Numerical Simulation Study of a Gas Well under Bottom Water Drive

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Abstract - *The development strategy of a water drive gas reservoir requires deep understanding of how to maintain the advantage of pressure support caused by the aquifer influx while controlling excessive water production. This simulation study is performed based on the well HBJ-01 of Habiganj Gas Field which is experiencing excessive water production from the early stages of its production. All the previous studies on Habiganj Gas Field indicated the presence of a strong bottom aquifer. The main objectives of this study are to determine the effects of perforation at different locations and production rates for controlling water production from gas well HBJ-01. The simulation model has predicted higher water saturations in near wellbore regions for production from top layers at rates higher than 30 MMSCFD for HBJ-01. Accumulation of water in near wellbore regions is identified as one of the main reasons for excessive water production at the early stages. Water accumulation in the near wellbore regions can be maintained with perforation in mid layers rather than at the top of the pay zone. The effect of different production rates with perforation in mid layers showed that production at lower rates lower than 20 MMSCFD would be the best strategy for controlling excessive water production and maximum recovery from the existing well .*

Key Words: Single well simulation, Cylindrical reservoir model, Water influx, Near wellbore, Perforation Strategies.

1. INTRODUCTION

Recovery from a gas well under water drive depends on the production rate, residual gas saturation, aquifer properties and the volumetric displacement efficiency of water invading the gas reservoir. As aquifer water encroaches towards the reservoir, improper production rate and perforation strategies can sometimes flood near wellbore regions due to excessive pressure drawdown around the wellbore. The Importance of Water Influx in Gas Reservoirs by AGARWAL et al. in 1965 indicated that gas recovery can be increased significantly by controlling the production rate and the manner of production [1][2].

The main uncertainty attached with reserve and recovery from a water drive gas reservoir is that of the areal extent and petrol physical properties of the underlying aquifer are barely found during exploration periods. In full field reservoir simulation study, aquifer properties can be adjusted upon history matching with reservoir pressure and production, yet the near well bore phenomenon remains unpredictable. The objectives of single well simulation include predicting the performance of individual wells, determining the effects of completion/production strategies on gas and water coning and optimizing perforation intervals [3].

The conceptual single well simulation model built for this study is based on the production well HBJ-01 of Habiganj Gas Field located in Bangladesh [4]. All the previous studies on Habiganj gas field indicated the presence of a strong bottom aquifer [5][6]. Only after few years of production, HBJ-01 started to experience huge water production with a water gas ration varied 18-20 STB/MMSCFD. Currently the well is being operated only at 15 MMSCFD to due limited produced water disposal capacity of the process plant of 1000 STB/D. The study reported here represents different rate schedules and completion strategies that can be used to avoid water encroachment in near wellbore regions at early stages of production as well as maximize recovery with minimum water production.

In conventional material balance analysis cumulative water influx is calculated using aquifer fitting with historical reservoir pressure and production data. Methods of calculating cumulative water influx includes the steady state method, the Hurst modified steady-state method and unsteady-state methods such as those of van Everdingen-Hurst and Carter-Tracy [7][8]. Carter-Tracy Water Influx model is used for this study [9].

2. RESEARCH METHODOLOGY

2.1 Simulation Model Description

A black oil reservoir model in cylindrical grid geometries is built with REVEAL reservoir simulator of Petroleum Experts consists of 13×20×7 (x, y, z) grid blocks, as shown in Fig. 1, where x represents the number of radius sectors in the reservoir in which the inner radius is the wellbore radius of 0.345 ft and the outer radius is the drainage radius of 2867 ft [10]. The reservoir model is equally distributed in y direction with a uniform sector angle of 18 degree.

The top of the model is at a depth of 9300 ft. The model includes 7 layers in z direction and each layer has a thickness of 10 ft. In addition, the numerical aquifer (Carter-Tracy model) is built at a depth of 9350 ft in the bottom side of the radial reservoir model.

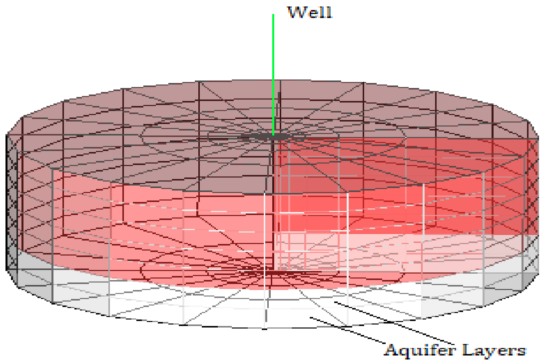

Fig - 1: Reservoir Model.

