POLITECNICO DI TORINO

Department of Environment, Land and Infrastructure Engineering

Master of Science in Petroleum Engineering

EFFECT OF FORMATION COMPACTION ON UNDERGROUND GAS STORAGE

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ABSTRACT

Underground Gas Storage facilities largely contribute to the reliability of gas supplies to consumers. Efforts to increase the working gas capacity and deliverability rates using dynamic flow simulations and geomechanical models to study the behavior of the UGS facilities have been greatly welcomed.

The study is aimed at evaluating the potential effect (negative or positive) of reservoir rock compaction on the performance of Underground gas storages. Production history data generated from a synthetic reservoir model will be used and an estimation of the working gas capacity for a 5-year cycle will be assessed. The Schlumberger Eclipse Simulation software is used to model a synthetic reservoir, 1570m deep, fully saturated with gas. A simplified reservoir model with a constant compressibility is going to be used as a reference(base) case. The second case involves substituting a constant rock compressibility in the base case model with a variation of compressibility as a function of pressure. The Eclipse 100 Simulator models rock compaction as a function of pressure dependent pore volume multipliers. These multipliers represent the variation of the rock compressibility during production.

A sensitivity analysis will be carried out between the base case (constant compressibility) and the variation of compressibility through the pore volume multipliers (by defining a realistic range of variation of compressibilities) and the performance of the Underground Gas Storage will be assessed through the working gas capacity and volume of gas injected.

Based on the simulations conducted for the scenarios between the constant compressibility and the variation of compressibility the results showed that the reduction in the working gas capacity for the variation in compressibility was negligible with a percentage reduction of 0.5%-1.5%. However, in stressing the system, other scenarios were also performed by reducing further the minimum pore volume multiplier from 0.97 to 0.80 and it led to a reduction in the working gas capacity with a percentage reduction from 3.9% to 25% therefore concluding that a minimum PVm of 0.80 characterized a highly compacted reservoir formation.

DEDICATION

TO ALMIGHTY GOD

TO MY WONDERFUL PARENTS.

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TABLE OF CONTENTS

ABSTRACT ... ii
ACKNOWLEDGEMENTS ... iv
1 INTRODUCTION ... 1
1.1 GOAL OF STUDY ... 2
1.2 WORKFLOW ... 2
2. UNDERGROUND GAS STORAGE ... 3
2.1 Origin and Development of Natural Gas Storage ... 3
2.1.2 Characteristic Parameters of Underground Gas Storages. ... 6
2.2 Types of Natural Gas Storage ... 7
2.2.1 Depleted Gas Reservoirs ... 8
2.2.2 Salt Caverns ... 9
2.2.3 Aquifer Storage ... 10
2.3 SEASONAL CYCLIC OPERATIONS ... 12
2.3.1 Methods of Optimizing Storage Reservoir Capacity ... 14
2.4 UGS Analysis in 3-D dynamic simulation ... 14
2.4.1 Parameters Influencing Underground Gas Storage ... 15
2.4.1.1 Porosity ... 15
2.4.1.2 Permeability ... 16
2.4.1.3 RELATIVE PERMEABILITY ... 16
2.4.1.4 Rock Compaction ... 17
2.4.1.5 Aquifer ... 18
3.0 ROCK COMPACTION ... 19
3.1 Brief Overview ... 19
3.2 Effect of Compaction and Subsidence of Production ... 22
3.3 HYSTERESIS DUE TO LOADING AND UNLOADING ... 23
3.4 Rock Compaction Models Available in a simulator ... 25
3.4.1 Fluid Dynamic Model and Geomechanical Model ... 25
3.4.2 Options to Model Compaction ... 27

4.0 CASE STUDY 33
4.1 SYNTHETIC MODEL 33
4.1.1 PVT Properties 34
4.1.2 PRODUCTION HISTORY 35
4.2 SIMULATION OF SYNTHETIC MODEL 35
4.2.1 CASE A; CONSTANT COMPRESSIBILTY- BASE CASE 36
4.2.2 CASE 2; VARIABLE COMPRESSIBILTIY 37
5.0 RESULTS AND DISCUSSIONS 43
5.1 SENSITIVITY ANALYSIS ON WORKING GAS CAPACITY 44
5.1.1 CASE A vs CASE B 45
CONCLUSION 49
REFERENCES 50
APPENDIX 1 : Input data for Case A 52
APPENDIX II: Pore Volume Multipliers used for Case B 63

LIST OF FIGURES

Figure 1 Graphical Report of UGS Distribution Worldwide (Acquired from CEDIGAZ UGS Report,2016) 4
Figure 2 Global underground gas storage as of end 2016 – by region (**Source : CEDIGAZ**) .. 5

Figure 3 Major UGS facilities in Italy (Source : AGIP) 6
Figure 4 Types of Natural Gas Storage........ 8
Figure 5 Underground Gas storage in Caverns........ 10
Figure 6 An Observation Well completed in an aquifer being tested with gas 11
Figure 7 A typical storage cycle process. 13
Figure 8 Field pressure and gas storage in partially depleted gas reservoir. 13
Figure 9 Shape of gas/brine rel. permeability according to variation in Sg for injection(left) and Withdrawal (right)........ 17
Figure 10 Effective Reservoir Rock Compressibility........ 21
Figure 11 Schematic of a graph interpretation of Depth and Pressure during Compaction ....**Error! Bookmark not defined.**
Figure 12 Schematic of an Interpretation of Oedometric tests........ 23
Figure 13 Rock Compaction: Hysteresis option........ 29
Figure 14 Reservoir Deformation Model (Boberg et al, 1991) 30
Figure 15 Representation of Cold Lake sand behavior by Roscoe et al showing consistency with that of Fig 2.12 31
Figure 16 Rock Compaction: Boberg Hysteresis option 32
Figure 17 3-D representation of an anticline reservoir model 33
Figure 18 3-D representation of an anticline reservoir model with 3 additional wells........ 35
Figure 19 Static Moduli vs. Stress in Loading conditions........ 38
Figure 20 A relationship between Uniaxial Compressibility and Effective Stresses 40
Figure 21 Pore volume multiplier as a function of the Effective Stresses 42
Figure 22: Pore volume multiplier as a function of the Effective Stresses……………………… 43
Figure 23: Variation of minimum Pore Volume Multipliers……………………………………..... 44
Figure 24 : Cumulative Gas Production of the UGS System……………………………………… 47
Figure 25Cumulative Gas Production of the UGS System………………………………………… 48

LIST OF TABLES

Table 1 The simplified reservoir characteristics used for the reservoir simulations 34

Table 2 Converting Relative Change in Pore volume as multipliers to be included in the Eclipse 100 39

Table 3 Calculated Pore Volume Multipliers as a function of Pressure 42

Table 4: Comparison of Average Working Gas between Case A and Case B(with different minimum PVMs)

Table 5: Comparison of Average Volume of Gas Injected between Case A and Case B (with different minimum PVMs)

1 INTRODUCTION

Underground Gas Storages are subsurface facilities that store large quantities of natural gas, mostly in salt formations, aquifers or in reservoir porous rock formations. The idea of Underground Gas Storages was developed to meet the natural gas demand for domestic, commercial and industrial purposes. The rapid increase in UGS facilities is because of an increase in consumption in areas far from the producing areas especially during low temperatures(winter) where high peak rates is high.

An attractive option to improve the performance of the Underground Gas Storage System is operating in overpressure conditions i.e., operating the storage system at a working pressure above the original formation pressure. Once the original formation pressure has been exceeded, the sealing capacity of the caprock and the mechanical integrity of the rock must be investigated. The operation of overpressure UGS systems are currently being operated in advanced countries in Europe, The United States and Canada.

Pressure depletion due to production can lead to reservoir compaction and subsidence of the surface above the reservoir. This phenomenon can prove very costly during production as well as surface facilities (Doornhof et al, 2006). The subsidence is normally dependent on the volume of fluid removed from the reservoir, and so on the pressure dropinduced by production The higher the volume removed the greater the compaction and thus the higher the rate of subsidence. A reverse phenomenon known as uplift occurs to the injection of formation fluids into the reservoir for pressure maintenance or due to water encroachment due to aquifer support. This causes an expansion in the geological formation because the pore volume has been increased (P. Teatini et al, 2011). The land uplift and subsidence also depends on many factors including depth of the reservoir, thickness and extent,as well as geomechanical properties of the porous medium.

Fluid flow simulator such as ECLIPSE models reservoir compaction as a function of pressure, Cr=Cr(Pf). The simulator measures the compaction in the grid cell as pore volume multipliers (ratio between current cell pore volume and initial cell pore volume). However, in reality, it is dependent on the effective stresses. Thus, although compaction which is modeled by the fluid simulator is correct, it doesn't account for a true variation throughout the reservoir during production or injection. Thus, a fully coupled simulation involving a stress simulator (i.e. geomechanical model) and fluid simulator has been the industry practice in estimating true rock compaction in the reservoir

1.1 GOAL OF STUDY

The primary focus of the study is to understand the potential effect (negative or positive) of reservoir rock compaction on the performance of Underground gas storages. Production history data generated from a synthetic reservoir model will be used and an estimation of the working gas capacity for a 5-year cycle will be assessed

1.2 WORKFLOW

To effectively understand the main role reservoir compaction plays in the optimization of the working gas capacity during the UGS program.

The ECLIPSE Black Oil (100) Simulation software is going to be used to model the behavior and further predict the effect of rock compaction on the performance of the UGS for a 5-year storage period.

A simplified reservoir model with a constant compressibility is going to be used as a reference (CASE A), in agreement with the common practice of hydrocarbon industry. The anticline model is built based on a synthetic dataset representing a gas reservoir.

The second case (CASE B) involves substituting a constant rock compressibility in the base case model with a variation of compressibility as a function of pressure. The Eclipse 100 Simulator models rock compaction as a function of pressure by using a special keyword ROCKTAB. The realistic range variation of the rock compressibility was achieved by converting pore volume multipliers into its corresponding uniaxial compressibility(Cm) and Young's Modulus of Elasticity(E)

A sensitivity analysis will be carried out between different scenarios (constant compressibility vs compressibility variation with pressure) so as to assess the effect of these scenarios in the performance of the Underground Gas Storage.

2. UNDERGROUND GAS STORAGE

Underground Gas storages(UGS) is a strategic approach which compensates for the high demand market with a constant supply of energy for domestic purposes through pipelines. This approach is developed to cope with the growing demand for energy across several countries in Europe and North America (D, L Katz et al, 1981).

Due to significant advancements in monitoring tools, subsurface gas storages have been found to have various environmental impacts on the formation (N. Castelleto et al, 2008). Several findings indicate that periodic injection and withdrawals of gas causes changes in the internal stress of the gas bearing formation as well as the formation surrounding it. These cyclic injection and withdrawals however, can be closely monitored with the aid of 3-D surface motion, in response to these internal stresses to effectively predict, with the aid of fluid-dynamic and geomechanical models to better analyze its effect on the performance of the UGS facility.

This section will help in providing a better understanding of the history and background as well as the operations of Underground gas storages and the geomechanical effects on the performance of UGS.

2.1 Origin and Development of Natural Gas Storage

The first country to recognize the need for natural gas storage was Canada in 1915 and the subsequent year (1916) United States of America. From the one reservoir storage facility in 1915, according to the CEDIGAZ (International Association for natural gas)'s report for Underground Storage in 2016, about **672** underground gas storage (UGS) facilities operate in the world, which represents a working gas capacity of 424 billion cubic meters (bcm), or 12% of 2016 world gas consumption. The Fig 1 shows the UGS distribution worldwide.

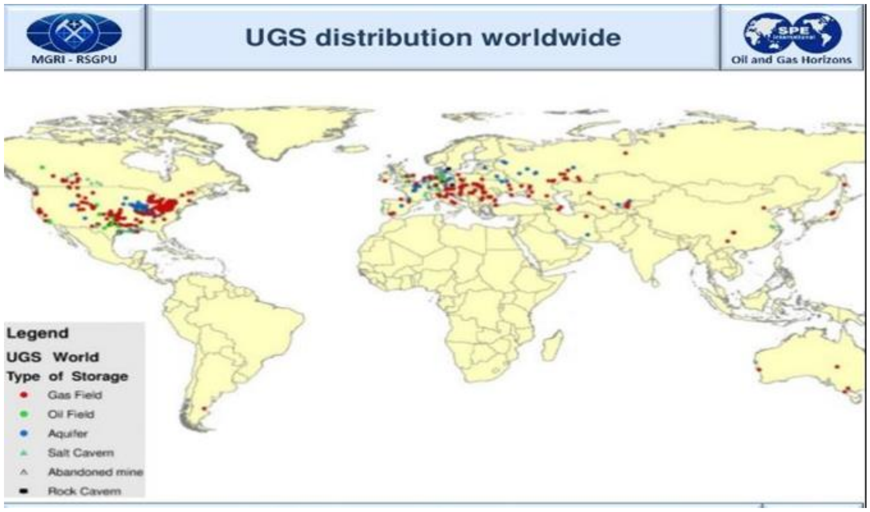

Figure 1 Graphical Report of UGS Distribution Worldwide (Acquired from CEDIGAZ UGS Report,2016)

Underground Storage facilities is fully developed in five (5) main regions, **North America**, the **CIS (Commonwealth Independent States), Europe, Asia and Oceania** and more recently the **Middle East** (Fig. 2.2). North America (United States and Canada) dominate more than 60% of the sites, consisting of **392** active storages in the US and **62** in Canada with a combined working capacity of 160bcm representing 38% of the world total. There are **143** facilities in Europe, **48** in the CIS (125.1bcm), 23 in Asia-Oceania(21.8bcm) and **3** in the Middle East(9.9bcm)

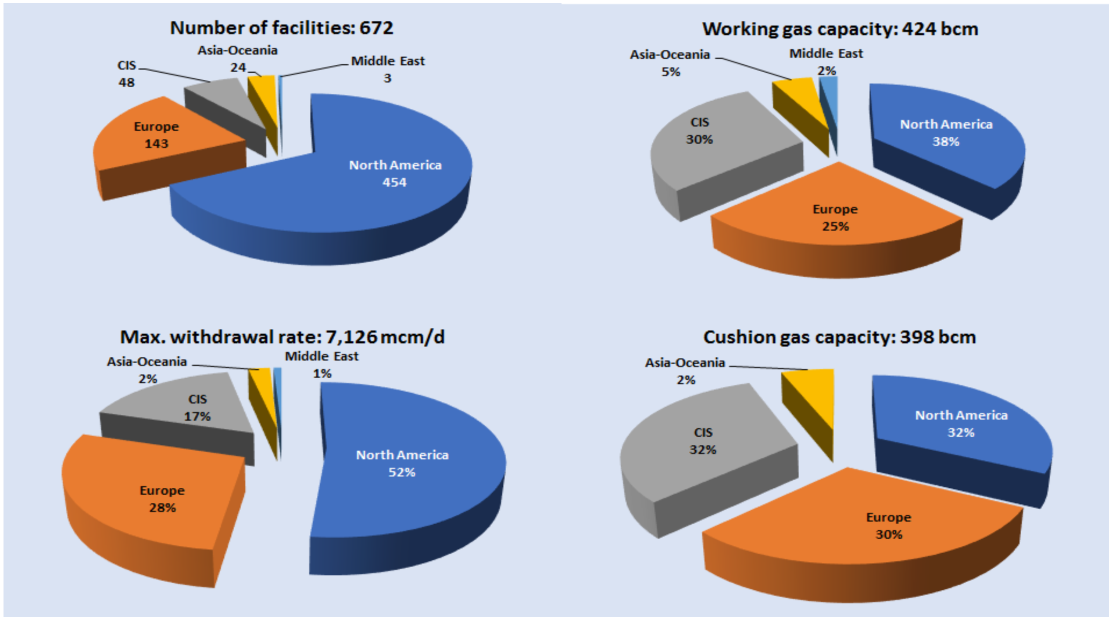

*Figure 2 Global underground gas storage as of end 2016 – by region (**Source : CEDIGAZ**)*

Underground Storages in the recent years has enables us to;

- Meet peak demand fluctuations especially exceeding the maximum capacity of the transport system
- Optimize the production of reservoirs located far from the consumption areas, and those, located in offshore zones where gas must undergo treatment in plants before they are transported through pipelines to consumers.

