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Using waterflood performance to characterize flow-units in a heterogeneous reservoir

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USING WATERFLOOD PERFORMANCE TO CHARACTERIZE FLOW-UNITS IN A HETEROGENEOUS RESERVOIR

Vamsi Krishna Alla

**Thesis Submitted to the
College of Engineering and Mineral Resources
at West Virginia University
in partial fulfillment of the requirements
for the degree of**

**Master of Science
in
Petroleum and Natural Gas Engineering**

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**Morgantown, West Virginia
2002**

**Keywords: Petroleum and Natural Gas Engineering, Reservoir
Simulation, Artificial Neural Networks, Reservoir Characterization,
Waterflooding**

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ABSTRACT

USING WATERFLOOD PERFORMANCE TO CHARACTERIZE FLOW-UNITS IN A HETEROGENEOUS RESERVOIR

Vamsi Krishna Alla

Simulation of waterflood performance is used to verify the characterization of flow-units in a heterogeneous reservoir. BOAST98 software was used for simulation of waterflood performance. Two adjacent five spot patterns in the Stringtown field in West Virginia were selected to be evaluated in this study.

The predicted permeability along with the porosity from Artificial Neural Network (A.N.N) was used for primary characterization purpose and identification of flow-units in the two five spots patterns.

Two alternate simulation models were developed. The simulation model was developed using the available data and those predicted using A.N.N. to verify that the flow-units model was an accurate description of the field. One model had two layers representing two flow units whereas the second model had three layers representing three flow units.

The output from the simulation runs was compared with 10 years of actual production history of both the wells. A close history matching was obtained with about 15-25% of total volume water injection rates into the individual patterns from each of the 6 wells. Though both the models were good in predicting the output, the second model which was developed for three flow units was better.

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I dedicate this work of mine to my parents and my family whose love and constant support throughout my life has been innumerable and incalculable.

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NOMENCLATURE

A.N.N.:	Artificial Neural Network
Bo:	Oil Formation Volume Factor, RB/STB
BOPD:	Barrels of oil per day
Bg:	Gas Formation Volume Factor, RCF/SCF
DX:	x-direction grid block dimension, ft.
DY:	y-direction grid block dimension, ft.
GR:	Gamma Ray
h:	Thickness, ft
K:	Permeability, mD
Kr:	Relative Permeability
Pc corr:	Capillary pressure corrected for an oil-water system, psia.
Pc exp:	Capillary pressure obtained for a water-air system, psia.
PID	Flow index per layer, for rates in STB/D.
PNN:	Probabilistic Neural Network
Rs:	Gas-Oil ratio, SCF/STB
rw:	Wellbore radius, ft
S:	Layer skin factor
Sw:	Water saturation, %
σ_{w-o} :	Interfacial tension for water-oil, dyn/cm.
σ_{w-a} :	Interfacial tension for air-water, dyn/cm.
ϕ :	Porosity, %

CHAPTER 1

INTRODUCTION

Flow units also called hydraulic flow units are the primary and fundamental units in reservoir characterization. They can be defined as the regions in a reservoir that control the flow of fluids in a reservoir. The flow units are correlated based on geological and petro-physical properties.

Every reservoir in general is heterogeneous and non-uniform. This heterogeneous and non-uniform reservoir can however be classified as uniform layers stacked one above the other. These individual layers have similar properties which affect the flow in the reservoir. The individual layer can be described as a flow unit¹⁻³. The distinction between different flow units in a reservoir is usually based on differences and similarities in properties namely permeability and porosity.

A better definition of flow units can be obtained with the use of fluid recovery (or waterflooding performance), pressure data or chemical fingerprinting. Often times, particularly in older fields, production is commingled and cannot be used to substantiate flow units. Moreover, the cost of extensive fluid and pressure testing is not economically sound. However, a simple method which still uses waterflooding but avoids the above said difficulties is the use of simulation technique. This project utilizes the BOAST98

simulator software to predict waterflooding performance and hence to test the method used for characterization of the flow units.

Waterflooding is the most widely used Secondary Recovery technique. It involves injection of water into the reservoir to improve the recovery of oil. Waterflooding is also called secondary recovery because it involves the recovery of oil left over after the primary recovery techniques.

Permeability and porosity are two parameters which are of great importance in defining the flow units. Often the information is not available on porosity and permeability. Porosity is mostly evaluated using well log information. Sometimes actual measurements from cores are also present. But in most cases these properties must be predicted in order to define the flow units appropriately. The accuracy of the flow unit description depends on the accuracy of the permeability and porosity prediction methods/techniques. This can be done with the use of Artificial Neural Networks(A.N.N.) which have been used successfully in previous studies to obtain reliable permeability values from geophysical log data.⁴

Although A.N.N can be used as a tool to predict the porosity and permeability and also flow units, it cannot be used to verify the accuracy of the flow unit identified. This study attempts to solve the problems mentioned. It attempts to use the waterflooding performance technique via reservoir simulation to verify the flow unit identified in a reservoir by other methods. Using simulation software the flow units and their possible

division into more flow units can be tested and verified successfully. This study is a positive step in that direction.

This study is an extension of the work “Reservoir Characterization of Upper Devonian Gordon Sandstone” performed at Department of Petroleum and Natural Gas Engineering in cooperation with West Virginia Geologic and Economic Survey.

CHAPTER 2

OBJECTIVES

Over the years various methods were developed to identify the flow units in the reservoir. Though these methods identify the flow units, the accuracy in describing the reservoir using the flow units identified by the flow unit identification methodologies has been in question. This is the primary objective of this study.

The primary objective of this work is to evaluate the accuracy of the methodology for identifying the flow units. Patterns B18 and B21 located in the Stringtown field were selected for the identification of the flow units and for verification of the methods that were used in the flow unit identification in these patterns.

Significant research work has been done on the reservoir description in the Stringtown Field. Previous study by Ademola⁵ and Thomas⁶ in this area tried to explain the flow units in this region. The studies suggest that there might be a two or three flow units in these patterns. These flow units are given input as layers to the simulator. There has been confusion as to the existence of this third flow unit (third layer as input to the simulator) in the reservoir containing the two patterns B18 and B21 from these studies.

West Virginia Geological Survey classified the producing zones in the Stringtown field based on the shale breaks in the region and designated then as Unit A, B, C. Also a lot of data was obtained from them which are critical for any kind of evaluation study. Unit A,

Unit B and Unit C are defined based on the change in geology due to the variation in the depositional environment. Patterns B18 and B21 had producing zones in Unit A and Unit B. Unit C was non-productive in the area of interest of this study.

From the data and information obtained from the Geologic Survey there seems to be a change in the geology in terms of the existence of Unit A and Unit B in this region. The objective of this study is to obtain a correct reservoir description in this region containing the patterns B18 and B21, also to verify the existence of third layer and to see if the change in geology has any effect on the flow unit description.

The flow units are identified and characterized by analyzing the data from the well logs and that from training the Neural Network. This study verifies the characterization of the flow units using waterflooding performance analysis. Mathematical simulation technique using BOAST98 simulator was used for predicting the secondary production of the producing wells B18 and B21. The objective was to match the production history of the above patterns for a period of about 3500 days for which period the data was available. The closer the match of the prediction with the actual, the better is the characterization done.

The study done by Gil, E⁷ uses simulation as a tool to only match the history in the pilot area. Also it uses the A.N.N to predict only the permeability and porosity. The current work is a step ahead of this previous work. This study utilizes A.N.N for not only predicting the permeability and porosity but also the flow units in the two patterns

selected. This study uses the results from the study by Ademola⁵ and Thomas⁶. They developed methodologies for identification of flow units using A.N.N. The permeability, porosity and flow units predicted from these studies were used in this study for verification purposes. The objective of this study is to evaluate the accuracy of the method used to predict flow units(using A.N.N) using waterflooding performance evaluation technique. BOAST98 Black Oil Simulator was utilized for the waterflooding performance evaluation technique.

Accurate and efficient modeling of flow in permeable media is of critical importance. Future oil and gas production is dependent upon enhanced oil recovery and accurate reservoir characterization models⁸. Historical production data is routinely collected and it carries much information that is useful for reservoir characterization and description of reservoir heterogeneity.

CHAPTER 3.

BACKGROUND AND THEORY

This chapter gives an overview of the location of the field and basic concepts of the technical terms used in this study. First the location and history of the field in which the patterns, with wells B18 and B21 as producers, were part are introduced. This is followed by the concept of flow units and the techniques used for evaluating them. Simulation of waterflooding performance is one technique to evaluate the correctness of the flow unit description and is discussed at the end.

3.1 Description of the Field ⁹

The Jacksonburg-Stringtown field is located on the western flank of Burchfield syncline, in southeastern Wetzel, eastern Tyler, and northwestern Doddridge counties, West Virginia (Fig. 3.1). The field was discovered about a century ago in 1895. This field contained an estimated 88,500,000 barrels of oil in place.

The primary producing formation in the field is the Upper Devonian Gordon Sandstone. The pay thickness in the field ranges from 4 to 15 ft. This variation is primarily a result of the topography of the pre-Gordon depositional surface and secondarily by post-depositional erosion. A secondary producing interval is the Mississippian Big Injun sand, approximately 800 feet above the Gordon, but it was not completed for primary production in the Stringtown field.

Figure 3.1. Stringtown oil field location

The 8500 acres field is roughly six miles long (north-south trend) and its width is approximately 2.5 miles. The reservoir area shape is like an inverted cone, wider in the north, narrower in the south. Encountered at an average depth of 3000 ft, the entire Gordon section is approximately 50 ft. thick and is bound at top and bottom by a series of interbedded sandstones and shales that have been proved to be correlative throughout the field. This sand is interpreted as shallow marine, shoreline deposits, which trends in a northeast-southwest direction. Analysis revealed that it is made up of 71% quartz, 13% cementing material, 4% feldspar and 12% minor rock fragments. It is a lightly gray, fine to very fine grain size, well sorted, massive to planar bedding with occasional shale laminations. The pay zone lies beneath a low-porosity, conglomeratic zone. Conglomerates are found to have generally unpredictable permeability, which can range

from 0 to 500 md. As a result, this conglomerate section may act as a permeability barrier, as a reservoir, or even as a thief zone for injected fluids.

3.1.1 Primary Production History:

Between 1897 and 1910 nearly 500 wells were drilled in this region. However, most of them were plugged by 1910. The average well spacing is 13 acres per well. The initial potential of these wells was estimated at an average of 72 BOPD, with a range of 0 to 300 BOPD (King, 1980). Wells were stimulated several times with nitroglycerine to increase production.

Solution gas drive and gravity drainage resulted in most of the primary production. The primary production carried on till mid 1920's. Primary production was estimated to be between 1454 (King, 1980) – 1590 (Morrison, 1991) BOPA (barrels of oil per acre). This was based on an effective area of 4,388 acres. The total production was estimated as 13 million barrels of oil. Primary production ranged from 824 BOPA to 2,700 BOPA as per the lease production records.

3.1.2 Gas Injection Project:

The gas injection project was started in the field in the year 1934 (Boone and others, 1986) or mid 1920's (Putscher and King, 1983). Limited testing and development continued through the 1950's, with five injection wells spread out through the field. An average of 154 BOPA of recovery was attained due to this gas injection over a limited

region of the field(Boone and others, 1986). A gas re-injection accounted for about 10% of the field cumulative production.

3.1.3 Waterflooding Project:

The pilot water flood of the Gordon was installed in 1981. This was done at an approximately 34acre dual five-spot. An average of 1300BOPA was recovered in 4 years. Lower than predicted(1500 BOPA) recovery is believed to be due to dump flooding of the eastern five-spot (Boone and others, 1986).

The success of the of the pilot waterflooding project led to a full-scale Waterflood in 1990. The full-scale Waterflood project involved approximately 8900 acres in three units. Unit 1 formed in 1981 consists of 1815 acres, and contains the pilot Waterflood. Unit 2 formed in 1986 consists of 5723 acres and is located north of and adjacent to unit 1. Unit 3 formed in 1995 consists of 1360 acres is located south of Unit 1. The target recovery as about 1500 barrels of oil. However, PennzEnergy encountered some technical problems which must be overcome to achieve this enhanced recovery goal.

More than 100 new wells for waterflooding and 40 more wells for production were drilled in this region since 1990. Of these newly drilled wells, 24 of them have been drilled with low angle deviations to accommodate surface topographic and logistical constraints. 1,864,782 barrels of oil have been produced between January, 1991 and February, 1999 as a result of the full scale Waterflood.

The daily and cumulative oil productions from 1897 to 1991 are shown in Figures 3.2 and 3.3.

Figure 3.2. Daily Oil Production Vs. Time in the Stringtown field. 1896-1991

Figure 3.3. Cumulative Oil Production Vs. Time in the Stringtown field. 1896-1991

3.2 Flow Units:

The definition of flow units was given in the introduction section of this thesis. In short it can be said as a zone in a reservoir where the flow of the oil or gas is continuous laterally and vertically and the properties are consistent throughout the zone. The hydraulic flow units are influenced highly by the pore throat geometric properties. Mineralogy and texture are the controlling parameters in the pore geometry. Mineralogy is affected by the type, abundance and location of the zone and texture is determined by the grain size, grain shape, sorting and packing method. A different combination of the above discussed geological properties will give a different flow unit. This flow unit will have similar flowing characteristics or fluid transport properties.

3.3 Techniques For Identification of Flow Units¹⁰

3.3.1 FZI Technique

Amaefule et al¹ presented a theoretical methodology to identify the flow units. He defined a concept called Flow Zone indicator, FZI, which classifies the flow units in a reservoir. An FZI is defined by the flowing formula

$$FZI = \frac{1}{\left(\sqrt{F_s}\right) \tau S_{gv}} \text{ ----- (1)}$$

where F_s is the pore throat shape factor, τ is the tortuosity, and S_{gv} is the effective surface area per unit grain volume. RQI is the reservoir quality index defined below.

$$RQI = 0.0314 \sqrt{\frac{K}{\phi_z}} \text{ ----- (2)}$$

where ϕ_z is the pore volume to grain volume ratio defined as

$$\phi_z = \frac{\phi_e}{[1 - \phi_e]} \text{ ----- (3)}$$

The above parameters were derived from a modified form of the Kozeny-Carmen¹¹ relation.

The above equations are derived by combining Darcy's law for flow in a porous media and Poiseuille law for flow in tubes. However in reality the reservoir pores are not straight but twisted and twirled in hundreds of ways. Kozeny¹² and later Kozeny-Carman¹¹ later developed a realistic model of a porous medium where the connected pores are not straight.

Defining Flow Zone Indicator, FZI and Reservoir Quality Index, RQI from equations 1, 2

we have, $RQI = \phi_z * FZI \text{ ----- (4)}$

or $\log(RQI) = \log(\phi_z) + \log(FZI) \text{ ----- (5)}$

where ϕ_z is defined by equation 3.

Thus the value of FZI can be calculated from the above equations for a point in a formation if the values of permeability and porosity are known for that point. If a plot of RQI vs. ϕ_z is drawn, it will be a straight line with slope of FZI since the equation is in the form of a straight line equation $y = mx + c$ where m is the slope of the straight line. If the plot is done on a log-log coordinates the line is still a straight line except that the slope will be unity for a constant FZI. From the above equation it can be said that different samples with similar FZI values will fall on the same straight line. Samples with different

FZI values will fall on different line parallel to one another with a unit slope. The mean FZI for a set of similar samples can be found out by knowing the intercept at the coordinate $\phi_z = 1$. The basic idea on how to classify hydraulic flow unit (also called HU) is the identification of straight lines with slope on a log-log plot of RQI versus ϕ_z .

3.3.2 From Core Data:

The pore throat related parameters, basically the RQI and FZI, can be calculated using the core data. Core data consists of basically the porosity and permeability of the core sample. These values suffice in the calculation of RQI and FZI. The hydraulic units can be identified for the values of the FZI. Theoretically speaking there should be one FZI value for each hydraulic flow unit. But due to human and non-human inaccuracies and errors there exist some differences in the values of the FZI property. Hence we obtain a distribution of FZI values around a mean of these values. Hence the mean value represents the FZI value for that flow unit. When different flow units exist, the overall scatter of the FZI is a superimposition of the individual distributions over the mean values of FZI for each of the flow unit. Identification of each flow unit (or therefore each mean FZI) would require careful delineation of the individual groups into each constituting flow unit by a straight line with the points scattered above and below this line. Abbaszadeh et al ¹⁰ discussed some of the cluster analysis techniques which aided us in the classification of these groups.

