CANDIDATE'S DECLARATION

It is hereby declared that this project or any part of it has not been submitted elsewhere for the award of any degree or diploma.

Signature of the Candidate

....

(FATICK NATH)

RESERVOIR SIMULATION OF HARIPUR GAS FIELD TO ANALYZE THE FIELD PERFORMANCE BY PRODUCTION AND PRESSURE HISTORY MATCHING

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DEPARTMENT OF PETROLEUM & MINERAL RESOURCES ENGINEERING

BUET, DHAKA

BANGLADESH

NOVEMBER 2010

RESERVOIR SIMULATION OF HARIPUR GAS FIELD TO ANALYZE THE FIELD PERFORMANCE BY PRODUCTION AND PRESSURE HISTORY MATCHING

A Project

Submitted to the Department of Petroleum & Mineral Resources Engineering

in partial fulfillment of the requirements for the

Degree of Master of Engineering (Petroleum)

By

FATICK NATH

DEPARTMENT OF PETROLEUM & MINERAL RESOURCES ENGINEERING

BUET, DHAKA

BANGLADESH

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RECOMMENDATION OF THE BOARD OF EXAMINERS

The undersigned certify that they have read and recommended to the Department of Petroleum and Mineral Resources Engineering, for acceptance, a project entitled RESERVOIR SIMULATION OF HARIPUR GAS FIELD TO ANALYZE THE FIELD PERFORMANCE BY PRODUCTION AND PRESSURE HISTORY MATCHING submitted by FATICK NATH in partial fulfillment of the requirements for the degree of MASTER OF ENGINEERING in PETROLEUM ENGINEERING.

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DEDICATED TO

MY BELOVED PARENTS AND RESPECTED TEACHERS

OF PETROLEUM ENGINEERING DEPARTMENT

ABSTRACT

Well-7 of Haripur gas field was spud in 1986 by BAPEX. After 07 years of uninterrupted oil production, the well ceased its production on 14th July, 1994. The 1^{st} work over of Sylhet well -7 was completed in March 2005. This well was recompleted in lower Bokabil sand as gas producer with an initial production capacity of 15MMCFD. The gas production was ceased again in July 2008. The 2^{nd} work over has been successfully completed in the existing perforation zone on February 2, 2010. Commercial gas production started from Sylhet-7 with an average production 6-8 MMSCFD with about 2100 psig well head pressure.

In this study, material balance, production data analysis (PDA), pressure transient analysis (PTA) and reservoir simulation are conducted to understand the different reservoir information and predict future production performance.

This study uses Material balance analysis tool MBAL, Well model software PROSPER, PDA tool TOPAZE, PTA tool SAPHIRE and commercial reservoir simulator CHEARS to find out reservoir characteristics, pressure and production history matching of producing sand of Haripur gas field.

This study estimates initial gas in place, recoverable reserves and remaining reserves of producing sand of Haripur gas field. Current study has yielded the gas initial in place of 24 BSCF of lower Bokabil (sand-D) sand which is close to Petrobangla recent study by RPS Energy. Permeability and skin factor of this formation are investigated by pressure transient analysis. No re-estimation of reserve for the other sands is conducted in this study.

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NOMENCLATURE

AAPG	American Association of Petroleum Geologists
BAPEX	Bangladesh Petroleum Exploration & Production Co. Ltd.
BBL	Barrel
B_g	Gas volume expansion factor
BGFCL	Bangladesh Gas Fields Co. Ltd.
BMSL	Below Mean Sea Level
BOC	Burmah Oil Company
BOGMC	Bangladesh Oil, Gas and Mineral Corporation (Petrobangla)
BPI	Bangladesh Petroleum Institute
BSCF	Billion (10^9) Standard Cubic Feet
BUET	Bangladesh University of Engineering and Technology
C_1	Methane
C_2	Ethane
C_3	Propane
CHEARS	Chevron Extended Application Reservoir Simulator
DST	Drill Stem Test
EURR	Estimated Ultimate Recoverable Reserve
E & P	Exploration and Production
ft	Feet
FWHP	Flowing Well Head Pressure
FBHP	Flowing Bottom Hole Pressure
FY	Fiscal Year (July to June)
G & E	Geological and Engineering
GFAP	Gas Field Appraisal Project
GGAG	German Geological Advisory Group
GIIP	Gas Initially in Place
GWC	Gas water Contact
HCU	Hydrocarbon Unit

HHSP	Hydrocarbon Habitat Study Project
HM	History Matching
IDA	International Development Agency
IKM	Intercomp-Kanata Management Ltd.
IMEG	International Management and Engineering Group Ltd.
IOC	International Oil Company
IPR	Improved Petroleum Recovery International. Ltd
JOE	Japan Oil Engineering Co.
JPT	Journal of Petroleum Technology
KB	Kelly Bushing
MBAL™	Material Balance Software
MB	Material balance study
MD	Measured Depth
MMBBL	Million (10^6) Barrel
MMscf	Million (10^6) Standard Cubic Feet
NE	North-East
NNE	North-north-east
NNE-SSW	North-north-east-South-south-west
UNECAFE	United Nations Economic Commission for Asia and Far East
UNECE	United Nations Economic and Social Council, Economic Commission for Europe
NPD	Norwegian Petroleum Directorate
NW-SE	Northwest- southeast
OECF	Overseas Economic Cooperation Fund, Japan
OGDC	Oil and Gas Development Corporation (Pakistan)
OIIP	Oil Initially in Place
OMS	Oil and Mining Services (UK)
ONGC	Oil & Natural Gas Corporation (India)
PB	Petrobangla
PEPP	Petroleum Exploration Promotional Project
PMRE	Petroleum and Mineral Resources Engineering Department of BUET
ppm	Parts per million

PPL	Pakistan Petroleum Ltd
PSC	Production Sharing Contract
psi	Pounds per square inch
PSOC	Pakistan Shell Oil Company
PVD	Term used by D & M to indicate Proved Reserve as Probable (PVD) due to absence of sales contract for Bibiyana Gas Field
P/z	Pressure/ Z factor
P1	Proven
P2	Probable
P3	Possible
2P	Proven + Probable
3P	Proven + Probable + Possible
RPS	RPS Energy is a UK based Petroleum Consultant
RFT	Repeat Formation Tester
RMS	Root Mean Square
RSC	Reservoir Study Cell of Petrobangla
SBHP	Shut in Bottom Hole Pressure
SGFL	Sylhet Gas Fields Ltd.
SE	South - East
SPE	Society of Petroleum Engineers
SSW	South-south-west
STANVAC	Standard Vacuum Oil Company
SW	South-West
SWHP	Shut in Well Head Pressure
Tscf	Trillion (10^{12}) Standard Cubic Feet
TDT	Thermal Decay Time log
TVD	Total Vertical Depth
TVDss	Total Vertical Depth, subsea
z	Compressibility factor

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Chapter 1

INTRODUCTION

1.1 Overview of Haripur Gas Field

Haripur gas field is located in Sylhet district, about 22km from the Sylhet city. It was the first discovered hydrocarbon field in Bangladesh. On the basis of geological survey, the Pakistan Petroleum Limited (PPL) started drilling activities in Haripur structure back in 1955. A total of eight wells were drilled in this field, of which two turned out as gas producer and one as oil producer. Well-1 blew out due to abnormal pressure. An abnormally high pressure encountered in the well-2 and to control the situation the well bore was plugged permanently and abandoned. Commercial Gas Production started from well-3 in 1961 and was shut down due to excessive production of water and sand. The well - 4 was drilled in 1962 from which high pressure gas and water started coming out with great intensity after drilling. The well was abandoned due to safety and technical reasons. The well - 5 was drilled in 1969 beside well - 4 as an observation well. The well - 6 was successfully drilled in 1964. This well had been completed as dual gas producer like well-3 and abandoned due to natural breakthrough of water[1].

Haripur well - 7 was spud in 1986 by the drilling contractor BAPEX with an objective to produce the remainder up-dip gas of Sylhet structure which could not be tapped through Well - 6 & 3. This is the first discovery of mineral oil in the country. Initially the oil production was around 350 barrels per day with negligible water cut. However, with time a gradual production declining trend had become apparent. After 07 years of more or less uninterrupted production the well ceased its production on 14th July, 1994. A wire line investigation was conducted in February, 1995. It was found that the well was killed by itself with a standing formation of water column in the tubing[2].

The 1st work over of Sylhet well -7 was completed in March 2005. This well was recompleted as gas producer with an initial production capacity of 15MMCFD. The Gas production was ceased in July 2008. The 2nd work over of Sylhet-7 has been successfully completed in the existing perforation zone on February 2, 2010.Commercial gas production started from Sylhet-7 with a average production 6-8 MMSCFD gas[3].

The reservoir simulation study is done in this project for the producing work over well of Haripur gas field by using the pressure and production history matching. This study estimates initial gas in place, recoverable reserves, remaining reserves and comparative production prediction is made for the producing sand of this field. Comparison has been made with the result of production data analysis, material balance and reservoir simulation study to verify the initial gas in place.

Nowadays, reservoir simulation in the oil industry has become the standard for solving reservoir engineering problems[4]. Simulators for various recovery processes have been developed and continue to be developed for new oil recovery processes. Reservoir simulation is the art of combining physics, mathematics, reservoir engineering, and computer programming to develop a tool for predicting hydrocarbon reservoir performance under various operating strategies. An oil or gas field can be produced only once at considerable expense. On the other hand, a model can be run repeatedly at a low cost over a short period of time. Reservoir Simulation is the key of real-time reservoir management[5].

There are some key steps to every reservoir simulation study[6]:

- Statement and prioritization of objectives
- Reservoir characterization
- Model selection
- Model construction
- Model validation

- Predictions
- Documentation

1.2 Objectives with Specific Aims and Possible Outcomes:

- To analyze the reservoir performance of producing sand of by matching the production and pressure history.
- To estimate initial gas in place, recoverable reserves and remaining reserves.
- To predict future production for the producing sand.

1.3 Outline of Methodology:

- Conduct production data analysis.
- Conduct conventional decline curve analysis.
- Conduct advance decline curve analysis.
- Conduct conventional material balance analysis.
- Conduct different approaches of material balance analysis.
- Check the consistencies with pressure transient analysis for the reservoir parameters used in different analysis.
- Study and review the typical steps involved in a reservoir simulation study.
- Determine the types of data needed for simulation.
- Collection of all relevant data.
- Study and review the different approaches for model validation.
- Study and review the basic components of a traditional history matching approach.
- Analysis and review the different approaches for performance prediction.
- Comparison of this study with the historical previous study conducted for this horizon.

Chapter 2

LITERATURE REVIEW

2.1 Introduction

Haripur gas field (currently renamed Sylhet Gas Field) is the first discovered hydrocarbon field in Bangladesh. The only commercial oil deposit was also discovered in Haripur, in December 1986[3]. The Sylhet structure was drilled after detail geological and geophysical study.

2.1.1 Location

Haripur Gas Field is located in Sylhet district and under PSC block 13 (see Figure 2.1) about 22 km northeast of Sylhet town and beside the Sylhet-Jaintia road. Sylhet-7 is only half kilometer from Sylhet-6 well.

2.2 Geology

Sylhet structure is exposed on the surface with rocks of Dupi Tila age. Geology varies with traps that are folded structures i.e. anticlines, often accompanied by faults.

2.2.1 Structure

Sylhet anticline is an exposed structure with outcrops of Tipam Sandstone. The structure was delineated by PPL during 1953-54 after conducting seismic and geological survey. The structure is a brachi-anticlinal one with relatively steeper SE flank. The structure is pitching NNE-SSW direction. PPL structural maps show the structure as a simple anticline without any faults.

After recording a number of multifold digital lines over the structure GGAG prepared new maps and presence of faults are observed on both pitching zones. A regional fault is also marked on the NW flank of the structure. As the digital multifold lines are quite widely spaced structural interpretation is somewhat speculative[3].

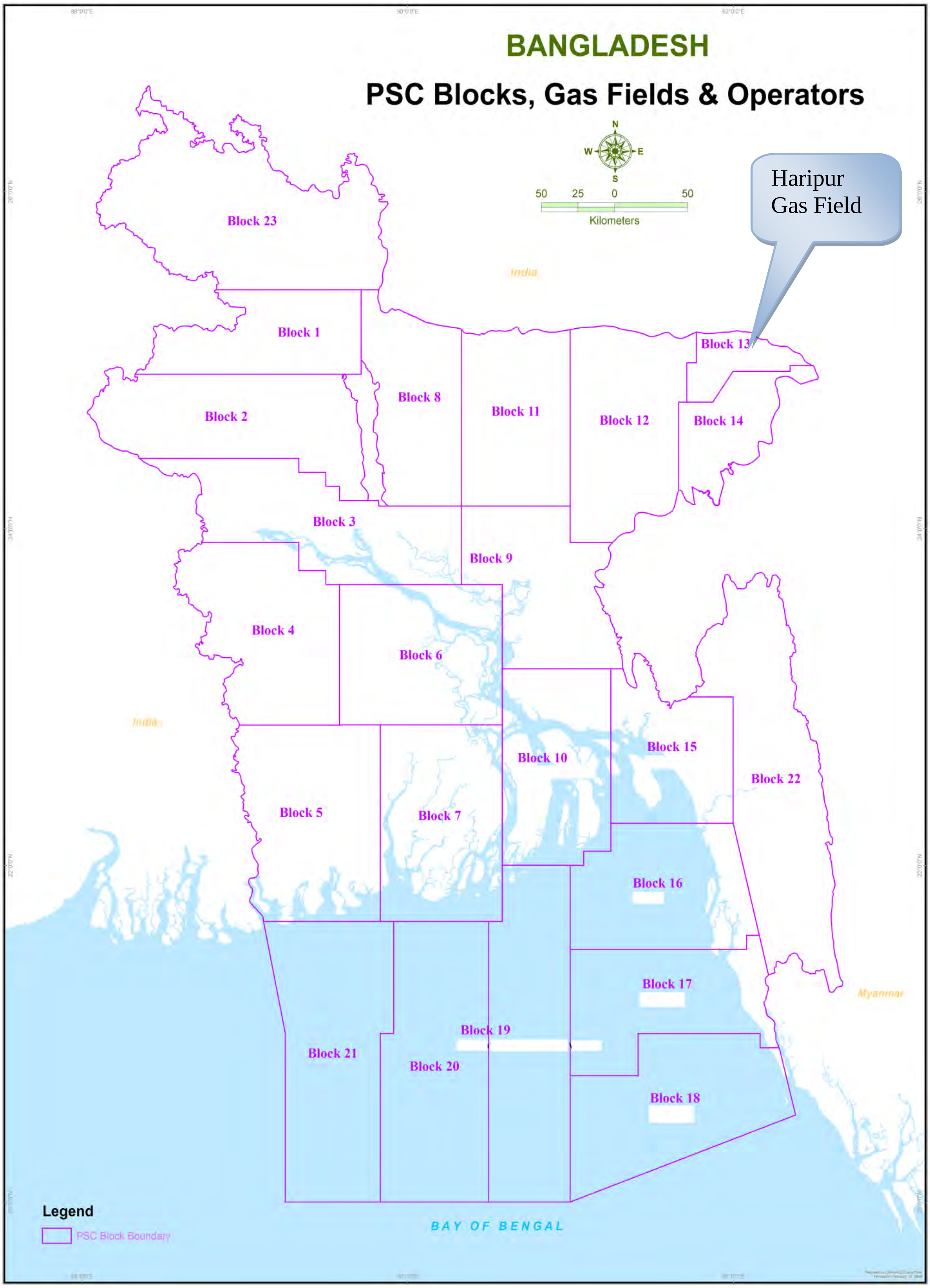


Figure 2.1 *PSC Block Map*[2]

2.2.2 Stratigraphy of Surma Basin

Haripur Gas Field is in the Surma Basin which stratigraphy is shown below. And the well Sylhet-7 is recompleted in the lower Bokabil zone.

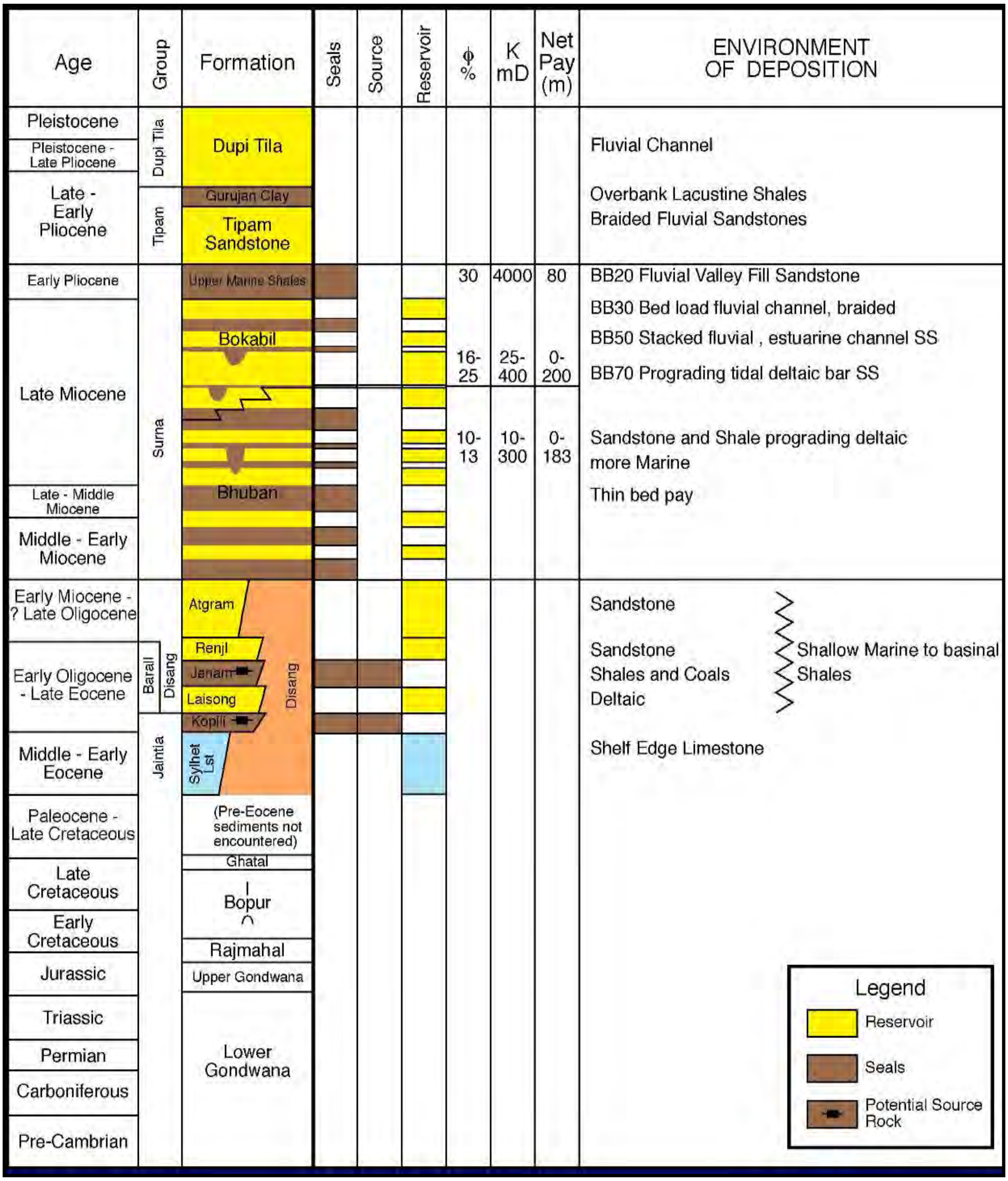


***Figure 2.2** Generalized Stratigraphy of Surma Basin*[3]

2.2.3 Stratigraphy of Haripur Gas Field:

The stratigraphic units encountered in this field are, from bottom upward, Bokabil Formation, Tipam Formation, Girujan Clay Formation and Dupitila Formation. Figure 2.4 shows the stratigraphic succession of the Haripur gas field[7].

The lowest unit, the Bokabil Formation, consists of altering sand and shale bed and about 950 meter of the units is drilled without reaching its base. The sandstone is fairly indurated and the shale is laminated. The top of Bokabil unit is marked by regional marker ‘Upper Marine Shale’. The sandstone beds of the Bokabil unit are designated from top downward as ‘A’ sand, ‘B’ sand, ‘C’ sand, ‘D’ sand and ‘E’ sand (Figure 2.3). In the Haripur-1 (currently Sylhet 7) well, only the ‘E’ sand is oil bearing while the Bokabil sands above are gas bearing[7].

The Bokabil formation is overlain by Tipam Sandstone Formation, a predominately sandy unit with a thickness of 920 meter. Above the Tipam sandstone formation lies Girujan Clay Formation, basically clay /shale unit with a thickness of 60 meter. The Dupitila Formation is a sand dominating unit with a thickness of about 135 meter.

The oil bearing sand is about 13 meter thick and occurs at depths between 2020 m to 2033 m below the surface of Sylhet-7 well. Later when the oil production suspended from ‘E’ sand, Sylhet 7 well is recompleted in the ‘D’ sand which is called Lower Bokabil sand.

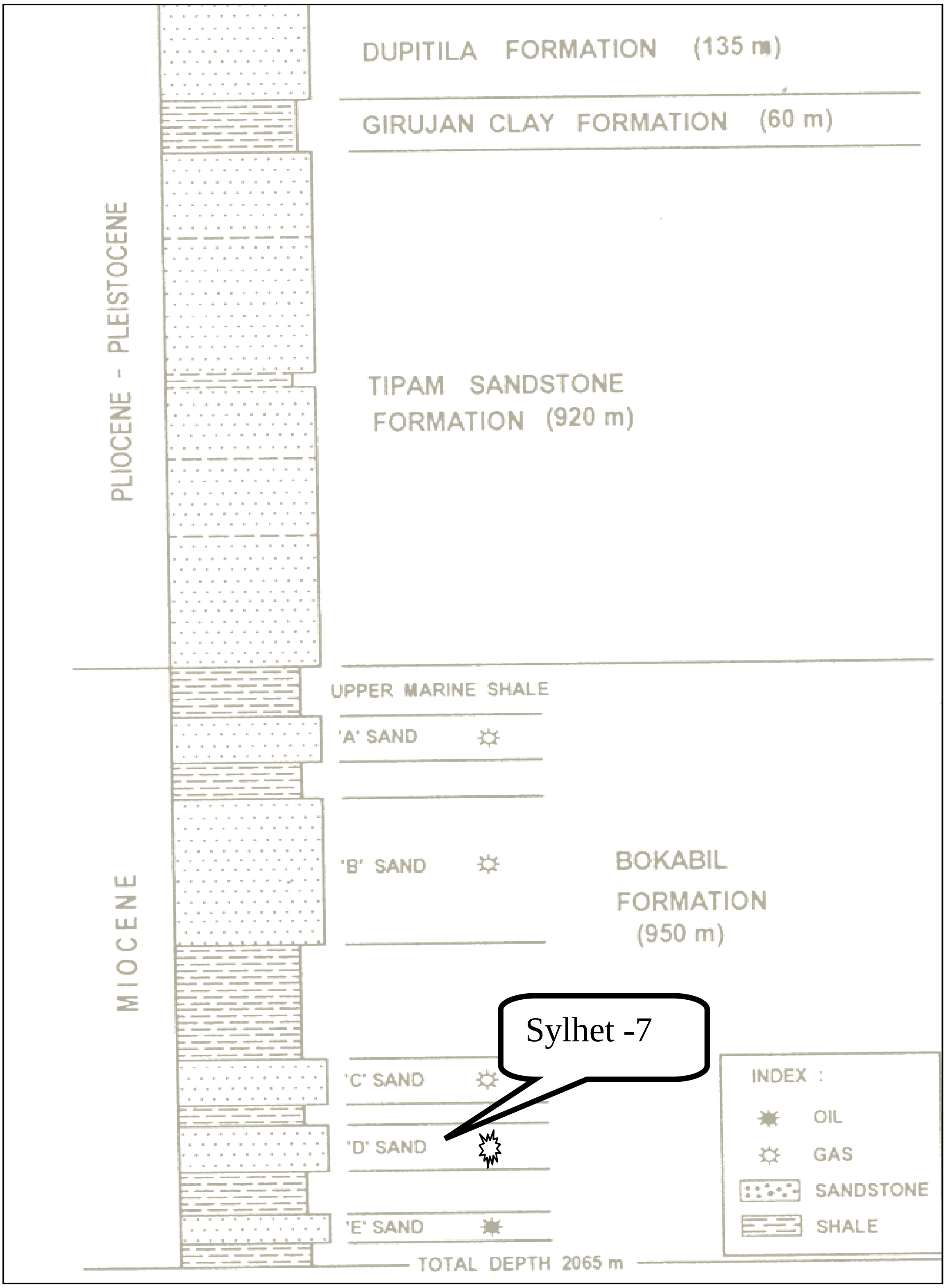


Figure 2.3 *Stratigraphy of Sylhet Gas Field* [7]

2.3 Reservoir

In Sylhet structure a total of four gas bearing and one oil bearing horizons were discovered. Out of these only two gas sands are on production and only oil sand produced for about 3 years from 1986. As in the other fields of the reservoir is sandstones and the age is considered to be Mio-Pliocene. The reservoir sands can be correlated from well to well. Structure contour and cross section of the Haripur gas field is given in Figure 2.4 and Figure 2.5[3].

2.3.1 Tipam

The shallowest gas sand named as 1665 ft Tipam Sandstone by PPL workers and is encountered in well 1, 2, 3, 6 and 7. This horizon consists of a number of gas sands and gas water contact is observed at 506m in all the wells. According to PPL in well 2 this horizon is below GWC and wet. There was no well perforated in the Tipam sand.

2.3.2 Upper Bokabil

Second gas sand encountered in the wells is named as Upper Bokabil Sand. It is found within a depth range of 1215m to 1315m (BMSL) in all the wells. GWC of this sand is observed at 1331m (BMSL) in well 2.

2.3.3 Second Bokabil

Gas sand within Bokabil, named as Second Bokabil Gas Sand was encountered in all the wells. In well 2 this sand is encountered below the gas water contact level and is wet. GWC is observed in well 1, 3, 6, 7 and Surma 1.

2.3.3.1 Surma-1/1A (Syl-8):

In April 1989, Scimitar Exploration Ltd. has drilled this well for the purpose of the first appraisal of Sylhet-7 oil discovery. But there was no significant/commercial oil found. However, Surma-1/1A (Syl-8) was established as a gas producer well in June 2010. On an average 3-4 MMSCFD gas is producing now from Bokabil C sand[1].

