# RESERVOIR SIMULATION OF HABIGANJ GAS FIELD TO MAXIMIZE ULTIMATE RECOVERY

**A Thesis by**

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# ABSTRACT

Reservoir simulation is the combination of physics, mathematics, reservoir engineering and computer programming that can predict hydrocarbon reservoir performances under various operating conditions. History matching is one of the most important activities during the development and management of petroleum reservoirs. Matched models are fundamental to ensure reliable future forecasts, and give an idea of the level of understanding of the geological and reservoir model.

The specific objective of this study was to select an appropriate production scenario among different alternatives considered for maximum gas recovery at the end of the prediction years. The goal of the study was achieved by calibrating an available PETREL generated geo-model of the reservoir collected from Petrobangla. The simulation model was generated using ECLIPSE 100 black oil simulator and validated by matching the available pressure and production history of different wells of the reservoir. Various parameters like horizontal and vertical permeability, transmissibility, relative permeability of the formation etc were varied to obtain a good pressure and production match. The history matched model was used for predicting production under different development conditions for few additional years.

Water table movement with time was tracked and considered for the placement of additional wells.

Finally, recoveries for different scenarios after the prediction years were compared to get an idea of the best development option among all the alternatives considered for further field development.

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# CHAPTER 1
# INTRODUCTION

Any reservoir study primarily aims to predict the future performance and the ways to enhance the ultimate recovery of a reservoir. Classic reservoir engineering cannot adequately account for the variations in reservoir and fluid parameters and manual approach of solving various equations are monotonous, time consuming and complex. On the other hand, by combining physics, mathematics, reservoir engineering and computer programming, reservoir simulation can predict hydrocarbon reservoir performance under various operating conditions even for extremely complex situation.

Before a simulation study can be used for performance prediction, it is necessary to build a proper reservoir model with available geological, petrophysical, fluid property and well data. After the construction of the reservoir model, it must be tested to determine whether it can duplicate field behavior which is known as history matching.

A hydrocarbon recovery project may involve a capital investment of hundreds of millions of dollars and the risk associated with the selected development plan must be assessed and minimized. That is why reservoir simulation is required for petroleum engineers to obtain accurate performance prediction for a hydrocarbon reservoir under different operating conditions.

The first step of a complete reservoir simulation study starts firstly with setting the objectives for the study and then selecting an adequate approach to fulfill the objectives. The next steps are to select consistent set of input data, careful planning of computer runs and finally analysis of result and report preparation.

Careful investigation of computer generated results is extremely important for a successful simulation study. Simulator generates results based on the provided information but it is the responsibility of the simulator engineer to judge the logical acceptance of the results generated by the simulator.

The potential of simulation was recognized in the late 1940ôs and early 1950ôs by a number of companies. Fundamental research on numerical analysis and development of practical methods for using available computers resulted in crude but useful simulators by the mid 1950ôs. Eventually, simulation became established as an important management tool for most large reservoirs.

The term simulation became common in the early 60ôs, as predictive method evolved into relatively sophisticated computer programs (Coats 1987). These programs represented a major advancement because they allowed solution of large sets of finite difference equation describing two and three dimensional, transient flow in heterogeneous porous media. This advancement was made possible by the rapid evolution of large scale, high speed digital computers and development of numerical methods for solving large systems of finite difference solutions.

During the 1960ôs reservoir simulation efforts were largely devoted to two-phase gas/water or three-phase black-oil reservoir problems. Recovery methods simulated were limited essentially to depletion or pressure maintenance.

During the 1970ôs, sharp rise in oil price, government trends toward deregulation and partial funding to field projects led to a proliferation of enhanced recovery processes. This led to a simulation of processes that extended beyond conventional depletion and pressure maintenance to miscible flooding, chemical flooding, $CO_2$ injection, steam or hot water stimulation, and in situ combustion. In addition to simple multiphase flow in porous media, simulators had to reflect chemical absorption and degradation, emulsifying and interfacial tension reduction effects, reaction kinetics, and other thermal effects and complex equilibrium phase behavior.

Research during 70ôs resulted in many significant advances in simulation model formulations and numerical solution methods. These advances allowed simulation of more complex recovery processes and reduced computing costs through increased stability of the formulations and efficiency of the numerical solution methods.

The reliability of modern simulators and the ready availability of computers indicate that simulation is practical for use on all sizes of reservoir for day to day decision making as well as for planning.

# CHAPTER 2
# OBJECTIVE OF THE STUDY

The Habiganj gas field is the second largest gas field of Bangladesh which is believed to be governed by strong water drive mechanism.

The objectives of this study are to-

- Calibrate the available reservoir geological model of Habiganj gas field using available field and well data.
- History match the model by changing and modifying reservoir and aquifer properties using ECLIPSE 100 black oil simulator.
- Predict the short term and long term future performances and ultimate recoveries of the field under various development and production scenarios.
- Select a scenario among the alternatives that gives maximum recovery at the end of the prediction years.

For any water drive reservoir, the tracking of water table movement is very important. A satisfactory water table movement match can result in more reliable performance prediction for individual wells.

For Habiganj gas reservoir, no successive water table movement data for a particular location was available and water table movement could not be history matched. Another objective of the study was to track the position of water table over time so that the knowledge can be used for further reservoir development.

# CHAPTER 3
# HABIGANJ GAS FIELD

The Habiganj Gas field, operated by Bangladesh Gas Fields Company Limited (BGFCL) is located approximately 75 miles northeast of Dhaka in east-central Bangladesh. The structure is the northern pitching end of the Baramura anticline of the Indian State of Tripura and is separated by a saddle from the higher elevated central part located in Tripura (Intercomp-Kanata Management 1991).

## 3.1 Reservoir Geology

Reservoir is basically divided into two distinct gas zone, the upper gas sand (UGS) and lower gas sand (LGS). UGS constitutes the major producing zone of the field. The reservoir geological description has been summarized according to the Intercomp-Kanata report (Intercomp-Kanata Management 1991).

The Habiganj anticline upper gas sand has a four way dip closure, uninterrupted by any significant faulting. The closure at the gas-water contact level is 11.5 km long and 4.5 km wide. The vertical closure in the dip direction exceeds 2500 feet. Sands are composed dominantly of quartz with some feldspars, micas and heavy minerals. Porosities are in the 30 percent range on an average and maximum permeability is as high as 4.5 Darcy.

Lower gas sand areal and vertical closure was difficult to determine because of the poor seismic data quality. The zone has an average porosity of 19 percent and permeabilities of less than 100 mD.

**Structure and Stratigraphy:** The Habiganj anticline is at the northernmost end of Barmura lineament but it is a closure independent of the northern flank of the Barmura closure. The structure lies on the western margin of the Chittagong-Tripura folded belt in the south central part of the Surma basin. The structure was first mapped by Shell in 1963 with a single fold seismic grid.

The sedimentary sequence encountered during the drilling of the Habiganj structure is as follows (RPS Energy 2009):

- Alluvium- this surface formation is entirely made up of loose sand.
- Dupi Tila/Tipam sand stone- Dupi Tila (2100-3200 m) and Tipam (900-1370 m) sandstone are composed of clear to white, medium to finely grained and poorly sorted loose quartz sand.
- Bokabil Formation- Bokabil (1200-1500 m) formation is composed mainly of sandstone, shale and siltstone
- Bhuban Formation- Bhuban (1800-3200 m) formation is composed mainly of very fine to medium grained, well sorted, sub angular to sub rounded, calcareous sandstone.

Regionally, Habiganj area is a part of Hatia petroleum system that is located in the south of the Tangail-Tripura high. The hydrocarbon source is probably from Miocene Bhuban shales, which have generated primarily natural gas with minimal condensate. Trap type is elongated asymmetrical anticline.

**Field Development:** Pakistan Shell Oil Company (PSO) discovered natural gas reserves with the drilling of the well, Habiganj No.1 (HB-1) in 1963. PSO drilled the second well Habiganj No.2 (HB-2) 90 feet bottomhole location from HB-1 to appraise the upper gas sand in 1963. Both HB-1 and HB-2 were left as suspended wells until final completion operations were undertaken in 1967. Initial production from the Habiganj Gas field started from these wells in February 1969. From 1984 to 2007, nine more wells have been drilled and among these eleven wells nine wells are producing currently. Gas production from HB-8 and HB-9 were ceased due to excessive water production from July 2004 and April 2008 respectively. The summary of the Habiganj gas field development is given in table 3.1.

Table 3.1: List of Wells of Habiganj Gas Field

| Well Name | Well Type | TD (m from KB) | Date spudded | Date completed | Present status | Production started | Production suspended |
|---|---|---|---|---|---|---|---|
| HB-1 | Vertical | 3506 | 24/03/63 | 24/06/63 | Producing | Aug-68 | - |
| HB-2 | Vertical | 5100 | 04/11/67 | 20/11/67 | Producing | Aug-68 | - |
| HB-3 | Vertical | 1610 | 20/07/84 | 20/08/84 | Producing | Jul-85 | - |
| HB-4 | Vertical | 1600 | 14/09/84 | 26/01/85 | Producing | May-85 | - |
| HB-5 | Deviated | 3521 | 25/08/88 | 31/01/89 | Producing | Feb-92 | - |
| HB-6 | Vertical | 5515 | 15/12/89 | 05/01/90 | Producing | Feb-92 | - |
| HB-7 | Vertical | 3120 | 02/03/99 | 02/06/99 | Producing | Apr-00 | - |
| HB-8 | Vertical | 1593 | 31/12/98 | 11/02/99 | Suspended | May-00 | Jul-04 |
| HB-9 | Vertical | 1592 | 29/05/98 | 18/07/98 | Suspended | Jul-98 | Apr-08 |
| HB-10 | Vertical | 1559 | 17/06/99 | 26/08/99 | Producing | Apr-00 | - |
| HB-11 | Vertical | 3200 | 20/08/07 | 05/01/08 | Producing | Jan-08 | - |

## 3.2 Previous Studies on the Reservoir

Several studies on Habiganj gas field were conducted at different times. After the discovery of the field, Shell (Alam 2002) estimated the initial reserve of gas for Upper Gas Sands on the basis of additional seismic data in 1963. Subsequent estimates of reserves were made by Petroconsultant GmbH in 1978, Bangladesh Oil Gas and Mineral Corporation (BOGMC) in 1982 and German Geological Advisory Group in 1984 (Alam 2002). GGAG estimated the recoverable reserve based on the single fold seismic grid data of Shell. DeGolyer and MacNaughton estimated proved and probable reserve (Alam 2002). After the drilling of two additional wells, GGAG and Petrobangla re-estimated the reserve of Habiganj field in 1986 (Alam 2002). Hydrocarbon Habitat Study (HHSP) estimated the reserve of the field in 1986 (Alam 2002). Gasunie estimated the recoverable reserve of Habiganj on 1989 (Alam 2002). Intercomp-Kanata Management (1991) retained by the Canadian International Development Agency (CIDA) evaluated six field initially and later total eight gas fields in Bangladesh for the Gas field Appraisal project of Project Implementation Unit of BOGMC in 1991. Individual reports were prepared on geology, geophysics, petrophysics, facilities and reservoir engineering of Habiganj field, the fifth of the eight fields under appraisal (Alam 2002). Another study was conducted by Well Drill Limited (1991). They estimated upper and lower gas sand reserves and indicated some significant points about reservoir, aquifer and fluid properties. Beicip Franlab-RSC/Petrobangla (2000) estimated Habiganj gas field fluid properties, reservoir temperature at a certain datum depth, compressibility and GIIP using log, core and other test data of ten wells in 2000. Hydrocarbon Unit and Norwegian Petroleum Directorate (HCU/NPD 2001) reviewed Habiganj data, drafted a new depth contour map on top of upper gas sand and re-estimated the volumetric reserve in 2001. RPS Energy (2009) conducted study on a number of gas fields located in Bangladesh Petrobangla in 2009. They prepared geological report, petrophysical report and reservoir simulation study report on Habiganj field under this project. The total reserve estimated by different companies/agencies has been summarized in table 3.2.

Table 3.2: Reserve Estimate by Different Companies/Agencies

| **Estimating Company/Agency** | **Estimated Reserves in TCF** | **Estimating Year** |
|---|---|---|
| Pakistan Shell Oil Company | 1.75 | 1963 |
| Petroconsultant GmbH | 3.475 (GIIP) | 1979 |
| BOGMC | 1.275 (Proven + Probable)<br>1.045 (Possible) | 1982 |
| GGAG | 1.437 (Recoverable) | 1984 |
| DeGolyer and MacNaughton | 1.704 | |
| GGAG and Petrobangla | 3.298 (GIIP) | 1986 |
| HHSP | 2.985 (Proven + Probable) | 1986 |
| Gasunie | 2.60 (Recoverable) | 1983 |
| IKM | 3.669(GIIP, Volumetric estimate) | 1991 |

| Estimating Company/Agency | Estimated Reserves in TCF | Estimating Year |
|---|---|---|
| | 10.5 (GIIP, P/Z estimate) | |
| Well Drill Limited | 3.6 (GIIP) | 1991 |
| Beicip Franlab RSC / Petrobangla | 4.623 (GIIP) | 2000 |
| HCU/NPD | 5.1 (GIIP, Volumetric estimate)<br>4.69 (GIIP, P/Z estimate) | 2001 |
| RPS Energy | 3.684 (GIIP) | 2009 |

# CHAPTER 4
# LITERATURE REVIEW

Simulation has become an essential part of reservoir study. Literally, simulation means assuming the appearance without the reality. Construction and operation of a model whose behavior assumes the appearance of actual reservoir behavior not only makes the performance prediction easier but also saves time and money. Whereas a field can be produced, only once, at considerable expense, a model can be produced or run many times at low expense over a short period of time. From intuition and judgment of the simulation engineer to complex mathematical model, various tools are required for a successful simulation study.

This chapter gives a brief overview of simulation technique, simulation steps, simulator types, mathematical and reservoir engineering concepts of simulator construction. Brief description of simulator workflow and the approach of history matching and performance prediction have also been included. The chapter also includes a brief description of ECLIPSE 100 black oil simulator, a successful and widely used commercial simulator which has been used to carry out the simulation part of this study.

## 4.1 Reservoir Simulation

Reservoir simulation is a numerical modeling which can be used to quantify and interpret physical phenomena with the ability to extend these to project future performance.

A typical reservoir simulation study is comprised of following steps (Carlson 2003):

- Geological Review
- Reservoir performance Review
- Data Gathering
- Approach
- Initialization
- History matching
- Predictions
- Report and presentation

Fig 4.1 depicts the major steps involved in the development of a reservoir simulator.

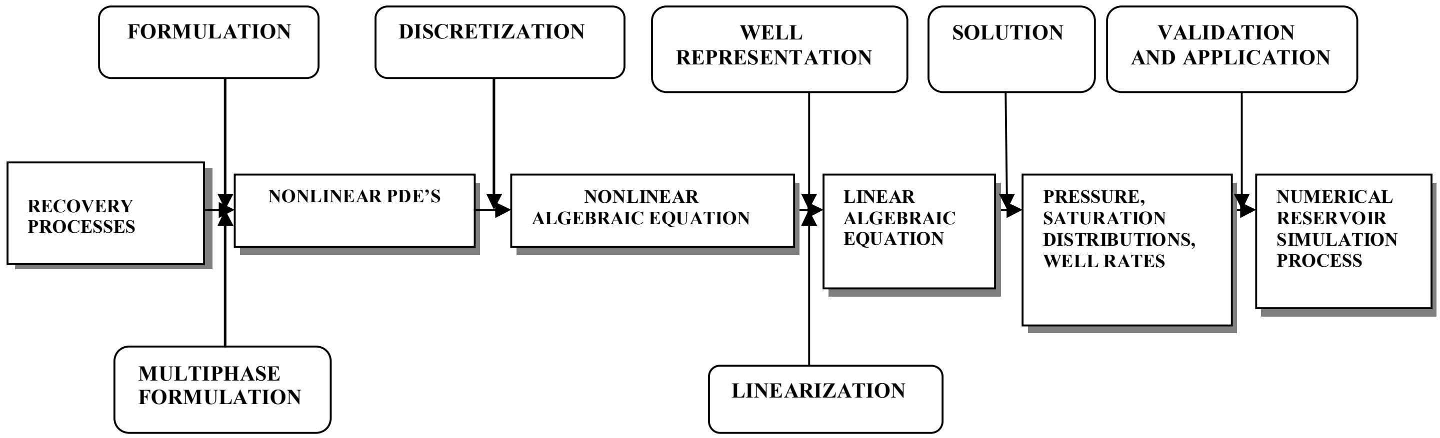


*Fig 4.1: Major steps used to develop reservoir simulator*

### 4.2 Classification of Reservoir Simulator

Reservoir simulators can be classified in several ways ( Ertekin; Abou-Kassem and King 2001).

Based on reservoir/fluid type:

- Black Oil Simulator: These type simulators are used in situations where recovery processes are insensitive to compositional changes in the reservoir fluids. In these simulators mass transfer is assumed to be strictly pressure dependent and fluid properties $B_o$, $B_g$, $R_s$ govern PVT behavior.
- Compositional Simulator: these are used when recovery processes are sensitive to compositional changes in the reservoir fluids. These are generally used to model volatile oil or gas condensate reservoir and multiple contact miscible processes. A cubic equation of state governs the PVT behavior.

Based on Geometry and Dimensionality:

- 1 Dimensional Models: Can be used for application involving laboratory core floods.
- 2 Dimensional Models: 2D models in rectangular coordinates can be used for areal applications or for cross sectional applications. 2D models in cylindrical coordinates can be used for single well coning application.
- 3 Dimensional Models: 3D models can be used for full field application.

Based on Recovery Processes:

- Conventional Recovery Simulators
- Chemical Flood Simulators
- Thermal Recovery Simulators
- Miscible Displacement Simulators

### 4.3 Reservoir Engineering Concepts of Simulation

Understanding basic reservoir engineering concepts for modeling flow problems in porous media is very important. Some of the concepts are discussed in brief below.

- *Fluid Potential:* fluid potential at a point is defined as the work required by a frictionless process to transport a unit mass of fluid from a state of atmospheric pressure and zero elevation (datum elevation) to the point of question. Fluid potential is defined as ʌ = P+ ɔD, where P= pressure, ɔ = gravity and D= datum level.
- *Darcy's Law:* Darcyȏs law is an empirical relationship between fluid flow rate through a porous medium and potential gradient. Q= -Akŭʌ /εŭx Q= fluid flow rate, A= cross sectional area, k= permability, ε= viscosity and ŭʌ /ŭx = fluid potential gradient.
- *Steady and Unsteady State Flow:* steady and unsteady state flow are basic concepts required by practicing engineers. For an incompressible fluid, pressure response is felt instantly with equal intensity at any point in the reservoir. For slightly compressible fluids, pressure shock will be initially absorbed by fluid compression until the fluids can no longer compress. The remainder of the energy

will be transmitted to the next point in space, and so on. Flow problems involving incompressible fluids have solutions that are independent of time and dependent on space only, whereas flow problems involving compressible or slightly compressible fluids have solutions that are dependent both on time and space.

- *Reservoir Rock Properties:* The basic rock properties required to for reservoir simulation are porosity and permeability. The concept of homogeneity, heterogeneity, isotropy and anisotropy are also required to understand the directional dependence of the properties
- *Reservoir fluid Properties:* Fluid properties of interest in reservoir modeling include fluid compressibilities and compressibility factors, solution-gas/liquid ratio, fluid densities, fluid formation volume factors and fluid viscosities.
- *Rock-Fluid Interaction Properties:* Capillary pressure, relative permeability are the properties that arise from the existence of two or more fluid in a pore space. In a two phase system, capillary pressure is, by definition, the pressure of the non wetting phase minus the pressure of the wetting phase. For a given reservoir rock and fluids at a constant temperature and composition, capillary pressure is a function of fluid saturation and saturation history. Relative permeability is the relative measure of the conductance of the medium for a particular fluid at a specific fluid saturation.
- *Law of Conservation of Mass:* Law of conservation of mass is a material balance equation written for a component in a control volume of the system to be modeled. In petroleum reservoirs control volume is made up of a porous medium containing one, two or three fluid phases. Considering a small box depicted in figure 4.2., the equation is developed as follows:

  $In = AM_x$

  $Out = A(M_x+\Delta M_x)$

  $Storage = A\Delta_x(\rho_1\varphi_1 - \rho_2\varphi_2)$

  $Source/Sink = q_x$

  Combining these yields:

  $$A\rho = \frac{1\,1\;\;11\;\;11\;\;111\;\;11}{1\,1} = A\frac{1\,1}{1\,1}\frac{(1_{\,1}1_{\,1}1\,1_{\,1}1_{\,1})}{1\,1} + A\frac{1\,1}{1\,1}$$

In the limit as qpxŸ 0 and qptŸ 0,

$$\frac{1\,1}{1\,1} = \frac{1\,(1\,1\,)}{1\,1} + q$$

An equation of state and transport relation is required to expand this conservation of mass.

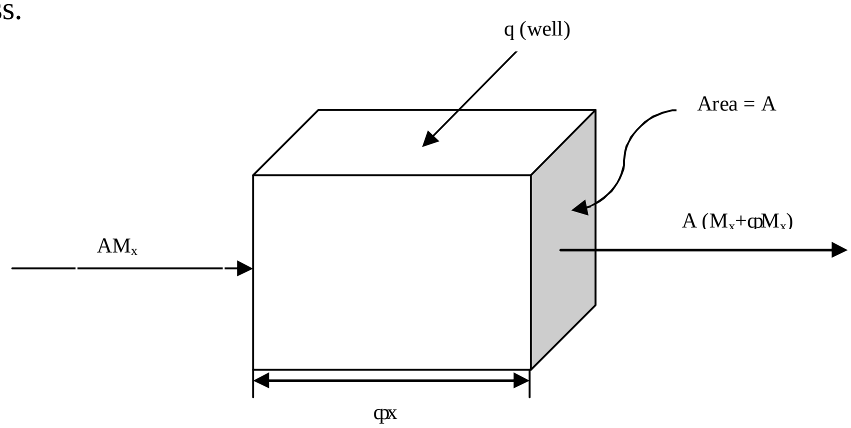


*Fig 4.2: Representative Element*

## 4.4 Mathematics of simulator construction

The mathematical principles required to develop numerical reservoir simulators include basic differential calculus, differential equation theory, numerical analysis, finite difference calculus and linear algebra.

- *Basic Differential Calculus:* Differential calculus forms the mathematical basis for describing recovery processes observed in hydrocarbon reservoir. In many engineering applications additional information such as the rate at which the function changes is also required along with the value of the function to solve a problem. Basic differential calculus deals with the derivatives, higher order derivatives, partial derivatives and the solution.
- *Basic Differential Equation:* differential equations relate an unknown function to the derivatives of the function and, possibly, to a known function. The simplest example of a differential equation is dp/dt = f(p,t), where, p(t) = unknown function and f(p,t) = known function
- *Finite Difference Calculus:* In petroleum reservoir applications, a situation often arises where functional values are known only at discrete points. For discrete

points. Mathematical techniques are also available to approximate values of functions and their derivatives at points where they are not known. Finite difference calculus is such a technique. It uses basic arithmetic operations to approximate derivatives, differential equations and other analytical operations performed on continuous function.

- *Basic Linear Algebra:* it is the branch of mathematics that deals with vectors, matrices and solution of linear equations. Writing the characteristic linearized finite difference equation at every unknown node generates a system of linear algebraic equations.

## 4.5 Workflow of the Simulator

The simulator starts the simulation process with the information primarily available at the beginning of the study. The information those are available at the beginning are as follows-

- *Static Model:*
  - Structure: tops, thickness, layering, faults, boundaries, shales, sands, rock type, depositional environment, grain size distribution, fractures, properties of aquifers
  - Rock properties at all points in the reservoir: These include permeabilities in all directions, porosities, capillary pressure, relative permeabilities
  - Initial reservoir condition: water, oil and gas saturations, pressures at all points in the reservoir, contacts
- *Well Data:*
  - Well locations, trajectory, completions, workover schedule
  - Production rates of oil, water and gas as a function of time,
  - Pressure History of the wells, Bottom hole flowing or tubing head pressure or build up pressures at specific times
  - Injection History- rates, fluids, pressures etc
- *Fluid Data:* PVT experiments with the reservoir fluids, viscosities, densities
- *Material balance of the reservoir history*
- *Reservoir compartments*

- *Reservoir mechanisms*
- *Surface facilities and conditions*

After getting all the initial information, the next step is to create a numerical grid of the reservoir from the static model that includes at all points rock permeability, porosity, relative permeability, capillary pressures, saturations, locations and volumes. Then PVT analysis and characterization of fluid is performed using equation of state and laboratory phase behavior experiments. Analysis of rock types, relative permeabilities, capillary pressure, imbibition and drainage are perfomed by special core analysis and properties are assigned to the grid blocks. The next step is to prepare well data. These include placement of wells in the grid, averaging and assignments of production rates to wells, assigning wells workover, assigning well controls, economic limits and time steppings. If bottom holes flowing pressures of the wells are not known, in that case lift curves must be generated to relate bottomhole pressures to tubing head pressures using well design and production rates. At this point the simulator is ready for the simulation run to be performed.

## 4.6 History Matching with Simulator

History matching is the process of calibrating the model to match the historical production and pressure data with that of simulator generated results. The objective of the history matching is to validate the reservoir simulation model for better understanding of reservoir processes. History matching methods are of two types. They are-

- *Manual History Matching:* Manual history matching involves the identification of the parameters known with most uncertainty and changing those parameters to obtain a good history match. Selection of input data is based on knowledge and experience. Manual history matching is the most widely used method.
- *Automatic History Matching:* these techniques generally use non linear optimization methods to achieve a best or “least squares” fit for the observed data. These procedures seek to minimize an objective function, Q, defined as $Q=\Sigma R_i^2$ where $R_i$ is a residual that may be defined in various ways depending on the data

to be matched. This method excludes human experience and knowledge and thus could produce errors in results.

### 4.7 General Approach of History Matching

The general approach of history matching consists of the following steps (Galas 2003):

- Matching field wide pressure
- Matching saturation dependent parameters (gas/oil/water production) on field wide basis.
- Matching saturation dependent parameters on a regional basis
- Matching saturation dependent parameters on an individual well basis.
- Iterating until match is satisfactory

Whenever field data is not matched, the data set should be examined and input parameters should be adjusted to improve the match, starting with those parameters with the highest uncertainty.

### 4.8 Simulation Approach for History Matching

Many authors have suggested many ways of history matching but not every method is useful for every field. However there are some general rules which can be adopted to start the history matching process. According to Crichlow (1977) there are several parameters which can be varied singly or collectively to minimize the differences between the observed data and those calculated by the simulator. Modifications are made on the following:

- *Rock Data modifications:*
  - Permeability
  - Porosity
  - Thickness
  - Saturations
- *Fluid Data modifications*
  - Compressibilities

- PVT data
- Viscosity

- *Relative Permeability Data*
  - Shift in relative permeability curve
  - Shift in critical saturation data
- *Individual Well Completion Data*
  - Skin effect
  - Bottomhole flowing pressure

Mattax and Dalton (1990) outlined a prioritization and suggested some changes should be rare. According to them, the reservoir and aquifer properties appropriate for alternation, in approximate order of decreasing uncertainty are:

- Aquifer transmissibility, kh
- Aquifer storage
- Reservoir kh (including vertical restrictions and directional variations)
- Relative permeability and capillary pressure function

The following additional properties must sometimes be altered, but they are usually known with acceptable accuracy.

- Reservoir porosity and thickness
- Structural definition
- Rock compressibility
- Reservoir oil and gas properties
- Water/oil and gas/oil contacts
- Water properties

### 4.9 Reservoir Performance Prediction with the Simulator

The prediction phase of a simulation study is the phase in which most of the study objectives are achieved. In this phase of the study, the simulation model is used to predict future performance of the reservoir. Because of the non uniqueness of the history matching process, predictions even from even the most closely matched model are subject to some biased error. Selection of prediction scenarios depend on the objective of a particular study. Generally a base case prediction is performed where a history matched model is continued to run up to a certain period without any change in production operations. After that any production scenario can be investigated to determine the extent of ultimate recovery and the feasibility of any field development.

### 4.10 ECLIPSE Simulator

ECLIPSE is an oil and gas reservoir simulator originally developed by ECL (Exploration Consultants Limited) and currently owned, developed, marketed and maintained by SIS (formerly known as GeoQuest), a division of Schlumberger. ECLIPSE 100 is used for blackoil simulation and ECLIPSE 300 is used for compositional and thermal simulation. With fully implicit, three-phase, 3D simulations, ECLIPSE Blackoil reservoir simulation software models extensive well controls and supports efficient field operations planning, including water and miscible-solvent gas injection. The blackoil model assumes that the reservoir fluids consist of three phasesð oil, water, and gas, with gas dissolving in oil and oil vaporizing in gas.

ECLIPSE is a batch program. This data file contains a complete description of the model. The model consists of reservoir description, fluid and rock property description, initial conditions, wells and their phase flow rates and surface facilities. The input file is a text file containing a collection of keywords and comments. Each keyword has a specific syntax although many keywords have similar or identical syntax. The data file is divided into sections by a few specific keywords. Each section has a particular purpose. In general, ECLIPSE keywords are usable only in certain sections of the data file. ECLIPSE reads the input data file section by section and processes each section in turn once that section has been read. Various data and consistency checks are made before proceeding to the next section. The last section is exceptional because it specifies time-dependent data and is not read and processed as a whole; the keywords are processed in the order they are read from the data file. (ECLIPSE Reference Manual 2008)

The first task performed by ECLIPSE is to allocate memory for the input data. The simulation grid geometry and properties are processed into a form more convenient for calculation of flows. For each cell, ECLIPSE calculates the pore volume, transmissibility in three dimensions and cell centre depth and creates connections to other cells to/from which fluids may flow. These quantities may be modified either by the user or by ECLIPSE.

The rock and fluid properties are specified next. The term fluid properties refer to a set of input tables that effectively define the phase behavior of each flowing phase. The term rock properties refer to sets of input tables of relative permeability and capillary pressure versus saturation. Effectively, this defines the connate (or irreducible) , critical and maximum saturation of each phase, supplies information for defining the transition zone and defines the conditions of flow of phases relative to one another. This strongly affects the ratios of produced phases, i.e. water cuts and GORs.

Next, the initial conditions are defined, often by specifying the OWC and/or GOC depths and the pressure at a known depth. ECLIPSE uses this information in conjunction with much of the information from previous stages to calculate the initial hydrostatic pressure gradients in each zone of the reservoir and allocate the initial saturation of each phase in every grid cell prior to production and injection. This is called initialisation.

The final section of the data file is where simulation actually begins. Wells are drilled, perforated and completed, production and injection targets are set up, wells are opened and fluids flow through the reservoir, driven by the wells.

ECLIPSE outputs various information at different time steps. Once the run has finished, the output is examined using text editors and post-processors of various degrees of sophistication.

