RESERVOIR SIMULATION STUDY OF FENCHUGANJ GAS FIELD

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CANDIDATE’S DECLARATION

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

Signature of the candidate

… … … … … … …

(MD. ASADULLAH)

DEDICATED TO

MY BELOVED PARENTS AND GRAND MOTHER

ABSTRACT

BAPEX operated Fenchuganj Gas Field, 40 kilometer south of Sylhet in Bangladesh, lies in the south central part of Surma basin. A second well FG-2 was spud on January 1985 after the first exploratory well drilled in 1960 was abandoned as dry hole. Three gas sands (Upper, Middle & Lower) were tested and completed the well at upper gas sand in 1988. Gas production from the well started on May 2004. Next a development well, FG-3 was drilled by BAPEX in 2004 and gas production started from January 2005. Gas production from upper gas sand of FG-2 was suspended after extracting 24 BSCF gas due to excessive sand and water production. Later the well was re-completed at lower zone and due to the same reason production rate was lowered. Therefore, future field development plans as well as diagnosis the reason of water break through of the well needs to be investigated.

Despite of volumetric analysis, under the project RMP-2 of Petrobangla in 2009, RPS Energy prepared dynamic reservoir simulation model of Fenchuganj Gas Field. In this current study, the geological model was revised by correlating with seismic and log data and imporated in a commercial 3D black oil reservoir simulator ECLIPSE^{TM} 100 to construct a dynamic reservoir simulation model. Later the dynamic simulation model was validated by using historical pressure and production rate data in history matching phase. Finally, the history match model was run for five different forecast cases to find out a better field development plan.

Forecast Case 5 of the current study yield 81.75% gas recovery out of 386.05 BSCF estimated GIIP after 25 years of prediction period by drilling additional three wells as well as workover of the existing wells. Aquifer support is identified in the upper gas sand during history matching as well as water break through in FG-2 has been investigated.

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NOMENCLATURE

AOFP	Absolute Open Flow Potential
BAPEX	Bangladesh Petroleum Exploration and Production Company Limited
BBL	Barrel
BHT	Bottom Hole Temperature
BMSL	Below mean sea level
BOGMC	Bangladesh Oil, Gas and Mineral Corporation (Petrobangla)
BSCF	Billion (10^9) Standard Cubic Feet
BUET	Bangladesh University of Engineering and Technology
C_1	Methane
C_2	Ethane
C_3	Propane
DST	Drill Stem Test
FG-1	First exploratory well drilled in 1960
FG-2	Second exploratory well drilled in 1986 (completed in UGS)
FG-2L	When FG-2 was completed in LGS, denoted as FG-2L
FG-2LW	When FG-2L will be plug off and side tracked to 1 km north of FG-2
FG-3	Development well drilled in 2004 by BAPEX that completed in UGS
FG-4	Directional well drilled by BAPEX in 2011
FG-5	First proposed well that will be completed in UGS in 2012
FG-6U	When 2nd proposed well, FG-6 will be completed in UGS (Directional)
FG-6M	When proposed well FG-6 will be completed in MGS (Directional)
FG-6L	When proposed well FG-6 will be completed in LGS (Directional)
FGPR	Field Gas Production Rate
FGPT	Field Gas Production Total
FGPR	Field Gas Production Rate
GGAG	German Geological Advisory Group
GIIP	Gas Initially In Place

GasSat	Gas Saturation
GWC	Gas Water Contact
HCU	Hydrocarbon Unit
KB	Kelly Bushing
MD	Measured Depth
MMSCFD	Million (10^6) Standard Cubic Feet per Day
NNE-SSW	North-north-east-south-south-west
OGDC	Oil and Gas Development Corporation (Pakistan)
PMRE	Petroleum and Mineral Resources Engineering Department
PPL	Pakistan Petroleum Limited
Psia	Pounds per square inch absolute
P/Z	Pressure / Z factor
RDMD	Reservoir and Data Management Division, Petrobangla
RPS Energy	A UK based Petroleum Consultant Company
RFT	Repeat Formation Tester
SIBHP	Shut In Bottom Hole Pressure
SITHP	Shut In Tube Head Pressure
SIWHP	Shut In Well Head Pressure
STB	Stock Tank Barrel
TVD	Total Vertical Depth
TVDss	Total Vertical Depth from sub sea level
UMS	Upper marine shale
WGPR	Well Gas Production Rate
WTHP	Well Tubing Head Pressure
WWPR	Well Water Production Rate
Z	Compressibility factor

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CHAPTER I

INTRODUCTION

Fenchuganj Gas Field is located in block # 14 of Bangladesh, about 40 km South of Sylhet. It is operated by Bangladesh Petroleum Exploration and Production Company Limited (BAPEX). The geological structure was first delineated by Pakistan Petroleum Limited (PPL), in 1959. The first exploration well (FG-1), was drilled in 1960. It was abandoned as a dry hole. After new interpretation of the structure by the German Geological Advisory Group (GGAG), a second well (FG-2), was drilled during 1985–1986. Three gas sands (Upper, Middle & Lower) were identified and tested. The well was completed at the upper gas sand in 1988. Gas production started on May 2004 as demand of gas increased after 2000 in Bangladesh. Later a development well (FG-3), was drilled by BAPEX in 2004. Gas production started from FG-3 in January 2005.

After almost three years with 24 BSCF gas extractions from FG-2, production was suspended due to excessive sand and water production. Later the well was re-completed at the lower gas sand and about 15 MMSCFD gas production started from November 2008. Again, due to sand and water production after June 2010, production rate was reduced to about 4.0 MMSCFD. Therefore, BAPEX was considering of drilling two new development wells as a part of reservoir management plan. Drilling of a new development well, FG-4 was started in November 2010.

Gas Initially In Place (GIIP), of Fenchuganj field was estimated to be 404 BSCF by Bangladesh Oil, Gas and Mineral Corporation (BOGMC), in 1988 [1]. In 2007 after drilling of FG-3, geological division of BAPEX re-evaluated the GIIP to be 477 BSCF [2]. Later, under the project RMP-2 of Petrobangla in 2009, Reservoir Simulation of Fenchuganj Gas Field was conducted for the first time by RPS Energy [3]. Their study estimated GIIP to be 450 BSCF. Later, it was found that the model did not support the actual historical production and pressure data. Therefore, the geological model is needed to be revised by correlating with seismic and log data. Thus, it becomes obvious that the simulation study must be carried out again with the revised geological model, which would match the actual historical production and pressure data. That will result in more confidence in the future performance predictions of the Fenchuganj Gas Field.

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. Whereas a field can operate only once, at considerable expense; a model can be operated or run many times at low expense over a short period of time. Observation of model performance under different operating conditions aids selection of an optimal set of conditions for the reservoir. Therefore, this innovative concept has been widely used in modern oil and gas industries.

In this study, a commercial 3D black oil reservoir simulator ECLIPSE 100 will be used to perform dynamic reservoir model construction, history matching and production performance prediction [4].

This study will help revise and update the GIIP of the Fenchuganj Gas Field. It will also find out the reason of water production in upper and lower zone of FG-2. The effect of the new development well(s) as well as old wells on future productivity/development plan of the field, will be investigated.

1.1 Objectives

The objectives of the study are as follows:

1. To revise and update the GIIP, recoverable reserves and remaining reserves of the Fenchuganj Gas field.
2. To forecast production performance (gas, condensate and water rates, wellhead pressure, water breakthrough, ultimate recovery) under different development scenarios.

1.2 Methodology outline

To achieve the above objectives the following methodology is adopted:

1. Collection of all relevant production and reservoir data from BAPEX and Petrobangla.
2. Study the previous reports and consult with persons involved at various stages of the field.
3. Construction of simulation model using the geological model.
4. Development of relative permeability curves as there is no special core analysis data.
5. Validation of the model by matching pressure and production history.
6. Forecast production performance (gas, condensate and water rates, wellhead pressure, water breakthrough, ultimate recovery, etc.) under different development scenarios.

CHAPTER II

LITERATURE REVIEW

Fenchuganj is an NNE-SSW trending exposed anticline in an area occupied by low hillocks (locally termed as tila). The highest peak of the tila is about 81 m from sea level, near the Ita tea garden. Fenchuganj is situated about 40 km south of Sylhet Town. The structure is about 30 km long and 8 km wide. Location map is shown in Fig. 2.1

2.1 Exploration and Development History

Most of the part of this section is taken from “Well Report Fenchuganj 2, Geological Evaluation Division, BOGMC, 1988” [5].

2.1.1 Gravity Survey

Pakistan Petroleum Limited (PPL) carried out gravity survey in the area during 1952-53 and a Bouguer anomaly map was prepared in the scale 1: 1,000,000 with 5 mgal intervals. The review group of Oil and Gas Development Corporation (OGDC) compiled a Bouguer anomaly map in the scale 1:250,000 during 1965-66. It was found that the gravity results were in good agreement with surface features. The positive gravity anomaly showed that the Fenchuganj is a structural nose.

2.1.2 Aero-magnetie Survey

Presence of the Fenchuganj structure was also indicated in the map during 1963-64 field season when OGDC covered entire Bangladesh by aeromagnetic survey.

2.1.3 Geological Survey

In 1959 PPL prepared a surface geological map of Fenchuganj structure from geological field data incorporating the seismic data. The structure was shown as a simple, un-faulted dip-closure. Dips showed were 30-35° in the eastern flank and 20-25° in the western flank with an axial trend of NNE-SSW. In 1967-68 field season, OGDC made few reconnaissance traverses in the area and found dips about 15-25° in the flanks and reported the structure as simple symmetrical anticline.

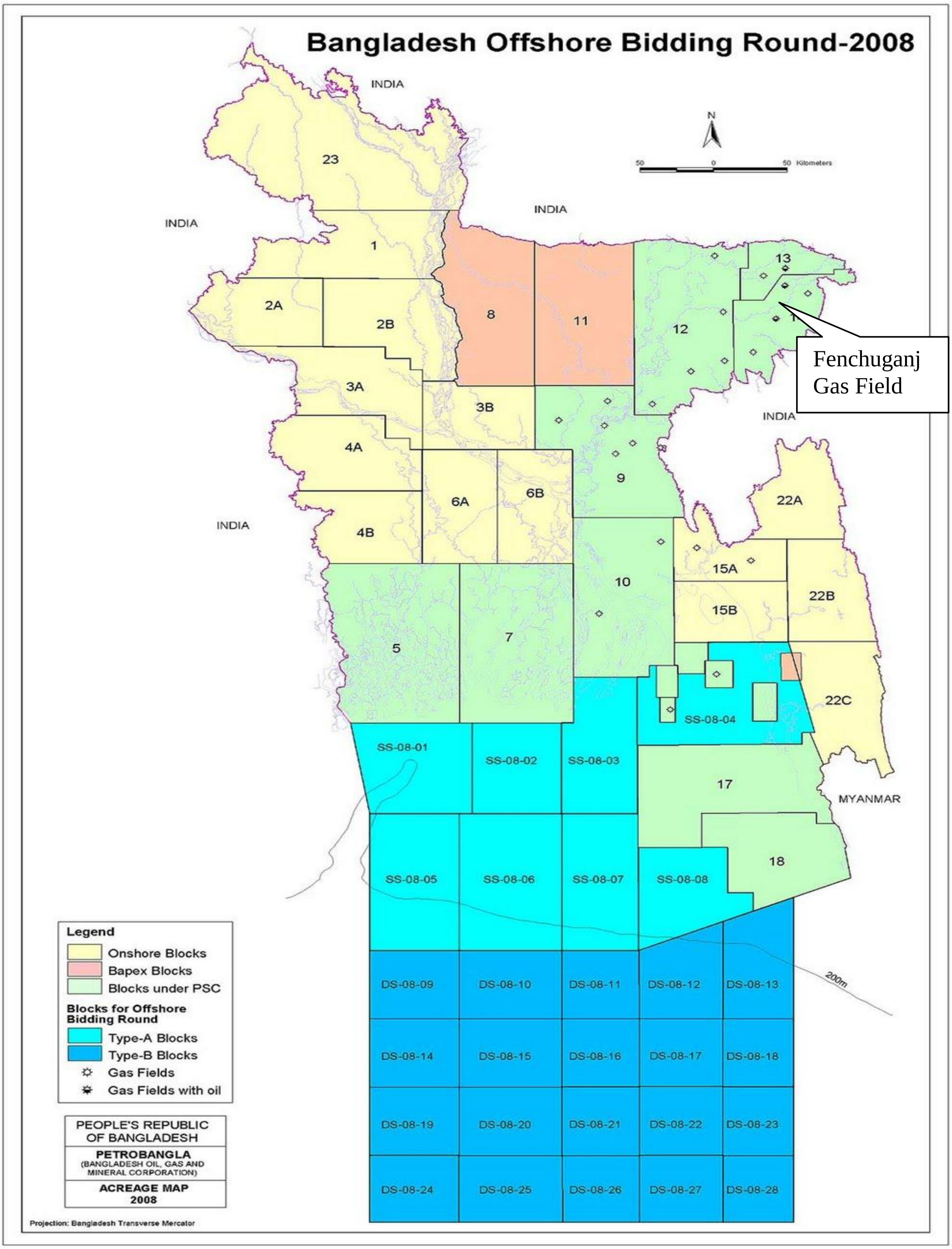

Figure 2.1—Block map of Bangladesh showing Fenchuganj Gas Field

During 1968-69 field season OGDC carried out geological investigation in the area and reported the structure as a simple anticline with a sub-meridional trend. It was also mentioned that the structure has closure of 7.5 km x 2 km with amplitude of 150 m. The dips was recorded in the eastern flank was 23° up to 18° in the western flank and 5°-15° in the comparatively broad (about 3 km) crestal part.

2.1.4 Seismic survey

In 1959 Geological Survey of India (GSI) conducted seismic survey in the area on behalf of PPL and two depth contour maps were prepared. The depth contour map near top of Bokabil revealed that Fenchuganj is a simple anticline with an amplitude of 150 m and the closer formed by 1200 m contour line is about 6.5 km long and 1.5 km wide.

During 1979-81 Prakala Seismos carried out multifold seismic survey on behalf of Bangladesh Oil, Gas and Mineral Corporation (BOGMC) which was later named as Petrobangla. The new seismic data was interpreted by German Geological Advisory Group (GGAG) with Petrobangla and the structure was delineated as an overthrusted anticline with a NNE-SSW axial trend. The western flank is trusted over the eastern flank.

2.1.5 Tectonics and structure

Fenchuganj Structure is situated almost at southeastern margin of the Surma Basin and is separated in the north from Kailashtila Anticline, in the east from Harargaj Anticline and in the south from Batchia Anticline. All these anticlinal structures are separated by saddles. The Fenchuganj Structure is a reversibly faulted anticline with a NNE-SSW trending axis. The major fault trends almost parallel to the axis and aligned in the eastern flank of the structure. This fault is wider in southern region and becomes narrower towards north. The eastern flank of the anticline is steeply dipping than the western flank due to reverse fault. Also from structural depth contour maps it appears that the structure is completely closed against the fault in the hanging wall. It is most likely that the structural growth is still continuing.

From surface geological map prepared by PPL (1959), it is observed that the amount of dips in the eastern flank varies from 30°-35°. Based on structural contour map on Upper Marine Shale (UMS), it appeared that the structure has both dip closure and fault closure (considering the fault is sealing). Dip closure decreases and fault closure increases with depth and at greater depth dip closure is almost completely replaced by fault closure. However, the structure has amplitude of about 250 - 300 m (in the reservoir sections where only dip closure is considered) and the maximum areal extent of the closed contour is about 13 km long and 3.5 km wide.

2.2 Geology

The Fenchuganj structure is situated in the transition zone between the central Surma Basin and the folded belt in the east and is closest to the eastern margin of the central Surma Basin. It is surrounded by different gas fields with Miocene reservoirs, such as Kailastila in the north, Beanibazar in the east and Rashidpur in the south. Therefore, geology of Fenchuganj gas field is similar to that of other fields situated in Surma basin. The reservoirs have been found in the Miocene sediments mainly composed of alternating grey to dark grey clay, very fine to medium grained sandstones [6]. The problem of identifying source rocks is compounded by the fact that the known hydrocarbon accumulated in traps formed in Plio-Pleistocene time. The gas-condensate and oil must have migrated relatively long distances into the traps because the shale interbeded with or adjacent to the reservoir are both organically lean and immature for hydrocarbon generation. It seems most likely that the source rocks of the gas-condensate are the Lower Miocene to Upper Oligocene shale in the basin center and in the synclinal troughs between the fold trends. The source rocks are terrestrial in origin.

2.3 Systematic Lithology / Stratigraphy

The stratigraphic succession of Fenchuganj Gas field is based on the two wells, FG-2 and FG-3. The drilled section of Fenchuganj gas field is represented by Bhuban, Bokabil, Tipam and Dupi Tila formation. The formation and age boundary are delineated with the help of lithology, paleontology and geochemical data [2]. Stratigraphic succession with brief lithological description of Fenchuganj Gas Field is given in Table 2.1.

Table 2.1—Stratigraphic Succession of Fenchuganj Gas Field

Depth (MMSL)	Thickness (m)	Formation	Age	Lithology
0 To 298	298	Dupitila	Late Pliocene	Mostly sandstone and minor clay. ***Sandstone:*** Brown to light brown, coarse, consolidated. Moderately sorted, highly ferruginous, composed of quartz with few mica quartzitic pebbles, clay galls and soft immature coal also present. ***Clay:*** Dark gray, very soft, sticky, soluble in water.
298 To 1150	852	Tipam	Middle Pliocene	Mostly sandstone and minor clay. ***Sandstone:*** Light to off white, medium, ferruginous, poorly consolidate, composed of mainly quartz with few mica & dark color minerals in place, soft immature coal also present. ***Clay:*** Gray to dark gray, soft to moderately hard and compact.
1150 To 1466	316	Upper Bokabil	Miocene	***Shale:*** Gray to bluish gray, soft to moderately hard, compact and laminated.
1466 To 1766	300	Middle Bokabil		Sandstone and shale alteration ***Sandstone:*** Light to clear, medium to fine, moderately consolidated, moderately sorted, occasionally calcareous. Composed of quartz with mica and variegated colored minerals. ***Shale:*** Gray, sandstone as above occasionally bluish gray, well laminated, silty, moderately hard and compact.

Table 2.1—Stratigraphic Succession of Fenchuganj Gas Field (continued)

Depth (MMSL)	**Thickness (m)**	**Formation**	**Age**	**Lithology**
1766 To 2236	470	Lower Bokabil	Miocene	Mostly shale with minor sandstone ***Shale:*** Gray to dark gray, hard and compact, well laminated silty, concoidal fractured. ***Sandstone:*** Light colored, fine to very fine, consolidated, well sorted mild calcareous, composed mainly of quartz with mica; dark-colored minerals are also present.
2236 down to 4977 (TD)	Varies from 914 to 2741	Upper Bhuban	Late Miocene	Alternation of sandstone and shale, with minor calcareous siltstone ***Sandstone:*** Light to clear, fine grained moderately consolidated, friable, well sorted, mainly quartz, mica and other dark colored minerals are present. Alternation of grey to dark grey, well laminated shale with minor brownish to grey siltstone intercalation with sandstone. It is light grey to clear, consolidated, friable, well sorted, quart, mica with dark minerals and occasional clay pebbles are also present. ***Shale:*** Gray to dark gray, hard and compact, well laminate, concoidal fractured. ***Siltstone:*** Gray to dark gray, occasionally bluish gray, well laminated, moderately hard and compact, calcareous.

2.4 Gas Water Contact

Gas water contact (GWC) was found at 2,080.5 m in UGS, and at 2,781.5 m in LGS while drilling FG-2 during 1988 [1]. Later while drilling FG-4 during 2011, the GWC in the UGS was detected at 2,060.5 m. Thus water level moved about 20 m upward over the eight years of production life. This is indicative of significant aquifer activity, which implies that the UGS is a water drive gas reservoir.

2.5 Development and Production History

The first exploratory well, FG-1 was drilled in 1960 to a depth of 2,439 m and was abandoned as a dry hole without testing any zone.

A second exploratory well, FG-2 was drilled in 1985 after re-evaluation of the structure. FG-2 was spud on 21 January 1985 and reached a total depth (TD) at 4,977 meter in November 1986. Three gas sands (Upper, Middle and Lower) were tested. The well was completed at upper gas sand by 3½” tubing in 1988. About 22 MMSCFD gas productions started on 22 May 2004 after 16 years of completion of the well as the demand of gas increased at early of 2000.

An appraisal well, FG-3 was drilled by BAPEX in 2004 at the depth of 3,150 m. Two gas sands were identified and tested (Upper and Lower). Lower sand was not capable of producing gas. However the well was completed as a dual producer as the completion string was procured already considering it would encounter similar type of sands as like the FG-2. Gas production started on 03 January 2005 from the upper sand.

In the middle of February 2007, water production increased along with sand from FG-2. After almost three years with 24 BSCF gas extractions from FG-2, production was suspended due to excessive sand and water production. Later the well was re-completed at the lower zone and about 15 MMSCFD gas production started from November 2008. Again due to sand and water production after June 2010, production rate was reduced to about 4.0 MMSCFD. Field production rate was decreased to about 22 MMSCFD in October 2010 from 45 MMSCFD during January 2005. Therefore, BAPEX was considering drilling two new development wells as a part of reservoir management plan. Drilling of a new development well FG-4 started in December 2010. FG-4 encountered new sand below the UGS. The new sand was tested and completed during February 2012 which is producing about 18 MMSCFD gas since then. Production from the UGS did not start as it was not completed. However, cumulative production of gas from the field as of March 2012 was 84 BSCF of gas and 67,622 BBL of condensate [7]. Cumulative gas production of the field is shown graphically in Fig. 2.2.

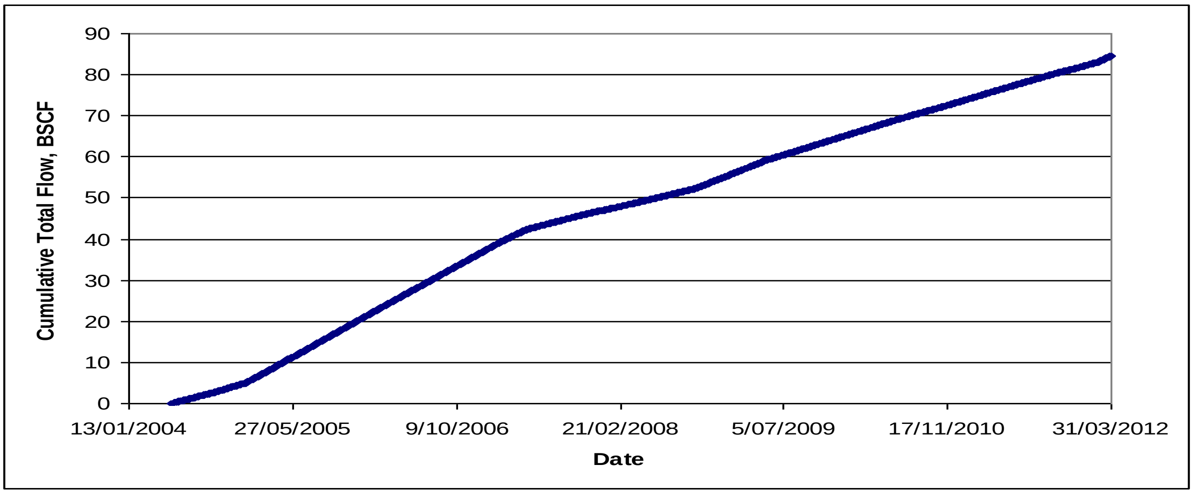

Figure 2.2—Cumulative gas production of Fenchuganj Gas Field

2.6 Drill Stem Test (DST) and Production Test Results

Most of this portion is taken from "Test Report, Fenchuganj-2, Part One & Two; prepared for Petrobangla, 01 Feb 1987–20 Jan 1988 & 31 March 1988–26 April 1988 [8]**.**

2.6.1 Drill Stem Test (DST)

FG-2: Four different sands identified in FG-2 were picked up for DST on the basis of available well logs and drilling information. The first sand (3064 - 3085 m) produced initially waxy oil with large quantity of water and subsequently produced only water. The remaining three sands were proved commercial and were as Lower, Middle and Upper gas sand (LGS, MGS, UGS). Test results were as follows

Lower Gas Sand, LGS (2768 - 2781 m): Initially a two meter interval (2777 - 2779 m) was perforated in this zone on 14th December 1987 and maximum gas flowed at 16.90 MMCFD with a condensate ratio of 4.45 BBL/MMSCF using $^{1}/_{2}$" choke. Another test was carried out on this sand through perforating a six meter interval (2768 – 2774 m) 0n 31st March 1988, and maximum gas flowed at 15.90 MMSCFD with a condensate ratio of 5 BBL/MMSCF through $^{1}/_{2}$" choke.

At FG-2, the Shut-in Wellhead Pressure (SIWHP) was 3260 psi and Shut-in Bottom Hole pressure (SIBHP) was 3995 psi. The Bottom Hole Temperature (BHT) was found 162°F. Calculated Absolute Open Flow Potential (AOFP) was about 47 MMSCFD.

Middle Gas Sand, MGS (2578 - 2584 m): A three meter interval (2578.6 - 2581.6 m) was perforated in this zone on December 1987 and maximum gas flowed at 24.65 MMSCFD with a condensate ratio of 3.94 BBL/MMCF through $^5/_8$" choke.

The SIBHP was 3708 psia with corresponding the SIWHP was 3047 psia. The BHT found during testing was 159°F. AOFP was calculated about 85 MMSCFD.

Upper Gas Sand, UGS (2062 - 2080.5 m): A six meter interval (2063 – 2069 m) was perforated on January 1988 and maximum gas was flowed at 29.01 MMSCFD with a condensate ratio of 0.60 BBL/MMSCF through $^3/_4$" choke. The SIWHP was 2509 psi and SIBHP was 2911 psi. The BHT was found 126°F during testing. Calculated AOFP was about 133 MMSCFD.

FG-3: No DST was performed in FG-3.

2.6.2 Production Test

Production test, performed in FG-2 and FG-3, are described next.

FG-2: After considering the DST result, it was decided to produce from UGS keeping the same perforation of 2063 – 2069 m. FG-2 was completed using $3^1/_2$" tubing in 7" liner casing. The completion work was jointly carried out by BOGMC and FLOPETROL at 1988. After completion Flow After Flow (FAF) test were carried out. Summary of the test result is shown in table 2.2.

Table 2.2—Production testing result for UGS

Activity	**BHP psia**	**Gas rate MMCFD**
Initial shut in pressure	2925	-
Flow test 24/64	2829	9.65
Flow test 32/64	2818	14.73
Flow test 40/64	2715	20.64
Flow test 48/64	2647	25.17

BHT was 157° F at 2039 m. AOFP was found 58 MMSCFD which was quite lowered than the DST value of 133 MMSCFD. Packer was set at 2017.56 m. During the clean up period, the packer began to leak. This leak might somewhat affect the buildup curve by the phenomenon of post production.

FG-3: Production test was done in UGS (In FG-3, 56 m thickness sand was found from 2030 - 2086 m interval) and the New Gas Sand II, NGS II (1992 - 2017 m). On the other hand, conventional test (not running the measuring gauge in testing string) was performed at 2910 - 2925 m and 3002 - 3014 m.

The NGS II (1992 – 2017 m) and the UGS (2030 - 2036 m) were perforated together and tested in a single production test. Log correlation between FG-2 and FG-3 suggests that the zone (2030 – 2086 m) in FG-3 is equivalent to the same sand of UGS of FG-2 whereas NGS II is developed only in FG-3. Cross sectional views of the encountered sands in FG-3 is shown in Fig. 2.3.

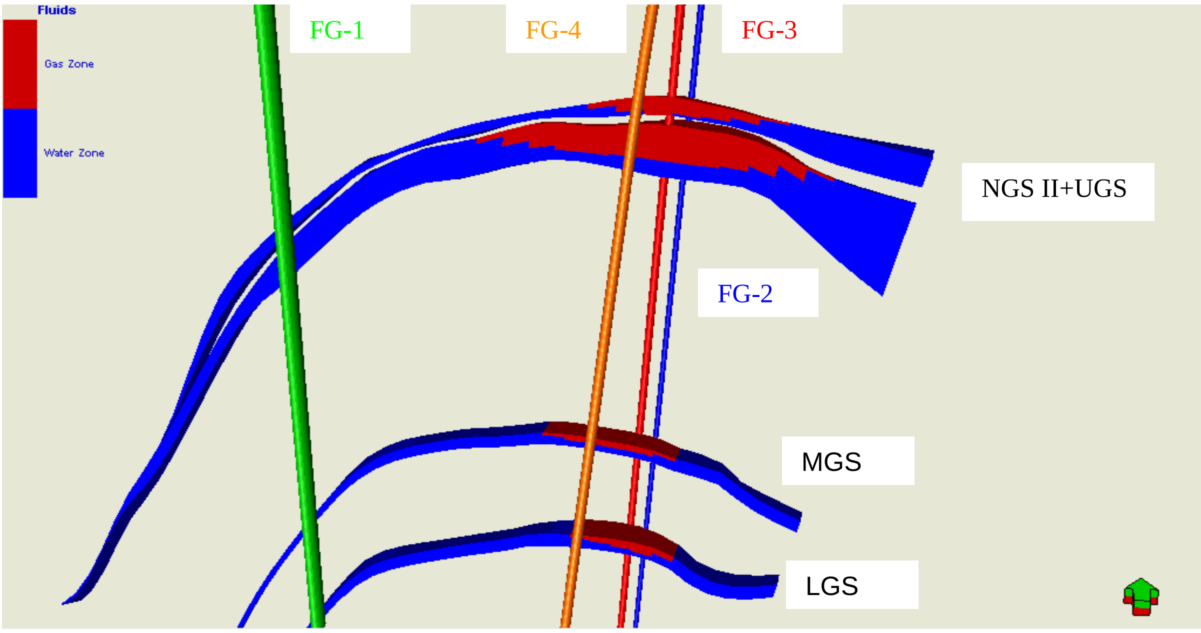

Figure 2.3—Producing gas sands encountered in Fenchuganj Gas Field

However, summary of Production Test (FAF type) results is shown in Table 2.3.

Table 2.3—Production testing result for Upper Zone & New Zone #II (1992 – 2086 m KB)

Activity	**WHP psia**	**Gas rate MMSCFD**
Initial shut in pressure	2480	-
Flow test 28/64	2210	11.092
Flow test 32/64	2065	13.983
Flow test 36/64	1954	15.633
Flow test 40/64	1765	18.430
Shut in pressure	2481	-
Flow test 48/64	1465	21.630
Final shut in pressure	2484	-

SIWHP was 2481 psia and SIBHP was found to be 2876.88psia

Bottom hole temperature was found 119.08° F at 1974 m

Perforation Intervals:1992-1998, 2001-2007, 2011-2017, 2030-2036, 2039-2045m.

