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Simulation of Fenchuganj Gas Field with Different Development Scenarios for Maximizing Recovery

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Abstract

This paper presents the results from simulation study with different development scenarios of Fenchuganj gas field of Bangladesh. It came into production in 2004 with only one well, which watered out after three years. It was then recompleted in a lower zone but soon water cut became too high, forcing a significant reduction in gas rate for sand free production. A second well is in production since 2005. Two more development wells were also under way. The need for simulation study was obvious at this point, which would provide insight to the production behavior, the state of depletion, and the possible effects of the development wells. The first simulation study was carried out in 2009. However, a second study was carried out later, which is the subject matter of this paper. For the second study, the geological model was revised and was validated by history matching. It reproduced the wellhead pressure and water production history of 7 years with reasonable accuracy. Thus reliability of the model was established, and predictive simulation was run for 25 years up to 2036. Five different development scenarios were simulated, which incorporated the existing wells as well as new wells. The results indicated highest recovery of about 81.75%, with six wells draining the three major sands.

Keywords: Reservoir Modelling, Reservoir simulation, History Matching, Production Forecast.

1. Introduction

A number of studies on Fenchuganj gas field indicated the Gas Initially in Place (GIIP) between 400 – 480 BCF (Petrobangla 1988, 2007). These studies primarily focused on reserves, using volumetric method only. There was very limited suggestion on the systematic development of the gas field for maximum recovery. After an interrupted production history since 2005, it became obvious that constructing a reliable geological model and making simulation runs with different development scenarios was necessary for this purpose. The first ever simulation was done in 2009 (RPS 2009). Later the geological model was revised with the help of the experts from Petrobangla and BAPEX, incorporating seismic, log, and core data, as well as knowledge of similar formations in Bangladesh. A reasonably good history match was obtained from the revised model. With this model, predictive simulation was run for 25 years up to June 2036, with five different development scenarios (Asadullah 2012).

Fenchuganj Gas Field is located in the Surma Basin of Bangladesh, about 40 km south of Sylhet. This 30 X 8 km structure was first delineated as a simple un-faulted anticline in 1959. The 1st exploration well FG-1 drilled in 1960 was a dry hole. A 2nd well FG-2 was drilled during 1985-86. It reached up to 4,977 m, and encountered 3 distinct gas zones, namely the Upper, Middle and Lower Gas Sand (UGS, MGS, and LGS). FG-2 was completed in the UGS in 1988, with perforation interval from 2,063m to 2,069m.The 3rd well FG-3 was drilled in 2004 up to a depth of 3,056 m. It encountered 3 more gas sands, designated as New Gas Sands 1, 2 and 3 (NGS-1, NGS-2, and NGS-3) (Petrobangla Well report 1988). The well FG-3 also penetrated the UGS, but entirely missed the MGS and LGS. FG-3 was completed in 2 zones- UGS and NGS-2 with perforation interval from 1,992m to 2,045m.

Although competed in 1988, FG-2 came into production in 2004 with an average rate of 22 MMSCFD. After extracting about 24 BCF of gas over 3 years, it was suspended in 2007 due to excessive water and sand production. It was recompleted in 2008 in the LGS (and henceforth designated as FG-2L), which resulted in 15 MMSCFD gas production initially. However, due to significant increase in water and sand production after June 2010, production rate was reduced to about 6.0 MMSCFD. Two more development wells were planned for this field. As of March 2012, the cumulative production stood at 84 BCF of gas, 67,622 bbl of condensate, and 135,077 bbl of water (Petrobangla 2010). Figure 1 and Table 1 show the sands and wells in Fenchuganj Gas Field.

Table 1: Wells and Sands in Fenchuganj Gas Field

Well	Sands	Depth (meters)	Year of Completion
FG-2	UGS	2062-2082	2004
	MGS	2578-2584	2013
	LGS	2768-2781	2009
FG-3	NGS II	1992-2017	2005
	UGS	2030-2080	2005