Histogram Analysis, probability analysis and the Ward's analytical algorithm are discussed for cluster analysis in here. However there are several other techniques which can be found in the literature.

3.3.2.1 Histogram Approach:

FZI exhibits a log-normal distribution which can be attributed to the strong relation of FZI with permeability, which in turn has a log-normal Gaussian distribution. A histogram of the FZI with the log-scale on x-axis should show “n” number of normal distributions for “n” number of hydraulic units. This is shown schematically below in Figure 3.4.

The frequency distribution is explained by the equation:

$$f = \sum_{i=1}^{N_{HU}} \frac{\omega_i}{\sqrt{2\pi\sigma_i^2}} \exp \left[-\frac{\left(Z - \bar{Z}_i \right)^2}{2\sigma_i^2} \right] \text{-----}(6)$$

The histogram distinctly separates the flow units when the clusters of data points are distinctly separate from one another. It also provides the FZI values in this case. This method is the easiest and simplest method available. But this has its inherent limitations.

It is difficult to separate the overlapped clusters easily and reliably. Thus, for most practical purposes this method fails because of the difficulty in delineating the distributions in the transition zones.

3.3.2.2 Probability Plot Approach:

The probability plot is also called a cumulative distribution function plot. It is an integral of the histogram i.e., the probability density function and hence the plot is smoother than the histogram plot. The identification of the flow units is easier because of the ease in identification of individual distributions. This is because of the reduction in the scatter of the data points due to the integration of the probability density function. The cumulative distribution function is given by the equation,

$$F = \frac{1}{2} \left[1 + \sum_{i=1}^{N_{HU}} \left(\omega_i \operatorname{erf} \left(\frac{Z - \bar{Z}_i}{2\sigma_i^2} \right) \right) \right] \text{-----}(7)$$

The number of straight lines and hence the FZI limiting boundary values for each HU can be obtained from the probability plot of log (FZI). The FZI value representing the hydraulic flow unit is calculated by averaging all the FZI values within the corresponding HU limits. The probability method is lot easier than the histogram method because it is visually easier to identify straight lines.

3.3.2.3 Ward's Algorithm:

The ward's algorithm is a cluster analysis technique in which all the available data points are merged one by one until the required number of clusters are obtained. The number of clusters is the input to the ward's algorithm. The advantage of ward's algorithm lies in

the manner in which the cluster variances are treated. Clusters are formed to minimize the increase in the within-cluster sums of squares of deviations from their mean.² Each cluster, thus tends to attain a minimum spread around its mean value, while still maintaining maximum separation from the other clusters. The sum of squared deviations within the group is calculated from the following equation,

$$W = \sum_{i=1}^{n_g} \sum_{j=1}^{n_i} (Z_{ij} - Z_l)^2 \text{ ----- (8)}$$

3.3.3 HU Prediction Using Log Data^{4,11}:

Three steps are needed to find the HU distribution in case where log data is available. First, those logs that are sensitive to dynamic flow parameters of pore-throat attributes are identified. This is done by either assessing the degree of correlatability of various logs with permeability or FZI, or by performing component analysis. The second step involves construction and training artificial neural networks which embodies information on the inter-relationship between logs and hydraulic units. The third step utilizes the database information and well log measurements to infer distribution of HUs along the logged wells.

3.4 Artificial Neural Networks^{13,14}

Artificial Neural Networks are tools that have complex and multitude mathematical models which are used for processing the information given to them. Inspired by the biological neural system the ANN's can be used to perform a wide variety of functions like prediction, classification, data association etc.

Though every component in an ANN may not have a counterpart in a biological brain, the basic components of the ANN's are modeled based on the brain's structure. The basic element in a brain is neuron. Each neuron is connected with up to 20000 other neurons. Each neuron has 4 parts namely dendrites, soma, axon and synapses. The figure 3.5 explains the various parts of a biological neuron and their functions.

Fig. 3.5. Biological neuron

The basic component in an ANN is also called a neuron. The artificial neuron simulates the four basic functions of a biological neuron. Each artificial neuron is connected to a certain number of other neurons each with varying degree of connectivity. The strength of each connection is represented by a connection weight specified to it. Learning in the ANNs is accomplished through training with examples or via exposing the system to an existing set of input/output data. During the learning process the training algorithm makes adjustments iteratively to the connection weights and giving the appropriate result as output. The figure 3.6 shown below shows the various parts and functions performed by an artificial neuron.

Fig. 3.6. Artificial neuron

Most applications of neural networks fall into the following five categories:

- **Prediction:** E.g. forecasting the stock-market, predict weather, identify people with cancer risk.
- **Classification:** E.g. used in speech, character, signal recognition etc.
- **Data association:** E.g. read and recognize handwriting in processing checks.
- **Data Conceptualization:** E.g. identify from a set those that are most likely to buy a particular product.
- **Data Filtering:** E.g. to remove the noise out of a telephone signal.

In petroleum and natural gas industry the ANNs can be used to solve problems relating to reservoir characterization, well simulation, identification of flow units, pressure transient analysis, well log-interpretation etc.

The advantage of ANNs lies in its ability to learn from training and to discard distorted data in the input data. ANNs are good at solving problems that are too complex for solution by conventional technologies. They are good for solving problems that do not have an algorithmic solution or for which an algorithmic solution is very difficult and too complex to be found. They are also well suited to problems that humans in general are good at solving, but for which traditional methods are not.

ANNs can be classified by their method of learning (or training). Some ANNs employ supervised training while others use unsupervised training. Supervised networks process the input by learning from the training set. Backpropagation, Probabilistic Neural Network (PNN), General Regression Neural and Network (GRNN) are examples of supervised networks. In unsupervised networks essentially no sample outputs or training set are provided to the network by which the network can measure its predictive performance for a given input. The network does this by clustering the data into similar groups based on the measured attributes or features given as input to it. The maximum number of categories into which the data needs to be categorized is specified in the beginning. An example of unsupervised networks is Kohonen network. ANNs are also classified as feedforward or recurrent (also called feedback) depending on how data is processed in the network.

3.4.1 Previous Work in Neural Network Prediction

A lot of work was done previously and thesis documents submitted on works which involved prediction of porosity and permeability using neural network. One previous work by Gil⁷ used random selection of test set through a random number generator for

training purposes. He used the porosity and permeability obtained from the prediction in his simulation study. He selected the flow units based on the variation of porosity and permeability alone and found that it enhanced his simulation results.

However recent study⁵ uses a pre-defined test set, the results of which were used for the work under study here. The selection of the predefined test set is done as described below.

A plot of the density vs. log of core permeability was developed to produce a linear relationship between the two properties. A linear trend was drawn and correlation coefficient found. The core permeability data is then divided into segments based on the distribution of data points around the trend line. Point with highest and lowest permeability values above and below the trend line were selected from each segment and fed to the A.N.N. This gives the A.N.N a wide range of data to compare with. These same points were chosen as constant test set for the A.N.N by identifying them in the training set pattern and marking them by row marking option. R^2 obtained from this approach was greater than 0.9 for all the wells.

Another recent study by Ben Thomas⁶ uses a different approach. This study used limited core permeability data that were available for a few wells to predict flow units and permeability within the field where only log-based data were available. The study predicts flow units first from the available core data and the predicted flow unit is input

along with the other input data to predict permeability and flow units for the remaining wells in the field. The steps taken are briefly described below.

First the flow units were identified for wells with core data available. Various techniques including manual review of the digital log data and Kohonen analysis were used in this step. The inputs in the Kohonen analysis were gamma ray, density, gamma ray slope, density slope, gamma ray baseline, density baseline, and core permeability. The next step was the development of an ANN model to predict permeability of the cored wells using the flow unit identified earlier as a model input. A flow unit prediction model was then developed for the cored wells alone using log data only. This flow unit prediction model for cored wells has the same log inputs, pre-defined test set, and the boundaries of the Flow Unit are same as for the model developed for permeability prediction of cored wells.

The flow unit prediction model developed is applied to the wells in the field having digitized well logs(gr/density). The flow unit output obtained along with flow unit ANN model inputs now become inputs to the ANN permeability prediction model which can be applied for the whole field. The ANN permeability prediction model is run on the digitized well log(gr/density) data which were previously used for flow unit prediction. The prediction of permeability and flow units obtained was verified to be good in this study.

3.5 Waterflooding Analysis

There are four most commonly used reservoir performance analysis methods¹⁵. They are

1. Volumetric Analysis
2. Decline Curves Analysis
3. Material Balance Analysis
4. Mathematical Simulation

The table 3.1 gives the applicability, accuracy, data requirement and results of each of the above technique. We discuss simulators in more detail as they are the most advanced and widely used tools nowadays and are the subject of this study.

3.5.1 Mathematical Simulation^{15,16}

Numerical or Mathematical Simulators are the most widely used tools for waterflooding performance analysis. Simulators can be used to find methods/techniques to improve the ultimate recovery of the reservoir. Numerical simulation is based upon the principle of conservation of mass i.e., material balance principle but takes into account the heterogeneity of the reservoir and direction of flow of the reservoir. Whereas the basic assumption in a conventional material balance is that of a homogeneous tank model, fluid production and injection occur at single production and injection points and that the fluid flow is non-directional. Simulators take the location of production and injection wells and their operating conditions. E.g., if the injection is constant pressure injection or constant rate injection etc. The advantage of this method unlike the conventional methods is that, the well can be turned on and off at any required times, the rates and the pressures of both the injection and producing wells can be specified either individually or both together.

Table 3.1. Comparison of the four waterflooding analysis methods.

	Data Type	Volumetric	Decline Curve	Material Balance	Mathematical Models
1. Applicability /Accuracy	Exploration	Yes/Questionable	No	Yes/Questionable	Yes/Questionable
	Discovery	Yes/Questionable	No	Yes/Questionable	Yes/Questionable
	Delineation	Yes/Questionable	No	Yes/Questionable	Yes/Fair
	Development	Yes/Better	No	Yes/Better	Yes/Good
	Production	Yes/Fair	Yes/Fair	Yes/Good	Yes/Very Good
2. Data Requirements	Geometry	Area, Thickness	No	Area, Thickness homogeneous	Area, Thickness heterogeneous Porosity,
	Rock	Porosity, Saturation	No	Porosity, Saturation, Rel. Permeability, Compressibility homogeneous	Saturation, Rel. Permeability, Compressibility, Capillary pressure heterogeneous
	Fluid	Formation Volume Factors	No	PVT homogeneous	PVT heterogeneous
	Well	No	No	PI for rate vs. time	Location Perforations, PI
	Production & Injection	No	Production	Yes	Yes
3. Results	Pressure	No	No	Yes	Yes
	Original Hydrocarbon in Place	Yes	No	Yes	Yes
	Ultimate Recovery	Yes with rec. eff.	Yes	Yes	Yes
	Rate vs. Time	No	Yes	Yes with PI	Yes
	Pressure vs. Time	No	No	Yes with PI	Yes

3.5.2 Types of Simulators^{15, 16}

Reservoir simulators can generally be classified into four types as given below.

Black Oil Simulators: This model is used to simulate isothermal flow of oil, gas and water under the conditions of viscous gravitational and capillary forces.

Compositional Simulators: This model takes into consideration the variation in phase composition with change in pressures.

Thermal Simulators: The thermal simulators can be used to model reservoirs with heat transport and chemical reactions apart from the fluid flow.

Chemical Simulators: These simulators can be used to model fluid flow and mass transport.

3.5.3 A Brief History of Simulation¹⁵

Simulation can be said to have begun in 1940 with the help of analog models. 2D and 3D finite difference equations were introduced into these simulators in 1950. These models could solve multiphase flow in heterogeneous porous media problems. During the 1960s much of the advancement was in the field of 3-phase, black-oil reservoir simulation. Solutions to enhanced oil recovery problems were incorporated into simulators during the 1970s. During the 1980s, the development extended to include the reservoir description. Today the advancement is so vast that complex reservoir heterogeneities can be described and also naturally fractured reservoir can be modeled. With the presence of modern super fast computers it has become possible to solve highly complex reservoir problems in a very reasonable time.

3.5.4 Model Characteristics¹⁵

Black Oil simulators are characterized as below

Based on Phase

1. “Single phase” when only oil or gas is flowing.
2. “Two phase” when two phases are flowing. e.g., oil and gas, oil and water or gas and water.
3. “Three phase” when all the three phases namely oil, gas and water are flowing.

Based on Direction of Flow

1. “1-dimensional linear or radial” when flow is in the direction of x, y or z.
2. “2-dimensional areal” when flow is in the direction of x-y or x-z or r-z. This is also called “cross-sectional” or “radial cross-sectional”.
3. “3-dimensional” when the flow occurs in the direction of x-y-z.

Based on Finite Difference Equation Used

The simulator is called “IMPES”, “implicit” or “fully-implicit” depending upon the solution used to solve the finite difference equations.

3.5.5 Simulation Process^{15,17,18}

A reservoir simulation process consists of majorly three main phases.

1. Describing the Reservoir.
2. History Matching and

3. Performance Prediction.

The above mentioned three phases are described in more detail below.

3.5.5.1 Describing the Reservoir

This phase contains of gathering all the required input data and building a reservoir model from it to describe the reservoir. Gathering all the required data can be a very time consuming and expensive phase. It requires a lot of team effort from the geo-scientists and the engineers. The reliability of the data gathered also needs to be checked since it is of great significance for the success of the reservoir modeling. The input data that needs to be gathered can be divided into four parts – general data, rock and fluid data, grid data, production/injection and well history data. These four data types are summarized in the table below.

Table 3.2. Data types input to a typical reservoir simulator

	General Data	Rock & Fluid Data	Grid Data	Production/Injection and Well Data
Data Name	Dimensions, grid definition, number of layers, original reservoir pressure, initial water-oil and gas-oil contacts	Relative permeability data, capillary perms, rock compressibility and PVT data	Elevations, gross & net thickness, permeabilities, porosities, saturations.	Oil, gas and water production/injection history. Future production and injection schedule for each well, well location, productivity index, skin factor and perforation interval for each well.
Where the data can be obtained	Can be obtained from base maps, log and core analysis and well pressure tests.	Can be obtained from lab test or correlations.	Can be obtained from well log and core analysis, well pressure and productivity tests.	Can be obtained from injection and production records, drilling, cementing and casing history records etc.

The input data gathered above along with the calculation method used for history matching is known as the reservoir model.

3.5.5.2 History Matching

The second step is the history matching. The production rates and pressure performance of the reservoir are calculated from the reservoir model developed above. This calculation is done for a period for which the history (i.e., past production and pressure data) is available. If the calculated rates match the actual production data then the model developed is said to be good. If not, modifications are done to some of the process parameters and the calculation is redone. This process of modifying these parameters to match the calculated data with the actual data is called history matching.

The reservoir parameters that need to be adjusted must be noted and the degree of adjustment should be noted. This is because some reservoir data are known with better accuracy than others. Also some reservoir formation properties like porosity, permeability, etc. are known only at the locations of the coring sites. Sometimes these data too may be in error. The error may be manual or the error may be in the measuring instrument itself. The data in the grids for the regions between the wells need to be interpolated.

3.5.5.3 Performance Prediction

This is the final phase of a reservoir simulation study. This step involves predicting the future performance of a reservoir under existing or future alternative plan. The main objective of this phase is to find the best operating conditions to maximize the economic recovery of hydrocarbons (oil and gas) from the reservoir. The history matching phase is

a vital phase before this phase because the accuracy of prediction will be good only if the accuracy of a history match is high.

3.6 Overview of BOAST98 Simulator^{18,19}

BOAST98 is a black-oil, three-phase, 3-D simulator that was used for history matching in this study. BOAST98 is a visual, dynamic, and interactive update of BOAST3 developed by U.S. Department of Energy (U.S. D.O.E.). This was published by U.S. D.O.E. in 1998 and can be obtained for free from the world wide web at www.npto.doe.gov. The original version BOAST was released in 1982 and was used quite extensively by various research, academic and industrial organizations. It's ease of use and features that make execution easier were the major reasons for its huge popularity. Subsequent modifications and updates led to the release of the present version of BOAST98. BOAST98 was compiled with Lahey FORTRAN 90 and ISS/Interacter. The minimum requirements for the simulator are Windows95, Windows NT, or Windows 3.1 with Win32s installed. It is recommended that the system using the simulator have at least 32 MB memory. It is also anticipated that 40 - 100 MB of free disk space is needed.