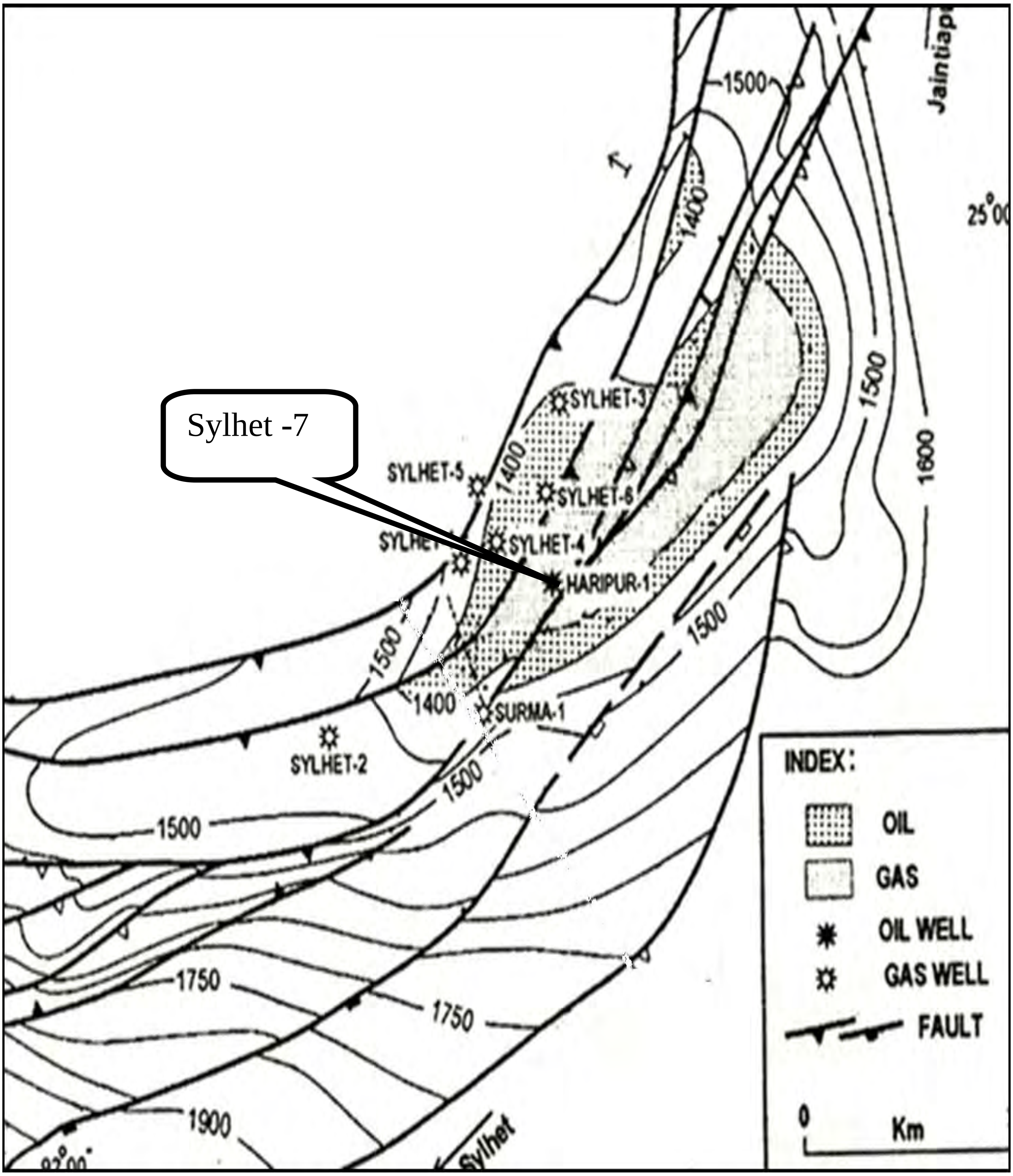


Figure 2.4 *Structure contour of Haripur gas field*[7]

2.3.4 Lower Bokabil

Sylhet-7 was spud on 12th September, 1986 by the drilling contractor BAPEX with an objective to drainage the remainder up-dip gas of Sylhet structure which could not be tapped through well no 6 & 3. The total drilling depth of this well was 2065 meter. During the drilling a potential oil zone was detected in the interval of 2009-2033 meter. The well was completed as oil producer after perforating the interval 2020-2033 meter. This is the first discovery of mineral oil in the country. Initially the oil production was around 350 barrels per day with negligible water cut. However, with time a gradual production declining trend had become apparent. After 07 years of more or less uninterrupted production of total 560,869 barrels of crude oil, the well ceased its production on 14th July, 1994. The natural well head pressure was zero at that time[3].

The first work over of Sylhet-7 was completed as gas producer in March 2005 with an initial production capacity of 15MMCFD. The Gas production was ceased in July 2008 due to wax deposition inside the tubing.

The second work over of Sylhet-7 has been successfully completed in the existing perforation zone (‘D’ sand) on February 2, 2010. The commercial gas production from Sylhet-7 has already been started since 15 February, 2010 with production of 6-8 MMSCFD gas.

2.4 Formation Properties from Previous Studies

According to PPL study average porosity of Upper and Second Bokabil sands are 25 percent. According to PPL this data is from core analysis. For Tipam sandstone reservoir the porosity was evaluated at 26 percent from log data. Average water saturation for two Bokabil sands is estimated to be 30 percent and the same for Tipam Sandstone was considered at 45 percent. Since sonic log indicate a higher porosity as well as porosity.

Log evaluation result (Petrobangla 1988) from Well - 7 indicates that the porosity of the Tipam Sand is ranging from 21 to 28 percent and water saturation from 45 to 68 percent. From RFT data gas water contact can be placed at 504 m and it matches with log data. This depth of GWC is also matching with PPL evaluated depth of GWC.

According to Petrobangla study porosity of Upper Bokabil Sand was ranging from 15 to 20 and water saturation from 30 to 35 percent. No gas water contact is observed in this horizon.

Porosity of Second Bokabil sand was found to range from 12 to 19 percent and water saturation from 40 to 45 percent. RFT data indicate the GWC at 1313m and this is also supported by log data. According to PPL report the GWC is at 1384m. This difference might be due to continuous production from this sand[3].

The Lower Bokabil sand was also found to be a good reservoir with 15–20 percent porosity and 25 to 45 percent water saturation. From RFT data GWC can be placed at 1949m. PPL used data from well 1 and placed GWC at 1941m. According to Log evaluation (Petrobangla 1988), interval 1964–1984 is oil saturated. RFT at 1966m collected 99 cft gas, 110 cc oil and 18 litre filtrate. Another RFT at 1983m collected 33 cft gas, 9 litre oil and 25 litre water (8000 ppm). DST within this interval did not flow to surface. According to pressure chart the well stopped flowing after hydrostatic pressure inside test string reached 2804 psig which gives pressure gradient of 0.435 psi/ft. The computer processed logs indicate high water saturation for this interval. Well drilled in Sylhet structure is given in the Table 2.1[3].

Table 2.1 *Well drilled in Sylhet structure*[7]

Well Name	Year	Total Depth (meter)	Main Hydrocarbon Zones (meter) (Perforated)	Remarks
Sylhet-1	1955	2987	1177-1223 (gas) 1232-1297(gas)	Rig destroyed by blow out, sank into crator filled with water; venting out of gas
Sylhet-2	1956	2818	1314-1366 (gas)	Plugged and abandoned; abnormally high pressure sand
Sylhet-3	1957	1675	1225-1299(gas) 1323-1661(gas)	Gas production well
Sylhet-4	1962	315	-	Rig destroyed by blow out.
Sylhet-5	1963	574	-	Observation Well
Sylhet-6	1964	1406	1211-1281(gas) 1307-1655(gas)	Gas Production well
Sylhet-7 (renamed as Haripur-1)	1986	2065	2020 - 2033(oil)	Oil discovery
Surma-1	1989	2183	2009 - 2033(oil)	Appraisal Well of Sylhet-7
Sylhet -7	April 2005	2065	1874 -1886 (gas) 1901-1908 (gas)	Recompleted Sylhet - 7 in sand 'D' (Lr. Bokabil Formation) as a gas production well after first workover.But due to wax deposition inside tubing production ceased in 2008.
Sylhet -7	Feb 2010	2065	1874 -1886 (gas) 1901-1908 (gas)	During after second workover,the tubing cleaned of Sylhet - 7 and recompleted again as a gas producer from sand 'D'(Second Bokabil)
Sylhet-8	June 2010	2183	1930.5-1936 (gas) 1938.4-1947.4 (gas)	Recompleted Surma-1 in sand 'C' & ‘D’ as a gas production well and after work over well producing from ‘C’ sand from June 2010.

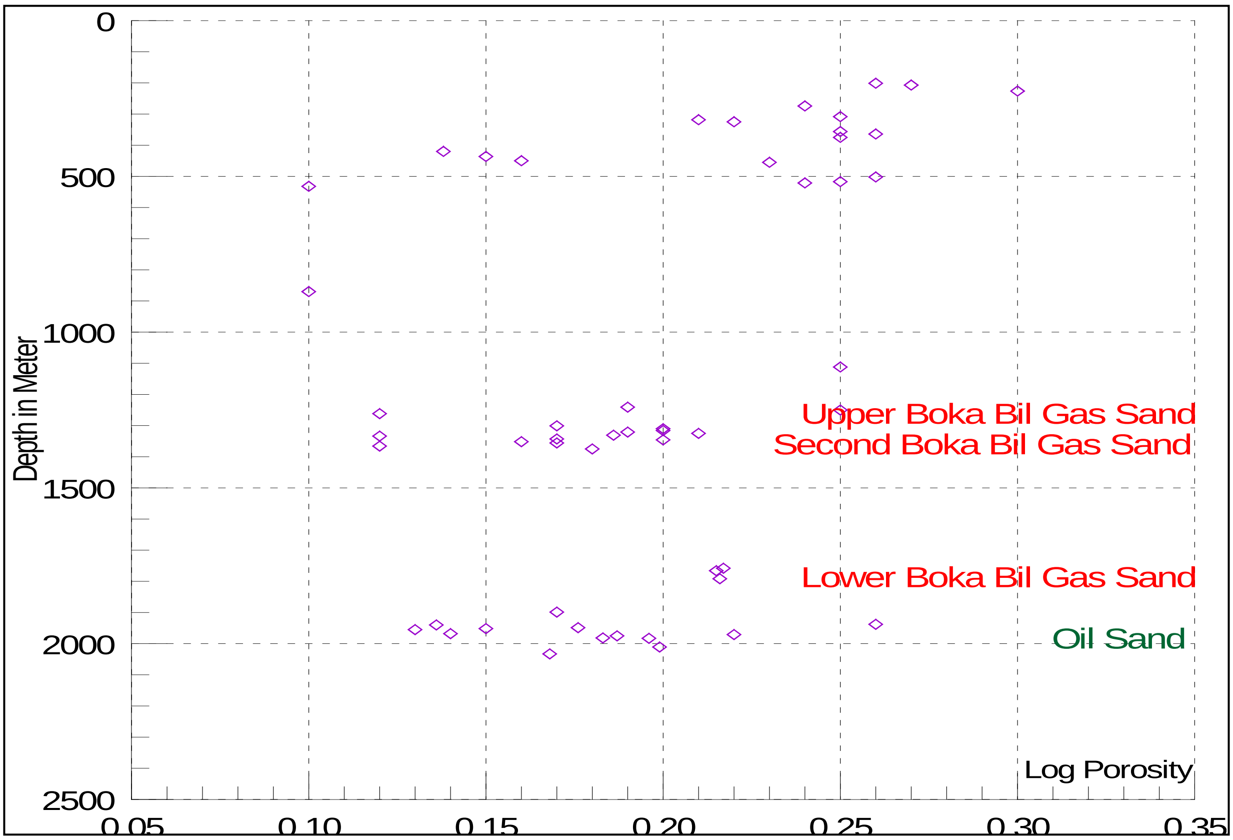


Figure 2.5 *Depth vs. Log porosity Plot for Different Sands*[3]

2.5 Historical Reserve Estimation

The reserve of the field was estimated by different workers at different time using different methodologies. Figure 2.2 shows a comparative scenario of historical reserve estimation done in Sylhet Gas Field on and before of 1971.

Table 2.2 *Summary of Reserve (BCF) Estimation of Sylhet Gas Field*[3]

Sand	PPL 1955	PPL 1957	A. H. Sweatman 1957	Ralph Davies 1958	MB Analysis 1965	PPL Nov. 1966	B. Bonnet 1967 (MB)	James Lewis 1971
Tipam	-	-	-	-	-	29.25	-	28.22
Up. Bokabil	516.3	497	146	210.40	197.48	311.37	235.41	320.98
Second Bokabil	189.8	189	70	119.68	114.61	204.72	-	203.07
Lower Bokabil	-	-	-	16.13	-	-	-	131.59
Total	706.1	686	216	346.21	312.09	545.34	235.41	683.85

A. H. Sweatman of PPL estimated the GIIP of Upper Bokabil Gas Sand at 146 BSCF and 70 BSCF for second Bokabil sand as proved reserve. For proven reserve 900 acres area was considered. Another 203 BSCF gas was estimated as possible GIIP for the Upper Gas Sand and 98 BSCF for the Second Bokabil Sand. The author considered a recovery factor of 70% for both sands for estimation of recoverable reserve[3].

In 1958 R. E. Davies and Associates estimated for two main sands and the deeper Bokabil Sand (1920M). Total GIIP was 346 BSCF with 210 BSCF in Upper Bokabil and 120 BSCF in Second Bokabil Sand. According to this report deeper Bokabil Sand contained 16 BSCF gas. The report considered a recovery factor of 85% for all three sands.

In the Proceedings of the Symposium on the Development of the Petroleum Resources of the Asia and the Far East (1959), gas reserve of Sylhet was mentioned as 280 BSCF.

In a technical note of May 1963 on geological and reservoir engineering data of Sylhet field, GIIP of 1665 ft Tipam Sand was estimated at 40 BSCF and for the 1030 ft Sand the figure was 10 BSCF. The report also contained a table showing reserve figures for two producing sands estimated by PPL in 1955 and 1957. According to this table GIIP of Upper Bokabil Sand was 516 BSCF and for Second Bokabil Sand was 190 BSCF. In 1957 GIIP was revised at 497 BSCF and 189 BSCF for Upper Bokabil and Second Bokabil Sands respectively. For both the cases recovery factor was considered to be 85%.

In April 1965 material Balance Analysis was done using BHP survey data and the GIIP in April 1965 was estimated at 197.48 BSCF for the Upper Bokabil and 114.61 BSCF for Second Bokabil Sands. Another MB analysis using pressure survey data of August 1966 provided very similar result. i.e. 193.02 BSCF for Upper Bokabil 114.85 BSCF for Second Bokabil Sands.

The reserve was updated in 1966 and two main gas sands and Tipam Sandstone (500M) were re-evaluated and the result was 310 BSCF for Upper Bokabil, 193 BSCF for Second Bokabil and 25 BSCF for Tipam Sand (500m). This study also observed that there is a possibility of loss of gas from both Upper and Second Bokabil Sands. The possibilities are the gas is fed into the sandstone sequences at shallower depth and gas is lost into air or both. The report also discussed the possibility of re-pressurization of Second Bokabil Sand by gas leaking from Lower Bokabil sand (1920m). In this report recovery factor is considered at 85%.

In 1967 material balance method was applied to re-estimate the GIIP of Upper Bokabil Sand and the result was 235 BSCF.

The last reserve study before independence was conducted in 1970-71. According to this report GIIP of the field is 683.85 BSCF. The estimate included all the four known gas sands. It may be mentioned here that all earlier reports considered maximum 3 gas sands including two producing gas sands. PPL also had a plan to drill Well 7 at a location about 580m south of Well 6.

Table 2.3 *Post Independence (after 1971) Reserve (BCF) Estimation for Sylhet Gas Field*[3]

Sand	Petrol Consult 1979 *	IMEG 1980	GGAG 1986	HHSPP 1986	Welldrill 1991	PMRE, BUET 2000
Tipam	No estimation conducted before					-
Upper Bokabil	130	291.5	245.08	291.5	400	840
Second Bokabil	34	155.2	230.18	152.5		
Lower Bokabil (1920 m)	No estimation conducted before					
Total	164	446.7	475.26	444.0	400	840

Recoverable

After independence of Bangladesh in 1971 both Sylhet and Chattak PPL became abandoned property and the Government of Bangladesh took control of these gas fields and Sylhet Gas Fields Ltd. was established.

Initially there was not much information about the Sylhet structure with less number of well drilling. But gathered information became more as well drilling increased throughout the structure and reflected in the reserve estimation by different authors over time. Table 2.3 shows post independence estimates conducted by different authors[3].

In 1977 The National Committee for Utilization of Natural Gas used 280 BSCF as recoverable reserve of Sylhet field.

First post independence study was made in 1979. Schubert and Schmidt conducted the study on Bangladesh gas reserve and they followed the probabilistic method. According to this estimate maximum recoverable reserve of two producing sands could be 455 BSCF and the minimum value could be 112 BSCF. The most likely value was 164 BSCF.

In 1980 IMEG conducted study on gas reserve and according to this study GIIP of two producing gas sands of Sylhet was 446.7 BSCF (291.5 + 155.2).

In 1986 GGAG did a study on gas reserve of the country and they followed the probabilistic approach. This study indicated that the most likely GIIP of two producing sands could be 475 BSCF and the maximum figure can go up to 937 BSCF and the minimum figure was 212 BSCF.

In the same year, Petrobangla under HHSPP re-estimated gas and condensate reserve of two producing gas sands only. This study placed the GIIP of two producing sands at 291 BSCF (Upper Bokabil) and 152 BSCF (Second Bokabil). Since then Petrobangla is using this reserve figures in all official publications[3].

In 1986 Sylhet well - 7 was drilled and oil was discovered at depth 2020-2035. During DST this interval flowed oil. This is the first oil discovery of the country. Immediately after DST, production test was carried out. Well - 7 opened a number of gas sands within a depth range from 175m to 500m and this interval belongs to Tipam Formation. Sylhet - 7 also opened Upper Bokabil, Second Bokabil and Lower Bokabil gas sands.

In 1987 the oil field along with the area within Block 13 was awarded to Scimitar Oil. Scimitar drilled one well (Surma-1) near well-7 and the oil sand was encountered in this well too. However during testing it did not flow, instead water flow was observed. Poor cement bond around target horizon could be a possible reason of water flow. No further action was taken. Scimitars contract was terminated in 1992.

In 1991 Welldrill was appointed to estimate the gas reserve of the country. Welldrill studied Sylhet field and according to this report gas reserve figure was taken from HHSPP report by Welldrill in 1986.

In 1992 Gasunie as a part of 3rd Natural Gas Development project carried out a study on gas reserve of the country. They used the reserve figure as estimated by HHSPP.

PMRE Department of BUET in 2001 re-estimated the reserve of the country’s gas fields and according to this study GIIP of two producing sands of Sylhet field is 840 BSCF. This study used material balance method.

PPL also did some material balance analysis for two producing sands using pressure data collected till 1965 and considering no water drive. According to those studies the GIIP of the Upper and Second Bokabil Sands are 197.483 and 114.606 BSCF respectively. Pressure survey data of 1966 indicated quite similar GIIP i.e. 193.021 and 114.851 BSCF for Upper and Second Bokabil Sands respectively. 1967 pressure survey data also indicated quite similar results. However, from 1967 pressure survey PPL Reservoir Engineers observed that the average SBHP of the Upper Bokabil Sand appeared to be recovering. SBHP of the Second Bokabil is stabilized and the pressure of Tipam Gas Sand appeared to be declining.

HCU-NPD study used the reserve estimate report of 1971 for Sylhet field and accepted the estimate as it is only report which included all four gas sands of the field. The same report also contained material balance estimate for two producing sands. Material Balance estimate for Upper Bokabil Sand indicate a GIIP of 411.65 BSCF and for Second Bokabil the figure is 264.39 BSCF[3].

2.6 Historical Production from the Sylhet Gas Field

The cumulative production from Sylhet gas field was 184.3 BSCF until June 2010.For the current report cumulative production figure is taken from MIS report of Petrobangla.

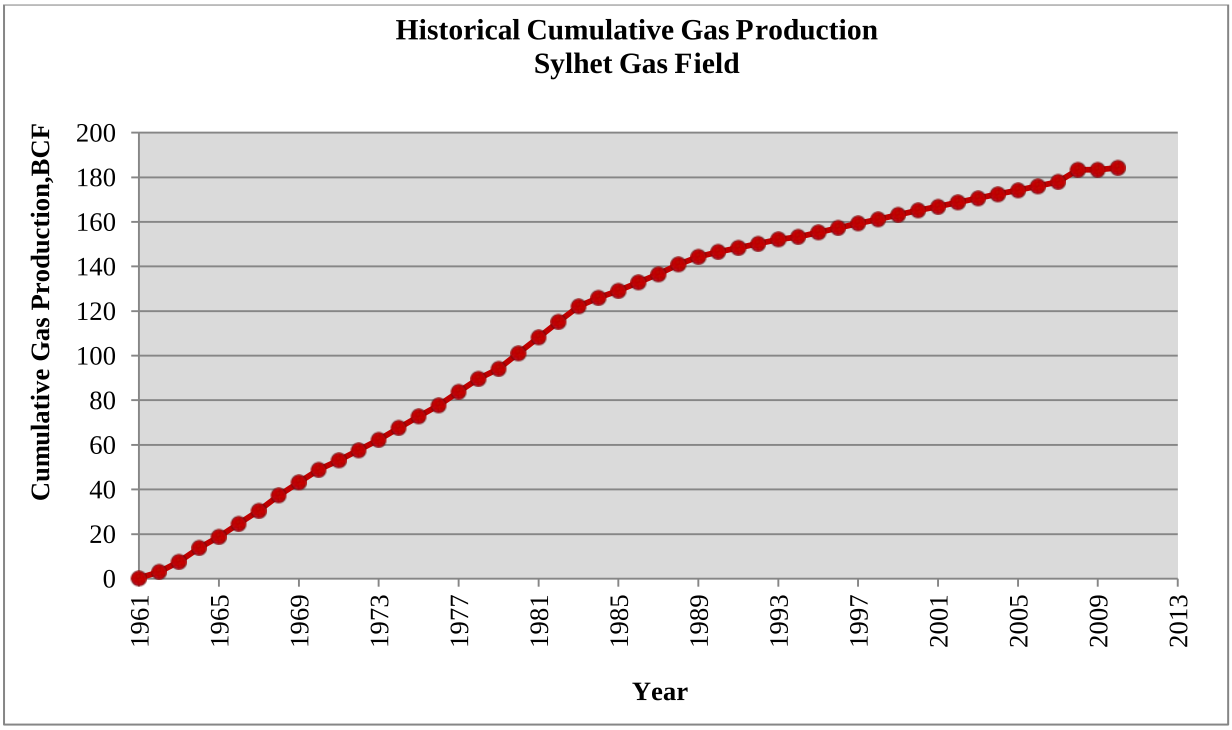


Figure 2.6 *Historical Cumulative Gas Production Plots*[8]

The GIIP and gas production data are given in the Table 2.4.

Table 2.4 *Sand-wise Historical Production*[3]

Well No	Production Started	Producing Sand	GIIP,2P (BCF)	Cumulative Oil Prod. (Until July-1994) (BBL)	Cumulative Gas Prod. Up to June 2010 (BCF)
Producing					
Sylhet -3	Dec-60	Second Bokabil	203.1	-	176.3
Sylhet - 6	Aug-64	Upper Bokabil	321		
Sylhet -7	Dec-87	Oil Sand	N/A	637,000	-
	Apr-05	Lower Bokabil	131.5	-	7.99
Non Producing					
No well drilled		Tipam	28.26	-	N/A
Field Total			**683.9**	**637,000**	**184.3**

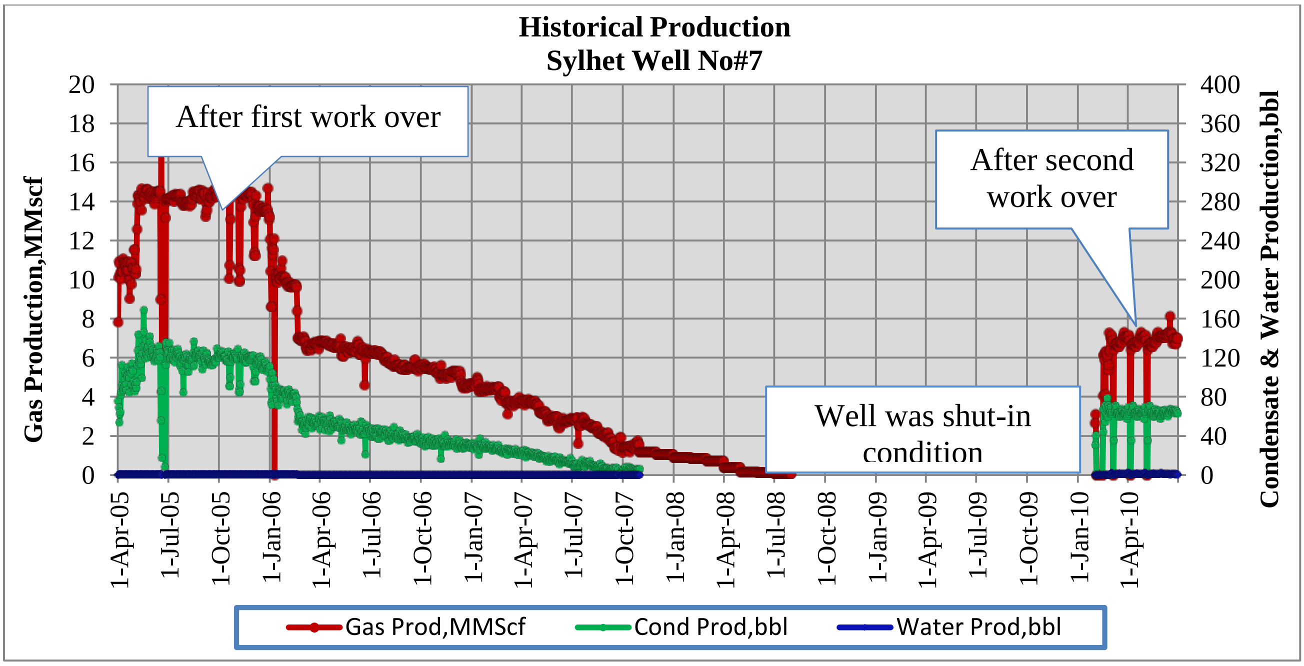


Figure 2.7 *Production history of Sylhet 7 (Lower Bokabil Sand)*[8]

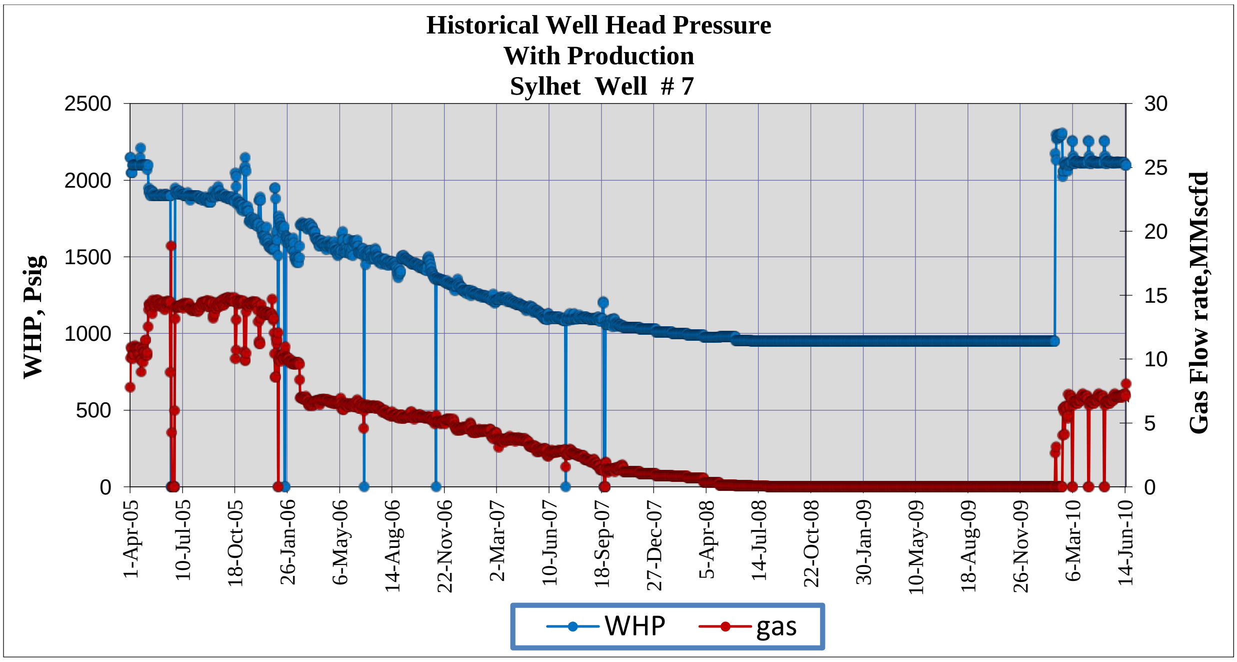


***Figure 2.8** Historical Gas Productions and Well Head Pressure [8] Plot for Sylhet -7 (Lower Bokabil Sand)*

2.7 Current Estimation

Current study conducted on only producing horizon of Haripur gas field - Lower Bokabil sand (sand 'D'). No re-estimation was conducted for the other discovered sands of Sylhet structure. After first work over, the well Sylhet -7 was producing from April 2005.But in July 2008, production was suspended from Sylhet-7 due to obstruction accumulation inside the tubing (Petrobangla). The field again came in online after second work over in February 2010. Current analysis is conducted taking into consideration of production data with more or less uninterrupted production from April 2005 to June 2010.Historical production and pressure plots are given in the Figure 2.7 and Figure 2.8 respectively.

In this study material balance, production data analysis and reservoir simulation are used to estimate the gas reserve of producing sand and performance analysis of the well.

Chapter 3.0

PRODUCTION DATA ANALYSIS

3.1 Introduction

Production analysis is a graphical procedure and a reliable technique to estimate reserves and well performance by using production data. This chapter deals with the production data analysis of producing horizon of Haripur gas field - lower Bokabil sand. Using more or less uninterrupted production data from April 2005 to June 2010, conventional decline analysis conducted to estimate the gas initial in place, remaining reserve of the sand and production forecast. Some advance decline scenarios also analyzed to investigate the performance of the well.

