CHAPTER 8

Underground Natural Gas Storage

8.1 Introduction

In the United States and a few other countries, the underground storage of natural gas has become increasingly important after World War II. The obvious reason for storage is that, traditionally, natural gas usage has been changing with seasons. The demand has been higher in the winter, prompted by residential heating. Thus, the “base load” and the “peak load” natural gas, not just in different seasons, but also different days within a season, can be quite different. This situation could create an imbalance between the receipts and deliveries of a pipeline network. To avoid supply disruptions, underground storage can be used to provide pipelines, local distribution companies, producers, and pipeline shippers with an inventory management tool, seasonal supply backup, and access to natural gas as needed (EIA, 2008). In addition, natural gas storage is also used by industry participants for commercial purposes: to store gas when gas price is low and withdraw and sell gas when the price is high (Speight, 2007).

Currently, most of the natural gas storage facilities are in the United States, with very few in Japan and Europe. By the end of 2007, there were about 400 underground storage reservoirs in the United States with working gas capacity of ~4,100 Bcf and deliverability rate potential of ~89 Bcf/d (EIA, 2008). There are other ways to store natural gas (such as in liquid form in above-ground tanks as LNG, discussed in Chapter 6). In this chapter, we will only focus on underground natural gas storage. The impact of LNG on gas storage will be briefly discussed at the end of the chapter.
8.2 Types of Underground Storage

There are primarily three types of underground storage facilities, and the descriptions below, widely acceptable in the industry, are taken mostly from the EIA (2004):

- **Depleted oil or gas reservoirs**—The advantage of converting a field from production to storage duty is that one can use the existing wells, gathering systems, and pipeline connections. It is usually close to consumption centers. This type of underground storage sites, as shown in Figure 8–1, is widely used in the United States (about 326 sites, accounting for 82 percent of the total at the beginning of 2008, EIA, 2008).

- **Aquifers**—An aquifer is suitable for gas storage if the water bearing sedimentary rock formation is overlain with an impermeable cap rock. Storage is created by injecting gas and displacing the water. Therefore, the water movement and cap rock quality should be taken into account when selecting and designing the storage (Katz and Tek, 1981). This type of storage usually requires more base (or cushion) gas (for definition see Section 8.3 “Storage Measures”) and greater monitoring of withdrawal and injection performance. With the presence of an active water drive, the deliverability rates may be enhanced.

- **Salt caverns**—Salt caverns provide very high withdrawal and injection rates relative to their working gas capacity. Base gas requirements are relatively low. As shown in Figure 8–1, the large majority of salt cavern storage facilities have been developed in salt dome formations located in the US Gulf Coast States. Salt caverns have also been leached from bedded salt formations in the Northeastern, Midwestern, and Southwestern United States to take advantage of the high injection/withdrawal rates and flexible operations possible with a cavern facility. Cavern construction is more costly than depleted field conversions when measured on the basis of dollars per thousand cubic feet of working gas capacity, but the ability to perform several withdrawal and injection cycles each year reduces the per unit cost of each thousand cubic feet of gas injected and withdrawn.

Some reconditioned mine caverns have been in use as well. Hard rock caverns can also be good candidates of gas storage (Heath et al., 1998).
To determine a field's suitability as a natural-gas storage, its physical characteristics such as porosity, permeability, and retention capability should be examined along with the site preparation costs, deliverability rates and cycling capability. The good underground storage reservoir is obviously the one that has high capability to hold natural gas for future use and high deliverability rate at which gas inventory can be withdrawn.

8.3 Storage Measures

It is necessary to introduce some of the concepts used in storage calculation before we go to the detailed calculation of the storage capacity. For consistency, here we use the same definitions as they are used by EIA (2004):

- **Total gas storage capacity**—the maximum volume of gas that can be stored in an underground storage facility by design. It is determined by the physical characteristics of the reservoir and installed equipment.

- **Total gas volume in storage**—the volume of storage in the underground facility at a particular time.
• **Base gas or cushion gas**—the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. It contains two elements (Tureyen et al., 2000):

  • *Recoverable base gas*—the portion of the gas that can be withdrawn with current technology, but it is left in the reservoir to maintain the pressure.