### 4.11 Other Commercial Reservoir Simulators

**CMG Suite:** CMG (Computer Modelling Group Ltd.) is a computer software engineering and consulting firm engaged in the development, sale and technology transfer of reservoir simulation software. They have developed numerical simulators for conventional gas/oil, heavy oil and unconventional reservoir management. Some of their simulators are IMEX, STARS, GEMS etc.

**Nexus® Reservoir Simulation Software:** It is developed by Halliburton, one of the worldôs largest provider of products and services to the oil and gas industries. It can be used for rapid simulation of multi reservoir model, production forecasts and integrated asset management.

**VIP® Reservoir Simulation Suite:** VIP®, Landmark's reservoir simulation technology suite, developed by Halliburton provides complete pre-processing, simulation and post-processing workflows to engineers and asset teams.

**JewelSuite Reservoir Modeling Software:** JewelSuit, developed by Baker Hughes builds and updates complex reservoir models. It has integrated seismic, geologic, flow simulation, and geomechanic models into a single, multidisciplinary workflow.

**Sensor Compositional and Black Oil Reservoir Simulation Software:** Sensor is a generalized 3D numerical model developed by Coats Engineering Inc to optimize oil and gas recovery processes through simulation of compositional and black oil fluid flow in single porosity, dual porosity, and dual permeability petroleum reservoirs.

**TechSIM Simulator:** This is an in house simulator of AEA Technology. It uses generalized compositional model and includes options for black oil, miscible flood and equation of state compositional simulation.

**ARCO:** ARCOôs in-house black-oil simulator employs IMPES and fully implicit techniques for time step discretization.

**SIMBEST II**: This is a fully implicit simulator developed by Scientific Software-Intercomp (SSI) which simulates black oil reservoirs, dual porosity reservoirs and pseudo-compositional modeling of retrograde condensates, gas cycling and volatile oils, and miscible gas injection.

**TIGRESS**: The TIGRESS simulator is based on a generalized compositional formulation which incorporates IMPES and fully-implicit solution Techniques.

## 4.12 Comparison of Commercial Simulators

The comparison of commercial simulators has been summarized according to the Ninth SPE Comparative Solution Project (Killough 1995). The project provides a reexamination black-oil simulation based on a model of moderate size and with a high degree of heterogeneity provided by a geostatistically-based permeability field. Nine participants provided data for a comparison which is based on a dipping reservoir with twenty-five somewhat randomly placed producers and a single water injector. Table 4.1 shows the comparison of the simulator based on simulation time steps.

Table 4.1: Comparison of Simulators

| Participant | Time Steps | Outer It | CPU (s) |
|---|---|---|---|
| AEA | 57 | 200 | 391[a] |
| | 57 | 200 | 3720[b] |
| ARCO | 31 | 98 | 181[c] |
| CMG | 48 | 256 | 1122[d] |
| ECLIPSE | 31 | 142 | 207[c] |
| | 31 | 142 | 535[d] |
| SENSOR | 33 | 55 | 102[c] |
| SSI | 34 | 95 | 427[e] |
| TIGRESS | 46 | 194 | 810[f] |
| VIP | 27 | 109 | 141[c] |

a= IBM R/S 6000/3AT

b= SUN Sparcstation 2

c= IBM R/S 6000/590 (xlf 3.1)

d= HP 735

e= IBM R/S 6000/370 (xlf 2.3)

f= IBM R/S 6000/365

# CHAPTER 5
# METHODOLOGY

This research is based on secondary data regarding Habiganj Gas Field. Geological and petrophysical data, measured rock & fluid properties, available production, completion & pressure test data and PETREL$^{TM}$ generated geo-model of the field were collected from Petrobangla and Bangladesh Gas Fields Company Limited (BGFCL).

A simulation model as described below was generated using ECLIPSE 100 black oil simulator. The model was further validated by matching historical wellhead pressure and water gas ratio of existing wells with that of simulator generated results. After getting a reasonable history match, the model would be run in prediction mode for different operating scenarios with additional infill drilled wells.

### 5.1. Habiganj Gas Field Reservoir Simulation Model

Habiganj reservoir simulation model was built using the data collected from Petrobangla and BGFCL (Bangladesh Gas Fields Company Limited) both in the form of hard copies and soft copies.

**Geologic Model:** The geologic model of Habiganj gas field was collected from Petrobangla. The model was built using PETREL$^{TM}$. The model grid consists of 62X142X62 blocks with dimensions of 100X100 m. The gas zone is divided into two layers, upper gas sand (UGS) and lower gas sand (LGS). The zones are separated by strong shale layer and there is no vertical connection between the layers. The UGS cells have an average height of 5.4 m and LGS cells have an average height of 1.8 m. the field has been modeled with corner point geometry. A numerical bottom aquifer has been connected with the UGS, a clear gas ï water contact was distinguished at the bottom of UGS at a depth of 4851 ft initially. No water zone was identified at the LGS. The field has been developed using 11 gas producing wells. Fig 5.1 and 5.2 show the 3D and top view of Habiganj reservoir

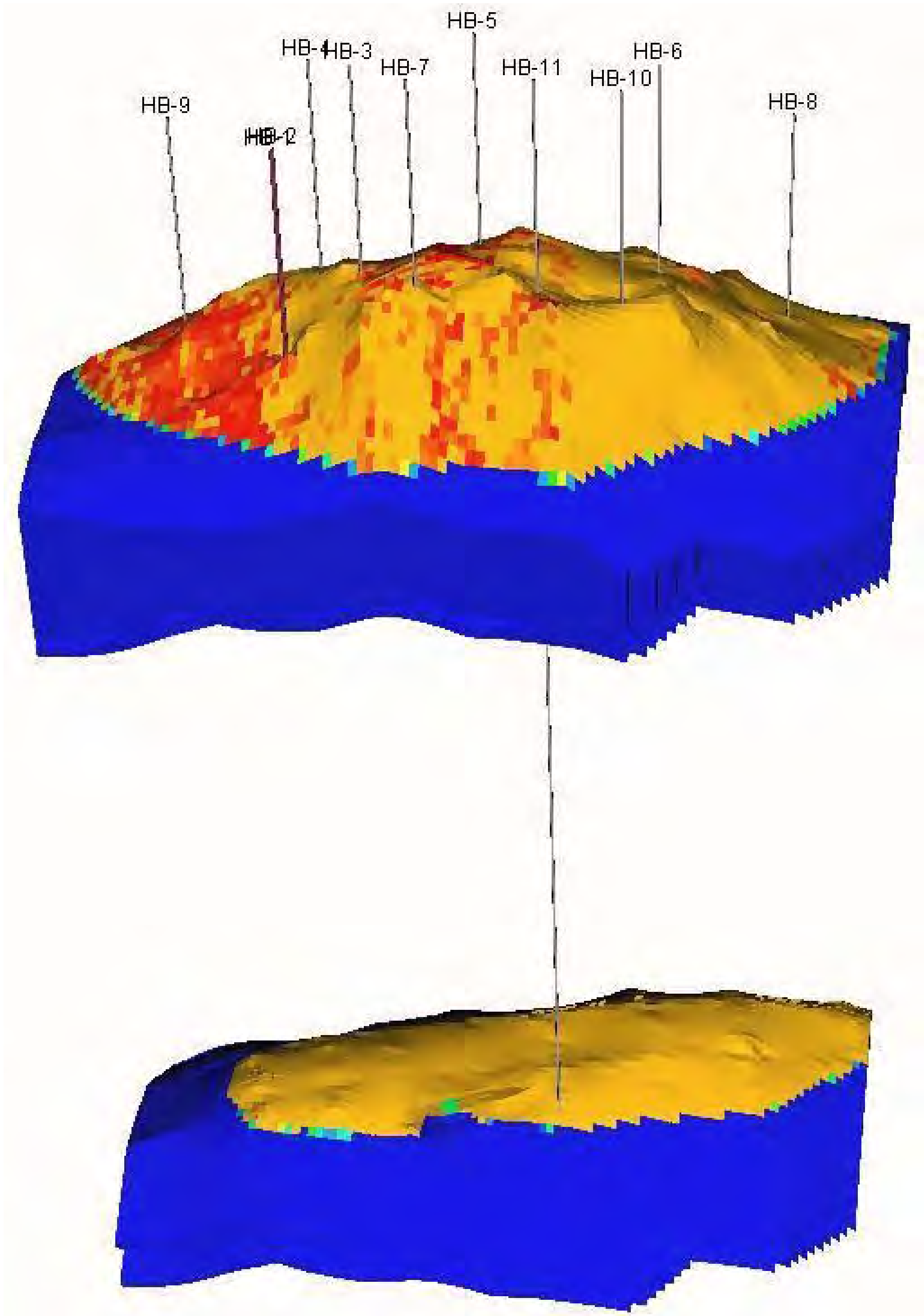


*Fig 5.1: 3-D view of Habiganj Reservoir*

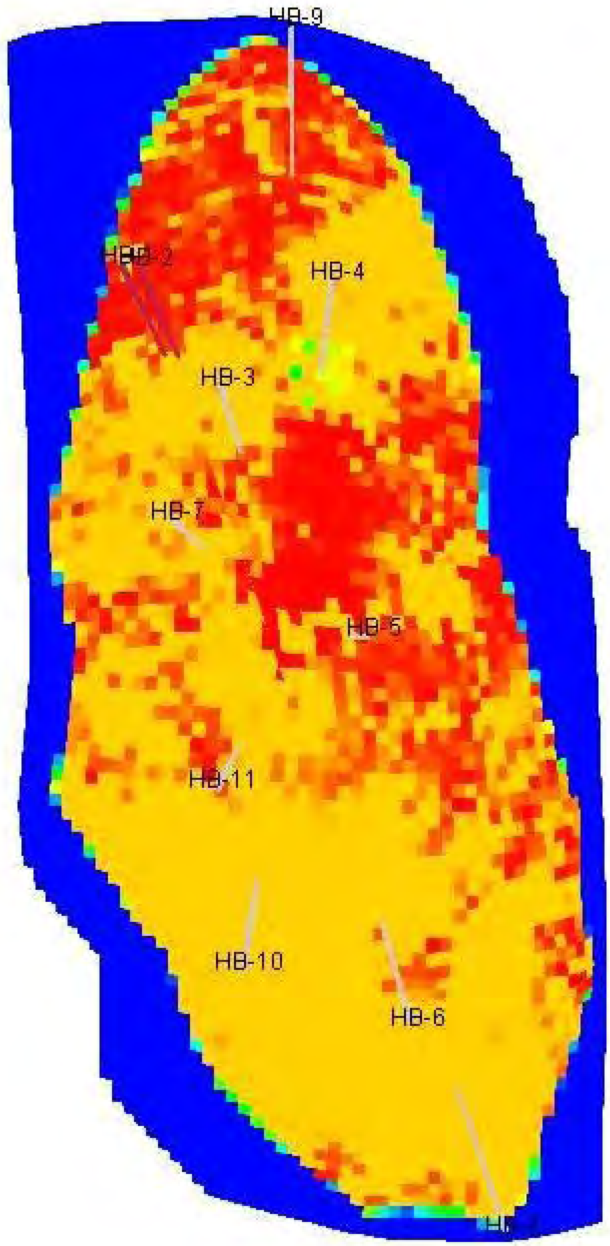


*Fig 5.2: Top View of Habiganj Reservoir*

**Rock Properties:** Rock property distributions of Habiganj UGS and LGS were also collected form Petrobangla. Average porosity of Habiganj UGS is 40% and permeability is as high as 4.5 Darcy. There was no measured vertical permeability for the field. So as a standard practice, initial vertical to horizontal permeability ratio was taken as 0.1. Rock compressibility at 3000 psia was taken as $3.X10^{-6}$ $psia^{-1}$.

**Fluid Properties:** Fluid properties of Habiganj UGS gas are summarized in Table 5.1, 5.2 and 5.3.

Table 5.1: Composition of Habiganj UGS gas

| Component | Mole Fraction |
|---|---|
| $N_2$ | 0.0078 |
| $H_2S$ | 0.0000 |
| $CO_2$ | 0.0001 |
| $C_1$ | 0.9773 |
| $C_2$ | 0.0148 |
| $C_3$ | 0.0000 |
| $iC_4$ | 0.0000 |
| $nC_4$ | 0.0000 |
| $iC_5$ | 0.0000 |
| $nC_5$ | 0.0000 |
| $C_6$ | 0.0000 |
| $C_{7+}$ | 0.0000 |
| | × 1.0000 |

Table 5.2: Dry gas PVT Properties

| Property | Value | Unit |
|---|---|---|
| Gas Specific Gravity | 0.564 | |
| Gas Density at Surface Condition | 0.044 | $Lb/ft^3$ |
| Gas FVF at Surface Condition | 191.0349 | Rb/Mscf |
| Gas Viscosity at Surface Condition | 0.0199 | cp |

Table 5.3: Water PVT Properties

| Property | Value | Unit |
|---|---|---|
| Density at Surface Condition | 64 | $Lb/ft^3$ |
| Viscosity at Surface Condition | 0.5 | cp |
| Compressibility at Surface Condition | $3.03X10^{-3}$ | $Psia^{-1}$ |
| FVF at Surface Condition | 1 | Bbl/STB |

Variations of fluid properties like gas formation volume factor and gas viscosity with pressure have been shown in Fig 5.3.

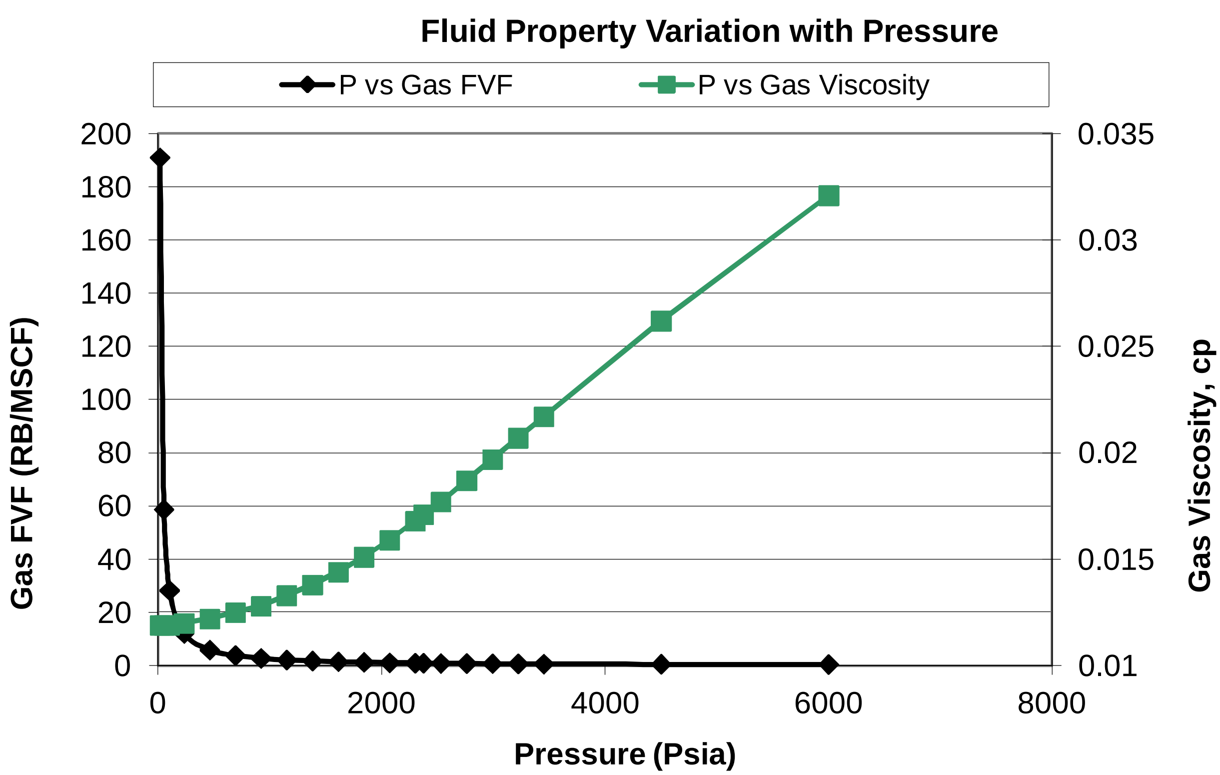


*Fig 5.3: Fluid Property Variation with Pressure*

**Production Data:** Though production from HB-1 and HB-2 started from August 1968, production data was available from February 1969. Nine more wells started producing from the reservoir subsequently within the period from 1985 to 2008. Gas, oil and water production data were collected up to the period May 2011.Well HB-8 was shut in July

2004 and well HB-9 in May 2008 due to low gas production and high water cut. Well HB-11 was completed at LGS initially and started production from lower gas sand in February 2008. But later in 2010, lower perforations were sealed due to the low gas production. After a work over HB-11 is now producing gas from UGS since May 2010.

**Pressure Data:** Along with production data, average tubing head pressures (THP) data were available. That is why; THPôs were used for pressure history matching purpose. Some shut in bottomhole pressures of different wells were also available at different times. These data were used to match average reservoir pressure.

**Relative Permeability/ Saturation data:** No special core analysis (SCAL) has ever been performed on Habiganj gas reservoir. Therefore no relative permeability saturation relationship data were available. Relative permeability data were considered to be the most uncertain among all other available data. Fig 5.4 shows the variation in relative permeability with water saturation. The graph has been plotted using the hypothetical data collected from Petrobangla for initial simulator runs.

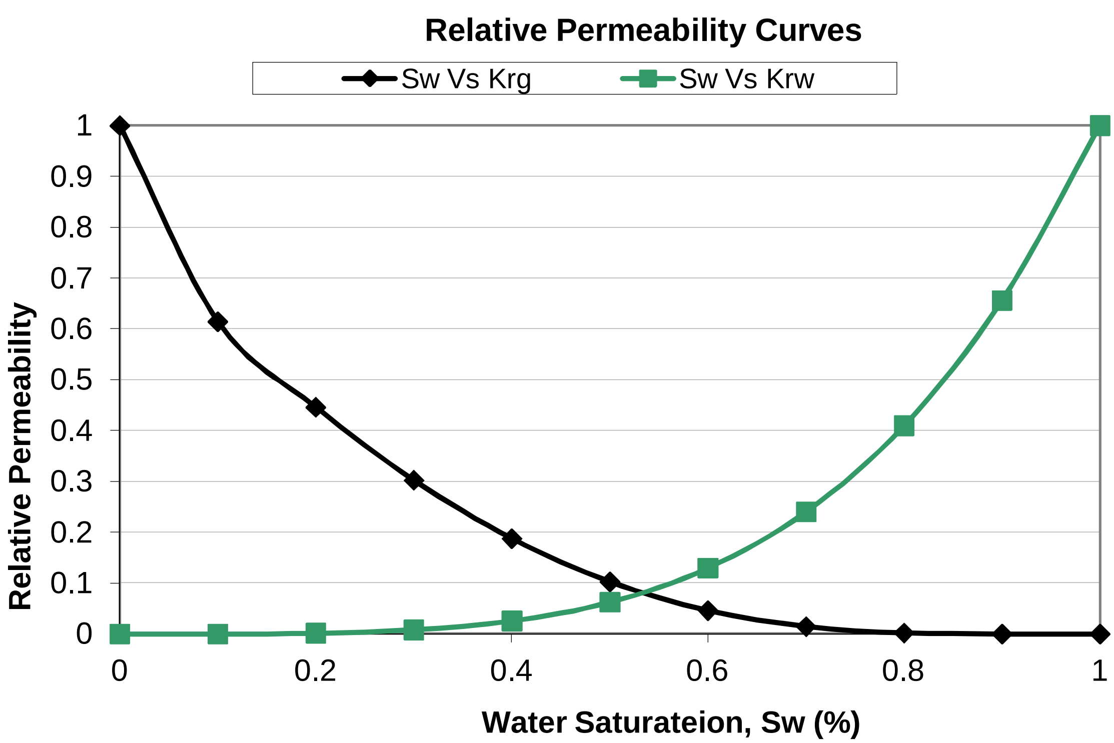


*Fig 5.4: Relative Permeability Vs Saturation curves*

**Well Performance Modelling**: To calculate tubing head pressures (THPs) from flowing bottomhole pressures (BHPs), the vertical lift performance curves are required. These curves were generated using an appropriate correlation (Petroleum Experts 2) by PROSPER. PROSPER is a well performance, design and optimization program for modelling most types of well configurations. It can calculate tubing pressure loss by various vertical lift performance (VLP) correlations. In the simulation model, three different flow performance tables have been used for different tubing inside diameters.

**Initialization:** The Model was initialized by specifying the datum depth and pressure at datum depth. Gas water contact was also specified. At datum depth of 1492 m, pressure was specified as 2150 psia. Gas water contact was also specified at this depth.

**Aquifer Properties:** Appreciable amount of water production from the beginning of gas production was observed and the pressure maintenance throughout the total historical production period was very good. Water production and historical pressure match could not be obtained without attaching an aquifer to the reservoir. Moreover, all the previous studies on Habiganj gas field indicated the presence of a strong bottom aquifer. That is why; a numerical bottom aquifer having an area of $5x10^6$ $ft^2$, porosity of 40% and permeability of 400 millidarcy was connected to the model to match the pressure and water production history. Aquifer initial properties are summarized in Table 5.4.

Table 5.4: Aquifer initial properties

| | |
|---|---|
| Aquifer Type | Bottom aquifer |
| Area | $5x10^6$ $ft^2$ |
| porosity | 40% |
| permeability | 400 md |
| Gas water contact depth | 1492 m |

# CHAPTER 6
# HISTORY MATCHING

## 6.1 History Matching Approach

The usual approach of history matching is to match field wide pressure and saturation properties first. After getting a field wide good match, the next step is to advance for individual well match. But very often it has been found that when there are many wells present in a reservoir, one or some of the wells are very difficult to be matched. These wells increase history matching time and sometimes very good match cannot be established. These wells are termed as ñrough wellsò.

In this study, an initial well wise match approach has been adopted. Habiganj gas reservoir is a proven water drive reservoir. That is why, water production rate and gas-water ratio match are very significant in order to get a reasonable performance prediction. The water production data of the individual wells obtained were not of very good quality. As a result, a field wide water production match could never produce a reasonable match. On the other hand, if a good pressure match and a reasonable and logical water production match for individual wells can be established, a reasonable field wide match will automatically be established. With this view, the wells of the Habiganj field were hypothetically divided into three groups for history matching convenience. The division was done on the basis of the geographic location of the wells. That is, the wells in the same vicinity were considered to be in the same group and history matching techniques were applied to the wells in a group. HB-1, HB-2, HB-3, HB-4 and HB-9 were place in one group. HB-6, HB-7, HB-8 and HB-10 were place in another group and HB-5 and HB-11 were placed in a third group.

## 6.2 History Matching Parameters

History matching parameters are listed according to the chronology of the changes not on the uncertainty of the parameters.

- *Pore volume*: The initial simulation run showed a good pressure match at the beginning of the history but a large deviation later. A change in pore volume was considered to get a better pressure history match. A 20% increase in the pore volume of the gas bearing zone produced a better pressure match for all the wells.
- *Critical Water Saturation:* Critical water saturation defines the largest water saturation for which water relative permeability is zero. Critical water saturation value controls at what value of saturation water is movable in the reservoir. No actual data for critical water saturation was available. History matched critical saturation value was set at 20%.
- *Aquifer Properties:* the bottom aquifer was given a uniform permeability of 400 millidarcy. But during history matching initial runs, it was found that the water table movement rate was faster than the expected movement rate. A 40% reduction in aquifer transmissibility better matched the water production.
- *Horizontal Permeability:* Initial runs showed a decline in pressure for almost every well at the end of historical life. A 20% increase in horizontal permeability of the gas bearing zone of the reservoir better matched the pressure.
- *Relative Permeability Curves:* As there were no special core analysis data of Habiganj gas field, the relative permeability curves initially used were purely based on the assumption. Relative permeability of water was slightly changed to match water movement inside the reservoir. Table 6.1 shows the changes in water relative permeability values. Fig 6.1 is the graphical representation of Table 6.1.

Table 6.1 : Change in Water Relative Permeability

| Sw | Original Krw | Changed Krw |
|---|---|---|
| 0 | 1 | 1 |
| 0.1 | 0.6561 | 0.6561 |
| 0.2 | 0.4096 | 0.4096 |
| 0.3 | 0.2401 | 0.2401 |
| 0.4 | 0.1296 | 0.1296 |
| 0.5 | 0.0625 | 0.053 |
| 0.6 | 0.0256 | 0.017 |
| 0.7 | 0.0081 | 0.012 |
| 0.8 | 0.003 | 0.005 |
| 0.9 | 0.001 | 0.001 |
| 1 | 0 | 0 |

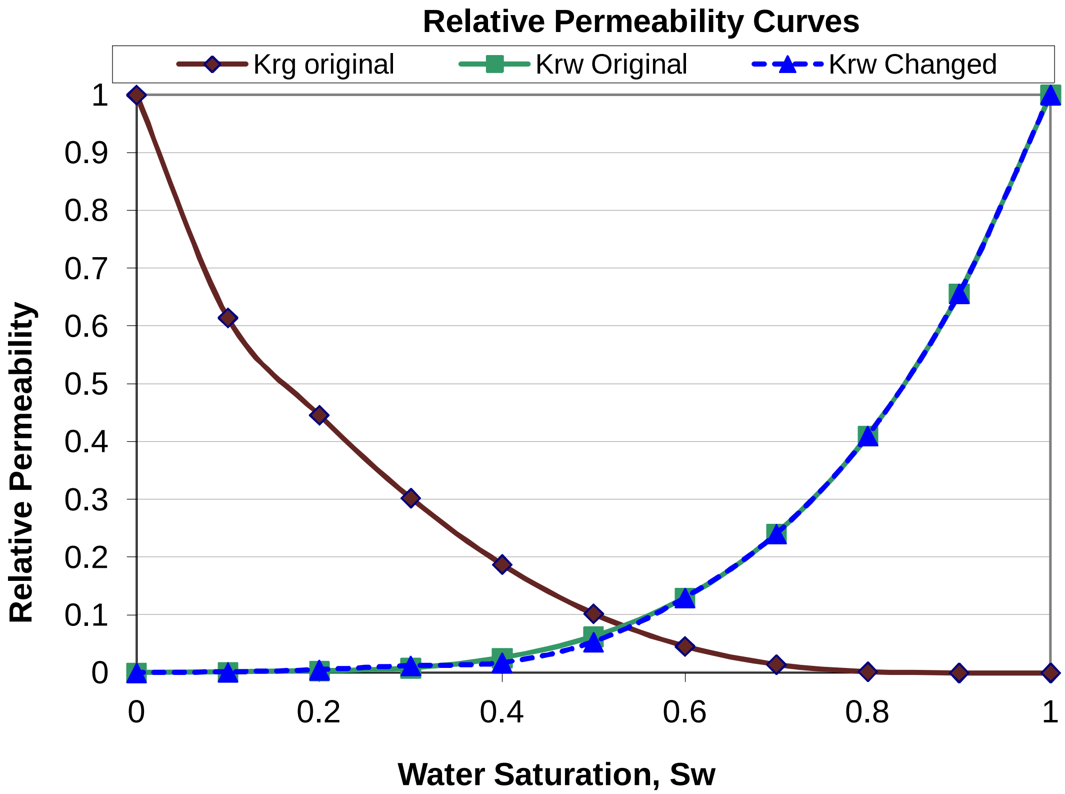


*Fig 6.1: Change in Water Relative Permeability*

- Productivity Index Multiplier: For well HB-6, a pressure deviation was observed from the very beginning of historical production. For this well, the pressure profile trend matched but the numerical pressure values were either higher or lower than the historical values. Productivity index multipliers were used for this well.

## 6.3 History Matching Results and interpretation

Following parameters were history matched-

- Average Reservoir Pressure
- Field wide water production
- Tubing head pressures for each well
- Water production for each well

The average reservoir pressure was matched with the available shut in pressure of different wells at different times. Most of the available data were 18 hours shut in pressure data. For a high permeability reservoir, shut in pressure quickly approaches the average reservoir pressure. This is also evident from the graphical match (Fig 6.2). The simulated average reservoir pressure data were slightly higher than the historical shut in pressure data. The match was reasonably satisfactory.

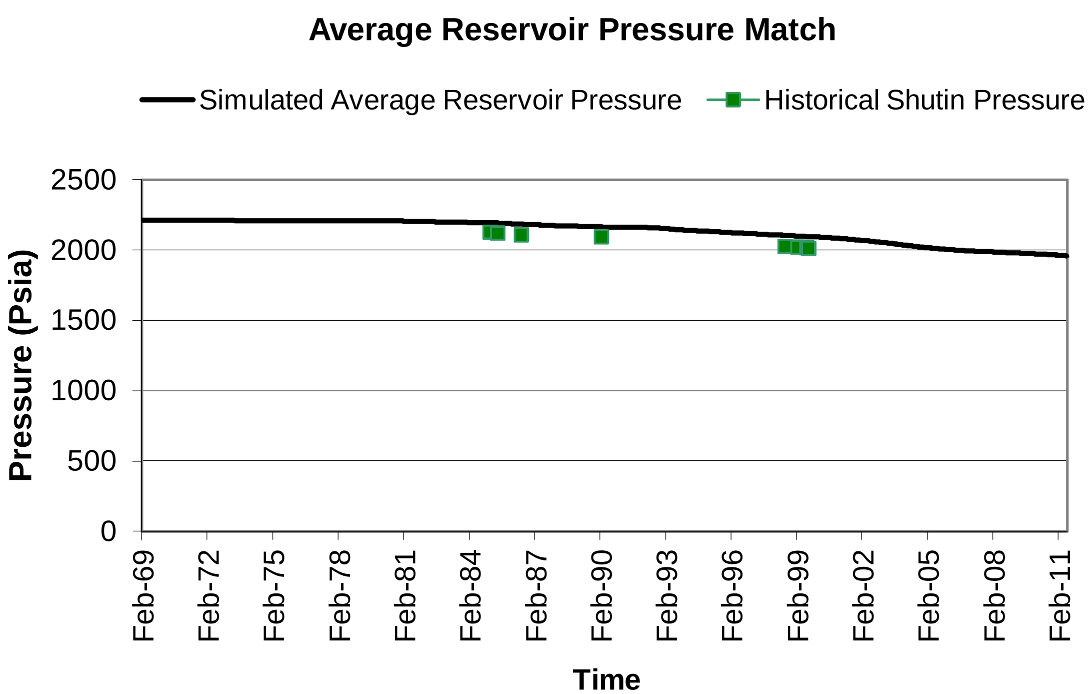


*Fig 6.2: Average Reservoir Pressure Match*

Fig 6.3 shows the field water production match. It is to be noted that historical water production data available were erroneous. So a good water production match was never realized. The objective was to obtain a reasonable water production match with a good pressure match. Field water production match is not so satisfactory. Production from well HB-8 was suspended on July 2004 due to excessive water production. This is not implied in simulated result. This can be because of the error in locating perforations of well HB-8 in the geo model. A gradual increase in simulated water production started from the middle of 2006. Water production rises to a maximum in March 2008 and reduces sharply from April 2008. This explains the actual condition that well HB-9 was suspended on April 2008 due to excessive water production. Historical data also showed an increase in water production during the period but simulated water production was higher than that of historical water production. Historical water production remained high even after the suspension of production from the well HB-9 which is contradictory to the actual condition. A good pressure match for well HB-9 (Fig 6.12) indicates that simulated water production should be taken as satisfactory. A gradual rise in simulated water production at the end of the historical years is mainly due to the increase in water production of well HB-1.