3.2 Conventional Decline Curve Analysis

Decline analysis[9] is a graphical procedure for analyzing declining production rates and forecasting future performance. A curve fit of past performance is done using certain standard curves. The curve fit is then extrapolated to predict potential future performance. Decline curve is a basic tool for using recoverable reserves. Conventional or basic decline curve analysis is used when the production history is long enough that a trend can be identified. Decline curves valid under the following assumptions:

- Boundary dominated flow
- Constant operating condition

Decline curve analysis is derived from empirical observations of the production performance of oil and gas wells. Decline curves represent production from the reservoir under boundary dominated flow conditions. This means that during the early life of a well, while it is still in transient flow and the reservoir boundaries have not been reached, decline curves should not be expected to be applicable. Typically, during transient flow, the decline rate is high, but it stabilizes once boundary dominated flow is reached. For most wells this happens within a few months of production. However, for low permeability wells (tight gas wells, in particular) transient flow conditions can last several years, and strictly speaking, should not be analyzed by decline curve methods until after they have reached stabilization.

All decline curve theory starts from the definition of the instantaneous or current decline rate (D) as follows:

$$D = -(\Delta q/q)/\Delta t = -(\Delta q/\Delta t)/q \qquad (3.1)$$

D is "the fractional change in rate per unit time", frequently expressed in "% per year". Exponential decline occurs when the decline rate, D, is constant. If D varies, the decline is considered to be either hyperbolic or harmonic, in which case, an exponent "b" is incorporated into the equation of the decline curve, to account for the changing decline rate.

Exponential decline is given by:

$$q/qi = 1/e^{Dt} \qquad (3.2)$$

Considering the exponential decline, conventional decline analysis was conducted on producing sand. Monthly average gas rate is taken for reducing the fluctuation of production data.

Production declines occur normally for a number of reasons such as pressure depletion, flow restriction, increasing back pressure, transient flow, water displacement etc. At this case, decline occurred due to flow restriction which decreases the flow capability of the well over time. Gradual development of obstruction or scalling is a common situation. So gradual decline points are selected to perform DCA in this study and computed the GIIP. Based on this GIIP, forecast up to 2018 is done assuming exponential fit decline.

The analysis includes the log rate vs. time (Figure 3.1) and gas rate vs. cumulative production (Figure 3.2) and both of these analyses yielded a closer GIIP of sand-D which is about is 28.22 BSCF.

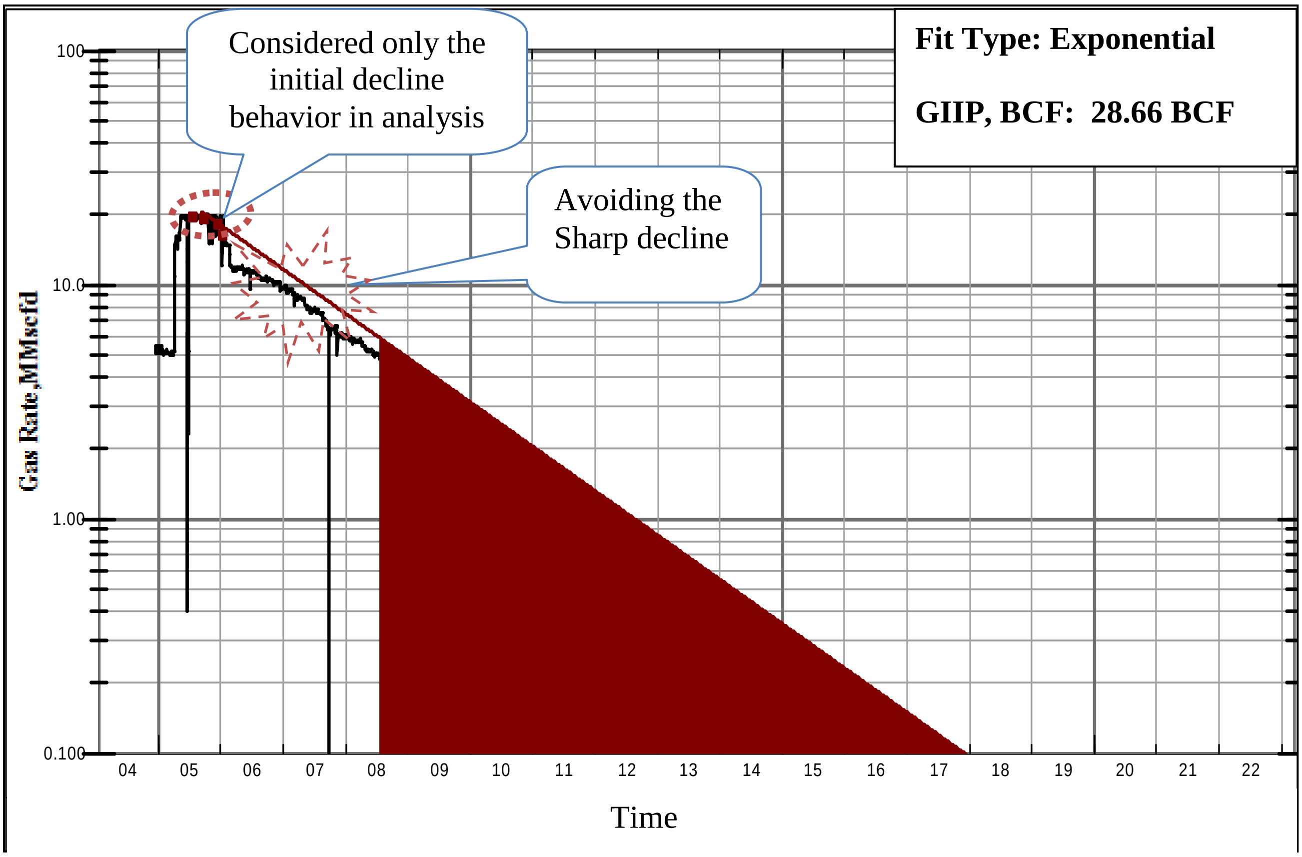


Figure 3.1 *Log rate vs. Time plot*

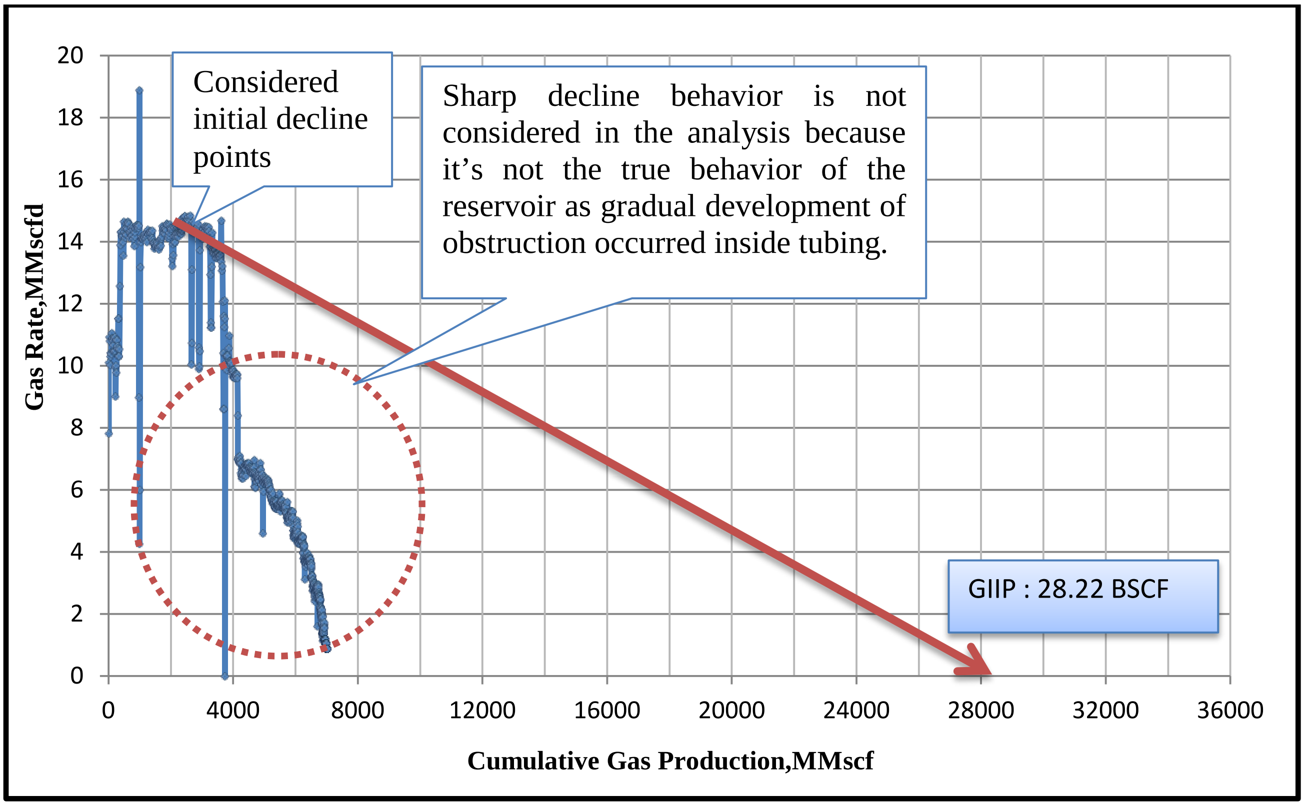


Figure 3.2 *Rates vs. Cumulative Production Plots*

3.3 Advance Production Data Analysis:

3.3.1 Background for Blasingame et. al. [9] Decline Analysis:

The production decline analysis techniques of Arps and Fetkovich are limited in that they do not account for variations in bottomhole flowing pressure in the transient regime, and only account for such variations empirically during boundary dominated flow (by means of the empirical depletion stems). In addition, changing PVT properties with reservoir pressure are not considered for gas wells.

Blasingame and his students have developed a production decline method that accounts for these phenomena. The method uses a form of superposition time function that only requires one depletion stem for type curve matching; the harmonic stem. One important advantage of this method is the type curves used for matching are identical to those used for Fetkovich decline analysis, without the empirical depletion stems.

When the type curves are plotted using Blasingame's superposition time function, the analytical exponential stem of the Fetkovich type curve becomes harmonic. The significance of this may not be readily evident until considering that, if the inverse of the flowing pressure is plotted against time, pseudo-steady state depletion at a constant flow rate follows a harmonic decline. In effect, Blasingame's type curves allow depletion at a constant pressure to appear as if it were depletion at a constant flow rate. In fact, Blasingame et. al. have shown that boundary-dominated flow with both declining rates and pressures appear as pseudo-steady state depletion at a constant rate, provided the rate and pressure decline monotonically.

Blasingame's improvements on the Fetkovich style of production decline analysis are further enhanced by the introduction of two additional type curves which are plotted concurrently with the normalized rate type curve. The 'rate integral' and 'rate integral derivative' type curves aid in obtaining a more unique match.

Normalized Rate:

$$PI\ (t) = q\ (t)/p_i\text{-}p_w\ (t) \tag{3.3}$$

Normalized Rate Integral:

$$PI\ int. = 1/t_e \int_0^{te} PI(t)dt \tag{3.4}$$

Normalized Rate Integral Derivative:

$$PI\ Int.\ Derivative = \partial\ (PI\ int)/\partial \ln\ (t_e) \tag{3.5}$$

3.3.2 Log Log Plot:

By replacing the time with an equivalent time, defined as the ratio of the cumulative to the flow rate, one can perform the variable flowing pressure test into a constant rate equivalent.

If we plot a [Pi – Pw (t)/q (t)] versus t_e = Q (t)/q (t) on a log-log scale the boundary dominated flow will exhibit a unit slope line, similar to pseudo-steady state in Pressure Transient analysis. Furthermore, if we take the derivative of the normalized pressure with respect to the logarithm of time t_e, the transient part will exhibit stabilization at a level linked to the mobility.

The noise level of the derivative of the flow regimes significantly reduce by taking the integral of normalize pressure and derivative of it. In particular, it is clearly possible to get an estimate of the reservoir transmissibility 'kh' from the derivative stabilization level. The 'kh' being known, one can then get first estimate of the reservoir size from the unit slope late time trend. This is the integral part of log log plot to understand the true model response to a pressure step clearly whereas the response to the real history is usually very erratic, because the equivalent time is jumping back and forth in time.

Integral of normalized pressure:

$$I\ (t_e) = 1/t_e \int_0^{te} \frac{\text{Pi} - \text{Pw}\ (\tau)}{q(\tau)} \tag{3.6}$$

Derivative of the Integral of normalized pressure:

$$\text{Derivative, } I`\ (t_e) = \frac{\partial\ \text{I (te)}}{\partial \ln(\text{te})} \tag{3.7}$$

3.3.3 Analysis on Producing Sand (Lower Bokabil)

Sylhet well - 7 is producing from lower Bokabil gas sand zone from April 2005 and after four years of more or less uninterrupted production the well was shut and production ceased in July 2008 due to scale and wax formation in the tubing.

Based on this production history, advanced production data analysis is conducted in this study using the Blasingame plot and log-log plot. This analysis indicates a GIIP of producing sand 16.7 BSCF. The production rate is matched reasonably but the pressure data are not satisfactorily matched because of poor quality and noisy production history. Time-dependent skin model is built to match the history of the model. Skin is observed abnormally increased over time where as it was negative after first work over. This suggests about the accumulation of obstruction in the tubing.

The PDA results generated by TOPAZE software applying Blasingame plot and log-log plot are presented in Appendix I.

3.3.4 Analysis of Bottom Hole Data as a Production data

In 2005, only bottom hole pressure survey conducted at Sylhet well - 7 by Schlumberger. That time, FAF test with three different rates and a build up test conducted. Since the pressure data is not matched agreeably in the previous PDA, so the analysis repeated using these three days bottom hole data as a production data.

Production analysis on producing sand and yielded a GIIP 13.1 BSCF with satisfactory production and pressure history matching. Reservoir parameters used (Figure 3.2) in this analysis is very closer to the core analysis report and those observed in the pressure transient analysis. This analysis could be the acceptable approach for the entire period before second work over if flow conditions remain unchanged but the well experienced flow restriction due to gradual development of obstruction inside tubing.

The PDA results generated by TOPAZE software applying Blasingame plot and log-log plot are presented in Appendix II.

3.4 Pressure Transient Analysis

In 2005, a bottom hole pressure survey conducted on producing horizon (Lower Bokabil) at the well Sylhet 7.This test was included flow after flow (FAF) test with three different rates followed by a pressure build up.

A reservoir model has been built for pressure transient analysis using the software SAPHIRE[10] on producing horizon to investigate the reservoir parameters. The model is considered the homogeneous channel reservoir with one fault surrounding.

The pressure transient analysis has yielded the average reservoir pressure 2678 psia and permeability of the formation is about 140 md. Skin value observed about 40 which is abnormally high. It could be happened due to presence of accumulation in the tubing or mud filtrate entered in the formation during completion which reduced the pressure. From the historical performance, it is also experienced that after first work over, pressure decline for the well occurred sharply due development of obstruction inside tubing. Second work over was done to clean the obstruction inside tubing.

Reservoir parameters observed in PTA and PDA are shown in Table 3.1. A Comparison of GIIP estimates on D-sand by PDA is sown in Table 3.2.

The pressure transient analysis results generated by SAPHIR software with different plots are presented in Appendix III.

Table 3.1 *Comparison of reservoir parameter observed in different methods:*

Analysis	Average reservoir pressure, psia	Skin	Permeability,md
Pressure Transient Analysis	2678	139~145	40~45
Blasingame Plot	2670 ~2680	35~40	139
Log-Log Plot	2675	45	145

Table 3.2 *Comparison of GIIP (BCF) estimates of different methods conducted on D-sand by PDA:*

PDA with Production History	PDA with BHP Data as a production Data	Conventional Decline Curve Analysis
16.70	13.10	28.20

3.5 Inflow Performance Relationship (IPR):

The flow from the reservoir into the well is known as the Inflow Performance. The plot of Producing Rate versus Bottomhole Flowing Pressure is called the Inflow Performance Relationship or IPR or Inflow Curve.

Absolute Open Flow potential is the maximum theoretical possible rate that the reservoir can flow. This is the well's potential flow rate against a zero sand face pressure. A model multi-rate ‘C’ and ‘N’ reservoir model built for Sylhet-7 using PROSPER and matched IPR (Figure 3.3.) using the FAF test data conducted in June 2005 by Schlumberger.

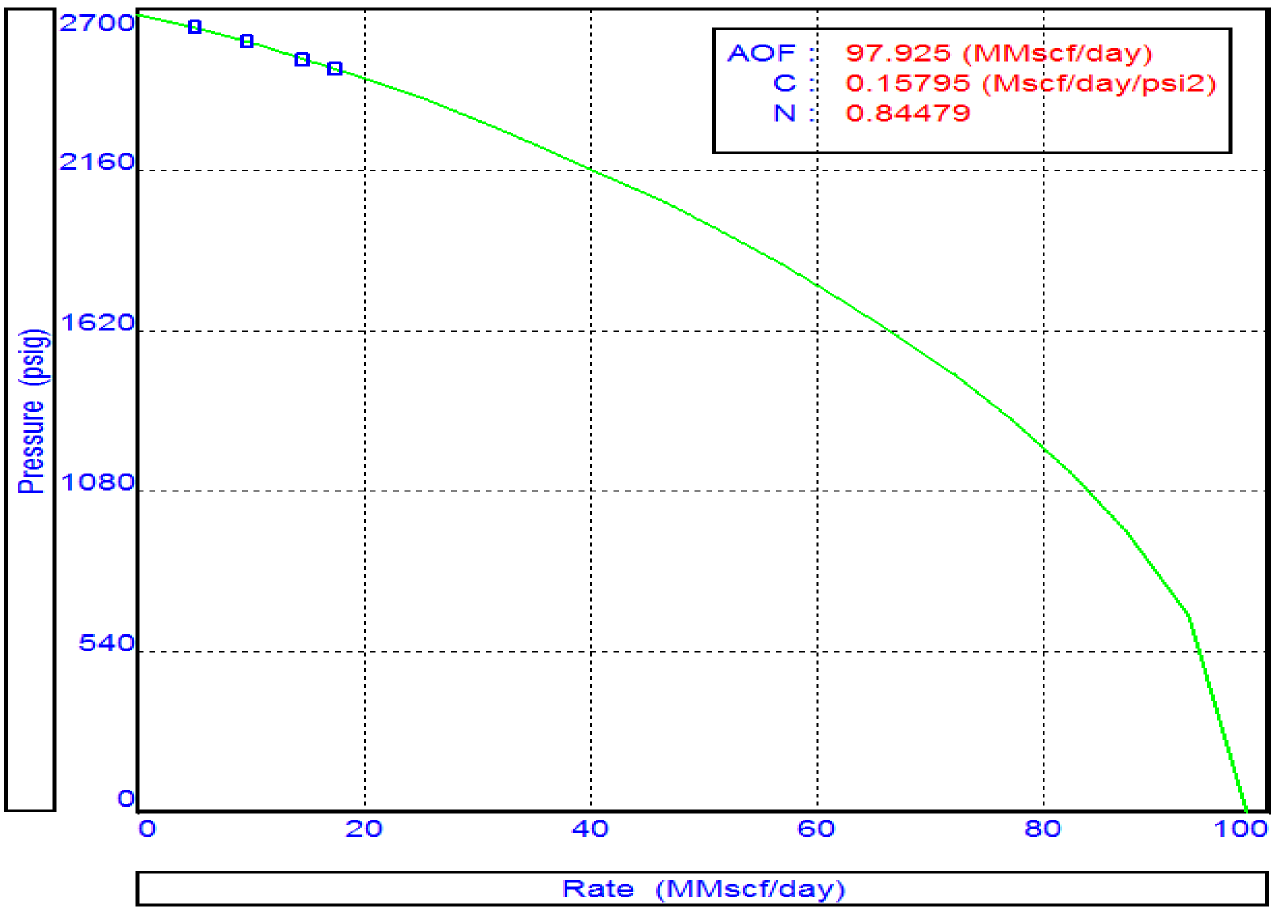


Figure 3.3 *Inflow Performance Relationship of Sylhet-7*

3.6 Vertical Lift Performance (VLP):

The flow in the well is from top of the perforations to surface is known as the Vertical Lift Performance. The plot of Producing Rate versus Bottomhole Flowing Pressure is called VLP Curve or Lift Curve.

A series of VLP curves generated in Figure 3.4 for different Bottom hole flowing pressures:

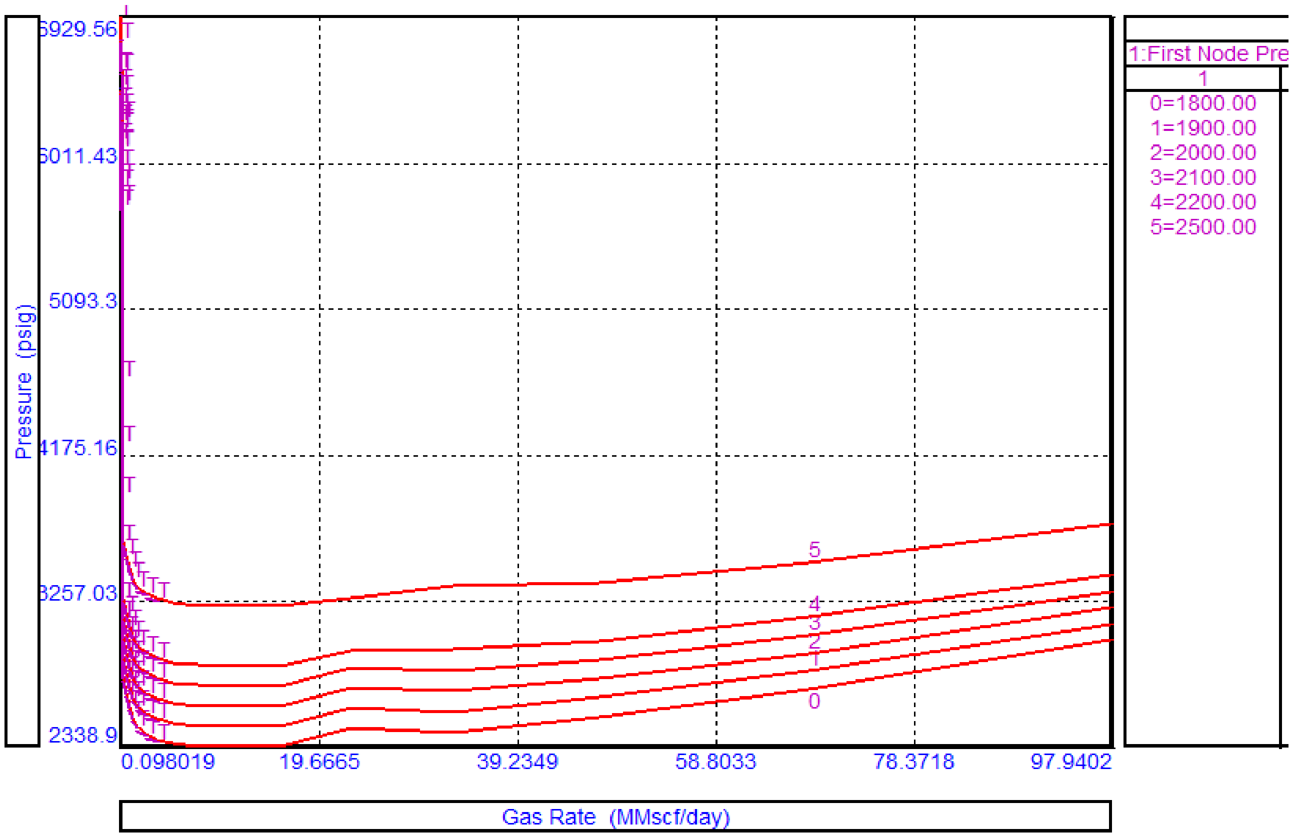


Figure 3.4 *Vertical Lift Performance Curve for Sylhet 7*

3.7 IPR/ VLP Matching

The matching process consists of two main steps:

- Matching of the VLP. The multiphase flow correlation will be tuned in order to match a down hole pressure measurement
- Matching of the IPR.

The IPR was tuned so that the intersection of VLP/IPR will match the production rate as per well test. The IPR/VLP matching is done for Sylhet-7 well which is shown in the Figure 3.5.

The VLP generated for different well head pressures during initial time period and the matching of VLP support the rate closer. After first workover, the well was producing with a rate of 14-18 MMScfd which is very closer to the matched rate. But any recent multi-rate and build up test data would make this matching more accurate and rate supportive.

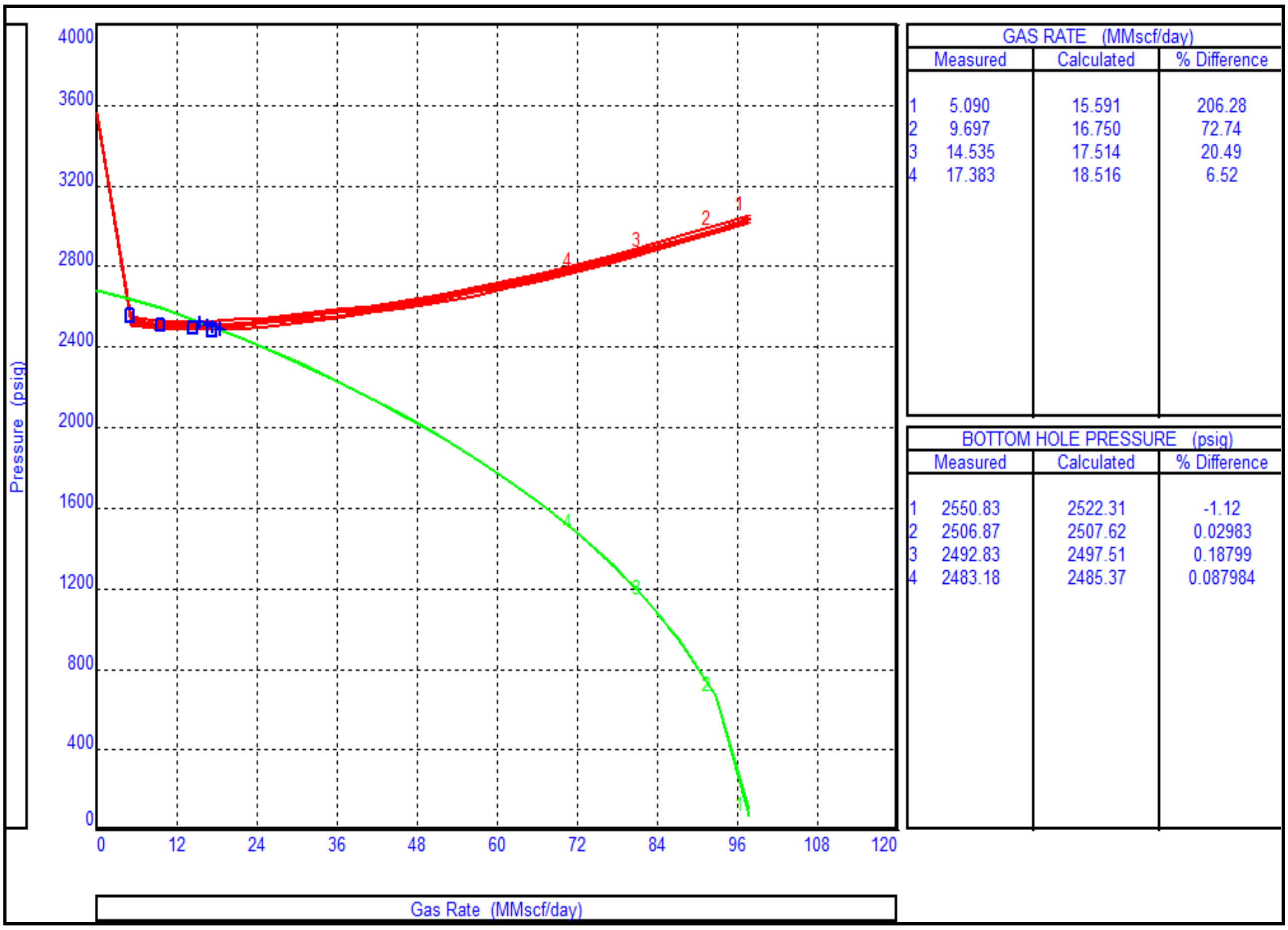


Figure 3.5 *IPR/VLP matching for Sylhet 7*

Chapter 4

MATERIAL BALANCE STUDY

4.1 Introduction

Conventional method material balance analysis and different other approaches of material balance performed in this chapter to estimate both reserves and initial gas in place for the producing sand (sand-D) of Haripur gas field.

4.2 Conventional Material Balance Analysis

For a gas reservoir conventional material balance analysis relies on obtaining a straight line on P/z vs. cumulative production (G_p) graph to estimate reserves and initial gas in place (GIIP).This method fully built up reservoir pressure, obtained by shutting the wells for few days.