Conventional testing was carried out for another two identified prospective zones (2,910 – 2,925 m and 3,002-3,014 m). It did not give any commercial gas flow result. Conventional testing is carried out maintaining minimum safety. In case of conventional testing, memory gauge was not run and DST string contains minimum tools. Therefore, actual bottom hole pressure and bottom hole temperature data can not measure by conventional testing.

2.7 Pressure Analysis

The formation pressure was measured during testing of the well [2]. As the pressure gauge was set above top of the gas sand, reservoir pressure was extrapolated. The extrapolated formation pressures of the zones are given in Table 2.4. Only two SFT pressure data are recorded in the reservoir zone (MGS & LGS) which are 4146.10 and 4530.32 psia. Fig. 2.4 shows the SFT pressure gradient (trend 2) which indicate higher pressure gradient then than the normal hydrostatic pressure gradient (trend 1). Reservoir pressure gradient shown in the plot are quite similar with the nearby gas fields in Sylhet region of Bangladesh.

Table 2.4—Formation pressure and pressure gradient extrapolated from FG-2 and FG-3

Well	Sand	Depth (m)	Depth (m) GL	Pressure (psia)	Reservoir Sand's Pressure (SFT) Gradient (psi/ft)
FG-2	UGS	2062 – 2082	2053	2940.7	
	MGS	2578 – 2584	2569	3722.7	0.49
	LGS	2768 – 2781	2759	4032.7	0.50
FG-3	NGS II	1992 – 2017	1983	2862	-
	UGS	2030 – 2080	2021	2917	-

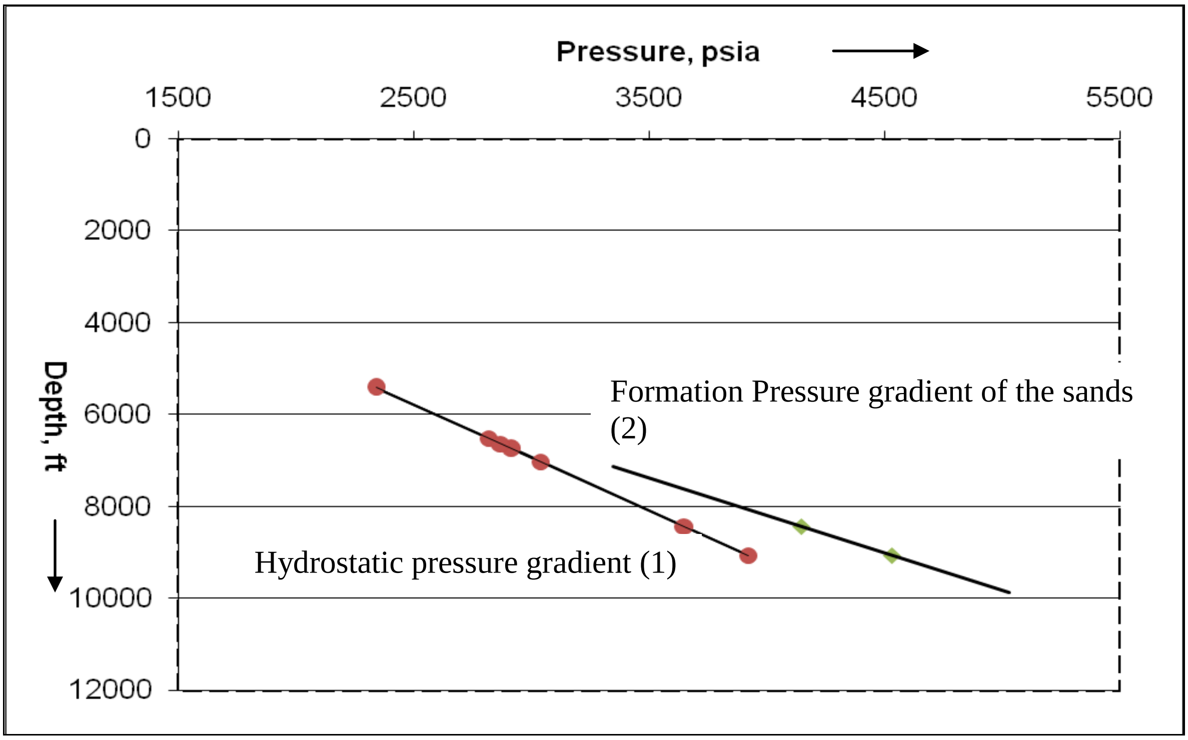

Figure 2.4—Depth versus pressure plot of encountered sands (MGS, LGS) and normal hydraulic gradient

2.8 Temperature Analysis

The formation temperatures of different sands were recorded during testing (DST and Production Testing) of FG-2 and FG-3 which are shown in Table 2.5. The temperature gradients are quite similar with the other fields in this region.

Table 2.5—Formation Temperature & Temperature gradient based on FG-2 and FG-3 data

Well	Reservoir	Depth (KB) (m)	Depth (m) GL	Temperature (°F)	Temperature Gradient (°F /100 ft)
FG-2	UGS	2062 - 2080	2053	126	0.757
	MGS	2578 - 2584	2569	159	0.996
	LGS	2768 - 2781	2759	162	0.961
FG-3	NGS III	1656 - 1665	1647	116	0.758
	NGS II	1992 - 2017	1983	124	0.753
	UGS	2030 - 2080	2021	125	0.754
	NGS I	2148 - 2154	2139	132	0.812

2.9 Previous Studies

A number of studies were carried out on Fenchuganj Gas Field since its discovery which are briefly discussed next.

The Geological Evaluation Division of BOGMC first estimated the GIIP of Fenchuganj Gas Field in 1988. According to that report, the total GIIP was 404 BSCF, out of which recoverable gas was 357 BSCF. That implied a recovery factor of 88.4%. Total recoverable condensate reserve was estimated as 886,780 barrels.

Gasunie in 1989 estimated the reserve of this field by using some core data. According to them, more or less 'standard' Bangladesh reservoir data and recoverable reserve were 50 BSCF under proven, 200 BSCF under Expected and 400 BSCF under higher/possible categories. Only recoverable reserve was indicated in this study. Gasunie estimation included two shallow sands, which were not tested. In other studies, only three tested sands were included. For the three tested zones recoverable reserve were 30 BSCF under proven, 80 BSCF under probable and 140 BSCF under possible categories.

In another report by Petrobangla in 1989 [9], the Estimated Ultimate Recoverable Reserve (EURR) of the field was mentioned to be 350 BSCF and recoverable condensate reserve about 800,000 BBL. In the next edition of the report in 1993, the same figures i.e. 350 BSCF was marked as GIIP (Proven and Probable) by Petrobangla. That used a recovery factor of 0.60 and arrived at a new recoverable reserve of 210 BSCF and this figure was used till early 2003. Both Welldrill in 1991 and Gasunie in 1992 used published figures of Petrobangla for the field in their respective reports. Welldrill used a recovery factor of 66% instead of 60%, and Gasunie used the same 60% recovery factor used by Petrobangla [10].

PMRE Department of BUET in 2001 used the reserve figure to be 404 BSCF in their report. HCU-NPD study in 2001 also used 404 BSCF as GIIP in their report [11]. 70% recovery factor is used in that report. Both studies used the figures firstly estimated in 1988 by BOGMC.

Bangladesh government formed a committee including the energy expert from various sectors to estimate the gas reserve of the country which was named as National Committee. In Estimate 1, the National Committee in 2002 used published figure of Petrobangla for the field [12]. In Estimate 2, the reserve figure for the field is the same as mentioned in the Geological Evaluation Division’s Report of BOGMC in 1988. The committee used 60% as recovery factor in Estimate 1 and 65% in Estimate 2.

It seems like these reports did not intend to do any independent reserve estimation. They just used the published figures for some others analysis.

In 2003 HCU updated the reserve figure with the assistance of NPD of Norway. Their estimated GIIP was 311.4 BSCF through volumetric analysis by probabilistic method. The same data after averaging is used for another estimate following deterministic approach. The result of this estimated GIIP was 388.1 BSCF [13]. Nothing was mentioned about recoverable reserve.

In 2007 Geological Division of BAPEX, after drilling the appraisal well, FG-3 and correlating both well, re-evaluated the reserve. Including three new gas zone which are developed only in FG-2, sand-wise GIIP figures are given in Table 2.5. This is a reserve estimation work based on log and seismic data.

Considering the tested Sands (excluding NGS III and NGS I) total reserve was estimated to be 410.60 BSCF whereas 320.34 BSCF was recoverable reserve.

Table 2.6—Sand wise estimated GIIP of Fenchuganj Gas Field by BAPEX (2007)

Zone/ Sand	Proven Reserve (BSCF)	Probable Reserve (BSCF)	Possible Reserve (BSCF)	Total (BSCF)		Remarks
	GIIP			GIIP	Recoverable	
NGS III	-	-	20.60	20.60	14.42	Not tested
NGS II	10.20	-	-	10.20	7.14	Not tested
UGS	146.00	60.00	-	206.00	144.20	Tested
NGS I	-	-	45.80	45.80	32.06	Not tested
MGS	12.00	-	62.00	74.00	67.00	Tested
LGS	24.00	-	97.00	121.00	102.00	Tested
Total	192.20	60.00	225.40	477.00	366.82	-

All of those past works mainly addressed only volumetric reserve. Those reserve estimation are mainly based on volumetric approach. Those did not mention anything about drive mechanism or development strategy.

During 2009-2010, RPS Energy, under the project RMP-2 of Petrobangla, estimated GIIP from the volumetric calculation using the commercial software package Petrel^{TM} to construct the geological model of Fenchuganj Gas Field. RPS Energy did the first and only simulation study for this field using commercial package Eclipse^{TM}. The GIIP thus estimated is shown in Table 2.7. They did history matching of pressure and rate data.

Table 2.7—RPS estimated GIIP of Fenchuganj Gas Field (2009-2010)

Reservoir	GIIP (BSCF)	
	ECLIPSE	Petrel
UGS	284	297
MGS	108	96
LGS	58	53
Total	450	447

Based on the scenarios evaluated in the report, a recoverable volume of 358 BSCF gas was mentioned for the field with 87% recovery factor using the existing wells as well as the drilling of six new wells over a period of thirty years production life of the field [3]. All the new wells come in production at a time as the simulation began. After five years of simulation period, production rate was shown decrease abruptly. And increasing the number of new wells from three to six only increased recovery 2%. Nothing was mentioned about pressure support by aquifer in any sand in that report. History matching was done up to December 2009.

In the current study, New Gas Sand II was included with Upper Gas Sand with corrected gas and water production rate. History matching was done from May 2004 to December 2011. It will help revise and update the GIIP of the field. It will also investigate the driving mechanism of the reservoir as well as to find out the reasons of water production by FG-2. It will also give a rational field development plan.

CHAPTER III

RESERVOIR SIMULATION MODEL CONSTRUCTION

The purpose of simulation is to estimate the field performance under one or more operating conditions. Practically a field can operate only once, at considerable expense. On the other hand, a model virtually can be operated or run many times at low expense over a short period of time. Observation of model performance under different operating conditions helps to select an optimal set of conditions for the reservoir [14].

The detailed procedure of simulation model construction of the field is discussed in this chapter. This section addresses the following issues: selection of the number of space/grid dimensions, representation of the reservoir rock and fluid properties, and coupling of the wells and the reservoir. The first step is to create a geological model of the reservoir. It is also called a static model, since it represents the reservoir fluids in static condition. Flow through the reservoir and production/injection of fluids through the wells are not considered at this stage. The second step is to import the static model and apply fluid flow phenomenon to it. On order to do this, the static model is modified and more data such as fluid properties, injection and production rates etc. are incorporated. Then it is called a dynamic model.

Simulation of petroleum reservoir performance refers to the construction and operation of a model whose behavior assumes the appearance of actual reservoir behavior. The model can be either physical or mathematical. A mathematical model is simply a set of equations that, subject to certain assumptions, describes the physical processes active in the reservoir. Although the model itself obviously lacks the reality of the oil or gas field, the behavior of a valid model simulates that of the field. Basic equation of reservoir simulation with governing condition and theory are available in literature. A computer program which solves these numerical equations is called reservoir simulator.

3.1 Geological Model Construction

The geological model was constructed based on structural map, well log data and special core analysis data. The commercial package Petrel™ was used for that purpose. Then the static or geological model was imported into the commercial 3D reservoir simulator called Eclipse^{TM}. After making required modifications the dynamic model was obtained. Then simulation was run to obtain history matching and forecasting.

The data required for the goelogical model construction are structural map, well log data such as porosity and water saturation data, and special core analysis data such as relative permeability and capillary pressure. This steps of model construction is described next.

3.1.1 Structural map with surface and zonal mapping

Structural map corresponds to the reservoir located in the four sands were used to create the main surfaces. Depth of top of surfaces was picked up from the structural map for each grid to create the surfaces. To construct the new surface maps, the structural map was selected as the reference surface. New surfaces were then constructed using the thickness from well log data. The process was performed until the top and bottom reservoir maps were generated. Finally, the zones were defined from each pair of nearby surfaces. Then petrophysical property is introduced.

3.1.2 Well Log Data

The required data from well log are porosity and water saturation. These data were assigned from sand distribution expected in the well area, which were correlated from FG-1, FG-2 and FG-3 well log interpretation. The net sand estimation using net to gross ratios over the four reservoirs interval as derived from gamma ray (GR) log of FG-1, FG-2 and FG-3 which are shown in Fig. 3.1

3.1.3 Special Core Analysis (SCAL) Data

The SCAL data includes relative permeability to water and gas, and capillary pressure. Special core analysis was not carried out for FG-2 and FG-3. Therefore all the SCAL data are borrowed from other available data from the nearby fields of Surma basin and Brooks-Corey’s correlation.

3.1.4 Petrophysical Modeling

Petrophysical modeling consists of Porosity and Permeability modeling and is described later.

Porosity Modeling

As mentioned earlier, core analysis was not carried out for this field. Therefore, porosity is calculated from Neutron-Density log cross plot. Based on the petrophysical evaluation, well logs for each of the wells were used to generate grid property distributions throughout the geological model for porosity using a Sequential Gaussian Simulation (SGS) algorithm.

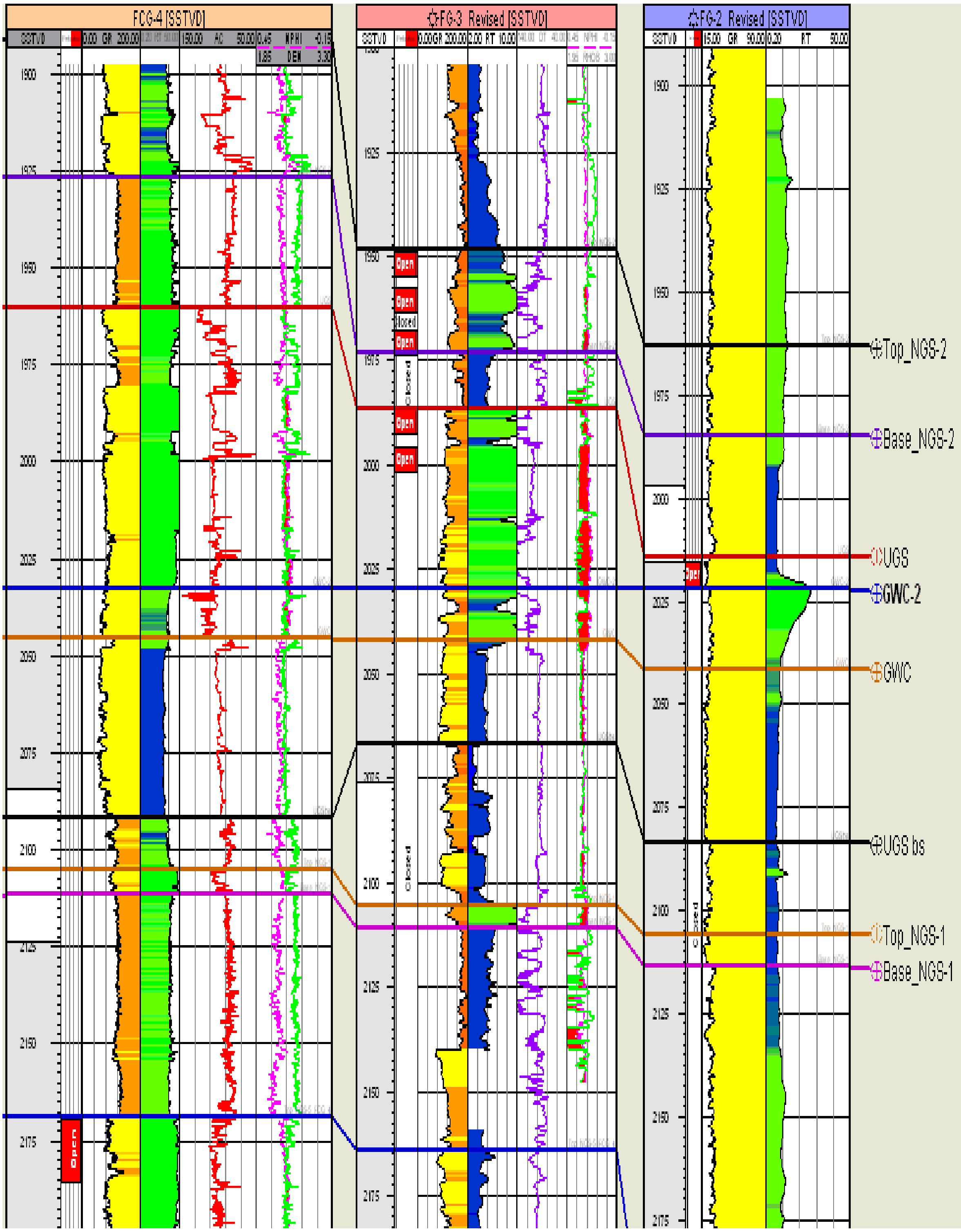

Figure 3.1—Log correlation of FG-2, FG-3 & FG-4 with GWC

The formation that is considered to be the reservoir should contain shale volume ≤ 40% and porosity ≥ 08%. Average reservoir porosity of the model is 22% for UGS and 18% for rest of the sands which are very much close to the BAPEX prepared well report [2]. Also log derived horizontal permeability was generated and assigned in the model. This geological model was then incorporated in Eclipse as input model for generating dynamic simulation model. This geological model was then put a quality check and updated several times.

3.2 Structure of ECLIPSE Data File

Widely used commercial reservoir software, ECLIPSE^{TM} 100 is a fully-implicit, three phase, three dimensional, black oil simulator with gas condensate option. Eclipse is a batch program written in FORTRAN77 which can be operated on any computer with an ANSI standard FORTRAN77 compiler having sufficient memory. Corner point and conventional block center geometry options are both available in Eclipse. Both radial and cartesian block center options are available in one, two or three dimensions.

An input file with all data concerning reservoir and process of its exploitation are needed to run Eclipse simulator. Input data for Eclipse is prepared in free format using a keyword system. It contains a complete description of the model. Any standard editor may be used to prepare the input file. Another option, Eclipse Office may be used to prepare data interactively through panels, and submit runs.

An Eclipse data input file is split into sections-header, each of which is introduced by a section-header keyword. Among them some are required, others are not. A list of all section-header keywords is given in following, together with a brief description of the contents of each section [4].

RUNSPEC Section: (Required)

The RUNSPEC section is the first section of an Eclipse data input file. It is a brief specifications of the run which contains the run title, start date, units, various problem dimensions (numbers of blocks, wells, tables etc.), flags for phases or components present and option switches.

GRID Section: (Required)

The subdivision of the reservoir into finite volume elements or cells is denoted a discretisation of thereservoir, and the set of elements is called the reservoir grid. The GRID section determines the basic geometry of the simulation grid and various rock properties (porosity, absolute permeability, net-to-gross ratios) in each grid cell. From this information, the program calculates the grid block pore volumes, mid-point depths and inter-block transmissibilities.

The reservoir geometry may be described using a Cartesian system with dimensions of every gridblock being specified with a DX, DY, and DZ value, or Corner Point Geometry can be used to define the x, y and z coordinates of each corner of each grid block.

Values of the top faces of all grid blocks (TOPS), porosity (PORO), and absolute permeability in the x, y, and z directions (PERMX, PERMY, and PERMZ) must be specified for each grid block. The net thickness can also be set for each grid block by NTG (net-to-gross) keyword. Data for TOPS is taken form structural map, and geological model whereas data for the others are taken from isopac map, and geological model.

EDIT Section: (Optional)

The EDIT section contains instructions for modifying the pore volumes, grid block centre depths, transmissibilities, diffusivities (for the Molecular Diffusion option), and non-neighbor connections (NNCs) computed by the program from the data entered in the GRID section.

PROPS Section: (Required)

The PROPS section contains tables of properties of reservoir rock and fluids as functions of fluid pressures, saturations and compositions (density, viscosity, relative permeability, capillary pressure etc.). It also contains the equation of state description in compositional runs.

- SWFN: It denotes water relative permeability and capillary pressure as functions of S_w
- SGFN: It specifies gas relative permeability and capillary pressure as functions of S_g

- PVTG: The physical properties of the dissolved gas, gas volume factor and gas viscosity are entered as functions of pressure after the PVTG keyword. In case of a gas-water system or a "dry gas" system, the same data are entered but the table keyword is PVDG.
- PVTW: FVF, compressibility and viscosity of water are specified by the keyword.
- DENSITY: It specifies stock tank fluid densities
- ROCK: Rock compressibility can be entered by this keyword.

REGIONS Section: (Optional)

The reservoir can be defined to a number of regions in this section. It splits computational grid into regions using the following keyword for calculation of

- PVTNUM: PVT properties (fluid densities and viscosities),
- SATNUM: saturation properties (relative permeabilities and capillary pressures),
- EQLNUM: initial conditions, (equilibrium pressures and saturations)
- FIPNUM: fluids in place (fluid in place and inter-region flows)

SOLUTION Section: (Required)

The SOLUTION section contains sufficient data to define the initial state (pressure, saturations, compositions) of every grid block in the reservoir. The keywords in the SOLUTION section may be specified in any order. All keywords must start in column 1. All characters up to column 8 are significant. This data may take any one of the following forms:

- EQUIL: Initial pressures and saturations are computed by Eclipse using data entered with the keyword (fluid contact depths etc.). The EQUIL data specifies the initial pressure at a reference depth, the initial water-oil and gas-oil contact depths and the capillary pressures at these depths, and the equilibration options.

- RESTART: The initial solution may be read from a restart file created by an earlier run of ECLIPSE. The name of the Restart file is entered using the RESTART keyword.

SCHEDULE Section: (Required)

The Schedule section contains specifications for individual wells, well completion data, well production rates, and time periods for which the rates apply. Vertical flow performance curves and simulator tuning parameters may also be specified in this section.

- RPTSCHED: It reports switches to select which simulation results are to be printed at report times
- TUNING: Time step and convergence controls can be assign using the keyword.
- WELSPEC: It introduces a new well, defining its name, the position of the wellhead, its bottom hole reference depth and other specification data
- COMDAT: It specifies the position and properties of one or more well completions; this must be entered after the WELSPECS
- WCONPROD: This keyword controls data for production wells
- WCONHIST: Observed rates for history matching wells are specified by the keyword.
- TSTEP/DATE: It advances simulator to new report time(s) or specified report date(s)
- WELPI: The individual well productivity indices can be specified under the keyword.

3.3 Simulation Model Construction

Thus section describes how the simulation model is constructed in using Eclipse office suite.

3.3.1 Griding:

The static model grid has dimensions (41x136x59) to represent the 6 horizons encountered in the field (Table 3.1). It has been discretized into 150 m x 150 m grid blocks in X and Y direction. On the other hand, the model grid layering was designed with a vertical resolution with average thickness of 2-3 m which was considered suitable for simulation of a gas-water system. Therefore, the model was not needed to upscale. Out of 59 vertical layers, total 44 layers were considered active. Both New Gas Sand III (NGS III) and New Gas Sand I (NGS I) were made inactive in the model. Because these are untested sands and there is no commercial value in them. Thus a 41 x 136 x 59 grid system resulting in 31,447 number of active simulation cells were used in the model.

Table 3.1—Layering of grid model of the reservoir

SL.	HORIZON		Simulation Layer	Status
1	New Gas Sand III	NGS III	1-6	Inactive
	Inter Layer	-	7	Inactive
2	New Gas Sand II	NGS II	8-15	Active
	Inter Layer	-	16	Inactive
3	Upper Gas Sand	UGS	17-42	Active
	Inter Layer	-	43	Inactive
4	New Gas Sand I	NGS I	44-46	Inactive
	Inter Layer	-	47	Inactive
5	Middle Gas Sand	MGS	48-51	Active
	Inter Layer	-	52	Inactive
6	Lower Gas Sand	LGS	53-59	Active

A 3D view of the field is shown in Fig. 3.2. Tested sands are shown in the model with griddings. Top one is the UGS, then the MGS and bottom one is the LGS.

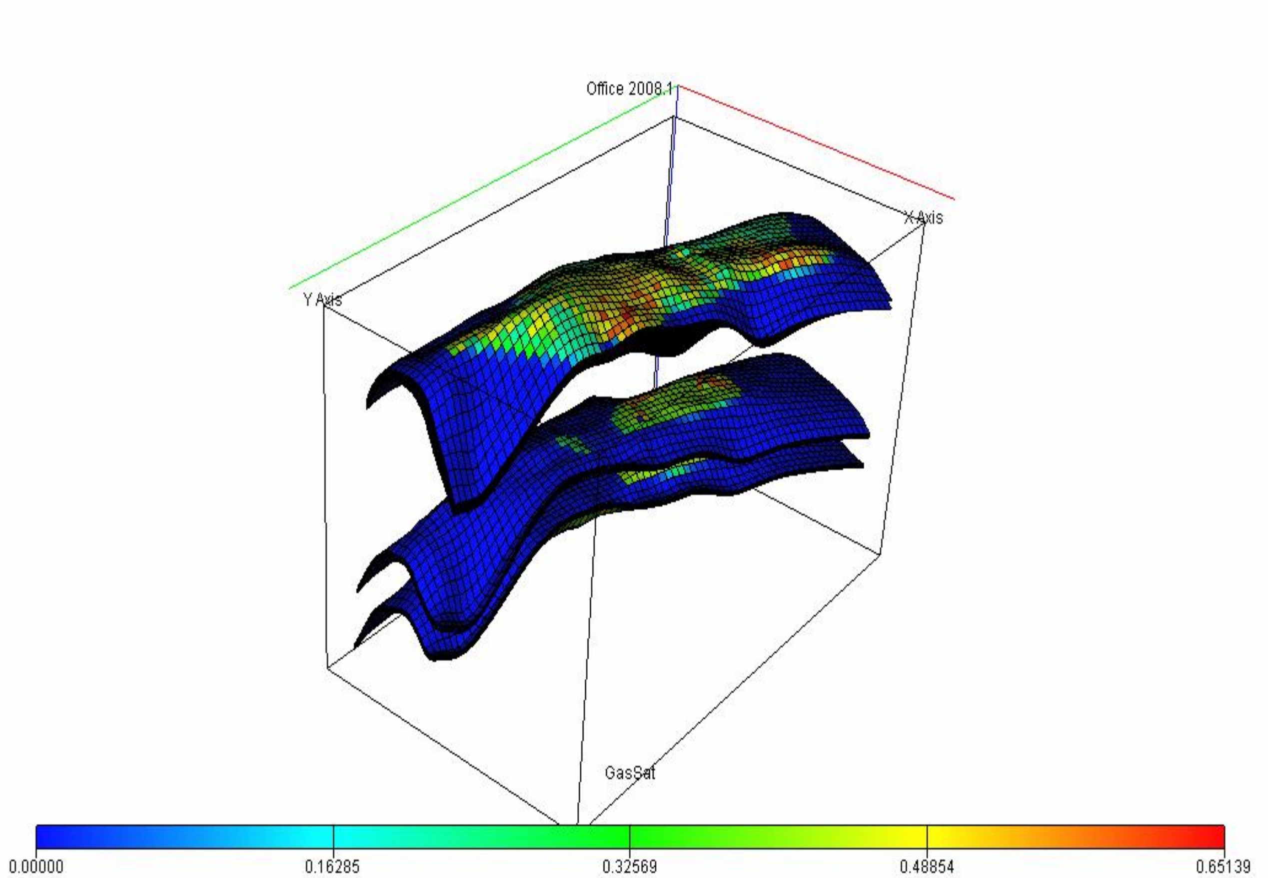

Figure 3.2—3D view of Fenchuganj Gas Field showing grid layers (UGS, MGS, LGS).

3.3.2 Petrophysical Modeling

Petrophysical modeling consists of Porosity and Permeability modeling and is described as following:

i) Porosity Modeling

Porosity of Geological model was kept same in simulation model. Porosity distribution of the second top most layers of UGS is shown in Fig. 3.3 which shows how the porosity distribution very areally. It is seen that most of the cells contain around 20% average porosity. There are also some areas (lower and upper left side portion) with very low porosity which are considered as non reservoir.

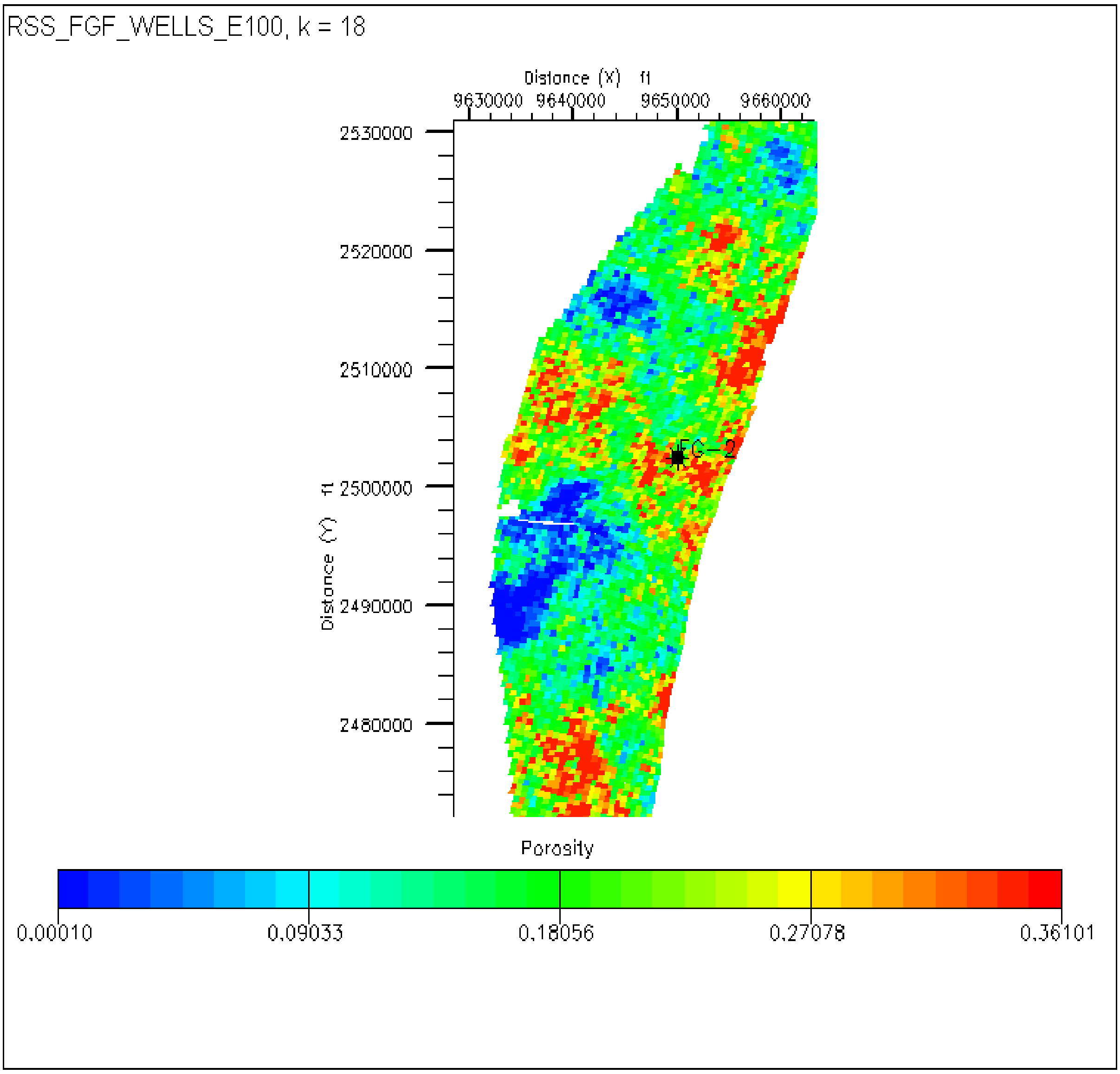

Figure 3.3—Porosity distribution in UGS of the simulation model

ii) Permeability Modeling

Based on log data, horizontal permeability was distributed in the geological model. This data was imported in Eclipse and maximum valve of permeability was found almost 1500 mD. However, for UGS, maximum cut off value 800 mD is used in simulated model considering the DST result of well FG-2. Average permeability 100 mD is used for this zone. For rest of the zones, this value is limited to 300 mD. Average permeability of 90 mD is used for these three sands. Horizontal to vertical permeability ratio 10% is considered for the model in absence of core analysis data.