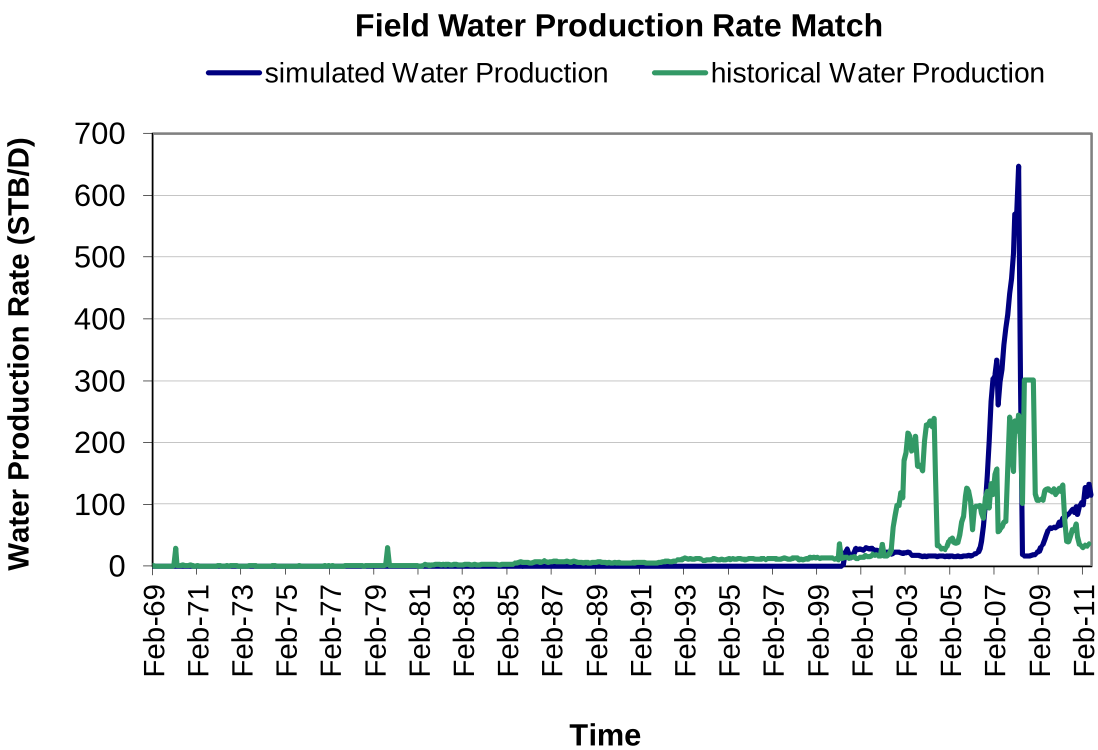


*Fig 6.3: Field Water Production Match*

Well HB-1 and HB-2 started producing gas from upper gas sand of Habiganj Reservoir on August 1968. Initial gas production rate for the wells were 2.34 MMSCFD for HB-1 and 0.717 MMSCFD for HB-2. At the end of the historical production period (June 2011) HB-1 and HB-2 were producing at rates of 17 and 18 MMSCFD respectively. Fig 6.4 and 6.5 show THP match for the wells HB-1 and HB-2 respectively. THP match for HB-1 and HB-2 are quite satisfactory. Both simulated pressure trend and numerical values well matched with the historical THP data.

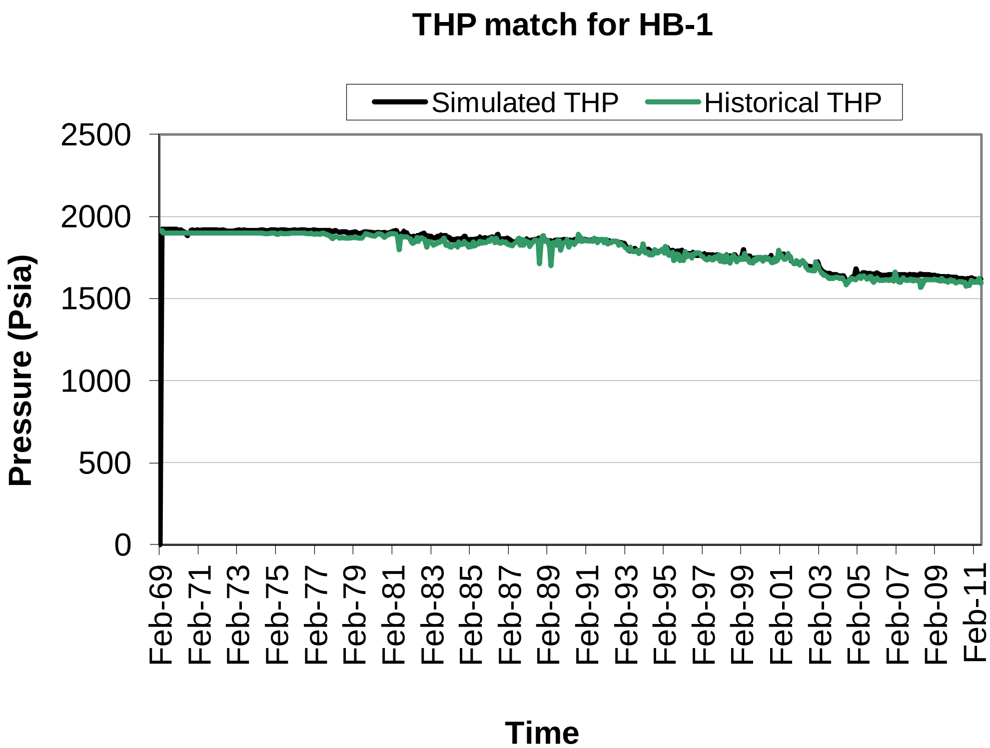


*Fig 6.4: THP Match for HB-1*

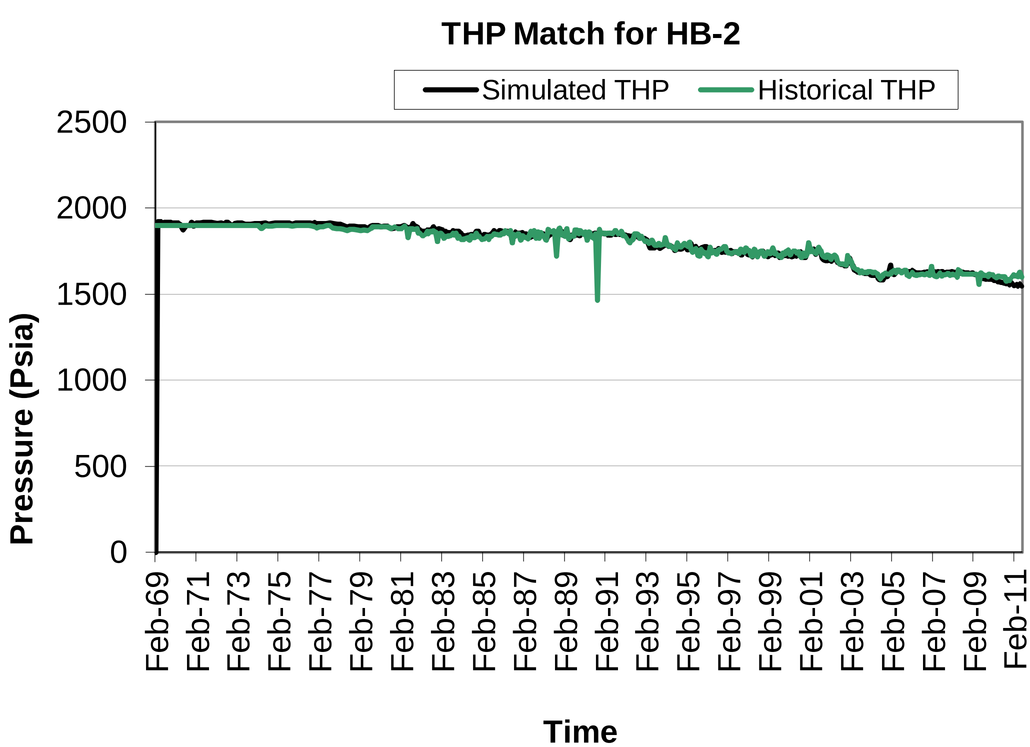


*Fig 6.5: THP Match for HB-2*

Wells HB-3 and HB-4 started producing gas from upper gas sand of Habiganj gas field from July 1985 and May 1985 respectively. Initially, HB-3 was producing gas at a rate of 10.92 MMSCFD and HB-4 was producing at a rate of 4.76 MMSCFD. At the end of the historical production period (June 2011) both the wells were producing gas at a rate of 36 MMSCFD. Fig 6.6 and 6.7 show THP match for wells HB-3 and HB-4 respectively. Simulated THP well matched with the historical THP except for the period 1986 to 1996. During this period, simulated THP values were higher than those of historical values. Historical gas production data for these wells show no huge fluctuation or increase in gas production rate for which pressure should decrease. The decrease in historical pressure data during the period can be because of the presence of error in pressure reading. It may also be due to the manual manipulation of pressure reading. The overall pressure match for these wells can be regarded as satisfactory.

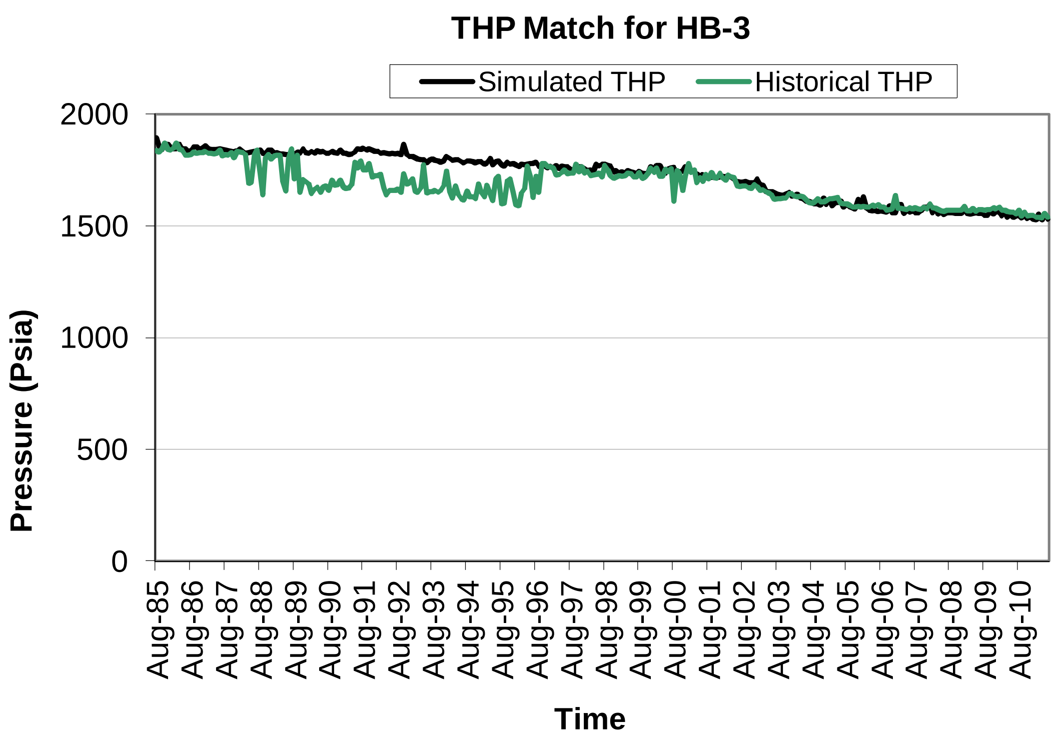


*Fig 6.6: THP Match for HB-3*

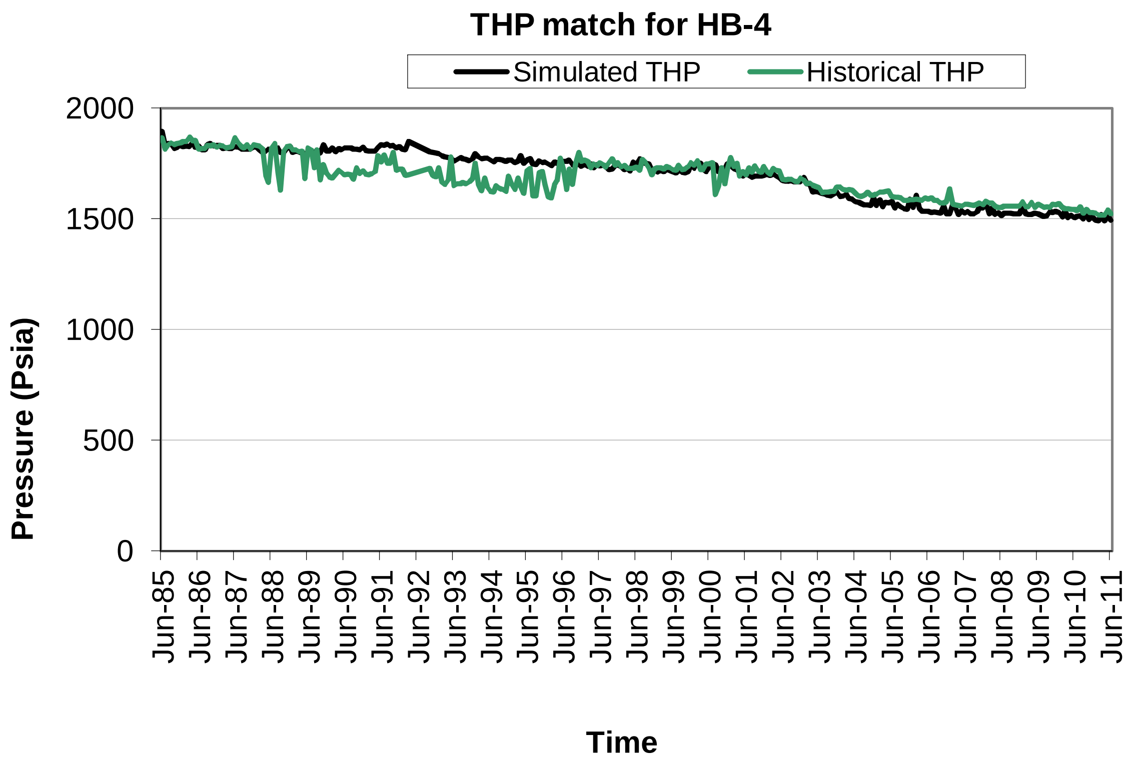


*Fig 6.7: THP Match for HB-4*

HB-5 is the only deviated well of Habiganj Gas field that started producing from upper gas sand at a rate of 15.8 MMSCFD from February 1992. The total depth of the well is 3521 meter and at the end of the historical production years it was producing at a rate of 26 MMSCFD. Fig 6.8 shows THP match for well HB-5. THP match for the only deviated well HB-5 was not so good. Simulated THP values were always less than the historical values. From the period 2003 to 2006 simulated pressure values drastically fell below the historical values. A manual calculation showed that for HB-5, for a production rate as high as 43 MMSCFD if THP value is 1416 Psia, bottomhole flowing pressure is approximately 3100 Psia whereas, bottomhole pressure calculated by pressure drawdown equation is approximately 2000 psia. Fluctuations in historical THP values do not match the implied production fluctuations. That could be due to the troubles in pressure or production gauges, errors in modeling the deviation, or this deviated well can be treated as a rough well that could not be history matched. However, one historical shut in bottomhole pressure for HB-5 was available which was matched to the simulated bottomhole pressure. The simulated plot showed a very good agreement with the historical data. Fig 6.9 shows the BHP match for HB-5.

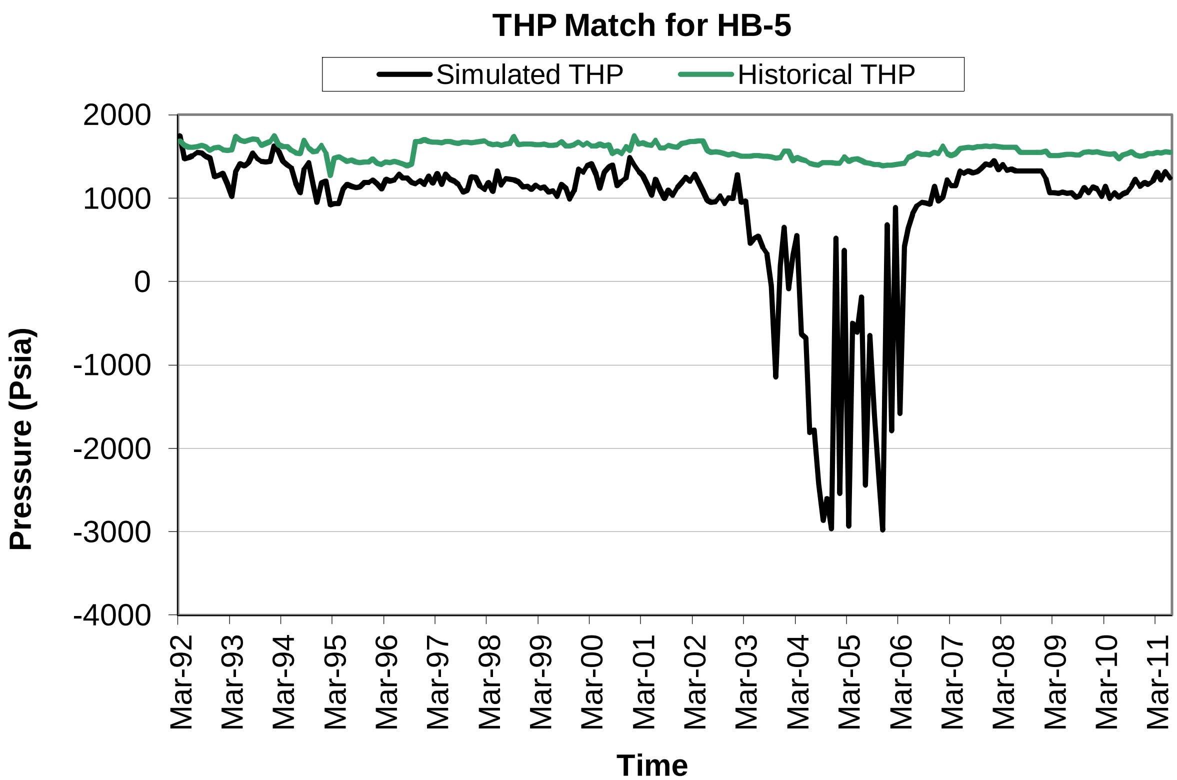


*Fig 6.8: THP Match for HB-5*

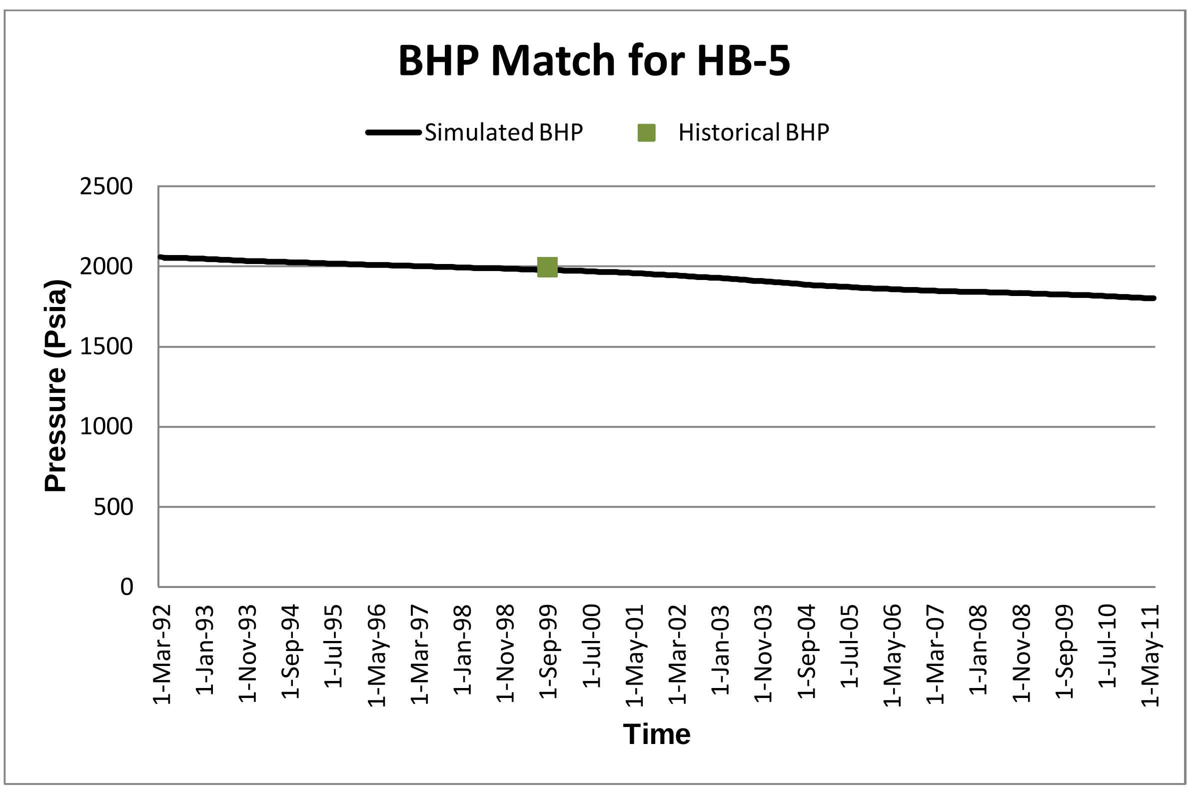


*Fig 6.9: BHP Match for HB-5*

Well HB-6 started producing from upper gas sand at a rate of 14 MMSCFD from February 1992. Total depth of the well is 5515 m and at the end of the historical production years, it was producing at a rate of 15 MMSCFD. Fig 6.10 shows the THP match for well HB-6. For this well, simulated THP well matched with the historical THP throughout the whole historical period. Well HB-7 started producing from upper gas sand at a rate of 5.2 MMSCFD from April 2000. Total depth of the well is 3120 m and at the end of the historical production years, it was producing at a rate of 40 MMSCFD. Fig 6.11 shows the THP match for well HB-7. Initial THP match for the well is very good. Later, when the gas production rate was gradually increased, simulated pressure fell below the historical values. The difference in pressure was never greater than 100 psi. Sometimes historical values showed an increase in pressure with increasing gas production and vice versa that cannot be logically explained. In these cases simulated pressure values showed a better agreement with the historical gas production. Fig 6.12 shows the variation of THP of HB-7 with gas production.

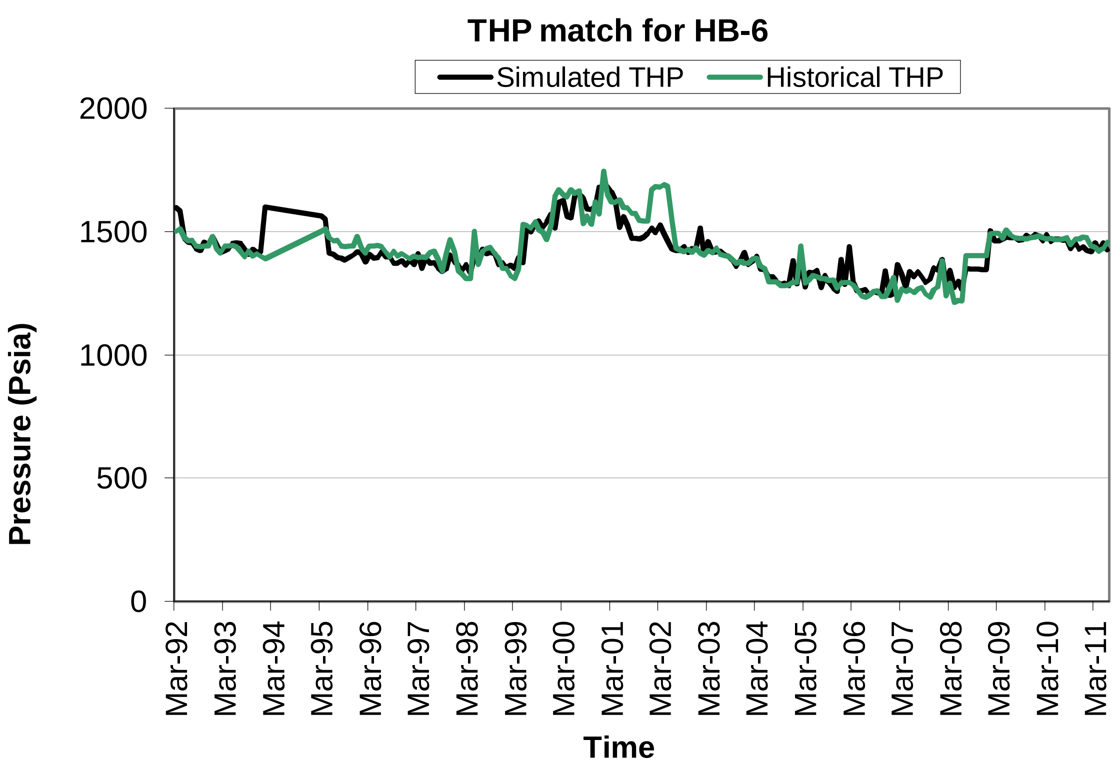


*Fig 6.10: THP Match for HB-6*

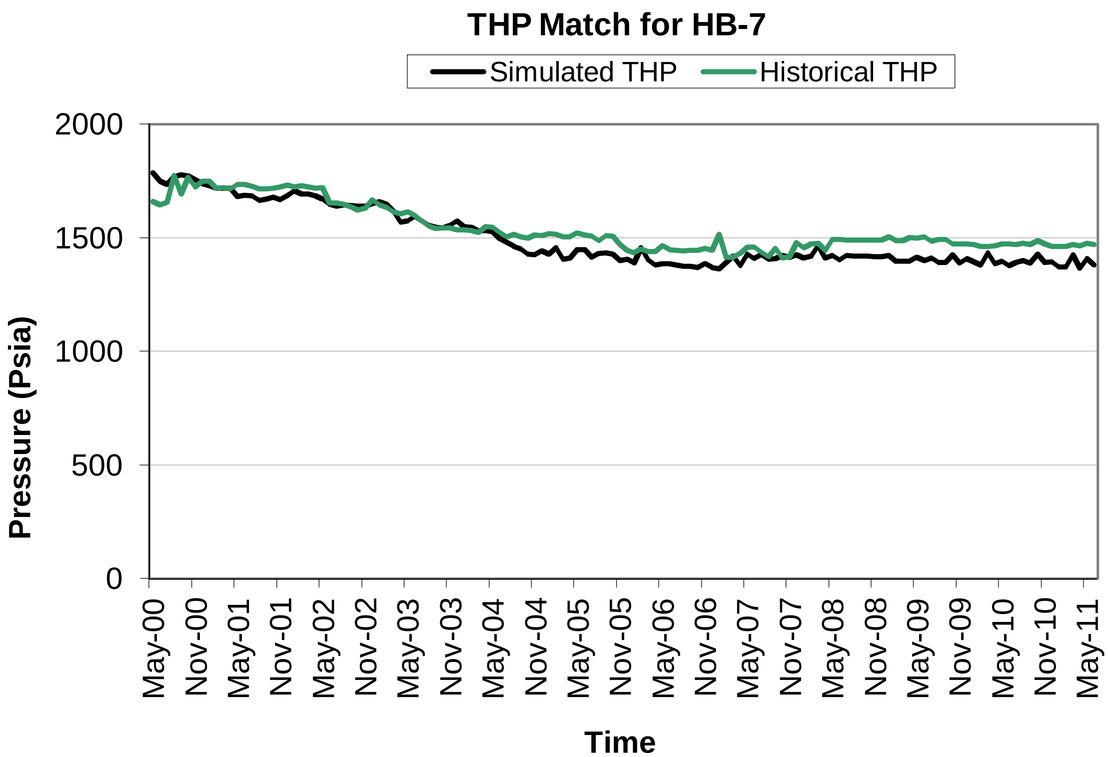


*Fig 6.11: THP Match for HB-7*

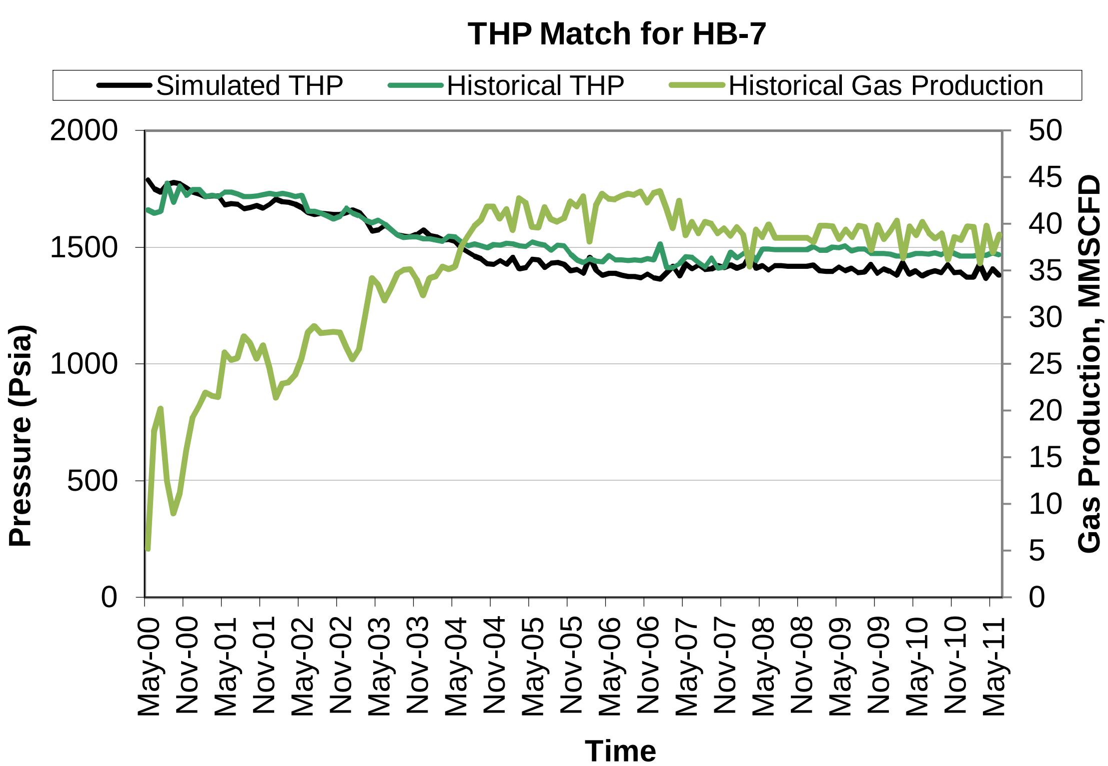


*Fig 6.12: Variation of THP with Gas Production for HB-7*

Wells HB-8 and HB-9 started producing gas from upper gas sand of Habiganj gas field from May 2000 and July 1998 respectively. Initially, HB-8 was producing gas at a rate of 5.5 MMSCFD and HB-9 was producing at a rate of 17 MMSCFD. Production from HB-8 and HB-9 were suspended from July 2004 and May 2009 respectively due to excessive water production. Fig 6.13 shows THP match for well HB-8. Initial pressure match is very good but some differences in historical and simulated values are seen later. It has been mentioned previously that the jump in water production of well HB-8 could not be matched. This may be because of the wrong placement of perforation levels in the geo model. THP match for HB-9 is shown in Fig 6.14. Simulated pressure matched with the historical values with reasonable accuracy.