Italy adopted the technology of UGS dating back in the 1960's. An already exploited gas field operated by AGIP in Cottemaggiore was used. Consequently, in the 70's other producing gas fields in Sergnano, Brugherio and Ripalta were converted.

Currently in Italy, ten (10) natural gas storages are in operations. Eight (8) sites are operated Stogit (Eni Group) ; Brugherio, Minerbio, Settala, Ripalta, Segnano, Sabbioncello, Cortemaggiore (Fiume Treste) while the deposits in Collato(Treviso) and Cellino are owned and operated by Edison.(Fig 3)

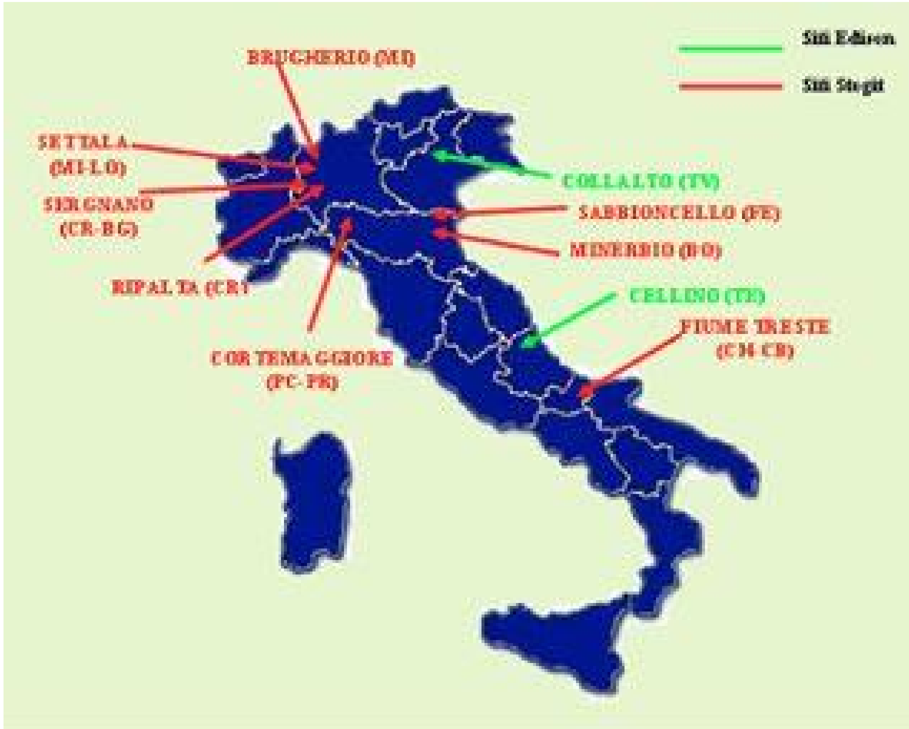

Figure 3 Major UGS facilities in Italy (Source : AGIP)

2.1.2 Characteristic Parameters of Underground Gas Storages.

In the discussion of Underground Gas Storages, we refer to the following parameters

- **Cushion (base) Gas:** This refers to the minimum volume of gas that is required in an underground gas storage(UGS) to provide the necessary working pressure to deliver the demanded gas to consumers without compromising the properties of the site.
- **Working Gas:** It is the available volume of gas that is movable for delivery. It is the quantity of gas that can be injected and withdrawn from storage. The working gas volume basically determines all the parameters of a UGS facility. The potential volume is dependent on many factors; properties of the formation (porosity, permeability, compressibility, etc., pressure range, pressure decline in the formation during production, sizes of trap, presence of an active aquifer).

- **Deliverability:** is the volume of as that can be withdrawn from the storage daily. It is expressed in MMscf/D. Deliverability of gas storage varies and normally depend on several factors; volume of gas in the reservoir at any time, the pressure in the reservoir, surface facility installations associated with the reservoirs. Generally, deliverability directly varies with the total volume of gas in the reservoir thus it is at its maximum when the reservoir is 'full' and reduces when the working gas is withdrawn. In the operation of the UGS under overpressure conditions (pressure above the original pressure) there is a potential of increasing the volume of gas stored as well as its deliverability.
- **Injection Capacity/Rate:** The injection rate/capacity refers to the total volume of gas that can be injected into an underground storage facility daily. Injection rates are also expressed in MMscf/D as with deliverability rate. The injection capacity also depends on factors like the deliverability; pressure in the reservoir, installation of surface facilities (compressors etc.) associated with the reservoirs. However, the injection rates vary inversely with the total volume of gas thus injection is minimum when the reservoir is 'full' and increases during withdrawal/production.

- **Peak rate**: The daily peak flow rate which can be withdrawn when the reservoir is completely full.

2.2 Types of Natural Gas Storage

According to the U.S. Department of Energy-Transmission, Distribution & Storage, there are three principal types of underground storages- Depleted gas reservoirs, Aquifer reservoirs and Salt cavern reservoirs (**Fig 4**). Each of these storage types are made up of unique features (such as working gas, cushion gas) which make them suitable for their type of application.

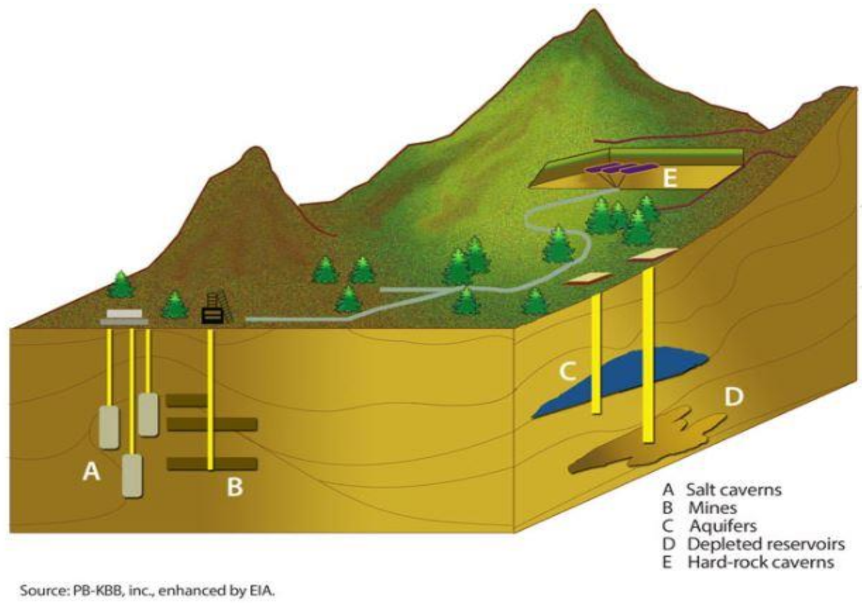

Figure 4 Types of Natural Gas Storage

2.2.1 Depleted Gas Reservoirs

These are the most common form of underground storage in which the reservoirs formations of natural gas fields that have produced all the recoverable gas. The depleted gas reservoir formations can hold injected natural gas thus making it the safest and the most economic type of storing natural gas underground. This is because it allows the re-utilization of extraction and distribution infrastructure during the productive life of the gas fields and hence reducing project start-up costs. However, some of the existing wells must be converted to injectors during cyclic injection and withdrawal and hence may require new completions to be done. Depleted gas fields may have natural gas already in place and therefore will reduce the need for an additional cushion gas. They tend to have very large working capacity which makes them useful for meeting seasonal demands and save cost during offseason purchases. Also, if the reservoir has a high porosity, permeability and sufficient base gas, high deliverability can be achieved. Daily deliverability normally varies vary widely largely due to differences in the surface equipment, cushion gas levels as well as the properties of the reservoir.

2.2.2 Salt Caverns

Underground salt formations are appropriate for natural gas storage because they allow very little of the injected natural gas to escape from storage. This is because of the strong nature of the walls of the salt cavern such that they make it impervious to gas throughout the life of the storage facility. Generally, in these types of storage facilities only one well is used for both injection and subsequent extraction of gas. After the well is drilled into the salt strata, fresh water is pumped into the well to dissolve the salt and the brine produced is normally injected into another formation. This process continues until a desired **cavern** is formed. Due to this development, salt caverns are said to be the costliest of the three. In addition, high workover cost is a required, this is because of the cavern's susceptibility to deteriorate overtime. Salt caverns have very high deliverability rates, since salt formations are essentially high-pressure storage facilities.

Most caverns can be designed for rapid cycling, i.e. the operators can change from withdrawal to injection and vice versa within one hour. Most salt caverns are designed for 10-20 days allowing working gas to be withdrawn in this period.

Deliverability rates in salt caverns can be as high as 300-500MMscf/day from a single cavern with 3-5Bcf of working gas capacity. It is important to note that in this type of storage facility, requirements for base gas is very low comparably ranging from **30-35%** of total gas capacity. The Fig 5 shows a graphical representation of the process of creating caverns for storage of natural gas.

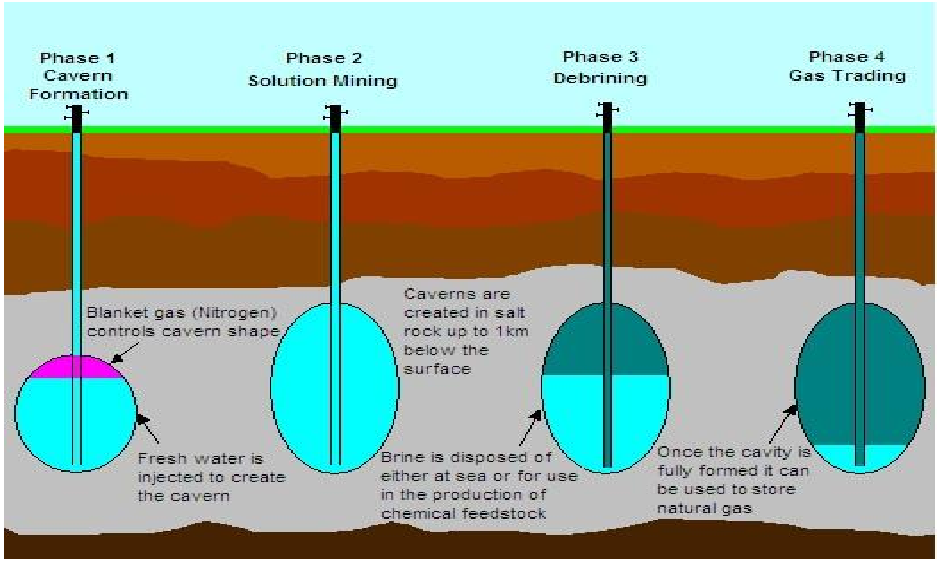

Figure 5 Underground Gas storage in Caverns

2.2.3 Aquifer Storage

Aquifers are generally porous and permeable subsurface formation containing water under pressure. Study of aquifers is very essential in understanding the movement of water in contact with natural gas (D.L Katz et al,1963). About **9%** of the total underground gas storage capacity applies this method of gas storage. A research by W.H Gober in USA outlined several factors that influenced the performance of Gas storage reservoirs developed by Aquifers. Some of the factors according to his findings included Aquifer boundary conditions, cyclic two-phase flow of gas and water and overpressure (W.H Gober 1965). Out of the many boundary conditions the most prime requirement for the development of an aquifer gas storage is have a tight sealing upper caprock.

Conventionally the pressure used in the gas storage reservoirs do not exceed the original reservoir pressure. This is to avoid breakage of the seal of the caprock. Considering this, a grant was awarded to the Pennsylvania State University to study the behavior of the rocks in overpressure conditions. The studies aimed at checking the feasibility of a reservoir gas storage in overpressure conditions.

Aquifer gas storage can be achieved by displacing a portion of water from the pores of the rock through the injection of gas a high pressure. Therefore, upon initial injection of gas into the aquifer an overpressure condition exists (W.H Gober, 1965). The reservoir experiences decline as soon as injection is stopped and withdrawals starts. In the Fig 6 below, the aquifer pressure increases after the gas is injected. The increase continues until steady state conditions is reached in the reservoir. After the injection of gas is halted the pressure declines and eventually stabilizes at the same level as the initial where the injection began.

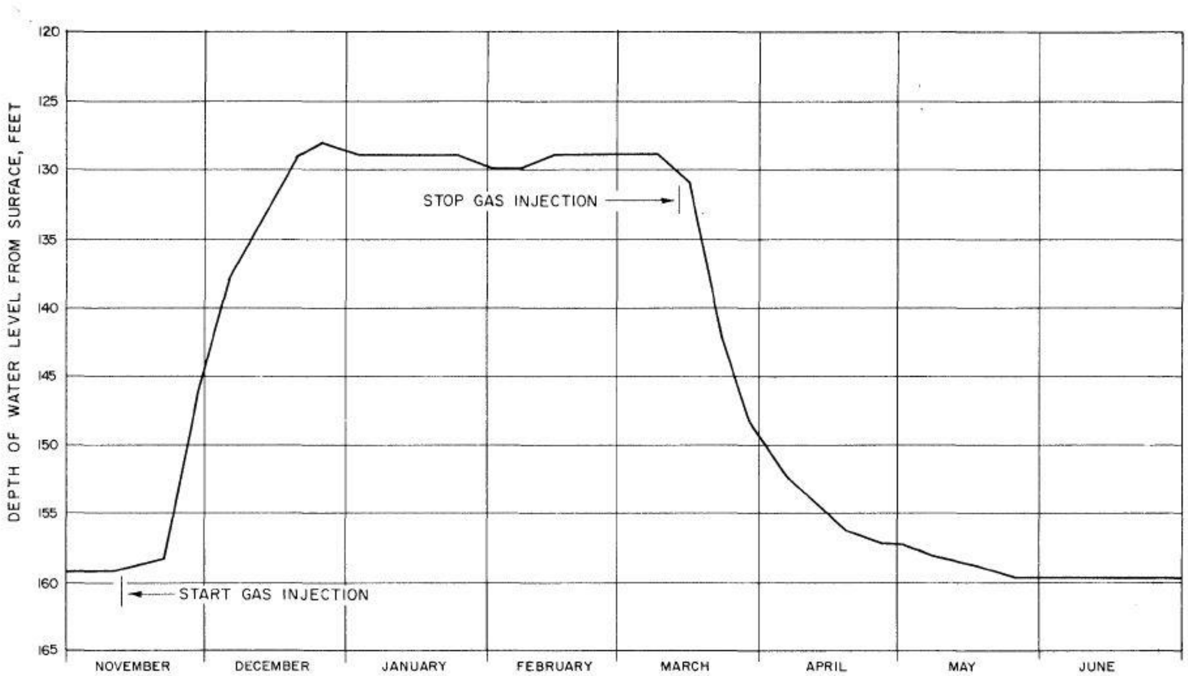

Figure 6 An Observation Well completed in an aquifer being tested with gas

For the reservoir pressure to return to its initial level, the water volume equivalent to the volume of the injected gas must be displaced from the reservoir. Gas is injected into the reservoirs at desired pressure using compressor stations or using the water displacement technique It can then be said that the two factors which greatly influence the performance of an aquifer are over pressuring and water displacement. Without overpressure the water would not be displaced and without the water displacement pore spaces for gas storage will not be developed.

