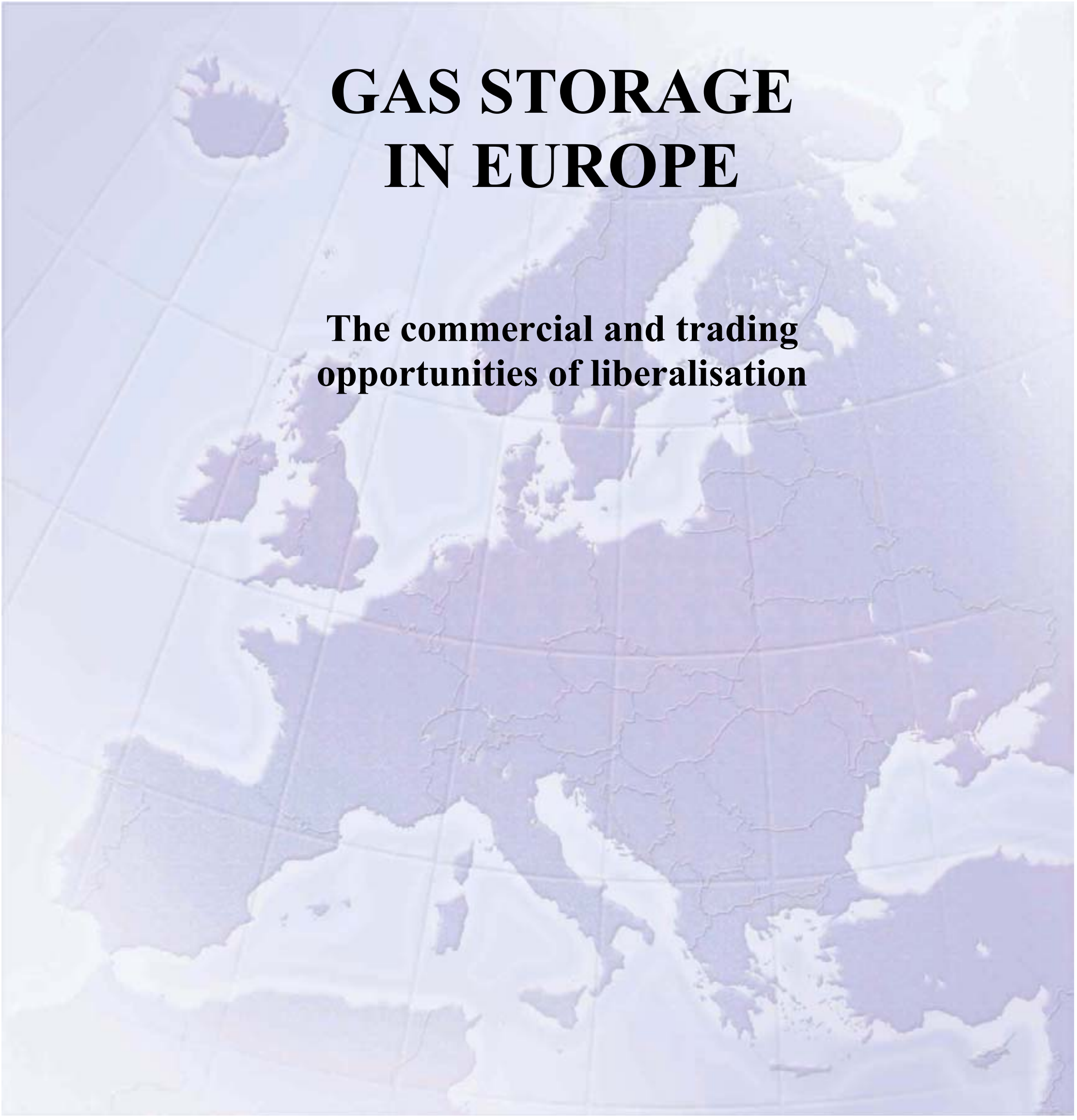

GAS STORAGE IN EUROPE

The commercial and trading opportunities of liberalisation

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About the Author

Mike Madden is an independent consultant based in Oxford, specialising in natural gas issues. He previously worked for 13 years with BG plc at Transco, where he was involved in the development, negotiation and management of gas transportation contracts that served the competitive market in the UK from its early beginnings to the introduction of the Network Code. Since leaving Transco at the end of 1994 he has provided consultancy both in the UK and world-wide. His clients include producers, gas marketers, power generators and large gas users to whom he provides advice on a variety of issues including the (UK) Network Code, gas storage, third party access in Europe. He is also a senior associate consultant with Gas Strategies.

Mike Madden has been assisted in this research by Jeff Titmas of Jeff Titmas Research, an Oxford-based consultant specialising in research across the gas industry both in the UK and abroad. Particular areas of experience include gas storage and gas market liberalisation. He is a graduate of Oxford University where he gained a scholarship from Lady Margaret Hall to study Mathematics and Computation.

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INTRODUCTION

Scope of the report

Gas storage in Europe provides a comprehensive overview of the changes that are taking place in gas storage both in the UK and throughout Continental Europe, and then goes on to consider the impact of these changes on the industry.

- Chapter 1 examines the traditional role of storage and explains how load duration curves are constructed and used;
- Chapter 2 considers the development of the commercial uses of storage against a background of gas-to-gas competition being introduced across Europe;
- Chapter 3 examines the various types of storage that are currently available, and the different roles they fulfill;
- Chapter 4 analyses the various alternatives to physical storage that are available, and how they fulfill the needs of the market;
- Chapter 5 examines the theory of storage tariffs and how storage tariffs can be constructed;
- Chapter 6 contains a number of case studies on new gas storage projects, and explains the operational and commercial rationale behind each project;
- Chapter 7 looks at gas storage in the UK, from the perspective both of the physical assets and also the developing commercial market. This chapter includes a review of the old regulatory tariff regime as well as the new auction scheme which is just being put in place;
- Chapter 8 examines the role and function of gas storage in the US market;
- Chapter 9 looks at the present structure of the gas market in Continental Europe and reviews some of the changes currently taking place.

Subsequent chapters contain in-depth analyses of the following Continental countries and also some countries from the former Eastern Bloc: Austria, Belgium, France, Germany, Italy, The Netherlands, Spain, the Czech Republic, Hungary, Poland and Slovakia. For each country the gas industry is considered under the following headings:

- Industry structure;
- Peak capacity and swing requirements;
- Storage facilities available;
- Alternatives to storage;
- Regulation.

Research methodology

The research is based on both primary and secondary materials. Face-to-face and telephone interviews were conducted with various players in the UK and Continental Europe. These players included utilities, producers, shippers, traders, generators, trade associations, regulators, government departments, gas industry consultants, analysts, academics and journalists.

In addition to this primary material, information was gathered from material published in Europe and North America. This included market reports, national and trade press, on-line data bases, company press releases, annual reports, and material published by governments, regulators and international agencies.

Strenuous efforts have been made to check all the information contained in this report, and to ensure that it is as up-to-date as possible at the time of publication.

Timing of research

The research was conducted between August 1998 and February 1999.

EXECUTIVE SUMMARY

Since the introduction of competition in both the US and UK markets, the structure of these gas markets has changed radically. Previously bundled merchant pipeline companies have found themselves being unbundled into separate transportation, storage and gas trading companies. The previously ‘safe’ incumbent monopoly has found itself exposed to the cold winter of gas-to-gas competition. Initially storage was included in the unbundled transportation companies but, as the ‘steely eye’ of the regulator focused on further reducing transportation costs, reducing cross subsidies and introducing competition, gas storage has found itself in the spotlight, both in terms of being unbundled as a now-separate link in the gas chain and in providing new and varied services for the newly developing competitive gas market.

The traditional role of storage

Traditionally gas storage has been seen as an insurance policy ensuring that, no matter what operational or weather conditions occur, the security of gas supplies to customers is always maintained. In fact many gas companies throughout the world, both in the past and still today, have actually referred to gas storage as an insurance policy. However, with the introduction of gas-to-gas competition, firstly in the US, then in the UK, and now soon to follow throughout most of Europe, this old role of gas storage as an insurance policy is beginning to change. Not that the traditional role of gas storage as a tool in managing the seasonal supply/demand match and maximising supply security is being abandoned, but rather that new and more commercially-orientated roles for gas storage are being found.

The developing commercial role of storage

As previously mentioned, in the newly competitive gas markets in the US, UK and also in parts of Europe, gas storage is finding a variety of new roles in facilitating the development of gas-to-gas competition. These roles are occurring for a variety of reasons. The development of effective gas-to-gas competition requires at least that transportation and storage be unbundled from gas trading. Once this unbundling has occurred, there is a need for both commercial and operational balancing of the transportation system. Therefore gas storage is developing a new role, both in the hands of the system operators to ensure a physical daily balance, and in the hands of shippers to ensure a commercial balance in order to minimise any penalties that may be levied by the transporter.

The development of gas trading both on an ‘Over the Counter’ basis and on an Exchange traded basis has also made demands on gas storage. In fact, gas storage has become a significant tool in the hands of gas traders, enabling them to minimise costs and maximise arbitrage opportunities by taking account of seasonal and daily pricing fluctuations. Another reason why gas storage is developing into a commercial tool is the requirement by regulatory bodies throughout the world to further unbundle transportation and storage. This has been done by separating the transportation and storage functions into at least separate business units and ideally completely separate companies. This separation then allows an easy identification of costs for both transportation and storage, which in turn has allowed the development of true competition in the storage market.

Choosing the right type of storage

Both in its traditional role in providing gas to ensure a seasonal supply/demand match, and in the new role that is developing for gas storage, it is important that the right type of storage is used to provide the particular service that is needed. The table on the following page shows, albeit in the form of a brief summary, the various types of storage that are commonly used throughout the world, and the roles that they fulfill.

Alternatives to storage

As the industry has begun to value both the peak gas supplies and the supply security which gas storage provides, and to seek to gain these benefits in the most effective and efficient manner, so a number of alternatives to storage have also developed. One alternative to storage is the interruption of gas supplies to large process users, such as power stations and chemical plants. Often these customers have the flexibility to be able to switch to an alternative fuel (such as gas oil, bottled propane or even coal) when the economics of doing so make sense. Historically interruptible customers pay less for their gas throughout the entire year, with little incentive to actually switch off when required to do so. However this is beginning to change, with many of the new interruptible customers being paid a 'market-related price' to switch off on days of high demand.

Other alternatives to gas storage include the provision of supply-side swing from gas supply contracts, short-term seasonal gas purchases, and sourcing gas from the Interconnectors. In the developing gas storage/peak gas market it is the interaction of these various sources of flexibility that will ultimately set the price of gas storage and supply flexibility. By analysing each of these alternatives to gas storage and the economic rationale of each method, it is possible to begin to understand how the peak gas and gas storage markets might develop.

Another important factor in establishing the value of peak gas and gas storage is the supply/demand match in the market. If the supply/demand match either within a particular country of within Europe as a whole were to go into deficit then the value of peak gas, and therefore storage, would rise significantly. Predictions as to when any particular market will move from surplus to deficit are notoriously difficult to make, not just as a result of the seasonal fluctuations that occur in the world's gas markets, but also due to the unpredictable intervention of governments which can change the characteristics of gas markets relatively quickly. A good example of this is the recent action taken in the UK to restrict the use of gas in power stations. Such action has dramatically reduced the size of the UK gas market, and made irrelevant many of the forecasts prepared by companies as to future gas usage. Therefore the challenge for many organisations who are currently considering the development of new storage facilities or enhancing existing ones is to predict the supply/demand match for the market which that facility would serve.

The development of new storage projects

One of the most obvious outcomes of the development of gas-to-gas competition and the new storage market has been the opportunity for the development of new storage

Summary of the various types of storage available and their uses

Storage type	Operational characteristics	Typical uses
LNG	Typically LNG storage is filled slowly during the summer months. However the deliverability for withdrawal is very high, and a facility can often empty within 5 days. Due to the compact nature of the facility they are often located at the extremities of the pipeline system.	LNG storage is particularly useful for meeting the 'needle-peak' situation which occurs when temperatures are low and gas demand rises quickly. LNG storage facilities are often located at the extremities of the pipeline system in order to provide transmission support and additional security of supply. It can be used as a trading tool, but this use is limited due to a lack of flexibility.
Salt Cavity	Salt cavity storage is in many ways the most flexible type of storage. It has faster injection rates than LNG and, although its withdrawal rates are not as high as those for LNG, a typical salt cavity can be emptied in 15 to 30 days. The location of any salt cavity facility is entirely dependent upon geology and therefore such facilities are rarely located near to an appropriate market.	Due to its inherent flexibility, salt cavity storage is one of the most popular types of storage, and can be used in a variety of ways, including: • Seasonal supply/demand matching; • As a gas trading tool; • To provide security of supply; • To provide transmission support in some cases.
Depleted field	Typically depleted fields have slow injection and withdrawal rates relative to their size, although these rates can be increased by extra expenditure. Typically a depleted field will fill slowly during the summer months, and empty over a period of between 60 and 180 days.	Due to the relatively slow injection and withdrawal rates, the ideal use for depleted field storage is the provision of long-term seasonal supply/demand flexibility. However, depending upon the flexibility of the storage provider, depleted gas fields can provide some or all of the following services: • Long-term storage for seasonal supply/demand matching; • As a gas trading tool for seasonal arbitrage opportunities; • To provide strategic gas supply security; • To solve 'Take-or-pay' problems.
Disused mines	These are not a particularly popular form of storage, as they are limited by location, gas quality issues and the need to ensure that the facility remains gas tight.	Disused mines are particularly useful facilities for providing strategic gas storage when gas might be required to remain in storage for long periods.
Aquifer	Aquifer gas storage facilities have particularly slow injection and withdrawal rates due to operational concerns on the impact of faster rates on the gas/water boundary.	Due to the constraints in relation to injection and withdrawal rates, aquifer gas storage tends to be used as a strategic asset, storing large volumes of gas to insure against a political situation causing supply problems or a long-term operational failure. With an increasing dependence of the EU on gas from Russia and other FSU states, and the continuing political instability of many of these states, it seems highly likely that more large-scale aquifer storage will be developed.

Source: MJMCSL

projects both in the UK and also elsewhere in Europe. For example, throughout Europe a number of new independent storage projects are either already underway or are being seriously considered. The development of these new independent storage projects would not have been possible without the potential unbundling of storage from transportation.

At the time of writing this report, many companies were considering potential storage projects throughout Europe, and were seeking to evaluate whether they should invest large sums of money in potentially speculative storage projects. Although the potential benefits of any storage projects could be huge, the cost and time commitment from the project developer are also high. It is worth noting that the commercial benefit derived from any new storage facility, or existing storage facility for that matter, will be largely dependent upon the seasonal and peak supply/demand match, as discussed previously.

When choosing whether or not to go ahead with a potential storage project, as well as the supply/demand match storage, developers also need to take account of the following issues:

- Type of storage facility required;
- Potential opportunities within the gas storage market;
- The physical location of the planned facility;
- The commercial characteristics of the local market;
- The physical characteristics of the local pipeline system.

The development of gas storage in the UK

In many respects the UK gas market and the way in which gas storage has developed within that market is a helpful model for the rest of Europe, since it is possible for other countries developing competitive gas and storage markets to learn from both UK successes and failures.

The UK market commenced liberalisation in 1989. Ten years later the gas storage market in the UK is about to undergo a minor revolution with the auctioning of both long-term (five years) and short-term (one year) storage capacity by BG Storage to the UK market. The fact that the UK gas storage market has developed at such a rapid pace over the last ten years, to the point where BG Storage and Ofgas have agreed to auction the storage services provided by BG Storage, provides an ideal example of what can happen in a liberalising gas market.

It is now clear that BG Storage should have been unbundled from Transco at the outset of competition in the UK. That fact that it is being done subsequently has made the process messy and created unnecessary upheaval in a market that has already encountered considerable change. In fact, at the time of the final editing of this report, Ofgas and BG Storage have agreed the new framework which will allow BG Storage to auction much of its storage capacity to the market in the UK.

Lessons learned from the US market

While the experience of the US gas market is not always directly applicable to the UK and the rest of Europe, due to the geographical, political and structural differences between the US and Europe, nevertheless there are also many parallels to be drawn and lessons learned from the US experience of gas market liberalisation. In particular, the fact that historically the old dominant monopolies held the majority of storage assets in the US is comparable with the current arrangements across much of Europe. As the US gas market has liberalised, the gas price has become more volatile and storage has played an increasingly pivotal role not only in managing the seasonal supply/demand match but also in managing price risk and volatility.

The following table shows the key role that gas storage has in meeting the peak day requirements of the US gas market.

Data on the US peak day requirements and available deliverability 1997/98		
Description	**Quantity (Bcf/d)**	**(Bcm/d)**
Peak day gas deliverability	74	2.1
Peak day gas demand	120	3.4
Difference	–56	–1.3
Source: Various		

The massive peak day requirement for storage of 56 Bcf/d (1.3 Bcm) is amply provided by a diverse and well-developed storage market which has a total working gas capacity of 3,765 Bcf (107 Bcm) and a total deliverability of 74.5 Bcf/d (2.1 Bcm/d). The continuing growth of the US gas market as a result both of increasing domestic gas demand and the increasing use of gas in power generation has prompted the continuing development of gas storage.

Another interesting development in the US storage market has been the emergence of gas hubs. In order to provide the services that these hubs or market centres offer, hub operators need to build gas storage. Three main types of hubs have developed: physical hubs, market hubs and market centres. These three types can be described as follows:

- A physical hub is a point at which gas can be transferred from one pipeline into one or more others. Physical hubs may also offer storage and gas processing facilities;
- A market hub is a facility that compliments the transfer facilities offered by a physical hub, offering hub services to facilitate the buying, selling and transportation of gas within the local facility. Hub services provided include storage, processing, peaking supply, title tracking, trading and wheeling;
- A market centre offers the services of a market via the physical infrastructure of one or more pipeline systems.

The development of these various types of hubs and market centres in the US has provided the UK and the rest of Europe with a significant model. There is already much debate over the type and location of gas hubs in Europe, although with the exception of the UK-NBP (National Balancing Point) no significant gas trading points in Europe have yet developed. While gas is being traded at other locations in Europe, such as Zeebrugge, the pre-eminent price marker is the NBP price due to the volume and liquidity of the market.

The role of gas storage in a developing competitive European gas market

The European gas market is at the dawn of a new age. The old monopoly industry structure is under attack both from within, with many customers demanding access to cheaper gas, and from without through the impact of the EU Gas Directive. Therefore over the next few years the structure and ownership of the European gas industry is likely to change as the industry adapts to new market conditions and the impact of the EU Gas Directive. The liberalisation of both the gas and electricity markets, combined with the decline of nuclear power and other environmental effects, means that gas demand will increase considerably over the next ten years, as shown by the following table.

Estimates of Western European gas supply and demand 2000 – 2010		
Year	**Consumption (Bcm)**	**Supply (Bcm)**
2000	365 – 385	370 – 380
2005	430 – 440	440 – 450
2010	430 – 500	450 – 510
Source: Gasunie		

As Europe slowly moves to a supply deficit situation, there will be an increased dependency on imports. These imports will tend to come from places outside the EU, such as Russia and the FSU. Clearly gas being sourced from such great distances will come with little swing and probably less security of supply than that of existing sources. Therefore the requirement for gas storage from a purely operational perspective is likely to increase.

The unbundling of transportation, storage and trading throughout the EU as a result of the EU Gas Directive is also likely to further increase the need for gas storage, since the developing gas transportation regime will need gas storage to enable both a physical and a commercial balance to be achieved. Similarly the development of gas trading which takes account of seasonal arbitrage opportunities is likely to require access to gas storage.

The diversity of gas markets in the EU

Despite the fact that the EU Gas Directive envisages the development of a free gas market across Europe, the timing and shape of that market will vary considerably from country to country. For example, the EU Gas Directive does give member states a fair degree of freedom in implementing the directive. Therefore the actual impact of competition and the role of storage in the market for each country will be dependent on a number of factors, including the following:

- The current structure of the industry;
- The number and type of the existing players;
- The supply/demand match;
- The type and location of storage available;
- The availability of alternatives to storage.