Production from well HB-10 started from April 2000 at a rate of 4.6 MMSCFD. At the end of the historical production years, well was producing at a rate of 40 MMSCFD. Fig 6.15 shows the THP match for HB-10. The average difference in simulated and historical pressure is less than 70 psi and the pressure match can be considered to be satisfactory enough.

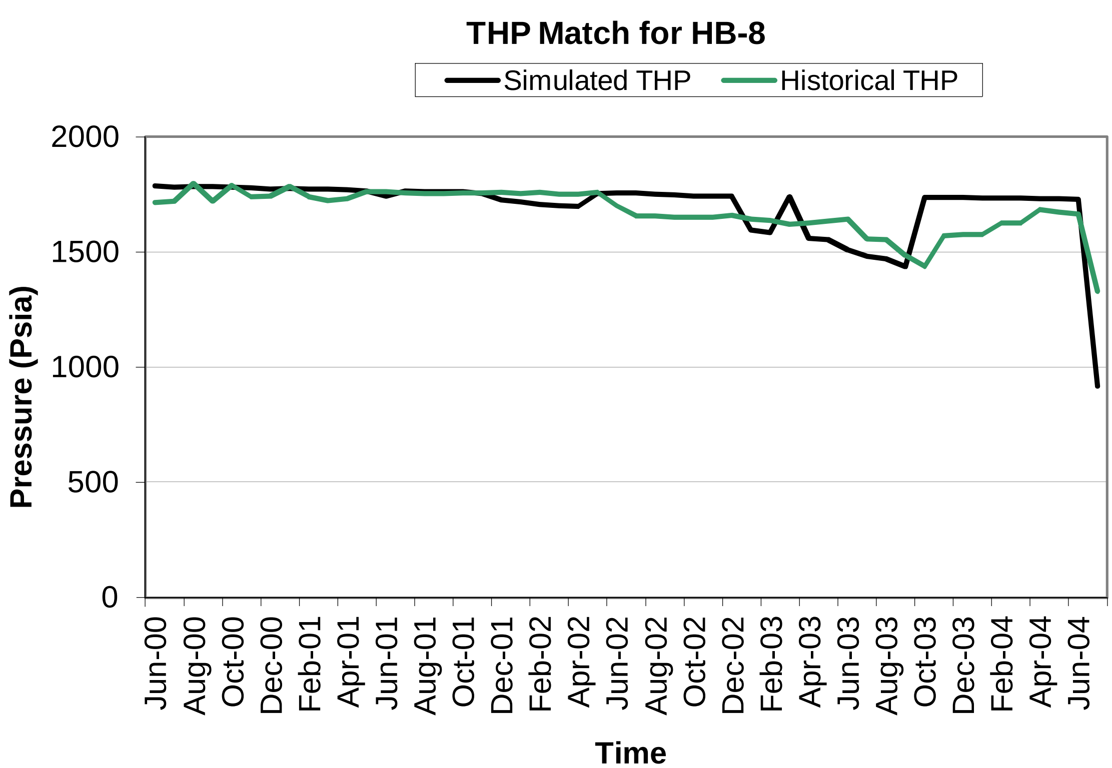


*Fig 6.13: THP Match for HB-8*

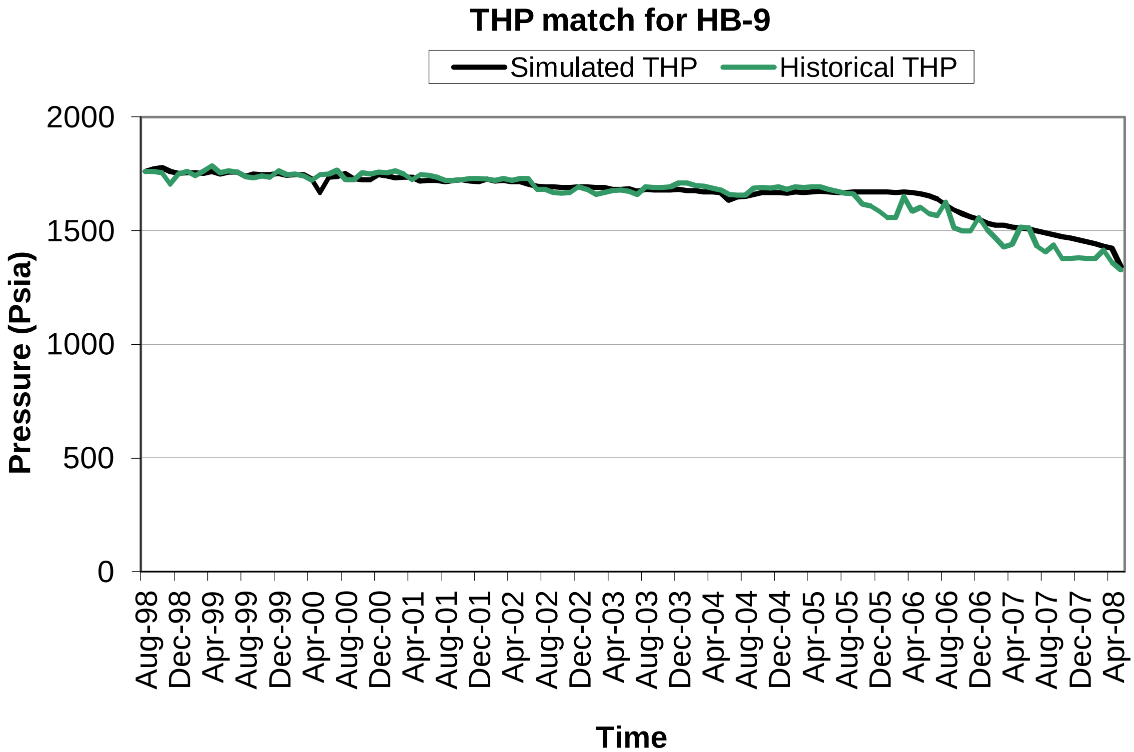


*Fig 6.14: THP Match for HB-9*

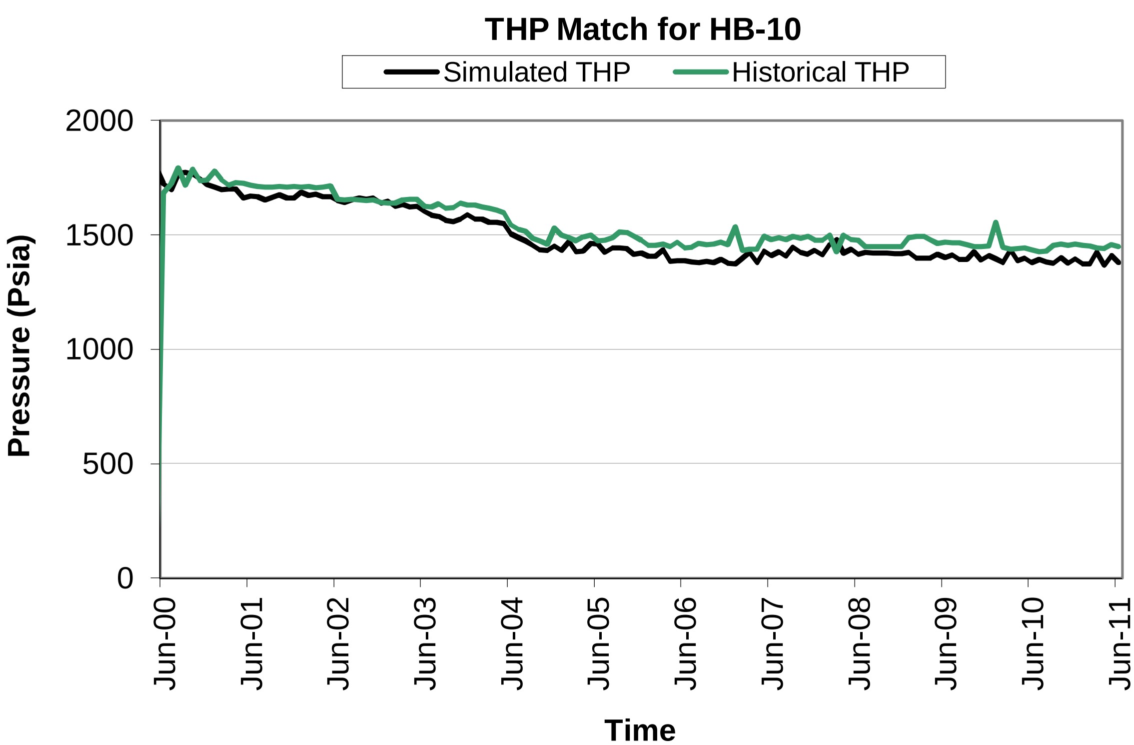


*Fig 6.15: THP Match for HB-10*

Well HB-11 is the only well in Habiganj gas field that was completed at lower gas sand and started production from January 2008 at a rate of 11 MMSCFD. Because of the lower porosity and permeability, very soon gas production rate was decreased to almost 1 MMSCFD. After a work over, lower zone was plugged back and production from upper gas zone started from August 2010. At the end of the historical production years, the well was producing gas at a rate of 30 MMSCFD. Fig 6.16 shows the THP match of HB-11 for production from upper gas sand. The match is reasonably good.

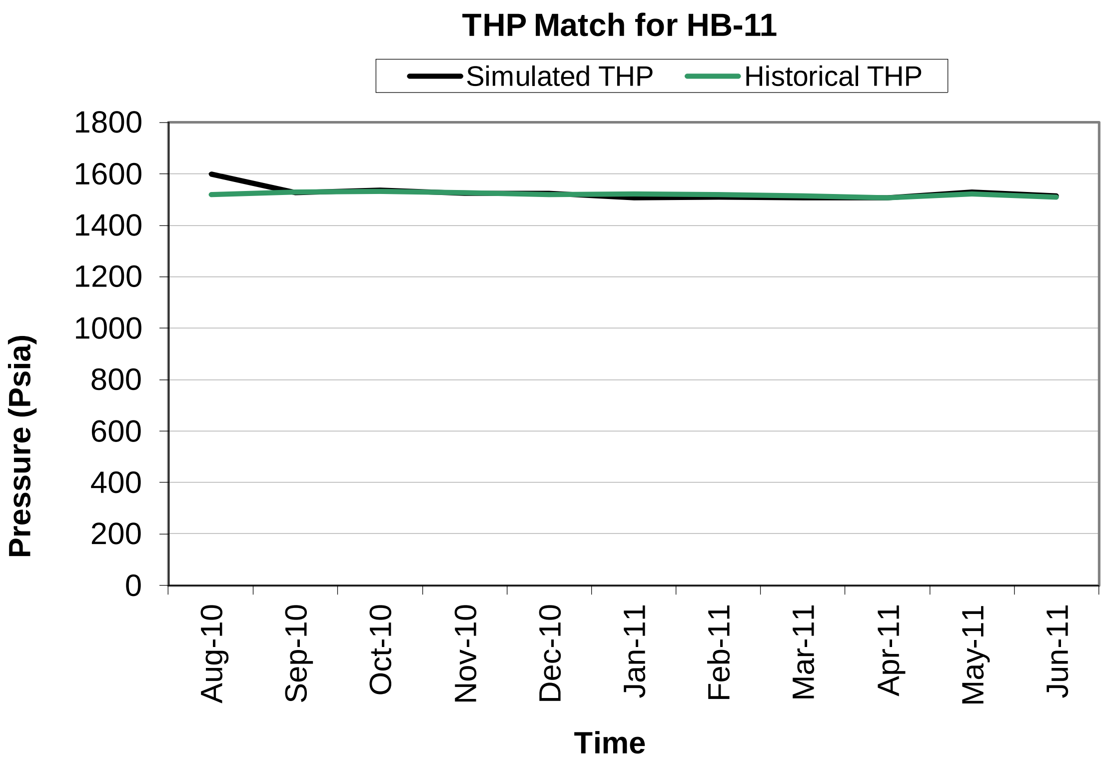


*Fig 6.16: THP Match for HB-11*

Figs 6.17 to 6.24 show the water production match for individual wells of Habiganj gas field. A good water production match for none of the wells could be realized for the possible reasons listed in the next paragraph. The objective of production history match was to get a reasonable and logical simulated water production from individual wells after getting a satisfactory pressure match.

The possible reasons for mismatch in historical and simulated water production are:

- Historical water production data available were erroneous. Some identical water production for different wells was observed for a period of time. Most of the production data were average of cumulative production of all the wells.
- Early water production from initial wells could be due to the condensation of water vapor as water production data are not measured at well site rather it is measured from separator tank.
- Sudden jump in historical water production could be due to the liquid loading of wells, the effect that cannot be shown by simulation.
- Skin and Non-Darcy effect together increase water production in gas reservoirs with bottom water drive (Armenta 2003), the effects that were not included in simulation model.