The BOAST98 application simulates isothermal, Darcy flow in three dimensions. The program assumes that the reservoir fluids can be described by three fluid phases (oil, gas and water) of constant composition. The composition of the fluids is assumed to depend on pressure alone. These assumptions are acceptable to a large percentage of the world's oil and gas reservoirs. BOAST98 can be used to simulate recovery of oil and/or gas by mechanisms like fluid expansion, displacement, gravity drainage, and capillary

imbibition. Primary depletion studies, pressure maintenance by water and/or gas injection, and evaluation of secondary recovery waterflooding and displacement operations are some of the typical field production problems that the BOSAT98 simulator can be used to solve.

BOAST98 is a finite difference, IMPES numerical simulator. IMPES stands for implicit pressure, explicit saturation. Both direct and iterative solution techniques are employed for solving systems of algebraic equations. The well model allows specification of rate or pressure constraints on well performance. Also, the wells can be added or recompleted during the simulation. The user can define multiple rock and PVT regions and three aquifer models are available for selection. BOAST98 is equipped with the capabilities of flexible initialization, a bubble-point tracking scheme, automatic time-step control, and a material balance check on solution stability. The user can control the length and content of the output.

The data input section of the BOAST98 can be classified as an initialization data section and recurrent data section. As the name suggests, the initialization data section includes data that is set and read once at the beginning of the simulation. It is not expected to change during the course of the simulation run. The initialization data basically defines the mathematical model, the run-control parameters and the physical attributes of the reservoir area under study. It consists of reservoir model grid dimensions and geometry, the distribution of porosity and permeability within the reservoir, fluid PVT data, rock relative permeability and capillary pressure data, initial pressure and saturation

distributions within the reservoir, specification of solution method, and various run control parameters.

The recurrent data is the name given to those data that is expected to change during the simulation run. The recurrent data consists of the location and initial specifications of wells in the model, time step control information for advancing the simulation through time, a schedule of individual well rate and/or pressure performance, changes in well completions and operations over time, and controls on the output type and frequency provided by the simulator.

3.6.1 Features Provided by BOAST98

Some of the simulator features provided by Boast98 are listed below.

3.6.1.1 Reservoir features:

- Optional three-phase relative permeability algorithm.
- Multiple rock regions and PVT regions allowed.
- Bubble point pressure can vary with depth and PVT region.
- Provision for three different analytic aquifer models.
- Direct input of noncontiguous layers.
- Net and gross thickness allowed.

3.6.1.2 Well Model Features:

- Individual well gas/oil ratio (GOR) and water/oil ratio (WOR) constraints.

- Minimum oil production and maximum liquid withdrawal well constraints.
- Multiple wells per grid block.
- Gas well model using a laminar-inertial-turbulent analysis.
- Maximum water/gas injection rates.

3.6.1.3 Numerical Features:

- Addition of two new iterative matrix solution methods: y and z direction line successive over-relaxation (LSOR) methods.
- Zero pore volume (inactive) grid blocks allowed.
- Optional two-point upstream weighting for reducing numerical dispersion.

3.6.2 Limitations of BOAST98:

Some of the Boast98 limitations are listed below:

- A large grid size of x-direction blocks, y-direction blocks, and z-direction blocks or layers will force the use of virtual memory and drastically slow down the array iteration processes.
- Maximum well blocks of 200.
- Maximum time steps of 8000.
- Maximum data sets of 200.
- Maximum wells of 150.
- Maximum nodes per well of 10.
- Maximum modifications to permeability, porosity, and transmissibility of 55 each.

- Maximum rock regions and PVT regions of 5.
- Maximum table entries for relative permeability curves and for capillary pressure curves of 25.
- The program fails if even one of the input variable is missing from any line of the input. This failure also happens if the order of input is not exactly correct.

This simulator consists of two basic components namely Edboast and Boast98. The Edboast is used to edit the input data, whereas the Boast98 is used to make the necessary calculations. Either the Edboast or the Boast98 application can be used to start a simulation run. However, the input data can be first reviewed by beginning with the Edboast program and any mistakes that may cause the BOAST98 application to fail can be located. More information about these applications is presented in Appendix A.

CHAPTER 4

METHODOLOGY

In order to achieve the main objective of the study the following steps were used which are listed below.

1. Selection of Study Area
2. Data Collection.
3. Development of Reservoir Model (Description of the model).
4. Evaluation of the Reservoir Performance

The above steps are explained in more detail below.

4.1 Selection of Study Area

The patterns B18 and B21 as producing wells located in the Stringtown field were selected for evaluation of this study. A previous study⁷ in this field was done in the pilot area of the same field. The patterns in the pilot area were very small. The productive part of the formation was entirely within UnitA. The patterns B18 and B21 selected for this study are larger and highly productive. The productive part of the formation exists both in UnitA and UnitB where as the productive part of the pilot area exists in UnitA only. Figure 4.1 shows the patterns B18 and B21 used in this study. Figure 4.2 shows the location of the patterns B18, B21 and the pilot area

Figure 4.1. Patterns selected for this study

A study of the entire field in terms of cumulative production was done and it was found that B18 and B21 have very high production per acreage. They were one of the best in the field. The availability of data along with the complexity of the reservoir in terms of characterization (as found from previous studies) led to the selection of the above mentioned producing well patterns. The cumulative production per acre for the first five years and the entire life time for the patterns, for which data was available, in the Stringtown field can be seen in Table 4.1.

Also of all the 9 wells (R-13, D-14, L-17, Th-8, PH-11, PH-9, LE-13, B-18, and B-19) for which core data was available two wells namely B-18 and B-19 were in these two patterns as can be seen in the Figure 4.1. B-18 is the producer in the B18 pattern and B-19 is the injector in the B21 pattern.

Figure 4.2 Location of the Patterns B18, B21 and Pilot Area with the Cored Wells.

In the Figure 4.2 shows the patterns with MM-1 and PH-12 as producing wells in the pilot area. It is represented by the two rectangles to the southwest of the patterns B18 and B21 as can be seen the Figure 4.2. Patterns B-18 and B-21 have wells Ball-18 and Ball-21 as producing wells as can also be in the figure above

Table 4.1: Production/Acre in the producing patterns of Stringtown field.

Well Name	5yr Cum. Prod/Acre	Cum. Prod/Acre	Well Name	5yr Cum. Prod/Acre	Cum. Prod/Acre
ALLEN, NANCY N-8	187.8	187.8	LEMASTERS, JASPER 6	11.1	940.4
ASH, EMELINE 6	654.3	857.5	LEMASTERS, JASPER 7	23.8	774.2
ASH, EMELINE 7	1665.2	1737.7	LEMASTERS, L J K13	356.9	456.1
BALL HEIRS N-11	51.6	59.3	LEMASTERS, S P 2	29.1	200.9
BALL, F R 18	3038.0	3232.1	LEMASTERS, S P L-10	451.0	451.0
BALL, F R 21	2767.6	3330.8	MAIN, MELVINA 1	37.4	1587.1
BALL, F R J-5	934.5	934.5	MCCOY, C K-8	1126.0	1491.8
BALL, F R J7	1793.3	2161.2	MCCOY, C L-8-B	331.6	331.6
BALL, F R L-6	117.4	117.4	MILLER, ISRAEL 3	5.2	14.7
DAWSON, J H 2	24.7	24.7	NOLAN, HENRY L-16	1389.4	1432.3
DAWSON, J H G-11	1421.2	1654.5	PENNICK, C C 22	8.7	219.6
DAWSON, J H G-13	149.8	203.4	PENNICK, C C 23	25.4	401.9
EDDY, A G N-10	64.7	72.1	PENNICK, C C 26	55.7	194.7
FLUHARTY, WILLIAM 8	32.7	172.2	PENNICK, C C 4	11.0	27.8
HALL, C T 3	4.6	76.3	PENNICK, C C L-15B	324.2	595.4
HOGGE, F L H-15	377.4	377.4	PENNICK, C C N-13	28.4	31.3
HOGGE, LUCIUS 1	661.1	663.1	PENNICK, C C N-16	197.9	197.9
HORNER, PETER 12	1031.6	1048.6	PENNICK, M H 6	27.3	4603.2
HORNER, PETER 7	16.0	112.7	PITTS, OLIVER 4	6.9	59.6
HUTSON, M E 1	11.3	119.3	REILLY, IRENE 10	1.3	65.3
LEMASTERS, A D 11	25.7	853.1	REILLY, IRENE 11	11.4	93.2
LEMASTERS, A D 15	1180.7	1314.9	REILLY, IRENE 8	21.8	98.7
LEMASTERS, A D 16	199.5	199.5	STACKPOLE, R M 4	0.4	127.4
LEMASTERS, A D 2	0.5	0.5	STACKPOLE, R M F-10	77.7	77.7
LEMASTERS, A D H10	2328.8	3135.8	THOMPSON HEIRS 10	1274.7	3676.4
LEMASTERS, A D H-13	716.9	829.3	THOMPSON HEIRS 9	331.4	504.8
LEMASTERS, J F-8	1526.2	1609.9	THOMPSON HRS E-7	1534.5	1845.1
LEMASTERS, J H-11	992.7	1130.0	WHARTON, W J 2	24.3	1171.3
LEMASTERS, JASPER 16	60.1	231.7	WYATT, SILAS E-3	134.1	134.1
LEMASTERS, JASPER 19	1429.9	1600.2			

4.2 Data Collection.

This step involves the phase of gathering the data that is required for running the model and also to analyze the output. The data that we need to gather are.

1. Production and Well Logs.
2. Well Completion History.
3. Shut-in-bottom hole pressure.
4. Production rates.
5. Dates of first oil, water and gas production.
6. WOR and GOR.

Sometimes all the data that is needed is not available. So assumption by estimation or correlation is needed in such cases.

Most of the data required for this study was obtained for “Reservoir Characterization of upper Devonian Gordon Sandstone” project. Both core and log data was collected for this project and obtained from “West Virginia Geologic and Economic Survey”.

Core Data: Core data for the wells named R-13, D-14, L-17, Th-8, PH-11, PH-9, LE-13, B-18, and B-19 was gathered. However data for the three wells R-13, D-11 and L-17 was found to be incomplete and inaccurate. They had very low permeability and hence were not used in the training of the database.

Log Data: Gamma Ray (GR), Density (RHOB), Neutron Porosity and Induction logs were run in the field. Of these GR and RHOB were used in this study because of their

availability. These logs were digitized subsequently and auto-corrected to check for their accuracy. Slopes of digitized GR and RHOB logs were calculated from first derivatives of GR and RHOB with respect to depth using the three point method.

Neural Network Prediction: A.N.N has been and is being used widely to predict permeability distribution. Previous work⁷ used random selection of test set through a random number generator for training purposes. However recent study⁵ uses a pre-defined test set, the results of which were used for the work under study here. The selection of the predefined test set is done as described below. Another study by Thomas⁶ used A.N.N to predict permeability and porosity from flow units. First flow units were predicted using A.N.N and later this information is used to develop an A.N.N model to predict flow units, permeability and porosity. The A.N.N model developed was used to predict permeability and porosity for the remaining six uncored wells in the dual five spot selected for this study. Table 4.2 and 4.3 summarize the predictions from A.N.N for the patterns B18 and B21. The porosity and permeability are predicted for every quarter foot and are averaged over the thickness range for the respective flow unit.

Table 4.2: A.N.N predictions indicating two flow units

Well name	Thickness, ft		Permeability, md		Porosity, %	
	Flow Unit 1	Flow Unit2	Flow Unit 1	Flow Unit2	Flow Unit 1	Flow Unit2
MHP9	0.5	7	23	188	0.20	0.25
FRB20	0.5	17	0.11	175	0.17	0.25
FRB19	6	4	38	140	0.18	0.23
B18	3	6	34	194	0.15	0.23
B21	2.5	10	46	211	0.13	0.23
MHP8	0.5	7	14	135	0.15	0.25
JBG5	3.25	6.25	14	137	0.17	0.27
JBG4	3.75	5.5	24	184	0.15	0.26

Table 4.3: A.N.N predictions indicating three flow units

Well name	Thickness, ft			Permeability, md			Porosity, %		
	Flow Unit 1	Flow Unit2	Flow Unit3	Flow Unit 1	Flow Unit2	Flow Unit3	Flow Unit 1	Flow Unit2	Flow Unit3
MHP9	0.5	7	0	23	188	0	0.20	0.25	0.00
FRB20	0.5	10.5	6.5	0.11	171	181	0.17	0.25	0.24
FRB19	6	0.5	3.5	38	110	154	0.17	0.19	0.23
B18	3	6	0	34	194	0	0.15	0.23	0.00
B21	2.5	3	7	46	197	216	0.15	0.21	0.23
MHP8	0.5	7	0	14	135	0	0.15	0.25	0.00
JBG5	3.25	6.25	0	14	137	0	0.17	0.27	0.00
JBG4	3.75	0.75	5	24	147	187	0.16	0.25	0.26

The data gathered from logs and database training can be classified as follows.

4.2.1 General Data:

Dimensions:

No of Grids in X-direction = 14

No of Grids in Y-Direction = 8

Length of grid = 194 ft.(2 patterns together), 100 ft.(Individual pattern)

Width of the grid = 194ft. (2 patterns together), 100 ft.(Individual pattern)

Height of the grids = variable as shown in the appendix.

Location of Wells (X,Y) for two patterns together:

Ball18 (Producer) – 4,4

Ball21 (Producer) – 11,4

Pennick8 (Injector Ball18 pattern) – 1,1

Pennick9 (Injector Ball18 pattern) – 1,8

Gorrell 5 (Injector common to both producers) – 6,2

Ball 20 (Injector common to both producers) – 8,8

Gorrell 4 (Injector Ball21 Pattern) – 14,1

Ball 19 (Injector Ball21 Pattern) – 14,6

Location of Wells (X,Y) for B18 patterns individually:

Ball18 (Producer) – 8, 6

Pennick8 (Injector Ball18 pattern) – 14,1

Pennick9 (Injector Ball18 pattern) – 1,1

Gorrell 5 (Injector common to both producers) – 13, 11

Ball 20 (Injector common to both producers) – 1, 15

Location of Wells (X,Y) for B21 patterns individually:

Ball21 (Producer) – 10, 7

Gorrell 5 (Injector common to both producers) – 1, 1

Ball 20 (Injector common to both producers) – 3,14

Gorrell 4 (Injector Ball21 Pattern) – 17,1

Ball 19 (Injector Ball21 Pattern) – 16,12

Number of Layers: 2 and 3

Original reservoir pressure = 700 psi.

Initial water-oil contact = 2884ft.

Initial gas-oil contact = 2992ft.

Other parameters for the reservoir model were:

- Reservoir pressure at the start of water injection = 700 psia.
- Producing wells bottom hole pressure = 1500 psia.
- Initial oil saturation = 67.5 %
- Irreducible water saturation = 22 %
- Irreducible gas saturation = 10.5 %
- Vertical permeability = 0.1 mD in layer 1, 0.1 mD in layer two.

The depths of the eight wells in the two patterns range from range from 2777 ft. to 3210, which means that the formation is practically horizontal in this part of the field. Hence a depth of 2894 ft which lies within that range was taken as the depth to the top of the first layer in each well.

4.2.2 Rock and Fluid Data:

4.2.2.1 Fluid Properties:

The Table 4.4 through 4.6 presents some of the physical properties for oil, gas and produced water. The gas analysis is from a producing well outside the pattern.

Table 4.4 Crude Oil Analysis.

Property	Value
Crude Gravity, °	45.3
IBF, ° F	96
Viscosity at 85 °F	3.5 cp
Density at 85 °F	0.7903 g/ml
% Tar	1

Table 4.5. Gas Analysis.

Property	Value
Specific Gravity	0.628
BTU/cu. Ft. at 14.73 psia	
Dry basis	989.8
Wet basis	972.6
Molecular weight	18.2
Compressibility factor	0.998

Table 4.6. Produced Water Analysis.

Property	M-1	H-12
Specific Gravity @ 75 °F	1.089	1.002
PH	4.3	7.46
Total Dissolved solids, mg/l	129116	7006

4.2.2.2 Relative Permeability Data:**Table 4.7. Relative permeabilities from well H-9**

Sw, %	Krw	Kro	Kro/Krw
19	0	1	
32.7	0.0077	0.51	66.234
37.7	0.012	0.436	36.333
41.6	0.016	0.37	23.125
46.2	0.024	0.283	11.792
48.5	0.029	0.235	8.103
50.8	0.037	0.19	5.135
52.7	0.045	0.148	3.289
54.1	0.052	0.114	2.192
55	0.06	0.098	1.633
55.6	0.066	0.089	1.348
56.2	0.074	0.076	1.027
57.3	0.08	0.05	0.625
58.2	0.096	0.033	0.344
59.5	0.107	0.0086	0.080
60.1	0.119	0.0039	0.033
60.8	0.135	0	0.000

Relative permeability data were available for one injector H-9 in the pilot region of the field. Table 4.7 summarizes the data available. Other important relevant information for the core is:

- Core depth: 2905 ft.
- Core description: sandstone, fine grain.
- Initial water saturation: 19%
- Porosity: 25.3%
- Oil permeability at initial water saturation: 34 mD.