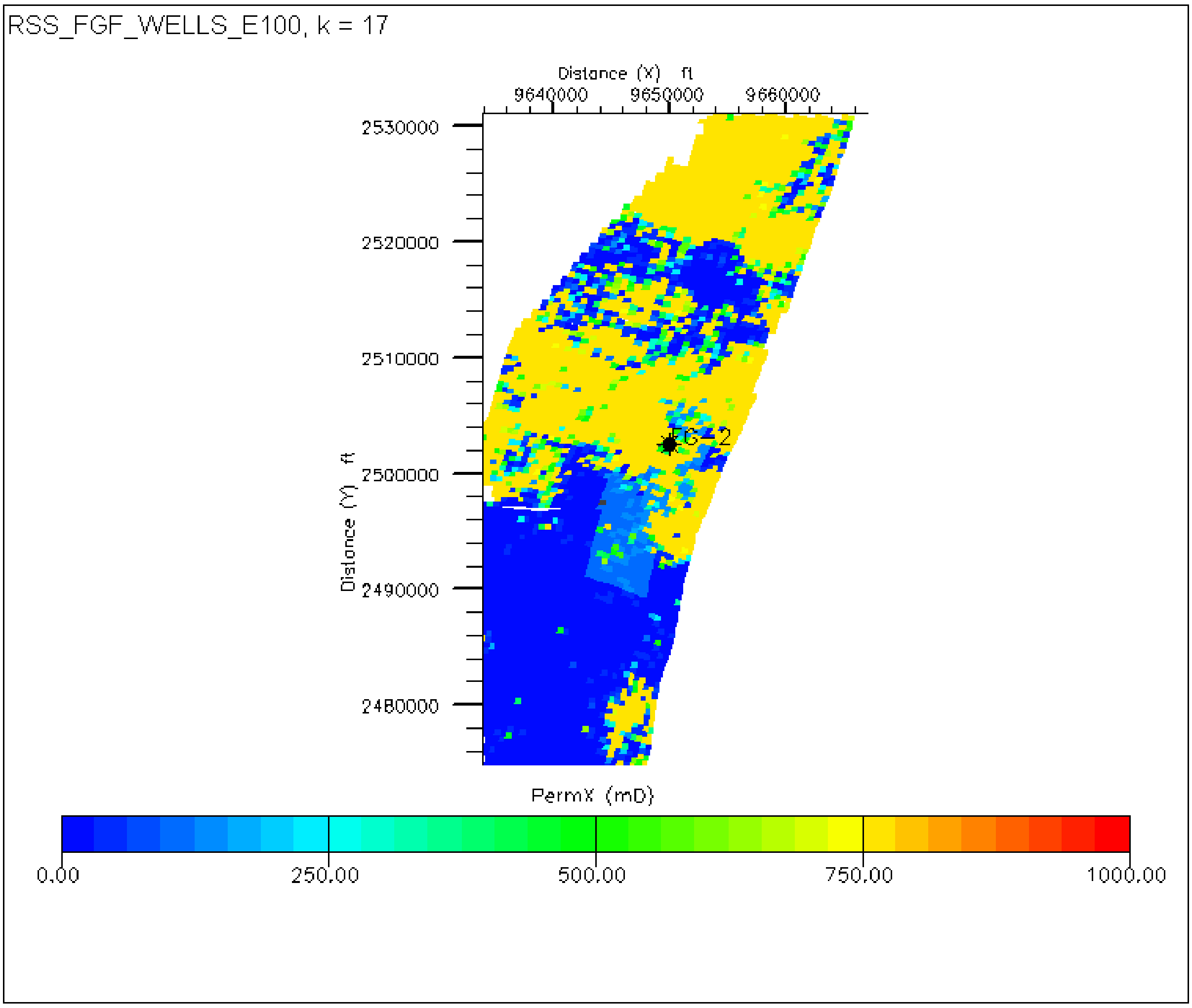

Figure 3.4—Permeability distribution in UGS of the model

Fig. 3.4 shows the horizontal permeability of the reservoir. It shows the permeability distribution of the top most layers of UGS. Top and middle section show higher range of permeability distribution than the average permeability of UGS. Between them, there is a small portion with the bottom portion having lower range of permeability.

iii) Fault

Two faults are identified by seismic data analysis. Major fault divides the reservoir up and down thorn. Down thorn is not considered in this model because no well is drilled in that area. As location of the major fault is behind the reservoir boundary in the up throne, it has no interference to the reservoir and excluded from the model. Small fault is included in the models which also do not have any impact on the reservoir.

iv) Aquifer Modeling

A numerical aquifer is modeled considering the production data analysis, pressure response and gas-water contact movement in upper gas sand which is discussed in history matching section.

3.3.3 PVT Property/ Fluid properties

The reservoir is modeled into the following two PVT regions, i.e., NGS II and UGS as PVT region I; MGS and LGS as PVT region II considering the availability of PVT data. Compositional analysis for the reservoir gas is taken from Laboratory Division of BAPEX which is shown in Table. 3.2.

Table 3.2— Gas Composition of FG-2 and FG-3

Component	Composition (mole%)	
	FG-2	FG-3
N_2	0.001	0.0009
CO_2	0.005	0.005
C_1	0.97	0.98
C_2	.013	0.012
C_3	0.0008	0.0007
iC_4	0.0002	0.0001
nC_4	0.0003	0.0002
iC_5	0.0003	0.0001
nC_5	0.0002	0.0002
Total	1	1

Therefore, available fluid composition data were used to generate the fluid properties for the four sands according to their temperature and pressure by using PVT_i suite in ECLIPSE. The following suite of PVT data were used in ECLIPSE, entered using the dry gas PVT property as "PVDG" (Table 3.3) keyword (units are standard ECLIPSE "Field" units), and the constant composition expansion simulation results are shown pictorially in Fig. 3.5 and Fig. 3.6.

Table 3.3—Dry Gas PVT Property (PVDG) Data Used in ECLIPSE for NGS II and UGS

PVT I (NGS II and UGS)			PVT II (MGS and LGS)		
Pressure psia	B_g Rb/Mscf	μ_g Cp	Pressure psia	B_g rb/Mscf	μ_g Cp
14.7	200.88	0.0121	14.7	200.88	0.0121
177.1	16.37	0.0122	232.3	12.4	0.0122
339.5	8.39	0.0123	450	6.25	0.0124
501.9	5.58	0.0125	667.6	4.12	0.0127
664.2	4.14	0.0127	885.3	3.05	0.013
826.6	3.28	0.0129	1102.9	2.4	0.0134
989	2.7	0.0131	1320.6	1.98	0.0138
1151.4	2.29	0.0135	1538.2	1.67	0.0144
1313.8	1.99	0.0138	1755.9	1.45	0.015
1476.2	1.75	0.0142	1973.5	1.28	0.0157
1638.5	1.56	0.0146	2191.2	1.15	0.0164
1800.9	1.41	0.0151	2408.8	1.05	0.0173
1963.3	1.29	0.015μ6	2626.5	0.96	0.0181
2125.7	1.19	0.0162	2844.1	0.89	0.019
2288.1	1.1	0.0168	3061.8	0.83	0.0199
2450.5	1.03	0.0174	3279.4	0.78	0.0209
2612.9	0.96	0.0181	3497.1	0.74	0.0218
2775.2	0.91	0.0187	3714.7	0.7	0.0228
2937.6	0.86	0.0194	3932.4	0.67	0.0237
3100	0.82	0.0201	4150	0.64	0.0246

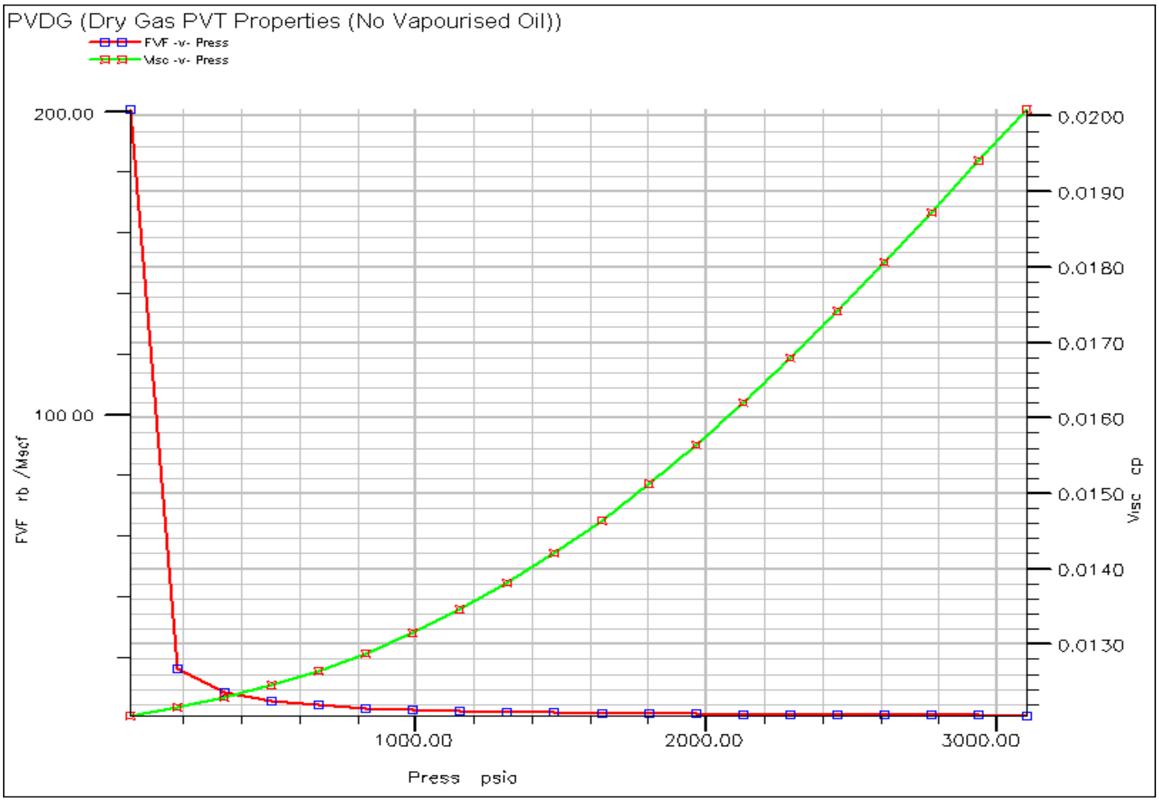

Figure 3.5—Gas FVF and Gas Viscosity vs. Pressure plot for NGS II and UGS

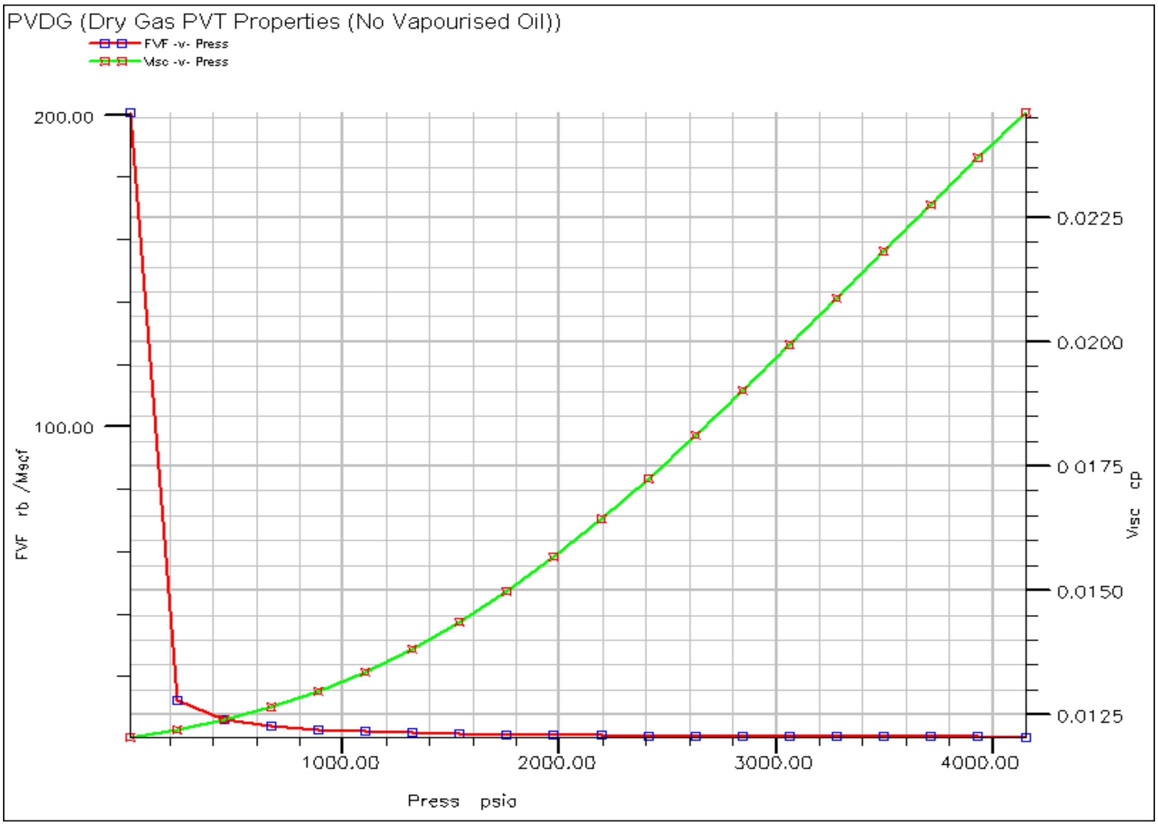

Figure 3.6—Gas FVF and Gas Viscosity vs. Pressure plot for MGS and LGS

Constant vaporized oil concentration, (Rv)

This is used to declare that the dry gas associated with each individual PVT table region contains a constant and uniform concentration of vaporized oil. Fenchuganj Gas Field is referred to as dry gas reservoir because no condensate is formed in the reservoir during the production. However, this does not preclude the production of condensate, because the temperature and pressure in the producing well and at the surface can be significantly different. Therefore, the reservoir is modeled as a Dry Gas Reservoir with no free oil except under saturated with a constant vaporized oil concentration, Rv (Table 3.4)

Table 3.4—Constant vaporized oil concentration, Rv value used in this model

PVT Region	Constant Rv per PVT region	Dew point Pressure
Region 1	0.0003	100
Region 2	0.006	100

Water PVT Property

Water PVT data used in the model is shown in Table 3.5

Table 3.5— Water PVT data of the model

Property name	Region 1	Region 2
Reference pressure, psia	2994	4034
Water FVF property at P_{ref}, rb/stb	1.00338	1.00338
Water compressibility, /psi	2.9081E-6	2.9081E-6
Water viscosity at P_{ref}, cp	0.710576	0.710576
Water viscobility, /psi	5.05757E-5	5.05757E-5

Fluid density

Three phase fluid density at standard condition is taken from laboratory analysis data from Laboratory Division of BAPEX which is shown in Table 3.6

Table 3.6—Fluid density for the reservoir

Name of the Fluid	Density, lb/cubic ft.
Oil	47
Water	63.92
Gas	0.0435

Rock property

Rock compressibility, 1.529896E-6/psi, is assumed considering the property of Surmra Basin and RPS report [3].

3.3.4 SCAL Section

Initial water saturation, Relative permeability and capillary pressure are modeled in this section.

Water and Gas Saturation

Based on the petrophysical evaluation, well logs for each of the wells is used to generate grid property distributions throughout the static model for initial water saturation, S_w using a Sequential Gaussian Simulation algorithm. These property maps were then directly imported with the structure grid from Petrel and finally gas saturations calculated from $S_g=1-S_w$.

Initial gas saturation of top most layers of UGS is shown in Fig. 3.7. Average grid gas saturation of the layer is from 0.3 to 0.5. Again area shown by reddish yellow is high gas saturation portion. On the other hand, area shown by blue color is considered as non reservoir portion with high water saturated area.

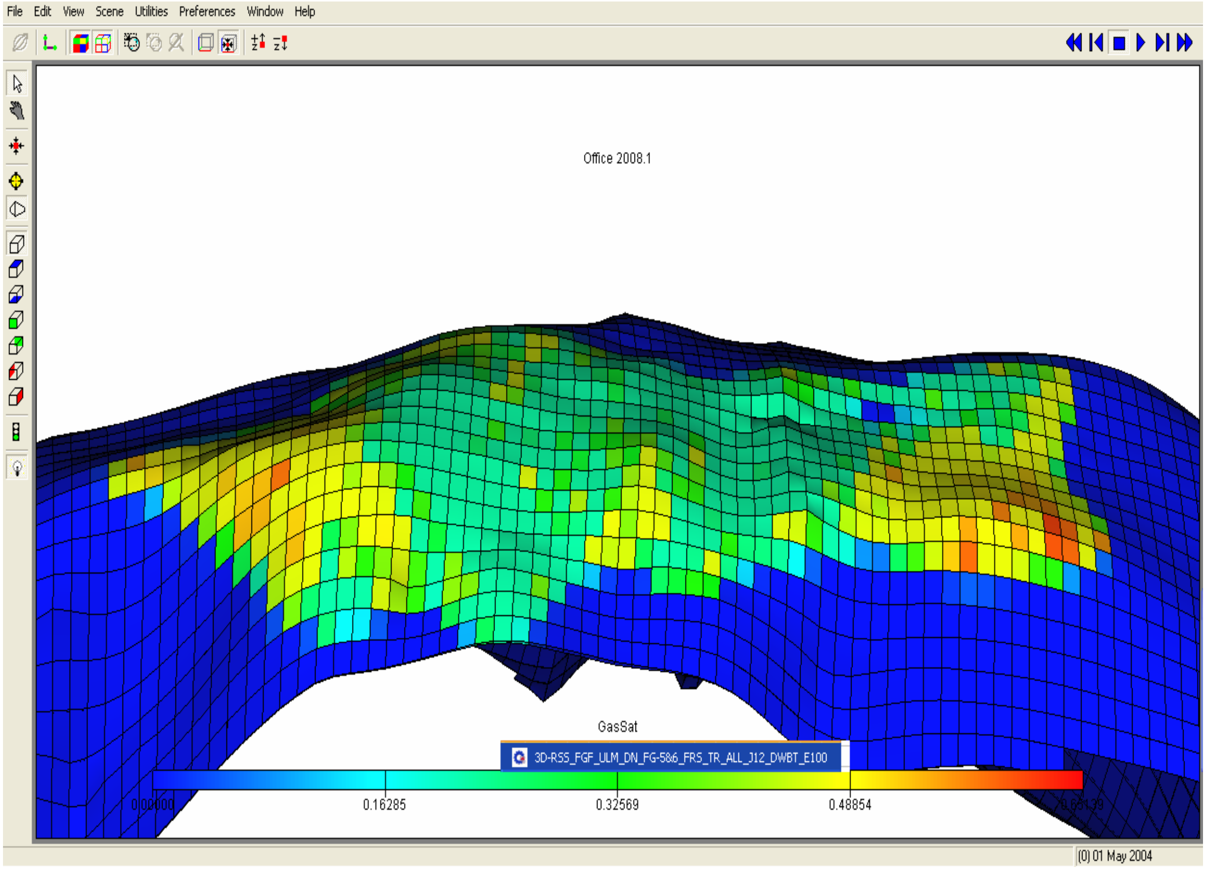

Figure 3.7—Initial gas saturation of UGS at the beginning of simulation run.

Relative Permeability and Capillary Pressure

There are no relative permeability data for Fenchuganj Gas Field. Therefore, Brooks-Corey correlation for two-phase flow is used to generate relative permeability curves for the simulation (Fig. 3.8). It is assumed that capillary pressure to water is the average values of the available capillary pressure, P_c data from other fields of Surma basin. The initial water distribution was used to scale the water-oil capillary pressure curves such that this water distribution is honored in the initial equilibration.

The final set of normalized relative permeability data derived from Corey's correlation are shown in Table 3.7 which is also shown graphically in Fig. 3.8

Table 3.7—Normalized Gas-Water Relative Permeability Data

S_g	k_{rwn}	k_{rgn}
0.00	1.00	0.00
0.05	0.77	0.00
0.10	0.59	0.01
0.15	0.44	0.02
0.20	0.33	0.4
0.25	0.24	0.06
0.30	0.12	0.12
0.40	0.08	0.16
0.45	0.05	0.20
0.50	0.03	0.25
0.55	0.02	0.30
0.60	0.01	0.36
0.65	0.01	0.42
0.70	0.00	0.49
0.75	0.00	0.56
0.80	0.00	0.64
0.85	0.0	0.72
0.90	0.0	0.81
0.95	0.00	0.90
1.00	0.00	1.00

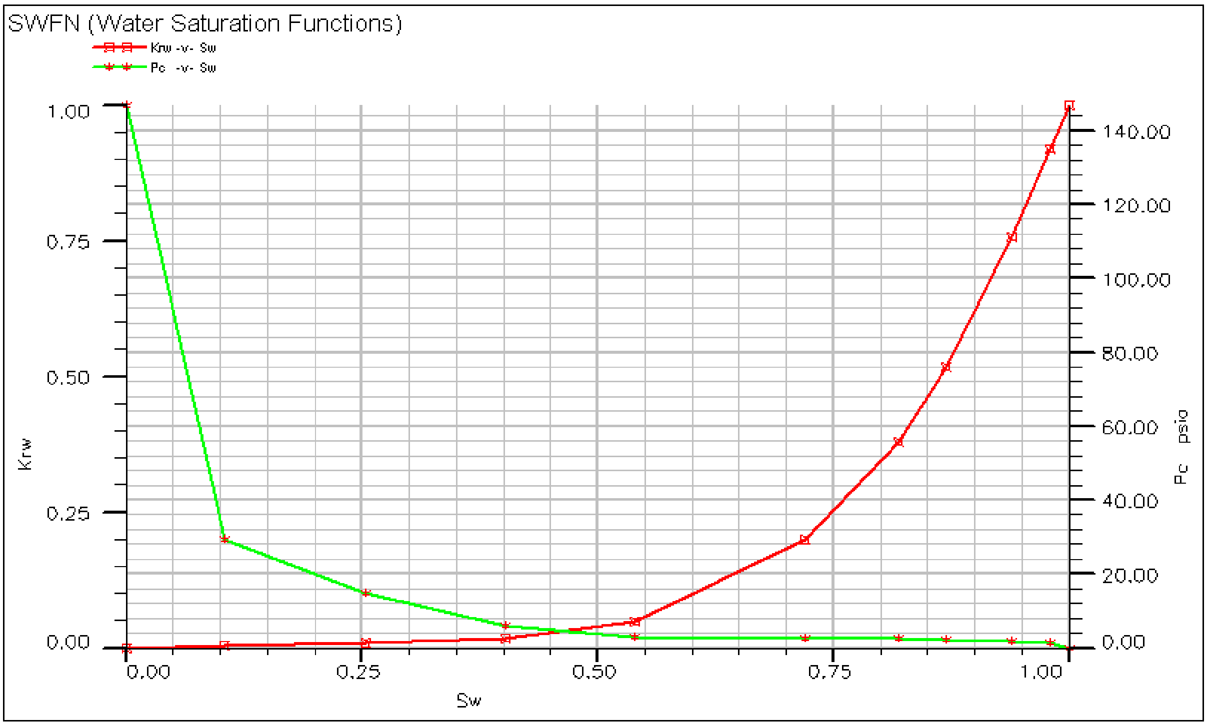

Figure 3.8—Normalized relative permeability and capillary pressure, Gas-Water

3.3.5 Model Initialisation

Equilibration section

As mentioned earlier, the reservoir is divided into four equilibration region though NGS II and UGS are completed together in well FG-3. Therefore, pressure and GWC for determining fluid in place, FIPNUM was also four which is shown in Table 3.8

Table 3.8—Pressure and gas-water contact for determining FIPNUM

Property	NGS II	UGS	MGS	LGS
Pressure, psia	2889	2940	3721	4034
Gas-Water contact, m	1968	2033.5	2537	2734.5

3.3.6 Region Section

Sand wise model is divided as shown in equilibration section.

Stability of Model

In order to confirm that the dynamic reservoir model is correctly initialised, a number of checks were made against the static simulation model. The geological model was updated before imported to Eclipse and checked several times for getting the best possible historically supportive dynamic reservoir model.

At first, the model is initialised and volumetrically compared with the static model. In addition, the data quality was checked using “NOSIM” to determine the input data reliability.

Moreover, the model is run with no production for the full field life in order to verify that both the field and aquifer models are stable and pressures do not significantly drift over time in order to ensure the average reservoir pressure is in a state of equilibrium prior to production.

3.3.7 Schedule Section

This is very important section for dynamic model where reservoir is coupled with well. The trajectories of wells FG-2 and FG-3 and FG-4 were created by importing wells deviation surveys with grid sizes and properties in SCHEDULE section. Then that Selected SCHEDULE for the wells were exported to WELSPECS and COMPDAT in ECLIPSE to locate the well and block intersections.

Vertical Lift Performance Curve

The reservoir simulation derives down-hole well pressures but requires the vertical lift models in order to allow well head pressure to be used as a production rate constraint.

Detailed well completion designs for each of the production wells were generated. Industry standard well performance software (Prosper^{TM}) was used in order to generate the vertical lift curves. As the wells produced from different reservoirs, for each a separate VLP table was generated for each well.

Generated lift curves are then used within the model to generate wellhead pressures based on the modeled fluid flow rates. Fig. 3.9 shows the vertical flow performance curve for FG-3 of upper sand as a sample.

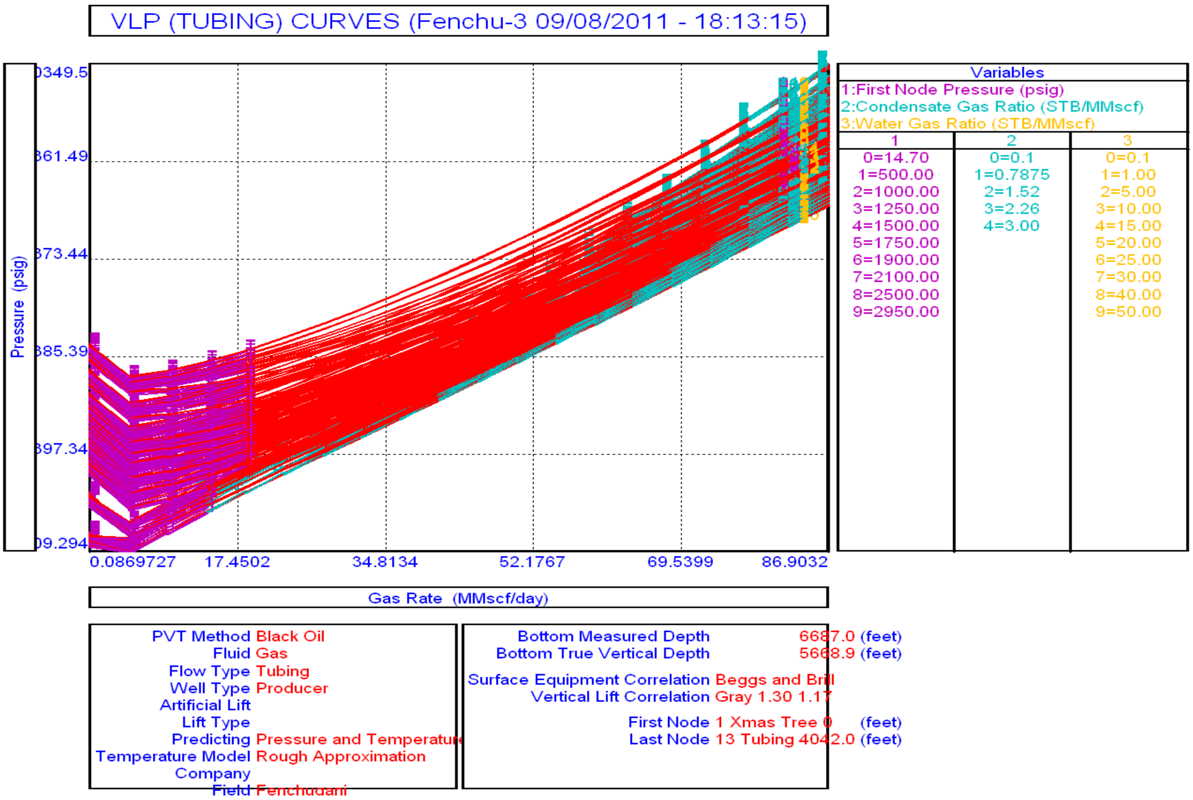

Figure 3.9—Vertical flow performance curve of FG-3

3.3.8 Summary Section

This section is modeled as per requirement of output profile for production, pressure, etc. with time.

