Underground storage of natural gas

7.4.1 Storage systems: principles, techniques and development

Introduction

Natural gas is stored underground in geological structures whose properties allow gas to be stored and withdrawn when required.

Gas storage is described as conventional when it is carried out using depleted or partially depleted gas production reservoirs, semiconventional depleted oil reservoirs or aquifers (in other words geological structures containing water) are employed, and special when caverns excavated in underground salt formations or abandoned coal mines are used.

The underground storage of gas has played and continues to play a vital role in supporting the development and stabilization of the gas market. Demand varies considerably on a seasonal and daily basis, mainly as a result of the residential sector, where gas is mainly used for heating. It should be remembered that the ratio of winter to summer consumption is on average 3:1; this may become 4:1 at times of peak daily demand. Fig. 1 shows an example of daily values for the consumption and supply of gas: it is recalled that volumes are measured in Sm$^3$ (standard m$^3$) and flow rates in Sm$^3$/d (standard m$^3$ per day); a Sm$^3$ is the volume of gas under ‘normal conditions’, in other words at 15.5°C and 1.01315 bar (atmospheric pressure).

For technical and economic reasons, production and transport systems require a relatively stable working regime to maximize usage and reduce expenditure; therefore storage structures able to match gas supply to the market requirements outlined above are necessary.

Gas storage thus provides a basic service which consists of storing the gas made available by the supply production system during the spring-summer period and not used by the market due to a drop in consumption (especially for heating purposes), and producing the volumes which the production system itself is unable to supply during the autumn-winter period but which are required to meet market demands.

In recent years, with the deregulation of the gas market in Europe, storage companies have also begun to provide special services in addition to this basic service. These are characterized by increased flexibility and include parking, counterflow and interruptible service, already available in the mature markets of the United States and the United Kingdom (see below). These services allow optimization of the storage capacity to the benefit of the market.

The fundamental role played by storage in the market certainty should be noted: strategic reserves of gas, generally kept in the storage systems of individual countries, guarantee market supply even if national or imported supply is reduced, and if

Fig. 1. Typical daily values for the consumption and supply of natural gas.
weather conditions are unusually severe for a long period of time.

Characteristic parameters of gas storage

It should be remembered that when discussing natural gas storage we usually refer to:

Working gas. The volume of gas which can be injected during the summer and withdrawn during the winter without compromising the normal performance of the reservoir.

Cushion gas. The volume of gas which remains immobilized inside the reservoir for the whole period during which it is used as storage: this allows the storage to work efficiently at the maximum possible performances.

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

Efficiency. The ratio between working gas and immobilized gas (immobilized gas: the amount of working gas, cushion gas and any remaining reserves present in the reservoir when it is converted into a storage system).

Types of gas storage and related issues

Most gas storage is carried out in depleted gas fields (around 70%), followed by those performed in aquifers and those in salt caverns.

Depleted gas fields (and similar)

The expertise developed in countries where depleted gas reservoirs are used allow guidelines to be drawn up for the selection of fields which are to be converted into gas storage. This selection is based on a careful analysis of geological data and the physical parameters of the pre-selected structures. The most important factors are: the shape and dimensions of the geological structure, the aquifer size, the gas-water contact (in the case of depleted or partially depleted reservoirs), the properties of the reservoir rock and cap rock (Fig. 2).

![Fig. 2. Storage facilities in depleted gas reservoirs.](image)

The most important physical parameters of the reservoir rock, which require careful evaluation, are:

- The porosity, which should be extremely high, thus providing greater storage capacity.
- The permeability, which expresses the ease or otherwise with which the rock allows a fluid, liquid or gas, to flow through it; the higher the permeability of the reservoir rock, the better suited it is to storage.
- The water saturation, which should be as low as possible since, if it is high, it reduces available volume.

Another factor to be considered is the ‘drive mechanism’, which expresses the ability of the aquifer to move within the reservoir rock as the reservoir is filled and emptied. In the depletion drive reservoirs the gas-water contact remains substantially stable during the productions and injection phases allowing high performances and minor problems during the production. On the contrary, in the water drive reservoirs the gas-contact moves upwards during the production phase and the water which has risen must be pushed back during the gas injection phase. In these reservoirs the performance is reduced due to water production and the need for more pressure to displace the water.

Storage in partially or wholly depleted oil reservoirs has similar characteristics to that in gas reservoirs converted into storage; consequently some of the operational and development methods applied to the latter remain valid. In some cases, the injection of gas into an oil reservoir may form part of the secondary recovery project for the oil itself, in this case as well as the typical benefits of storage there are also those of the additional recovery of oil. It should be added that the treatment facilities needed to give the gas the requisite quality specifications before it is channelled into the transport network often differ from those needed for gas reservoirs, since the fraction of liquid hydrocarbons suspended in the gas must be removed.

Gas storage in abandoned mines are not discussed since these are of minor importance.

![Fig. 3. Phases of storage in an aquifer.](image)
Aquifers

As far as gas storage in aquifers is concerned, the geological structure (trap), which should preferably be an anticline, must first be found. The structure is sometimes identified using geological surveys, but generally is localized using geophysical systems.

The most important requirement for storage facilities in aquifers is the seal of the cap rock, which must be suitably thick and have low permeability values, close to zero, as in shaly formations. This second requirement is necessary as during the injection of gas the hydrostatic pressure is always exceeded.

When the original pressure is exceeded in order to increase the volume of working gas in storage of this type (and that in depleted gas reservoirs), care must be taken not to exceed the threshold pressure, in other words the pressure above which the gas begins to pass through the cap rock. The threshold pressure is determined in the laboratory by means of tests on cores collected during the drilling phase, and subsequently with long injection tests performed in the wells (early injection).

To study gas storage in aquifers extrapolations based on the data acquired with early injection are employed. As a result, predictions of the reservoir’s behaviour during the various phases of storage are initially uncertain since a production history for the reservoir rock is not available, as is the case for depleted gas reservoirs.

When storage is initiated in an aquifer, the gas displaces the water, advancing more rapidly where permeability is higher, and thus leads to the formation of a gas bubble. After a few years, as injection continues, the water in the upper part of the reservoir is entirely displaced by the gas; at this point the storage can become operational (Fig. 3).

Salt formations

For storage in salt formations, caverns obtained by dissolving the salt mass in fresh water pumped through one or more wells are used. The salt is then extracted from the water; when this is not considered economically viable, it is reinjected into another suitable geological formation. An understanding of the shape of the cavern and the properties of the rocks surrounding it are important elements for determining the minimum and maximum pressure at which the storage can be operated. Generally speaking, this type of storage does not have a high working gas capacity, but do provide considerable peak rates (Fig. 4).

Comparison between different types of storage and phases of storage

The main characteristics of the different types of storage are compared in Fig. 5; for a detailed
discussion of geostructural aspects and for reservoir studies, see Section 7.4.2.

With specific reference to conventional storage (depleted or partially depleted gas reservoirs), Fig. 6 shows the different stages of conversion into gas storage. For the purpose of illustration the case of a partially depleted field is considered, i.e. a field containing some remaining reserves. Clearly, storage in aquifers or salt caverns contain no primary gas, and all of the gas present in the reservoir has been injected.

**Historical development of storage systems**

The underground storage of natural gas began in Canada in 1915, and in the United States the following year. These two countries were the first to realize the economic importance and technical possibility of storing natural gas in natural reservoirs.

The use of gas storage spread considerably with the development and production of gas reservoirs at large distances from the areas where the gas was used, and especially with the development of importation from one country to another.

The gradual discovery of gas production fields in areas increasingly distant from areas of consumption, an increase in the gas market and the seasonal variability of natural gas consumption created the right conditions for the development of storage activities.

One option was to link the sources of supply (national production fields, imports) with gas pipelines whose sizes have been determined as a function of peak demand. Another option was to determine the size of the gas pipelines in accordance with a constant mean supply, supported by appropriately located storage systems aimed at meeting periodic peaks in consumption. The first option entailed larger investments, a failure to optimize supply with negative economic consequences, a less efficient use of gas pipelines due to their excessive size, and a slower response time to market fluctuations.

The tendency to store gas in order to modulate supply began by using tanks located at the surface (gasometers) near towns, and, as production fields became depleted, by converting these into storage reservoirs. These have extremely high storage capacity and are thus more suited to the growing need of the gas market for storage.

Today there are more than 580 storage fields in the world, of which 70% are in the United States; the remainder are concentrated almost exclusively in Europe and Russia. Current total availability at world level is calculated to be 286 GSm³ of working gas, with a daily peak rate at maximum capacity of about 5.0 GSm³/d.

In the following, the situation for storage sites in Europe, the United States and Canada, and Russia is described.

**Europe**

Most of Europe’s large storage sites have been created in depleted or partially depleted gas reservoirs. About 80% of total working gas and daily peak rate is concentrated in 40 fields out of a total of 103 fields.

Currently, Germany is in first place for the availability of working gas and daily peak rate, followed by Italy. Tables 1 and 2 show the availability of working gas and daily peak rate for each country and for different types of storage.

**United States and Canada**

Also, in the United States and Canada most gas storage is in depleted or partially depleted reservoirs; in the USA, the greatest concentration is found in the Eastern States. At the end of 2004, there were a total of 456 operational fields. Table 3 shows the availability of working gas and daily peak rate, along with their subdivision by storage typology.

**Russia**

Although the first large storage field became operational as early as the 1950s, the development of Russia’s storage system is relatively recent. In the late 1980s it was decided to expand the system rapidly with the development of 8 new storage fields. Today Russia has more than 60 storage fields, of which 70% are in depleted production reservoirs, accounting for about 85% of working gas capacity.

Most activities are now aimed at increasing the amount of working gas by raising the storage pressure by up to 40-50% above the original reservoir pressure. Table 4 shows the availability of working gas and daily peak rate, subdivided also by storage typology.
Figs. 7 and 8 show the total availability of working gas and peak rate, as well as their subdivision by storage typology.

The determination of the size and the development a storage field

The determination of the size and the development a storage field involves finding a geological structure suitable for the storage of gas by analyzing its mineralogical properties and technical and commercial aspects.