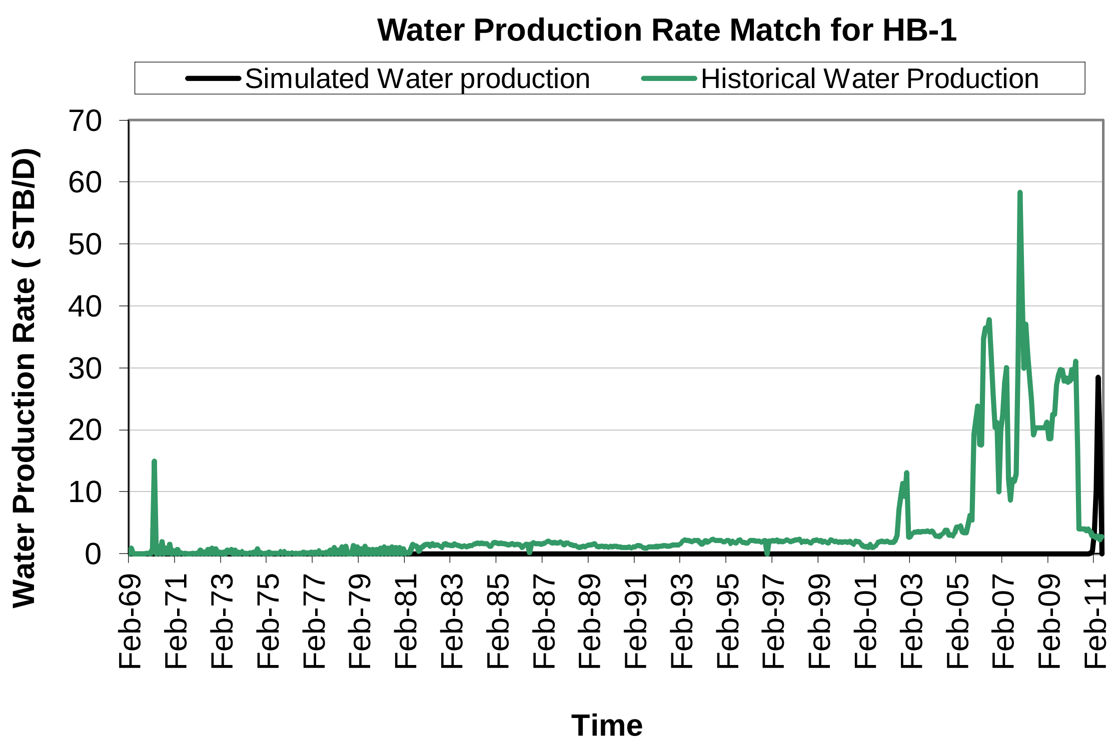


*Fig 6.17: Water Production Rate Match for HB-1*

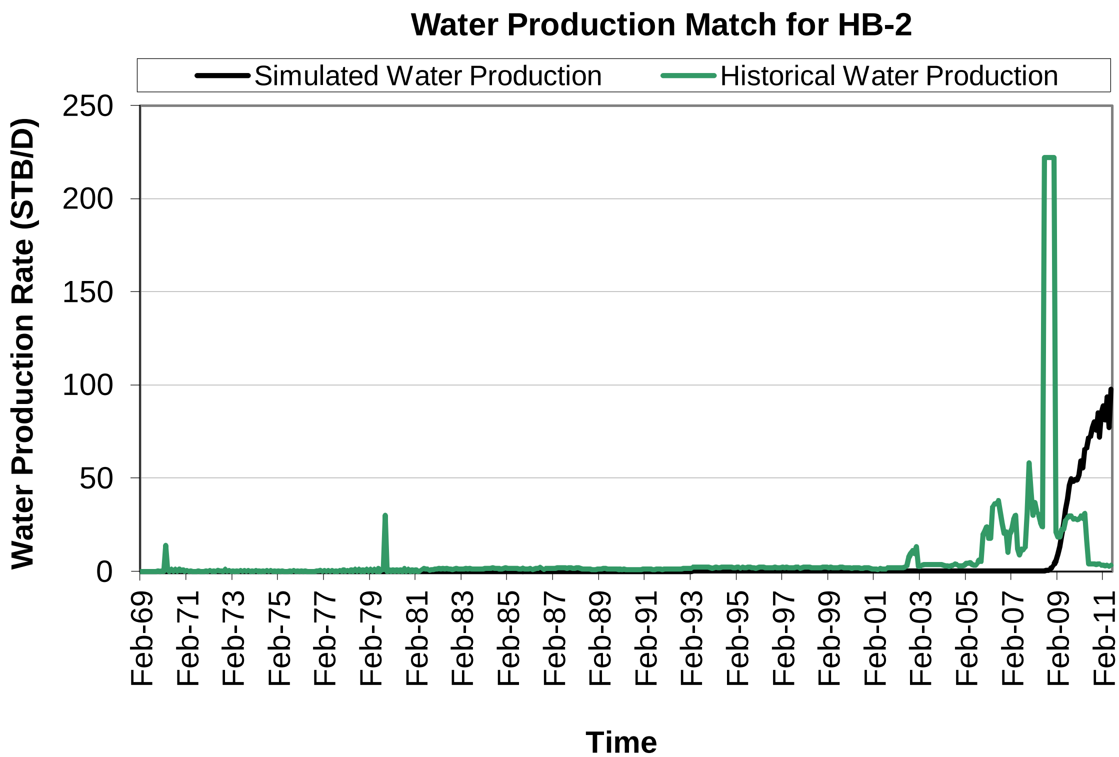


*Fig 6.18: Water Production Rate Match for HB-2*

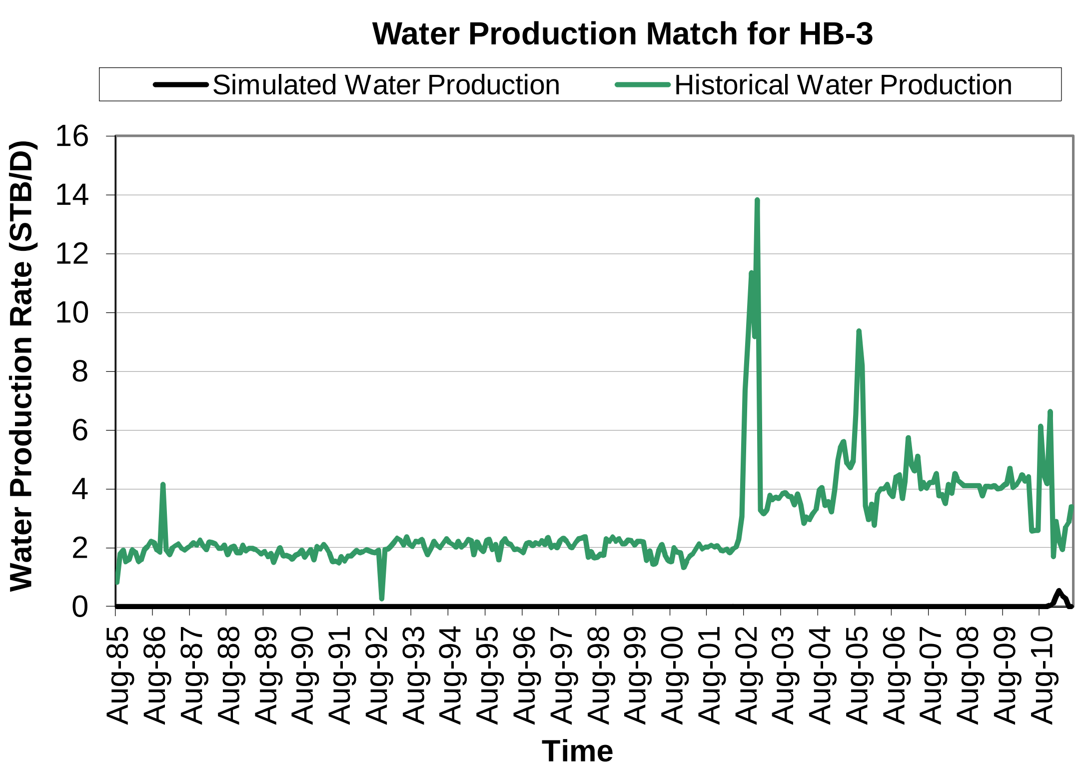


*Fig 6.19: Water Production Rate Match for HB-3*

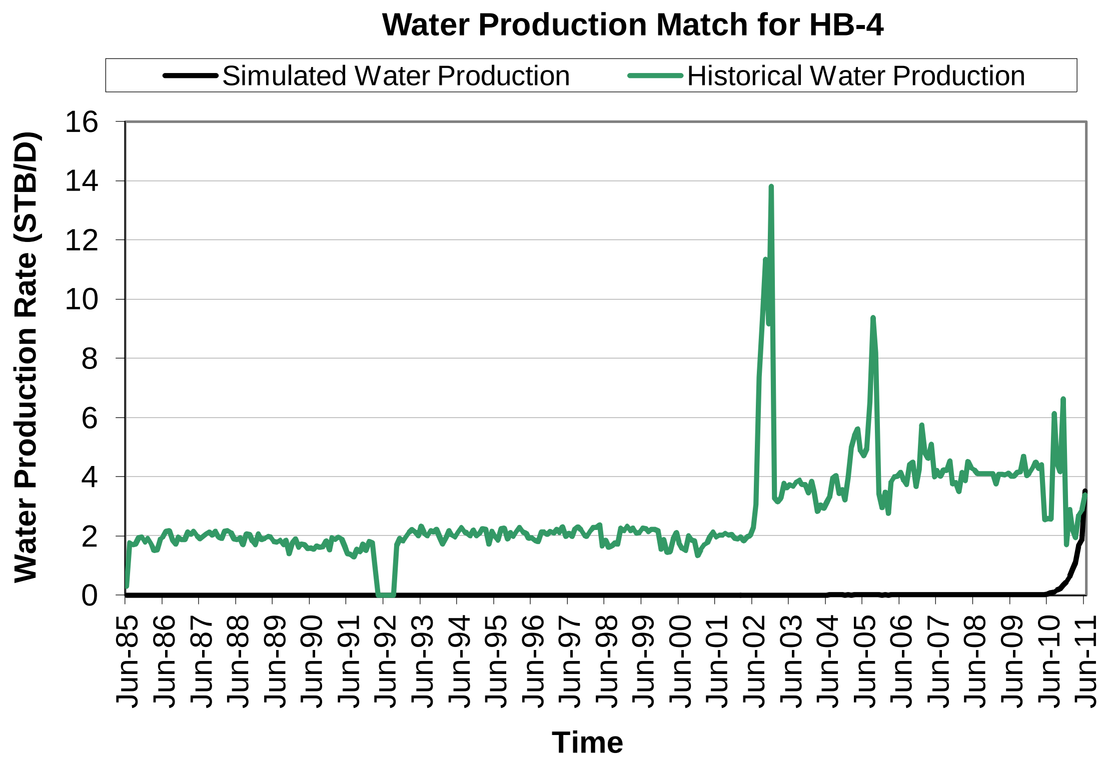


*Fig 6.20: Water Production Rate Match for HB-4*

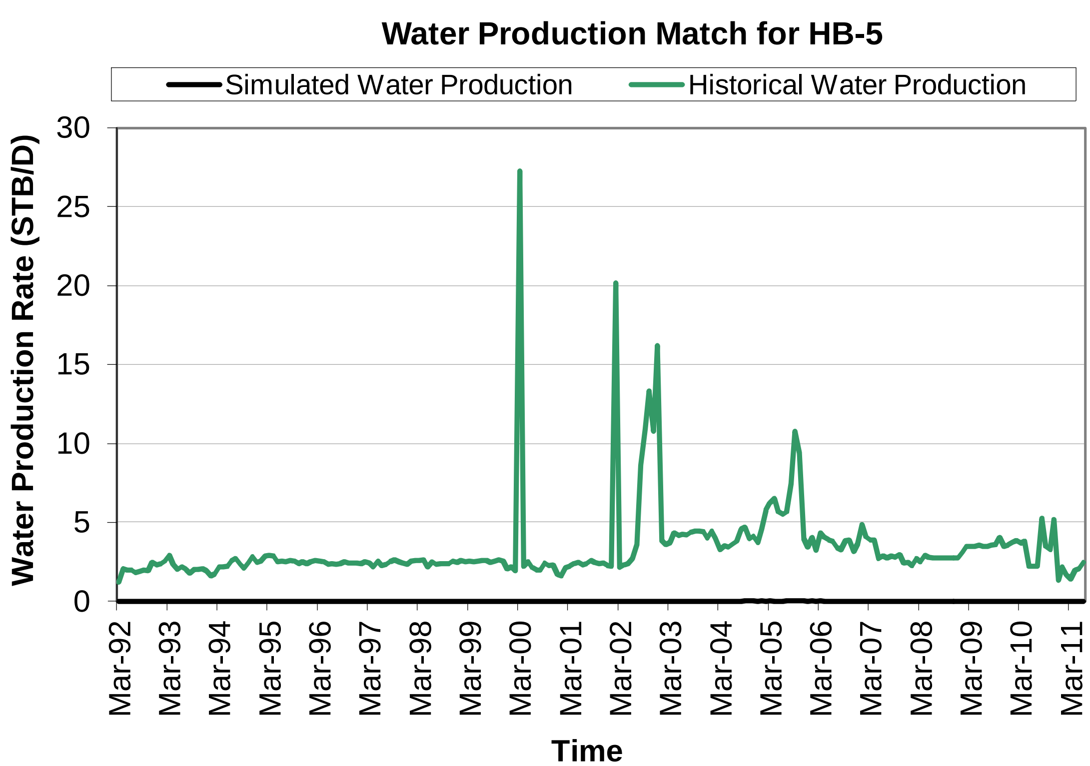


*Fig 6.21: Water Production Rate Match for HB-5*

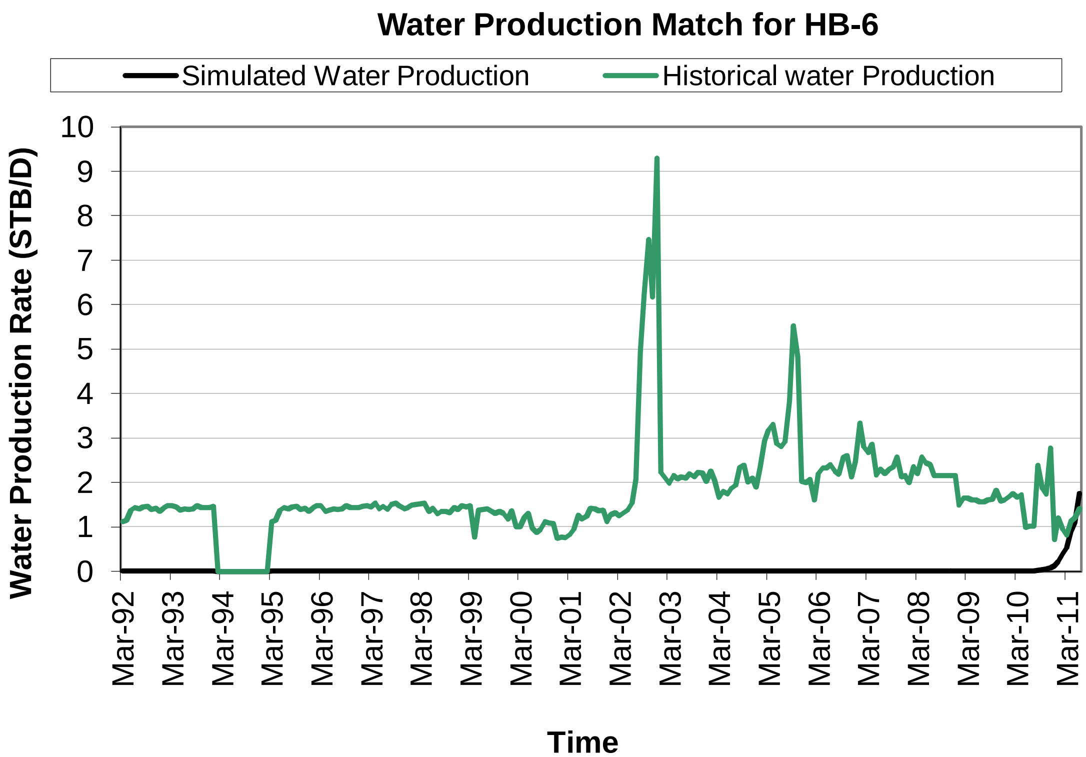


*Fig 6.22: Water Production Rate Match for HB-6*

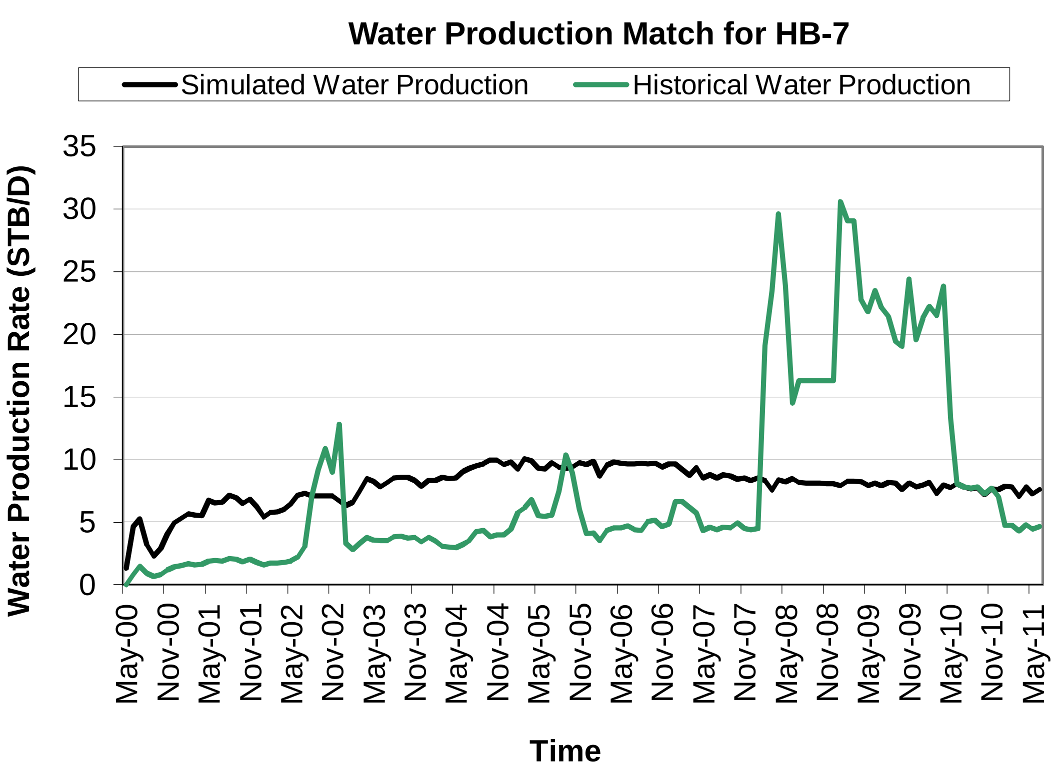


*Fig 6.23: Water Production Rate Match for HB-7*

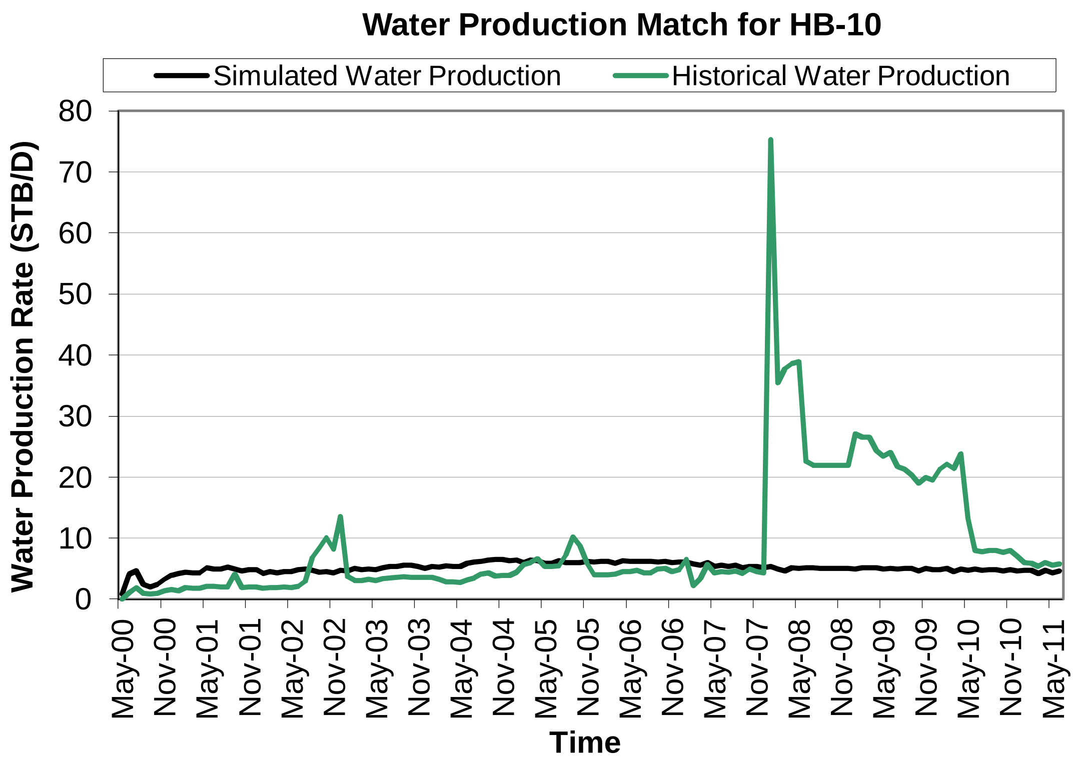


*Fig 6.24: Water Production Rate Match for HB-10*

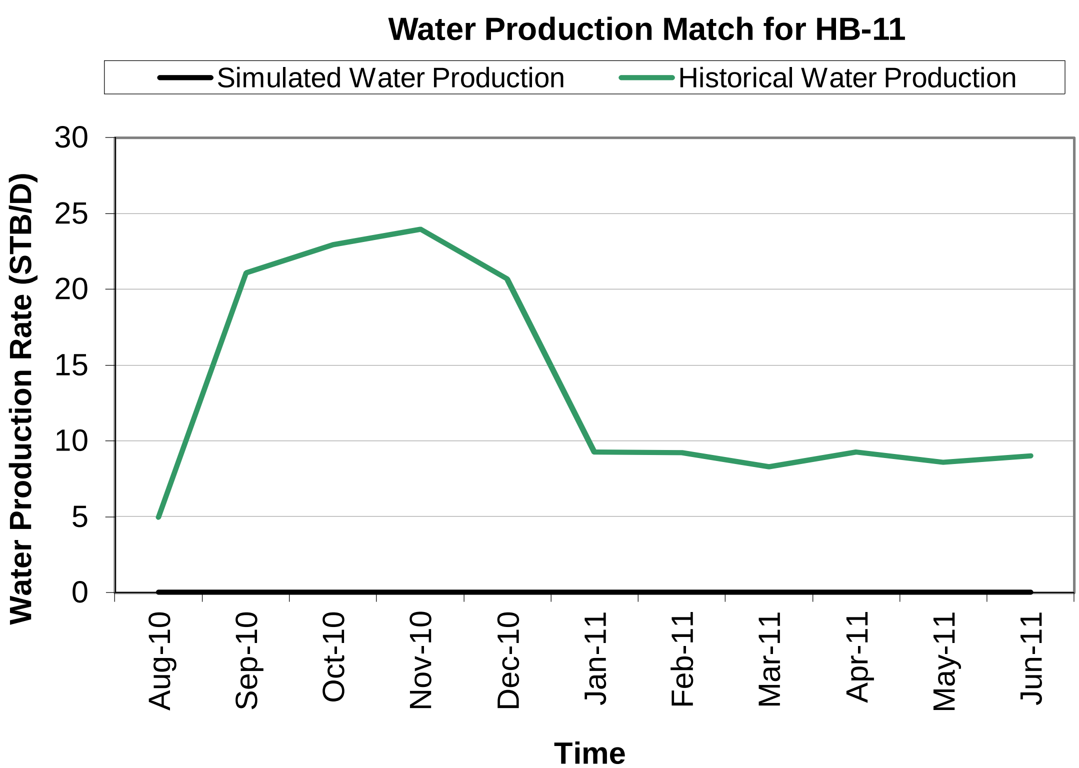


*Fig 6.25: Water Production Rate Match for HB-11*

# CHAPTER 7
# PREDICTION

A good history match is followed by performance predictions under different production scenarios. The prediction case scenarios for this study have been chosen based on the conditions of the existing wells. The objective was to find out whether the scenarios have any effect on the recoveries from the reservoir.

This chapter presents the performance of the field for different prediction scenarios

## 7.1 Short Term Prediction Case Scenarios

The history matched simulation model was run for five different short term prediction case scenarios. As the water production and in some cases, gas production and pressure data seemed to be erroneous, it was decided that the model would be run for additional five years. Though HB-1 and HB-2 started production from 1969, most of the remaining wells started producing from 90ŝs. It is assumed that a very well history matched simulation model can predict the performance with acceptable accuracy for half the period of the historical production period. Only 10 monthsô production data were available for the latest developed well HB-11. So the decision of running the model in prediction phase for additional 5 years was justified. The prediction scenarios are discussed below.

- Scenario 1: Base Case Prediction / Do- Nothing case
- Scenario 2: Reduction in Production for High Water Cut Wells
- Scenario 3: Workover of High Water Cut Wells
- Scenario 4: Production with Additional One Well
- Scenario 5: Production with Additional Two Wells

*Scenario 1:* In this case, history matched model was run for additional five years without any change or modification. It was assumed that the wells would be producing at constant rates equal to the production rates of last available historical production rates. The predicted result revealed that all wells except HB-1 and HB-3 would be producing smoothly without having high water cut throughout the predictive years. Well HB-1 would experience an immediate water breakthrough (Fig 7.1) and well HB-3 would experience an increase in water production from January 2014 (Fig 7.2) which would continue to rise sharply for the predictive periods. The prediction result can be treated as satisfactory because BGFCL has reduced well HB-1ôs production to half the original rate by the end of the year 2011 because of excessive water production.

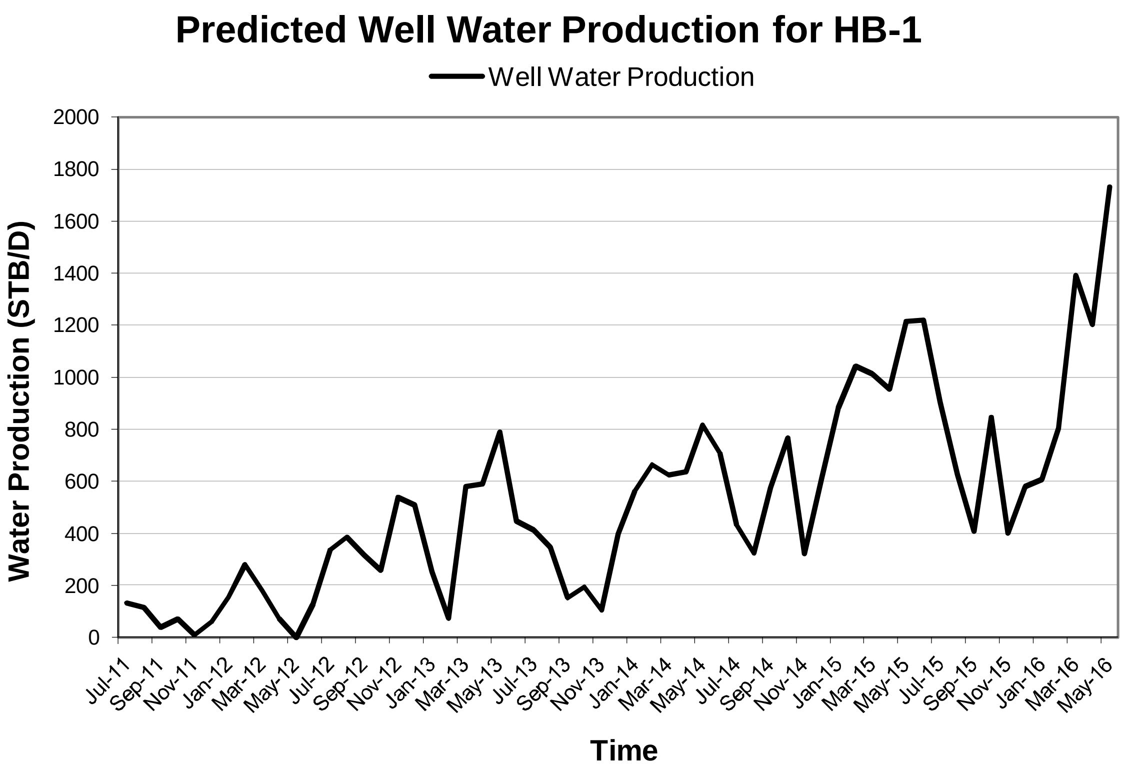


*Fig 7.1: Predicted Well Water Production for HB-1*

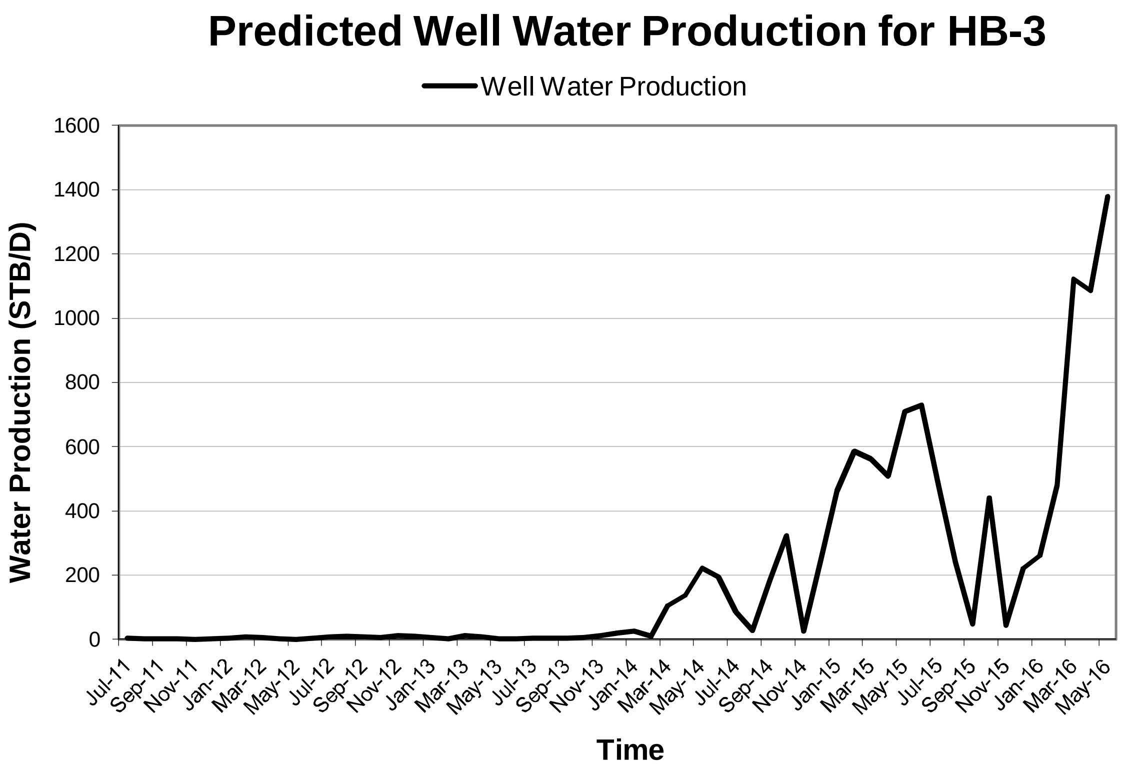


*Fig 7.2: Predicted Well Water Production for HB-3*

*Scenario 2:* In this prediction case, the productions from well 1 and well 3 were reduced to half the rate at the end of historical years. The objective was to find out whether a reduction in production would bring any change in water breakthrough time. It was observed that reduction in production would decreases the water production for well 1 and 3 but there would be no change in water breakthrough time (Fig 7.3 and Fig 7.4). Water production would suddenly increase sharply because the water table would reach the lower perforation level. If any delay is to be made to the breakthrough time, production should be lowered much before the water tables reaches the perforation level. Once high water production is observed, lowering the gas production will decrease the amount of water production but neither the breakthrough time will be delayed, nor will the well water gas ratio be decreased. In fact, in case of well 1 and 3 well water gas ratio increased for lower gas production (Fig 7.5 and Fig 7.6).

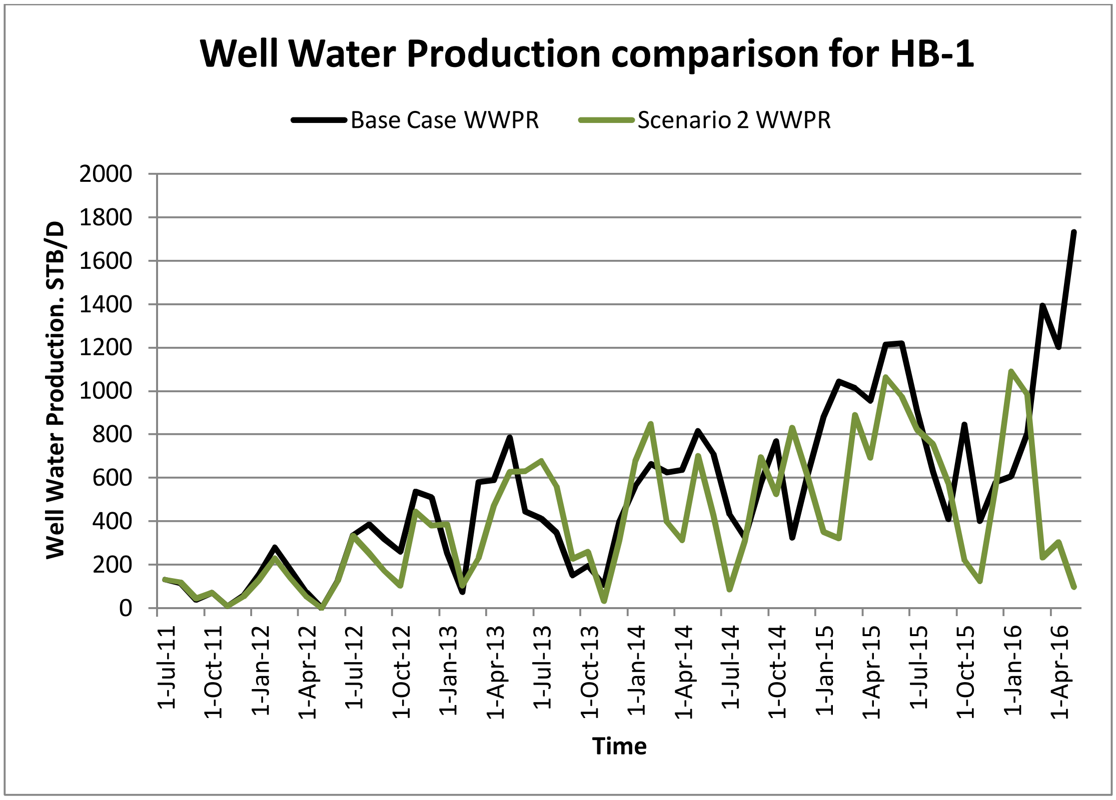


*Fig 7.3: Well Water Production Comparison for HB-1*

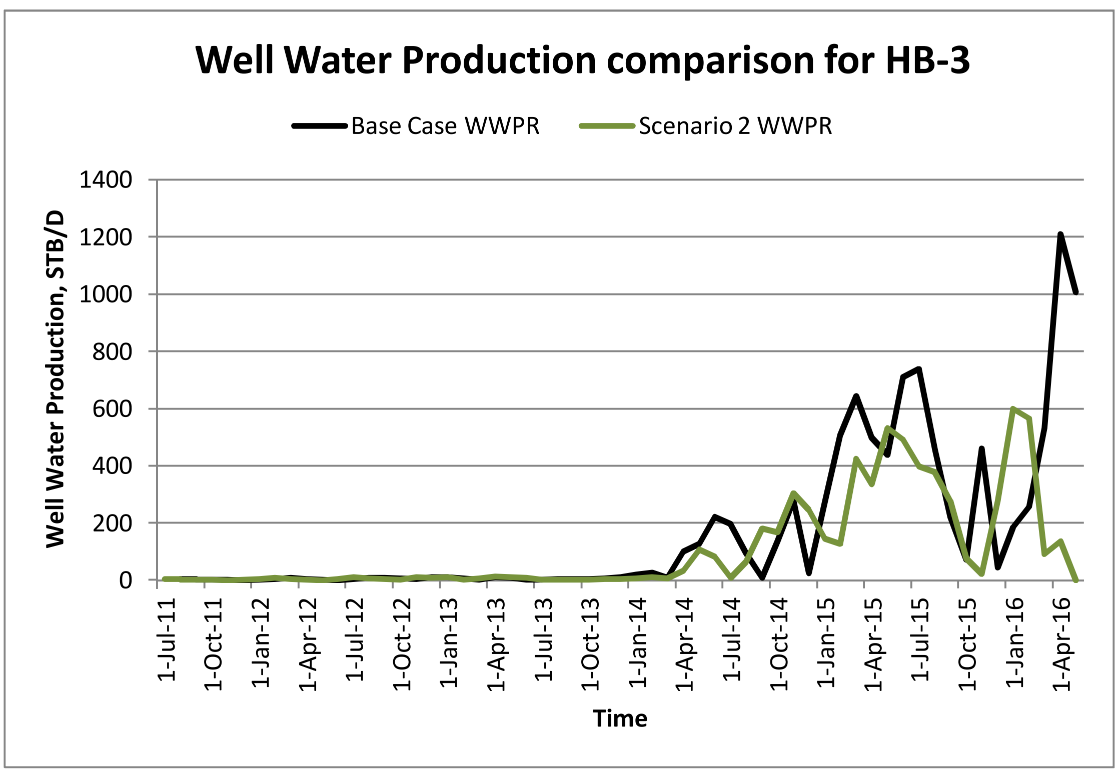


*Fig 7.4: Well Water Production Comparison for HB-3*

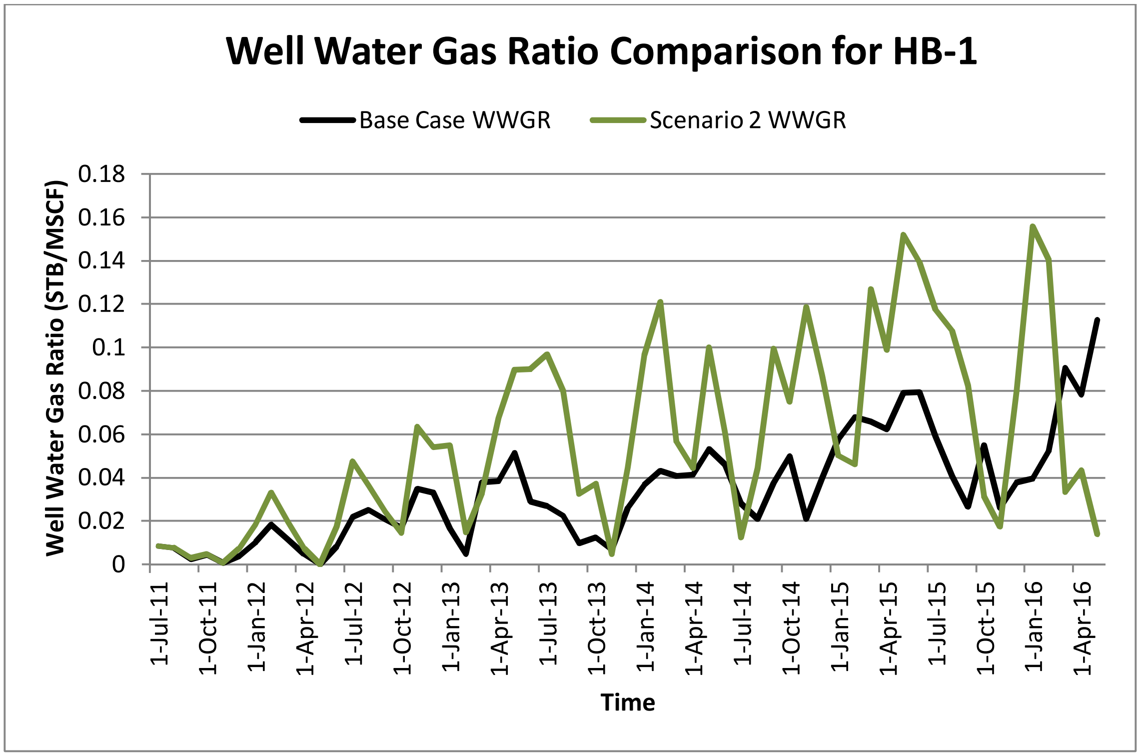


*Fig 7.5: Well Water Gas Ratio Comparison for HB-1*

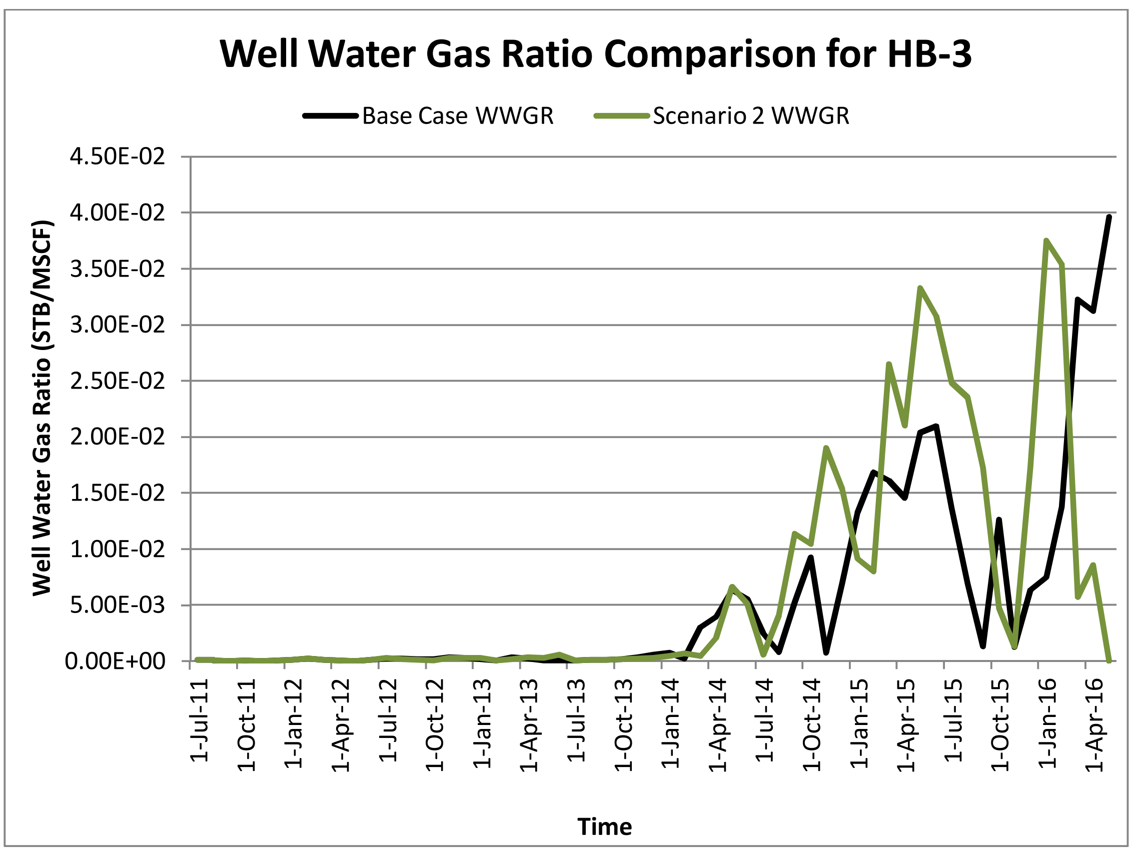


*Fig 7.6: Well Water Gas Ratio Comparison for HB-3*

*Scenario 3:* In this prediction case, the workover of well 1 and well 3 to plug back the lower perforations was considered. Once the water production would sharply increase, the lower perforations would be sealed off. The water production from the two wells would be ceased and no water breakthrough would be observed during the prediction years (Fig 7.7 and Fig 7.8).