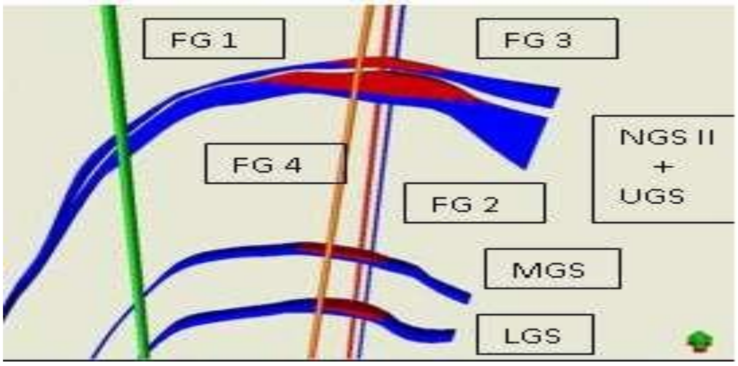

Figure 1: Sand Layers and wells of FGF (Cross Section)

2. History Matching

History matching was performed from May 2004 to December 2011 on pressure, water and condensate production. Some sample results are presented here. Figures 2 and 3 show the pressure match for wells FG-2 and FG-3. Figures 4 and 5 show the water production from wells FG-2 and FG-2L. Table 2 summarizes the history matching results.

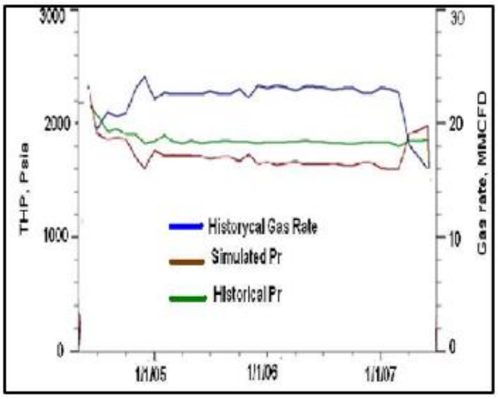

Fig. 2: Well Head Pressure History Match of Well FG-2

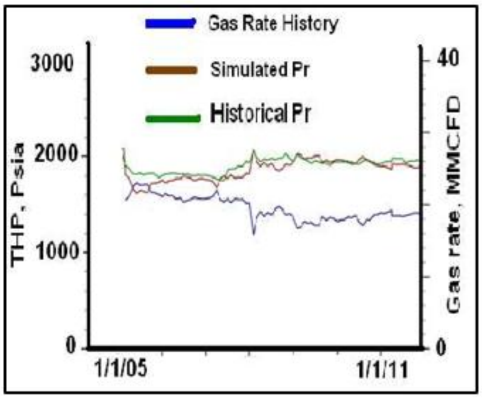

Fig. 3: Head Pressure History Match of Well FG-3

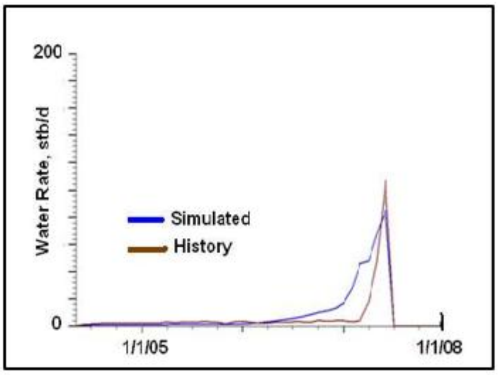

Fig. 4: Water Rate History Match of Well FG-2

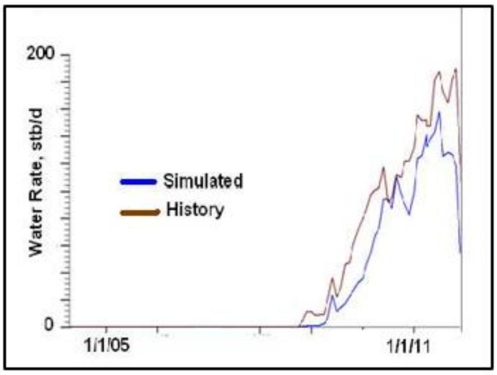

Fig. 5: Water Rate History Match of Well FG-2L

Table 2: Summary of History Matching Results of Fenchuganj Gas Field

Well	Matching parameter	Well	Matching parameter
FG-2	Pressure	Good	Well watered out and Re-completed at lower sand, henceforth called FG-2L
	Water cut	Close	
FG-2L	Pressure	Good	Well was watered out
	Water cut	Close	
FG-3	Pressure	Excellent	Well is producing
	Water cut	Excellent	

3. Predictive Simulation

Once confidence is gained on the reservoir model through satisfactory history matching, predictive simulation is run with the 5 cases discussed next. For all cases, following common parameters and constraints are applied:

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

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

iii. Water Rate: Except for case 1, the maximum water production rate of 200 STB/day per well is used, which is the maximum handling capacity of the field. This is also the rate when sand production begins.

iv. Flowing Wellhead Pressure: It is set to 1,000 psia for all cases considering national grid line pressure. A minimum value of 500 psia was also used to see whether it would increase the life of the producing wells, or increase the ultimate recovery.