Mineralogical properties

In the following the analysis is limited to a few aspects of mineralogical nature, leaving a more detailed and in-depth discussion to Section 7.4.2. The main stages of the determination of the size and the development of a storage reservoir are: a) the geological study of the structure selected and its cap

Table 1. Availability of working gas in Europe

<table>
<thead>
<tr>
<th>COUNTRY</th>
<th>WORKING GAS (GSm³)</th>
<th>PEAK RATE (MSm³/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>3.0</td>
<td>35</td>
</tr>
<tr>
<td>Belgium</td>
<td>0.7</td>
<td>20</td>
</tr>
<tr>
<td>Denmark</td>
<td>0.8</td>
<td>24</td>
</tr>
<tr>
<td>France</td>
<td>10.5</td>
<td>214</td>
</tr>
<tr>
<td>Germany</td>
<td>19.0</td>
<td>445</td>
</tr>
<tr>
<td>Italy</td>
<td>15.4</td>
<td>282</td>
</tr>
<tr>
<td>Holland</td>
<td>2.5</td>
<td>144</td>
</tr>
<tr>
<td>Poland</td>
<td>1.5</td>
<td>52</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>3.6</td>
<td>138</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>2.1</td>
<td>42.5</td>
</tr>
<tr>
<td>Slovak Republic</td>
<td>2.7</td>
<td>33.4</td>
</tr>
<tr>
<td>Spain</td>
<td>2.1</td>
<td>13</td>
</tr>
<tr>
<td>Hungary</td>
<td>3.6</td>
<td>46.6</td>
</tr>
<tr>
<td>Total</td>
<td>67.5</td>
<td>1,489.5</td>
</tr>
</tbody>
</table>

Table 2. Availability of working gas in Europe by storage typology

<table>
<thead>
<tr>
<th>TYPE OF STORAGE</th>
<th>WORKING GAS (GSm³)</th>
<th>PEAK RATE (MSm³/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depleted fields</td>
<td>42.0</td>
<td>856</td>
</tr>
<tr>
<td>Aquifers</td>
<td>16.0</td>
<td>208.0</td>
</tr>
<tr>
<td>Salt caverns</td>
<td>9.5</td>
<td>425.5</td>
</tr>
<tr>
<td>Total</td>
<td>67.5</td>
<td>1,489.5</td>
</tr>
</tbody>
</table>

Table 3. Availability of working gas in the USA and Canada by storage typology

<table>
<thead>
<tr>
<th>TYPE OF STORAGE</th>
<th>WORKING GAS (GSm³)</th>
<th>PEAK RATE (MSm³/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depleted fields</td>
<td>111</td>
<td>1,875</td>
</tr>
<tr>
<td>Aquifers</td>
<td>13</td>
<td>275</td>
</tr>
<tr>
<td>Salt caverns</td>
<td>5</td>
<td>350</td>
</tr>
<tr>
<td>Total</td>
<td>129</td>
<td>2,500</td>
</tr>
</tbody>
</table>

Table 4. Availability of working gas in Russia by storage typology

<table>
<thead>
<tr>
<th>TYPE OF STORAGE</th>
<th>WORKING GAS (GSm³)</th>
<th>PEAK RATE (MSm³/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depleted fields</td>
<td>76</td>
<td>800</td>
</tr>
<tr>
<td>Aquifers</td>
<td>13</td>
<td>150</td>
</tr>
<tr>
<td>Salt caverns</td>
<td>1</td>
<td>50</td>
</tr>
<tr>
<td>Total</td>
<td>90</td>
<td>1,000</td>
</tr>
</tbody>
</table>
rock; b) the study of its behaviour during the production phase, for depleted or partially depleted gas reservoirs (conventional storage); c) the dynamic simulation of the behaviour of the reservoir during the injection and production phases, using mathematical models developed for this purpose; d) the determination of performance when the reservoir is filled to the original pressure and to a pressure above the original one, by assuming different dynamic pressure values at the wellhead; and e) the determination of reservoir performance as a function of the number and type of wells (vertical or horizontal wells), and the type of completion (completion with gravel pack, large diameter tubing, etc.).

For depleted or partially depleted gas reservoirs, the studies mentioned in the first two points have already been carried out and updated during the productive life of the reservoir. Specifically, the analysis of dynamic behaviour undertaken during the primary production phase allows the identification of the characteristic parameters of the reservoir-aquifer system (drive mechanism by simple expansion, moderate water-drive, strong water-drive); these are fundamental for determining the dimensions in terms of the capacity and productivity of the future storage. As far as the dynamic simulations are concerned mathematical models are used; these are generally three-dimensional and are able to simulate production history and predict the future performance of the reservoir during the storage phase. These simulations allow the determination of the possible performance as well as the other parameters characterizing the storage (working gas, peak rate of delivery/injection, cushion gas), by assuming different values for reservoir pressure and wellhead pressure (Figs. 9 and 10).

**Technical and commercial aspects**

As mentioned above, the determination of the size and the development of a geological structure to be used for storage depends on the geometry of the reservoir and its petrophysical properties, but also on other parameters which are established during the planning phase, and which take account of market requirements (the need for working gas and daily peak rate), and the restrictions imposed by the transport network.

Economic aspects must also be studied and tariffs for the services offered set on the basis of current regulations. Only once the analyses described above have been carried out, can the size of the facilities be determined in an optimal way, and the number of wells be established with a reasonable margin of certainty that the volume of gas stored and delivered will be used, and thus that the services on offer are competitive.

**Services and ways of using storage systems**

The traditional services offered by storage reservoirs are production services, seasonal control services and strategic reserves services.

In recent years, many European countries, including Italy, have followed the example of the existing practice in the USA and the United Kingdom, which attempts to increase the flexibility of storage systems by providing a broad range of so-called ‘special’ services, with undisputed benefits both for the operators of gas storage and for gas sales companies.

In the following, the different types of service on offer are briefly analysed.
Production services
For technical and financial reasons, production reservoirs are developed in such a way as to consider optimal a daily production profile which is essentially flat. This is due to the fact that the determination of the size of the treatment plants and the number and type of wells to allow production fields to follow market fluctuations would entail additional costs and financial problems.

Production services thus involve the storage of a sufficient volume of gas in order to obtain optimal performance from the production system, both from the point of view of production and of surface facilities. **Fig. 11** shows an example of a comparison between production profiles with and without a storage system.

Seasonal control services
Seasonal control is the traditional service provided by storage systems. Gas is injected during the spring and summer and then withdrawn during the autumn and winter to meet the demands of the market. Each natural gas sales company estimates the need for stored gas on an annual basis at the beginning of winter. More specifically, each company defines, on the basis of availability from national production and/or imports, the contribution required from storage reservoirs to meet its total predicted sales (both in terms of seasonal volumes and daily peak rate), on the basis of individual sales sectors, i.e. the residential, industrial and thermoelectric sectors.

Strategic reserves services
Another fundamental role played by storage systems is to provide the strategic reserves to be used to guarantee supply: the volume of gas which must be kept in storage reservoirs for this purpose is generally established by the relevant government authorities of each country. The gas held in storage reservoirs may be owned by storage operators or by gas sales companies. Strategic gas reserve is only withdrawn under unusual circumstances such as particularly hard winters, or significant and prolonged reductions in gas imports or national gas production. Once produced, other gas is re-injected into the reservoirs during the summer in order to maintain the volume considered necessary to ensure gas supply at a national level.

The issue of strategic reserves is particularly important in countries where the availability of gas depends heavily on imports and is thus subject to potentially prolonged reductions due to political problems, or the partial or total unavailability of transport systems due to breaks in pipelines or the failure of boosting stations.

Special services
Among the new services on offer, the most common are listed below.

**Parking.** This involves injecting and withdrawing gas over short periods of time, ranging from a week to a month, thus allowing the customers of the storage to meet temporary imbalances in the volumes supplied and sold, avoiding the application of penalties by the transport company.

**Interruptible storage.** This is a service in which both working gas and peak rate are offered at particularly low prices, since the storage operator may interrupt supply at very short notice. These services which are offered on the basis of the capacity margins inherent in a storage system may become unavailable.
in the event of unplanned maintenance work, plant failures, the closure of wells, etc.

Capacity trading. This involves the buying and selling of volumes of gas by customers, who, for market reasons (variations in gas demand or supply), have booked smaller or larger volumes than necessary from storage systems. This is common practice in almost all countries, and allows an optimal use of storage capacity and the avoidance of additional expenditure.

Figs. 12 and 13 show the variations in some parameters (gas in the reservoir, working gas and peak rate) during the injection and later production cycles.

The gas market and need for stored gas

In the coming decades, an increase in gas consumption in most countries is predicted, mainly as a result of growing consumption in the thermoelectric sector. Annual consumption is predicted to increase on average by 2.4% over the next three decades, going from 2,527 GSm³ in the year 2000 to about 5,000 GSm³ in 2030. The contribution made by gas to primary energy consumption will increase from 23% in the year 2000 to 28% in 2030.

The forecast growth of the gas market will necessarily lead to an increase in the number of structures to be used for storage as well as an increase in the storage capacity. The increase in storage capacity in Europe and the United States between today and 2010 (no reliable data are available for Russia and Eastern countries) will be in the order of 57 GSm³ for working gas, and 1,100 millions of Sm³/d for peak rate (35% in Europe). The total availability of storage systems in 2010, without considering possible increases in Russia and Eastern countries, should thus be about 350 GSm³ of working gas and about 6 GSm³/d for peak rate.

Criteria used to determine the need for storage systems

Before outlining the criteria used to determine the need for gas, it is worth noting some of the parameters characterizing the gas market.

Degree days. These express the difference in degrees Celsius (or Fahrenheit) between a reference temperature of 18°C (64°F), at which consumption for residential heating purposes is considered to be zero, and the mean daily temperature; in other words the °C/d represent the complement to the value of 18°C (64°F) given by the forecast and actual temperature. For example, if during October the mean value of degree days is 5°C/d, the mean temperature to be considered for the month is 13°C. Fig. 14 shows an example of a temperature profile (forecast and actual) in °C/d; by summing the degree days for a month or a season it is possible to obtain estimates of the demand for gas for heating purposes.

Specific consumption. This is the volume of gas used for heating per 1°C/d variation with respect to the reference temperature of 18°C.

Flexibility. This parameter is linked to the ratio of the minimum number of days required to deliver a given volume of gas to the number of days in a year. If, for example, this ratio is 0.9, the volume in question can be supplied in 328 days. Flexibility increases as the value of the ratio decreases: this means that the greater the flexibility, the larger the daily volume of gas which can be used during the winter.

As has already been stressed, the regulatory seasonal function played by storage systems became necessary to meet market demand. Here, the main parameters used to determine the need for stored gas are listed; these parameters are the annual sales and the relevant monthly and daily profiles for the industrial, thermoelectric, basic residential and

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**Fig. 12.** Peak flow rate for injection and production during a storage cycle.

**Fig. 13.** Examples of storage cycles.
residential heating sectors, as well as the monthly and daily profile of volumes supplied over the course of the year.

**Annual sales and monthly and daily profiles**

The need of each individual sales company for stored gas is estimated on the basis of the different components of the market (thermoelectric, industrial, residential domestic and residential heating sectors). The residential heating sector, in particular, presents the greatest degree of forecasting uncertainty, since it depends on actual climate conditions. For planning purposes, requirements are estimated both in terms of the volume of gas needed and the daily peak rate, taking into consideration both a ‘normal’ temperature profile based on a 30-50 year period (variable depending on the country) and a particularly cold trend (occurrence probability from 1:20 to 1:50 years).

The method used to determine the residential sales profile involves calculating the specific consumption for heating purposes in millions of Sm$^3$/°C/d. This can be obtained from the ratio of the volume of gas sold during the previous winter to the total value of degree days in the geographical areas where the market of the gas company is located. This value is then ‘normalized’ by taking account of annual mean degree days for the time period considered.

Once the specific consumption has been determined, the sales profile for residential heating is then defined on the basis of the mean monthly temperatures (for monthly volumes), or three day averages (for daily volumes), taking into consideration any variations in the number of customers served.

