DATA AND FEASIBILITY DESIGN FOR UNDERGROUND GAS STORAGE SYSTEM

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May, 2009

DATA AND FEASIBILITY DESIGN FOR UNDERGROUND GAS STORAGE SYSTEMS

A dissertation submitted in partial fulfillment of the requirements for the Degree of Bachelor of Technology

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This is to certify that the work contained in this dissertation titled **"Data and feasibility design of Underground Gas storage system"** has been carried out by **Purvi Indras** and **Ankit Srivastava,** under my supervision and has not been submitted elsewhere for a degree.

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This is to certify that **Ms. Purvi Indras, B.Tech. (Applied Petroleum Engineering II)** of University of Petroleum And Energy Studies, Dehradun-248110, has successfully completed her project work on – ***"Underground Gas Storage"*** in Chemical Tracer Laboratory at **INSTITUTE OF RESERVOIR STUDIES, OIL AND NATURAL GAS CORPORATION LIMITED, Chandkheda Campus, Ahmedabad-380005**.

Ms. Purvi Indras has been involved in the project work including analytical work to the best of her ability and as per our satisfaction.

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Acknowledgment

First and foremost, we are thankful to **University of Petroleum & Energy Studies** for giving us opportunity to carry out our major project on **"Data and feasibility design for Underground storage system"**.

We are indebted to, **Dr. B.P. Pandey (Dean Emeritus, College of Engineering)**, for his constant support and guidance during this study. We would like to express our sincere gratitude for his patience and encouragement throughout this work, without which this work would not have been possible.

We take immense pleasure in thanking **Prof. P. H. Rose** who has been a source of inspiration and for her timely guidance in the conduct of our project work. Her contributions are infused throughout this report.

I the undersigned take an opportunity to express my gratitude and sincere thanks to **Mr. K P. Dhingia, Chief Manager (Reservoir), Institute of Reservoir Studies, Chandkheda, Ahmedabad** for providing excellent facilities to carry out the activities for completion of the Project work on 'Use of Inter-well Gas tracer techniques for Understanding Flow Behavior in Underground Gas Storage System'.

We are extremely grateful to the entire **UPES faculty** for their significant contribution to my academic and intellectual development.

At last we would like to thank all of our colleagues for making our stay at UPES memorable.

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ABSTRACT

Underground storage reservoirs provide energy to various markets during the times when the demand exceeds the supply from the pipelines. Some underground storage reservoirs are designed and operated to provide seasonal gas to designated and predictably constant markets. They are called "base load" types of reservoirs. Others are designed to respond only to extreme demand for gas. The economic use of natural gas for space heating in some regions requires the storage of gas near the market in summer and the production of that gas during the winter. This situation exists because the principal supply of gas is produced at considerable distance from a major portion of the space heating market, and it is uneconomical to build long pipelines with sufficient capacity to meet peak loads in winter Underground porous formations necessarily contain some fluid, water, gas, oil or combinations thereof. The pore space per unit of rock volume may be limited as in shale comprising caprock - or it may be substantial as in productive zones. Pressure changes in the reservoir gas phase create pressure gradients in the aquifer water phase, causing water movement. Water entering the space originally occupied by gas influences the pressure of the gas phase for a given amount of gas in place. Study of gas reservoir pressures or of quantities of gas in place must depend upon calculations of water movement. This report points out in more detail the need for understanding water movement, the nature of aquifers, and the practical significance of the study. To make reservoir calculations, it is necessary to have information on the properties of the fluids and the character of the porous beds. The pressure at the gas-water contact is required for water movement calculations. A calculation procedure for predicting the performance of water drive gas reservoirs without the usual assumptions of simplified, idealized geometry and homogeneity is presented in this report.

At the later part of the study is aimed at understanding the use of Interwell Tracers in Understanding the flow behavior of the injected gas in the reservoir.

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List of Abbreviations Used

a	constant in gas compressibility factor correlation, z = a + bP
A	area; cm_2, ft_2 or thick sand parameter
A_{mn}	coefficients
B	constant in gas compressibility factor correlation, z = a + bP, $(psia)_{-1}$
B_n	term used in calculating pressures defined under appropriate equation in Chapter 5
C	compressibility of fluid, vol/(vol)(psi) term used in calculating pressures defined under appropriate equation in Chapter 5
C_n	term used in calculating pressures
D_n	defined under appropriate equation in Chapter 5
e	2.718, base of natural logarithm
e_w	water influx rate, f t $_3$/day
Ei	exponential integral
En	term used in calculating pressures defined under appropriate
f, F	fraction of circle open to flow
f_g	fractional flow of gas
f_g'	$df_g(s)/dS$
F_{PV}	supercompressibility factors
g	acceleration due to gravity
g_c	Standard acceleration due to gravity
G	Gas gravity
G_P	Gas produced
h	Aquifer thickness
h'	Thickness of cap rock, ft

h "	distance from top of aquifer to bottom of well bore completed in porous zone within cap rock
H	depth of well, feet
H	H+h'/h
K'	permeability of cap rock, millidarcys

CHAPTER- 1

INTRODUCTION

Chapter 1

INTRODUCTION TO UGS SYSTEM

1.1 Introduction:

Introduction to the field of Underground Storage must start with the definition of the process:

"*Underground storage is the uniquely efficient process that matches the constant supply (of natural gas) from long-distance pipelines to the variable demand of markets, which are subject to weather, for engineering and economic advantage.*"

Storage reservoirs are unique warehouses developed to provide a ready supply of gas in times of peak demand permitting pipelines to operate at or near their design capacity despite or daily fluctuations which occur in energy consumption. During the summer, when the pipeline capacity exceeds the market demand, the natural gas is injected into the underground storage reservoirs. During the periods in winter when market demands exceed pipeline supply, the gas is withdrawn from the underground storage fields to supplement the throughput from pipelines. In underground environment, the gas is stored either in porous

Underground storage projects operate on planned time horizons which generally exceed 25 to 30 years. During their operating life, the storage reservoirs become subject to losses of gas which reduce their inventory below values carried on the books. Reconciliation of the inventory physically residing in the storage horizon with the book values carried by gas accounting becomes important for economic as well as technical reasons.

Uncontrolled movement of gas away from the storage horizon not only represents decrease in amount and value of a cash flow producing asset; but, it creates a decrease in deliverability of gas to markets as well. The gas escaping from the storage field also may cause environmental and safety problems. Losses from storage reservoirs directly affect the verification of inventory and assurance of deliverability. That is why the inventory audits represent an indispensible component of any storage operation.

1.2 Performance Attributes

Evaluation of the performance of underground storage reservoirs involves recognition of three basic requirements called *performance attributes*. These are:

- Verification of inventory,
- Assurance of deliverability,
- Containment against migration.

The *inventory* represents the gas residing in the storage horizon. It is made up of two parts:

- Base gas(or cushion gas)
- Top gas(or working gas)

The base gas, part of which is physically or economically unrecoverable, remains in the storage horizon to provide the pressure energy necessary for withdrawal of top gas. The top gas, which is withdrawn and sold to markets during winter is replenished through injection every summer.

The deliverability, measured in terms of millions of standard cubic feet per day, is a storage attribute which relates to the ability of the storage field to deliver the gas to its dedicated market. It critically depends on the equalized pressure prevailing underground. Since the pressure is a function of the amount of gas in the storage container, it simply follows the deliverability is a function of inventory. If the container does not hold the gas, it becomes subject to the attrition of its inventory through the migration of the gas.

Contained in the environment of the storage reservoir under positive pressure, and, lighter than other fluids sharing the pore space, the storage gas tends to migrate. Many factor can contribute to movement of gas away from the storage horizon. The pressure gradients, permeability of rock, integrity if cap rock, geometry, fractures, faults, geological features, operating conditions and equipment limits are among many such factors.

For the purpose of this introduction, it should suffice to recognize and discern two kind of storage losses:

- Major losses across reservoir limits,
- Minor losses sometimes called seepage losses.

The major losses may be due to caprock failure, unstable fingering, excessive over-pressure or other factors. There are diagnostic means of their detection as well as prognostic means for their remedy. The methodology used involves reservoir engineering, computer simulation, real time monitoring, and periodic inventory audits.

The minor, but usually continuing, losses occur due to various causes. Casing collar leaks, faulty mechanical joints, corrosion pin holes, imperfect cement bonds, seepage from Christmas trees, venting, flaring, pipeline leaks, accidental blow-outs, are among some usually cited. Seepage losses are sometimes too small to detect on annual or bi-annual surveys. Their cumulative effect, however, can be ascertained quantitatively through periodic inventory audits.

The present methods for periodic inventory audits may be listed as:

- Volumetric method through shut in pressure surveys,
- Use of reservoir inventory-pressure data,
- Graphical analysis of pressure-content plots.

1. The *volumetric method* involves integrating pressures over gas-filled pore volumes using estimates or calculations of expansion factors, sub-surface geometry, porosity, pressure transient analysis, and geostatic. They provide calculations of gas-in-place which is compared to the book inventory to provide a cumulative loss or ineffective gas pressure by difference.
2. The use of *reservoir performance data* permits calculation of the inventory from stabilized pseudo-pressure before and after injection seasons and the measured gas quantities. The industry standards call for the use of ΔQ equation and modified ΔQ equation respectively for constant volume reservoirs and those subject to partial or full water drive conditions. Quite often, computer simulation, unsteady state or semi-steady state, water drive calculations become necessary for reliable determination of inventory.
3. *Graphic analysis* of pressure content data involves continual tracking of pseudo-pressure against the content in p/z vs. I quadrant.

CHAPTER- 2

CONCEPT OF INVENTORY

Chapter 2

Concepts of Inventory

2.1 Introduction

Underground storage reservoirs provide energy to various markets during the times when the demand exceeds the supply from the pipelines. Some underground storage reservoirs are designed and operated to provide seasonal gas to designated and predictably constant markets. They are called "base load" types of reservoirs. Others are designed to respond only to extreme demand for gas. They are called "peak shaving" reservoirs. For example, Honor Rancho, in California is a "base load" reservoir; Playa del Rey, also in California is a "peak shaving" reservoir. They fulfil different roles in markets served by the Southern California Gas Company.

There are three basic requirements called performance attributes in the operation of underground storage reservoirs. These are:

- Verification of inventory,
- Assurance of deliverability
- Containment against migration.

The top gas or working gas in the storage field is the amount sold to the market at times of demand. In underground storage reservoirs, the working gas shares the storage horizon with base gas, more commonly referred to as cushion gas. While both are constituted of identical molecules, their role and nature are quite different in storage. The working gas is regularly bought and sold while the cushion gas constantly resides in the reservoir and provides the pressure necessary to deliver the working gas.Since working gas and cushion gas perform different functions, they must receive separate treatment and attention in engineering work and economic evaluation. That is why it becomes important to clearly categorize different classes of gas volumes in storage and to subdivide each class as necessary.

2.2 Methodology in Categorizing Classes of Gas Volumes in Storage

2.2.1 Total Volume in Storage

The total volume in storage relates to the total amount of natural gas in the storage field at any particular time. The total quantity of gas changes from a minimum value after

withdrawal to a maximum value after injection. It represents the sum total of native gas, injected cushion gas, and regularly injected and withdrawn working gas.
The total volume in storage is calculated from shut-in pressure surveys or the pressure content performance of the field using volumetric and thermodynamic equations.

2.2.2 The Working Gas (Top Gas)

The working gas, sometimes called top gas, varies by necessity from season to season depending upon the weather. For each reservoir it is a quantity determined by demand. Its upper limit, or maximum value, is determined by the maximum pressure designed for the storage reservoir. Technical considerations of caprock integrity, threshold pressure, depth and geometric spillpoints are usually the factors which determine the maximum pressure to be carried on any underground storage reservoir.

The amount of working gas is determined algebraically by the gas metered in and out of the storage reservoir. In the early stages of design and development of storage reservoirs, this quantity is estimated by engineering calculations and computer simulation of expected reservoir performance. Later, when the storage development matures into a full grown, steady-state operation, the working gas is best determined by actually producing the storage reservoir to the limits of its capability. In unusually cold winters, special season end tests are occasionally conducted to determine the true working gas volume as nearly as possible. The amount of the working inventory which can be produced during each withdrawal operation depends upon the compression, dehydration, pipeline, and other facilities at the surface.

2.2.3 The Cushion Gas

The cushion gas, by virtue of its presence in the storage reservoir, provides the pressure necessary for the deliverability of working gas to the market. The cushion gas has two components:

- Recoverable cushion gas
- Non-recoverable cushion gas

The part of the cushion gas which is physically recoverable is left unproduced during the storage operations for two reasons:

1. Each storage reservoir is designed for a minimum rate of deliverability to meet its market demand. That deliverability requires a certain minimum pressure level to be available during either the peak or last day of the withdrawal season.

2. With the equipment available and designed to match the characteristics of the storage reservoirs to the market

Due to the characteristics of surface equipment and the nature of most storage reservoirs. it's possible to withdraw some limited amount of cushion gas when necessary after all of the working gas is produced. Such practice, however, is only resorted to under exceptional and justified circumstances.

A certain portion of the cushion gas in each storage reservoir is totally unrecoverable for physical reasons. In reservoirs subject to water drive, i.e. the part of the cushion gas i.e. dispersed in such small quantities to remain totally immobile. In most producing gas reservoirs approximately 10% of maximum inventory is considered physically unrecoverable at surface pressure level called abandonment pressure. Recovery of gas at pressure lower than this pressure would involve such extremely expensive and unfeasible equipment that some consider it practically unrecoverable

CHAPTER- 3

GAS STORAGE IN AQUIFERS

Chapter 3

GAS STORAGE IN AQUIFERS

3.1 Introduction

Underground porous formations necessarily contain some fluid, water, gas, oil or combinations thereof. The pore space per unit of rock volume may be limited as in shale comprising caprock - or it may be substantial as in productive zones. Pressure changes in the reservoir gas phase create pressure gradients in the aquifer water phase, causing water movement. Water entering the space originally occupied by gas influences the pressure of the gas phase for a given amount of gas in place. Any study of gas reservoir pressures or of quantities of gas in place must depend upon calculations of water movement. This chapter will point out in more detail the need for understanding water movement, the nature of aquifers, and the practical significance of the study.

3.2 Need for Study of Water Movement in Gas Storage Operations

The economic use of natural gas for space heating in some regions requires the storage of gas near the market in summer and the production of that gas during the winter. This situation exists because the principal supply of gas is produced at considerable distance from a major portion of the space heating market, and it is uneconomical to build long pipelines with sufficient capacity to meet peak loads in winter. Since many distributing companies and pipeline systems depend upon underground storage for a substantial part of their send-out on a cold winter day, considerable engineering and managerial effort goes into handling storage matters.

Because of this dependence on stored gas, it is natural that careful studies are now made on gas storage fields. The operator is asked to predict the seasonal storage capacity and field deliverability for winter operation. How much gas can a storage field deliver to market on the last day of February with available compressors? How much gas can be stored in the field next summer? How much gas do you lose in underground storage? These are the questions which have provided the incentive to study underground storage operations.

The testing of gas well flow capacity and the plotting of pressure decline curves during gas production were early techniques borrowed from gas production operations for use in storage projects. The concept of water drive as a reservoir mechanism has been recognized by the oil industry since the study made on the East Texas Oil Field. Any attempt to extend the techniques established for oil or gas production to the operation of gas storage fields indicates differences in applicability, mainly due to the special nature of storage operations.

The usual storage field is equipped to produce at rates so that its working storage gas content can be produced in 30 to 120 days. Although gas producing fields may have excess flow capacity, they seldom produce their reserve in less than five full years and more likely in 12 to 18 years. Well spacing in storage fields may be 20 to 40 acres, as compared to 160 or 640 acres for production. Field pressure declines of 20 pounds per square inch per day are quite normal in storage; such rates might be considered excessive in production. Gas storage operations present a much more variable pressure-time schedule than naturally producing reservoirs because of the injection of gas in summer and withdrawal in winter. Approximate methods of predicting water movement suitable for gas producing fields are not adequate for gas storage fields because of the cyclic nature of the reservoir pressures.

The recent advent of aquifer storage is, perhaps, the most prominent example where the information on the rate of water movement is required. In aquifer storage, the pore volume necessary for the storage of gas is created by expulsion of water from its native formation by pressurization above the initial discovery level. Initial. Evaluation of a possible aquifer storage project depends upon calculation of the rate at which gas can be injected to develop the gas bubble. The gas injection rate depends on the rate at which water may be moved within the aquifer. Likewise, estimates of gas withdrawal during winter are dependent upon calculated rates of water return and the resultant gas reservoir pressure.

In early gas storage practice, gas was injected into old gas fields to raise the pressure. The level of pressure seldom reached the initial discovery value. Discovery pressure in many instances corresponds to the hydrostatic pressure. This occurrence of petroleum and water in underground strata at hydrostatic pressure is a verification of the concept that the pore space in the earth's crust is filled with water unless oil or gases are present. In recent years, gas reservoir pressures have been raised in storage fields above the initial or hydrostatic values, a practice described as "over pressuring". The use of these higher pressures has increased the capacity of storage fields significantly. Calculations of water movement become important in predicting the effect of time at the overpressure condition on the growth of the gas bubble. Verification of gas inventory in such fields requires knowledge of water movement. Investigations of overpressure effects on water movement in the research supported by the Michigan Gas Association developed quantitative methods for handling the cyclic pressure schedule.

This research was initiated to bring together the knowledge required to predict water movement in gas storage operations. The goal was to develop calculation procedures which could be utilized directly by engineers in charge of the operation of storage fields.

3.3 Nature of Aquifers

An aquifer is a water-filled blanket zone or layer of underground porous rock extending for distances measured in miles. The study of the nature of aquifers is appropriate and essential to understanding the movement of water in contact with natural gas. The aquifer rock is permeable enough so that water will move through the porous matrix at a significant rate when it is subjected to a pressure gradient. Figure 3-l from Hubbert (24) shows how water can flow underground due to effects of gravity. The aquifer in Figure 1-1 takes in water at the outcrop up dip and the water moves toward an outcrop down dip. In this case, the water in the aquifer will be fresh, at least near the intake, and may be potable throughout the extent of the blanket sand.

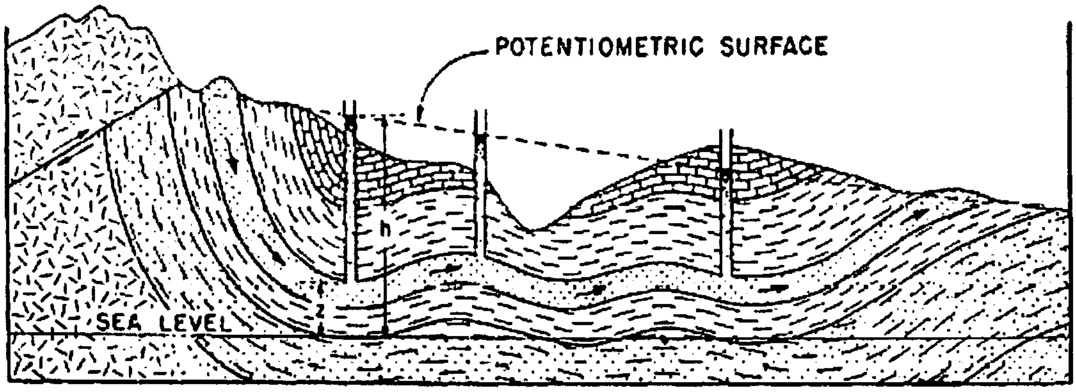


Figure 3.1 Regional flow of water through Sand from Higher to Lower Outercrop. (Hubbert, Courtesy AAPG)

A study of the Woodbine aquifer supplying water to the East Texas Oil Field shows that pressure gradients may extend to distances of 100 miles. The Woodbine aquifer, Figure 3-2, on the other hand, has no outlet for water and therefore contains the sea water prevalent at the time when it was buried by the overburden. Thus the nature of water in blanket sands may vary in character from essentially fresh water to nearly saturated brines, all depending upon the geological history and communication with the surface through one or more outcrops.

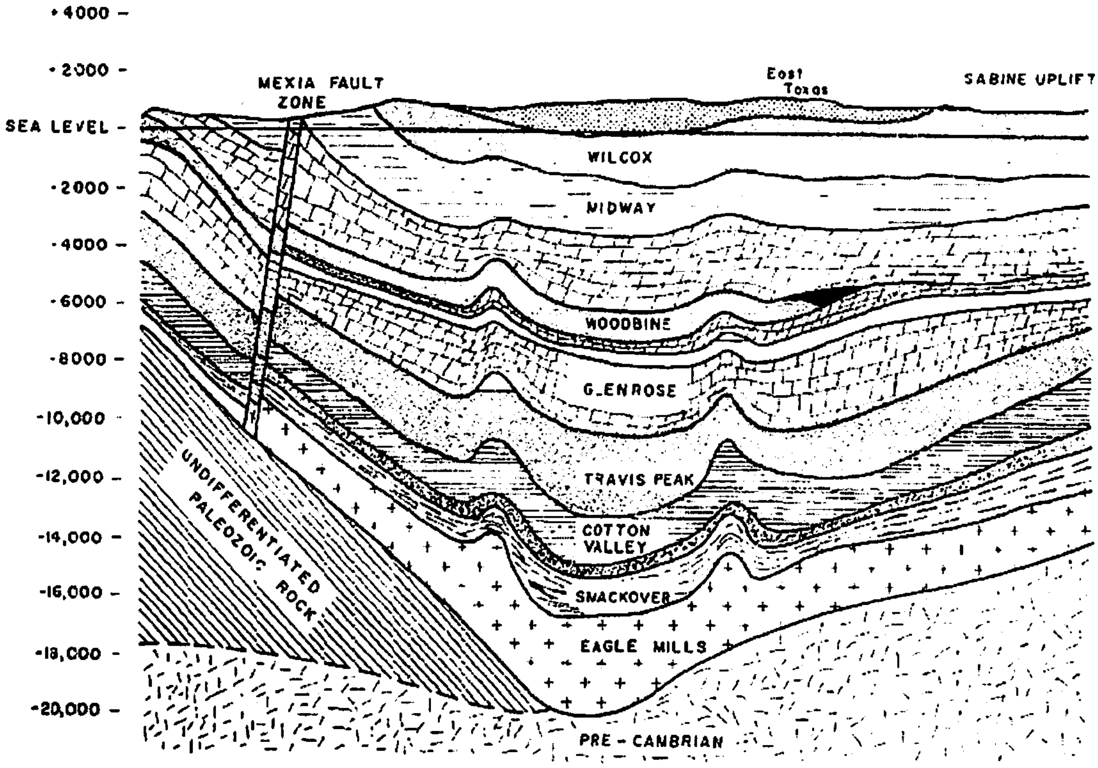


Figure 3.2 Cross Section East Texas Basin , East- West Section(Bell & Shepherd)

The Marshall sandstone of Mississippian age covers much of Central Michigan, and is considered to be an aquifer. While the permeability is not high enough to permit rapid water movement, pressure gradients have been observed in this sand over a distance of miles. The water in the Marshall formation contains a high concentration of salt, approaching saturation. The stray sand gas fields in Central Michigan are used for gas storage as shown in Figure 3-3.

Brine movement takes place during storage cycles, but seldom changes the volume of the gas reservoir by more than one to three per cent per year, even when the reservoir pressure is held for long periods either at low pressures or at some reasonable overpressure.