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

4. Result and Discussion

Case -1: This is a "do nothing" case, where production with the existing two wells (FG-2L and FG-3). No constraint on water production is applied either. The simulated field production profile is shown in Figure 6. The first peak production of about 45 MMSCFD was sustained for three years. The second peak production of about 35 MMSCFD lasted for seven months only. Then forecasting starts from January 2012, with a steady rate of 24 MMSCFD. Gas rate would be maintained up to 2019, followed by sharp decline. Water production would increase steadily from negligible amount to about 500 bbl/day from 2010 to 2016. Later on, a more drastic increase in water production is likely, which will force early shut in. It will not be feasible to operate this field beyond 2016 with current scenario, unless adequate water handling facilities and sand trapping facilities are added. The cumulative gas production will be 207.70 BCF, with recovery factor of 53.80% at the end of simulation run in 2036.

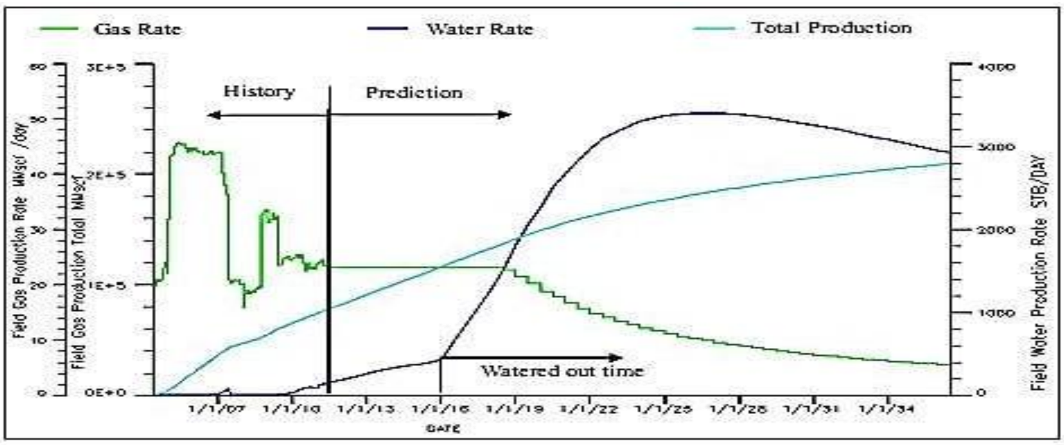

Figure 6: Field production profile for case 1

Case 2: This is similar to case 1, except that the maximum water production is set to 200 bbl/day. Same wells (FG-2L and FG-3) with the same rates and wellhead pressure limit are applied. The simulated production profile is shown in Figure 7. Water production would be doubled to about 400 bbl/day in only six months in 2016. Forecasted gas rate will decrease drastically after 2016 to maintain water production at 200 bbl/day per well. Thus both wells would water out after 2016. Cumulative gas production will be 179.60 BCF with recovery factor of 46.52%. This scenario will not be acceptable considering the less amount of gas production after 2018.

