NATURAL GAS STORAGE ENGINEERING

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Keywords: Gas Storage, Natural Gas, Storage, Deliverability, Inventory.

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Summary

Underground storage of natural gas is an efficient process that balances the variable market demand against the constant supply of natural gas from the pipelines for engineering and economic advantages. Storage reservoirs are unique warehouses that store natural gas in times of low demand and provide a ready supply of gas in times of high demand. The various attributes that impacts design and performance of the gas storage reservoirs namely *inventory, deliverability,* and *containment* are presented in detail. In addition, the various methods that are used for inventory analysis are discussed.

1. Introduction

When gas is produced in one locality and consumed in another, economical transportation is essential. The most cost-effective and efficient natural gas transportation mode is through pipelines which operate at or near their design capacity. Steady need for natural gas seldom occurs. Therefore, to balance the variable market demand against the constant supply of natural gas from long-distance pipelines, gas storage preferably near the market is employed. When the pipeline capacity exceeds the market demand, the natural gas is injected into the underground storage reservoirs. When market demands exceed pipeline supply, the gas is withdrawn from the storage reservoirs to supplement the supply from pipelines. In addition, gas storage provides a ready supply of gas in case of the unforeseen supply disruptions.

To minimum requirements for considering an underground prospect for gas storage include:

a. A structure overlain by a caprock. The water in the water filled caprock seals the tight rock from penetration by the gas phase and prevents the gas from rising vertically, due to buoyant forces or from moving laterally and causes the gas to accumulate in the storage zone below the caprock.

b. Sufficient depth to allow the storage to take place under pressures. The pressure will allow satisfactory quantities of gas be stored into a given space and permit gas to flow readily into and out of a storage horizon.

c. A high porosity and permeability storage zone beneath the caprock that permits gas to be stored in sufficient quantities and to permit the gas to flow into and out of it readily.

d. Water below the storage zone to confine the stored gas.

All of these conditions are normally met in underground petroleum reservoir where hydrocarbon have been found trapped below a caprock and confined by underlying water for millions of years. That is why many gas storage fields are partially depleted gas (or oil) fields which have been converted to storage. Where depleted oil and gas reservoir are not available, gas can be stored in water bearing sandstones or aquifers. Aquifer storage accounts for significant potion of the gas stored underground today. When a closed structure capped by caprock quality rock is found, gas can be injected and stored in the porous sand. However, the integrity of the caprock and the quality of the sand for gas storage must be first confirmed by drilling and testing wells. In addition to natural underground structures, gas can also be stored in manmade cavities such as solution cavities in salt beds or mined caverns. Solution cavities in salt beds have been used for gas storage.

Depleted gas reservoirs are normally pressurized to back to their original discovery pressure when they are converted to storage reservoirs. However, if a good cap-rock is present, a top storage pressure higher than discovery pressure can be considered. This practice has two advantages, the larger storage capacity and higher flow capacity. However, compression requirements, market needs, production problems, and economics must be considered when selecting the storage top pressure. A storage top pressure above the discovery pressure should not be selected when the caprock is thin or mechanical conditions are questionable. Aquifer storage reservoirs, on the other hand, require gas injection at pressures above the initial value in order to displace the water and create the gas reservoir.

There are typically two types of storage facilities; "base-loading" and "peak-shaving". Base-loading facilities are capable of storing sufficient volume of natural gas to provide constant seasonal market demands. They require long injection and withdrawal cycles, turning over the natural gas in the storage usually once a year. Peak-shaving facilities on the other hand, are designed to be turned over several times in one year in response to extreme short term demand for gas. As a result, they hold much less natural gas than base-load facilities. Salt cavities are the most common type of peak-shaving storage facility.

Design, operation, and monitoring of underground storage reservoirs involve recognition of three basic requirements or attributes:

a. Inventory which represents the volume of the gas that resides in the storage horizon.

b. Deliverability which represents the ability of the storage field to deliver the gas to the market. Deliverability depends on the pressure which is a function of the volume of the gas in the storage; therefore deliverability is related to inventory.

c. Containment which represents the ability of the storage field to prevent movement of gas away from the storage horizon. Migration of gas away from the storage horizon results in attrition of the inventory and consequently loss of the deliverability. The gas loss due to migration often depends on the pressure in the storage filed which is related both to inventory and deliverability.