This data was, however, changed in the simulation process for the history matching purposes. Figure 4.2 compares the actual relative permeability data from the well H-9 with the data that was used for the simulation by Gil⁷ and also those used in this study. Appendix H shows the same plots that were used in this study in more detail.

Figure 4.3 Comparison of relative permeabilities.

4.2.2.3 Capillary Pressure Data:

Table 4.8 lists the reported values of the Air-brine capillary pressure test that were made in the well Lemasters-13.

Table 4.8. Capillary pressure air-brine from well L-13

Water Saturation	Capillary pressure, psi
100	0
99.53	1
97.69	2
71.43	4
62.28	8
55.21	17
52.58	30
47.94	70

- Depth: 3050.5 ft.
- Porosity: 19.4%
- Permeability: 37 mD
- Grain density: 2.67 g/cc.

These experimental values of the capillary pressure were adjusted to account for the presence of oil instead of air, using the following expression:²⁰

$$P_{\text{corr}} = P_{\text{exp}} \times (\sigma_{\text{w-o}} / \sigma_{\text{w-a}})$$

Where:

P_{corr} = Capillary pressure corrected for an oil-water system, psia.

P_{exp} = Capillary pressure obtained for a water-air system, psia.

$\sigma_{\text{w-o}}$ = Interfacial tension for water-oil, dyn/cm

$\sigma_{\text{w-a}}$ = Interfacial tension for air-water, dyn/cm

In the simulation process, σ_w -a was taken equal to 72 dyn/cm, and σ_w -o equal to 20 dyn/cm.⁸ The capillary pressure values used in the simulator are presented in Appendix F.

4.2.2.4 PVT Data:

Since no PVT data were available for the field, these were computed using correlations²⁰. The data for oil API gravity and viscosity, the formation temperature, the water viscosity were known for the field of our study.. The PVT properties used in the program are summarized below in Tables 4.9 through 4.11 for oil, water and gas.

Table 4.9. Oil PVT properties.

Pressure, psia	Viscosity, cp	Bo, RB/STB	Rs, SCF/ STB
14.7	3.600	1.0000	0.0
80.0	3.229	1.0254	14.5
100.0	3.132	1.0275	18.9
120.0	3.038	1.0296	23.5
1000.0	0.6100	1.4234	120.0
Slope (P>Pb)	0.125E-02 cp/psia	-0.800E-06 RB/STB/psia	0.0

Table 4.10. Water PVT properties.

Pressure	Viscosity, cp	Bo, RB/STB
14.7	1.4527	0.9911
120.0	1.4585	0.9909
1000.0	1.465	0.9880

Table 4.11 . Gas PVT properties.

Pressure, Psia	Viscosity, cp	Bg, RCF/SCF	Pseudo PRS, psia ² /cp	Rock Comp., 1/psia
14.7	0.0112	0.1048E+01	0.00E+00	0.380E-05
120.	0.0114	0.7446E-01	0.3592E+07	0.380E-05
1000.	0.0196	0.4800E-02	0.4800E+09	0.380E-05

Other important PVT related data that was used as input are given below.

Bubble point pressure at start of simulation, PBO = 1000 psia.

Depth at which PBO applies, PBODAT = 2882 ft.

Constant PBO gradient, PBGRAD = 0.0000 psia/ft

Slope of oil viscosity vs pressure, VSLOPE = 0.0012460

Slope of oil Formation Volume factor vs Pressure, BSLOPE = -0.0000008

Slope of solution gas-oil ratio vs Pressure, PSLOPE = 0.0000000

Maximum pressure entry(all PVT tables), PMAX = 1000 psi.

4.2.3 Grid Data:

The porosity and permeability for each block were assigned averaging the predicted^{5, 6} values in the injectors and the producer Ball18 and Ball21. Also the gross and net thickness values for each block were also assigned by interpolation based on the values obtained for the producers and injectors. Table 4.1 and 4.2 show the values of porosity, permeability and thickness of the flow units that were input in the development of the two simulation models. The Appendix C, contains all the grid data used in the simulation.

4.2.4 Recurrent Data for the Simulator:

The recurrent data given to the simulator as input are read periodically by the program during the course of the simulation run. The recurrent data includes information about the location and initial specifications of wells in the model such as, number of layers completed and a schedule of individual well rate and/or pressure performance over a time interval, changes in well completions and stimulation or damage that were done over time. It also contains information about the time step control information used incrementing the time in a simulation run and also the controls for printing output for the run made. The actual production and injection data from history are tabulated in Appendix B.

4.2.4.1 Productivity Index (PID):

The productivity index also known as PID is a function of permeability and thickness of the layer. The layer flow index can be estimated by the following equation,

$$PID = \left[\frac{0.00708Kh}{\ln \left(\frac{0.121\sqrt{DX * DY}}{r_w} \right) + S} \right] \text{-----} (9)$$

Where:

PID: Flow index per layer, for rates in STB/D.

K = layer absolute permeability, mD.

h = layer thickness, ft.

DX = x-direction grid block dimension, ft.

DY = y-direction grid block dimension, ft.

r_w = wellbore radius, ft.

S = layer skin factor.

The productivity index value gives a physical value to account for changes in the well condition, basically changes in the skin factor, S, to indicate if any damage or any stimulation is performed in the well.

Several wells had treatments throughout the project's life. This information was used to assign different skin factor values at different times. Table 4.12 summarizes the different treatments reported for the pilot wells, as well as the time elapsed since the beginning of the flooding project.

Table 4.12. Well treatments in pilot wells.

Well	Treatment	Elapsed days
FRB 18 (Producer)	Fresh Water Cleaning followed by cleaning with paraffin solvent and crude to displace solvent and crude oil out of perforations.	Done in November 94
FRB 21 (Producer)	No information available.	
MHP 8 (Injector)	Frac job done twice, acid treatment done thrice, solvent cleaning done once	Done over a period of time from 10/22/90 to 5/17/1994
MHP 9 (Injector)	Acid treatment done three times. Treatment done with Mag M Solvent to increase the injection rate.	Done over period of time from 10/16/95 to 9/9/98
FRB 20 (Injector)	No information available	
JBG 5 (Injector)	No information available	
FRB 19 (Injector)	No information available	
JBG 4 (Injector)	Acid treatment done to increase injectivity	Done in February, 1996.

4.2.4.2 Injection Rates:**Table 4.13. Average water injection rates with 2 flow units.**

Injection well	Average water injection rate, % of total
MHP 8	20
MHP 9	20
FRB 20	40
JBG 5	40
FRB 19	20
JBG 4	20

Table 4.14. Average water injection rates with 3 flow units.

Injection well	Average water injection rate, % of total
MHP 8	15
MHP 9	15
FRB 20	45(20+25)
JBG 5	45(20+25)
FRB 19	20
JBG 4	20

The water injection rates assigned to the injectors were chosen between 15 and 25% of the total rate, as shown in Table 4.12 and 4.13. Only with those low percentages an acceptable match between actual and simulated water production was achieved.

4.3 Development of the Reservoir Models

The description of the reservoir model for simulation utilizes the data collected from step 1 (Gathering the data). The properties of the reservoir are input in the form of a 2 dimensional grid model. The properties that are input into the grid model are porosity, permeability and thickness. Four models were developed overall starting with a two flow unit model with two patterns together. This model utilized the data from the A.N.N prediction showing two flow units as can be seen in Table 4.1. These flow units are input to the grid model as layers one below the other with very low vertical permeability (0.1md).

A three flow unit model was developed with properties based on the A.N.N prediction show three flow units as in Table 4.2. These three flow unit model was more complex in the sense that more data was needed for input and more grid blocks needed to be extrapolated. These three flow units were characterized as three layers stacked one below the other in the grid model. This second model was developed with the two patterns together. The difference between these two models can be seen in figure 4.3 next page.

Two more models were developed to simulate the three flow units behavior in the region but with individual patterns. For B18 a two-flow unit model was developed which was later converted to a three-flow unit model to give a better description of the reservoir. A three flow unit model B21 pattern was developed from the data obtained in Table 4.2. The grid model for the individual patterns with three flow unit models and for the two flow unit model with B18 and B21 together is shown in Appendix C

Figure 4.4.1 2-Dimensional View of the flow units with thickness of each flow unit

Figure 4.4.2. 2-Dimensional View of the flow units with thickness of each flow unit

Figure 4.4.3. 2-Dimensional View of the flow units with thickness of each flow unit

4.4 Evaluation of Reservoir Performance

4.4.1 Run the simulator

This step involves the running of the reservoir simulation model to get the prediction. The required data are input to the simulation and model is prepared. The data input types can be classified in four types namely General Data, Rock & Fluid Data, Grid Data Production/Injection and Well Data. These data types were discussed in the introduction section previously. We set some conditions with these data input like minimum bottomhole flowing pressure, maximum and minimum reservoir pressure, maximum WOR, GOR etc. Once the data are input and the model prepared the simulation run is made and the output collected in a file and/or screen maps.

4.4.2 Compare simulator results to actual data

After running the simulator, comparison of the results from the output of the simulator run are made with that of the actual production data. Actual oil, gas, water production rates and oil, gas, water cumulative production volumes are compared with those from the simulator output by plotting them on a spreadsheet graph. This step is useful for the following purposes

1. To identify wells not producing oil, gas or water.
2. To identify wells with incorrect breakthrough.
3. To check the frontal movement in the layers or flow unit of interest.
4. To check the breakthrough of the layers.

The above steps are needed to find out which wells are not matching the historic oil, gas or water rates. This step helps us to see if the waterfront is arriving too fast, too slow or

the bottomhole restriction imposed are restricting the well production or not etc. This step assists in the next step of changing the model parameters.

The following plots compare the actual data with the simulator results.

1. Production vs. time plot.
2. Pressure vs. time plot.
3. WOR or GOR vs. time plot.

Fig. 4.5.: Ball18 Production Rates Vs Time

Fig. 4.6: Ball21 Production Rates vs Time

Fig. 4.7: WOR comparison for the two producers

Fig. 4.8: GOR comparison for the two producers

Fig. 4.9. Actual Bottom Hole Pressure Vs. Time

4.4.3 Adjust model parameters

This step involves the adjustment in the model parameters for the next run to better the history match. Which parameters need adjustment is based on the knowledge gained from the previous step. The key pressure matching parameters are pore volume, rock compressibility, permeability and vertical communication. Relative permeability has a lot of impact on the oil and water history matching.

Changes made to the horizontal permeability in x and y-directions in the zones effects the production allocation to each flow unit. However, changes made to the vertical permeability either allows or prevents lateral or vertical communication between the zones. Adjusting the completion productivities (kh) or PID (Productivity Index) can be used to fine-tune the production allocations among the producing zones (or layers) in a well. Changes made to the permeability and porosity also effect the water production.

4.4.4 Summary of the adjustments

At the beginning of the study simulator runs were made on a homogeneous model to find to see if the results are encouraging enough to cater further study. The patterns were modeled and run separately. These models had homogeneous properties meaning only one average value for each layer was given as input for the properties porosity, permeability and thickness. On obtaining a good result with the homogeneous run, a heterogeneous two layer model with two patterns together was prepared. The layers represent the flow units in the region.

The injection into the patterns needed to be cut down to 20% in all the injectors into each

pattern to obtain a good match. Adjustments were needed in the PID values and bottom hole pressure to obtain the required lag in time. Though the output was satisfactory in terms of the final quantity of cumulative oil produced, the matching with history for the B18 was not good.

An analysis of the permeability predicted and logs suggested a probable existence of a third layer in the region. A three layer heterogeneous model was prepared and simulator run was done. The water injection % was 40% in common injectors in the B18 and B21 patterns, 25% in the B18 pattern only wells and 20% in the B21 only wells. Certain adjustments were made to the relative permeability to obtain a better match. On comparison with the actual history the pattern B18 was still not matching history properly. Also a lot of water was being produced. This suggested that the distribution of water might not be correct and this could be done only with the patterns run separately.

So the next step was the preparation of separate models to represent each pattern individually. Inspection of the permeability and log data suggested that the B18 had 2 flow units throughout, whereas B21 had predominantly 3 flow units. A model for B18 pattern was developed with 20% injection in all the injectors with two layers to represent two flow units in this pattern. For the B21 pattern a model with three layers and 25% injection from all the injectors was prepared. The reason for the change in injection percentages was due to the thinking that B21 is a bigger pattern and takes in more water than B18.

The match improved a lot but the water production was still very high. Hence the models were rerun with reduction in the injection percentage into each pattern. The best match for B18 was obtained with 20% injection from the common and 15% from the B18 only (wells not injecting into B21) injectors. For B21 the injection from common injectors was 25% and 20% from B21 only (wells not injecting into B18) injectors. The relative permeability data needed adjustment in these runs. At the end of the study the patterns B18 and B21 had different relative permeability input. The relative permeability data plots comparing the simulator input to actual data can be seen in Figures H-1 to H-5 (Appendix H). The decrease in the injection rates was done after a close observation of the patterns neighboring B18 and B21. Table 4.14 shows in tabular form some information about the neighboring patterns.

Table 4.14 Information about the patterns neighboring B18 and B21

Name	Acreage	Water-flooding Start Date	1st Yr Cum, Stb	5 Yr Cum, Stb	Cum. Prod, Stb	5yr Prod/Acre	Cum. Prod/Acre	Cum. Inj, Stb
TH 10	51.7	4/1/1991	491	65841	189895	1274.7	3676.4	647723
JL 16	35.8	1/1/1991	251	2152	8299	60.1	231.7	1120987
JL 19	34.4	3/1/1991	314	49239	55102	1429.9	1600.2	1273917
M HP 6	43.8	1/1/1972	250	1198	201838	27.3	4603.2	1392253
FRB J-7	38.0	3/1/1993	14143	68186	82172	1793.3	2161.2	1052829
FRB L-6	60.4	7/1/1997	1175	7093	7093	117.4	117.4	625194
FRB J-5	37.0	6/1/1996	1	34541	34541	934.5	934.5	786480
EA 6	52.3	4/1/1991	708	34245	44883	654.3	857.5	1194021
EA 7	39.0	4/1/1991	7295	64989	67817	1665.2	1737.7	860551
FRB 18	35.1	4/1/1991	1024	106534	113340	3038.0	3232.1	1694947
FRB 21	39.9	4/1/1991	1279	110551	133047	2767.6	3330.8	1691968

The location of the patterns with the producing wells TH10 (Thompson Heirs 10), JL 16 (Lemasters, Jasper 16), JL19 (Lemasters, Jasper 19), FRB J-7 (Ball, FR J-7), FRB L-6

(Ball, FR L-6), FRB J-5 (Ball, FR J-5), EA 6(Ash, Emeline 6), EA 7(Ash, Emeline 7) can be seen in Figure 4.1.

On seeing the wells MHP 6, JL 16, TH 10 and EA 7 it is evident that they are patterns larger than B18 pattern. It is possible that these patterns are taking in more water from the injectors MHP9 and MHP8. Also patterns surrounding B21 patterns with producing wells FRB J-7, FRB L-6, FRB J-5, SM 3 and EA6 are either almost same or larger than B21 pattern. Also some of these patterns have their water injection started quite later than that of B18 and B21. Looking at the size of the surrounding patterns and their injection history the injection percentage into the patterns from the respective wells was reduced as can be seen in Table 4.12 and Table.13 which range from 15-25%. The analysis and the results are discussed in more in the next Chapter titled “Results and Discussion”.

CHAPTER 5.

RESULTS AND DISCUSSION

5.1 Introduction

As was discussed in the Objectives section (Chapter 2) the objective of this work was to identify the flow units and verify the accuracy of the methodology for identifying the flow units. The methodology that was used for verification purposes was the one developed by Ademola⁵ and Ben Thomas⁶. The whole process was an iterative procedure and some modification of the parameters for history matching purposes. The results that will be shown are brief and were obtained after a lot of refining.