3.3.9 Production Allocation

Production data showing the perforated intervals were available for the producing wells. The data were in the form of Microsoft Excel spreadsheets covering the period from May 2004 to December 2011 for the wells FG-2, FG-2L and FG-3. The spreadsheets contain daily production volumes of gas, condensate and water as well as wellhead pressures. As there are no separate Inlet Separator for producing wells FG-2 and FG-3, it was difficult to allocate condensate and water for the two wells. FG-2 started producing from May 2004 whereas FG-3 from January 2005. In 22 May 2007 production of FG-2 was suspended due to excessive sand and water production. Then workover operation was done in FG-2 and completed it in the LGS which is denoted as F-2L. It was put in production in October 2008 with initial rate of 15 MMSCFD. In that time only FG-3 was continuing production for almost 15 months. Therefore average condensate and water production rate with respect to gas flow rate for this period is used for entire historical flow period. Rest of the condensate and water are allocated for FG-2 or FG-2L when separate rate was not available. Monthly production data is used as input data for history matching.

The total gas produced from both the UGS and the LGS at the end of the history matching till December 2011 is 79.33 BSCF. On the other hand, only 7.96 BSCF gas has been produced from the LGS.

3.3.10 Creating Restart File

After completing the coding of all input data into the model, and checking the reliability of volumetric calculation, a restart file is generated for history matching of the production and pressure profile of the field with respect to simulated model. It is discussed in the next chapter. Volumetric GIIP is found to be 386.04 which is shown in Table 3.9. This is the updated GIIP for Fenchuganj Gas Field.

Table 3.9—Model estimated GIIP of Fenchuganj Gas Field

Reservoir	GIIP (BSCF)
NGS II	13.65
UGS	260.70
MGS	32.93
LGS	78.77
Total	386.05

As NGS I and NGS III were not tested, it is not used in this study. On the other hand, NGS II and UGS were completed together for FG-3. Therefore, both of the two sands are termed as UGS in this study as contribution of NGS II is very small.

3.3.11 Uncertainty of the model

There is no available Modular Formation Tester (MDT) or Repeat Formation Tester (RFT) type pressure data for the middle or lower zone of the reservoir to provide information on initial reservoir conditions. Initial reservoir pressure for middle and lower zone was taken from testing result. As the pressure gauge was set above the top of the gas zone, extrapolated reservoir pressure was used.

The GWC was observed in upper zone. In other cases for MGS and LGS, the bottom pay zone was considered as GDT (gas-down-to) in well report. Reviewing the log and consulting with relevant persons, separate GWC were considered for middle and lower zone.

Permeability was distributed according to log though its value that was limited according to testing report of the wells.

The initial water saturation distribution in the model was also been based on sequential Gaussians Simulation algorithm while well logs were honored to position the wells correctly.

All available data were reviewed and where no data were available appropriate assumptions or correlations are applied.

CHAPTER IV

HISTORY MATCHING

This section describes the history matching part of the simulation process with the aims of confirming the initial reservoir conditions and obtaining an acceptable match of observed reservoir behavior.

The model has been “driven” by gas rate (“GRAT” in ECLIPSE) and a fairly good match has been obtained for the wells FG-2 and FG-3 and FG-2L (FG-2 is known as FG-2L after work-over of FG-2 in LGS), respectively. Therefore pressure, water and condensate rates have been matched for each well in respect to the gas rate and the simulation model can be used for performing predictive scenarios.

4.1 History Match Variables

There is no single, universally accepted strategy for performing a history matching [15]. A strategy involving sequential adjustment of one variable at a time to progressively match the observed behavior is adopted. The analyses of the available production and pressure data as reported in the previous section provided the initial understanding of the well and reservoir behavior. It also helped to determine the variables that needed to be adjusted for history matching. The following variables are used to achieve the history matching of the simulation model.

- Local permeability adjustment to modify pressure drawdown;
- Attaching analytic aquifers for pressure support;
- Vertical to horizontal permeability ratio adjustments to limit vertical communication;
- Some changing of transmissibility near FG-2 to achieve water breakthrough.
- Pore Volume (PV) and Well productivity index multiplier to match initial pressure drawdown.

4.1.1 Local permeability adjustment: Local permeability in some cells around the well in geological model was unusually low. On the other hand, test result show for UGS with permeability value of 623 mD. Therefore local permeability in the well area was modified manually and global permeability of the reservoir sands was also modified by applying some multipliers of 1.10 to allow water to breakthrough in the drainage points and for better pressure response.

4.1.2 Incorporating the aquifer

Pressure is usually the first primary variable to be matched in history matching. For pressure matching, attaching aquifer is one option. For attaching aquifer, there should be reasonable explanation. FG-2 and FG-3 was perforated in UGS for producing gas. FG-2 was shut in after three years of production due to excessive sand and water production whereas FG-3 is still producing gas with a steady pressure profile. Fig. 4.1 and Fig. 4.2 show pressure and production profile of the field. According to trends, there is hardly any pressure decline. Schlumberger, also agreed with this strong pressure support in UGS, in their consulting service report on behalf of HCU in 2012 [16]. It gives the idea about the reservoir that either it contains higher GIIP than previously estimated or has strong aquifer support. Popular field technique of plotting the reservoir averaged value of $^{P}/_{Z}$ as a function of the cumulative gas production, G_p is applied to find out which one is active for the reservoir. Plot is shown in Fig. 4.3 which indicates the presence of non non-volumetric behavior. Havlena-Odeh interpretation to define the drive mechanism was also investigated [17]. Non-linear shape shown in Fig. 4.4 gives the clear indication of aquifer support.

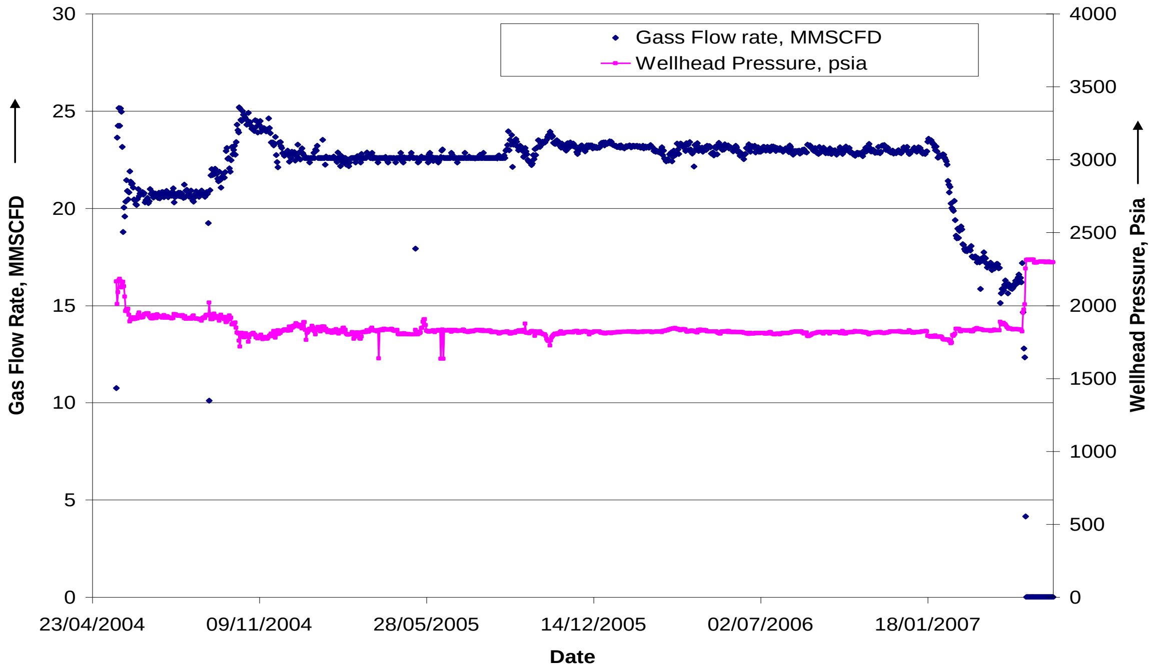

Figure 4.1—Pressure and Production profile with respect to time of FG-2 for UGS

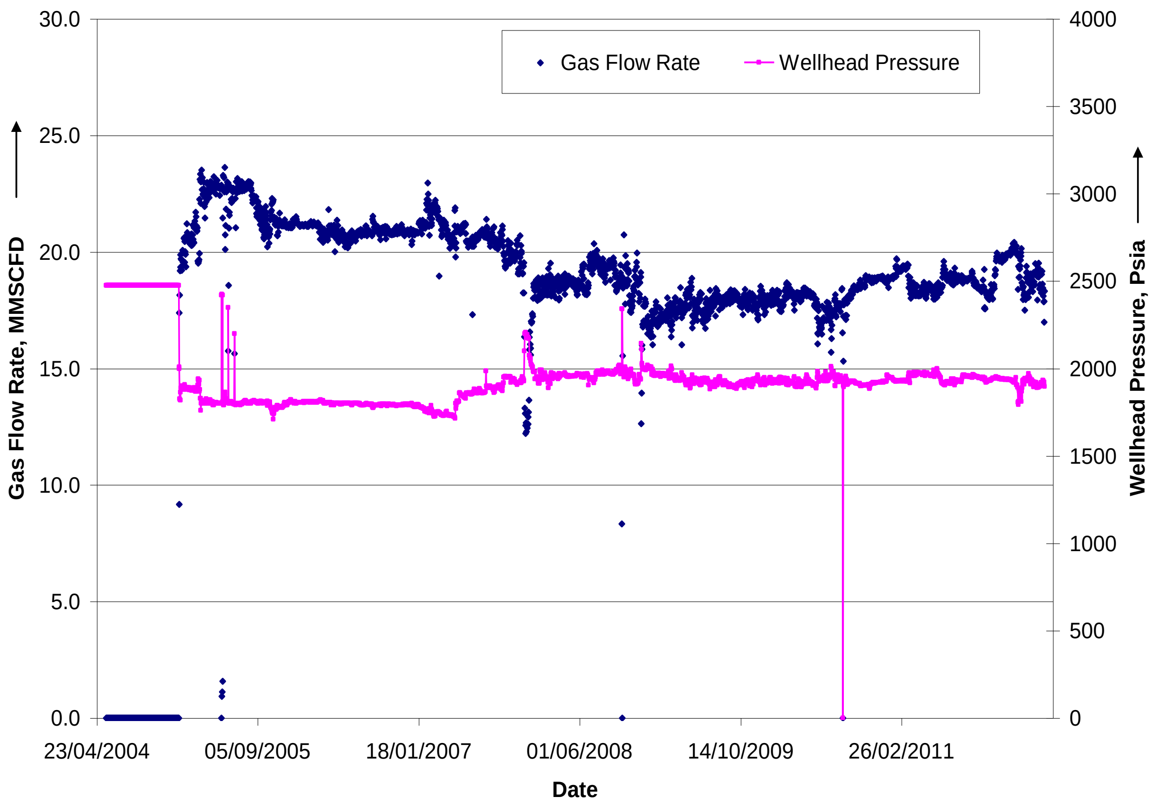

Figure 4.2—Pressure and Production profile with respect to time of FG-3 for UGS

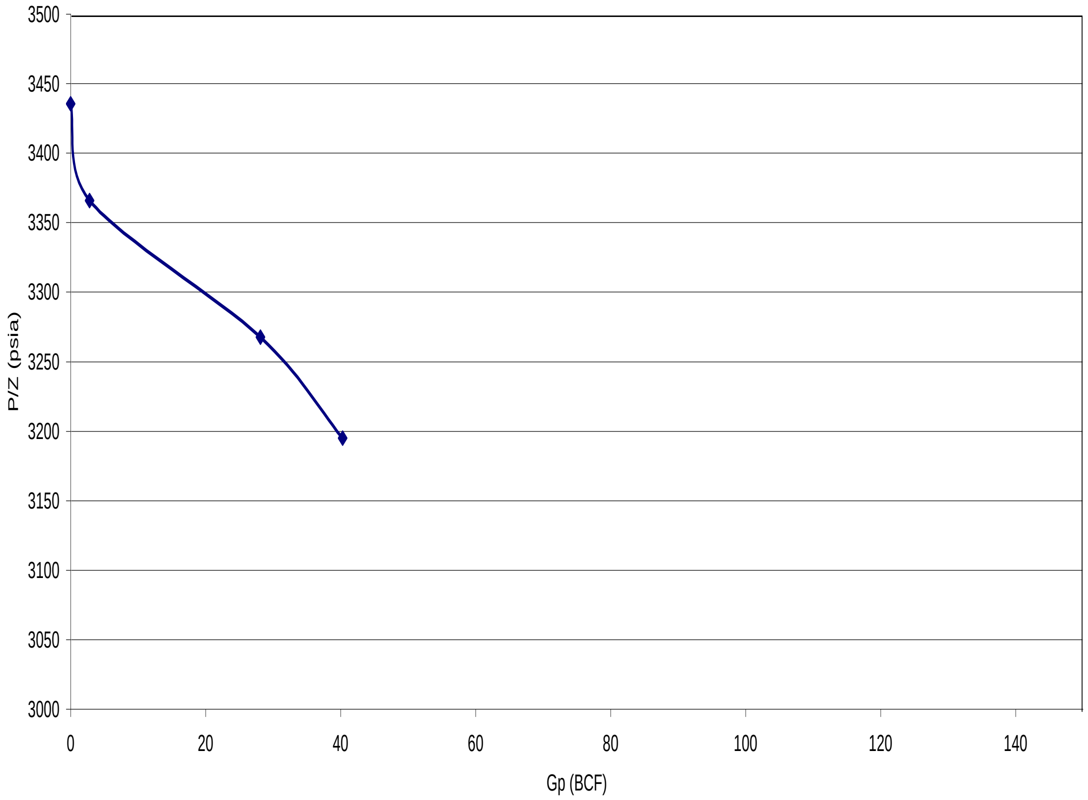

Figure 4.3—Gas material balance plot for finding drive mechanism for UGS

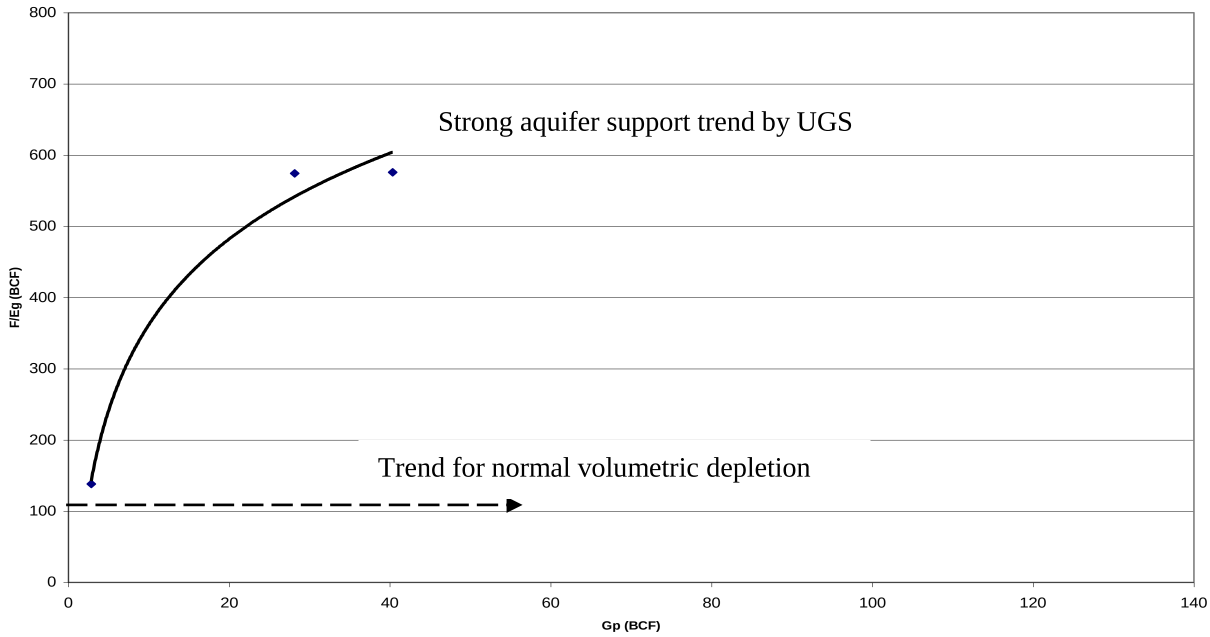

Figure 4.4—Havlena Odeh plot to identify drive mechanism of UGS

Finally while drilling FG-4 in 2011, GWC was found at 2060.5 m in log that raised 20 m from previously determined value in FG-2. Therefore, a numerical aquifer is attached to the bottom of UGS to support the reservoir pressure for matching the observed THP. Also directions of the aquifer connection to the sand layers were adjusted to match the water. On the other hand, for LGS such pressure support can not be established by production and pressure profile.

4.1.3 Productivity Index (PI) Multiplier

Well productivity index (PI) multiplier is used in some wells in particular layers to improve the matches of the initial pressure drawdown around the wells.

4.1.4 Pore volume (PV) multiplier

For LGS model estimated GIIP was found very low compared to BAPEX estimated GIIP to be 121 BSCF. Therefore a pore volume multiplication 1.25 (25% increase) was used in the major layers (layers 53 – 57) which made the model estimated GIIP to be 78.77 BSCF. This made the historical pressure match better.

4.1.5 Transmissibility multiplier

It is used around well for better match the down-dip well water breakthrough and better pressure response.

4.2 History Match Result

As mentioned in Chapter II, the only simulation study was performed during 2009 by RPS. The rate history used in that work is shown in Fig. 4.12 [3]. The pressure history was matched based this rate history. Later on during this study, several inconsistencies and errors were found in the RPS simulation work especially for FG-2. If there are several sands, production starts from deeper to upper sand sequence as standard practice. In case of Fenchuganj Gas Field, FG-2 was first completed at UGS though it contained deeper LGS and MGS. To reduce the high demand supply gap by producing from more prospective zone than the others may be the reason. In previous simulation study, FG-2 was shown completed in LGS first instead of UGS with almost ten times lower production data. Water production was wrongly allocated to both wells. When actual historical production rate of FG-2 in UGS was given as input to Eclipse, it was found that the model did not reproduce the historical pressure profile maintaining the production rate. In order to address this problem, the geological model was updated and history matching was done incorporating the updated geological model in this study.

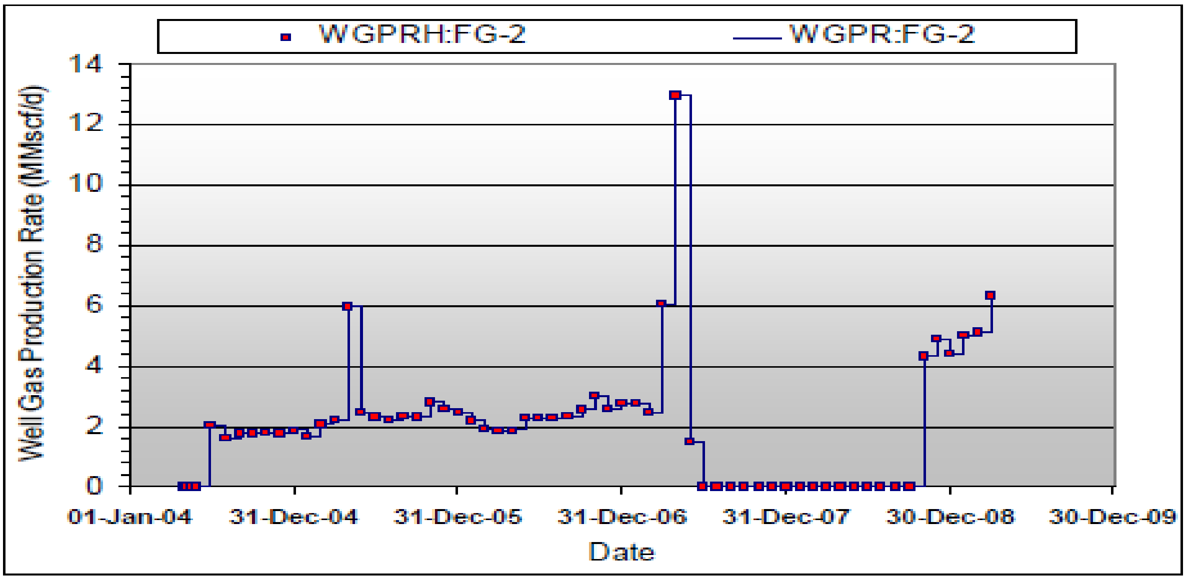

Figure 4.5—Previous History matching of FG-2 of UGS by RPS Energy

Matching individual well pressures and pressure gradients throughout time is attempted during the first stage of the history matching. To match pressure and pressure gradients, the matching parameters used are aquifer connectivity, reservoir kh, transmissibility across faults, and regional pore volume. Changing aquifer connectivity and regional pore volume may affect the match to average reservoir pressures. The results of the history match are presented in the following subsection.

4.2.1 Gas Rate Matching

Figure 4.6 to Figure 4.9 show the match to gas rate in each of FG-2, FG-2M, FG-3 and FG-2L, respectively. Excellent match is achieved for each, which implies that permeability and well PI has been matched perfectly, a key measure for future forecasts.

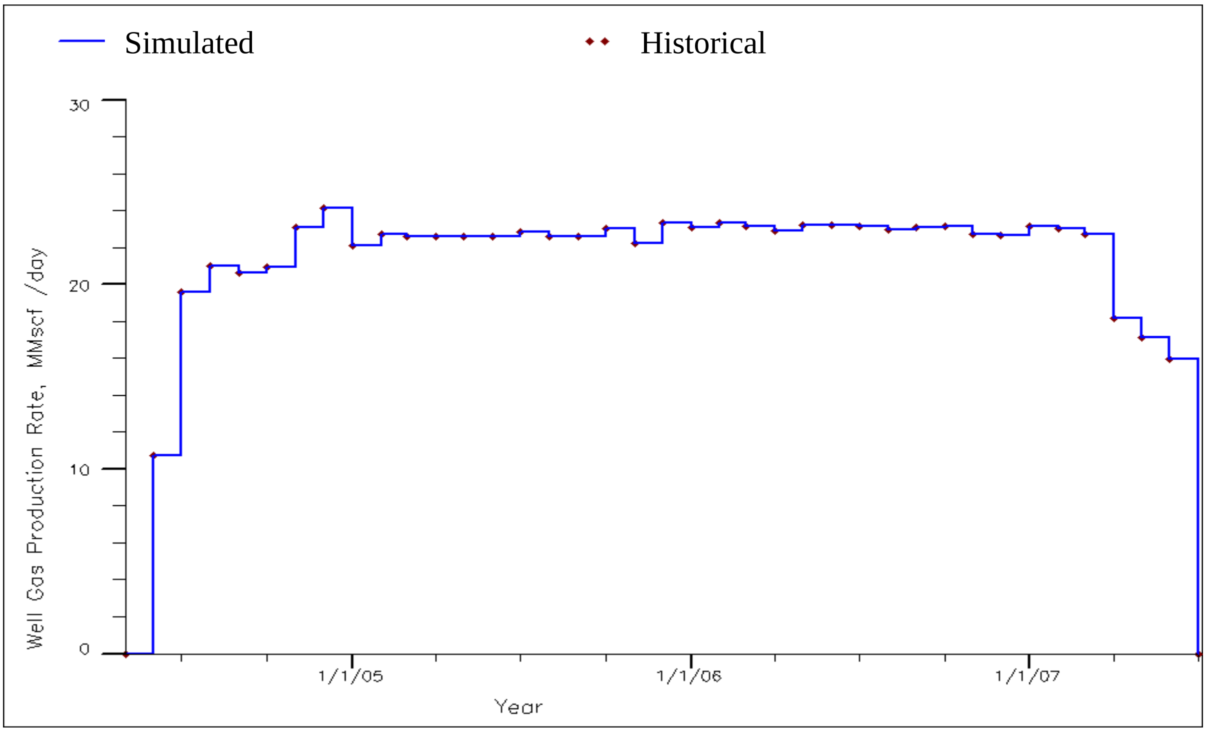

Figure 4.6—Gas Rate History Match for FG-2

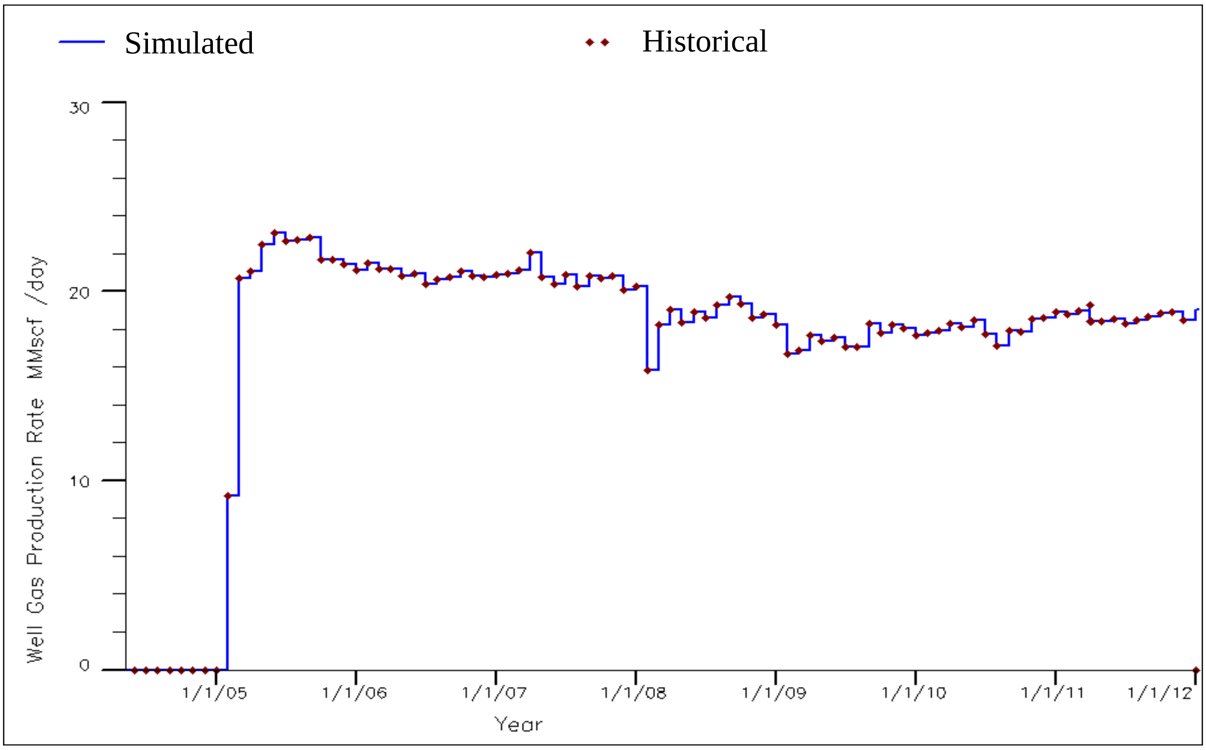

Figure 4.7—Gas Rate History Match for FG-3

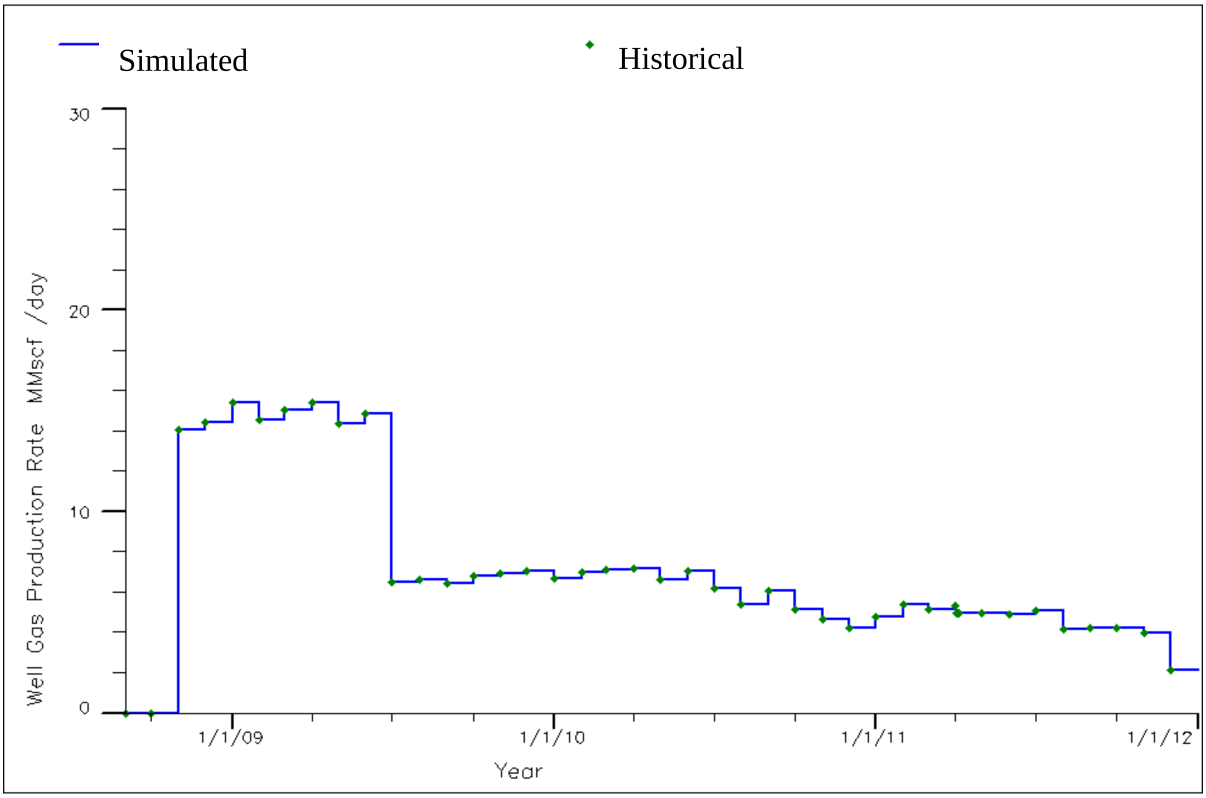

Figure 4.8—Gas Rate History Match for FG-2L

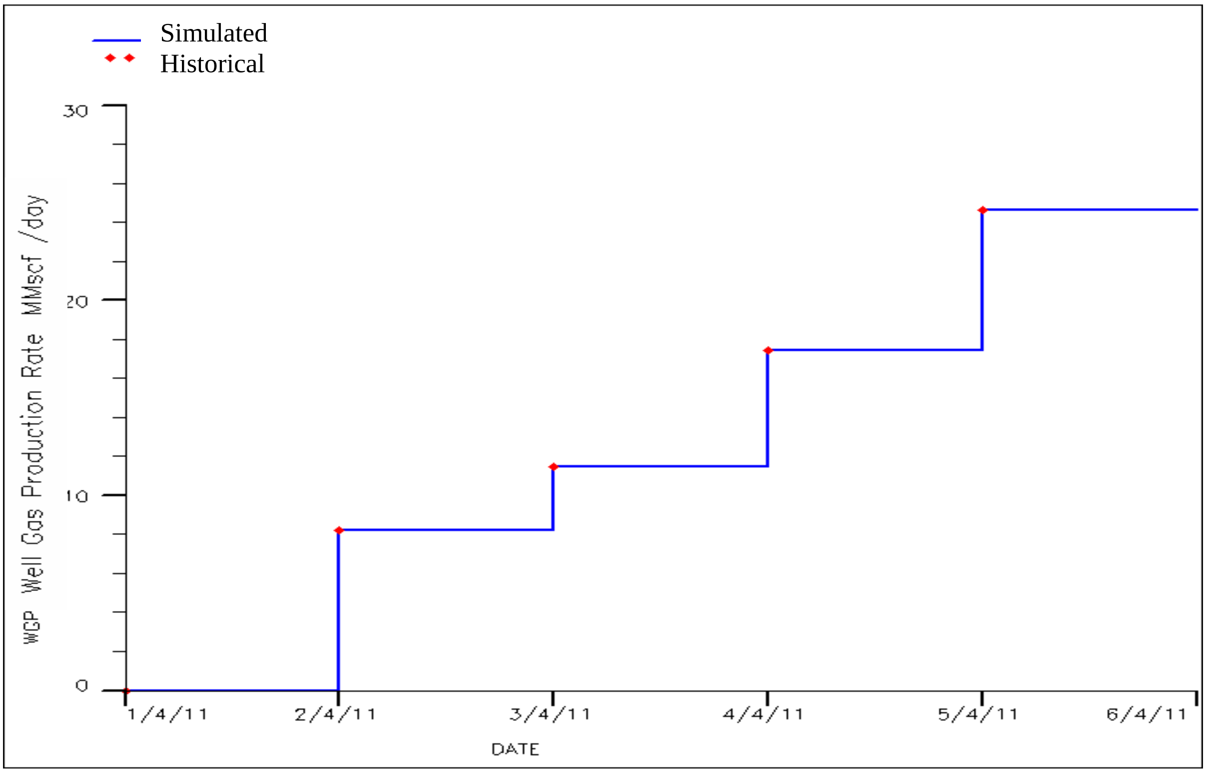

Figure 4.9—Gas Rate History Match for FG-2M (In this case flow rates during DST are used to perform history match).