  • *Non-recoverable base gas*—the portion of the gas that cannot be withdrawn with the existing facilities both technically and economically.

The relationship among the total gas storage capacity, total gas volume in storage, and base gas is illustrated in Figure 8–2.

• **Working gas capacity**—the total gas storage capacity minus base gas, i.e., the volume of gas in the reservoir above the level of base gas. So, for a given storage capacity, the higher the base gas is, the lower the working gas will be, the less efficient the storage will be.

• **Injection volume**—the volume of gas injected into storage fields during a given period.

• **Deliverability or deliverability rate, withdrawal rate, withdrawal capacity**—a measure of the amount of gas that can be delivered or withdrawn from a storage facility on a daily basis with the unit of MMscf/d, same as that for production rate. Occasionally, it is expressed in terms of equivalent heat content of the gas withdrawn from the facility such as dekatherms per day. A therm is roughly equivalent to 100 scf of natural gas; a dekatherm is about 1 Mscf. In general, a facility's deliverability rate varies directly with the total amount of gas in the reservoir; it is at its highest when the reservoir is most full and declines as working gas is withdrawn.

• **Injection capacity or rate**—the amount of gas that can be injected into a storage facility on a daily basis. As with deliverability, injection capacity is usually expressed in MMscf per day, although dekatherms per day is also used. By contrast, the injection rate varies inversely with the total amount of gas in storage; it is at its lowest when the reservoir is most full and increases as working gas is withdrawn.
8.3 Storage Measures

These measures for any given storage facility are not necessarily absolute and are subject to change or interpretation. In the following sections, natural gas storage is viewed in terms of a depleting or increasing pressure in a closed reservoir without active water drive. If the reservoir pressure is supported by active water movement, equations have to be modified (Katz and Tek, 1981; Mayfield, 1981).

8.3.1 Total Gas Volume and Injected Gas Volume in Storage

The injected gas volume in a depleted gas reservoir can be calculated by using a similar approach as discussed in Section 1.6.4 “Gas Formation Volume Factor” of Chapter 1 for the initial gas-in-place calculation of a producing field (Eq. (1.13)). Assume the reservoir pore volume is constant, the initial gas-in-place in the depleted gas reservoir in standard conditions is $G_i$, and the total gas volume in storage facility is $G$, then the cumulative injected gas volume, $G_s$ is

$$G_s = G - G_i,$$

or, by employing the formation volume factors at initial and final conditions

$$G = G_i \frac{B^{gi}}{B^g} - G_i = G_i \left( \frac{B^{gi}}{B^g} - 1 \right).$$

Figure 8–2 Storage measures

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or, by employing the formation volume factors at initial and final conditions

$$G = G_i \frac{B^{gi}}{B^g} - G_i = G_i \left( \frac{B^{gi}}{B^g} - 1 \right).$$
Note: the $G_i$ is the residual gas in a depleted gas reservoir that will be used for storage, or the initial gas in a storage field after the seasonal withdrawal and at the beginning of the resumption of injection. It can be calculated by using Eq. (1.13). Substituting Eq. (1.12) into Eq. (8.2) and assuming the temperature is constant, Eq. (8.2) becomes

$$G_s = G_i \left( \frac{p/Z}{p_i/Z_i} - 1 \right) = \frac{G_i}{p_i/Z_i} \left( \frac{p}{Z} - \frac{p_i}{Z_i} \right). \quad (8.3)$$

In Eqs. (8.1 to 8.3), the subscript $i$ stands for the initial conditions of the gas storage. The pressures are measured when the storage is at its maximum and minimum capacities. The pressures measured are then near the maximum and minimum pressures. Eq. (8.3) is valid when there is no active water drive.

**Example 8–1 Calculation of total gas volume**

A depleted gas reservoir is converted to natural gas storage. The reservoir data and conditions are given in Table 8–1. Calculate the total gas volume in the reservoir and the total injected gas volume at $p = 6,000$ psi. For convenience, $Z$ is given as 1.07 (otherwise it can be calculated by using the correlations given in Chapter 1 with $\gamma_s = 0.6$). Assume the temperature will be the same as the initial temperature.