The accuracy of reserve calculations by volumetric method is dependent upon the accuracy of data available, mainly the quality of seismic and log data. On the other hand, the accuracy of reserves calculated from the material balance studies is dependent upon the accuracy of the well's production and pressure data. Unlike the volumetric method, the material balance accounts for reservoir heterogeneity and continuity variations, which occur within the reservoir. The accuracy of the material balance approach for estimating reserves increases with production and pressure decline.

The general form of material balance equation was first presented by Schilthius in 1941.The equation is derived as a volume balance, which equates the cumulative observed production, expressed as an underground withdrawal, to the expansion of the fluids in the reservoir resulting from a finite pressure drop.

4.2.1 Material Balance Analysis on Producing Sand:

Material balance study of Lower Bokabil sand conducted using MBAL software. Because of unavailability, limited down hole data used in this study. This study yielded a GIIP of 26.996 BCF.

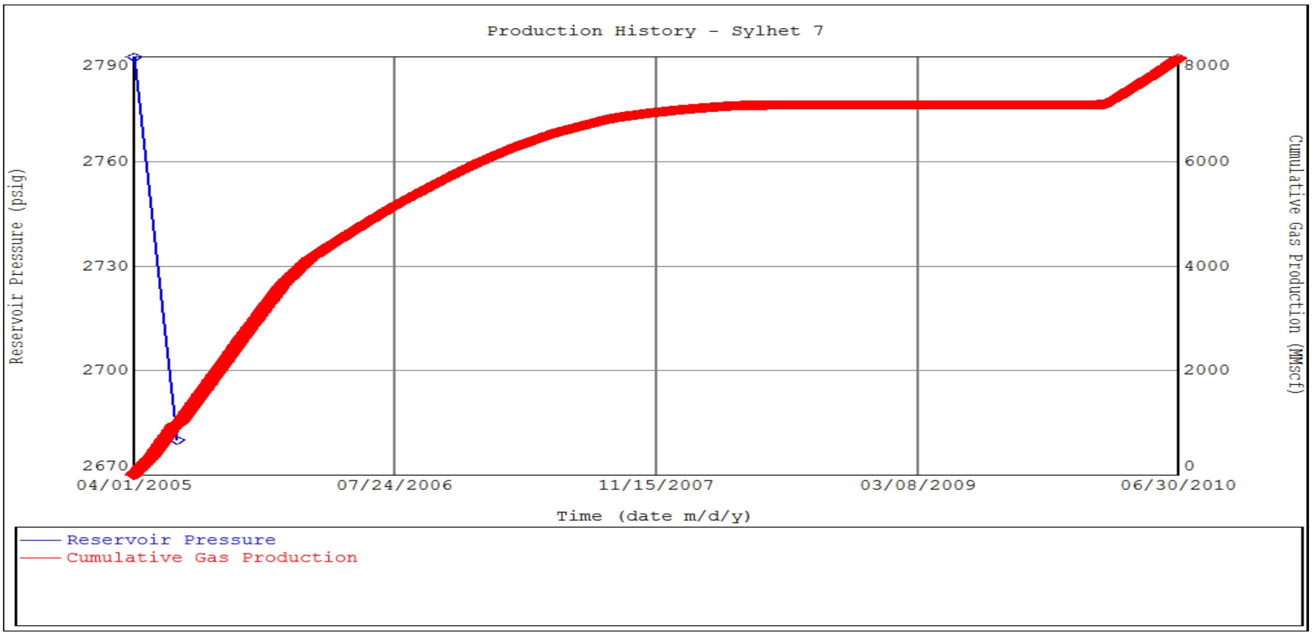


Figure 4.1 *Cumulative Gas Production History with Reservoir Pressure*

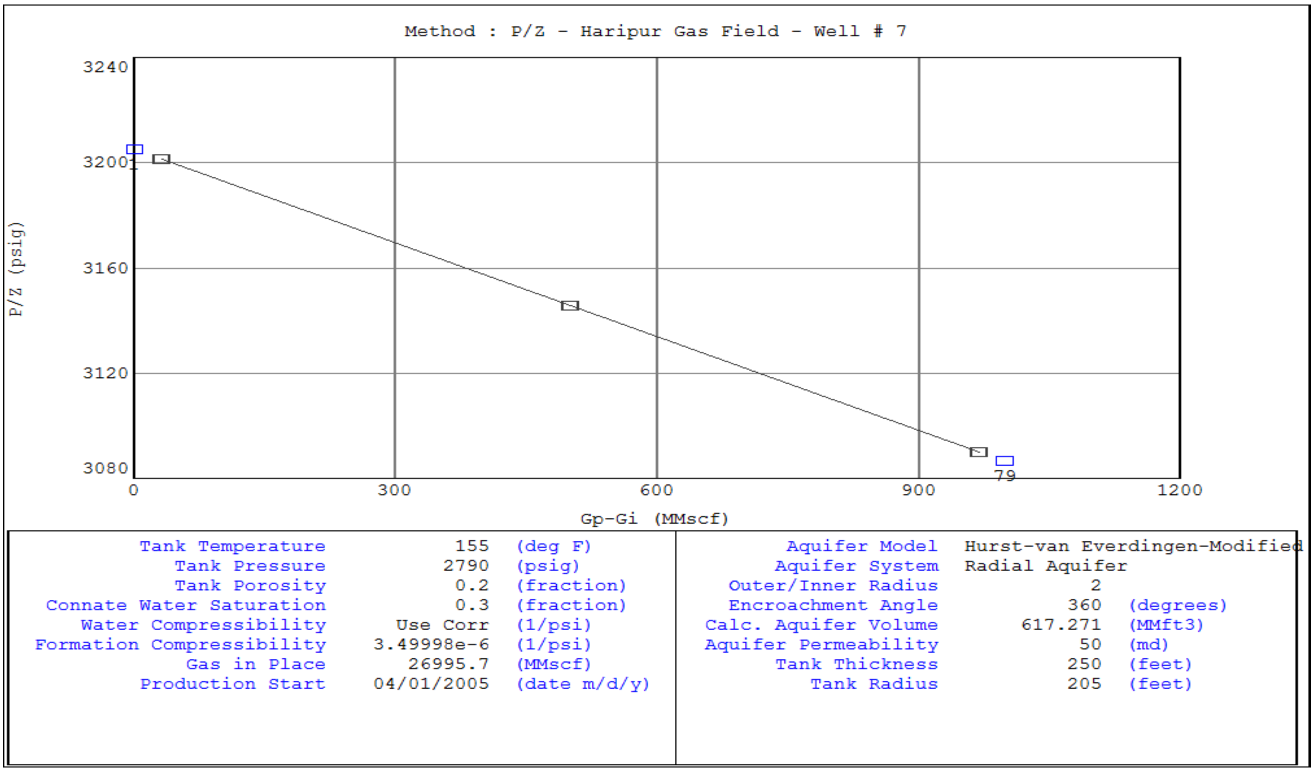


Figure 4.2 *P/z vs. Cumulative Production Plots*

4.2.2 Drive Mechanism:

Material Balance analysis suggests that the driving force of reservoir is expansion drive mechanism.

4.2.3 Existence of Aquifer Support:

Using Hurst-van-Everdingen-Modified aquifer model based on available data, no aquifer support observed in the sand-D.

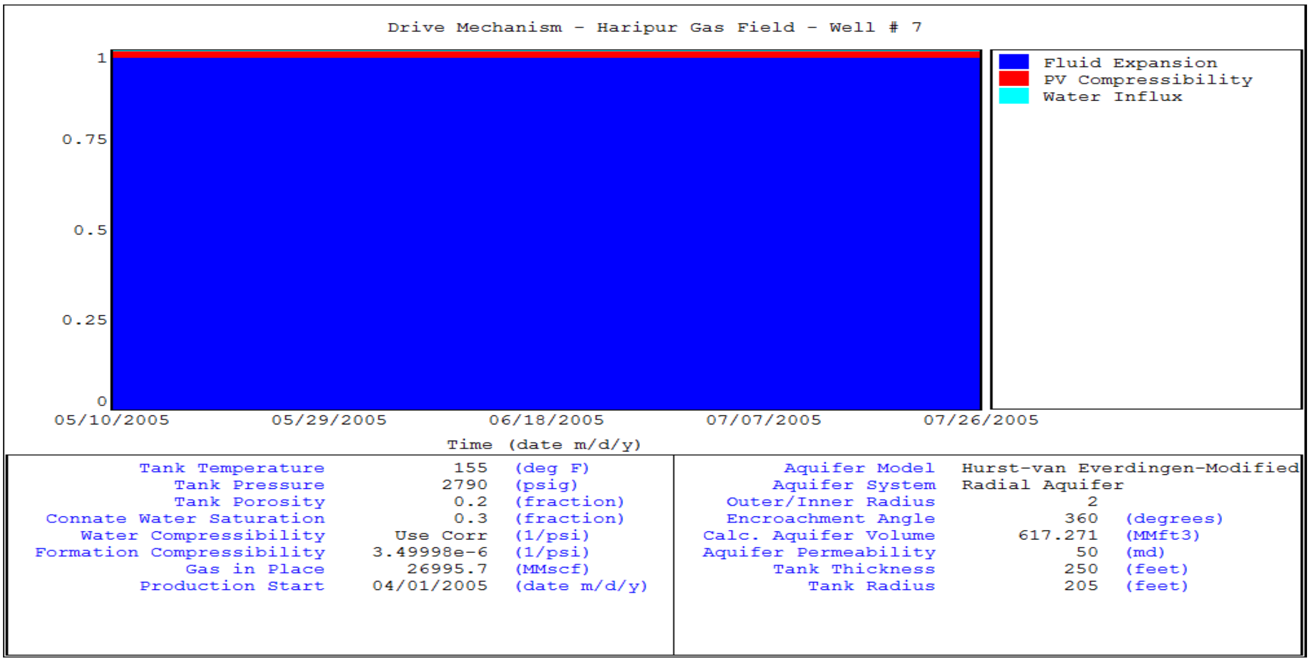


Figure 4.3 *Drive Mechanism*

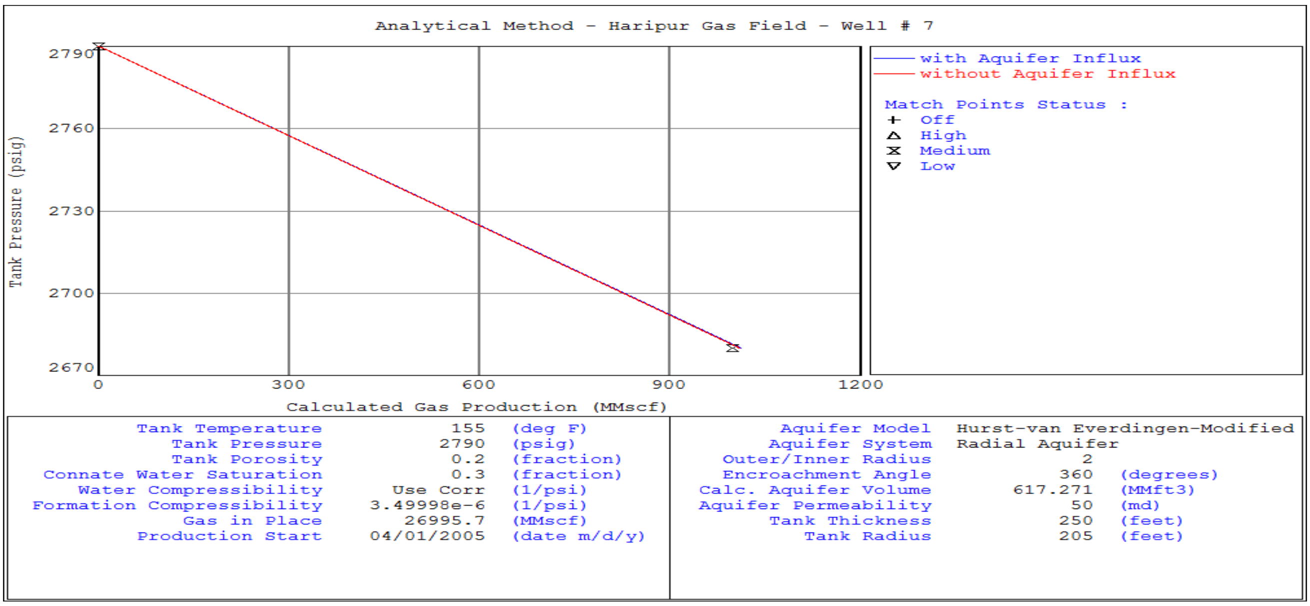


Figure 4.4 *Aquifer Influx*

4.2.4 Production and Tank Pressure History Matching with Prediction:

In this Material balance model, production history and the pressure history is satisfactory matched (are shown in Figure 4.5, Figure 4.6). Based on GIIP found in this analysis comparative prediction is done for the remaining reserve (Figure 4.7).

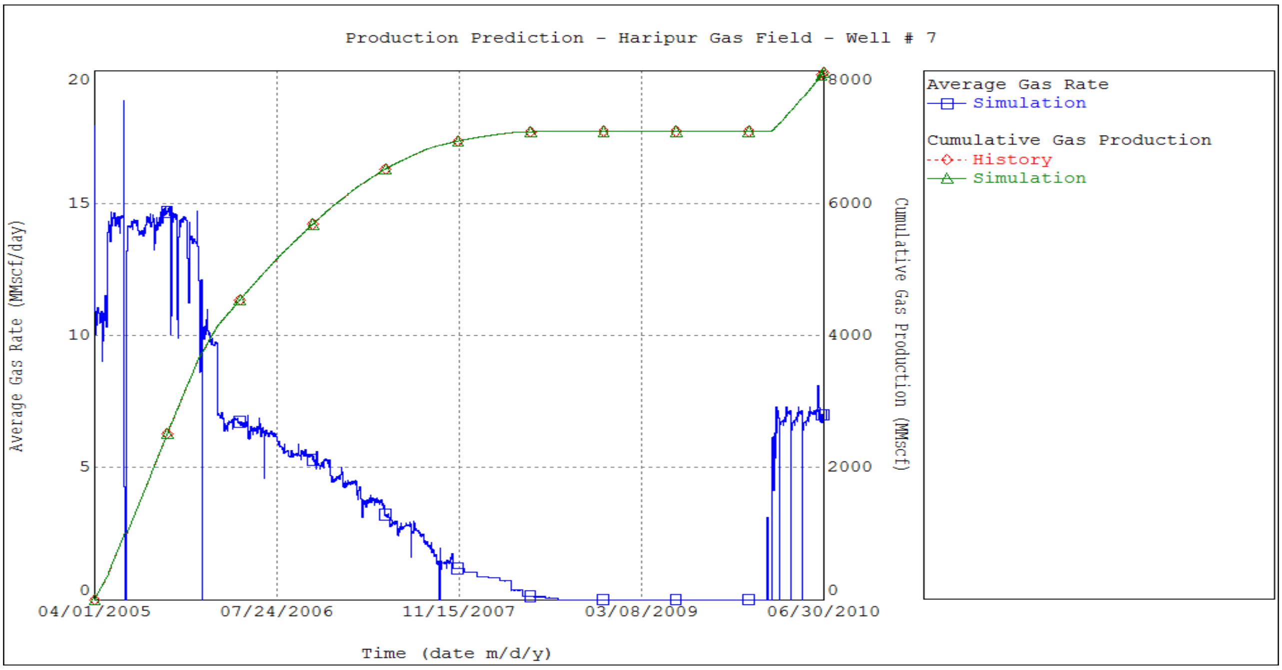


Figure 4.5 *Production History Matching*

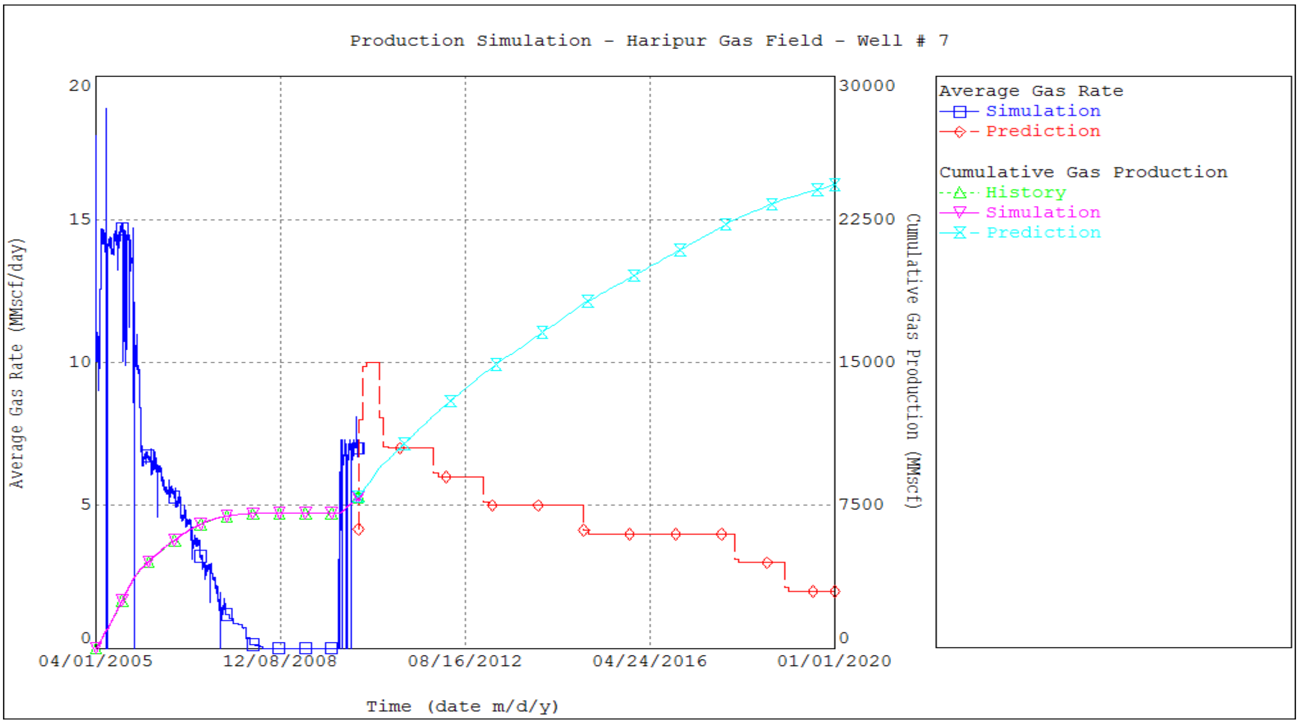


Figure 4.6 *Production history matching with Prediction*

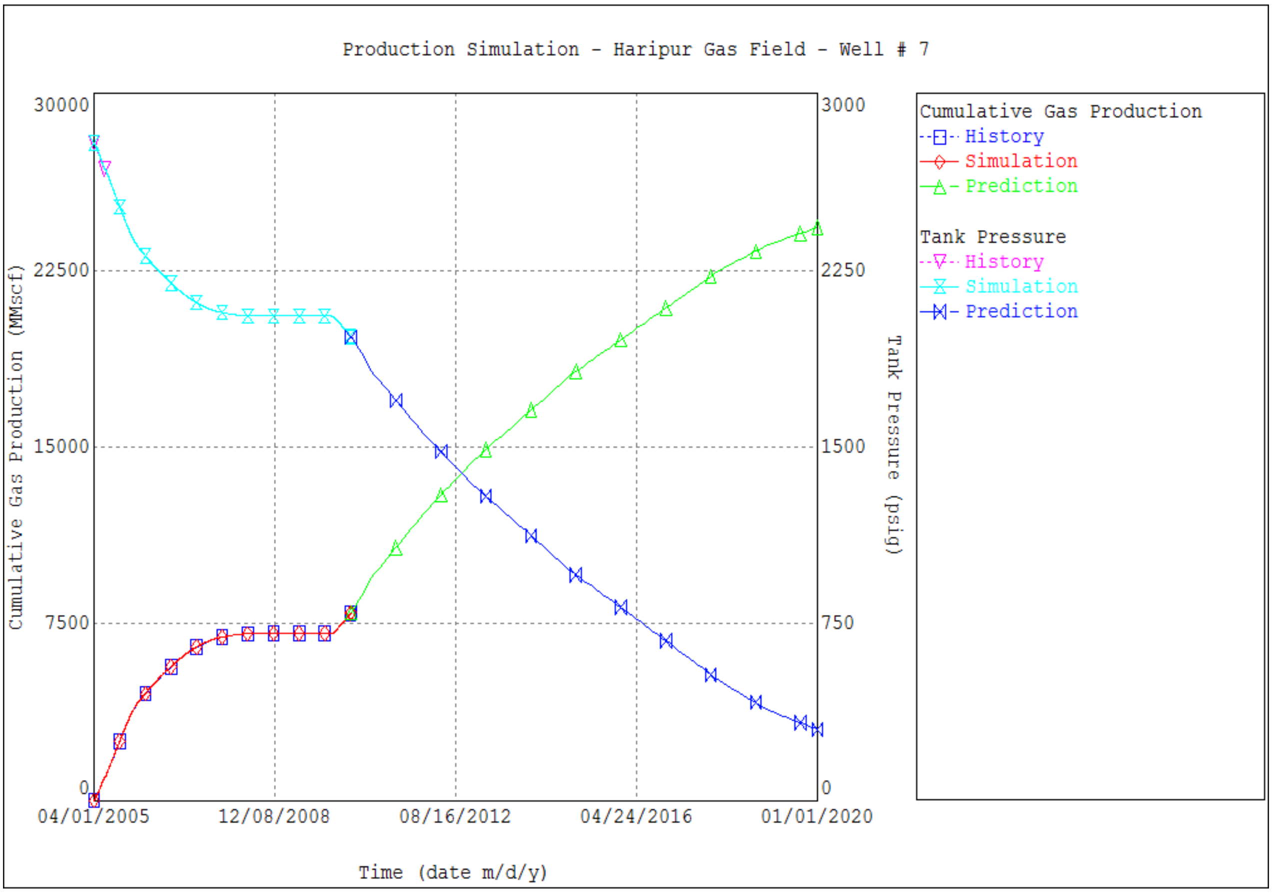


***Figure 4.7** Cumulative Production and Tank pressure history matching with Prediction*

4.3 Different Approaches Used in the Study of Material Balance:

Because of critical demand-supply situation, pressure tests are not conducted on a regular interval in Haripur Gas Field; the same prevails elsewhere in the country. In the material balance study, due to non-availability of needed pressure surveys, four approaches have been taken using (a) static bottom hole pressure (SBHP) estimated from shut-in wellhead pressure (b) shut-in wellhead pressure (SWHP) (c) flowing bottom hole pressure (FBHP) of the well (d) flowing wellhead pressure (FWHP). Data for approach (a) and (b) were recorded during occasional shut-ins due to some production problems or any other reasons.

4.3.1 Static Bottomhole Pressure Estimated from Shut-in Wellhead Pressure:

To record the static bottom-hole pressure or the reservoir pressure by down hole gauge measurement, the well is required to shut-in for a few days for pressure build up. This is not feasible due to critical demand-supply situation. But different wells of the field were shut-in from time to time because of production problems or any other reason and pressure build up data were recorded in these situations. The recorded shut-in wellhead pressure data was taken from monthly records of Haripur Gas Field, SGFL and corresponding bottomhole pressure were calculated. The calculated static bottom hole pressure is, however, not a substitute for the data recorded from a properly designed well test program, particularly due to the uncertainty of the degree of pressure stabilization achieved during shut-in wellhead pressure measurements. In the absence of any well-test program, this approach can be a good alternative.

4.3.2 Shut-in Wellhead Pressure:

In this approach field recorded shut-in wellhead pressure are used to make a *p/z* vs cumulative production plot. The approach is based on the assumption that there is no liquid in the wellbore. For the material balance study, *P/ z* term has been calculated by the means of calculating the z-factor using Hall and Yarborough (1973) correlation.

Since static gas gradient is very small, the plots set out for *p/z* using the shut-in wellhead pressure vs. cumulative production for Lower Bokabil sands of Haripur Gas Field, should provide quite acceptable results. This method will yield erroneous results if there is a liquid build up in the tubing.

4.3.3 Flowing Bottomhole Pressure of the Well:

Theoretically it has been understood for many years that original gas in place can be estimated using measured gas volumes and flowing pressures. This method is based on the pseudo steady state pressure behavior, which requires that the rate of change of pressure at every location of the reservoir is constant. It can also be assumed that after the attainment of the pseudo steady state the rate of change of the average reservoir pressure is also constant as production continues. Mattar and McNeil (1998) illustrated that original gas in place can be determined from the flowing data (pressure and production). These authors have opined that it is possible to determine original gas in place with reasonable certainty when shut-in pressures are not available.

This procedure requires the flowing sand face pressure at the wellbore to be measured for plotting p_{wf}/z vs. cumulative production. A straight line drawn through the flowing sand face pressure data and then a parallel line from the initial reservoir pressure gives the original gas in place. The method of calculating the reserves of medium and high permeability reservoirs, from flowing pressure data have the potential of preventing loss of valuable production, without having to shut-in the well. The method is specially suitable for Haripur Gas Field as well as for other gas fields of Bangladesh where routine pressure testing cannot be conducted due to critical demand-supply situation. The flowing bottomhole pressure is calculated from the monthly representative flowing wellhead pressure and the monthly average gas flow rate of different wells, using the PROSPER software. The recorded flowing wellhead pressure data was taken from monthly records of Haripur Gas Field, from Reservoir and Data Management Cell, Petrobangla. For the material balance study, z-factor for the *p/z* term is calculated using the same excel spreadsheet as in the shut-in wellhead pressure case.

4.3.4 Flowing Wellhead Pressure:

In this approach daily average flowing wellhead pressure data are used. The z-factor for the *p/z* term is calculated using the same excel spreadsheet as in the shut-in wellhead pressure. The flowing wellhead pressure data was taken from daily records of Haripur Gas Field, SGFL.Mattar and McNeil demonstrated in the "flowing" material balance method that the wellhead 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 FWHP vs. cumulative production, it has been observed that the apparent gas in place figure of the producing sand of Haripur Gas Field are lower than that of obtained from static bottomhole pressure and shut-in wellhead pressure methods. This makes sense because flowing wellhead pressure decreases from the shut-in wellhead pressure because of frictional losses. The straight line drawn from the initial wellhead pressure in parallel to the flowing wellhead pressure data gives the original gas in place.

4.4 Discussion on Material Balance Results

In this section the results of the material balance study using the different approaches have been presented. In this discussion gas in place value of the Sylhet-7 of the sand is evaluated using the four different methods of material balance study, i.e., (1) SBHP (2) SWHP (3) FBHP, and (4) FWHP for the well 7 finally for the sand itself gas in place values are estimated from the plot of *p/z* vs. cumulative production. Remaining reserve is calculated from the graphs assuming the abandonment *p/z* to be 1000 psia, based on FBHP approach.

4.4.1 Lower Bokabil Sand:

There are one well recompleted in D Sand i.e. in lower Bokabil. Material balance studies have been conducted using the respective well data.

Well Sylhet 7

The *p/z* vs. cumulative production graphs of Well Sylhet -7 for static bottom-hole pressure, shut-in wellhead pressure, flowing bottomhole pressure and flowing wellhead pressure appears in Figure 4.8, Figure 4.9, Figure 4.10 and Figure 4.11 respectively.

The initial uptrend of the pressure points of the plots is because of the fact that only Sylhet -7 produced from Sand-D during the years 2005 to 2008. Gas in place values estimated from the plots of *p/z* vs. cumulative production using the static bottomhole pressure, shut-in wellhead pressure, flowing bottomhole pressure and flowing wellhead pressure approaches are 27 BCF, 28 BCF, 24 BCF and 21 BCF respectively. As of July 2008, the cumulative production from Well Sylhet -7 was 7.087 BCF. Assuming the gas in place value for Sylhet-7 as 24 BCF (using flowing bottomhole pressure approach), reserve at the abandonment p/z of 1000 psia is 16 BCF. Remaining reserve for this location is 8.0 BCF. The recovery factor of this sand till July 2008 is 66.67%.