4.2.2 Pressure History Matching

Regional pressures and pressure gradients are matched during the first stage of history match. To match pressure and pressure gradients, the matching parameters most commonly used are aquifer connectivity, reservoir permeability depth product (kh), transmissibility across faults, and regional pore volume. Changing aquifer connectivity and regional pore volume may affect the match to average reservoir pressures and the match to average reservoir pressure may need to be revised.

Pressure profile of FG-3 of UGS as shown in Fig. 4.11 is an excellent pressure history matching among the Fig. 4.10 to 4.13. On the other hand, there are no available production data for MGS as it is not put in production using FG-2M (denoted as FG-2M when FG-2 will be completed in MGS). Therefore, history matching of FG-2M is done using only available DST data. Obviously quality of matching would be verified after putting it in production. Moreover, pressure profile of FG-2, perforated in UGS, is shown in Fig. 4.10. Water breakthrough took place after three years of production. Simulated pressure profile shows a decreasing trend after FG-3 started producing from the same producing UGS layer. Deviation between simulated and historical pressure increases when water production increased which is quite reasonable. This well took almost four years to drill, complete and testing before putting it ready for production. This unusually long delay was caused by various problems during drilling and completion phase such as fishing, squeezing, etc. Considering all these condition, simulated matching pressure profile is quite reasonable with the historical profile.

Pressure profile of FG-2L (denoted as FG-2L after completing FG-2 by workover operation in LGS) is shown in Fig. 4.12. Gas flow was lowered just after six month of production due to excessive water production with sand. Quite close match is found between simulated and historical pressure profile.

In UGS there is strong pressure support whereas production and pressure trend of LGS seems to be depletion type. Therefore, aquifer is attached only in UGS. On the other hand, prediction about driving mechanism can be made after put it in production.

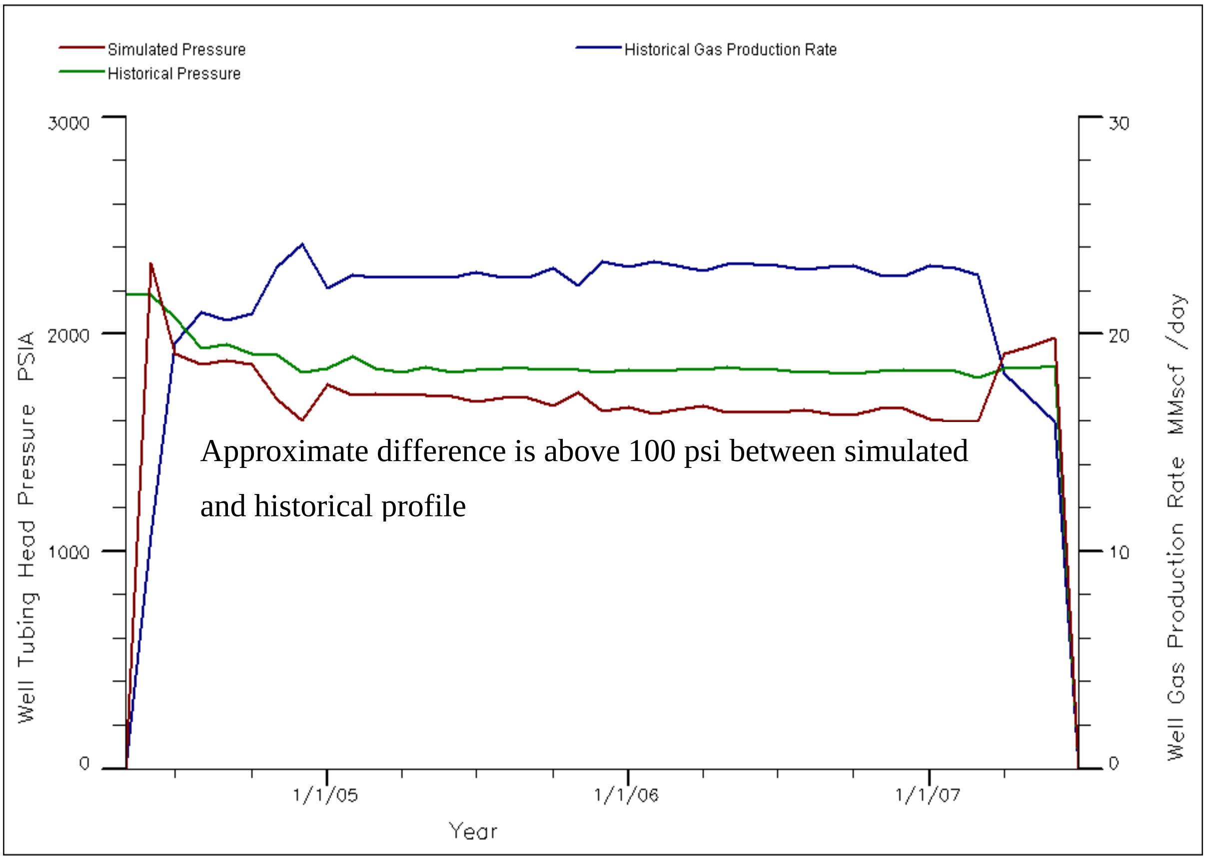

Figure 4.10—Well Head Pressure History Match of FG-2

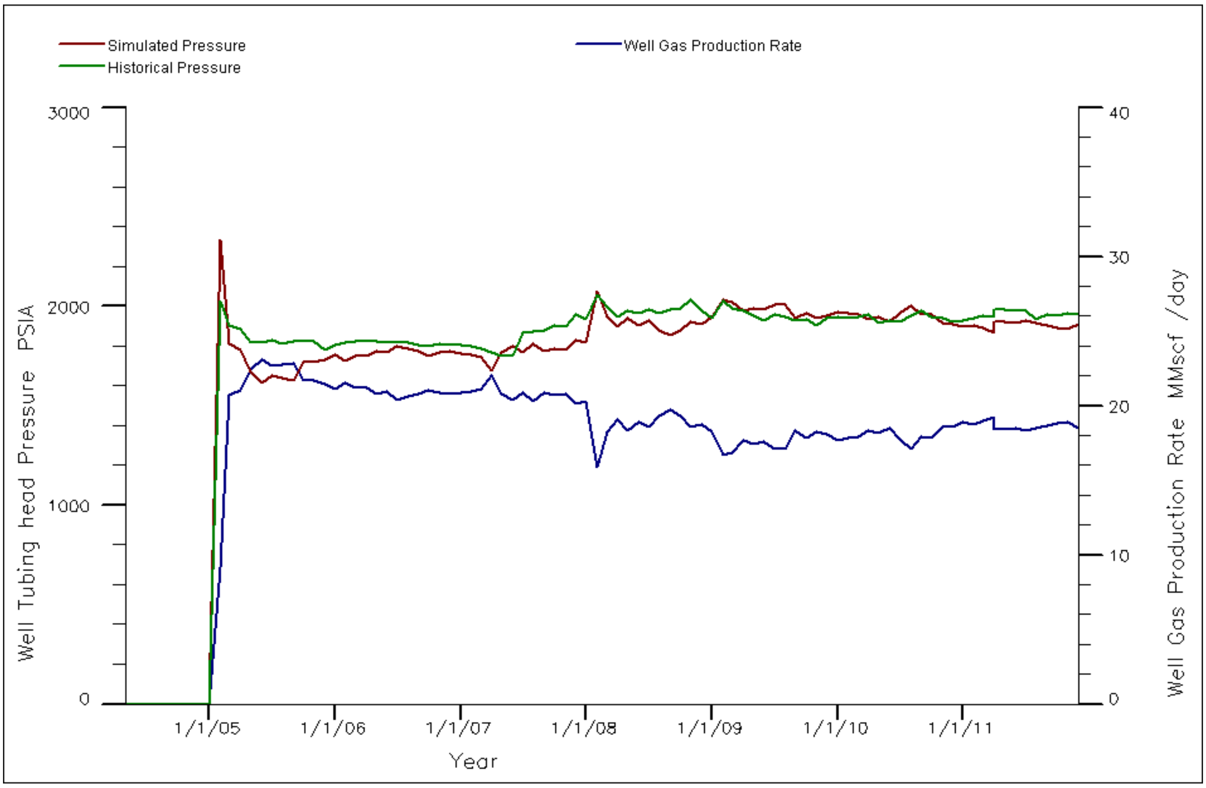

Figure 4.11—Well Head Pressure History Match of FG-3

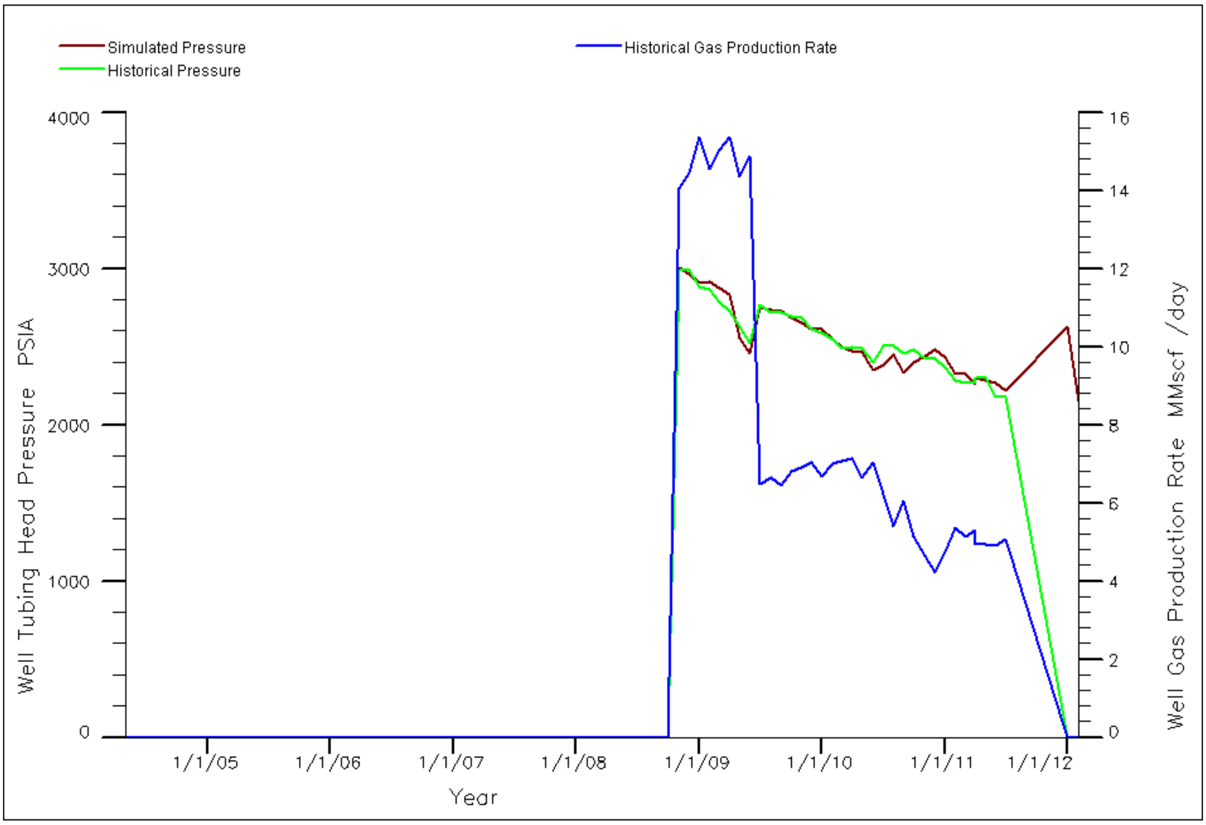

Figure 4.12—Well Head Pressure History Match of FG-2L

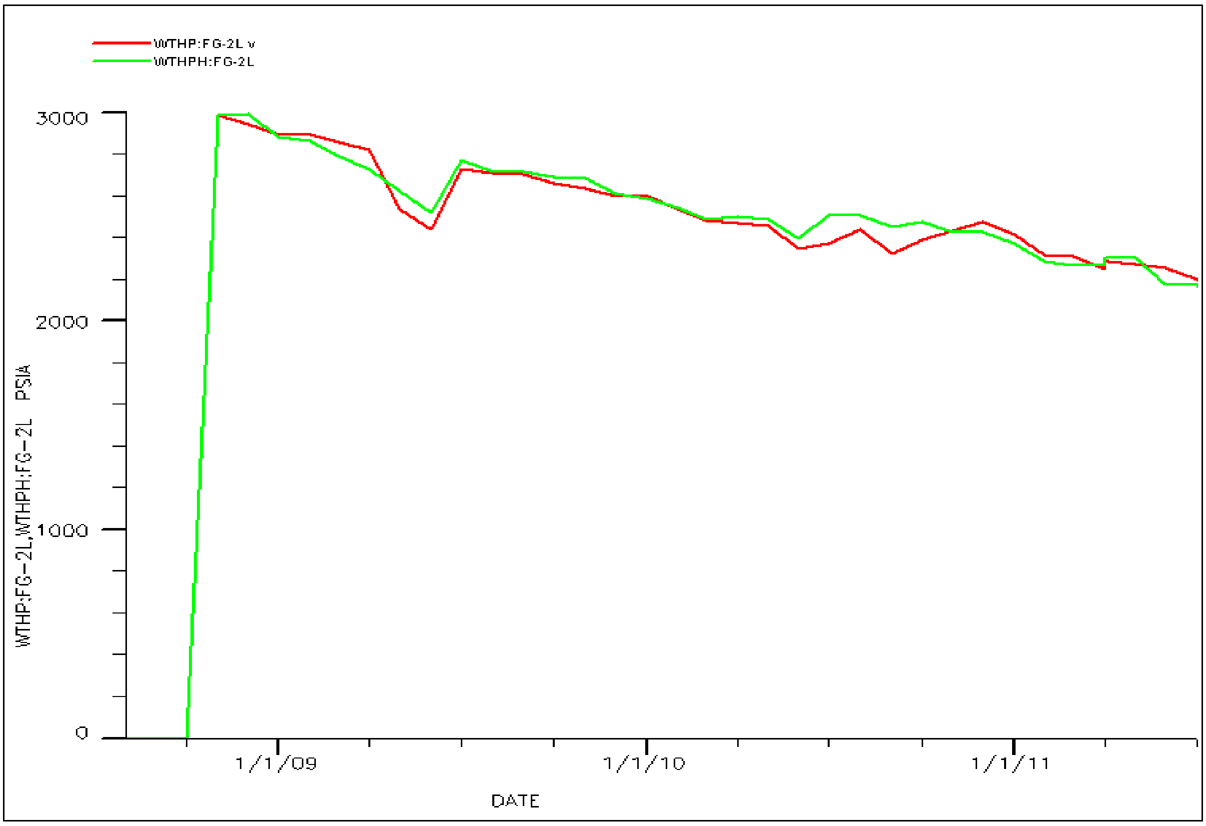

Figure 4.13—Well Head Pressure History Match of FG-2M

4.2.3 Water Rate History Matching

Water history matching is shown in the following Fig. 4.14 to Fig. 4.16. Among the three plots, Fig. 4.15 shows excellent matching of water production for FG-3 with historical profile. Water breakthrough in FG-2 started from February 2007 and ultimately the well was shut in due to excessive sand and water production. From Fig 4.14, it is seen in simulated history matching, water breakthrough starts from January 2007 which is a very close match. Again, from October 2008 (Fig. 4.16) gas production started after re-completing the well in LGS. Here also the water production started from FG-2L after six month of production. Simulated profile also shows the same trend.

Possible reasons for such behavior of water production are as follow:

1. Position of FG-2 or FG-2L is the same, and the well location is in the flank position of the reservoir which is close to the water table.

2. For LGS of FG-2L, GWC is clearly mentioned at 2781.5 by the Geological Division of Petrobangla and confirmed in saturation log [1].

3. In LGS (lower gas sand interval 2768 – 2781 m), perforation interval are 2768 – 2774 m and 2777 – 2779 m. There is clear GWC at 2781.5 m just 2.5 m below the lower perforation. From volumetric calculation, it was found that water table should take six months to rise up 2.5 m maintaining historical production for FG-2L. Detailed calculation is shown Appendix A. Practically gas production was reduced to about 6 MMSCFD after seven months from initial production rate of 15.5 MMSCFD due to water production. Moreover, it was also observed that water gas ratio increased three times after six months which is shown in Fig. 4.17. Eventually water table rise after depleting the gas zone and water breakthrough occurs. In this particular case, less perforation interval might delay the water breakthrough which might increase the gas recovery.

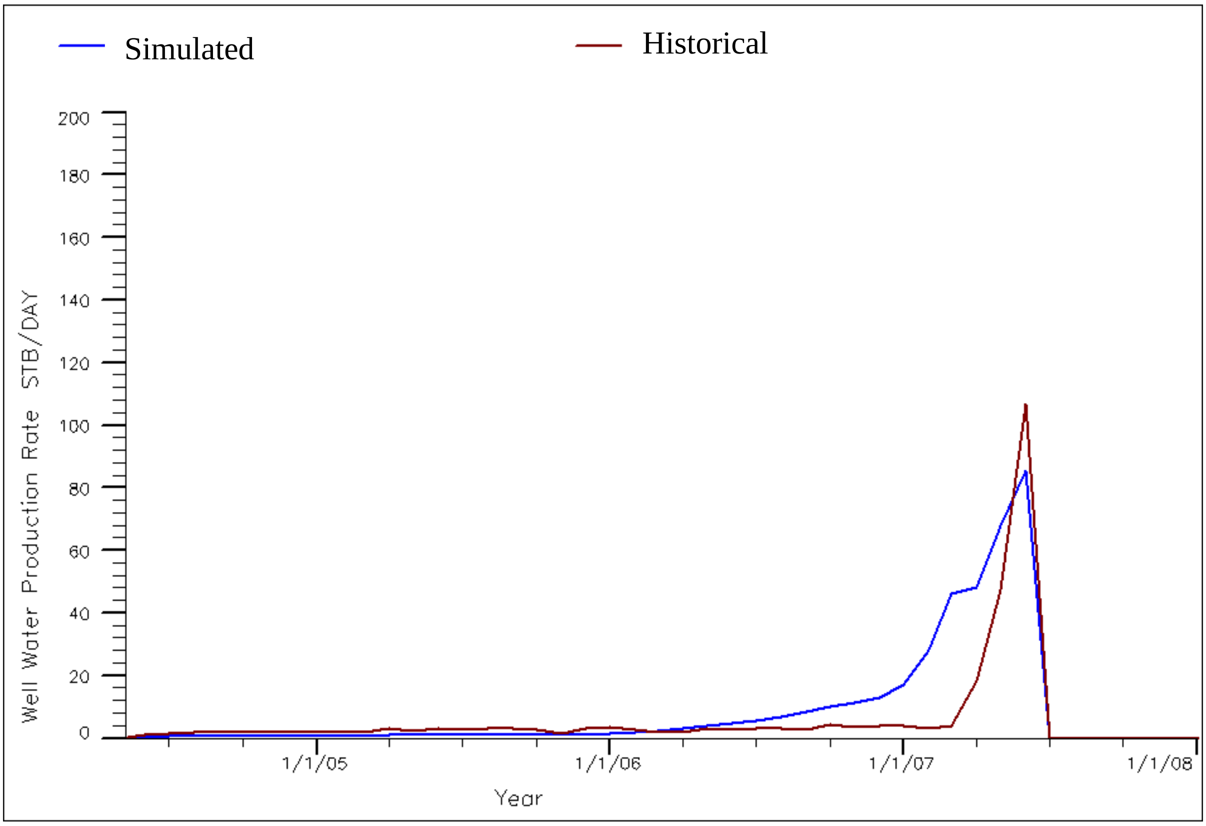

Figure 4.14—Water Rate History Match of FG-2

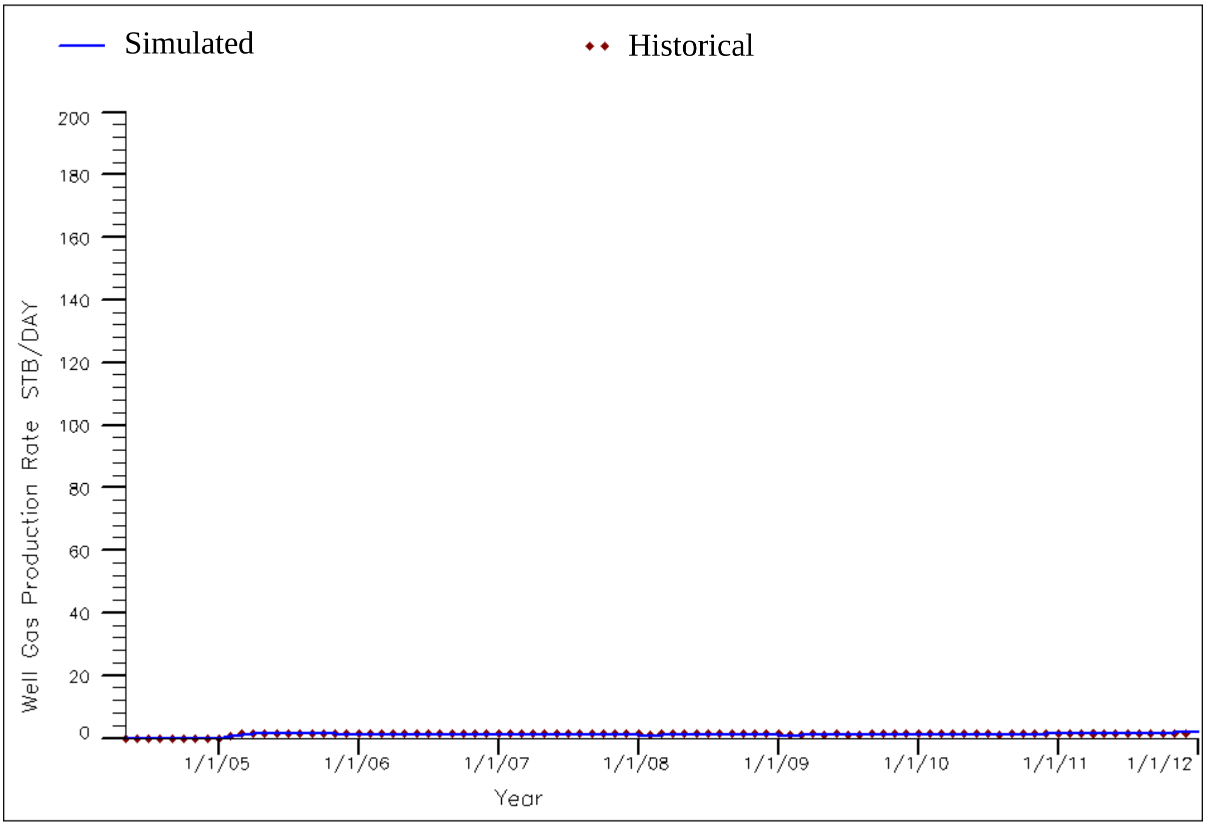

Figure 4.15—Water Rate History Match of FG-3

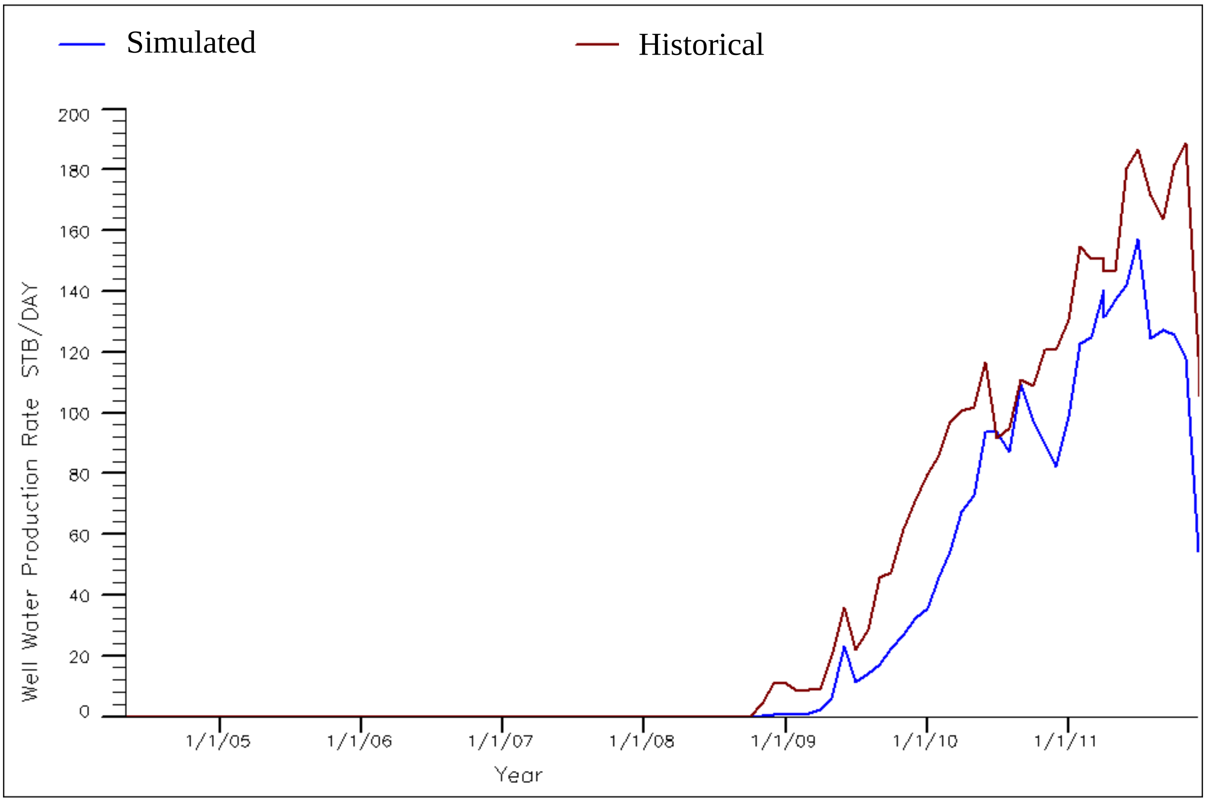

Figure 4.16—Water Rate History Match of FG-2L

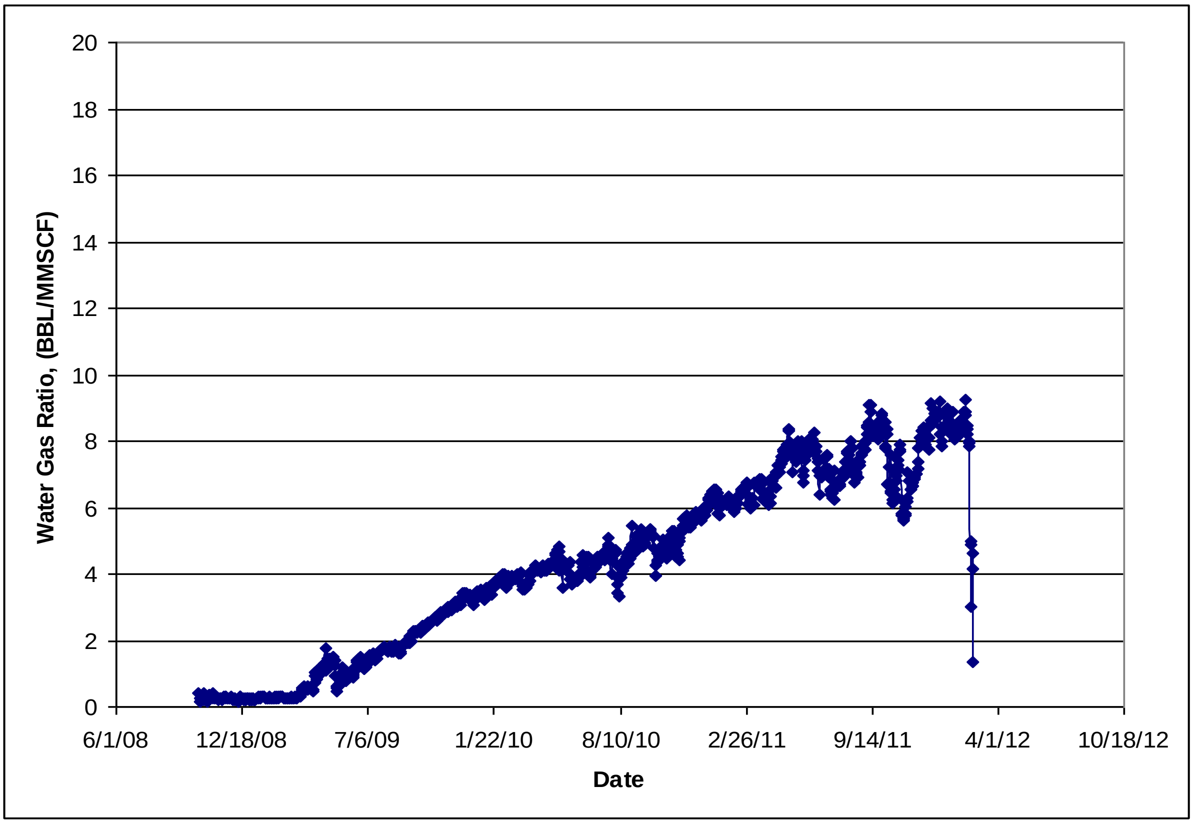

Figure 4.17—Water gas ratio of FG-2L that started to increase just after six month

4.2.4 Condensate Rate History Matching:

Condensate rate history matching are shown in the following three plots (Fig. 4.18 to 4.20). Well wise daily condensate production rate is plotted against time. Excellent matching is found in case of FG-3 (Fig. 4.19) whereas in case of FG-2, simulated profile is quite close to historical profile as shown in Fig. 4.18 considering production of huge water.

