GAS INJECTION AS AN ALTERNATIVE OPTION FOR HANDLING ASSOCIATED GAS PRODUCED FROM DEEPWATER OIL DEVELOPMENTS IN THE GULF OF MEXICO

A Thesis

by

YANLIN QIAN

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2004

Major Subject: Petroleum Engineering

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Approved as to style and content by:

Stuart L. Scott (Co-Chair of Committee)	Robert A. Wattenbarger (Co-Chair of Committee)
Brian J. Willis (Member)	Stephen A. Holditch (Head of Department)

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ABSTRACT

Gas Injection as an Alternative Option for Handling Associated Gas Produced from Deepwater Oil Developments in the Gulf of Mexico.(May 2004)

Yanlin Qian, B.S., Southwest Petroleum Institute

Co-Chairs of Advisory Committee: Dr. Stuart L. Scott
Dr. Robert A. Wattenbarger

The shift of hydrocarbon exploration and production to deepwater has resulted in new opportunities for the petroleum industry(in this project, the deepwater depth greater than 1,000 ft) but also, it has introduced new challenges. In 2001,more than 999 Bcf of associated gas were produced from the Gulf of Mexico, with deepwater associated gas production accounting for 20% of this produced gas. Two important issues are the potential environmental impacts and the economic value of deepwater associated gas. This project was designed to test the viability of storing associated gas in a saline sandstone aquifer above the producing horizon. Saline aquifer storage would have the dual benefits of gas emissions reduction and gas storage for future use.

To assess the viability of saline aquifer storage, a simulation study was conducted with a hypothetical sandstone aquifer in an anticlinal trap. Five years of injection were simulated followed by five years of production (stored gas recovery). Particular attention was given to the role of relative permeability hysteresis in determining trapped gas saturation, as it tends to control the efficiency of the storage process. Various cases were run to observe the effect of location of the injection/production well and formation dip angle.

This study was made to: (1) conduct a simulation study to investigate the effects of reservoir and well parameters on gas storage performance; (2) assess the drainage and imbibition processes in aquifer gas storage; (3) evaluate methods used to determine relative permeability and gas residual saturation ; and (4) gain experience with, and

confidence in, the hysteresis option in IMEX Simulator for determining the trapped gas saturation.

The simulation results show that well location and dip angle have important effects on gas storage performance. In the test cases, the case with a higher dip angle favors gas trapping, and the best recovery is the top of the anticlinal structure. More than half of the stored gas is lost due to trapped gas saturations and high water saturation with corresponding low gas relative permeability. During the production (recovery) phase, it can be expected that water-gas production ratios will be high. The economic limit of the stored gas recovery will be greatly affected by producing water-gas ratio, especially for deep aquifers.

The result indicates that it is technically feasible to recover gas injected into a saline aquifer, provided the aquifer exhibits the appropriate dip angle, size and permeability, and residual or trapped gas saturation is also important. The technical approach used in this study may be used to assess saline aquifer storage in other deepwater regions, and it may provide a preliminary framework for studies of the economic viability of deepwater saline aquifer gas storage.

DEDICATION

This work is dedicated to Wenxin Wang, my husband, who gives me love and support all of the time. I also want to dedicate this thesis to my happy, shining daughter, Shangshang, and to my parents, Qianyouzhong and Wanjinshu in China, who supported me throughout this study.

ACKNOWLEDGMENTS

I would like to express my sincere gratitude and appreciation to Dr. Stuart L. Scott, chair of my advisory committee, for his valuable guidance, support, and patience in helping me bring this research to completion.

Dr. Robert A. Wattenbarger, co-chair of my committee, has encouraged my efforts throughout the course of this project. Without his time and efforts, this endeavor would not have been possible. Dr. Wattenbarger has been an ever-present force in helping me to mature as a student and as a researcher. His dedication to helping me succeed is deeply appreciated.

Dr. Brian J. Willis of my thesis committee has been both patient and generous with his time. The confidence of my committee members in my abilities has been unwavering, and has helped to make this a solid project.

I thank Dr. Walter B. Ayers, for, editorial comments on my thesis, as well as discussions, advice, kindness, and encouragement. I greatly appreciate the help and encouragement of Mazher Ibrahim during my research.

Finally, I thank the Minerals Management Service for participating in and providing the funding for this research project.

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CHAPTER I
INTRODUCTION

1.1 Alternatives for Handling Associated Gas

The Gulf of Mexico (GOM) is a major oil and gas province, and the move to deepwater exploration and production has provided new opportunities for the petroleum industry. Deepwater gas production from the GOM has increased in the last 5 years, as shown in Fig1.1, From 1985 to 2001, total gas production has increased from 33 to 999 Bscf/yr In 2001, deepwater production accounted for more than 20% of the GOM gas production. Among the new challenges presented by this shift to deepwater operations is the necessity of handling the gas associated with major oil fields.

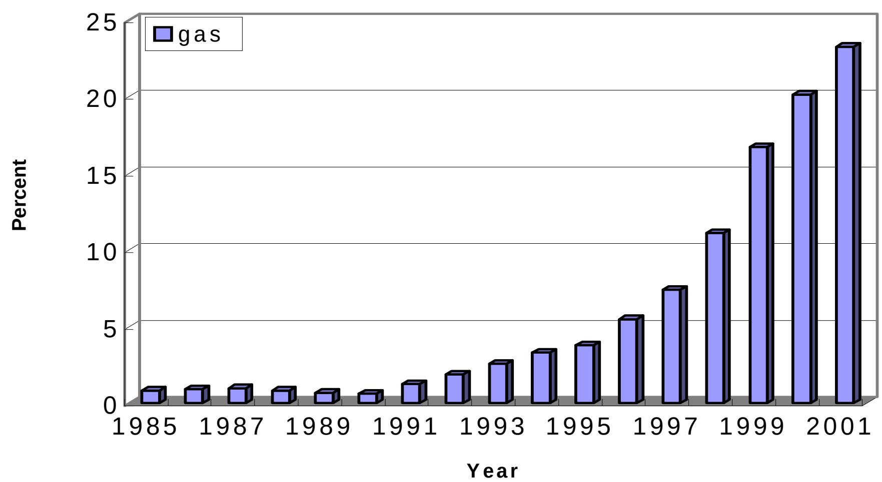

Fig. 1.1 - Gas Production from Gulf of Mexico's Deepwater is Increasing Rapidly (MMS, Minerals Management Service).

This thesis follows the style of *Society of Petroleum Engineers Reservoir Evaluation and Engineering*.

In a deepwater setting, oil can be produced and then be transported via tanker from floating structures, however for the associated gas must also be handled in some manner. A number of gas handling alternatives are available. These include:

- Pipeline Transportation - conventional single-phase gas pipeline or a multiphase pipeline where the gas is combined with produced oil;
- Gas Injection - injection into the producing reservoir or injection into a nearby or uphole aquifer;
- Liquefied Natural Gas (LNG) and transportation to shore via tanker;
- Gas to Liquids (GTL) and transportation to shore via ship or tanker;
- Compressed Natural Gas (CNG) and transportation to shore via ship;
- Gas to Wire (GTW) – offshore generation of electricity for transmission to shore via high voltage subsea cables;
- Gas to Solids (GTS) - conversion to solid forms such as hydrates for transport to shore via ship; and
- Lease Use - conversion to other forms of energy for use offshore in the operation of the producing field.

Tapia[1] developed economic models to compare these alternatives. His results showed that, for a field located at water depth less than 10,000 ft and at a distance less than 200 miles from existing facilities, a pipeline is the most profitable gas transportation option. However, CNG and GTL are economic alternatives when gas productions rates are greater than 110 MMscf/D. LNG is an economic alternative where gas rates greater than 400 MMscf/D.

The objective of this study was to investigate the gas injection as an alternative for handling the associated gas produced from the deepwater oil developments.

1.2.Aquifer Gas Storage

For some deepwater fields, particularly those with small gas reserves or those in remote location, a pipelines is not economically viable. When gas can not be flared , the usage has to be deferred, and gas may be injected into an underground storage reservoir or producing reservoir

For the gas injection option, two alternatives are (1) injection into the producing reservoir and (2) injection into a nearby or uphole aquifer. While injection into the producing reservoir provides pressure support, the effect of gas reinjection on oil production is often difficult to predict. Reservoir heterogeneity can result in rapid gas breakthrough, in which case gas cycling can reduce efficiencies and decrease oil production. This paper considers the case of gas injection into an aquifer and not the producing reservoir

USA maximum working gas in storage was approximate 3,121 Bcf in 2002 according to EIA(Energy Information Administration) estimates. Aquifer gas storage is a mature industry in USA since 1960's. Gas storage is used to balance USA market demand. Natural gas is injected into the aquifers in the summer when demand falls below the supply, and it is withdrawn from storage to provide steady supply in winter, when demand is high.

Aquifer gas storage offers possibilities for large volumes of gas to be trapped and unrecovered. This trapped gas results when water encroaches into the pore space previously occupied by gas. For seasonal aquifer gas storage, the first cycle is very inefficient because of gas is trapped in the aquifer, but for the following season, it is going more efficient, because almost all the injected gas can be produced. There are many technical paper about aquifer gas storage, one of these example is from Coat (Fig.2.1)

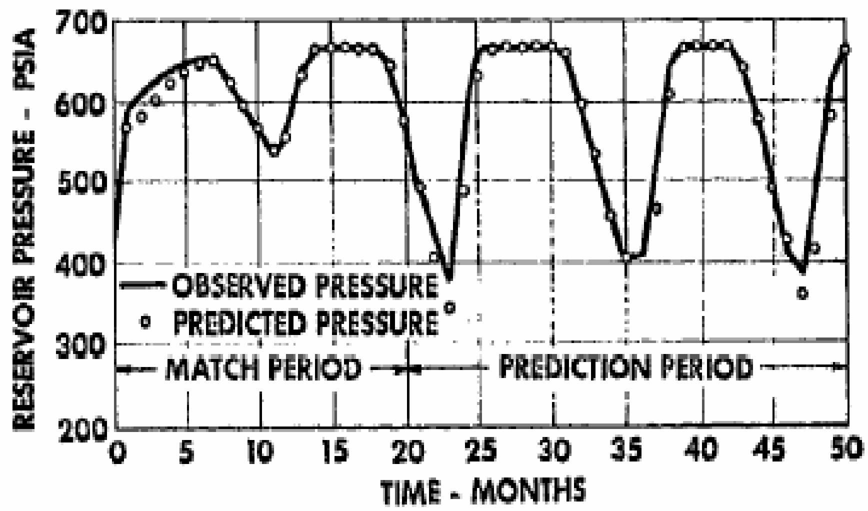

Fig. 1.2 –An Example of Typical Seasonal Gas Storage in an Aquifer. (From Coats *et al*[2]). Every Year Has an Injection Period and a Production Period.

There is an important difference between gas storage considered in this paper and seasonal storage. This paper considers only one storage cycle. The gas is injected and then it is produced back, so the trapped gas is more serious. But this will allows gas use to be deferred. Gas injected into an aquifer can be recovered later.

1.3 Simulation of Gas Storage

To investigate the basic mechanism of gas storage in aquifer, various simulation runs were conducted, assessing impacts of well location, and formation dip on the gas storage performance. Other reservoir parameters and fluid properties, including rock properties such as permeability and porosity, were also considered. The IMEX model of CMG (Computer Model Group) was to investigate aquifer gas storage performance. Chapter II presents a review of the literature explaining the parameters that affect aquifer gas storage, Chapter III discusses the simulation model, and the simulation results will be analyzed in Chapter IV.

Few papers in the petroleum literature have reported the effects of various parameters on the performance of aquifer storage reservoirs. So far, no study has reported simulations of deepwater aquifer gas storage in Gulf of Mexico. Thus, a study was needed to determine the reservoir impact of gas injection and to define generic outputs that affect gas storage performance in deepwater aquifers.

1.4. Trapped Gas Saturation and Hysteresis

When producing the stored gas, hysteresis occurs in the relative permeability, which results in trapped gas. This trapped gas cannot be recovered, because it doesn't flow. The trapped gas saturation analysis, the second stage of this study, dealt with assessing recoverable gas from an aquifer gas storage reservoir.

In this project, the gas trapping mechanisms are described, and various empirical correlation of S_{gr} vs. S_{gi} were investigated and compared. The hysteresis in relative permeability options in the reservoir simulator were also investigated in this project.

1.5. Overview of Research and Study Objectives

The purposes of this project were to (1) conduct a simulation study to investigate the effects of reservoir and well parameters on gas storage performance, (2) assess the drainage and imbibition processes in aquifer gas storage, (3) evaluate the methods used to determine relative permeability and residual gas saturation, and (4) gain experience and confidence in the hysteresis option in CMG for determining the trapped gas saturation. This project gives an up-to-date analysis of numerical simulation of the hysteresis phenomenon, and it reports the correlation between relative permeability and gas saturation.

CHAPTER II
LITERATURE REVIEW

In this chapter, a review of literature concerning alternative methods of handling associated gas was presented and the basic mechanism of an aquifer gas storage reservoir. In addition, residual gas saturation and relative permeability hysteresis are reviewed.

2.1. Handling of Associated Gas

Flaring of associated gas has been recognized both as wasteful of a potentially valuable resource and as an environmentally undesirable practice. Therefore, gas handling in deepwater of GOM has been of great concern.

The alternatives for handling associated gas include: export via pipeline; gas injection for later recovery; processes such as LNG, GTL, CNG and export via shuttle tanker; conversion to products (e.g. methanol) for transport via ship; generation of electricity for transmission to shore; and conversion to other forms of energy for use offshore or transport to shore.