Several reasons however limit the usage of aquifer storage as the preferred storage method, Developments costs are greater in aquifer storage facilities than in depleted gas reservoirs because all the associated infrastructure must be built from scratch including extraction equipment, pipelines for transportation, dehydration equipment etc. and it hence will only be the option if the depleted gas reservoirs are not applicable in that area. Also since no gas was initially present, base gas must be injected to build and maintain the pressure. Loss of gas and contamination of water are common problems with aquifer storage

2.3 SEASONAL CYCLIC OPERATIONS

Typically, Underground Gas Storage(UGS) facilities operate on an annual cyclical manner. Injection is performed during the summer periods where peak level is generally low and withdrawals are done during the high peak winter periods.

Cyclic operations are generally similar for all methods of storage reservoirs. In depleted gas reservoirs, for example, the reservoir can produce for some period until depletion occur. After a period of depletion, the gas storage is initiated. Cyclic injections and production periods can be stimulated for the field. The number of years of storage is dependent on the productivity of the wells as well as the reservoir characteristics. As already stated above, gas injections normally start from March/April to September of the year where temperatures are relatively warm and thus low peak demand for natural gas.

Depending on the well program for a field, one or more wells used for the extraction during the initial productive life can be used as injector during the injection period. A target field injection rate is also considered. After injection is completed successfully and the reservoir is pressurized, withdrawals are initiated. Again, injector wells can be converted to extraction wells and produced. Production periods starts from the month of October and ends in March. A year of injection and withdrawal is normally considered as a **cycle.** These cycles are designed to be repeated for several years (Fig 7)

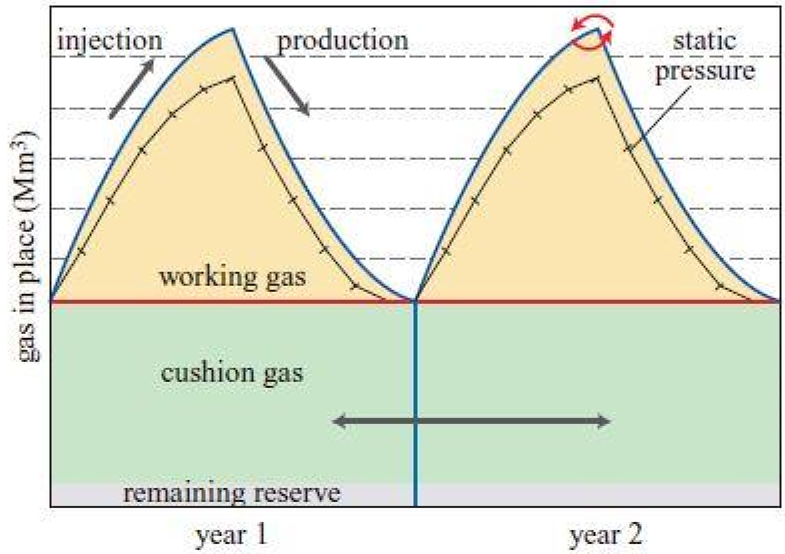

Figure 7 A typical storage cycle process.

The Fig 8 describes a design of a gas storage program on a depleted field. The reservoir was depleted for about 2 years and a storage cycle of 10 years was designed at a target rate of 200MMcf/day and 260MMcf/day for injection and production respectively.

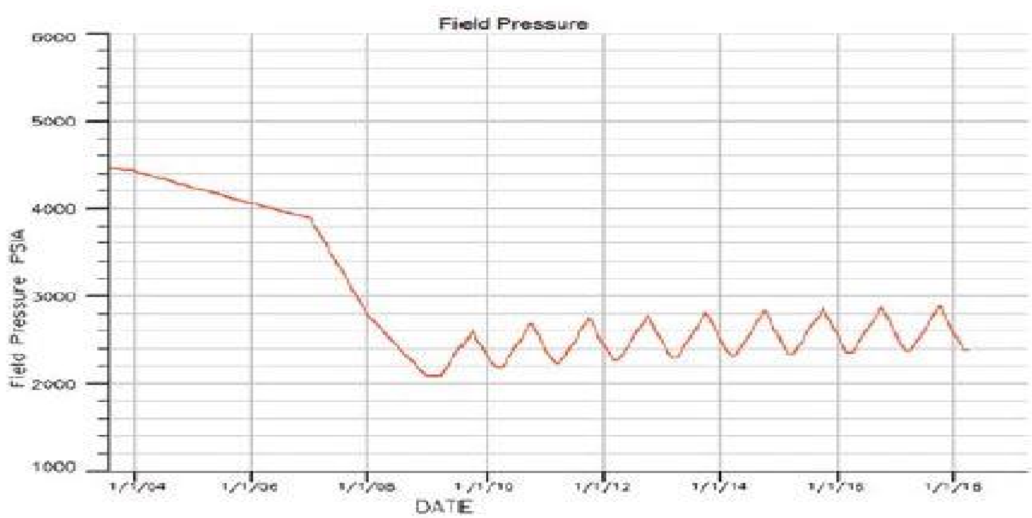

Figure 8 Field pressure and gas storage in partially depleted gas reservoir.

2.3.1 Methods of Optimizing Storage Reservoir Capacity

The performance of an operational underground gas storage reservoir can be increased through series of interventions outlined below

- **Increasing the number of wells**

  This is the most common practice adopted by operators of underground gas storage. Addition of new wells to the existing wells allows significant increases to be obtained. The maximum number of wells depends on the reservoir size and must be properly defined to avoid interference between wells and thus reducing the performance of the reservoir.

- **Upgrade of Compressor modules and Treatment facilities**

  To minimize pressure losses, flowlines can be expanded, if necessary. Installation of additional treatment columns and addition of more compressors can aid in increasing the capacity of the storage facility

2.4 UGS Analysis in 3-D dynamic simulation

Simulating a reservoir behavior with the aid of a mathematical models takes into consideration, the relative movement of fluid in the reservoir governed by relative permeabilities, the pore volume variations and aquifers, among others. The use of numerical models of finite differences makes it possible to also take into consideration the reservoir heterogeneities and communication between zones. Particularly, history matching techniques (comparison between the model and production history data) by adjusting the parameters also broadens the understanding of the reservoir. Addition to that, mature fields (already in exploitation) has large amount of production history and therefore its study gives a thorough understanding of the reservoir behavior. The parameters adjusted when using the history matching techniques makes it possible to carry out simulations of underground gas storage under a wide range of scenarios. These simulations allow the evaluation of the response of the reservoir to cyclic gas injection and withdrawal, particularly in relation to the water table movement in the aquifer.

Information derived from the simulation helps in the economics evaluation process which ascertains the viability of the project

2.4.1 Parameters Influencing Underground Gas Storage

2.4.1.1 Porosity

Porosity $(\emptyset)$ is an important parameter in reservoir engineering and varies according to the type of rock. According to the SLB Oilfield glossary, Porosity is the percentage pore volume that can store fluid. Porosity can be formed because of the natural deposition of sedimentary rock(primary) or the because of geological processes such as dissolution, fractures after the deposition of the rock. (secondary).

$$\emptyset = \frac{V_p}{V_b} \tag{2.1}$$

As the sediments were deposited and buried and the rocks were being formed during past geological times, some void spaces that developed became isolated from the other void spaces due to excessive cementation. Thus, many of the void spaces are interconnected while some of the pore spaces are completely isolated (Tarek Ahmed, 2006). In reservoir engineering, the effective porosity which is the interconnected pore volume contribute to fluid flow in a reservoir.

In the selection of a reservoir for the operation of a storage facility, it is better to select a reservoir with high porosity as porosity is an important parameter in determining the hydrocarbon in place in material balance equations.

2.4.1.2 Permeability

Permeability is an important parameter which influences the injection and the production phases. Permeability is a property of the porous medium that describes the ease with which fluids can be transmitted through interconnected rock pores. The rock permeability, k, is a very important rock property because it controls the directional movement and the flow rate of the reservoir fluids in the formation (Tarek Ahmed, 2006). The higher the permeability the more suitable it is for Underground gas storage. Withdrawal and injection capabilities are also maximized when the storage reservoir has a high permeability thus leading to high deliverability

2.4.1.3 RELATIVE PERMEABILITY

Relative Permeability is greatly discussed in aquifer storage operation, During the process of injection (the non-wetting phase) displace the water (wetting phase) and during production the water tends to displace the gas. The term drainage is used to indicate a saturation change in the direction of decreasing the wetting phase whereas imbibition refers to increasing the wetting phase. A storage cycle can therefore be referred to a drainage process(production/withdrawal) followed by an imbibition process(injection) in terms of relative permeability. Several publications indicating gas saturation as a major contributor to the performance and optimization of a depleted gas storage reservoir (Fishlock et al 1988). Their research was aimed at analyzing the effect of gas remobilization for better production forecast. The Fig 9 below showed gas/brine relative permeability curves for injection and withdrawal according to the variation in Gas Saturation(Sg). In their study of the comparative study between secondary drainage relative permeability obtained under injection and withdrawal they concluded that the rock fabric plays an important role in gas remobilization and were independent of production rates.

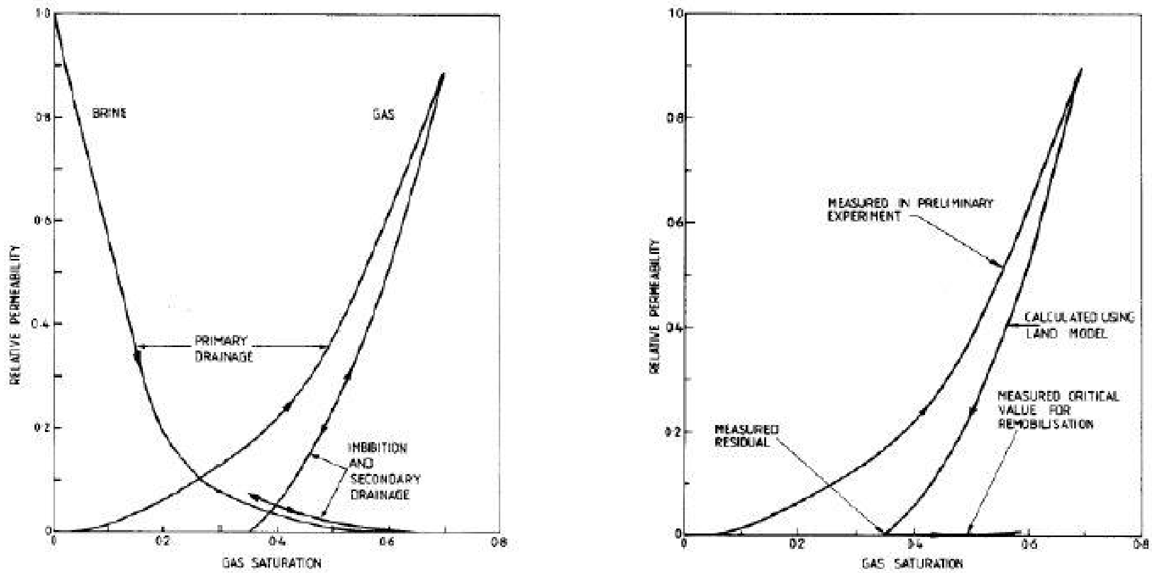

Figure 9 Shape of gas/brine rel. permeability according to variation in Sg for injection(left) and Withdrawal (right)

2.4.1.4 Rock Compaction

The best-known examples of rock mechanical effects on reservoir scale behavior are reservoir compaction and associated surface subsidence. Operational problems related to subsidence are environmental concerns, like risk of flooding in land operations, or platform safety concerns in offshore production. Most of compaction-induced problems are associated with casing collapse within or adjacent to the compacting reservoir. It is on the other hand well established that formation compaction may be a prominent drive mechanism in relatively soft oil/gas reservoirs.

Compaction, driven by production is predominant in many reservoirs and as a result responsible for both improvement or loss of recovery in reservoirs as well as other operational problems (M. Jongerius,2015). Reservoir rocks are subjected to in-situ stresses during burial resulting from overburden pressure exerted by the weight of the overlying sediments, tectonic stresses generated by the movement of the Earth's crust and pore pressure resulting from the presence of fluids in rock pores. In reservoir engineering the magnitude of the overburden pressure (Po) is calculated by knowing the depth of the reservoir and average density of the overlying rock formation. The next chapter gives a brief overview of rock compaction and its effect on the performance of a reservoir during production and injection.

2.4.1.5 Aquifer

A production mechanism due to depletion occurs when dealing with a very limited aquifer. However, if the volume of the aquifer gradually becomes larger than the volume of gas in the reservoir, production mechanism changes from depletion drive to a partial water drive. Conventional Underground Storages have usually been carried out in reservoirs that have produced due to expansion or partial water drive during primary production. Storages made in reservoirs which have strong water drive can be compared to those carried out in aquifers. An active water influx into gas reservoir reduces the ultimate recovery of gas. This is as a result of the reduction in the sweep efficiency and residual gas trapped in the invaded zones at high pressure. When a depleted gas storage reservoir is bounded by an active aquifer, water migrates upward into the reservoir during the production phase of the I/W cycles and fills the pore spaces that were originally saturated by gas. The invaded water gradually reduces the volume o the reservoir ready for gas storage. Water encroachment into a gas reservoir can increase the water content of the produced gas

3.0 ROCK COMPACTION

3.1 Brief Overview

Pressure depletion because of production can cause shear failure in weak reservoir rocks and significant deformation. As the pressure of the reservoir drops, portion of the load carried by the reservoir rocks (effective stresses) increases and can result in significant compaction of the reservoir (M Gutierrez and H Hansteen, 1994).

Compaction however can only occur with the expulsion or compression of the pore fluids within the pores of the rock. Formation compressibility refers to the relative change in the rock volume per unit change in pressure under isothermal conditions. Formations are compressible even though they are solid materials. The formation compressibility can be measured in the laboratory and derived from correlations. (Hall, 1958). Changes in formation compressibility on reservoir rocks can generally depend on the degree of consolidation, the stress field path and the type of formation. However, the correlations developed by Hall does not take into consideration these factors.

The general equation for compressibility is

$$C = -\frac{1}{V}\frac{\delta V}{\delta p} \qquad (3.1)$$

The negative (-) sign in the equation is determined by the Δp to force the coefficient C to be a positive value.