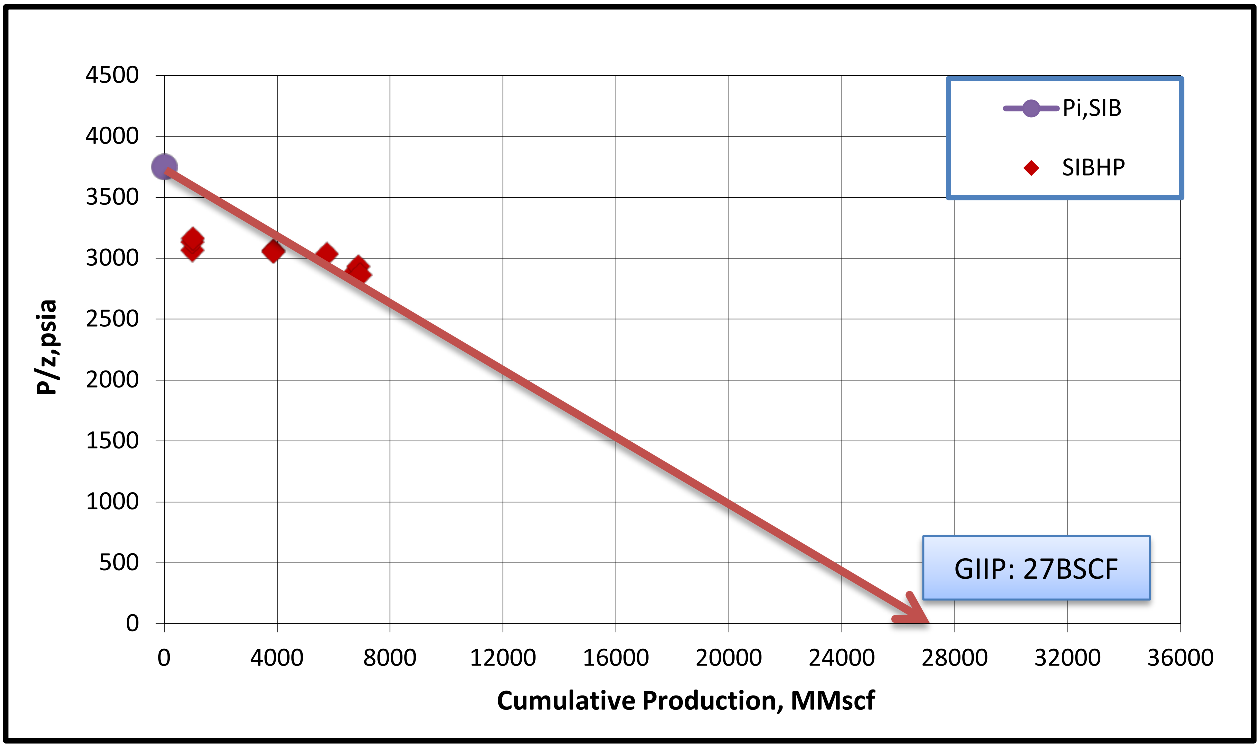


Figure 4.8 *P/Z Shut-in Bottomhole Pressure Vs Cumulative Production*

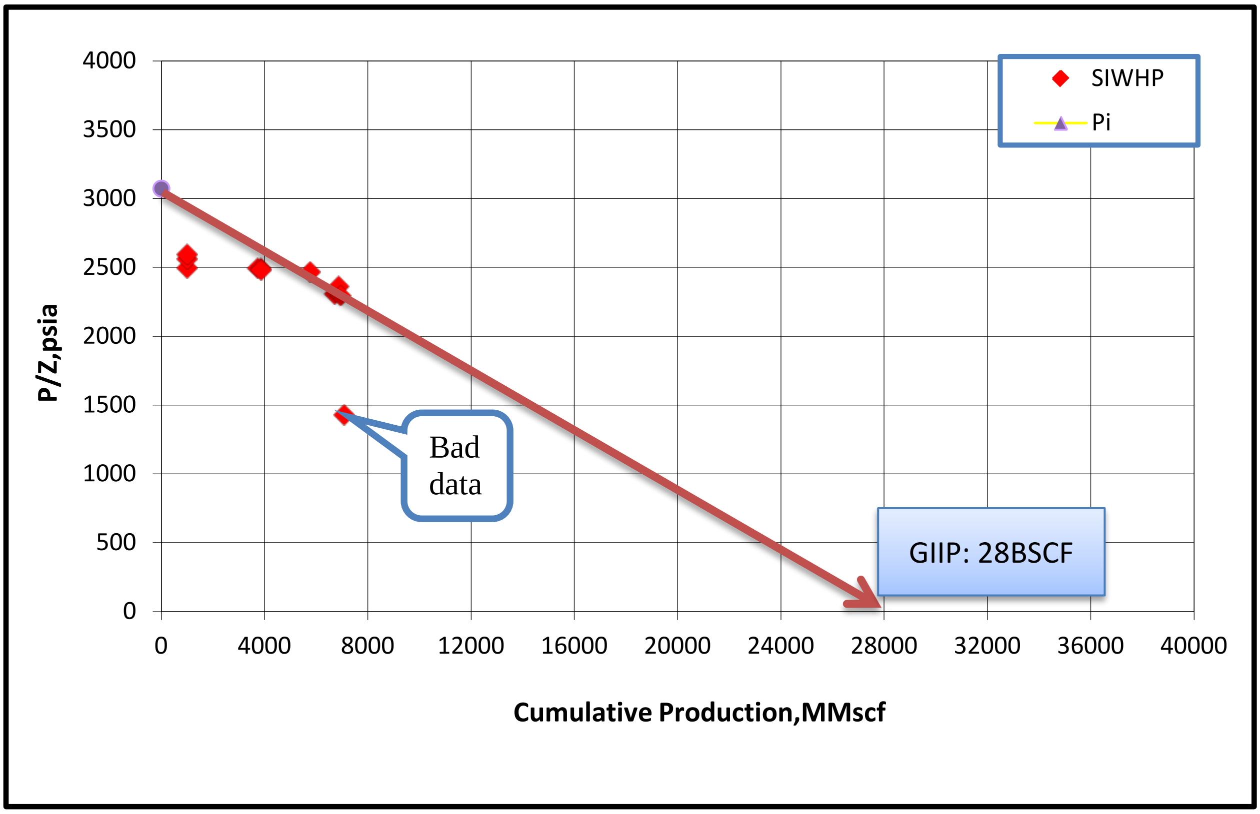


Figure 4.9 *P/Z Shut-in Wellhead Pressure Vs Cumulative Production*

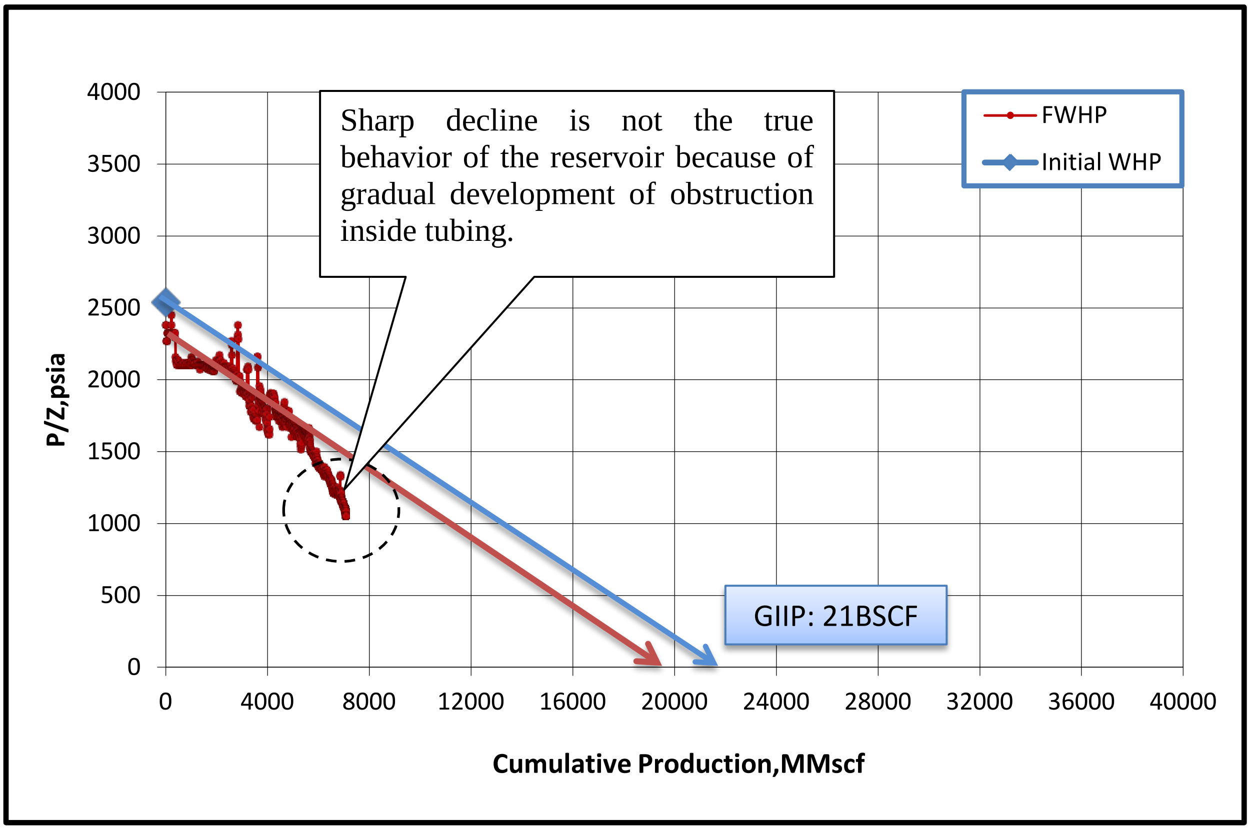


Figure 4.10 *P/z Flowing Well head Pressure Vs Cumulative Production*

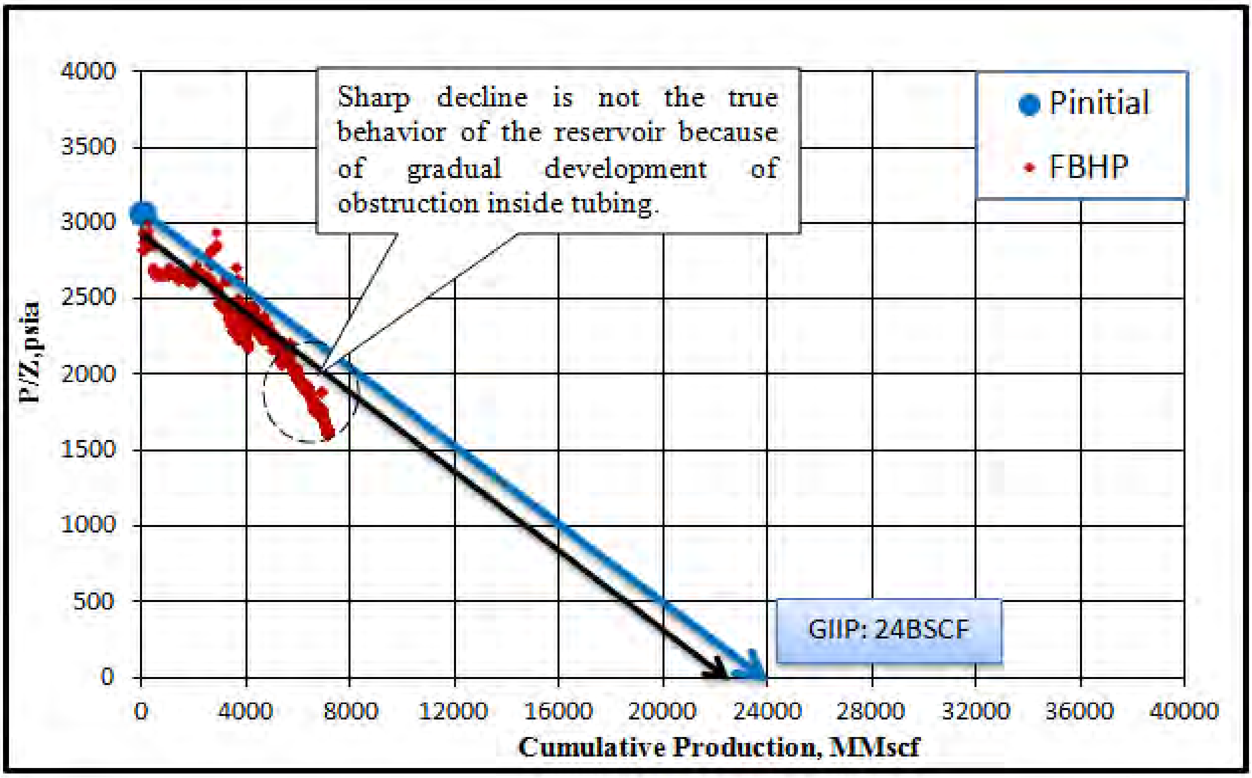


Figure 4.11 *P/Z Flowing Bottomhole Pressure Vs Cum. Production*

4.4.2 Comparison of Results

The results obtained using different approaches of material balance are shown in Table 4.1 and a comparison made (Table 4.2) with PB study by RPS energy.

Table 4.1 *Comparison of GIIP (BCF) from Material Balance Method***:**

Well	Using Different Approaches of Material Balance				Conventional Material Balance	Reserve @ 1000 psia Abandon FBHP Approach	Cum Prod.,	Remain. Reserve,	Recov. Factor %
	SBHP	SWHP	FBHP	FWHP					
Syl-7	27.0	28.0	24.0	21.0	26.99	16.0	7.078	16.922	66.67

Table 4.2 *Comparison of gas in place (BCF) estimates of different studies conducted on D-sand:*

Petrobangla study by RPS Energy (Conventional Material Balance) (2009)	Using FBHP Approach
15 - 105	24.0

Chapter 5.0

RESERVOIR SIMULATION

5.1 Introduction

Reservoir simulation is the process of mimicking or inferring the behavior of fluid flow in a petroleum reservoir system through the use of either physical or mathematical model. This chapter deals with the different steps involve in a reservoir simulation study with a commercial simulator and finally application of this steps in the reservoir simulation study of producing sand (sand-D) of Haripur Gas Field (Figure 5.6). The producing reservoir sand of Haripur Gas Field has been simulated by history matching using a commercial reservoir simulator CHEARS. Implicit black oil model has been used to simulate the reservoir. The confidence level of the forecasts depends heavily on the accuracy of the geological data as well as the fluids and reservoir properties.

5.2 Reservoir Simulator

CHEARS (2007b) is a general purpose reservoir simulator able to study black oil, compositional, thermal compositional, miscible or variable-bubble-point-black-oil recovery processes. It includes several different phase behavior options, combined with a robust well management code for modeling well behavior, oil and gas producing facilities, and producing practices. CHEARS is structured so this full capability is maintained in a single code at little computational penalty, even for simple black-oil problems.

The simulator can simulate problems in one, two or three dimensions using rectangular (x-y-z) coordinates, with any combination of oil, gas or water phases and characterizing the reservoir fluid into one or more components. Inter block mass transfer is represented by Darcy's law with relative permeability, capillary pressure and gravity effects. The reservoir description capability includes naturally fractured and communicating faulted reservoirs. The model also allows special connection of non-neighbouring grid cells for unconventional problems. Multiphase correlations are fully coupled to provide pressure losses in the tubing.

CHEARS has non-linear regression parameters built into it whereby the program user may find the best values of porosity, permeability, relative permeability that will match observed field history.

5.3 Mathematical Basis for Implicit Black oil Model

The simulation model is a fully implicit, three dimensional, multi-component model for simulating isothermal processes. The finite difference formulation is a block centered approximation to the partial differential equations. In addition to seven point finite difference approximations, the model allows the linking of any pair of grid cells for mass transfer.

In finite difference formulation a partial differential equation is converted to a finite difference equation using the Taylor series expansion. The reservoir is discretized to a number of blocks and each block is represented by a finite difference equation. The boundary conditions are also converted to corresponding finite difference equations. These result in a set of algebraic equations which is then solved using a suitable scheme.

Normally the Mathematical Decisions in Simulation in shown below (Figure 5.1) the flow chart:

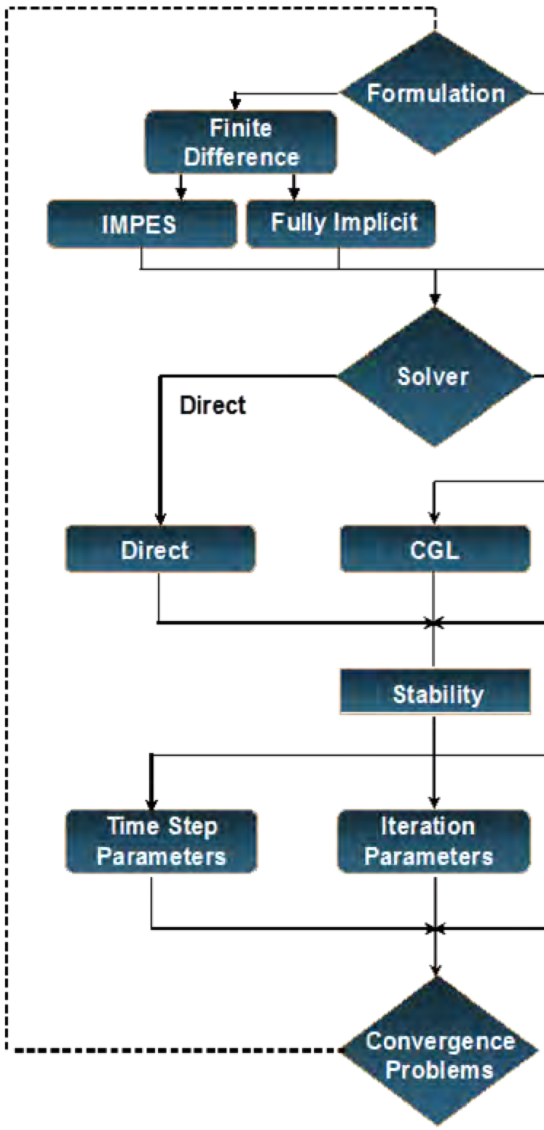
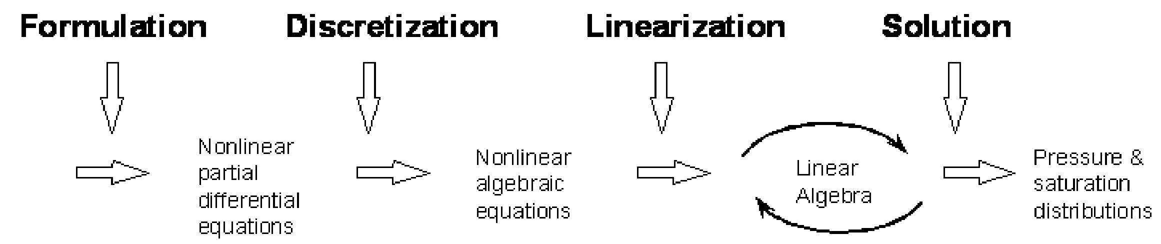


Figure 5.1 *Mathematical Decisions flow in Simulation*

Mathematical formulation used in the model is briefly discussed below:

The backbone of a reservoir simulator is a set of mathematical techniques (Figure 5.2) used to predict the behavior of fluids in petroleum reservoirs. These different techniques and their interrelationships are shown in the following figure.



Formulation:	**A set of simultaneous, non-linear, partial differential equations describing the physical principles for flow in porous media**
Discretization:	**The spatial (grid blocks) and temporal (time steps) representation of the system**
Linearization:	**Formulation of solution (variables solved implicitly or explicitly)**
Solution:	**Solution of large systems of equations by linear equation solvers for pressure and saturations for each grid block at each time step**

Figure 5.2 *Interrelationships between Mathematical Techniques*

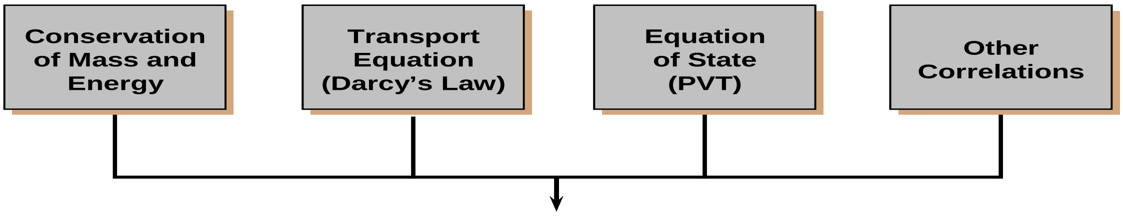
In the first step, the fundamental assumptions of reservoir simulation are stated in mathematical terms and applied to a petroleum reservoir. This process creates a set of simultaneous, nonlinear, partial differential equations (PDEs) called the governing equations or the partial differential model. Because they are too complicated to solve analytically, the remaining mathematical techniques must be used to “integrate” these equations to generate useful data for the petroleum engineer, such as pressure and saturation profiles, production schedules, or ultimate recovery.

Four physical principles are used to derive the partial differential model for fluid flow in porous media:

- *Conservation of mass,* which states that the mass of fluid entering an element in the reservoir minus the mass leaving must equal the net increase in mass of the fluid in that element.
- *Conservation of energy,* which states that the energy entering an element in the reservoir minus the energy leaving must equal the net increase in energy in that element.
- *Darcy's Law*, or some similar rule that describes the rate of fluid movement into or out of the reservoir element.
- An *equation–of–state* that describes the pressure–volume–temperature (PVT) characteristics of the particular fluid flowing in the reservoir element.

To develop the mathematical model of the processes occurring in the reservoir, these physical principles are applied to a small element of the reservoir. The principles of conservation of mass and energy are used to write independent mass and energy balances on each phase in that elemental volume. Darcy's law is used to convert fluid velocities to pressure gradients. An equation–of–state is used to calculate physical properties. As this elemental volume is conceptually shrunk to zero, a partial differential equation (the familiar diffusivity equation) is formed that relates pressure and temperature gradients throughout the reservoir to saturation and composition changes through time.

The mass balance equations formed are the primary equations of the mathematical model.



The Diffusivity Equation
(Single Phase, 1-D Flow)

$$\frac{k}{\mu}\frac{\partial^2 P}{\partial x^2} = \phi c \frac{\partial P}{\partial t}$$

These mass balance equations are enforced on every grid cell in the model as well as on the entire model. It is important to note that the mass refers to components not phases. In a black oil model the components are oil, gas and water, while the phases are vapor and liquid. The liquid phase contains oil and solution gas. The vapor phase contains gas and in the case of the condensate option may contain oil. Similarly, a compositional model contains the components are C1, C2, … Cn, CO2, etc. Both liquid and vapor phases may contain all components

Extending the system to three phases (1-D) and introducing production terms gives:

$$\frac{\partial}{\partial x}\left(\frac{k_{ro}\,k_x}{\mu_o B_o}\frac{\partial \Phi_o}{\partial x}\right) - \frac{\partial}{\partial t}\left(\frac{\phi S_o}{B_o}\right) + \tilde{q}_o$$

$$\frac{\partial}{\partial x}\left(\frac{k_{rw}\,k_x}{\mu_w B_w}\frac{\partial \Phi_w}{\partial x}\right) - \frac{\partial}{\partial t}\left(\frac{\phi S_w}{B_w}\right) + \tilde{q}_w$$

$$\frac{\partial}{\partial x}\left(\frac{k_{rg}\,k_x}{\mu_g B_g}\frac{\partial \Phi_g}{\partial x} + R_s\frac{k_{ro}\,k_x}{\mu_o B_o}\frac{\partial \Phi_o}{\partial x}\right) - \frac{\partial}{\partial t}\left(\frac{\phi S_g}{B_g} + \frac{\phi R_s S_o}{B_o}\right) + \tilde{q}_g + R_s\tilde{q}_o \qquad (5.1)$$

There are three types of quantities in these equations: primary variables, dependent variables, and fixed quantities. The *primary variables* are the independent unknown quantities that are functions of space and time. In a reservoir simulator, the primary variables are the unknowns that will be solved for. The *dependent variables* are the quantities whose values can be expressed as a function of one or more primary variables. For example, water relative permeability is a function of water saturation, and porosity is a function of pressure. The *fixed quantities* are constants whose value does not depend on the primary variables.

Primary Variables (Unknowns)	**Dependent Variables = f(Primary Variables)**		**Fixed Quantities (Constants)**	
P_o = Oil phase pressure	**kro, krw, krg**	**= Oil, water, gas relative perm**	**k**	**= Permeability**
P_w = Water phase pressure	**μ_o, μ_g**	**= Oil & gas viscosity**	**h**	**= Distance to reference depth**
P_g = Gas phase pressure	**ρ_o, ρ_w, ρ_g**	**= Oil, water, gas densities**	**μ_w**	**= Water viscosity**
S_o = Oil saturation	**B_o, B_w, B_g**	**= Oil, water, & gas formation volume factors**	**q_o, q_w, q_g**	**= Oil, water, gas production rates**
S_w = Water saturation	**R_s**	**= Solution gas-oil ratio**		
S_g = Gas saturation	**ϕ**	**= Porosity**		

In the partial differential model above, there are three equations (one for the oil component, one for the water component, and one for the gas component) and six unknowns (three pressures and three saturations). In order to get a solution to the mathematical model, there must to be as many equations as there are unknowns (the primary variables). Three additional equations are therefore needed to complete the mathematical model. These additional equations are frequently called constraint equations. Two constraint equations are obtained by using capillary pressure (a function of saturation) to relate phase pressures.

Finally, the saturations must sum to unity.

$$So+Sw+Sg=1.0 \qquad (5.2)$$

With the appropriate boundary conditions, then, these equations form the partial differential equation model of three phases flowing in a single direction in a reservoir. Extension to the other two dimensions is straightforward.

To be of practical use, these equations must be integrated to give actual values of pressure and saturation at any given time. However, even for the most trivial cases, these equations are extremely difficult to solve. To further complicate the matter, different sets of boundary conditions imposed on the same set of flow equations will generate different results. For the general case, no analytical solution can be found at all. Therefore, other mathematical techniques (numerical methods) must be used to solve them. These techniques are discussed in the following sections.

5.4 Key Steps in a Simulation Study[6]:

There are mainly seven (Figure 5.3) key steps involve conducting a simulation study:

1. Statement and prioritization of objectives
2. Reservoir characterization
3. Model selection
4. Model construction
5. Model validation
6. Predictions
7. Documentation

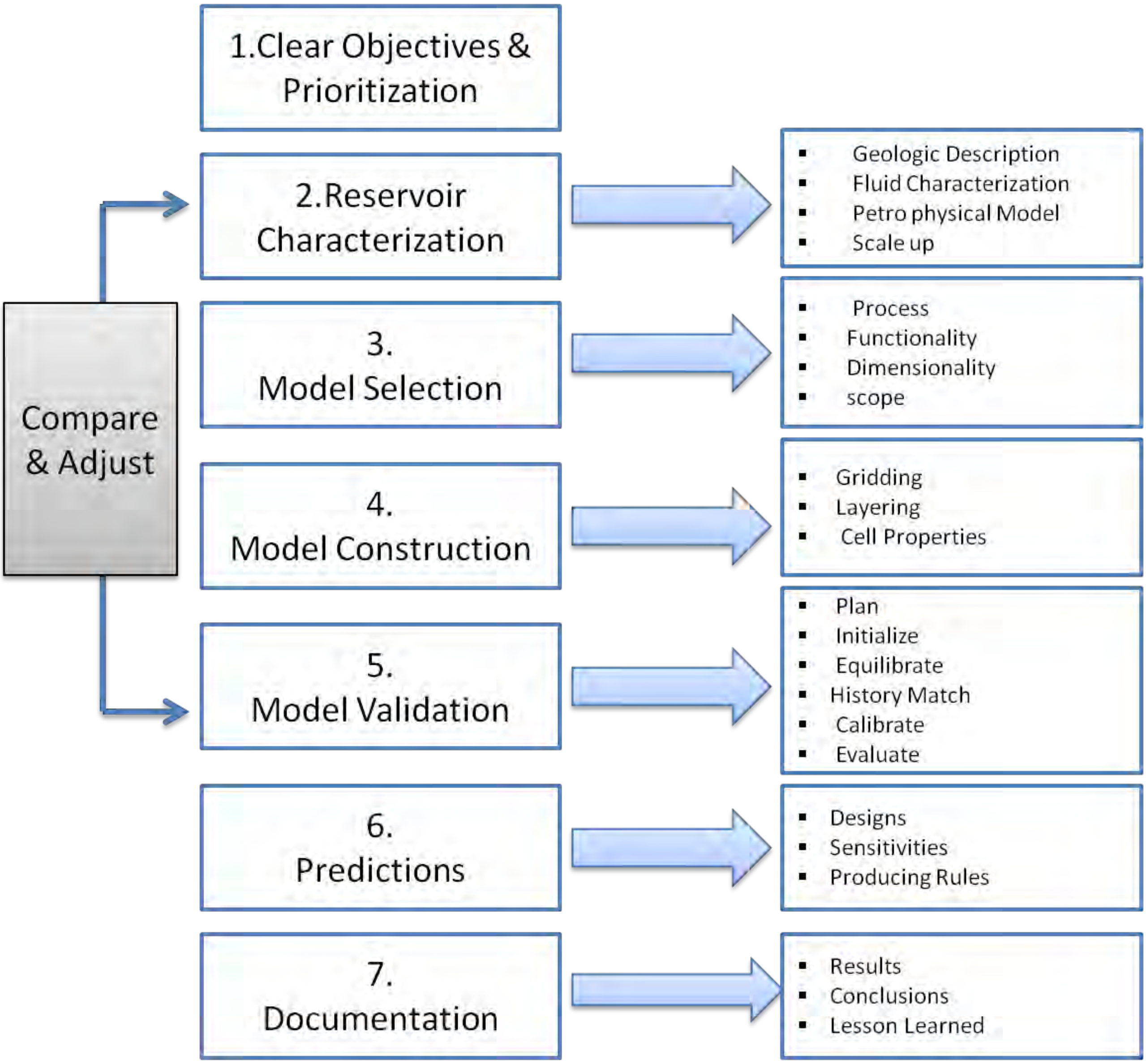


***Figure 5.3**: Steps in a Simulation Study*

5.4.1 Setting Objectives:

The first step in the reservoir study is to specifically define what you are trying to accomplish. The type and complexity of simulation efforts depend on the goals and objectives of your study, which should be carefully crafted to be in line with the business reasons described previously.