These attributes are discussed in detail below.

2. Inventory

Inventory represents the total volume of the natural gas in the storage field at any given time. It represents the sum total of native gas and injected gas. It varies from a minimum value at the conclusion of withdrawal to a maximum value at the conclusion of injection. The total volume in storage is calculated from pressure surveys or the pressure-content performance using volumetric and material balance equations. The gas volumes in storage are classified into two categories:

a) Working Gas (Top Gas) which is the regularly injected and withdrawn gas each cycle. It varies from season to season depending upon the demand. The amount of working gas is determined by metering gas in and out of the storage reservoir. Its upper limit is defined by the designed maximum pressure for the storage reservoir and the capacity of the surface facilities such as compression, dehydration, pipeline and others. Factors which are considered for selecting the maximum pressure include caprock integrity as well as the threshold pressure, depth, and geometric spillpoints.

b) Cushion Gas (Base Gas) which is the gas that is left behind at all times in the reservoir during the storage operations. Each storage reservoir is designed for a minimum rate of delivery to meet its market demand. To assure this rate is available even during the last day of the withdrawal season a minimum pressure level must be maintained in the storage field. Otherwise, expensive and unfeasible surface equipment must be utilized. The cushion gas can be subdivided into three categories as illustrated in Figure 1. It is possible to withdraw some limited amount of cushion gas, when necessary, after all of the working gas is produced with the available equipment at the surface. This portion of the cushion gas is the "economically recoverable cushion with existing equipment." The remaining cushion gas is not recoverable with existing equipment and can be divided into two parts. The first part is physically recoverable but requires expensive and uneconomical surface equipment. The second part is physically nonrecoverable. For example, when water invades the gas zone in a water-drive reservoir, a fraction of gas is dispersed in small quantities and becomes immobile and is physically nonrecoverable. Similarly, when a depleted oil reservoir is converted to storage, the gas that remains in solution with oil at the abandonment pressure is physically nonrecoverable.

Figure 1. Working and Cushion gas in a Storage Reservoir

3. Deliverability

The flow rates required to meet peak loads and to turn over the working inventory during the withdrawal cycle in gas storage reservoirs are much higher than are those used in normal production practices. Therefore, significantly higher number of wells is needed to meet the deliverability requirements. Accordingly, the number, spacing pattern, and penetration of wells in a storage field warrant careful consideration. The number of storage wells necessary to meet the deliverability requirements can be determined based on the individual well deliverabilities. Storage field deliverability is the summation of individual well deliverability for all the active storage wells. Different criteria may be used to estimate number of wells needed to meet peak load requirements. One possible approach is to assume that a peak demand for gas occurs at a date near the end of the withdrawal season. From the postulated seasonal demand, the amount of gas in the field for this date and the corresponding reservoir pressure can be estimated. The number of wells needed to meet this withdrawal rate can then be then evaluated based on the individual well deliverability. The calculated the total number wells in conjunction with the postulated seasonal demand are used to assure that the working gas can be turned over during withdrawal season.

The well deliverability is invariably the limiting factor because the surface facilities such as gathering lines, dehydration plants, and compressor stations are normally designed to handle all the gas that the wells will deliver. The results of the individual well tests such as back-pressure test, isochronal test, or any other type of well performance tests are used to estimate the well deliverability. The tests from the old wells in depleted reservoir can be used to establish a preliminary the well deliverability and estimated the number of well needed to be drilled. When drilling takes place, tests can be run on the new wells to insure the cumulative deliverability matches the required field deliverability. In aquifer storage reservoirs, several wells must be first drilled and results of core analysis, well log interpretation, and well tests can be used to establish the preliminary the well deliverability.