The speed at which the market liberalises and consequently the subsequent impact on storage is largely dependent upon the willingness of the member state government to introduce reform, and the desire of the industry to embrace it.

Conclusions

The gas storage market in the UK and the rest of Europe is likely to undergo a period of rapid change. This will occur as a result of the European gas market beginning to embrace competition, but also as a result of the increasing gas demand and the move of the market from a supply surplus to a supply deficit. The challenge both for holders of existing storage capacity and the potential builders of new storage capacity is to accurately forecast the timing and impact of these events on the availability and price of peak gas. Projects that are developed too early will initially be uneconomic due to a low value being placed on peak gas and storage in a 'surplus market', whereas projects that are developed too late will miss the 'premium years' when peak gas prices are high.

Chapter One:

THE TRADITIONAL USES OF STORAGE

Introduction

This chapter has been written as a general introduction to the traditional role of gas storage as an integral part of the gas transmission system. In particular it focuses on the following areas:

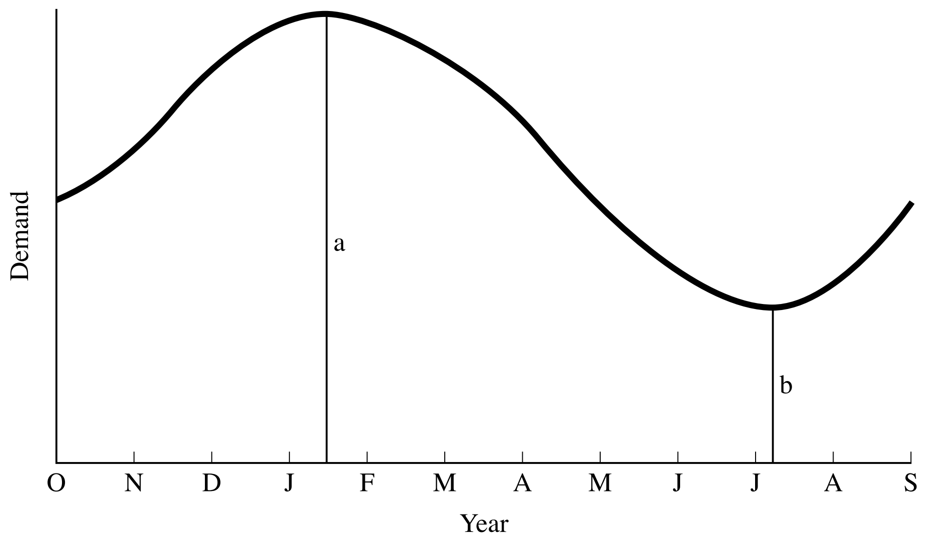
- Load duration curves;
- Seasonal supply/demand matching;
- Security of supply and optimisation of the transmission system.

The purpose of this chapter is to lay a basic foundation for the less knowledgeable reader. Those more familiar with these concepts may wish to move directly to Chapter 2. Although this report covers the majority of the European nations in discussing gas storage, this chapter will draw heavily on the experience of Transco, the UK pipeline owner, for two reasons. Firstly the UK market is one of the most advanced in terms of developing competitive storage and, secondly, Transco and BG Storage make available in the public domain a vast array of information upon which this report has been able to draw.

Load duration curves

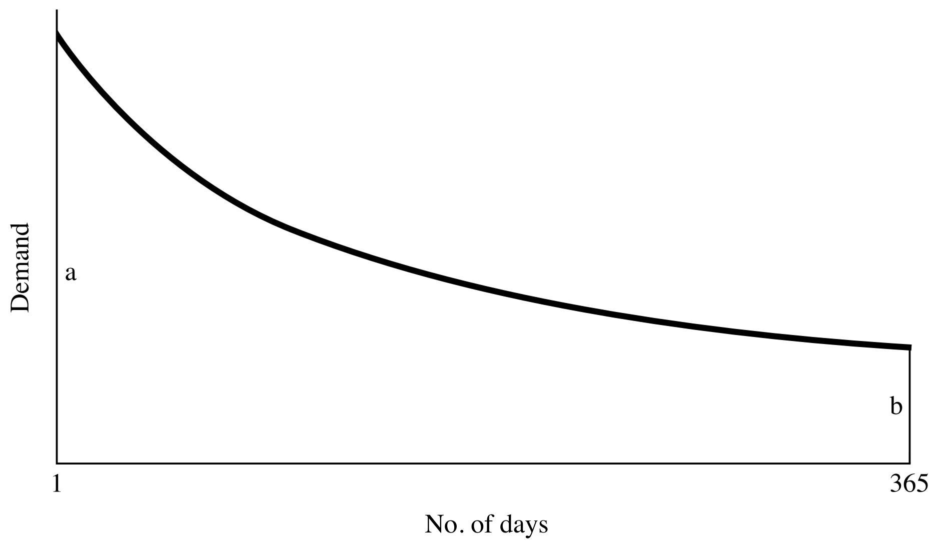
Prior to examining how load duration curves are used to estimate the need for storage, it is worthwhile gaining an understanding of how a load duration curve (LDC) is constructed. An LDC shows the relationship between demand and the number of days for which that demand is equalled or exceeded. The days correspond to those in a supply year (1 October to 30 September). Figures 1.1 and 1.2 show an LDC constructed from a typical annual demand curve. Two days are marked on the diagrams. Day ‘a’ has the greatest demand over the year, and therefore corresponds to Day 1 in the LDC, since no other days have a greater demand. Day ‘b’ has the least demand over the year, and so is in position 365 in the LDC, as every other day’s demands exceed this. LDCs are used taking into account seasonal requirements (1 in N LDCs) and peak daily requirements (1 in N peak). These are detailed further in the next two sections. In the UK the most common LDC takes into account a 1 in 50 winter and a 1 in 20 peak day.

Figure 1.1: A typical annual demand curve



Source: MJMCSL

Figure 1.2: A typical load duration curve

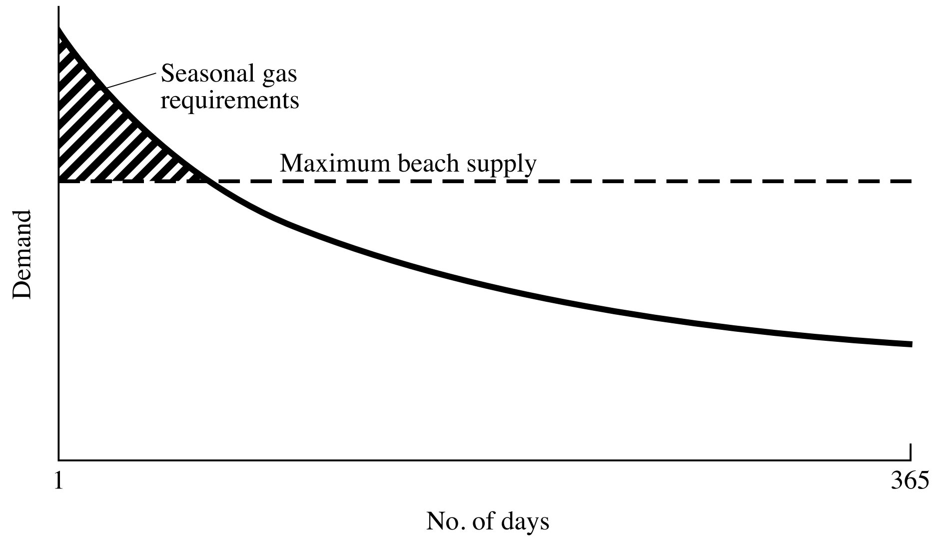


Source: MJMCSL

1 in 50 seasonal demand

One of the most common uses of LDCs is simulating the effect of a winter of particular severity and long duration. Historically in the UK British Gas as a monopoly gas supplier, and now Transco as a monopoly transporter, construct 1 in 50 LDCs. These ensure that the gas supply would not fail in more than one winter every fifty years on average. By superimposing on this diagram (see Figure 1.3) the maximum availability of gas supplies, it is possible to ascertain the overall need for storage capacity. The indicated area above the supply limit but below the LDC represents the amount of gas that has to be provided over and above the normal supply arrangements.

Figure 1.3: Seasonal requirements



Source: MJMCSL

Calculation of a 1 in 50 load duration curve

A 1 in 50 load duration curve is calculated separately for each demand model for each year. The data required consists of:

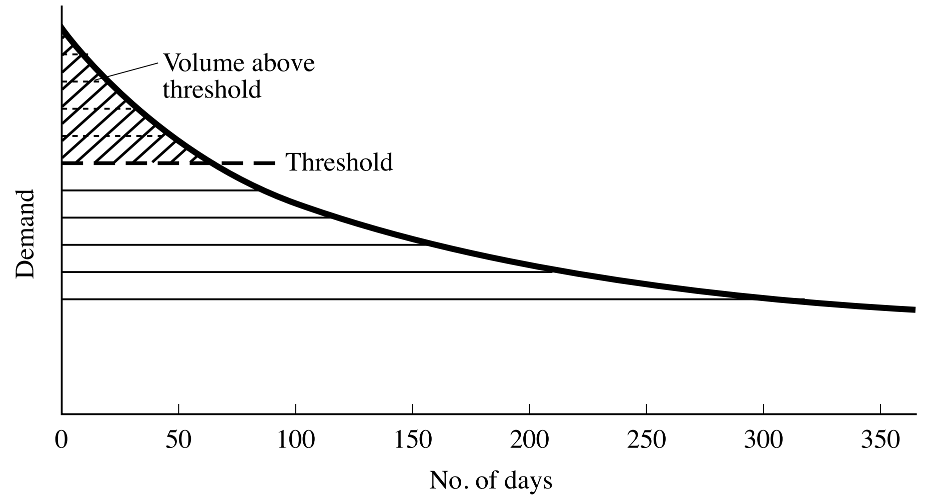
- Historical weather data, and
- A daily demand model for the year in question.

A typical LDC is then calculated using the following procedure:

1. Generate many sets of simulated daily demands for the year in question, based on the long series of historical weather data;
2. Calculate the volume of gas above a given threshold for each of the simulations;
3. Fit a statistical distribution to each of these volumes;
4. Read off from this statistical distribution the 1 in 50 volume (i.e. the value with a 0.02 probability of being exceeded;
5. Repeat steps 2 to 4 for a number of different thresholds;
6. Finally a complete 1 in 50 LDC curve is constructed by combining the threshold 1 in 50 volumes. The peak day demand must also be known (see next section).

The following diagram provides an example of a simulated LDC.

Figure 1.4: Simulated load curve



Source: Transco 1996 Base Plan Assumptions

1 in 20 peak day demand

The peak day demand in any year occurs on Day 1 on the LDC for that year. Sometimes this day and the days leading up to this day are referred to as the 'needle peak' for obvious reasons. A 1 in 20 peak LDC ensures that the gas supply will not fail due to a daily peak more than one year in twenty. When calculating a 1 in N peak LDC, Day 1 is set to the 1 in N peak day.

Calculation of a 1 in 20 peak day

The estimated 1 in 20 peak day demands are calculated in much the same way from simulated daily demands, as follows:

1. Generate many sets of simulated daily demands for the year in question, based on the long series of historical weather data;
2. Select the peak day demand from each simulation;
3. Fit a statistical distribution to these demands;
4. Read off from the statistical distribution the 1 in 20 peak day demand (i.e. the value with a 0.05 probability of being exceeded).

(Note: The 1 in 20 peak demand is expected to be exceeded one winter in 20, with each winter counting only once. This means that in such a winter the 1 in 20 peak day may be exceeded on more than one occasion.)

What useful purpose do they serve?

1 in 50 load duration curves are used for estimating the seasonal gas required, and hence are used in determining the extra gas required over and above the regular contracted volumes and any swing that may have been agreed. Often this amount determines the storage capacity required from storage facilities.

The 1 in 20 peak day demand can be used to forecast the capacity at which a pipeline system needs to operate at the extreme. If the gas supply cannot provide enough gas on one day to meet this demand, then extra deliverability is required. Often this determines the deliverability required from storage facilities.

Seasonal supply/demand matching

An important aspect for both a monopoly gas transporter and supplier and a pipeline company serving a competitive market is the ability to ensure that there is a supply/demand match. Seasonal supply and demand matching is the balance of inputs to the pipeline system with outputs from it. It is carried out to ensure that there are sufficient supplies to meet the demand requirements of shippers, their end users, and shrinkage from the system. Supply and demand should match up even during periods of severe demand resulting from a cold winter.

Traditionally the process of matching supply and demand against a security criteria of 1 in 20 peak days and 1 in 50 winters has been taken as the standard. The amount of storage that is required can be determined once this information has been gathered, as the load duration curve method has illustrated.

A gas monopoly has all the information it requires, as it owns its pipelines and negotiates its own supply contracts. However, following the introduction of competition and the separation of transportation and trading, pipeline operators no longer have direct access to that information by right. Therefore it is necessary to collect as much information as it can from players in the market. The following section illustrates how this is done in the UK by Transco.

Managing the supply/demand match for a competitive market

In order to compile supply/demand information, Transco takes information from commercial data sources, industry journals, and returns from a questionnaire sent out to every gas player in the market. In this questionnaire Transco seeks the views of producers, shippers, major end users, and other transporters in order to ensure that the supply and demand information used for planning purposes is as realistic as possible.

Once this data has been collected, a supply/demand match paper (known as the 'Base Plan Assumptions') is produced by Transco each year. Although it is recognised that this information is not as accurate as it should be, the Base Plan Assumptions outline Transco's forecasts of future supply and demand over a ten-year period. Due to the uncertainties of both supply and demand forecasting, particularly for power generation, alternative high and low demand forecasts are made. The supply scenario is used to match the central demand case.

Demand forecasts

Forecasting gas demand even when British Gas was a monopoly was an exacting business. However, with the introduction of competition in the UK it has become a complex and difficult business. Forecasts of the growth in annual demand are based on consideration of a combination of historical trend information, local demand intelligence, new Transco contracts with large end users, general economic factors, comparative fuel prices, prospective conservation and environmental measures, potential new growth areas and possible taxation effects, supplemented by specialist consultancy work.

Transco has developed a consistent technique for demand modelling, which is briefly outlined below. This is done separately for each different supply zone, and is based on Composite Weather Variables defined and optimised for each supply zone.

Assumptions

The general assumptions made for demand include the following:

- Economic growth in line with historical trends;
- Inflation averages;
- Consumer spending;
- Material changes in real crude prices;
- Market prices for gas;
- Competitiveness of gas supplies in comparison with alternative fuels, particularly within the industrial sector.

The economic forecasts are based on information obtained from independent forecasting bodies.

Power generation

Another important factor in forecasting daily and seasonal demands is power generation, not only because of the clear impact that it can have on gas demand, but also because of the role that many gas-fired power stations can have in providing an alternative to gas storage when interrupted. The approach that Transco has adopted in forecasting this rapidly changing and uncertain market has been to develop a model that forecasts total power generation in the market, including electricity supplied from imports, nuclear, coal, hydro and gas-fired power stations. In addition, the model also forecasts consumption of gas-fired power stations on an individual basis and identifies whether the station is supplied directly through a private pipeline or via Transco's National Transmission System (NTS).

The current policy of the UK government to restrict usage of gas in power generation, and its open-ended time scale, has provided Transco with the added difficulty of needing to make an educated guess at the power station load over the next ten years. It has done this by establishing a number of criteria, as follows:

- The presence of transportation contracts;
- A financial commitment to either ship gas or pay for the pipeline connection to the NTS;
- Other speculative loads might be considered on merit.

Mild Weather Correction

The annual demand forecasts made by Transco are based on an assumption of seasonal normal weather conditions. Since recent years have been significantly warmer (the last winter being the warmest for 65 years), these weather conditions have been adjusted in what is called a Mild Weather Correction. This correction is supported by independent expert analysis, predominantly carried out by the Meteorological Office, of the likely effect of global warming.

With regard to peak demand conditions, independent experts find themselves unable to conclude how extremes of temperature will be affected by global warming. The cold spell over the 1996 New Year period, particularly in Scotland where weather conditions were considerably worse than 1 in 20, serves as a reminder that peaks are just as likely to occur as in the past. Consequently, Transco considers the prudent approach is to make no consequential adjustment to the cold weather statistics associated with peak demands.

Demand sensitivities

The calculation of gas demands is not an exact science, and it is necessary for Transco to make a series of assumptions and to design the pipeline system based on a particular supply/demand scenario. Therefore high and low cases have been developed by considering a number of factors that could contribute to either increasing or decreasing demand over the forecast period.

Factors that increase demand

- Low gas prices as compared with other fuels;
- Earlier re-phasing of power station projects;
- Increased exports (e.g. as demand increases in Ireland);
- Further switching to gas, including the switch to dual-fired power stations;
- Additional government support for gas projects;
- Introduction of mains pipeline extension projects;
- Less emphasis on energy conservation measures.

Factors that decrease demand

- A continuation of the mild weather seen since 1987;
- The gas price advantage over other fuels being eroded;
- Less growth due to depressed economic activity;
- Demand reductions due to greater emphasis on energy conservation measures;
- Large loads close to supply terminals that build their own pipelines and so by-pass the NTS;
- Lower load factors for power stations, due to increased competition from embedded generation and from cheaper coal following the renegotiation of contracts in 1998.

Supply forecasts

Future supply is perhaps the most difficult for Transco to forecast, as there is no right of access to information. Indeed, with such a level of competition, players in the gas market do not want to give any more information than they are legally required to divulge. The primary and preferred source of supply information is from producers, although some is collected from shippers. Transco also aggregates the field specific information requested in the questionnaire, which accounted for about 80% of the supply information used by Transco in 1998, to determine the terminal data. Additional information has also been obtained from network users and commercial sources.

Development of infrastructure

The development of import terminals and the enhancing of pipeline capacity will result in an increased gas supply. However, there will always be uncertainties involved with the timing of these projects and exactly how new supplies will be phased in. It is important to be as accurate as possible, since the maximum supply capacity is needed to estimate how much extra deliverability is needed on a day of peak demand.

In the UK a number of players in the gas market are developing their own storage facilities to compete with those owned by BG Storage. The larger of these will be included in the supply forecasts, the other facilities being too small to impact the national supply/demand match. Any participant who is planning to build a new storage facility is requested to complete the relevant section of the questionnaire.

The Bacton-Zeebrugge Interconnector has also had an effect on the supply forecasts. Originally it was predicted that no gas would flow into the UK for at least ten years. But already gas has been imported into the NTS as gas prices on the Continent have dropped substantially in connection with the low oil prices.

Supply sensitivities

The following would lead to reduced gas supply availability:

- A continuation of the current low oil price worldwide;
- Low annual gas prices in the UK;
- Further delays to storage developments (e.g. problems with planning permission);
- New and planned developments producing less gas than expected.

However, the following would lead to increased supply availability:

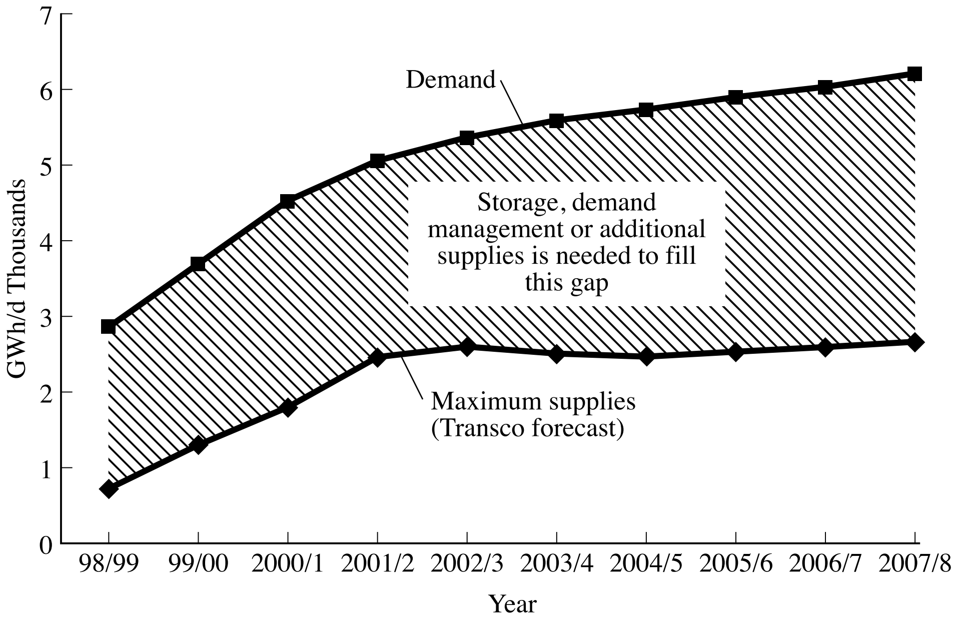
- Additional pipeline connections to Europe;
- Continued low gas prices in Europe leading to imports via the Interconnector;
- New technology leading to increased recovery of existing reserves.