A number of economic models are being developed to comparison these various alternative[,3,4,5,6] The economic models seek to capture the performance of the various gas handling options and to allow their comparison on the basis of their impact on project economics and conservation of natural resources. Factors such as size of resource, gas rate, water depth, pressure (separator & reservoir), gas composition, temperature, etc. must be considered when comparing the various alternatives. In addition to economic parameters, many nations are concerned about conservation of natural resources. Processes that utilize a large percentage of the produced gas to bringing the gas to market are less desirable.

2.2. Gas Storage in Aquifers

Since the early 1960's, aquifer gas storage fields have been developed in many parts of the USA. Gas storage is playing an increasingly important role in gas supply management. Natural gas is injected during summer when supply exceeds demand, and it is withdrawn in the winter to meet the market needs. The prospective deepwater site modeled for gas storage in this study is a blanket water-bearing sand in an anticlinal structure[7]

Aquifer storage now accounts for about 22% of the total gas storage capacity in the USA. Most of the saline aquifer storage fields are in the mid-continent area. Walter *et al*[8] presented the results of a simulation study of one such field, the Sciota aquifer gas storage field in Illinois. This field has been in operation since early 1970's and is currently operating with 12 injecting wells and five observation wells.

There have been many technical papers about the performance of the gas storage reservoirs. For example, Coats, *et al*[2] described the interaction between the gas storage and the aquifer pressure behavior, and Kuncir *et al*[9] presented two studies of the size impact and data uncertainty on aquifer gas storage.

2.2.1 Parameters Affecting Gas Storage Reservoir

The basic parameters affecting the performance of an aquifer gas storage reservoir are aquifer size, structure, and thickness of the storage zone. Also important are rock properties, such as permeability and porosity, and fluid properties, including relative permeability and capillary pressure.

Several papers discussed the experimental studies of the basic mechanisms of aquifer gas storage at a reservoir pore scale. Briggs and Katz[10] conducted an experimental and simulation study on the mechanism of the drainage of water from sand in developing aquifer gas storage. Their experimental results demonstrated three characteristics of aquifer gas storage.

Gober[11] made a qualitative analysis of the parameters affecting aquifer storage, such as boundary conditions, well completions, overpressure, and cyclic two-phase flow. However, they didn't conduct a numerical reservoir simulation or experimental study of the effects of these factors on the performance of an aquifer gas storage reservoir.

2.2.2 Gas Storage Simulation

The complexity of a real reservoirs makes it nearly impossible to conduct a comprehensive investigation of all these parameters in a simulation study. Only a few papers tried to address the effects of various parameter on aquifer gas storage.

Arastoopour and Chen[12] performed a sensitivity analysis of the primary reservoir parameters using a 3D numerical simulation model of a tight gas reservoir. They studied the effects of absolute permeability, porosity, and capillary pressure on the production of gas from single well. Their study showed that production rates, particularly gas production rates are sensitive to both the absolute permeability and the relative permeability.

Kuuskraa and Wicks[13] (1992) published a simulation investigation of the geologic and reservoir mechanisms controlling gas recovery from the Antrim shale. Their parametric sensitivity study of the field included: fracture spacing, porosity, gas sorption time, rock compressibility, absolute and relative permeability, and skin. This study, which was done using COMEPT-3D reservoir simulator, showed that absolute permeability has a large effect on the gas production rate. They also found that relative permeability is equally as important as absolute permeability in affecting gas production rate.

Wang[14] made a parametric simulation study and also conducted a history match of an actual gas storage aquifer. And his simulation study shows that the formation permeability is the most important parameter affecting the cumulative gas recovery. And the formation dip angle and porosity are of second-order importance in affecting the cumulative gas recovery.

2.3. Residual Gas Saturation

The residual gas saturation (S_{gr}) is always used to estimate recovery from aquifer gas storage reservoirs. Various methods are available for predicting the residual gas saturation. Geffen[15] *et al* measured residual gas saturation of 15 to 50 percent the pore space for various porous media. They investigated the factors that affect the residual gas saturation, such as flooding rate, static pressure, temperature, sample size, and saturation conditions before flooding. Their results indicated that the residual gas saturation could be 35 percent of pore volume in the actual field situation.

Naar and Henderson,[16] on the other hand, concluded that residual nonwetting phase saturation under imbibition should be about half the initial non-wetting phase saturation.

Keelan and Pugh[17] concluded that trapped gas saturation existed after gas displacement by wetting-phase imbibition in carbonate reservoirs. Their experiments showed that the trapped gas varied with initial gas in place and that it was a function of rock type.

Agarwal [18] addressed the relationship between initial and final gas saturation from an experimental perspective. He worked with data from data from 320 imbibition experiments. Multiple regression analysis techniques were used by rock type. Four different sets of data were obtained. These included: (1) consolidated sandstones; (2) limestones; (3) unconsolidated sandstones; and (4) unconsolidated sands. Agarwal's results show that it is impossible to develop a general correlation of high accuracy. However, established relationships can provide estimates of the residual gas saturation when laboratory data are unavailable.

In 1967, building on work of Naar and Agarwal, Land[19] proposed a relationship between the residual gas saturation (S_{gr}) and the maximum historical gas saturation.(S_{gi}) established during the drainage process. Land[20] later experimentally verified the model by comparing the calculated with experimental imbibition relative permeability. The stationary-liquid-phase method was used to measure several hysteresis loops for alundum and Berea sandstone samples, and a good match was observed.

Recently, various empirical $S_{gr}$and S_{gi} relationship[21,22,23,24,25] were proposed. Most of them are based on limited experimental results. However, two of these relationships gained popularity because of the supporting experimental data.

First, Jerauld[23] worked on fifty Berea and Prudhoe Bay sandstone samples, and proposed the hyperbolic form the relationship. Aissaouir[25] demonstrated a piecewise linear relationship with two parameters: S_{grm} and S_{go}. S_{go} is the saturation corresponding to the intersection of the two segments. Aissaoui's work is based on twelve Fontainebleau sandstone plugs. Later, Suzane[21] worked on sixty experimental S_{gr}- S_{gi} plugs, and the experimental results showed that the Aissaoui'sempirical relationship best describe her data set.

2.4. Extension of Previous Work

Only a few of the published studies have investigated some of the basic mechanisms controlling the behavior of an aquifer gas storage reservoir. A comprehensive simulation study of the effects of the various combinations of the primary reservoir parameters on performance of and aquifer gas storage reservoir was not found. There are also very few papers that discuss residual gas saturation determination and hysteresis in CMG. Two main objectives of this research are to (1) study the factors that affect gas storage in an aquifer by comprehensively investigating the effects of the primary parameters on the dynamic performance, and (2) investigate the hysteresis option in CMG. These objectives were accomplished by making simulation runs for all the representative value combinations of the primary reservoir parameters and conducting a comprehensive analysis of the methods of residual gas determination of the aquifer gas storage reservoir in reservoir scale.

CHAPTER III
CONSTRUCTION OF THE RESERVOIR MODEL

To conduct a simulation study, it was necessary to choose a simulator and to create a geologic model. The first step preparing the simulation cases was to determine the representative values of the main parameters, which should reflect reservoir characteristics and operational condition in a hypothetical aquifer gas storage field.

3.1 Description of the Simulators

For this study, a simulation software owned by Computer Modeling Group Ltd is used. IMEX is a black oil simulator in CMG. It models three phases fluid in gas, gas-water, oil-water reservoir in one, two, or three dimensions. IMEX models multiple PVT and equilibrium regions, as well as multiple rock types, and it has flexible relative permeability choices.

3.2 Geological Model

The gas storage reservoir constructed for simulation is a blanket or tabular sandstone that is charged with saline water. This saline aquifer is located in a deepwater setting on the continental slope; water depth is 6,000 ft, and top of the reservoir is 20,000 ft below sea level (Fig. 3.1).

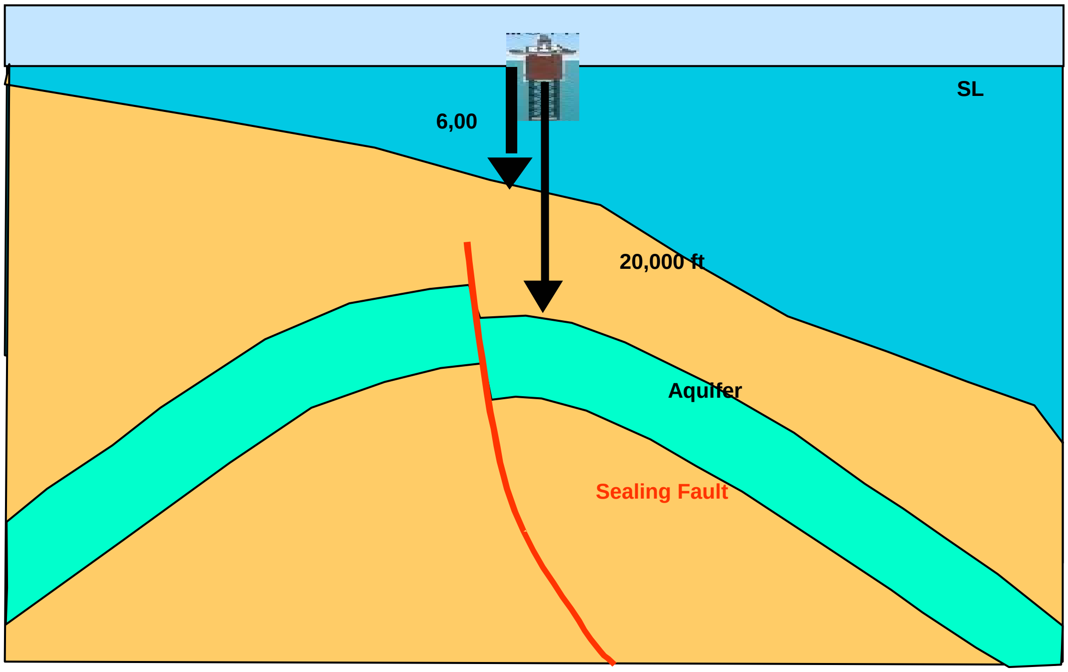

Fig. 3.1 - Schematic of the Modeled Field Areas.

Structurally, the model is an anticline that plunges 20º from the center, front edge of the model toward the back of the block (Fig. 3.2). The plunge is constant along the axis, on the right and left flanks of the symmetrical anticline are 10º. Crestal elevation of the model is 20,000 ft below sea level (Fig. 3.1). Elevation of the anticlinal crest is – 22,655 ft at the rear of the block. The boundaries of the block are inferred to be no-flow boundaries in the reservoir model, owing to presence of faults or sandstone pinch-outs. Sealing horizons overlie and underlie the sandstone aquifer. For this model, I inferred that reservoir properties of the tabular sandstone are homogeneous. Reservoir porosity is 20% and permeability is 300 md.

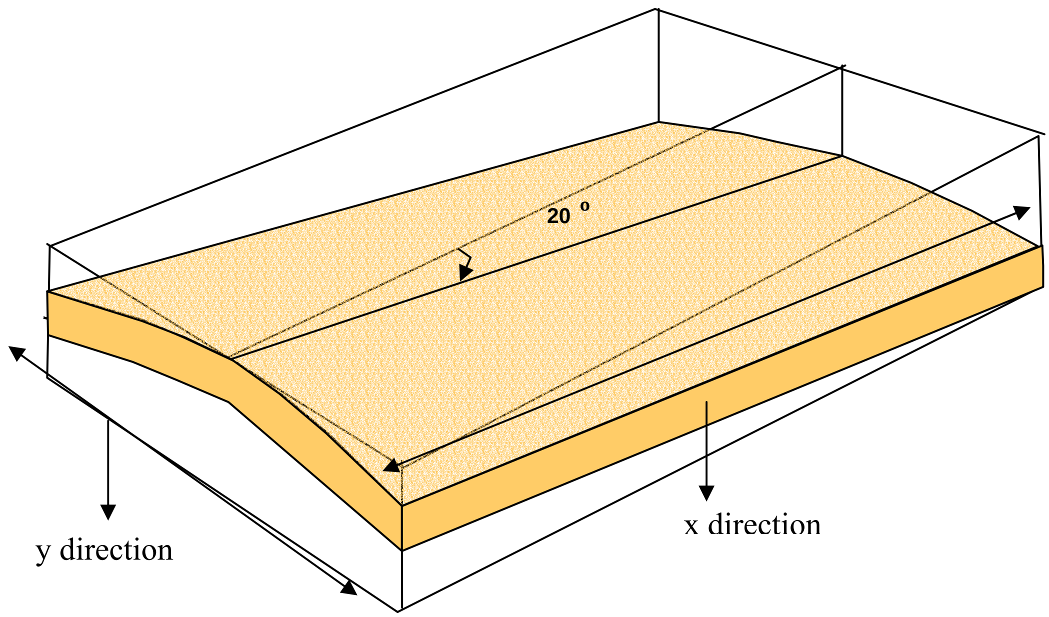

Fig. 3.2 - Simulation Model Dimensions and Description.

3.3. The Simulation Model

Simulations were made using a 4 layers cross section model with initial water saturation of 100%. The grid model dimensions of 51×41×4 were used. This model represents a 7800 × 6300 × 850-ft aquifer.(Fig.3.3) In the x direction, the grid length increases with a geometric factor of 1.08, whereas the grid in y direction is equally spaced at 150 ft.