In the current study our clear objectives:

- Estimate the GIIP.
- Evaluating historical reservoir performance by matching pressure and production forecast.
- Prediction of future production.

5.4.2 Reservoir Characterization

There are many sources (Figure5.4) of data which can contribute to the reservoir characterization effort. All data should be used to develop an understanding of the reservoir. Each type of data does not correlate to only one specific part of the description. Each piece of data may have multiple uses to describe various characteristics, or to validate interpretations of other characteristics.

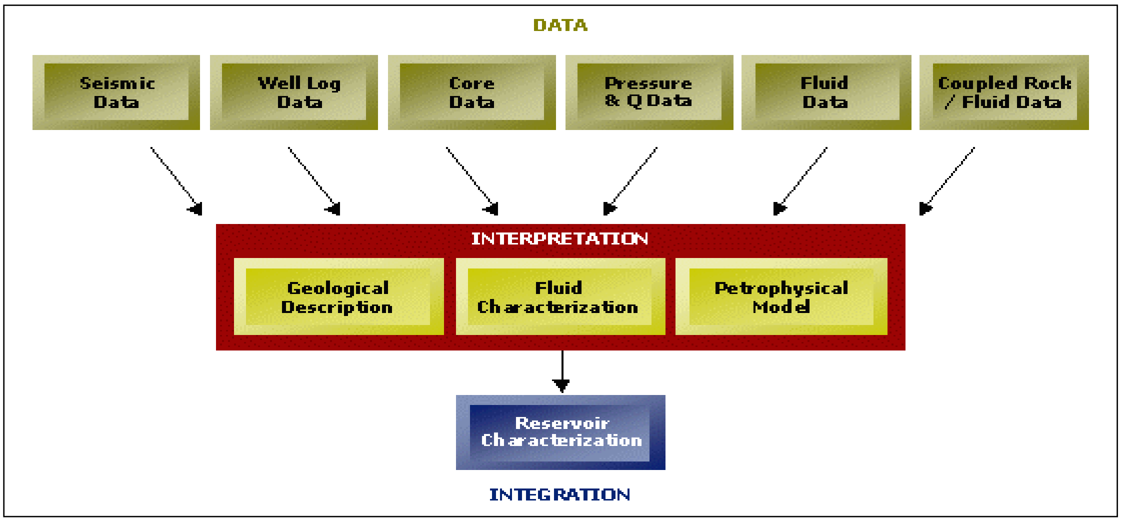


Figure 5.4: *Data sources of reservoir characterization*

5.4.2.1 Geologic Description

The first step in characterizing a reservoir is to develop the geological description, which describes (Figure 5.5) the reservoir's structure, geometry and continuity.

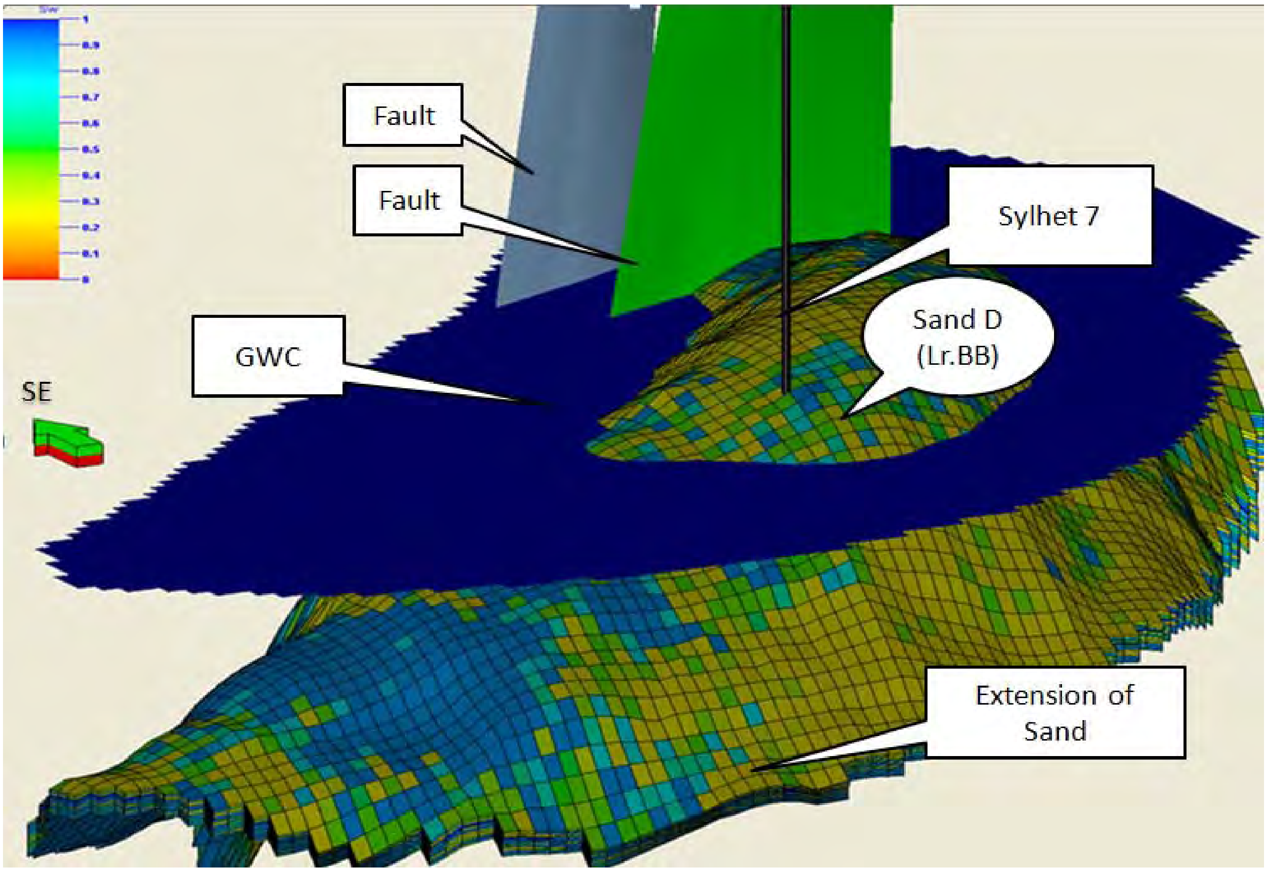


Figure 5.5 *Saturation Distribution of Sand D from Geo-model (Sources: Petrobangla)*

Geo-model suggests that there are two faults in Sylhet structure but they are not affected the Sand-D. Upper part of the GWC (Fig 5.5) is used in this study from where Sylhet7 is producing.

5.4.2.2 Fluid Characterization

In order to properly evaluate reservoir performance, it is necessary to understand the general phase behavior, which is defined by the Pressure, Volume and Temperature (PVT) relationship. Steps needed to characterize the reservoir fluids:

- Classify the fluid type
- Determine reservoir fluid properties
- Describe reservoir production mechanisms

5.4.2.3 Model size

Primary geo-model was 94 X 83 X 16. Due to make the computation simple, model was set to 50 X 9 X 16 keeping the reservoir area same. Total no. of cells reduced to 7200 from 124,832. The final grid size information is given below:

Table 5.1 *model information*

Cell Axis	Cell no. of Model	Dimension Unit, ft
X	50	616.64
Y	9	323.96
Z	16	12.50

5.4.3 Model Construction

This step involves transforming the geologic and petro physical data into a simulation grid format. Key reservoir parameters such as vertical permeability, horizontal permeability and relative permeability depend on scale and model dimensions. Therefore, model properties have to be properly scaled–up to cell dimensions in use. Following steps are applied to construct the model for preparing simulation input deck. The input deck should be checked for data consistency for the following parameter in all sequential steps:

1. Problem description:
    - Process (Black oil, compositional, condensate, etc.)
    - Start Date
    - Model size and other parameter dimensions
    - Equation solver type and mathematical formulation

2. Output specifications:

    - Time-variant cell properties
    - Well rate and cumulative volume
    - Field rate and cumulative volume
    - Material Balance region report
    - EXCEL output files

3. Fluid properties:

    - Oil, gas and water tables
    - Thermal properties
    - Component properties, equilibrium ratios

4. Coupled rock- fluid properties:

    - Oil-water and gas-oil relative permeability
    - Flow options (dispersed, segregated, mixed, etc.)
    - Special Rel-perm options

5. Initialization data:

    - Initial fluid contacts
    - Datum pressure and depth
    - Equilibrium region parameter

6. Grid dimensions:

    - Grid system
    - Number and sizes of cells in each dimension

7. Cell properties:

   - Top depth
   - Gross and net thickness
   - Porosity
   - Horizontal and vertical permeability
   - Rock property region

8. Recurrent data:

   - Location and completion of modeled data
   - Production constraint
   - Well limit
   - Historic Production
   - Flow tables

5.4.3.1 Reservoir Grid Description

Partial differential equations that describe fluid flow in reservoirs are solved numerically, by discretizing the differential equations with difference equations. To use difference equations, reservoir is treated as if it is composed of discrete volume elements and changes in conditions within each volume element are computed over each of many discrete time intervals. Reservoir volume elements are termed as grid blocks. A three-dimensional grid model (Figure 5.7) for D-sands of Haripur Gas Field was used for the simulation purpose to predict the future performance of the reservoir. Only the producing sands were modeled and simulated. The reservoir sand to be simulated is divided into 50 grid blocks in I direction and 9 grid blocks in J direction after up-scalling. The number of grid blocks in the vertical direction considered 16 in K direction which varies with the thickness of the sand.

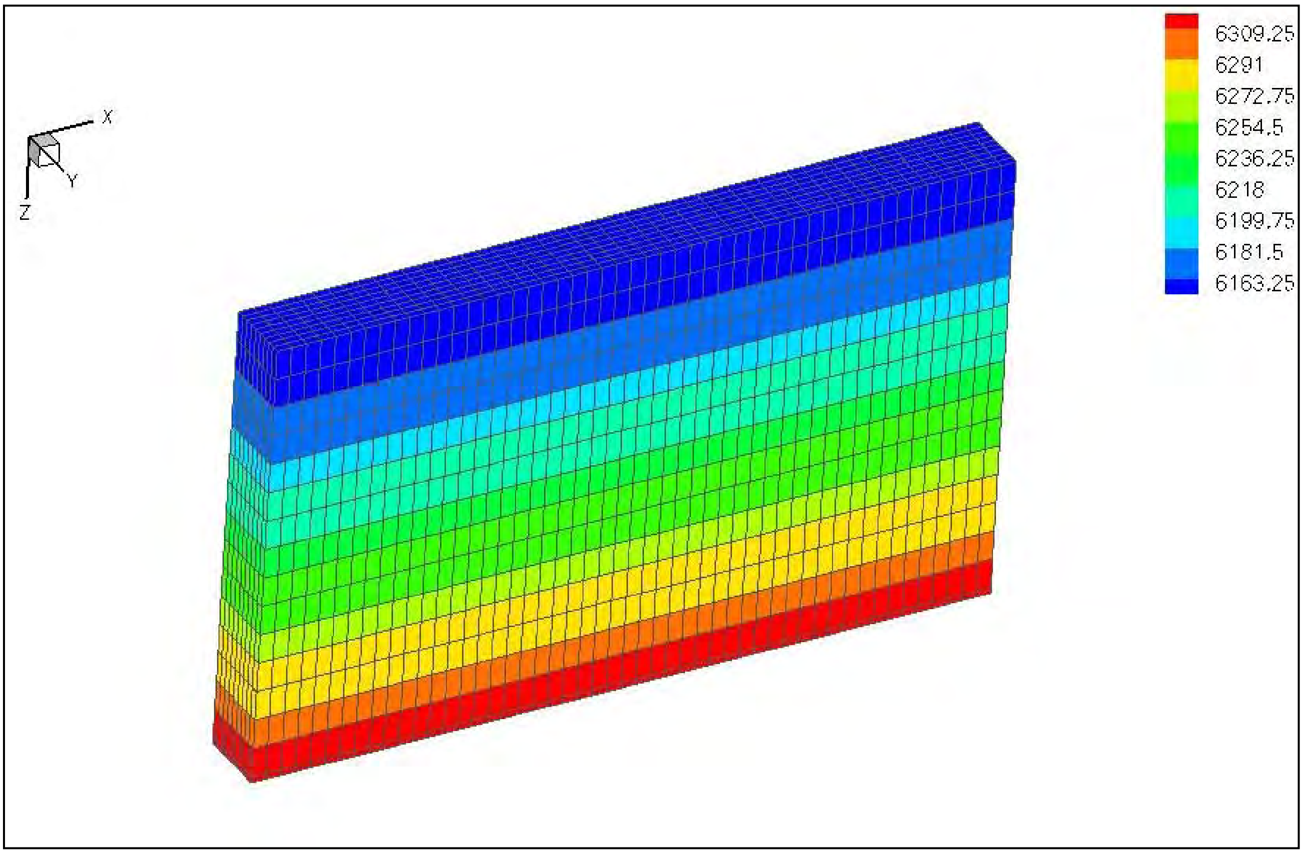


Figure 5.6 *50X9X16 Simulation Model Over Depth*

5.4.4 Input Parameters

Most of the input parameters used in this study are taken from Petrobangla and some of the data are assumed compared with other field of Sylhet region due to unavoidability of the data.

5.4.4.1 Fluid Properties[8]

The gas formation volume factor, gas viscosity, compressibility, solution gas oil ratio and fluid composition used in this study are given in the Table 5.2 and Table 5.3.

5.4.4.2 Well Parameters

The well parameter obtained from the well completion details compiled by Halliburton. These values are shown in Table 5.4.

Table 5.2: *Gas formation volume factor, gas viscosity, compressibility and solution gas oil ratio*

Pressure, psia	Formation Volume Factor, Bg (RB/STB)	Viscosity (CP)	Compressibility (1/psi)	Solution Gas-Oil Ratio (SCF/STB)
14.7	1.062	1.04	1.41E-05	1
264.7	1.15	0.975	1.41E-05	90.5
514.7	1.207	0.91	1.41E-05	180
1014.7	1.295	0.83	1.41E-05	371
2014.7	1.435	0.695	1.41E-05	636
2514.7	1.5	0.641	1.41E-05	775
3014.7	1.565	0.594	1.41E-05	930
4014.7	1.695	0.51	1.41E-05	1270
5014.7	1.827	0.449	1.41E-05	1618
9014.7	2.357	0.203	1.41E-05	3010

Table 5.3 *Fluid composition*

Component	**Mole fraction**	**Mol. Wt. (gram)**
N_2	0.00274	28.01
CO_2	0.00148	44.01
C1	0.95139	16.043
C2	0.02525	30.07
C3	0.00992	44.097
iC4	0.0021	58.124
nC4	0.00257	58.124
iC5	0.00108	72.151
nC5	0.00072	72.151
C6	0.009	84
C7+	0.00185	96
Total	1.00	

Table 5.4 *Well parameter*

Sand	**Well**	**Pay Zone TVD (ft)**	**Avg. Res. Thickness (ft)**	**Porosity**	**Permeability (md)**	**Rock Compre. (1/psi)**
D (Lr. Bokabil)	SYL-7	6145 - 6412	287	0.18	135~145	1.41E-05

5.4.5 Model Validation

Validation can be broken into a sequence of steps:

- Development of a validation plan.
- Initialization - review the model ensure that all data were properly input. Also includes calculating initial pore volumes, pressures and saturations, and original fluids in place.
- Equilibration - bringing the model to equilibrium with respect to internal and external boundary conditions (no pressure or saturation changes).
- History Matching - achieving a match between model and measured field performance over a significant period of time at known rates.
- Calibration - the process of adjusting parameters to match well performance with known back pressures, usually flow rate vs. FBHP or FWHP.
- Evaluation of results.

Model validation process is presented in Figure 5.8.

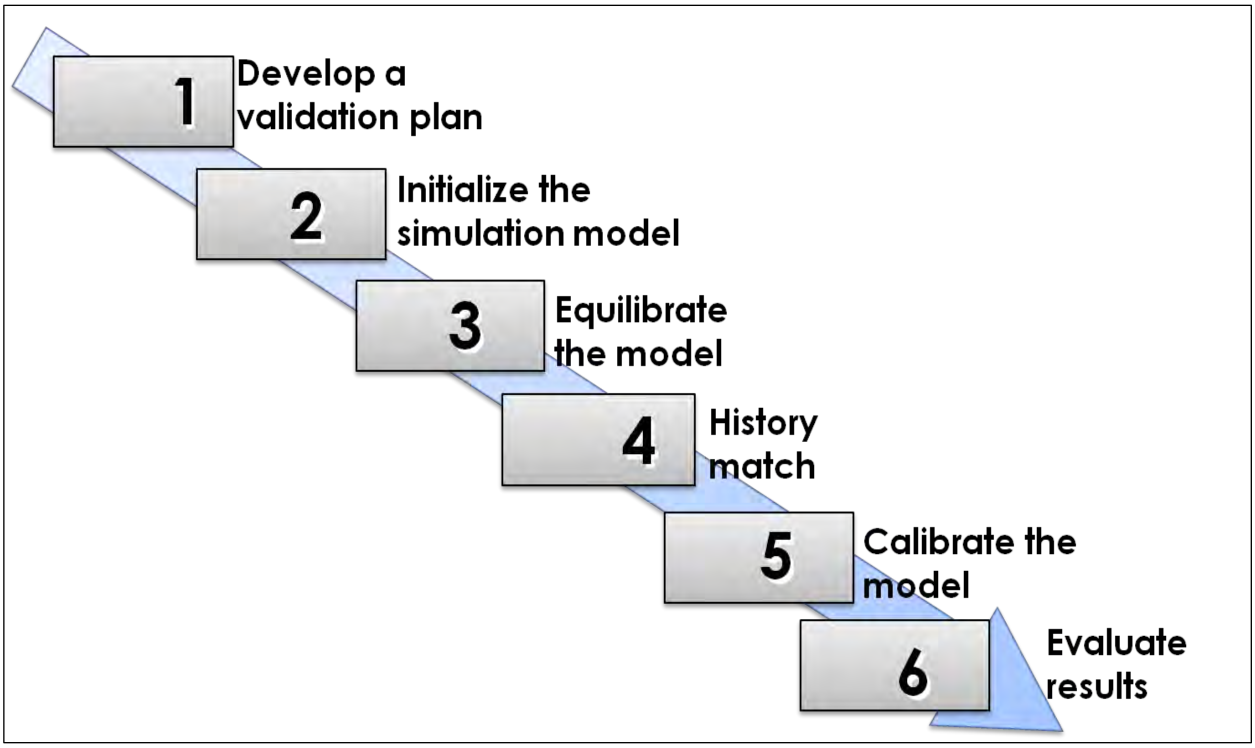


Figure 5.7 *Model Validation Process*

5.4.5.1 History Matching

The process of history matching is very useful and powerful reservoir description technique although it has inherent non-uniqueness problem associated with it. The key factors such as, gas rate and reservoir pressure depletion with time of the model are compared with the actual reservoir performance. Daily wellhead pressure data and gas rates were assimilated on a monthly average basis for history matching. A good match validates the reservoir model used. The gas rate, cumulative production and reservoir pressure depletion along with the model output for Sylhet 7 are done in this study.

5.4.5.1.1 Production History Match

The producing sand of Bokabil region has been simulated using course grid. Most of the data for fluid properties are assumed compared with the other near fields of Sylhet region. From the production history matching it is observed that the initial and late time period production history is not matched as expected but in mid time period it matched better. Historical production rate and cumulative production are closely matched in this model which is shown in Figure 5.9 and Figure 5.10.

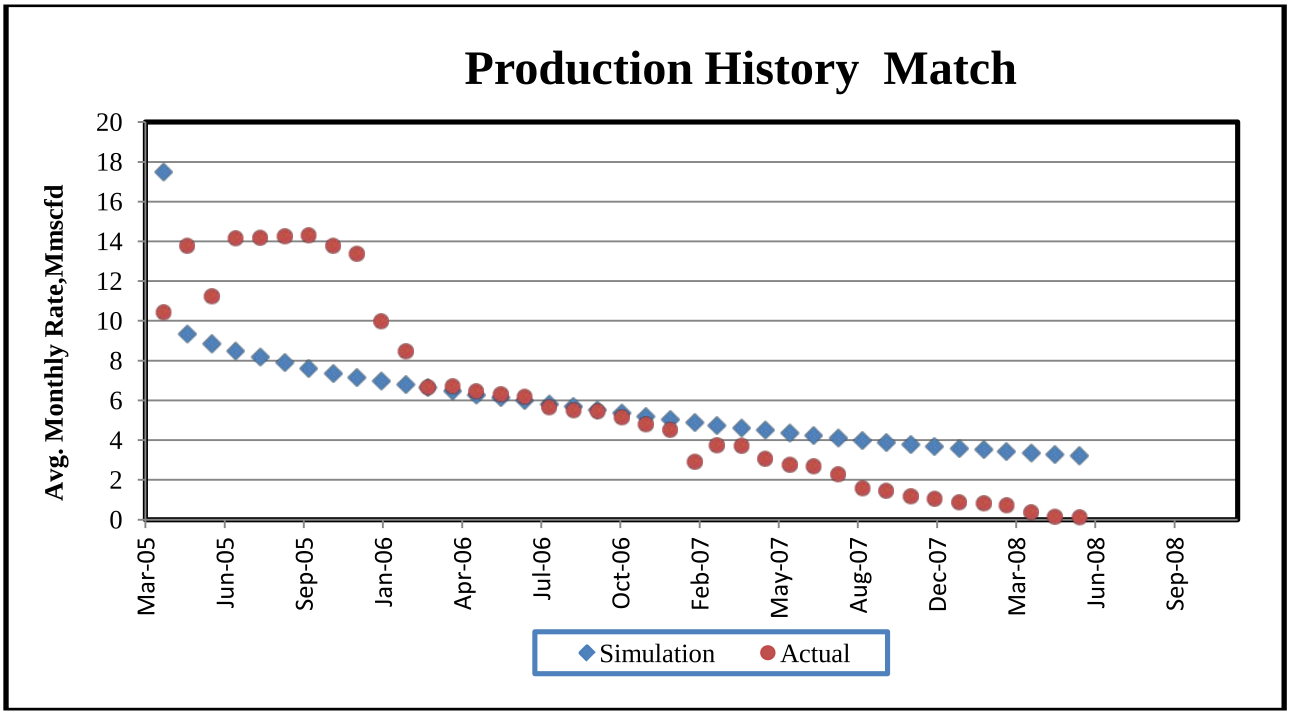


Figure 5.8 *Simulated and Actual Production History of well Sylhet-7*

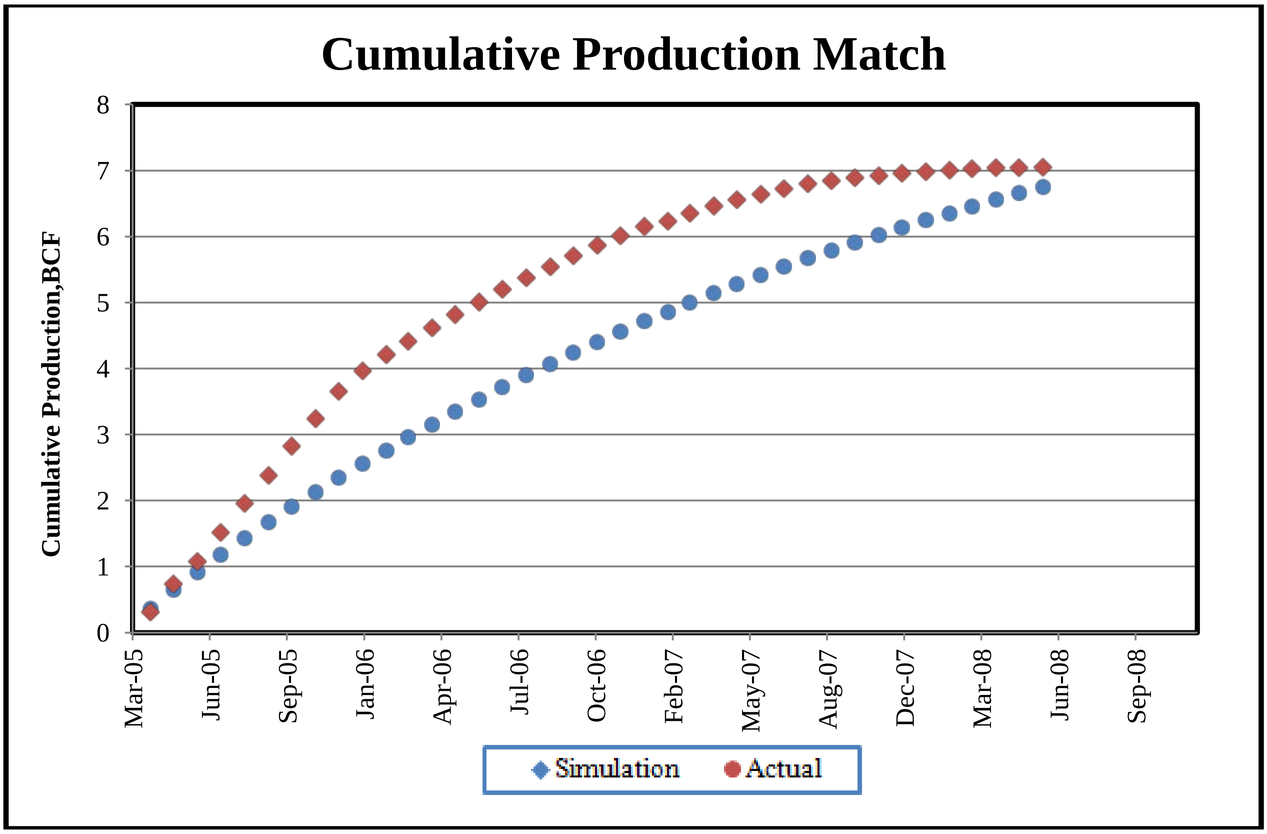


Figure 5.9 *Simulated and Actual Cumulative Production History of well Sylhet-7*

5.4.5.1.2 Pressure History Match

Because of poor quality data monitoring, monthly average pressure data considered in this current study. Sylhet 7 is a vertical well and using the pressure gradient and considering the mid perforations as the datum bottom hole pressure calculated from well head pressure. From the pressure history matching it is observed that the initial time period pressure history after first work over matched better but the later period pressure history is not matched as expected. According to well test data and production analysis, total skin value for this well dramatically increased due to gradual development of obstruction inside the tubing which could be potentially affected for this drastic pressure decline. So this pressure decline does not significantly represent the true behavior of the reservoir.

The pressure history match plot is given in the Figure 5.10.