Supply/demand matching

Supplies are matched to demand on an annual basis to create an exact match. For peak demand conditions, all supplies are assumed at their maximum deliverability, with any shortfall made up through storage, demand management or other currently unaccounted for supplies. When additional supplies are necessary, an aggregated annual supply of 5% above annual demand is assumed. All additional supplies are assumed to be at a swing of 150%. With a swing of approximately 200% required to meet peak day demand, an increase in the longer-term requirement for storage or demand management consequently results.

Any surplus of annual supplies does not imply a surplus of maximum supply above peak day demand. The maximum supply is the sum of all supplies at their maximum deliverability. The figures below compare the peak day demand with maximum supply. The difference between the demand and the supplies represents the requirement for storage, demand management or unaccounted for supplies required to achieve a perfect match. Figure 1.5 shows the Transco forecast in their 1999 Base Plan Assumptions paper, of peak day demand and maximum supplies.

Figure 1.5: The supply/demand match 1998–2008



Source: Data used from Transco Base Year Plan Assumptions 1999

When there is a surplus of annual gas, production from those fields with a higher proportion of hydrocarbons liquids are assumed in preference to those fields which are predominantly gas. The basis for this assumption is the economics of producing reservoirs containing hydrocarbons liquids (high load factor) and the current higher value of hydrocarbons liquids compared to gas.

Security of supply

Gas storage is not only used in order to meet peak seasonal requirements, but is also used to maximise the security of the gas supply in two particular respects:

- The operational security of the gas supply system, and
- The optimisation of the gas transmission system.

Operational security

The provision of gas storage is an important factor in ensuring that supplies are maintained both in extremes in demand and in emergencies. If the gas pressure in the pipeline system drops below a certain level, the network could become unsafe. It is also very expensive and difficult to shut off and reconnect supplies, so a shut-off of supplies is only an option in very exceptional circumstances.

The total requirement for storage is more than that needed to cope with peak seasonal demand. Additional stored gas is needed to ensure security of supply. This extra gas, called operating margins gas, enables the system to cope with emergencies such as:

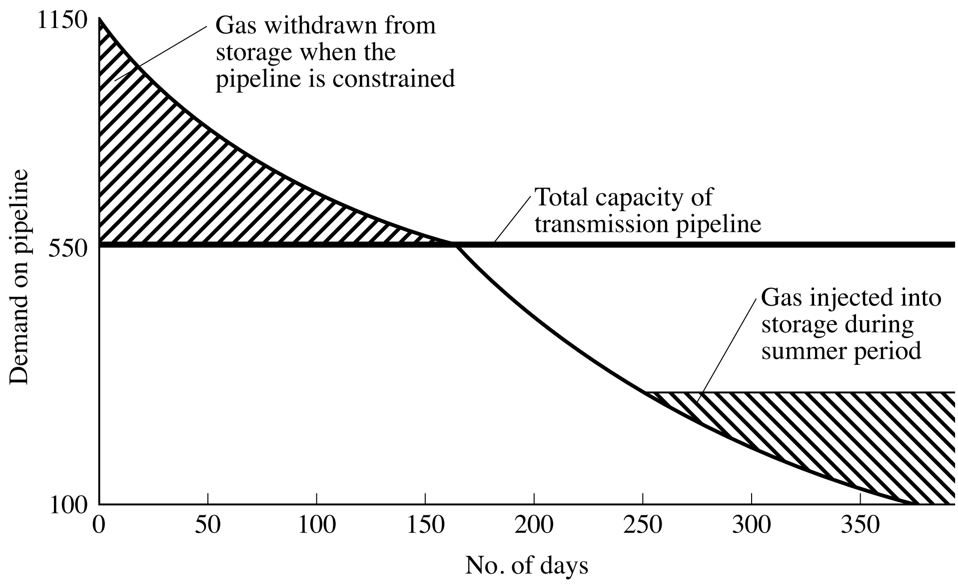
- Offshore alerts;
- Large forecasting errors;
- Compressor trips and breakdowns;
- Breaks in the pipeline;
- Orderly run-down if supplies become exhausted.

Large storage facilities are useful for providing back-up when major failures occur. For example, the Rough facility (a depleted field off the coast of North-East England) is able to store approximately 30 TWh, which is equivalent to the amount of gas needed to supply the UK market for up to 13 days.

Optimising the transmission system

The load on a gas field and pipelines can be evened out over the year if sufficient gas storage is available to meet seasonal increases in demand, and gas is put into stock during periods of low demand. Gas transmission companies throughout the world use the specific location of storage facilities to maximise the use of their gas transmission system. They do this, for example, by usually locating LNG storage facilities at the extremities of the system. Basically gas surplus to requirements during periods of low demand is stored in the storage facility so that when the local demand exceeds the transmission capacity of the pipeline (i.e. it is constrained), the local storage facility delivers gas into the pipeline in the opposite direction to normal flow, into the local area of gas demand.

Figure 1.6: Use of storage to optimise gas demands



Source: MMCSL

An example from BG Storage

Certain BG Storage LNG facilities are nominated as ‘constrained’ facilities, where shippers who book a constrained LNG service agree to withdraw some of their gas from storage on days of very high demand if directed to do so by Transco. They also agree to maintain a minimum quantity of gas in store. In exchange, the shipper receives a transmission benefit. Constrained sites are situated on the parts of the NTS most remote from beach terminals. On days of high demand, some of the gas required at the extremity of the network comes from the local LNG site. This means that the pipelines feeding the locality do not have to provide gas for the full demand on a peak day. The required capacity of the pipeline has therefore been reduced and investment saved. The use of LNG storage to save on pipeline investment is known as transmission support.

Minimum inventory percentages

The minimum inventory percentages give the percentage of space at the BG constrained LNG facility which is required to hold enough transmission support gas for a 1 in 50 winter. The percentage is calculated after the space for operating margins gas has been set aside. The percentages for Winter 1998/99 are set out in Table 1.1. These percentages are recalculated every year. In general they are expected to rise from year to year, as demand in the relevant local area grows.

Table 1.1: Minimum inventory percentages for Winter 1998/99 at constrained LNG facilities

Date Week commencing 6.00 am on	**Avonmouth**	**Dynevor**	**Isle of Grain**
1 Oct 1998 to 7 Dec 1998	98%	73%	61%
14 Dec 1998	97%	73%	61%
21 Dec 1998	96%	73%	61%
28 Dec 1998	94%	71%	60%
4 Jan 1999	91%	68%	58%
11 Jan 1999	84%	61%	52%
18 Jan 1999	73%	53%	44%
25 Jan 1999	59%	43%	34%
1 Feb 1999	45%	34%	26%
8 Feb 1999	32%	25%	18%
15 Feb 1999	21%	16%	11%
22 Feb 1999	11%	8%	6%
1 Mar 1999	4%	3%	2%
8 Mar 1999	1%	1%	1%
15 Mar 1999	0%	0%	0%
15 Mar 1999 to 30 Apr 1999	0%	0%	0%

Source: BG Storage Services 1998/99

Constrained demand threshold

These define the level of demand at which Transco may make constrained LNG withdrawals on behalf of the storage customer to provide transmission support gas.

Table 1.2: Constrained demands threshold

Facility	**Constrained LDZ**	**Demand (Mcm/day)**
Avonmouth	South Western	20.0
Dynevor Arms	South Wales	14.7
Isle of Grain	South Eastern	37.8

Source: BG Storage Services 1998/99

Transmission benefits

In recognition of the transmission support obligations, shippers of the constrained service receive a transmission benefit. This reflects the saved investment in the pipeline system. The transmission benefit is subtracted from the price of deliverability for the storage service. Details of transmission benefits are given in the Transco Transportation pricing document. The benefits change whenever Transco change the NTS prices. The current benefits are reproduced below.

Table 1.3: Transmission benefits from 1 October 1998

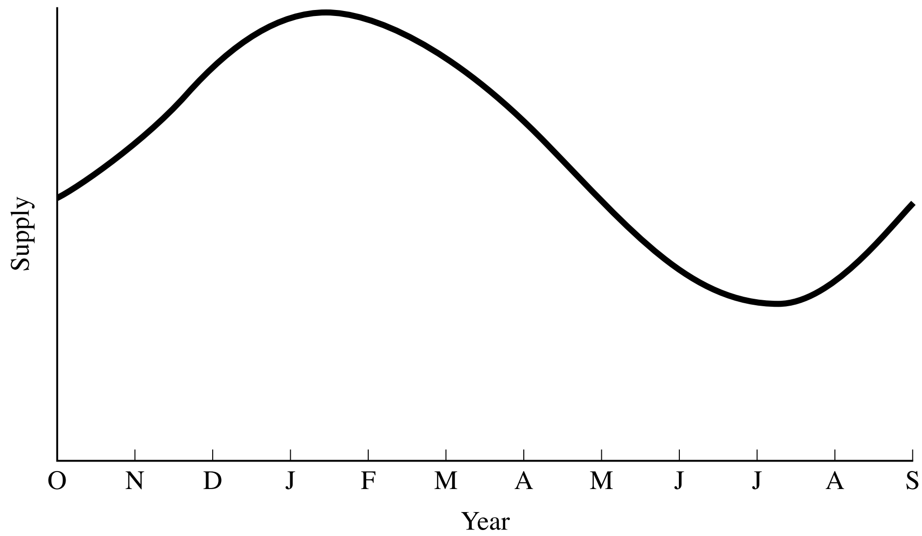
Facility	**Deliverability charge**	**Transmission benefit**	**Final charge**
Dynevor Arms	1.452	–0.329	1.123
Isle of Grain	0.730	–0.219	0.511
Avonmouth	1.076	–0.402	0.674

Source: BG Storage Services 1998/99
Note: All figures are in pence per peak day kWh per annum

Optimising the production system

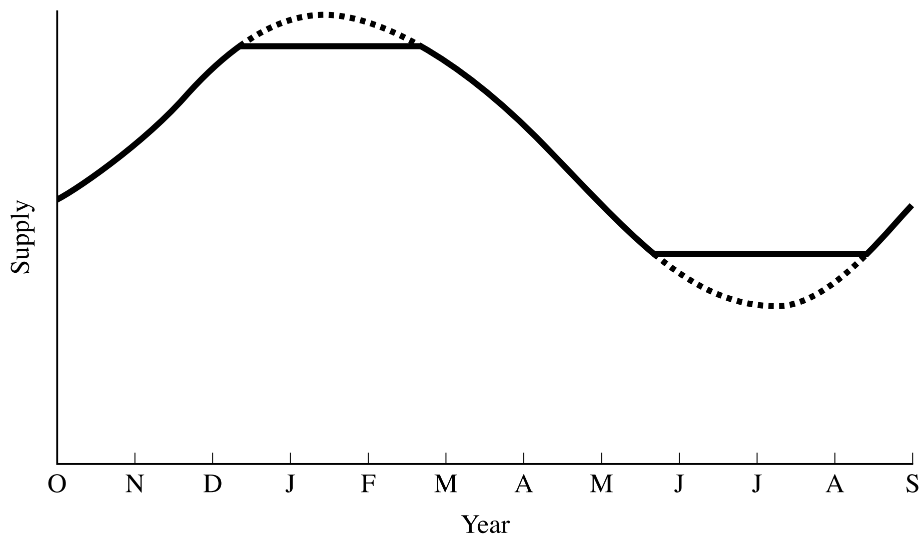
The judicious use of storage facilities may also be used in the optimisation of the capacity of production wells, gas gathering systems, and offshore pipelines. Further, by reducing the maximum extraction rate of a production well, the life of a gas well may also be extended. As has been seen earlier, the use of storage minimises the variation in inputs required at other entry points to the system while maintaining the annual volume. This reduces the amount of swing required both at the gas field and in the contracts between producers and shippers, if storage is used to perform ‘peak shaving’ (see Fig 1.7 and 1.8).

Figure 1.7: Annual supply



Source: MJMCSL

Figure 1.8: Annual supply with storage



Source: MJMCSL

This can lead to a reduced capacity requirement in the production equipment and associated pipelines, thus reducing development costs. This may lead to the promotion of the development of fields which would be considered as marginal if the peak day demand was considered without storage facilities.

Chapter Two:

COMMERCIAL USES OF GAS STORAGE

Introduction

The gas market within the UK has undergone radical change in the last ten years, with a steep change occurring with the introduction of the Network Code in March 1996. The privatisation of British Gas in the mid-1980s provided a new commercial focus towards storage: it no longer had only to provide security of supply but also to reduce operating costs for British Gas. The initial introduction of competition into the gas market had little effect on the storage operation, as balancing of gas supplied under the original gas transportation contracts was achieved on a monthly or annual basis. However, the introduction of the Network Code in 1996 brought radical change with the introduction of daily balancing, which has allowed more commercial opportunities for the players in the market to reduce costs and increase profits.

Storage has ceased to be just a tool in the hands of engineers, enabling the system to balance on a seasonal basis, but is now also a commercial tool to enhance the profitability of the company. The areas covered in this chapter will include:

- Gas balancing;
- Gas trading;
- Storage trading.

The purpose of this chapter is to identify how storage is developing as a commercial and operational tool, particularly in the developing competitive gas market.

Gas Balancing

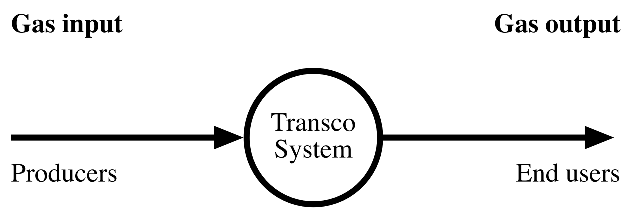
The development of gas-to-gas competition, and the subsequent unbundling of gas trading, transportation and in some cases storage, has meant that the transporter now requires all users of the pipeline system to balance on an hourly, daily or monthly basis depending upon the relevant pipeline system. Failure to balance supply and demand within the agreed tolerances would mean that the relevant organisation would incur balancing charges. Consequently the ability of the shipper or gas marketing company to use gas storage to minimise these balancing charges has been a new development in the use of gas storage.

The UK example of the Network Code

Prior to providing an albeit brief description of some facets of the UK Network Code, it is worth mentioning the fact that the Network Code is currently under review and that the final result of the review is likely to be substantial changes to the capacity booking, capacity trading and the flexibility mechanism. However at the time of writing these changes were still at the discussion stage with the earliest implementation date being 1st October 1999.

As stated above, prior to the introduction of the Network Code gas transportation contracts demanded simply a monthly or annual balance of gas commodity. The cost of both transmission and storage of the gas was effectively bundled into the overall transportation charge, and shippers therefore did not need to achieve a daily balance and were protected from exposure to daily variations. In the extreme this allowed shippers to input no gas on during the first half of the month, and double their deliveries during the second half of the month, whilst continuing to take gas at the supply point throughout the entire month. To protect the system and ensure safe operation, British Gas balanced the system by varying inputs under the legacy gas purchase contracts. (NB: Legacy contracts is the term given by the industry to gas purchase agreements signed between the old British Gas and producers under the old pre-competition regime.)

Figure 2.1: Pre-Network Code trading options

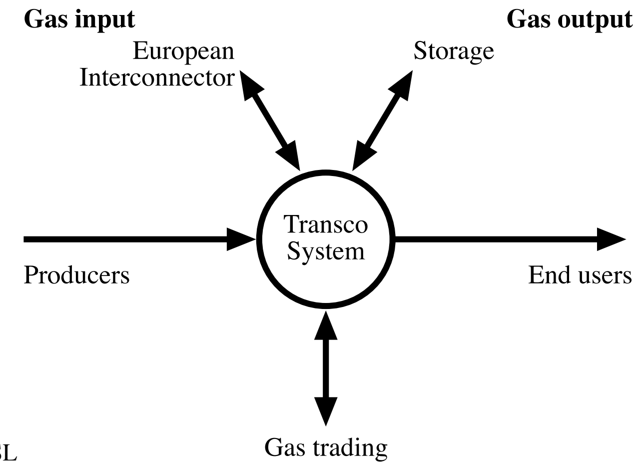


Source: MJMCSL

Figure 2.1 above shows in a schematic format how the original monthly balancing regime operated, with deliveries and offtakes matched on a monthly basis.

The limitation of this regime was a lack of flexibility or the ability to trade gas commodity and capacity. The introduction of the Network Code imposed a regime on all shippers to achieve a daily balance (within certain tolerances) or pay for the consequences. Therefore in order to avoid these daily balancing charges it has become necessary for many shippers to purchase storage or other alternatives. The addition of storage contracts to the portfolio of supply contracts provides additional flexibility in achieving this daily balance and avoiding scheduling and balancing charges, as shown by Figure 2.2.

Figure 2.2: Post Network Code trading options



Source: MJMCSL

Operation in the within day gas market

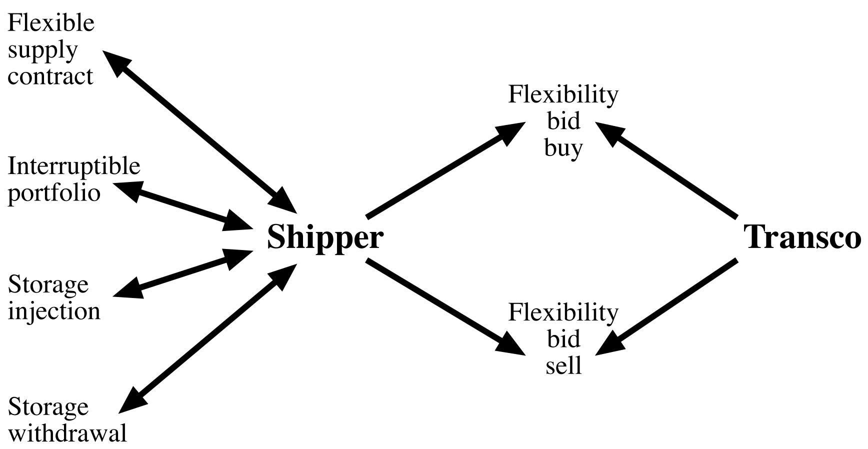
The introduction of the commercial balancing regime has required the introduction of certain balancing tools to ensure that the physical system can safely balance should the commercial regime fail to achieve a balance of inputs and outputs. The tools available to Transco are interruption, operating margins gas (as mentioned previously), and the flexibility market.

When a shipper has a clear idea of its supply and demand on a particular day, it may decide to offer to buy from or sell gas to Transco via the flexibility mechanism. For a 'system buy' (i.e. when the system is short of gas) a shipper can request more gas from a producer, arrange for a large industrial consumer to stop using gas, withdraw gas from storage, or stop injecting into storage. For a 'system sell' (i.e. when the system has too much gas) a shipper reduces input from the producer, turns an interruptible customer back on to gas, stops withdrawing from storage, or injects into storage.

To start the process, the shipper places a 'flexibility bid' with Transco via the Transco UK-Link computer system. This specifies whether it is a buy or a sell, the quantity of energy, how it should be implemented, at which location, and the price per kWh. Whenever Transco decides it is necessary to use 'flexibility gas' it chooses the best bid, normally on the basis of price (lowest price for a system buy, highest price for a system sell) although Transco may also choose bids on the basis of location if certain quantities of gas are wanted at specific locations. Once Transco have accepted a particular bid the successful bidder is informed.

A shipper with a storage contract may therefore offer storage gas on the flexibility mechanism both as a system buy (i.e. when the system is short of gas, storage withdrawal is brought on or injection is stopped) or a system sell (i.e. when the system is long on gas, storage withdrawal is turned off or injection is started). This effectively doubles the opportunities available for activity in the flexibility market.