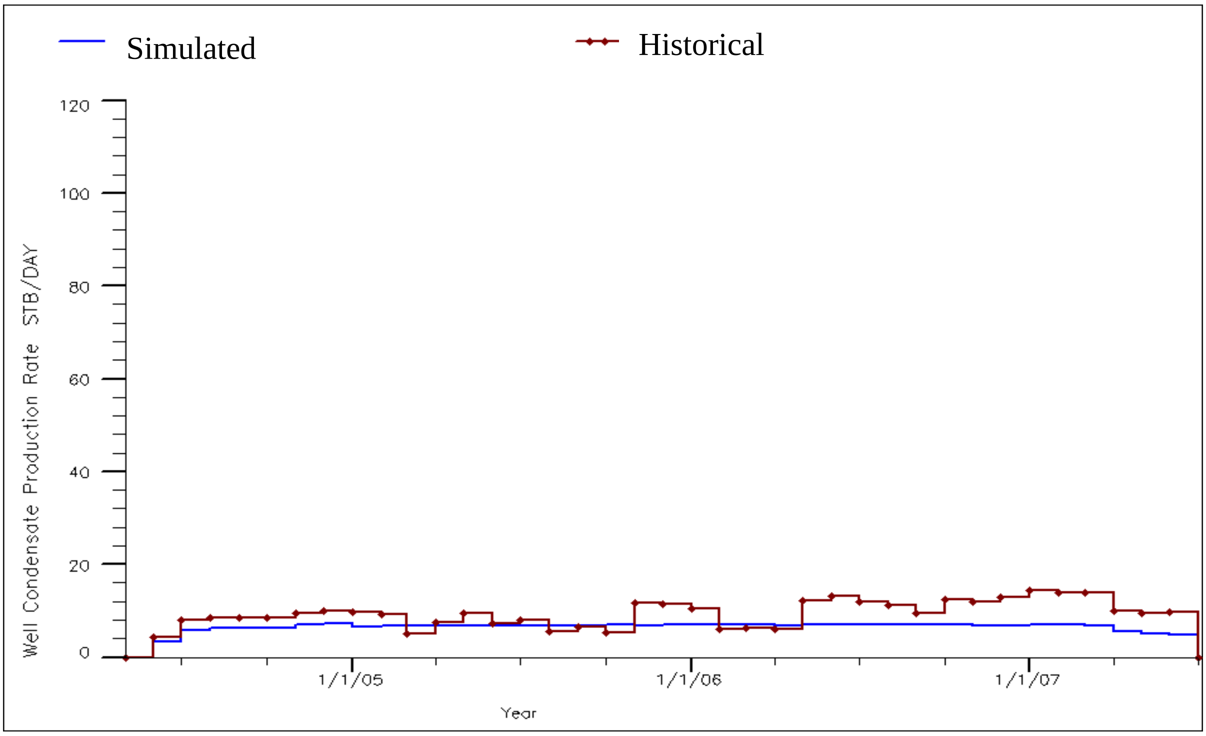

Figure 4.18—Condensate Rate History Match of FG-2

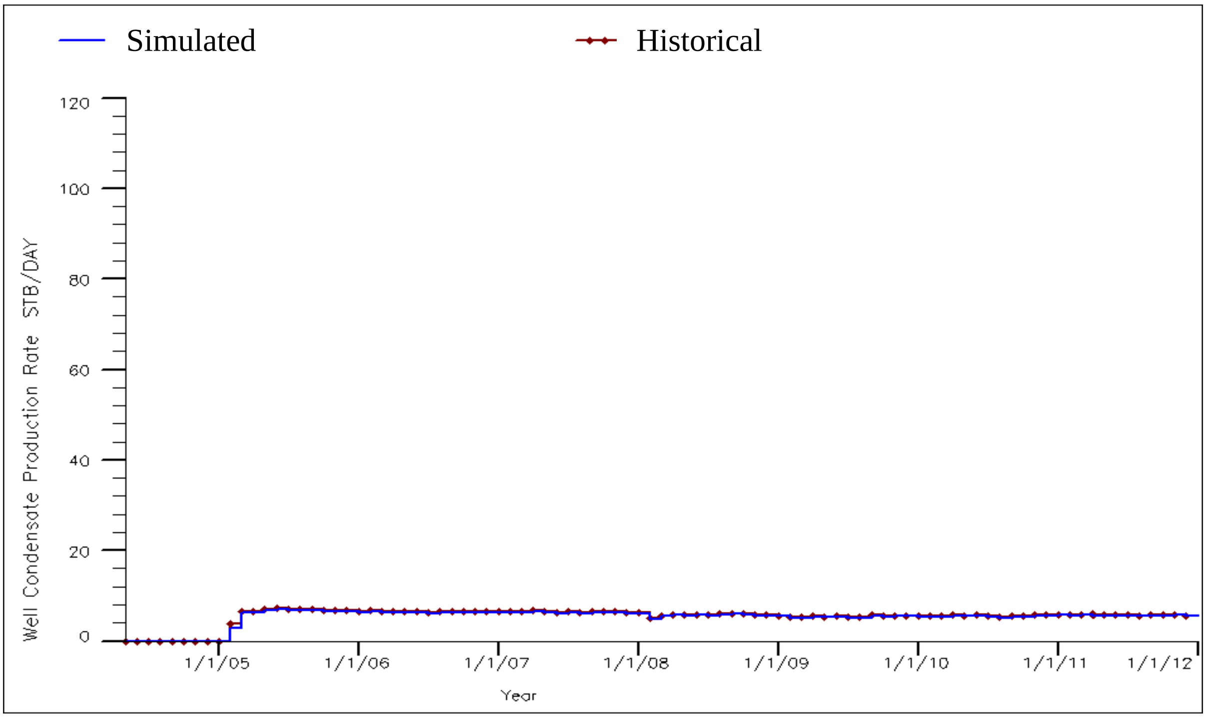

Figure 4.19—Condensate Rate History Match of FG-3

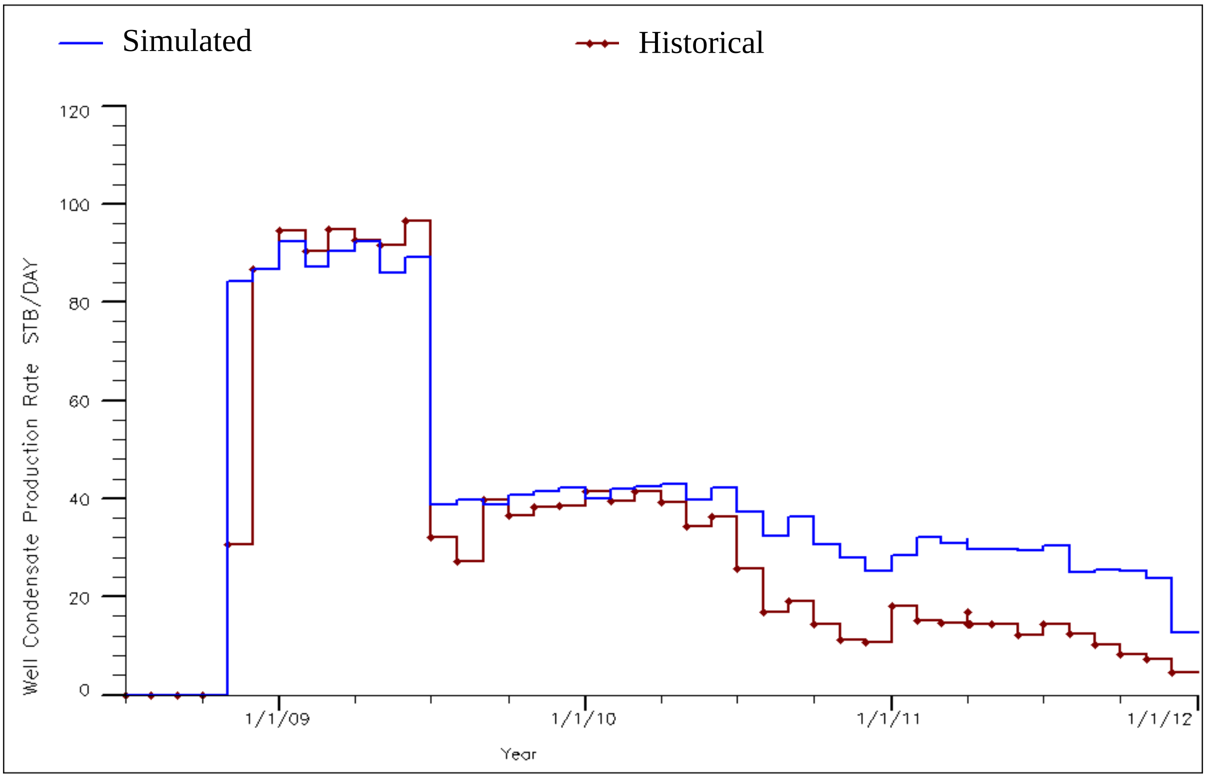

Figure 4.20—Condensate Rate History Match of FG-2L

On the other hand, later portion of Fig. 4.20 shows some discrepancy. Due to huge water production at this stage in limited volume of separator condensate did not get sufficient settle time to separate from water. Therefore, condensate recovery reduced.

4.2.5 Summary of the matching results

Table 4.1 shows the summary of the results of history matching part for each individual well. It is observed that the overall matching of pressure and rates is quite satisfactory. Therefore, it may be concluded that the reservoir is modeled correctly, which should give a good level of confidence on the outcomes of the forecasting part of this works.

Table 4.1—Summary of well wise history matching result

Well	Matching parameter	Reference figure	Quality of match (discussed section)	Remarks
FG-2	Pressure match	Fig. 4.10	Quite close (4.2.2)	Well watered out and shut in
	Water rate	Fig. 4.14	Close (4.2.3)	
	Condensate rate	Fig. 4.18	Good (4.2.4)	
FG-2L	Pressure match	Fig. 4.12	Close (4.2.2)	Well watered out and shut in
	Water rate	Fig. 4.16	Close (4.2.3)	
	Condensate rate	Fig. 4.20	Close (4.2.4)	
FG-3	Pressure match	Fig. 4.11	Excellent (4.2.2)	Well is producing
	Water rate	Fig. 4.15	Excellent (4.2.3)	
	Condensate rate	Fig. 4.19	Excellent (4.2.4)	

CHAPTER V

FORECASTING FIELD PERFORMANCE

The history matching part of this simulation work is presented in the previous chapter. It is shown that the historical pressure and rates matched reasonably well. Thus it can be assumed that the reservoir was modeled correctly. Based on that model, the future performance of the field is evaluated. Different development scenarios are considered.

5.1 Forecast Assumptions and Cases

Before embarking on forecasts, a number of following forecasting assumptions and cases require further explanation.

Duration: Simulation started from May 2004 to December 2011 (for history matching). Then forecasts are generated for the next 25 years up to June 2036.

Economic Gas Rate: A minimum gas rate of 1 MMSCFD per well is applied.

Water Rate: Maximum water production rate of 200 stb/day per well is used.

Flowing Wellhead Pressure (FWHP): Wellhead pressure is set to 1000 psia for all cases. A minimum value of 500 psia was also used to compare the impact whether it would increase the life of the producing wells, or increase ultimate recovery.

Squeeze job: The impact of squeezing bottom perforation of FG-2L in LGS to arrest water production was also investigated.

Well type: Additional one vertical well and one directional well were considered with dual completion producing from separate layers.

Existing wells: All the existing wells were re-used in the predictive scenarios

Predictive Cases

Predictive cases were run up to 2036, with five different scenarios including a "Do Nothing" Case. From the available production data, it was observed that water production rapidly increases to a restrictive level after a certain period of time. However, sand of the field is loose formation type. It is practically observed from the Fenchuganj Gas Field, when water production comes close to 200 bbl/day, sand comes out from the well which will cause damage to surface facilities. Therefore, an upper limit on water production was applied such that the field facilities can handle a maximum of 200 stb/day per well with controlling sand production for all forecast cases excluding forecast case 1. For all cases abandonment pressure is set to 1000 psia.

The following prediction cases were investigated.

- Forecast Case 1: Do nothing, i.e., to continue gas production with the existing wells without any investigation to improve well or reservoir performance.

- Forecast Case 2: Do nothing (case 1), but set the water production upper limit to 200 stb/day per well.

- Forecast Case 3: Workover operation of FG-2L by plugging off the lower perforations (3 m squeezed off) in LGS keeping the condition of forecast case 2, and set the water production upper limit 200 to stb/day for each well.

- Forecast Case 4: One additional well (FG-4) was directionally drilled in UGS on the southern flank keeping the condition of forecast case 3, and set the water production upper limit 200 stb/day per well.

- Forecast Case 5: Drilling of three additional wells, i.e., FG-4 directionally drilled in UGS, FG-5 will be vertically drilled in UGS on the southern flank behind FG-4, and FG-6 will be directionally drilled which will cover all three sands. Here the water production upper limits is also set to 200 stb/day per well. Also FG-6 has duel completions.

5.2 Results of Predictive Cases

5.2.1 Forecast Case 1:

Do nothing case; i.e., continue gas production with the existing two wells (FG-2L and FG-3) without improving well or reservoir performance in anyway. The production profile of the field for the “Do Nothing” case is presented in Figure 5.1. Here FG-2L and FG-3 are shown in production from LGS and UGS respectively. First peak production of about 45 MMSCFD was sustained for three years. Second peak production of about 35 MMSCFD lasted for seven months only due to water production with sand in FG-2L. Then forecasting starts from January 2012 with a steady production of 24 MMSCFD. Gas rate would be maintained up to 2019, and then declining would start. On the other hand, steady increase in water production from 2010 to 2016 from negligible to about 500 bbl/day is expected. Later on, a more drastic increase will happen which may force early shut in. It will not be feasible to operate this field beyond 2016 with current scenario, unless water production increased is addressed and adequate water handling facilities are added. However, total gas production will be 207.70 BSCF with recovery factor of 53.81% at the end of simulation run in 2036.

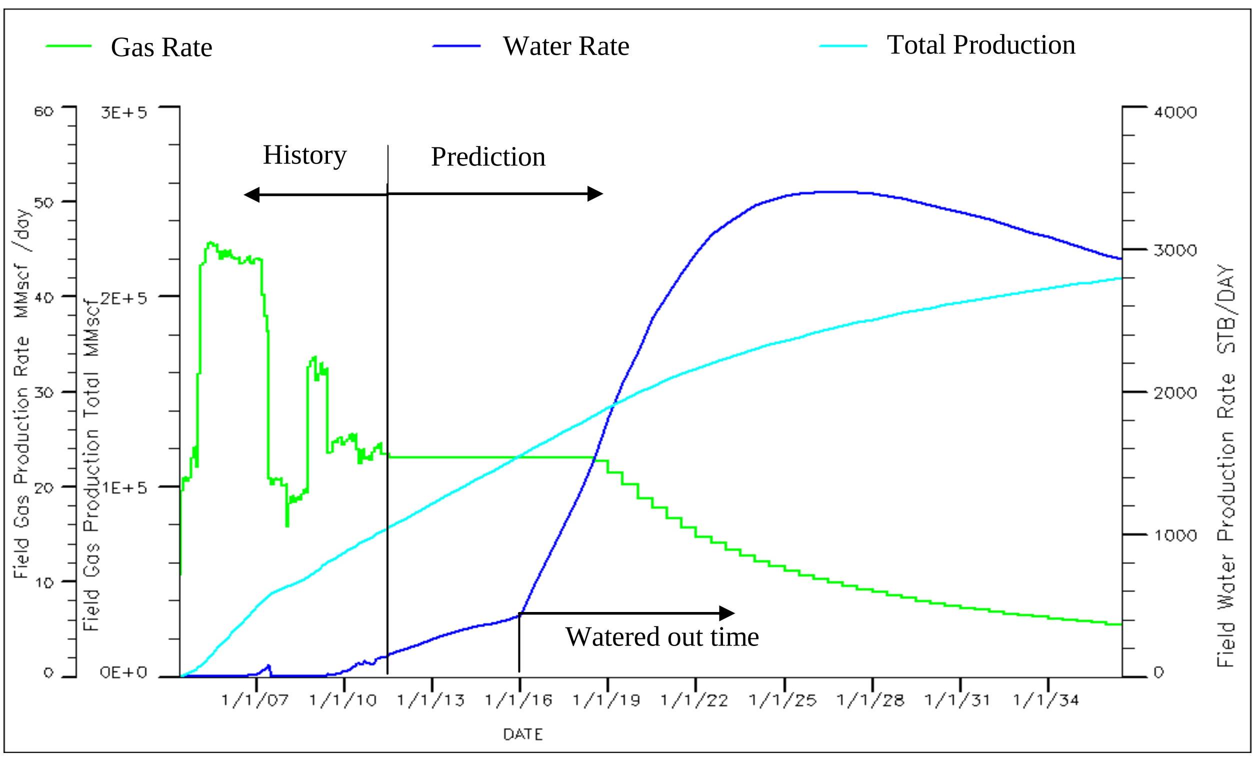

Figure 5.1—Field Production profile of forecast case 1

5.2.2 Forecast Case 2:

Same wells (FG-2L and FG-3) with same production rates and wellhead pressure limit are applied. In addition water production limit is set to 200 bbl/day. This forecast is quite similar to the previous one. As like forecast 1, second peak production of about 35 MMSCFD was sustained for only six months. Later, due to increase of water production gas production was decrease. It is seen from Fig. 5.2 that water production would be doubled to about 400 bbl/day on only six months in 2016. Eventually due to water production in both wells, forecasted gas rate will decrease drastically after 2016 to maintain water production 200 bbl/day per well. That is both wells would water out after 2016. In this case total gas production will be 179.60 BSCF with recovery factor of 46.53%. This scenario will also not be acceptable considering very small amount of gas production after 2018.

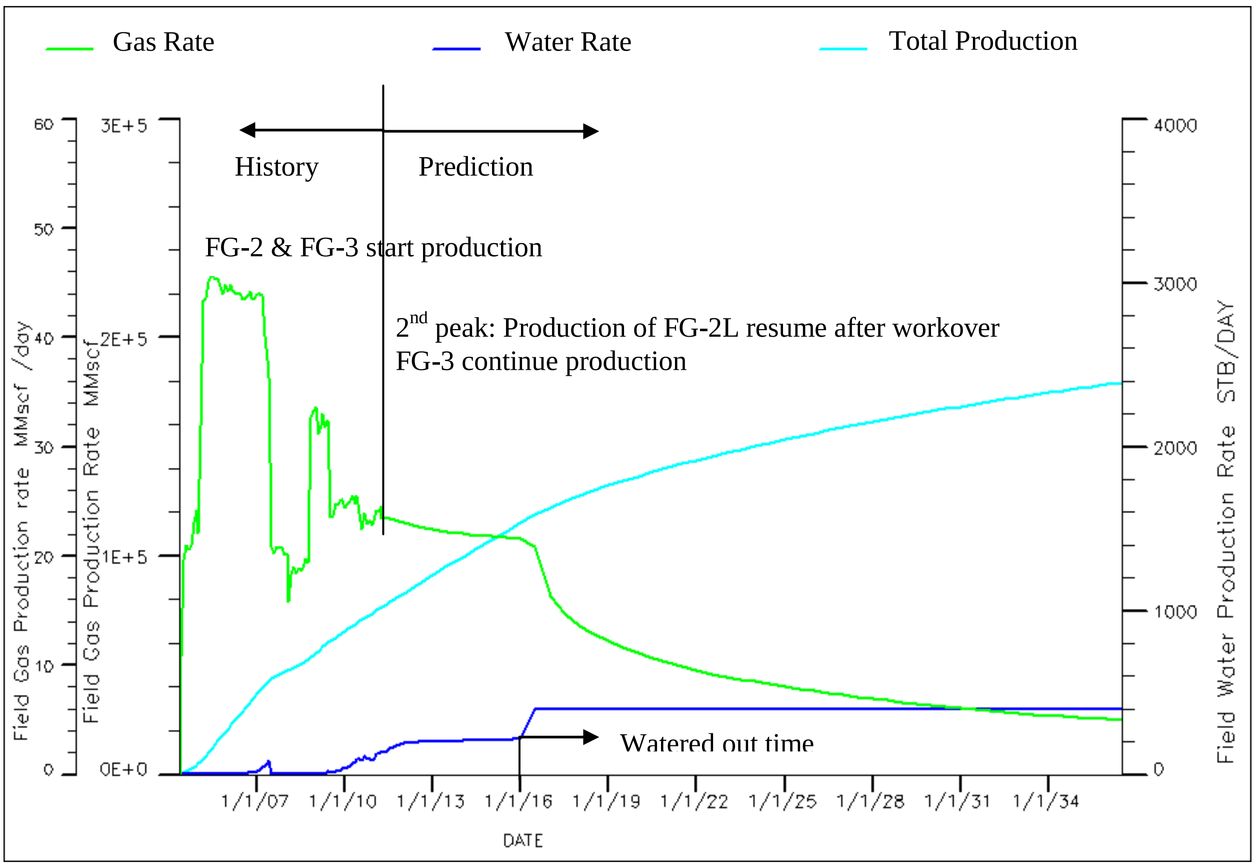

Figure 5.2 : Field Production profile of forecast case 2

5.2.3 Forecast Case 3:

Same wells (FG-2L and FG-3) with same production rates and same 1000 psia abandonment wellhead pressure are applied. Water production limit is also set to 200 bbl/day. In addition to that impact of workover for the wells by plugging the lower perforations (3 m squeezed off) is investigated. Field production profile is shown in Fig. 5.3. This forecast figure is quite similar to forecast 2. The difference between forecast 2 and forecast 3 is the workover of wells which increases the recovery by almost 2%. In this case total gas production will be 186.10 BSCF with a recovery factor 48.21%.

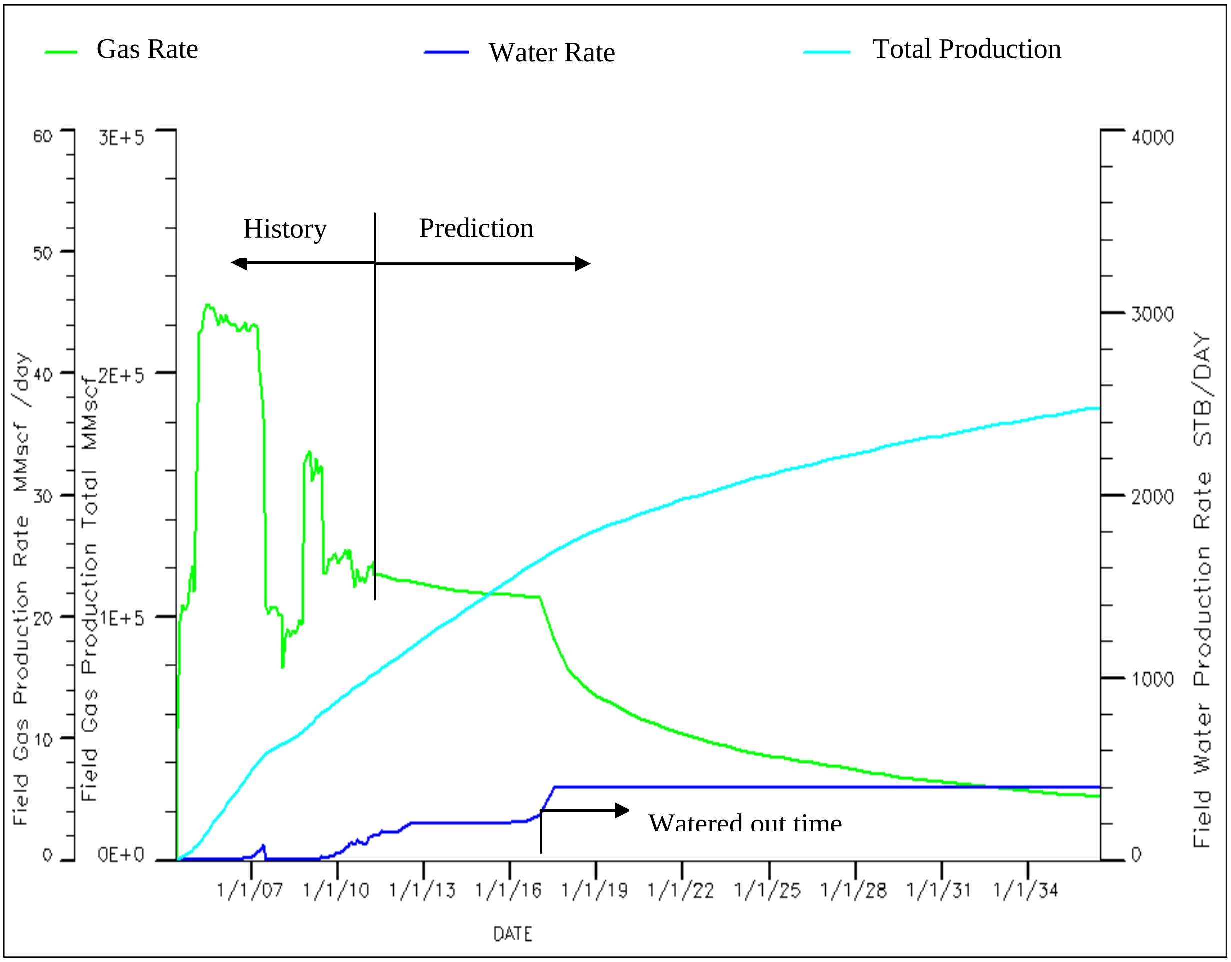

Figure 5.3—Field Production profile of forecast case 3

5.2.4 Forecast Case 4:

In forecast 4, shown in Fig. 5.4, same wells (FG-2L and FG-3) with same production and abandonment pressure constrain is considered. Also water production limit is set to 200 bbl/day and work over of the wells by plugging the lower perforations as like forecast case 3. In addition, one direction well (FG-4) is drilled in UGS on the southern flank according to BAPEX plan. Forecast scenario started from January 2012. When FG-4 would come in production with gas rate of 25 MMSCFD, it would make total field production 46 MMSCFD as seen by the third peak in Fig. 5.4. Production rate will decline due to water breakthrough in FG-3 after 2015. Water break through will take place in FG-4 after 2020 that will again drastically reduce production rate. However, total gas production will be 237.40 BSCF with recovery factor of 61.50% at the end of simulation run in 2036. It gives the indication of drilling a new well in the UGS will increase recovery 13.4% than the forecast case 3.

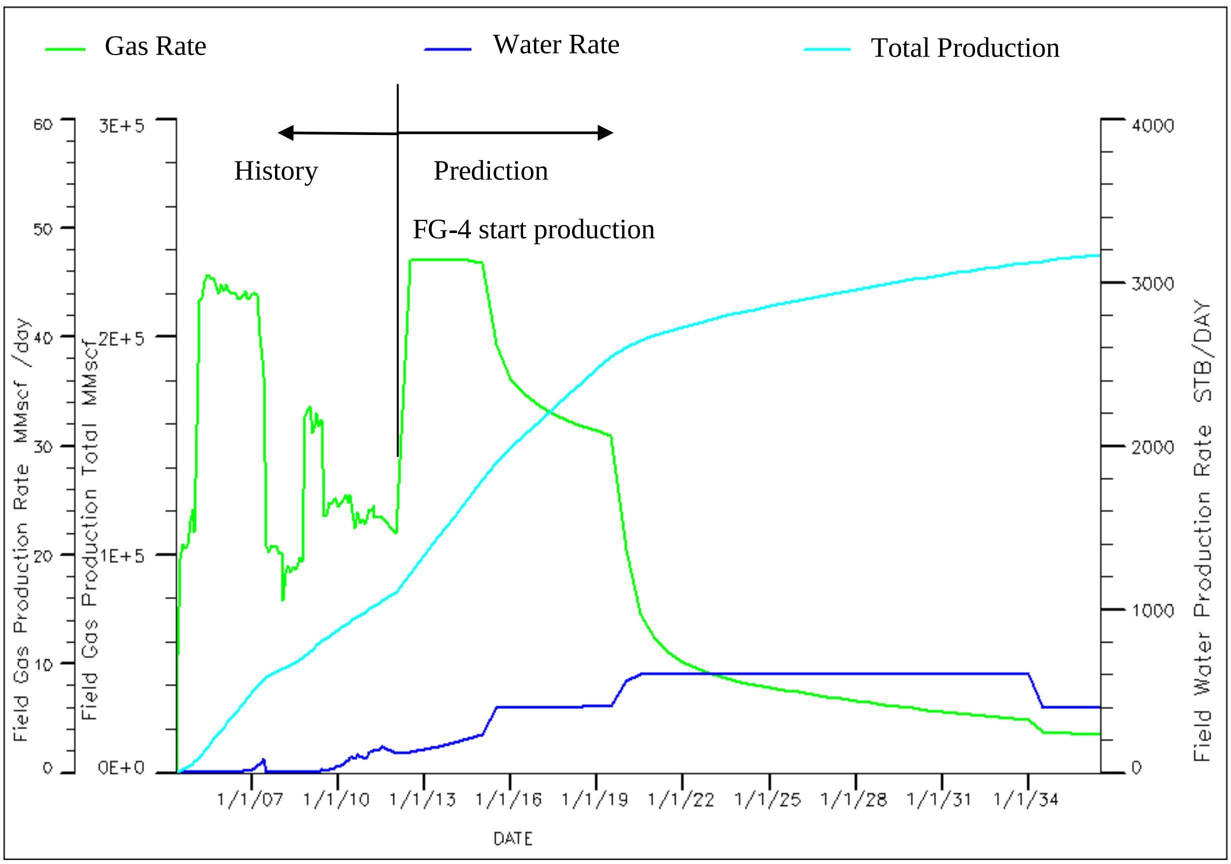

Figure 5.4—Field Production profile of forecast case 4

5.2.5 Forecast Case 5:

In forecast 5, shown in Fig. 5.5, same wells (FG-2L, FG-2LW, FG-3 and FG-4) with same production and abandonment pressure (1000 psia) constrain as in forecast case 4 are considered. Again water production limit is set to 200 bbl/day and workover operation for the wells by plugging the lower perforations is considered. In this case, two additional wells, i.e., FG-5 was vertically drilled in UGS within 1.2 km from FG-4 on the southern flank and FG-6 was directionally drilled to cover all the three sands on the northern side of FG-2. Production profile of the field for this case is presented in Figure 5.5. In this case, due to additional two wells (FG-5 and FG-6), field average gas production will be maintained above 50 MMSCFD for eight years. Then declining will start after 2021. Total gas production is found to be 315.60 BSCF with recovery factor of 81.76% at the end of simulation run in 2036. Among the five cases, clearly, it is the best case as it increases the recovery 20% than the forecast case 4.