Generally, a maximum withdrawal rate per well is selected. There are several factors that will influence the maximum withdrawal rate from a well or field. One of the most significant is water conning. A high-pressure drawdown during a withdrawal will create a high differential in pressure at the bottom of the well between the gas and the underlying water. This will cause the water to rise and reach the bottom of the well. The minute it reaches the well, there will be a reduction in the deliverability of the well. This is undesirable in storage operations. The pressure drawdown, during withdrawal, that will cause water to reach the well will vary from well to well and from field to field. It must be determined by experience, and depends upon the pressure level in the field at the time of withdrawal, the thickness of the reservoir gas sand between the total depth of the well and the underlying water, and the permeability of this thickness of sand plus any permeability barrier between the gas reservoir and underlying water reservoir. In fields where there are no water problems, maximum withdrawal rates may be limited by the transmission line pressure against which the field must feed, or by the installed horsepower at the compressor station which must compress the gas into the transmission line. Maximum withdrawal rates should be set low enough to prevent the breakoff and flow of small particles of reservoir rock, because of the severe cutting effect of such particles on metal, leading possibly to rupture.

Wells must be drilled such that nearly uniform pressures across the reservoir can be achieved during injection and withdrawal. This is advantageous because for any given inventory the flowing pressure will be higher (or lower) for any withdrawal (or injection) rate. This will reduce the need for compression due to low (or high) flowing pressures. Therefore, it is a good practice to drill half of the new wells in the high flow capacity areas such top of the structure or high permeability areas and the other half around the periphery of the field or in the low permeability areas. This will allow the wells in high flow capacity areas to provide the needed deliverability while the well in the other part to facilitated the drainage of gas from the periphery or low permeability areas. Although it is possible to partially eliminate the pressure sink in the reservoir through the gathering system during the periods when gas is not withdrawn from the reservoir, it usually impractical because all the wells may not be attached to a single gathering system and there are usually some sorts of flow restrictions within the gathering system.

Experience has shown that most storage wells suffer loss of deliverability over time due to damage. In a study performed by the Gas research Institute (GRI) in United State the deliverability from storage field decline an average of 5% per year. A gradual deterioration in well capacity cannot be detected during normal field operations. Periodic testing is essential in order to determine individual well and overall field performance. Annual well tests are recommended when they can be made economically on a large scale, possibly with some additional checks on troublesome wells. The major causes of damage in gas storage wells are bacteria, inorganic precipitates, hydrocarbon and organic residue, and particulate plugging. Sulfate-reducing bacteria grow in anaerobic environment encountered in bottom of wellbore and cause damage at sandface. Inorganic precipitates included iron compounds which are often formed as result of bacterial activities and quartz fragments which blocked the sandface. The organic residue is formed as result of degradation of compressor oil, lubricants, and production chemical used for pipeline corrosion control. The particulate are often entrained by gas being injected and plug the sandface.

When the storage field deliverability deteriorates either the delivery capacity of present wells must be increased or additional wells must be drilled. Remedial procedures to increase well deliverabilities are generally more economical than drilling additional wells to make up the lost deliverability. It is estimated that gas storage industry in US spends $100 million each year to recover or replace the lost deliverability. Identification of damage mechanisms is the first step in optimization of the remediation treatment. Proper candidate well selection is just as crucial. Historical data and reservoir/geological description are required to rank candidates and design the treatment. Generally, multi-rate well test are necessary to evaluate the impact of stimulation treatment and ranking of candidate wells. Electronic flow measurement (EFM) system that capable of collecting high-frequency pressure and flow rate data at wellhead are widely used in storage operations. Analysis methods have been proposed to utilize such data to monitor well conditions and provide a dynamic assessment of damage in the wells.

The stimulation techniques that are commonly utilized to restore well deliverability include acidizing; fracturing; a combination of acidizing, hydroblasting, and perforating; and refracturing. It is important to note that when hydraulic fracturing is employed to re-store well deliverability, certain issues should be considered. Uncontrolled fracture height growth can compromise the storage reservoir seals resulting in gas loss. The continuous cycling of dry natural gas through storage reservoir often results in evaporation of interstitial water near the wellbore and the reduction of water saturation below irreducible water saturation. The introduction of fracturing fluid into such formation will result in reduction of gas permeability and it might take a long time before the full benefit of stimulation treatment is achieved. The use of non-aqueous stimulation fluids such as liquid CO_2 has been shown to provide some benefits in this regard.