**Table 8–1 Input Parameters for Example 8–1**

<table>
<thead>
<tr>
<th>Variable</th>
<th>Quantity</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$A$</td>
<td>200</td>
<td>acre</td>
</tr>
<tr>
<td>$h$</td>
<td>50</td>
<td>ft</td>
</tr>
<tr>
<td>$\phi$</td>
<td>0.25</td>
<td></td>
</tr>
<tr>
<td>$S_w$</td>
<td>0.25</td>
<td></td>
</tr>
<tr>
<td>$\gamma_s$</td>
<td>0.6</td>
<td></td>
</tr>
<tr>
<td>$T_i$</td>
<td>150</td>
<td>°F</td>
</tr>
<tr>
<td>$p_i$</td>
<td>1,000</td>
<td>psi</td>
</tr>
<tr>
<td>$Z_i$</td>
<td>0.91</td>
<td></td>
</tr>
</tbody>
</table>
Solution

Use Eq. (1.12) for the calculation of the formation volume factors

\[
B_{gi} = 0.0283 \times \frac{0.91 \times (150 + 460)}{1,000} = 0.0157 \text{ res ft}^3/\text{scf},
\]

\[
B_{s} = 0.0283 \times \frac{1.07 \times (150 + 460)}{6,000} = 0.0031 \text{ res ft}^3/\text{scf}.
\]

Use Eq. (1.13), at 1,000 psi

\[
G_i = 43,560 \times \frac{200 \times 50 \times 0.25 \times (1 - 0.25)}{0.0157 \times 1,000,000} = 5,202 \text{ MMscf}.
\]

Total gas volume in storage at 6,000 psi can be calculated as

\[
G = 5,202 \times \frac{0.0157}{0.0031} = 26,346 \text{ MMscf}.
\]

The cumulative gas volume injected can be obtained from Eq. (8.1)

\[
G_s = 26,346 - 5,202 = 21,144 \text{ MMscf},
\]

or by using Eq. (8.2)

\[
G_s = 5,202 \times \left( \frac{0.0157}{0.0031} - 1 \right) = 21,144 \text{ MMscf}.
\]

This is an important exercise as, in reality, the initial gas-in-place for a given storage is often not known. By recording the cumulative injected gas volume at given conditions \((p \text{ and } T)\) and assuming the temperature is constant at all time (a reasonable assumption), then \(p/Z\) versus \(G_s\) can be plotted. If there is no aquifer support, this line should be straight, as demonstrated in Figure 8–3, and the slope can be determined. Rearranging Eq. (8.3) gives

\[
\frac{p}{Z} = \frac{G_s(p_i/Z_i)}{G_i} + \frac{p_i}{Z_i}.
\]
A plot of \( p/Z \) versus \( G_s \) should yield a straight line and the slope should be \((p_i/Z_i)/G_i\). Therefore the initial gas-in-place can be obtained by

\[
G_i = (p_i/Z_i)/\text{slope.}
\]  \hspace{1cm} (8.5)

\( p/Z_i \) can be determined by measuring the pressure at initial conditions through a pressure buildup test.

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**Example 8–2** Calculation of initial gas-in-place

Determine the initial gas-in-place for a shallow, low pressure gas storage reservoir. The injected gas over time and the \( p/Z \) data are given in Table 8–2.

**Table 8–2** Input Data for Example 8–2

<table>
<thead>
<tr>
<th>Year</th>
<th>Season</th>
<th>( G_s ), Bcf</th>
<th>( p/Z ), psia</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year ( i )</td>
<td>Spring</td>
<td>13.5</td>
<td>365</td>
</tr>
<tr>
<td></td>
<td>Fall</td>
<td>17.6</td>
<td>470</td>
</tr>
<tr>
<td>Year ( i + 1 )</td>
<td>Spring</td>
<td>14.5</td>
<td>389</td>
</tr>
<tr>
<td></td>
<td>Fall</td>
<td>17.5</td>
<td>465</td>
</tr>
</tbody>
</table>