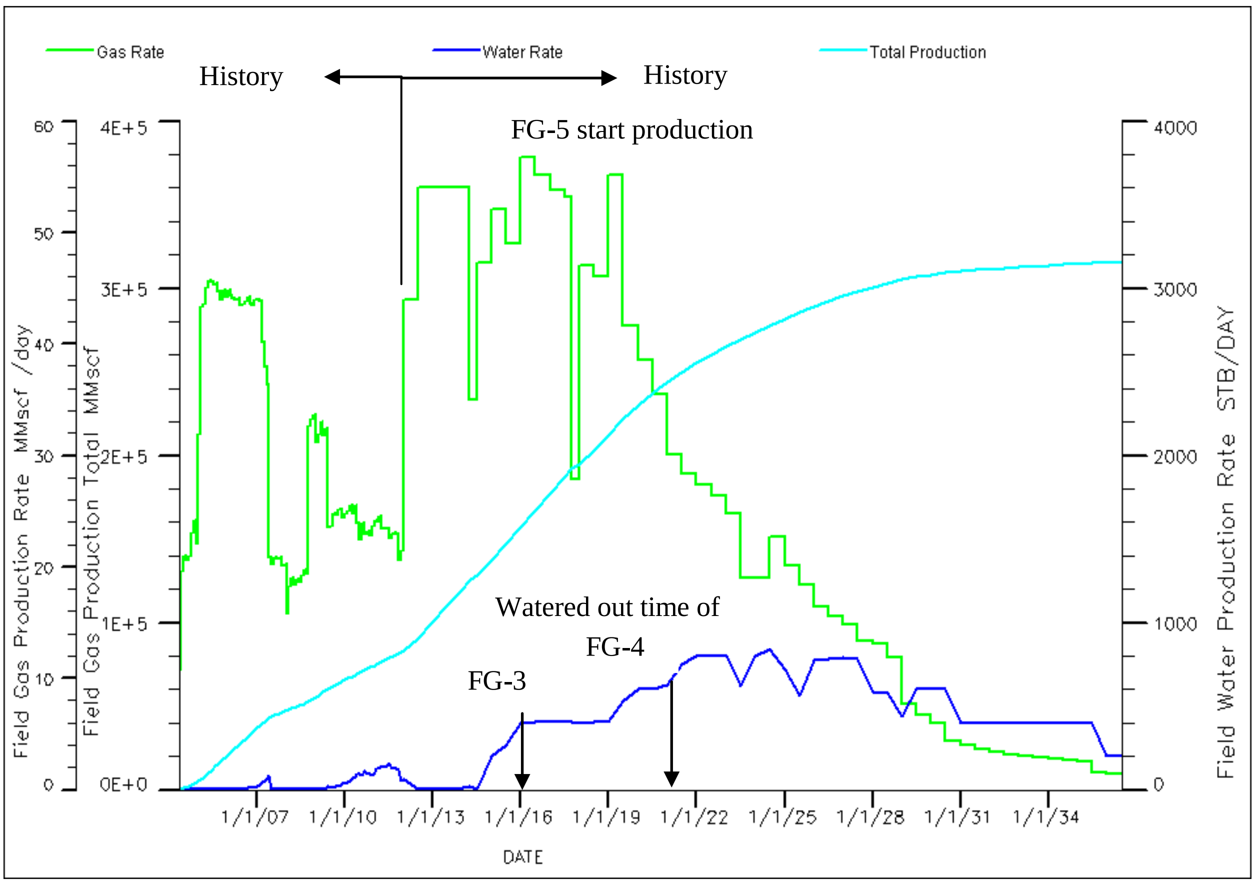

Figure 5.5— Field Production profile of forecast case 5

5.3 Individual Well performance with other considerations

Forecast case 5 was found to be most beneficial. Therefore, it is discussed in more detailed by mentioning the individual well performance separately in the following sections. Also well location, water movement, saturation change, impact of abandonment pressure on recovery, etc., are discussed in later sections.

5.3.1 Individual well performance

FG-2L is completed in LGS by workover of FG-2 which started production from May 2009. After sand and water production by FG-2L, lower perforation (2777 – 2779 m) was plugged off to continue production. The upper perforation (2768 – 2774 m) of FG-2L will be plugged off in October 2012 and workover will be done by side track to one kilometer south (later known as Well-2LW of FG-2). It is found that FG-2LW will produce 20 BSCF more gas if side tracked. Figure 5.6 shows pressure and production profile before and after the workover. Finally FG-2LW will be shut off in July 2024 due to water and gas production constrain though wellhead pressure will be still higher than 1000 psia.

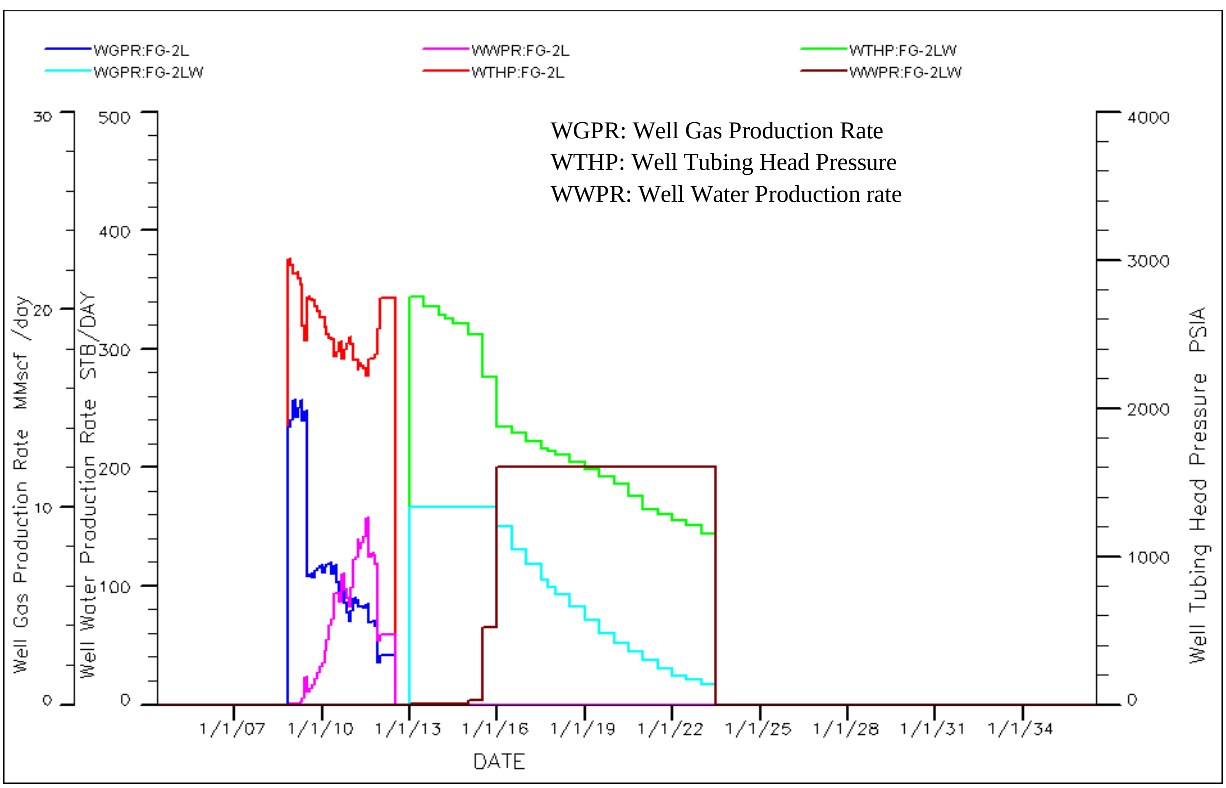

Figure 5.6—Pressure and Production profile for well-2L & FG-2LW (forecast case 5)

In Fig. 5.7, historical production of FG-3 is shown up to December 2011. After that, prediction is shown from January 2012 to June 2014. Later lower perforation of FG-3 will be plugged off to arrest water production and prediction will be restored from September 2014. From January 2016 water break through will occur that is shown by blue sharp peak in graph. After that declining production profile will be shown to maintain 200 bbl/day water production limits. Finally in June 2027 FG-3 will be shut off as it will not able to produce even 1 MMSCFD gas maintaining 200 bbl/day water. Wellhead pressure profile during shut off will be still high about 1900 psia.

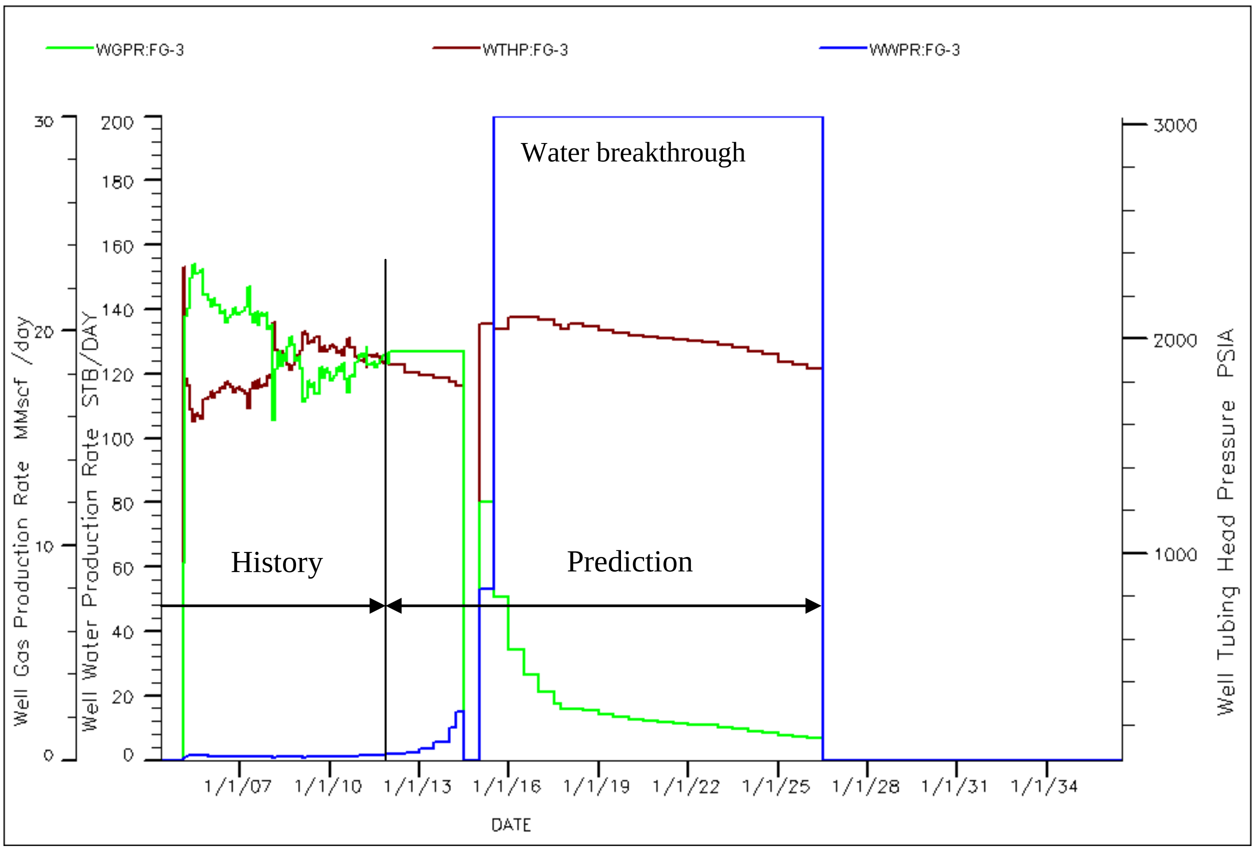

Figure 5.7—Pressure and Production profile of FG-3 (Forecast case 5)

Fig. 5.8 shows the forecast profile of FG-4. It will start producing 25 MMSCFD gas from July 2012. After workover to arrest water production in 2018, 12 MMSCFD gas will be produced and finally in 2021 water breakthrough will occur. Abandonment pressure of the well will be 1500 psia during 2025.

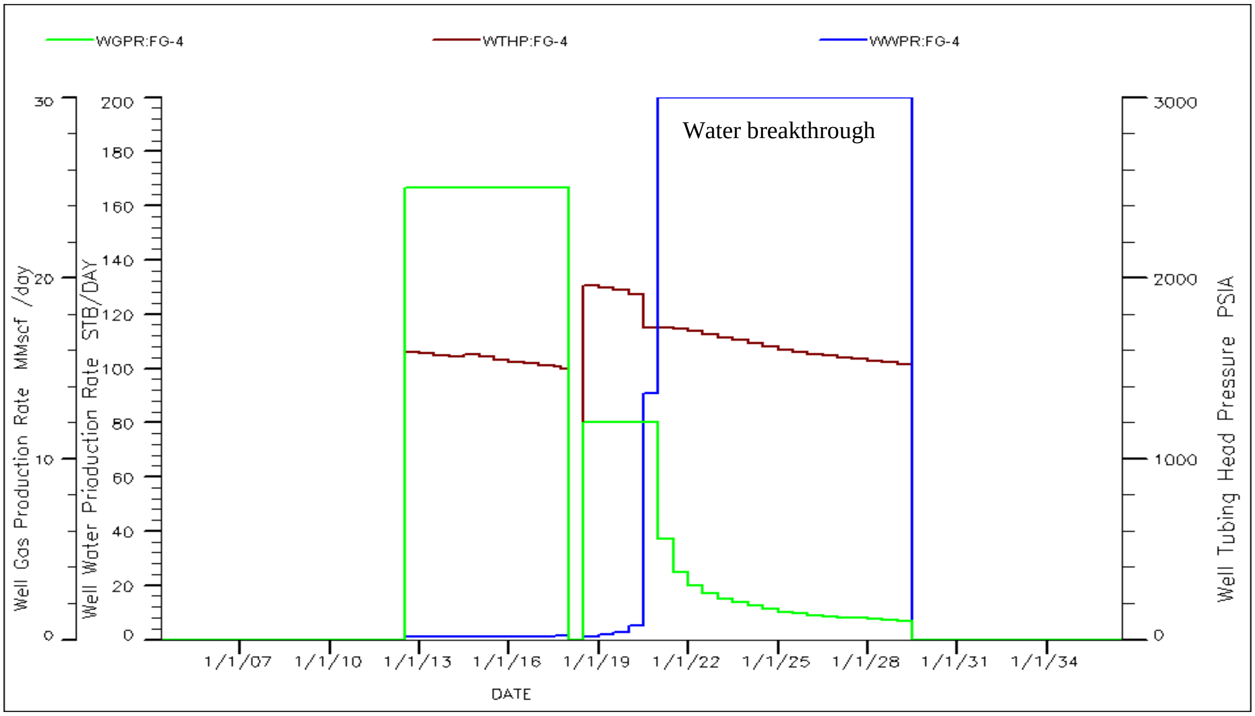

Figure 5.8—Pressure and Production profile of FG-4 (Forecast case 5)

FG-5 will come in production from July 2015 (Fig. 5.9). It will take 10 years to water out if it will maintain10 MMSCFD production rate. However, flowing pressure will be 1200 psia which is quite low compared to other wells.

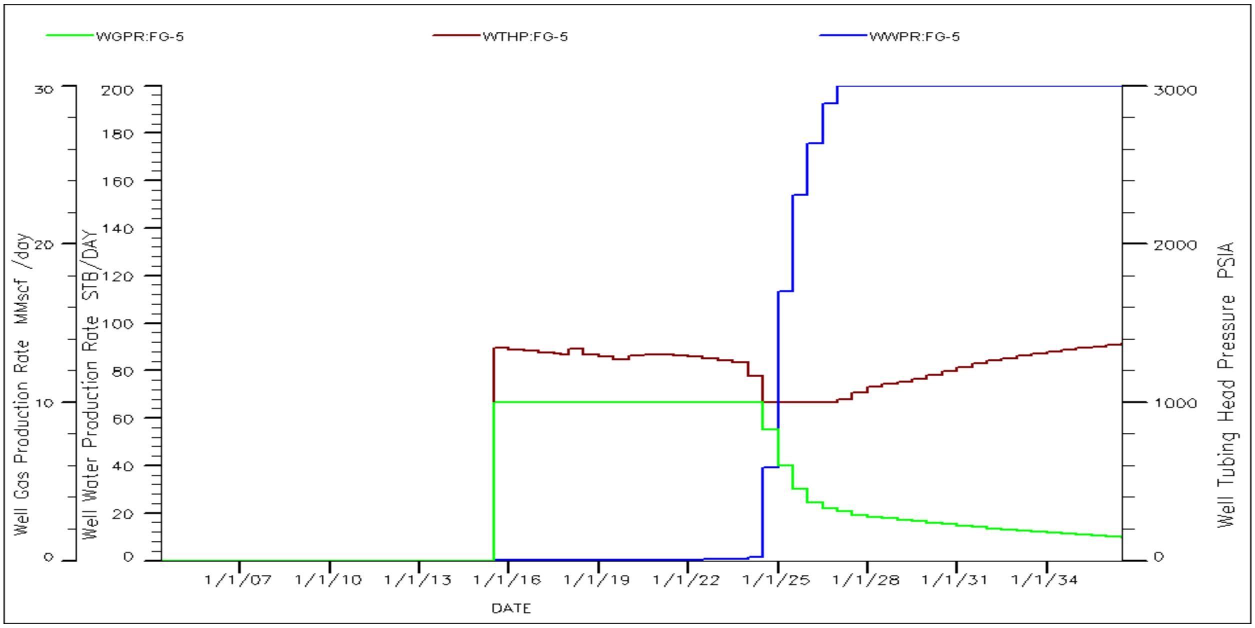

Figure 5.9—Pressure and Production profile of FG-5 (Forecast case 5)

Figure 5.10 shows prediction profile for the directional well (FG-6). Its location is in between FG-2 and FG-3 and it will cover the UGS (denoted FG-6U when it will be perforated in this sand), MGS (FG-6M) and LGS (FG-6L). Productivity of the well is not good but it will evacuate the untapped gas before shut off due to water production constrain. Its position is mainly based by considering the saturation and relative location of GWC in MGS and LGS.

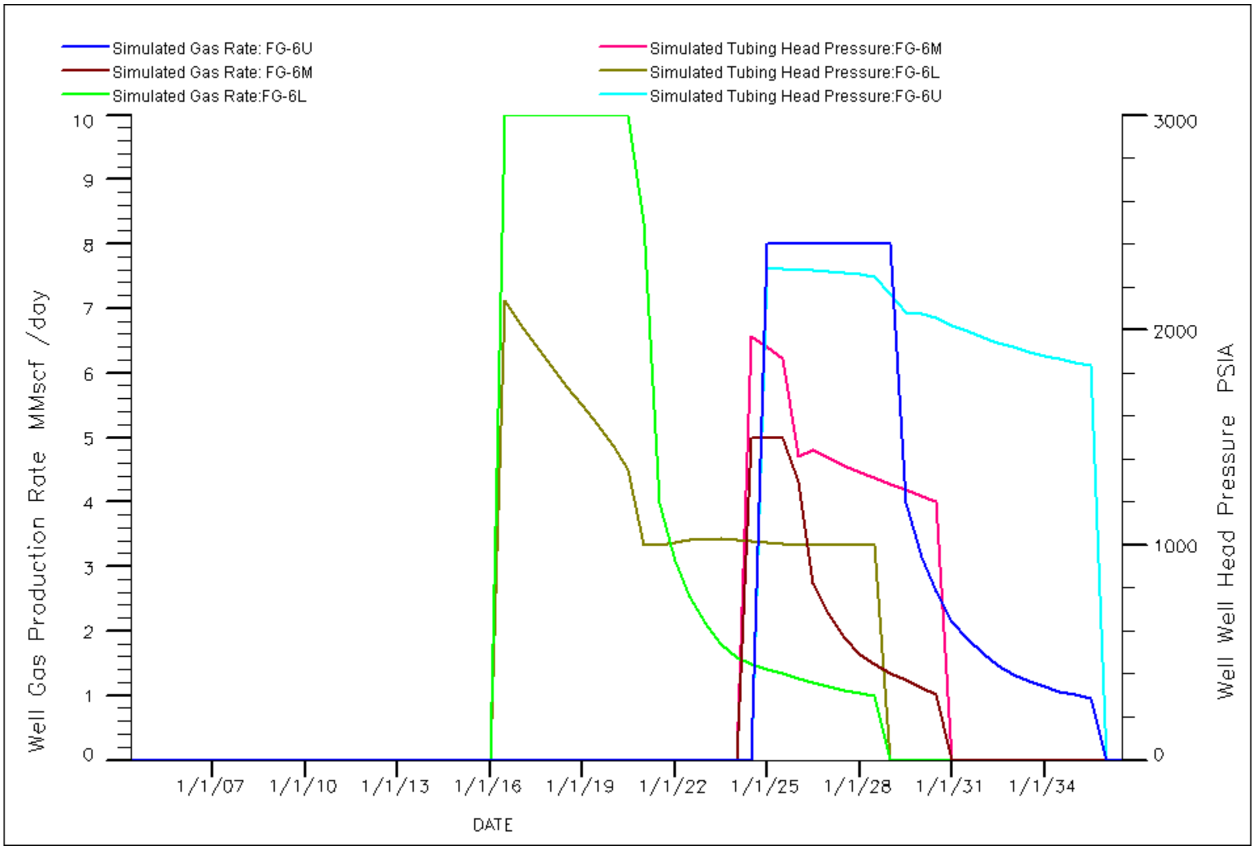

Figure 5.10—Pressure and Production profile of FG-6 (Forecast case 5)

5.4 **Well Location**

Relative well location is shown in Fig. 5.11. The location and trajectory of the directional well, FG-4 is kept the same as recently drilled by BAPEX. FG-5 is to be drilled 1.2 km south from FG-4. It is also in up dip position relative to FG-4. There is also good gas saturation around the well (about 0.3 to 0.4). It will evacuate gas from UGS. FG-6 is to be drilled to the north of FG-2 that will cover all the three sands. Location of FG-6 is chosen by observing the saturation profile and also considering almost one km areal distance from the existing nearby well, FG-2. Relative position of FG-6 is in up dip compared to FG-2.

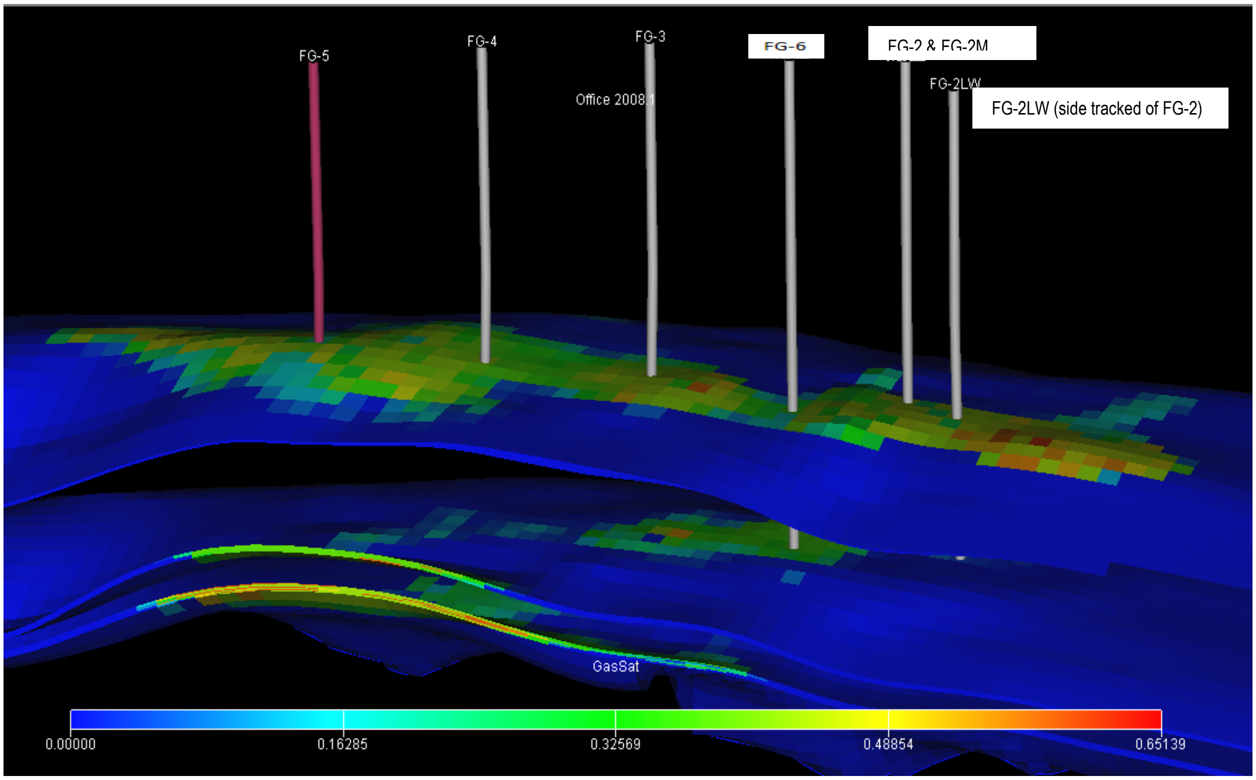

Figure 5.11—Relative location of wells in UGS for forecast case 5

5.5 Gas saturation and Water Movement

Gas saturation of the UGS at the beginning of simulation, after history matching and at the end of simulation is shown in Fig. 5.12. In Fig. 5.12(a), average gas saturation of reservoir area is from 0.30 to 0.60 (greenish to reddish yellow). Outside the reservoir boundary (area covered by blue color) water saturation is the maximum. As gas production continues, gas saturation is decreasing and water saturation is increasing as shown in Fig. 5.12(b) to 5.12(c). Therefore, at the end of simulation in 2036, water saturation would be the maximum in most of the reservoir area (most of the portion will be filled with blue color) as shown in Fig. 5.12(c).

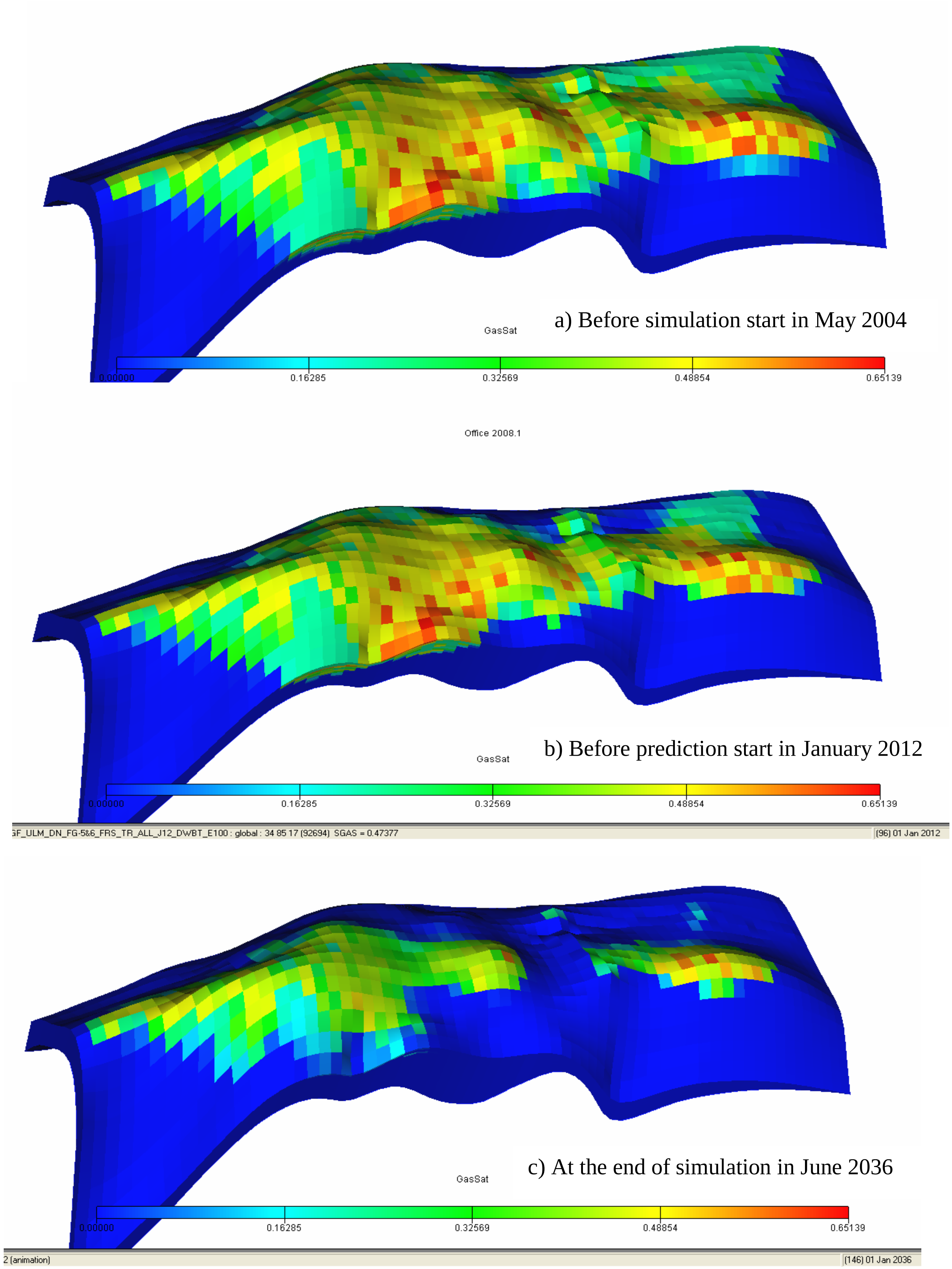

Figure 5.12—Gas saturation of UGS at different time

Last perforation of FG-3 is at 2,045 m in UGS that lies in simulation layer 22. Simulated gas saturation of this layer is shown in Fig. 5.13(a, b, c) at different times. It shows how gas saturation of simulation layer 22 is decreasing. FG-3 will water out around 2016 as per simulated case 5, which is clearly seen in Fig. 5.13(c). It shows the high water saturation (blue color) reaching the lower perforation of FG-3.