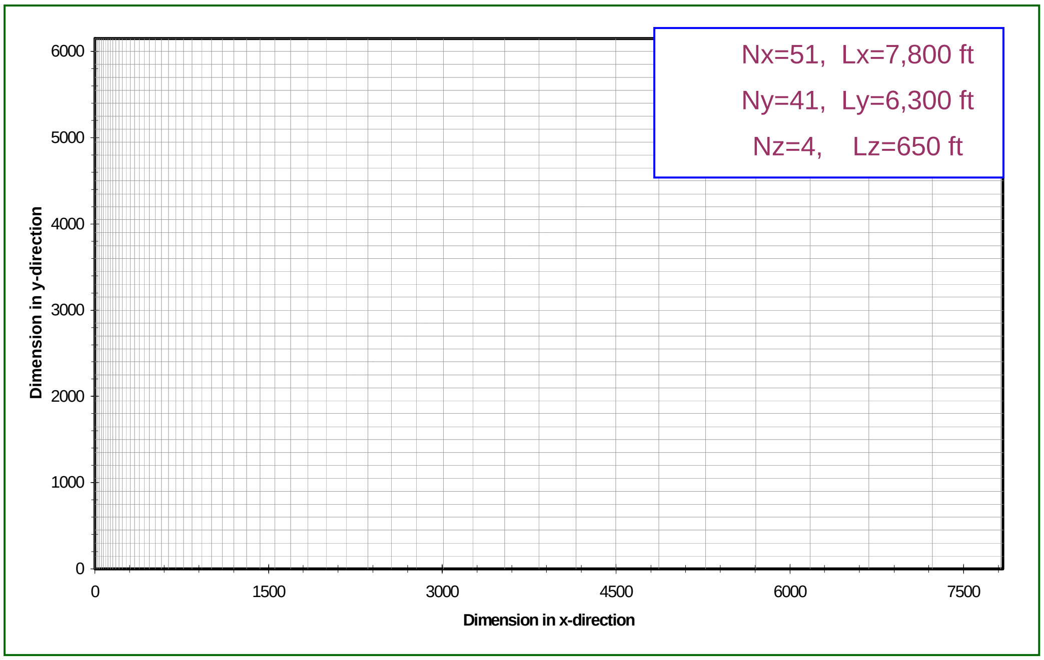

Fig. 3.3 - The Simulation Grid System of the Model.

3.4. The Simulation Data

A numerical model of a gas storage aquifer was designed to investigate the effects of the primary reservoir parameters (Table 3.1) on gas injection and withdraw performance. The ranges of parameters that were used in this research were as follows:

- Formation plunge, α= 1.7, or 20 degrees
- Three different well locations modeled were: (1)crest of the anticline; (2) north edge of the field, and (3) 1000 ft east of well 1.

Table 3.1 - Simulation Model Parameters for Case 1.

Grid	51 x 41 x 4
Structure	Anticline
Plunge, degrees	20
Porosity, fraction	0.20
Permeability, md	300
Thickness, ft	650
k_v/k_h	0.001
Pore volume, ft^3	6.25×10^9

3.5. Rock Property Parameter

3.5.1 Porosity

Most potential gas storage sandstones in deepwater of GOM have porosities ranging from 10% to 30%. A rock porosity of 20% was used in our study.

3.5.2 Permeability

Permeability of Tertiary age sandstones in the Gulf of Mexico is highly variable. For this preliminary study, a horizontal permeability value of 300 md was used ; the vertical permeability is 1/1000th of horizontal permeability.

3.5.3. Compressibility

Rock compressibility is dependent of with porosity. Lee[27] developed a correlation between pore-volume compressibility and porosity for sandstone, Since we used sandstone in the research, we choose the rock compressibility values from Newman's sandstone correlation of $4*10^{-6} psi^{-1}$

3.6. Reservoir Parameters

3.6.1. Formation Dip

Formation dip is an important parameter in determining the gas recovery in aquifer storage reservoirs. Dip varies in structural setting of different aquifers, and commonly, it varies in different part of and individual aquifer. For our simulation runs, twodip values of 1.7 and 20 were used, these value will represent the range in dip of most aquifer gas storage fields. The highest point of the aquifer is 20,000 feet. The elevation of each of the cell of the gridblock would be given by the formula .

$$\text{Elevation} = 20{,}000 + \theta\left(\text{Gridboundary} + \frac{\text{Delta} - \text{y}^2}{\text{Totalwidth}}\right)$$

3.6.2 Formation Thickness

The thickness of the formation can affect the well completion plan and the gas withdrawal efficiency. In this study, a constant of thickness (h) of 650 ft was used, and the thickness of four layers are 100,150,200,200ft respectively. The reference pressure is assumed to be 10,000 psi at depth of 20,000ft.Table 3.2 presents other constant data used in my parametric simulation.

Table 3.2 Reservoir Condition Parameters Used in the Model.

Well radius (ft)	0.25
Constant reservoir temperature (°F)	245
Reservoir pressure (psi)	10,000
Ambient temperature (°F)	60
Water density (lbs/ft^3)	0.0624
Gas specific gravity	0.6

3.7. Well Locations

Three different well location cases were run. Each case had only one well for both injection and production. Case 1 has the well at the crest of the anticline. Case 2 has the well at the north edge of the anticline. Case 3 had the well 1, 000 ft east of well 1. (Fig. 3.4)

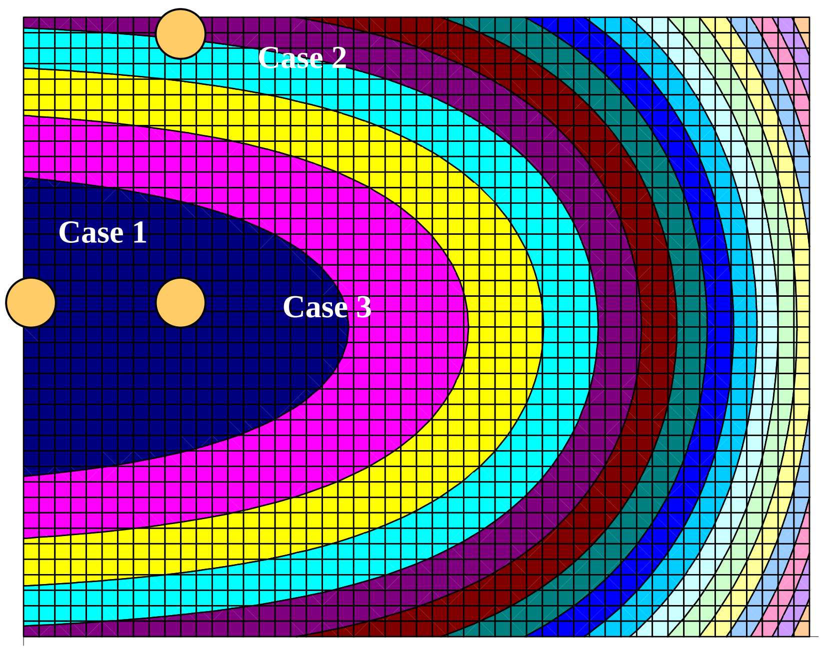

Fig. 3.4 - Simulation Grid Showing Well Locations for the Various Cases. In Each Case, Only One Well Was Active.

3.8. Rock Property: Relative Permeability

Relative permeability is affected by pore geometry, wettability, fluid distribution, and saturation history. Land[15]developed a two-phase, relative permeability equation in term of pore-size distribution and is used in IMEX model.

$$C = 1/(S_{grmax} - S_{gc}) - 1/(S_{gi}-S_{gc})$$

It requires one set of drainage and imbibition values to be entered in IMEX. This relative permeability table will be used to calculate the constant C. Table 3.3 is the gas/water relative permeability and gas saturation. Since there are no experiment measurement, the data we used came from the Core Lab data.

Table 3.3-The Gas/Water Relative Permeability.

S_g	k_{rg}	k_{rw}
0	0	1
0.1	0.041	0.67
0.15	0.082	0.45
0.2	0.12	0.3
0.275	0.18	0.16
0.325	0.25	0.08
0.38	0.3	0.035
0.45	0.39	0.017
0.66	0.68	0

In IMEX, a model by Carlson is used to simulate the relative permeability hysteresis of the nonwetting phase (gas).

3.9. Injection and Production Scheme

For each case, the well was completed only in the upper layer. (Fig 3.5). Gas was injected at a constant rate of 10 MMscf/d for 5 years for each case. Then the injection well was changed to production well. During injection, the formation pressure will increase. The constant maximum injection rate will control the formation pressure. During the production phase, we used two constraints. The primary constraint is a constant minimum bottomhole flowing pressure of 2,160 psi. The secondary constraint is a maximum constant gas withdrawal rate of 10 MMscf/d, which was used to avoid an unreasonable rate at the beginning of the gas withdrawal phase.

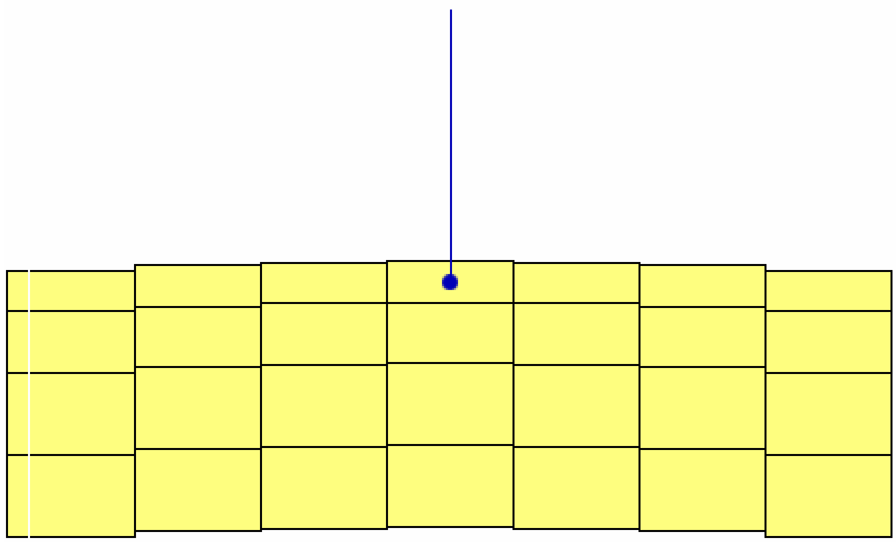

Fig 3.5 Schematic of the Well Perforation.

Water production was controlled by the relative permeability behavior in the well gridblock. In most cases, the water/gas ratio was low for a period of time, then it increased rapidly. The economic limit of production depends on this water/gas ratio, but no attempt was made to perform an economic analysis in this work. Each case was run to a water/gas ratio of 1,000 STB/MMscf.

CHAPTER IV
SIMULATION RESULTS AND DISCUSSION

For this study, a numerical model of a hypothetical gas storage aquifer was designed to investigate the effects of primary reservoir parameters and the gas injection and withdrawal scheme on the performance of aquifer gas storage reservoir. The focus was on the effects of formation dip and well location. The results of the simulation cases are summarized in the following sections.. More details are shown for Case 1, since it is the most favorable case.

4.1. Effect of Formation Dip

Formation dip angle is an important parameter for aquifer gas storage. In this project, Two cases were run. One has a dip angle of 1.7 degree, whereas the others has a dip of 20 degrees.

The simulation results show that the case with a higher dip favors gas trapping near the crest of the anticline. Owing to the gravity difference of gas and water, the gas more readily migrates up dip in the structure having the greatest dip, and it forms a gas cap around the top of structure. Table 4.1 shows the effects of formation dip angle on the cumulative gas production .

Table 4.1 Simulation Result Showing Effect of Dip on Reservoir Performance.

	Case 1	**Case1a (Plunge=1.7)**
Plungedegree	20	1.7
Total gas injection (Bscf)	18,3	18.3
Total gas production (Bscf)	7.1	5.6
Total water production (MSTB)	18.2	906.6
Recovery (%)	39.1	30.8
Project life (years)	7.0	6.5

4.2 Effect of Well Location on Aquifer Gas Storage Performance

Based on the previous simulation result, I choose dip angle of 20 for the next cases. Three cases were run to test the effects of well location on aquifer gas storage reservoir performance. Case 1 has the well at the crest of the anticline. Case 2 has the well at the north edge of the anticline, and case 3 had the well 1,000 ft east of well 1. The total gas injected for each case is 18.27 Bscf in 5 years.

Table 4.2 shows the simulation results of three different well locations. The end of the simulation in each case was taken to be when the producing water/gas ratio reached 1,000 STB/MMscf.

Table 4.2 - Simulation Results of Three Different Well Locations.

	Case 1	**Case 2**	**Case 3**
Well grid location	1,21,1	26,21,1	26,21,1
Total gas injection (Bscf)	18.3	18.3	18.3
Total gas production (Bscf)	7.1	3.8	3.9
Total water production (MSTB)	18.3	16.8	18.3
Recovery (%)	39.1	21.3	22.1
Project life (years)	7.0	6.1	6.1

Analysis of the results (**Table 4.2**) indicates that injection the well location has great effect on aquifer gas. The best well location is on the crest of the anticline, where highest recovery factor of 39.1% was recorded. Well 2 has the poorest recovery (21.3%). The effect of being lower on the structure probably tends to spread out the gas bank and also causes the injected gas to migrate upward where it is trapped at the crest of the anticline.

Fig 4.1 shows the cumulative gas injection and gas production for case 1. The lower curve is a straight line, which indicates that the gas production rate is constant at 10 MMscf/d until the end of the run (water/gas ratio reaches 1,000 STB/MMscf). Water production increases rapidly near the end of the run, but it doesn’t restrict the gas rate for the specified conditions. Fig 4.1 shows that 39.1%of the injected gas was recovered.