---

**Figure 8–3** \( p/Z \) curve vs cumulative gas storage

A plot of \( p/Z \) versus \( G_s \) should yield a straight line and the slope should be \((p_i/Z_i)/G_i\). Therefore the initial gas-in-place can be obtained by

\[
G_i = (p_i/Z_i)/\text{slope.}
\]  \hspace{1cm} (8.5)

\( p/Z_i \) can be determined by measuring the pressure at initial conditions through a pressure buildup test.
8.3 Storage Measures

Solution

Plot $p/Z$ versus $G_s$ (see Figure 8–4) by using the data provided in Table 8–2. Obviously this is an ideal case as it shows the slopes from both Year $i$ and Year $i + 1$ are pretty much the same and is about 25.5 psia/Bcf. Extrapolate the line and intercept it with the vertical axis. This gives $p_i/Z_i = 21.0$ psia (at $G_s = 0$). Use Eq. (8.5), the initial gas-in-place for this given gas storage is

$$G_i = \frac{21.0}{25.5} = 0.824 \text{ Bcf.}$$

This is also a good tool to evaluate the gas losses in storage, which is one of the critical issues in gas storage that should be addressed.

8.3.2 Losses in Gas Storage

Gas loss in gas storage is a very serious issue. It happens when the cap rock does not seal well, cement around the wellbore is flawed, or there is a communication between the storage and other reservoirs. Once gas loss is happening, the storage deliverability or withdrawal rate will decline from year to year, and the operator will have to bear with high cost or even the risk of not meeting the peak demand. A

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1. Some of the material in this section is contributed by Phil Lewis, 2009.
report (Neukarn, 2008) showed that the annual losses can be up to 0.5 Bcf. If the gas price is $4/Mscf that means this storage is losing $2 million per year, which is a significant loss. Therefore, gas storage must be monitored properly to determine the magnitude of such loss, the root cause, and remedy it as soon as it is detected.

For gas storage that is converted from depleted gas reservoir with no water drive, the gas flows to the wells primarily by gas expansion. Then a procedure can be used to determine the gas loss (Mayfield, 1981).

There are several ways to determine the reservoir pressure. One way is to conduct regular (e.g., semiannual) pressure build-up tests similar to pressure surveys done in gas production fields. Another way is to monitor the bottomhole pressure in observation wells. Ordinarily, these pressure surveys are conducted in the fall and spring when reservoir pressure is near maximum and minimum for total gas volume calculation (as discussed in Section 8.3.1 “Total Gas Volume and Injected Gas Volume in Storage”). The preferred observation well is the one at the location with the highest permeability. The plot is usually smoother and more reliable for the injection season as the injection rate is usually constant. During the withdrawal season, fluctuation can happen as the demands from pipeline systems can be different (Mayfield, 1981).

The total gas in storage or gas-in-place can be plotted along with the determined $p/Z$. If there is no gas loss, all data points should fall on the same line after repeated cycles of injection and withdrawal. If the slope of the line becomes smaller, this is likely to mean that the storage increases because of gas migration or leakage.

When there is gas loss, parallel lines would appear from year to year and are shifted towards a larger gas volume at a given $p/Z$. The difference between these lines is gas loss. This can be seen in Example 8–3.

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**Example 8–3 Calculation of gas loss**

Assume this is the same storage reservoir as that shown in Example 8–2. After a few years, well deliveries started declining. The bottomhole pressure over $Z$ and gas injected in Year $i + 2$ are collected and summarized in Table 8–3.

**Solution**

Plot $p/Z$ versus $G_s$ for different years in Figure 8–5. Results show that the line from Year $i$ is overlain with that from Year $i + 1$. The line from Year $i + 2$ is parallel with those from Year $i$ and Year $i + 1$ but shifted towards a larger $G_s$. This implies that the storage is losing gas.
8.3 Storage Measures

From the data set of Year \( i \) and Year \( i + 1 \), Eq. (8.4) yields

\[
\left( \frac{p}{Z} \right)_{i+1} = 25.5(G_s)_{i+1} + 21.0.
\]

Similarly, from the data set of Year \( i + 2 \), Eq. (8.4) yields

\[
\left( \frac{p}{Z} \right)_{i+2} = 25.2(G_s)_{i+2} + 4.4.
\]
Choose \( p/Z = 465 \) psia, then \((G_s)_{i+1} = 17.4 \) Bcf, and \((G_s)_{i+2} = 17.9 \) Bcf. So the gas loss = \((G_s)_{i+2} - (G_s)_i = 0.5 \) Bcf.