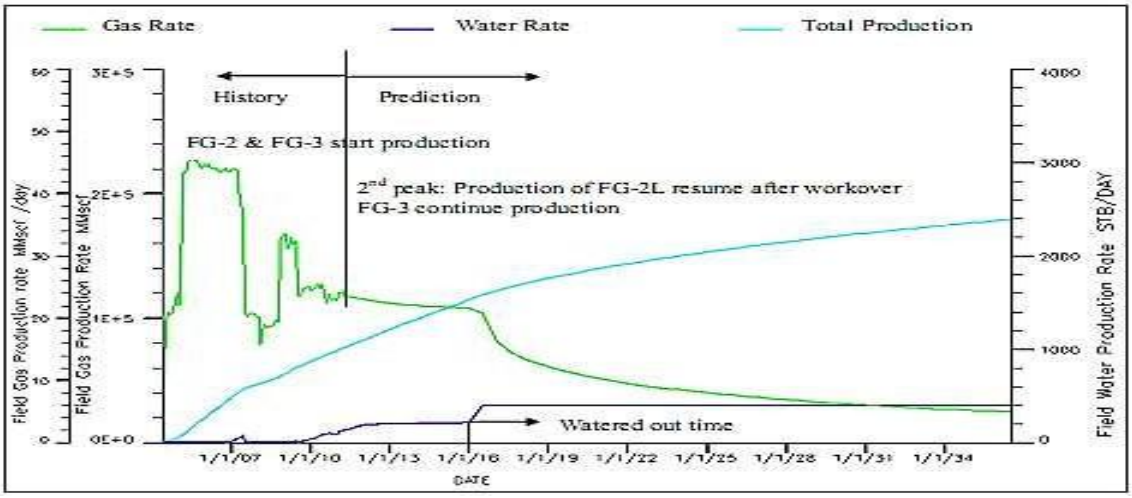

Figure 7: Field production profile for case 2

Case 3: Same conditions of case 2 are applied. Only addition is that the impact of plugging the lower perforation (3 m squeezed off) is investigated. The simulated field production profile is shown in Figure 8. This forecast is quite similar to case 2. However, it shows about 2% increase in recovery. The cumulative gas production will be 186.80 BCF with a recovery factor 48.39%.

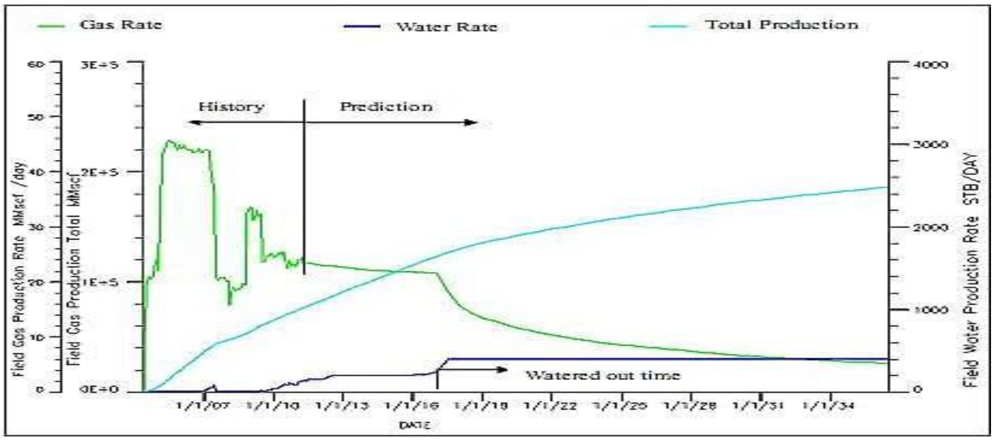

Figure 8: Field production profile for case 3

Case 4: All conditions of case 4 are applied. In addition, one direction well (FG-4) is placed in the UGS on the southern flank (according to BAPEX plan). The simulated field production profile is shown in Figure 9. Forecast is started from January 2012, when FG-4 would come in production with initial gas rate of 25 MMSCFD. It would make total field rate 46 MMSCFD as seen by the third peak in Figure 5. Production rate will decline due to water breakthrough in FG-3 after 2015. Water break through will take place in FG-4 after 2020 to drastically reduce production. However, cumulative gas production will be about 237.40 BCF, with a recovery factor of 61.50%. It indicates that drilling a new well in the UGS will be beneficial, with about 13% increase in recovery over case 3.