The sales profile for industrial purposes is generally flat, and takes into consideration any periods of inactivity predicted by the various users; the thermoelectric profile may be influenced significantly, and in a different manner from country to country, by the more or less intensive use of air-conditioning during the summer.

The total consumption thus obtained allows the storage requirements to be defined on a mean monthly and daily basis both in the case of a normal thermal trend and in the case of cold winters (Fig. 15).

**Annual supply and monthly and daily profile**

The supply profile over the course of the year depends on the flexibility of national production fields, and import contracts; these flexibilities are used to maximize winter supply, thus reducing the need for stored gas to meet market demands.

![Fig. 15. Typical pattern for daily winter demand in a European country.](image)
On the basis of sales and supply profiles, each company determines the volumes of stored gas to be reserved.

In turn, the storage companies check the compatibility of these requests with the characteristics of their own storage system, and any restrictions imposed by surface facilities and/or the transport network.

In the course of the season a monthly check is made on any deviation from the programme as a result of the actual profile of both sales and availability, and where necessary, the forecast injection/supply strategy is adjusted to obtain optimal performance from the storage system.

**Alternatives solutions to reduce the need for stored gas**

In most countries with a mature gas market, the various operators (gas sales companies, transport companies, etc.) often adopt a series of alternative solutions to reduce the need for stored gas. Alternatives to storage are taken into consideration if they are economically advantageous, and are essential when the availability of stored gas has reached its limits, or is insufficient due to a lack of suitable geological structures. Table 5 highlights the impact of these various alternatives on the need for working gas and peak rate.

**Development costs and management of storage fields**

**Investments**

The investment cost for the development of a new storage field depends on the type of storage and, in the case of identical types of storage, on its capacity, which may or may not permit economies of scale.

Investment costs for a storage project can be subdivided into: a) exploration costs (unnecessary where partially depleted or depleted gas/oil reservoirs are used); b) drilling costs which are related to the number and depth of the storage wells; c) costs of the cushion gas volume; and d) costs of surface facilities, related to the size of the treatment and compression plants. In this context we should remember that similar surface facilities are generally used for conventional and semiconventional storage.

The overall cost of a single storage facility depends on: a) the size of the surface facilities necessary for treatment and compression of the gas; b) the number and depth of the wells; c) the number of caverns/wells in the case of salt cavities; and d) the volume of cushion gas.

**Table 5. Possible alternative to reduce storage demand**

<table>
<thead>
<tr>
<th>Contribution to the reduction of working gas</th>
<th>Contribution to the reduction of the peak rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flexibility of the demand</td>
<td>High</td>
</tr>
<tr>
<td>Interruptible market</td>
<td>Low</td>
</tr>
<tr>
<td>Flexibility of the LNG plants</td>
<td>High</td>
</tr>
<tr>
<td>Line-pack</td>
<td>High</td>
</tr>
<tr>
<td>SPOT demand contracts</td>
<td>Medium</td>
</tr>
<tr>
<td>contracts</td>
<td>Low</td>
</tr>
</tbody>
</table>

**Operating costs**

The cost of managing gas storage can be divided into fixed and variable costs. *Fixed costs* are those related to the workforce, insurance, maintenance work, etc. *Variable costs* are the costs of the fuel and/or electrical energy required to power the compressors, consumer goods, etc.

**Economic considerations on the development of storage in depleted gas reservoirs**

For this type of storage exploration costs are generally unnecessary, since the reservoir is already well-known from the point of view of both the geology and productive behaviour. On rare occasions additional wells may be necessary in order to locate the boundaries of the reservoir more accurately; more frequently, new wells of a different type from existing wells may have to be drilled (horizontal wells, wells with gravel pack, i.e. wells with calibrated sand filters or wells with large diameter tubing) to allow high daily flow rates and reduce the time required to inject/withdraw gas.

Most existing surface facilities (gas dehydration plants, compressors, pipelines, instrumentation, control room, etc.) and wells can also be used for storage facilities, even though with some modifications.

The volume of gas to be immobilized as cushion gas depends on the size of the reservoir and the drive mechanism (the volume of gas is smaller for reservoirs which produce by simple expansion than for those which produce by water-drive). The impact of cushion gas on total investments depends on how much of this is still present in the reservoir when it is converted into a storage site, and on how much must be purchased at market prices and injected into the reservoir.
Economic considerations on the development of gas storage in aquifers

The search for these geological structures requires considerable exploration expenditure to identify those suitable for storage. Once the structure has been identified, it is necessary to drill all of the development wells and build the treatment and compression plant, without the possibility of using existing facilities.

The volume of gas to be immobilized as cushion gas is large, since the front of the aquifer must be kept at a distance from the productive zone; the impact on total investments is significant, since all of the gas used for this purpose must be bought on the open market and injected into the reservoir.

Economic considerations on the development of gas storage in salt caverns

These types of storage use underground caverns which are sometimes created by the exploitation of salt formations to extract rock salt; in other cases they are created specifically for storage. It is clear that in the former case investment costs are limited to those for wells and the treatment and compression plant, whereas in the latter case exploration costs and the cost of artificially creating the cavity must also be taken into consideration.

The volume of gas used as cushion gas is relatively modest, and is conditioned only by the minimum pressure which we wish to maintain at the end of the flowing cycle.

Estimates of investment costs

On the basis of the considerations outlined above, rough estimates for typical storage are as follows: storage in depleted reservoirs: 170-200 millions of euro; storage in aquifers: 250-300 millions of euro; and storage in salt caverns: 290-340 millions of euro.

It should be noted that it has been assumed that the cushion gas consists of gas acquired on the market and injected into the reservoir. Table 6 shows the main parameters characterizing ‘typical’ European storage, while Table 7 shows the mean impact of individual items of expenditure.

Methods of increasing the storage capacity

The performance of gas storage which is already operational can be increased with smaller investments than those required for the development of a new field by carrying out a series of interventions, as outlined below.

Increase of original reservoir pressure (depleted gas/oil reservoirs)

The maximum pressure which can be reached is calculated by reservoir studies aiming to define the geometry and extent of the reservoir rock, and with laboratory analyses of cores collected from the top of the reservoir.

Table 6. Main parameters in a typical European storage

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Depleted reservoirs</th>
<th>Aquifers</th>
<th>Salt caverns</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total volume (MSm³)</td>
<td>1,665</td>
<td>1,000</td>
<td>430</td>
</tr>
<tr>
<td>Working gas (MSm³)</td>
<td>1,000</td>
<td>500</td>
<td>300</td>
</tr>
<tr>
<td>Efficiency (%)</td>
<td>60</td>
<td>50</td>
<td>70</td>
</tr>
<tr>
<td>Depth (m)</td>
<td>1,300</td>
<td>900</td>
<td>1,260</td>
</tr>
<tr>
<td>Storage pressure (bar)</td>
<td>135</td>
<td>90</td>
<td>150</td>
</tr>
<tr>
<td>Peak rate (MSm³/d)</td>
<td>12</td>
<td>6</td>
<td>18</td>
</tr>
<tr>
<td>Number of wells</td>
<td>25</td>
<td>20</td>
<td>10</td>
</tr>
<tr>
<td>Working gas/well (MSm³)</td>
<td>40</td>
<td>25</td>
<td>30</td>
</tr>
<tr>
<td>Peak rate/number of wells (MSm³/d)</td>
<td>0.48</td>
<td>0.24</td>
<td>1.8</td>
</tr>
</tbody>
</table>

Table 7. Mean impact of the main items of investment costs

<table>
<thead>
<tr>
<th>Class of investment</th>
<th>Depleted reservoirs (%)</th>
<th>Aquifers (%)</th>
<th>Salt caverns (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Surface plants</td>
<td>30</td>
<td>25</td>
<td>40</td>
</tr>
<tr>
<td>Wells</td>
<td>25</td>
<td>15</td>
<td>35</td>
</tr>
<tr>
<td>Cushion gas</td>
<td>45</td>
<td>60</td>
<td>25</td>
</tr>
</tbody>
</table>
the reservoir. These analyses aim to characterize the cap rock and determine its petrophysical and geomechanical properties (threshold pressure, permeability, porosity, etc.).

In addition, the condition of existing wells must be evaluated, and the presence of faults and the fracture gradient of the cap rock must be investigated.

On the basis of these investigations the maximum working pressure can be calculated, thus avoiding any possible gas leaks caused by exceeding the threshold pressure and any potential mechanical damage to the cap rock caused by fracturing.

The maximum injection pressure is limited to the lowest of the following values: the pressure value calculated as the sum of the hydrostatic pressure on the cap rock plus the threshold pressure, the value at which the integrity of the well may be compromised and the fracture value of the cap rock.

*Increasing the number of wells*

This is now common practice among storage operators, and allows significant increases to be obtained, especially in the peak rate of the storage. The maximum number of wells depends on the type and size of the reservoir, and must be defined so as to avoid interference problems between wells and reductions in the reservoir performance.

*Upgrading treatment and compression facilities*

The work required is basically restricted to the installation of additional treatment columns and one or more compression modules able to operate at the actual capacity of the reservoir. If necessary, the flow lines must be expanded in order to minimize pressure losses.

*Operating systems to manage and control production*

The technology currently used to manage technical, managerial and commercial problems in storage fields make use of computer systems which allow control of production and processing, optimization of production and injection, and management of commercial issues.

*Control of production and processing*

The computer systems used are management and remote control systems which allow: constant monitoring of the functional conditions of plants and field appliances, thereby guaranteeing the safety of appliances, people and the environment; remote management of storage facilities which are partially manned or unmanned, thus significantly reducing expenditure and control of production in a more effective and dynamic way; and centralization of production management and planning to improve response times to the numerous demands of the market.

The fundamental issue which must be tackled in controlling production and processing is the definition of the *optimal automation level* for the plants.

A simplistic approach would be to automate all appliances. However, aside from obvious economic considerations, it has been demonstrated that even from a technical point of view this may lead to a reduction in the overall availability of the plant and an increase rather than decrease in the number of employees.

This problem can be tackled by defining the *plant’s availability* as:

$$A = \frac{MTBF}{MTBF + MTTR}$$

where A is the percentage value of availability, which expresses the ability of a system to perform the task for which it is designed; MTBF (Mean Time Between Failures) is the temporal value which expresses the mean interval between two subsequent system failures, assuming that the cause of the first failure has been eliminated; MTTR (Mean Time To Repair) is the temporal value which expresses the mean time required to repair a system failure.

Appropriate formulas allow the value of the availability of complex plants to be calculated by combining the values for MTBF and MTTR of individual components. The specific treatment of this argument lies outside the scope of this chapter, however it is important to highlight that, while the value of the MTBF is an intrinsic characteristic of the product, the value of the MTTR to be used in the formula is made up of a number of contributions. Some of these contributions arise from the intrinsic characteristics of the system and are related to the organizational structure of the user into which, computer systems and remote control are added in order to improve the efficiency and economy of the system, also achieved by the fact that the plants can be unmanned.