5.2 Preliminary Simulation Runs

At the beginning when the accurate permeability and porosity predictions were not available, homogeneous reservoir models for the B18 and B21 producing patterns were developed. The thickness, porosity and permeability in the pattern were taken as homogeneous for the 2 layers. The homogenous values for the properties were based on the readings from the electric logs and available core data. Simulation was done using this homogenous model developed to see if the production prediction and properties that we had at hand were good enough to require a further analysis of the study.

The results obtained were quite promising. The homogenous B18 pattern gave a simulated cumulative oil production of 127MSTB as against the actual cumulative oil

production of 113 MSTB over a period of 9½ years. The B21 homogenous model simulation predicted a cumulative oil of 128 MSTB as compared to 133 MSTB of actual production. The output was good and gave enough promise to go for a further research in the field.

The analysis from the simulation using the homogenous properties suggested that reservoir we were dealing with was quite heterogeneous. It also suggested that a better match could be obtained if the actual permeability and porosity was used for the wells instead of homogeneously attributing the same values to all the wells. It was also deduced that perhaps a better distribution of the water injected could be obtained if the simulation was done with the 2 patterns together.

Based on the above analysis a heterogeneous model with the 2 patterns together was developed in the next stage.

5.3 Primary Simulation Study of Heterogeneous Model

Thickness, porosity and permeability for each of the 2 flow units predicted using ANN⁵ were obtained for each of the 2 producers and the 6 injectors. A heterogeneous model having B18 and B21 as primary producers was then developed with the 2 patterns together. The prediction from ANN was based on data from each quarter foot interval. Averages were calculated for thickness, porosity and permeability for each of the flow unit predicted. The averages for each of the wells were input in the grids and the intermediate values were attributed based on the variation of the properties across the

pattern. The attribution was done based on visual inspection of the variation of the properties. This requires careful inspection of the difference in the properties in the x-direction and y-direction.

The simulation of the heterogeneous model was done and the results are plotted against the actual production history. The predicted cumulative oil production compared with the actual data can be seen in the plots Figure 5.1 and Figure 5.2. The other comparison plots can be seen in the plots D.1 to D.10 (Appendix D). The injection into the patterns had to be cut down to obtain a better match. 20% was injected with the non-common injectors namely Pennick 9 (MHP9), Pennick 8 (MHP8), Ball19 (B19) and Gorrell 4 (JBG5). Whereas 40% was injected into the patterns from the common injectors namely Ball 20 (B20) and Gorrell 5 (JBG5).

Figure 5.1 (Dual Five Spot Pattern 2 Layers)

Figure 5.2 (Dual Five Spot Pattern 2 Layers)

B21 production prediction was satisfactory in terms of cumulative oil and gas production. B18 though the final quantity (cumulative oil 108 MSTB as against the actual 113 MSTB) was within 5% of the total actual production, the matching of the history was an area that needed further inspection. The production of the oil was a lot slower in the prediction as compared to the actual history. The actual cumulative oil history shows that 90% of the total production being done in 1400 days or in 3½ years. The simulator predicts 90% of the actual total oil in 3100 days that is like 8½ years.

A further analysis of the production prediction, the ANN prediction and the data from the geologic survey suggested that perhaps there is a third flow unit mostly in the B21 pattern. It also suggested that the waterfront in B18 is perhaps moving faster and hence

cutting down the oil front. The slowing down of the waterfront in B18 could be achieved by either cutting water being injected into the pattern or adjusting (lowering) the relative permeability of water or a combination of both methods.

A heterogeneous model with three flow units was then developed.

5.4 Simulation of Heterogeneous Model with 3 Flow Units

A study on this field by Thomas⁶ suggested that there might be third flow units in certain parts of the pattern with B21 as the main producer. In fact the flow unit 2 is split into two flow units based on the permeability breaks and their location in the UnitA or UnitB. It is found that the flow unit described in section 5.3 might exist partially in UnitA and partially in UnitB. Unit A and UnitB as discussed in the background study are defined by the West Virginia Geological Survey based on the shale breaks in the region. The definition of the third flow unit in this section is based on this premise.

Producer B21 and three injectors namely B19, JBG4 and B20 appeared likely to have the third flow unit based on the study by Thomas. The permeability values when averaged over the second and third flow unit were found to be different though the difference was not very high as was in the case of unit one and unit two. Whereas the producer B18 and the injectors namely MHP8, MHP9 and JBG5 appeared to have only two flow units and their definition and interval did not change.

Figure 5.3 (Dual Five Spot Pattern 3 Layers)

Figure 5.4 (Dual Five Spot Pattern 3 Layers)

The simulation run was done on the heterogeneous model with three flow units. The results predicted from the simulation are compared with the actual production history and can be seen in the plots show in Figure E.1 to E.10 (Appendix E). The cumulative oil comparison plots can be seen in Figure 5.3 and Figure 5.4

The results show that the simulator prediction for B21 is very good and accurate. The B18 prediction was improved quite a bit but the problems addressed in section 5.3 still seemed to persist. Also the gas production was not shown in the prediction.

From the analysis of this simulation study, it appeared that the two patterns have different rock properties in terms of relative permeability. Also it seemed that the water injected into the patterns was not being distributed to the two well patterns, as it should. It appeared that more water is being injected into the B18 pattern. B21 pattern being big in area and also having higher thickness should be getting more injection volume than B18.

One solution to this problem was to run the patterns individually and see if the rock properties were different and if the distribution of the injection into the patterns was being affected.

5.5 Final Simulation Study

Based on the leads from section 5.4 two separate simulation models were prepared for pattern B18 and pattern B21. B18 simulation model had two flow units whereas B21 model had three flow units.

There was not much significant improvement in B18 prediction. B21 prediction was good as always. This can be seen from the plots in Figure 5.5 Figure 5.6. The other comparison plots can be seen in Figure F.1 to F.4 (Appendix F). A three flow unit model was then developed for the B18 pattern to incorporate the potential existence of a third flow unit in the injector B20 that is a common injector for the two producing patterns. The results of the predictions in comparison with the actual data are plotted in Figure 5.7 to Figure 5.8 and Fig G.1 to G.4 (Appendix G).

Figure 5.5 (Single Pattern 2 Layers)

Figure 5.6 (Single Pattern 3 Layers)

Figure 5.7 (Single Pattern 3 Layers)

Figure 5.8 (Single Pattern 3 Layers)

The simulation run was done using this model and the prediction was improved significantly with 15% injection in MHP8 and MHP9, and 20% injection in the common injectors namely JBG5 and B20. The prediction for B21 obtained with 20% injection in the non-common injectors namely JBG4 and B19, and 25% injection in the common injectors. The explanation for the reduction in the injection percentages was discussed in the previous chapter in section 4.4.4. Also slight adjustments were made to the relative permeability data to obtain a better history match. Changes to other parameters were also made every time to get a possible explanation for the reservoir behavior. Changes made include increasing the permeability in B18 pattern, decreasing and increasing thickness in some sections of the patterns, changing PID values etc. These changes had no effect on the desired output.

CHAPTER 6

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions That Can Be Made From This Study

The primary objective of this study was to see if reservoir simulation could be used as a tool to verify the accuracy of the flow unit prediction methodologies, thereby aiding in the characterization of flow units in a heterogeneous reservoir. This study was quite successful in achieving these goals.

This study was used to test if the flow units predicted by the methods developed by Ademola⁵ and Thomas⁶ were an accurate description of the reservoir. It used the results of the above studies for the patterns B18 and B21 to verify their accuracy. The closeness in the history match that was obtained proved that simulation of waterflooding performance could be used with considerable accuracy to verify the flow unit prediction methodologies.

Apart from the main objectives there were certain other conclusions made at the end of this study. They are

1. The reservoir region had different rock properties in the B18 and B21 pattern regions. This was quite evident with the history match obtained with a little modification to the original relative permeability data. The patterns in the pilot

region of the Stringtown field had pay zone all in the Unit A. Whereas the patterns that were selected for this study namely B18 and B21 had pay zones in both Unit A and Unit B. This perhaps is the reason for the regions to have different rock properties namely relative permeability.

2. The actual B18 production history shows that the oil bank arrives at the producing well faster and within a shorter duration of time. This can be seen as the peak in the oil rate vs. time curve. The peak starts and ends in a span of 600-700 days. Whereas the peak of B21 has a span of 1500 days. This suggests that the permeability in the B18 region is considerably higher than the prediction. Also the pay zone may be thinner than what is predicted. A thinner and higher permeability region would follow the pattern of such a high peak and shorter duration.

3. The water injection into the patterns used in the simulation was from 15-25% as against 25% from each well. A better match was obtained with the reduction in the injection percentages. This may be due to the adjacent patterns being bigger than the pattern of study, late pressurization in the adjacent patterns as compared to the pattern of study, the adjacent patterns being more productive than the pattern of study. One or more of the above causes may lead to less percentage of water being injected into the patterns. A lot of factors contribute to the distribution of the common injection waters. Only in highly theoretical and ideal cases would the water be distributed equally into the four patterns of which the injector is a part. The permeability, the thickness of the pay zone, elevation,

pressurization history etc. all plays a picture in the distribution of the injection water.

6.2 Recommendations For Future Study

Research has no end. An end of one study is the beginning for a new study. Research in any field has to be continued to attain progress in that area. Success or failure of a study should lead to more research to see how the knowledge can be increased thereby helping the mankind to lead a better life.

Though, this study has come to conclusion there is a lot of scope for improvement and future study. Some of the recommendations are presented below for a person who wishes to pursue research in this area of study.

The simulator software used for this study was Boast98 developed by DOE and is free software that can be downloaded from the web. Though the software was good enough for this study, it has its own limitations being free software. One of the limitations is its drawback in handling highly complex cases. As the complexity of the simulation in this study increased (from homogeneous case to heterogeneous case and from two flow unit case to three flow unit case), the time to get a better history match increased. Commercial simulation software which is more adept at handling the complex cases (models with more flow units etc.) would perhaps enhance the history matching and may be in a shorter duration of time.

This study could be extended to include more complex cases where the number of flow units is more than 3. Also it can be extended to check for more than two patterns together, for e.g., like a region with 4-5 adjoining patterns etc.

It should be noted in this context that the accuracy of a history match is highly dependent on the accuracy of the data input into the simulator. The better the accuracy of the input the better is the match. Sometimes errors crop in the measurement of actual parameters. This will result in the simulator output being out of match with the actual history. In such cases a need arises to adjust the parameters input to the simulator to obtain a better match. In such cases thorough research needs to be done on the methods and technology used to measure the values of the parameters and adjustments need to be made which in fact depict the actual value in the reservoir.

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APPENDIX A.

Description of Edboast and Boast 98 Simulator Software.

Description of Edboast and Boast98 simulator

1. EDBOAST.

Edboast is the user interface for entering the data input to the model. Figure A.1 shows a snapshot of the editor. It has seven horizontal menu items on the top. These menu items are File Name, Directory, Extension, Options, Help, Quit, and About as can be seen in the Figure below. The “Directory” menu item can be used to select the file in which the file containing the input data for the simulation is saved. The “File Name” can be used to select the file for editing the input data. The “Options” button can be used to enter the reservoir, fluid, solution method and other pertinent information.

Figure E.1. EDBOAST Main Menu Window.

Options button on clicking gives a dropdown sub-menu. Selecting the “Edit” button brings up the EdBoast Home Page dialog window. The EdBoast Home Page consists of 14 edit buttons. These 14 buttons are Begin, Grid, Porperm, Transm, Table, Initial, Codes, Aqu, Wells, Recurr, Default, Next, Accept, and Abort. This window is depicted in Figure A.2

Button 1. BEGIN. This button brings up a dialog frame, which consists of five lines of reservoir description called “Header”. These five lines can be used to give a brief description of the run for future

references. The next two boxes in the frame take integers as input. This input controls are for restart initialization or restart run, and for writing a post-run Table.

Figure A.2. Main input data menu in EdBoast.

Button 2. GRID. This button brings up tables for entering reservoir model grid dimensions (I, J, and K) and geometry data (grid size).

Button 3. PORPERM. PORPERM button brings up tables for entering reservoir porosity and permeability data. Also a special dialog box is presented for each region modified for porosity or permeability.

Button 4. TRANSM. Presents options for transmissibility modifications.

Button 5. TABLE. Takes the number of distinct rock and PVT regions and provides the user the buttons for Relative Permeability (RelPerm) Oil PVT Data (OilPVT), Water PVT Data (WaterPVT) Gas PVT Data (GasPVT), KGC Properties (KGC Prop), PVT data, Density Data (Stk Tank). All these buttons on clicking produce forms for entering the respective data. The rock region is a saturation dependent data set for relative permeability. The PVT region is a pressure dependent data set, including oil, water, and gas PVT tables.

Button 6. INITIAL. This button produces a set of forms one followed by the other for each layer and rock region of data to enter the pressure and saturation initialization data.

Button 7. CODES. This button introduces debug and diagnostic controls options and solution method specifications. The data can be entered in a series of two dialogs

Button 8. AQUI. This button can be used to install (by giving data) an aquifer into the model.

Button 9. WELLS. The total number of wells that will be used in the simulation, well number, the number of well nodes, and the well name for each well are entered with this option. The X, Y, Z coordinates of each well node is also entered.

Button 10. RECURR. This button introduces a set of six forms for each data set for entering recurrent data. The total number of data sets entered (maximum 200) is displayed initially. Up to 21 data sets with associated information are allowed in the first page and 22 data sets on each succeeding page. This allows a preview of the number of elapsed times days and also a break down on the number of NEW and OLD (modified) wells that are in each data set.

Button 11. DEFAULT. This button will provide a set of pre-defined input data, which allows the beginner to learn the software when no data is available.

Button 12. NEXT. Clicking of this button results in advancing to the next button in the original line up. This button produces the same result as when Tab plus the Enter key are hit. Also the Up and Down arrow keys (on keyboard) will advance or reverse the highlighted button selections.

Button 13. ACCEPT. This button will allow the saving of the edited input data under the same or a different file name.

Button 14. ABORT. Returns to the original main menu. The same file name is in the buffer and another command such as Preview or Boast98 can apply to file name previously selected.

2. BOAST98.

Boast98 is the application which evaluates the reservoir performance. The performance calculation is based on finite-difference, implicit pressure, and explicit saturation method, with options for both direct and iterative methods of solution. The reservoir is described by three dimensional grid blocks and by three fluid phases. Other options include non-vertical wells (vertical and angled wells), multiple rock and PVT regions, bubble point tracking, automatic time step control, material balance checking for solution stability, multiple wells per grid block, and rate or pressure constraints on well performance. All these options can be set using the Edboast editor.

The Boast98 application can be started indirectly by selecting the “Transfer” or “Boast98” option under the “Options” menu of the EdBoast application, or directly by typing the name under a DOS prompt, or by clicking on the icon in a directory window of the computer operating system.

The main menu bar (horizontal) on top of the application has File Name, Directory, Extension, Option, Help, Quit, and About Options. Most of these menu items, excepting the sub menu items in Option, have essentially the same function as were described earlier in the EdBoast application. Figure A.3 presents a snapshot of the Menu items before the run is started.

Figure A.3. Primary Menu Display of BOAST98.

The sub menu and their functions in the Option menu item are described below.

View. View the input data file contents chosen under the menu item File Name. The data file that is displayed will be read only and the data cannot be altered.

Simulate. The selection of this option will begin the simulation run using Boast98 with live time graphics in effect.

Plot. The selection of this option will display a plot of the results of the last time step of the last simulation run. The plots can be 2D or 3D. The kind of plot can be selected from the selection that appears henceforth.

Edit. The edit option on selection leads to the EDBOAST application for editing the current file name. The Edboast Home Page editor will be presented, immediately if EDBOAST application is in the current directory, containing the input data from the current file selection of BOAST98. If EDBOAST is not in the current directory, the program will lead to hard disk directories for locating the file EDBOAST.EXE.

Transfer. The selection of this option transfers to any executable application by selecting the proper directory-using Directory and the Transfer will show a list of executables.

Graphs. Default is turned on. The selection of live graphics will slow the total simulation time down somewhat, especially for larger grid sizes.

Histry. Default for history matching is turned off. Turning on Histry will allow the matching of historical production information with the simulated performance values. This switch can be turned on either before or after the start of simulation run. The switch can be found under the Option menu or under the Explore menu. This comparison is only seen under the Explore selection during suspension of the run.

Debug. This option can be used to debug the flowing well pressure (PWFC) calculations. This turns on special dialog windows, which depict excess pressures building up around the wells.