Figure 2.3: The flexibility mechanism bidding process



Source: MJMCSL

The ability to buy low priced gas on the flexibility mechanism and sell it back later is one of the arbitrage opportunities that have developed since the introduction of the Network Code.

In fact, United Gas are in the process of developing their own salt cavity storage facility which will ‘suck’ gas from the system when it is cheap, selling the gas back to the system later at a higher price.

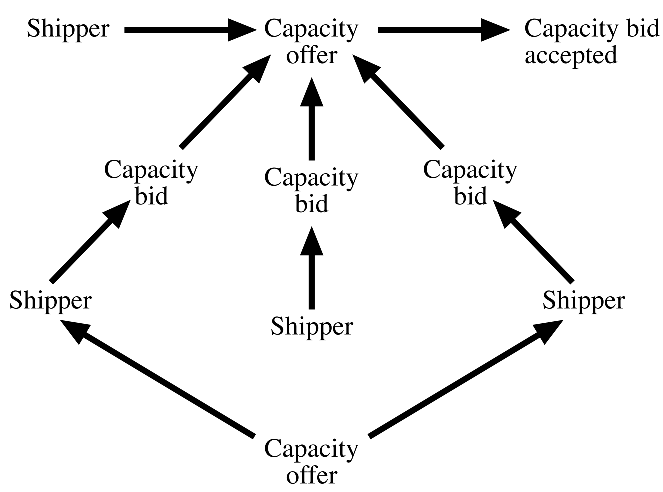
At the time of writing this report a number of significant changes to the flexibility mechanism of the UK Network Code were being discussed, which may result in the replacement of the flexibility mechanism with an ‘On-the-day Commodity Market’ (OCM). However, despite these possible changes, there will always be a role for storage that is sufficiently flexible to operate within the day, as most gas transportation systems need to effect a daily balance.

Capacity trading

Capacity trading is another trading mechanism under the Network Code that allows a shipper to recover costs of capacity booked previously that is not being fully utilised, and a shipper with insufficient capacity to purchase additional capacity. The addition of secondary (or interruptible) entry capacity ensures that all available capacity is open to the market and not hoarded. The flexibility mechanism allows shippers to correct imbalances created in the system by other imbalances.

In the UK a shipper with spare capacity posts a capacity offer which specifies the quantity, location, duration and the suggested price of the capacity. A shipper needing capacity is able to scan the list of outstanding offers. For each offer, the shipper can see what capacity bids have already been made (but not the bidder’s name). The shipper may then post a bid for some or all of the capacity, or for some or all of the duration. The bid price does not have to be the same as the suggested price. On the closing date, the offering shipper reviews the bids and selects one winner. The computer system then effects the transfer of the capacity rights. Two shippers may also agree to trade capacity without using the bidding process. Here the selling shipper records the offer plus the name of the buying shipper. The buying shipper simply confirms the trade.

Figure 2.4: A schematic showing capacity trading



Source: MJMCSL

A secondary market in entry capacity has been established in an attempt to ensure that capacity is not hoarded. Reserved but unused capacity is auctioned off on a daily basis to the shipper placing the highest bid. This allows producers to sell gas and shippers to move gas into the system on a short-term basis as changing market conditions allow. If the incumbent shipper then chooses to use its reservation, then the auctioned capacity arrangement is terminated.

Gas trading to overcome capacity restrictions

Gas trading 'on the system' is another way of overcoming capacity restrictions. One shipper with spare entry capacity inputs gas and then sells it to another shipper with insufficient entry capacity. It also allows a specialist role, that of the wholesaler of gas who inputs gas into the system and sells it on.

A shipper with storage rights may purchase gas from any low-cost source (e.g. the spot market, by gas trades with other shippers or, as mentioned above, the flexibility market) and inject that gas into storage. On days of very high prices the shipper may then either reduce the amount of gas purchased at a higher price, or sell its stored gas to purchasers in the same market at that high price. The differential prices need, of course, to reflect the charges associated with storing the gas and the reservation of storage capacity.

The availability of storage gas allows shippers to manage prices. As the cost of the gas in store is known by the shipper (cost of gas = initial cost of gas + cost of injection and withdrawal), it is easier to make decisions relating to the use of this gas in relation to other gas in the market place, and to manage peak prices.

The example of the European Interconnector

The commissioning of the European Interconnector has added a further dimension to gas trading in the UK gas market. While the Transco network on the UK side of the Interconnector balances on a daily basis, the Continental side of the Interconnector needs to balance on an hourly basis. Consequently any shippers who fail to meet these obligations will incur balancing charges, and therefore the flexibility provided by storage helps these players maximise flexibility and minimise balancing charges. In the long term, when the UK reaches a supply/demand deficit it is expected that gas will flow into the UK. However no-one predicted the flow of gas into the UK so early in the Interconnector's life as a result of the impact of low oil prices on Continental gas prices. Given that the market is sufficiently buoyant, then it may be expected that storage contracts will play an important part in decisions to import or export gas via the Interconnector.

Gas Trading

Another important aspect in the development of storage as a competitive tool has been the growth in short-term gas trading. (NB: For the purposes of this report, short-term means less than one year.) A variety of gas trading markets have developed from within day gas trading markets to longer-term gas trades which extend for up to one year. However, prior to examining exactly how storage can assist gas trading, it is worth identifying briefly how an organisation can gain competitive advantage from gas trading.

Gaining competitive advantage in the gas trading market

Gas trading promotes competition and flexibility in operation. The following assets give the shipper a competitive advantage:

- Flexible gas system input contracts;
- Flexible gas system output contracts;
- In-depth knowledge of the market and its seasonal variations;
- Timing;
- The ability to anticipate changes in system requirements;
- The addition of storage.

Gas trading takes place both ahead of the day and within the day.

Using storage to facilitate gas trading

As previously mentioned, storage has been used to increase the flexibility of gas traders in a very competitive market. The following examples have been chosen from the UK market, although the principles would apply anywhere that gas-to-gas competition had begun to develop, and trading and transportation had been unbundled.

Taking advantage of seasonal price variations in the UK

An interesting characteristic of developing competitive gas markets is the move towards seasonal pricing profiles, where the price of the commodity (in this case, gas) reflects the economic signals associated with supply and demand. Therefore, on high demand days when gas is scarce and operating costs are high, the cost of gas is high, whereas on low demand days when there is a surplus of gas and costs are low, gas prices are also lower. Therefore in markets that display these seasonal pricing profiles, there is also the opportunity to arbitrage price between different times of the year with the assistance of storage. It is possible for a gas trader to purchase gas during periods when gas prices are low, store the gas, and then when prices are higher sell the gas back to the market. This process works profitably for the trader providing that:

$$G_H - G_L > COS + INT$$

Where:

G_H = High gas price
G_L = Low gas price
COS = Cost of storage
INT = Interest charge on gas in storage, plus miscellaneous transport costs.

Clearly the trader is taking some risk by expecting gas prices to reach a certain level, although the risk can be minimised by careful observation of the market in previous years.

Minimising 'Take-or-pay' costs

Another less obvious use of storage in relation to gas trading is the use of storage to minimise 'Take-or-pay costs'. While the use of storage cannot prevent the huge Take-or-pay liabilities that incumbent monopolies incur when they lose market share to new competitors, storage can help to smooth out 'blips' between supply and demand from year to year. It is often difficult in developing competitive markets for new entrants to accurately forecast their gas demand more than a few months ahead, since the accuracy of such a forecast will depend upon the success of their marketing campaign and the prevailing conditions in the market. Nevertheless it is often necessary for these new market entrants to make a commitment to purchase on the basis of Take-or-pay. Therefore the combination of access to gas storage with an existing gas supply contract can allow any Take-or-pay charges to be minimised.

Locational arbitrage

It is possible for pricing differentials to exist between different locations which are of a sufficient magnitude to allow traders to make a profit by arbitraging gas between the two locations. A good example of this would be the price arbitrage that can exist from time to time between gas prices in Continental Europe, where the price is based on long-term gas contracts with a large proportion of oil indexation, and UK gas prices that are based on the IPE natural gas futures market. Under current circumstances prices in the UK, particularly during the summer months, can be cheaper than on the Continent. Consequently one possible scenario would be for large European utilities to purchase cheap UK gas in the summer, store it, and re-deliver it to the UK in the winter at twice the price.

However, things do not always go as planned. Many players were expecting the winter 1998/99 prices to be higher in the UK than on the Continent, thus facilitating such reverse trading. The consistently low oil price of some $10.00 per barrel has reduced gas prices on the Continent making such trades uneconomic.

Enhancing low security supply contracts

A shipper with storage rights effectively adds security to low security supplies. If cheap but insecure CIS gas forms a significant part of the shipper's portfolio, then the addition of storage rights means that it could be sold into a premium market. This could lead, for example, to a reduction in the number of commercial interruptible contracts, enhancing the portfolio of gas supplies.

Storage Trading

With the development of competitive gas markets, and the increasing use of storage as a commercial tool, has come the development of secondary gas storage markets. These have developed for a variety of reasons, which include:

- Trading by players who have over-booked;
- Trading by traders;
- The purchase of spare capacity.

It is also interesting to note that some organisations have felt the need to develop their own independent storage facilities, with capacity far in excess of their needs. When these projects are finally completed it is likely that they will provide storage capacity for the needs of others as well as for the organisation owning the facility.

The example of BG storage

Under the previous regime, BG Storage only offered one-year storage contracts and monopolised the storage market. However under the new arrangements all storage capacity at Rough and Hornsea will be offered to market participants via an auction, commencing with the storage year 1999/2000. Such an auction, which will include the offer of 50% of capacity for one-year periods and 50% for longer (five-year) periods, will ensure that all storage capacity is offered to the market.

Requiring BG Storage to auction a significant proportion of its storage capacity rights on longer-term contracts will help to promote the development of competitive and liquid secondary markets. There are two ways in which such secondary markets might be expected to develop, as detailed below.

Storage services

Some market participants would secure storage capacity on a five-year basis in the primary auction. As their requirements changed over time, and as the gas market developed, opportunities would arise for selling the storage capacity rights on to other market participants. The terms of such trades would be for the parties to determine. However it would be possible, for example, for the five-year bundled (deliverability, space and injectability) capacity rights to be sold on the basis of shorter-term bundled contracts. Alternatively contracts for unbundled services might be offered. In this way a successful bidder in the primary auction for five-year storage capacity might choose to make available, on the secondary market, the separate storage services of deliverability, space and injectability for durations ranging from one day up to five years.

It is an open question whether or not a facilitator would be necessary to ensure that such secondary storage markets develop. To the extent that such a facilitating role was required, there are further questions concerning the commercial arrangements under which the market operator would act, and whether or not BG Storage might undertake such a role. With the considerable growth in gas trading since the introduction of the Network Code in 1996, using both Over-the-Counter and Exchange-based markets, Ofgas considers that secondary storage trading is likely to develop without any party adopting a formal market-making role. BG Storage would, however, have a role in facilitating the secondary market by ensuring the efficient transfer of capacity rights subsequent to a trade between two parties following the specification of nomination rights in the primary auction. Of course the development of this secondary storage market, particularly if based on the purchase of long-term storage capacity does depend on the price structure of the auction and the willingness of players to commit themselves to long term storage contracts.

Development of financial instruments

The second way in which the primary auction of storage capacity under five-year contracts would be expected to stimulate secondary markets is through the link between storage capacity and other risk management tools available to market participants. Some gas market participants would consider a storage capacity right secured in the primary auction simply as a part of their overall gas trading portfolio, to be managed within the company's established risk management framework. Under this view, a five-year storage contract would represent a stream of financial options which would enable the company both to mitigate the risks associated with potentially high peak gas prices, and to exploit the opportunities available from securing gas when prices were low. The storage capacity would therefore be viewed in the same way as would gas purchase agreements, Over-the-Counter gas trades, and gas purchases on an exchange. Each element of the portfolio would have its own characteristics, and each would contribute to the overall capability of the company in securing competitive advantage in a gas market characterised by increasing liquidity and transparency.

Under this view, the secondary trading embarked upon by a company that was successful in the primary storage auction would be somewhat different from that which might be expected under the first possibility discussed above. In this case, the trades entered into by the company in the secondary market would not necessarily be identifiable as 'storage trades', and need not be characterised by traditional storage parameters such as deliverability, space and injectability. Instead the trades would be associated with financial risk management products (for example, 'call' options designed to mitigate the exposure of the counter-party to high peak gas prices). The ability to offer such financial products would depend, in part, on the success of the company in securing storage capacity in the primary auction. It would also depend on the overall characteristics of the company's trading portfolio. For this reason, two companies securing five-year storage capacity in the primary auction under the same terms might offer very different products in the secondary market, reflecting the differences between their trading portfolios in which storage was just one of many components.

Chapter Three:
TYPES OF STORAGE

Introduction

As gas markets have developed throughout the world, they have all experienced the same problem, that of trying to match a predominantly flat supply profile from either gas fields or LNG ships to a predominantly seasonal gas demand. In each of the world's gas markets the need for some sort of storage has been recognised, and a variety of types of gas storage have been developed. The purpose of this chapter is to examine the various types of gas storage facility that are available, and which part of the gas storage market they are best suited to. The areas described within each type of facility will include:

- The physical characteristics associated with each storage facility;
- The operational characteristics associated with each storage facility, including
  - injection
  - withdrawal
  - cycling
  - cushion gas;
- Typical uses of these storage facilities;
- Capital and operating costs;
- Any future technical developments.

Covering the areas outlined above, the following types of storage facilities will be examined:

- LNG;
- Salt cavity;
- Depleted fields;
- Disused mines;
- Aquifers.

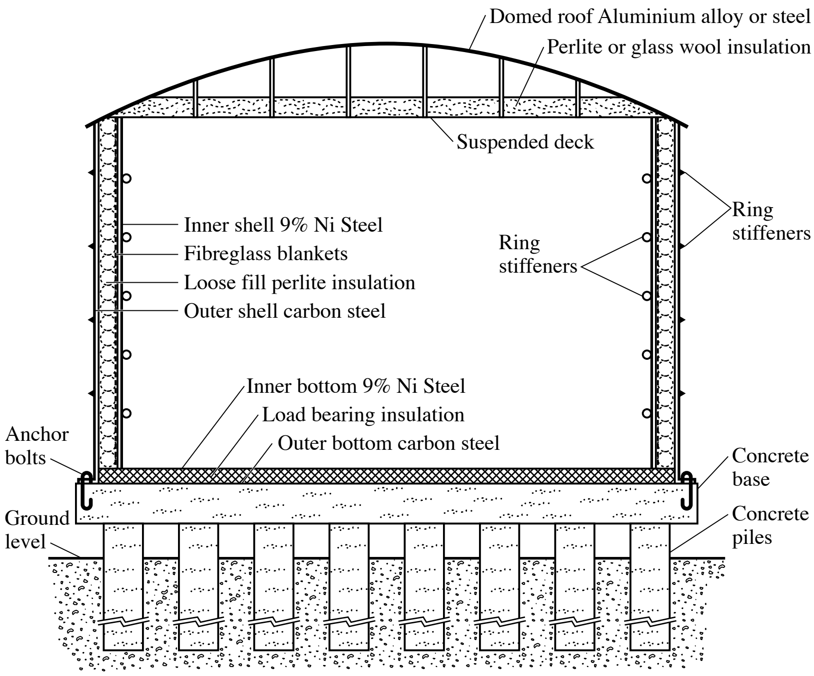
LNG

The ability of gas companies to liquefy natural gas and transport it throughout the world has opened markets for gas sources that had previously been dismissed. Large quantities of gas had been found in remote areas of the world but had become known as 'gas without a market', and were regarded as more of a nuisance than a benefit. The fact that natural gas only liquefies at -162°C (-259°F), when 600 m^3 of gas liquefies to form 1 m^3 of LNG at atmospheric pressure, had provided engineers and scientists with a variety of technical and operational challenges over a number of years. One of these challenges was the fact that many materials, including steel, become highly brittle and fail at these low temperatures.

The physical characteristics of LNG storage

The characteristic of natural gas whereby it liquefies at -162°C, and at the same time reduces its volume by a factor of 600, is both a strength and a weakness. LNG is one of the most volatile substances known to man, and consequently a variety of solutions have been developed by the world's engineers in order to provide safe and secure storage and transportation facilities. The ability to store such large volumes of gas in such a small space has been in many cases the answer to the problem of large seasonal demand variation. With large proportions of the gas market consisting of temperature-sensitive domestic heating loads, the industry either had to make large capital investments in upstream production and downstream pipeline assets, which might only be needed for a few days in the year, or invest in more economic solutions such as LNG storage which can be strategically sited on the pipeline network. (NB: Since the focus of this report is on gas storage facilities rather than on the transportation of LNG, it is not the intention of this report to discuss the various options for moving LNG by ship.)

Figure 3.1: A typical example of an LNG above-ground tank

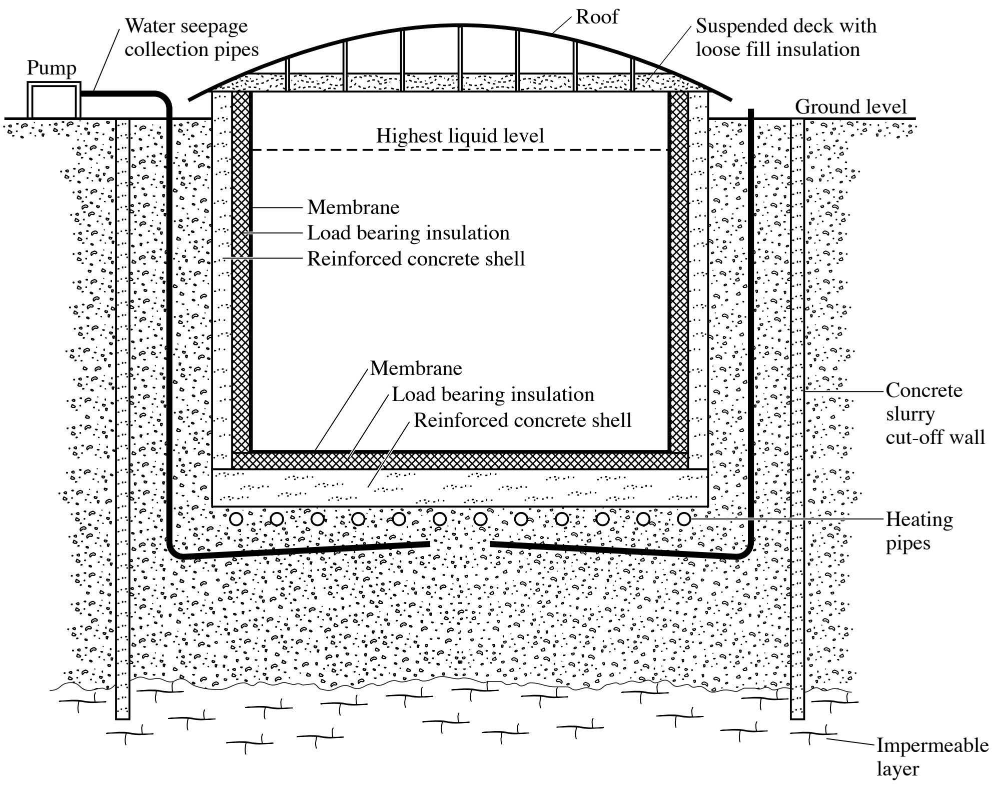


N.B. Not shown are the loading/unloading pipework and pumps, measuring equipment, inspection manhole, surge and splash plates, etc.

Source: Based on a diagram in 'Frozen Fire'

One of the most common ways of storing LNG is in an above-ground tank, similar to that shown in Figure 3.1. Although there are a number of different varieties of LNG tank, most of them consist of double-walled containers made of metal, with an inner shell made of an LNG-resistant material, e.g. 9% Ni steel as shown in the above diagram. The outer tank would then be constructed of ordinary steel, and would provide the structural support for the tank roof. Sandwiched between the inner and outer tanks is insulation to keep the heat out.