4. Containment

The injected gas must remain in the gas storage reservoir for an extended period of time. The possibility that gas might find a way to escape through permeable channels in the overlying or underlying reservoir seals or mechanical imperfections in the wellbores and piping system should be considered carefully. Monitoring systems are necessary to ascertain that gas does not leave the intended storage system and alert the operator to an unexpected gas movement so that corrective action can be accomplished. The major component of the monitoring system is a group of observation wells. There are different types of observation wells including storage zone gas observation wells, storage zone water observation wells, spillout water observation wells, and water observation wells in intermediate permeable layers above the caprock.

Gas pressure observation wells are an important part of storage operations. These wells remain shut-in continuously, and wellhead pressures are gauged, usually with a deadweight gauge, as often as once a day. These pressures can be correlated with working gas content. Since water confines the gas and it is subject to movement under pressure, water bearing zones surrounding the gas bubble must be included in the monitoring system. Water observation wells in all general directions are helpful; both to determine the structural details and to show continuously that gas has not reached the location in question. A general guiding principle is that the wells on the edges of the field should be observed both for absence of gas and the degree of pressure change.

Spillout observation wells are needed near the structure saddles to determine whether gas has reached the saddle. In some instances it may be desirable to maintain field pressures above field discovery pressure in order to increase the storage capacity. Good structural control must be achieved all around the field, and the spill point must be known to be well below the original water level, before this procedure is attempted.

The caprock will not permit any gas to escape from the storage reservoir if the storage top pressure does not exceed the initial reservoir pressure. To assure that caprocks can resist gas movement when subjected to pressures above the initial pressure, threshold pressure measurements can be performed on sample of caprock However, unknown geological anomalies, that interrupt the continuity of the caprock, may permit upward gas migration. Gas entering the water filled confining zone above the caprock would cause a significant water level change in the observation wells in this zone. Uncontrolled gas migration may permit gas to enter water-bearing zones used for local water supply. Provisions should be made for venting any unexpected water well gas without permitting it to accumulate where it could form a combustible mixture with air.

Mechanical problems such as poor cement bonds or casing leaks can be also sources of gas loss through wellbores. Cement bond logs and casing surveys must be conducted periodically to locate potential problems. Temperature logs and spinner surveys are also useful tool to confirm any gas leakage from the wellbore.

Small gas reservoirs frequently exist adjacent to large storage reservoirs. It is often difficult to confirm whether these reservoirs are communication. Pressure fluctuations in these small reservoirs may be entirely due to pressure transmission through underlying continuous brine aquifers. Periodic sampling and analysis of gas produced from the small reservoirs will provide evidence if gas migration from the storage reservoir exists, provided that stored gas can be distinguished from native field gas. It is very unlikely that gases from two different sources will have identical compositions. As a result, the relative proportions of the various hydrocarbons in natural gas (methane, ethane, propane, etc.) and of the non-hydrocarbon gases (nitrogen, carbon dioxide, helium, argon, etc.) can frequently be used to distinguish gases from different sources. Gas analyses should be made of all natural gases in the vicinity of the depleted gas field about to be converted. Such analyses may also help identify the source of the gas found in the water wells. Gas analysis may be a useful tool for studying underground gas movement and possible gas migration to nearby reservoirs. However, the concentrations of some of the components may change during migration. Unlike the chemical composition, the isotopic composition of natural gas is relatively unaffected by migration. Isotopes of an element only differ in the number of neutron within their nuclei. The two stable isotopes of carbon, ^{12}C (C-12) and ^{13}C (C-13) are present in all organic materials. The isotopic composition of carbon or isotope ratio (^{12}C /^{13}C) generally serves as more reliable indicators of gas origin. To differentiate between native gas and storage gas, the composition and geochemical fingerprint of both native gas and storage gas must be determined. In an active gas storage field, the volume and the composition of the injected gas may vary with time. Therefore, historical data on the composition of injected gas in addition to samples of current injection gas are necessary. When historical data are not available, samples of the gas from a number of observation wells may be used to represent the range of the geochemical composition of stored gas. The accuracy of this assumption will depend on degree of mixing in the storage field. The geochemical fingerprint of native gas can be established by analysis of samples from producing wells completed in the storage formation but are sufficiently distant from the storage field that they could not contain any migrated storage gas.