In order to change the Boast98 simulation display the right hand mouse button must be clicked. This causes all the simulation activity to pause. The original menu at the top of the window is replaced by a secondary 7-item menu display. The secondary items are Grid map, Layer, Flow, Explore, Capture, Resume, and Abort. Figure A.4 shows a snapshot view of the Menu displayed after run suspension using the right mouse button.

Any changes to the graphic presentations during the active simulation run can be done now by selecting from secondary menu items “Grid map”, “Layer”, and “Flow”. When “Explore” is chosen, a series of graphic probes is permitted in order to inspect the various reservoir simulation categories. “Capture” produces a captured image of the desktop, including the graphic windows of Boast98, shown at the time. The menu item “Resume”, as the name suggests, will resume the reservoir simulation run from the time step where it was suspended (by the click of right mouse button). The “Abort” option selection brings up the Run Complete notice box containing the elapsed time, including any suspension time.

Figure A.4. Boast98 Secondary Menu shown during simulation.

APPENDIX B.

Production and Injection History of Ball 18 and Ball21.

Table B.1 Production history of Ball 18:

Date	Total Days	Oil Rate, Stb/D	Gas Rate, Mcf/D	Water Rate, Stb/D	Cum. Oil, MStb	Cum. Gas, MMcf	Cum. Water, MStb
1/1/1991	0	0.0	0.0	0.0	0	0	0
2/1/1991	31	0.0	0.0	0.0	0	0	0
3/1/1991	59	0.0	0.0	0.0	0	0	0
4/1/1991	90	1.4	0.3	0.2	0	0	0
5/1/1991	120	3.2	0.0	0.2	0	0	0
6/1/1991	151	2.7	3.2	0.2	0	0	0
7/1/1991	181	3.0	9.5	0.2	0	0	0
8/1/1991	212	2.9	5.4	0.0	0	1	0
9/1/1991	243	3.5	5.6	0.1	1	1	0
10/1/1991	273	3.0	5.5	0.1	1	1	0
11/1/1991	304	2.4	6.0	0.0	1	1	0
12/1/1991	334	2.7	5.2	0.0	1	1	0
1/1/1992	365	2.7	3.8	0.0	1	1	0
2/1/1992	396	3.0	4.8	0.0	1	1	0
3/1/1992	425	3.5	3.3	0.0	1	2	0
4/1/1992	456	3.5	3.9	0.0	1	2	0
5/1/1992	486	3.5	4.9	0.0	1	2	0
6/1/1992	517	1.9	4.3	0.0	1	2	0
7/1/1992	547	4.4	3.7	0.0	1	2	0
8/1/1992	578	7.5	2.0	0.0	2	2	0
9/1/1992	609	29.9	3.2	0.0	3	2	0
10/1/1992	639	54.6	6.2	0.0	4	2	0
11/1/1992	670	72.3	12.8	0.0	6	3	0
12/1/1992	700	97.9	12.1	0.0	9	3	0
1/1/1993	731	138.6	12.6	0.0	13	4	0
2/1/1993	762	181.7	13.2	0.0	19	4	0
3/1/1993	790	235.2	15.4	0.0	26	4	0
4/1/1993	821	240.8	17.5	0.0	33	5	0
5/1/1993	851	243.0	23.8	0.0	40	6	0
6/1/1993	882	212.7	25.4	0.0	47	6	0
7/1/1993	912	200.8	24.8	0.0	53	7	0
8/1/1993	943	192.2	22.5	0.0	59	8	0
9/1/1993	974	207.7	22.8	0.0	65	9	0
10/1/1993	1004	208.2	22.5	0.0	71	9	0
11/1/1993	1035	199.3	23.9	0.0	77	10	0
12/1/1993	1065	177.0	21.2	0.0	82	11	0
1/1/1994	1096	129.5	17.6	0.0	86	11	0
2/1/1994	1127	124.7	16.1	3.3	90	12	0
3/1/1994	1155	103.4	12.7	22.9	93	12	1
4/1/1994	1186	70.4	14.1	36.5	95	12	2
5/1/1994	1216	53.9	11.4	40.9	97	13	3
6/1/1994	1247	33.3	8.7	44.8	98	13	4
7/1/1994	1277	34.9	6.5	54.1	99	13	6
8/1/1994	1308	28.9	4.3	60.1	100	13	8
9/1/1994	1339	26.1	4.8	58.2	101	13	10
10/1/1994	1369	26.0	3.5	63.5	101	14	12
11/1/1994	1400	19.4	3.1	54.6	102	14	13
12/1/1994	1430	17.4	3.0	66.3	102	14	15
1/1/1995	1461	15.4	2.0	58.7	103	14	17
2/1/1995	1492	13.7	1.7	50.0	103	14	18

3/1/1995	1520	15.1	1.6	71.1	104	14	21
4/1/1995	1551	14.3	1.6	70.8	104	14	23
5/1/1995	1581	14.5	2.2	56.9	105	14	24
6/1/1995	1612	13.0	2.3	54.0	105	14	26
7/1/1995	1642	14.4	2.5	56.5	105	14	28
8/1/1995	1673	14.6	1.1	56.3	106	14	29
9/1/1995	1704	12.8	1.3	56.0	106	14	31
10/1/1995	1734	3.6	1.3	34.2	106	14	32
11/1/1995	1765	0.0	1.2	0.0	106	14	32
12/1/1995	1795	4.9	0.3	56.8	107	14	34
1/1/1996	1826	4.1	0.0	42.9	107	14	35
2/1/1996	1857	5.6	0.4	30.9	107	14	36
3/1/1996	1886	7.9	0.3	35.1	107	14	37
4/1/1996	1917	7.3	0.5	34.2	107	14	38
5/1/1996	1947	5.3	0.7	41.7	107	14	39
6/1/1996	1978	5.0	0.7	44.8	108	14	41
7/1/1996	2008	6.0	0.5	53.9	108	14	42
8/1/1996	2039	6.0	0.5	65.1	108	14	44
9/1/1996	2070	3.9	0.6	55.0	108	14	46
10/1/1996	2100	2.5	0.6	21.2	108	14	47
11/1/1996	2131	6.3	0.4	50.4	108	14	48
12/1/1996	2161	6.7	0.2	44.2	109	14	49
1/1/1997	2192	7.1	0.6	47.5	109	14	51
2/1/1997	2223	5.6	0.6	24.4	109	14	52
3/1/1997	2251	6.0	0.4	21.4	109	14	52
4/1/1997	2282	5.9	0.6	30.1	109	15	53
5/1/1997	2312	6.7	0.5	36.2	109	15	54
6/1/1997	2343	4.3	0.5	23.8	110	15	55
7/1/1997	2373	2.8	0.6	19.7	110	15	56
8/1/1997	2404	5.7	0.4	15.8	110	15	56
9/1/1997	2435	6.1	0.3	20.5	110	15	57
10/1/1997	2465	6.5	0.4	22.1	110	15	57
11/1/1997	2496	6.2	0.5	23.6	110	15	58
12/1/1997	2526	6.0	0.6	21.8	111	15	59
1/1/1998	2557	6.2	0.5	18.3	111	15	59
2/1/1998	2588	2.5	0.5	17.6	111	15	60
3/1/1998	2616	10.5	0.6	14.0	111	15	60
4/1/1998	2647	3.1	0.2	19.9	111	15	61
5/1/1998	2677	2.7	1.0	13.9	111	15	61
6/1/1998	2708	2.2	0.3	12.3	111	15	61
7/1/1998	2738	1.4	0.3	10.4	111	15	62
8/1/1998	2769	1.8	0.3	13.1	112	15	62
10/1/1998	2830	2.4	0.2	15.8	112	15	63
11/1/1998	2861	2.4	0.2	16.0	112	15	63
12/1/1998	2891	3.1	0.3	21.8	112	15	64
1/31/1999	2922	4.6	0.4	24.4	112	15	65
2/28/1999	2953	3.5	0.3	16.7	112	15	65
3/31/1999	2982	3.4	0.0	16.8	112	15	66
4/30/1999	3013	3.1	0.0	18.5	112	15	66
5/31/1999	3043	3.3	0.0	21.7	112	15	67
6/30/1999	3074	3.1	0.0	19.3	112	15	67
7/31/1999	3104	2.8	0.0	20.9	112	15	68
8/31/1999	3135	2.5	0.0	9.6	113	15	68
9/30/1999	3166	2.0	0.0	15.8	113	15	69
10/31/1999	3196	2.7	0.0	21.3	113	15	69
11/30/1999	3227	3.5	0.0	27.3	113	15	70

12/31/1999	3257	2.9	0.0	22.5	113	15	71
1/1/2000	3288	3.5	0.0	29.1	113	15	72
2/1/2000	3319	3.0	0.0	25.6	113	15	72
3/1/2000	3347	2.5	0.2	27.1	113	15	73
4/1/2000	3378	2.5	0.2	25.7	113	15	74
5/1/2000	3408	2.3	0.3	23.3	113	15	75
6/1/2000	3439	1.4	0.1	12.9	113	15	75
7/1/2000	3469	0.0	0.0	0.0	113	15	75
8/1/2000	3500	0.0	0.0	0.0	113	15	75

Table B.2 Production history of Ball 21:

Date	No. of Days	Oil Rate, Stb/D	Gas Rate, Mcf/D	Water Rate, Stb/D	Cum. Oil, MSTB	Cum. Gas, MMcf	Cum. Water, MSTB
1/1/1991	0	0.0	0.0	0.0	0.0	0.0	0.0
2/1/1991	31	0.0	0.0	0.0	0.0	0.0	0.0
3/1/1991	59	0.0	0.0	0.0	0.0	0.0	0.0
4/1/1991	90	3.1	0.3	0.3	0.1	0.0	0.0
5/1/1991	120	5.2	0.0	0.2	0.3	0.0	0.0
6/1/1991	151	3.2	7.3	0.2	0.3	0.2	0.0
7/1/1991	181	3.6	15.4	0.3	0.5	0.7	0.0
8/1/1991	212	3.6	6.4	0.0	0.6	0.9	0.0
9/1/1991	243	3.3	6.6	0.0	0.7	1.1	0.0
10/1/1991	273	3.0	6.7	0.0	0.7	1.3	0.0
11/1/1991	304	2.8	5.6	0.0	0.8	1.5	0.0
12/1/1991	334	3.2	5.1	0.0	0.9	1.6	0.0
1/1/1992	365	3.1	4.4	0.0	1.0	1.7	0.0
2/1/1992	396	4.6	5.6	0.0	1.2	1.9	0.0
3/1/1992	425	4.0	3.7	0.0	1.3	2.0	0.0
4/1/1992	456	4.0	6.0	0.0	1.4	2.2	0.0
5/1/1992	486	3.8	5.6	0.0	1.5	2.4	0.0
6/1/1992	517	4.0	4.9	0.0	1.6	2.5	0.0
7/1/1992	547	3.4	4.0	0.0	1.7	2.6	0.0
8/1/1992	578	4.4	4.2	0.0	1.9	2.8	0.0
9/1/1992	609	6.1	2.5	0.0	2.0	2.8	0.0
10/1/1992	639	6.8	3.7	0.0	2.3	2.9	0.0
11/1/1992	670	3.0	2.6	0.0	2.3	3.0	0.0
12/1/1992	700	1.6	1.5	0.0	2.4	3.1	0.0
1/1/1993	731	1.1	0.5	0.0	2.4	3.1	0.0
2/1/1993	762	4.3	0.2	0.0	2.6	3.1	0.0
3/1/1993	790	25.1	0.1	0.0	3.3	3.1	0.0
4/1/1993	821	37.3	0.4	0.0	4.4	3.1	0.0
5/1/1993	851	51.4	2.5	0.0	6.0	3.2	0.0
6/1/1993	882	50.0	3.9	0.0	7.5	3.3	0.0
7/1/1993	912	53.2	5.2	0.0	9.1	3.5	0.0
8/1/1993	943	56.7	5.3	0.0	10.8	3.6	0.0
9/1/1993	974	57.1	6.0	0.0	12.5	3.8	0.0
10/1/1993	1004	85.8	6.6	0.0	15.1	4.0	0.0
11/1/1993	1035	99.9	6.6	0.0	18.0	4.2	0.0
12/1/1993	1065	99.8	8.7	0.0	21.0	4.5	0.0
1/1/1994	1096	75.5	8.8	0.0	23.3	4.7	0.0
2/1/1994	1127	132.7	9.1	0.0	27.3	5.0	0.0

3/1/1994	1155	176.5	7.4	0.0	32.6	5.2	0.0
4/1/1994	1186	164.3	15.0	0.0	37.5	5.7	0.0
5/1/1994	1216	125.8	19.4	0.0	41.3	6.2	0.0
6/1/1994	1247	126.9	20.2	0.0	45.1	6.8	0.0
7/1/1994	1277	142.0	15.2	0.0	49.4	7.3	0.0
8/1/1994	1308	146.2	16.2	0.0	53.7	7.8	0.0
9/1/1994	1339	145.5	19.5	0.0	58.1	8.4	0.0
10/1/1994	1369	151.7	17.5	0.0	62.7	8.9	0.0
11/1/1994	1400	136.7	17.1	0.0	66.8	9.4	0.0
12/1/1994	1430	140.7	17.4	0.0	71.0	9.9	0.0
1/1/1995	1461	128.2	14.2	0.0	74.8	10.4	0.0
2/1/1995	1492	115.3	13.4	0.0	78.3	10.8	0.0
3/1/1995	1520	123.8	13.1	0.0	82.0	11.2	0.0
4/1/1995	1551	120.2	13.7	0.0	85.6	11.6	0.0
5/1/1995	1581	125.7	18.4	0.0	89.4	12.1	0.0
6/1/1995	1612	116.7	19.6	0.0	92.9	12.7	0.0
7/1/1995	1642	117.4	21.8	0.0	96.4	13.4	0.0
8/1/1995	1673	95.8	9.8	0.0	99.3	13.6	0.0
9/1/1995	1704	101.3	10.4	0.0	102.3	14.0	0.0
10/1/1995	1734	93.3	8.6	0.0	105.1	14.2	0.0
11/1/1995	1765	107.7	9.2	0.0	108.3	14.5	0.0
12/1/1995	1795	73.8	8.1	0.0	110.6	14.7	0.0
1/1/1996	1826	53.8	9.4	13.2	112.2	15.0	0.4
2/1/1996	1857	21.6	6.5	27.4	112.8	15.2	1.2
3/1/1996	1886	24.0	4.4	27.4	113.5	15.3	2.1
4/1/1996	1917	36.8	2.0	37.6	114.6	15.4	3.2
5/1/1996	1947	31.0	2.3	47.0	115.6	15.5	4.6
6/1/1996	1978	26.8	3.3	43.7	116.4	15.6	5.9
7/1/1996	2008	30.6	3.0	63.2	117.3	15.7	7.8
8/1/1996	2039	26.9	2.7	66.7	118.1	15.7	9.8
9/1/1996	2070	27.7	3.1	62.8	118.9	15.8	11.7
10/1/1996	2100	32.8	2.9	55.2	119.9	15.9	13.4
11/1/1996	2131	26.2	2.9	66.7	120.7	16.0	15.4
12/1/1996	2161	25.3	3.1	61.1	121.5	16.1	17.2
1/1/1997	2192	20.7	2.4	62.0	122.1	16.2	19.0
2/1/1997	2223	21.0	2.1	42.8	122.7	16.2	20.3
3/1/1997	2251	18.2	1.1	39.5	123.3	16.3	21.5
4/1/1997	2282	18.6	2.2	35.0	123.8	16.3	22.6
5/1/1997	2312	18.1	1.5	36.2	124.4	16.4	23.7
6/1/1997	2343	21.3	1.4	36.7	125.0	16.4	24.8
7/1/1997	2373	15.4	1.6	47.1	125.5	16.5	26.2
8/1/1997	2404	17.0	2.0	36.0	126.0	16.5	27.2
9/1/1997	2435	16.9	1.7	30.7	126.5	16.6	28.2
10/1/1997	2465	18.6	1.3	34.1	127.0	16.6	29.2
11/1/1997	2496	17.1	1.3	35.1	127.6	16.7	30.2
12/1/1997	2526	25.5	1.6	49.7	128.3	16.7	31.7
1/1/1998	2557	8.7	1.4	30.2	128.6	16.7	32.6
2/1/1998	2588	3.5	2.0	20.1	128.7	16.8	33.2
3/1/1998	2616	4.1	0.8	15.0	128.8	16.8	33.7
4/1/1998	2647	5.0	0.3	27.6	129.0	16.8	34.5
5/1/1998	2677	3.3	0.4	12.2	129.1	16.9	34.9
6/1/1998	2708	3.8	0.5	14.4	129.2	16.9	35.3
7/1/1998	2738	8.8	0.4	19.9	129.4	16.9	35.9
8/1/1998	2769	6.3	0.5	18.8	129.6	16.9	36.5
10/1/1998	2830	9.1	0.8	39.6	129.9	16.9	37.7
11/1/1998	2861	7.7	2.2	45.1	130.1	17.0	39.0

12/1/1998	2891	9.2	1.0	55.3	130.4	17.0	40.7
1/31/1999	2922	6.9	0.6	41.0	130.6	17.0	41.9
2/28/1999	2953	5.9	0.4	44.6	130.8	17.0	43.2
3/31/1999	2981	6.2	0.0	47.3	131.0	17.0	44.7
4/30/1999	3012	6.3	0.0	63.5	131.2	17.0	46.6
5/31/1999	3042	6.5	0.0	44.3	131.4	17.0	47.9
6/30/1999	3073	2.9	0.0	46.3	131.4	17.0	49.3
7/31/1999	3103	3.5	0.0	51.1	131.6	17.0	50.8
8/31/1999	3134	4.2	0.0	36.3	131.7	17.0	51.9
9/30/1999	3165	3.0	0.0	53.4	131.8	17.0	53.5
10/31/1999	3195	4.2	0.0	62.0	131.9	17.0	55.4
11/30/1999	3226	5.5	0.0	59.9	132.1	17.0	57.2
12/31/1999	3256	4.2	0.0	45.4	132.2	17.0	58.5
1/1/2000	3287	4.4	0.0	48.6	132.3	17.0	60.0
2/1/2000	3318	4.0	0.0	45.1	132.4	17.0	61.3
3/1/2000	3347	4.1	0.4	33.7	132.6	17.1	62.4
4/1/2000	3378	3.2	0.3	24.5	132.7	17.1	63.1
5/1/2000	3408	5.9	0.7	51.9	132.8	17.1	64.6
6/1/2000	3439	7.2	0.5	32.8	133.0	17.1	65.6
7/1/2000	3469	0.0	0.0	0.0	133.0	17.1	65.6
8/1/2000	3500	0.0	0.0	0.0	133.0	17.1	65.6

Table B.3 Quarter of Cumulative Injection of the wells in the dual five spots.