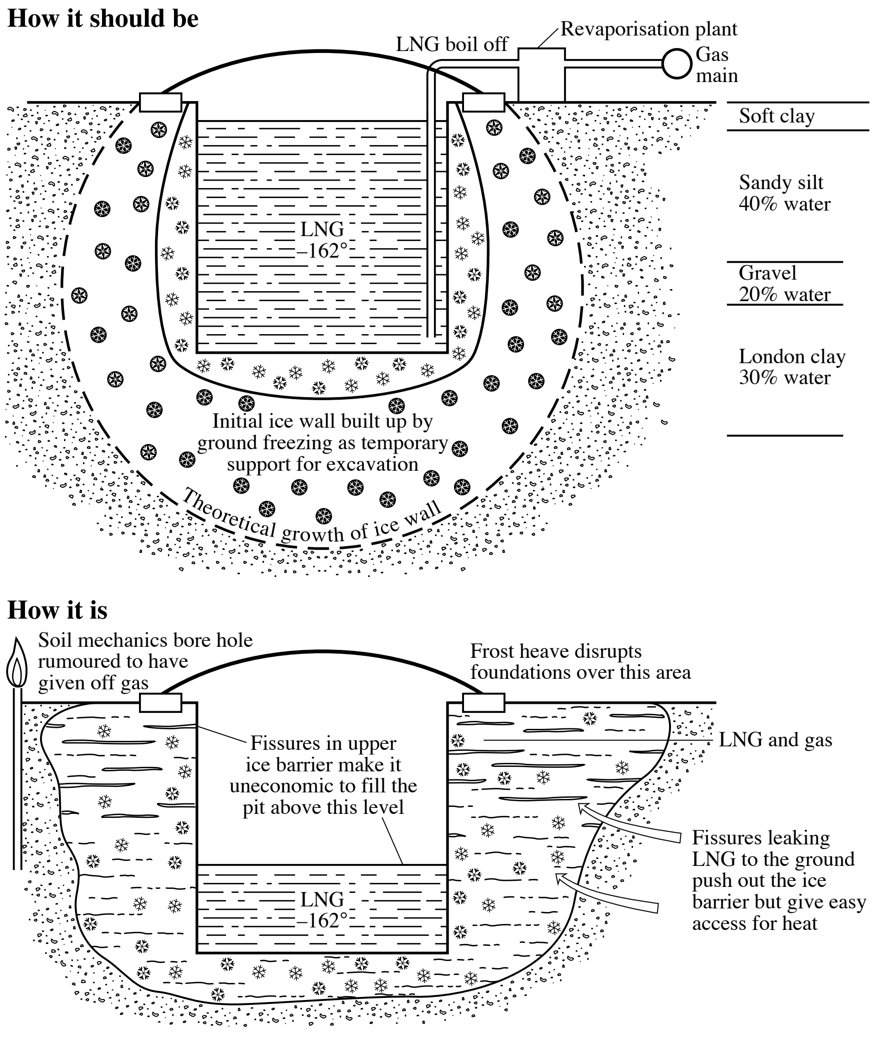
Figure 3.2: Cross-section of a typical in-ground LNG tank



Source: Based on a diagram in 'Frozen Fire', from an original article by Peter Ferguson in New Civil Engineer.

An alternative means of storing LNG is in an underground facility, as shown in Figure 3.2. In essence a cylindrical hole is dug in the ground and then lined with load-bearing concrete, insulation and an LNG-proof membrane. This type of design also poses a number of challenges for the engineers. One of the main requirements is for the ground to be thoroughly stabilised so that the tank will not be adversely affected by future ground settlement. Another major problem is that of dealing with underground water. Sometimes, if soil freezing is allowed to develop unchecked, frost heave can occur which can, in extreme cases, affect the integrity of the in-ground tank. Figure 3.3, adapted from an article by Peter Ferguson in *New Civil Engineer*, shows the effects that can occur when frost heave gets out of control.

Figure 3.3: Effects of frost heave on an in-ground LNG tank



Source: Based on a diagram in 'Frozen Fire'

The operational characteristics associated with LNG

Traditionally LNG has been seen to be an insurance policy, storing large volumes of gas in a relatively confined space, and with the ability to deliver those volumes of gas at high rates over relatively short durations. The purpose of this section is to briefly describe the operational characteristics of typical LNG facilities.

Injection rates

Traditionally LNG facilities are filled slowly over long periods of low gas demand, such as during the summer months in the UK. The process of cooling the LNG to the temperature at which it liquefies (-162°C) is most economically undertaken at low rates. Therefore, depending on the particular LNG facility, the time taken to fill an LNG facility can be several weeks, or even months.

The following table shows typical filling rates for LNG facilities in the UK.

Table 3.1: Injection rates for UK LNG storage facilities			
Storage facility	**Rate (GWh/d)**	**Space (GWh)**	**Time to fill (days)**
Glenmavis	3.7	551	149
Dynevor Arms	2.9	276	95
Isle of Grain	5.4	1,213	224
Avonmouth	2.6	827	318
Partington	5.2	1,195	229
AVERAGE	4.0	812.4	203
Source: BG Storage			

As can be seen from Table 3.1 the average filling rate for UK LNG storage facilities is 4.0 GWh/d and it takes an average of 203 days to fill an LNG storage facility.

Withdrawal rates

When it comes to emptying an LNG storage facility, the very high withdrawal rates set LNG in a class of its own. The primary function of LNG storage facilities is to ensure that on the very coldest days of the year sufficient gas is available to meet the gas demand. Due to the temperature-sensitive nature of peak gas demand, as the temperature falls to very low levels gas demand rises rapidly. LNG storage facilities need to be able to deliver their gas promptly and at a high delivery rate into the gas market. LNG storage facilities have what is known as high deliverability, as shown in Table 3.2 which indicates the withdrawal rates for the UK LNG storage facilities.

Table 3.2: Withdrawal rates for UK LNG storage facilities			
Storage facility	**Rate (GWh/d)**	**Space (GWh)**	**Time to empty (days)**
Glenmavis	110.0	551	5
Dynevor Arms	55.0	276	5
Isle of Grain	243.0	1,213	5
Avonmouth	165.0	827	5
Partington	235.0	1,195	5
AVERAGE	161.6	812.4	5
Source: BG Storage			

As can be seen from Table 3.2 the average withdrawal rate for UK LNG storage facilities is 161.6 GWh/d. This is 40 times higher than the average filling rate, and means that on average a UK LNG storage facility can be emptied within 5 days. These two tables, Tables 3.1 and 3.2, provide a very clear picture of how LNG facilities have been designed to function in the current commercial and operational climate.

Cycling

Due to the long lead times required to fill LNG storage facilities, unlike some other types of storage facility LNG facilities are not used for cycling. They are designed to be filled only once during the year.

Cushion gas

In operating LNG storage facilities cushion gas is not really an issue. All the gas in an LNG facility can be recovered by removing the LNG and regasifying it. The complete removal of all gas from a facility might, however, have implications due to the fact that the storage facility could possibly then warm above the -162°C temperature required for LNG storage.

It is worth noting that gas can be lost during the process of storage through ‘boil off’ if the LNG is not kept under pressure. There is then constant molecular activity with the liquid literally boiling off and returning to the gaseous state.

Typical uses of LNG storage

There are basically two types of LNG storage facility throughout the world. There are those that are primarily used as LNG receiving terminals, and are required to store gas at the terminal for a variety of reasons, including the following:

- Late arrival of a ship;
- Strategic security considerations;
- Seasonal requirements of the gas market.

The other main type of onshore LNG storage facility is a ‘peak shaving facility’. Typically, peak shaving facilities are located at the extremity of the gas transportation system and are primarily used for the following reasons:

- Provision of peak shaving storage to meet seasonal requirements, and
- The provision of transmission support.

The benefits of LNG

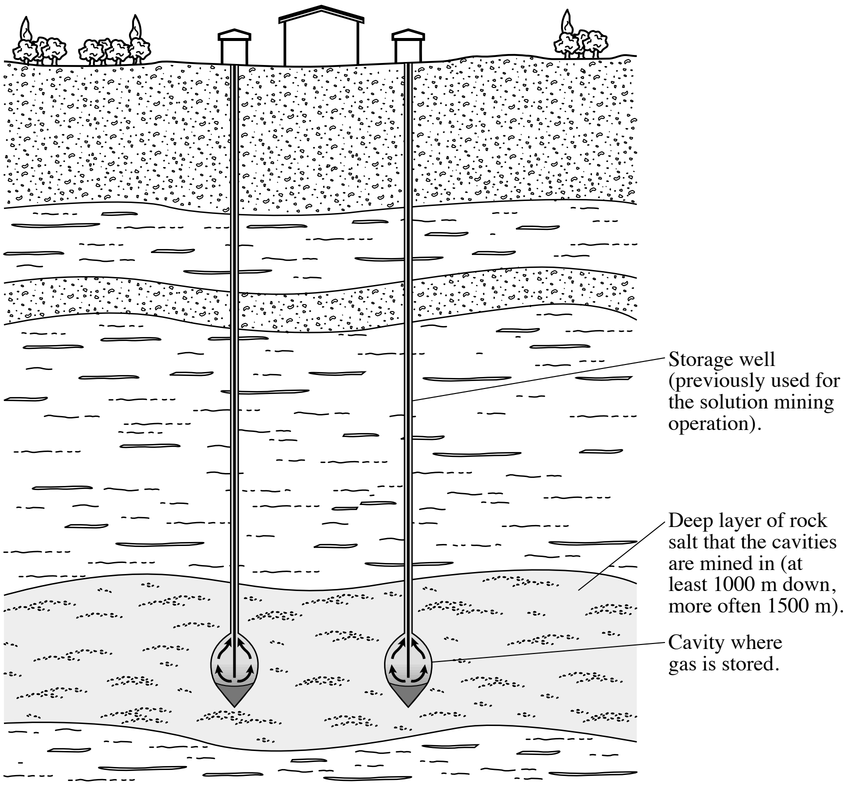
The reason why LNG peak shaving facilities are a preferred method for meeting the ‘needle peak’ is because of their ability to provide large amounts of gas over a relatively short duration in an economical way. In theory, the world’s LNG reserve of some 2,400 million m^3 could be sent out in 6.7 days at a send-out capacity of 370 million m^3/day. In some cases LNG is stored in small satellite stations to meet local needs, although it is not actually liquefied at this location. This does mean that LNG can be located near to the source of likely demand, although there are safety issues to be considered if LNG is to be located near to centres of population.

Salt cavity

Physical characteristics of salt cavity storage

The solubility of rock salt renders feasible the process of leaching out cavities by injecting fresh water into salt layers more than 1,000 metres underground. As the remaining rock salt layer is impermeable and non-porous, gas cannot escape and can therefore be safely stored in the resulting cavity. The leaching process uses nine cubic metres of water to remove one cubic metre of salt. This requires an abundant source of fresh or only slightly salty water, and some means of disposal must be found for the resulting brine. In order for the project to be feasible, the insoluble content of the rock salt must be less than one quarter. Also, the stability of the subsoil must be maintained, which places constraints on the dimensions of the cavities and the distances between them. During leaching the shape of the cavity is continually monitored by ultrasound imaging.

Figure 3.4: Typical Salt Cavity Storage Site.



Source: MJMCSL

Salt cavity storage sites consist of several such cavities, with volumes varying from 100,000 m^3 to 500,000 m^3. The storage capacity for a given cavity volume is proportional to the maximum operating pressure, which increases with the depth of the cavity. Comparatively smaller volumes of gas can be stored in salt cavities than in aquifers or depleted fields.

Operational characteristics of salt cavity storage

Movement of gas in the cavity is controlled by compression and expansion. There is no resistance to movement as the salt cavity is hollow, and therefore gas can be injected and withdrawn at a relatively fast rate. However, since this causes wide variations in temperature and pressure, regular monitoring must be carried out in order to maintain safety standards. Salt cavities can be emptied and filled many times in a year, and the operational procedure is one of the safest among the different types of gas storage facility.

Injection rates

One of the main benefits of salt cavity storage facilities over other types of storage is their ability to be filled at a relatively high rate, as shown in Table 3.3.

Table 3.3: Typical injection rates for salt cavity storage			
Storage facility	**Daily Rate (GWh/d)**	**Space (GWh)**	**Time to fill (days)**
Hornsea	21.4	3,495	163
Source: BG Storage			

Withdrawal rates

Withdrawal rates for salt cavity storage are also high, although not as high as those for LNG. Nevertheless they are sufficiently high to be able to redeliver relatively high volumes of gas into the gas market over short periods of time, as shown by the example used in Table 3.4 describing the salt cavity storage facility at Hornsea in the UK.

Table 3.4: Typical example of withdrawal rates from salt cavity storage			
Storage facility	**Daily Rate (GWh/d)**	**Space (GWh)**	**Time to empty (days)**
Hornsea	195	3,495	18
Source: BG Storage			

Tables 3.3 and 3.4 show that while salt cavity storage might not have such a high withdrawal rate as LNG storage facilities, it can fill and empty (in the process known as cycling) several times during the year.

Cycling

One of the benefits of salt cavity storage, if built into the original design, is its ability to cycle gas in and out a number of times throughout the year. Many of the traditional storage providers who own and operate salt cavity storage are unable to provide more than one or two storage cycles a year. However, as the competitive market has developed and new storage facilities are built or old ones redesigned, the number of cycles available from salt cavity storage has continued to increase. In some cases the number of cycles that a salt cavity facility can undergo in one year is as high as ten. Clearly the ability to cycle reduces the unit cost of providing the storage service, giving competitive advantage to both the storage provider and the storage user.

Cushion gas

Cushion gas is the term used to describe the gas within the salt cavity that cannot be made use of by the storage provider. While this cushion gas can eventually be recovered at the end of the facility's useful life by displacing it with nitrogen or some other inert gas, nevertheless during assessment of the cost of a salt cavity storage facility the cushion gas is normally treated as a capital cost. (NB: There are exceptions to this rule, as described in Chapter 5 on storage tariffs, where the storage user provides the cushion gas and there is a corresponding reduction in the storage tariff.) The percentage of cushion gas required varies from facility to facility due to variations in the operational characteristics of each site. (For example, shallow salt cavities will operate at considerably lower operating pressures than deep salt cavities.) The need to provide cushion gas for salt cavity storage is undesirable since it increases the initial capital cost of the project and therefore increases the overall storage tariffs. Therefore a considerable amount of research is taking place throughout the world into the feasibility of using an alternative inert gas rather than natural gas, a project made more difficult by the fact that the two gases can not be allowed to mix.

Typical uses of salt cavity storage

In many respects salt cavity storage is one of the most flexible and versatile types of storage facility available and, as a result of this, it provides a variety of services.

Seasonal supply/demand matching

One of the most common uses of salt cavity storage throughout the world is for providing gas to manage the seasonal supply/demand match. This service is often known as peak shaving. Salt cavity storage is ideal for this purpose as, due to its high injection and withdrawal rates, it is able to deliver large amounts of gas over short periods of time.

Daily balancing

With the development of competitive gas markets throughout the world, and the subsequent unbundling of trading and transportation, many players need to achieve a daily balance. Salt cavity storage, with its fast injection and withdrawal rates, is ideally suited to this purpose. In some parts of the world, particularly in the US, when tied to a gas trading hub salt cavity storage allows the hub operator to provide a number of different hub services to the users of the local pipeline system.

Gas trading

The development of competitive gas markets has also encouraged the development of gas trading and the corresponding arbitrage opportunities. Again the operational characteristics of salt cavity storage mean that it is an ideal tool for gas traders who wish to take advantage of arbitrage opportunities in the gas trading market.

Development and operating costs associated with salt cavity storage

Development costs are much higher for salt cavity facilities than for other types of underground storage. The cost per unit of working gas capacity is roughly twice that of a comparable project using a depleted field or an aquifer. Operating costs are also greater for salt cavity storage projects, particularly if they are emptied and refilled many times annually.

The costs can be substantially reduced by selling brine, perhaps to a nearby chemicals company. Piping costs are significantly less if the storage site is near to a source of fresh water. Overall, though, salt cavity storage is only economically viable in situations that offer a high value per unit of working gas capacity, or require a high withdrawal rate.

Future developments

Several gas companies world-wide are undertaking research into new techniques of salt cavity storage. Thyssengas, one of the major German gas companies, has started to use fracture tests to obtain additional information about the strength of the salt layer. Air is forced into boreholes, thus causing artificial fractures in the salt. Then, using complex modelling techniques, Thyssengas is able to change the possible dimensions of the cavern and increase the maximum and permissable working pressures. The change in pressure alone can increase the storage capacity by 15%. Gaz de France are investigating the possibility of storing gas in thin salt layers only 100 metres thick, as opposed to the previous requirement of at least 250 metres thickness.

Depleted fields

Prior to discussing depleted oil and gas fields and their role in providing suitable storage facilities, it is worth considering the issue of exactly when a gas field becomes a potential storage facility. For many of the old gas fields that have reached, or are nearing, depletion the issue is a contractual one as well as a physical one. Many of the early gas purchase contracts with incumbent monopolies were agreed on the basis of the sale of the whole field on a depletion basis, with various economic and geophysical tests identifying when the field was ‘officially’ depleted. The concept of a gas field being depleted does not mean that it is empty, but rather that when viewed from a contractual perspective it is no longer economic for the producer to extract the remaining gas. Once the gas field in question has been officially declared to be depleted, the gas purchase contract is terminated and the owner of the gas field may decommission the field or redevelop it for use as a gas storage facility.

It is important when discussing gas storage not to become myopic on when gas fields might be used to store gas, since any gas field that is partially depleted may be used as a gas storage facility. Therefore the ability to use even a relatively new gas field to store gas may enhance the economics of a previously marginal gas project.

With many gas fields in the already mature gas markets throughout the world having reached depletion or approaching depletion, there is a considerable amount of interest in depleted field storage. A depleted oil or gas field is an asset that has already paid for its development costs through the sale of its original oil and gas, and this means that the cost of developing an existing gas field into a gas storage facility can be quite low. However the challenge for potential developers of depleted field gas storage facilities is the size of that project, as turning even an average-sized field into a storage facility could easily swamp the storage market and reduce the potential value of the service being sold.

Physical characteristics of depleted field storage

A depleted oil or gas field is the most natural geological structure in which to store gas. Gas is stored in porous rock between 500 and 3,000 metres below the surface. The volume of gas that can be injected can be estimated from the production history of the field, although there is no guarantee that the storage volume will be the same as the original capacity. High porosity and permeability of the rock layer is desirable, since the injection and withdrawal rates will be higher. The field has an impermeable cap of rock which prevents the gas from escaping. The thicker this cap is, the more the pressure can be increased above the original pressure of the field.

Operational characteristics of depleted field storage

As the gas is stored in porous rock, it is a lot more difficult to inject and withdraw gas than it is in the case of gas stored in a salt cavity. As a result, the filling and withdrawal periods must be longer, and the withdrawal rates fall significantly as the volume of stored gas decreases. The storage capacity can be increased, but only with careful monitoring of ground water levels around the site to make sure that no gas escapes. As a field is nearing the end of its production life, careful calculations and research need to be done to optimise the point at which to convert it for storage use.

Injection rates

Depleted field gas storage facilities operate in a similar fashion to ordinary gas fields. Clearly the actual injection rates will vary depending upon the characteristics of the particular facility concerned and how full or empty the field is. For example, it is often necessary to re-compress gas in order to inject that gas into storage, particularly if the gas storage facility is remote from the high-pressure pipeline system. Also, as the facility fills, the pressure required to deliver gas into the facility increases. A typical example of a depleted field storage facility is the Rough field in the UK, which is owned and operated by BG Storage. The injection rates for Rough are shown in Table 3.5.

Table 3.5: A typical example of injection rates for a depleted gas field

Storage facility	Injection Rate (GWh/d)	Capacity (GWh)	Time to fill (days)
Rough	160	30,334	190

Source: BG Storage

As can be seen from Table 3.5, it takes much longer to fill Rough than it does to fill a salt cavity storage facility. This is a function of the geological characteristics of the depleted gas field. If gas is injected too quickly into the depleted field, the physical structure of the field might be damaged and its overall size reduced.

Withdrawal rates

As with injection rates, withdrawal rates are dependent upon the operational characteristics of the depleted gas field itself, and the pressure and configuration of the surrounding pipeline infrastructure. Table 3.6 shows the withdrawal rates for the Rough field.