In a *manned plant*, it is tolerable for a minor failure to interrupt the functioning of part of the plant, since it is reasonable to suppose that timely maintenance work will allow production to resume after a very short time, thus contributing only in a limited way to a decrease in availability.

For *unmanned plants* the situation is different: in this case, the same type of failure, given the time required to intervene (we can assume that maintenance workers must travel to the site from elsewhere), may lead to a long period of unavailability. This problem can be resolved by the modularization and redundancy
of the plant itself; these properties can be exploited by the automated system to attain the required levels of availability.

On the basis of these considerations, it is obvious that during the design of computerized management systems for unmanned or partially manned storage stations, adjusting the layout of the plants is particularly important.

When choosing and designing monitoring systems the following criteria must be taken into account: the modularity of the system’s hardware and software architecture, the integration with other existing systems in the plant, flexibility in adapting to varying needs and types of plant, the expansibility of hardware and software in the field, advanced functions and the independence from the hardware platform.

The need for flexibility in meeting the various requirements which may emerge over the course of the productive life due to a different use of the storage fields or the modification of plants make it advisable to choose standard and open system technologies, based on a distributed database to which all SCADA (System Control And Data Acquisition) functions refer.

**Hardware and remote control architecture.** The hardware architecture is designed and built using computerized systems operating on heterogeneous platforms and on three functional levels. The primary element of this architecture is the process control system, typically of the DCS (Distributed Control System) type. This consists of modules to control processing and plant supervision units, able to interface with the plant remote control systems (Fig. 16).

At a higher functional level, a SCADA is installed which, using appropriate links and communications protocols, exchanges data and exploits the automation logic of the station’s DCS, thus allowing the storage facilities to be remote controlled.

The architecture is completed with the installation of host computers, linked to the SCADA, which are able to implement applications aimed at optimizing production processes and carrying out production accountancy.

**Software architecture.** Implementing the aforementioned hardware architecture allows the development of software which, by exploiting the process automation, minimizes the controls and interventions which the operator is required to make on individual parts of the plant. These applications can manage all types of regulation and control, and any malfunctions detectable in the field by restarting and/or shutting down the production process.

Production is controlled and regulated at the station by implementing a hierarchical software architecture at the DCS level, operating on three levels of functions which interact with one another; these are the implementation of:

- A first level of management logic for individual appliances such as pumps, engines, etc., in line with internal management and safety practice; implementation of process control loops.
- A second level of automated management functions for complex parts of the plant such as a well/separator unit or a dehydration column.
- A third level of functions able to manage automatically entire parts of the plant such as the wells, the dehydration columns, etc.

Furthermore, process control scans will also be implemented at predetermined time intervals.

The storage facilities are remote controlled by linking the SCADA (usually centralized in a suitable location) to the station DCS, with special care devoted to choosing the type of connection and the communications protocol. Where necessary, hardware and software redundancy must be installed in both systems and in the relevant lines of communication, in order to ensure a high degree of safety from the point of view of operational continuity. On the station DCS a fourth level of functions is implemented allowing the plants to be remote controlled during the withdrawal and storage phases.

The type, and above all the number, of variables in transmission is directly proportional to the degree of automation obtained on the station control system. Host computers, on which production control and management functions have been implemented, are also connected to the SCADA. These may include the balance of gas withdrawn and injected, and its distribution over the wells, control of the production parameters of the wells, display of production and storage trends, and integration with applications developed on centralized information systems for the distribution of data to management and technical units.

**Systems architecture.** The systems architecture involves implementing four different levels of functions allowing a high degree of automation of the plant to be achieved, especially as concerns the production process (see again Fig. 16).
The activities carried out automatically by the system, and at the request of the operator, are as follows: a) automatic management of the production phase and maintenance of the production levels set by the operator; b) automatic management of the storage phase; c) control of the correct functioning of the plant during the withdrawal and storage phases, and switch to the shut-down phase in the event of malfunction; and d) control and maintenance of the requisite safety levels during the production and storage phases.

The district control room operator supervises and manages the plant, sending commands which act on levels 3 and 4 of the DCS software architecture. These allow the required production level to be set, and the automatic management of those plant units which present anomalies, or which are undergoing maintenance work to be disabled. It is the operator’s task to check the station DCS diagnostics information and the condition of the data communication lines with the district SCADA. Using this procedure to manage storage fields is simple, dynamic and allows risk and the impact of human error to be reduced to a minimum.

Production management. Production management at storage fields is thus entirely automated, and is implemented from the district control room by sending a single command indicating the required flow rate. This command is finalized on the station DCS, which manages the wells and facilities in such a way as to guarantee the required level of production. The system automatically checks that all production units are functioning correctly and that safety standards are maintained; it also automatically carries out actions aimed at maintaining the required level of production and, in the event of malfunction, shuts down the plants.

As far as the control and management of production are concerned, algorithms are installed on the DCS, at the fourth level of the applications software, which reproduce the curve characterizing the reservoir’s deliverability and injectivity. Using these algorithms allows the following operations to be carried out automatically: a) the adjustment of the maximum flow rate of the wells depending on reservoir cumulative production; b) the management of the production of wells as a function of flow rate and according to priorities and criteria established as a function of their location and production properties; c) the control of the pressure differential between the reservoir and the tubing applicable on each well; and d) the adjustment of the field’s regime as a function of reservoir cumulative production.

Optimization of production and injection

The optimization of the production and injection allows: the exploitation of the different physical properties of each field in an optimal way, taking into consideration surface constraints, so as to obtain significantly improved performance without altering the volumes moving through the storage system; the optimal use of each level of the reservoir as a function of its petrophysical properties and drive mechanisms; and the determination the daily flow rate of each well at any time taking account of its location, the type of completion, the production and injection carried out.

In this context, it is worth remembering that storage fields can be divided into two major categories: base storage fields and peak storage fields. Base storage fields are used throughout the winter for a number of days ranging from a minimum of 90 to a maximum of 140; these fields contain a large volume of working gas (from about 0.5 to 3.5 GSm3) and exhibit a slow decrease in daily peak rate during production (Fig. 17). The ratio of working gas to daily peak rate is about 50-60 millions of Sm3/millions of Sm3/d. Most storage in depleted gas reservoirs and some in aquifers belong to this category.

Peak storage fields are used only for brief periods over the winter to meet peaks in daily demand; the number of days of use may range from a minimum of 15-20 to a maximum of 40-50, depending on their storage capacity. Working gas is usually less than 0.5 GSm3, with a ratio of working gas to daily peak rate of about 30-40 millions of Sm3/millions of Sm3/d. The decrease in daily peak rate during production is considerable (Fig. 18). Most storage fields in salt caverns, and some in depleted gas reservoirs and aquifers, belong to this category.

If the annual, monthly and daily requirements of the storage system’s customers are known, the amount of working gas and the peak rate needed from the storage system can be calculated. Each customer communicates their own requirements to one or more storage companies; on the basis of total requirements, each storage company defines the volume which...
individual storage fields must deliver and inject each month.

Total demand is distributed over the different storage fields making up the system by optimizing the production properties of each of these (base storage fields or peak storage fields), and taking into consideration any constraints on compression and treatment plants and the transport system. Using and managing storage systems in this way allows the best withdrawal/injection profile to be identified for each field, with the aim of ensuring that the system performs in an optimal way.

The basic data used for optimization are the deliverability/injectivity curves for all of the fields constituting the storage system, and the load curve which the system must satisfy (the volume of gas which the various fields being optimized must supply). Specifically, the deliverability/injectivity curves are obtained by means of the following three parameters: daily rate as a function of cumulative production/cumulative injection ($Q_d$); cumulative production/cumulative injection as a function of time ($S$); and pressure as a function of cumulative production/cumulative injection ($p$).

Fig. 19 shows the difference in performance between a storage system where production has been optimized and one where this is not the case. Fig. 20 shows a winter demand profile and the optimized contribution of the different types of storage, including the storage of Liquefied Natural Gas (LNG) in tanks installed at the surface.

**Management of commercial issues**

Management of commercial issues deals with difficulties which emerged following the deregulation of the gas market in almost all European countries and in the United States. It allows the management of the processes of buying and selling gas on the national and international markets, the management of the processes of booking the transport and storage capacity needed for sales, and management of the processes of sales consolidation.

Deregulation was intended to encourage competition and exchange both on a national level and between different countries, in order to eliminate monopolies and reduce consumer prices, and has led to the introduction of a vast number of regulations for the sale of gas and the provision of associated services (storage, transport, etc.). These make it necessary to use computerized systems and specialized software to manage these complex procedures.

Regulations, especially in Europe, are often extremely complex, and take into account differing conditions in individual countries (laws, transport...
regulations, storage regulations, Authority deliberations, etc.). However, EU directives, currently in the process of definition, aim to harmonize these procedures and to introduce criteria of reciprocity in order to simplify and render more transparent the exchanges between different countries.

Outline of legislation on storage fields

In most European countries, the use of geological structures for storage is granted in the form of a licence issued by central State agencies. Some countries, including the United Kingdom, are an exception; here no licence is needed, only an authorization from the relevant agency. In the United Kingdom, licences are obligatory only when one or more levels of a reservoir which is still in production are to be used for storage. Also in the USA the geological structures used for storage are granted by a license issued by the Department of Natural Resources of each Federal State.

The regulations governing the use of licenses and authorizations are issued by central State agencies (the ministry, the national mineral office, etc.) in the form of laws, decrees and exemplary rulings. In many countries the authority to issue evaluations of environmental impact and construction licenses is delegated to Regions (Districts) or local governments. The task of drawing up criteria for the determination of allowed revenues and price structures and any criteria for prioritizing the assignation of available capacity, on the other hand, is delegated to regulatory bodies such as: OFGEM (Office of Gas and Electricity Markets, United Kingdom), CRE (Commission de Régulation de l’Énergie, France), AEÉG (Autoritá per l’Energia Elettrica e il Gas, Italy), and FERC (Federal Energy Regulatory Commission, USA).

The duration of licences ranges from 5 to 30 years, with the option of one or more extensions of predetermined length. The companies holding storage licences may be gas transport companies, gas distribution companies, or storage companies. In addition to ensuring sufficient finance for the development and management of this activity, they must have the requisite know-how for the implementation of the operations.

Regulation of services offered by storage systems

The fees for storage services may be established by negotiation, regulation, or a mixture of the two. In countries with several storage operators, none of which dominates the market, and where available capacity is sufficient to meet market requirements, fees are usually established by negotiation between storage operators and customers. In these countries, services can be offered on a competitive basis without compromising the range of services on offer, thus encouraging operators to become more efficient and therefore to contain prices. In Europe, negotiation is applied in the United Kingdom; in the USA services are now mainly negotiated.

In countries where the total availability of gas storage is insufficient or limited with respect to market requirements, or where there are few operators, of which one is in a dominant position (and where there is thus no possibility of genuine competition), regulation is needed to avoid distorting the market and discrimination between users. Such regulations systems allow storage companies a rate of return on the expenditure incurred by establishing an adequate profit margin.

In both cases (negotiated or regulated systems), remuneration must also take account of possible technical risk (gas leaks, decrease in performance, etc.), and risks linked to the margin of uncertainty inherent in forecasts of the use of stored gas over the medium to long term.