Date	Days	Ball19 Cum, MStb	Pennick#9 Cum, MStb	Ball20 Cum, MStb	Gorrel5 Cum, MStb	Pennick8 Cum, MStb	Gorrell4 Cum, MStb
1/1/1991	0	0.1	0.0	0.8	0.6	0.0	0.0
2/1/1991	31	1.5	1.0	2.3	1.8	0.3	1.3
3/1/1991	59	2.9	2.5	4.0	3.2	0.6	3.1
4/1/1991	90	4.1	4.0	5.4	4.5	1.0	4.4
5/1/1991	120	5.4	5.3	6.6	5.9	1.4	5.6
6/1/1991	151	6.5	6.1	7.6	6.8	1.7	6.7
7/1/1991	181	7.3	6.7	8.4	7.4	1.9	7.5
8/1/1991	212	8.2	7.5	9.6	8.0	2.0	8.2
9/1/1991	243	8.7	7.9	10.1	8.4	2.1	8.8
10/1/1991	273	9.5	8.2	10.7	8.7	2.3	9.6
11/1/1991	304	10.4	8.8	11.4	9.3	2.4	10.5
12/1/1991	334	11.4	11.1	13.9	10.5	2.5	12.0
1/1/1992	365	12.3	14.3	17.0	11.7	2.6	13.6
2/1/1992	396	13.3	17.3	19.8	13.5	2.8	15.2
3/1/1992	425	14.3	20.4	22.5	15.5	3.0	16.9
4/1/1992	456	15.3	22.6	24.6	17.6	4.3	18.6
5/1/1992	486	16.4	24.5	26.3	19.8	6.3	20.5
6/1/1992	517	17.4	26.6	28.1	22.2	8.0	22.2
7/1/1992	547	18.4	28.9	29.6	24.3	9.2	23.8
8/1/1992	578	19.4	31.2	32.1	27.2	10.6	25.4
9/1/1992	609	20.4	34.1	34.3	30.2	11.8	26.9
10/1/1992	639	21.3	37.0	36.6	33.2	13.0	28.6
11/1/1992	670	22.3	39.5	38.7	35.9	14.2	30.1
12/1/1992	700	23.2	42.1	40.7	38.7	15.2	31.6

1/1/1993	731	24.2	44.4	42.6	41.4	16.1	33.1
2/1/1993	762	25.0	46.4	44.3	43.8	16.6	34.4
3/1/1993	790	26.0	48.7	46.2	46.4	17.3	35.9
4/1/1993	821	26.9	50.9	47.9	48.9	18.0	37.4
5/1/1993	851	27.9	53.0	49.7	51.3	18.5	38.8
6/1/1993	882	28.7	55.0	51.3	53.6	18.8	40.2
7/1/1993	912	29.5	56.9	52.8	55.7	19.0	41.4
8/1/1993	943	30.4	58.9	54.4	58.0	19.3	42.7
9/1/1993	974	31.3	60.8	56.0	60.2	19.7	44.0
10/1/1993	1004	32.2	62.8	57.5	62.4	20.2	45.2
11/1/1993	1035	33.0	64.5	58.9	64.5	20.6	46.3
12/1/1993	1065	33.9	66.2	60.4	66.5	21.2	47.6
1/1/1994	1096	34.7	67.9	61.7	68.2	22.1	48.6
2/1/1994	1127	35.6	69.6	62.9	69.9	23.0	49.8
3/1/1994	1155	36.5	71.4	64.4	71.9	24.1	51.1
4/1/1994	1186	37.3	73.1	65.9	73.7	25.1	52.3
5/1/1994	1216	38.1	74.8	67.3	75.6	26.1	53.6
6/1/1994	1247	38.9	76.4	68.7	77.3	27.0	54.9
7/1/1994	1277	39.7	77.8	70.0	79.0	28.0	56.1
8/1/1994	1308	40.4	79.4	71.3	80.7	29.1	57.3
9/1/1994	1339	41.2	80.9	72.6	82.2	30.1	58.5
10/1/1994	1369	41.9	82.6	73.9	83.9	31.2	59.8
11/1/1994	1400	42.7	84.1	75.2	85.5	32.1	61.0
12/1/1994	1430	43.4	85.7	76.5	87.1	33.1	62.2
1/1/1995	1461	44.1	87.1	77.7	88.7	33.9	63.3
2/1/1995	1492	44.7	88.1	78.9	90.1	34.7	64.3
3/1/1995	1520	45.5	89.1	80.1	91.6	35.5	65.4
4/1/1995	1551	46.2	90.0	81.2	93.0	36.2	66.5
5/1/1995	1581	47.0	90.8	82.4	94.5	36.9	67.5
6/1/1995	1612	47.6	91.2	83.3	95.8	37.3	68.3
7/1/1995	1642	48.4	91.7	84.5	97.3	37.6	69.2
8/1/1995	1673	49.1	92.3	85.6	98.8	37.8	69.8
9/1/1995	1704	49.8	92.9	86.6	100.3	38.0	70.5
10/1/1995	1734	50.4	93.3	87.6	101.8	38.0	71.2
11/1/1995	1765	51.0	94.1	88.6	103.0	38.1	71.9
12/1/1995	1795	51.6	94.5	89.5	104.2	38.1	72.7
1/1/1996	1826	52.2	95.6	90.4	105.3	38.8	73.4
2/1/1996	1857	52.8	96.4	91.2	106.3	39.1	74.1
3/1/1996	1886	53.4	97.0	92.0	107.3	39.3	74.9
4/1/1996	1917	53.9	97.4	92.7	108.3	39.4	75.8
5/1/1996	1947	54.5	97.7	93.5	109.3	39.5	76.7
6/1/1996	1978	55.0	98.1	94.3	110.4	39.7	77.5
7/1/1996	2008	55.5	98.5	95.1	111.4	39.8	78.3
8/1/1996	2039	56.1	98.9	95.9	112.5	40.0	79.1
9/1/1996	2070	56.6	99.5	96.6	113.4	40.3	79.9
10/1/1996	2100	57.1	100.1	97.3	114.3	40.7	80.7
11/1/1996	2131	57.6	100.6	98.1	115.1	41.1	81.5
12/1/1996	2161	58.1	101.3	98.7	116.0	41.5	82.1
1/1/1997	2192	58.6	101.9	99.3	116.8	41.8	82.7
2/1/1997	2223	59.0	103.0	99.9	117.5	42.5	83.2
3/1/1997	2251	59.5	104.6	100.5	118.1	43.1	83.7
4/1/1997	2282	59.9	105.8	100.9	118.7	43.5	84.2
5/1/1997	2312	60.3	107.0	101.5	119.3	43.8	84.6
6/1/1997	2343	60.7	108.3	102.0	119.8	43.9	85.0
7/1/1997	2373	61.0	109.3	102.4	120.3	44.1	85.4
8/1/1997	2404	61.4	110.5	102.9	120.8	44.3	85.8

9/1/1997	2435	61.8	111.5	103.3	121.2	44.5	86.2
10/1/1997	2465	62.2	112.3	103.8	121.7	44.7	86.6
11/1/1997	2496	62.5	113.0	104.3	122.1	44.9	87.0
12/1/1997	2526	62.8	113.7	104.7	122.6	45.0	87.4
1/1/1998	2557	63.2	114.3	105.3	123.1	45.1	87.8
2/1/1998	2588	63.6	114.7	105.7	123.6	45.1	88.1
3/1/1998	2616	64.0	115.0	106.2	123.9	45.1	88.5
4/1/1998	2647	64.3	115.2	106.7	124.4	45.1	88.9
5/1/1998	2677	64.7	115.5	107.2	124.9	45.4	89.3
6/1/1998	2708	65.0	115.7	107.6	125.2	45.9	89.7
7/1/1998	2738	65.4	116.1	108.1	125.5	46.5	90.2
8/1/1998	2769	65.7	116.4	108.6	125.8	46.6	90.6
9/1/1998	2800	66.0	117.0	108.9	126.2	47.0	91.0
10/1/1998	2830	66.3	117.8	109.1	126.5	47.3	91.4
11/1/1998	2861	66.6	118.5	109.3	126.8	47.5	91.7
12/1/1998	2891	66.9	119.3	109.6	127.1	47.7	92.1
1/31/1999	2953	67.3	119.6	109.9	127.4	47.7	92.6
2/28/1999	2984	67.6	119.9	110.3	127.7	47.8	93.0
3/31/1999	3012	68.0	120.2	110.7	127.9	47.8	93.5
4/30/1999	3043	68.3	120.5	111.1	128.3	47.8	93.9
5/30/1999	3073	68.6	120.6	111.5	128.6	47.9	94.3
6/30/1999	3104	69.0	120.8	112.0	129.0	48.2	94.7
7/1/1999	3134	69.3	121.0	112.4	129.3	48.4	95.1
8/1/1999	3165	69.7	121.1	112.8	129.6	48.6	95.5
9/1/1999	3196	70.0	121.2	113.1	129.9	48.7	95.9
10/1/1999	3226	70.3	121.5	113.5	130.3	48.9	96.3
11/1/1999	3257	70.6	121.7	113.8	130.5	49.0	96.7
12/1/1999	3287	70.9	121.9	114.0	130.8	49.1	97.1
1/1/2000	3318	71.2	122.3	114.4	131.1	49.3	97.4
2/1/2000	3349	71.5	122.5	114.8	131.4	49.4	97.8
3/1/2000	3378	71.8	122.8	115.3	131.7	49.6	98.2
4/1/2000	3409	72.1	123.1	115.7	132.0	49.7	98.6
5/1/2000	3439	72.4	123.3	116.0	132.2	49.8	98.9
6/1/2000	3470	72.7	123.5	116.4	132.5	49.9	99.2
7/1/2000	3500	73.0	123.6	116.7	132.7	50.0	99.6
8/1/2000	3531	73.3	123.7	117.0	132.8	50.3	99.9

Table B.4 Injection rates averaged annually (25% of the total)

% of Total Year	25% Ball19, MStb/D	25% Gorrell4, MStb/D	25% Gorrell5, MStb/D	25% Ball20, MStb/D	25% Pennick8, MStb/D	25% Pennick 9, MStb/D
1	31	33	29	38	7	30
2	32	54	77	73	35	85
3	29	44	76	54	17	66
4	26	40	56	44	32	53
5	23	29	47	36	14	24
6	18	26	32	25	9	19
7	13	14	18	16	10	34
8	11	13	12	13	7	16
9	11	13	10	12	4	7
10	10	12	8	12	5	7

APPENDIX C

Model grid showing the variation in thickness, permeability etc. in the layers.

This grid model is for the run with two five spot patterns together with two layers

Note: The first row and first column which are bold in all the following Tables (C-1 to C-24) represent the grid numbers. The other cells which are bold represent the location of the well (injector or producer).

Table C.1: Thickness of layer 1 in a 2 flow unit model with B18 and B21 together

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
8	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	1.5	2	3	3	3.5
7	0.5	1	1	1	1	1	1	1	1	2	2.5	3	4	5
6	0.5	1	1.5	1.75	2	2	2	2	2	2.5	3	4	5	6
5	1	1.5	2.5	2.5	2.5	3	3	3	3	3	3	3	4	5
4	1	1.5	2.5	3	3	3	3	3	3	3	2.5	3	3	5
3	0.5	1	2.5	2.5	3	3	3	3	3	2.75	2.75	2.75	3	3.5
2	0.5	1	1.5	2	3	3.25	3	3	3	3	3	3	3.5	3.5
1	0.5	1	1.5	2	3	3	3	3	3	3	3	3.5	3.5	3.75

Table C.2: Thickness of layer 2 in a 2 flow unit model with B18 and B21 together

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
8	7.5	7	7	8	10	12	12	17	10	7	5	5	5	4
7	7	7	7	10	15	15	17	15	12	8	6	6	5	4
6	7	7	7	10	12	12	12	12	12	10	8	6	5	3.75
5	6.5	6.5	6.5	6.5	10	10	12	12	9	10	10	6	5	4
4	6.5	6.5	6.5	6	6	6	6	6	8	9	10.5	6	5	4
3	7	7	6.5	6.5	6.25	6.25	6	6	7	7	7	6	5	4
2	7	7	6.5	6.5	6.5	6.25	6	6	6	6	6	6	5	4.5
1	7	7	6.5	6.5	6.5	6	6	5.5	5.5	5	5	5	5	5.5

Table C.3: Porosity of layer 1 in a 2 flow unit model with B18 and B21 together

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
8	0.11	0.12	0.12	0.11	0.10	0.09	0.08	0.07	0.08	0.00	0.00	0.00	0.00	0.00
7	0.11	0.12	0.13	0.12	0.11	0.11	0.10	0.09	0.10	0.11	0.13	0.15	0.00	0.00
6	0.11	0.13	0.14	0.14	0.13	0.12	0.12	0.10	0.11	0.12	0.13	0.15	0.17	0.18
5	0.11	0.13	0.14	0.15	0.14	0.14	0.13	0.12	0.12	0.13	0.13	0.15	0.17	0.17
4	0.11	0.13	0.14	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.13	0.16	0.17	0.17
3	0.11	0.13	0.13	0.14	0.15	0.15	0.15	0.15	0.15	0.14	0.14	0.16	0.16	0.16
2	0.11	0.12	0.13	0.13	0.14	0.15	0.15	0.15	0.15	0.14	0.14	0.15	0.16	0.16
1	0.11	0.11	0.12	0.13	0.00	0.00	0.00	0.00	0.15	0.15	0.15	0.15	0.15	0.15

Table C.4: Porosity of layer 2 in a 2 flow unit model with B18 and B21 together

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
8	0.25	0.24	0.24	0.24	0.24	0.24	0.24	0.25	0.25	0.00	0.00	0.00	0.00	0.00
7	0.25	0.24	0.24	0.00	0.24	0.24	0.24	0.25	0.24	0.24	0.23	0.22	0.00	0.00
6	0.25	0.24	0.23	0.00	0.23	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23
5	0.26	0.24	0.23	0.22	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.23
4	0.26	0.25	0.24	0.23	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.24	0.24	0.24
3	0.26	0.25	0.24	0.24	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24	0.24	0.24
2	0.26	0.25	0.25	0.25	0.26	0.26	0.25	0.25	0.24	0.24	0.24	0.25	0.24	0.25
1	0.26	0.26	0.25	0.25	0.00	0.00	0.00	0.00	0.25	0.25	0.25	0.25	0.25	0.25