5. Inventory Analysis

Inventory analysis or verification is a way to keep track of amount of gas in the storage field. Reconciliation of the inventory that is actually in the storage horizon with the values carried by gas accounting (book values) is important both for economic as well as technical reasons. Gas losses from storage reservoir reduce the inventory below the book values which represent a financial loss and directly affect deliverability. That is why the inventory analysis is an indispensable aspect of storage operation. The objectives of inventory verification include the following:

- To verify that the book inventory is actually present in the reservoir.
- To determine the magnitude of the gas loss (if any).
- To monitor growth (or shrinkage) of the gas bubble in aquifer storage reservoirs.

The basic data used for inventory analysis are shut-in well pressures and volumes of gas metered into (injection) and out of (withdrawal) the field. The methods for inventory analysis include:

- *Volumetric Method*
- *Pressure-Content Method*
- *Inventory Per Pound Method*

Each of these methods will be described below.

5.1 Volumetric Method

The storage fields are shut-in during the turnaround times in spring and fall of each year when the market demand and pipeline supply of gas are in balance. Generally, these periods are long enough to allow for substantial pressure equalization between the wells. Given the shut-in pressures and the gas filled pore volume assigned to each well based on the geostatistical method which integrates distributions of formation thickness (generally from the isopach map), porosity, and water saturation, the gas-in-place can be calculated. The calculated gas-in-place can then be compared to the book inventory to evaluate cumulative loss or ineffective gas figure by difference.

5.2 Pressure-Content Method

This method involves preparing a plot of the average bottom-hole pressure divided by gas deviation factor (*p/z)* against corresponding book inventories (*I*). For a volumetric (constant volume) reservoir, pressure-content plot will be represented by a straight line which passes through the origin as illustrated in Figure 2. The slope of the line is inversely proportional to the pore volume of the gas bubble. In volumetric reservoirs as the inventory changes, *p/z* remains on the same line.

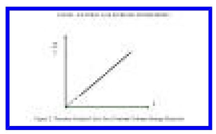

Figure 2. Pressure-Content Curve for a Constant Volume Storage Reservoir

The average bottom-hole pressure is determined by volumetrically averaging shut-in pressure during turnaround times at the end of injection and withdrawal cycles. However to monitor the inventory on a continuous basis during injection and withdrawal cycles, the pressure readings on a *key indicator well* is often used. The *key indicator well is* an observation well that is completed in the storage horizon is believed that its pressure closely correlates with the average pressure in the storage field. In practice, the indicator well pressures at the surface (*psig*) are correlated to volumetrically averaged *p/z* in bottom-hole (*psia)* using the shut-in pressures at the end of each cycle. In the rare instances where there are more than one key well available, it may be necessary to calculate an average pressure. If the storage reservoir has been subject to loss of its inventory, the pressure-content line will be subject to a lateral parallel shift to the right as illustrated in Figure 3. The intercept of the line with the inventory axis provides the magnitude of the loss.

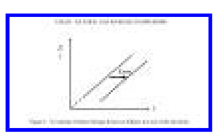

Figure 3. A Constant Volume Storage Reservoir Subject to Loss of the Inventory

When a storage reservoir is subject to water drive, the pressure-content plot exhibits two different traces on withdrawal and injection. This is illustrated in Figure 3. The different curvature during withdrawal and injection is the reason that these plots are commonly referred to as “hysteresis" plots.

As illustrated on Figure 4, at the beginning of the injection cycle the water continues to move in since the gas bubble pressure is lower than aquifer pressure. As result, the gas bubble volume continues to shrink. This results in a steep increase in pressure. As the inventory is being restored from minimum value (I_{min}) to a maximum value (I_{max}), the pressure in the gas bubble will continue to increases and eventually the gas bubble and aquifer reach a pressure balance upon which the water ceases to move in. After this point, the plot traces a straight line since gas bubble volume remains almost constant. The gas bubble pressure eventually exceeds aquifer pressure and the water begins to move out. This causes the gas bubble volume to expand and pressure increase will be attenuated. At beginning of the withdrawal cycle, the gas bubble pressure is above the aquifer pressure and gas bubble volume is still expanding as water continues to move out. The inception of gas withdrawal results in a steep decline in pressure. However the pressure in the gas bubble will continue to decreases as withdrawal continues and eventually the gas bubble and aquifer reach a pressure balance and water ceases to move out. After this point, the plot again traces a straight line since gas bubble volume remains almost constant. The gas bubble pressure eventually falls below aquifer pressure and the water begins to move in again. This causes the gas bubble volume to shrink and pressure decline will be attenuated.