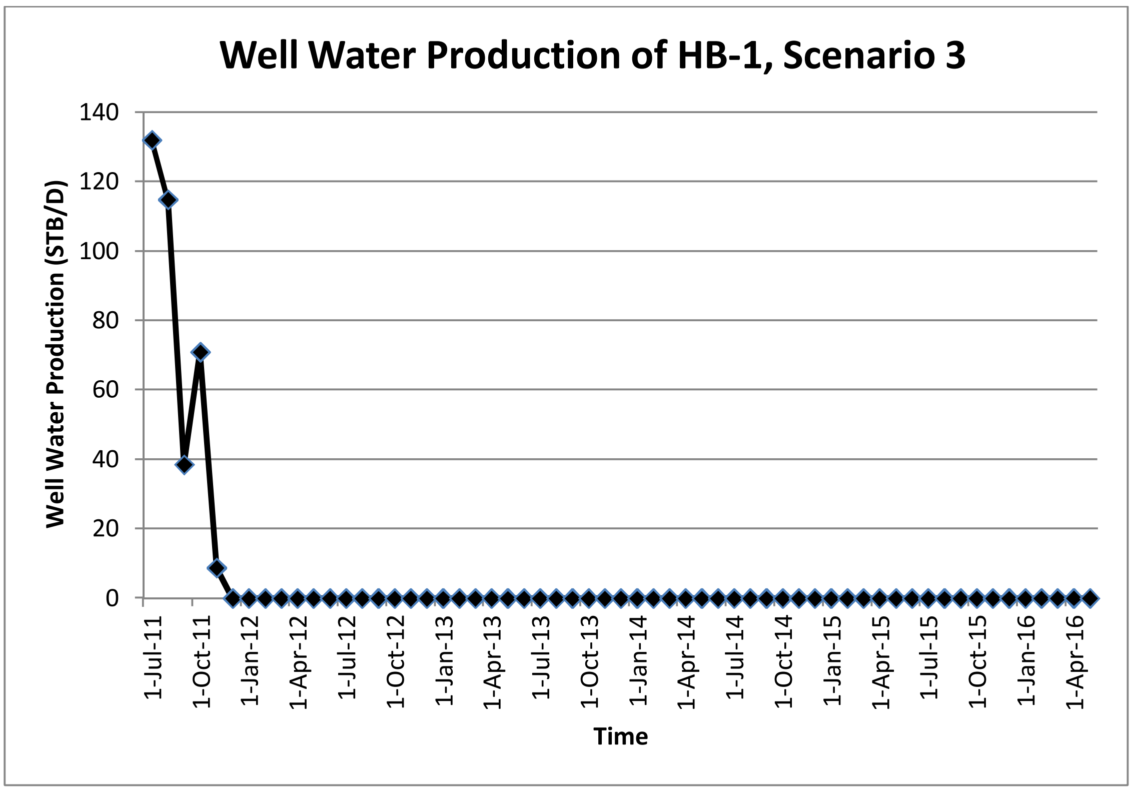


*Fig 7.7: Scenario 3 Well Water Production of HB-1*

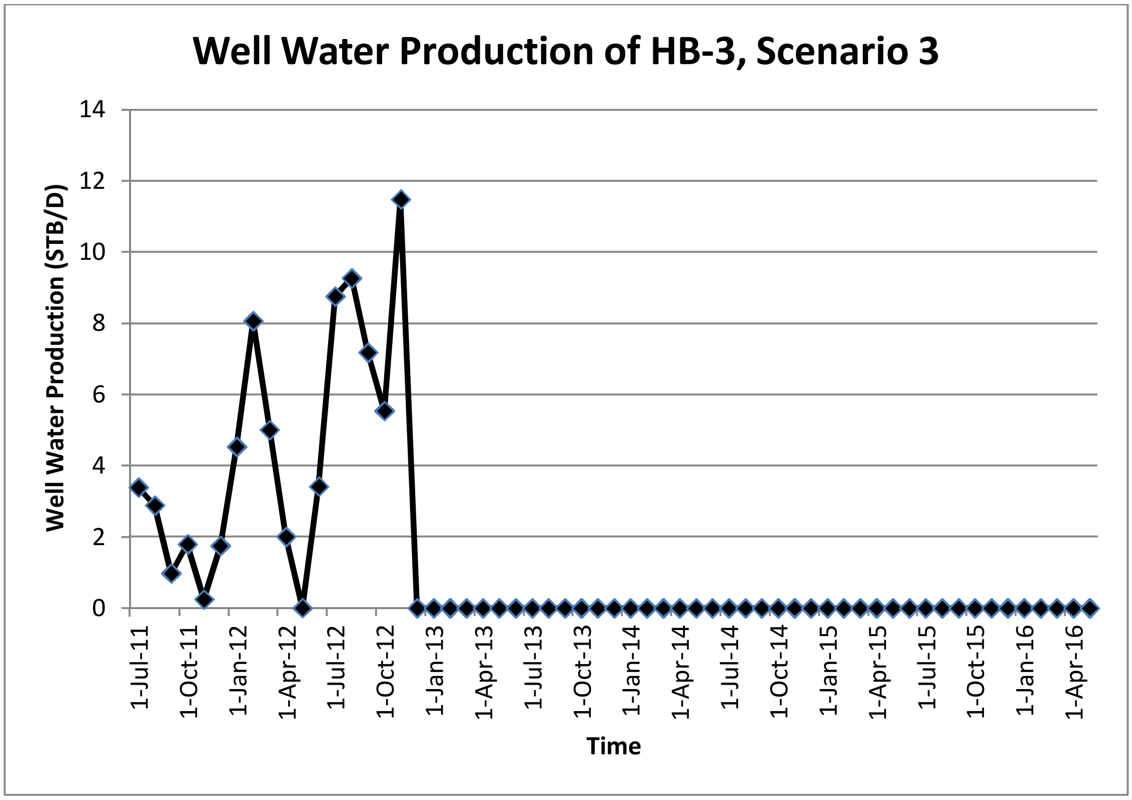


*Fig 7.8: Scenario 3 Well Water Production of HB-3*

*Scenario 4*: in this prediction case, drilling of a new well was considered with all other wells producing at their normal rate. Workover of HB-1 and HB-3 was also considered as workover proved to be the only effective solution to control water production from those wells. The new well was named as HB-12 and it was considered that production from the well would start from June 2012. The location of the well was selected based on the gas saturation of the reservoir at the time when drilling was considered and on the density of the wells at a particular area of the reservoir. The production rate was set at 20 MMSCFD. Tubing head pressure variation (Fig 7.9) shows a gradual and consistent decrease over time with no sharp pressure fall. Water production profile (Fig 7.10) shows negligible water production throughout the whole prediction period.

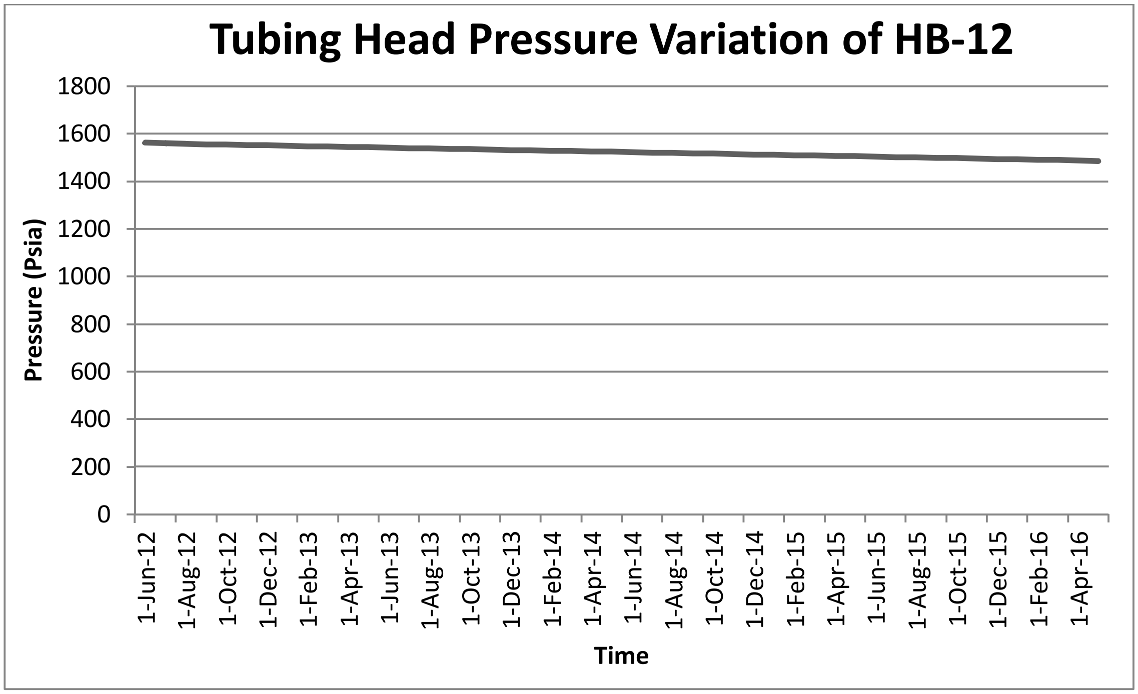


*Fig 7.9: Tubing Head Pressure Variation of HB-12*

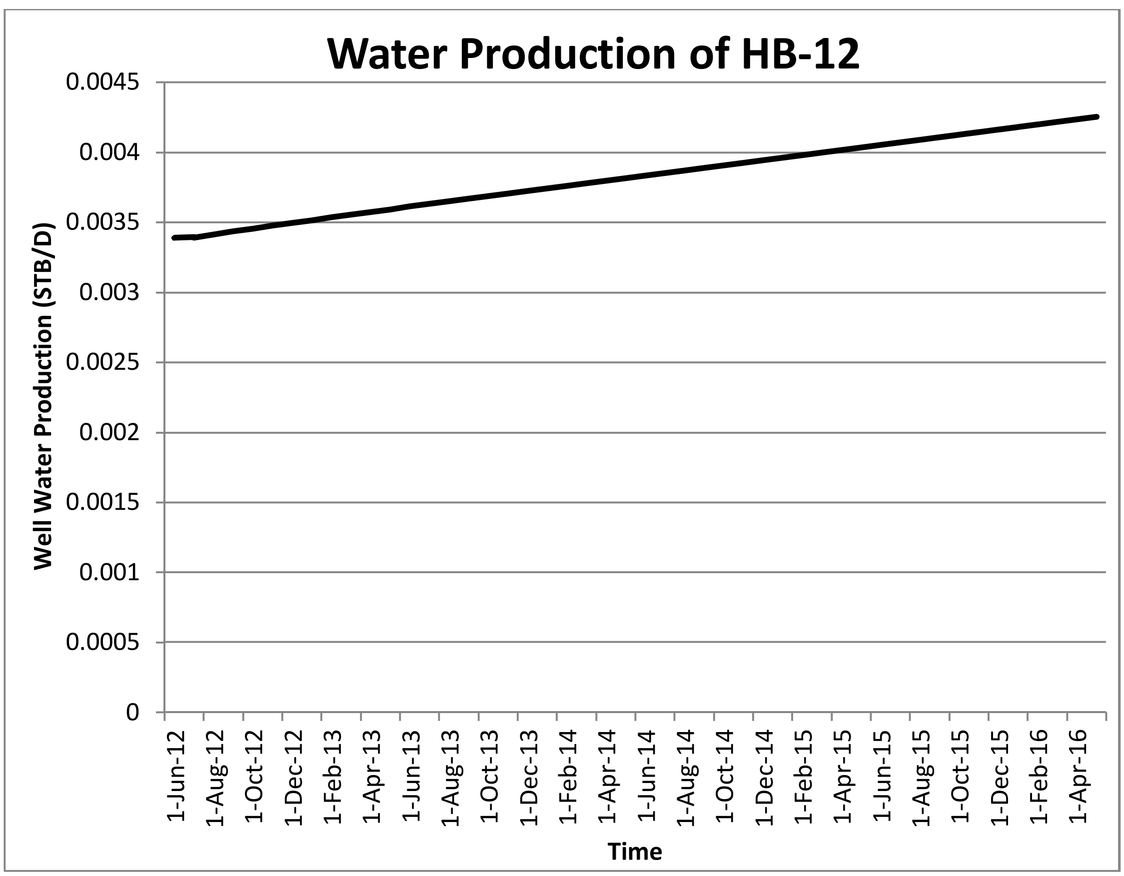


*Fig 7.10: Water Production Profile of HB-12*

*Scenario 5:* in this prediction case, drilling of two additional wells was considered. The wells were named as HB-12 and HB-13. The locations of the wells were selected applying the same criteria as applied for HB-12 alone, i.e. the gas saturation and the density of the existing wells. The gas production started from June 2012 and production rate for each well was set at 20 MMSCFD. Tubing head pressure variation (Fig 7.11) shows a gradual and consistent decrease over time with no sharp pressure fall for both the wells. Water production profile (Fig 7.12) of the wells shows negligible water production throughout the whole prediction period.

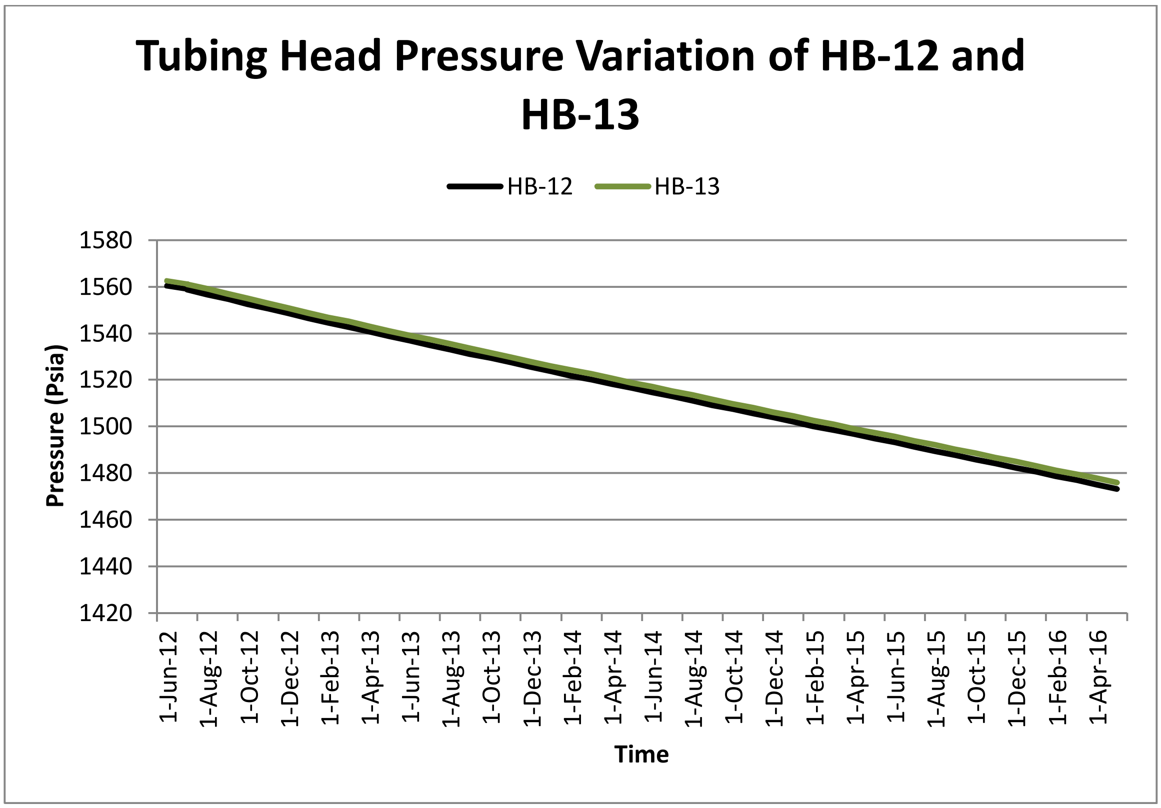


*Fig 7.11: Tubing Head Pressure Variation of HB-12 and HB-13*

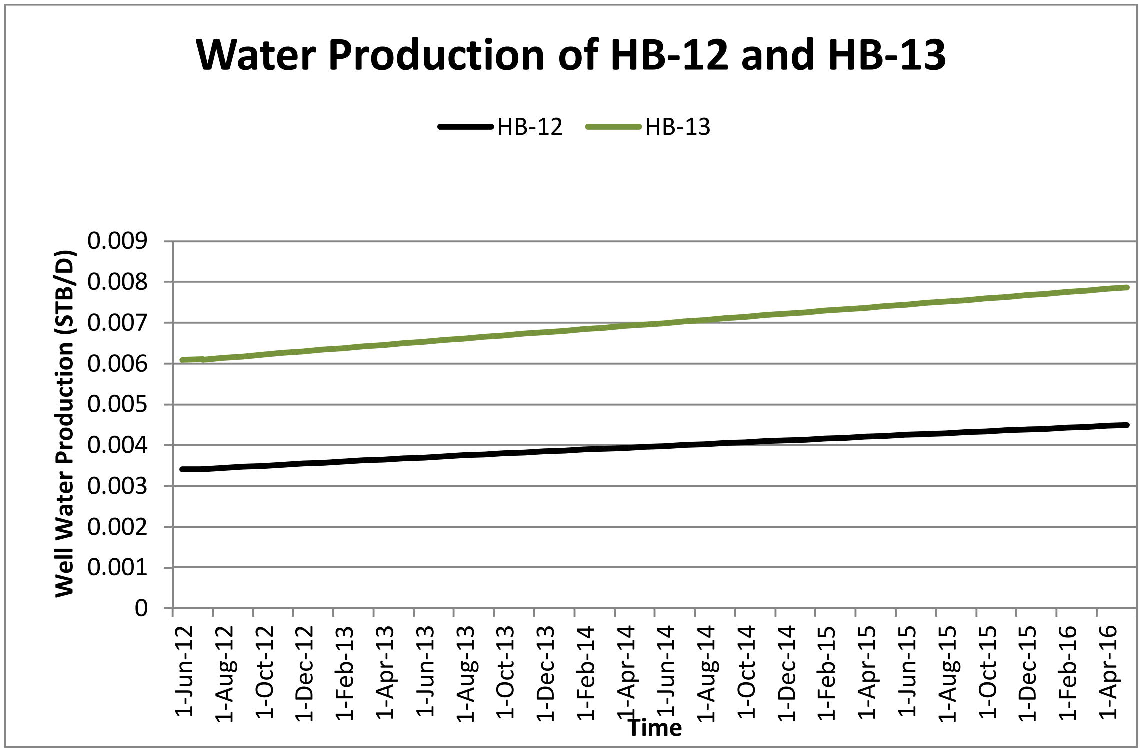


*Fig 7.12: Water Production Profile of HB-12*

Fig 7.13 shows the position of added wells (well HB-12 and well HB-13) with all other wells of Habiganj gas field.

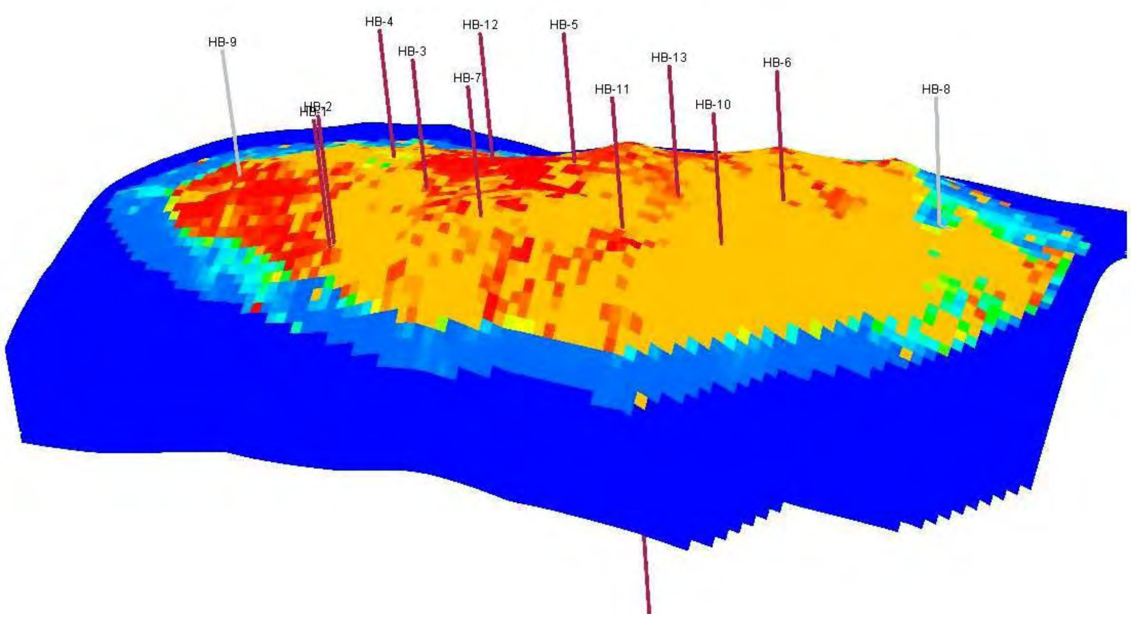


*Fig 7.13: Position of Added Wells*

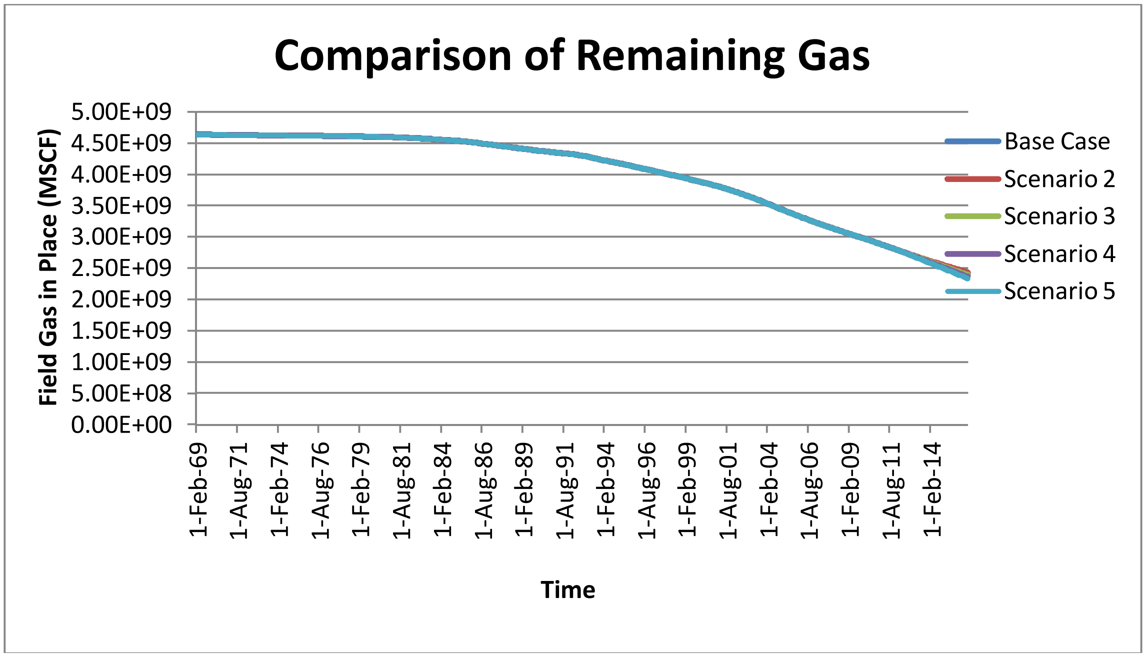


*Fig 7.14 Amount of Remaining Gas till the End of Prediction Years( short term)*

Fig 7.14 shows the remaining gas in place for different scenarios after 2016. The cumulative recovery for Scenario 1,2,3,4 and 5 will be 48.27%, 47.62%, 48.27%, 48.92% and 49.56% respectively.

### 7.2 Long Term Prediction Case Scenarios

It is expected from any simulation study that it will provide an idea about the long term field performances. The initial prediction runs of this study were designed only for additional five years because of the poor data quality. However, some long term (up to 2040) prediction cases under different production scenarios were run to see the effect of each scenario on ultimate recovery. It cannot be said confidently that the results of these long term prediction cases will be accurate.

A well economic limit of 1000 MSCFD gas production and 1000 STB/D water production were set for all the scenarios. That is, any well producing less than 1000 MSCFD gas or greater than 1000 STB/D water will automatically get shut down. The prediction case scenarios are discussed below.

- Scenario A: Base Case Prediction up to 2040
- Scenario B: Prediction up to 2040 With Additional Two Wells
- Scenario C: Prediction up to 2040 With Workover of High Water Cut wells
- Scenario D: Prediction up to 2040 With Additional Two Wells and Workover of High Water Cut Wells

*Scenario A*: in this case, the simulation model was run for additional 28 years with well economic limits set. Fig 7.14 shows the variation of gas production rate of the wells with time.

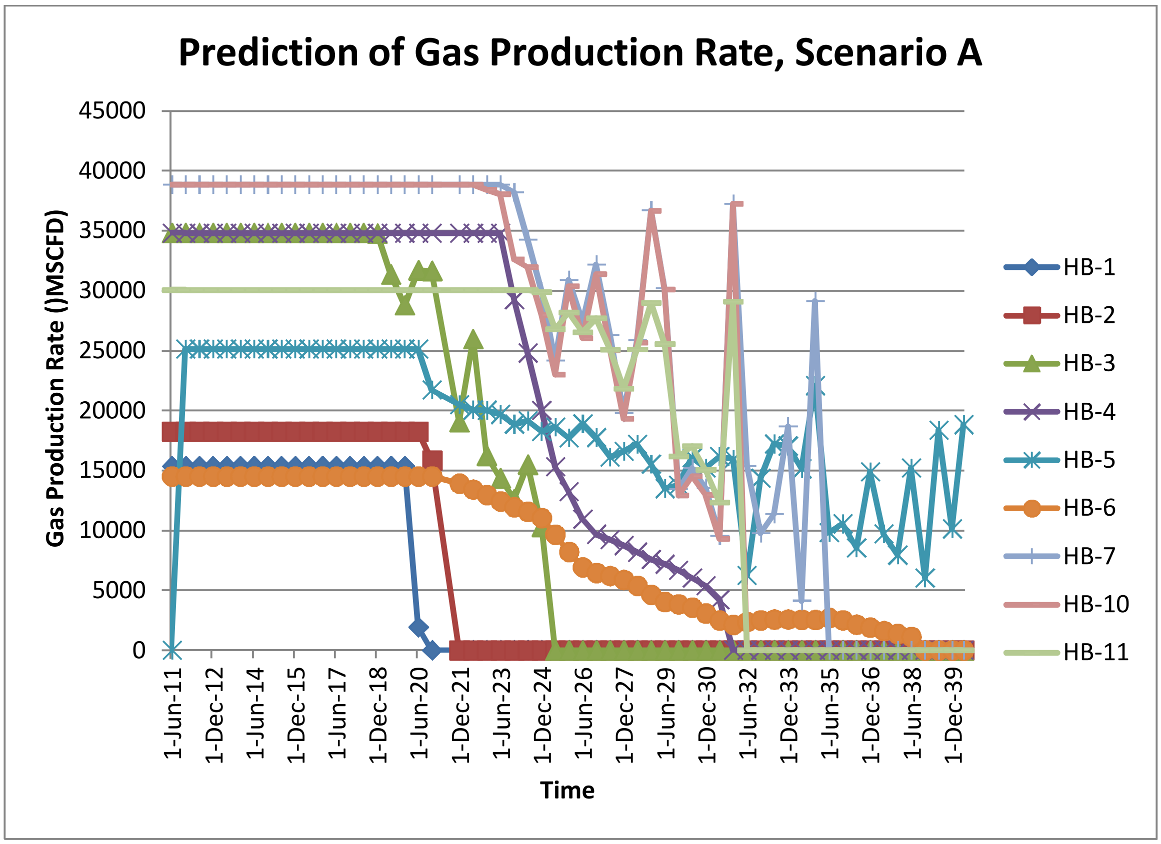


*Fig 7.15: Gas Production Rates of wells, scenario A*

Only well HB-5 will continue to produce up to 2040. Well HB-1 will terminate production in the year 2020 followed by HB-2 in 2021. HB-3 will be the next well to stop production from 2025. All other wells (HB-4, HB-6, HB-7, HB-10, HB-11) will be shut down within the period from 2031 to 2038. Total gas production for this scenario will be 3.2 TCF that will result in an ultimate recovery of 70.7%.

*Scenario B*: In this case, drilling of two additional wells was considered. The simulation model was run for additional 28 years (up to 2040). The positions of the wells were same as the positions selected for Scenario 5 (Section 7.1). Initial production rates for the wells were set at 20MMSCFD. Fig 7.15 shows the variation of gas production of the wells for Scenario B.

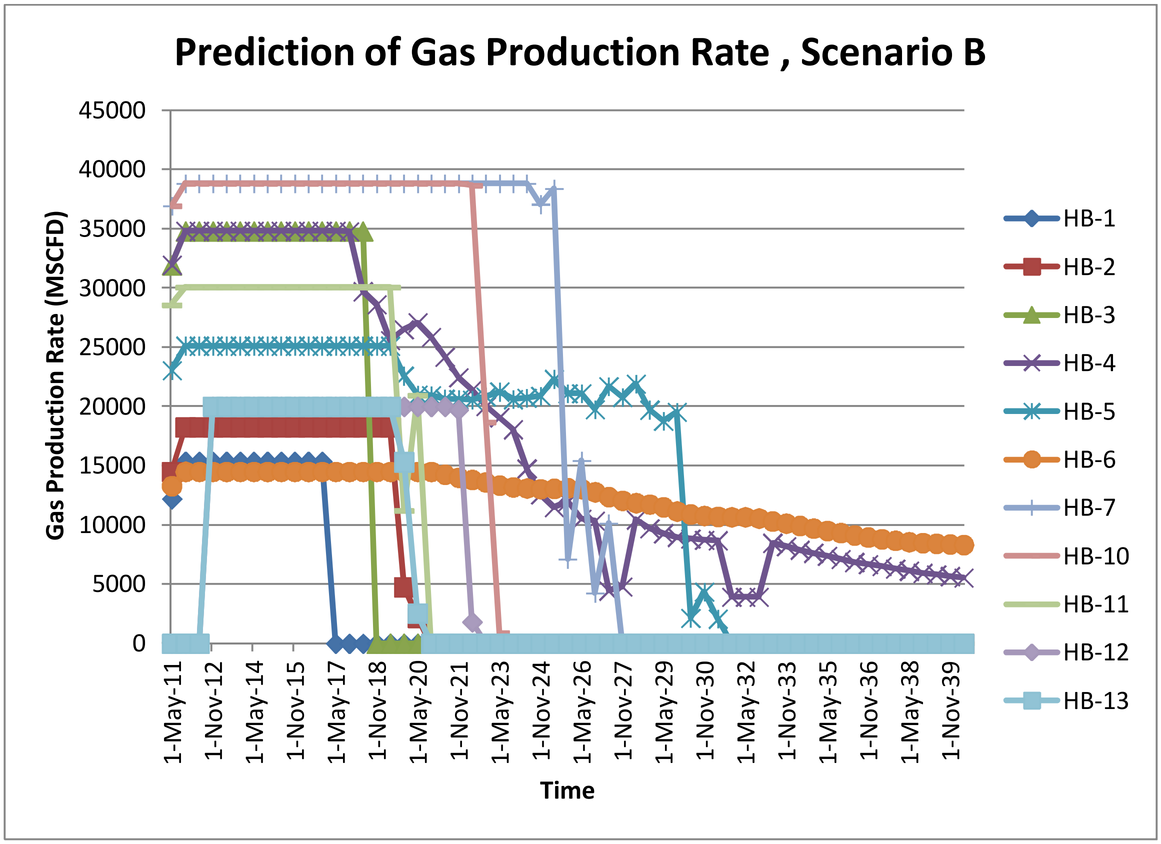


*Fig 7.16: Gas Production Rates of wells, scenario B*

Wells HB-4 and HB-6 will continue to produce up to 2040. All other wells will be shut at earlier times compared to Scenario A. Ultimate recovery will be 65%

*Scenario C*: In this case, workover of high water cut wells to plug back the lower perforations was considered. Workover schedules were set by observing the onset of high water production from the wells as seen in Scenario A. Workover schedules chosen for different wells are as follows:

HB-1: November 2011

HB-2: May 2020

HB-3: May 2013 and May 2018

HB-4: May 2018

HB-5: May 2018 and May 2028

HB-6: May 2021

HB-7: May 2023

HB-10: May 2022

HB-11: May 2019

Fig 7.16 shows the variation of gas production rate of the wells for Scenario C.