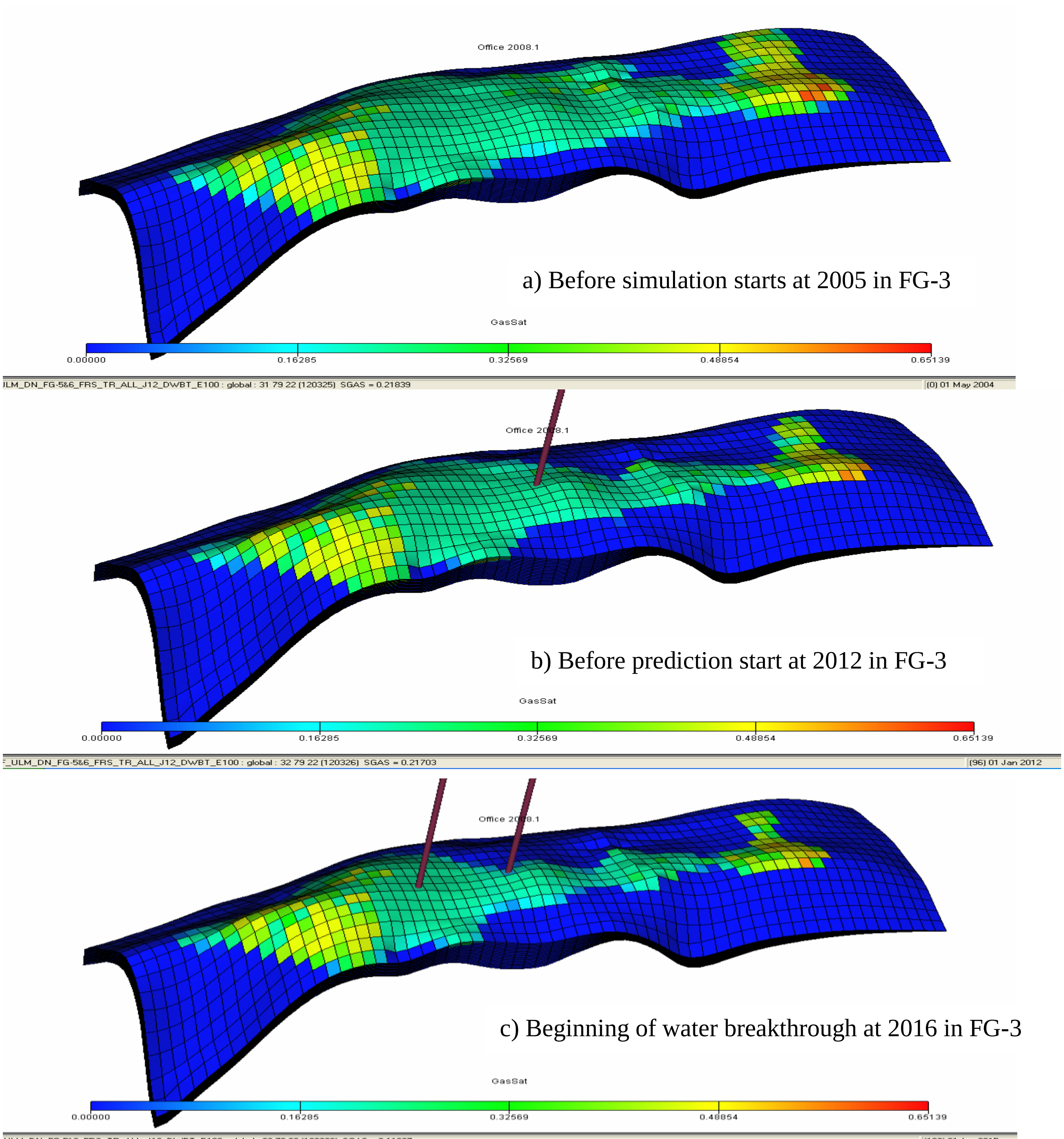

Figure 5.13—Water movement at lower perforation (layer 22 about 2045 m in UGS) of FG-3

5.6 Impact of lowering the wellhead pressure

Fig. 5.14 shows the same scenario as described in Fig 5.5 of forecast case 5. The difference is that this case is run for 500 psia abandonment pressure instead of 1000 psia. Cumulative gas production is found to be 316.20 BSCF at the end of simulation in 2036 whereas, it is found to be 315.60 BSCF for 1000 psia abandonment wellhead pressure (case 5). Incremental gas production is only about 0.60 BSCF, accompanied by large amount of additional water production.

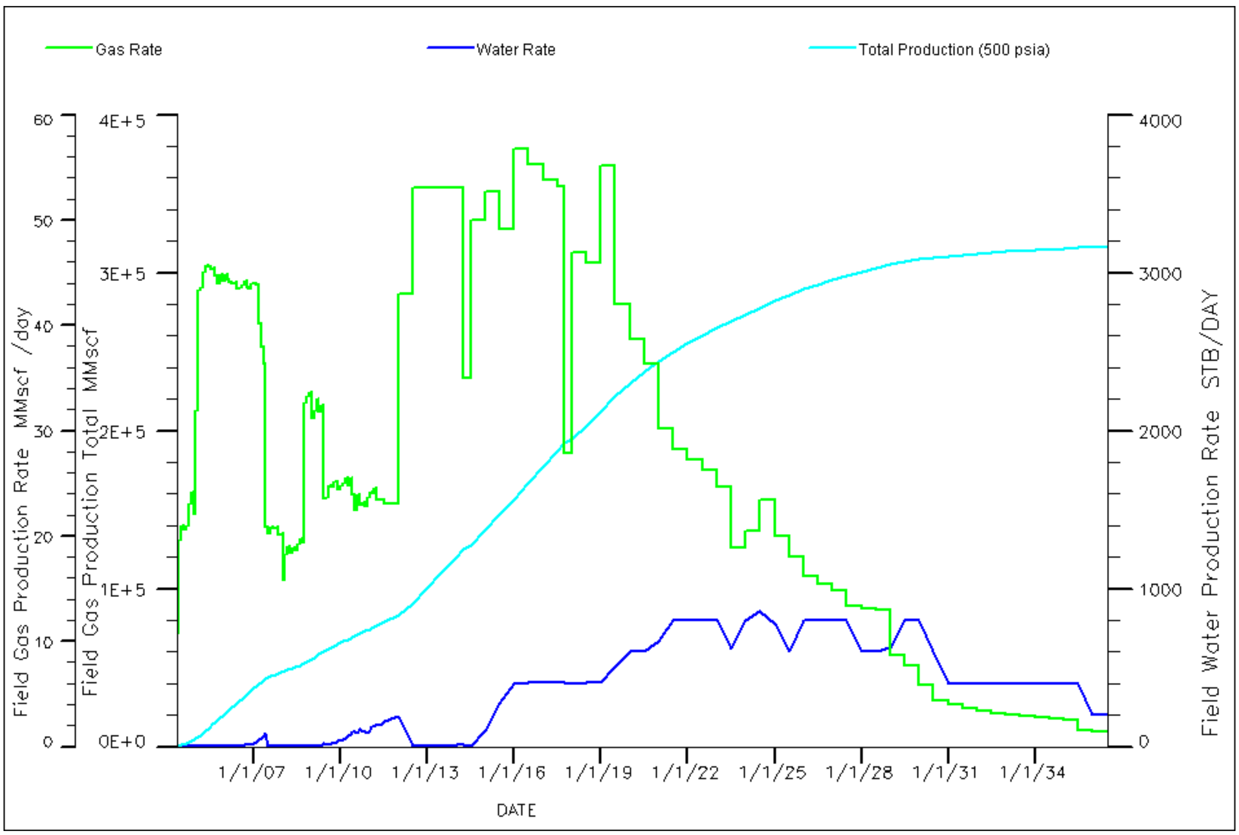

Figure 5.14—Production profile at wellhead pressure 500 psia of Forecast 5

On the other hand, Fig. 5.15 shows comparative cumulative gas production of the field for case 5 under the respective two well head pressures of 500 psia and 1000 psia. Only forecast case 5 is run at the lower wellhead pressure as the other forecast cases show high abandonment pressures. It is clearly shown from the Fig.5.15 that both cases result in almost same recovery (81.75% for 1000 psia and 81.91% for 500 psia abandonment pressure). That means, abandonment pressure have little incremental effect on recovery as the reservoir has strong aquifer support.

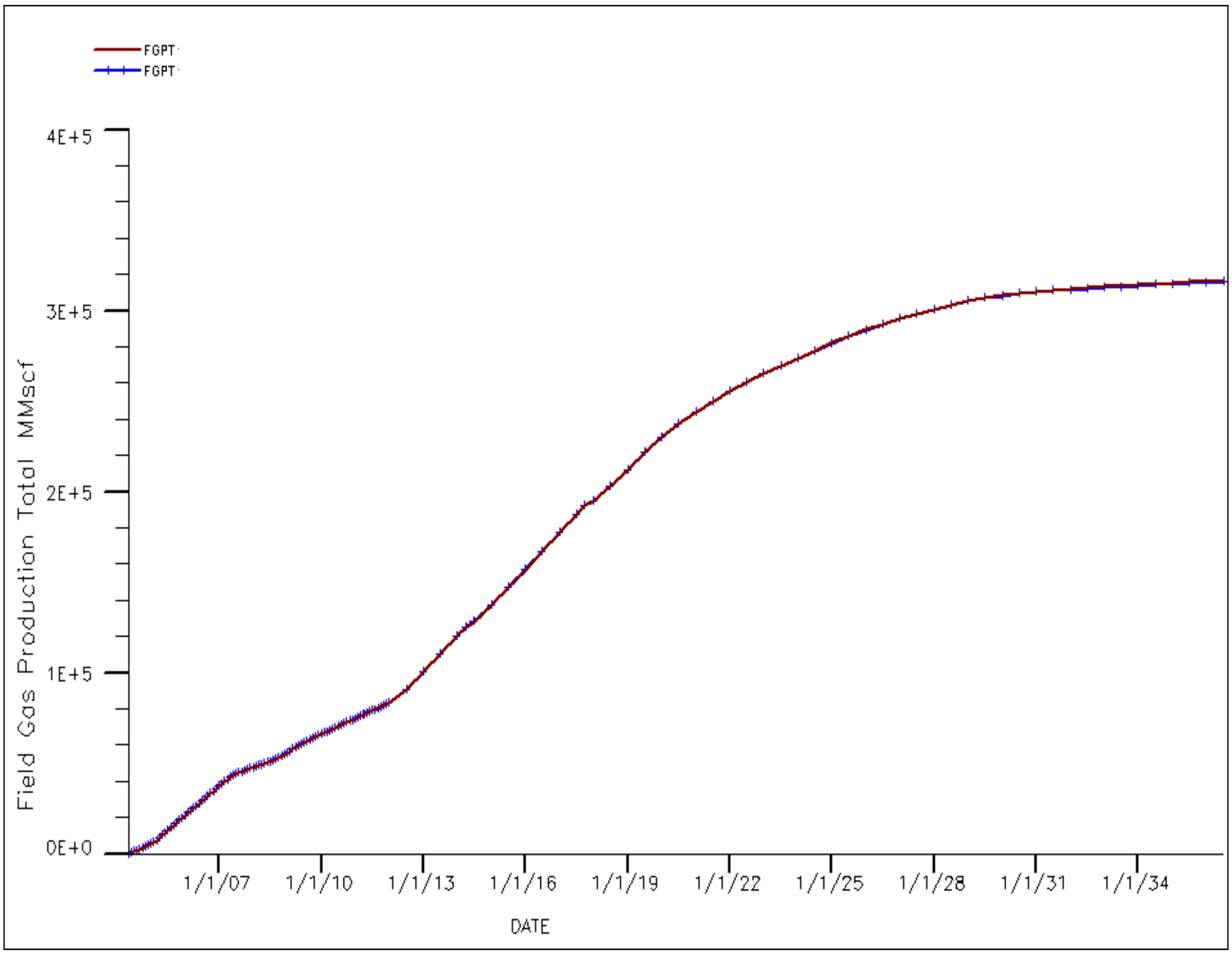

Figure 5.15—Cumulative recovery of forecast 5 at 500 psia and 1000 psia wellhead pressure

5.6 Ultimate Recovery

Fig 5.16 shows the relative Field Gas Production Rate for the five forecast cases. Forecast case 4 will keep field gas production rate more than 40 MMSCFD upto 2015 and then decline will start. Decline will start in forecast case 5 from 2021. Therefore forecast case 5 will give better recovery among the five forecast cases as well as better field gas production rate.

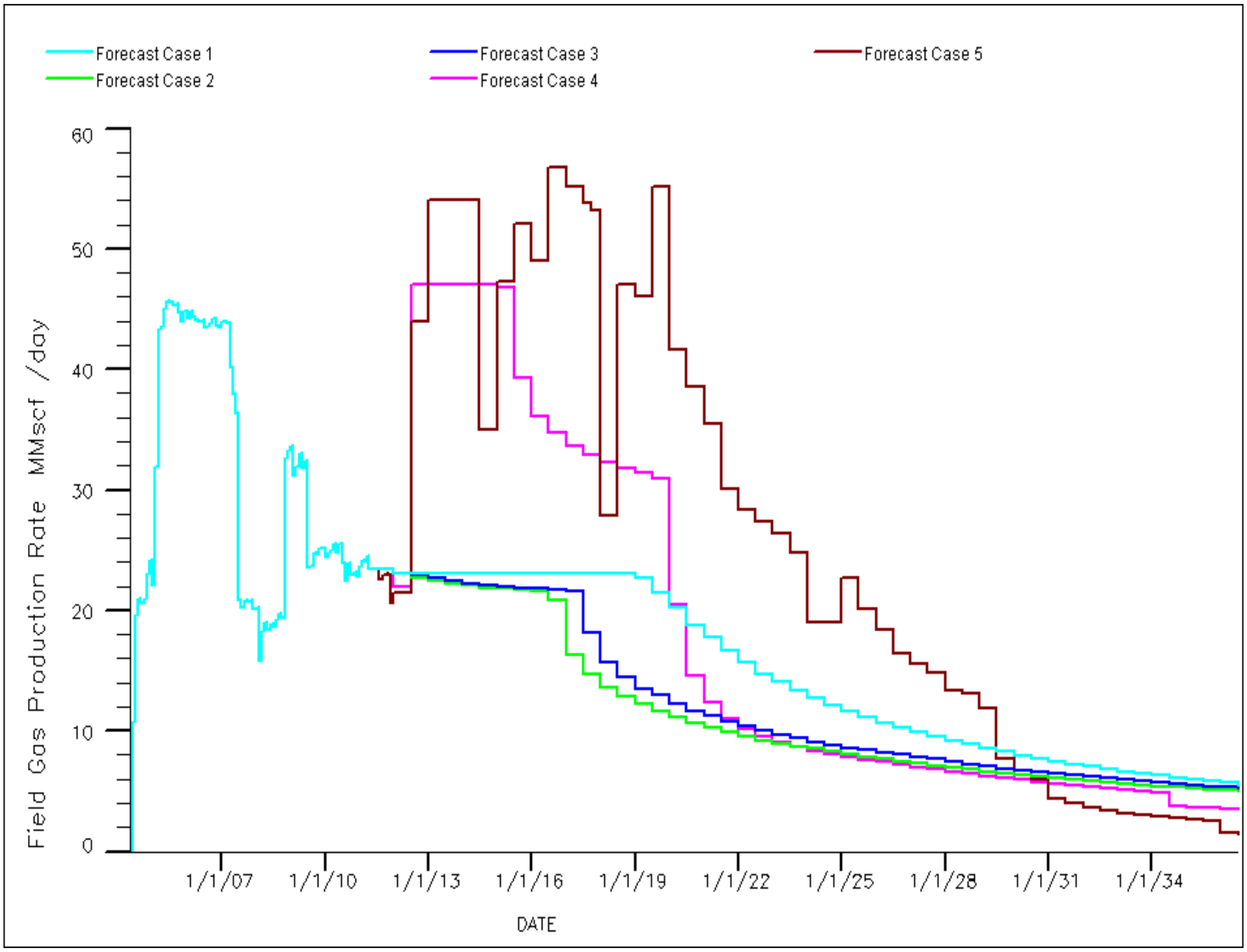

Figure 5.16—Field Gas Production Rate of the five forecast cases

Ultimate recoveries of all the cases are shown in Fig. 5.17 and tabulated in Table 5.1. In history matching section from May 2005 to December 2011, recovery is same for all the cases. Then different recovery curves are found depending on forecast scenarios. In forecast 4, one additional well is drilled that gives 61.49% recovery. However forecast case 5 will give maximum recovery 81.75% of estimated GIIP 386.05 BSCF.

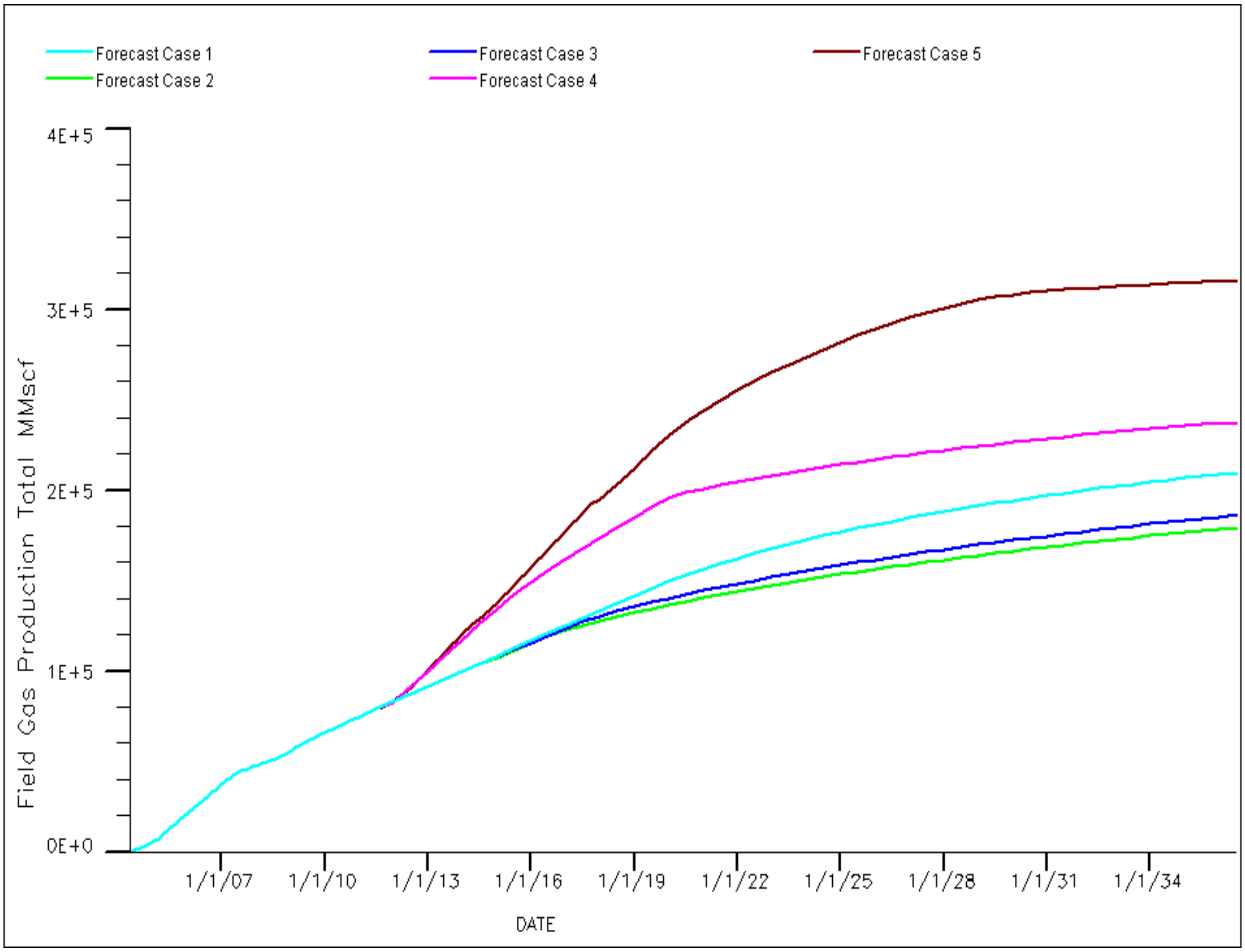

Figure 5.17—Field Gas Production Total of the five forecast

The result from the five forecast cases are tabulated in Table 5.1. Forecast 4 and 5 give the indication that numbers of wells have significant impact on ultimate recovery. In case 5 recovery of the Field, 81.75% seems to be high for water drive reservoir. It is quite reasonable as in the simulation study, total five wells (including existing two wells) are to be drilled in UGS. It increases the recovery percentage. Also development of MGS (with total 25 BSCF produced gas) has good impact to increase the ultimate recovery of 81.75% for forecast case 5. Without developing the MGS, recovery will be 75.28% for similar comparison with forecast case 4.

Table 5.1—Sand wise cumulative gas production and recovery factor for the forecast cases

<table>
<tr><th rowspan="2">Forecast No</th><th rowspan="2">Reservoir Sand</th><th rowspan="2">Completed Well</th><th rowspan="2">Field GIIP (Sand wise) (BSCF)</th><th colspan="2">Cumulative Gas Production (BSCF)</th><th colspan="2">RF (%)</th><th rowspan="2">Aban-donment Pressure (psia)</th></tr>
<tr><th>Sand wise</th><th>Total</th><th>Sand wise</th><th>Total Field</th></tr>
<tr><td rowspan="2">Case 1</td><td>UGS(2)</td><td>FG-2, FG-3</td><td rowspan="11">386.05
(UGS 274.35
MGS 32.93
LGS 78.77)</td><td>166.70</td><td rowspan="2">207.70</td><td>60.76</td><td rowspan="2">53.80</td><td rowspan="11">1000</td></tr>
<tr><td>LGS(1)</td><td>FG-2L</td><td>41.00</td><td>52.05</td></tr>
<tr><td rowspan="2">Case 2</td><td>UGS(2)</td><td>FG-2, FG-3</td><td>145.10</td><td rowspan="2">179.60</td><td>52.89</td><td rowspan="2">46.52</td></tr>
<tr><td>LGS(1)</td><td>FG-2L</td><td>34.50</td><td>43.80</td></tr>
<tr><td rowspan="2">Case 3</td><td>UGS(2)</td><td>FG-2, FG-3</td><td>151.90</td><td rowspan="2">186.80</td><td>55.37</td><td rowspan="2">48.39</td></tr>
<tr><td>LGS(1)</td><td>FG-2L</td><td>34.90</td><td>44.31</td></tr>
<tr><td rowspan="2">Case 4</td><td>UGS(3)</td><td>FG-2, FG-3,</td><td>202.50</td><td rowspan="2">237.40</td><td>73.81</td><td rowspan="2">61.49</td></tr>
<tr><td>LGS(2)</td><td>FG-4, FG-2L</td><td>34.90</td><td>44.31</td></tr>
<tr><td rowspan="3">Case 5</td><td>UGS(5)</td><td>FG-2, FG-3, FG-4, FG-5, FG-6U</td><td>235.50</td><td rowspan="3">315.60</td><td>85.84</td><td rowspan="3">81.75</td></tr>
<tr><td>MGS(2)</td><td>FG-2M, FG-6M</td><td>25.00</td><td>75.92</td></tr>
<tr><td>LGS(3)</td><td>FG-2L, FG-2LW, FG-6L</td><td>55.10</td><td>69.95</td></tr>
</table>

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

In absence of special core analysis data, Corey's correlation was used to generate the relative permeability curves for this study. There was no bottom hole pressure data. Wellhead pressure data of the wells together with the wellbore diagrams were used to tune the multiphase flow correlation to obtain bottom hole pressures. Then, various wellhead pressures as well as possible production rates were used to generate the vertical flowing performance curves.

In this study, geological model was updated as the previous model did not support the historical production and pressure data. Seismic and log data with reservoir performance were correlated to revise the geological model. Later, this updated geological model was imported in Eclipse to generate the simulation model. Updated model estimated GIIP was found to be 386.05 BSCF considering the three sands tested (UGS, MGS and LGS), which is about to be 64 BSCF less than the previously estimated GIIP. Water allocation was also revised. A better history matching was achieved using the updated information. The revised model adopted in this study yields more reliable prediction.

Water breakthrough in FG-2 was also investigated. Strong pressure support from aquifer for UGS was identified. Similar types of pressure support for MGS and LGS could not be found. Wellhead pressures for all of the producing wells were set at 1000 psia, as changing the minimum wellhead pressure to 500 psia showed a very little incremental effect on recovery.

Based on the current model, a recovery factor of 46.52% (forecast 2) is achievable using the existing wells and water production constrains limit of 200 bbl/day after a 25 years prediction period. Recovery factor could be increased to 81.75% (with recoverable gas of 315.60 BSCF out of GIIP to be 386.05 BSCF) by drilling additional three new development wells and performing workover to the existing wells.

6.1 Comparison with the previous Simulation study

1. RPS generated geological model was not correct as it does not support the historical production and pressure data.
2. Actually FG-2 was first completed in UGS in 2004. In RPS report, however, FG-2 was shown completed in the LGS with incorrect gas production rates. This was also corrected in this study.
3. In the RPS report, water production was wrongly allocated to both wells. Water allocations in both wells were also revised in this study.
4. GIIP is found 386.05 BCF in this study whereas it was estimated to 450 BCF in RPS report.

6.2 Conclusions

The following conclusions can be made from the study.

1. Revised geological model yields better match with actual history. Therefore, forecasts based on the updated model give more confidence. Revised model estimated GIIP is 386.05 BSCF.
2. Additional infill wells have significant impact on recovery. Three additional wells will increase the overall field recovery factor to 81.75%.
3. Development of the MGS would yield 25 BSCF gas, with 69.95% recovery for that sand.
4. To evacuate the untapped gas from LGS, FG-2 (currently shut in) should be side tracked to 1 km south. It will produce 23 BSCF more gas.
5. Reservoir has strong pressure support in the UGS that give clear indication of water drive mechanism for the upper gas sand which is also corroborated by sudden increase of water production in different wells.
6. Water breakthrough of FG-3 will occur near 2016 if FG-4 is put under production from UGS as shown in forecast 5 from 2012. Moreover, for FG-4, water breakthrough will occur after 2021.
7. Lowering of Well Head Pressure shows very little incremental effect on recovery due to strong aquifer support.

8. FG-2 watered out within a relatively short production life due to its location in the flank position of UGS, which is close to the water table.

6.3 Recommendations

1. Saturation log should be run to determine GWC movement and to identify water breakthrough in FG-3.
2. FG-4 is producing gas from newly found gas sand below UGS since February 2012. FG-4 should be put in production from UGS as early as possible.
3. There should be an integrated program for proper testing and bottom hole pressure surveys on a periodic manner. That will help to characterize the reservoir, model it accurately for updating reserves and diagnose any problem easily.
4. In case of drilling new wells, core samples should be taken for core analysis.
5. To carry out 3D seismic survey in this field not only in these existing wells but also behind the fault to confirm the extent of reservoir continuity. It will also delineate the reservoir margin and give an updated structural map. That will give scope to rebuild the geological model with these new sands (found in FG-4) for carrying out a comprehensive full field analysis.

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APPENDIX-A

Volumetric Depletion Area Calculation for FG-2L to find the reason of water out

Gas Production from FG-2L (denoted as FG-2L after workover operation of FG-2) started from 10.10.2008 with an average gas rate of 14.50 (±0.5) MMSCFD. Just after six month, WGR increased three times from original WGR of 0.7 after producing 2.65 BSCF gas which is shown in Fig. 6.1

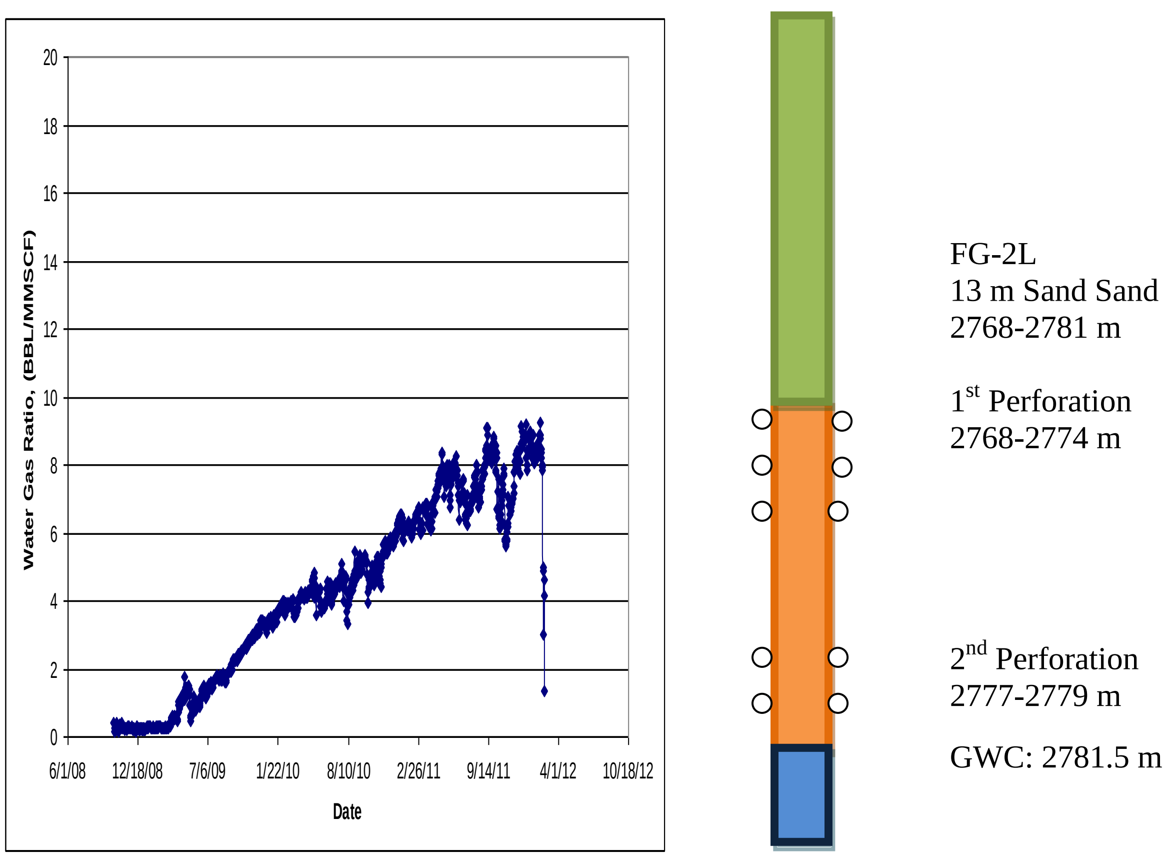

Figure A.1—Water gas ratio of FG-2L that started to increase just after six month and with schematic completion

This volumetric calculation is done as like BAPEX report [2]. All data used by that report is also used here. As perforation is made just above 2.5 m of GWC, volume of gas that occupied by that portion is calculated and found to be 2.67 BSCF (shown in Table A.2). On the other hand cumulative produced gas by the well in first six month is 2.65 BSCF. Both are very close to each other. Therefore, after depleting the gas, water started to come from that water zone. As the sand is loose formation type, sands also started to come with water.

For Volumetric Estimation

GIIP = Area(sq km)X Avg Eff. Thickness(m)X1E6X35.3147XPorosityXGas SaturationX1/Bg

Recoverable Reserve =GIIPX0.7

Table A.2—Volumetric GIIP calculation for LGS and 2.5 m of LGS

Zone	Gross Thickness (m)	Area in sq. km	Avg Eff. Thickness (m)	Porosity (%)	Sg(%)	Bg	GIIP BSCF	Recoverable GIIP (BSCF)
LGS	13	2.02	11.77	0.18	0.65	0.00495	19.85	13.89
LGS w	**2.5**	**2.02**	**2.2634615**	**0.18**	**0.65**	**0.00495**	**3.82**	**2.67**