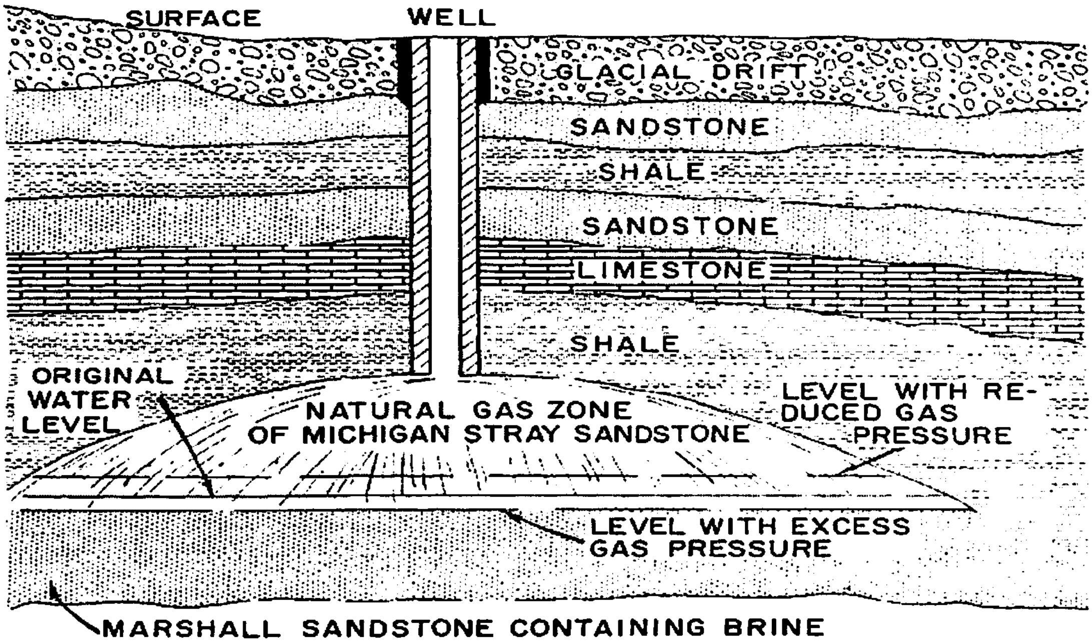


Figure 3.3 Water Level Changes in Michigan Stray Sand during gas Storage.

Water Movement in aquifers may be demonstrated by considering the behavior of a group of wells completed in a shallow aquifer used as a source for potable water, Figure 3-4. The diagram illustrates the water levels in adjacent wells when one of the wells is produced. Water production lowers the pressure or head around the well bore and water flows towards the supply well because it is at a lower pressure than the water in the sand some distance away.

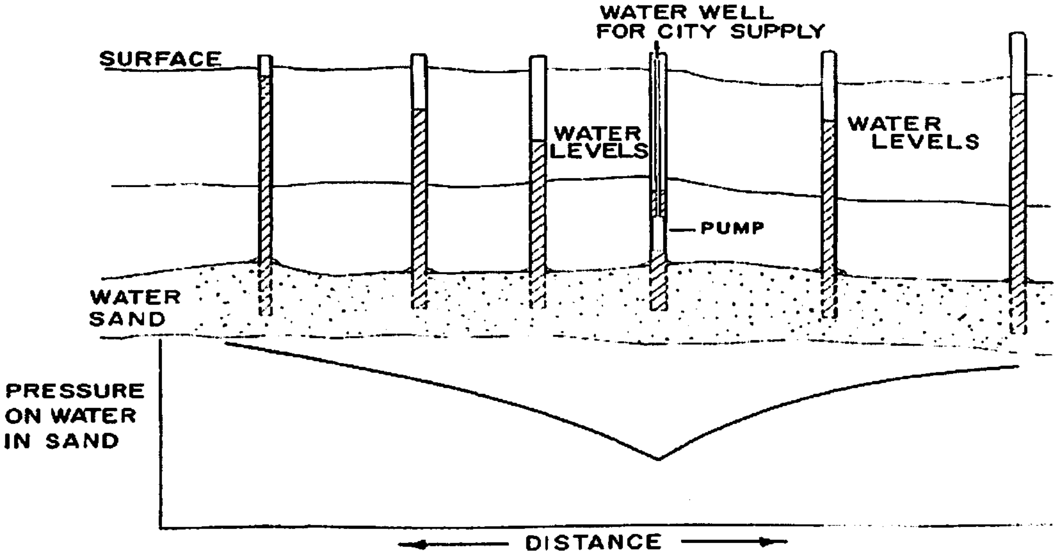


Figure 3.4 Water Level in Wells as a Measurement of Pressure.

Consider now a growing gas bubble in an aquifer gas storage project. Figure 3-5. Gas is injected rapidly enough to hold the gas bubble at a pressure ΔP above the initial aquifer pressure. Water flows away from the gas bubble, causing it to expand.

The pressure in the surrounding sand is raised as indicated at various successive times, t1, t2, t3 etc. When water flows out from the gas bubble, where does it go? It simply compresses the water ahead of it. Since such movement is in a radial direction away from the bubble, there is an increasing quantity of water associated with successive increments of radial distance.

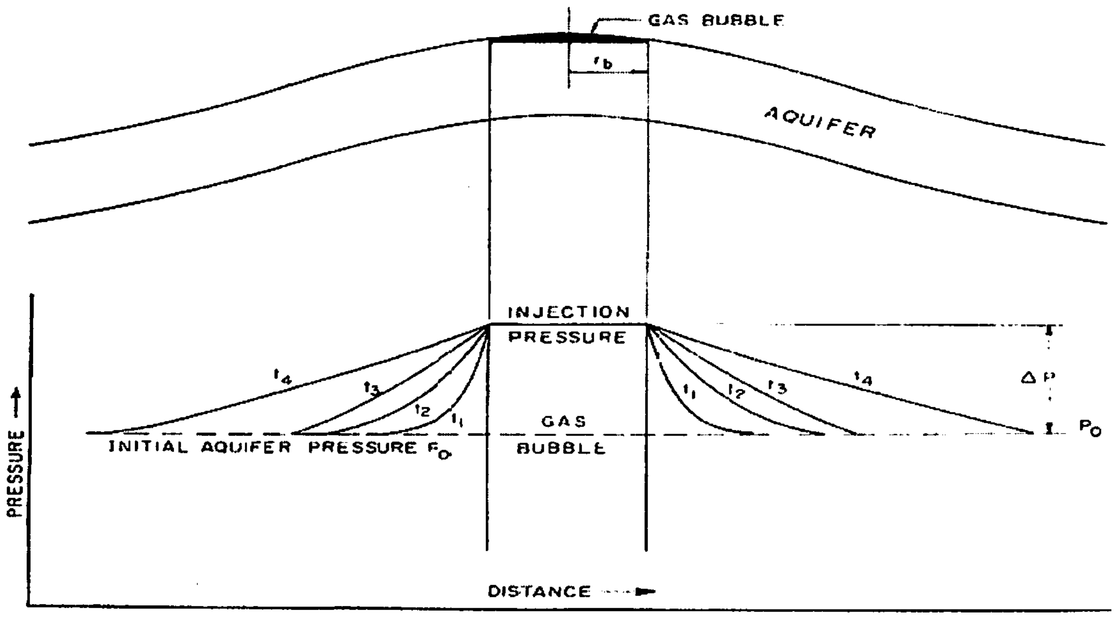


Figure 3.5 Effects of Time on the Pressure Distribution in Aquifers

Water is among the least compressible of liquids. However, for every pound per square inch rise on a million cubic feet of water, the million cubic feet will shrink by some 3.0 cubic feet. Thus the water compressibility is said to be 3.0 x 10-6(volumes)/(volume)(psi). Figure 3-6 shows the compressibility of pure water. The compressibility of water varies with mineral content and dissolved gases.

When porous sand containing water is subjected to pressure rise through water pressure, the combined compression of the water and the rock is approximately twice that of pure water. Therefore, if the above million cubic feet of water were contained in porous sandstone of about 20 per cent porosity, a pressure rise of one pound per square inch would shrink the composite sand-water system by about seven cubic feet.

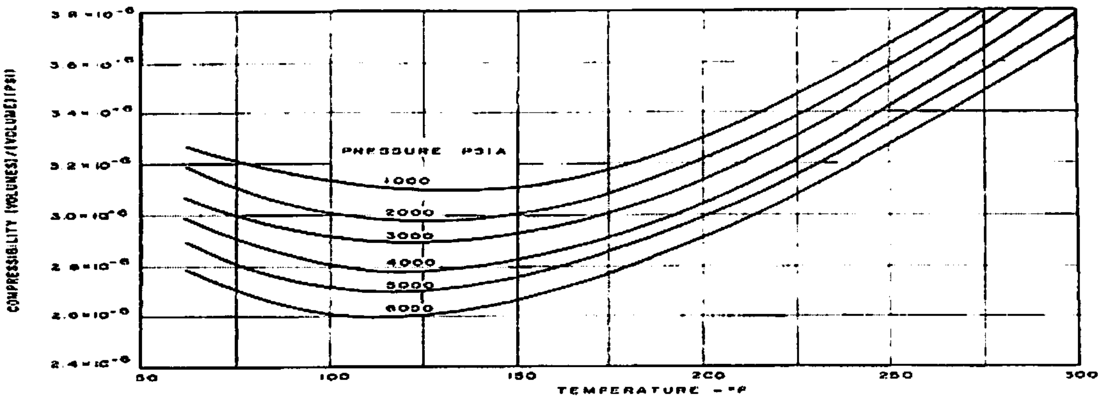


Figure 3.6 Compressibility of Water

Figure 3-7 shows a section of an aquifer limited by pinch out in one direction and change into shale in the other. The volume of the gas reservoir might be five per cent of the total sand volume. When gas pressure changes, water movement will take place, but to a limited extent. Water movement caused by a pressure change of 1000 pounds per square inch on a gas bubble occupying five per cent of the total pore space in a limited aquifer could not change the volume of the bubble by more than 13 per cent.

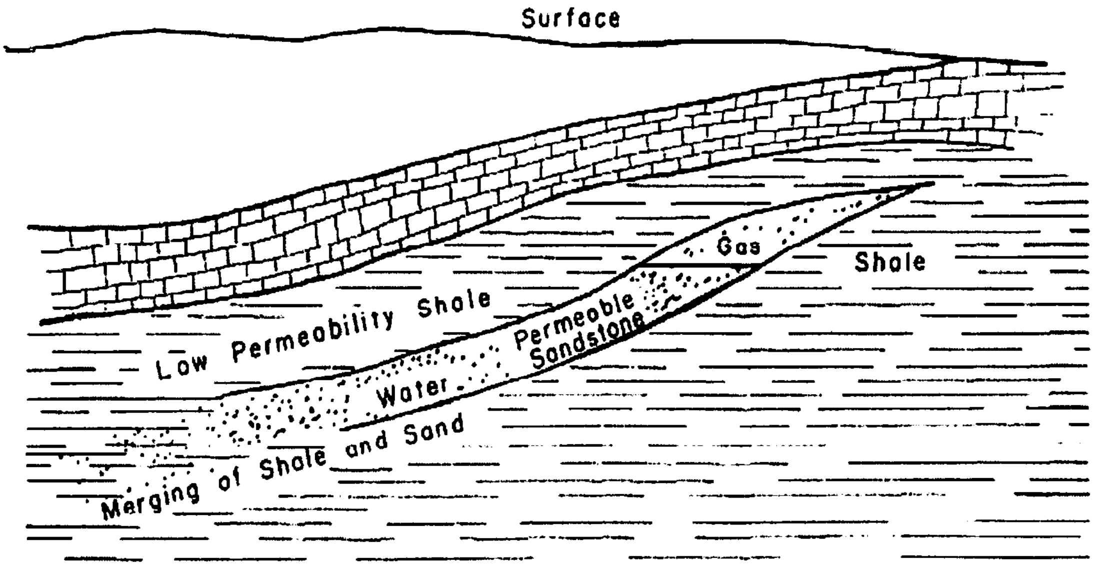


Figure 3.7 Section of Limited Aquifer.

A limited aquifer may be described as a closed system. Typical examples of such systems are found in the Ellenburger formation of West Texas and among the sand lenses of the Illinois basis. Water movement into or out of a gas field situated on an aquifer may be restricted due to the limited size of the water bearing sand or due to the low permeability of the blanket sand. The Marshall sand in Michigan, Figure 3-3, permits only relatively small quantities of water movement in a given gas injection or withdrawal season due to the low permeability of the sand.

Water movement in an aquifer has been discussed without considering the nature of the caprock confining the gas to the more permeable rock. Caprock is a low permeability and low porosity layer, normally consisting of shale, limestone, or dolomite. It may have porosity from two to eight per cent and a permeability of 10-4 to less than 10-6 millidarcy. However, this permeability is far too great for holding gas if water were not present in the pores of the caprock.

The Threshold Pressure for gas to displace water from low permeability caprock core is a measurement which may be made to evaluate caprocks. The permeability of the caprock core may be 10-5 millidarcy and water will flow through such a core very slowly under a pressure differential. However, if gas is brought to the face of the water saturated core, the flow will stop if the pressure differential is below the threshold pressure for gas to displace water.

Threshold pressures of 100 to 500 pounds per square inch or more often are required for gas to displace water from caprock cores with permeabilities of 10_{-4} to 10_{-6} millidarcy. Thus the water in the caprock blocks the movement of gas and retains it in the reservoir. Figure 3-8 illustrates the water-gas contact at the top of the gas bearing zone and at the base of the water bearing caprock.

When a gas reservoir or aquifer is discovered at hydrostatic pressure, then the pressures in the caprock and in the porous aquifer formation would be in balance. However, when gas is injected in an aquifer storage project, overpressure is required which in turn places a pressure gradient across the caprock greater than the normal hydrostatic gradient. This overpressure must not exceed the threshold pressure for gas to displace water from the caprock, for then gas would gradually permeate the caprock, dry it out, and start gas leakage. It should be noted that all caprock leakage found to date is believed to be due to imperfections or discontinuities in the caprock and not due to threshold displacement from relatively uniform caprock.

Low permeability rocks surrounding gas bubbles of normal gas fields are not limited to the cap, but may also form the sides of the gas reservoir through transition from sand to shale. Such gas reservoirs are described as sand lens or stratographic traps. In such cases, not only is the top of the sand zone bounded by low permeability rock, but also the sides and even the bottom. Horizontal water movement then would be similar to that described for vertical movement at the interface between the porous sand and the caprock. Turn

Figure 3-8 on its side in visualizing the restraint which impervious rock places on gas and water movement.

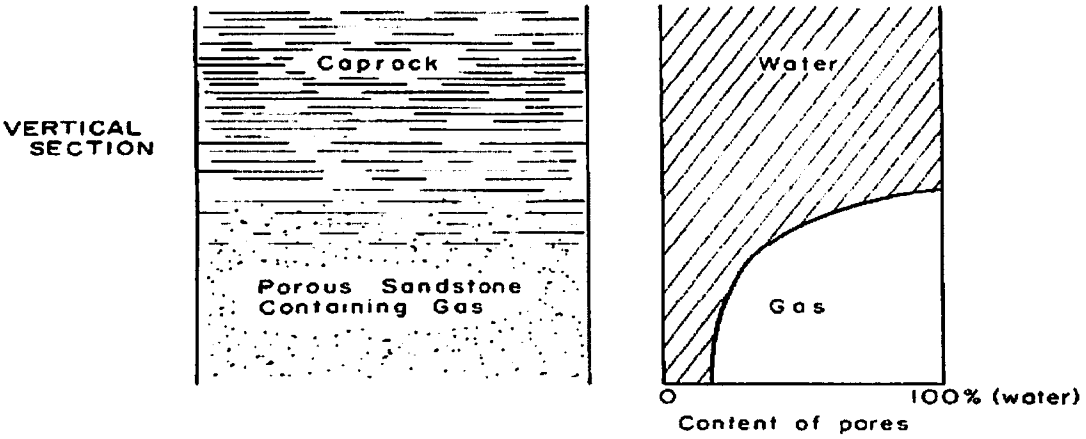


Figure 3-8 The Water-gas Contact at the Base of the Caprock.

3.4 Significance of the Study

Experience with gas storage operations has shown that consideration of water movement results in greatly increased accuracy in prediction of pressure and gas in place. It can be maintained that three specific break-throughs of considerable significance were made when:

(1) Pressurization of gas reservoirs above discovery pressure was adopted for gas storage fields.

(2) Design procedures were developed for predicting the development rates of aquifer storage projects.

(3)The effect and extent of water movement were ascertained on a quantitative basis for predicting the production-pressure behavior of storage reservoirs subject to cyclic pressure changes.

The use of overpressure and seasonal cyclic operations received little attention in oil and gas production research because they are not part of normal producing operations. It is quite fitting that the gas storage industry should sponsor developments in these areas where they have specific applications. With the growing reliance on storage gas for meeting heavy winter loads, the gas industry is placing more emphasis on accurate predictions of the storage capacity of a reservoir during a summer period, upon the deliverability of gas in winter, and on assurance that injected gas is present in the storage reservoir.

All gas storage in aquifers must take place under overpressure conditions, unless the water is removed through wells. Initial injection of gas into water well, as depicted in Figure 3-4, requires a gas pressure equal to the reservoir pressure just to displace the water from the well bore. Extra pressure is needed to cause the gas to enter the porous bed and force water back, thus providing space for the injected gas. Upon gas withdrawal, the gas bubble pressure declines and water begins to return into the gas space.

For aquifer storage reservoirs, the concept of maintaining gas reservoir pressure above initial aquifer pressure during injection and withdrawing gas at pressures lower than original aquifer pressure is now generally accepted. The pressure of the gas reservoir in a developing aquifer storage field is illustrated in Figure 3-9. The same procedure of using overpressure can be followed for depleted gas or oil reservoirs, recognizing that in the period of overpressure, water may be pushed outward to enlarge the gas bubble.

Depleted oil fields subject to water drive may be used for gas storage. In studies of oil fields in which water drive is the principal mechanism of production, the extent of water influx into the field must be known before a material balance may be completed to predict oil in place. Likewise, the behavior of the aquifer feeding the oil field must be determined if a prediction is to be made to the effect of gas injection on reservoir pressure.

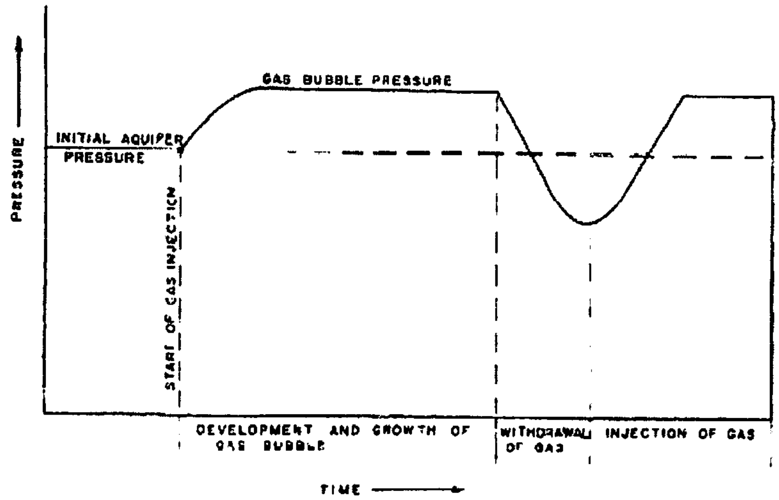


Figure 3-9 Relation of Gas Bubble and Initial Aquifer Pressures

When two or more oil, gas or storage reservoirs are situated adjacent to the same aquifer, the interference which one field may cause in the behavior of the aquifer toward a second field requires an understanding of water movement.

The calculations of water movement are all of the unsteady state type in which time must be considered as a variable. Since solutions to unsteady state flow equations are available only for the cases of constant pressure difference or for constant rate of water movement, it is necessary to simplify the pressure-time curve into a series of constant pressure steps. Likewise the variable rate curve may be viewed as a succession of constant rate steps. For gas storage operations with rapidly changing pressures, the use of electronic computers becomes desirable in order to handle a large number of calculations with high speed and accuracy.

The techniques used in the analysis of storage reservoirs subject to water drive were improved when reliable equations and methods for predicting the water movement were developed. Such calculation procedures permit better understanding of the water movement and result in more accurate methods for predicting the volumetric behavior of storage reservoirs.

More specifically, these calculations give information on the following:

1. The reservoir pressure for a specified schedule of gas injection and gas withdrawal on a storage field. The reservoir pressure is needed to predict flowing pressures on gas wells and for calculating compression requirements.

2. The quantity of water moving into or out of a gas bubble. This information is required in determining gas inventory in storage fields, and gives the permissible overpressure schedule corresponding to a desired growth rate.

3. In aquifer storage projects, the time required to develop the storage bubble. A clear understanding of the water movement as related to the bubble growth pattern provides a sound basis for selecting the optimum rates for injection and withdrawal schedules.

4. Accurate determination of inventory gas which in turn reflects the gas loss, should it occur.

5. The effect of water movement around one reservoir which may influence water pressures around a second reservoir. This interference may be handled by a joint calculation for the two reservoirs.

Auxiliary calculations to assist in handling aquifer storage reservoirs include pumping tests to determine in situ properties of the rock and aquifer pressure gradient calculations which assist in locating the boundary of the gas bubble.

This chapter outlines procedures by which water movement calculations may be made for various types of reservoirs under a variety of conditions. Refinement of the methods set forth, along with a thorough plan for gathering field data should provide the quantitative knowledge desired in efficient operation of a specific gas storage field. Since this Monograph represents only a small portion of the larger field of reservoir engineering, it is recommended that those readers not generally familiar with the oil and gas production industry consult established references, such as books by Muskat (44)(45), Pirson (50), Calhoun (4), Craft and Hawkins (10), Katz et al (35), etc.

3.5 System Calculations

In this age of computers, engineers and managers desire to find computation procedures for predicting the operation of their gas delivery system. Calculation procedures for handling pipe line flow, compression requirements, and well deliverability have been developed. To these calculations one can now add reservoir performance including water movement, thus completing the methods required for predicting the total system performance.

Figure 3-10 shows a simple system with a pipeline supply, a market and a storage facility close to the market. The steps in computing some critical quantity, such as horsepower requirements for storage are given on the figure. Similar calculations could be made to determine the delivery pressure at the market for a fixed horsepower in the compression station at the storage field. For reservoirs which exhibit significant water movement, this chapter of the report provides ways of completing the system calculation.

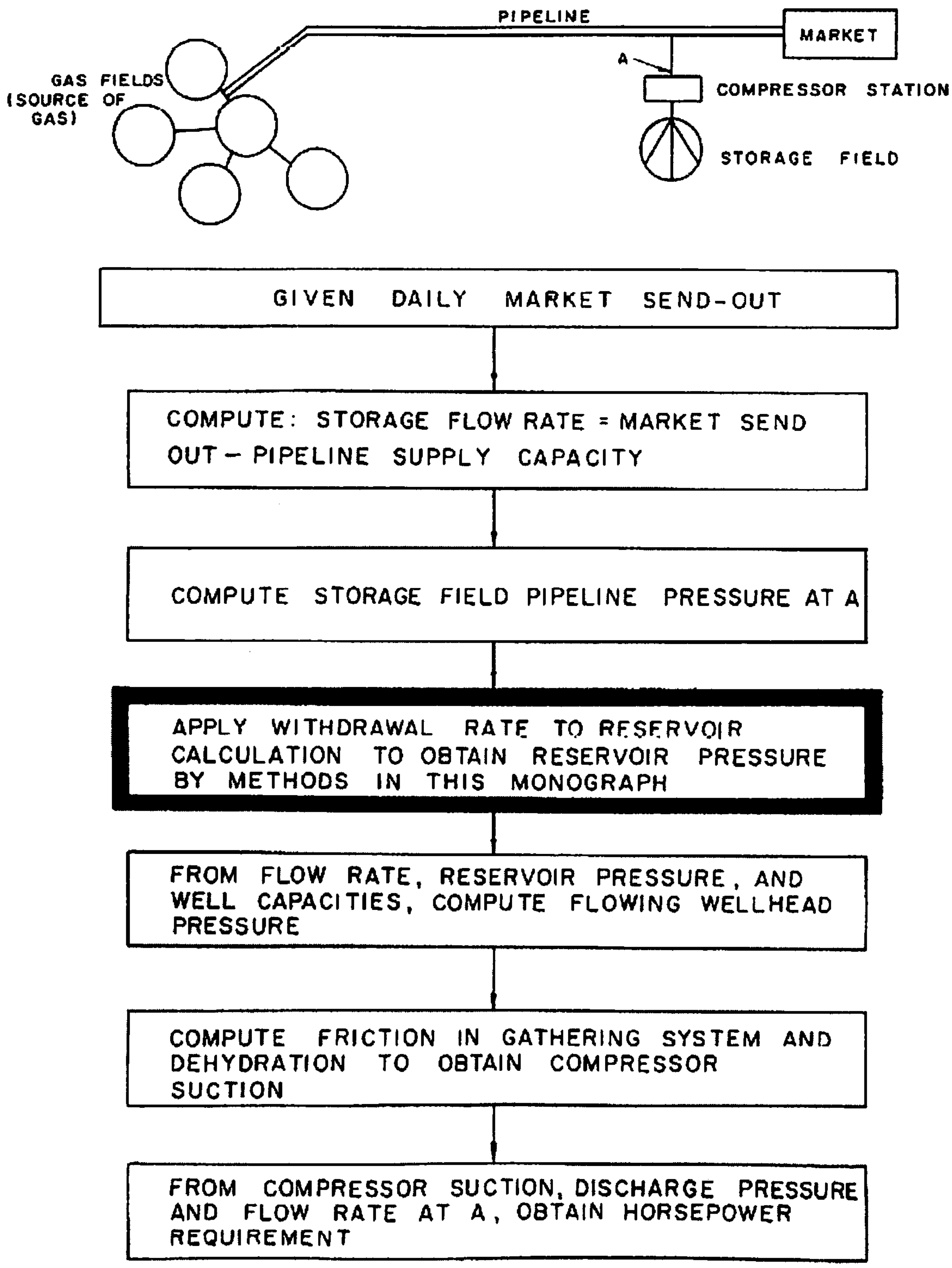


Figure 3-10 Application of Water Movement Calculations in Predicting Performance of Gas Supply-Pipeline-Storage System.