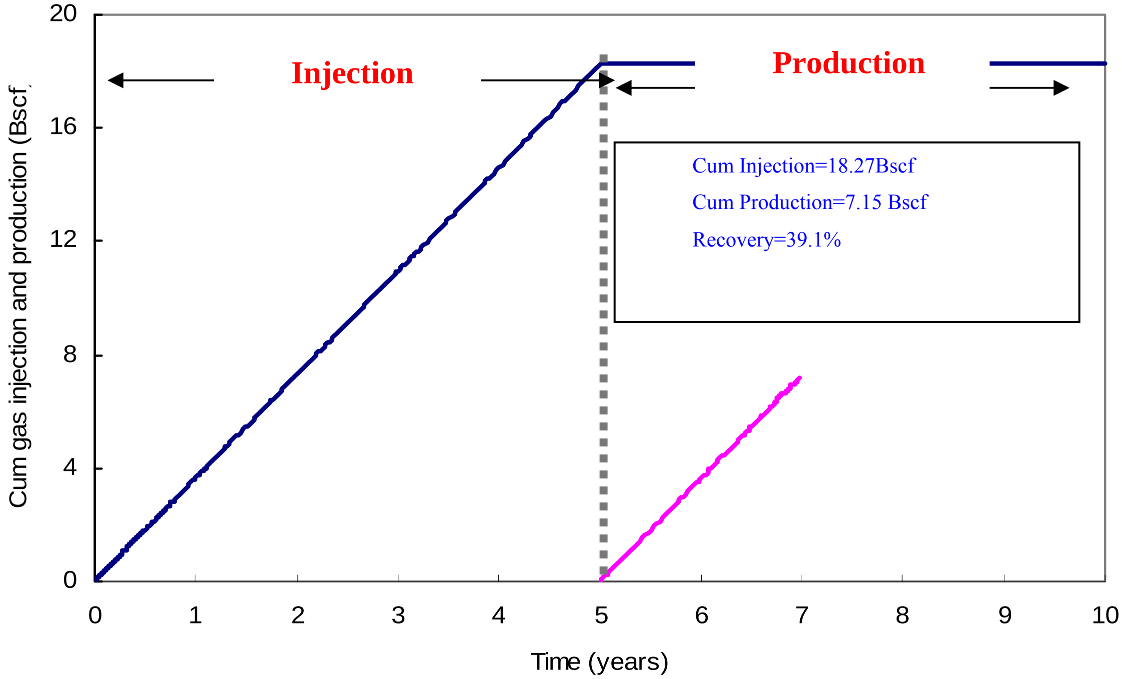

Fig. 4.1 – Cumulative Injection and Production for Case 1. The Production Ends at 6.9 Years When the Water/Gas Ratio Reaches 1,000 STB/MMscf.

. **Fig. 4.2** shows the same information in a different way. This figure shows the gas in the reservoir at any time. At the end of the run it shows how much gas is left in the reservoir.

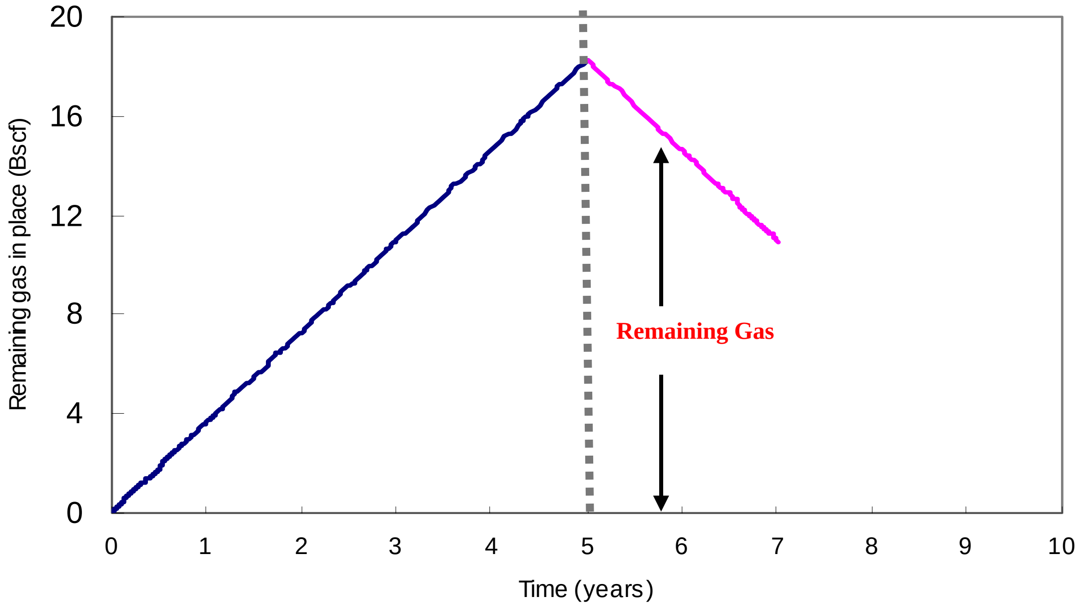

Fig. 4.2 - Simulation Results for Case 1, Showing the Amount of Gas in the Reservoir at Any Time.

Fig. 4.3 shows the gas injection and production rates plus the water/gas ratio for case 1. The water production is negligible until near the end of the project. Then, when water hits, the water production increases rapidly. A cut-off water/gas ratio of 1,000 STB/MMscf was used to determine the end of the project. However, the water production climbs so rapidly in Fig. 4.3 that a water/gas cut-off of 100 STB/MMscf would give about the same recovery.

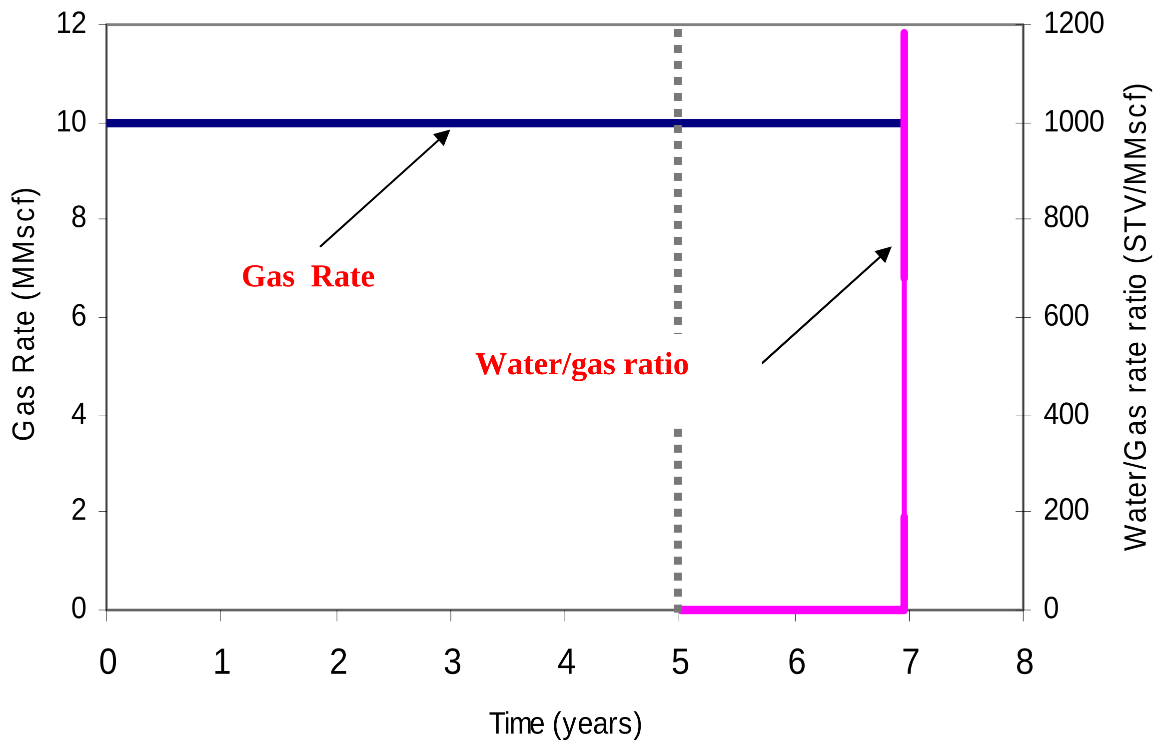

Fig. 4.3 - Simulated Cumulative Water Production of Case 1.

Fig. 4.4 shows the average pressure data for Case 1. Note that the average pressure increases during the injection period from 10,000 psi to about 11,100 psi and then decreases to 10,700 psi during the production phase.

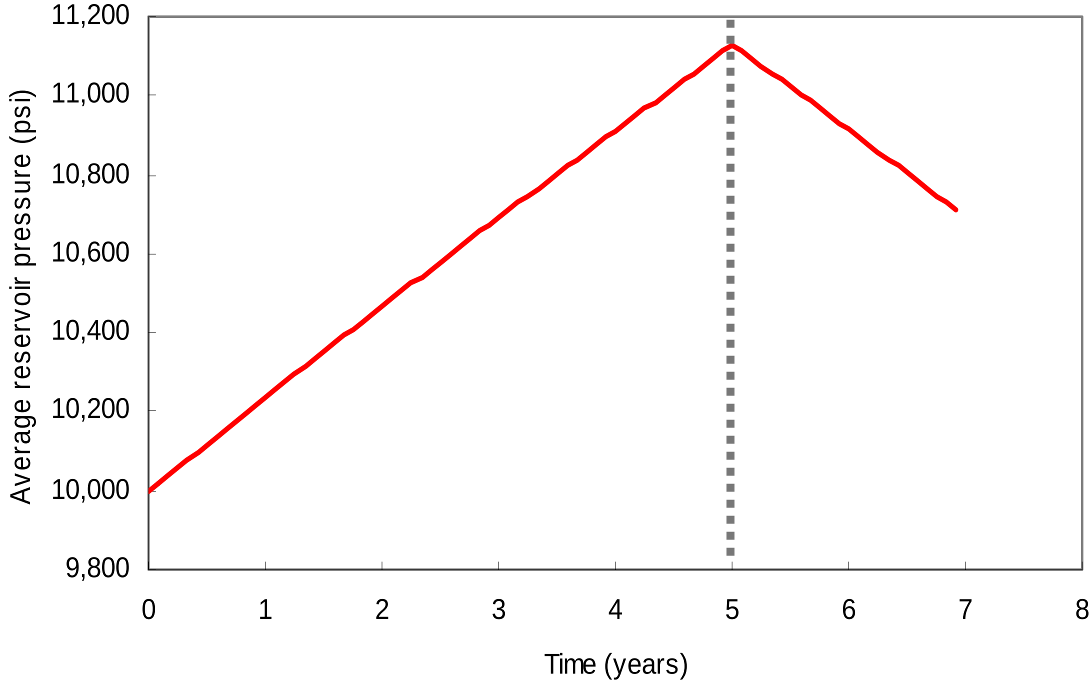

Fig. 4.4 - Simulated Average Reservoir Pressure for Case 1.

Fig. 4.5 shows the results of all three cases. This plot shows the recovery plotted vs. the water/gas ratio, which is chosen for the cut-off of the project (the economic limit). These results are very interesting.. For Case 1, Fig. 4.5 shows that the recovery will be about 39% no matter what cut-off is used for water/gas ratio. That is because the water seems to encroach into the wellbore as a sharp front with water production increasing very rapidly after breakthrough.

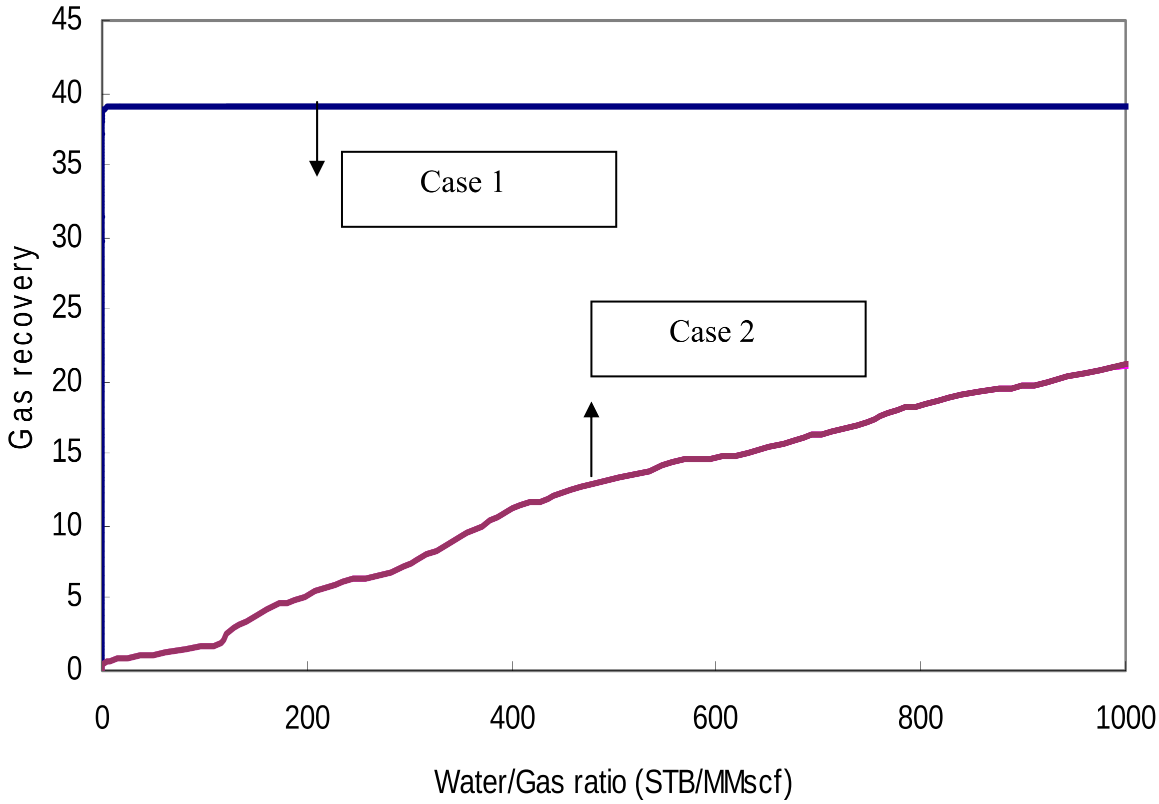

Fig. 4.5 - Gas Recovery Percent vs. the Cut-Off Water/Gas Ratio for the Three Cases.