Table 3.6: A typical example of withdrawal rates for a depleted field

Storage facility	Withdrawal Rate (GWh/d)	Space (GWh)	Time to empty (days)
Rough	455	30,334	67

Source: BG Storage

Cycling

Due to the relatively slow injection and withdrawal rates it is not physically possible to cycle most depleted field storage facilities more than once a year. Nevertheless, through the judicious use of the storage capacity that they have booked, some players are able to cycle their individual capacity more than once, although this is effectively being done by using capacity that other players are not using. If all players tried to cycle depleted field gas storage more than once they would be constrained by the physical operating characteristics of the gas storage facility.

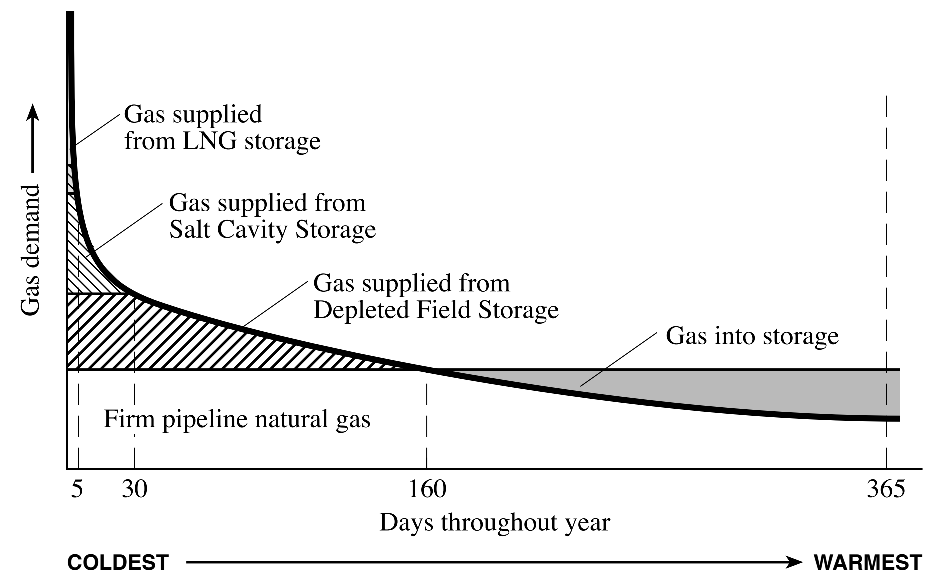
Cushion gas

The issue of cushion gas is an interesting one as regards depleted field storage facilities. If the old gas field was simply decommissioned or abandoned the remaining gas would, by inference, be uneconomic to extract. However to operate efficiently it might be appropriate for a higher level of gas to be left in the gas field than would normally be the case if the field was simply depleted. Those entrepreneurial storage projects which may use partially depleted fields are effectively using the remaining gas as cushion gas. This issue has been quite a thorny one for regulators throughout the world. Many storage providers would argue, with some justification, that cushion gas in a depleted field is part of the capital cost of providing the storage services and therefore they should be able to include the value of the cushion gas in the rate base. However many regulators would dispute both the value of the cushion gas and the level at which it can be included in the base rate. Throughout the world cushion gas in depleted gas fields is typically between 40% and 60% of the total capacity.

Typical uses of depleted field storage

Depleted fields are the most widely used form of gas storage, and the easiest to construct. They can be used for a variety of purposes, as described below.

Figure 3.5: Typical uses of gas storage



Source: MJMCSL

Annual supply/demand matching

Their relatively large capacity enables depleted field storage facilities to provide a supply and demand matching service throughout the year. As can be seen from Figure 3.5, depleted field storage provides a large proportion of the seasonal supply/demand matching requirement of a typical gas market. The figure shows the depleted field gas storage facility delivering gas into the system for some 160 days per annum covering the high demand period, and filling during the remainder of the year when demand on the system is lower.

Security of supply

With the development of gas fields in a number of countries such as Russia and the CIS, and gas being delivered from these fields into the Western European gas markets, there are concerns both over the operational ability of these countries to consistently deliver gas to the Western European market, and also the political stability of these gas-producing nations. Therefore the combination of large depleted field storage facilities with relatively insecure gas supplies results in a relatively inexpensive but secure source of gas. Some countries have enough storage capacity to maintain gas supplies from storage for several months, even when their main source of gas has been cut off. It is also quite common for producers who need to shut down production, either for planned maintenance or as a result of an emergency, to use depleted field storage as a means of meeting any contractual obligations.

Development and operational costs associated with depleted field storage

Depleted fields have the lowest development costs of the different types of storage, as much of the equipment is already in place. For example, the wells and some of the operating machinery installed when the field was initially developed to produce oil or gas can sometimes be adapted and re-used. Thorough research needs to be carried out on the geological structures and the field production data to optimise the capacity, and any wells previously drilled but no longer required must be plugged and carefully monitored in order to ensure that no gas escapes.

Future developments

Any improvements in offshore drilling and extraction technology can also provide benefits to the development of depleted gas field storage. The advances in drilling technology over the last few years mean that the injection and withdrawal rates for some old depleted fields can be improved by using new horizontal drilling techniques. Horizontal drilling can be used to increase the injection and withdrawal rates by a factor of six. The relative cost of horizontal drilling as opposed to the standard vertical wells is about double.

Disused mines

In order to avoid the complications and costs associated with drilling or leaching out a cavity, some disused mines have been converted into storage facilities. These are both convenient and economical, as the storage space and shafts have already been created. However disused mines do have certain drawbacks, and there are relatively few in operation for storage purposes.

Physical characteristics of disused mine storage

Although there is no excavation to be done, a considerable amount of work needs to be carried out to ensure the stability, safety and impermeability of the mine shafts. Some of the gas is absorbed by coal, which increases the actual storage capacity. To begin with the mine is filled with water to flush out the air and mine gas that is present, and then gas is injected which compresses and then expels the water. Injection and withdrawal are controlled by compression and expansion. As with salt cavities, there is no rock for the gas to be forced through, and therefore rates are relatively quick.

Operational characteristics of disused mine storage

Gas is absorbed by coal and when released the heavier fractions tend to be retained for longer. This means that when the storage facility is emptied, the first gas to emerge has a lower heating value. This value gradually increases as the reservoir is drained, until the last gas with its higher heating value is extracted. In order to compensate for this, a supply of propane must be kept and injected into the gas on withdrawal as necessary to maintain a constant heating value. As the injection and withdrawal of gas is controlled by compression into a hollow space and expansion from that space, the withdrawal rate is quite high and the facility can be emptied and refilled more than once a year. Almost all of the gas can be recovered.

Typical uses of disused mine storage

Disused mine storage facilities have a high deliverability, and can be used as a peak shaving facility on a monthly, or even weekly or daily, basis. Those with larger capacities can also be used to help ensure security of supply.

Development and operational costs associated with disused mine storage

No excavation has to be carried out, but storing gas in disused mines is notorious for problems with leakage. All the mine shafts have to be plugged and tested for structural soundness and gas tightness. Also, as the composition of the gas is altered during storage, the gas must be treated on withdrawal.

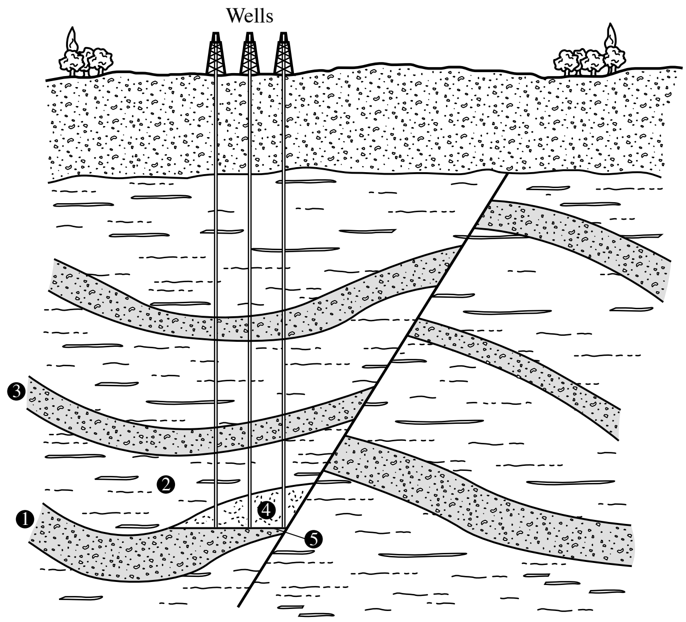
Aquifers

When there are no gas fields in an area, and also no salt layers suitable for the leaching out of salt caverns, it is sometimes possible to create an aquifer. The idea behind this is to simulate a real gas field by finding a similar rock formation and using that to store gas.

Physical characteristics of aquifer storage

An aquifer storage facility is an artificial gas field created by injecting gas through wells drilled into porous rock (sandstone, limestone, dolomites or chalk) deep underground. The porous rock must be capped by a gas-tight layer that forms a dome-shaped rock structure, as shown in Figure 3.6. The gas displaces water from the rock, and the water is compressed and moves downwards. This water exerts the necessary pressure to force the gas back out of storage during withdrawal.

Figure 3.6: A typical aquifer



Source: MJMCSL
Notes: 1 Aquifer-Porous permiable layer (Resevoir)
2 Impermiable cap rock
3 Upper control aquifer
4 Gas
5 Water level gas/water interface

Porosity and permeability of the rock itself must reach a certain level to maximise the amount of recoverable gas as well as improving the injection and withdrawal rates. The storage capacity of the aquifer depends on a number of factors. The dimensions of the anticline, particularly the height, are important. Other necessary details are the porosity of the rock and the maximum operating pressure the structure can withstand. The pressure needed to make storage feasible entails depths of between 500 and 2,000 metres.

Operational characteristics of aquifer storage

Aquifers are artificial gas fields, and in many ways bear a close resemblance to depleted field storage. Injection and withdrawal rates are relatively slow, and the initial filling of the reservoir is a fairly lengthy process. Therefore most aquifers operate under an annual cycle of injection during the summer and withdrawal during the winter. The deliverability is higher when the rock porosity is greatest and the reservoir is full. Deliverability tails off as the reservoir depletes, and eventually the water becomes able to invade the base of the wells. At this point the gas remaining is the cushion gas, which cannot be recovered.

Typical uses of aquifer storage

Aquifers have a high working gas volume, but a relatively poor withdrawal rate. As a result, they are used to regulate seasonal demand, and also constitute strategic reserves that can be called upon if supply from one or more sources were temporarily interrupted.

Development and operational costs associated with aquifer storage

The cushion gas is the greatest investment cost, as it cannot be recovered. On average it occupies over 50% of the storage volume.

Future developments

Up to a fifth of the cushion gas can be replaced by an inert gas such as nitrogen or carbon dioxide. Gaz de France has been conducting research into this possibility, and has successfully implemented the procedure at three of its aquifer facilities. However there are numerous technical difficulties, such as keeping the inert gas and the natural gas from mixing.

Chapter Four:

ALTERNATIVES TO PHYSICAL STORAGE

Introduction

The purpose of the chapter is to discuss both existing and potential future alternatives to physical gas storage. As the two main functions of storage are seasonal supply/demand management and the provision of flexibility as a gas trading tool, storage can be provided either entirely or in part by other gas industry facilities. The current or potential alternatives to gas storage to be covered in this chapter include:

- Interruption as an alternative to storage;
- Demand-side management;
- Supply-side swing;
- Seasonal purchases;
- The Interconnector as a source of storage.

For each of these alternatives to storage an explanation will be provided of how the alternative works and also what the economic rationale is for using that particular facility. It is worth noting that as the gas market as a whole is beginning to liberalise, so the true value of these alternatives is slowly beginning to emerge.

Interruption as an alternative to storage

An interruptible gas contract is the term used for a gas contract that may be interrupted partially or totally by the gas seller, with the end-user either switching to an alternative fuel or switching off the process which would normally consume the gas supply. In discussing the role of interruption as an alternative to physical gas storage, the following four areas will be examined:

- Transporter interruption-based contracts;
- Traditional interruptible contracts;
- Commercial profit-sharing interruptible contracts;
- The impact of Combined Cycle Gas Turbines (CCGTs).

It should be noted that the differences between different types of interruptible contract, such as the transporter interruption-based or commercially-based interruption, are quite blurred.

Technically speaking, any form of interruption might be seen as a demand-side response to the supply/demand matching problem, in that switching off an interruptible end-user does not actually release more peak gas into the market. It does, however, reduce the demand for peak gas, and therefore the effect is the same. Consequently many players and market commentators see interruptible customers as at least a partial substitute for gas storage.

Transporter interruption-based contracts

One example of a transporter who uses the interruptible contracts is Transco, who may sometimes have a need to interrupt customers due to capacity constraints on their system. Prior to discussing the role of Transco's interruption-based contracts, it is worth noting that at the time of writing this report an industry-wide review of interruption was taking place. Therefore some of the information given here may be impacted by this review.

(NB: The following section is a summary of an information pack provided by Transco.)

Background to Transco interruption

Maintaining a balance in the gas supply system is a complex process, especially during the winter months when demand is at its highest. Transco has a statutory duty to provide adequate capacity to meet firm demand through the winter, and should demand on the gas transportation system exceed capacity, then Transco has to take steps to overcome the shortfall and maintain secure supplies to its firm customers. In exchange for a reduction in the transportation charges, certain large end-users will interrupt their gas supply and switch to an alternative fuel for agreed periods when requested to do so by Transco. Under the current arrangements, Transco can in fact interrupt for a number of reasons:

- Network capacity constraints;
- High system demands;
- Testing interruption capability;
- Emergency situations.

Network capacity constraints

If Transco has reason to think that gas demand in the transportation system will exceed capacity, it will instruct shippers to interrupt supplies to some or all of their interruptible customers in order to reduce demand and ensure that there is sufficient gas in the system to supply firm customers.

The number of customers interrupted will vary according to the cause of the capacity constraint, and can be widespread across the National Transmission System or confined to a particular local distribution system. A constraint in a local distribution system will affect only a small number of interruptible customers. This localised type of capacity constraint may be caused by severe local weather conditions, or by the location of a customer within the transportation system: some customers are classified as being network sensitive loads, in that they are on a part of the network that has only limited transportation capacity. In order to maintain supply to firm customers in these sections of the transmission system, while maintaining a safe pressure within that system, these interruptible network sensitive load sites have a high probability of interruption. Transco interrupts these customers in order to maintain security of supply to firm customers further downstream, but the number of interruptions depends on the demands placed on the system and therefore varies from year to year. A customer who does not interrupt when requested to do so can put the security of the system at risk, and therefore Transco makes charges on customers who fail to interrupt on request.

High system demands

If the forecast demand reaches a very high level (currently 85% of maximum peak day demand), the system is deemed to have reached full capacity and certain storage facilities are brought into play to support demand. As the storage supplies are limited, they are used to support firm demand only and therefore when the demand on the system is over 85% of peak day some customers are likely to be requested to interrupt.

Testing interruption capability

Under the contractual arrangements, Transco has the right to interrupt for up to three days in any one year in order to test that the interruption process is working effectively.

Emergency situations

In the event of an emergency situation, for example a failure of beach gas supplies or a pipeline fault, interruption may be required of some or all of the interruptible customers in the locality affected by the emergency. In this case there will not be the usual notice period, and customers will be required to interrupt as soon as possible.

The process of interruption

The shipper is informed of the need for interruption

In normal situations, as opposed to the emergency situation described above, there is a minimum of five hours notice given by Transco to the shipper to inform them that interruption is required. This period of time will give the shipper an opportunity to decide which customers to interrupt, if the situation is such that not all customers in the locality involved need to be interrupted.

Shippers and/or suppliers inform their interruptible customers

Once a shipper or supplier has been notified by Transco that interruption will be required, that shipper or supplier must in turn notify their customer(s) of the need to interrupt. Only in a localised emergency would Transco communicate directly with an end-user.

Shippers confirm interruption with Transco

Within five hours of being informed by Transco of the need to arrange interruption, the shipper or supplier must confirm to Transco that their customers have interrupted, or have arranged to interrupt, at or before the time set by Transco.

Restoration

Restoration is the term used for the decision by Transco that the constraint situation has been resolved and supply can be restored to those customers who have been interrupted. Transco informs shippers of the time at which customers can resume taking gas, and the shippers pass on this information.

Consequences of interruption

Because the process of interruption is undertaken in order to protect the security of the system, Transco will penalise those customers who, despite having agreed to interruption in the terms of their contract, refuse to interrupt when requested to do so. There are two ways in which the customer can be penalised:

Disconnection

If Transco deems such action necessary in order to maintain the security of the system, then it is possible that a customer who refuses to interrupt when requested to do so will have their supply disconnected. Once the situation that led to the system constraint has been resolved, the customer will then be reconnected, which can be both a lengthy and also an expensive process.

Financial penalties

Under the Network Code, a shipper whose customers refuse to interrupt when requested to do so is liable to certain charges. The shipper or supplier will in turn pass these charges on to the customer(s) concerned.

Other interruptible services provided by Transco

IFA

IFA is a service that allows an interruptible customer to continue to receive a certain proportion of gas, up to 30% of the normal supply, during a period of interruption. This amount would enable essential services to be maintained, such as staff canteens or water heating.

Inter-supply point transfer of firm offtake capacity

This service, also known as ‘buddying’, allows a shipper to release capacity from a firm supply point and temporarily allocate it to an interruptible customer. This means that an interruptible customer can continue to receive gas during a period of interruption, as long as its ‘buddy’ is willing to release gas.

The swap option

This option allows an interruptible customer and a firm customer to swap their positions on a permanent basis. This means that a previously interruptible customer now has the status of a firm customer.

Partial interruption

Rather than total interruption, this option allows a customer to reduce their intake rather than simply turn off their supply altogether. This would only be appropriate where reduction rather than total interruption would be enough to maintain the security of the system. This service is only available to large interruptible customers whose intake is through a single meter.

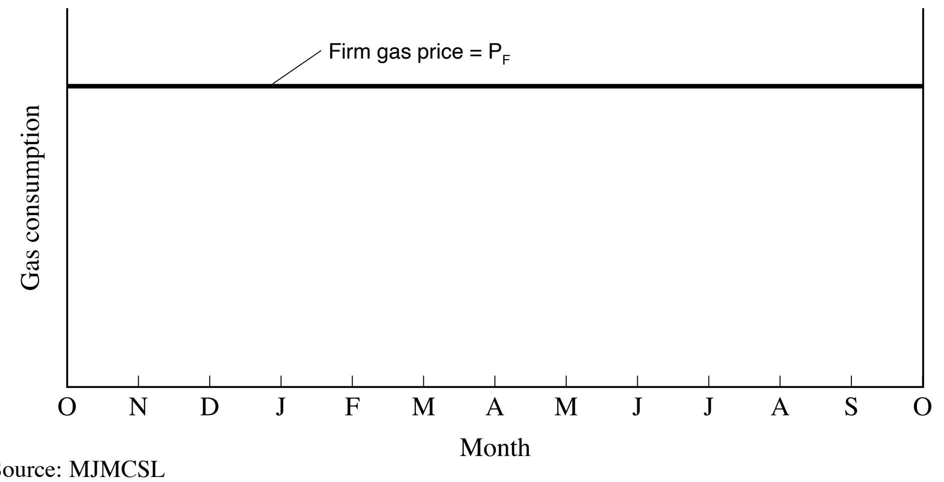
Traditional interruptible contracts

The interruptible contracts traditionally used in Great Britain, and still in use elsewhere in the world, provided an end-user with a flat discount off the price of gas in return for a commitment to switch off for a number of days each year as requested by the gas seller. Originally these flat discount prices were given to end-users when BG plc was an integrated transporter and marketer and, on that basis, the discounted prices allowed for the following:

- Transportation constraints;
- Supply/demand marketing constraints;
- Displaced storage.