CHAPTER- 4

DATA REQUIRED FOR FIELD CALCULATIONS

Chapter 4

DATA REQUIRED FOR FIELD CALCULATIONS

To make reservoir calculations, it is necessary to have information on the properties of the fluids and the character of the porous beds. The pressure at the gas-water contact is required for water movement calculations. The usual procedure in obtaining this pressure is to use gas well pressures as the basic data. Generally the gas bubble is assumed to be at a weighted average pressure considered uniform throughout the gas phase. The production-pressure history of a gas field provides the first approximation of the gas pore volume. This initial gas pore volume may be used along with gas production or injection data to calculate changes in pressure which would be caused solely by the production or injection of gas if the pore volume were constant.

4.1 Fluid Properties

The density of natural gas is used to convert metered quantities of gas to volumes in the reservoir. Calculation of bottom-hole pressures from well head pressures also employs gas densities. The customary method of expressing the density of the gas is the gas law involving the compressibility factor:

$$pV = ZnRT \qquad (4.1)$$

Where p = pressure, psia
V = volume of n moles of gas at pressure, p, and temperature, T, cubic feet
Z = compressibility factor, dimensionless
n = pound moles of gas
R = gas constant =10.73
T = temperature, °R = °F + 460
In case it is desired to use an expression for the volume of gas, then V in cubic feet per pound at T and p becomes

$$V=\frac{ZnRT}{P}=\frac{ZnRT}{29\,G_p} \qquad (4.2)$$

where G = gas gravity = molecular weight/29. At 14.7 pounds per square inch absolute and 60°F, one pound mole of an ideal gas has a volume of 379 cubic feet. The compressibility factor is often expressed as a function of temperature, pressure and gas gravity in chart form. Fig. 4-1 is the compressibility factor for natural gas of 0.6 gravity, containing no more than minor concentrations of carbon dioxide, nitrogen, or other nonhydrocarbons. The American Gas Association report on gas measurement provides tables of super compressibility factors, F_{PV}, which are equal to t $(1/z)^{0.5}$.

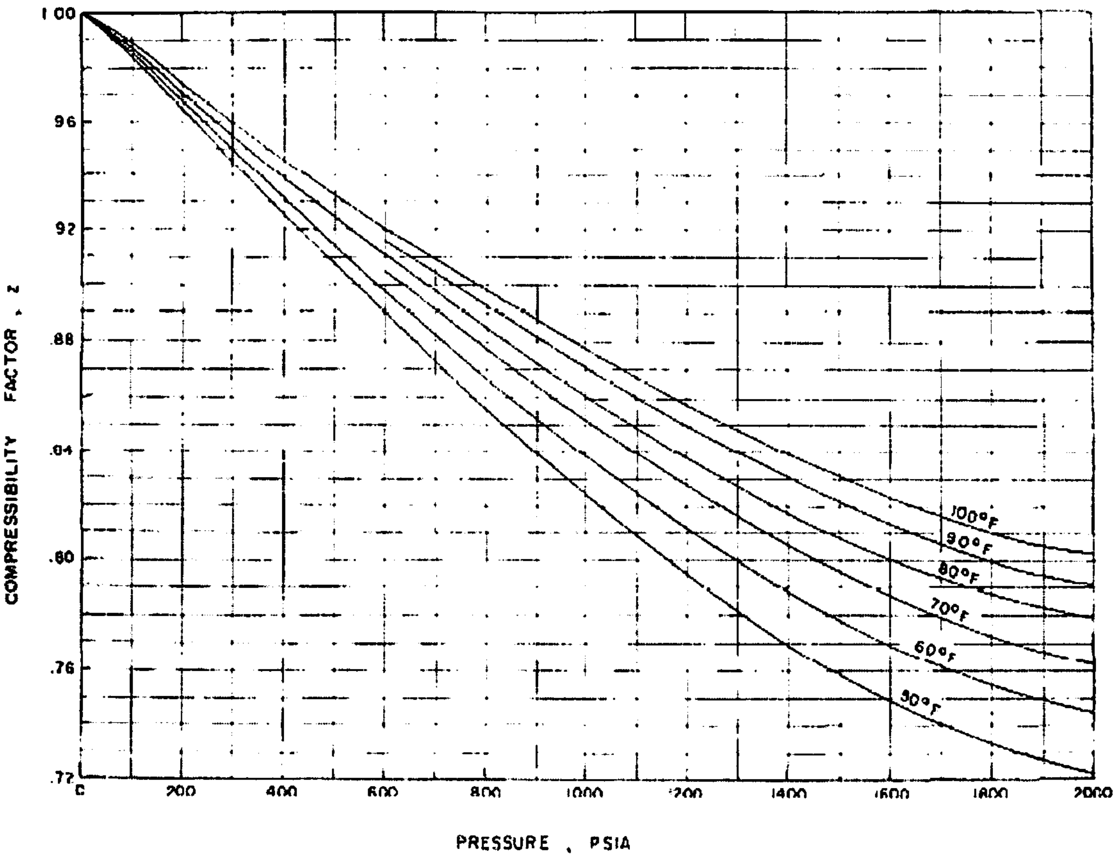


Figure 4-1 Compressibility Factors of 0.6 Gravity Natural Gas.

4.2 Reservoir Properties

The dimensions and character of reservoir rock vary from field to field and normally are measured for each case. The porosity and permeability are obtained by routine analyses on cores. In addition to permeability data on cores, well tests may be used to obtain insitu permeabilities.

The method for calculating the permeability from pump tests on an aquifer. For methods of determining rock permeability from gas well flow in steady state or from pressure draw-down or pressure build-up data. Permeabilities calculated from such well tests are normally more representative of the formation than these from cores.

Rock compressibility has been measured by finding the combined compressibility of water and rock in the laboratory. By calculating the effect of water compressibility on such a measurement, effective compressibility of the rock alone was determined as shown by Figure 4-4 from Hall. To obtain the composite compressibility of the rock-water system, the effective compressibility of the rock should be added to that of the water or brine contained therein. Insitu compressibilities of the rock-water system may be measured by pump tests. Connate water is present in gas reservoirs and occupies part of the pore space.

It may be estimated from capillary pressure measurements. Figure 4-5 presents a curve of connate water content versus capillary pressure for sands. Figure 4-6 presents curves of connate water versus permeability for typical rock.

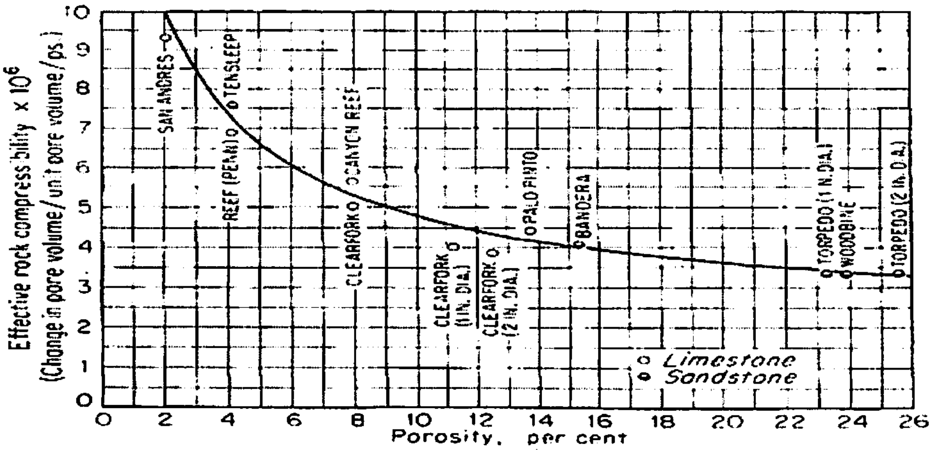


Figure 4-2 Effective Reservoir-Rock Compressibility. (Hall)(17)(Courtesy AIME)

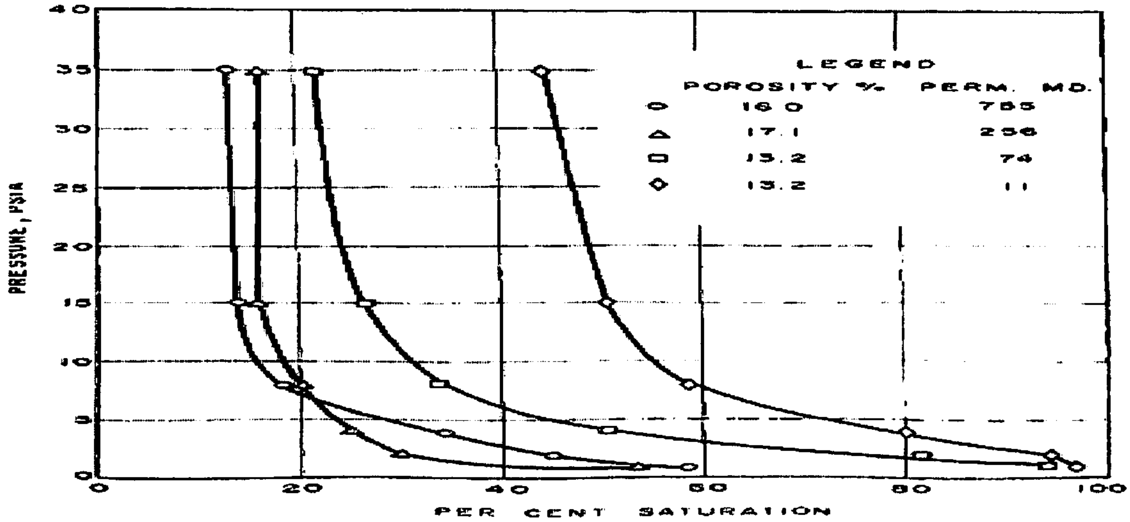


Figure 4-3 Capillary Pressure Curves for Sands.

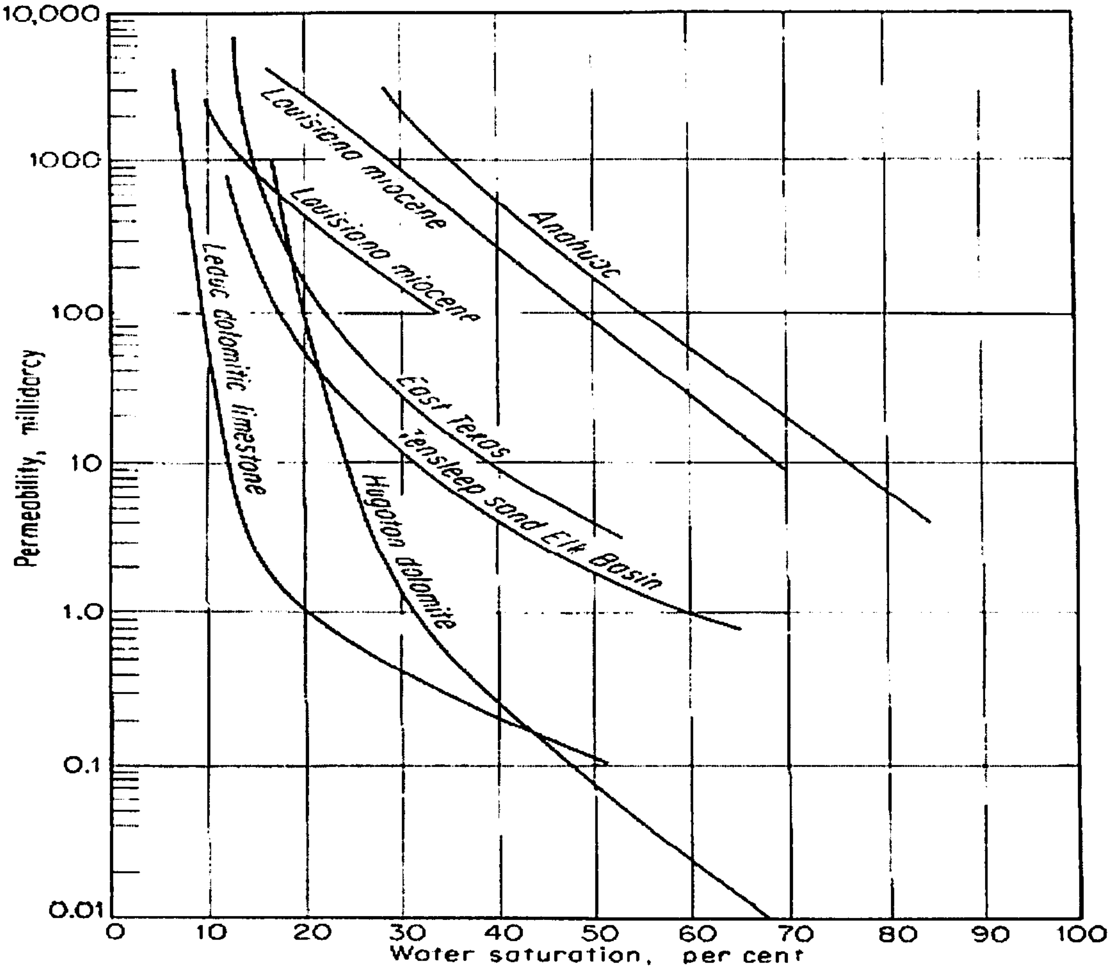


Figure 4-4 Connate-Water Curves for Typical Rock. (Katz et al.)(Courtesy McGraw-Hill Book Company)

4.2.1 Geology of the Gas Bubble and Aquifer

The geometry of the gas bubble is used together with data on porosity and connate water to find the volume of the gas sand and the pore volume containing gas. The geometry is also needed for comparison of the gas bubble with the model of the aquifer-gas system, for which the bubble radius (r_b of Figure 4-3) must be determined. Since the gas bubble is assumed to have a uniform pressure, its radius should be an average value for the area through which gas pressure is transmitted effectively. The radius (r_b) is used as the radius of a circle whose area is equal to that of the gas zone. Alternately, the volume of the gas reservoir may be considered as a cylinder with the average gas zone thickness used as the height of the cylinder and (r_b) used as the cylinder radius:

$$r_b = \sqrt{\frac{V_r}{\pi h}} = \sqrt{\frac{V_i}{\pi h \phi_g}} \qquad \text{(4.3)}$$

Where,
r_b = radius of bubble, feet
V_r = gas reservoir volume, cubic feet
V_i = net gas pore volume in the reservoir, cubic feet
h = average gas zone thickness, feet
ø_g = fractional porosity containing gas

The thickness of the aquifer is needed for determination of the dimensions of the model representing the gas-water system. This information is accumulated from core data and logs for wells drilled in the area. Geologists and petroleum engineers are familiar with the preparation of isopachous maps. Abundant data are normally available on the gas reservoir thickness. It should be emphasized that not only is the formation thickness at the gas reservoir of interest, but also the surrounding aquifer at distances of ten miles or more from the gas bubble. For reservoirs which have operating gas-injection or withdrawal-pressure data, the geometry and reservoir characteristics are required only for the first approximation of water movement.

4.2.2 Reservoir Temperature

The reservoir temperature is usually measured by a recording or maximum thermometer. Ground temperature at 100 feet from the surface is approximately equal to the mean average annual atmospheric temperature, and hence varies with the locality. Many temperature-depth relationships are represented by straight lines starting at the 100 foot value. A temperature-depth line should be determined for each storage project.

4.2.3 Gas Reservoir Pressure

The pressure at the interface between the gas bubble and the aquifer is normally taken as the average gas bubble pressure. Likewise, the volume occupied in the reservoir by a given quantity of gas is computed from the reservoir temperature and an average reservoir pressure.

For high permeability reservoirs, the gas bubble pressure may be uniform within +0.5 per cent and there is little problem in arriving at an average reservoir pressure. For low-permeability reservoirs or those with a high permeability in the center and low permeability on the edges, much effort is required to compute an acceptable average gas bubble pressure.

4.2.3.1 Calculation of Reservoir Pressure from Well Head Pressure

Gas field pressures are often reported from measurements at the well head. A calculation may be made to obtain the bottom hole or reservoir pressure from the well head pressure data. The relationship between the bottom-hole pressure and the well head pressure is given by

$$p = (p_{wh} + 14.7)\, e^{\frac{0.01877\, GH}{T_a z_a}} \qquad \text{...} (4.4)$$

Where,

P = bottom hole pressure, psia
P_{wh} = well head pressure, psig
T = average well bore temperature, oR = oF + 460
z = compressibility factor at the average well bore temperature and pressure
G = gas gravity
H = depth of well, feet
e = base of natural logarithm, e = 2.718

For shallow gas storage fields at pressures below 1000 pounds per square inch, the difference between the average well bore pressure and the well head pressure is nominal with regard to determining the compressibility factor. The trial-and-error feature of Equation 4-9 can be eliminated for these low pressures by using the compressibility factor at the well head pressure and mean well bore temperature, both of which are known.

4.2.4 Pressure Observation Wells

Gas storage fields often have static pressure observation wells which remain closed-in during the injection and production periods. Such wells are used to observe the static gas bubble pressure. They usually are chosen because of their location and relatively low flow capacity.

For rapid changes in reservoir pressures, observation wells are needed to follow the gas bubble pressure.

In the absence of pressure observation wells, one or more production-injection wells should be shut in at regular intervals until the pressure at the well bore equalizes with that in the gas bubble. Often the entire field is closed-in at the end of the injection season and again at the end of the withdrawal season for a period of three to ten days, with daily pressure observations on all wells. Although the latter procedure provides only two reservoir pressures per year, it is better to have two good points for use in water movement calculations than several non-representative ones.

4.2.5 Low Permeability or Non-Uniform Reservoirs

In addition to the paucity of reliable pressure data, a second problem frequently arises in determining the true average gas reservoir pressure. The permeability of the gas-bearing formation may be so low that severe pressure gradients occur in the reservoir during most of the year, with high pressures around the wells during and after injection and low pressures during and after withdrawal.

Variations in permeability often occur within the reservoir, with the center having a high permeability and the outer areas a low permeability. Methods for predicting the pressure behavior have been developed based on models involving high and low permeability for various parts of the reservoir.

One method of obtaining the average reservoir pressure at the end of a shut-in period is to contour the field for pressure and weight the pressures according to the sand volume or pore space represented by each segment of the reservoir.

Fortunately, the rate of water movement is low in aquifers when their permeability is low. In general, it follows that for those reservoirs for which there is uncertainty in the gas bubble pressure because of low permeability, the water movement rate is relatively small and thus less significant in predicting gas reservoir pressures for future injection-production schedules.

4.2.6 Initial Gas Pore Volume

When geological data permit, the initial gas phase pore volume should be determined from isopachous maps, porosity, and connate water. The initial pore volume may also be computed from gas production and reservoir pressure data by a material balance.

Writing of the gas law Equation 4-1 at the initial time and at some later period when the cumulative production and reservoir pressure are known gives an expression for V_o, the pore volume of the reservoir if it remains unchanged.

$$n_o = \frac{p_o V_o}{z_o R T_o}$$

$$n_2 = \frac{p_2 V_2}{z_2 R T_2} \quad \text{.......... (4.5)}$$

Subtracting above two Equations and solving for V_o. with the assumption that $V_2 = V_o$ and $T_o = T_2$.

$$V_o = \frac{(n_o - n_2) R T_o}{\frac{p_o}{z_o} - \frac{p_2}{z_2}} \quad \text{.......... (4.6)}$$

The decrease in moles of gas ($n_o - n_2$) is calculated from gas production (G) in terms of standard P cubic feet measured at T_{base} and P_{base}.

$$n_o - n_2 = \frac{G_p p_{base}}{R T_{base}} \quad \text{.......... (4.7)}$$

In field units R = 10.73.

On Substitution of above Equation

$$V_o = \frac{G_p p_{base} T_o}{T_{base}\left(\frac{p_o}{z_o} - \frac{p_2}{z_2}\right)} \quad \text{.......... (4.8)}$$

A simple solution to this equation is obtained by plotting the cumulative gas production G versus p/z and determining V_o. from the slope of the line.

$$V_o = \frac{p_{base} T_o}{T_{base}} \frac{G_p}{(p_o/z_o - p_2/z_2)} = \frac{m p_{base} T_o}{T_{base}} \quad \text{.......... (4.9)}$$

Where m = minus reciprocal slope of p/z line versus G_p standard cubic feet per pounds per square inch.

Figure 4-7 is a plot of cumulative gas production (G_p) versus the ratio of the reservoir pressure to the compressibility factor (1 /z) for Field X. Physically, m in Equation 4-15, is obtained by reading the values of two points on the straight line as follows:

The value of V_o is 316 million cubic feet of space. A word of caution is given about using the physical slope of the line without regard to scales.

$$m = \frac{G_{p_2} - G_{p_1}}{\frac{p_1}{z_1} - \frac{p_2}{z_2}} \qquad \text{..........(4.10)}$$

For Figure 4-7, the value of m is

$$\frac{7.0 \times 10^9 - 0}{610 - 280} = 21 \times 10^6 \text{ SCF/psi} \qquad \text{..........(4.11)}$$

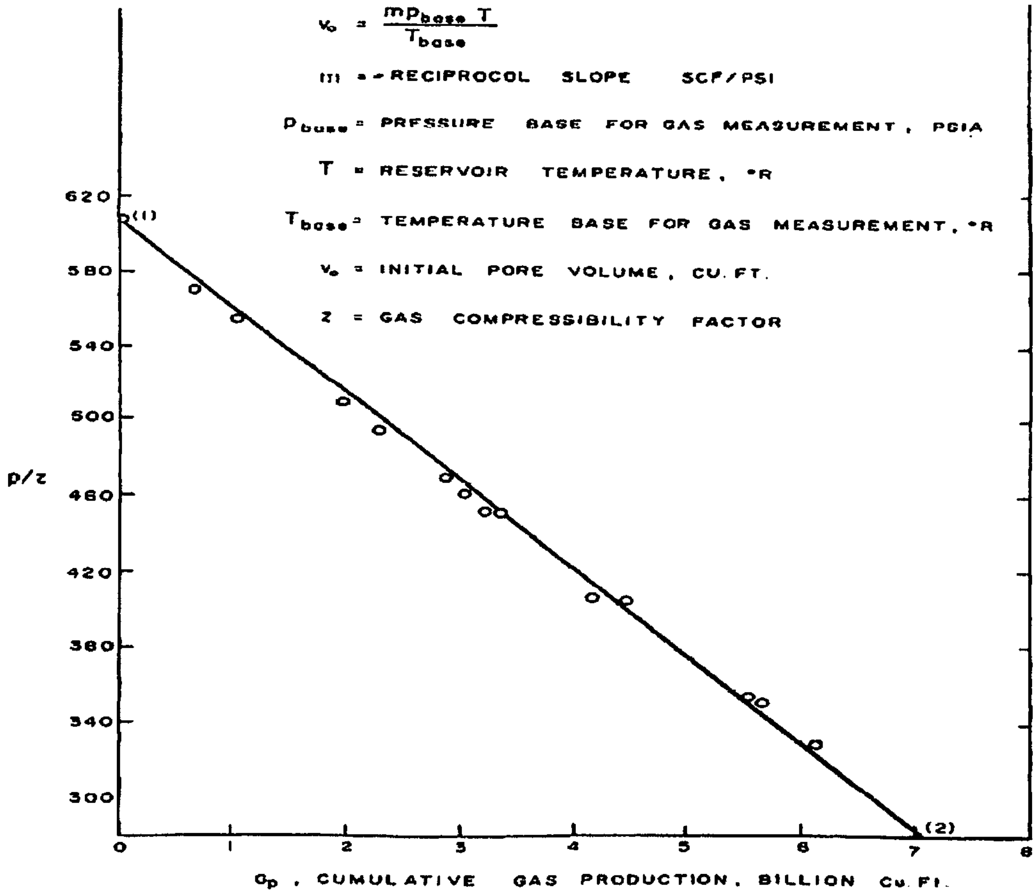


Figure 4-7 Determination of Initial Pore Volume of Field X from p/z Versus G Plot

CHAPTER- 5

GENERALIZED METHOD FOR PERFORMANCE CALCULATION FROM FIELD DATA

Chapter 5

GENERALIZED METHOD FOR PERFORMANCE CALCULATION FROM FIELD DATA

A calculation procedure for predicting the performance of water drive gas reservoirs without the usual assumptions of simplified, idealized geometry and homogeneity is presented in this chapter. Solutions of the diffusivity equation governing the movement of water in aquifers have been given in earlier chapters for various geometric configurations of reservoir-aquifer systems. These solutions are all based on some simplifying assumptions which idealize the considered field model to some extent. Assumption of uniform formation properties, a gas bubble of constant volume and fixed geometry for the system are typical of those needed for developing analytical solutions for the flow equations. Actual characteristics of aquifers encountered in production or storage operations, however, are often far from those described by various models.