Cases 2 and 3 look very different from Case 1. Both cases 2 and 3 have almost identical plots on Fig.4.5, so they appear as one line. Also, the water encroachment is somewhat gradual and the value of the water/gas ratio cut-off becomes very important. The operator would have to decide what cut-off value would be appropriate for a particular project.

CHAPTER V
RESIDUAL GAS SATURATION AND RELATIVE PERMEABILITY HYSTERESIS

Trapped gas saturation, the second phase of our study, dealt with assessing recoverable gas in aquifer gas storage. Residual gas saturation is known to be dependent on both pore network characteristics and initial gas saturation. The economic impact of residual gas saturation (S_{gr}) on aquifer gas storage can be very high.

Many methods are available to estimate residual gas saturation. In this chapter, the gas-trapping mechanisms are described and the correlations developed by Naar and Henderson, Agarwal , Land, Aissaoui, Kleppe, Jerauld, were presented and compared.

The methods of calculating imbibition relative permeability is described, and experimental calculated and simulated residual gas saturations are compared and they are shown to match well.

5.1. Gas Trapping Mechanism

For aquifer gas storage, the rock is initially and completely saturated with the wetting phase. For the problem addressed in this project, the wetting phase is assumed to be water, and nonwetting phase is assumed to be gas. When the gas is injected, the water is displaced by the gas, and the water saturation is reduced until critical gas saturation is reached. At this point, the gas begins to flow. As the S_g increases, the relative permeability of gas also increases. Gas enters the largest pore size first, and then invades the smaller and smaller pores (**Fig. 5.1**).

When the gas saturation reaches the maximum gas saturation value, S_{gi}, the direction of saturation changes is reversed from decreasing water saturation (drainage) to an increasing water saturation (imbibition). Then, water will enter the smallest pores first, trapping some of the gas.

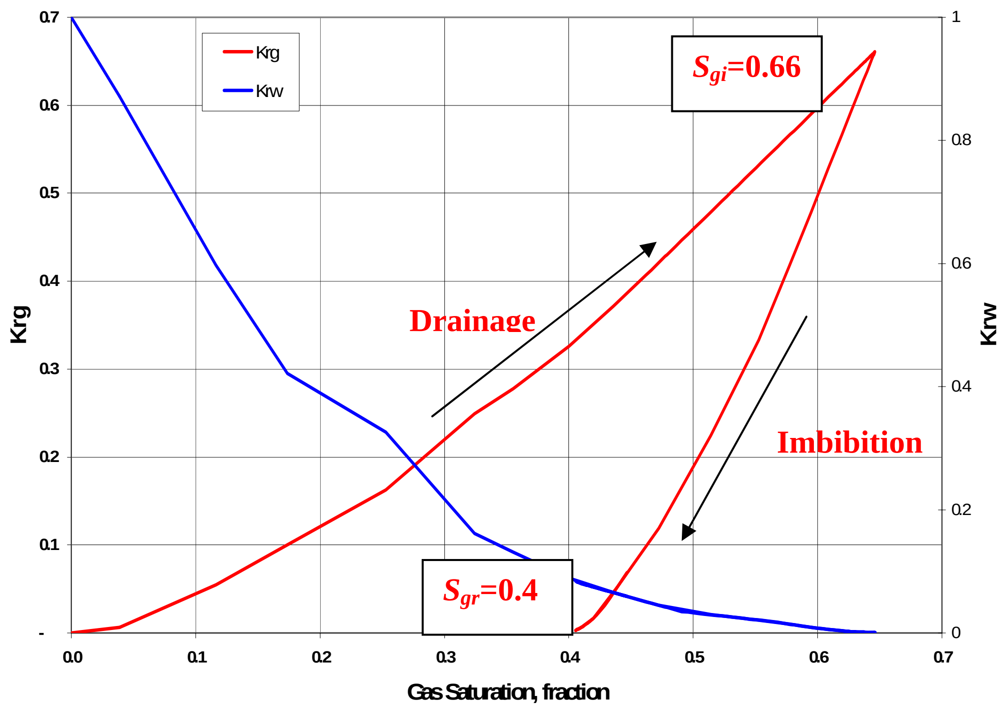

Fig. 5.1 - Drainage and Imbibition Processes (from Core Lab Data[27]).

Thus, the gas storage process is inherently inefficient in terms of reservoir volumes. As an example, Fig. 5.1 shows that 66% of the pore space can be used to store gas (at the most). Of this, 40% of the pore space contains trapped gas. That means that 60.6% of the gas is trapped. A theoretical maximum recover would be 39.4%

Recovery efficiency = Gas produced/Gas injected

$$= \left(\frac{66-44}{66-0} = 39.4\% \right)$$

For parts of the reservoir which do not reach the maximum value of 66% gas saturation, the trapped gas percentage is even higher. An additional factor in determining the efficiency of gas storage is the high water cuts that can limit production long before the residual gas saturation is reached.

5.2. Residual Gas Saturation Determination

Many methods are available for estimation of residual gas saturation. These correlation attempt to use different approach to determine S_g, but none was entirely satisfactory. Most of these methods require special core analysis to establish at least one value for S_{gr}.Then, other values can be calculated for different starting values of gas saturation. However, the first two of the following methods can be used to calculate S_{gr} without special core analysis.

5.2.1. Naar and Henderson's Method

In 1961, Naar and Henderson[16] concluded that the residual gas saturation under imbibition should be about half of the initial non-wetting phase saturation.(Fig 5.2)

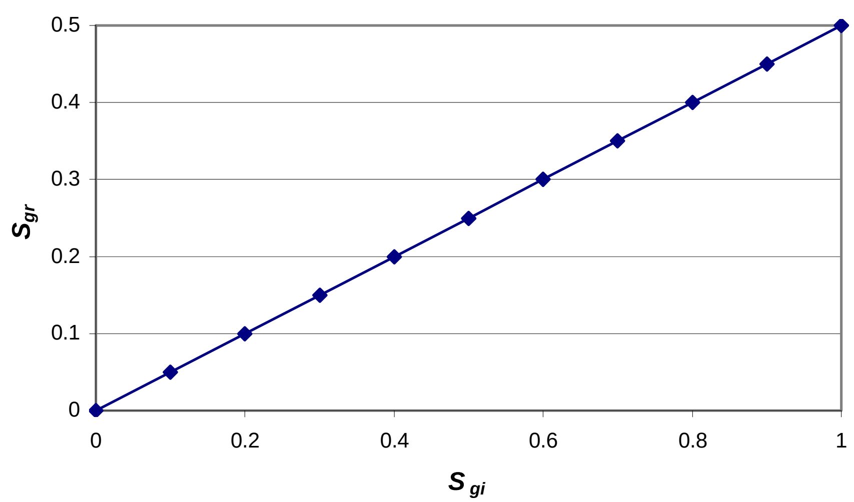

Fig. 5.2 - Theoretical S_{gr} vs S_{gi} Relationship by Naar and Henderson[16].

Their findings are given in the equation,

$$S_{gr} = \frac{1}{2} S_{gi} \text{ ....}(5\text{-}1)$$

This method doesn't require additional parameters, therefore, when laboratory data are not available, and it can be a good estimate rather than an arbitrarily assumed value.

5.2.2. Agarwal's Method

In 1967, Agarwal[18] developed a correlation using 320 experimental data values from published and unpublished sources. The data points were segregated by rock type. The rock types included consolidated sandstone, limestones, unconsolidated sandstones, and unconsolidated sands. Agarwal applied multiple regression analysis methods and obtained the residual gas saturation equation as following:

For consolidated sandstone: (see Fig 5.3)

$$S_{gr} = A_1 S_{gi} - A_2 S_{gi}^{2} \text{ ....}(5\text{-}2)$$

The correlation for the limestone data is:

$$S_{gr} = A_1\phi + A_2 \log K + A_3 S_{gi} + A_4 \text{ ....}(5\text{-}3)$$

The correlation for unconsolidated sandstone is:

$$S_{gr} = A_1 S_{gi} + A_2(\mathrm{Sgi}\,\phi) + A_3\,\phi + A_4 \text{ ....}(5\text{-}4)$$

The correlation for unconsolidated sand is:

$$S_{gr} = A_1 S_{gi} + A_2 (S_g i)^2 + A_3 (S_g i\phi) + A_4\phi 2 + A_5 \text{ ....}(5\text{-}5)$$

Coefficients of the regression equation are listed in the Table 5.1

Table 5.1. Coefficients of the Regression Equations of Agarwal

	A1	A2	A3	A4	A5
Eq	0.8084	$-0.6386*10^{-2}$			
Eq	-0.5348	$0.3355*10$	0.1545	$0.1440*10^{2}$	
Eq	-0.5125	$0.2609*10^{-1}$	-0.2676	$0.14796*10^{2}$	
Eq	$0.4936*10$	$-0.3004*10^{-1}$	$-0.2013*10^{2}$	$0.1615*10^{-1}$	$-0.1448*10^{3}$

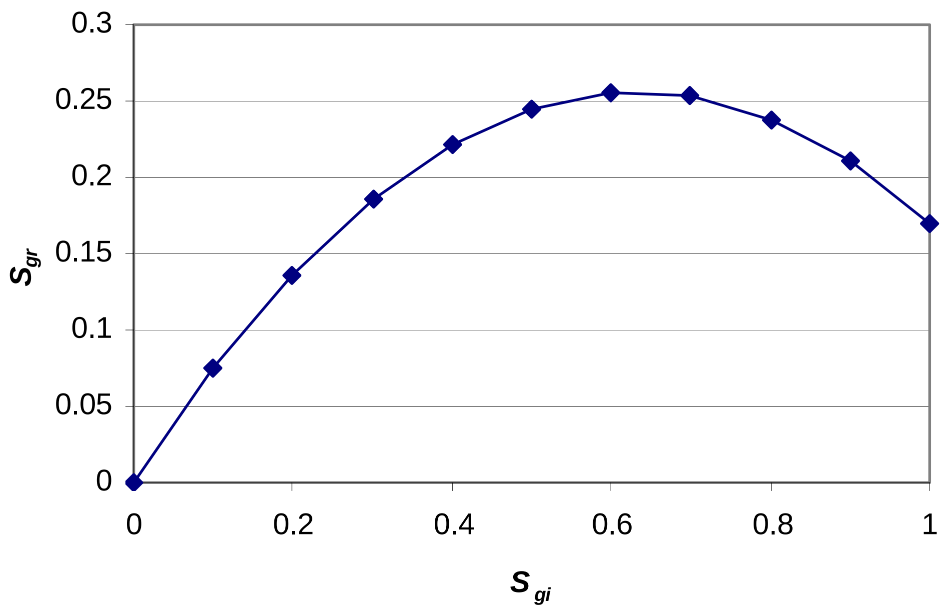

Fig. 5.3 – Theoretical S_{gr} vs S_{gi} Relationship of Agarwal[18].

Agarwal compared the experiment data with Naar Henderson line, S_{gr}=1/2 S_{gi}. Fig 5.4 presents S_{gr} vs ½ S_{gi} for consolidated sandstone. The sources of the data are Chierici, Crowell, Kruger, and Elliott.