Criteria used to determine prices

In the case of a regulated system, fees are established on a cost reflective basis through calculation of the allowed revenue by applying a rate of return to investments and operating costs (fixed by the energy sector regulatory body in Europe and by the FERC in the USA), while guaranteeing an adequate profit margin to encourage this industry. The fee structure may cover the combined provision of working gas and daily peak rate, or the separate provision of working gas, daily peak rate and gas injected into or removed from the storage.

When the service is negotiated, the rate of return is not set by any controlling body, although the logic behind the calculation of profits is basically identical; in this case it is clear that it is the market which mainly determines profits and prices.

The methodology used to establish fees assumes that profits must be distributed over the services on offer. If separate services are offered, then the proportion of profits (associated with the relevant part of the facilities) attributed to working gas and daily peak rate must be established. When a package of services is offered, total profits are distributed over working gas and daily peak rate in a given ratio depending on the type of storage (m³ working gas / m³/d rate).

In the case of a regulated service, the fee structure should: a) facilitate competition and avoid cross-subsidiarity between stored gas users; b) encourage an efficient use of storage; c) ensure an adequate development of investments if these are necessary; and d) be stable, clear, transparent and reviewed at
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Predetermined intervals in order to take into account possible variations in costs and storage parameters, and possible increases in efficiency. If necessary international benchmarking, or reference to the services offered by other countries may be considered in order to support the tariffs determined.

For a negotiated service, the fee structure must: a) be non-discriminatory; b) avoid cross-subsidisation between stored gas users; c) encourage effective competition in the use of storage services; and d) allow an adequate development of investments depending on the need for gas from storage fields.

The relevant authorities (ministries, energy authorities, etc.) may re-examine the need for regulation or negotiation, depending on changes resulting from the greater offer of storage services.

Compression and treatment of gas

Volumes of gas are moved between the transport system and the storage through the gas storage station. The station contains all the machinery and plants needed to inject natural gas from the transport system into the reservoirs and to deliver gas from the reservoir to the transport network.

The sizes of all appliances contained inside the stations are determined so as to allow a complete storage cycle, on the basis of the maximum performance obtainable from the reservoir. In this context, it should be remembered that each cycle is comprised of an injection phase (storage) and a delivery phase (production) in which the volumes stored during the previous phase are returned to the system from which they were withdrawn. In order to define the sizes of the appliances, the in/out volumes of a storage cycle (working gas) are determined by means of the reservoir studies based on the physical properties of the field and petrophysical properties of the reservoir rock, using mathematical models able to simulate the various phases of storage.

The main processes to which the gas is subjected in the storage stations are compression for injection into the reservoir, and if necessary, for channeling into the gas pipeline, and treatment of the gas in order to attain the necessary quality specifications before it is channelled into the gas pipeline.

Compression station

The purpose of the compression plant is to raise the pressure of the gas withdrawn from the transport network to values such that it can be injected into the reservoir during the in-phase (storage), or, by contrast, channelled into the transport network during the out-phase (production).

The pressure inside the storage reservoir varies widely depending on how full it is, and is usually above the working values of the primary network of gas pipelines, generally between 40 and 70 bar. The delivery pressure of the compressors during the injection phase varies depending on how full the reservoir is and the injection rate; the final value for very deep conventional reservoirs or aquifers may exceed 250 bar. The compression ration during the injection phase can thus reach high values.

During the delivery phase, both conventional and semiconventional storage need compression only during the final stage of the cycle, since the reservoir pressure is generally higher than network pressure (free flow). The amount of working gas which can be produced without the need for compression depends on the drive mechanism and the pressure values reached at the end of the injection phase.

The compression plant is placed between the transport network and the flow line (gas pipeline connecting the station to the storage wells); this pipeline is made of special steel tubes, suitably dimensioned to limit the loss of pressure to a few bars and to minimize the noise generated by the gas in transit.

The compression plant generally consists of several units which are linked by operating a series of valves; these valves allow different types of operation to be configured, different working conditions to be employed and maintenance operations to be performed on individual units without compromising the overall working of the plant. In addition to the compression units, the plant has feeder, refrigeration, control and flow regulation systems.

Since the main function of the compression plant is to enable the withdrawal of volumes of gas from the transport network and its injection into the reservoir, the determination of the size of the compressors is based on this operation which requires a high level use of the installed compression capacity. The reader is again referred to Fig. 12, which shows, in particular, the peak injection rate of a generic storage cycle. This pattern is the result of calculations made with reservoir simulations (mathematical models), which take into account all of the parameters required to describe the behaviour of the formation and its ‘injectivity’ (the ability to absorb volumes of gas as a function of how full it is). The determination of the size of the compressors is thus based on the daily rates and the delivery pressures at which they must operate; these pressures vary from the beginning to the end of the injection cycle, and must always be above reservoir pressure in order to overcome the pressure drop in the reservoir through flow lines and the tubing linking the well bottom to the wellhead.
Delivery pressures which are excessively high with respect to reservoir pressure, however, cannot be employed since these might damage the reservoir and its cap rock. The pressure differential to be applied depends on the type of reservoir rock; usually in formations consisting of well-cemented sandstone or limestone it may reach 30-35% of reservoir pressure. In any case, the maximum delivery pressure must not exceed the value established by competent authorities when the concession is assigned or authorized; a potential increase of pressure with respect to original pressure is calculated on the basis of the properties of the reservoir and cap rock. The above discussion implies that, at the end of the cycle, the injection rate must be decreased to avoid exceeding the pressure limits imposed.

The compressors commonly used in storage facilities may be of reciprocating or of the centrifugal type, usually two-stage or multi-stage, which perform better (in terms of gas outlet temperature, capacity, performance) than single stage compressors.

Reciprocating compressors (horizontal, vertical, V-shaped) are mainly used for limited flow rates and high delivery pressures. Since the flow in a reciprocating compressor is pulsed dampers need to be installed to reduce the pulsations of the gas as it enters and exits the compressor, so as to decrease the load on pipelines and the noise levels of the compressor itself.

Centrifugal compressors, on the other hand, are mainly used for high flow rates and limited compression ratios.

The compression units are always equipped with filters or separators at the intake and outlet; the former ensure the removal of solid or liquid particles which might damage the compressor or cause it to work inefficiently, while the latter prevent lubricating oil from being dragged into the treatment plant below the compressor, which may cause problems during later treatment phases. The separators are also useful for eliminating any liquid condensation phases resulting from the cooling of the gas in refrigeration and/or inter-refrigeration systems between the various stages of compression.

The engines which power the compressors may be electric, and have a constant or variable rotation velocity; the latter solution is generally extremely expensive in terms of initial investments. Gas-powered internal combustion engines, especially turbine motors, can be used for centrifugal compressors.

The selection of which types of compressors to use in a compression plant (centrifugal or reciprocating) must take into consideration the mean flow rates and pressure of the storage system. When the pressure and rate allow the use of both centrifugal and reciprocating compressors, the optimal solution is sought first of all on the basis of the flexibility of the compressors. Reciprocating compressors generally better meet this requirement, whilst maintaining higher performance than centrifugal compressors. However, it should be stressed that this difference is decreasing as a result of technological developments in centrifugal compressors, and that often the overall flexibility of the compression plant depends on various factors (configuration, number of modules used, type of engines, etc.). On the other hand, economic considerations make it evident that the investment costs for reciprocating compressors are higher than those for centrifugal compressors; the same can be said for maintenance costs, while fuel costs depend on the type of engine used. In the overall technical evaluation it is necessary to consider the environmental constraints which can strongly influence operating and maintenance costs and control the project selections.

As can be seen from the above discussion, it is not possible to make an a priori selection of the optimal type of compressor and the best configuration of the compression station, because of the large number of variables which can influence the choice towards one solution or another.

Compression station

The management of storage fields requires a degree of flexibility in terms of daily peak rate, due both to purely economic considerations and to constraints imposed by the properties of the reservoir. The range of values for injection and production flow rates depends on how full the reservoir is and the working pressures, and may be extremely broad. Consequently, the ability to regulate pressure and exit flow rate from the compressor are vital factors. When possible, it is preferable to regulate these by varying the rotation velocity of the engine driving the compressor. This can be achieved, for example, by coupling the compressor to gas combustion engines (varying the gas/air ratio), or to electrical engines with a variable rotation velocity. Engines with a constant rotation velocity, on the other hand, are regulated by recycling. There are various other ways to regulate engines, depending on the type of compressor and its constituent elements; reciprocating compressors can be regulated by varying the volume of dead space, or by operating at single-effect rather than double-effect. The ‘stop-start’ system, however, is not advisable given the impact it may have on machines and instrumentation. Delivery pressures are generally regulated by suitably calibrating the delivery stimulus.
Treatment plant

The gas injected into storage reservoirs is withdrawn from the transport network. As a result, it meets given specifications; in other words it has a dew point for water and hydrocarbons which meets the required limits for supply to consumers. The same can be said for its content of inert gases, sulphur compounds and CO₂. Why therefore is it necessary to treat the gas exiting from the storage fields during the production phase? The main reason is that the gas injected into reservoirs becomes enriched with water and sometimes heavier gaseous hydrocarbons (which condense to form gasoline at the surface) present in the interstices of the geological formation used for storage (depleted or partially depleted reservoirs). The presence of water in the gas produced is particularly significant for storage in aquifers or reservoirs which produce by water-drive, where water in the vapour state is frequently associated with water influx due to phenomena of water coning or fingering.

Consequently, before being channelled into the gas pipeline, the gas must pass through the wellhead separators, the plant separators and then through the treatment plants.

Here the treatment process and the appliances used for this purpose are briefly described; the factors used to determine their size, which are rather different from those normally used for the development of a gas field, are also outlined (for a more detailed discussion of treatment plants see Chapter 5.4).

Treatment plants can be subdivided into first treatment plants and definitive treatment plants. First treatment plants include separators, heaters, and pumps for the injection of hydrate inhibitors (glycol and/or methanol).

Separators are cylindrical containers whose diameters vary depending on the flow rates which they need to treat. They are equipped with appliances able to control the level of the separated liquids and the value of working pressure. The task of the separators, usually installed at the wellhead and at the entrance/exit to the treatment plant, is to withhold any free water (or other liquids such as glycol and/or gasoline) and the water which condenses as a result of cooling and the decrease in the gas velocity due to variations in the diameter of the separator.

Heaters are appliances consisting of a cylindrical body containing two coils, one carrying the gas to be heated, the other carrying the gas combustion fumes. Both coils are immersed in a water bath which for obvious reasons must be no hotter than 90°C. The purpose of these heaters, like that of the pumps used to inject glycol and/or methanol, is to prevent the formation of hydrates inside appliances and in the pipelines connecting the wellhead to the treatment plant.

The definitive treatment plants may be absorption dehydration plants (glycol plants), solid-bed treatment plants, or cooling dehydration plants (LTS, Low Temperature Separator).