The edge of the gas bubble is not perfectly circular, for example. In many instances this interface between the gas and water may not be accurately approximated by either a linear or a radial geometry. The presence of communicating or non-communicating faults, heterogeneities such as local variations of porosity and permeability, anisotropy (directional variations of properties), the fact that the edge of the gas bubble is never at a fixed location, and other factors may prevent the actual field problem from being accurately represented by one of the geometric models treated earlier. Under these circumstances it becomes quite desirable to develop a characteristic function which will adequately represent the past behavior and accurately predict the future performance of a particular field.

The purpose of this chapter is to present a method for developing such a characteristic function for a field using production-pressure data obtained from that field. The method is a modification of the "resistance function" concept formulated by Hutchinson and Sikora. Hicks, Weber and Ledbetter presented a related treatment using both analog and digital computers.

The use of the method is limited to instances in which field data are available. It is not useful, for example, in predicting the performance of an aquifer storage project before gas injection is initiated. In cases such as this, where no field data are available, a geometric model must be used.

5.1 Steps for Calculating the Field Performance

To use the resistance function gas bubble pressures corresponding to gas injection or withdrawal quantities, at least 15 to 30 monthly time periods are needed. The three major steps in using the resistance function technique are the approximation with models at early times, the fit with field data, and the extrapolation to future times, as shown on Figure 6-2. These stages will be considered in the order in which they are used.

Given:

Geological data for a gas-aquifer system and the pressure-injection or withdrawal quantities at corresponding times. Should the production-injection data be available at odd times, it is necessary to prepare a table of pressures(p) and corresponding cumulative gas withdrawal quantities (G_p) at uniformly spaced times of 0, Δt, $2\Delta t$, $3\Delta t$, . . .

1. Pick a plausible model (radial, thick sand, linear, or hemispherical).

2. Estimate V_o, the original pore space. This estimate may be made from isopach maps or from plots of p/Z versus cumulative production.

3. Calculate K_r and t_D corresponding to the model using values from Table 5-1 for n = 1, 2... m. It is recommended to go to m = 10 if possible.

4. Calculate all the values of the variable S_n defined as n_nRT for n = 1, 2 . . . i.

$$S_n = n_n RT = \frac{V_o}{\left(\frac{a}{p_n} + b\right)} - \frac{p_{base} T}{T_{base}} G_{p_n} \quad \text{...(5.1)}$$

Where in field units:

V_o = initial pore volume occupied by the gas, cubic feet

a and b are constants for the linear approximation of gas compressibility factor with pressure $z = a + bp$.

a is dimensionless while b has the dimensions of 1/pressure

p_{base} = base pressure, psia

R = gas law constant

n_n = pound-moles of gas-in-place at time $t = n\Delta t$

T = reservoir temperature °R, 460 + °F

T_{base} = base temperature °R, 460 + °F

G_{p_n} cumulative gas production, cubic feet measured at T_{base} and p_{base} at the time $t = n\Delta t$

Δt = time interval

n = a particular time interval

5. From values of t_D(or for linear model), obtain the values for each time step for

For radial model: $t_D = \frac{0.00633Kt}{\mu\phi c r_b^2}$ P_t from Appendix A, C, or E

For linear model $\theta = \frac{0.00633Kt}{\mu\phi c}$ compute P_t as $\sqrt{\theta}$

For thick sand model $t_D = \frac{0.00633Kt}{\mu\phi c r_b^2}$ P_t from Appendix I

For hemispherical model $t_D = \frac{0.00633Kt}{2}$ P_t from Equation 2-21

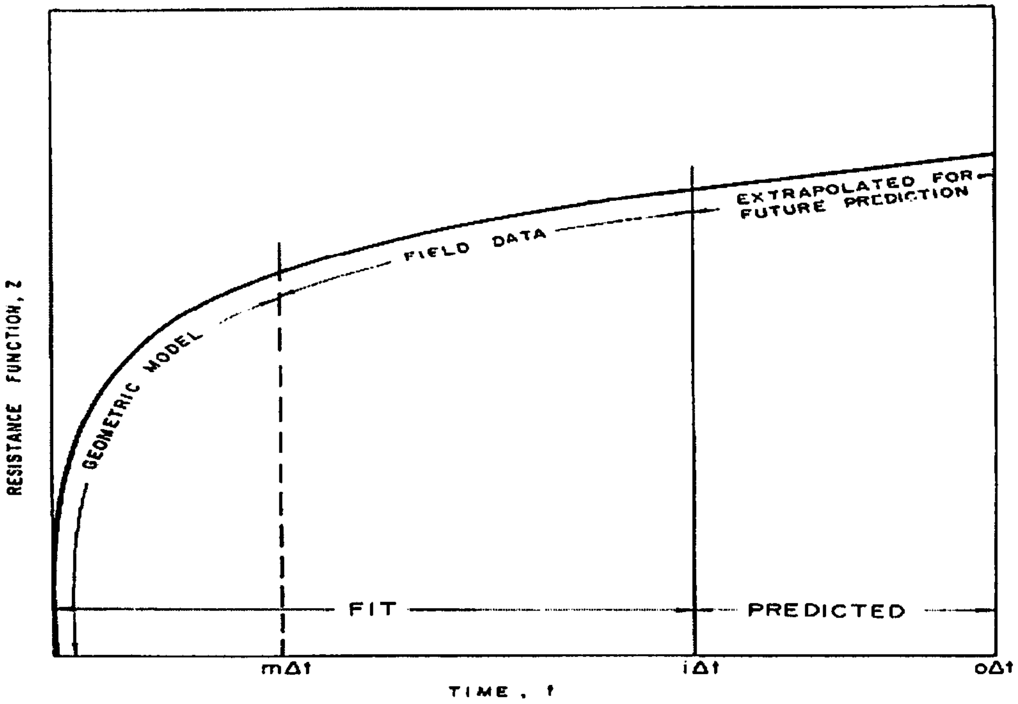


Figure 5.1 The Resistance Function Curve.

6. Compute

$$\Delta P_{t_n} = P_{t_n} - P_{t_{n-1}} \quad \text{.......} \quad (5.2)$$

7. Compute p_1, setting n = 1 in Equation 5-2 which corresponds to the gas-water contact pressure at the end of the first time step t_1

$$p_1 = B_1 + \sqrt{B_1^2 + C_1} \qquad \text{.......................................(5.3)}$$

Where

$$B_1 = -\frac{1}{2}\left\{\left[\left(\frac{a}{p_o} + b\right) S_o - bS_1\right]\frac{K_r}{\Delta t}\,\Delta P_{t_1} - p_o\right\}$$

$$C_1 = \frac{aS_1 K_r P_{t_1}}{\Delta t}$$

8. Compute w1 from

$$e_{w_1} = \frac{p_o - p_1}{K_r \Delta P_{t_1}} \qquad \text{....................................... (5.4)}$$

9. Compute P_n, in indicated sequence for n = 2, 3 . . . m from Equations (5.5) and 5.6

$$p_n = B_n + \sqrt{B_n^2 + C_n} \qquad \text{.......................................(5.5)}$$

Where

$$B_n = -\frac{1}{2}\left\{\left[\left(\frac{a}{p_{n-1}} + b\right) S_{n-1} - bS_n\right]\frac{K_r}{\Delta t}\,\Delta P_{t_1} - p_o + K_r \sum_{j=2}^{n} e_{w_{n-j+1}} \Delta P_{t_j}\right\}$$

$$C_n = \frac{aS_n K_r P_{t_1}}{\Delta t}$$

$$e_{w_n} = \left(p_o - p_n - K_r \sum_{j=2}^{n} e_{w_{n-j+1}} \Delta P_{t_j}\right) \Big/ K_r \Delta P_{t_1}$$

10. Compare the calculated pressures with the observed pressures on the gas bubble, expressed as a sum of the absolute value of the deviations. Select a new K_r such as $2K_r$ and repeat calculations above to obtain a new sum of the deviations. Continue selecting K_r's until a minimum occurs in a plot of deviation versus K_r.

11. Compute ΔZ_1, ΔZ_2. . . . . ΔZ_m from:

$$\Delta Z_n = (K_r)_{optimum}\, \Delta P_{t_n} \qquad \text{.......................................(5.7)}$$

12. Compute alternately ΔZ_n, p_n and e_w for n = (m+ 1), (m + 2). . . . . i, where i is the number of last time increment of the remainingn available data. The equation to be used to compute Δ Zn is

$$\Delta Z_n = \frac{1}{e_{w_1}}\left\{p_o^* - p_n^* - \sum_{j=2}^{n-1} e_{w_{n-j+1}}\Delta Z_j + \left(\frac{a}{p_n} - b\right)\frac{S_n \Delta Z_1}{\Delta t} - \left(\frac{a}{p_{n-1}} - b\right)\frac{S_{n-1}\Delta Z_1}{\Delta t}\right\} \qquad \text{........(5.8)}$$

13. Since the initial estimate of V_o obtained from isopach maps or plot of p/z versus cumulative production may be in error, it may be desirable to repeat steps 3 through 12 for different values of the initial pore volume, V_o. The value of V_o which gives the best estimate of the initial pore volume, V_o.

The pressures with asterisks denote field data while the pressures without asterisks are computed pressures. The pressures p_n are computed from:

$$p_n = B_n + \sqrt{B_n^2 + C_n} \qquad \text{..............(5.9)}$$

Where

$$B_n = \frac{1}{2}\left\{\left[\left(\frac{a}{p_{n-1}} + 1\right)S_{n-1} - bS_n\right]\frac{\Delta Z_1}{\Delta t} - p_o^* + \sum_{j=2}^{n} e_{w_{n-j+1}}\Delta Z_j\right\}$$

And

$$C_n = aS_n\Delta Z_1/\Delta t$$

The qua.ntities e_{w_n} should be computed from

$$e_{w_n} = \left(p_o - p_n - \sum_{j=2} e_{w_{n-j+1}}\Delta Z_j\right)\Big/\Delta Z_1$$

5.2 Self Correcting Features of the Computational Procedure:

The ΔZ calculated at each time step is forced to comply with the following restrictions of inequalities:

$$\Delta Z_{n-1}\frac{(n-2)}{(n-1)} \le \Delta Z_n \le \frac{\Delta Z_{n-1}}{(1-\epsilon)}\frac{(n-1)}{(n-2)} \qquad \text{..............(5.10)}$$

The inequalities 5.10 imply that whenever ΔZn calculated from Equation 5.5 is less than the left hand side of the above inequality it is set equal to that left hand side value.

Likewise, if it should exceed the right hand side then it is set equal to the upper bound value represented by the right hand side.

The factor (1- c) is included to relax an otherwise too severe restriction. An = 0.02 has been found to work satisfactorily on the problems solved.

In order to preserve the analogy between the resistance function and the corresponding dimensionless pressure drop curve derived from the solution of the diffusivity equation, the "resistance function" Z must not violate three conditions as pointed out by Hutchinson and Sikora.

These are:

1. $Z(0) = 0$
2. $\frac{dZ}{dt} \geq 0$ for all t
3. $\frac{d^2Z}{dt^2} \leq 0$ for all t

The possibility of an upward-curving resistance function is not eliminated by the restriction imposed by Equation 5.10. In the process of generating the resistance functions if d^2Z/dt^2 appears to come out positive a straight line is drawn (actually computed automatically by a digital computer) from the last point generated such that it is tangent to the previously established portion of the Z curve at some earlier time step. This procedure smoothes the resistance function curve over several time steps whereas Equation 5.10 limits it point wise.

CHAPTER- 6

DEVELOPMENT OF AQUIFER STORAGE FIELDS

Chapter 6

DEVELOPMENT OF AQUIFER STORAGE FIELDS

Much of the engineering development of projects storing gas in water sands involves calculation of the movement of water in contact with natural gas. The evaluation of a potential storage structure involves water movement calculations based on a geometric model. Pump tests may be made prior to gas injection to evaluate the cap rock and determine in-situ permeability and compressibility.

A method is presented for locating the bubble edge at times after the storage reservoir has been developed.

6.1 In-situ Permeability and Compressibility from Pump Tests

Laboratory tests on cores are normally made to determine the matrix permeability of aquifer zones. However, the formation may have a different effective value than that obtained by averaging core data. Fractures not included in test cores will influence the insitu permeability as will other non-uniformities. Pumping tests on a well may be used to obtain the in-situ permeability.

Coincident with this pumping, pressure observations on an adjacent well completed in the aquifer will provide data for computation of the insitu composite compressibility of the water-sand system. Figure 6-1 illustrates the location of wells which may be used in a pump test.

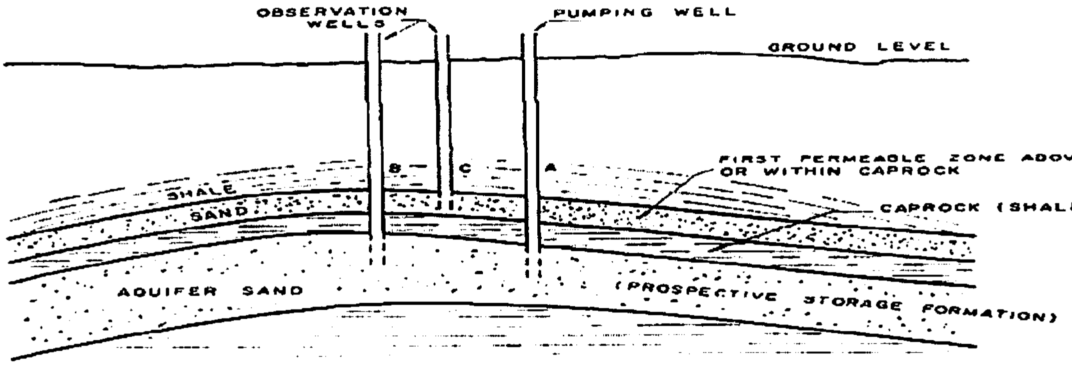


Figure 6-1 Pumping of Water Wells to Obtain Insitu Permeability and Compressibility as Well as Cap Rock Leakage In any pump test the preferred method is to pump at a constant rate. When only a single well is available, the water level in the pumping well is needed to obtain the insitu permeability.

When there is an observation well in addition to the pumping well, both K and c can be obtained without knowing the water level in the pumping well. Table 6-1 lists some of the combinations of data which can be used. The table gives information required to compute K and c from various combinations of data.

Case1. Pump Test on Single Well. (No measurement on well B, Figure 6-1). Drawdown and Build-up Pressures Observed on Pumping Well Only. The insitu permeability and compressibility of an aquifer can be calculated from the drawdown test on a well pumping at a constant rate. The "point source" solution given by Horner in field units is

$$p = p_o + \frac{70.6\, q\mu}{Kh}\, Ei\left\{\frac{-\mu\phi c r_w^2}{4(0.00633)Kt}\right\} \qquad \text{...(6.1)}$$

Where

p_o = initial aquifer pressure, psia -

r_w = well radius, feet

t = time, days

P = pressure at the well bore at time t, psia

= formation porosity, fraction

K = permeability, millidarcys

μ = fluid viscosity, centipoises

C = fluid compressibility, vol/(vol)(psi)

q = water pumping rate, bbl/day

Table 6-1 Variety of Tests for Insitu Permeability and Compressibility

Calculations presented as:	Figure 7-1, Well A (with pump and water level recorder)	Figure 7-1, Well B (with water level recorder)	Computations which can be made
Case I	Pump well, shut-in well, measure rate of pressure build-up	Not used	Unsteady state computation of K
Case II	Pump well, recorder not used	Observe level for drawdown and for build up	Unsteady state computation of K, c
Case III	Pump well, measure rate of pressure draw-down	Observe levels during drawdown	Pseudo steady state computation of K in addition to those of Case I and Case II

The exponential integral function (Ei) is defined as:

$$- Ei(-x) = \int_{x}^{\infty} \frac{e^{-y}}{y} dy \qquad \text{(6.2)}$$

It may be represented by the series:

$$E_i\{-x\} = \ell n\, x + .5772 - x + \frac{x^2}{(2)(2!)} - \frac{x^3}{(3)(3!)} + \ldots (-1)^n \frac{x^n}{(n)(n!)} \qquad \text{(6.3)}$$

If the value of x is small: i. e., less than 0.01, then Ei(-x) can be approximated by:

$$Ei(-x) = \ell n\, x + .5772 \qquad \text{(6.4)}$$

Substitution of Equation 6.3 in Equation 6-1 yields

$$p = p_o + \frac{70.6\, q\mu}{Kh} \left\{ \ell n \left(\frac{\mu \phi c r_w^2}{4(0.00633\, Kt)} \right) + .5772 \right\}$$

$$p = p_o + \frac{162.6\, q\mu}{Kh} \left\{ \log_{10} \left(\frac{\mu \phi c r_w^2}{4(0.00633) Kt} \right) - .2508 \right\}$$

$$p = p_o + \frac{162.6\, q\mu}{Kh} \left\{ \log_{10} \left(\frac{\mu \phi c r_w^2}{0.00633\, Kt} \right) - 0.351 \right\} \qquad \text{(6.5)}$$

If the well is pumped at a constant rate, then a plot of p versus log t will approach a straight line. The slope of this line, pounds per square inch per cycle, is equal to - $\frac{162.6\, q\mu}{Kh}$

If q, μ, and h are known, the insitu permeability can be calculated from the slope. While it may appear that insitu compressibility, c, may also be calculated from these equations, the calculation is so sensitive to errors in measurement of the radius of the well bore, r_w, as to be impractical.

Unfortunately, skin effect at the well can give an erroneous slope on the drawdown curve at early time. Therefore, the pressure build-up curve is usually used to obtain a more accurate value for the permeability. If the total pumping time is designated by t_o and the shut-in time by Δt, the well pressure after shut-in is given by superimposing two solutions of the form of above Equation

$$p = p_o - \frac{162.6\, q\mu}{Kh}\left\{\log_{10}\left(\frac{\mu\phi c r_w^2}{0.00633\, K(t_o + \Delta t)}\right) - 0.3513\right\}$$

$$- \frac{162.6\, q\mu}{Kh}\left\{\log_{10}\left(\frac{\mu\phi c r_w^2}{0.00633\, K\Delta t}\right) - 0.3513\right\}$$

which simplifies to

$$p = p_o - \frac{162.6\, q\mu}{Kh}\ \log_{10}\left\{\frac{t_o + \Delta t}{\Delta t}\right\} \qquad \ldots(6.6)$$

A plot of pressure versus $\log_{10} \frac{t_o + \Delta t}{\Delta t}$ will approach a straight line after the after flow and skin effects of the well damp out. The insitu permeability can be calculated from this slope expressed in pounds per square inch per cycle. The slope is equal to - $\frac{162.6\, q\mu}{Kh}$

Case 2: Pump Test on a Single Well, Drawdown and Build-up Pressures Observed at an Observation Well Only.

The insitu permeability and compressibility of an aquifer can be calculated from the drawdown and build-up pressures at an observation well. In Equation 6-6 r_w is replaced by r, the distance between the pumping well and the observation well. The pressure of the observation well is given by:

$$p = p_o - \frac{162.6\, q\mu}{Kh}\left\{\log_{10}\left(\frac{\mu\phi c r^2}{0.00633\, Kt}\right) - 0.3513\right\} \qquad \ldots\ldots\ldots\ldots(6.7)$$

where p. is the initial pressure of the observation well. There is no change in the equation describing the pressure build-up, Equation 6-8. The formation insitu permeability can be calculated from the same procedure as outlined in Case 1.

An effective compressibility value may be determined by using Equation 6-9. If the observation well pressure is plotted as (p - p,) versus $\log_{10}$ t, then the slope of the straight line portion of this curve is - 162. 6 qp /Kh and the intercept of this straight line (value of p at $\log_{10}$ t = 0 or t = 1) is:

$$\frac{162.6\, q\mu}{Kh}\left(\log_{10} \frac{\mu\phi c r^{2}}{0.00633\, K} - 0.3513\right) \qquad (6.8)$$

from which c may be calculated. Alternatively, any point (Ap, log t) on the straight line portion of the curve may be used in the equation:

$$p - p_{o} = \Delta p = -\frac{162.6\, q\mu}{Kh} \log_{10} t + \frac{162.6\, q\mu}{Kh} \log_{10}\left(\frac{\mu\phi c r^{2}}{.00633\, K} - 0.3513\right) \qquad \ldots\ldots\ldots(6.9)$$

to calculate c.

Case 3: Pump Test on Single Well, Drawdown and Build-up Pressures Observed at the Pumping Well and One Observation Well

The quasi-steady state formula can be used at sufficiently large times. The pseudo-steady state is reached when the rate of pressure decline, dp/dt, is constant and the same at both wells.

Darcy's law can be used.

$$q = \frac{KA}{\mu} \frac{dp}{dr} \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \ (6.10)$$

Where q is water flow rate into the producing well. Rearranging Equation 6.10 and integrating between two well

$$\int_{p_1}^{p_2} dp = \int_{r_w}^{r} \frac{q\mu}{KA}\, dr = \int_{r_w}^{r} \frac{q\mu}{K(2\pi r)h}\, dr$$

or

$$p_2 - p_1 = \frac{q\mu}{2\pi Kh} \ln\left(\frac{r}{r_w}\right)$$

and hence

$$= \frac{q\mu \ln\left(\frac{r}{r_w}\right)}{2\pi h(p_2 - p_1)} \qquad \text{.............................(6.11)}$$

6.2 Calculation for Development of Aquifer Gas storage field

An aquifer is being considered for gas storage. The sand occurs at a depth of 1250 feet and is considered a suitable structure. The average physical properties of the sand determined from core data are porosity 14.5 per cent, permeability 168 millidarcies, and sand thickness 164 feet. A well in the aquifer was pumped at 1370 barrels per day and the pressure observed at both the pumping well and a neighboring well, 500 feet away, during pressure drawdown and buildup*

Predict the insitu permeability of the sand and the effective compressibility of the aquifer. The pressure build-up data for the pumping well are given in Table 6-2 and pressure drawdown data for the observation well are given in Table 6-3.