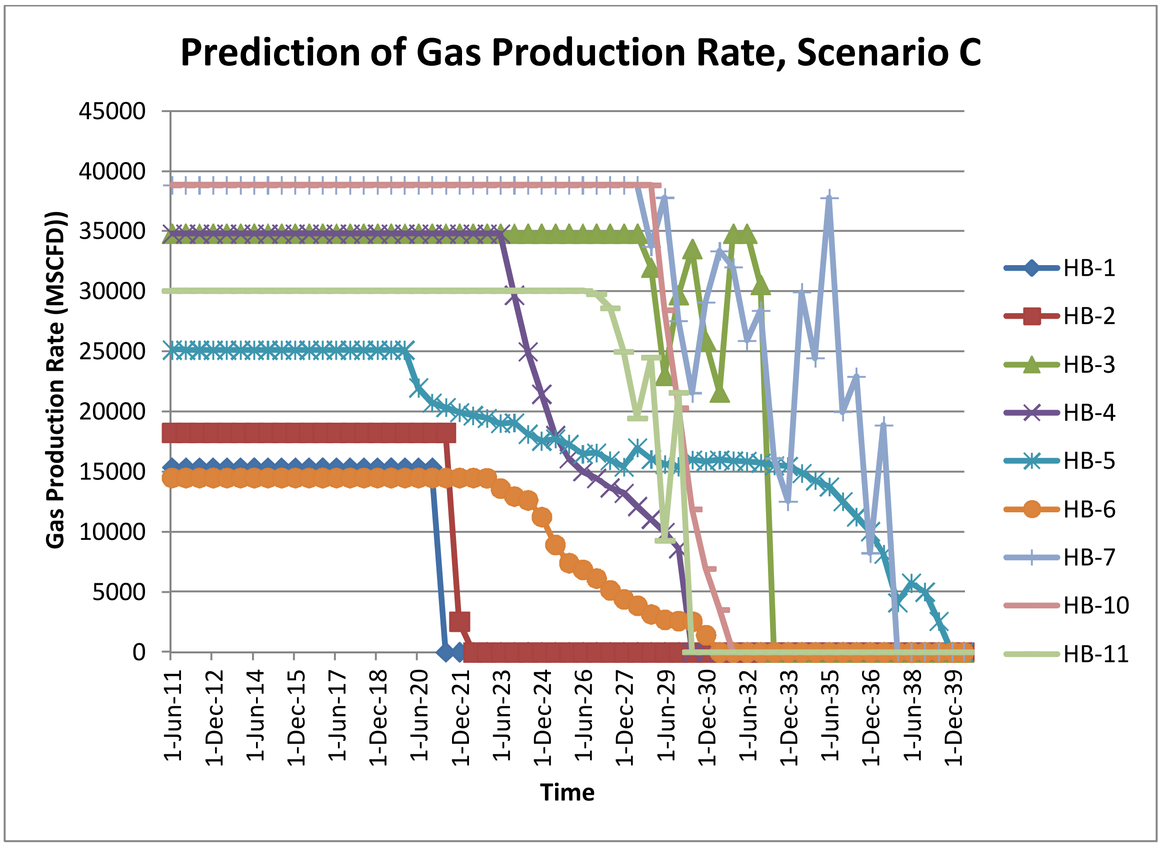


*Fig 7.17: Gas Production Rates of wells, scenario C*

Total Gas production for this scenario will be 3.44 TCF and ultimate recovery will be 74%.

*Scenario D:* In this case, addition of two wells and workover of high water cut wells to plug back lower perforations were considered simultaneously. Workover schedules were set by observing the onset of high water production from the wells as seen in Scenario B. Workover schedules chosen for different wells are as follows:

HB-1: November 2011

HB-2: May 2019

HB-3: May 2013 and May 2018

HB-4: May 2017

HB-5: May 2019 and May 2028

HB-6: May 2020

HB-7: May 2023

HB-10: May 2022

HB-11: May 2016

HB-12: May 2019

HB-13: May 2019

Fig 7.18 shows the variation of gas production rate of the wells for scenario D.

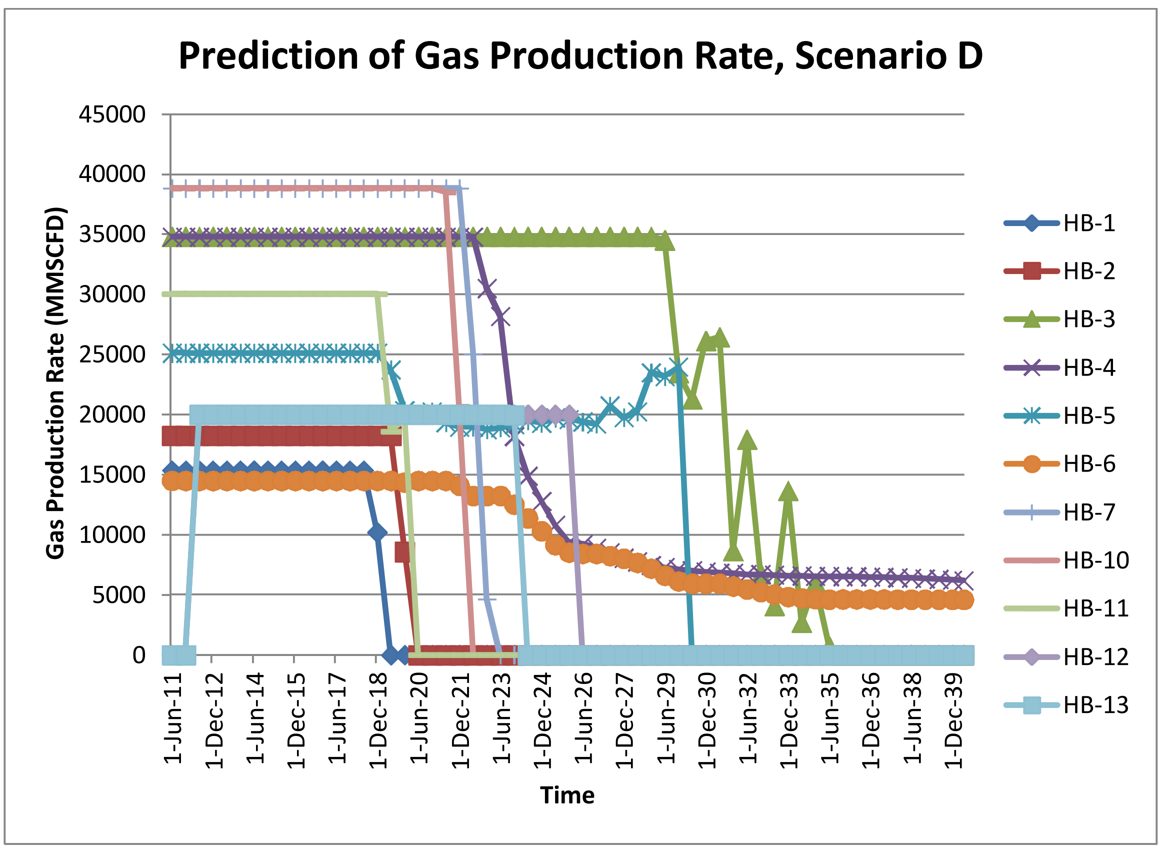


*Fig 7.18: Gas Production Rates of wells, scenario D*

Total Gas production for this scenario will be 3.20 TCF and ultimate recovery will be 69%.

Fig 7.19 shows the comparison of remaining gas in place and total gas production for different long term prediction scenarios. Incremental recovery with additional two wells (Scenario B) will be greater compared to incremental recovery with no additional well (Scenario A) during initial predictive years. After few years, total gas production of Scenario B will start to decrease and finally from August 2022, total amount of gas produced by Scenario B will fall below the total amount of gas produced by Scenario A. the difference in production will increase gradually.

When a highly permeable reservoir is depleted quickly with additional wells, the water table upward movement also gets faster. Water front reaches the lower perforations of the wells more quickly and wellsô producing life becomes short. That is why ultimate recovery for Scenario A is greater than that of Scenario B (70.7% for Scenario A, 65% for Scenario B).

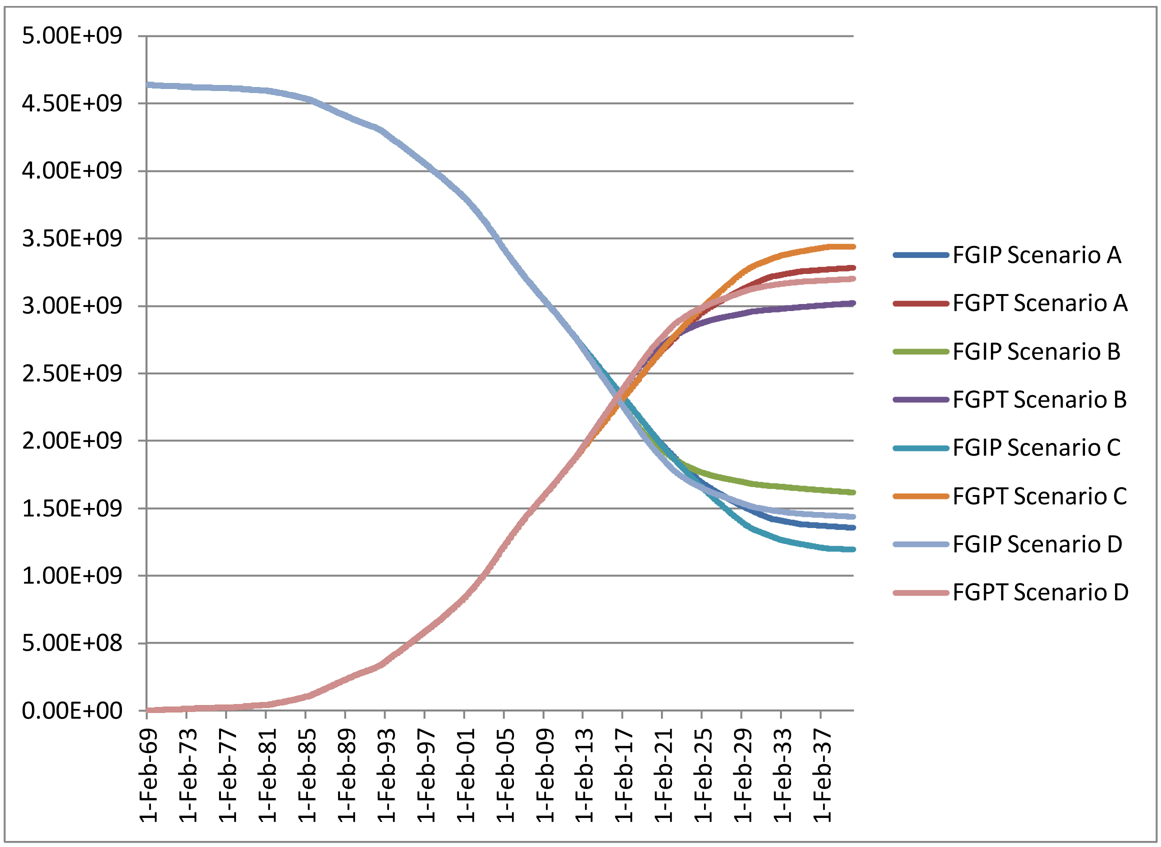


*Fig 7.19: Comparison of Gas in Place and Total Gas Production for Different scenarios*

Plugging back the lower perforations of high water cut wells (Scenario C) will increase the flowing life of most of the wells. Total gas production for Scenario C will be highest that will result in an ultimate recovery of 74%.

Addition of two wells and workover of the high water cut wells (Scenario D) together will produce more that will result in a higher ultimate recovery (69%) than that of Scenario B (65%). The ultimate recovery for Scenario D will still be less than Scenario C because of the same fact that high depletion rate will result in the fast movement of water table and wells will be suspended earlier.

Figs 7.20 to 7.30 show the comparison of gas production rate and total gas production of individual wells for all the long term prediction scenarios.

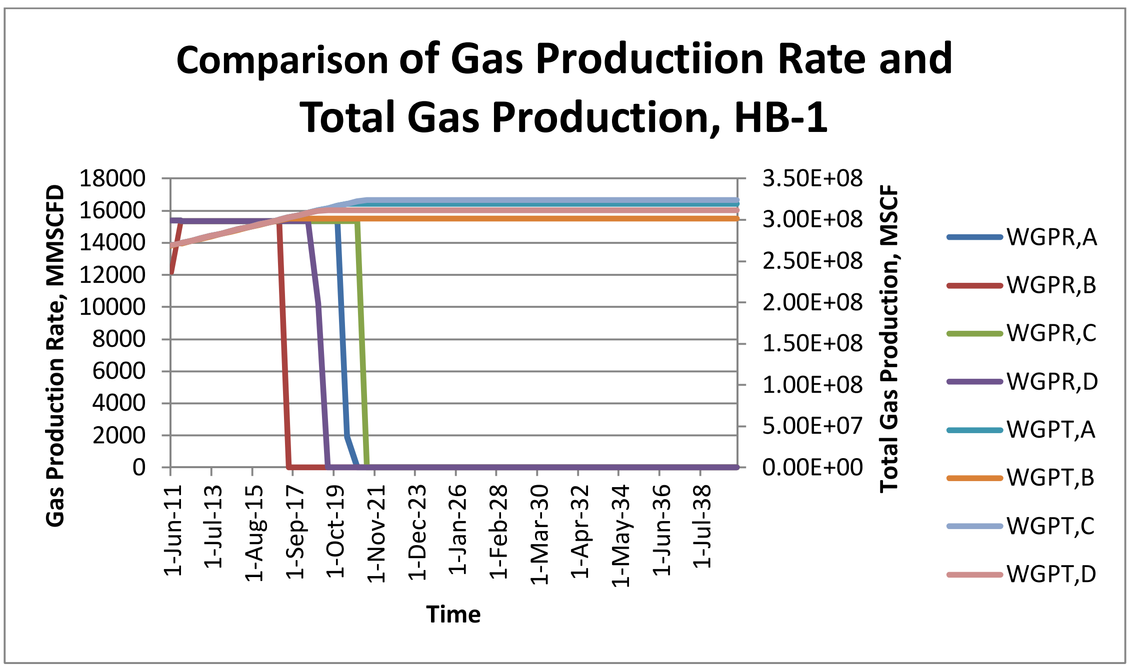


*Fig 7.20: Comparison of Gas Production Rate and Total Gas Production of HB-1 for Different scenarios*

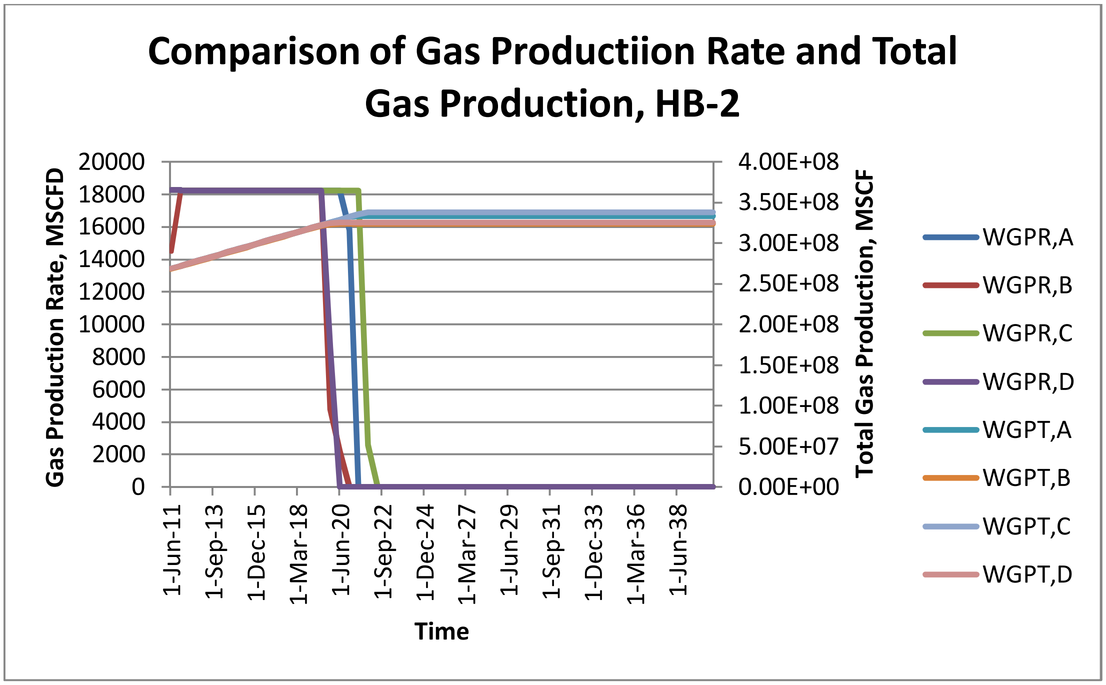


*Fig 7.21: Comparison of Gas Production Rate and Total Gas Production of HB-2 for Different scenarios*

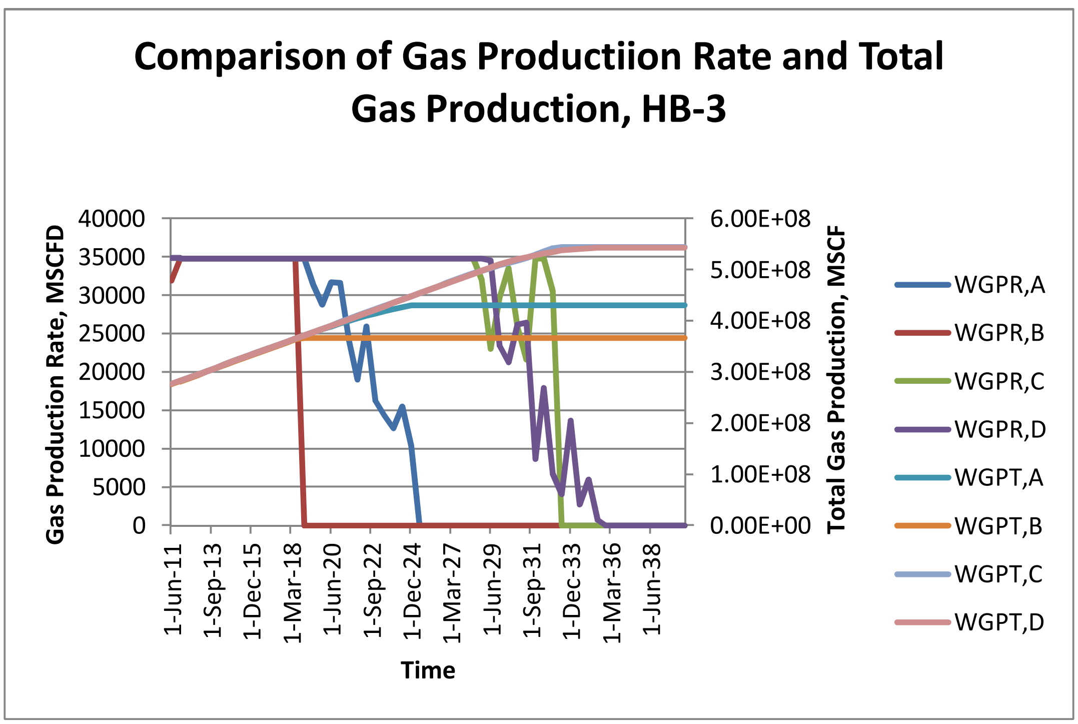


*Fig 7.22: Comparison of Gas Production Rate and Total Gas Production of HB-3 for Different scenarios*

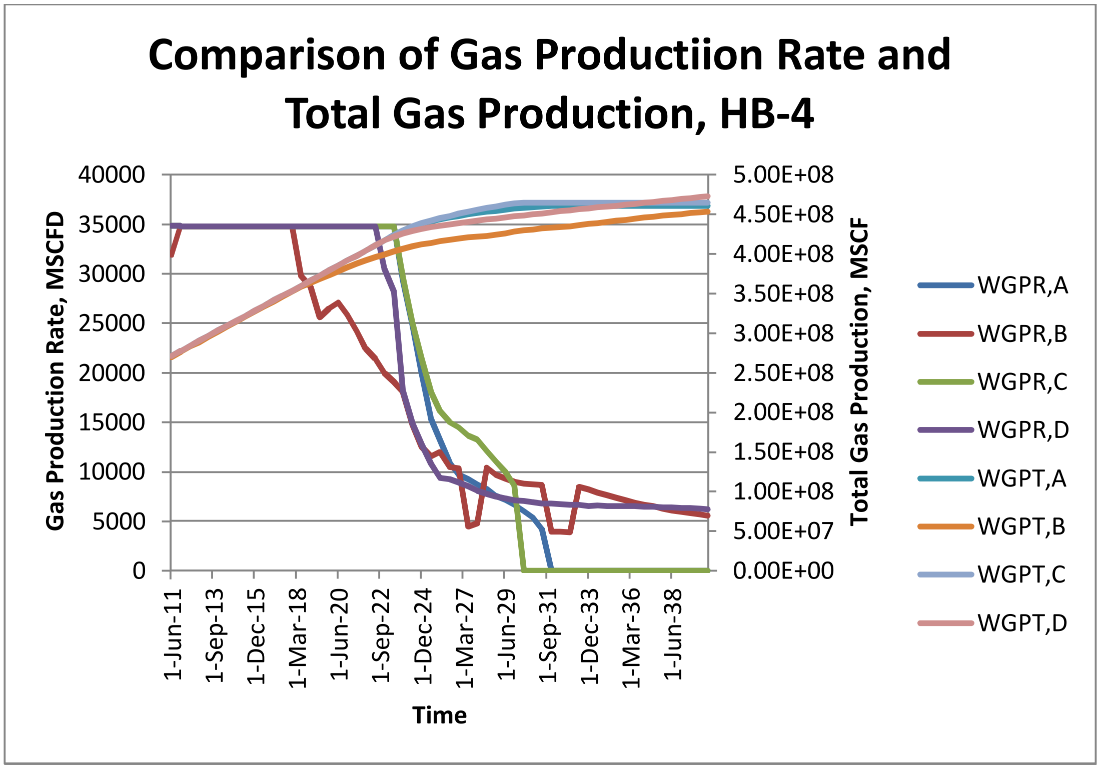


*Fig 7.23: Comparison of Gas Production Rate and Total Gas Production of HB-4 for Different scenarios*

For HB-1, HB-2 and HB-3(Fig 7.20, 7.21, 7.22) highest ultimate recovery will be obtained from Scenario C. Well life will be longest for Scenario C in case of wells HB-1 and HB-2. In case of HB-3, well life will be longest for Scenario D but production rate will start to fall earlier in this case. As a result ultimate recovery for this case will be lower than that of Scenario C. In case of HB-4, wellsô producing life will be longest for Scenario B and Scenario D and highest ultimate recovery will be obtained from Scenario D (Fig 7.23). When reservoir is depleted quickly with additional wells, most of the wells face an early water breakthrough and decline in gas production rate. When economic limits will be violated, the wells will be shut down. When majority of the wells will be shut down, the wells that will still be producing will get longer life because of the fact that water table movement rate will be slowed down. The existing wells will be producing conveniently. In this way, addition of two wells and plugging back the lower perforations of the well will together result in highest recovery for HB-4.

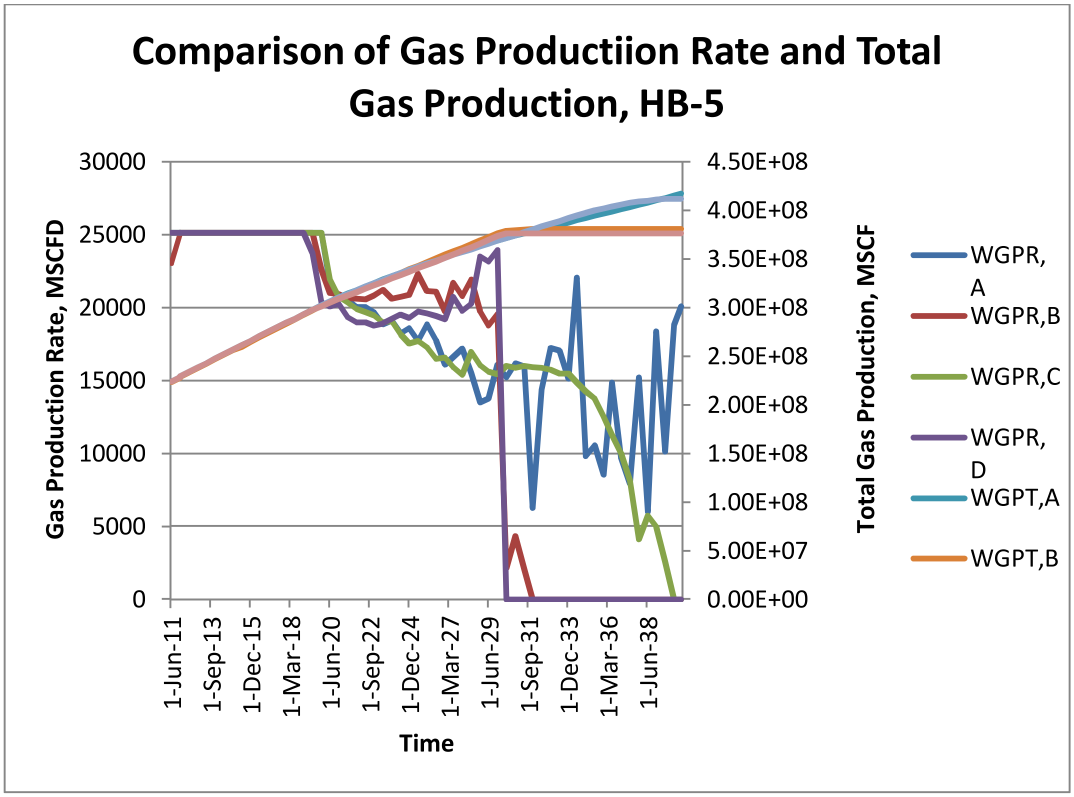


*Fig 7.24: Comparison of Gas Production Rate and Total Gas Production of HB-5 for Different scenarios*

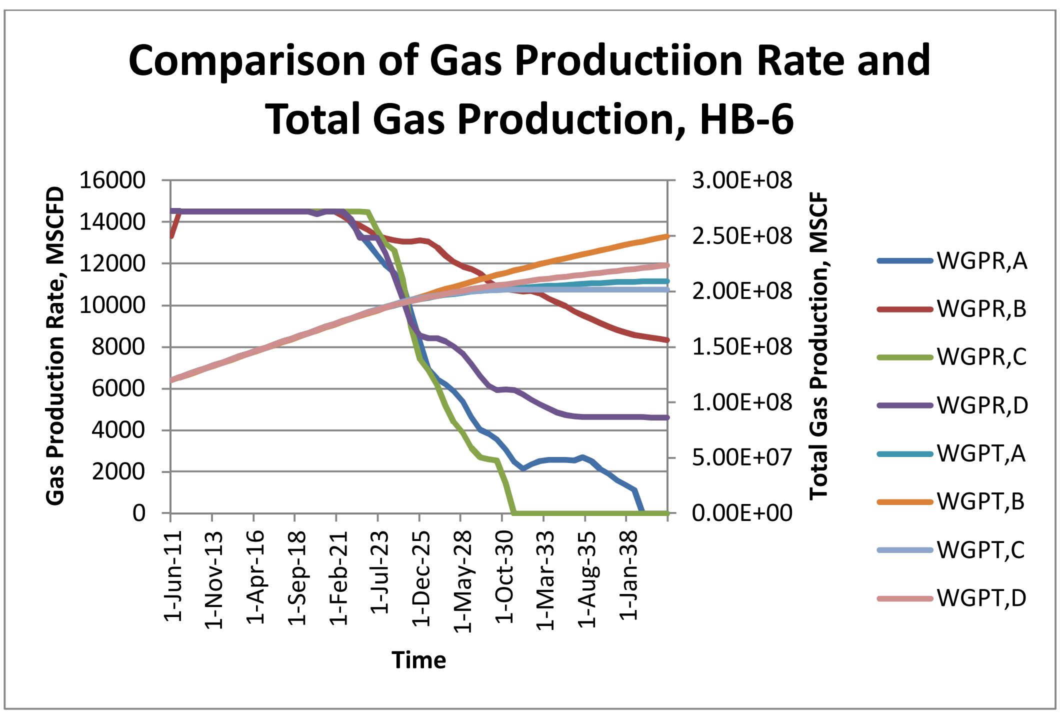


*Fig 7.25: Comparison of Gas Production Rate and Total Gas Production of HB-6 for* Different scenarios

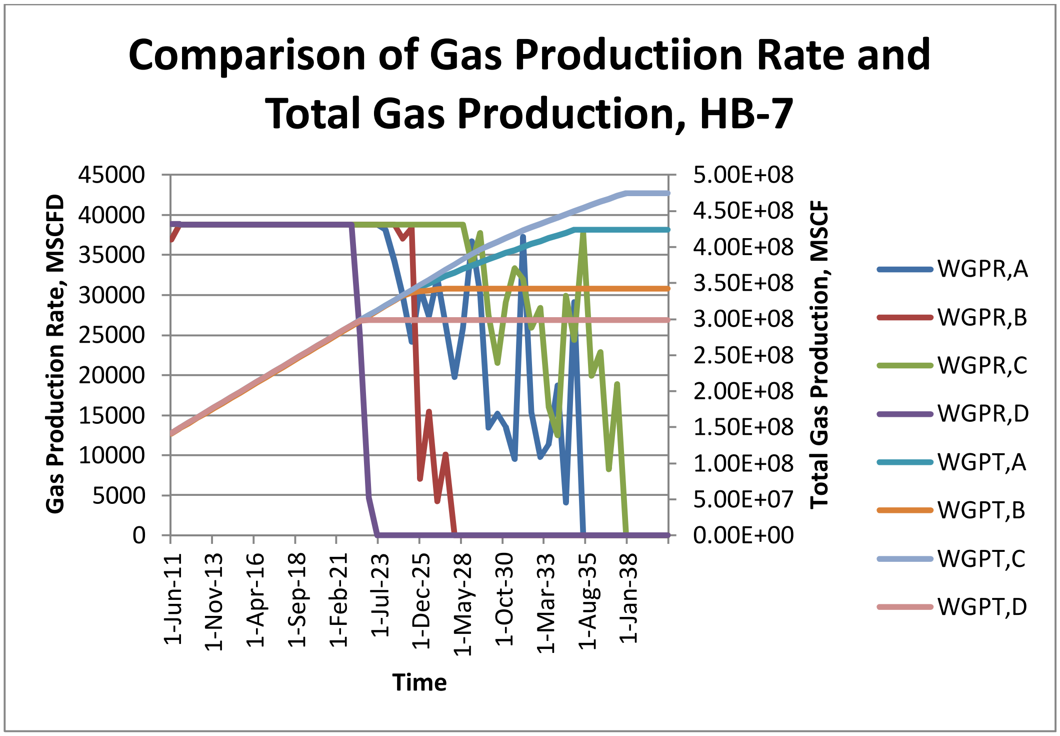


*Fig 7.26: Comparison of Gas Production Rate and Total Gas Production of HB-7 for Different scenarios*

Similar is the case for HB-5 and HB-6 ( Fig 7.24, Fig 7.25). For HB-5, ultimate recovery is highest for Scenario A. Well will be producing throughout the predictive years if the depletion rate is not increased by additional wells or other wellsô production lives are not improved by workovers. For Scenario B, all other wells except HB-4 and HB-6 get suspended within 2031. Early suspension of other wells increases the producing life and ultimate recovery of HB-6. In fact, plugging back the lower perforations will result in lowest ultimate recovery for HB-6 because of the fact that other wells will be producing for longer time because of workover and HB-6 will experience early water breakthrough.

Ultimate recovery for HB-7 and HB-10 (Fig 7.26, 7.27) will be highest for Scenario C for usual reasons.