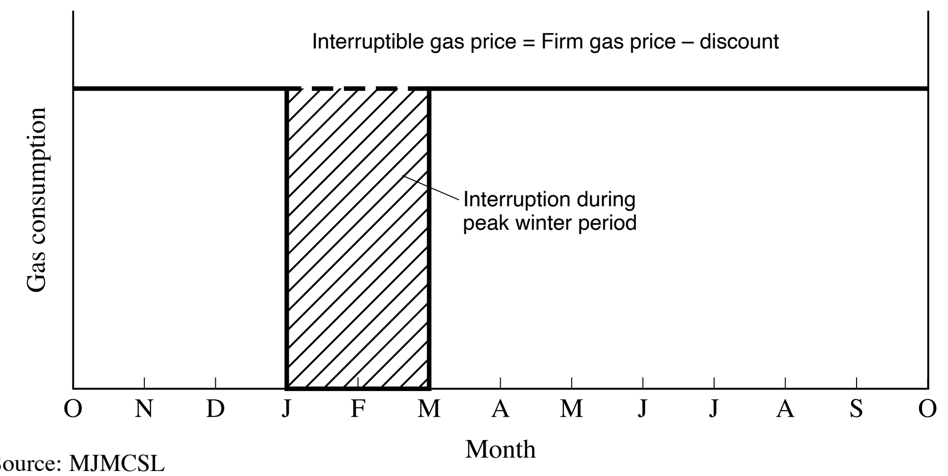
Figures 4.1a and 4.1b show in schematic form how the discount to an interruptible end-user would have worked.

Figure 4.1a: Schematic of a firm process load



Source: MJMCSL

Figure 4.1b: Schematic gas consumption of an interruptible load process



Source: MJMCSL

Typical operation of traditional interruptible contracts

These traditional 'flat discount' interruptible contracts would allow the merchant pipeline company as an integrated transporter and trader the ability to interrupt for a maximum number of days per year, say 63 days, although some contracts do allow for interruption to be based on a number of hours per year. In return for this flexibility, the merchant pipeline would sell gas to the end-user at a discount on the normal firm price. Clearly the interruptible customer would have additional costs in ensuring the availability of an alternative fuel, such as fuel oil or gas oil, as well as the additional costs of providing plant with dual fuel burning ability. Nevertheless the discounts offered by the merchant pipeline companies, combined with the perceived low probability of interruption, provided sufficient incentive for many large process end-users to purchase interruptible gas supplies despite the inconvenience of having to switch from gas to an alternative fuel at short notice (typically five to eight hours).

Benefits to the merchant pipeline

The ability of the merchant pipeline to interrupt large process end-users provided a variety of benefits, such as:

- Seasonal supply/demand matching;
- Optimisation of the pipeline system;
- Additional security against system failure.

Consequently traditional interruptible services were very much seen as a complementary service to storage, as they provided many of the same benefits as storage. However, the price paid for interruptible gas by end-users tended to be related more to the costs incurred by the end-user in providing a dual fuel ability and the cost of that fuel, rather than to the economic benefits to the merchant pipeline of providing an alternative to constructing physical storage. For those end-users who understood the economics, this was extremely irritating!

Problems associated with traditional interruptible contracts

One of the main problems with the flat discount contract structure was that it provided little or no positive incentive on the end-user to actually interrupt. Therefore such a contractual arrangement often caused considerable strain between the gas seller and the end-user when the seller requested interruption. Another problem that has also arisen in recent years has been the general lack of interruption due to warmer winters. Eleven out of the last twelve winters have been warmer than Seasonal Normal Temperature (SNT), a fact attributed to the impact of the greenhouse effect. Consequently many end-users began to see themselves as firm end-users who paid less for their gas!

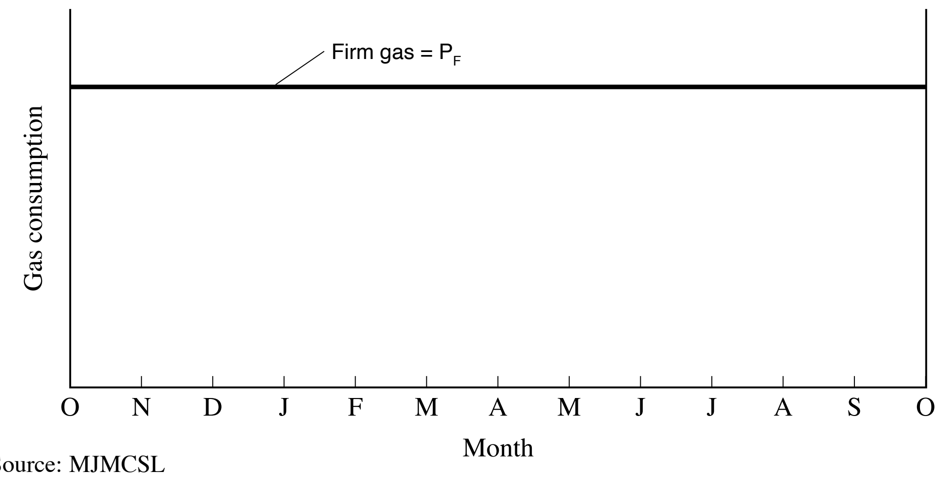
With the introduction of competition, and the separation of transportation and trading, the one flat discount was split into two: one portion that related to the degree to which the site was constrained by the transportation system, and one portion that related to the extent to which the end-user contributed to the gas seller's supply/demand match. In many respects this was the beginning of commercial interruption, although it was not perceived as such at the time.

Commercial profit-sharing interruptible contracts

With the introduction of the Network Code, and the implementation of daily balancing, the interruptible market in the UK has moved towards a more market-based pricing structure. This change in the pricing structure of interruptible contracts is a recognition of the fact that gas prices in the UK market now follow seasonal trends and that very high prices indeed have been seen on high demand days, as much as 16.92 p/kWh (£4.97 per therm). Some interruptible end-users, particularly those with alternative fuel supplies, have recognised that it may be commercially advantageous either to switch off or switch to the alternative fuel supply and to sell gas either directly or indirectly into the lucrative seasonal peak market. Such a rationale has led to a series of profit-sharing arrangements between end-users and shippers, where interruptibility effectively becomes another source of gas that can either be traded on the day-ahead gas market or bid into the Network Code flexibility mechanism.

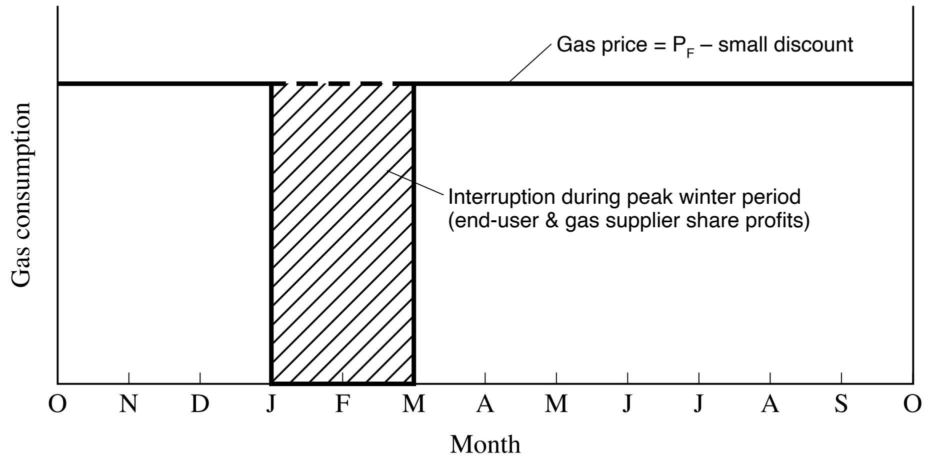
Operation of profit-sharing interruptible contracts

Figure 4.2a: Schematic of a firm process load



Source: MJMCSL

Figure 4.2b: Schematic of an interruptible process load



Source: MJMCSL

Figures 4.2a and 4.2b show in schematic format a typical profit-sharing structure. The end-user will be given a small discount off the firm price for a similar service, to cover the costs of administering an alternative fuel supply, although the main benefit comes when the end-user is interrupted. This type of contract structure does two things: it provides market-related prices to the interruptible market, and it provides a considerable incentive to the interruptible customer to switch off.

Problems associated with profit-sharing interruptible contracts

Despite the fact that many end-users and gas marketing companies recognise that the development of market-priced interruptible contracts is a constructive way forward, there are a number of concerns that need to be recognised and resolved where possible. For example, in the UK within day gas market on 16 and 17 December 1997, gas was being sold for nearly £5.00 a therm. Clearly many interruptible customers would willingly either switch to an alternative fuel or simply 'off gas' for such a sum. However, failure to actually reduce would mean that the gas marketing company might incur large balancing costs. In an ideal world the potential exposure to these large balancing costs would need to be passed on to the end-user, but the question arises of how many end-users would be prepared to carry such a liability or understand the full implications of not complying with a request to interrupt. While the development of profit-sharing interruptible contracts does seem to be the best way forward for a gas market that is continually seeking to send the right economic signals, there is a clear need to educate end-users regarding the implications. It is also important to note that, as the gas transportation and supply system becomes more operationally and economically efficient, the failure of an end-user to comply with a request to interrupt may have implications that are not only commercial but also operational.

The impact of CCGTs

The development of the CCGTs and the resulting 'dash to gas' has created an entirely new dynamic in the interruptible/storage market. Prior to the introduction of CCGTs into the gas market in the UK, the potential for interruption on a peak day consisted of some 7 MTPD. However, with the introduction of CCGTs the potential size of the interruptible market increased to some 78 MTPD (228 GWh) for the 1998/99 gas year, increasing to 120 MTPD (361 GWh) for the 2000/2001 gas year. This means that the forecast level of available interruption is approaching some 80% of the deliverability of Rough. This massive increase, both in the UK gas demand and the potential availability of interruption, has changed the dynamics of the peak market. However, it should be noted that these forecast levels of gas demand required by CCGTs may very well change as a result of the current restrictions on gas usage in power generation.

The point at which a power generator would choose to switch from gas to oil is based on a number of parameters, including the following:

- The price differential between gas and the substitute fuel;
- The maintenance cost of switching;
- Any Take-or-pay issues;
- The political implications of switching off if no alternative fuel is used.

Operation of interruptible CCGTs

Clearly the ability of gas marketers and transporters (where transmission system constraints exist) to interrupt large process loads such as CCGTs, does provide considerable flexibility to the operator of the transportation system. In particular, the ability for the transporter to make large reductions in demand at clearly identified locations in the gas supply system provides a very useful tool for dealing with within day balancing problems and localised system constraints. There is also an opportunity for the power generator and gas marketer to arbitrage between the revenues received from producing electricity from gas and selling that gas in the short-term gas market.

Problems associated with using CCGTs to provide pseudo storage

During the winter of 1997/98 considerable concerns were expressed by the National Grid Company, who operate the high-voltage transmission system in the UK, that the continual interruption of CCGT power stations on the National Grid could endanger the security of electricity supplies. While most commentators believe that the actual danger to electricity supplies was minimal, as most power stations that were interrupted could switch to gas oil, nevertheless there was a genuine concern that the large scale interruption of CCGTs would drive up the price of peak day electricity.

Demand-Side Management

An alternative, at least in part, to using physical gas storage is demand-side management (DSM). DSM is the name given to the process of managing the supply/demand match by manipulating the sales portfolio of a gas marketing company. DSM can take a variety of forms, such as:

- Tariff design;
- Legislative control;
- Selective marketing.

In many respects, DSM is not so much an alternative to storage as a sophisticated addition to storage. Basically DSM is a process whereby the behaviour of the end-users is influenced through the various forms listed above. While it will never do away with storage altogether DSM, when used well, will minimise the need for storage.

Tariff design

Perhaps one of the most common means of DSM is the use of tariff management. By creating sales tariffs in a particular manner it is possible to encourage certain types of customers. In their most simple form, gas tariffs consist of two parts: a fixed portion that usually relates to a capacity-related charge, and a variable portion known as the commodity charge, which relates to the quantity of gas consumed. By varying the ratio of these two charging components it is possible to vary the real cost to the end-user and hence influence their buying decision, as shown in the following example.

100% fixed charge

Perhaps the most simple way of charging is to recover costs through a one-off fixed charge. Such a tariff structure can, if the fixed charge is large enough, deter end-users who only require small quantities of gas since the less gas is consumed the higher the unit cost. Such a tariff structure may deter smaller end-users, but may actually encourage some users of gas to use more gas than they otherwise might, or just be inefficient in their use of gas.

Tariff (T_1) = F

A good example of a fixed charge tariff would be where the end-user pays a lump sum as part of their overall rental charge for a property. Such arrangements were used in the UK in the late 1960s and early 1970s, when residents of flats were members of district heating schemes, and paid an additional premium on their rent for space heating and hot water. As previously mentioned, such an arrangement provides little incentive for the end-user to minimise gas consumption. It is also interesting to note that similar heating schemes were also unsuccessful in the former Soviet Union, when residents tended to open the window rather than reduce the setting on the thermostat!

100% commodity charge

At the other extreme to the 100% fixed charge is the 100% commodity charge. Under this tariff the end-user is only charged for the actual gas consumed. In many respects this arrangement is ideal for smaller end-users of gas, but it provides no incentive on end-users to use a certain quantity of gas. Consequently the whole of the risk in terms of providing gas lies with the gas marketer.

Tariff (T_2) = C_1 * GU

where
C_1 = Commodity cost in p/therm or p/kWh
GU = Gas used in cubic feet or cubic metres.
(NB: The thermal usage is obtained by multiplying the volume by the calorific value of the gas.)

As has already been said, to a large extent the merchant pipeline and/or the gas marketer is taking all the risk in providing capacity in the pipeline system, and therefore the commodity-only tariff tends to be associated with a pure interruptible service. In some parts of the world, principally in the US, an interruptible tariff can be based on the marginal cost of moving gas through the pipeline system. The downside of such an arrangement is that the end-user will also be interrupted for long periods of time when the pipeline is 'capacity constrained'.

Load factor based tariff

An ideal end-user in terms of DSM would be a process load that consumes gas on a flat daily and seasonal profile, with a load factor of 100%. Loads with a load factor of less than 100% require the gas marketing company and the pipeline to provide capacity that might only be used for part of the time. Consequently some sales tariffs make a higher charge per unit for lower load factors, hence discouraging the more 'peaky' intermittent loads.

Tariff (T_3) = (C_2*GU) + (CP*PDR)
where
C_2 = Commodity charge
GU = Gas Usage
CP = Capacity charge
PDR = Peak day requirement

Clearly the higher the capacity related charge for T_3, the more likely the end-user is to be encouraged to ship more gas to minimise charges. The more gas that is moved, the higher the load factor and the lower per unit charge incurred by the end-user. Such an arrangement not only benefits the end-user but also reduces the amount of storage required by the pipeline.

In an ideal environment, the pipeline company would manipulate the rate of fixed to variable costs incurred by end-users in order to influence their behaviour and minimise overall storage costs.

Legislative controls

Limit the size of the market

Another means of managing the demand side of the supply/demand match is legislation of some sort. During the 1970s the gas demand in Great Britain was outstripping the availability of gas supplies and consequently the government used legislation to limit the availability of gas to new users. In fact, new industrial and commercial users of gas had to join a waiting list to be connected to the gas supply system, which is a far cry from the situation today and was a very British solution to supply/demand management.

Incentives and decrees

Sometimes governments use legislation in the opposite way to encourage or mandate the use of gas. For example, in South Korea the traditional fuel for cooking and heating homes is a coal-like brick that gives off a variety of pollutants, including smoke that visibly pollutes the atmosphere. The government of South Korea has implemented a programme of legislation and incentives that encourages members of the public to switch from their traditional fuel to the cleaner, more environmentally friendly natural gas.

Another more recent example of the use of government control to influence the behaviour of end-users has been the gas moratorium in the UK. This was a situation where the government believed that the increasing use of gas in the production of electricity was against the national interest, as the electricity industry was becoming too dependent upon gas as a primary source of energy for producing electricity. Consequently, after a period of consultation with the various participants in the industry, the Department of Trade and Industry issued a White Paper which stated the government position on the use of gas in power generation. It is not the intention of this report to discuss the DTI White Paper in any detail, merely to comment on this use of government intervention as a rather crude means of DSM.

Taxation

Perhaps the favourite of all government methods in terms of DSM is taxation, since not only does increased taxation control the size of the market but it also increases government revenues. The weakness in such an argument is whether or not existing customers can substitute alternative fuels in place of gas if the price increases. For example, if an end-user has previously invested a considerable amount of money in heating plant fuelled by gas, it is unlikely that an increase in taxation will reduce the energy consumption or encourage fuel switching. However, if the end-user is examining the possibility of investing in new plant, and fuel choice is an issue, then the level of taxation may well influence the buying decision.

Supply side swing

Another alternative to gas storage is the provision of swing gas from a gas supply contract. In a gas purchasing agreement, swing is defined as follows:

Swing is a measure of the flexibility inherent in the contract to varying nomination up to a peak deliverability where:

$$\text{Swing} = \frac{\text{Peak}}{\text{Average}} \times 100 \text{ expressed as a percentage}$$

Traditionally, in the UK gas market the gas being delivered into the Transco system has had a swing factor of between 130% to 170%. This has been necessary to provide sufficient peak gas supplies to the domestic market, which has a swing factor of some 286%. The purpose of this section is to describe how supply-side swing gas might be able to offer an alternative to storage, and addresses the following issues:

- The physical operation;
- Comparison of storage and swing;
- Analysis of cost drivers.

The physical operation

In order to provide additional supply-side flexibility, it is necessary for the producer of the gas to invest in additional plant that will allow the field to produce gas at a higher rate than it would with the existing plant. Having made this additional investment, the producer is then requested not to actually deliver any additional gas except on a small number of days each year. The producer and the operator of the field would expect notice of any required increase of deliveries along the following lines:

- Up to 25% increase: 4 hours notice;
- 25% to 50% increase: 8 hours notice;
- 50% to 100% increase: 12 hours notice.

While it might be possible for more gas to be delivered at shorter notice, typically the producer and the operator will only have a reasonable endeavour obligation to do so. In terms of the physical operation of the field, clearly the actual activity will depend upon the nature of the field (i.e. whether it is an associated gas field or not, how far away from the beach the field is, and so on). Typically an increase in the delivery rate will involve additional compression and processing plant being brought on line, as well as notification to the operator of any third party offshore transportation system.

Comparison of storage and swing

While this entire chapter has been dedicated to an examination of alternatives to physical storage, it is important to remember that the different alternatives are comparable but not identical. Therefore the following table makes a comparison between the provision of swing from a storage facility and the provision of swing from a gas sales contract.

Table 4.1: Comparison of supply-side swing with storage	
Storage : Advantages	**Swing gas: Advantages**
• Provides a home for gas when prices are low. • Reduces the need for capital expenditure offshore. • Onshore storage can reduce system entry charge. • High security of supply rating. • Flexibility in operation.	• Available throughout the year. • Cost of flexibility is included in price. • Simple to operate. • Spare swing gas can be sold in spot market.
Storage: Disadvantages	**Swing gas: Disadvantages**
• Needs to be booked in advance. • To put gas into storage, it first needs to be purchased. • Future price unknown. Source: MJMCSL	• Commodity price of gas tends to be higher. • Not flexible. • Can be linked to Take-or-pay obligations

As can be seen from the above table, supply-side swing and gas storage are similar but different. Each has its own merits and demerits. The issue, therefore, is the ability to choose the appropriate source of supply-side flexibility in order to meet the requirements of the organisation concerned.

Seasonal purchases

Since the development of competition in the UK, and the emergence of a short-term spot gas market, it has been possible for gas marketing companies to manage their supply/demand match by purchasing gas from the short-term spot market. (NB: Within the context of this report, short-term can mean anything from one day to one year.) While it is not the intention of this report to provide a detailed explanation of short-term gas trading, it may nevertheless be helpful to provide the reader with a brief overview of both Over-the-Counter (OTC) trading and Exchange trading.

Background to gas trading

The development of short-term trading tends to follow an evolutionary process, starting with 'one-off' spot deals OTC and developing into a fully commoditised market with a regulated commodity exchange and an unregulated underlying spot market. Both OTC and Exchange-traded gas markets have been developed to meet the needs of physical players in the market. However, although many of their functions overlap, there are also differences between the two markets.

Differences between OTC and Exchange markets

The OTC markets developed first in response to the physical needs of players with surplus capacity and buyers with temporary shortages. As liquidity increased in the OTC markets, so the Exchange-traded markets have merged. Their primary function has been to allow players to manage price risk in an increasingly volatile market.