Gas loss can also be determined by plotting \( G_s/(p/Z) \) versus time (year). If \( G_s/(p/Z) \) does not change with time, it is an indication that the storage facility is secure. If the values are increased with time, that will be an indication that either the storage is losing gas or the effective size of the storage is increased. The amount of gas lost can be determined by using the procedure outlined above.

### 8.3.3 Injectivity in Gas Storage Well

The expression for injectivity of a gas storage well can be inferred from the expressions for the productivity of a gas well, remembering that in storage, gas is injected into a closed system (unless there is a leak). So steady state is not applicable in injectivity evaluation of gas storage wells. Under pseudosteady state, the injectivity can be calculated by

\[
q_{inj} = \frac{kh(p_{inj}^2 - p^2)}{1,424\mu ZT\ln\left(\frac{0.472r_e}{r_w}\right) + s}.
\]  

For transient flow, in terms of real gas pseudopressure,

\[
q_{inj} = \frac{kh[m(p_{inj}) - m(p_i)]}{1,638 T}\left[\log t + \log\frac{k}{\phi(\mu c_i)r_w^2} - 3.23 + 0.87s\right]^{-1},
\]  

or, in terms of pressure squared difference,

\[
q_{inj} = \frac{kh[p_{inj}^2 - p^2]}{1,638 \mu ZT}\left[\log t + \log\frac{k}{\phi(\mu c_i)r_w^2} - 3.23 + 0.87s\right]^{-1}.
\]

In Eq. (8.7), the \( m(p) \) is defined in Eq. (3.19).

In Chapter 3, we presented a comprehensive method of combining material balance \((p/Z \text{ versus } G_p)\) along with well deliverability, and showed how to establish a forecast of well performance. The production rate decreases as the reservoir pressure decreases. In storage, the injection rate may also decrease as the reservoir pressure...
increases, therefore the driving pressure difference decreases for a constant injection pressure.

**Example 8–4** Calculate the injection rate of a well in a given gas storage

Given: the well bottomhole injection pressure is 3,000 psi. The reservoir pressure at the time and the temperature are 1,500 psi and 200°F, respectively. \( r_e = 660 \text{ ft}, \ r_w = 0.359 \text{ ft}, \ k = 1 \text{ md}, \) and \( h = 45 \text{ ft}. \) The average Z-factor and viscosity are 0.897 and 0.0175, respectively. Repeat the calculation when the reservoir pressure is 2,000 psi. (The average Z-factor and viscosity are 0.890 and 0.0181 cp, respectively).

**Solution**

Use Eq. (8.6),

\[
q_{\text{inj}} = \frac{1 \times 45 \times (3,000^2 - 1,500^2)}{1,424 \times 0.0175 \times 0.897 \times (200 + 460) \times [\ln\left(\frac{0.472 \times 660}{0.359}\right) + 0]}
\]

\[= 3,040 \text{ Mscf/d}.\]

Repeating the above calculation for average storage pressure equal to 2,000 psi, the injection rate is 2,200 Mscf/d, showing the impact of the pressurization of the reservoir on well injectivity.

**8.4 Discussion**

The emergence of LNG as a major contributor to natural gas supply in the United States will most certainly alter traditional storage patterns and their seasonality. While the calculations presented in this chapter will still be valid, in practice, there will probably be a lot fewer large cycles, such as one in the summer and one in the winter, of storage injection and production as has been the case in the past. Instead cycles may be a lot smaller and repeated several times in a year; reflecting weather induced high and low demand of heating or air conditioning loads. Management of gas storage, with its ability to inject and withdraw relatively quickly in conjunction with a steady or discreet supply of LNG, becomes an important new dimension in natural gas use.
8.5 References


Mayfield, J.F. 1981. Inventory verification of gas storage fields. JPT 33 (9).