In glycol plants, glycol dehydrates the gas by absorbing the water vapour present within it. The phenomenon of dehydration by glycol (diethylene glycol DEG and triethylene glycol TEG) is due to the highly hygroscopic properties of glycol, which allow it to decrease the vapour pressure of the water, reducing it to the liquid state. Both DEG and TEG have high boiling points, are thermally stable and their efficiency decreases with use. The only major difference between the two products lies in TEG’s greater dehydration capacity, due to the higher concentration obtained during the regeneration phase (98% as opposed to 95% for DEG). Whereas TEG can be heated to temperatures of up to 206°C, DEG cannot exceed 164°C. In choosing between these two products, the fact that TEG costs more than DEG, and tendency of TEG to ‘foam’ in the presence of even small amounts of gasoline in the gas must also be taken into consideration. Treatment with glycol plants is used when only the water present in the gas produced from the storage reservoirs needs to be removed. The main requisites of these units are the effectiveness of the surface glycol-gas contact, the effectiveness of the absorbing solution, and the simplicity of its regeneration, the adaptability of the process to the different operating regimes.

Solid-bed plants for dehydration and condensate removal are used either to eliminate mainly heavier gaseous hydrocarbons and traces of water vapour (short-cycle plants), or to eliminate mainly water with traces of heavier gaseous hydrocarbons (long-cycle plants). The adsorbent material used is sylvabead; briefly, the adsorption process is as follows: the gas from the reservoir containing water and gasoline in the liquid phase and in the form of vapour enters the separators where the liquid phase is separated out. The saturated gas continues on its way and enters the upper part of the adsorber, exiting the lower part in conditions of undersaturation, in other words free of condensate and dehydrated (the removal of gasoline and water vapour takes place by capillary attraction of the adsorbent material’s numerous surface holes). As it exits the adsorber, the gas is filtered through cyclone filters, and then checked and channelled into the gas pipelines. Short-cycle plants have three adsorbers, of which one adsorbs, one heats and one cools. Long-cycle plants have two adsorbers, one of which adsorbs while the other regenerates. The difference between the two plants lies principally in the working time. If sylvabead is kept in adsorption for a short time, it mainly adsorbs gasoline vapour (short-cycle plants);
by contrast, if the adsorption period is lengthened, sovabead eliminates mainly water vapour, which then displaces the gasoline initially adsorbed.

In LTS plants, dehydration occurs by cooling the gas by simple expansion (Joule-Thomson effect); this causes water vapour and heavier gaseous hydrocarbons to condense. LTS plants can be used in combination with glycol and solid-bed dehydration plants; consequently these units can be used in reservoirs which reach high pressures at the end of the injection cycle and where it is thus possible to use an adequate pressure differential for a large part of the supply cycle.

There are other types of treatment plants, such as condensate removal refrigeration plants which use the cooling effect produced in the transition from the liquid phase to the gaseous phase of some specific fluids (ammonia, chlorofluorocarbons), or desulphurization plants. However, these are not widely used in storage reservoirs; for a discussion see Chapter 5.4.

Gas quality and measurements

In the context of treatment processes, the central importance of control of the dew point for water and hydrocarbons should be recalled in order to avoid the formation of solid plugs (hydrates) and the condensation of water and condensates thus preventing phenomena related to corrosion of the pipes. The dew point required, before channelling the gas into the pipelines, varies as a function of weather conditions in different countries (countries with cold winters need higher dew points), and may range between $-10^\circ$C and $-15^\circ$C in winter and $-5^\circ$C and $-10^\circ$C in summer, at the pipeline pressure.

After treatment and before flowing into the gas pipeline, further checks are carried out for fiscal and commercial purposes. These include determining the heat capacity and the Wobbe index (important to guarantee correct and safe combustion in domestic appliances), and a compositional analysis to describe the product and provide the information required to measure quantities of gas correctly.

Generally speaking, the measurement appliances installed in storage facilities may be of traditional or automated type. The former consist of volumetric counters or calibrated diaphragms which indicate (or record) values subsequently used to determine the volumes treated and instant flow rates. In automated measurement units, the equipment described above is coupled with a ‘flow computer’ which uses the parameters supplied by the counter or the diaphragm to calculate volumes and instantaneous flow rates automatically and continuously. As mentioned at the beginning of this chapter, the unit of measurement for volumes is the Sm$^3$ (under reference conditions for temperature and pressure of 15.5$^\circ$C and 1.01325 bar respectively). For commercial purposes, the measurement of quantities of gas is often expressed in energy units (GJ) rather than Sm$^3$, to take account of the fact that the gas produced by a storage system never has an identical composition over time. In this case the Gross Calorific Value (GCV) needs to be measured with a gas chromatograph or continuous samplers.

In the case of measurement with a volume counter the main parameters which enter the expression to calculate the flow and the volume are: the number of revolutions of the turbine in the time period considered; the operating pressure and temperature; and the coefficient related to the deviation from the ideal gas law behaviour, under working and reference conditions.

For measurements using a venturimeter diaphragm the parameters required for the formula used to calculate the flow and the volume are: $a$) the diameter of the aperture; $b$) the pressure difference between positions upstream and downstream of the aperture; $c$) the operating pressure and temperature; $d$) the unit mass volume; $e$) the coefficient which groups together the conversion factors of the measurement units, and the compressibility and flow coefficients.

Safety systems

Safety in storage systems concerns various zones, in particular the safety of treatment and compression plants, reservoir safety and well safety.

Special care is devoted to the safety of the compression and treatment plants, to allow these to work safely and reliably by remote control, unmanned or partially manned. Specifically, the layout of the various plants is carefully evaluated so as to avoid interferences and allow the circulation of people and vehicles with maximum safety. The plant is of fail-safe type, so that in the event of failure, and even in the absence of power, all appliances automatically switch to safety mode.

As far as environmental protection is concerned, compression plants are built and operated in accordance with laws regarding noise pollution, air quality and solid and liquid discharges in general; specifically, compression units are housed in sound-proof rooms, so as to avoid exceeding given noise levels outside.

Recovery systems are provided for the chemicals, used to treat gas after regeneration, which leak out as a result of plant failures or maintenance, in order to limit their dispersal in the atmosphere.

Stations are equipped with fire detection systems both in open areas and closed rooms. In open areas, the fire detectors consist of fusible plugs and/or heat detectors.
sensitive wire. In closed areas, flame and/or optical smoke detectors are installed; some closed rooms have an automatic inert gas (halon) intake system for use in the event of fire. Before the introduction of halon, ventilation systems are automatically shut down and the flame-proof shutters on the air intakes are closed. The flame, smoke and explosive mixture detectors are connected to a panel containing the control modules; under anomalous conditions these activate the alarm status on the DCS and activate the automatic fire extinguishing systems.

The plant’s shut-down system includes devices which are activated if there is an anomaly in operating parameters or if a fire or explosive mixture is detected. There are two types of facility shut-down. The first type involves a general shut-down of the station’s plants either with automatic or manual depressurization of the plants. This type of shut-down is activated in the event of fire, or without depressurization of the plants activated automatically or manually in the event of high/low pressure on the plant’s outflow manifold. The second type is a partial shut-down of individual units or appliances in the plant, activated due to abnormal operating conditions or the detection of fire in closed rooms.

Reservoir safety requires periodic checks to ensure that there are no gas leaks through the cap rock or the casing cementing of the various wells. Leaks can be detected from the behaviour of the reservoir (volumes injected/withdrawn, pressure patterns over time) and by monitoring the pressures in the casing annular space. Another important aspect of reservoir safety involves monitoring possible surface movements resulting from the injection and withdrawal of gas. During a year the reservoir undergoes at least one cycle of withdrawal and injection, with an alternation of depressurization and pressurization. Checks are carried out by precision levelling on the vertical datums of the reservoir and by monitoring microseismic activity, using a network of stations located over a vast area which includes the storage reservoir.

To guarantee well safety, each well area is equipped with a pneumo-hydraulic monitoring system connected to a control panel to ensure that the well and its associated equipment (separators, blowers, etc.) are protected. The control panel operates the monitoring instruments by means of an hydraulic circuit which acts on the safety valves installed in the tubing, and a pneumatic circuit to monitor and operate the wellhead shut-down valves and all the other valves situated on the pipeline manifold in the well area.

Normally there are three hierarchical levels of shut-down: emergency shut-down, process shut-down and local shut-downs.

Emergency shut-down occurs in the event of fire; the process areas are equipped with a detection system with fusible plugs that melt at temperatures above 70°C, shutting the well with the following effects: a) closure of bottomhole valves; b) closure of wellhead valves; c) closure of the well area exit valves and sections of the plant; and d) opening of the depressurization valves with which each section of the plant is equipped, leading to discharge into the blow-down valve. Shut-down can also be activated by local operation of the safety valves, or by commands sent by operators from the shut-down control panel.

Process shut-down is activated automatically by high/low pressure sensors located on the process lines; the liquid discharge of the separators is operated by level monitors mounted on these.

Local shut-downs involve part of the plant and are activated automatically or manually to safeguard individual components in the event of excessive pressure or low/high levels of liquid in the separators.

Problems caused by the transport network

Transportability constraints

The gas transport system can be thought of as consisting of two subsystems of gas pipelines, conventionally described as primary and distribution pipelines. The primary network is the network used to transport large volumes of gas, and consists of large diameter pipelines which can operate at a maximum pressure of 75 bar. The distribution network, on the other hand, is characterized by small diameter pipes placed in more urbanized areas characterized by lower pressures (up to 5 bar) and thus able to transport small volumes of gas. Storage reservoirs, which need to supply large volumes of gas with high peak rate, are generally connected to the primary network.

In order to develop a storage field, it is important to know the maximum pressure and flow rate in the pipeline to which the field is connected. These parameters must be taken into consideration when determining the sizes of the compression and treatment plant, and the field facilities. In some cases, to maximize the potential of a storage reservoir, the economic viability of expanding the transport system may be considered.

Interactions between the storage system and transport network

The storage system must guarantee the maintenance of minimum pressure levels in the primary network to ensure that customers are served continuously. This is normally known as networf balancing and involves maintaining adequate levels of line-pack (the volume of gas which fills the pipelines
in the network) in the gas pipelines. The peak hour demands of the market are met both by storage fields and with the contribution of line-pack. In transport systems consisting of large diameter pipelines stretching over many km, the contribution of line-pack in terms of peak hour and daily rate may be considerable (several tens of millions of Sm³).

Normally, the transport operator uses line-pack at times of maximum demand for residential use (morning and evening peaks in demand) and replaces the volume used during the night (Fig. 21). To this end, the transport operator also books volumes of gas from the storage system, like the gas sales companies. Since this is a service which affects the continuity of supply to customers, transport operator access to storage systems is generally prioritized; this means that the volumes requested are supplied even when the overall capacity of the storage system is not sufficient to meet the total demands of the market.

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**Franco Falzolgher**
Scientific Consultant
7.4.2 Underground structures for natural gas storage

Introduction

As discussed in Section 7.4.1, when a gas field is brought into production, the surface plants and required wells are designed to ensure constant average production throughout the years and handle the inevitable decline of production. The supply of natural gas from a number of fields generally requires regulation of the relative production for comprehensive use of the capacities of the major natural gas pipelines. However, together with the constant production of gas, there is a variable seasonal demand, higher in winter given the greater consumption for heating. The connection between constant supply and variable demand is provided by underground natural gas storage: when demand is lower than supply, excess gas is injected underground and is retrieved during periods of greater request.