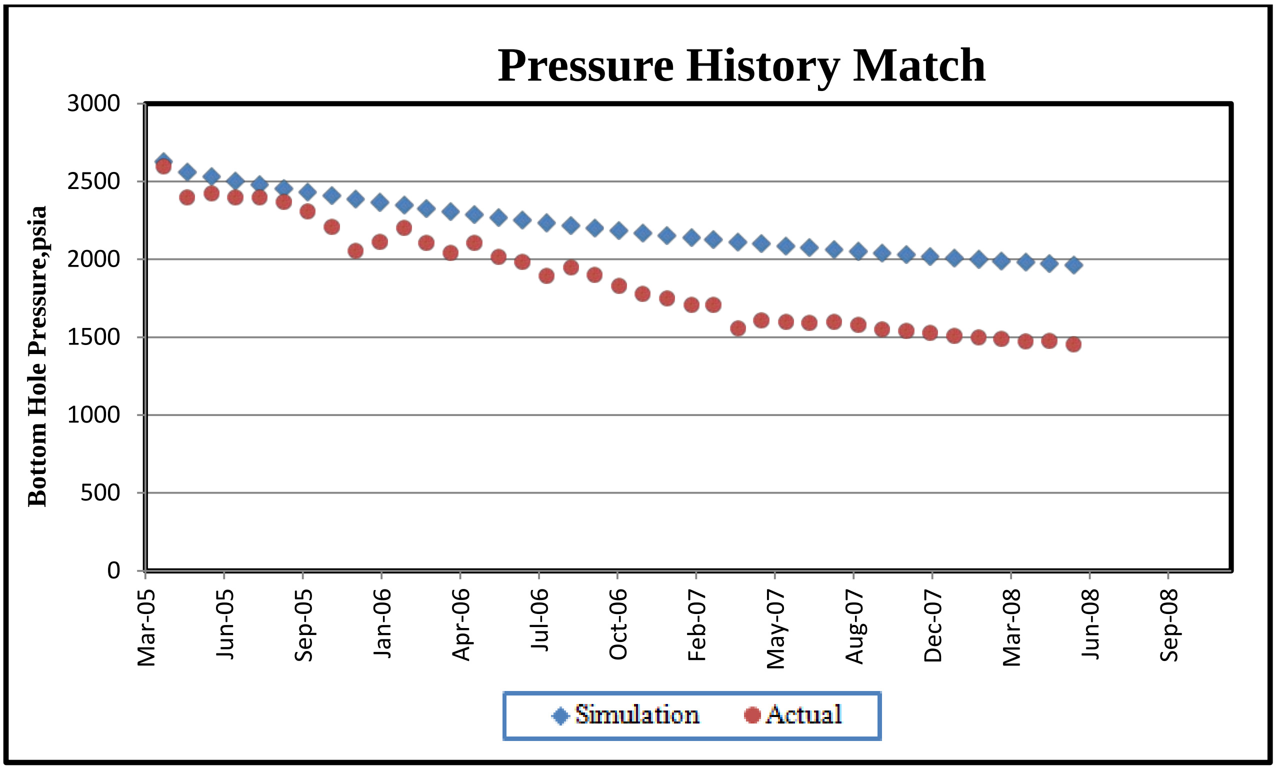


__Figure 5.10__ Simulated and Actual Bottom Hole Pressure History of well Sylhet 7

5.4.5.1.3 Production Prediction:

Based on the current model comparative production and pressure depletion prediction is made which are shown in figure 5.11 and 5.12.

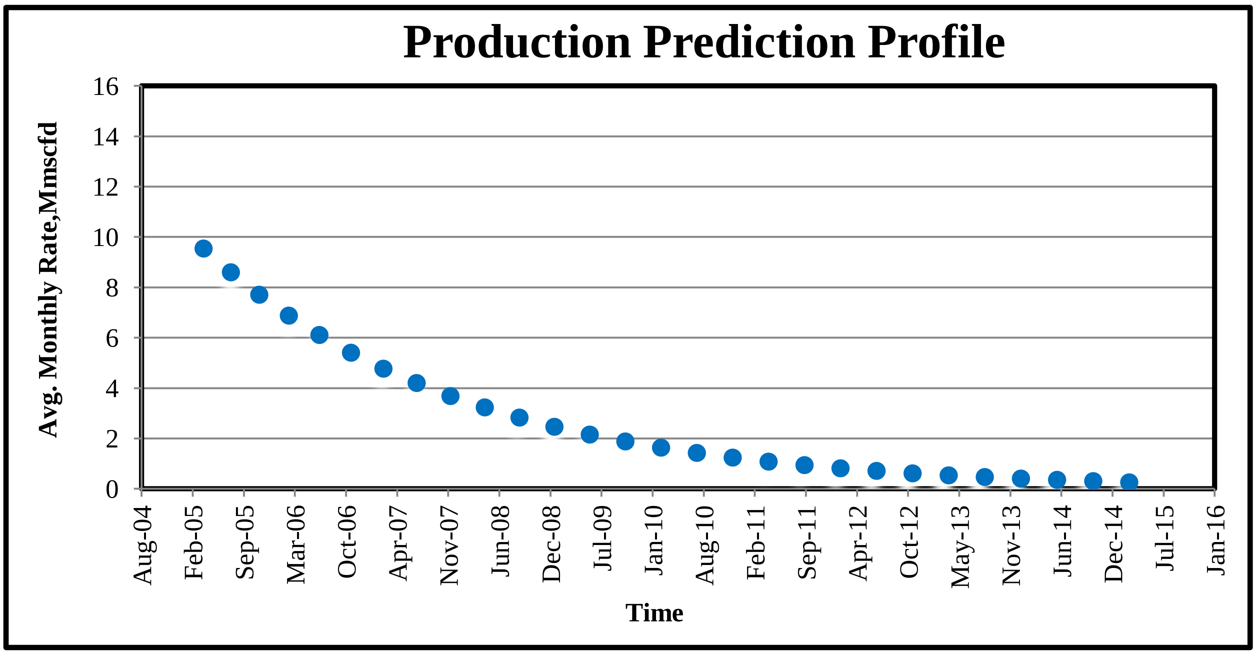


***Figure 5.11:** Production Prediction Profile for the Sand D of Sylhet 7*

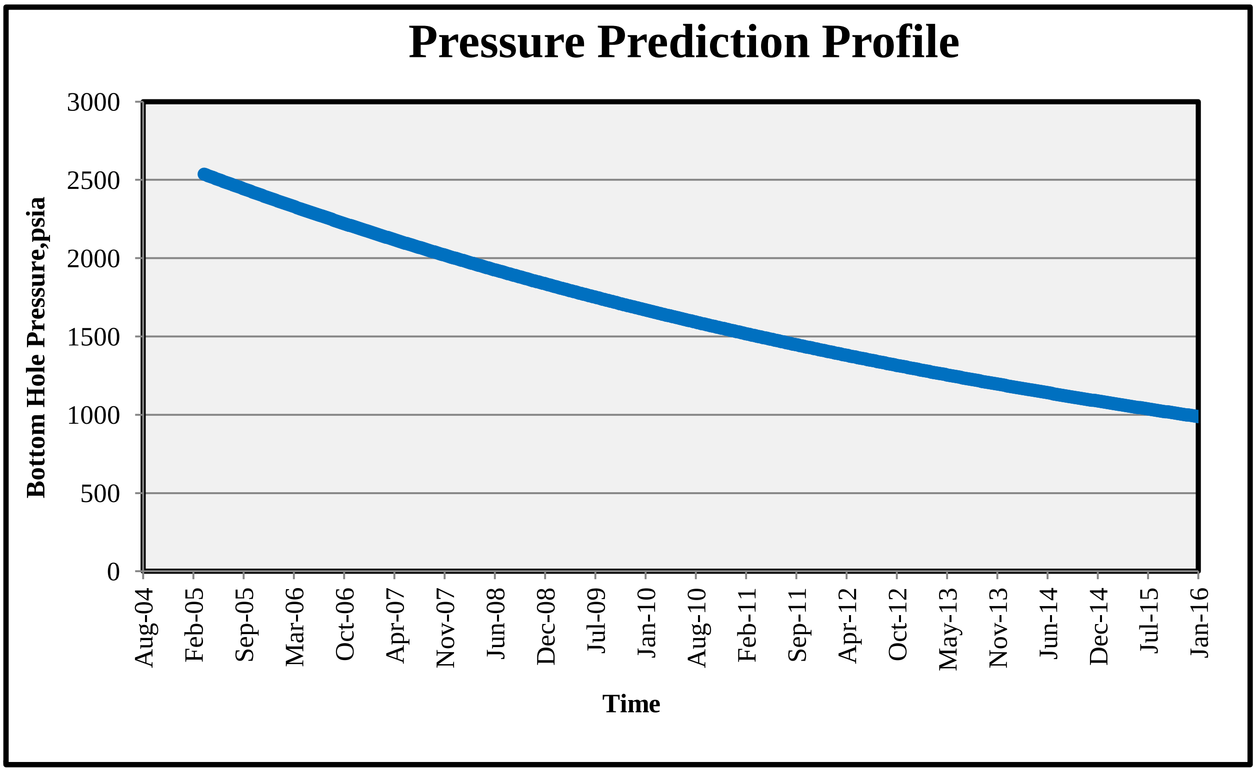


Figure 5.12: *Pressure Depletion Prediction Profile for the Sand D of Sylhet 7*

5.5 Discussion on Simulation Result

Simulation results including the history matching of producing sands of Haripur Gas Field is discussed in this section. Haripur Gas Field has been simulated till 2015. The prediction of future field performances involves prediction of the reservoir pressure depletion along with the off take rate of reservoir fluids. It is important that for a model to behave like the actual reservoir it must mathematically incorporate all the physical aspects of the actual reservoir. The only available way to test the model is to simulate past performance of the reservoir and compare the simulation results with actual, historical performance.

In simulation model, reservoir parameters (porosity, permeability, transmissibility etc.) are considered homogeneous for the whole producing sand and for the entire period of time productivity index assumed constant. So the model is limited to uncertainties due to heterogeneity of reservoir because of data inadequacy.

The present simulation study yielded (Table 5.5) a gas in place values about 32.51 BCF for the producing sand of Sylhet gas field. The cumulative production from Sylhet7 till July 2008 is 7.087 BCF. According to the current model prediction, reserve at the abandonment p/z of 1000 psia is 21.20 BCF. Remaining reserve for this location is 11.31BCF. The recovery factor for this sand is about 65.21%.

A comparison is made with PB recent study by RPS energy in Table 5.6.

Table 5.5 *Simulation Results:*

Lr. Bokabil (D-Sand)	GIIP,BCF (Considering connected pore volume with History Matching)	Reserve@ 1000 psia Abandon (BCF)	Cum Prod. (till July 2008) (BCF)	Remaining Reserve, (BCF)	Recovery Factor, (%)
Sylhet-7	32.51	21.20	7.078	11.31	65.21

Table 5.6 *Comparison of gas in place (BCF) estimates by reservoir simulation conducted on D-sand:*

Petrobangla study by RPS Energy (2009)	Current Study (Considering the connected pore volume)
46	32.51

Chapter 6

CONCLUSION AND RECOMMENDATION

6.1 Summary of Result

From different type of analysis, the gas initially in place (GIIP) found are listed in Table 6.1.

Table 6.1 *Summary of Result (BCF)*

Lr. Bokabil Sand	Different Approaches of Material Balance				Conventional Material Balance	Advance Production Data Analysis	Decline Curve Analysis	Reservoir Simulation (considering connected pore volume)
	SBHP	SWHP	FBHP	FWHP				
Sylhet7	27	28	24	21	26.997	16.7	28.20	32.51

6.1.1 Production Data Analysis

- After first work over, pressure declined sharply due development of obstruction inside tubing. Second work over was done to clean the obstruction inside tubing and well behavior followed the initial production trend. So it is believed that the sharp decline was not the actual behavior of reservoir.

- The GIIP Lower Bokabil sand of Haripur Gas Field obtained by Advanced Production Data Analysis and conventional Decline Curve Analysis are 16.7 BSCF and 28.20 BSCF respectively.

- TOPAZE model with initial Bottom Hole Production data indicates a GIIP 13.10 BSCF with satisfactorily production and pressure history matching. This analysis could be the acceptable approach for the entire period before second work over if flow conditions remain unchanged but later the well experienced flow restriction due to gradual development of obstruction inside tubing.

- TOPAZE model with daily production data indicates a GIIP 16.7 BSCF and reservoir pressure is not matched well because of poor quality of data.

6.1.2 Pressure Transient Analysis

- The pressure transient analysis using SAPHIRE has yielded the reservoir pressure 2678 psia and permeability about 135 md which are used to match the production data analysis and reservoir simulation.
- Geo-model based on 2D seismic shows that sand-D is not affected by the fault which suggest no compartmentalization. On the other hand, well test data suggests the evidence of barrier which could be due to porosity variation or facies change.

6.1.3 Material Balance Study

- Based on available data no aquifer support observed in the D-sand of Haripur Gas Field.
- The GIIP of Lower Bokabil sand of Haripur Gas Field obtained by flowing bottom hole pressure method (FBHP) and conventional material balance using average reservoir pressure are 24.0 BSCF and 26.89 BSCF respectively.
- The cumulative production from Sylhet - 7 is 7.087 BCF. Assuming the GIIP using FBHP approach as 24 BCF, reserve at the abandonment p/z of 1000 psia is 16 BCF. Remaining reserve for this sand is 8.913 BCF. The recovery factor of this well is 66.67%.

6.1.4 Reservoir Simulation

- The producing sand has been simulated using a commercial simulator. The simulated results compared reasonable with the actual production and pressure history of the producing sand. Based on the built model a comparative prediction was made for future production.
- Producing sand simulated assuming homogeneous porosity and permeability.
- Considering the pore volume connected with history matching, GIIP yielded 32.51 BCF. As of July 2008, the cumulative production of the field is 7.087 BCF. According to the current model prediction, reserve at the abandonment p/z of 1000 psia is 21.20 BCF. Remaining reserve for this location is 11.31BCF. The recovery factor for this sand is about 65.21%.

6.2 Conclusion:

- The reserve estimates for D sand of Sylhet Gas Field were done using different methodologies. Considering all these methods it seems that the flowing material balance (FBHP) is the better approach because this method is based on the pseudo steady state pressure behavior.
- Reservoir simulation study result limited to the uncertainties due to heterogeneity of reservoir which are not considered due to data inadequacy.

6.3 Recommendation:

- Proper attention should be given for pressure and flow monitoring in the well which will help to reduce the uncertainties in data quality for analysis.
- Uncertainties involve in reservoir pressure and draw down will be reduced by conducting periodic bottom hole pressure survey and that will help to accurately model the reservoir and analysis.
- Conducting 3D seismic survey in future will help to understand the Sylhet structure more which may create a more opportunities.

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APPENDIX I

Main Results	Production Data Analyis
Company : Sylhet Gas Field Limited Well : Sylhet - 7	Field : Haripur Gas Field Test Name / #

Test date / time	
Formation interval	
Perforated interval	
Gauge type / #	
Gauge depth	
Porosity Phi (%)	18
Well Radius rw	0.25 ft
Pay Zone h	111.549 ft
Water Salt (ppm)	10000
Form. compr.	3E-6 psi-1
Reservoir T	155 °F
Reservoir P	2675 psia
Fluid type	Gas
Gas Gravity	0.587
Pseudo-Critical P	678.905 psia
Pseudo-Critical T	348.528 °R

Sour gas composition

Hydrogen sulphide	0
Carbon dioxide	0
Nitrogen	0
Temperature	155 °F
Pressure	2675 psia
Properties	@ Reservoir T&P

Gas

Z	0.884885
Mug	0.0179347 cp
Bg	0.00574644 cf/scf
cg	3.59043E-4 psi-1
Rhog	0.125112 g/cc
Total Compr. ct	3.62043E-4 psi-1
Connate Water (%)	0

Selected Model

Model Option	Standard Model, Material Balance
Well	Vertical, Time Dependent Skin
Reservoir	Homogeneous
Boundary	Circle, No flow

Main Model Parameters

Tmin	0 hr
Tmax	29208 hr
k.h, total	442 md.ft
k, average	3.96 md
Pi	2675 psia
STGIIP	16.7 bscf
STGIP	9.46 bscf

Model Parameters

Well & Wellbore parameters (: Sylhet - 7)

Skin# 1	-1.36
Skin# 2	-1.68
Skin# 3	-3.56
Skin# 4	-0.177
Skin# 5	7.65
Skin# 6	36.9
Skin# 7	43.6
Skin# 8	43

Reservoir & Boundary parameters

Pi	2675 psia
k.h	442 md.ft
k	3.96 md
Re - No flow	1230 ft

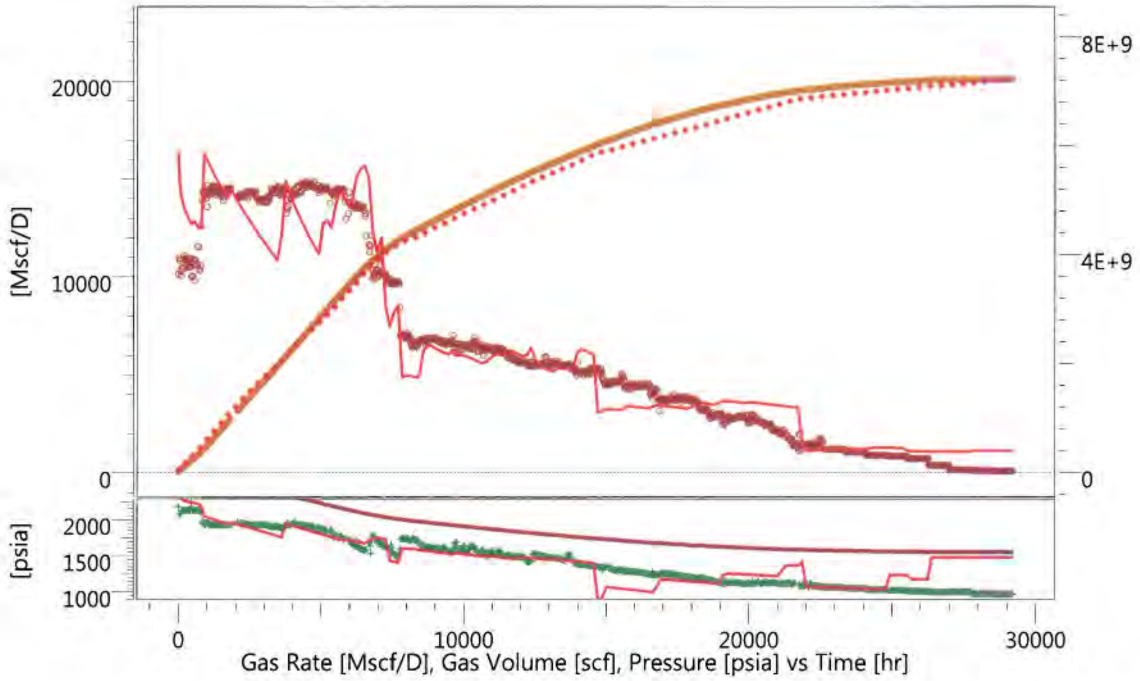
Derived & Secondary Parameters

TMatch	14300 [hr]-1
PMatch	1.66E-4 [psi2/cp]-1

Abandonment

Ab. rate (qa)	0 Mscf/D
Ab. time (ta)	N/A hr
Q(ta)	N/A scf

Production history plot	Production Data Analyis
Company : Sylhet Gas Field Limited Well : Sylhet - 7	Field : Haripur Gas Field Test Name / #



Rate
- q
- Q
- q model
- Q model

Pressure
- Pi
- p
- p model
- Pbar

Pressure - Production

Tmin	0 hr
Tmax	29208 hr
Pi	2675 psia

Selected Model

Model Option	Standard Model, Material Balance
Well	Vertical, Time Dependent Skin
Reservoir	Homogeneous
Boundary	Circle, No flow

Main Model Parameters

Tmin	0 hr
Tmax	29208 hr
k.h, total	442 md.ft
k, average	3.96 md
Pi	2675 psia
STGIIP	16.7 bscf
STGIP	9.46 bscf

Model Parameters

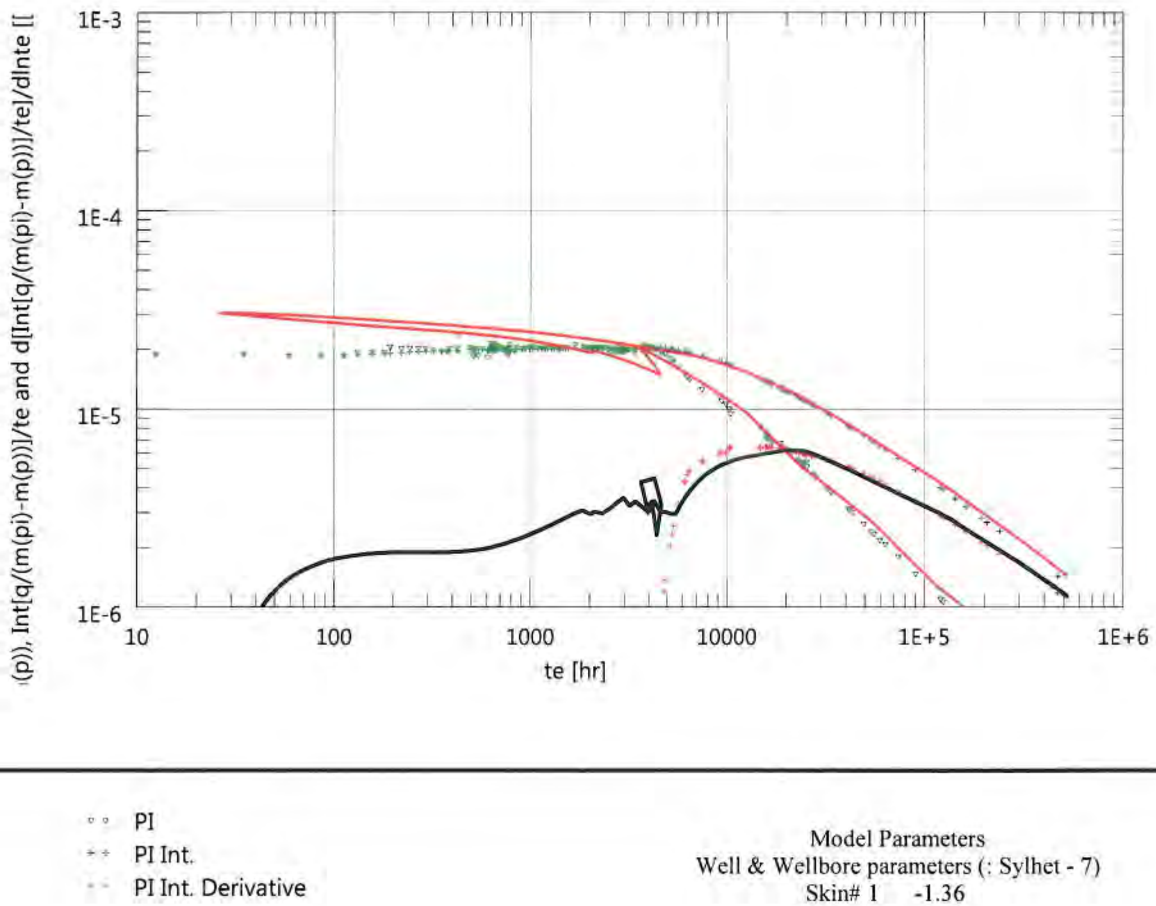
Well & Wellbore parameters (: Sylhet - 7)

Skin# 1	-1.36
Skin# 2	-1.68
Skin# 3	-3.56
Skin# 4	-0.177
Skin# 5	7.65
Skin# 6	36.9
Skin# 7	43.6
Skin# 8	43

Reservoir & Boundary parameters

Pi	2675 psia
k.h	442 md.ft
k	3.96 md
Re - No flow	1230 ft

Blasingame plot	Production Data Analyis
Company : Sylhet Gas Field Limited Well : Sylhet - 7	Field : Haripur Gas Field Test Name / #



Pressure - Production

Tmin	0 hr
Tmax	29208 hr
Pi	2675 psia

Selected Model

Model Option	Standard Model, Material Balance
Well	Vertical, Time Dependent Skin
Reservoir	Homogeneous
Boundary	Circle, No flow

Main Model Parameters

Tmin	0 hr
Tmax	29208 hr
k.h, total	442 md.ft
k, average	3.96 md
Pi	2675 psia
STGIIP	16.7 bscf
STGIP	9.46 bscf

Model Parameters

Well & Wellbore parameters (: Sylhet - 7)

Skin# 1	-1.36
Skin# 2	-1.68
Skin# 3	-3.56
Skin# 4	-0.177
Skin# 5	7.65
Skin# 6	36.9
Skin# 7	43.6
Skin# 8	43

Reservoir & Boundary parameters

Pi	2675 psia
k.h	442 md.ft
k	3.96 md
Re - No flow	1230 ft

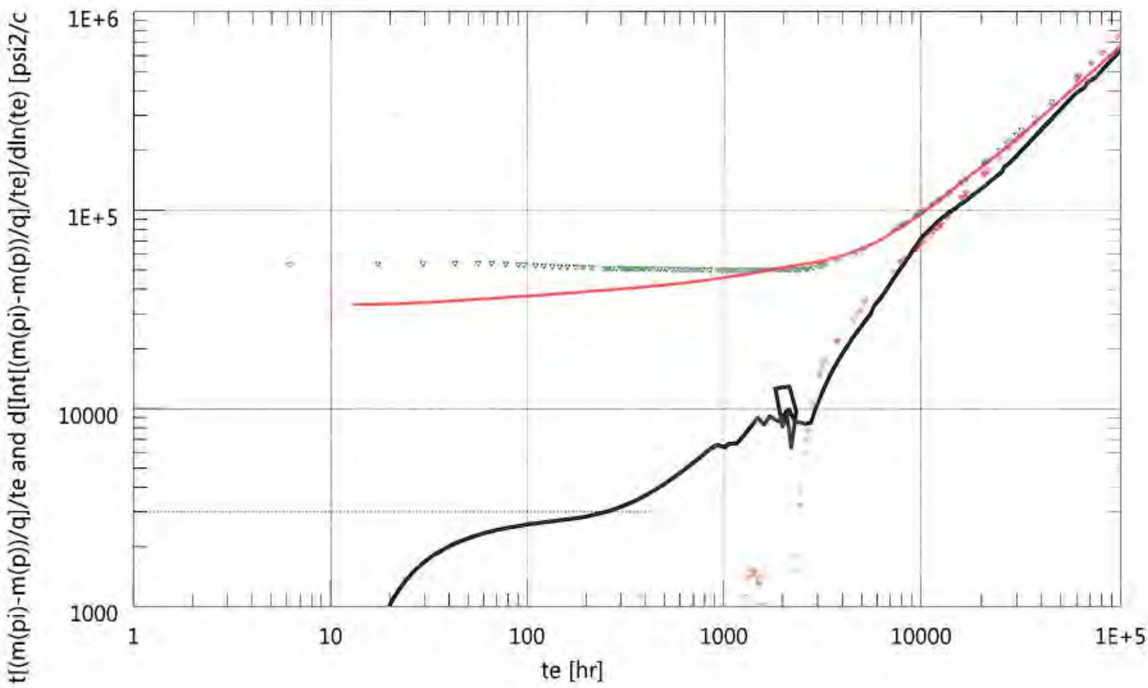
Derived & Secondary Parameters

TMatch	14300 [hr]-1
PMatch	1.66E-4 [psi2/cp]-1

Abandonment

Ab. rate (qa)	0 Mscf/D
Ab. time (ta)	N/A hr
Q(ta)	N/A scf

Loglog plot	Production Data Analyis
Company : Sylhet Gas Field Limited Well : Sylhet - 7	Field : Haripur Gas Field Test Name / #



Integral of normalized pressure
Integral of normalized pressure Derivative

Pressure - Production

Tmin	0 hr
Tmax	29208 hr
Pi	2675 psia

Selected Model

Model Option	Standard Model, Material Balance
Well	Vertical, Time Dependent Skin
Reservoir	Homogeneous
Boundary	Circle, No flow

Main Model Parameters

Tmin	0 hr
Tmax	29208 hr
k.h, total	442 md.ft
k, average	3.96 md
Pi	2675 psia
STGIIP	16.7 bscf
STGIP	9.46 bscf

Model Parameters

Well & Wellbore parameters (: Sylhet - 7)

Skin# 1	-1.36
Skin# 2	-1.68
Skin# 3	-3.56
Skin# 4	-0.177
Skin# 5	7.65
Skin# 6	36.9
Skin# 7	43.6
Skin# 8	43

