Well, Reservoir and Fluid Data from Well A

Oil FVF	1.66 rb/STB
Viscosity	0.294 CP
Total Compressibility	1.75 X 10^{-5} /psi
Pay thickness	87 ft
Wellbore radius	0.51 ft
Porosity	26.3%

i) Summary of PTA Results

From the entire history, 3 sets of pressure buildup (PBU) and 2 sets of pressure draw down (PDD) data were chosen for analysis. The results are summarized in Table 2.

Table 2: Summary of PTA Results

Parameter	**Pressure Transient Analysis**					
	PBU15	**PBU38**	**PBU44**	**PDD10**	**PDD15**	**Average**
Permeability, k (mD)	174	110	130	152	153	143.8
Skin, s	-0.219	-2.82	-2.6	-2	-1.75	-1.88
Quality of match	Good	Good	Good	Satisfactory	Good	-

As summarized in Table 2, the permeability (k) and skin (s) estimated from the 5 PTAs are in the range of 110 mD to 174 mD and -2.82 to -0.219 respectively. The average values for k and s from all 5 PTA's are 143.8 mD and -1.88 respectively. PBU15, PBU38, PBU44 and PDD15 are considered as good analysis because the infinite acting radial flow (IARF) periods were clearly seen on the pressure derivative curves, and good matching was obtained from simulation. Figure 1 is shown as an example which represents PBU15. PDD10 is considered satisfactory because the IARF period is not clearly visible, and the matching is not as good.

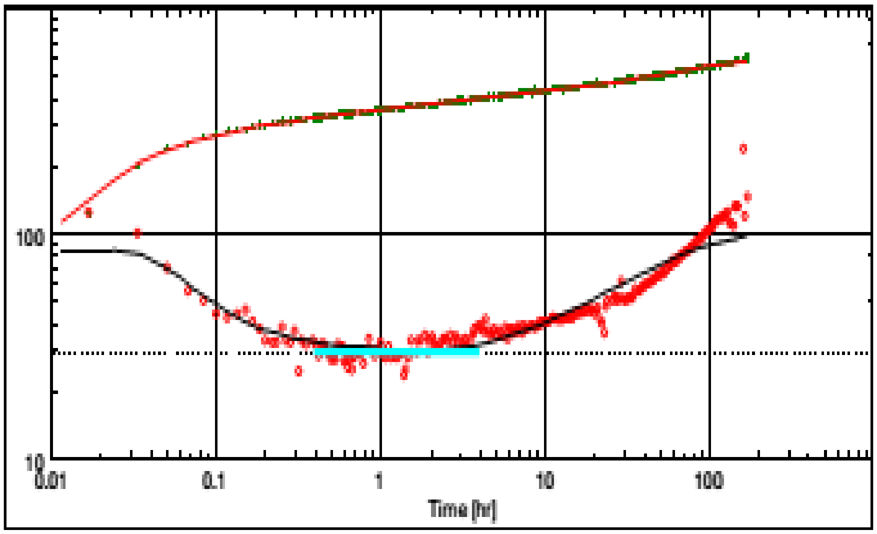

Figure 1: Log –log and derivative matching for PBU15

ii) Summary of RTA Results

A period of 6 months was selected where a clear declining trend is seen (Figure 2).