2.1.1 Reservoir Rock and PVT Properties

The reservoir petro physical data listed in Table 1 is used to fill the array properties section in the simulator. The black oil model is initiated with lean gas comprised of 99.4 % methane and PVT properties are calculated with Lee et al. correlations for input parameters listed in Table 2.

Table 1: Input data for reservoir rock properties [11][12]

Parameter	Value
Reservoir Top	9300 ft
Grid Thickness	10 ft
Porosity	20 Percent
Formation Net Thickness	40 ft
Permeability (I-J-direction)	150 md
Vertical Perm/Horizontal Perm	0.10
Initial Water Saturation	20 %

Table 2: Input Data for PVT Calculations [11][12]

Parameter	Value
Gas Gravity	0.565
Separator Pressure	1000 psig
Condensate to Gas Ratio	1.21 STB/MMscf
Condensate Gravity	40 API
Water Gravity	1.2
Mole Percent H2S	0 Percent
Mole Percent CO2	0.179 Percent
Mole Percent N2	0.397 Percent

2.1.2 Well Model

The vertical lift performance curves are generated using Petroleum Experts 2 correlation with PROSPER production system analysis program of Petroleum Experts [13]. Vertical lift performance (VLP) curves incorporated in the simulation model are generated for a perforation length of 30ft with tubing inside diameters of 4.625 in for different tubing head pressures and water to gas ratios (WGR) and condensate to gas ratios (CGRs). Fig. 2 represents the inflow (IPR) and outflow (VLP) curves at different reservoir and surface conditions.

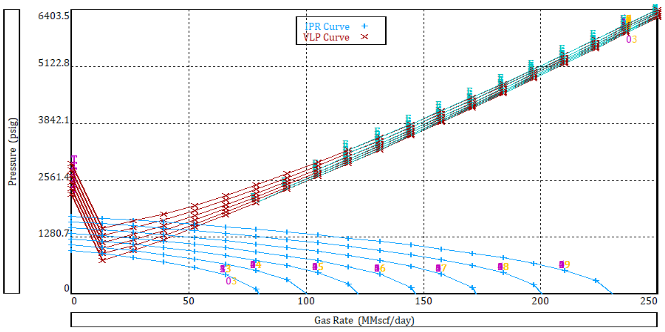

Fig – 2: Inflow (IPR) v Outflow (VLP) Plot.

2.2 History Matching and Model Validation

The simulation model is run with initial condition listed in Table 3. As there are no special core analysis data of Habiganj gas field, the relative permeability curves initially used are based on the assumption [12]. The model is further validated by matching historical wellhead pressures and WGR of the existing well with that of simulator generated results.

Table 3: Initial condition parameters [12]

Parameter	Value
Reference pressure (Initial reservoir pressure)	3515 psi
Reference depth (Mid-perforation depth)	9320 ft
Water Gas Contact (WGC)	9340 ft
Water saturation below WGC	100 Percent

Relative permeability of water is slightly changed to match water movement inside the reservoir [14]. As no actual data for critical water saturation was available, history matched critical saturation value is set at 20%. Aquifer properties presented in Table 4 are obtained as a result of history matching with production and reservoir pressure data.

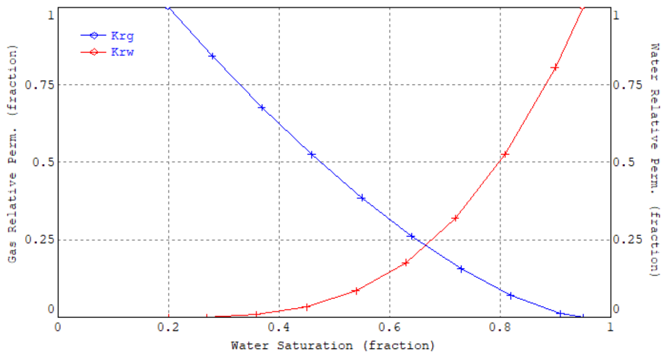

Fig - 3: Relative Permeability Curves.

Table 4: Aquifer Properties

Parameter	Value
Aquifer Model	Infinite Acting (Carter-Tracy model)
Porosity	30 Percent
Permeability	50 md
Thickness	20 ft
Inner Radius	2867 ft
Compressibility	3x10-6 Psi-1
Encroachment Angle	360 Degree

3. RESULTS AND DISCUSSION

After history match and adjustments of different parameters reservoir simulation is run for 4017 for final prediction studies. Results of different parameters are investigated as reservoir average results (Region 2) and near wellbore results (Regions 3). Region 2 is defined as total reservoir drainage area volume from wellbore radius 0.345 ft to the outer radius 2867 ft and Region 3 is defined as the near wellbore region to a distance of 90 ft around the wellbore.