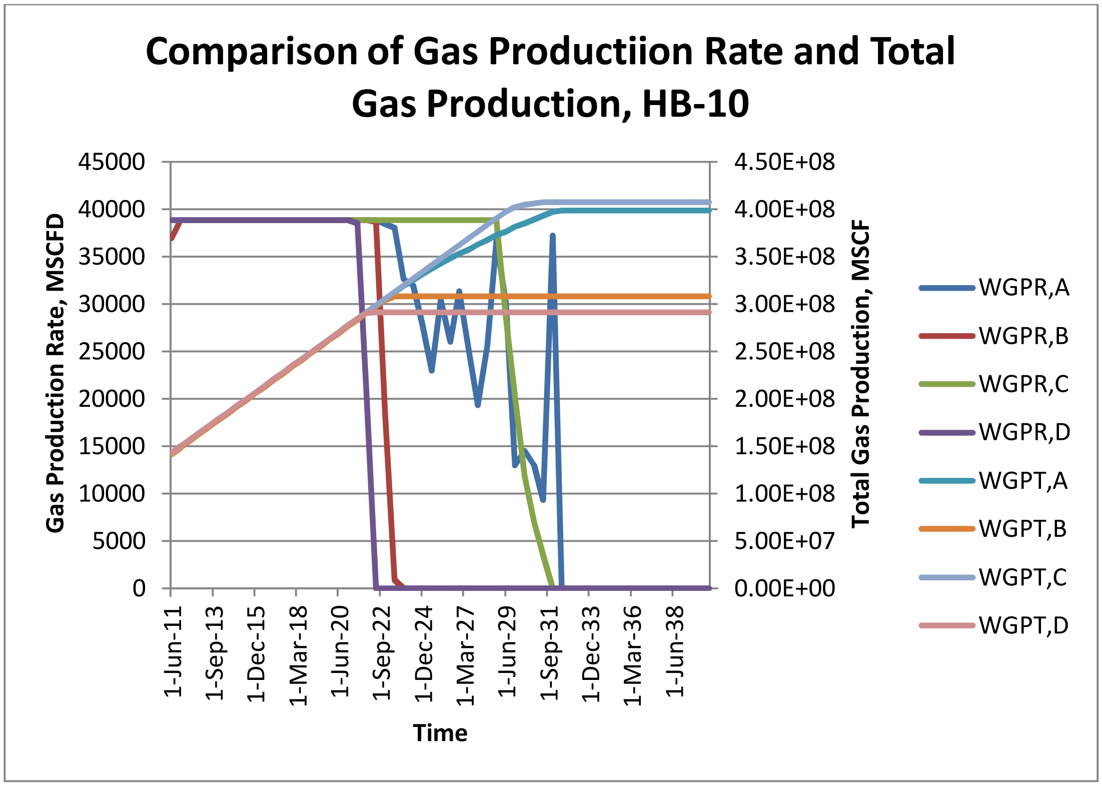


*Fig 7.27: Comparison of Gas Production Rate and Total Gas Production of HB-10 for Different scenarios*

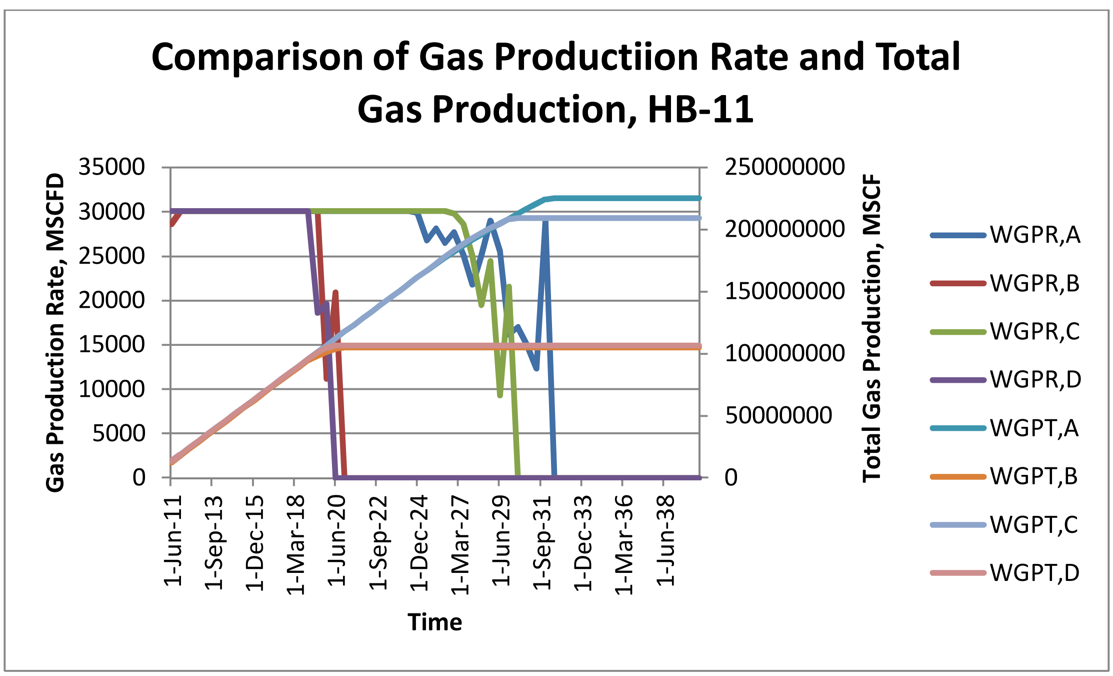


*Fig 7.28: Comparison of Gas Production Rate and Total Gas Production of HB-11 for Different scenarios*

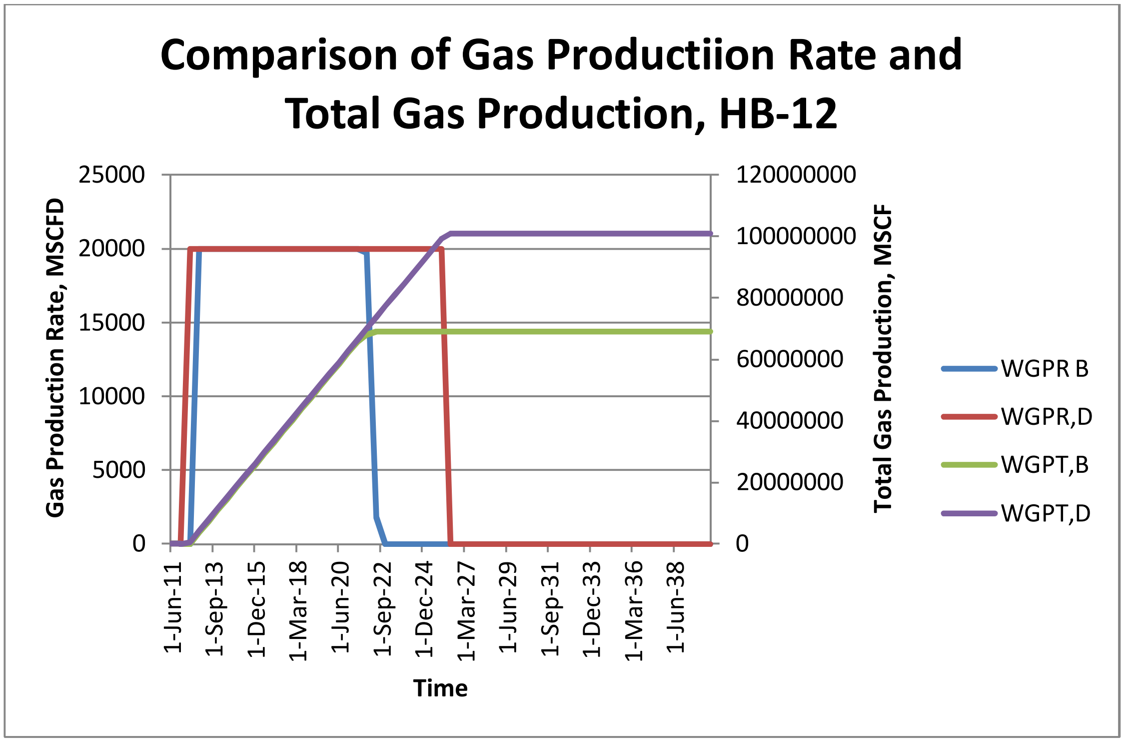


*Fig 7.29: Comparison of Gas Production Rate and Total Gas Production of HB-12 for Different scenarios*

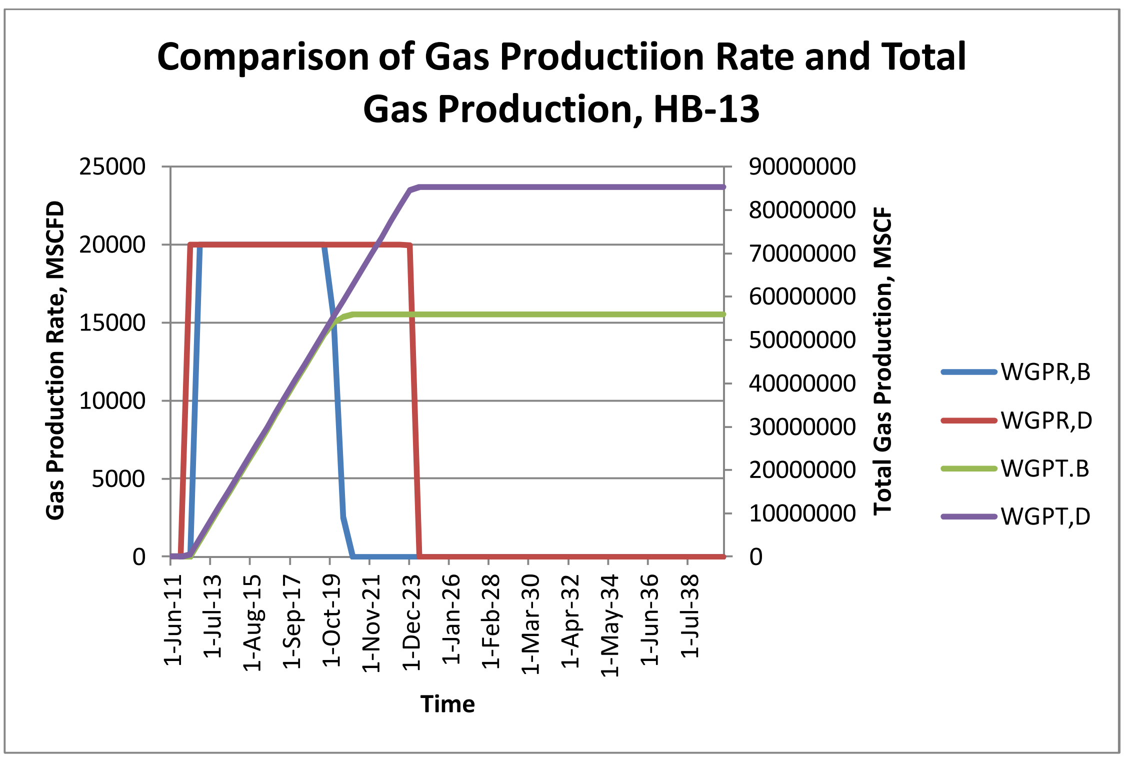


*Fig 7.30: Comparison of Gas Production Rate and Total Gas Production of HB-13 for Different scenarios*

Ultimate recovery for well HB-11 will be highest for Scenario A (Fig: 7.28) and that for wells HB-12 and HB-13 will be highest for Scenario D (Fig 7.29, Fig 7.30).

It is clear from this study that the ultimate recovery of Habiganj field is rate dependent. Scenario C is recommended for further production strategy as it gives the highest ultimate recovery. Under the present gas supply shortage, situation may prompt operators to go for either Scenario B or D for quick gain in production but in the long run these strategies will be detrimental for the reservoir.

# CHAPTER 8
# WATER TABLE MOVEMENT TRACK

A clear gas-water contact at 1492 m was distinguished at the bottom of upper gas sand during the drilling of exploration well HB-1(Intercomp Kanata Management 1991). No successive gas water contact at the same location was measured afterwards and the movement of gas-water contact could not be history matched due to the unavailability of data. However, simulated result can give an idea about the water table movement. This tracking can be useful in deciding the position of infill wells. Fig 8.1 and 8.2 show the position of water table at the beginning and at the end of historical years. At the end of the historical production years (June 2011), the position of water table was at 1453 m.

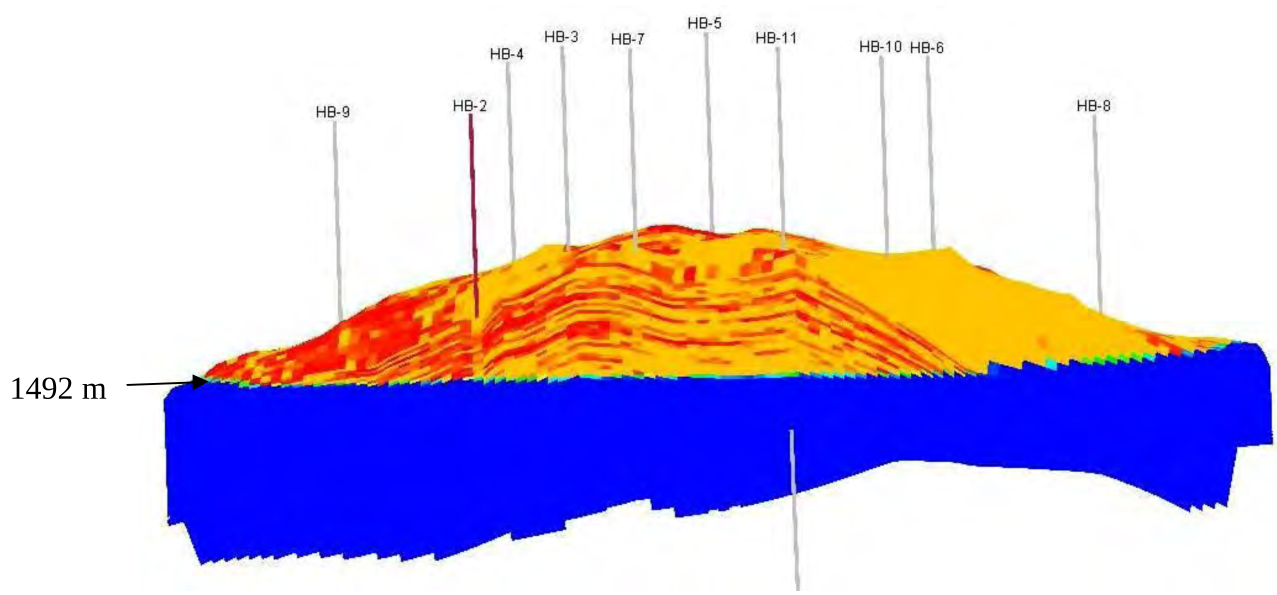


*Fig 8.1: Initial Position of Water table*

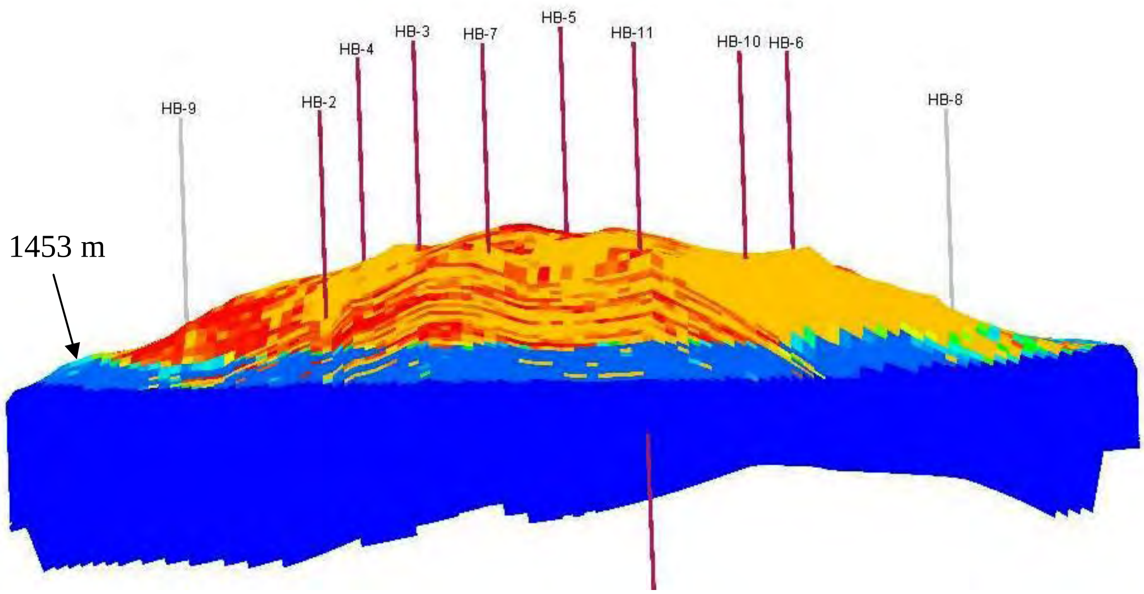


*Fig 8.2: Final Position of Water table*

Though the water table movement could not be history matched, it is known that well HB-8 and HB-9 were suspended due to excessive water production. That means, at the time of suspension, water table reached near the lower perforations of the wells. The lower perforation of HB-8 is located at the depth of 1448 m from the surface. Simulated result showed that, at the time of suspension (July 04), water table was at the depth of 1451 m from the surface level (Fig 8.3). The lower perforation of HB-9 is located at the depth of 1455 m from the ground level. Simulated result showed that, at the time of suspension (May 08), water table was at the depth of 1453 m approximately (Fig 8.4).

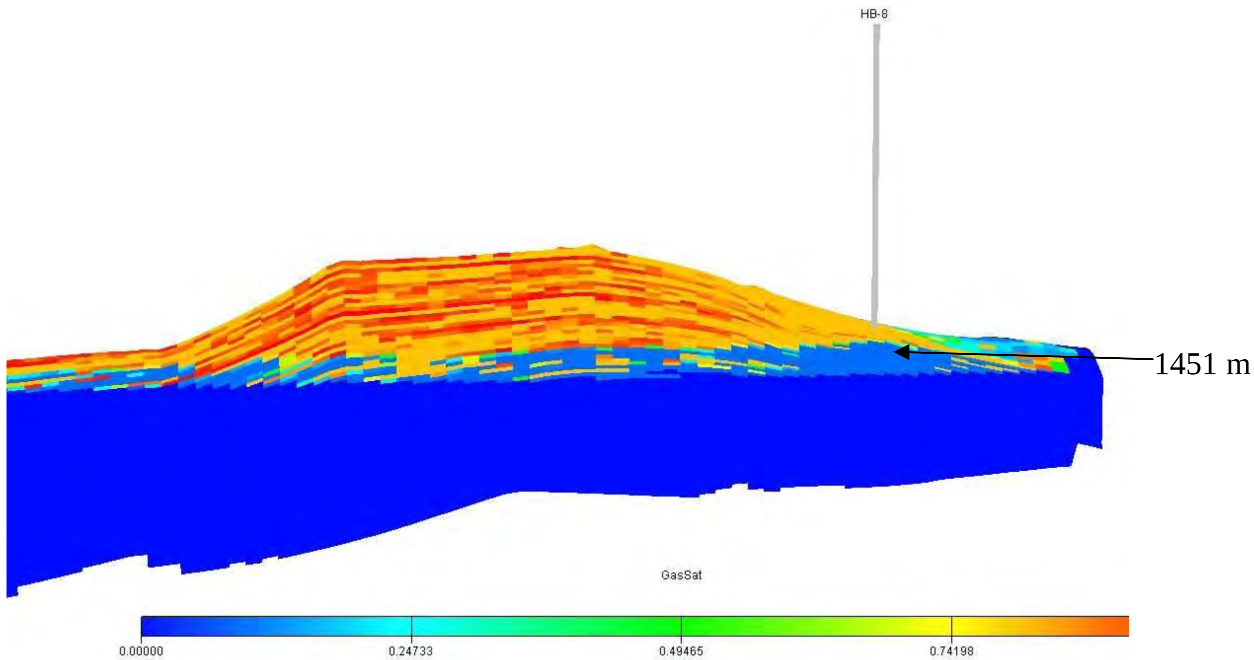


*Fig 8.3: Position of Water table at HB-8(July 04)*

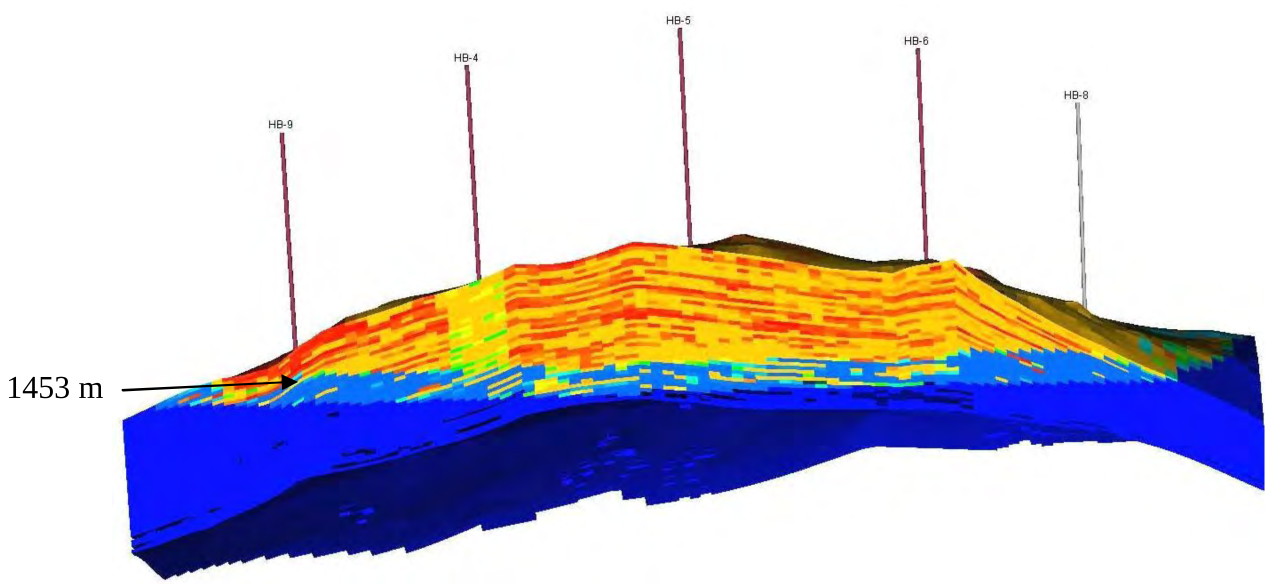


*Fig 8.4: Position of Water table at HB-9 (May 08)*

# CHAPTER 9
# RESULTS AND DISCUSSIONS

### 9.1 Reserve Estimation

Any simulation study estimates the gas initially in place (GIIP). The GIIP estimated by this study is 4.64 TCF. The following table shows the estimates done by other companies/agencies.

Table 9.1: Reserve Estimate by Different Companies/Agencies

| **Estimating Company/Agency** | **Estimated Reserves in TCF** | **Estimating Year** |
|---|---|---|
| Pakistan Shell Oil Company | 1.75 | 1963 |
| Petroconsultant GmbH | 3.475 (GIIP) | 1979 |
| BOGMC | 1.275 (Proven + Probable)<br>1.045 (Possible) | 1982 |
| GGAG | 1.437 (Recoverable) | 1984 |
| DeGolyer and MacNaughton | 1.704 | |
| GGAG and Petrobangla | 3.298 (GIIP) | 1986 |
| HHSP | 2.985 (Proven + Probable) | 1986 |
| Gasunie | 2.60 (Recoverable) | 1983 |
| IKM | 3.669(GIIP, Volumetric estimate)<br>10.5 (GIIP, P/Z estimate) | 1991 |
| Well Drill Limited | 3.6 (GIIP) | 1991 |
| Beicip Franlab RSC / Petrobangla | 4.623 (GIIP) | 2000 |
| HCU/NPD | 5.1 (GIIP, Volumetric estimate)<br>4.69 (GIIP, P/Z estimate) | 2001 |
| RPS Energy | 3.684 (GIIP) | 2009 |

## 9.2 Short Term prediction Results

Different short time prediction scenarios are compared below.

Table 9.2: Comparison of Recovery

| Prediction Scenario | Cumulative Recovery Percentage | Cumulative Gas Production of Prediction Years (bcf) |
|---|---|---|
| Base Case (scenario 1) | 48.27 | 450 |
| Scenario 2 | 47.62 | 415 |
| Scenario 3 | 48.27 | 450 |
| Scenario 4 | 48.92 | 469 |
| Scenario 5 | 49.56 | 508 |

- Workover of wells will not increase the recovery
- Workover will only help the wells to maintain the gas rate with reasonable water production.
- Adding one well will slightly increase the recovery
- Adding two wells will bring approximately 1.3% increase in cumulative recovery.

It is to be noted that as Habiganj upper gas sand has no proven stranded zone, addition of wells will only help to deplete the reservoir more quickly. Moreover, Habiganj field is highly permeable. Sometimes drilling of new wells is considered for highly tight gas reservoirs where production from remote zones with existing wells takes extremely long time. However, sometimes for water drive reservoirs, fields are depleted quickly because of rapid water table rise (Agarwal 1967). This can be done either by increasing production rate from existing wells or by adding new wells. In case of Habiganj field, addition of two wells maybe considered to increase the recovery rate for short time. Whether this strategy will affect the ultimate recovery need to be seen by running the simulator to the economic limit of the reservoir.

## 9.2 Long Term Prediction Results

The simulation model was run for additional 28 years (up to 2040) based on economic gas and water production limit. The accuracy of long term prediction is diminished but nevertheless the results are very much helpful. The results are very much indicative and can be used for long term development strategy. The long term prediction cases were run to observe the long term performance of the field under different prediction case scenarios. The results have been summarized.

- Different long term prediction scenarios are compared below

Table 9.3: Comparison of Ultimate Recovery

| Prediction Scenario | Ultimate Recovery Percentage | Total Gas Production (TCF) |
|---|---|---|
| Scenario A | 70.7 | 3.28 |
| Scenario B | 65 | 3.02 |
| Scenario C | 74 | 3.44 |
| Scenario D | 69 | 3.20 |

- Cumulative recovery of the field with additional two wells will be higher than that of Scenario A (prediction up to 2040 with no added wells) during initial years.
- Total amount of gas produced by Scenario B will fall below the total amount of gas produced by Scenario A from August 2022.
- Ultimate recovery will be lowest with additional two wells because production from additional wells will increase the rate of water table movement.
- Workover of high water cut wells to plug back the lower perforations will result in highest ultimate recovery.
- Ultimate recoveries for wells HB-1, HB-2, HB-3, HB-7 and HB-10 will be highest For Scenario C.

- Ultimate recoveries for wells HB-4, HB-12 and HB-13 will be highest for Scenario D, for HB-5 and HB-11 will be for Scenario A and for HB-6 will be for Scenario B.
- Workover will decrease recoveries from wells HB-5, HB-6 and HB-11

It is observed that workover will decrease the total production from HB-5, HB-6 and HB-11. Because of the time constraint it was not observed with an additional prediction run that what will happen to ultimate recoveries of the wells if these wells are continued to flow without any workover (considering workover of other wells).

# CHAPTER 10
# CONCLUSIONS AND RECOMMENDATIONS

Habiganj field is a highly permeable strong bottom water drive gas reservoir. Several studies were performed by different agencies and consultants. The present simulation work matched the pressure-production history very well with the exception of water production. Water production data archived by BGFCL is not accurate and hence not reliable.

The principal objective was to track the movement of the water table and subsequently device a future production operation plan. The water table position determined by this simulation after 39 years of production was at 1453 m while actual observed position of water table at that time was at 1455 m that results an error of 0.13% only. This study estimates GIIP as 4.64 TCF which is close to the last few estimates done by other studies.

It has been found that addition of two more wells will increase short term production by about 1.3% but in the long run it will affect ultimate recovery. The maximum ultimate recovery of 74% will be obtained by continuing the present production strategy with timely and sequential workover of different wells as they water out. Due to high permeability of the reservoir and rapid movement of the water table, Habiganj was found to be rate sensitive. A slower production than the present rate may result in higher ultimate recovery. No more wells should be drilled in the field at this point.

With limited core data and lack of designed data collection system, the present simulation did a remarkable job of estimating GIIP and pressure-production match.

**Recommendations**

A special core analysis of Habiganj gas field should be carried out to obtain real core data. Gas-water contact should be determined on a regular basis to improve history match results. Water production data of individual wells should be measured and maintained accurately to get good water production matches. Reservoir and aquifer properties should be re determined to get more accurate petrophysical data.

Some scopes for future studies are:

- History match the reservoir with real SCAL data.
- History match the water table movement with real data.
- Determination of the height of the transition zone.
- Determination of the presence and effect of coning and cusping for different wells.
- Determination of ultimate recovery under different sets of workover operations and schedules.
- Economic analysis of different workover operations and determination of an optimum solution for further field development.

# Nomenclature

| | |
|---|---|
| A | Cross Sectional Area ($ft^2$) |
| $B_g$ | Gas Formation Volume Factor (SCF/STB) |
| $B_o$ | Oil Formation Oolume Factor (RB/STB) |
| D | Datum level. (Feet) |
| k | Permeability (md) |
| P | Pressure (Psi) |
| Q | Fluid Flow Rate ($ft^3$/sec) |
| $R_s$ | Solution Gas Oil Ratio (Scf/STB) |
| ʐ | Mass Flow Rate |
| kh | Transmissibility |
| $S_w$ | Water Saturation |
| $S_g$ | Gas Saturation |
| $k_{rg}$ | Relative Permeability with respect to Gas |
| $k_{rw}$ | Relative Permeability with respect to Water |

Greek Symbols

| | |
|---|---|
| ɔ | Gravity |
| ŭʌ /ŭx | Fluid Potential Gradient |
| ɛ | Viscosity (cp) |
| ɟ | Density (lb/$ft^3$) |
| ʌ | Fluid Potential |

Abbreviations

| | |
|---|---|
| BGFCL | Bangladesh Gas Fields company Limited |
| BHP | Bottomhole Pressure |
| BOGMC | Bangladesh Oil Gas and Mineral Corporation |
| CIDA | Canadian International Development Agency |
| CMG | Computer Modelling Group Ltd |
| FGIP | Field Gas in Place |

| | |
|---|---|
| FGPR | Field Gas Production Rate |
| FGPT | Field Gas Production Total |
| FVF | Formation Volume Factor |
| GGAG | German Geological Advisory Group |
| GIIP | Gas Initially in Place |
| GOR | Gas Oil Ratio |
| GWC | Gas Water Contact |
| HCU | Hydrocarbon Unit |
| HHSP | Hydrocarbon Habitat Study |
| IKM | Intercomp-Kanata Management |
| KB | Kelly Bushing |
| LGS | Lower Gas Sand |
| mD | milli Darcy |
| MMSCFD | Million Standard Cubic Feet per Day |
| NPD | Norwegian Petroleum Directorate |
| OWC | Oil Water Contact |
| PSO | Pakistan Shell Oil |
| PVT | Pressure Volume Temperature |
| SCAL | Special Core Analysis |
| TD | Total Depth |
| THP | Tubing Head Pressure |
| UGS | Upper Gas Sand |
| VLP | Vertical Lift Performance |

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