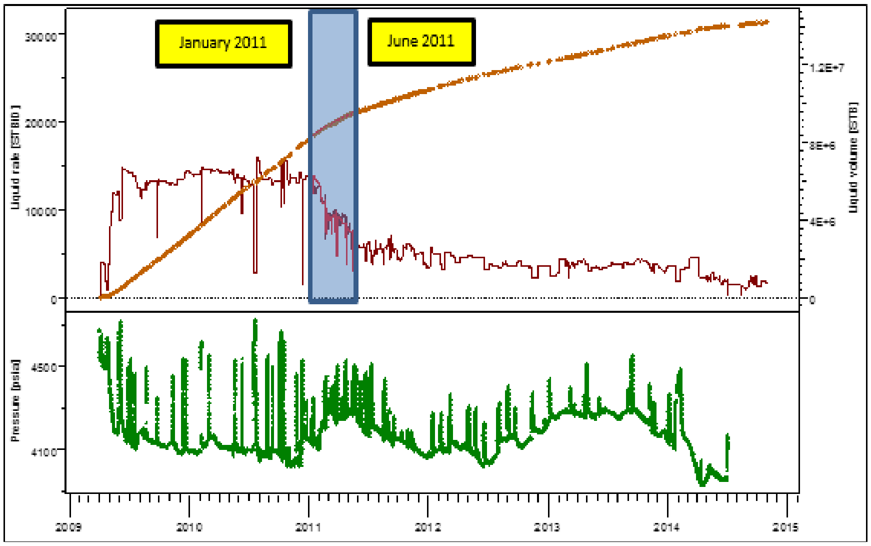

Figure 2: Rate and Pressure History of Well A

Data from this period were analyzed using Fetkovich and Blasingame methods. The results are summarized in Table 3.

Table 3: Summary of RTA Results

Parameter	**Rate Transient Analysis**		
	Fetkovich	**Blasingame**	**Average**
Permeability, k (mD)	208	119	163.5
Skin, s	-1.08	-0.293	-0.69
Quality of the Analysis	Good	Good	

It can be seen that the values of k and s from the two methods are in the range of 119 mD to 208 mD and -1.08 to -0.293 respectively. The average values are 163.5 mD and -0.69 respectively. Both analyses are considered good because the actual data match closely with the type curve (Figure 3).