Solution:

A. Determination of the insitu permeability using the pressure build-up data on the pumping well. In Equation 6-8

$$p = p_o - \frac{162.6\, q\mu}{Kh} \log_{10}\left[\frac{t_o + \Delta t}{\Delta t}\right] \qquad \text{.....................(6.8)}$$

Substitute $\Delta p = p - p_o$ to obtain

$$\Delta p = -\frac{162.6\, q\mu}{Kh} \log_{10}\left\{\frac{t_o + \Delta t}{\Delta t}\right\} \qquad \text{............................(6.17)}$$

From the build-up data, determine $(t_o + \Delta t)\, \Delta t$ and Δp for each data point

Table 6-2 Pressure Build-up Data - Pumping Well

Time since Pumping ceased Hours, Δt	$\frac{t_o - \Delta t}{\Delta t}$		Pressure Feet of water	Δp^*, Feet of Water	Δp psi
0.05	72.05/.05	= 1441	1060	-25	-10.8
0.1	72.1/.1	= 721	1066	-19	- 8.25
0.0167	72.167/1.67	= 433	1062	-23	- 9.95
0.33	72.33/.33	= 219	1064	-21	- 9.09
0.50	72.5/.5	145	1065	-20	- 8.67
1	73/1	= 73	1068	-17	- 7.35
2	74/2	= 37	1070	[illegible]	- 6.50
3	75/3	= 25	1072	-12	- 5.20
4	79/4	= 19.75	1074	-11	- 4.76
9	81/9	= 9	1075	-10	- 4.33
55	127/55	= 2.31	1080.5	- 4.5	- 1.95
70	142/70	= 2.03	1081	- 4	- 1.73
118	190/118	= 1.61	1082.2	- 2.8	- 1.21
190	262/190	= 1.38	1082.3	- 2.7	- 1.17

t_o = 72 hours - 3 days, pumping time

*Initial pressure prior to pumping = 1085 feet of water
Pumping rate = 1370 barrels water per day, 40 gpm.

Table 6-3 Pressure Drawdown - Observation Well

Pumping time, hours	Pressure, feet of water	Δp, feet of water	Δp, psi
0	1085	0	0
0.33	1084	0	0
0.75	1083.84	- 0.16	- 0.0693
1.33	1083.05	- 0.95	- 0.0411
2.0	1082.02	- 1.98	- 0.855
3.0	1080.73	- 3.27	-1.41
4.0	1079.68	- 4.32	-1.87
5.0	1078.26	- 5.74	-2.44
8.0	1077.17	- 6.83	-2.96
10.0	1076.60	- 7.40	-3.20
20.0	1074.55	- 9.45	-4.08
40.0	1072.28	-11.72	-5.08
60.0	1070.53	-13.47	-5.32
72.0	1070.03	-13.97	-6.04

A plot of Δp versus ln $\left\{\frac{t_o + \Delta t}{\Delta t}\right\}$ is shown in Figure 6-2. The slope is -3.55 pounds per square inch per cycle. Hence $-\frac{162.6\, q\mu}{Kh} = -3.55$

*The difference in distance to the initial water level is due to a difference in the height of the wellheads above sea level.

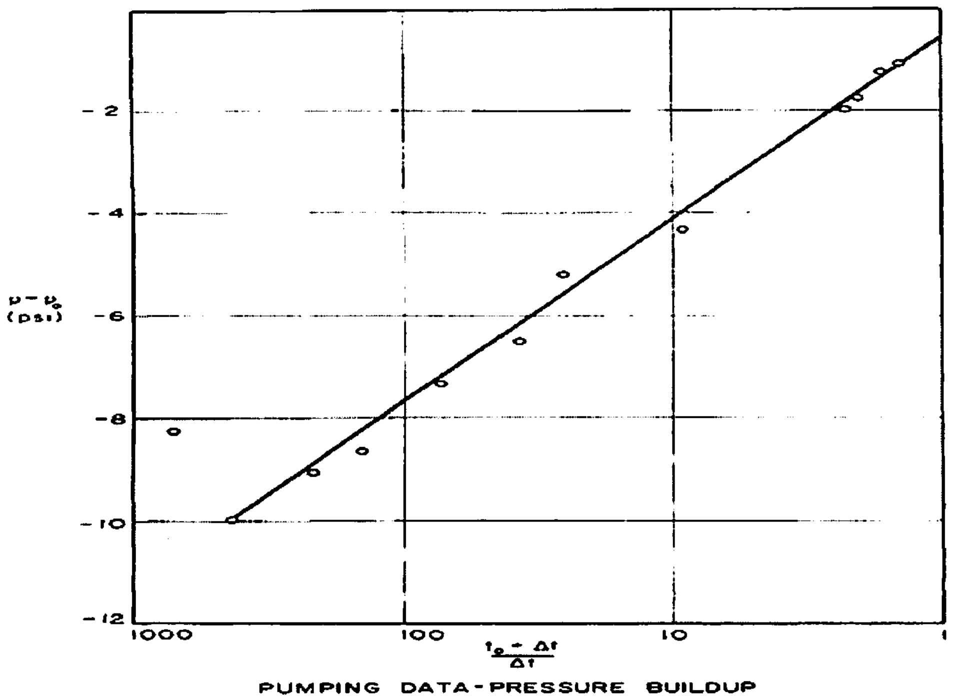


Figure 6-2 Pressure Build-up Curve for calculation for Development of Aquifer Gas storage field

Or

$$K = \frac{(162.6)(1370)(1)}{(3.55)(164)} = 383 \text{ mD}$$

B. Determination of the insitu permeability and compressibility using the drawdown data on the observation well. Substituting the pressure drop $\Delta p = p - p_o$ in Equation 6.7 yields

$$\Delta p = \frac{162.6\, q\mu}{Kh}\left\{\log_{10}\left(\frac{\mu\phi c r^2}{0.00633\, Kt}\right) - 0.3513\right\} \qquad \text{........................(6.18)}$$

From the data, calculate the pressure drop for each time step.

A plot of Δp versus $\log_{10} t$ is shown in Figure 6-3. The slope is - 3.31 pounds per square inch per cycle. Hence

$-\frac{162.6\, q\mu}{Kh}$ =-3.31pounds per squar inch per cycle

Or

$$K = \frac{(162.6)(1370)(1)}{(3.31)(164)} = 410 \text{ mD}$$

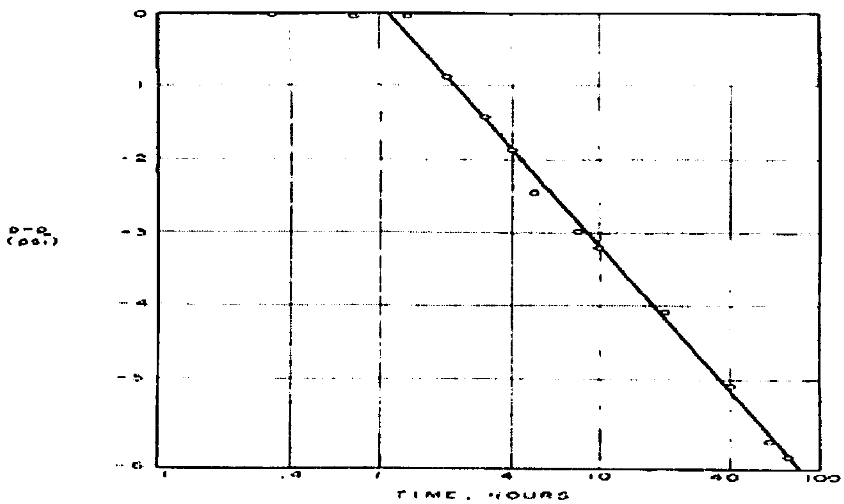


Figure 6.3 Plot of Δp and $\log_{10} t$

For a truly homogeneous formation, the two K values calculated above should be identical. In case they differ, the second K value determined from the observation well pressure plot should be used in the following compressibility calculations.

Calculate the compressibility at t = 72 hours = 3 days, D p = - 6.04 pounds per square inch.
From Equation 7-18

$$\mathrm{Log}_{10}\frac{(\phi\mu c r2)}{(0.0063Kt)} = \frac{\Delta p}{162..6\, q\mu/Kh} + 0.3153$$

$$\mathrm{Log}_{10}\frac{(\phi\mu c r2)}{(0.0063Kt)} = -6.04/3.31+0.3513= 1.4734$$

$$\frac{(\phi\mu c r2)}{(0.0063Kt)} = 0.0339$$

$$C=\frac{0.0339*0.0063*410*3}{1*0.145*500*500} = 7.3 \text{ x } 10\text{-}6 \text{ (vol)/(vol)(Psi)}$$

6.3 Evaluation of Cap Rock

Once a structure with a satisfactory closure has been found and it is determined that a permeable zone therein is covered with an impermeable cap rock, pump tests may be used to evaluate the fluid communication across the cap rock. These pump tests are likely to be the same as those used to provide data for determining the insitu permeability of the prospective storage formation and its in-situ compressibility.

Figure 6-1 shows the completion of three wells in a prospective aquifer project. Two are completed in the prospective storage formation and one in the first permeable formation above the cap rock. Pumping a well in the storage formation for a period of time: e.g., 10 to 30 days, lowers the pressure in the water zone and a potential difference is created between the zone above the cap rock and the zone below.

At discovery, the initial water levels in all wells should be observed. If the wells in the storage zone have a lower level than in the zone above the cap rock, the information is indicative either of a satisfactory seal by the cap rock or of a slow transfer from the upper to the lower zone. If water is transferring from the above zone to the lower prospective storage zone, the composition of the water in the storage zone should reveal that mixing of the two waters has taken place. If there is localized transfer, the water in the lower zone near the transfer site will have the same composition as the water in the upper zone. Water in the lower prospective storage zone may have a different composition away from the location where the transfer is taking place.

The pump test will upset the initially observed potential between the zones and any fluid transferring because of the lowered pressure in the storage zone will be reflected in a decrease in pressure and hence fluid level in well C of Figure 6-1 completed in the first permeable zone above the cap rock.

When pumping tests are made to determine the insitu permeability and insitu compressibility of the formation and leakage is occurring, then the movement of water through the cap rock in addition to the movement of water in the porous zone will affect the pressure drawdown in the pumping and observations wells. Hantush has developed a procedure for analyzing the cap rock leakage coefficient K'/h' where K' and h' are the permeability and thickness of a cap rock, respectively, above a porous zone. His results show that the permeability obtained at observation wells will be in error by a factor of e at the point of inflection in the plot of pressure drawdown versus log of time, where r is the distance from the pumping well to the observation well

The effect of the factor $e^{r/\sqrt{\frac{Khh'}{K'}}}$ is small for pressure observations of the pumping well, because the factor for $r = r_w$ is essentially unity. Thus leakage does not appreciably affect the pressure drawdown behavior of the pumping well. However, the pressure behavior at the observation well where r is large is affected by this factor and the calculated permeability by standard procedure is too high by the factor $e^{r/\sqrt{\frac{Khh'}{K'}}}$. The leakage can be estimated if good drawdown data are available from a pumping and an observation well. An alternate method utilizing the data from two or more observation by plotting the distance between the pumping well versus the slope of the pressure drawdown versus log time curve.

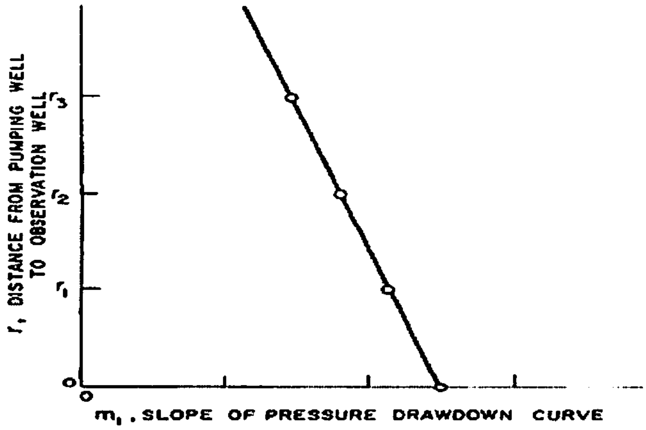


Figure 6.4 Determination of Correct Slope for Calculating Permeability.

The value of the slope when the line is extrapolated to r = 0 is the correct value of the slope used in calculating the permeability. From Equation 6-11, the slope of the drawdown line is: $m_o = \frac{q\mu}{162.6\ Kh}$

The coefficient of leakage (K'/h') can then be determined from

$$\frac{r}{\sqrt{\frac{Khh'}{K'}}} = \log \frac{m_o}{m_i}$$

$$\frac{K'}{h'} = \frac{Kh}{r^2}\left(\log \frac{m_o}{m_i}\right)^2 \qquad \text{...(6.12)}$$

Where m_o is the extrapolated value of the slope and m_i is the slope of the drawdown pressure curve at a given distance r from the pumping well.

The effect of changes in barometric pressure on the water levels in open water wells, undisturbed by any pumping tests or flow, should be noted. The water level in a well indicates the pressure difference between the reservoir open at the bottom of a well and atmospheric pressure at the top. For a constant reservoir pressure, any change in barometric pressure requires a change in the height of the water column for equilibrium conditions. The water levels do rise and fall in accordance with barometric changes, with some dampening. Figure 6-2 is an illustration of the parallel movement of a water level in an open well in an undisturbed aquifer and barometric pressure.

Witherspoon et al developed a method for obtaining the cap rock permeability by analyzing the pressure drawdown for an observation well completed in the cap rock. Although this method allows one to calculate the permeability of the cap rock, it does not show if leakage is occurring through fractures or at discontinuities in the cap rock at a fault.

The application of this method is presented starting with Figure 6-3, the assumed geometry Calculate the following dimensionless parameters:

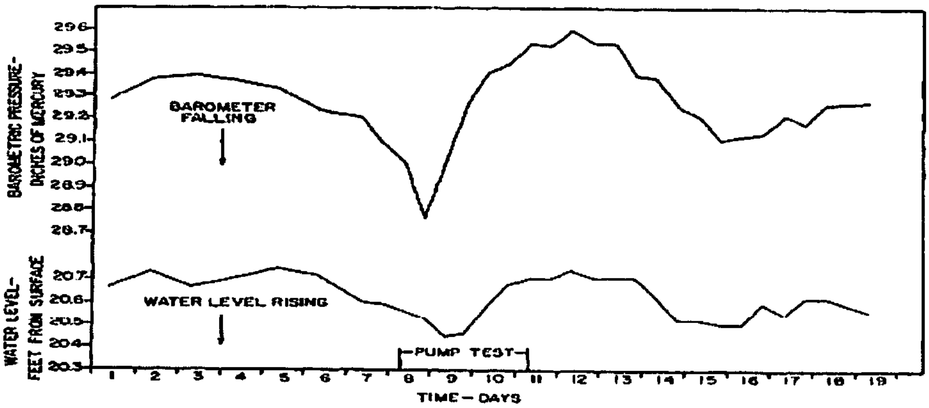


Figure 6-5 Effect of Changes in Barometric Pressure on Water Level in Open Well on Undisturbed Aquifer. (Witherspoon and Nelson)

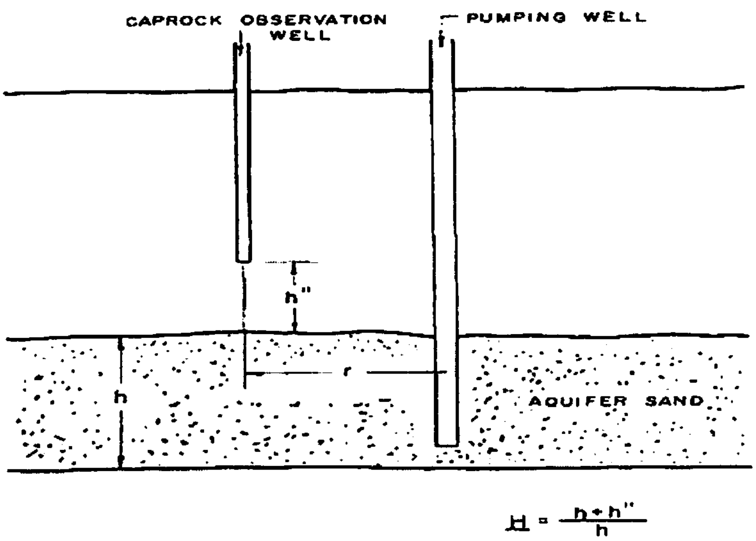


Figure 6-6 Geometry for Pumping Test to Determine Cap Rock Permeability

Where:
h = thickness of aquifer
h" = distance from top of aquifer to bottom of well bore completed in porous zone within cap rock
Also calculate:

$$\frac{\Delta p'}{\Delta p}$$

where: $\Delta p'$= pressure drawdown at time t at well bore completed in cap rock, psi.
Δp = pressure drawdown at time t in reservoir directly below cap rock (calculated from Equation 6-11), psi.

From pump data and reservoir geometry, read □from Figure 6-7 and determine the permeability of the cap rock from

$$K' = \frac{\alpha K}{t_D r^2} = \frac{\alpha K}{\left(\frac{.00633\ Kt}{\mu \phi c r^2}\right) r^2} = \frac{\alpha \mu \phi c}{.00633\ t} \qquad \text{.......................................(6.23)}$$

K' = permeability of cap rock, millidarcys
K = permeability of aquifer, millidarcys
μ = Viscosity, centipoise
126 = porosity of aquifer, fraction
c = compressibility of liquid in aquifer, vol/(vol)(psi)
t = time, days

$$a = \frac{t_D r^2 K'}{K}$$

r = distance between wells, feet

For an observation well in the cap rock to be effective in taking observations over periods of days, it should be completed in a zone with greater permeability than the typical cap rock material. Should this be true, the application of Figure 6-7 is no longer rigorous because horizontal flow in the permeable layer will upset the assumed character of the cap rock in preparing the Figure.

Thus, the observation of a pressure drawdown for a well complete in the first permeable zone above the cap rock while a well in the proposed storage zone is pumped is considered to be the best confirmation that leakage is taking place between the two zones. This drawdown in the observation well, if small, does not necessarily mean the cap rock is unsatisfactory since a poor well completion through the cap rock or leakage across a fault plane below the closure could have caused the pressure drawdown in the observation well above the cap rock.

6.3 Calculations to Evaluate an Aquifer Project

Once the thickness (h), the porosity the permeability (K) the compressibility (c) is determined and the water or brine viscosity (μ) is known, water movement calculations may be made for the geometric model which applies. It is necessary to assume a gas bubble radius in such calculations.

Figure 6-8 presents the results of such water movement calculations with the radial model for a series of permeabilities, selected reservoir properties, and a gas bubble pressure rise above original aquifer pressure of 300 pounds per square inch.

h = 100 feet= 0.18
C = 7x10-6 vol/(vol)(psi)
μ = 1.0 cp
r_b = 2000 feet
Gas of 0.6 gravity stored at 1100 psia at 75°F
$p_i - p_o$ = 1100 - 800 = 300 psi

For similar conditions, one may read the rate of bubble development from Figure 6-8.

The calculation for a given aquifer is relatively simple. To determine the number of gas wells required for gas injection the individual well injection capacity may be computed from the formation permeability. Gas injection and withdrawal calculations may be made by using steady state flow equations,

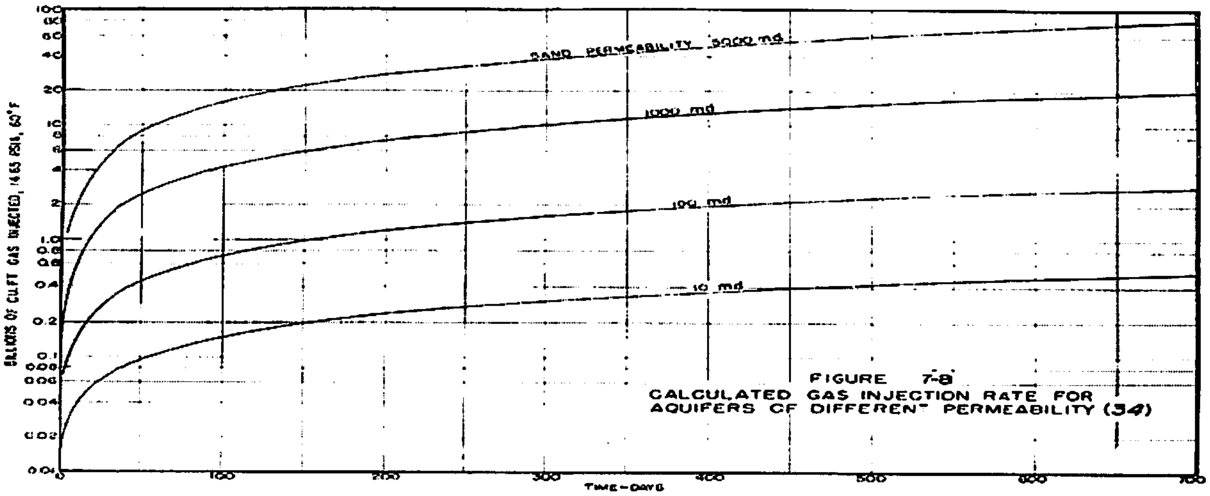


Figure 6-7 the Rate of Bubble Development

6.4 Initial Gas Injection

When an aquifer storage field is ready for gas injection, one would expect to have at least two storage wells completed on top of the structure with water standing in these wells somewhere near the surface. How fast should gas be injected initially? Water moves relatively slowly, and it will take time for gas to displace the water into the formation. It is recommended that gas pressure be applied to the wellhead in 100 pounds per square inch increments with observation of the recession of the water level in the wellbore before increasing the gas pressure.

Once water is displaced from the wellbore, full gas injection pressure for depths of 1200 feet or more could well be 100 to 150 pounds per square inch above the initial aquifer pressure. Sudden increases in wellhead pressure with a full water column would increase the bottom hole pressure almost instantaneously, running the risk of fracturing the reservoir rock by such practice. It may take 2 or 3 days before the formation will begin to take gas at a rate equal to some 50 percent of its ultimate capacity.

Once gas injection has started, the neighboring observation well should show a pressure response in a matter of hours and is likely to show the presence of gas in a few days. The initial wafer of gas may be very thin, especially for layered systems. This means that during initial gas injection, gas may-travel relatively great distances. This gas layer may travel down structure as much as 100 feet before the effects of gravity arrest the downward movement.

Figure 6-9 gives a view as to the mechanism by which gas enters the water bearing rock.

The instability of gas displacing water can be very great. Gas will preferentially enter the zone with the highest permeability. Once gas starts moving into a zone, it will continue to flow because the pressure transmits more easily through this gas layer than through the water layers due to the differences in viscosity of water and gas, Figures 6-9b and 6-9c show how the gas water interface may be conceived to develop. Water retained in the layers between those containing gas will drain down through the gas layers by a slow percolation process. Eventually the gas bubble will develop a "bottom" but during high rates of injection, even in later years, the instability effects may create a jagged interface between the gas bubble and the water zone.

Although only one well is shown in Figure 6-9, simultaneous injection may occur on a group of wells. The practice is often followed of injecting into the second, third and fourth wells, etc. only after the gas zone has reached the well in question. This, in effect, assures that only one gas bubble is being created. It is expected that a series of separate bubbles simultaneously created around a group of wells would eventually coalesce. However, in the early days, one can conceive of some undue interference with water drainage patterns by having several gas layers.

In a matter of 1 to 3 years, the water in the sand at the "ceiling" of the reservoir will have drained down to its residual content and the gas bubble will correspond to the structure of the cap rock.

Figure 6 -10 shows a sketch of an aquifer bubble after full coalescence has taken place and much of the water has drained out. In effect, the gas bubble is now similar to a water drivegas field. When water is being pushed out, the gas water contact is concave downward (Figure 6-10a) since some head of water is required to move the water from the center of the bubble to its periphery. The shape is concave upward (Figure 6-10b) upon gas withdrawal and water return.