3.1 Near wellbore results

3.1.2 Effect of Perforation Intervals

Initially simulation is run with a 30 ft of perforation in successive vertical layers at three different locations [Layers (1 2 3), (2 3 4) and (3 4 5)] and the well is maintained at a fixed rate of 30 MMSCFD. Changes in water saturations is found highly sensitive upon changing perforation locations in near wellbore regions. Although changes in average water saturation is found nearly same for all three cases but significant changes observed in near wellbore region (Region 3) for perforations location at layers (1 2 3) and (2 3 4). Results of average and near wellbore water and gas saturations are graphically presented in Fig. 4 and 5.

3.1.3 Effect of Production Rate

As the changes of water saturation in near wellbore regions is found less sensitive for perforation at layers (3 4 5), further the simulation is run for three different production rates at 20, 30 and 40 MMSCFD with perforation in layers (3 4 5). Average water saturation changes for all three production rates are found nearly same. But initially slightly higher water saturations resulted in near wellbore region for production rates at 30 and 40 MMSCFD as shown is Fig.5. The rapid changes in wellbore water saturations could be considered as a result of higher aquifer rates in near well bore regions due to higher reservoir pressure drawdown at higher production rates.

Throughout the roduction period of 5843 days, a gradual change of water saturations in the near wellbore regions is observed for production at 20 MMSCFD. In Fig. 6, blue and red lines indicate the aquifer rates and water saturations in near wellbore regions respectively.

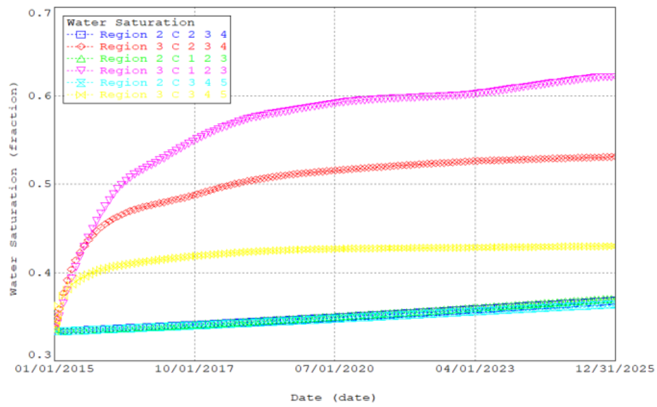

Fig - 4: Results of average and near wellbore water saturation at different perforation intervals.

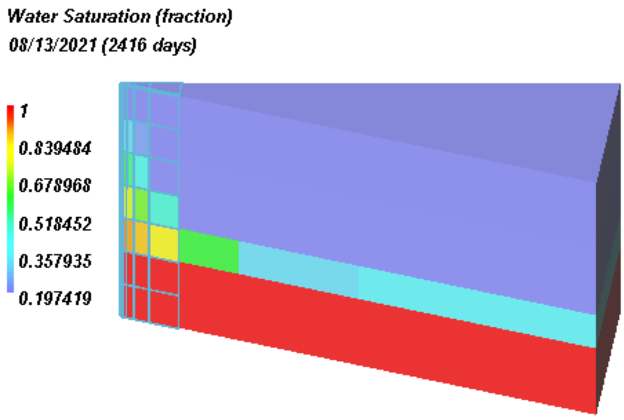

Fig - 5: Results of near wellbore water saturation after 2416 days for perforation at layers (1 2 3).

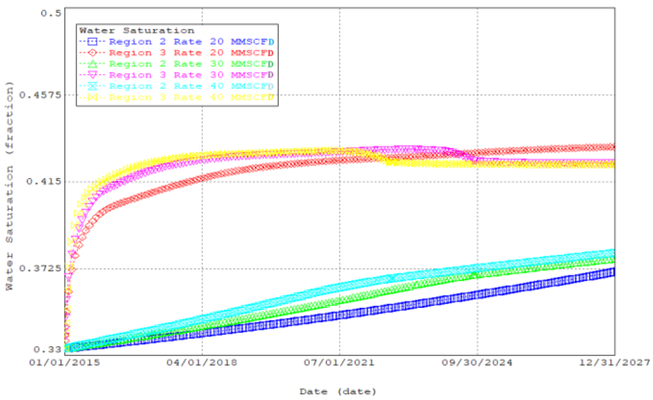

Fig - 6: Results of average and near wellbore water saturation change at different production rates.