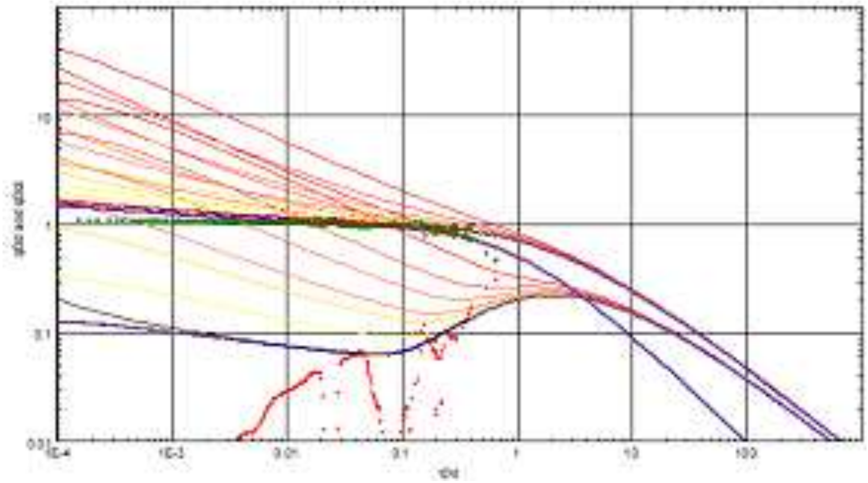

Figure 3: Production data matching on Blasingame Type curve

iii) Comparison of PTA and PDA Results

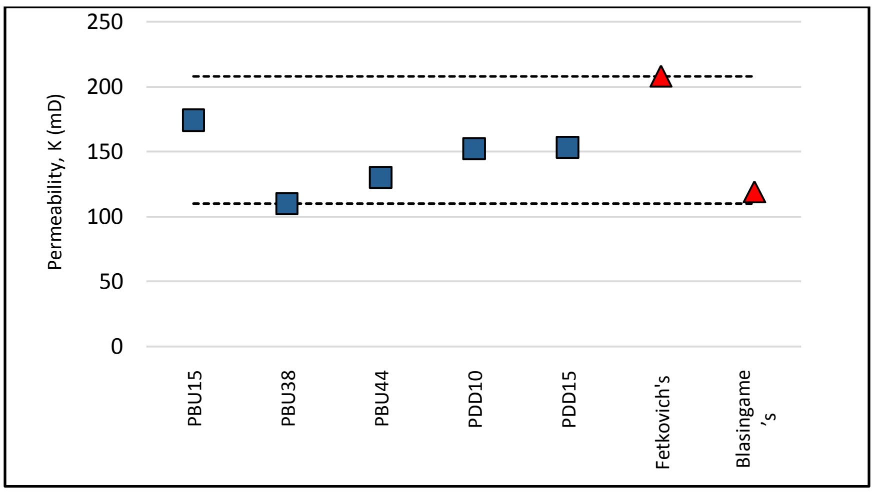

Figure 4: Comparison of k from PTA and PDA

Figure 4 shows the comparison of reservoir permeability, k estimated from the five PTA's, and two PDA's. The results show that the reservoir permeability estimated from all of the seven analysis fall within the range of 110 mD to 208 mD. Particularly, k from Blasingame method is very close to k from PBU38 and PBU44. The average k from PTA and from PDA differs by 14%. Hence, it can be concluded that k from both methods are reasonably close for the case study.

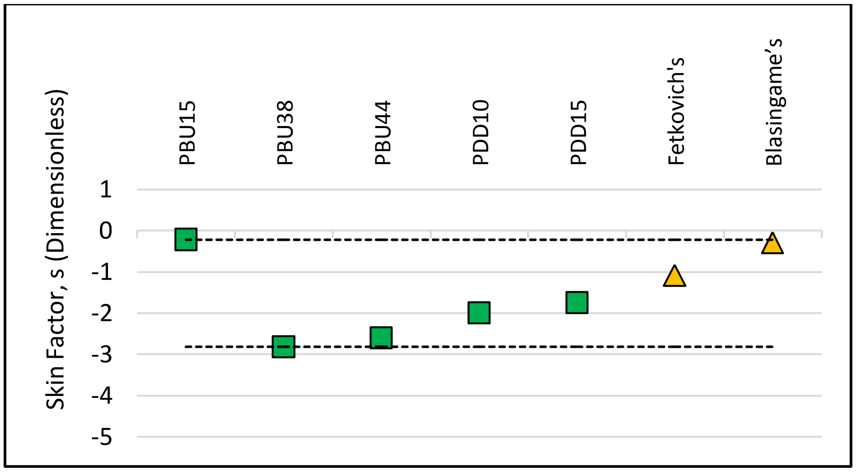

Figure 5: Comparison of s from PTA and PDA

Figure 5 shows the comparison of skin, s estimated from the five PTA's, and two PDA's. It can be seen that all of the seven analysis estimated that Well A has low skin factor, which is in the range of -0.219 to -2.82. In particular, s from Blasingame method is very close to that from PBU15. The average s from PTA (-1.88) and PDA (-0.69) differ by a small amount, and both indicate slightly stimulated condition. Hence, it can be concluded that s from both methods are reasonably close for the case study.

iv) Comparison of PTA and PDA methods

Both PTA and PDA have their own limitations. PTA requires pressure and production data of a few hours to days, while PDA requires data of a few months to years. However, PTA can be planned and performed anytime during the life of a well, while PDA can only be performed when the well undergoes natural decline in its production rate. On the other hand, PDA data is usually very noisy while while PTA data quality should be better because the data is obtained in a controlled manner. PTA is usually much more costly than PDA. Besides, PDA can provide information not only on reservoir characterizations, but also on future well performance.

CONCLUSION

Both PTA and PDA provided reasonably close estimation of permeability and skin for Well A. The differences in average permeability and skin factor from both methods are only 14% and ±1 respectively. However, this is from only one case study. Many more case studies should be conducted to see whether PDA can be a reliable substitute for PTA.

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