In addition, fields for underground natural gas storage are generally located near areas where the demand is greatest and may consist of depleted gas reservoirs, aquifers or artificial caves. Most storage is done in depleted gas fields, followed by storage in aquifers. On the other hand, storage in artificial caves − while unable to compete with other systems in terms of the amount of gas stored − is becoming quite common since it ensures high productivity for short periods and very little prior notice, thus meeting sudden demands for gas.

This section will take a closer look at the reservoir studies ordinarily conducted for gas storage.

Gas storage in depleted gas fields

When a gas field approaches the end of its productive life, it is advisable to consider transforming it into a gas storage field.

A depleted (or about to be depleted) gas reservoir is generally marked by low pressure and high water saturation in the zone originally occupied by the gas due to its displacement by water of the aquifer. Gas saturation behind the water front ranges from a minimum, corresponding to the residual gas saturation near the original gas/water contact, to a maximum, corresponding to gas saturation near the gas/water contact in depleted or semi-depleted reservoirs (see Chapters 4.1 and 4.3).

When gas is injected into a depleted reservoir, it displaces the water and occupies its place, without however displacing the gas remaining in the pores after primary gas production. It is important to remember that, thanks to its compressibility, the residual gas also helps supply the energy needed during the subsequent production phase. Fig. 1 shows the original position of the gas/water contact (AA’) for a water drive gas reservoir and the position at the end of production (BB’). After injection of the gas, the contact position (CC’) retreats, climbing again during the output phase up to the maximum admissible quota (DD’). Beyond this level, the storage wells might also produce water, causing serious problems for production and malfunctioning of the surface equipment. It is important to remember that conversion of the depleted or semi-depleted reservoirs is generally less costly than other underground gas storage systems and has another series of advantages, first and foremost better knowledge of the reservoir’s characteristics, through both consolidated geological data and the production history of the wells (see also Section 7.4.1).

![Diagram of gas storage in depleted gas fields](image)

**Fig. 1.** Layout of movement of gas/water contact in underground storage in depleted reservoirs.
Exploitation of a gas field generally requires the presence of piping connecting to the line network for gas supply, and surface areas where gas treatment plants are located. For the purposes of gas storage, these areas can be used for the installation of compressors, and for the construction of new treatment plants if the old ones are inadequate and impossible to modify.

Not all depleted gas fields are suitable for gas storage however. Their conformation must be such that the gas injected during storage can be recovered without loss and that the reservoir productivity promptly meets the demand for gas during the production cycle. For that reason, reservoirs with marked petrophysical heterogeneities or lack of structural (displacement due to faults) uniformity or low permeability are unsuitable.

**Pressure/stored volume relationship**

Let us consider a volumetric reservoir (without water drive, see Chapter 4.3) in production. The $p/z$ ratio of the average reservoir pressure and the gas compressibility factor to that pressure ($z=1$ for an ideal gas) is, in first approximation, the linear function of the volume of gas produced, as illustrated in Fig. 2, where A is the initial situation before production and B is the situation at the end.

In the case of an aquifer drive reservoir (see again Chapter 4.3), the $p/z$ ratio is no longer the linear function of the gas produced since water enters the pores originally occupied by the gas. The reservoir pressure (and therefore the $p/z$ ratio) tends to be greater with respect to the volumetric reservoir, given equal volumes of gas produced. Since the aquifer shows a delayed response to the drop in pressure of the zone that was originally a gas zone, the deviation from the volumetric reservoir is even more apparent after a certain volume of gas has been produced (AB in Fig. 3).

In the case of gas injection in a volumetric reservoir, the $p/z$ ratio is the linear function of the volume of the injected gas (CD in Fig. 4). Instead, with injection of gas in a water drive reservoir, the reservoir pressure (and therefore the $p/z$) tends to be

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**Fig. 2.** Ratio of pressure $p$/compressibility factor $z$, versus cumulative production in volumetric reservoirs.

**Fig. 3.** Ratio of pressure $p$/compressibility factor $z$, versus cumulative production in water drive reservoirs.

**Fig. 4.** Ratio of pressure $p$/compressibility factor $z$, versus injected gas volume in volumetric gas reservoirs.
initially higher with respect to the volumetric reservoir and tends to become ultimately stabilised due to an increase of the volume of the area the gas occupies following retreat of the water table (CD in Fig. 5).

In the case of the reversible storage/production cycle in the presence of an active aquifer, the trend in the $p/z$ ratio based on the volume of stored gas is not linear and generally presents a hysteresis. This is illustrated in Fig. 6, where $E$ is the situation before injection and $D$ is the situation after injection is completed.

In the case of a reservoir subjected to one cycle of injection and production a year – typical of most storage systems – the general form of the $p/z$ curve based on the stored volume is indicated by curve $ED'D'E'$ in Fig. 7. The section $ED'$ corresponds to the injection, the section $D'D$ corresponds to pressure stabilization upon completed injection (drop of the pressure in the aquifer); the section $DE'$ corresponds to the output flow phase, the section $E'E$ corresponds to pressure stabilisation at zero production due to the delay in aquifer response.

The examples give a qualitative, simplified idea of the relationship between pressure and produced/stored gas volume. More precise analysis must quantify the influence of the aquifer as well as the not always negligible contribution of porous volume compressibility. The delay in aquifer response may, in fact, have a noticeable effect on pressure during the alternating phases of injection and production. Moreover, porous volume compressibility may change significantly according to pressure, particularly for relatively shallow, unconsolidated formations. While for a production reservoir, the decompression of the porous volume takes place over a number of years, in the case of a storage reservoir, the phases of compression and decompression are very rapid, generally lasting less than six months. In this case, the elastic variation of the porous volume following this stress can have a delayed compensation effect on the reservoir pressure very similar to that of an aquifer drive.
Productivity of a storage reservoir and function of cushion gas

For a gas storage reservoir, the gas volumes that can be stored and, above all, those that can be reversibly produced over the limited period of the output flow are of great importance. Compared to a gas reservoir, whose production is distributed over a number of years, a storage reservoir must guarantee a production of comparable quantities of gas concentrated over a period of 5-6 months at the most. For that reason, the storage reservoir must have a high level of productivity.

Since the wells are the points of gas extraction, a high number of wells can clearly lead to high reservoir productivity. Still, given the wells’ high unit cost, it is preferable to use a limited number, making sure that each has high productivity, meaning that relatively high flows should correspond to limited losses of pressure in the passage from the reservoir to the surface. These losses take place within the porous medium, at the interface between the reservoir and the borehole and within the production string.

These pressure losses in the porous medium depend basically on rock permeability and are therefore not generally susceptible to ameliorative variations. It is evident that, for this reason, reservoirs with low permeability are difficult to convert into storage fields. Instead, losses of pressure at the interface between the reservoir and the borehole can be reduced considerably by increasing the diameter of the borehole and, even more, by using horizontal wells wherever conditions allow. Whatever the case may be, the well drilling and completion techniques must allow for minimum damage of the formation around the well. Given the high output demand, there are significant pressure losses due to friction within the production string. In order to reduce these losses to a minimum, pipes with a wider diameter than normally employed for gas reservoir production are used.

It should be noted that high flows mean high linear fluid velocity. In the case of poorly consolidated formations, this can lead to disastrous sand production in the wells during output flow, something that must be taken into account in well completion design (see Chapter 3.7).

Operating conditions of surface plants being equal, the greater the average reservoir pressure, the greater the flow that theoretically can be obtained from the gas wells. Thus, storing gas at higher pressure, means – aside from a greater amount of gas stored – the possibility of greater initial well productivity, a circumstance that makes a storage project more attractive. However, the technical limitation for maximum pressure in injection is that beyond which the integrity of the cap rock can no longer be assured, or when there would be an excessive volume of gas stored with migration of gas that escapes beyond the spill point. Legislative limitations also vary from country to country, however: at present in Italy, it is possible to store gas in a depleted reservoir up to a pressure no greater than the original pressure of the virgin reservoir.

Together with the maximum daily flow rate that the reservoir can provide, the gas storage design also determines a minimum flow rate necessary to meet the demand for gas. In order to ensure this minimum flow, reservoir pressure must not fall below a set value. The minimum volume of gas in the reservoir, sufficient to supply the needed energy, corresponds to the cushion gas volume. This volume must always be kept in a storage reservoir since gas output flow could lead to poor operative conditions of surface plants, causing a dangerous rise in the reservoir water table, and making it impossible to meet contractual gas supply obligations. It should however be kept in mind that, during emergencies, it is possible to release part of the cushion gas without creating problems by recovering productivity through lowering pressure at the wellheads.

Reservoir simulation for storage optimization

The simulation of reservoir behaviour with mathematical models allows to take into account the aquifers, the variations of the porous volume, and the relative motion of water and gas, governed by the relative permeability curves. The use of numerical models of finite differences also makes it possible to take into account reservoir heterogeneities, and the possibility of intercommunication between the various levels. In particular, using the history matching technique (a comparison between the history of production and model data, see Chapter 4.6), by adjusting reservoir and well parameters, our understanding of the reservoir deepens as the historical data increases.

It is obvious that a ‘mature’ gas reservoir (in an advanced state of exploitation) has a large amount of historical data to reproduce and therefore its study leads to a thorough understanding of the reservoir, essential for injecting gas for storage. Optimized transformation of a depleted reservoir into a storage reservoir necessitates a study that reasonably reproduces historical production data over time for all the wells: bottom hole pressure, wellhead pressure, gas production, initial moment of water production, amount of water produced. An example of the history matching of pressure data for a gas well is given in Fig. 8.
Using reservoir characteristics adjusted when performing history matching, it is therefore possible to carry out mathematical model simulations of storage under different scenarios. That way, we can take into account a number of variable wells in different locations and completions as well as surface plant operation conditions. These simulations allow evaluation of how the reservoir might respond to alternating phases of the injection/production flow cycle, particularly vis-à-vis the aquifer’s response and relative cyclical movements of the water table.

The information obtained helps to formulate an economic evaluation that is helping in confirming the feasibility of a project for new storage system or for modifying an existing one. A graphic example of this data is seen in Figs. 9, 10, and 11. Figs. 9 and 10 show the trends of the gas over time for volume stored in the depleted reservoir and the gas pressure, simulated during the alternating phases of the storage and output flow cycles. It should be observed that, before beginning output flow/injection, a minimum amount of gas is injected in the reservoir, and the amount of stored gas and the reservoir pressures must never fall below specific values. The potential outflow of gas in a general storage cycle is known as the working gas. The amount of gas that remains stored in a reservoir is the cushion gas. The drift observed in Fig. 9 depends on the fact that part of the energy supplied in injection for re-creation of the gas reservoir is gradually dissipated with pressurisation of the aquifer, which responds more slowly than the gas zone. Fig. 11 shows, for an average flow cycle, the curve of the output flow that the reservoir can assure, based on the volume of the output flow. This curve best describes a reservoir’s capacity to meet the production demand. Generally speaking, for reservoirs that – properly regulated – contribute an average constant supply to the available gas pipeline network, the maximum flow can remain constant up to an outflow of 30-40% of the working gas.