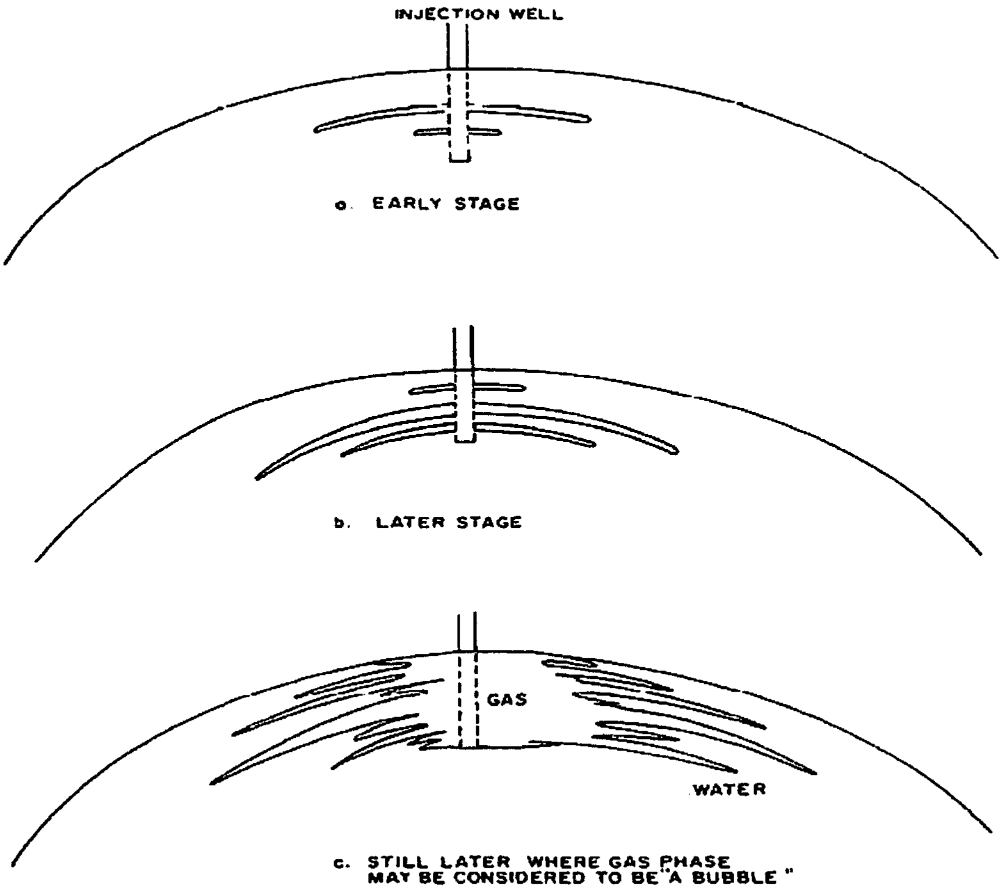


Figure 6-8 Development of Gas Bubble in an Aquifer.

6.5 Water Movement Calculations

The gas bubble in an aquifer storage project eventually reaches a stage where sufficient data points are available to compare predicted and observed performance of the gas reservoir.

The geometric model used in evaluating the aquifer before gas injection would be the normal starting point in such a comparison. After sufficient development has taken place, there are no significant differences between predicting gas bubble pressure for a given injection-withdrawal schedule for aquifer projects and naturally occurring water-drive gas fields used for gas storage.

A method for calculating the gas bubble-aquifer behavior at early stages has been devised. The method has as yet been applied by the authors to only one field.

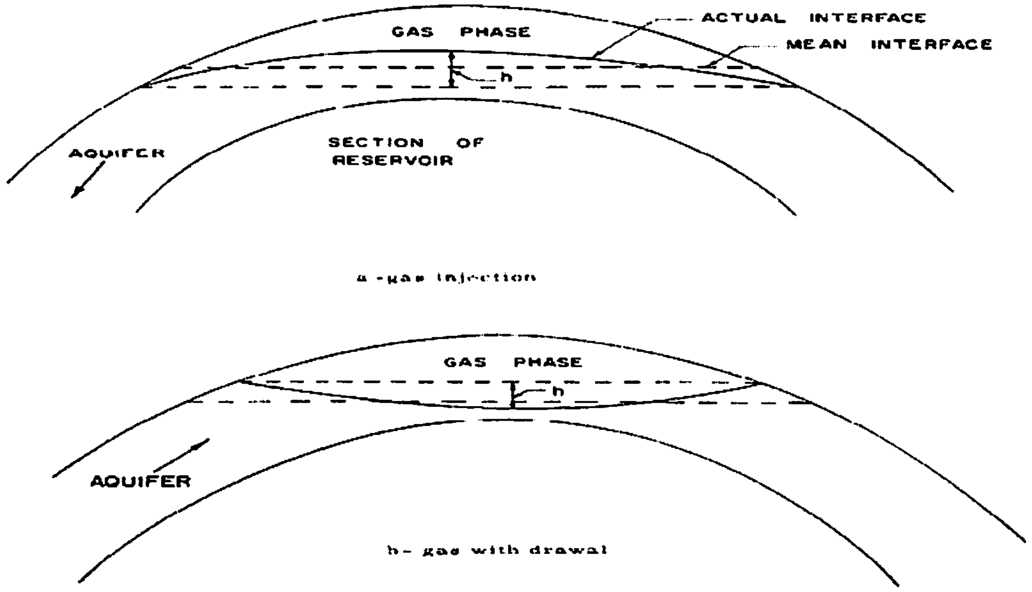


Figure 6-9 Illustration of Bubble Bottom Shape for Aquifers.

6.6 Pressure Gradients in Aquifers

In order to evaluate the applicability of the unsteady-state water movement equation to the aquifer in question, one may compare observed pressures in the aquifer observation wells with calculated pressures. These calculated pressures are determined from equations involving the $P_D(r_D, {}_Dt)$ function.

The dimensionless pressure values tabulated in Appendices F and G are presented at various discrete radii within the aquifer. The values of $P_D(r_Dt,{}_D)$ for the constant terminal rate case at $r_D = 1.0$ are identical to the P_t function. That is, the P_t function simply represents the dimensionless pressure at the inner boundary, $r_D = 1$, in the same manner that the $P_D(r_D,t_D)$ tables represent dimensionless pressures at other discrete values of the dimensionless
radius.

6.5 Location of Gas-Water Contact (Bubble Edge)

In the operation of gas storage reservoirs the gas-water interface moves in accordance with the cyclic pressure schedule. In the case of aquifer storage reservoirs the interface continually advances downward and radially outward as the gas bubble is grown. This growth process is ideally represented as shown in Figure 6-10. After an aquifer storage reservoir has been grown for a period of time, it is desirable to determine, if possible, the radial extent of the gas bubble.

This knowledge allows conclusions concerning the approach of the gas to the spill point. The degree of approach of a gas bubble to a water observation well is often desired.

The method described here of locating the interface requires that the gas bubble and aquifer be approximately stabilized at a constant pressure p_o, This can be accomplished by shutting in the field after a period of growth and letting the pressure approach a constant value. The method further requires observation water well at a known distance r from the center of the gas bubble, Figure 6-13. If after stabilization gas is injected to maintain the reservoir at a pressure □p above the stabilized value then a pressure reading at the water well at a known time after this initiation of gas injection allows determination of the reservoir radius r_b The method is equally applicable when gas is produced to maintain a constant pressure drawdown of Δp.

The calculation of r_b is a trial-and-error procedure involving use of the tabulated function $P_D(r_D,t_D)$. This quantity is defined in terms of aquifer pressure as

$$P_D(r_D, t_D) = \frac{p_0 - p}{p_0 - p_1}$$

Where, p_1 is the constant pressure maintained in the gas reservoir and p_o is the approximately stabilized pressure of aquifer and reservoir at "zero time" (time of initiation of gas injection). The term p is pressure in the aquifer at radius r and time t while $r_D = r/r_b$ and $t_D = .00633$

Values of [1 - $P_D(r_D,t_D)$] versus dimensionless time $t_D^{Kt/\mu\phi c r_b^2}$ ·for finite aquifers of various ratios R between exterior and interior radii. The values of (1 - P_D) are equally valid for infinite aquifers only at those times t D for which [1 - $P_D(r_D,t_D)$] = 1.0 (or close to 1.0, e. g. 0.99 or 0.98). For example, the first seven rows of the table for R = 5.0 are applicable to an infinite aquifer since the effect of the exterior boundary is not felt until t_D= 2.5, the eighth row down [1 - $P_D(5,2.5)$] = . 9230 < 1.0.

Calculation of r_b requires the following procedure. After stabilization (shut-in) of reservoir and aquifer at an approximately constant pressure p_o, gas is injected (or produced) to hold the reservoir at a pressure p_1, □p above (or below) p_o. After a period of time t, the pressure p in a water observation well located r feet from the bubble center is read. Then from Equation 6-22

$$[P_D(r_D, t_D)]_{observed} = \frac{p_o - p}{p_o - p_1} = \frac{p_o - p}{\Delta p} \qquad (6.24)$$

A value of r_b is assumed and the dimensionless variables r_D and t_D are calculated as r/r_b and $.00633\ Kt/\mu\ cr_b$

$P_D(R,t_D)$ is 0.98 or larger. The value of $P_D(r_D, t_D)$ is then read from this sub-table and compared to the observed value calculated from Equation 6-24. If the two P_D values do not agree another rb must be assumed and the same procedure repeated. Finally the P_D values will agree for a certain assumed r_b which is then the answer.

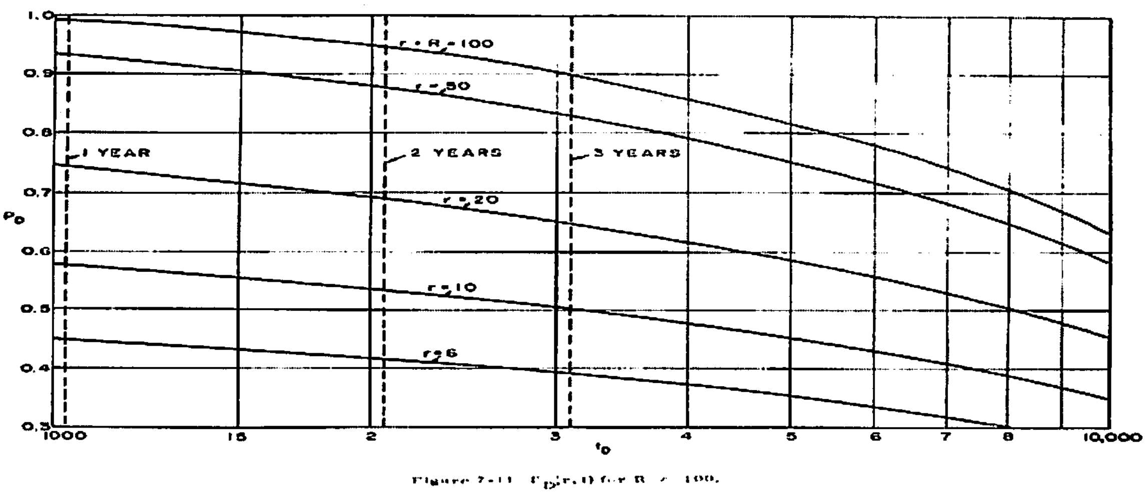


Figure 6.10 $F_D(r, t)$ for R = 100.

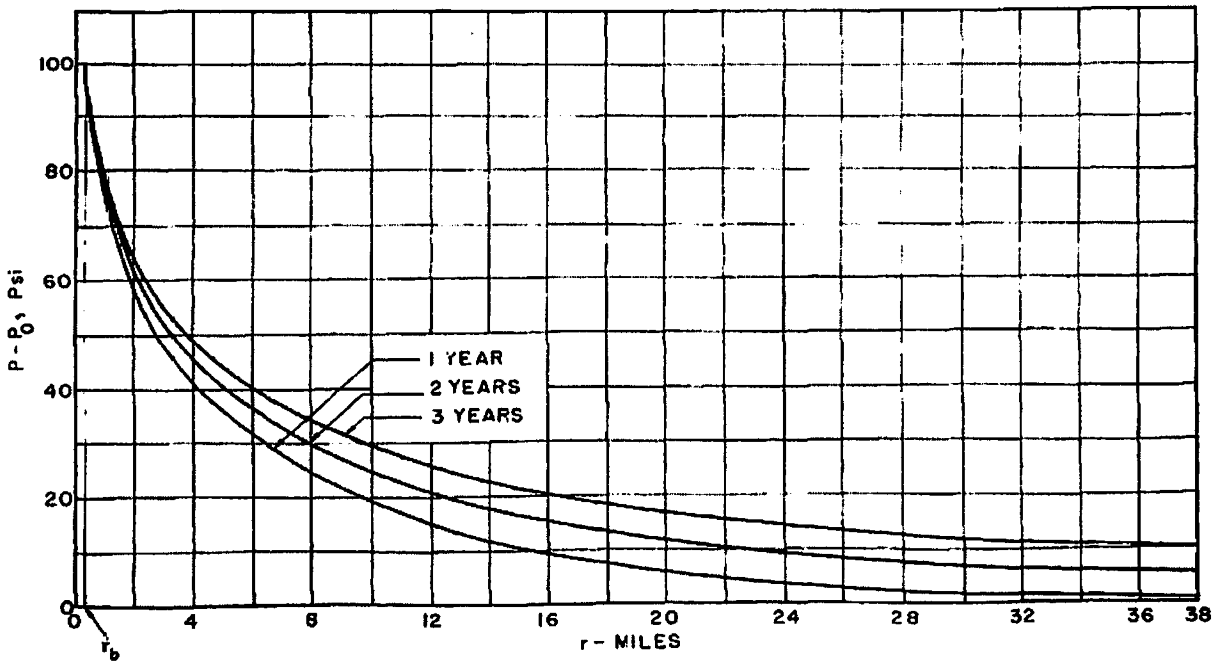


Figure 6.11 Pressure gradient in Aquifer of Example Calculation

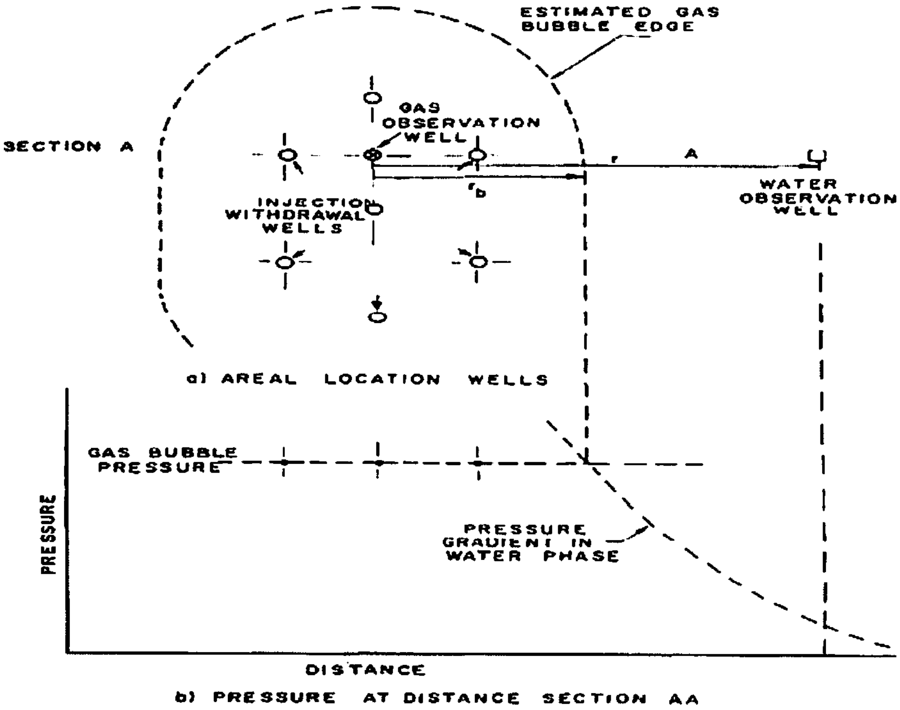


Figure 6-12 Illustration of Location of Gas Bubble Edge.

Chapter 7

CASE STUDY ON- AQUIFER STORAGE FIELDS

Chapter 7

A Case study on - AQUIFER STORAGE FIELDS

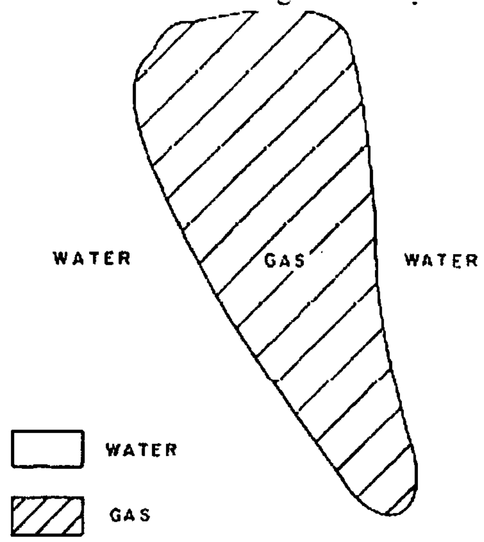
The performance of three natural gas storage fields formed by injecting gas into an aquifer initially containing no gas or oil is analyzed in this section. The computations for two of the reservoirs are made by means of the generalized performance method employing the resistance function and including the moving boundary equations. A third reservoir is treated by the adaptation of the hemispherical model for a changing radius gas bubble. The calculations employing the geometric models without moving boundaries were much less satisfactory and are not included. No calculations are made of the pressures which would be observed if water movement did not occur. since it was known that the entire gas bubble was created by water displacement

7.1 Field Details:

Field F

Field F, a storage reservoir, was formed by injecting gas into a sandstone aquifer initially containing only water. A plan sketch, Figure 7-1, shows a horizontal view of this field.

Figure 7-1 Areal Sketch Showing Boundary of Field F.



7.1.1 Geology and Field Data

The storage sand, countered at an average depth of 2450 feet below the surface, is 2500 feet thick. This sand consists of alternate layers of fine- to very-coarse-grained sandstone with several randomly spaced, non-continuous, thin, green shale laminations. The thin laminations at intervals present full vertical pressure penetration.

Impervious layers of dolomite and shale form the cap rock. The lower two layers of dolomite and shale in this cap rock are more than twenty and forty feet thick, respectively.

No faults are known to exist in the immediate vicinity of the aquifer. Information indicates the aquifer is infinite.

A summary of the reservoir and aquifer properties is given in Table pressure history is tabulated in Table 7-2.

Table 7-1 Storage Field Reservoir Data

Aquifer

Rock Characteristics

Formation	Mt. Simon Sandstone
Depth of the top of the aquifer	2490 ft
Average net thickness	2500 ft
Average porosity	14.8%
Average Permeability	100 millidarcy

Fluid Characteristics

Liquid Viscosity	1centipoise
Compressibility of liquid and formation	$7*10^{-6}$ vol/volpsi

Gas Reservoir

Rock Characteristics

Formation	Mt. Simon Sandstone
Structure	Structural dome
Average reservoir thickness	40 ft

Fluid Characteristics

Reservoir tempreture	70°F
Compressibility correlation	Z=a+bP
Constant a	0.98
Constant b	-0.000083 $(psi)^{-1}$
Base pressure Pb	14.65 psia
Base tempreture Tb	60°F

Pressure 1097.4 psia (well- bottom)

Table 7-2 Gas Inventory and Pressure History for Field F

Pressure Base = 14.65 psia
Temperature Base = 60°F

Time Weeks	Cumulative Gas Injection, MMcf	Pressure, psia (well-bottom)	Time Weeks	Cumulative Gas Injection, MMcf	Pressure, p (well-botto
0	0	1067.1	47	2895	1249.7
1	6	1075.0	48	3006	1252.2
2	10	1076.7	49	3146	1255.4
3	17	1086.5	50	3271	1252.4
4	21	1085.1	51	3402	1254.7
5	22	1077.8	52	3436	1214.4
6	31	1094.4	53	3356	1155.6
7	41	1099.2	54	3356	1144.7
8	52	1100.1	55	3356	1134.9
9	75	-	56	3574	1220.8
10	111	1168.7	57	3715	1217.6
11	111	1101.0	58	3621	1149.9
12	111	1087.5	59	3723	1173.2
13	153	-	60	3646	1128.1
14	198	-	61	3645	1123.2
15	241	-	62	3645	1117.3
16	261	-	63	3690	1132.2
17	318	-	64	3690	1121.1
18	369	-	65	3906	1203.8
19	412	-	66	4067	1119.8
20	468	-	67	4302	1164.4
21	481	1145.6	68	4440	1257.1
22	507	-	69	4582	1259.0
23	567	-	70	4724	1258.5
24	624	-	71	4874	1261.4
25	667	-	72	5061	1261.9
26	725	-	73	5171	1262.3
27	794	-	74	5315	1254.4
28	862	-	75	5472	1263.1
29	938	1189.5	76	5627	1261.3
30	1041	1244.6	77	5927	1260.3
31	1129	1242.7	78	6087	1261.5
32	1224	1246.7	79	6250	1262.8
33	1315	1243.8	80	6412	1262.8
34	1407	1242.2	81	6558	1259.9
35	1505	1243.7	82	6720	1260.4
36	1595	1240.1	83	6892	1260.0
37	1695	1241.9	84	7057	1261.7
38	1800	1242.8	85	7210	1258.6
39	1881	1235.3	86	7318	1245.5
40	2015	1251.9	87	7460	1246.3
41	2152	1259.5	88	7609	1246.1
42	2276	1258.3	89	7745	1242.5
43	2393	1254.0	90	7860	1235.6
44	2528	1258.9	91	7995	1235.4
45	2662	1259.9	92	8103	1230.2
46	2777	1247.1	93	8215	1238.7

Table 7.2: Continued

Time Weeks	Cumulative Gas Injection, MMcf	Pressure, psia (well-bottom)
94	8391	1238.7
95	8879	1245.6
96	8707	1243.1
97	8826	1235.1
98	9035	1250.4
99	9156	1241.2
100	9220	1219.4
101	9165	1156.6
102	9077	1149.0
103	9077	1151.0
104	9179	1189.2
105	8300	1176.3
106	9269	1168.0
107	9340	1183.2
108	9359	1163.6
109	9366	1169.4
110	9399	1152.4
111	9224	1091.4
112	9184	1107.8
113	9104	1081.2
114	9058	1080.0
115	9055	1089.0
116	9058	1092.4
117	9058	1093.4
118	9058	1094.7
119	9058	1096.0
120	9084	1097.0
121	9294	1162.2
122	9456	1160.7
123	9731	1216.9
124	9964	1232.4
125	10183	1251.0
126	10373	1251.7
127	10494	1244.4
128	10691	1252.4
129	10878	1251.7
130	11063	1256.7
131	11253	1258.5
132	11429	1256.7
133	11609	1258.0
134	11819	1263.5
135	12019	1263.9
136	12213	1263.0
137	12404	1261.5
138	12817	1265.2
139	13023	1265.0
140	13232	1267.9
141	13438	1266.3
142	13599	1261.2
143	13826	1266.1
144	14042	1265.2
145	14240	1263.2
146	14463	1255.0
147	14678	1266.1
148	14883	1259.5
149	15006	1248.9
150	15265	1262.8
151	15486	1264.7
152	15698	126[illegible].7
153	15935	1265.8
154	16153	1265.7
155	16303	1252.2
156	16340	1221.5
157	16340	1201.3
158	16340	1187.4
159	16030	1103.6
160	15944	1127.2
161	15764	1101.9
162	15579	1067.1
163	15568	1092.5
164	15348	1052.3
165	15085	1013.9
166	14964	1008.5
167	14832	1000.4
168	14731	1006.5
169	14731	1030.5

7.1.2 Calculations and Results

Since the sand containing gas and water was thick, and the gas-water interface moves rather drastically in early stages, the hemispherical model as modified was employed. The first fourteen points (weeks) were not used, but rather 15 through 60 were selected in comparing calculated and observed pressures to determine the coefficient to be used in predicting future performance.

The coefficient was then used to predict behavior from 61 weeks through 171 weeks. Figure 11-2 shows the results of the reservoir pressures computed as compared to the observed values. The shapes of the curves are somewhat different, possibly reflecting the layered nature of the sand and lack of vertical pressure penetration.
Various values of □in Equation

$$r_{b_j} = S_f \left\{ \left(\frac{a}{p_{n-1}} + b \right) S_{n-1} \right\}^{\alpha/2}$$

were tried in the solution. The value of $\alpha = 0.50$ which corresponds to a parabolic cap rock geometry used for the results in Figure 7-2.

The resistance function method was tried and it gave the proper shape of the pressure curve. However, the amplitude of the cyclic pressure variation was much smaller than the observed values, indicating the actual resistance exceeded that predicted from early behavior.