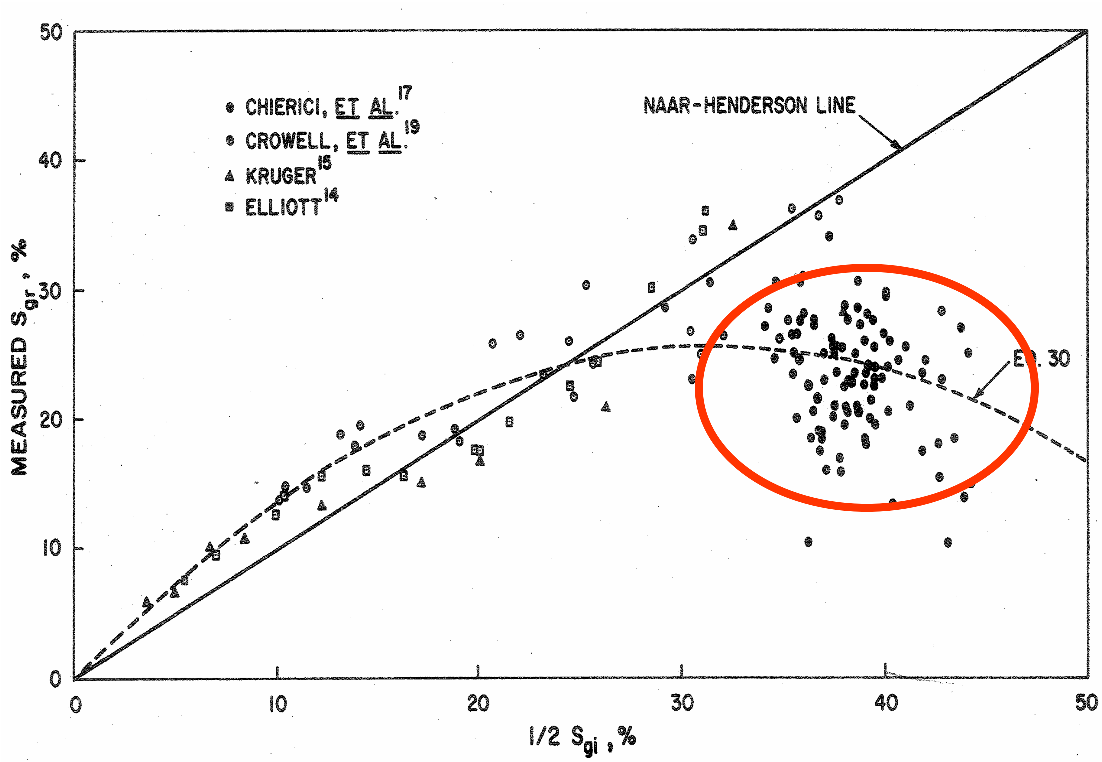

Fig.5.4- Measured S_{gr} vs. Naar and Henderson Line for the Consolidated Sandstone (Agarwal's dissertation).

From the Fig. 5.4, we can see that the Crowell, Kruger and Elliott agree with the Narr and Henderson's line, whereas the Chierici's data show a very different trend. In fact, the Chierici data appear to be a separate population that exhibit no trend and falls below the trend line exhibited by the other three populations.

Fig 5.4 shows that S_{gr} calculated vs. S_{gr} measured for the consolidated sandstone. The Chierici data show a diversified population, and this indicates that the correlation is not accurate and should not be used for determining the residual gas saturation.

5.2.3. Land's Method

After Naar and Agarwal' work, Land[19] noticed that the available data seemed to fit to an empirical functional form, and he proposed the following relationship (Fig 5.5) This equation require one parameter, C, which is dependant on rock type. C can be determined by only one lab test (S_{gr} for a corresponding S_{gi}). The data required for determining C are the drainage curve, and a minimum of one additional point on some corresponding experimental imbibition curve.

$$\frac{1}{S^*_{gr}} - \frac{1}{S^*_{gi}} = C \text{ ....(5-6)}$$

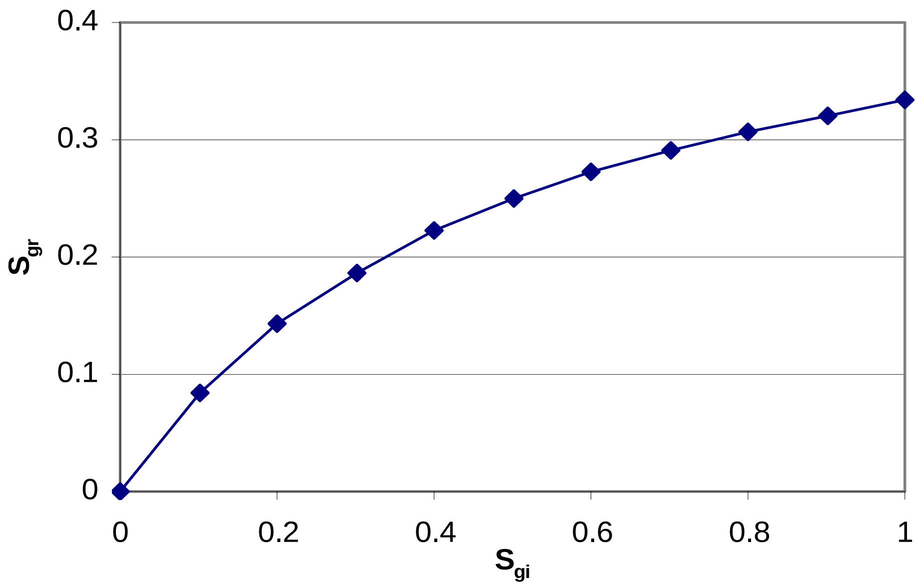

Fig. 5.5 - Theoretical S_{gr} vs S_{gi} Relationship Proposed by Land.

S^*_{gr} and S^*_{gi} are effective residual and effective initial saturation; S^*_{gr} is expressed as fractions of the pore volume excluding the pore volume occupied by the irreducible wetting phase. $S_{gr}{}^* = \dfrac{S_{gr}}{1-S_{wc}}$, and S_{gi}* are expressed as $S_{gi}{}^* = \dfrac{S_{gi}}{1-S_{wc}}$. C is the Land coefficient which is rock-type dependant. This equation is based on matching of experimental data obtained from Holmgren, Dyes, Kyte, Dardaganian and Crowell. He found that C is same for samples of any given sand. This equation is only defined if S_{gi} is lower than $1\text{-}S_{wc}$, so this equation is usually used in a simplified form, (see Fig 5.6).

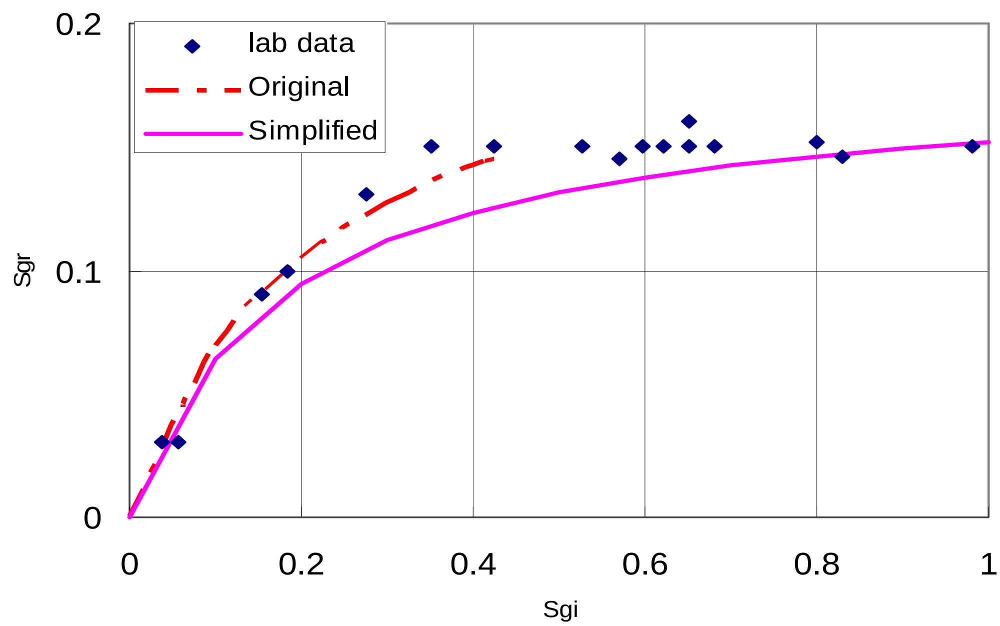

Fig. 5.6 - Comparison of Original and Simplified Land's Method [19].

Subsequently, Land experimentally verified the model with two samples[19]. One was a Berea sample, and the other was an Alundum sample. So, Land's law is based on measurements from only two samples, which is too limited.

In CMG, a modified version of Land equation is used to determine the residual gas saturation at each gridblock.

5.2.4. Kleppe's Method

Kleppe[22] developed a new method for predicting residual gas saturation from values of initial gas saturation and maximum residual gas saturation. In the absence of experimental data, it was suggested that the residual gas saturation could be obtained from a linear relationship with the maximum residual saturation at the end of the complete imbibition curve. (Fig 5.7)

$$S_{gr} = \frac{S_{gi}}{S_{g\max}} S_{gr\max} \qquad \text{...(5-7)}$$

S_{grmax} is maximum residual gas saturation after a complete imbibition process, and S_{gi} is the initial gas saturation of the scanning imbibition curve. S_{gmax} is the maximum gas saturation.

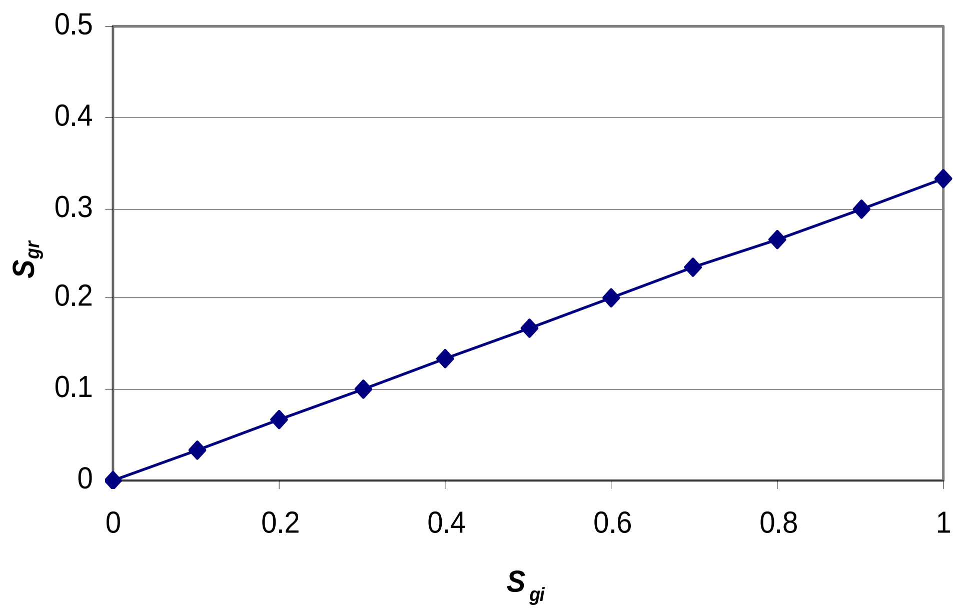

Fig 5.7- Theoretical S_{gr} vs S_{gi} Relationship Proposed by Kleppe[22].

5.2.5. Jerauld's Method

Jearauld[23] evaluated fifty Berea and Prudhoe Bay sandstone samples and proposed the following equation, which requires S_{gmax} and S_{grmax}. This is modlified Land equation, it require one parameter, S_{grmax}. It has a hyperbolic form with a nil slope at S_{gi} equal to 1.(Fig 5.8)

$$S_{gr} = \frac{S_g{}^{\max}}{1 + \left[\frac{1}{S_{gr}{}^{\max}}\right]\left[S_g{}^{\max}\right]^{1/(1-S_{gr}{}^{\max})}} \qquad \text{.......................................(.5-8)}$$

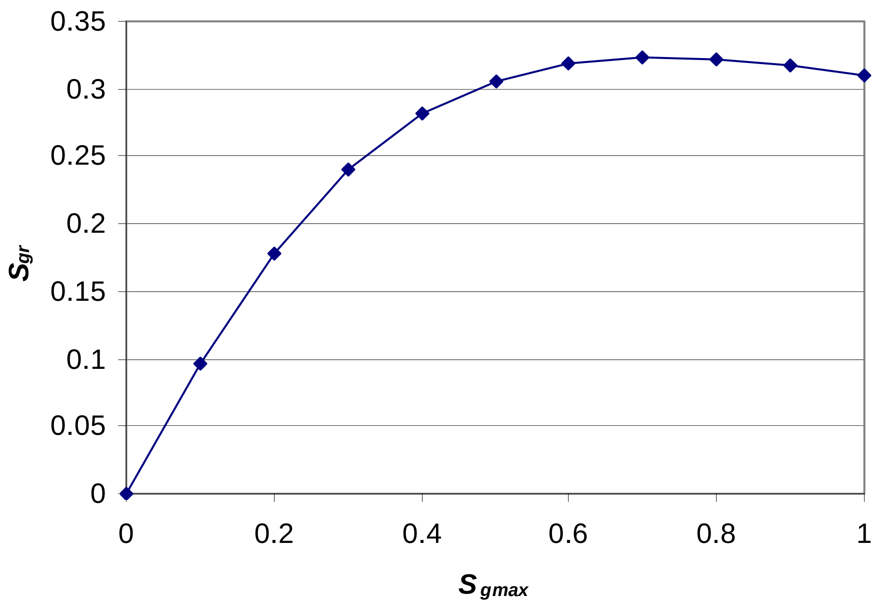

Fig 5.8-Theoretical S_{gr} vs S_{gi} Relationship Proposed by Jerauld[23].

Jerauld's expression is depend on one parameter, S_{grm}, and not recommended to be used if S_{wir} is low or high respectively.