Compressibility is categorized into three;

- **Rock matrix compressibility**; which is the fractional change in volume of the solid rock material(grains)with a unit change in pressure. Mathematically the rock matrx compressibility is given by

$$C_r = -\frac{1}{V_r}\left(\frac{\delta V_r}{\delta p}\right)T \qquad (3.2)$$

Where Cr= rock matrix compressibility, psi^{-1}, bar^{-1}

Vr= volume of solids

- **Rock bulk compressibility**; which is the fractional change in volume of the bulk volume of the rock with a unit change in pressure. Mathematically it is also given by

$$C_b = -\frac{1}{V_b}\left(\frac{\delta V_b}{\delta p}\right)T \qquad (3.3)$$

Where Cr= rock bulk compressibility, psi^{-1}, bar^{-1}

Vr= bulk volume

- **Pore compressibility**; which is the fractional change in pore volume of the rock with a unit change in pressure.

$$C_p = -\frac{1}{V_p}\left(\frac{\delta V_p}{\delta p}\right)T \qquad (3.4)$$

Where Cp= rock matrix compressibility, psi^{-1}, bar^{-1}

Vp= Pore volume

To estimate its importance in such cases, a series of laboratory tests were made to obtain usable values for reservoir rock compressibility. To estimate the importance of rock compressibility, **Howard, N. H, 1958** conducted series of Laboratory tests and obtained a relationship between Pore compressibility(Cp) and porosity as shown in Fig 10 and a mathematical correlation was developed.

$$C_p = \frac{2.587 \times 10^{-4}}{\emptyset^{0.4358}} \qquad (3.5)$$

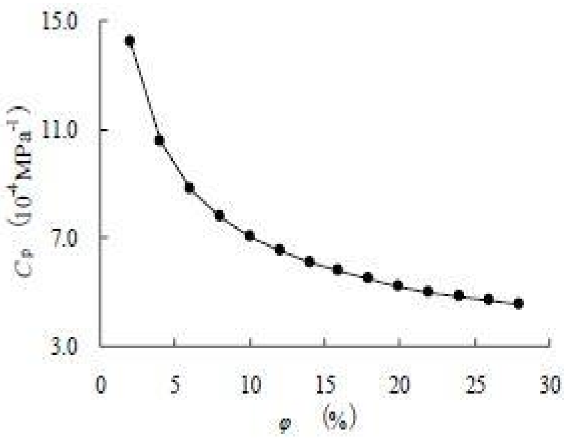

Figure 10 Effective Reservoir Rock Compressibility

G.H. Newman, 1973 also used 79 samples of limestones and sandstones to develop a relationship between the formation compressibility and porosity. The generalized hyperbolic form of the equation was proposed as:

$$C_f = \frac{a}{1 + cb\emptyset} \tag{3.6}$$

Where:

For consolidates sandstones

a=97.32×10^{-6}

b= 0.699993

c= 79.8181

For limestones

a= 0.8535

b= 1.075

c= 2.2×10^{6}

3.2 Effect of Compaction and Subsidence of Production

Pressure depletion in a producing field is a major contributing factor of reservoir compaction, movement of the overburden and subsidence of the surface above the reservoir. This compaction and subsidence can prove costly, both for production and surface facilities.

Subsidence is a gradual settling or sudden sinking of the Earth's surface owing to subsurface movement of earth materials (USGS Report, 2002). It occurs naturally because of plate-tectonic activity, above active faults and in places where fluid is expelled from underlying sediments. The high rate of subsidence is caused by **Compaction;** which is a decrease in the volume of the reservoir resulting from pressure reduction and fluids (oil, water or gas) production.

In the oil and Gas industry some cases of subsidence have become well-known. **Goose Creek Field,** south of Houston in 1918 was one of the very first that receive intense study. A porous medium, such as a hydrocarbon producing formation, contains fluid within its solid structure. Sediments deposited under water may have high porosity immediately after deposition, and it may behave more like a liquid with solid material in suspension, rather than a solid material containing liquid. As more and more sediments accumulate, the original layer must support the weight of the new layer. If fluid pathways exist, some of the liquid will be expelled, and porosity will decline.

The effect of subsidence because of production and 'inflation (during injection of gas) on caprocks are based on mining engineering activities but can also be applicable to Underground Gas storages.

In subsidence, the major problem is the scale of the subsidence (Cuss et al, 2003). For example, a meter of subsidence spread at a large surface of about one to two kilometers is not a major problem as effect is very negligible. The main problem arises when it moves a few meters over a short distance (like a fault).

Subsidence in oil and gas production is a well-known phenomenon and can be predicted modelled. Reservoir(pore) pressure decline can lead to a 'relaxation' of the reservoir and can be transmitted to the surface normally as depression (bowl-shaped subsidence). Furthermore, during gas storage operations where reservoir rocks are inflated(injection) and deflated(production) can lead to a reactivation and development of faults and fractures in the reservoir rock and sealing rock. These faults and fractures can lead to subsidence.

Land subsidence is induced by subsurface fluid withdrawals. This however depends on many factors including, time of occurrence, magnitude and extent of area involved, amount of fluid produced at a given period, pore pressure decline, fluid and geomechanical characteristics. In reverse however, during injection of fluids, Land uplift occurs (P. Teatini et al, 2010). This is achieved through the migration of the injected fluid to the ground followed by an expansion of the geological formation. Land uplift due to subsurface injection of fluid helps to enhance production of hydrocarbon(EOR), reactivate old aquifer systems as well as reduce anthropogenic land subsidence

3.3 HYSTERESIS DUE TO LOADING AND UNLOADING

Several mathematical formulations have been developed to model the behavior of rocks under stress, but to date there is no single formulation that the industry has accepted above the others. The best of these models has mechanisms for elastic and plastic deformations thermal effects and time-dependent, or creep, effect

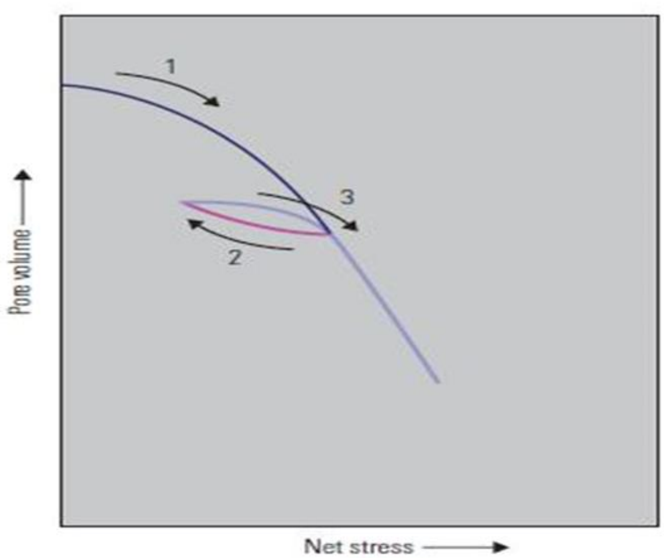

Figure 11 Schematic of an Interpretation of Oedometric tests

Compaction hysteresis, increasing the net stress on a material that is in its plastic state causes a rapid decline in volume (1). If the material is **unloaded,** the volume rebound is not as large as the collapse was, and it is often close to the elastic response (2). **Reloading** the material initially causes a quasi-elastic response, until the previous high net stress is reached (3). At the point, the material again follows the plastic failure line (Doornhof et al, 2006).

A compressibility equation is therefore needed for reservoir unloading after a loading cycle has been completed to study the effects of hysteresis. G. Gambolati et al, 2008 developed a relationship between the vertical uniaxial compressibility(Cm) and the vertical effective stress (σ_Z) represented as:

$$\mathbf{C_M = 1.3696 \times 10^{-2} * \sigma_Z^{-1.1347}} \qquad (3.7)$$

This equation only holds for true rock compaction in virgin loading (I loading cycle) whereas expansion of rock is controlled by uniaxial compressibility in unloading or reloading. The rock expansion by reloading and unloading controlled by Cm is represented by

$$C_m = \frac{1}{1+e_o-C_r.log\frac{\sigma_Z}{\sigma_{zi}}} \times \frac{C_r}{\sigma_z ln10} \qquad (3.8)$$

Where Cr= swelling index; Cc/3, where Cc is the rock compression index given by

$$C_C = \frac{\Delta e}{\Delta log \sigma_z} \qquad (3.9)$$

Where, the void ratio is given by $e = \frac{\emptyset}{1-\emptyset}$

3.4 Rock Compaction Models Available in a simulator

Reservoir modelling is an important aspect in reservoir engineering study. It involves constructing a numerical model of a reservoir based on data available from geophysics, geological and petrophysical measurements, well test data and interpretation. The data employed for modelling a reservoir covers all the rock and fluid characteristics including pressure, temperature regimes in the reservoir, reservoir structure etc., Several mathematical models (Eqn 3.10, 3.11, 3.12, 3.13) are built in computer programs to be used for the description of the reservoir behavior.

3.4.1 Fluid Dynamic Model and Geomechanical Model

In the black oil model, the flow equation for a standard gas-water system (Peaceman, 1977] is given by

$$\nabla . \left(\frac{Kk_{r,i}}{B_i \mu_i}\right)(\nabla \rho_i - \rho_i g \nabla_z) + \frac{q_i}{\rho s_i} = \frac{\partial}{\partial_t}\left(\frac{\emptyset S_i}{B_i}\right) \qquad (3.10)$$

Where : I refers to gas or water phase

∇ = divergence operators

K= hydraulic conductivity

Ø= Porosity

P= pressure in the fluid phase (g or w)

Si= degree of saturation (g or w)

Bi= Formation volume factor (g or w)

Kr= Relative permeability

μ= viscosity

q= mass injection rate (-ve if production) per unit volume of the reservoir)

t= time

ρ= Density

Ground displacement in Underground Gas storage projects is usually caused by migration to the ground surface due to deep deformation of a reservoir that has been produced ir injected. Based on the poroelastic theory (Biot, 1941), equations governing deformation in isotropic medium is given by

$$G\nabla^2 \mu + (G + \lambda)\nabla(\nabla . u) = \alpha \nabla_p + b \qquad (3.11)$$

Where G and λ are shear modulus and Lame constant respectively, α refers to the Biots coefficient, p is the pore pressure and b is the vector of body forces.

An isotropic stress-strain relationship is however the most common assumption in reservoir geomechanics studies. This is because the vertical displacement or insitu deformation is usually available for model calibrations (Settari et al, 2005). Therefore, for isotropic elastic medium, a constitutive matrix D relating the effective stress tensor to the strain tensor is given by

$$D = \frac{E(1-v)}{(1+v)(1-2v)} \qquad (3.12)$$

Where E is the Young's Modulus of Elasticity. The Young's Modulus of Elasticity is also related to the Uniaxial compressibility(Cm) through the familiar equation

$$C_M = \frac{(1+v)(1-2v)}{E(1-v)} \qquad (3.13)$$

Indicating that the constitutive matrix D is a function of C_M, v and s

In this project, ECLIPSE Simulator owned by Schlumberger Information Solutions is used to model and simulate fluid flow. The simulator solves Black Oil model by using ECLIPSE 100 module and compositional and thermal models by using the ECLIPSE 300 module. Eclipse also provides means of processing the results as well as visualization.

For the purposes of this study we employ the ECLIPSE 100 model. The basic features of an input file are as follows;

- **RUNSPEC** – This section contains a description of the simulation i.e., title of simulation, start date, number of grid blocks and wells, table dimensions, number of pressure nodes, etc.
- **GRID** – describes the geometry of the grid blocks and rock properties dependent on saturation and pressure e.g., relative permeabilities, PVT tables etc.)

- **REGIONS** – section that divides grids into sections to compute different properties separately from different segments of the reservoirs
- **SOLUTION** – section that contains data as the base for the computation of initial state of the reservoir.
- **SUMMARY**- section that contains the results output. The output of the data can be graphically plotted and displayed after the simulation
- **SCHEDULE**- The schedule section specifies operations to be controlled or constrained. The operations can be injection and production.

For purposes of this study, rock compaction models developed in the simulator are discussed as follows;

3.4.2 Options to Model Compaction

1. **Constant Compressibility**: Reservoir rock compressibility is a factor which is mostly neglected in reservoir engineering calculations. The main reason is because it has been assumed that the pore compressibility is of the same order as the water compressibility and also it is fairly constant with stress. This is mostly used in reserve estimation during the calculation of Hydrocarbon Originally In place. However, several publications have been written in the importance of rock compressibility on the calculation of oil in place by pressure decline data. The ECLIPSE simulator models rock compaction as a simple compressibility (rock compressibility), which is entered using the *'ROCK'* keyword (Eclipse Reference Manual, 2011).

2. **Variation of Rock Compressibility**: Usually in reservoir simulation compaction of the pore space is modeled as a function of fluid pressure. To estimate its importance in such cases, a series of laboratory tests were made to obtain usable values for reservoir rock compressibility. The total, or effective, compressibility of

any reservoir rock is a result of two separate factors, namely, expansion of the individual rock grains, as the surrounding fluid pressure decreases, and the additional formation compaction brought about because the reservoir fluids become less effective in opposing the weight of the overburden as reservoir pressure declines. To estimate the importance of rock compressibility on Porosity (Howard, N. H, 1958) conducted series of Laboratory tests and came by a conclusion as shown in the graph below (Fig 13)

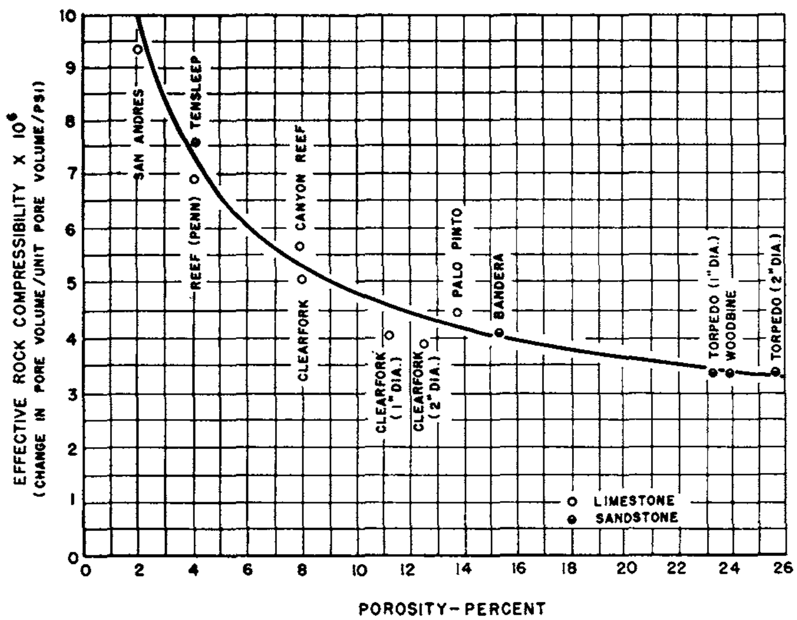

Fig 13: Effective Reservoir Rock Compressibility

A tabular description of compaction as a function of pressure (can be either reversible or irreversible) can be modeled using the ECLIPSE simulator. The input consists of a table which specifies the pore volume multiplier as a function of cell pressure. The corresponding pore volume to cell pressure is: $\boldsymbol{PV(P) = PV_0 \exp[Cr\,(P - Pref)]}$. By this equation pressure dependent pore volume multipliers and transmissibility multipliers are obtained and is used in the simulator to model a reservoir with a variation in rock compressibilities.

3. **Hysteresis Option:** The simulator also models rock compaction option for hysteresis during injection when the pore pressure increases and during

depletion to describe the behavior of a reversible reflation from each starting pressure.