In order to meet sudden spurts of high user demand for gas, high production reservoirs – often characterized with a low working gas value – are used; their productivity curves may have a plateau of maximum flow lower than 10% of the working gas.
Gas storage in the aquifers

Aquifers, underground geological formations, bent over so that they can constitute a trap but having water inside the pores, are generally characterised by excellent porosity and high permeability. Their extension may be significant. If they meet the conditions for gas trapping, these formations can be used as gas storage fields. Natural gas storage in the aquifers requires injection of gas inside a porous medium initially containing only water. The gas injected in the structure top displaces the water and, thanks to the effect of differences in density, accumulates at the top of the structure.

Requisites

It is important to underline that not all aquifers are suitable for natural gas storage: the basic requisites are their ability to store gas without loss and produce stored gas with high productivity. For that reason, thorough knowledge of the structure is required, supported by good seismic and geological control. In the case of an anticline, the position of the spill point that guarantees maximum trapping must be well defined, nor should there be any dislocations (faults) that can impede hydraulic continuity in the porous medium initially containing only water. The gas injected in the structure top displaces the water and, thanks to the effect of differences in density, accumulates at the top of the structure.

Operation

It is important to underline that, before the creation of the first gas chamber, the porous medium is completely saturated with water. Under these circumstances, in order to introduce the gas (fluid gas that does not wet the rock), a differential pressure with respect to the water must be applied to the gas corresponding to the gas/water capillary pressure (see Chapter 4.1). In addition, due to the effect caused by the gas/water relative permeability curves, which under these conditions indicate low effective permeability to gas, initially it is necessary to use higher injection pressures than the maximum pressure used during regular storage. Due to the greater area of contact with the area completely saturated with water, the pressure needed to displace the water tends to decrease considerably once a first bank of gas is created around the well, as described by Darcy’s law.

Characterization

In contrast to depleted gas reservoirs whose past production history supplies the instruments needed for best understanding of the reservoir, in the case of aquifers, initial reservoir knowledge is based exclusively on seismic-geological data and the little existing well data. For that reason, when country legislation allows storage in aquifers, knowledge of the structure and hydraulic continuity of the porous...
medium should be obtained before conversion through drilling of suitably distributed key wells. Petrophysical characterisation of the reservoir should therefore be carried out on rock samples obtained during continuous coring. Aside from permeability and porosity measurements carried out on these samples, useful tests include compressibility of the reservoir rock and determination of the characteristics of the cap rock’s tightness, marked by the threshold pressure beyond which the gas can migrate vertically through the cap rock itself.

The study of an aquifer already transformed into storage reservoir, performed with the history matching technique on the basis of an historical number of storage-flow cycles, is a basic instrument both for the better knowledge of the reservoir and the periodic verification of the inventory (volumes, pressures, etc.) of the gas stored.

Storage in artificial cavities

Underground storage of natural gas can also be carried out in cavities created inside accumulations of salt through artificial washing with water. These accumulations are present in nature in two forms: salt domes and salt beds. Salt domes are the result of the plastic deflection of salt which has been pressed upwards with time through weak points in the sediment due to the pressure of sediments above it and the difference of density. They are generally oblong in shape and vertical and can reach horizontal diameters of over a kilometre, rising up to several kilometres in height. Salt domes are generally used to store natural gas and are found at a depth of between 500 and 2,000 metres. Salt beds on the other hand are extended formations, consisting of alternating formations of salt and other evaporitic rocks: they can reach a thickness of 500 metres, while they are generally no deeper than 1,000 metres.

Salt accumulations consist of almost pure sodium chloride generally employed for industrial purposes and which may be extracted with traditional mining methods (underground mining) or controlled dissolution with fresh water. Thanks to the latter methods, saturated saline solutions may be obtained and used directly in chlorine and caustic soda plants. The salt’s impermeability makes the cavities obtained this way excellent for storage of materials where salt is insoluble (saturated saltwater drilling mud, liquid and gaseous hydrocarbons, ecc.).

The use of artificial salt caves to store hydrocarbons is relatively recent, starting in Canada at the beginning of the Second World War and continuing during the 1950s in North America and Europe with the storage of LPG. During the 1980s, the United States created strategic reserves of oil inside salt formations with a stored volume of 94 million cubic metres. The storage of gas inside salt cavities started later, in the United States during the 1960s.

The caves are not very large: average volumes run from 50,000 to 500,000 m³, although recently new technologies have allowed construction of cavities over 300 m in length with capacities of up to 2,500,000 m³.

Notes on the construction of artificial salt caverns

Not all caves originally used for salt extraction are suitable for gas storage: the cavities may have a particular shape that could lead to internal collapse during storage operations (injection and output flow) with consequential safety problems. If the salt washing generates a lateral peak higher than the base of the last well casing, it might be impossible to recover the gas that occupies it during removal of the salt water, making well recompletion procedures extremely difficult.

Before developing a cave, we must first know the shape of the embedded rock of the salt deposit, and determine the availability of both water for salt dissolution and sites for disposal of the salt water. The geometry and internal consistency of the accumulation of salt can be identified (if not already known through previous geological and geophysical studies for oil prospecting) by means of geoseismic surveys and test well drilling with continuous coring of the formations.

It should be kept in mind that salt dissolution can also be performed using brackish water with a low salt content, which increases its availability. When not sent to chlorine-soda production plants operating in the area, salt water is generally disposed of in underground formations.

The well drilled for the construction of the cave is the same that will be later used for storage operations. The drilling mud must be saturated with salt in order to ensure integrity of the hole inside the salt. After installation of suitable casing, the well is completed with two concentric tubes (Fig. 12): fresh or brackish water is generally injected from the inner pipe. The gap between this and the successive pipe is used to let out the salt water and the gap between external tubing and casing, is used to create an oil blanket above the aqueous phase, in order to keep fresh water from coming into contact with the roof of the cave under construction, and avoid the unwanted formation of an upper-side culmination. As the salt is dissolved, the inner pipe is lowered further to allow greater contact between the water and salt. The cavity formed is oblong and pear-shaped, with a wider base section and debris accumulating on the bottom. If water circulation is inverted, with extraction from the inner pipe, the cavity tends to adopt a wider top section.
Cave design is generally done with the help of mathematical models that take into account the thermodynamic properties of the salt and the water used. Control of dimensions is done during salt dissolution through acoustic instruments such as sonar. Once a cave of the desired size is obtained, it is emptied using the same gas that will be stored in it. It should be noted that debris and part of the salt water cannot be completely eliminated and remain at the base of the cave. During storage, this water tends to vaporize in the gas making it necessary for the gas produced to be dehydrated before being sent to the gas pipelines.

In order to construct a cave with a volume of about 400,000 m³, roughly ten times the volume of water is needed; construction time, with an optimum flow of water of 300 m³/h, is approximately 20 months. The average life span of a cave for gas storage operations is about 30 years.

**Characteristics of salt cavern storage**

Since they are completely impermeable, artificial salt caverns are ideal gas containers. In contrast to other storage systems in porous mediums, salt cavern storage presents very high productivity which means that the caves can be used specifically for profitable peak shaving operations. In fact, in emergency situations or in the case of a sudden demand, the gas can immediately be released into the network. Storage operations are also much faster than with other systems. For these reasons, it is possible to have several injection/output cycles a year, marked in average by a high output for 5-10 days and injection for 10-20 days. Another advantage is the use of lower amounts of cushion gas to ensure well productivity during the output phase (30-40% as compared to an average of 50%, typical of storage in depleted reservoirs).

Given the limited volume of gas that can be stored (and therefore the limited volume of working gas), storage in artificial caverns cannot compete with other storage systems as regards supply of relatively constant flows in the periods of maximum gas demand.

The maximum pressure of cavern storage does not generally exceed a gradient of 19,600 Pa (0.2 kg/cm²) per metre of depth, starting from the cave roof pressure. The minimum pressure during output is limited by geomechanical considerations: with time, stress due to sharp changes in pressure can lead to plastic deformation of the salt, even causing a sizeable reduction of the artificial cave’s volume. As an empirical rule, it is advisable to keep minimum pressure during output from dropping below a gradient of 8,800 Pa (0.09 kg/cm²) per metre of depth starting from the pressure at the cave roof.

**Well typologies and completion in the gas storage fields**

**Use of existing completions for injection/production**

In the case of transformation of depleted gas reservoirs into storage reservoirs, the tendency – if the mechanical conditions of the wells allow it and if the location is in the structural top – is to reuse the wells with existing completions both for injection operations and production. It should be kept in mind that the existing wells that cannot be used directly for storage are still an important source of information for storage control thanks to reservoir studies. Used as monitoring wells, they can supply precious information on the trends of reservoir pressure and...
even on the movement of the water table during injection/output operations.

**Modification to existing completions**

During gas injection, in order to overcome pressure loss along the path to the reservoir, wellhead pressure must be higher than during production. For that reason, the wellhead equipment must be rendered compatible with the injection conditions. Moreover, it is often convenient to proceed to recompletion of existing wells to meet the new demand for high productivity during the output cycle. In fact, in order to reduce the pressure loss, recompletion with pipes of greater internal diameter may be necessary.

With high output flows and with fairly unconsolidated formations, it is possible that sand is drawn into the well, due to high velocity of gas flow at the interface between the casing and the formation. In order to avoid sanding of the well and the start of dangerous abrasion and breakage within the pipes, filters are generally used (gravel packs in particular: see Chapter 6.2), which must be installed with extreme care to reduce damage and loss of internal pressure as much as possible.

**New completions**

When the use of existing wells, even if modified during completion, does not allow the productivity demanded during output of the storage reservoir, additional wells must be drilled. It is obvious that wells designed *ad hoc* for storage reservoirs operations are more suitable than recovered wells not designed for this purpose. The use of horizontal well at structural tops can generally, despite high unit costs, meet the double goal of guaranteeing high productivity and minimizing the number of wells needed. However, the complex morphology of reservoirs and the presence of active aquifers and heterogeneities in the porous medium justify the development of storage with conventional wells.

The study of the reservoir by mathematical simulation makes it possible to calculate the number of wells needed, the sections of the tubing best suited to storage operations and the maximum head pressure during injection of the gas in the reservoir. Well completions are designed with this in mind. Most of all, the well must be capable of operating in constant safety and reduce the possibility of accidental interruption of production to a minimum.

**Fig. 13** shows a typical storage well completion: the gravel pack is present at the bottom in the open hole, and the mechanical filter is inserted in it at the base of the tubing. After that comes the production packer, the surface controlled subsurface safety valve that automatically closes the well in the case of a sudden rise in flow. Above that lies the glycol injection valve to prevent the formation of hydrate plugs inside the tubing. The completion ends with the wellhead, designed for a maximum pressure that is greater than the maximum pressure predicted during gas injection.
Bibliography


GIANFRANCO ALTIERI
Scientific Consultant