5.2.6. Aissaoui's Method

Recently, Aissaoui[25] worked on twelve Fontainebleau sandstone plugs and proposed a piecewise linear relationship. This equations is requires two parameters, S_{grm} and S_{go}. S_{grm} is the trapped gas saturation beginning with $S_{gi} = 1$ followed by imbibition. S_{go} is the saturation corresponding to the intersection of the two segments. (Fig 5.9) S_{go}. and S_{grm} can be measured from the lab.

$$
\begin{aligned}
S_{gr} &= \frac{S_{grm}}{S_{go}} S_{gi} \qquad (S_{gi} < S_{go}) \\
S_{gr} &= S_{grm} \qquad (S_{gi} > S_{go})
\end{aligned}
\qquad \text{.................................(5-9)}
$$

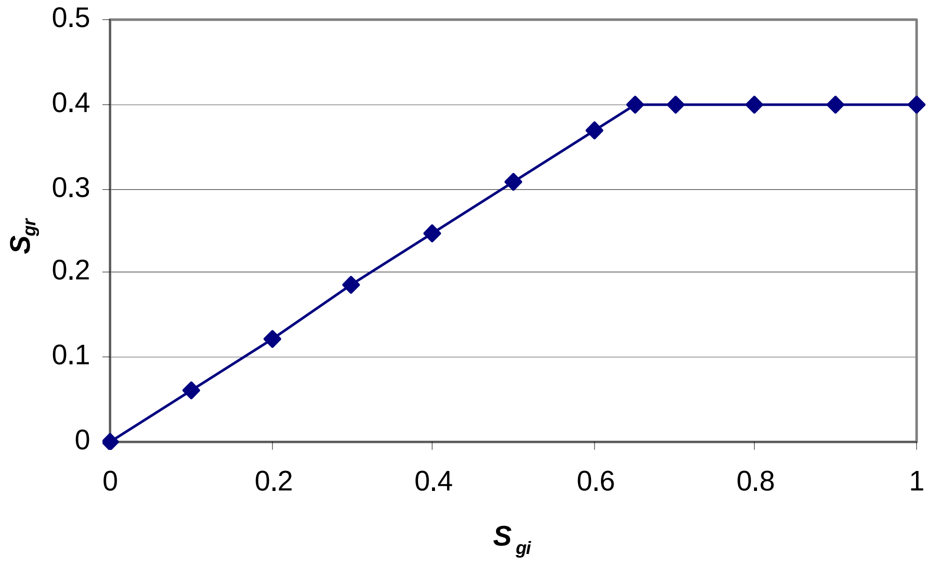

Fig. 5.9 - Theoretical S_{gr} vs S_{gi} Relationship Proposed by Aissaoui[25].

The empirical relationship proposed was later checked by Suzanne *al*[20], and the experimental result show that it best describe her data set. It is a piecewise linear relationship with two parts. And although it is more accurate, it is not recommended because the complicated procedure to measure S_{go} and S_{grm}.

5.3. Comparison of Methods

Various empirical correlations of S_{gr} *vs.* S_{gi} have been
proposed. Most of them require an addition parameter, which implies that special imbibition core analysis must be done. **Fig. 5.10** shows the comparison of different theoretical S_{gr} *vs.* S_{gi} relationships. The initial gas saturation in aquifer gas storage reservoirs is generally in the range of 0.0-0.7, and in this S_{gi} range, there is little difference in the S_{gr} *vs.* S_{gi} relationships demonstrated by different methods.

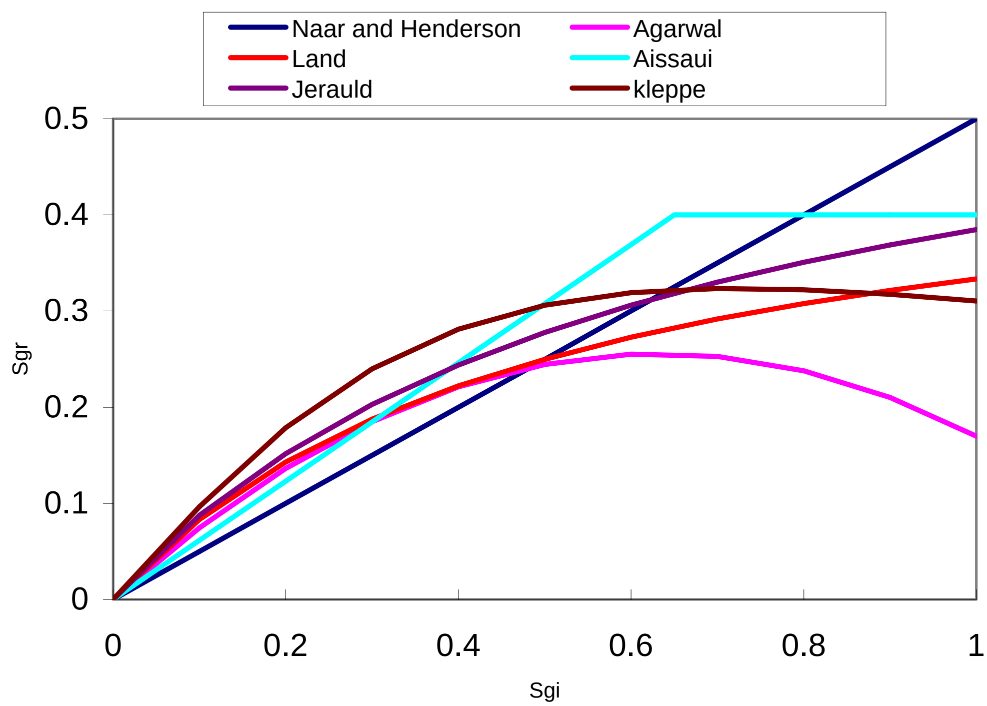

Fig. 5.10 - Comparison of S_{gr} vs S_{gi} Relationships Proposed by Different Authors.

5.4. Relative Permeability Hysteresis in CMG Model

Fig. 5.11 show simulation results depicting how gas saturation changes with time in various gridblocks. The top line is S_g of the gridblock of the well. During injection, S_g increases from 0% to about 65%. Then, during the production phase, S_g decreases to 40% (the trapped, or residual, gas saturation). (For this gridblock, S_{gi} = 0.65 and S_{gr} = 0.40). For the other gridblocks, S_{gi} is lower and the corresponding S_{gr} is lower. The bottom line represents grid block conditions furtherest from the injector.

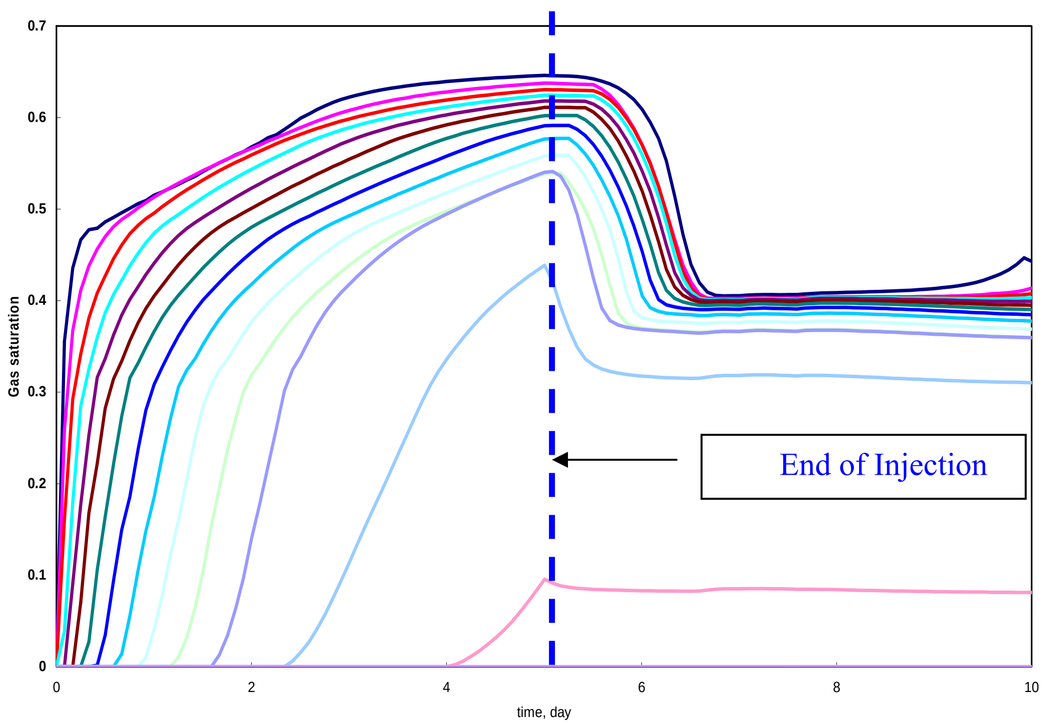

Fig. 5.11 - Simulation Results Showing Gas Saturations for Various Gridblocks – Case 1 (Well at Top of Structure).

An example of the "family of curves" calculated by the simulator is shown in **Fig. 5.12**

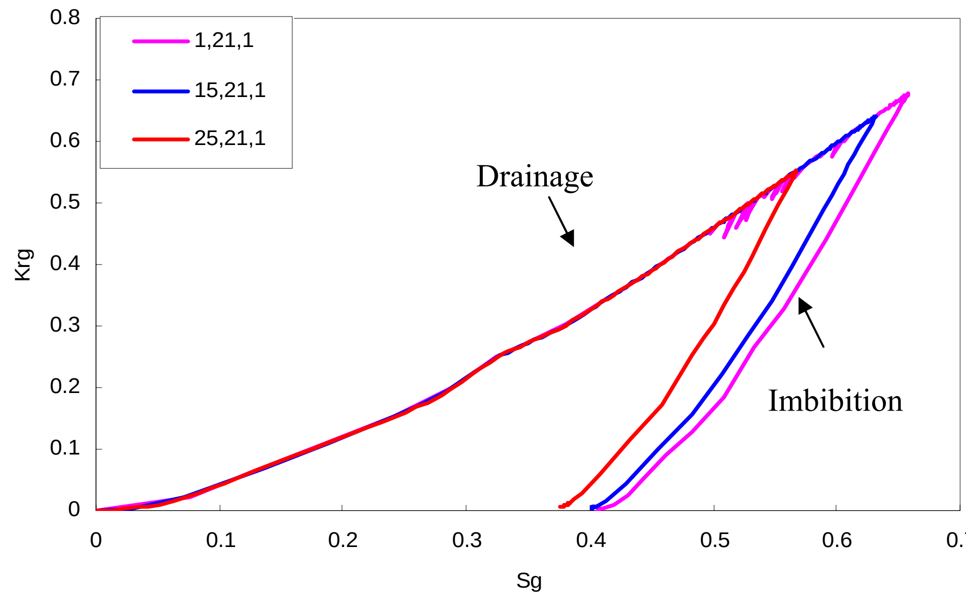

Fig. 5.12. – Illustration of the Drainage Relative Permeability Curve (top) and the Family of Imbibition Curves Calculated for Various Gridblocks in the CMG Simulator[27].

The procedure for calculating of residual gas saturation is described as follows.

1) One set of drainage and imbibition values is entered in IMEX. This relative permeability table will be used to calculate the constant, C.(see table 3.3)

2) Use modified Land's correlation to calculate the Land constant, C,

$$C = 1/(S_{grmax} - S_{gc}) - 1/(S_{gi}-S_{gc}) \quad (5\text{-}10)$$

where S_{gc} is critical gas saturation, and S_{grmax} is maximum residual gas saturation, must be entered on the HYSKRG option in IMEX. It is a value obtained from an imbibition curve from connate liquid saturation.

3) For the Drainage process, when IMEX uses the hysteresis option and the saturation is increasing, the drainage curve is used to calculate k_{rg}. The maximum saturation for every block is being saved at every timestep, and this maximum historical saturation is called S_{gi}.

4) For the imbibition process, when the saturation decreases from the historical maximum, IMEX uses this equation to calculate S_{gr}. C was determined above.

$C = 1/(S_{gr}-S_{gc}) - 1/(S_i-S_{gc})$ ……………..…………………………………(5-11)

C was determined above, S_{GH} = maximum historical saturation and S_{gc} is just the dsgc from the relative permeability table (drainage).

S_g is then shifted using

$S_{g\,(shift)} = S_{gc} +(S_g-S_{grh})(S_{gh}-S_{gc})/(S_{gh}-S_{grh})$…………………………………(5-12)

5) A table look up is done on the drainage curve using S_g (shift) rather than S_g to obtain the k_{rg} , which accounts for imbibition.

As long as S_g is less than the historical maximum then this procedure is followed; when S_g becomes larger than S_{GH}, we go back to using S_g directly on the drainage krg curve, and S_{GH} is reset to its new larger value

CHAPTER V
SUMMARY AND CONCLUSION

This project was a preliminary analysis to evaluate the feasibility of storing gas in an aquifer near a producing oil field. The main objective was to assess the viability of storing the gas for the future use.

The cases chosen for this study are not comprehensive, but may represent a somewhat typical aquifer storage situation. A number of other cases were run before these final three cases were put together. It was obvious from these runs that a steeper aquifer dip has a significant beneficial effect on storage efficiency. Another important factor is the magnitude of the residual (trapped) gas saturation. This value varies considerable in reservoir rocks, but might be determined fairly accurately with special core tests for a particular aquifer.

In spite of the limited nature of this investigation, it is still possible to reach some conclusions.

1. Recovery (efficiency) of stored gas will not be nearly as high as cyclical gas storage in aquifer projects. The maximum storage/recovery efficiency for our simulation runs was 39.1%.

2. Higher dips enhance the efficiency of gas storage/recovery in aquifers.

3. Well location has an important effect on the aquifer gas storage performance, the best well location is on the crest of the anticline.

4. Simulation of the gas storage/recovery process requires that relative permeability hysteresis be modeled. The residual (trapped) gas saturation is an important simulation parameter for the recovery (imbibition) process.

5. Gas storage in aquifers does appear to be feasible for the deep off-shore projects. Though the storage/recovery process might have a relatively low efficiency, it may still compete with the economics of alternatives.