For pressures below the starting pressure, the behavior is partially reversible(Fig14)

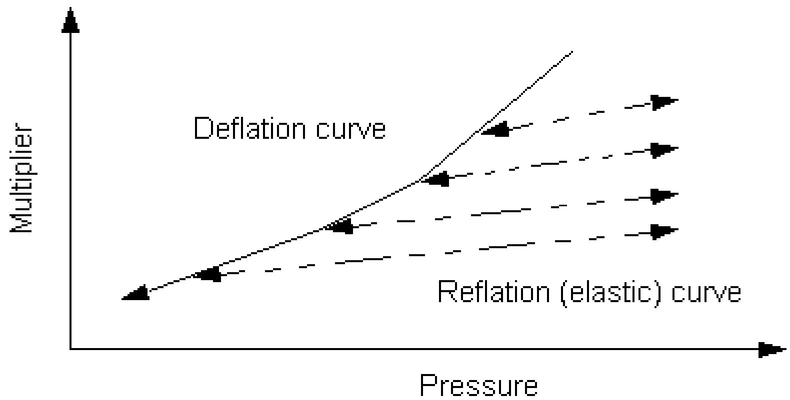

Figure 14: Rock Compaction: Hysteresis option

The 'BOBERG' Option based on Boberg, Beallie and McNab (1991) can also be used to model cyclic dilation and recompacting. In the BOBERG option the pore spaces also deflates and re-inflates for given pressures above the minimum elastic limit provided by the deflation cure and the maximum elastic limit provided by the dilation curve (Fig 13)

Boberg, Beattle, McNab, (1991) performed reservoir simulations involving cyclic steam stimulation (CSS) in the Cold Lake Oil-Sands deposits in Northern Alberta and based on that models for dilation and recompaction (reflation) were built.

Recompaction on the other hand has two phases; (1) an initial elastic period where there is no recovery of dilation and porosity changes only as a function of compressibility and (2) and a reflation period with an improved compressibility which allows recovery of some dilations during injection. Fig (15) shows a schematic behavior of the model.

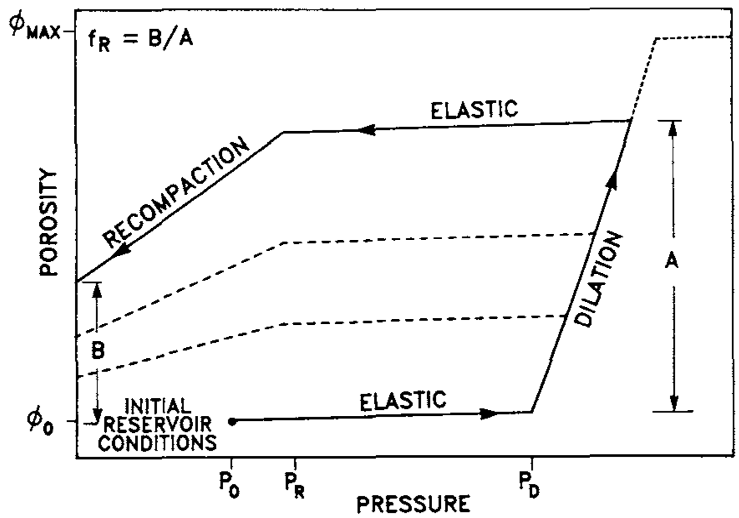

Figure 15: Reservoir Deformation Model (Boberg et al, 1991)

As the pressure depletes just before the recompaction pressure, (P_R), the slope of the porosity- pressure function is determined by the low compressibility, illustrated by the upper line named 'elastic'

The simulator tracks the maximum pressure and porosity that is achieved by each grid blocks during dilations and the values obtained are used in Equation 3.14 below during the initial elastic period.

$$Ø=Ør \exp[C(P-Pref)] \qquad (3.14)$$

Below the recompaction pressure, (P_R), the reservoir begins to recompact. Blocks that undergo large dilation will recompact more and vice versa. Residual dilation fraction(F_R) refers to the fraction of the total dilation in the grid block that is unrecoverable. As pressure reduces to recompaction pressure, (P_R), the minimum allowable porosity for each block is calculated from its historical maximum dilation porosity and (F_R). The minimum porosity applies *at p=0.* With the coordinates of both ends of the recompaction function thus specified, Eqn 3.14 can be used to calculate the recompaction compressibility for each block. Because a single F_R value is used for all blocks, the method allows more recompaction in blocks that dilated more, while guaranteeing that the porosity will never fall below the original value. The dashed lines in Fig 13 show recompaction behavior for two grid blocks where less dilation occurred than in the case represented by the solid lines. The different recompaction compressibilities are clear. (Recompaction cases shown in Fig 14 used F_R=0.50.). The shape of Fig 3.4 is consistent with the experimental study performed by Roscoe et al which describes constant total stress condition in the cold Lake Clearwater formation (Fig 16).

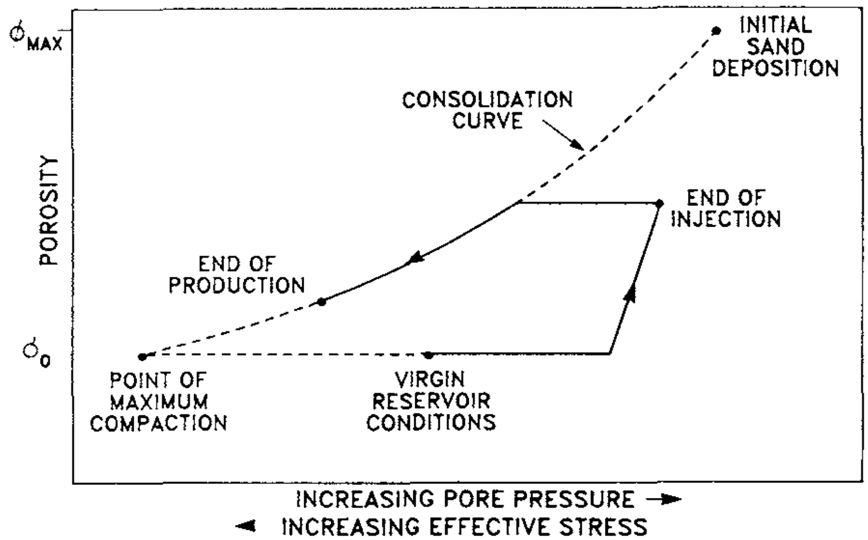

Figure 16 Representation of Cold Lake sand behavior by Roscoe et al showing consistency with that of Fig 15

Using the keyword 'ROCKTABH' you can input the input curves that describe the reversible (or elastic) behavior. In this model, the elastic behavior is bounded at high pressure by the dilation curve made up of the last point on each elastic curve. A table is terminated by a null record (i.e. a record with no data before the terminating slash (/) (3.7)

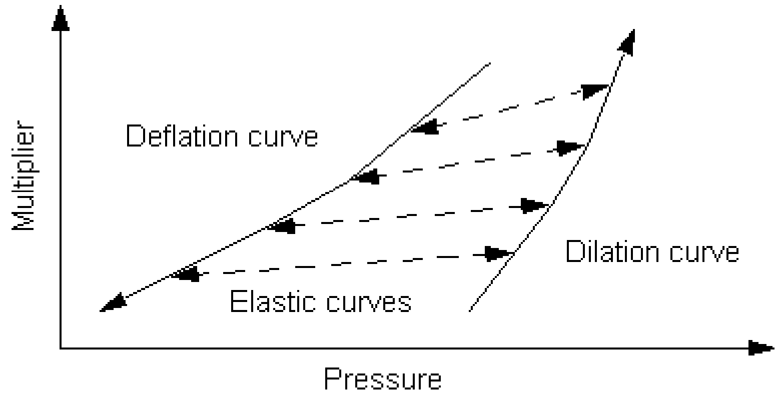

Figure 17: Rock Compaction: Boberg Hysteresis option

4.0 CASE STUDY

The Schlumberger Eclipse Simulation Software was used in this research study. A synthetic model representing the behavior of a gas reservoir was used in the reservoir simulation. The skeleton of the synthetic model is filled with the reservoir characteristics as defined based on the simplified representation. Details of the workflow is illustrated in this chapter.

4.1 SYNTHETIC MODEL

The gas reservoir lithology mainly comprises of fine grained, poorly to unconsolidated shaly sandstone. The Eclipse 100 simulator was used to model a synthetic anticline reservoir. The reservoir is made up of 72000 cells. 60 in the X direction, 60 in the Y direction and 20 in the Z direction (Fig 18). It has an initial pressure of 158.69 barsa at datum depth of 1540m and a reservoir temperature of 32 ^{o}C based on the calculation of temperature gradient.

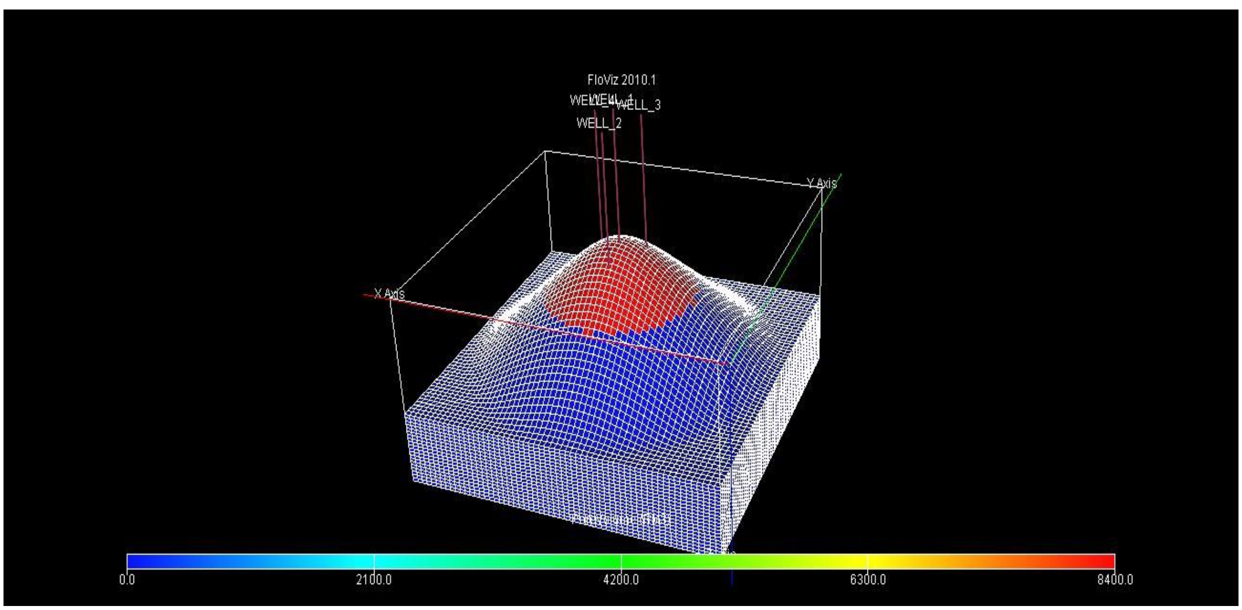

Figure 18 3-D representation of an anticline reservoir model

The reservoir is assumed to be a homogenous, isotropic anticline model with no-flow boundaries. The reservoir has 7 wells, both acting as injectors and producers during cyclic operations.

The properties of the synthetic model with the defined reservoir characteristics is seen in the tables below.

4.1.1 PVT Properties

Reservoir Properties

Initial Parameters	**Value**	**Unit**
Porosity	0.21	-
Permeability(X)	50	mD
Permeability(Y)	50	mD
Permeability(Z)	5	mD
Net to Gross	0.8	-
Reservoir Temperature	32	^{o}C
Irreducible Water Saturation	--	--
Critical Water Saturation	0.30	-
Critical Gas Saturation	0.15	-
Gas Gravity	0.68133	Kg/m^3
Water Density	1021.7	Kg/ m^3
Water Compressibility	3.8741×10^{-5}	1/barsa
Rock Compressibility	3.48×10^{-5}	1/barsa
Water Formation Volume Factor (Bw)	1.0110	rm^3/sm^3
Gas Formation Volume Factor(Bg)	1.14973	rm^3/sm^3
Original Gas in Place	4.2×10^9	Sm^3
Initial Reservoir Pressure	158.69	barsa
Reservoir Depth	1575	m

Table 1 The simplified reservoir characteristics used for the reservoir simulations

4.1.2 PRODUCTION HISTORY

The field began production in January 2016 with 7 wells. The production history comprises of four (4) years of production decline followed by injection for the pressure to build up until it reaches the initial reservoir pressure of 158barsa, after which a period of 10 years is dedicated to gas storage. The storage is operated in a cyclical manner i.e., for each year, six (6) months was dedicated to production and the other six (6) for injection. The injections were normally done during the low peak periods, between May-September at an injection rate of 18.5MMsm^3/D and a maximum BottomHole Pressure(BHP) of 200barsa. The production was done during winter period October -April at a production rate of 25.5 MMsm^3/D.

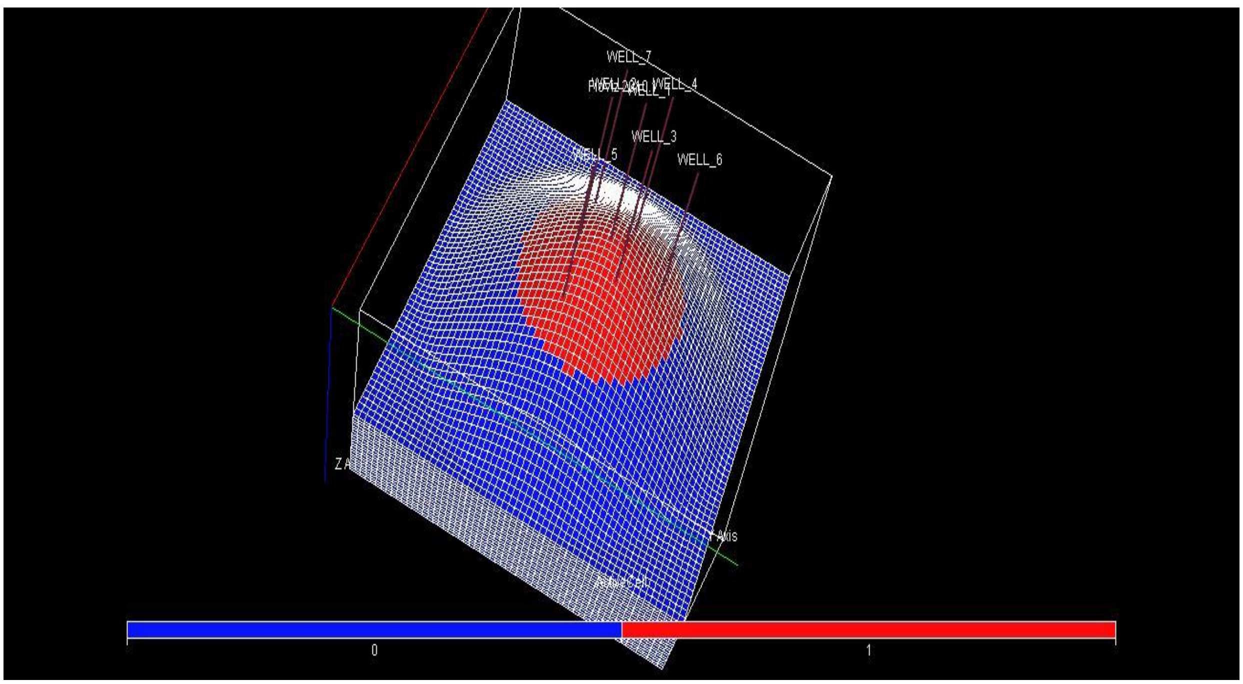

Figure 19 : 3-D representation of an anticline reservoir model with 3 additional wells

4.2 SIMULATION OF SYNTHETIC MODEL

In the following the effect of rock compaction on the behavior of a gas reservoir during production was studied using the Eclipse 100(black oil) simulator. The study was divided into 2 main cases; the first case was to keep the compressibility of the formation constant. The second is to vary the compressibility as a function of pressure during the entire production life.