Table 4: Recovery and water production at different production rates

Production Rate MMSCFD	Recovery Fraction	Water Production STB/D						
		500 days	1000 Days	1500 Days	2000 Days	3000 days	4000 days	5000 days
20	0.58	337	389	430	468	535	650	775
30	0.50	556	660	736	821	1005	abandoned	
40	0.38	799	958	1100	abandoned			

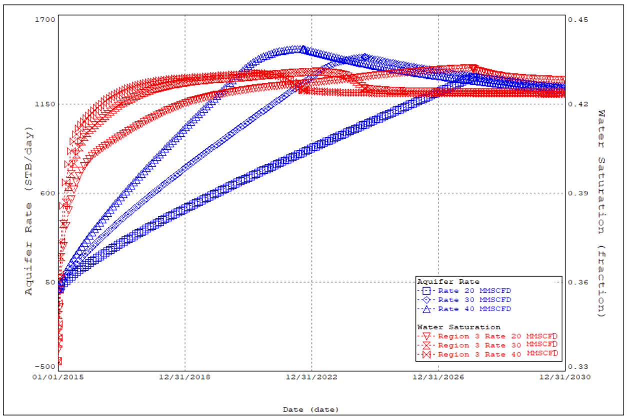

Fig - 7: Near wellbore water saturations and aquifer rates at different production rates.

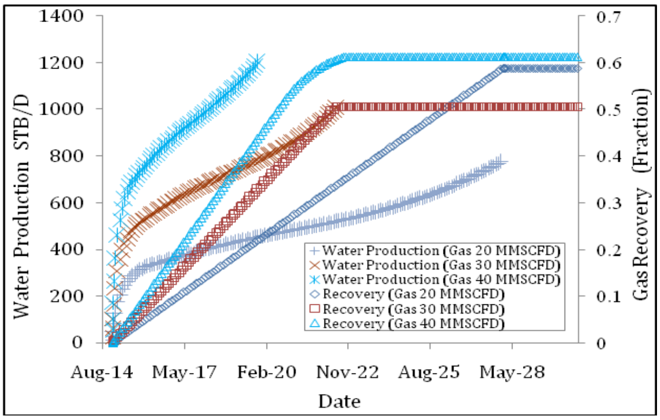

Fig – 8: Recovery and water production scenario for perforation in layer (3 4 5) at different production rates.

3.2 Average Reservoir Results

Based on the near wellbore results, simulation is further run for fixed production rates at 20, 30 and 40 MMSCFD for 30 ft of perforation at layers (3 4 5) with production constarins of maximum allowable water production of 1000 STB/D, minimum flowing tubing head pressure of 1000 psia and minimum gas production of 10 MMSCFD. Results of water production and recovery at different fixed production rates are shwon in Table 5 and Fig. 8.

Producing the Well at 40 MMSCFD, water production rate is found excessively high throughout the production period of 5843 days. After 1500 days, water production exceeds the allowable produced water handing capacity of the facility and the well became abandoned with 38% recovery.

Although initial water production is found higher for gas production maintaining at 30 MMSCFD, a stabilized water cut is observed at late times. The well reached the abandonment condition after 3000 days with 50% recovery.

The maximum recovery is resulted with the production maintaining at 20 MMSCFD and the initial water cut upto 2000 days is found 50% lower than the production at 30 MMSCFD. Water production is remained below the maximum allowable water production throughout the entire production period until the well reached the minimum flowing tubing head pressure of 1000 psia.

4. CONCLUSIONS

At the end of simulation, for the same lengths of perforation and production rate of 30 MMSCFD, water saturation in near wellbore region arises to 0.62 and 0.53 for perforation in top layers (1 2 3) and (2 3 4) respectively. But water saturation only changes to 0.42 for perforation in mid layers (3 4 5). It is observed that water accumulations around the wellbore occurred as results of maximum pressure drop created by perforation in top layers.

For the same lengths of perforation, significant changes in average water saturation is observed for production from the mid layers (3 4 5) at rates higher than 30 MMSCFD. Due excessive amount of water production at late times, only 38-50% of reserved can recover with production rates higher than 20 MMSCFD. At the same time, water production can be maintained below the maximum limit throughout the entire period with production rate at 20 MMSCFD and 58% of the reserve can be recovered.

It can be concluded that the selection of perforation locations is found highly sensitive for accumulation of water in near wellbore regions and producing the well from mid layers at lower rates would be the best strategy for maximum recovery.

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