Reservoir & Boundary parameters

Pi	2675 psia
k.h	442 md.ft
k	3.96 md
Re - No flow	1230 ft

Derived & Secondary Parameters

TMatch	14300 [hr]-1
PMatch	1.66E-4 [psi2/cp]-1

Abandonment

Ab. rate (qa)	0 Mscf/D
Ab. time (ta)	N/A hr
Q(ta)	N/A scf

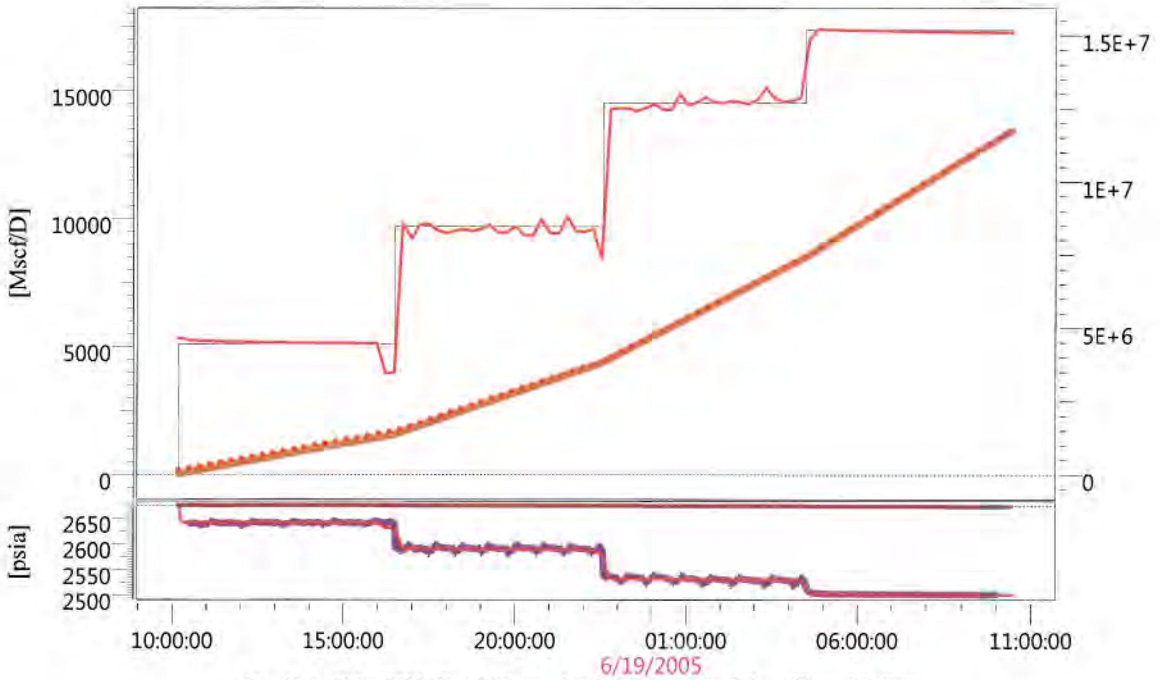
APPENDIX II

Main Results	PDA with Bottom Hole Data
Company : Sylhet Gas Field Limited Well : Sylhet 7	Field : Haripur Gas Field Test Name / # : 1

Test date / time	
Formation interval	
Perforated interval	
Gauge type / #	
Gauge depth	1904m MD
Porosity Phi (%)	18
Well Radius rw	0.291667 ft
Pay Zone h	211.614 ft
Water Salt (ppm)	10000
Form. compr.	3E-6 psi-1
Reservoir T	155 °F
Reservoir P	2680 psia
Fluid type	Gas
Gas	
Gas Gravity	0.579
Pseudo-Critical P	679.724 psia
Pseudo-Critical T	345.407 °R
Sour gas composition	
Hydrogen sulphide	0
Carbon dioxide	0.00148
Nitrogen	0.00274
Water	
Salinity, ppm	10000
Temperature	155 °F
Pressure	2680 psia
Properties	@ Reservoir T&P
Gas	
Z	0.88822
Mug	0.0178674 cp
Bg	0.00575734 cf/scf
cg	3.58069E-4 psi-1
Rhog	0.123173 g/cc
Water	
Rsw	14.2542 scf/stb
Bw	1.02777 B/STB
cw	3.1951E-6 psi-1
Muw	0.452559 cp
Rhow	0.980467 g/cc
Total Compr. ct	3.61069E-4 psi-1
Connate Water (%)	0
Selected Model	
Model Option	Standard Model, Material Balance
Well	Vertical, Time Dependent Skin
Reservoir	Homogeneous
Boundary	Circle, No flow

Main Model Parameters	
Tmin	2.77778E-4 hr
Tmax	24.8803 hr
k.h, total	16100 md.ft
k, average	145 md
Pi	2673.56 psia
STGIIP	13.1 bscf
STGIP	13 bscf
Model Parameters	
Well & Wellbore parameters (: Sylhet 7)	
Skin# 1	35
Skin# 2	47
Skin# 3	50
Skin# 4	53
Skin# 5	53
Reservoir & Boundary parameters	
Pi	2673.56 psia
k.h	16100 md.ft
k	145 md
Re - No flow	1090 ft
Derived & Secondary Parameters	
TMatch	3.85E+5 [hr]-1
PMatch	0.00605 [psi2/cp]-1
Abandonment	
Ab. rate (qa)	0 Mscf/D
Ab. time (ta)	N/A hr
Q(ta)	N/A scf

Production history plot	PDA with Bottom Hole Data
Company : Sylhet Gas Field Limited Well : Sylhet 7	Field : Haripur Gas Field Test Name / # : 1



Gas Rate [Mscf/D], Gas Volume [scf], Pressure [psia] vs Time [ToD]

Rate
- q (Production #3)
- Q
- q model
- Q model

Pressure
- Pi
- p (Pressure #3)
- p model
- Pbar

Pressure #3 - Production #3

Tmin	2.77778E-4 hr
Tmax	24.8803 hr
Pi	2673.56 psia

Selected Model

Model Option	Standard Model, Material Balance
Well	Vertical, Time Dependent Skin
Reservoir	Homogeneous
Boundary	Circle, No flow

Main Model Parameters

Tmin	2.77778E-4 hr
Tmax	24.8803 hr
k.h, total	16100 md.ft
k, average	145 md
Pi	2673.56 psia
STGIIP	13.1 bscf
STGIP	13 bscf

Model Parameters

Well & Wellbore parameters (: Sylhet 7)

Skin# 1	35
Skin# 2	47
Skin# 3	50
Skin# 4	53
Skin# 5	53

Reservoir & Boundary parameters

Pi	2673.56 psia
k.h	16100 md.ft
k	145 md
Re - No flow	1090 ft

Derived & Secondary Parameters

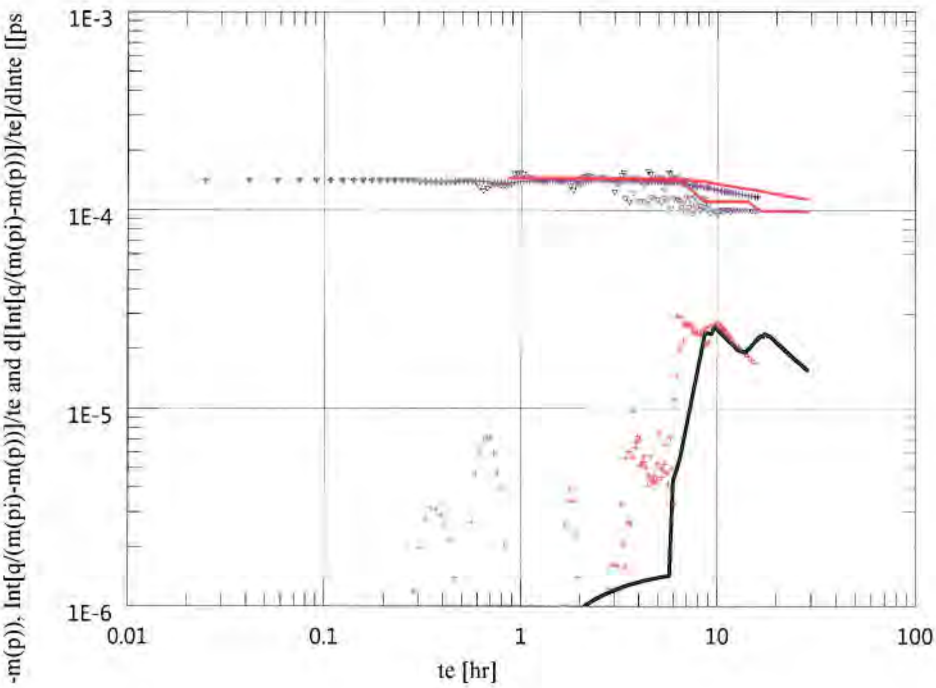
TMatch	3.85E+5 [hr]-1
PMatch	0.00605 [psi2/cp]-1

Abandonment

Ab. rate (qa)	0 Mscf/D
Ab. time (ta)	N/A hr
Q(ta)	N/A scf

Blasingame plot	PDA with Bottom Hole Data

Company : Sylhet Gas Field Limited   Field : Haripur Gas Field
Well : Sylhet 7   Test Name / # : 1



PI
PI Int.
PI Int. Derivative

Pressure #3 - Production #3

Tmin	2.77778E-4 hr
Tmax	24.8803 hr
Pi	2673.56 psia

Selected Model

Model Option	Standard Model, Material Balance
Well	Vertical, Time Dependent Skin
Reservoir	Homogeneous
Boundary	Circle, No flow

Main Model Parameters

Tmin	2.77778E-4 hr
Tmax	24.8803 hr
k.h, total	16100 md.ft
k, average	145 md
Pi	2673.56 psia
STGIIP	13.1 bscf
STGIP	13 bscf

Model Parameters

Well & Wellbore parameters (: Sylhet 7)

Skin# 1	35
Skin# 2	47
Skin# 3	50
Skin# 4	53
Skin# 5	53

Reservoir & Boundary parameters

Pi	2673.56 psia
k.h	16100 md.ft
k	145 md
Re - No flow	1090 ft

Derived & Secondary Parameters

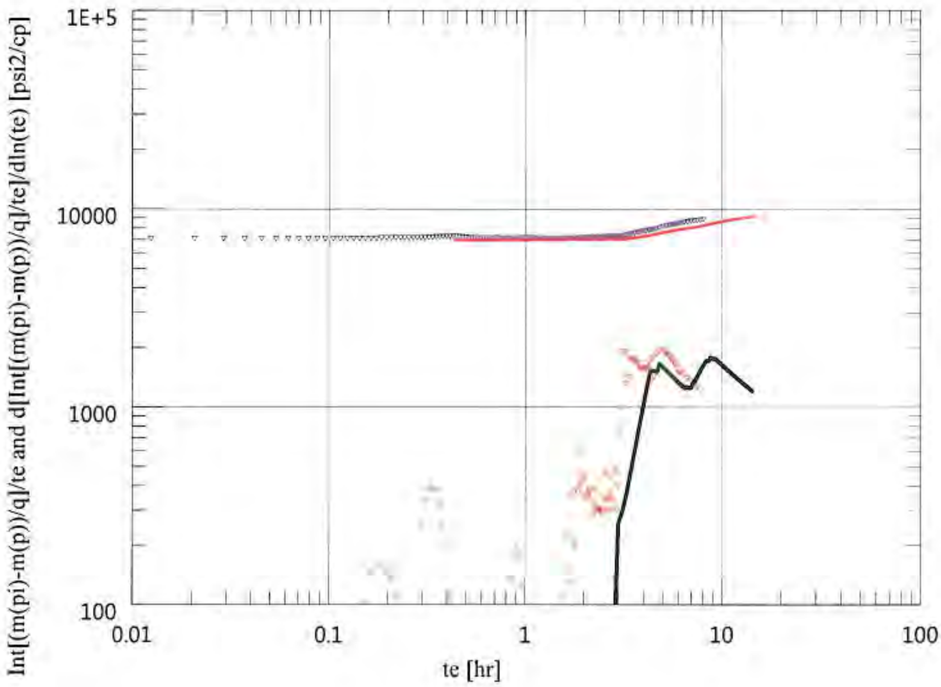
TMatch	3.85E+5 [hr]-1
PMatch	0.00605 [psi2/cp]-1

Abandonment

Ab. rate (qa)	0 Mscf/D
Ab. time (ta)	N/A hr
Q(ta)	N/A scf

APPENDIX III

Loglog plot	PDA with Bottom Hole Data
Company : Sylhet Gas Field Limited Well : Sylhet 7	Field : Haripur Gas Field Test Name / # : 1



Integral of normalized pressure
Integral of normalized pressure Derivative

Pressure #3 - Production #3

Tmin	2.77778E-4 hr
Tmax	24.8803 hr
Pi	2673.56 psia

Selected Model

Model Option	Standard Model, Material Balance
Well	Vertical, Time Dependent Skin
Reservoir	Homogeneous
Boundary	Circle, No flow

Main Model Parameters

Tmin	2.77778E-4 hr
Tmax	24.8803 hr
k.h, total	16100 md.ft
k, average	145 md
Pi	2673.56 psia
STGIIP	13.1 bscf
STGIP	13 bscf

Model Parameters

Well & Wellbore parameters (: Sylhet 7)

Skin# 1	35
Skin# 2	47
Skin# 3	50
Skin# 4	53
Skin# 5	53

Reservoir & Boundary parameters

Pi	2673.56 psia
k.h	16100 md.ft
k	145 md
Re - No flow	1090 ft

Derived & Secondary Parameters

TMatch	3.85E+5 [hr]-1
PMatch	0.00605 [psi2/cp]-1

Abandonment

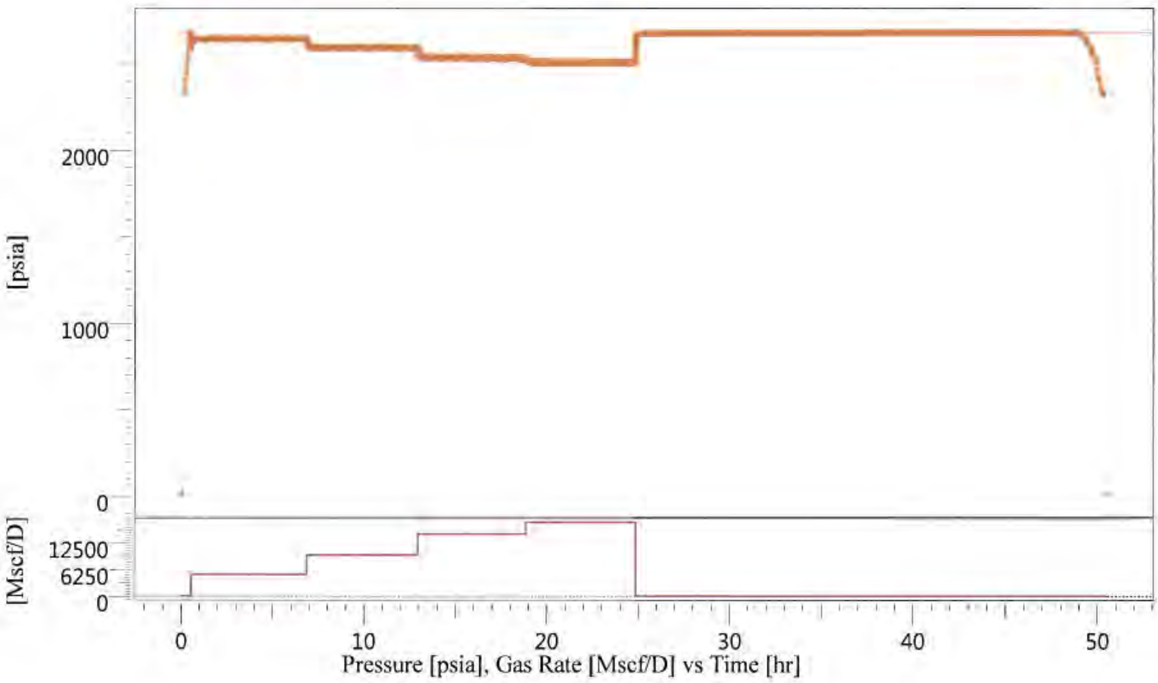
Ab. rate (qa)	0 Mscf/D
Ab. time (ta)	N/A hr
Q(ta)	N/A scf

Main Results	Pressure Transient Analysis
Company : Sylhet Gas Field Limited Well : Sylhet # 7	Field : Haripur Gas Field Test Name / # Pressure Buildup

Test date / time	18.06.2005
Formation interval	
Perforated interval	1874 - 1908m MD
Gauge type / #	
Gauge depth	1904m MD
TEST TYPE	Standard
Porosity Phi (%)	18
Well Radius rw	0.25 ft
Pay Zone h	111.549 ft
Water Salt (ppm)	10000
Form. compr.	3E-6 psi-1
Reservoir T	155 °F
Reservoir P	2680 psia
Fluid type	Gas
Gas Gravity	0.5973
Pseudo-Critical P	677.511 psia
Pseudo-Critical T	351.226 °R
Sour gas composition	
Hydrogen sulphide	0
Carbon dioxide	0
Nitrogen	0
Temperature	155 °F
Pressure	2680 psia
Properties	@ Reservoir T&P
Gas	
Z	0.880777
Mug	0.0180571 cp
Bg	0.00570909 cf/scf
cg	3.57734E-4 psi-1
Rhog	0.12814 g/cc
Total Compr. ct	3.60734E-4 psi-1
Connate Water (%)	0
Selected Model	
Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	One fault
Main Model Parameters	
TMatch	10800 [hr]-1
PMatch	9.87E-7 [psi2/cp]-1
C	0.0228 bbl/psi
Total Skin	41.2
k.h, total	15000 md.ft
k, average	134 md
Pi	2678.37 psia

Model Parameters	
Well & Wellbore parameters (: Sylhet # 7)	
C	0.0228 bbl/psi
Skin	41.2
Reservoir & Boundary parameters	
Pi	2678.37 psia
k.h	15000 md.ft
k	134 md
L - No flow	164 ft
Derived & Secondary Parameters	
Delta P (Total Skin)	125.525 psi
Delta P Ratio (Total Skin)	0.825664 Fraction

History plot	Pressure Transient Analysis
Company : Sylhet Gas Field Limited Well : Sylhet # 7	Field : Haripur Gas Field Test Name / # Pressure Buildup



Syl7 Pres build-up #1

Rate	0 Mscf/D
Rate change	17382.8 Mscf/D
P@dt=0	2524.94 psia
Pi	2678.37 psia
Smoothing	0.1

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	One fault

Main Model Parameters

TMatch	10800 [hr]-1
PMatch	9.87E-7 [psi2/cp]-1
C	0.0228 bbl/psi
Total Skin	41.2
k.h, total	15000 md.ft
k, average	134 md
Pi	2678.37 psia

Model Parameters

Well & Wellbore parameters (: Sylhet # 7)

C	0.0228 bbl/psi
Skin	41.2

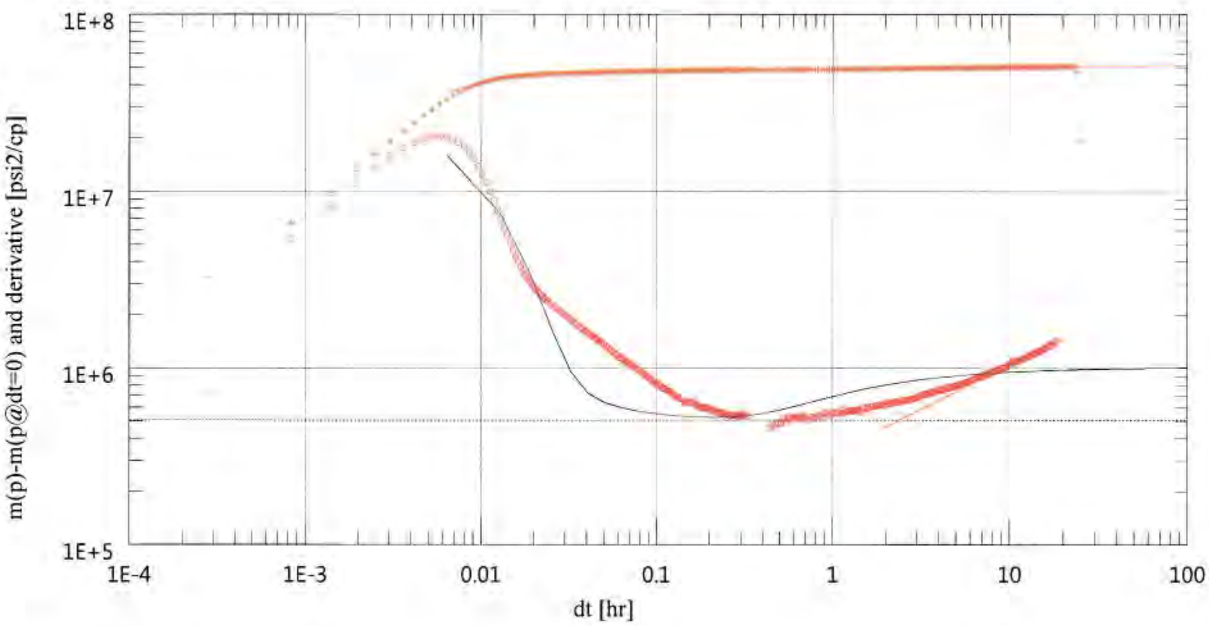
Reservoir & Boundary parameters

Pi	2678.37 psia
k.h	15000 md.ft
k	134 md
L - No flow	164 ft

Derived & Secondary Parameters

Delta P (Total Skin)	125.525 psi
Delta P Ratio (Total Skin)	0.825664 Fraction

Log-Log plot	Pressure Transient Analysis
Company : Sylhet Gas Field Limited Well : Sylhet # 7	Field : Haripur Gas Field Test Name / # Pressure Buildup



Syl7 Pres build-up #1

Rate	0 Mscf/D
Rate change	17382.8 Mscf/D
P@dt=0	2524.94 psia
Pi	2678.37 psia
Smoothing	0.1

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	One fault

Main Model Parameters

TMatch	10800 [hr]-1
PMatch	9.87E-7 [psi2/cp]-1
C	0.0228 bbl/psi
Total Skin	41.2
k.h, total	15000 md.ft
k, average	134 md
Pi	2678.37 psia

Model Parameters

Well & Wellbore parameters (: Sylhet # 7)

C	0.0228 bbl/psi
Skin	41.2

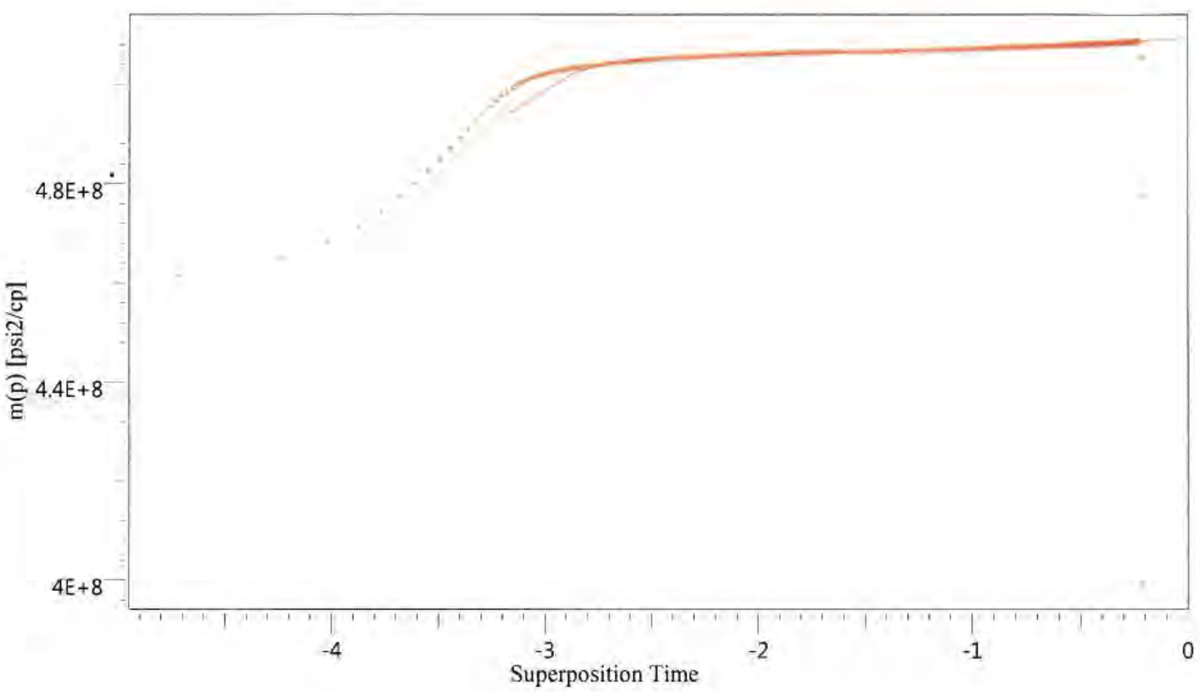
Reservoir & Boundary parameters

Pi	2678.37 psia
k.h	15000 md.ft
k	134 md
L - No flow	164 ft

Derived & Secondary Parameters

Delta P (Total Skin)	125.525 psi
Delta P Ratio (Total Skin)	0.825664 Fraction

Semi-Log plot	Pressure Transient Analysis
Company : Sylhet Gas Field Limited Well : Sylhet # 7	Field : Haripur Gas Field Test Name / # Pressure Buildup



Syl7 Pres build-up #1

Rate	0 Mscf/D
Rate change	17382.8 Mscf/D
P@dt=0	2524.94 psia
Pi	2678.37 psia
Smoothing	0.1

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	One fault

Main Model Parameters

TMatch	10800 [hr]-1
PMatch	9.87E-7 [psi2/cp]-1
C	0.0228 bbl/psi
Total Skin	41.2
k.h, total	15000 md.ft
k, average	134 md
Pi	2678.37 psia

Model Parameters

Well & Wellbore parameters (: Sylhet # 7)

C	0.0228 bbl/psi
Skin	41.2

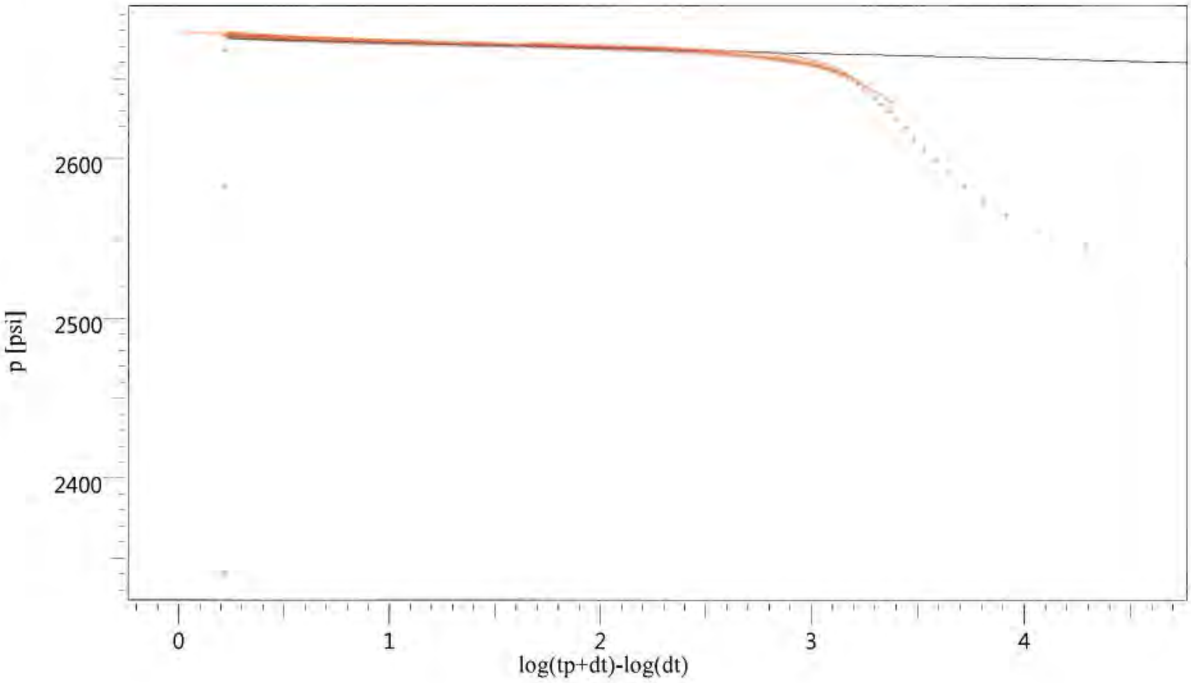
Reservoir & Boundary parameters

Pi	2678.37 psia
k.h	15000 md.ft
k	134 md
L - No flow	164 ft

Derived & Secondary Parameters

Delta P (Total Skin)	125.525 psi
Delta P Ratio (Total Skin)	0.825664 Fraction

Horner plot	Pressure Transient Analysis
Company : Sylhet Gas Field Limited Well : Sylhet # 7	Field : Haripur Gas Field Test Name / # Pressure Buildup



— Line #1 (Syl7 Pres build-up #1)

Syl7 Pres build-up #1

Rate	0 Mscf/D
Rate change	17382.8 Mscf/D
P@dt=0	2524.94 psia
Pi	2678.37 psia
Smoothing	0.1

Line #1 (Syl7 Pres build-up #1)
p vs Log(dt)

Slope	-3.27423 psi
Intercept	2675.45 psia
P@1hr	2671.41 psia
k.h	16500 md.ft
k	148 md
Skin	44.6