7.2 Field G

Field G, on the fringe of the Illinois basin, is an aquifer type-gas storage field. An areal view of Field G is shown in Figure 7-3. Cross sectional views are given in Figures 7-4 and 7-5.

7.2.1 Geology and Field Data

Field G utilizes the Eau Claire and Mt. Simon formations in the St. Croixau Series in the Illinois basin. The structure is an asymmetrical east -west trending anticline with 120 feet of Cambrian closure. The cap rock over these formations consists of dense shales and argillaceous dolomites.

The 245 foot thick, lower unit of the Eau Claire consists of three fine to coarse grained porous sandstones separated by dense, dark green dolomitic shales and argillaceous nodular dolomite.
The lower two sands are usable storage sands. Several faults along the northern edge of the reservoir allow the gas to migrate between these sands and the underlying Mt. Simon,

Gas is injected into the Mt. Simon and B sands and produced from all four zones. The sand to sand faces at the faults give good communication while the shale to shale contacts at the fault hold gas satisfactorily.

The thickness of the Mt. Simon sandstone is 2112 feet and consists of siltstone, very fine grained to granular sandstone and scattered thin red and green sandy shales.

The Mt. Simon's pressures will be used and predicted in this study and the gas injection quantities are the sum of the Mt. Simon and the B zone injections.

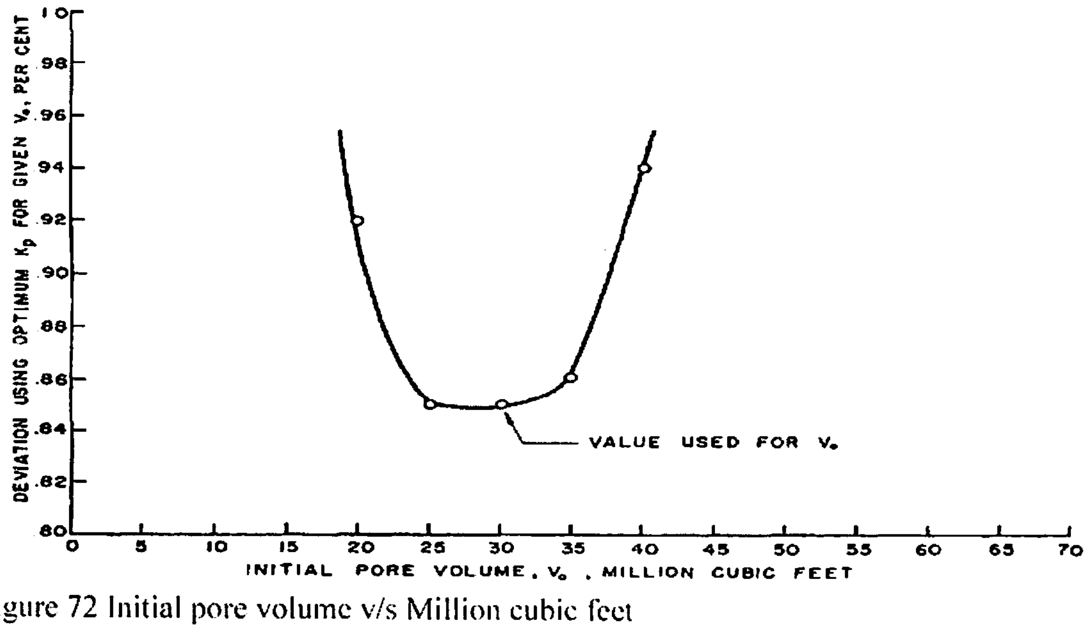


Figure 72 Initial pore volume v/s Million cubic feet

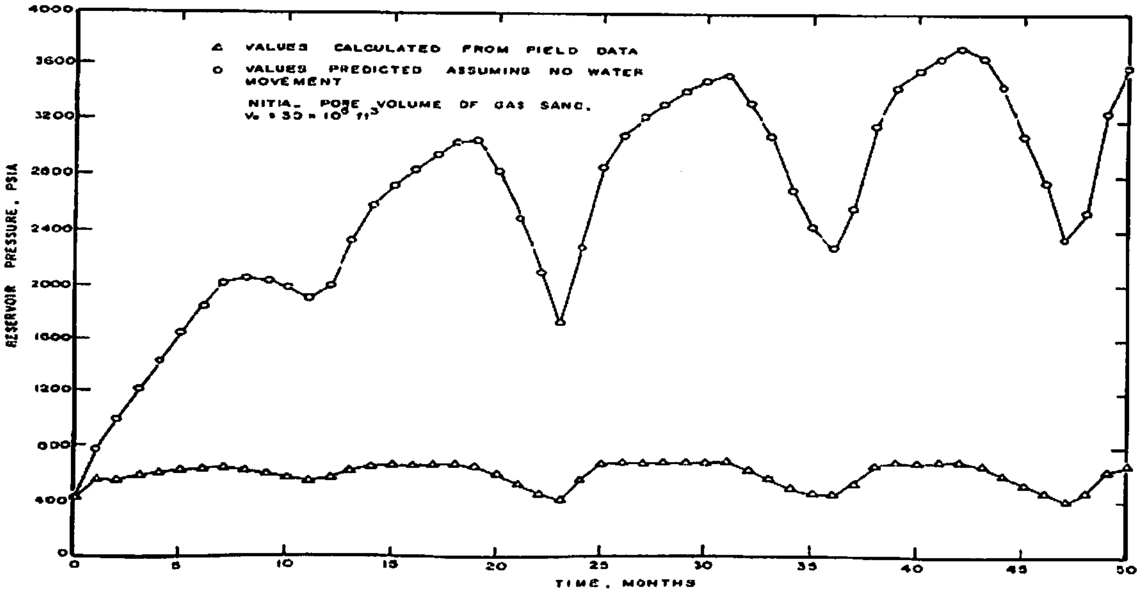


Fig: 7.3 Comparison of Field F predicted Pressures, Assuming No water Movement with Observed pressure

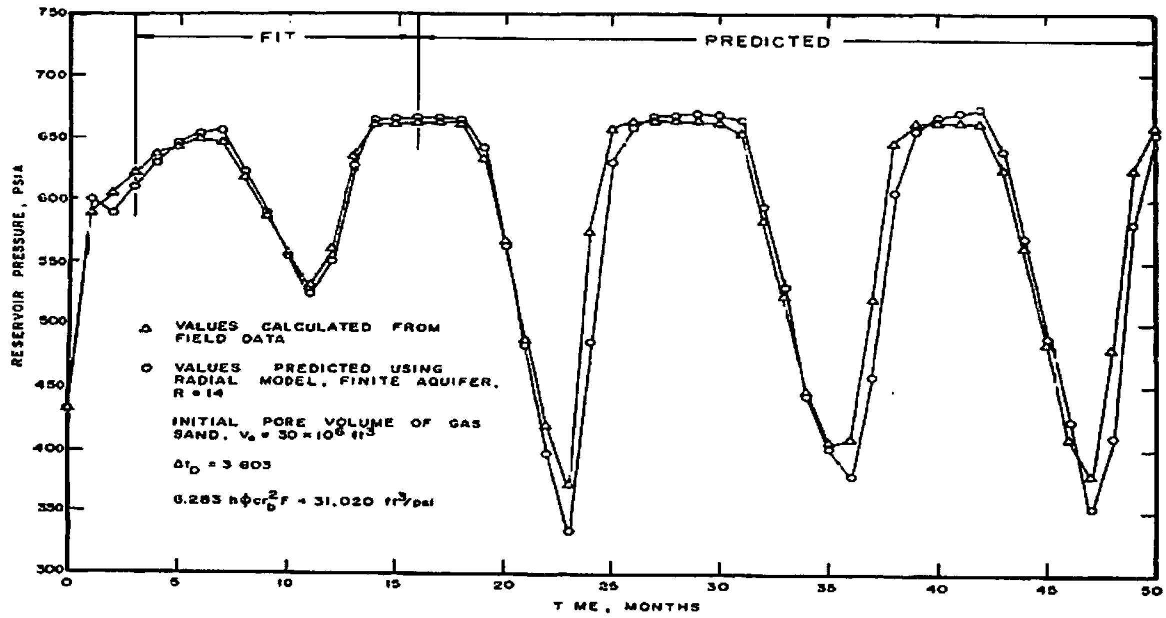


Figure 7.4 Comparison of Field F Pressure predicted Using Radial Model (infinite aquifer. R=14) with Observed pressure.

The reservoir and properties of Field G are given in Table 7-3 and the production pressure history in Table 7-4.

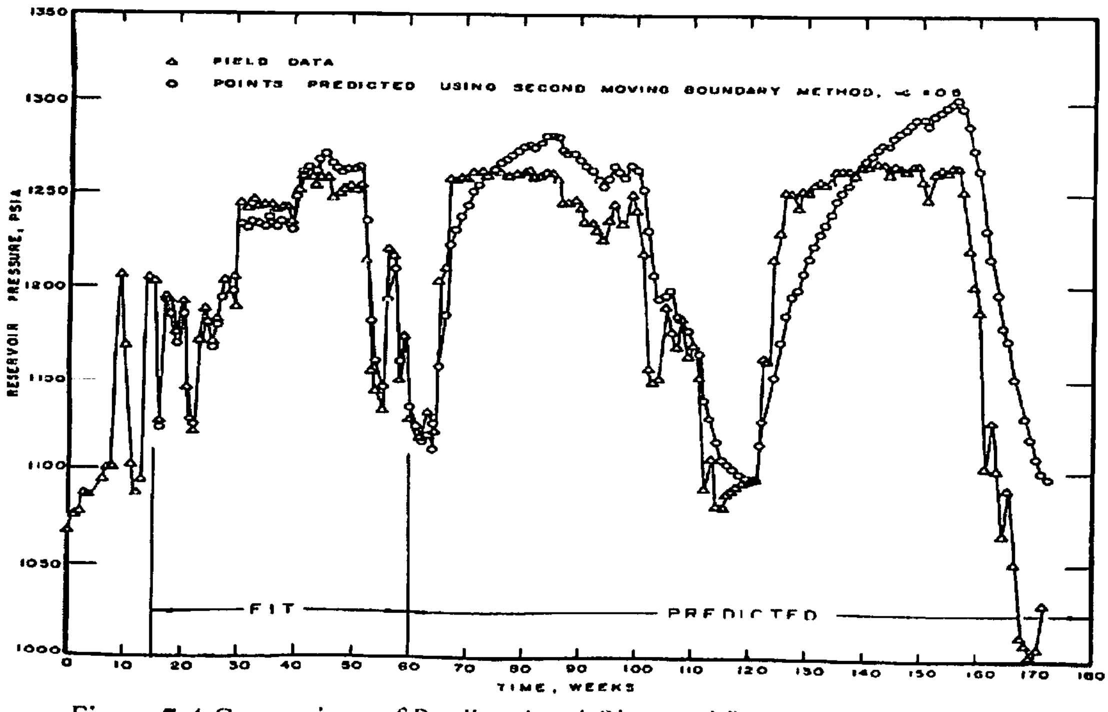


Figure 7-4 Comparison of Predicted and Observed Pressures for Field F.

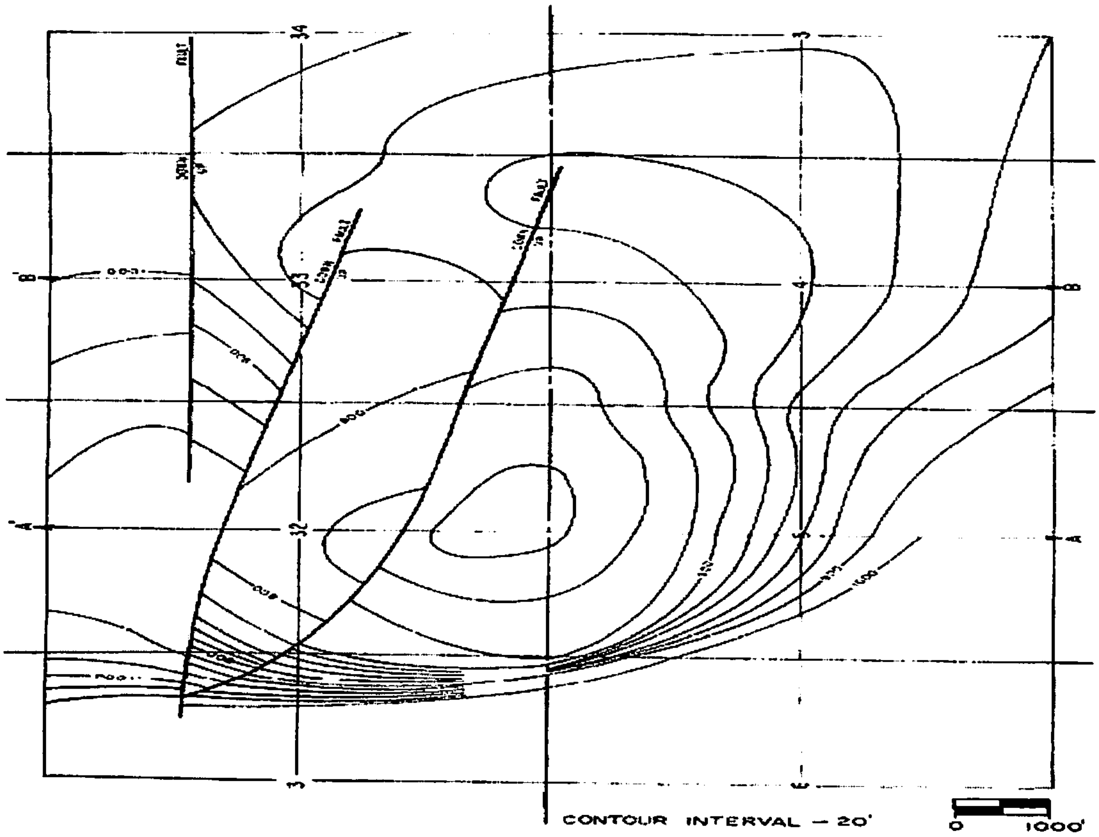


Figure 7-5 Areal View of Field G.

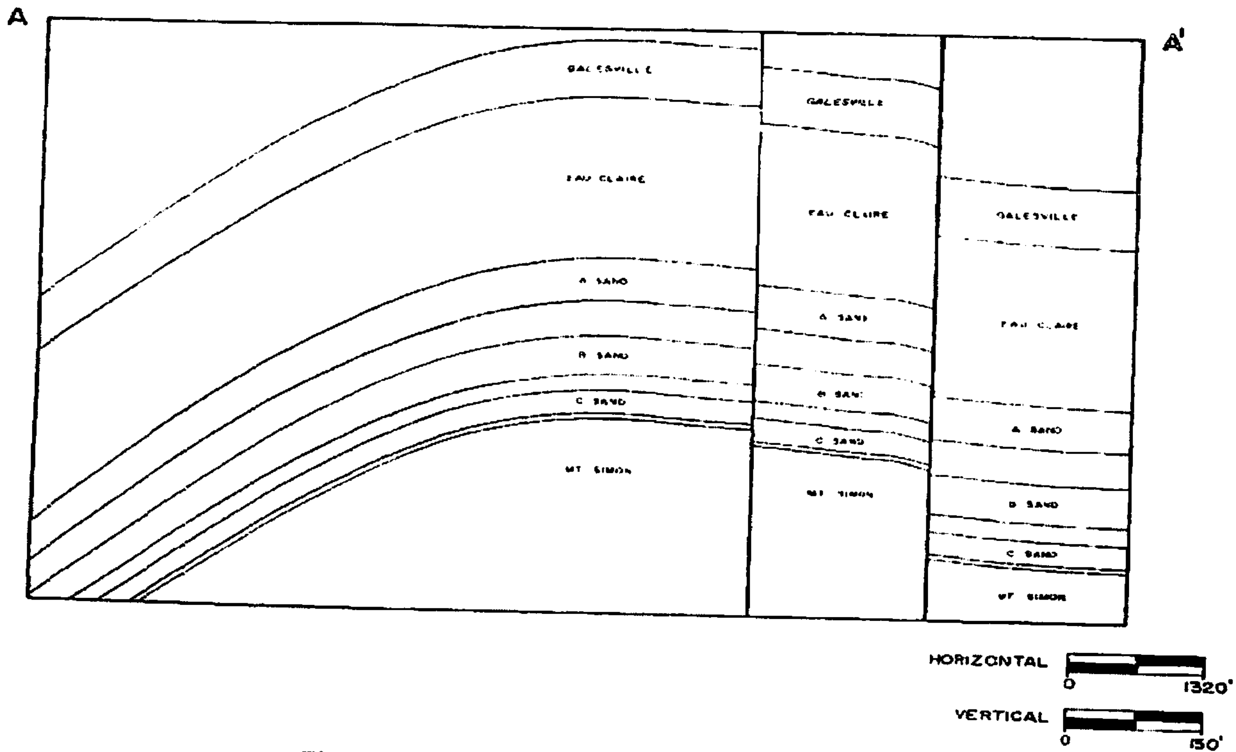


Figure 7.6 Cross Sectional AA of field G

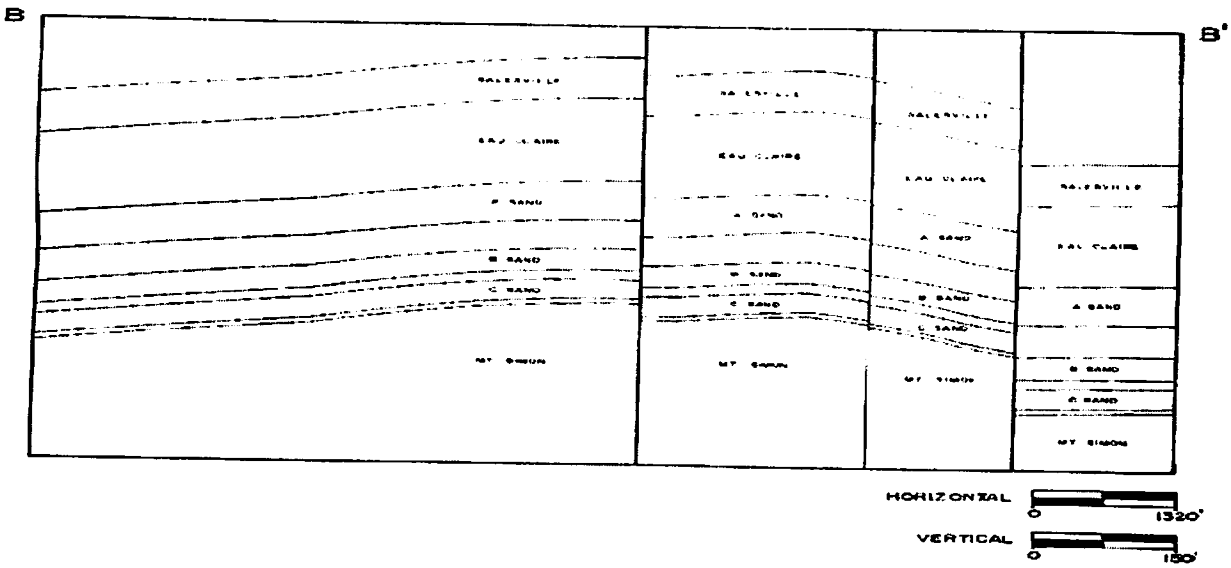


Fig 7.7 Cross Section BB of Field G.

Table 7-3 Storage Field G Reservoir Data

Aquifer	
Rock Characteristics	
Formation	Mt. Simon sandstone
Depth to top of aquifer	1421 feet
Average net thickness	2112 feet
Average porosity	17.5%
Average permeability	150 millidarcys
Fluid Characteristics	
Liquid viscosity	1 centipoise
Compressibility of liquid and formation	7×10^{-6} vol/vol-psi
Gas Reservoir	
Rock Characteristics	
Formation	Eau Claire and Mt. Simon sandstone
Structure	Anticline
Average reservoir thickness	63 feet
Fluid Characteristics	
Reservoir temperature	$58.5^{0}F$
Gas compressibility correlation, $z = a + bP$	
Constant a	0.998
Constant b	$-0.00016\ (psi)^{-1}$
Base condition for gas measurements	
P_b	14.7 psia
T_b	$60^{0}F$
Pressure	615 psia, reservoir

Table 7-4 Gas Inventory and Pressure History for Field G

Pressure Base = 14.7 psia
Temperature = 60°F

Time (Months)	Cumulative Gas Injection, MMcf	Pressure, psia (Reservoir)	Time (Months)	Cumulative Gas Injection, MMcf	Pressure, psia (Reservoir)
-	-	615.0	22	7018	707.3
1	22	691.0	23	7378	683.1
2	152	667.0	24	8150	713.2
3	254	630.0	25	8762	700.8
4	385	657.4	26	9235	694.1
5	527	658.3	27	9727	697.6
6	680	658.4	28	10346	713.7
7	841	658.4	29	10997	690.1
8	994	657.3	30	10893	659.5
9	1161	656.8	31	10289	618.6
10	1317	657.0	32	10846	699.0
11	1472	653.2	33	11630	717.7
12	1615	651.8	34	12274	705.2
13	1776	654.3	35	13294	744.4
14	2248	705.3	36	14394	740.5
15	2928	703.4	37	15588	737.8
16	3605	710.1	38	16660	736.9
17	4229	692.4	39	17671	742.1
18	4754	658.3	40	18691	740.0
19	5022	673.1	41	19329	708.9
20	5633	696.5			
21	6332	690.4			

7.2.2 Calculations and Results.

The resistance function method was used, as modified for the moving boundary. The radial model was used for the first 16 points (months) and the next 6 points determined resistance function directly. A linear extrapolation which corresponds to the limited aquifer was employed, as shown on Figure 7-6.