Table C.5: Permeability of layer 1 in a 2 flow unit model with B18 and B21 together

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
8	29	30	28	24	20	15	10	5	8	0	0	0	0	0
7	27	30	29	27	22	17	13	10	14	15	17	15	0	0
6	25	30	20	29	25	20	15	18	22	26	30	26	22	18
5	23	28	31	32	28	26	20	24	28	32	34	34	32	30
4	22	27	32	34	30	25	20	25	30	34	38	36	36	36
3	21	26	31	32	25	20	18	21	25	30	34	40	40	40
2	20	22	24	24	20	16	16	20	25	30	34	39	44	44
1	18.5	20	20	21	0	0	0	0	0	28	33	38	44	49

Table C.6: Permeability of layer 2 in a 2 flow unit model with B18 and B21 together

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
8	186	186	184	182	180	178	176	175	170	0	0	0	0	0
7	184	188	187	186	182	174	177	180	180	175	170	160	0	0
6	182	186	190	190	184	170	175	180	185	183	180	170	155	140
5	180	185	190	190	184	165	175	180	187	190	195	180	170	155
4	170	180	190	194	185	160	170	180	190	200	211	200	185	170
3	155	165	170	180	160	150	155	162	170	185	200	190	185	180
2	140	145	155	165	145	137	150	160	165	175	180	188	185	185
1	135	140	145	150	0	0	0	0	0	175	180	182	184	184

Table C.7 Thickness of layer 1 of B18 only three flow unit model

[illegible]

Table C.8 Thickness of layer 2 of B18 only three flow unit model

[illegible]

Table C.9 Thickness of layer 3 of B18 only three flow unit model

[illegible]

Table C. 13 Permeability of layer 1 of B18 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
15	0.11	0	0	0	0	0	0	0	0	0	0	0	0	0
14	5	5	7	0	0	0	0	0	0	0	0	0	0	0
13	7	8	10	11	11	11	0	0	0	0	0	0	0	0
12	10	12	14	15	17	18	19	20	18	0	0	0	0	0
11	12	15	17	18	20	21	21	22	19	17	16	15	14	0
10	16	18	20	21	23	22	23	24	22	20	19	18	17	0
9	19	21	20	22	25	25	25	26	24	23	22	20	18	0
8	22	24	25	26	27	28	28	28	27	25	23	21	20	0
7	24	25	26	27	28	29	32	30	30	26	25	23	22	0
6	25	26	27	29	29	31	33	34	30	28	26	25	24	0
5	25	26	27	28	30	30	32	32	30	27	25	23	21	0
4	24	25	27	28	29	29	30	30	28	26	23	21	19	0
3	24	25	27	27	27	27	28	29	26	25	22	20	17	0
2	23	25	25	26	26	26	26	27	25	23	21	19	16	14
1	23	23	24	25	25	25	25	26	24	22	20	17	14	14

Table C. 14 Permeability of layer 2 of B18 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
15	175	0	0	0	0	0	0	0	0	0	0	0	0	0
14	176	177	175	0	0	0	0	0	0	0	0	0	0	0
13	177	177	178	179	179	179	0	0	0	0	0	0	0	0
12	178	179	179	180	180	180	182	182	170	0	0	0	0	0
11	179	180	180	181	182	182	183	184	171	162	153	145	137	0
10	180	180	181	182	183	184	184	184	172	166	160	150	143	0
9	181	182	183	185	186	186	185	184	177	170	165	155	146	0
8	182	183	184	187	188	189	190	185	180	175	170	160	149	0
7	183	184	185	187	189	190	192	190	185	178	174	165	152	0
6	184	186	188	190	191	192	193	194	185	182	178	170	155	0
5	184	186	188	190	191	192	193	190	185	178	174	166	152	0
4	185	187	189	190	190	191	191	189	182	175	170	162	149	0
3	186	188	189	189	189	189	189	185	179	173	165	158	146	0
2	187	188	188	188	188	188	188	182	175	170	163	155	142	140
1	188	187	187	187	187	187	187	182	175	168	160	152	145	135

Table C. 15 Permeability of layer 3 of B18 only three flow unit model

[illegible]

Table C.16 Thickness of layer 1 of B21 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	0	0	0.5	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0.5	1	1.5	2	2.5	2.5	3	2.5	0	0	0	0	0	0	0
3	0	0	1	1.5	1.5	2	2.5	3	3	2.5	3	3.5	4	4.5	5	6	0
4	0	1.5	1.5	2	2	2	2.5	3	2.5	2.5	3	3.5	4	4.5	5	5.5	0
5	0	2	2	2	2	2.5	2.5	3	2.5	2.5	3	3	3.5	4	5	5.5	0
6	0	2	2	2.5	2.5	2.5	2.5	3	2.5	2.5	2.5	3	3.5	4	4.5	5	0
7	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3	3.5	4	4.5	5	0
8	0	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3	4	4	4.5	0
9	0	3	3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3	4	4	4.5	0
10	0	3	3	3	3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3	3.5	4	4	0
11	0	3	3	3	3	2.5	2.5	2.5	2.5	2.5	2.5	2.5	3	3.5	3.5	4	4
12	0	3	3	3	3	3	3	3	3	3	3	3	3.5	3.5	3.5	3.5	4
13	3	3	3	3	3	3	3	3	3	3	3	3	3.5	3.5	3.5	3.5	3.75
14	3.25	3	3	3	3	3	3	3	3	3	3	3	3	3.5	3.5	3.5	3.75

Table C.17 Thickness of layer 2 of B21 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	0	0	10.5	8	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	9	8	6	5	4	3	3	3	0	0	0	0	0	0	0
3	0	0	9	7	6	4	3	3	3	3	3	2	1	1	0.5	0.5	0
4	0	0	8	7	6	4	3	3	3	3	2.5	2	1	1	0.5	0.5	0
5	0	0	8	6	5	4	3	3	3	3	2.5	2	1.5	1	1	0.5	0
6	0	0	7	6	5	4	3	3	3	3	2.5	2	1.5	1	1	0.5	0
7	0	0	7	6	5	4	3	3	3	3	2.5	2	1.5	1	1	0.5	0
8	0	7	6	6	5	4	3	3	3	3	2.5	2	1.5	1	1	0.5	0
9	0	7	6	5	4	4	3	3	3	3	2.5	2	1.5	1	1	0.5	0
10	0	6.5	6	5	4	4	3	3	3	2.5	2	1.5	1	1	1	0.5	0
11	0	6	6	5	4	4	3	3	2.5	2	2	1.5	1	1	1	0.5	0.5
12	0	6	5.5	5	4	4	3	3	2.5	2	1.5	1.5	1	1	1	1	0.5
13	6	6	5.5	5	4	4	3	3	2	1.5	1.5	1.5	1	1	1	1	0.5
14	6.25	6	5.5	5	4	4	3	3	2	1.5	1.5	1.5	1	1	1	1	0.75

Table C.18 Thickness of layer 3 of B21 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	5	5	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	5	5	5	5	5	6	6	6	6	0	0	0	0	0	0	0
3	0	5	5	5	5	5	6.5	6.5	6.5	6.5	6	5.5	5	4.5	4	3.5	0
4	0	0	5	5	6	6	6	6	6	6	6	5.5	5	4.5	4	4	0
5	0	0	4	5	5	5	6	6	6.5	6.5	6	5.5	5.5	5	4.5	4.5	0
6	0	0	3	3	4	5	6	6.5	7	7	7	7	6	5.5	5	5	0
7	0	0	2	3	3	5	6	6	7	7	7	7	6	5.5	5.5	5.5	0
8	0	0	2	2	2.5	3	4	5	6	7.5	6	6	6	5.5	5.5	5.5	0
9	0	0	0	2	2	3	4	6	6	6	6	6	6	5.5	5	5	0
10	0	0	0	0	2	3	4	5	6	6	6	6	6	5.5	5	5	0
11	0	0	0	0	0	4	7	5	6	6	6	6	5.5	5.5	5	5	6
12	0	0	0	0	0	0	4	5	6	6	6	5.5	5.5	5	5	5	6
13	0	0	0	0	0	0	0	4	6	6	5.5	5.5	5.5	5	5	5	6
14	0	0	0	0	0	0	0	0	0	0	5.5	5	5	5	5	5	5

Table C.19 Porosity of layer 1 of B21 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	0	0	0.17	0.17	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0.17	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0	0	0	0	0	0	0
3	0	0	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.17	0
4	0	0	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0
5	0	0	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0
6	0	0	0.17	0.17	0.16	0.16	0.16	0.16	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0
7	0	0	0.17	0.17	0.16	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.16	0.16	0.17	0.17	0
8	0	0.17	0.17	0.17	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.16	0.16	0.17	0.17	0
9	0	0.17	0.17	0.17	0.16	0.16	0.16	0.15	0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0
10	0	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0
11	0	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
12	0	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
13	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
14	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16

Table C.20 Porosity of layer 2 of B21 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	0	0	0.25	0.25	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0.25	0.25	0.23	0.22	0.21	0.21	0.2	0.2	0	0	0	0	0	0	0
3	0	0	0.25	0.25	0.23	0.22	0.21	0.21	0.2	0.2	0.2	0.2	0.2	0.19	0.19	0.19	0
4	0	0	0.25	0.25	0.23	0.22	0.21	0.21	0.2	0.2	0.2	0.2	0.2	0.19	0.19	0.19	0
5	0	0	0.25	0.25	0.23	0.23	0.21	0.21	0.21	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0
6	0	0	0.25	0.25	0.23	0.23	0.21	0.21	0.21	0.21	0.2	0.2	0.2	0.2	0.2	0.2	0
7	0	0	0.25	0.25	0.25	0.24	0.24	0.21	0.21	0.21	0.21	0.2	0.2	0.2	0.2	0.2	0
8	0	0.25	0.25	0.25	0.25	0.24	0.24	0.21	0.21	0.21	0.21	0.2	0.2	0.2	0.2	0.2	0
9	0	0.26	0.25	0.25	0.25	0.24	0.24	0.21	0.21	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0
10	0	0.26	0.25	0.25	0.25	0.24	0.24	0.21	0.21	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0
11	0	0.27	0.25	0.24	0.24	0.23	0.23	0.21	0.21	0.21	0.21	0.21	0.22	0.23	0.23	0.23	0.23
12	0	0.27	0.25	0.24	0.24	0.23	0.23	0.22	0.22	0.22	0.22	0.22	0.24	0.23	0.23	0.23	0.23
13	0.27	0.25	0.24	0.24	0.24	0.23	0.23	0.22	0.22	0.22	0.22	0.22	0.23	0.23	0.23	0.24	0.24
14	0.27	0.25	0.24	0.24	0.24	0.23	0.23	0.23	0.22	0.22	0.22	0.22	0.23	0.23	0.24	0.24	0.25

Table C.21 Porosity of layer 3 of B21 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	0.24	0.24	0.24	0.24	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0.24	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0	0	0	0	0	0	0
3	0	0.24	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0
4	0	0	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0
5	0	0	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0
6	0	0	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0
7	0	0	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.24	0.24	0
8	0	0	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0
9	0	0	0	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0
10	0	0	0	0	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0
11	0	0	0	0	0	0.23	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0.25	0.25	0.25
12	0	0	0	0	0	0	0.23	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0.25	0.25	0.25
13	0	0	0	0	0	0	0	0.23	0.23	0.23	0.24	0.24	0.24	0.24	0.25	0.26	0.26
14	0	0	0	0	0	0	0	0	0	0	0.24	0.24	0.24	0.24	0.25	0.26	0.26

Table C.22 Permeability of layer 1 of B21 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	0	0	0.11	5	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	5	5	10	13	16	19	22	25	0	0	0	0	0	0	0
3	0	0	8	12	14	17	20	22	25	27	29	31	33	35	37	38	0
4	0	0	11	15	18	21	23	25	28	30	30	31	33	34	34	36	0
5	0	0	14	18	21	24	27	30	32	34	33	31	33	33	34	34	0
6	0	0	17	21	24	26	30	33	36	38	37	36	35	34	33	33	0
7	0	0	20	24	26	29	33	35	40	46	42	37	35	34	33	32	0
8	0	20	23	26	29	32	35	38	41	42	42	38	35	33	32	31	0
9	0	20	22	25	28	30	33	36	41	43	42	38	34	32	31	31	0
10	0	19	22	25	27	29	32	35	38	41	40	39	35	31	31	30	0
11	0	19	21	24	26	28	31	33	35	39	38	37	36	31	30	28	28
12	0	18	20	23	25	27	29	31	33	36	35	34	33	31	30	28	26
13	16	18	20	22	24	26	28	30	32	34	33	32	31	29	28	27	26
14	14	16	18	20	22	24	26	28	30	32	31	30	29	28	27	26	24

Table C.23 Permeability of layer 2 of B21 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	0	0	171	170	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	171	170	168	165	162	158	154	150	0	0	0	0	0	0	0
3	0	0	170	170	168	166	164	162	160	158	163	153	143	133	123	110	0
4	0	0	170	170	169	168	168	168	167	166	167	158	148	138	129	120	0
5	0	0	168	169	170	171	172	173	174	175	171	163	154	145	136	128	0
6	0	0	166	168	171	174	176	179	181	184	176	168	160	152	144	135	0
7	0	0	164	168	172	176	180	184	188	197	182	173	165	158	150	143	0
8	0	155	161	167	172	177	182	187	192	192	190	182	174	166	158	150	0
9	0	152	156	160	165	170	175	180	185	190	184	177	170	163	167	151	0
10	0	149	154	159	164	168	172	176	179	183	178	173	168	163	158	153	0
11	0	146	150	154	158	162	166	170	173	177	173	169	165	161	158	155	153
12	0	144	147	150	153	156	160	163	167	170	166	163	160	158	156	154	151
13	140	142	145	148	151	154	157	159	161	163	161	159	157	155	153	153	149
14	137	140	142	144	146	148	150	152	154	155	154	153	152	151	150	149	147

Table C.24 Permeability of layer 3 of B21 only three flow unit model

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	170	175	181	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	170	175	175	173	173	172	172	170	168	0	0	0	0	0	0	0
3	0	0	170	171	171	171	170	170	170	165	163	161	158	156	154	0	0
4	0	0	165	167	169	171	173	175	177	179	176	173	168	164	160	157	0
5	0	0	160	164	168	172	176	180	184	188	183	178	173	168	164	160	0
6	0	0	155	161	167	173	179	185	191	197	190	185	180	175	169	163	0
7	0	0	150	155	160	168	176	182	190	216	200	190	182	176	171	166	0
8	0	0	150	155	158	163	170	180	200	210	208	200	192	184	176	169	0
9	0	0	0	160	165	170	176	183	190	205	200	195	189	183	177	172	0
10	0	0	0	0	160	170	180	185	190	195	192	189	185	182	178	175	0
11	0	0	0	0	0	160	168	175	180	185	184	183	182	181	180	178	180
12	0	0	0	0	0	0	160	165	170	175	176	177	178	179	180	181	182
13	0	0	0	0	0	0	0	160	160	165	168	171	174	177	180	182	184
14	0	0	0	0	0	0	0	0	155	160	165	170	174	179	183	186	187

APPENDIX D

Comparison plots of 2 flow unit simulation with 2 patterns together

Figure D.3 **Figure D.4**

Figure D.5

Figure D.6

Figure D.7 **Figure D.8**

Figure D.9

Figure D.10

APPENDIX E

Comparison plots of 3 flow unit simulation with 2 patterns together

Figure E-1 **Figure E-2**

Figure E-3 **Figure E-4**

Figure E-5

Figure E-6

Figure E-7 **Figure E-8**

Figure E-9 **Figure E-10**

APPENDIX F

**Comparison plots for simulation of individual patterns
B18 with 2 flow units and B21 with 3 flow units**

Figure F.1 **Figure F.2**

Figure F.3 **Figure F.4**

APPENDIX G

**Comparison plots for simulation of individual patterns
after cutting down water injection %
B18 with 3 flow units and B21 with 3 flow units**

Figure G-1

Figure G-2

Figure G-3 **Figure G-4**

APPENDIX H

Comparison of Relative Permeability Data used in this study

Figure H-1: Relative Permeability used in the 2 Layer 2 Pattern Model

Figure H-2: Relative Permeability used in the 3 Layer 2 Pattern Model

Figure H-3: Relative Permeability used in the 3 Layer Single Pattern B18 Model

Figure H-4: Relative Permeability used in the 3 Layer Single Pattern B21 Model