4.2.1 CASE A; CONSTANT COMPRESSIBILTY- BASE CASE

In this scenario, seven (7) vertical wells were used for the simulation of the UGS program. All the seven (7) well were used during the period of production and later converted to injectors for pressure maintenance.

In this scenario, a constant compressibility of $(\mathbf{3.48 \times 10^{-5}\,\frac{1}{barsa}})$, is included in the input file used to run the simulation. In the ECLIPSE 100 simulator a simple compressibility is modeled by entering the keyword 'ROCK' in props section of the input file. The reservoir was modeled under normalized pressure conditions

Under normalized pressure conditions. In the Normalized pressure conditions, the reservoir is going to produce with a static flowing BottomHole pressure of 40 bars and injecting at a static flowing BottomHole pressure of 158 barsa.

The reservoir was made to produce for a period of 4 years, from 1st January 2016-28th February 2020 after which the wells were shut and injection was initiated until the pressure in the reservoir reached the initial pressure (158 barsa). This preceded a 10-year storage program, 6 months of production from October to April at a production rate of 25.5MMsm^3/Day of gas and a 6 month of injection at a rate of 18.5MMsm^3/Day.

The control mode for the wells was the BottomHole Pressure. This was achieved by changing the 'Item 3' which was initially GRAT to BHP for the KEYWORD: '***WCONPROD'.***

Also in the KEYWORD, '***WCONINJE'*** the 'Item 4' was changed from RATE to BHP. This was done for both normalized and overpressure scenarios.

The SUMMARY section of the input file(dataset) provides an output of the reservoir simulation. The results of interest were exported from the RSM file into the excel for analysis. The interested results recorded were namely;

- **FGIP** (Field Gas in Place, sm^3)

- **FPR** (Field Pressure/Average Reservoir Pressure, barsa)
- **WBHP** (Flowing BottomHole Pressure, for each of the four wells, barsa)
- **FGPT** (Field Gas Production Total, sm^3)
- **FGIT** (Field Gas Injection Total, sm^3)

The Field Gas Production Total(FGPT) and the Field Gas Injection Total were particularly important parameters in calculating the working gas and the volume of gas injected at the end of the 10-year storage. The working gas is calculated by finding the difference between the total gas produced at the beginning and the end of each production period. The volume of gas injected was also calculated by finding the difference between the gas injected at the beginning and end of each injection period. Results of this case is used as a **base case** for subsequent case studies. The inputs of the dataset are presented in **Appendix A** below.

4.2.2 CASE 2; VARIABLE COMPRESSIBILTIY

Compressibility of rocks is one of the main parameters in reservoir geomechanics. Rock Compressibility is a function of the reservoir fluid pressure and in-situ stresses and therefore cannot be considered as constant through the entire life of the reservoir. However, in analyzing the reservoir behavior during production and compaction estimation, rock compressibility is either neglected or simplified and thus could have a significant impact in the presence of unconsolidated sands or chalk. Moreover, changes in state of stress because of compaction could also influence operations such as hydraulic fracturing design, cap rock integrity, fault sealing etc.

Several studies by (T. J Plona and J.M Cook, 1995), (G Gambolati et al, 2008) have been devoted to understanding the changes in the formation compaction and the effective vertical stresses during production.

Gambolati et al, developed a relationship between the uniaxial compressibility(C_M) and the effective vertical stress(σ_Z); $\mathbf{C_M = 1.3696 \times 10^{-2} * \sigma_Z^{-1.1347}}$, where the units are bar^{-1} and bar for uniaxial compressibility and effective vertical stress respectively.

This correlation was used in this study for virgin loading conditions (Fig 20) to derive a relation between Young's Modulus(E), effective stresses and Uniaxial Compressibility (C_M) (Eqn4.1)

$$C_M = \frac{1}{E}\left(\frac{(1+v')(1-2v')}{1-v'}\right) \qquad \text{Eqn 4.1}$$

Where Cm= Uniaxial Compressibilty1/barsa)

v'= Poisson's Ratio

E= Young's Modulus(GPa)

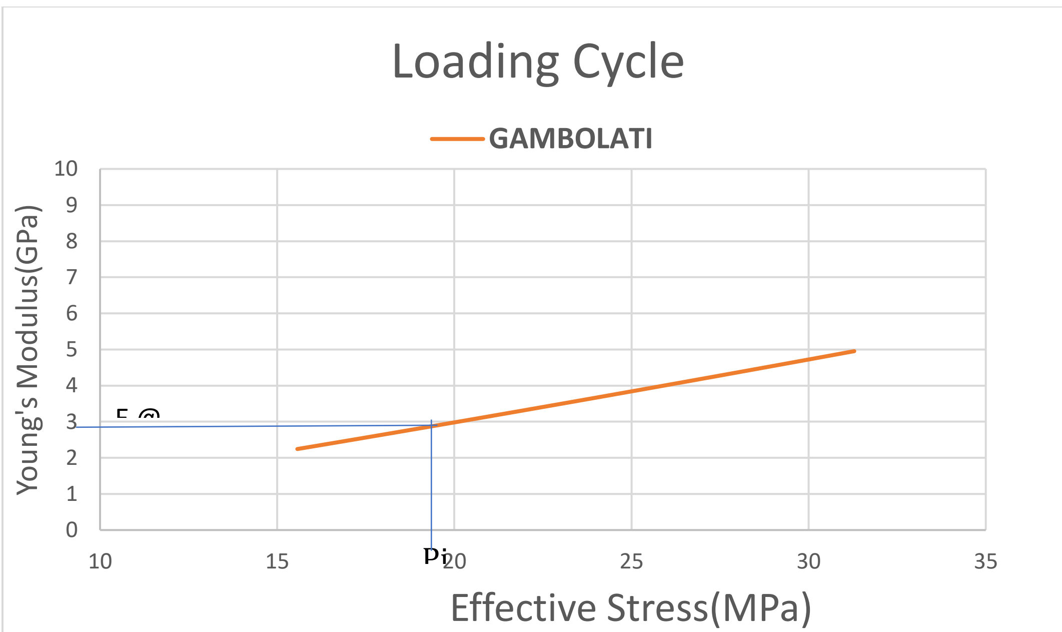

Figure 20: Static Moduli vs. Stress in Loading conditions

To better understand the effects of varying the rock compressibility as a function of pressure ECLIPSE 100 was used.

To account for the effect of rock compaction on the reservoir simulation, the keyword 'ROCKCOMP' is included in the RUNSPEC section of the data file. The compaction is assumed to be irreversible i.e., the pore spaces do not re-inflate under increasing pressure.

In the PROPS section, the ROCKTAB keyword is used instead of the ROCK keyword. The ROCKTAB expresses the rock compaction effects as a reduction of pore volume and transmissibility reduction as a function of the changes in the stress field due to production (M. Jongerius, 2015). This is achieved by introducing pressure dependent pore volume multiplier(PVm) and transmissibility(permeability) multiplier(Tm) ranging from zero to one. In this study the permeability reductions are neglected and are therefore set equal to one. The pore volume multiplier is equal to the change in the pore volume (Table 4.2)

Quantity	**Input in Eclipse Simulator**
Change in Pore Volume	Pore volume Multiplier(PVm)
Change in Permeability	Transmissibility Multiplier(Tm)

Table 2 Converting Relative Change in Pore volume as multipliers to be included in the Eclipse 100

The compressibilities are expressed as a function of pressure (Fig 4.4) and later converted into pore volume multipliers to input it into the Eclipse Simulator (Table 3). The pore volume multiplier is expressed in the equation 4.2 below and expressed in the graph against pressure (Fig 21).

$$\boldsymbol{PV\,(P) = PV_0 \exp\left[Cr\,(P - Pref)\right]} \qquad \text{Eqn 4.2}$$

Where;

Pv(p)= Pore volume corresponding to cell pressure

Pv(o)=initial pore volume

Cr= Rock compressibility

Pref= Reference Pressure (Pressure at Datum), bars

P= Cell Pressure, bars

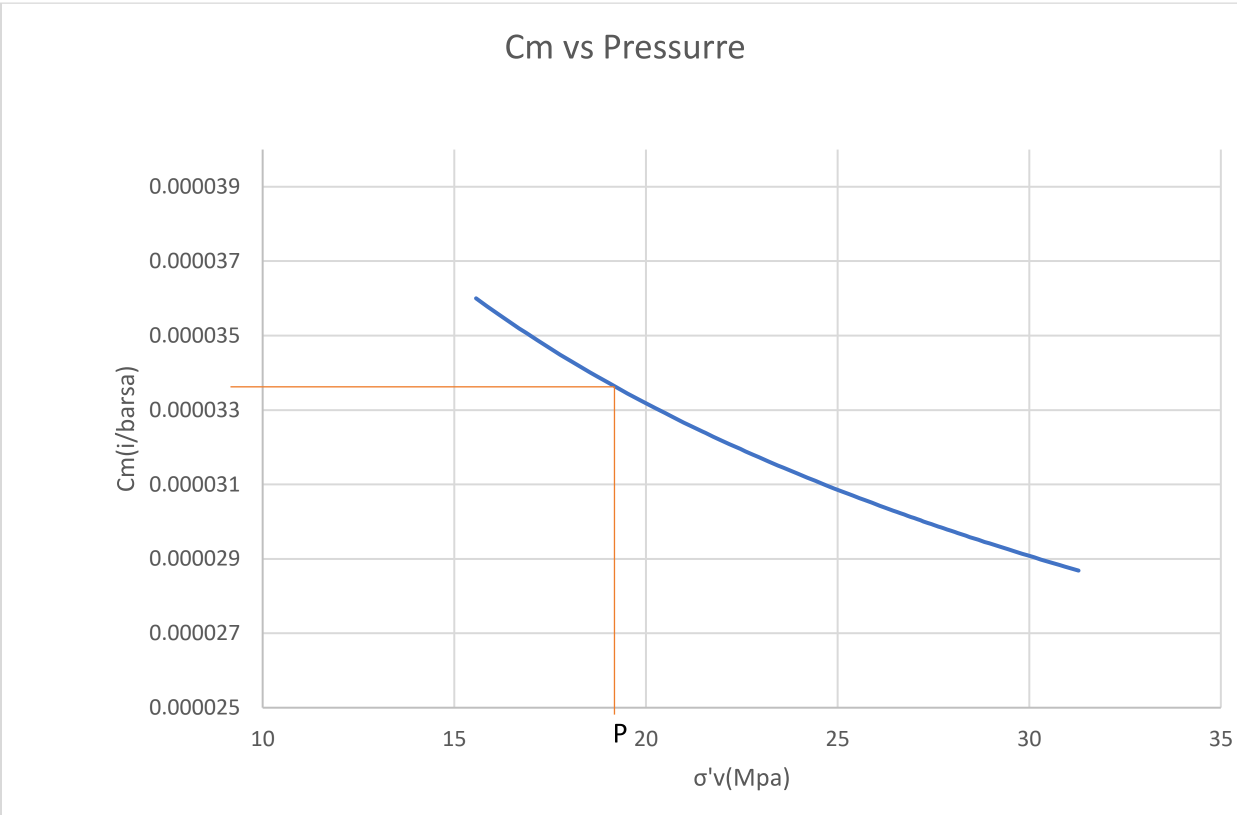

Figure 21: A relationship between Uniaxial Compressibility and Effective Stresses

P(BARSA)	PVMult	Perm_mult
44.12993	0.996719264	1

49.03325	0.9968433	1
53.93658	0.996968467	1
58.8399	0.997094801	1
63.74323	0.997222338	1
68.64655	0.997351116	1
73.54988	0.997481175	1
78.4532	0.997612559	1
83.35653	0.997745312	1
88.25985	0.997892678	1
93.16318	0.998015115	1
98.0665	0.998152268	1
102.9698	0.998290994	1
107.8732	0.998431358	1
112.7765	0.998573414	1
117.6798	0.998717233	1
122.5831	0.998862886	1
127.4865	0.999010451	1
132.3898	0.999160001	1
137.2931	0.999311627	1
142.1964	0.999465421	1
147.0998	0.999621483	1
152.0031	0.999779912	1

156.9064	0.999940827	1
161.8097	1.000104348	1

Table 3 Calculated Pore Volume Multipliers as a function of Pressure

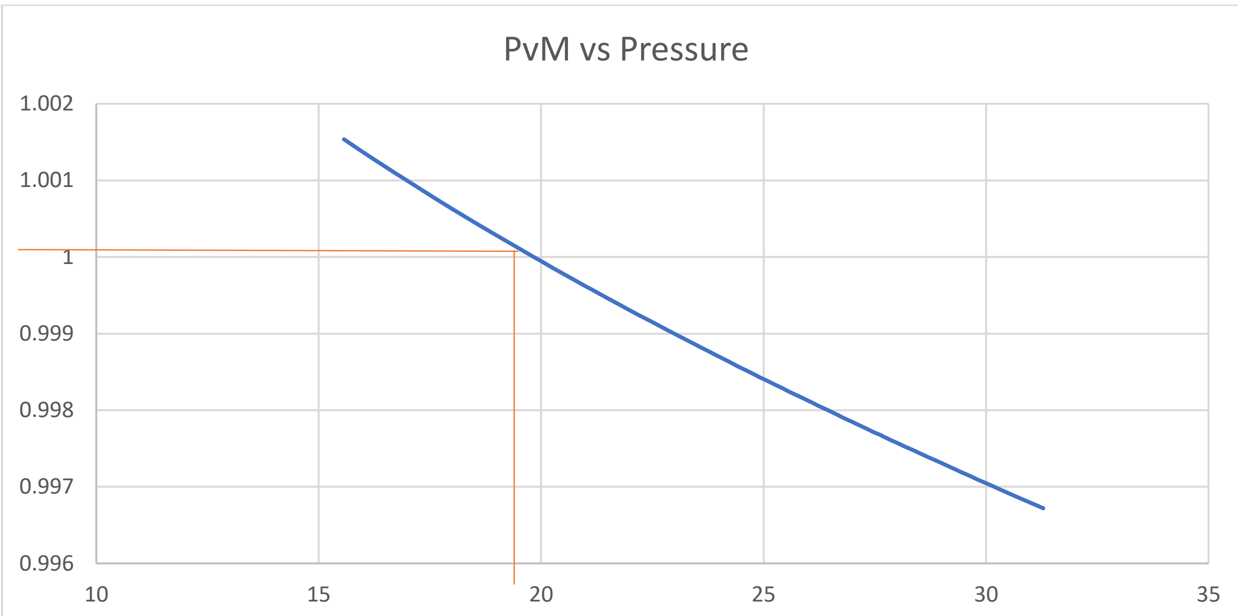

Figure 22: Pore volume multiplier as a function of the Effective Stresses

5.0 RESULTS AND DISCUSSIONS

To better understand the effect rock compaction has on the amount of gas that can be produced in terms of working gas capacity, the variations of the rock compressibilities were further analyzed. This was achieved by taking a robust approach by trying to stress the range of the Cm and E by varying the minimum Pore volume multipliers that were included in performing the simulations of varying compressibility as function of pressure.