Figure 4. Pressure-Content Plot for a Storage Reservoir Subject to Water Movements

For an aquifer storage reservoir without any inventory losses, the pressure-content loop for consecutive withdrawal/injection cycles remains inside the basic envelope delineated by two limiting gas bubble volume at maximum and minim inventories. If the storage reservoir has been subject to loss of its inventory, the pressure-content loop will be subject to a lateral shift to the right as illustrated in Figure 5.

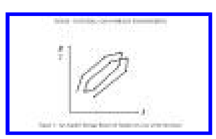

Figure 5. An Aquifer Storage Reservoir Subject to Loss of the Inventory

5.3 Inventory Per Pound Method

This method involves preparing a plot of total and incremental inventories per pound against time. The total and incremental inventories per pound are defined as:

$$TIPP = \frac{G_b}{p/z}, \qquad IIPP = \frac{\left(G_{bi} - G_{bw}\right)}{\left[\left(p/z\right)_i - \left(p/z\right)_w\right]}$$

where:

TIPP	: Total inventory per pound (total inventory per pressure unit)
G_b	: Book inventory
p/z	: Average pressure divided by real gas deviation factor
IIPP	: Incremental inventory per pound (pressure unit)
w	: End of withdrawal cycle
i	: End of injection cycle

For a volumetric (constant volume) reservoir, the total and incremental inventories per pound are constant with time. However if the reservoir has been subject to loss of the inventory, the total inventory per pound will increase with time while the incremental inventory per pound will remain constant. If both total and incremental inventories per pound increase with time, then the gas bubble is growing.

Related Chapters

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Glossary

Aquifer	: A Water bearing sandstone formation in subsurface
Acidizing	: Use of acid to increase or restore rock permeability
Back-pressure Test	: A multi-rate test where the pressures at each rate is stabilized
Base-loading	: A Storage field capable of providing steady gas supply
Book Inventory	: The net volume of the gas in the storage measured at surface
Caprock	: A water filled tight rock that prevents gas penetration
Containment	: The ability of the storage field to prevent gas from migration
Cushion Gas	: Gas which is left behind at all times in the storage
Damage	: Reduction of the rock permeability to gas near the wellbore
Deliverability	: Ability of the storage field (or well) to deliver the gas to the market
Drawdown	: The difference between the reservoir pressure and wellbore pressure
Fracturing	: Use of hydraulic pressure to create fractures in the rock
Inventory	: The volume of the gas in the storage horizon
Isochronal Test	: A multi-rate test where the pressure only at one rate is stabilized

Peak- shaving : A Storage field capable of providing short-term extreme gas supply

Permeability : A parameter that reflects ability of the rock to conduct fluids

Stimulation : Increase of the rock permeability to gas near the wellbore

Water Conning : The rise of the underlying water into a gas zone

Well Log : A tabulated record of geophysical tool measurements at various depths in a well

Working Gas : Gas which is the regularly injected and withdrawn from the storage

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Biographical Sketches

Kashy Aminian was born in Tehran, Iran in 1953. He holds Ph.D. (1982) and M.S.E (1978) in chemical engineering from University of Michigan and B.S. (1976) in chemical engineering from Tehran University.
He has been a Professor of Petroleum & Natural Gas Engineering for the past 16 years at West Virginia University in Morgantown West Virginia. He has 28 years of distinguished service in both industry and academia. He has extensive experience in natural gas reservoir and storage engineering and has published over 75 technical articles. Aminian is a member of Society of Petroleum Engineers (SPE)

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To cite this chapter
Kashy Aminian, Shahab D. Mohaghegh ,(2008),NATURAL GAS STORAGE ENGINEERING, in *Petroleum Engineering-Downstream*, [Ed.Pedro de Alcantara Pessoa Filho], in *Encyclopedia of Life Support Systems (EOLSS),* Developed under the Auspices of the UNESCO, Eolss Publishers, Oxford ,UK, [http://www.eolss.net] [Retrieved March 10, 2009]