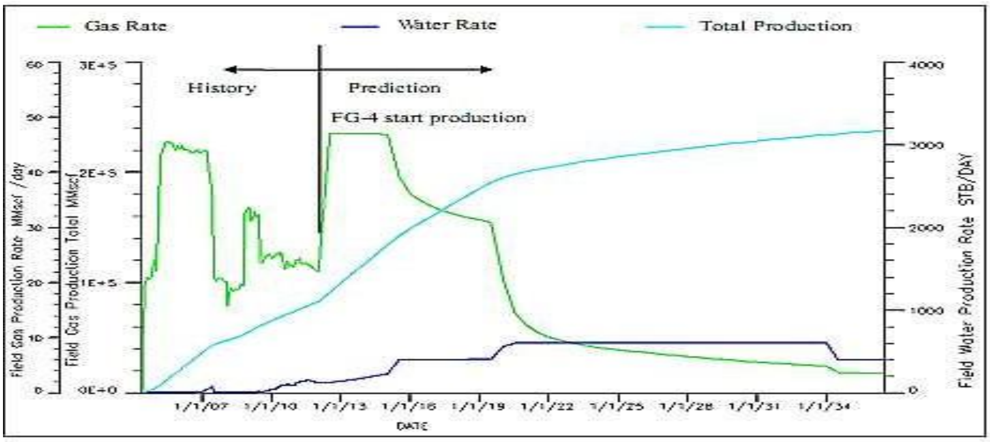

Figure 9: Field production profile for case 4

Case 5: All conditions of case 4 are applied here. In addition, two more wells are added. FG-5, a vertical well is placed in the UGS within 1.2 km from FG-4 on the southern flank. FG-6 is a directional well covering all the three sands on the northern side of FG-2. It will be completed in all three sands; hence the completions are designated as FG-6U, FG-6M, and FG-6L. The simulated field production profile is shown in Figure 10. With the additional two wells, the average field gas production will be maintained above 50 MMSCFD for about eight years, followed by decline after 2021. The cumulative gas production is expected to be about 315.60 BCF, with a recovery factor of 81.75%. This is the best case as it shows highest recovery from the field, and 20% increase in recover over case 4.

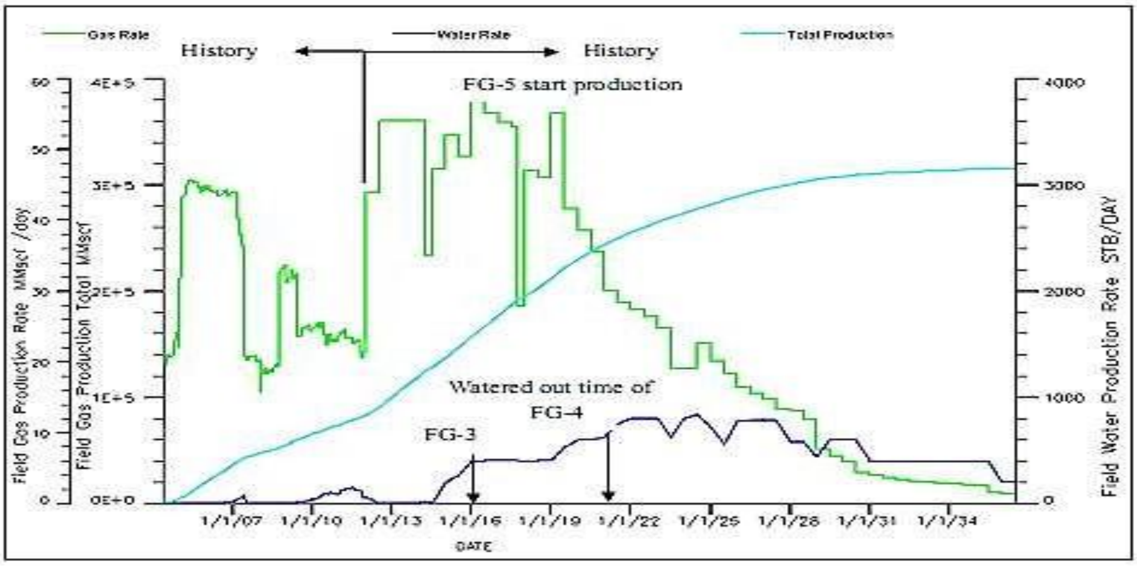

Figure 10: Field production profile for case 5

Ultimate recoveries of all the cases are summarized in Table 3. The graphical comparison of all cases is shown in figure 11. Case 4 and 5 indicates that numbers of wells have significant impact on ultimate recovery. In case 5, recovery of 81.75% seems to be high for water drive reservoir. However, it should be mentioned that MGS and LGS has no strong aquifer support. Two wells will extract the MGS, and three wells will drain the LGS. Thus the high recovery as per case 5 is possible. 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 BCF 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 3: Summary of Predictive Simulation Runs