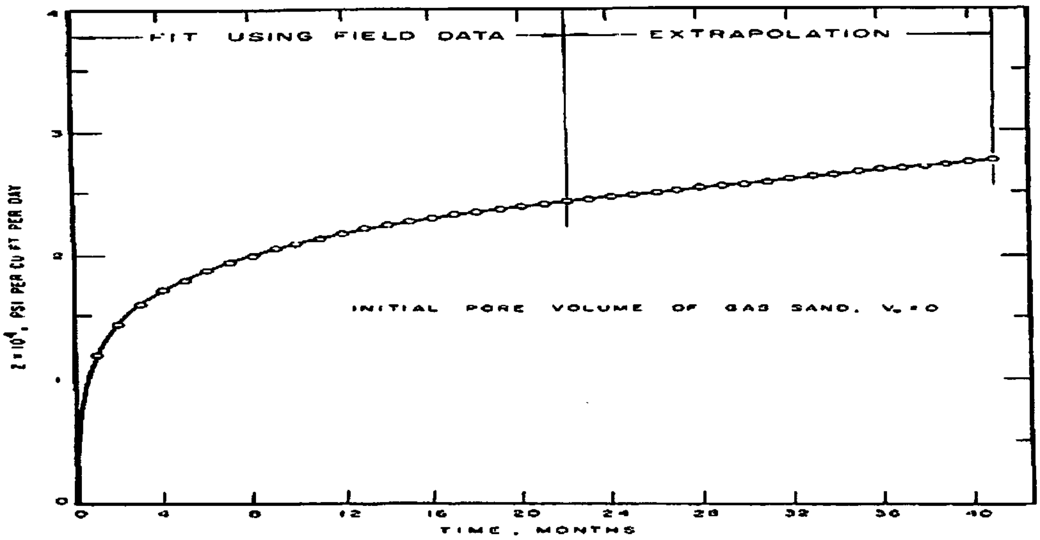


Figure 7.8 Resistance Function for field G

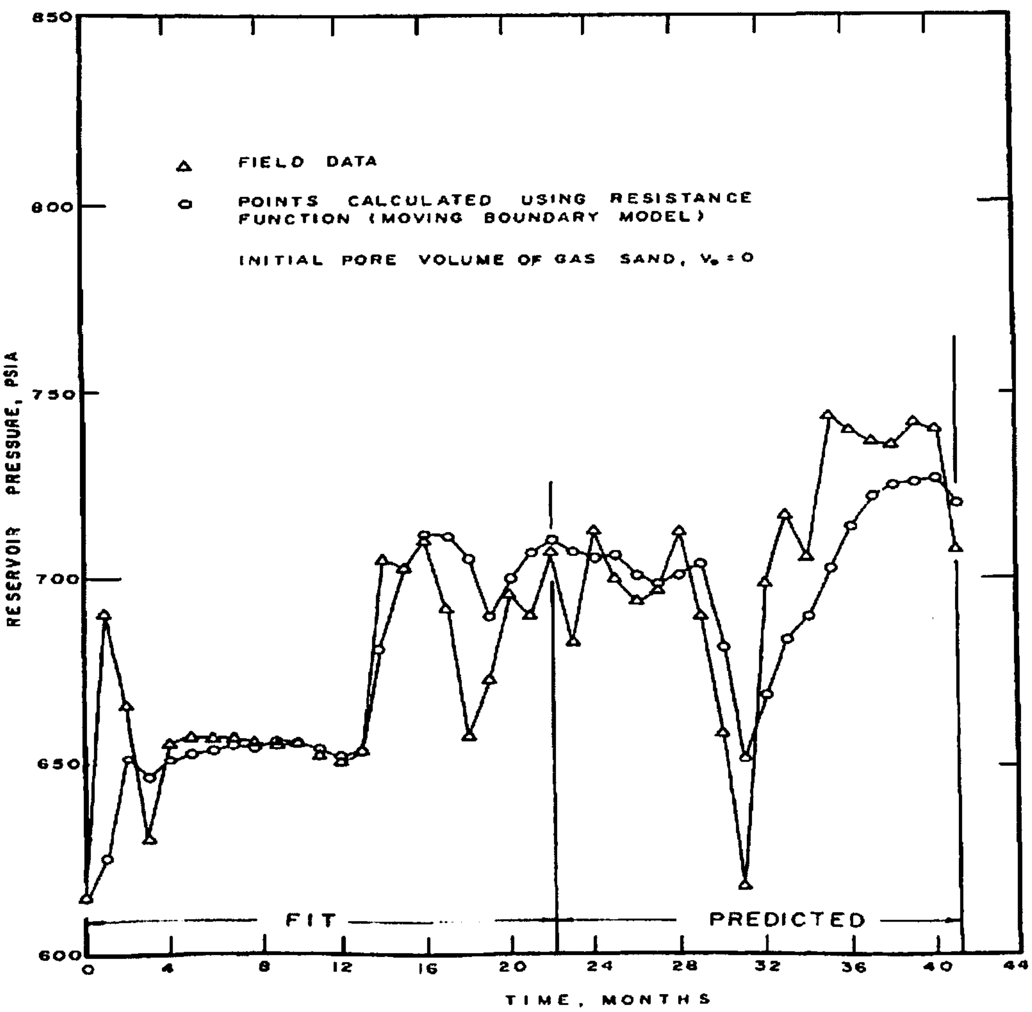


Figure 7.9 Comparison on Predicted and Observed Pressure for Field G

Various values of α for the moving boundary modification were tried including 0.7, 1.0, 1.5, and 2.0. The best results were found for 2.0; the comparison of computed and observed pressures is given on Figure 7-8.

The value of V* was arbitrarily chosen as one-half the maximum gas bubble volume or176.8 x 10_6 cubic feet.

7.3 Field H

Gas injection was started into this aquifer-type storage field some five years ago and withdrawal has occurred during five seasons. A sketch of Field H is shown in Figure 7.9.

7.3.1 Geology and Field Data

Field H is located in the extreme northeastern portion of the Forest City Basin. The gas storage anticline trends in a north-south direction, is asymmetrical (being steeper on the east than on the west), and is doubly plunging.

The reservoir, situated in the Mt. Simon sandstone, is composed of sandstone and conglomerate.

The sandstone ranges from fine to very coarse in size (quartz grains vary from 1/8 to 2 mm. in diameter); the conglomerate ranges from granule (individual quartz grains 2 to 4 mm. in diameter) to pebble (greater than 4 mm. in diameter) in size. Many shale partings and shaly sandstone streaks occur in all parts of the Mt. Simon. The individual quartz grains vary in degree of rounding from to well-rounded. The average thickness of the Mt. Simon reservoir is 115 feet, the weighted average porosity is 15.8%, and the weighted average permeability is 314 millidarcys.

The cap rock for the Mt. Simon reservoir is the Eau Claire member of the Bresbach formation which lies immediately above the Mt. Simon reservoir. The Eau Claire is composed of shaly limestone, limestone and dolomite, shale, siltstone and silty limestone. The Eau Claire averages in excess of 200 feet in thickness; permeability ranges from less than one-tenth of a millidarcy to 1 x 10^{-6} millidarcys.

The reservoir and aquifer properties are given in Table 7-5 and the production-pressure history tabulated in Table 7-6.

7.3.2Calculations and Results

The generalized performance method was employed, with a moving boundary modification as in Field G. Here ▯was used as 0.40. For the radial model, 16 time increments (months) were employed followed by 30 months for the resistance function, Figure 7-9. The pressure behavior for the remaining 44 months computed on the first try was excellent, Figure 11-10.

The reference volume, V*, used was 172 x 10_6 cubic feet (see Chapter 8) arbitrarily taken as one-half the maximum gas bubble volume.

The radial model gave better agreement for Field H than for Field G, possibly because the aquifer was of limited thickness. However, the results were not based on a moving boundary

Table 7-5 Storage Field H Reservoir Data

Aquifer

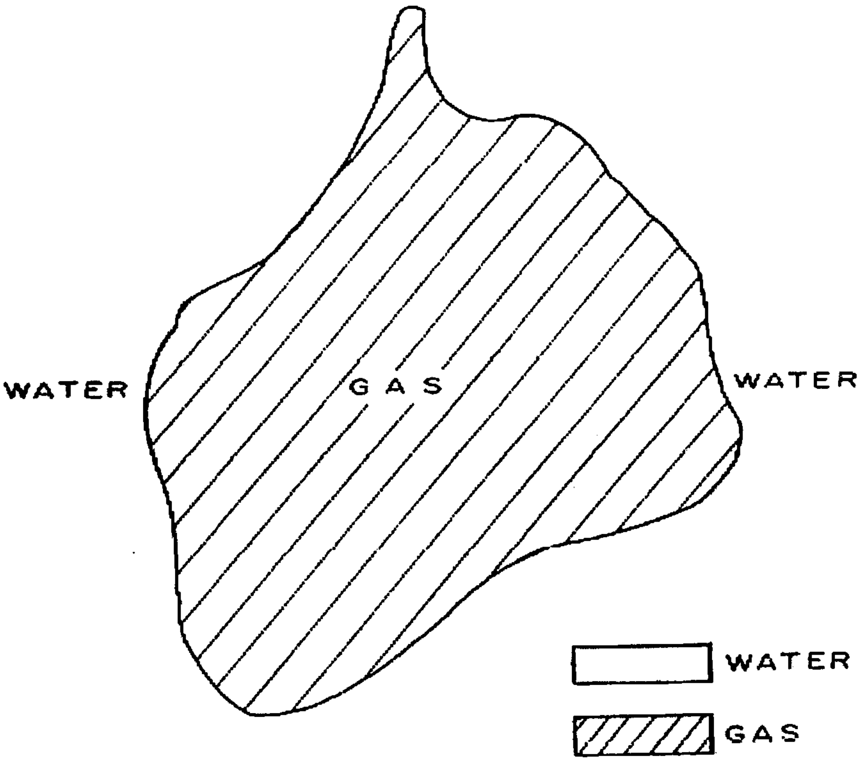
Rock Characteristics	
Formation	Mt.Simon Sandsstone
Depth to top of Aquifer	2648 Ft
Average net thickness	119ft
Average porosity	15.8%
Average permeability	314 mD

Fluid Characteristics	
Liquid Viscosity	1 centi poise
Compressibility of liquid and formation	7×10^{-6}

Gas Reservoir

Rock Characteristics	
Formation	Mt.Simon Sandsstone
Structure	Anticline
Average reservoir thickness	119 ft
Fluid characteristics	
Reservoir tempreture	79°F
Gas Compressibility correlation z=a+bP	
Pb	14.73 Psia

Tb	60°F
Initial Pressure	1042 Psig (well Head)



7.10 Areal Sketch of field II

Table 7-6 Gas Inventory and Pressure History for Field H

Pressure Base = 14.73
Temperature Base = 60°F

Time (Months)	Reservoir Gas Inventory MMcf, 14.73 psi	Pressure, psig (wellhead)	Time (Months)	Reservoir Gas Inventory MMcf, 14.73 psi	Pressure, psig (wellhead)
0	-	1042	31	19790	1130
1	224	1060	32	18934	1090
2	500	1070	33	18019	1060
3	791	1075	34	18807	1118
4	907	1056	35	20425	1180
5	907	1050	36	23607	1240
6	907	1047	37	24473	1210
7	907	1040	38	26117	1224
8	923	1058	39	29950	1290
9	975	1070	40	31620	1272
10	1032	1082	41	30509	1160
11	1318	1097	42	30509	1160
12	1934	1110	43	29175	1120
13	2554	1120	44	28469	1110
14	3902	1158	45	28972	1120
15	5314	1176	46	31210	1190
16	6369	1170	47	35678	1270
17	7389	1167	48	40110	1320
18	7389	1120	49	42980	1320
19	7402	1108	50	44695	1300
20	7446	1100	51	44781	1260
21	7523	1097	52	46896	1282
22	8712	1162	53	46842	1250
23	10354	1208	54	45683	1200
24	12233	1230	55	43614	1152
25	15074	1268	56	41355	1103
26	17560	1280	57	39737	1084
27	20503	1270	58	41695	1090
28	21474	1242	59	41695	1157
29	20933	1190	60	45966	1230
30	20513	1162			

7.3.3 Conclusions

For aquifers, no case study was available with good insitu compressibility and permeability to permit prediction of reservoir pressures prior to injection-pressure experience. It was found that for a sand of 119 feet in thickness, the resistance function method, modified for moving boundary, gave a very good prediction of pressures for the injection-withdrawal schedule.

The results for the thick aquifers with a degree of lamination were only moderately satisfactory. Neither the adapted hemispherical model nor the resistance function seemed fully adequate to the relatively early life of these storage reservoirs. However, the results can be of utility in predicting the gross reservoir behavior for storage operations.

Chapter 8
Tracers in Underground Gas Storage

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At present, aquifer storage, if and when operated successfully, appears to be the most economical method for areas devoid of depleted oil or gas fields. It is well known, on the other hand, that the success of aquifer storage depends critically on the presence of suitable geological conditions. Sufficient porosity, adequate permeability and good cap rock are among the prime requirements for such storage.

In many areas, the above factors do not simultaneously coexist. Sufficient porosity and permeability but lacks of adequate structural closure, adequate closure but leaky cap rock, semi-open structure, communicating faults or no anticline at all are typical of such conditions.

The storage of gas in such strata must require new techniques and new concepts not yet explored to date. There has been some work, reported in the literature, in storage of gas in aquifers with no structural closure. To date these methods have not yet been explored sufficiently for a significant evaluation of their potential.

8.1 Problems Associated with Leaks from Over-pressured Storage Reservoirs

Leakage or Spill from over pressured Reservoirs

In depleted oil or gas reservoir storage or in "aquifer storage" the presence of a suitable cap rock is of paramount importance for the retention of natural gas within the structural boundaries of the reservoir. The cap rock that constitutes the overburden to natural petroleum reservoir obviously does possess proved integrity to retain the gas at least up to discovery pressure. If overpressure conditions are sustained in a field, depending upon the extent of overpressure, possibility exists of gas leaking across the cap rock or moving in uncontrolled manner to formations beyond areas of minimum structural closure.

The leakage or spill of gas from a storage reservoir may be due
to:

1. Exceeding the threshold pressure of the cap rock,
2. Mechanically fracturing the cap rock because of excessive overpressure
3. by having "overpressure" of excessive extent or duration to cause water to be pushed beyond the seal of structural closures

4. By fractures extending through and across the cap, induced during drilling or formation stimulation
5. By poor bonding of the cement between casing and hole
6. By existing permeable faults or incipient fractures in the native formation.

Tracers can be used to determine how these gases behave in storage.

8.2 Tracers for underground gas storage

Several studies have been performed on the security of gas in such storage.
Tracers, both radioactive and chemical, have been used for evaluating gas loss by tagging the stored gas. Early work assessed the use of helium (Frost, 1946, 1950) and radioactive tracers (Armstrong et al., 1951) for tagging gas. There was some fear that these were not suitable for long-term monitoring of gas in storage. Helium was thought to be too mobile, and radioactivity was not suitable for use in gases for public consumption. One study of produced gas (Walker et al., 1966) proposed the use of ethylene as a tracer for stored gas, since it did not occur in natural gas. A series of tests in both water-saturated and dry sandstone cores showed that ethylene had some losses but was suitable for use as an identifying tracer.

8.2.1 Procedure in Current Use:

The three tracer methods for identification of injected storage gas in current use are:

1) Addition of tracers,
2) Compositional analysis of the stored gas,
3) Isotope ratios of selected components in the gas.

Operators had little knowledge of tracer gas migration characteristics or of the stability of many tracers under reservoir conditions. All operators depended on inventory or pressure methods to monitor the integrity of their storage systems. Tracers were likely to be used only when specific questions came up, although there has been a decrease in use of radioactive tracers because of public opinion. Olefins are often used as gas tracers (Walker et al., 1966) but have recently become suspect because of the possibility of biogenic olefins, as reported for ethylene (Cole et al., 1985). Sulfur hexafluoride and chlorofluorocarbons are also commonly used tracers. Compositional analysis may have some problems as a gas identifier because of the possibility of compositional alterations due to mixing with other gases on passing through the formation.

Specific concentrations of such gases as He, Ar, N2, and CO2 have been used as gas identifiers but these may also undergo compositional changes. The ratio of C-13 to C-12 in stored gas has been used to differentiate stored gas from "swamp" gas or other biogenic sources (Coleman, 1985). The industry seems to be relatively unconcerned about the lack of monitoring, probably because there are no other storage options.

8.3 Troubleshooting with tracers

One of the most common uses of tracers in underground gas storage is for troubleshooting when gas-loss problems arise. One interesting application of tracers is described in a paper (Araktingi et al., 1982) giving a case history of leakage problems in a gas-storage cavity in Utah. It shows how problems are solved by combining many different kinds of information. In this case, reservoir simulation, well logging, tracer surveys, surface monitoring and engineering evaluations were used together to arrive at a solution to the problem. The avenues of gas leakage were identified by using a different tracer for each path. In this case, tritium gas, Kr-85, tritiated methane, and sulfur hexafluoride were used as initial test tracers. Tritiated ethane was used as a final tracer when many of the well problems had been solved.

8.4 Inter Well Gas Tracing

Gas injection may have an entirely different function and hence a different behavior in the reservoir. The function of tracer used must be related to the operation being carried out and to the behavior of injected gas. The tracer should identify the source of injected gas and be able to monitor its appearance in the field. From these data, one can obtain directional flow trends, discern the presence or absence of flow barriers or conductive channels, and note unexpected response times. A gas usually moves at different velocity than that of carrier gas. As a result, the concept of an ideal tracer must be modified to suit the process being traced.

Any tracer that 1) is a gas under reservoir conditions. 2) has a low detection limit. 3) can survive the reservoir environment is eligible for the use as tracing gas. The should be affordable and if, it occurs naturally in reservoir, its concentration should be low enough and that it can be overcome at a reasonable cost. To be a gas at reservoir pressures, the tracers critical temperature must be below reservoir tempreture.N_2, Ar, CO, N_2O are stable and unreactive under reservoir conditions.

8.4.1 Types of Gas Tracers:

1. Radio Active gas Tracer
   - Tritium Gas
   - Krypton -85
   - Trititited methane / ethane/ propane/ butane.
   - Carbon -14 Tagged hydrocarbon
2. Non-Radioactive Tracers:
   - SF_6: measured Chromatographically using ECD
   - Halofluro Compounds-Freons
   - CO: Tagged with carbon -14 to have more sensitivity
   - N_2O: measured Chromatographically using ECD
   - CF_4 (Perfluro Methane) and $C2F_6$ (Perfluro Ethane) : their current limit of detection is 0.1 ppm
   - And no ultra sensitive method has been developed for analyzing them.
   - Cyclic Perfluro compounds: (These compounds have relatively large molecules with substantial partition into the oil phase. There would be significant lag of tracer relative to gas front.
   - Their sampling and analytical procedures are specific.

8.4.2 Designing Aspects for Gas Tracers Injection Program:

Four basic parameters are required for designing a tracer program using Gas tracers:

1. Well location Map.
2. Pay thickness of Reservoir and area concerned.
3. Average porosity of the formation.
4. Minimum detection limit of the possible chemical/ radioactive tracer to be used.

Design Calculation:

$PV = r2 * \pi * h * a * \emptyset * 0.5 * 0.178$

Where,

r= pattern radius

h=pattern thickness

π=3.1416

ø=average pattern porosity

0.5= pattern water saturation

0.178= barrel per cubic foot

A= fractional sweep pattern (sweep degree/360)

PV = pattern volume in barrels

The tracer to be used need to have the properties to ensure their behavior as traced phase. Hence the tracer must have the specific properties as:

- No reactivity with substances present in the reservoir
- Stability at reservoir conditions of temperature and pressure.
- No absorption on or exchange with the formation in the reservoir
- Following the labeled phase without influencing its properties
- Having minimum partition with the phases
- Producing clear unambiguous response during analysis
- Minimal environmental consequences

A gas tracer need to be gas at reservoir conditions, chemically inert, thermally stable to survive I the reservoir and sensitivity to get detected in lowest possible concentration levels. The chemical gas tracers which may possibly be used with natural (as carrier) along with their reported sensitivities are SF_6 (sensitivity=10^{-10} v/v), Perdeuterated methane CD_4 (sensitivity = $7*10^{-15}$ moles/m3) and N_2O (sensitivity= 10ppb). SF6 is the most suitable as its minimum detection limit is quite low and there is no possibility of its natural presence in natural gas. The required quantity of gas tracer has to be worked out considering the pattern volume for gas phase and also the detection limit of analytical equipment Gas Chromatograph. Due care has to be taken for observing significant peak counts / concentration of these tracers while they would reach to the producer undergoing dispersion through porous media of the reservoir and dilution in the reservoir/ chase fluids. Special considerations have been given to the distinctive behavior and physical properties of the gas tracers. They have significant solubility in oil, low viscosity of gas phase may lead to early break through and also undergo Chromatographic separation in oil and water.

The quantity injected is chosen to ensure that the produced tracer concentration exceeds a minimum detection limit but do not exceed the predetermined upper limit. This requires a way of estimating the volume in which the tracer will be diluted, Vd. The two procedures to estimate the dilution volume are:

1) The total dilution model, in which V_d, is calculated using gas filled pore space at a radius, r, to the average distance from the closest producers, and the thickness, h, of the formation.
2) The model of Brigham which estimates the amount of tracer required to achieve the given peak concentration using the dilution given by the pattern geometry, the number of layers and their permeability and the dispersivity of the tracers.

The amount of tracer required is based upon reservoir pore volume and does not take into account the reservoir pressure and must be increased because tracers are commonly analyzed in terms of volume per unit volume (v/v) at surface conditions. Design of tracer test takes in to account the total gas volume at surface conditions when calculating dilution volumes. The increase in dilution volume is due to several factors:

1) Gas is used under reservoir conditions. Due to its compressibility and reservoir pressure, reservoir gas dilution volume is released by the reservoir oil at surface conditions.
2) Increase due to large volume of reservoir gas dissolved in the reservoir oil, which is released by reservoir oil at surface conditions.
3) Of life gas is used to produce the well, dilution from this source must also be included. Since gas life is re-circulated, it also has the potential for contaminating other wells with produced tracer. This raises the dilemma of using enough tracers to overcome the dilution but not much that it will be source of contamination for other wells.

8.4.3 Execution

The execution of tracer program involves injection of the required amount of tracers in the identified injector and further monitoring of tracer response by regularly collecting the produced fluid samples and their analysis.

8.4.3.1 Required Equipment/ facility/ Arrangements

The main facilities and equipment required for execution of the tracer tests and also related arrangements are as under:
1) For tracer injection: the air driven Hydraulic pump system for injecting gas tracer.
2) For sampling of produced fluid samples: proper sampling hook up at test separators and sampling cylinders.
3) For analysis of samples: Gas Chromatograph with Electronic capture detector and other related arrangements and accessories for analyzing gas samples for gas tracer (SF6).

8.4.3.2 Gas Tracer Injection

The air driven hydraulic pump would be required for getting the gas tracer from the cylinder by pumping it towards the injection point. The arrangement of pressure gauges of appropriate ratings is to be made. To ensure that SF6 cylinder gets completely vacated, some weighing arrangement for cylinder would also be required. In the end the kerosene injection may be required through the pump so that all the remaining SF6 in pump assembly and flow line reaches up to the injection point and nothing is left behind. The injection of SF6 may first require its blending with other gas material to neutral buoyancy before injection of pulse of tracer. This to avoid the separation of gas tracer and carrier gas in the injection line/ tubing. Samples are taken and analyzed to about the proper blending and concentration and quantity of the tracer being used.

8.4.3.3 Monitoring

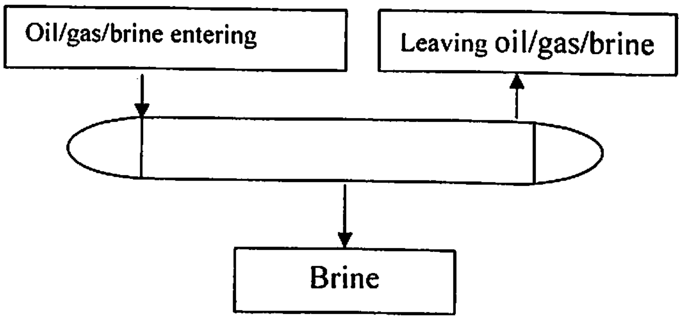
As the tracers have specific characteristics they follow identically the movements of fluid phases and undergo no loss or separation from the injection fluid during their movement through the reservoir. Hence by monitoring the movement of fluids in the reservoir with the help of tracers we may get valuable information in terms of fluid advancement, reservoir description and identification of flow channels for gas movements.

8.4.3.4 Tracer sampling

Velocities of gases are considerably higher than those of liquids because of their higher mobility. As a result, tracer breakthrough can occur quite early if there is a continuous gas path from injector to producer. Such paths can form from gravity override, through permeable channels or fractures, by viscous fingering, and / or a number of other mechanisms. Sampling programs for gas tracers need to be prepared for this. Its important to collect early samples on a frequent schedule. Selected samples may be analyzed on regular basis until tracer is found. If no tracer is found, the samples lying in between those analyzed may be discarded.

Most gas samples are collected at gas-liquid separator. This has the advantage of providing a gas sample from which the condensable liquids have been separated. Separator pressure is usually only a few atmospheres and sample are easy to collect. The principal problem with sampling using a facility or a test separator is dilution of tracer by separator gas volume and contamination of tracer from other wells.

Well head test separator



A small test separator can be mounted on individual wells. In all cases, it's necessary to flush the sample cylinder with sample gas before collecting a sample for analysis. The phase behavior of the tracer and its partition into the liquid phases in the separator should always be kept in mind when choosing sampling conditions.

Its possible to collect samples by passing the produced gas through a suitable absorber. Inorganic ad carbon molecular sieves for this purpose are sold by chromatography supply houses.

8.4.3.5 Analysis

The analysis of the produced gas will require proper analytical equipment. In most of the cases the chemical gas sample can be analyzed by using Gas Chromatography system which is based on Electron capture Detector (ECD). In case of radioactive sample it will require to liquefy the gas samples through burning and condensation or by utilizing cryogenic separation to liquefy the samples separately for different components. After liquefaction the samples can be analyzed in Liquid Scintillation Counter for all beta radio-isotopes.

8.5 Conclusion

The interwell gas tracer technique is quite useful for understanding the flow characteristics in underground gas storage system. This will be helpful further in assuring proper storage and avoiding undesirable seepage or breakthrough of gas from possible producing ends/ wells.

The tracer program will involve the designing, implementation and monitoring. The execution of gas tracer injection will preferably be carried out at starting or at initial phase of gas storage.

The monitoring of gas tracer breakthrough will require proper sampling and analysis through suitable equipment under planned equipment.

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