The initial minimum pore volume multiplier (at minimum pressure) obtained from Gambolati et al, 2005 is **0.996** and was further stressed to **0.994 and 0.992.** Its corresponding Uniaxial compressibility and corresponding Young's Modulus of Elasticity was calculated using the Eqn(5.2) below

$$PV_{mult} = e^{C_{r(P-Pref)}} \tag{5.1}$$

$$C_r = \frac{\ln(PVmult)}{P-Pref} \tag{5.2}$$

Other simulations were performed using minimum PVMs; **0.99, 0.97, 0.95, 0.90, 0.80** (Figure 23) and sensitivity analysis between the Case A and Case B; for each minimum Pore Volume Multiplier was performed to study its effect on their working gas capacities.

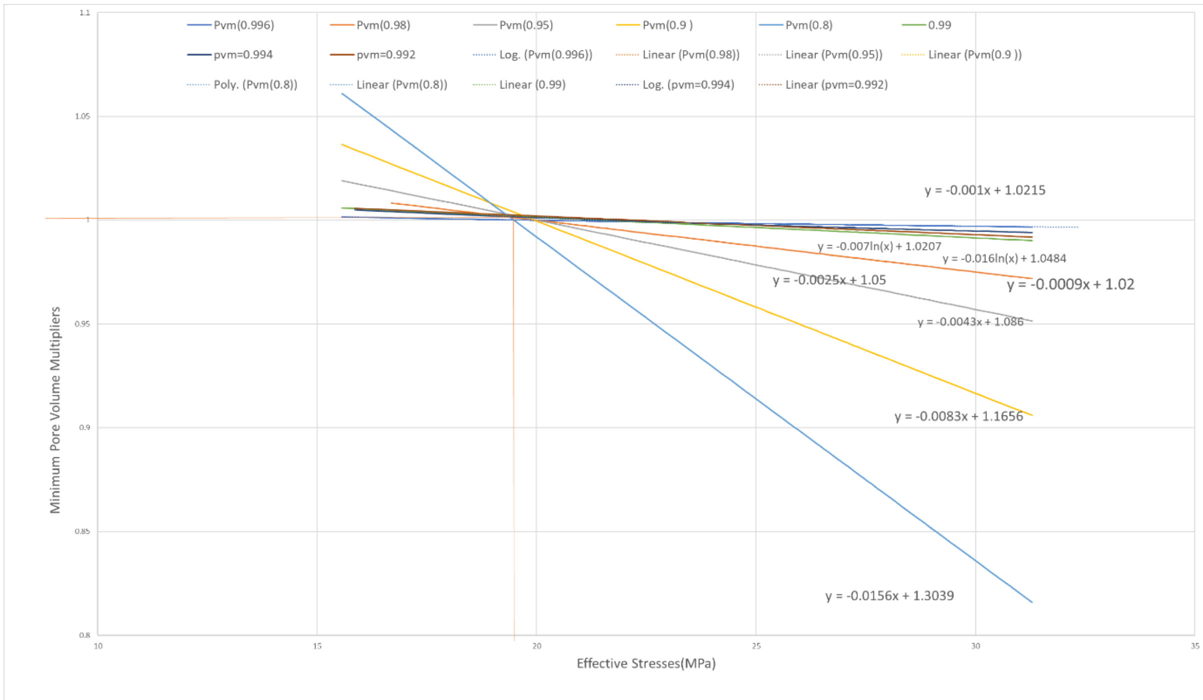

Figure 23: Variation of minimum Pore Volume Multipliers

5.1 SENSITIVITY ANALYSIS ON WORKING GAS CAPACITY

The results below are based on the simulations run using the two cases; constant compressibility and variation compressibility and their working gas capacity and volume of gas injected for a 5-year cycle was calculated. The working gas capacity and volume of gas injected is calculated using the equations below

Working Gas Capacity= Gas Produced @ end of year – Gas Produced @ beginning of year

Volume of Gas Injected = Volume of gas injected at end of year – Volume of gas injected at the beginning of the year

5.1.1 CASE A vs CASE B

In this scenario, a sensitivity analysis between the constant compressibility case and the variation of compressibility where a minimum PVM of **0.996** was performed for a 5-year storage cycle.

The results provided below shows a slight increase in the working as capacity when the constant compressibility is used instead of using the variation of compressibility for a realistic range of compressibility values between 2.87×10^{-5} to 8.58×10^{-5} 1/barsa. Using the case B means the UGS system would be producing between 102MMsm^3/Day to 282MMsm^3/Day **less** for the 5-year storage cycle indicating a percentage reduction of **0.56% - 1.56%**

Max Cm(1/barsa)	Min E(Gpa)	Minimum PVm	ΔWG(MMsm^3/D)	ΔWG%
2.87E-05	**3.4**	**0.996**	-102.84	**-0.569902593**
5.16E-05	**1.9**	0.994	-137.789	**-0.763577483**
7.15E-05	**1.39**	0.992	-246.179	**-1.364236196**
8.58E-05	**1.16**	**0.99**	**-282.089**	**-1.563236606**
2.50E-04	**0.4**	**0.97**	**-715.549**	**-3.965317293**
4.30E-04	**0.23**	**0.95**	**-1231.897**	**-6.826733707**
8.60E-04	**0.115**	**0.9**	**-2388.275**	**-13.23496806**
1.78E-03	**0.05**	**0.8**	**-4654.696**	**-25.79466472**

Table 4: Comparison of Average Working Gas between Case A and Case B(with different minimum PVMs)

Similar analysis was carried out on the remaining minimum pore volumes multipliers (0.97, 0.95, 0.90, 0.80) and sensitivity analysis between the base case (Case A) and variation of compressibility (Case B) were performed to estimate its effect on the performance of the UGS facility in terms of Working Gas Capacity and volume of gas Injected (Table 4 and Table 5).

From the results it was observed that a further reduction in the minimum pore volume multipliers (at minimum producing pressure of 40 barsa) there was further loss of working gas capacity from a percentage reduction of 1.5% at a minimum pore volume multiplier of 0.99 to a significant 25% reduction at a minimum pore volume multiplier of 0.8.

This is due to the relation between the rock compaction and the minimum pore volume multiplier. A decrease in the minimum pore volume multiplier and increase in the compaction of the reservoir. This means that for instance, at the minimum producing pressure of 40 barsa for a Min PVM=0.8 the reservoir is highly compacted such that it causes a hindrance to fluid flow. This is evident in compaction drive reservoirs where excessive compaction has led to production problems. Excessive compaction has been heavily linked to decline in the reservoir permeability, subsidence and fracture.

The same condition applies for the volume of gas injected back into the reservoir. From the results is can be observed that a further reduction in the minimum pore volume multiplier means the volume of gas injected back during cyclic injection is reduced as clearly seen in Table 5

Max Cm(1/barsa)	**Min E (Gpa)**	**Minimum PVm**	**Δvol**	**Δvol%**
0.00002868	**3.4**	**0.996**	**-75.863**	**-0.450926797**
0.000051577	**1.9**	**0.994**	**-104.781**	**-0.622814294**
0.0000715	**1.39**	**0.992**	**-195.796**	**-1.163804005**
0.00008583	**1.16**	**0.99**	**-225.78**	**-1.342027765**
0.00025	**0.4**	**0.97**	**-589.626**	**-3.504714602**
0.00043	**0.23**	**0.95**	**-1028.147**	**-6.11126681**
0.00086	**0.115**	**0.9**	**-2019.31**	**-12.00270213**
0.00178	**0.05**	**0.8**	**-3977.282**	**-23.6408135**

Table 5: Comparison of Average Volume of Gas Injected between Case A and Case B (with different minimum PVMs)

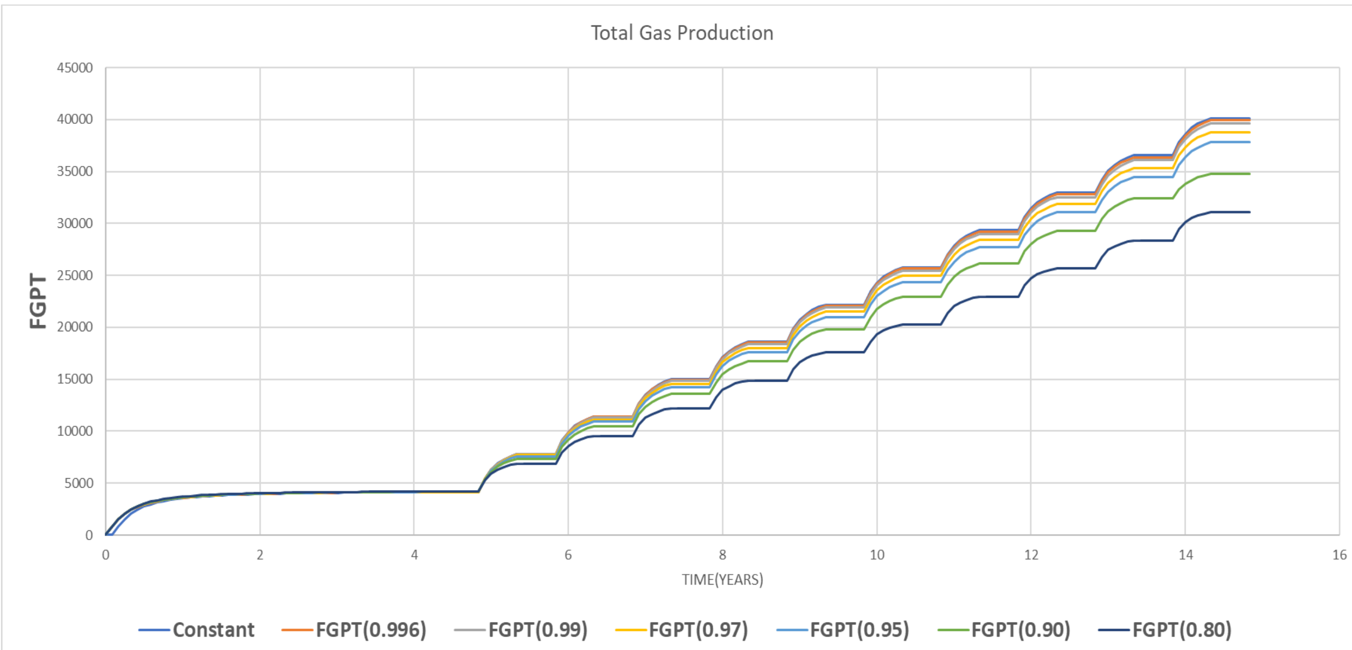

Figure 24 : Cumulative Gas Production of the UGS System

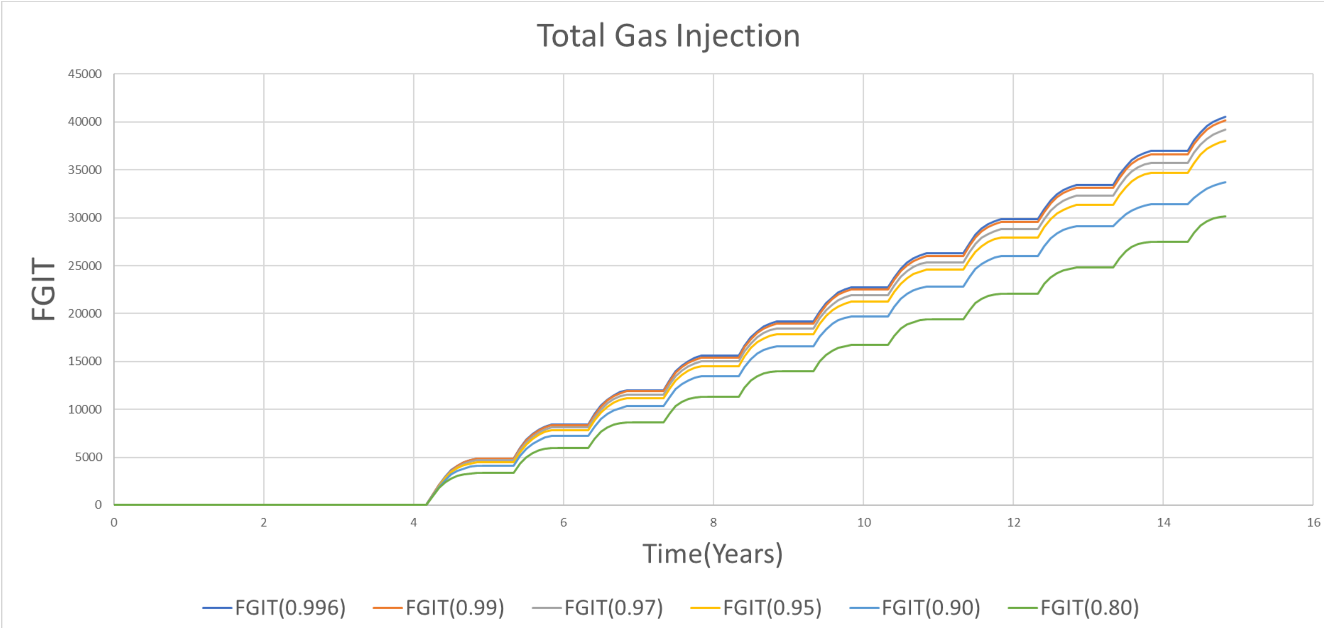

Figure 25Cumulative Gas Production of the UGS System

Other sensitivity analysis in overpressure conditions were also performed. A 150%Pi (240 bars) increase resulted in the increase in the working gas capacity however when compared using the same scenario of constant compressibility versus variation of compressibility it showed similar trends with the most stressing action on the production rather than the injection

CONCLUSION

Rock compaction is one of the factors which could play an important role in the optimization of the working gas capacity in Underground gas storage systems. Efforts to evaluate the potential effect of reservoir rock compaction on the performance of the UGS facility have been studied. Simulation involving the use of fluid flow simulator; ECLIPSE and geomechanical models have proved to be of a great help in the prediction of the working gas volume for an Underground Gas Storage system.

Production history data was obtained from a synthetic gas reservoir, 1570 meters deep with an initial primary production of 4 years (2016-2020) followed by a 10-year cyclic gas storage program (2020-2030).

The objective of this study was to evaluate the potential impact of reservoir rock compaction on the performance of the UGS programs. Two cases were modeled in the simulator to evaluate its impact on the working gas capacity, CASE A (Base Case) where the rock compressibility in the simulator was kept constant and CASE B where the compressibilities were varied as a function of pressure as obtained by the correlation developed by (G. Gambolati et al, 2005). The ECLIPSE simulator models the variation of rock compressibility as a function of pressure by using Pore Volume Multipliers. The variation of compressibilities were achieved by converting the Pore volume multipliers into corresponding compressibilities using the Eqn 5.2 above.