	Sand (wells)	Well/ completion	GIIP (BCF)	Cum Production (BCF)		RF (%)	
				Sand wise	Total	Sand wise	Total
1	UGS (2)	FG-2, FG-3	274.35	166.70	207.70	60.76	53.80
	LGS (1)	FG-2L	78.77	41.00		52.05	
2	UGS (2)	FG-2, FG-3	274.35	145.10	179.60	52.89	46.52
	LGS (1)	FG-2L	78.77	34.50		43.8	
3	UGS (2)	FG-2, FG-3	274.35	151.90	186.80	55.37	48.39
	LGS (1)	FG-2L	78.77	34.90		44.31	
4	UGS (3)	FG-2, FG-3, FG-4	274.35	202.50	237.40	73.81	61.49
	LGS (1)	FG-2L	78.77	34.90		44.31	
5	UGS (5)	FG-2, FG-3, FG-4, FG-5, FG-6U	274.35	235.50	315.60	85.84	81.75
	MGS (2)	FG-2M, FG-6M	32.93	25.00		75.92	
	LGS (3)	FG-2L, FG-2LW, FG-6L	78.77	55.10		69.95	

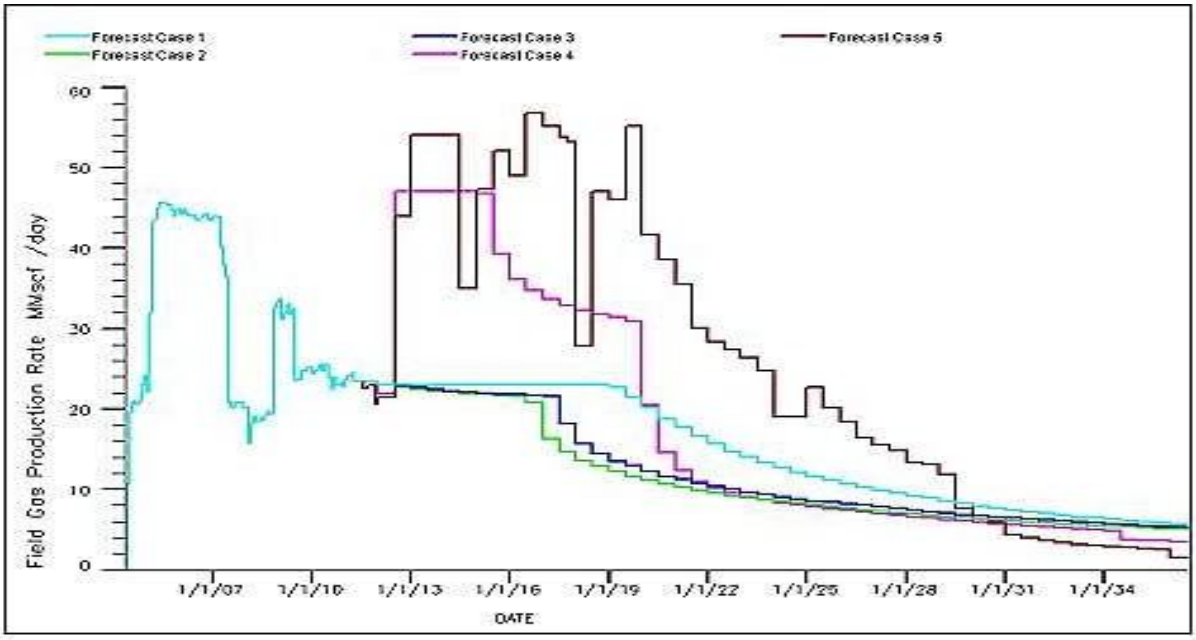

Figure 11: Comparison of the 5 cases

5. Conclusions

A revised geological model of the Fenchuganj Gas Field is obtained and validated through more than 7 years of history matching. Predictive simulation with different scenarios, including a “do nothing” case is conducted for next 25 years up to June 2036. It is seen that additional wells will have positive impact on the recovery of this field. The best case is case 5, where a total of 6 wells are used. These would drain all three sands using 10 completions. The overall recovery under this scenario is 81.75%, or 315.6 BCF of gas. Development of the MGS would yield 25 BCF gas, with 69.95% recovery from that sand. To evacuate the untapped gas from LGS, FG-2 (currently shut in) should be side tracked to 1 km south. It will produce additional 23 BCF. 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.

6. References

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