NOMENCLATURE

Bscf = 1,000,000,000 standard cubic feet

MMscf = 1,000,000 standard cubic feet

LNG= Liquefied Natural Gas

GTL= Gas to Liquids

CNG= Compressed Natural Gas

GTS= Gas to Solids

GTW= Gas to Wire

EIA= Energy Information Adminsatration

C = Trapping characteristic, constant for each rock type.

k = absolute permeability, md

k_{rg}= Gas relative permeability

k_{rg} =Water relative permeability

p = Pressure, psi

h = Thickness

p_{wf} = Bottom hole pressure , psi

q= Production rate, MMscf/d

S_{gr} = Residual gas saturation(fraction of pore volume)

S_{gi} = Initial gas saturation established by drainage(fraction of pore volume)

S^*_{grm}=Residual gas saturation (fraction of pore volume) corresponding to S_{gi}=1.0

S_{go} = Breaking value of initial gas saturation(fraction of pore volume)

$S*_{gi}$ = Effective initial gas saturation. Expressed as $S^*{}_{gi} = \dfrac{S_{gi}}{1 - S_{wc}}$.

$S*_{gr}$: = Effective residual gas saturation , expressed as $S^*{}_{gr} = \dfrac{S_{gr}}{1 - S_{wc}}$

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APPENDIX A

Data File

```
RESULTS SIMULATOR IMEX
RESULTS SECTION INOUT
*TITLE1  'This data for anticline aquifer'
*TITLE2  'for gas storage problem'
*INUNIT *FIELD

*OUTUNIT *FIELD


*INTERRUPT *RESTART-STOP
*RANGECHECK *ON
*XDR *ON
*MAXERROR  20
*WPRN *WELL  *TIME
*WPRN *GRID  *TIME
*WPRN *SECTOR  *TIME
*WPRN *ITER  *NONE
*WSRF *WELL 1
*WSRF *GRID *TIME
*WSRF *SECTOR  *TIME
*OUTDIARY *BRIEF *PRESAQ *HEADER  20
*OUTPRN *WELL *BRIEF
*OUTPRN *TABLES *ALL
*OUTSRF *WELL *LAYER  *NONE
*OUTSRF *SPECIAL 1 21 1 KRG
*OUTSRF *SPECIAL 1 21 1 SG
*OUTSRF *SPECIAL 10 11 1 SG
*OUTSRF *SPECIAL 10 11 1 KRG
*OUTSRF *SPECIAL 3 11 1 KRG
*OUTSRF *SPECIAL 3 11 1 SG
*OUTSRF *SPECIAL 4 11 1 KRG
*OUTSRF *SPECIAL 4 11 1 SG
*OUTSRF *SPECIAL 1 21 1 KRW
*OUTSRF *SPECIAL 11 1 1 SW
*OUTSRF *SPECIAL 1 11 1 KRW
*OUTSRF *SPECIAL 2 11 1 KRW

*OUTSRF *RES *ALL



RESULTS XOFFSET 0.
RESULTS YOFFSET 0.
RESULTS ROTATION 0
RESULTS AXES-DIRECTIONS 1. -1. 1.
```

```
GRID VARI 51 41 4
KDIR DOWN

DI IVAR

DJ CON 150.

DK KVAR
        100. 150. 2*200.

PAYDEPTH ALL


**$ RESULTS PROP NULL  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = NULL block, 1 = Active block
NULL CON 1.

**$ RESULTS PROP PINCHOUTARRAY  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
**$ 0 = PINCHED block, 1 = Active block
PINCHOUTARRAY CON 1.

**$ RESULTS PROP FAULTARRAY  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0  Maximum Value: 0
FAULTARRAY CON 0
RESULTS SECTION GRID

RESULTS SPEC 'Grid Thickness'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 1
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 100
RESULTS SPEC REGION 'Layer 2 - Whole layer'
RESULTS SPEC REGIONTYPE 1
RESULTS SPEC LAYERNUMB 2
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 150
RESULTS SPEC REGION 'Layer 3 - Whole layer'
RESULTS SPEC REGIONTYPE 1
RESULTS SPEC LAYERNUMB 3
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 200
RESULTS SPEC REGION 'Layer 4 - Whole layer'
RESULTS SPEC REGIONTYPE 1
RESULTS SPEC LAYERNUMB 4
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 200
RESULTS SPEC REGION 'Layer 5 - Whole layer'
RESULTS SPEC REGIONTYPE 1
RESULTS SPEC LAYERNUMB 5
```

```
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 200
RESULTS SPEC STOP
RESULTS PINCHOUT-VAL       0.0002 'ft'
RESULTS SECTION NETPAY
RESULTS SECTION NETGROSS
RESULTS SECTION POR

RESULTS SPEC 'Porosity'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.2
RESULTS SPEC STOP

**$ RESULTS PROP POR  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 0.2  Maximum Value: 0.2
POR CON 0.2
RESULTS SECTION PERMS

RESULTS SPEC 'Permeability I'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 300
RESULTS SPEC STOP

RESULTS SPEC 'Permeability J'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 300
RESULTS SPEC STOP

RESULTS SPEC 'Permeability K'
RESULTS SPEC SPECNOTCALCVAL 0
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 0
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.3
RESULTS SPEC STOP

**$ RESULTS PROP PERMI  Units: md
**$ RESULTS PROP Minimum Value: 300  Maximum Value: 300
PERMI CON 300.
```

```
**$ RESULTS PROP PERMJ  Units: md
**$ RESULTS PROP Minimum Value: 300  Maximum Value: 300
PERMJ CON 300.

**$ RESULTS PROP PERMK  Units: md
**$ RESULTS PROP Minimum Value: 3  Maximum Value: 3
PERMK CON 3.
RESULTS SECTION TRANS
RESULTS SECTION FRACS
RESULTS SECTION GRIDNONARRAYS
CPOR  MATRIX   4.E-06
PRPOR MATRIX   10000.

RESULTS SECTION VOLMOD
RESULTS SECTION SECTORLEASE

RESULTS SECTION ROCKCOMPACTION
RESULTS SECTION GRIDOTHER
RESULTS SECTION MODEL
MODEL *GASWATER
**$ OilGas Table 'Table A'
*TRES     245.
*PVTG *EG 1
**  P       EG       VisG
   14.7      4.1589    0.014469
   2013.72   607.058   0.016939
   4012.74   1153.28   0.021469
   6011.76   1552.827  0.028436
   8010.78   1838.845  0.038932
   1.00098E+04  2052.35   0.054772
   1.200882E+04  2219.385  0.078881
   1.400784E+04  2355.323  0.115972
   1.600686E+04  2469.45   0.173711
   1.800588E+04  2567.624  0.264665
   2.00049E+04  2653.697  0.409634
   2.20039E+04  2730.32   0.643371
   2.400294E+04  2799.374  1.024465
   2.600196E+04  2862.243  1.652587
   2.8001E+04  2919.967  2.698787
   3.E+04    2973.347  4.45914
*DENSITY *GAS 0.0457797
*DENSITY *WATER 60.6753
*BWI      1.028426
*CW       2.934E-06
*REFPW    10000.
*VWI      0.239
*CVW      0

RESULTS SECTION MODELARRAYS
RESULTS SECTION ROCKFLUID

*ROCKFLUID
```

```
*RPT 1
*SWT  *SMOOTHEND *POWERQ
0.340000  0.000000  0.000000
0.430000  0.017000  0.000000
0.510000  0.035000  0.000000
0.590000  0.080000  0.000000
0.675000  0.160000  0.000000
0.725000  0.300000  0.000000
0.850000  0.450000  0.000000
0.900000  0.670000  0.000000
1.000000  1.000000  0.000000

*SLT  *SMOOTHEND *POWERQ
0.340000  0.680000
0.550000  0.390000
0.620000  0.300000
0.675000  0.250000
0.725000  0.180000
0.800000  0.120000
0.850000  0.082000
0.900000  0.041000
1.000000  0.000000

*HYSKRG 0.4
*MODBUILDER *SMOOTH *ALLPL *DSLTI 0.05  **$ ModelBuilder passed through this Keyword

*MODBUILDER *SMOOTH *ALLPL *DSWTI 0.05  **$ ModelBuilder passed through this Keyword

*MODBUILDER *SMOOTH *ALLPL *DSLTI 0.05  **$ ModelBuilder passed through this Keyword

*MODBUILDER              *TYPE:1_KRWRG_KRGRW_SWCON_SGCON_SWCR_SGCR_NW_NG
*1________1.5  **$ ModelBuilder passed through this Keyword

*KROIL *STONE2 *SWSG


RESULTS SECTION ROCKARRAYS
RESULTS SECTION INIT
*INITIAL
*USER_INPUT
*DATUMDEPTH 2.E+04   *INITIAL
**$ Data for PVT Region 1
**$ -------------------------------------
*REFDEPTH 2.E+04
*REFPRES 1.0597E+04

*GOC_PC 0
*WOC_PC 0


RESULTS SECTION INITARRAYS
```

```
**$ RESULTS PROP SW  Units: Dimensionless
**$ RESULTS PROP Minimum Value: 1  Maximum Value: 1
SW CON 1.

**$ RESULTS PROP PRES  Units: psi
**$ RESULTS PROP Minimum Value: 10000  Maximum Value: 10000
PRES CON 10000.
RESULTS SECTION NUMERICAL
*NUMERICAL

RESULTS SECTION NUMARRAYS
RESULTS SECTION GBKEYWORDS
RUN



DATE 2003 04 08.

WELL  1 '1-A'
INJECTOR MOBWEIGHT '1-A'
INCOMP GAS
OPERATE MAX STG  1.E+07 CONT
OPERATE MAX BHP  1.5E+04 CONT

GEOMETRY K 0.25 0.37 1. 0.
PERF GEO  PSEUDOP '1-A'
          1 21 1 0.99000001 OPEN FLOW-FROM 'SURFACE'


OPEN '1-A'

DATE 2003 05 08.

DATE 2003 06 08.

DATE 2003 07 08.

DATE 2003 08 08.

DATE 2003 09 08.

DATE 2003 10 08.

DATE 2003 11 08.

DATE 2003 12 08.

DATE 2004 01 08.

DATE 2004 02 08.

DATE 2004 03 08.
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DATE 2004 04 08.

DATE 2004 05 08.

DATE 2004 06 08.

DATE 2004 07 08.

DATE 2004 08 08.

DATE 2004 09 08.

DATE 2004 10 08.

DATE 2004 11 08.

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DATE 2005 01 08.

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DATE 2006 12 08.

DATE 2007 01 08.

DATE 2007 02 08.

DATE 2007 03 08.

DATE 2007 04 08.

DATE 2007 05 08.

DATE 2007 06 08.

DATE 2007 07 08.

DATE 2007 08 08.

DATE 2007 09 08.

DATE 2007 10 08.

DATE 2007 11 08.

DATE 2007 12 08.

DATE 2008 01 08.

DATE 2008 02 08.

DATE 2008 03 08.

DATE 2008 04 08.

INJECTOR MOBWEIGHT '1-A'
INCOMP GAS
OPERATE MAX STG 1.E+07 SHUTIN
OPERATE MAX BHP 1.5E+04 CONT

WELL 2 'producer'

```
PRODUCER 'producer'
OPERATE MIN BHP  2160. SHUTIN
OPERATE MAX STG  1.E+07 SHUTIN

GEOMETRY K 0.25 0.37 1. 0.
PERF GEO  PSEUDOP 'producer'
        1 21 1 0.99000001 OPEN FLOW-TO 'SURFACE'


SHUTIN '1-A'

OPEN 'producer'

DATE 2008 05 08.

DATE 2008 06 08.

DATE 2008 07 08.

DATE 2008 08 08.

DATE 2008 09 08.

DATE 2008 10 08.

DATE 2008 11 08.

DATE 2008 12 08.

DATE 2009 01 08.

DATE 2009 02 08.

DATE 2009 03 08.

DATE 2009 04 08.

DATE 2009 05 08.

DATE 2009 06 08.

DATE 2009 07 08.

DATE 2009 08 08.

DATE 2009 09 08.

DATE 2009 10 08.

DATE 2009 11 08.

DATE 2009 12 08.
```

DATE 2010 01 08.

DATE 2010 02 08.

DATE 2010 03 08.

DATE 2010 04 08.

DATE 2010 05 08.

DATE 2010 06 08.

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DATE 2010 10 08.

DATE 2010 11 08.

DATE 2010 12 08.

DATE 2011 01 08.

DATE 2011 02 08.

DATE 2011 03 08.

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DATE 2012 03 08.

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DATE 2012 09 08.

DATE 2012 10 08.

DATE 2012 11 08.

DATE 2012 12 08.

DATE 2013 01 08.

DATE 2013 02 08.

DATE 2013 03 08.

DATE 2013 04 08.

STOP
***************************** TERMINATE SIMULATION *****************************

RESULTS SECTION WELLDATA
RESULTS SECTION PERFS

VITA

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Education

Texas A&M University: Master of Science in Petroleum Engineering.

Graduation Date: May 2004

Southwest Petroleum Institute , CHINA (Aug.1995): Bachelor of Petroleum Geology

Research

Texas A&M University, College Station, TX, U.S.A (May 2001-May 2004): Research associate, aquifer gas storage simulation

Specialized Courses

Reservoir fluids, reservoir models, reservoir simulation, well performance, fluid flow in petroleum reservoirs, well drilling, modern petroleum production, petroleum development strategy, fluid mechanics, transport phenomena, advanced reservoir engineering

Experience

China Nation Petroleum Company (Aug 1995-Aug 2001): Responsible for reservoir characterization, reservoir and production engineering, and enhanced oil recovery.