Sensitivity analysis were performed between the two cases. The results in terms of working gas capacity was obtained for a 5 -cycle. In the results it was observed that there was a slight decrease in the working gas volume when the compressibilities were varied (between 2.87×10^{-5} to 8.58×10^{-5} 1/barsa) in the simulator compared to using the constant compressibility. This means, the UGS will be producing 102MMsm^3/D to 282MMsm^3/D more gas if the CASE A was adopted indicating a percentage of **+0.56% to 1.56% .** The reservoir system was further stressed by reducing further the minimum Pore volume multiplier and sensitivity analysis of working gas capacity and volume of gas injected between the different minimum pore volume multipliers and the constant rock compressibility was performed. Similar trend as with the first case continued. The working gas capacity continued to decrease from 3.9% to 25% as the minimum pore volume multiplier (Min PVm) was reduced from 0.97 to 0.80. This was concluded that, at a minimum pore volume multiplier of 0.80 the formation was highly compacted and therefore could have resulted in a decline in the permeability, or fracture closure and thus causing a hindrance to fluid flow in injection and production scenarios.

An exciting area for the future is to work on the simulation of hysteresis(loading and unloading) effects to assess its impact on the working gas capacity of the Underground Gas Storage.

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-
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APPENDIX 1 : Input data for Case A

```
RUNSPEC
------------------------------------------------------------


TITLE
322111_AQ


START
 1 JAN 2016 /


METRIC


GAS
```

```
WATER

DIMENS
  60 60 20 /

EQLOPTS
 IRREVERS /

ENDSCALE
'NODIR'     'REVERS'    /

TABDIMS
  1* 1* 21 41 8* 1 /

VFPPDIMS
  20 10 10 1 1 4 /

WELLDIMS
  7 15 2 7 /

MESSAGES
 8* 50000 2000 2* /

UNIFIN
UNIFOUT

NSTACK
25 /

UDQDIMS
7* 4 2* /
```

```
UDQPARAM
3* /

UDADIMS
480 1* 480 /



----------------------------------------------------------------
GRID
----------------------------------------------------------------

INIT

GRIDFILE
  2 /

NEWTRAN

NOECHO

INCLUDE
INPUT\3221.grid /      --GRID, PORO, PERMX, PERMZ, NTG

COPY
'PERMX'  'PERMY'  /
/

ECHO



-----------------------------------------------------------
EDIT
```

```
---------------------------------------------------------



---------------------------------------------------------
PROPS
---------------------------------------------------------



ROCK
-- Pressure    cr
-- (barsa)     (1/barsa)
   158.6900   3.48E-005 /


PVTW
-- Ref p Bw            cw              muw    viscosibility
-- (bars)      (rm3/sm3)    (1/bars)       (cP)    (1/bars)
   158.69      1.0110       3.8741E-05     0.6484  0.0007 /

DENSITY
-- fluid densities at surface
--   oil     wat   gas
--   kg/m3   kg/m3    kg/m3
     600     1021.7  0.68133 /

PVDG
-- Pressure    Bg           Visg
-- (barsa)     (rm3/sm3)    (cp)
0.980665       1.14973              0.01060
4.903325       0.22863              0.01073
9.806650       0.11351              0.01090
```

14.70998	0.07514	0.01107
19.61330	0.05596	0.01124
24.51663	0.04446	0.01141
29.41995	0.03679	0.01158
34.32328	0.03132	0.01175
39.22660	0.02722	0.01193
44.12993	0.02404	0.01210
49.03325	0.02150	0.01228
53.93658	0.01942	0.01246
58.83990	0.01769	0.01264
63.74323	0.01623	0.01282
68.64655	0.01499	0.01300
73.54988	0.01391	0.01319
78.45320	0.01297	0.01337
83.35653	0.01214	0.01356
88.25985	0.01141	0.01374
93.16318	0.01076	0.01393
98.06650	0.01018	0.01412
102.9698	0.00965	0.01431
107.8732	0.00918	0.01450
112.7765	0.00875	0.01470
117.6798	0.00836	0.01489
122.5831	0.00800	0.01508
127.4865	0.00767	0.01528
132.3898	0.00737	0.01547
137.2931	0.00710	0.01567
142.1964	0.00684	0.01587
147.0998	0.00661	0.01607
152.0031	0.00639	0.01627
156.9064	0.00619	0.01647
161.8097	0.00600	0.01667
166.7131	0.00582	0.01687

```
171.6164    0.00566          0.01707
176.5197    0.00550          0.01728
181.4230    0.00536          0.01748
186.3264    0.00523          0.01769
191.2297    0.00510          0.01789
196.1330    0.00498          0.01810       /

EQUALS
SWL   0.30 /
/


SCALECRS
YES /

SGFN
  0.00 0.00000    0
  0.05 0.00056    0
  0.10 0.00316    0
  0.15 0.00871    0
  0.20 0.01789    0
  0.25 0.03125    0
  0.30 0.04930    0
  0.35 0.07247    0
  0.40 0.10119    0
  0.45 0.13584    0
  0.50 0.17678    0
  0.55 0.22434    0
  0.60 0.27885    0
  0.65 0.34063    0
  0.70 0.40996    0
  0.75 0.48714    0
```

```
0.80 0.57243     0
0.85 0.66611     0
0.90 0.76843     0
0.95 0.87965     0
1.00 1.00000     0     /     ng=2.5, nw=1.8
```

```
SWFN
    0.00    0.00000    0
    0.05    0.00455    0
    0.10    0.01585    0
    0.15    0.03288    0
    0.20    0.05519    0
    0.25    0.08247    0
    0.30    0.11450    0
    0.35    0.15112    0
    0.40    0.19218    0
    0.45    0.23757    0
    0.50    0.28717    0
    0.55    0.34092    0
    0.60    0.39872    0
    0.65    0.46052    0
    0.70    0.52623    0
    0.75    0.59581    0
    0.80    0.66921    0
    0.85    0.74637    0
    0.90    0.82725    0
    0.95    0.91181    0
    1.00    1.00000    0     /     ng=2.5, nw=1.8
```

```
COPY
 'SWL' 'SWCR'  /
 'SWL' 'SGU'   /
```

```
/

ADD
 'SGU'    -1  /
/

MULTIPLY
 'SGU'    -1  /
/

EQUALS
'SWCR' 0.30 /
'SGCR' 0.15 /
'KRWR' 0.60 /
'KRGR' 0.90 /
'PCW'  0.00 /
/


----------------------------------------------------------
REGIONS
----------------------------------------------------------



----------------------------------------------------------
SOLUTION
----------------------------------------------------------

EQUIL
     1540    158.69     1575     0    1*     0    1*    1*     0     /

RPTRST
```

```
 BASIC=5 /



------------------------------------------------------------
SUMMARY
------------------------------------------------------------

RPTONLY
SEPARATE
EXCEL
DATE
RUNSUM

FPR
FPRP
FGPR
FGPT
FWPR
FWPT
FWGR
FGIP
FGPV
FGIP
FGPV
FGIR
FGIT
WGPR
 /
WGPT
 /
WWPR
 /
```

```
WWPT
 /
WWGR
 /
WBP
 /
WTHP
 /
WBHP
 /
WUBHP1
/
WUBHP2
/
WUBHP3
/
WUBHP4
/


----------------------------------------------------------
SCHEDULE
----------------------------------------------------------


RPTSCHED
WELSPECS /


INCLUDE
VFP\Well_1.Ecl /        --TAB. VFP 1
INCLUDE
VFP\Well_2.Ecl /        --TAB. VFP 2
INCLUDE
```

```
VFP\Well_3.Ecl /          --TAB. VFP 3
INCLUDE
VFP\Well_4.Ecl /          --TAB. VFP 4

WELSPECS
 WELL_1 'GROUP_1' 30 30 1* GAS /
 WELL_2 'GROUP_1' 30 25 1* GAS /
 WELL_3 'GROUP_1' 26 33 1* GAS /
 WELL_4 'GROUP_1' 35 33 1* GAS /
 WELL_5 'GROUP_1' 22 26 1* GAS /
 WELL_6 'GROUP_1' 30 40 1* GAS /
 WELL_7 'GROUP_1' 38 25 1* GAS /
/

COMPDAT
 WELL_1 30 30 1  4 OPEN 2*  0.19050 1* 0.00 1* Z  /
 WELL_2 30 25 1  4 OPEN 2*  0.19050 1* 0.00 1* Z  /
 WELL_3 26 33 1  4 OPEN 2*  0.19050 1* 0.00 1* Z  /
 WELL_4 35 33 1  4 OPEN 2*  0.19050 1* 0.00 1* Z  /
 WELL_5 22 26 1  4 OPEN 2*  0.19060 1* 0.00 1* Z  /
 WELL_6 30 40 1  4 OPEN 2*  0.19060 1* 0.00 1* Z  /
 WELL_7 38 25 1  4 OPEN 2*  0.19060 1* 0.00 1* Z  /
/

COMPORD
'*'  INPUT /
/

GRUPTREE
'GROUP_1' FIELD /
 /
```

```
WVFPEXP
'WELL_1*'   EXP NO YES1 /
/

--UDQ
--DEFINE WUBHP1 WBP 'WELL_1' * 0.85        /
--UNITS WUBHP1 BARSA                       /
--DEFINE WUBHP2 WBP 'WELL_2' * 0.85        /
--UNITS WUBHP2 BARSA                       /
--DEFINE WUBHP3 WBP 'WELL_3' * 0.85        /
--UNITS WUBHP3 BARSA                       /
--DEFINE WUBHP4 WBP 'WELL_4' * 0.85        /
--UNITS WUBHP4 BARSA                       /
--/

/
```

APPENDIX II: Pore Volume Multipliers used for Case B

```
ROCKTAB
--  P(BARSA)       PVMult        Perm_mult
  44.12993       0.996719264     1.0
  49.03325       0.996843300     1.0
  53.93658       0.996968467     1.0
  58.8399        0.997094801     1.0
  63.74323       0.997222338     1.0
  68.64655       0.997351116     1.0
  73.54988       0.997481175     1.0
  78.4532        0.997612559     1.0
  83.35653       0.997745312     1.0
  88.25985       0.997892678     1.0
  93.16318       0.998015115     1.0
```

```
  98.0665      0.998152268    1.0
  102.9698     0.998290994    1.0
  107.8732     0.998431358    1.0
  112.7765     0.998573414    1.0
  117.6798     0.998717233    1.0
  122.5831     0.998862886    1.0
  127.4865     0.999010451    1.0
  132.3898     0.999160001    1.0
  137.2931     0.999311627    1.0
  142.1964     0.999465421    1.0
  147.0998     0.999621483    1.0
  152.0031     0.999779912    1.0
  156.9064     0.999940827    1.0
  161.8097     1.000104348    1.0  /
ROCKTAB
--  P(BARSA)     PVMult     Perm_mult
  44.12993     0.9902129    1.0
  49.03325     0.9907033    1.0
  53.93658     0.9911936    1.0
  58.8399      0.9916839    1.0
  63.74323     0.9921743    1.0
  68.64655     0.9926646    1.0
  73.54988     0.9931549    1.0
  78.4532      0.9936453    1.0
  83.35653     0.9941356    1.0
  88.25985     0.9946739    1.0
  93.16318     0.9951163    1.0
  98.0665      0.9956066    1.0
  102.9698     0.9960968    1.0
  107.8732     0.9965873    1.0
  112.7765     0.9970776    1.0
  117.6798     0.9975679    1.0
```

```
  122.5831     0.9980583     1.0
  127.4865     0.9985486     1.0
  132.3898     0.9990389     1.0
  137.2931     0.9995293     1.0
  142.1964     1.0000196     1.0
  147.0998     1.0005099     1.0
  152.0031     1.0010031     1.0
  156.9064     1.0014906     1.0
  161.8097     1.0016825     1.0  /


ROCKTAB
--  P(BARSA)     PVMult     Perm_mult
  44.12993     0.971782     1.0
  49.03325     0.973008     1.0
  53.93658     0.974234     1.0
  58.8399      0.975460     1.0
  63.74323     0.976686     1.0
  68.64655     0.977912     1.0
  73.54988     0.979137     1.0
  78.4532      0.980363     1.0
  83.35653     0.981589     1.0
  88.25985     0.982935     1.0
  93.16318     0.984041     1.0
  98.0665      0.985267     1.0
  102.9698     0.986492     1.0
  107.8732     0.987718     1.0
  112.7765     0.988994     1.0
  117.6798     0.990170     1.0
  122.5831     0.991396     1.0
  127.4865     0.992622     1.0
  132.3898     0.993847     1.0
```

```
  137.2931     0.995073    1.0
  142.1964     0.996299    1.0
  147.0998     0.997525    1.0
  152.0031     0.998264    1.0
  156.9064     0.999997    1.0
  161.8097     1.001202    1.0  /



ROCKTAB
--  P(BARSA)     PVMult      Perm_mult
  44.12993     0.95146587    1.0
  49.03325     0.95357429    1.0
  53.93658     0.95568273    1.0
  58.8399      0.95779116    1.0
  63.74323     0.95989958    1.0
  68.64655     0.96200801    1.0
  73.54988     0.96411644    1.0
  78.4532      0.96622487    1.0
  83.35653     0.96833333    1.0
  88.25985     0.97064791    1.0
  93.16318     0.97255017    1.0
  98.0665      0.97465859    1.0
  102.9698     0.97676014    1.0
  107.8732     0.97887548    1.0
  112.7765     0.98098389    1.0
  117.6798     0.98309231    1.0
  122.5831     0.98520073    1.0
  127.4865     0.98730919    1.0
  132.3898     0.98941761    1.0
  137.2931     0.99152603    1.0
  142.1964     0.99363445    1.0
  147.0998     0.99574291    1.0
```

```
  152.0031      0.99785133     1.0
  156.9064      0.99995975     1.0
  161.8097      1.00206817     1.0  /



ROCKTAB
--  P(BARSA)       PVMult       Perm_mult
  44.12993       0.90592      1.0
  49.03325       0.90999      1.0
  53.93658       0.91406      1.0
  58.8399        0.91813      1.0
  63.74323       0.92222      1.0
  68.64655       0.92627      1.0
  73.54988       0.93034      1.0
  78.4532        0.93441      1.0
  83.35653       0.93848      1.0
  88.25985       0.94294      1.0
  93.16318       0.94662      1.0
  98.0665        0.95069      1.0
  102.9698       0.95475      1.0
  107.8732       0.95882      1.0
  112.7765       0.96289      1.0
  117.6798       0.96696      1.0
  122.5831       0.97103      1.0
  127.4865       0.97510      1.0
  132.3898       0.97917      1.0
  137.2931       0.98324      1.0
  142.1964       0.98731      1.0
  147.0998       0.99138      1.0
  152.0031       0.99545      1.0
  156.9064       0.99952      1.0
```

```
  161.8097      1.00359     1.0  /

ROCKTAB
--  P(BARSA)      PVMult      Perm_mult
  44.12993      0.81582     1.0
  49.03325      0.82347     1.0
  53.93658      0.83112     1.0
  58.8399       0.83877     1.0
  63.74323      0.84642     1.0
  68.64655      0.85407     1.0
  73.54988      0.86172     1.0
  78.4532       0.86937     1.0
  83.35653      0.87702     1.0
  88.25985      0.88541     1.0
  93.16318      0.89231     1.0
  98.0665       0.89996     1.0
  102.9698      0.90761     1.0
  107.8732      0.91526     1.0
  112.7765      0.92291     1.0
  117.6798      0.93056     1.0
  122.5831      0.93821     1.0
  127.4865      0.94586     1.0
  132.3898      0.95351     1.0
  137.2931      0.96116     1.0
  142.1964      0.96881     1.0
  147.0998      0.97646     1.0
  152.0031      0.98410     1.0
  156.9064      0.99175     1.0
  161.8097      1.00705     1.0
```