OTC trades tend to be informal, bilateral agreements between players. The key features of OTC markets are as follows:

- Flexibility: deals can be tailored to meet the needs of individual counterparties in terms of volume size, deal maturity and a range of products. This applies even in the case of standardised OTC contracts, which are now increasingly being used to speed up trading;
- Anonymity through brokers: brokers ensure anonymity so that players do not need to reveal their market positions. In brokered trades the seller pays commission to the broker for setting up the deal. However, most trades are still carried out directly between players;
- No margin payments: unlike Exchange trades, no margin payments need to be paid to the exchange clearing house. These margin payments, however, are only temporary and give more security to the counterparties;
- Reduced regulation: this is both an advantage, in that less administration is required, and a disadvantage, in that the traders have less security.

The introduction of Exchange trading is an important step in developing a liquid commodity market. Prior to the launch of an Exchange futures contract the spot market often lacked liquidity, due to a number of reasons:

- Lack of price transparency;
- Concerns over counterparty risk;
- No reliable price indicator;
- Lack of a standardised contract.

While a standardised OTC gas contract has now been developed in the UK, trading through the Exchange still offers a number of benefits:

- Price transparency and reliability: screen-based trading on an Exchange ensures that all prices and deals are accurately reported at the end of the day. In the OTC market, price reporters publish prices and deals, but between 30% and 40% of trades may not be reported;
- Removal of counterparty risk: there is no counterparty risk since the clearing house is counterparty to all deals;
- Standard terms and conditions: all contracts are for a standard volume of a standard commodity with a standard delivery point;
- Complete anonymity.

Growth of OTC versus Exchange markets

Experience from both UK and US gas industries has shown that growth in the Exchange markets tends to boost liquidity, volumes and confidence in all short-term trading markets, including the OTC markets.

How Exchange trades work

This section outlines how Exchange trading operates both from a generic view and also in the particular case of the IPE-NBP gas futures contract. EJC Energy would like to acknowledge the help and assistance of the IPE in producing this section.

Contract specification

Both futures and options contracts are identified not only by the commodity being traded, but also by the delivery month and other specifications in the contract. The specifications of the IPE-NBP gas futures contract at the end of January 1998 are described below. It should be noted that there is no direct link between buyers and sellers, as the London Clearing House (LCH) is the counterparty for all trades.

- Trading hours: 1000 to 1700 (London time);
- Contract description: monthly strip of equal daily natural gas deliveries;
- Contract (lot) size: 1,000 therms of natural gas each day during delivery month;
- Trading size: trades are in multiples of 5 lots or 5,000 therms each delivery day;
- Quotation: the contract price is denominated in Sterling, and is pence per therm;
- Tick size: the minimum price fluctuation is 0.01 pence per therm with no price limits;
- Margin: all open positions are marked-to-market daily and subject to initial margin;
- Contract period: trading up to 12 months forward;
- Cessation of trading: contracts cease trading at the close of business on the second business day immediately prior to the day on which delivery commences;
- Balance of the month: once a monthly contract ceases trading it becomes a balance of the month contract, reducing in size each day, and representing the number of daily gas deliveries which must be made during the remainder of the contract month;
- Delivery: contracts are traded for the future transfer of rights in respect of natural gas at the UK NBP. Sellers transfer rights to the LCH, the counterparty to every contract, and the LCH transfers these rights on to the buyers.

Placing orders

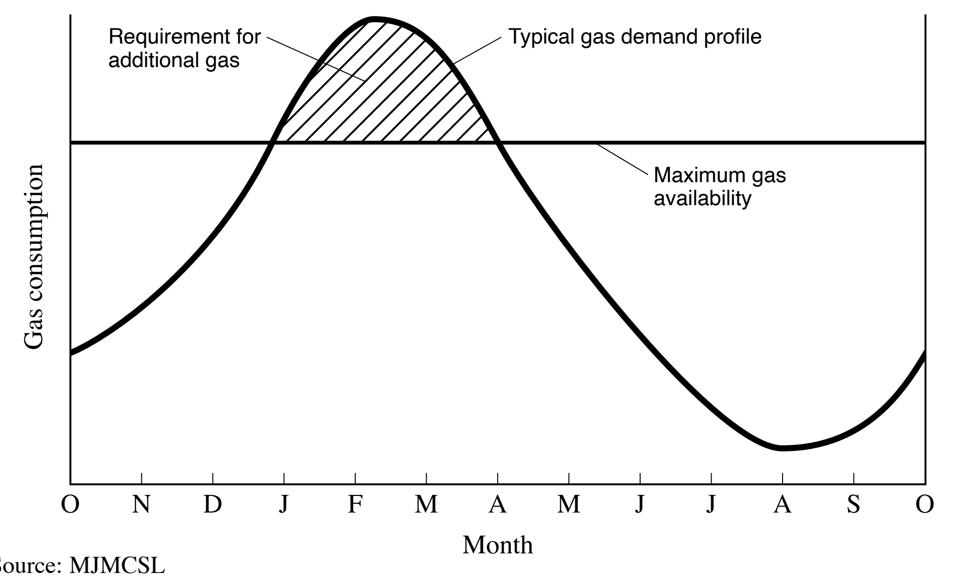
Most futures contracts, including IPE contracts (but not its natural gas contract), are traded on the Exchange floor by open outcry, giving all present an equal chance to take the other side of the trade. If a willing seller is found to meet the buyer's order, the trade is posted with the Exchange. In reality, exchanges publish price quotes electronically, to provide a timely record of pricing trends, even before the official record of the transaction is submitted.

The IPE-NBP contract is traded by means of the IPE's automated Energy Trading System (ETS). ETS provides an anonymous screen-based market, where the LCH becomes the counterparty to all trades. It is also open to participants who have executed off-exchange gas contracts on a bilateral basis and can exchange such forward contracts for IPE gas futures by using the Exchange of Futures for Physical (EFP) mechanism.

Except where Exchange members operate on their own account, all transactions must be carried out through a member of the Exchange. Gas industry participants can access the IPE market in two ways: either as clients of IPE members, or by becoming a trade associate member of the Exchange. Clients can execute trades through an IPE member broker, receiving prices either from electronic quote vendor services or from the brokers themselves. In order to do so they must enter into bilateral execution and clearing agreements with an IPE member who offers execution and/or clearing services.

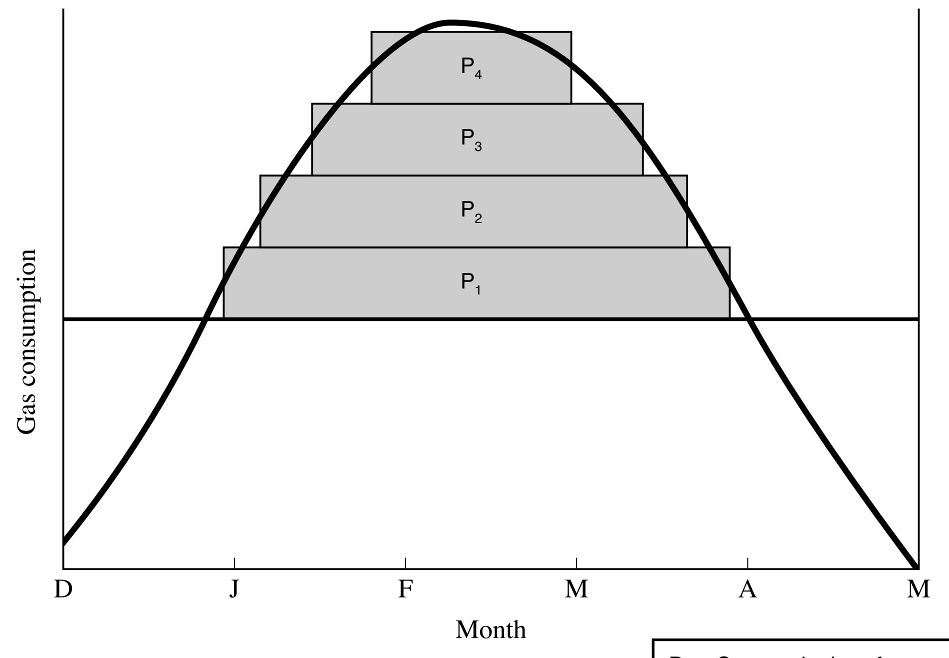
Buying gas to meet a seasonal deficit

Figure 4.3a: Typical requirement for seasonal gas



Source: MJMCSL

Figure 4.3b: Typical seasonal gas profile



Source: MJMCSL

P_N = Seasonal price of gas

As can be seen from the above figures, on some occasions the gas marketing company will be seeking to fill the gap between gas which is actually available via long-term contracts or other secure sources, and gas which is needed to meet the needs of their customers. The figures show in a schematic form the gas marketer and his requirement for additional gas.

Whatever the process used by the gas marketer in obtaining gas, the net effect is as shown in Figure 4.3b, where strips of gas are purchased over a period of time.

The Interconnector as a source of storage

Another well-documented alternative source of storage for the UK gas market is the Bacton-Zeebrugge Interconnector. The connection of the UK and Continental gas transportation systems via the Interconnector, with their different market structures and prices, has provided the opportunity for companies to arbitrage gas purchases on either side of the Interconnector.

How would the Interconnector provide storage?

One way in which the Interconnector could be used to provide an alternative source of storage would be for an organisation to purchase gas in the UK at the low summer prices (say 10 p/therm), and store it in storage facilities on the Continent. This storage gas could then be redelivered to the UK during peak winter periods at prices as high as 20 p/therm. In this scenario, gas actually flows through the Interconnector during the summer and then back again during the peak winter months. However, it is not always necessary for the gas to actually flow in both directions, as it is possible to achieve the same end by a series of gas swaps.

Factors that affect the storage arbitrage opportunities

Prior to the commissioning of the Interconnector, most commentators believed that gas would physically flow from the UK to the Continent for between 10 and 15 years before the UK reached a supply/demand deficit. However, none of these commentators predicted an oil price of less that $10.00 per barrel. The significance of this is that the price of gas on the Continent is indexed at least in part to the oil price, and this has meant that gas prices on the Continent have been cheaper than those in the UK. The consequence of this is that gas is physically flowing from the Continent to the UK, a scenario that no-one had predicted.

A dynamic market in peak gas

It can be seen that as well as the different types of physical storage that are available, there are a variety of alternatives that can also meet many of the requirements of the gas marketing companies in managing their supply/demand match. Therefore it seems highly likely that, as the competitive gas market develops in Continental Europe as well as in the UK, the true market price of peak gas, swing and storage will emerge.

Chapter Five:

THE UNDERLYING THEORY OF STORAGE TARIFFS

Introduction

The development of storage as an unbundled service separate from transportation and sales has only begun to emerge in recent years. Indeed, the majority of European countries have yet to publish formal unbundled storage tariffs, although one of the results of the EU Gas Directive and the development of competition is that such tariffs will emerge. The purpose of this chapter is to examine how storage tariffs can be developed in different environments. Therefore the following areas will be examined:

- An examination of North American storage tariffs;
- The development of auctions.

The main objective of this chapter is to provide the reader with an understanding of how storage tariffs are constructed and the theory that supports these tariff structures.

An examination of North American storage tariffs

No examination of storage tariffs would be complete without an examination of the developments taking place in the US. In many respects the unbundling of gas storage and the development of true competition between different storage companies is more advanced in the US than elsewhere in the world. Therefore it is useful to look at the following areas:

- Typical regulated storage tariffs , and
- The development of market-based rates.

Typical regulated storage tariffs

As with most storage tariffs a typical storage tariff in the US would include the following components:

- Reservation (or deliverability) charge;
- Space (or capacity) charge;
- Injection and withdrawal charges;
- Fuel use charges;
- Additional surcharges as applicable.

Clearly the exact nature of the storage tariff will depend on the nature of the storage service provided. For example, some storage providers in the US require customers to provide their own cushion gas, which will add to the inventory costs but will cause a corresponding reduction in the rates charged by the storage provider. A number of different storage services could be provided, which might include any of the following:

- All year round injections;
- Discount for winter injections;
- Discounts for summer withdrawals;
- Interruptible storage;
- Short notice injection and withdrawal services.

Example of a typical regulated US storage tariff

Due to the diversity of storage tariffs available, it is not possible to provide a comprehensive overview. Therefore a fictitious but typical example of a regulated US storage tariff has been chosen. In this fictitious example, the storage provider (known as EJC Storage Services) has 100 Bcf of available capacity that can provide a storage service of between 5 and 130 days duration for firm delivery. The US regulator has set a series of approved maximum rates for EJC Storage Services, which are described below.

Table 5.1: Fictitious approved maximum rates

	Charges
Deliverability	\$3.00/Mcf/month
Capacity	\$0.03/Mcf/month
Injections and withdrawals	\$0.01/Mcf
Fuel - Injection	\$1.0
- Withdrawal	\$0.1
Additional surcharges	\$0.002/Mcf

Source: MJMCSL

As mentioned previously, EJC Storage Services can provide a number of different levels of service, from a needle peaking service of 5 days to a seasonal service of 130 days. For a fixed working gas capacity the lower the number of days of withdrawing gas the higher the deliverability charges. Therefore there is a higher cost per unit stored for shorter duration services since the same amount of gas is being moved over a shorter period. The following table shows the variation in prices as a result of changes in duration.

Table 5.2: Indicative average prices for storage services of varying durations

Service duration	**Average cost[1] (\$/Mcf)**
5 days	5.0
10 days	3.2
30 days	1.3
50 days	0.9
100 days	0.6
130 days	0.5

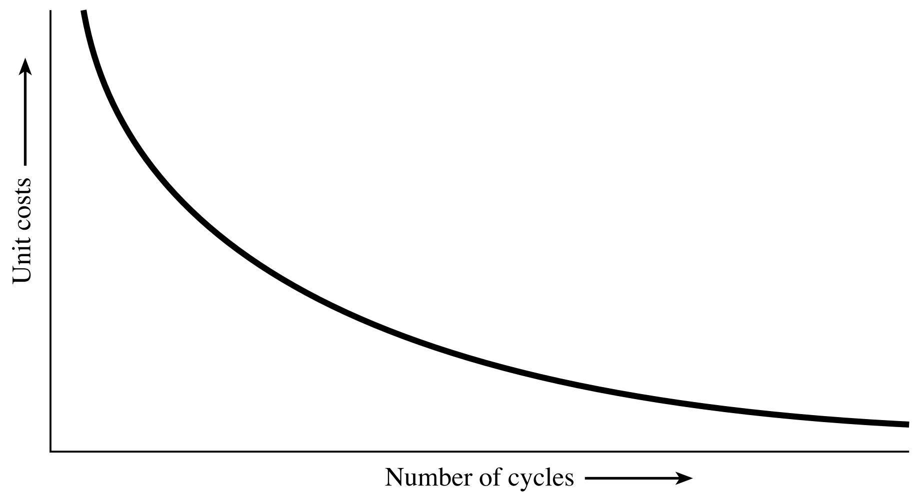
Source: MJMCSL
Note: [1] Indicative prices only

The above figures are based on a 'single cycle' approach to the use of gas storage. This approach, which has been the operational strategy of the traditional incumbent monopoly, is changing as gas-to-gas competition develops and all players are looking to reduce overall costs and also for creative ways to make money. Therefore the concept of cycling storage has developed.

The benefits of cycling gas storage

As mentioned above, with the development of gas-to-gas competition and decreasing margins, many players sought to be more creative in their use of large assets such as gas storage in order to maximise profits. One way in which this has been achieved has been through the increased cycling of gas storage facilities. Under the old regime employed by the traditional incumbent monopoly, gas storage was seen exclusively as the tool of operational staff whose responsibility it was to maintain the security of the gas supply system. Storage was seen as an insurance policy, only to be used in case of an emergency. However, with the development of gas-to-gas competition this has changed, with storage now being seen as an important commercial tool in the hands of the commercial staff of players in the competitive gas market. New storage facilities in the US can typically be cycled up to 10 times per year. Effectively, each time the fixed space and deliverability costs are cycled, the fixed costs are reduced by half, as shown by the following diagram.

Figure 5.1: Storage cycling



Source: MJMCSL

The development of storage cycling has meant that new independent storage providers have been able to gain competitive advantage over the old traditional storage providers, by increasing the number of cycles that the facility can be used for.

The development of market-based rates

A more recent development in the establishing of gas storage tariffs in the US has been the development of market based rates (MBRs) as a result of increasing competition between storage providers. It has been argued that the development of MBRs is to the benefit of all players in the gas industry, since in the absence of regulated rates there are industry savings in terms of time in dealing with the regulator, as well as the market as a whole being the best determinant of gas storage prices.

How can MBRs be justified?

FERC requires that any applicant for MBRs lacks market power in the US market it intends to serve. Therefore a critical factor for the regulator in agreeing to MBRs is its analysis of the market and the position of the applicant within that market. There are two main economic measures of an organisation's market power:

- Market share, and
- Herfindahl-Hirschman Index (HHI)).

Market share

The market share of a storage provider is probably one of the simplest measures of market power, since the overall size of the storage market and the number of providers would be known. However storage providers will often argue that gas storage also has to compete against interruptible customers, seasonal gas supplies and supply-side swing, and that therefore even as the only provider of physical storage there is sufficient competition from alternative sources of gas to justify MBRs. While such arguments rarely win the approval of the regulator, it does not prevent the storage provider from trying.

Traditional economic theory states that any player with market share in excess of 25% has the ability to dominate the market within which it operates. Clearly the exact level at which a storage provider is deemed to be a dominant market player will be determined by the regulator taking into account other circumstances such as potential alternatives to gas storage.

Herfindahl-Hirschman Index (HHI)

Prior to discussing the use of HHI it is useful to define exactly what is meant by HHI.

> 'The HHI for a market is the sum of the squares of each storage provider's market share. For example, if a market has two sellers with market shares of 0.75 and 0.25 respectively, the HHI is computed as follows:
> $(0.75)^2 + (0.25)^2 = 0.6250$
> The lower the HHI, the less market concentration and the greater the likelihood of a competitive market.'

If the HHI is small then the market is not concentrated between a small number of players, customers have plenty of choice, and competition is well developed. Alternatively, if HHI is high competition is limited and MBRs are unlikely to be allowed.

New market entrants, particularly where they are seeking to compete against the traditional monopoly provider of storage, tend to be able to use MBRs, although to a large extent it does rely on the approach of the regulator. Similarly the incumbent monopoly provider of storage, who will almost certainly have the largest market share, is unlikely to be able to have MBRs, on the basis that they might abuse a dominant position.

The development of auctions

Another means of setting storage tariffs is the auctioning of the primary capacity that is held by the incumbent monopoly. At the time of writing this report, one of the most recent examples of the use of auctions to introduce competition is being developed in the UK. It is not the intention of this section to go into the fine detail of the UK auction process, but rather to identify the fundamental principles associated with such an arrangement.

The reason for auctions

There is a strongly held belief that the 'best' regulated markets are those that have been fully exposed to competition and are effectively regulated by the competitive market. It is relatively easy to achieve this in a gas market where the sales function can be unbundled and competition developed. It is, however, more difficult to achieve when the area where it is desirable to introduce competition involves a natural monopoly such as gas transportation or gas storage. Hence the need for regulatory supervision. However, one other way of introducing competition is the auctioning of the storage services provided to a number of different parties. In theory at least, by auctioning the available storage services to a number of different parties a competitive price is paid for the services, and appropriate economic signals are also sent to the market by the secondary capacity trading market that develops.

How does the auction work?

Define the product

First of all it is necessary to define the exact nature of the product being auctioned. For example, the maximum capacity, deliverability, injection and withdrawal rates need to be defined. This may not be as easy as it sounds, since these capacities and rates will often vary, being functions of pressure and volume.

Define the type of auction required

The term 'auction' is a generic one, used to cover all types of different auctions. There are in fact a variety of different auction types that, if used, would send differing economic signals to the market place. For example a 'pay-as-bid' auction would mean that the customer who bid the highest price would be assured of obtaining their capacity, and the storage provider would achieve a high price, but not all the storage services might be sold. It might also be possible to use an auction to allocate volume but to charge customers on the basis of a clearing price. Whatever the final structure of the auction, the economic impact of the chosen auction needs to be clearly understood.

Minimise the opportunities for dominance

One of the main fears of potential participants in competitive storage auctions is that the larger player, or the old incumbent monopoly, will be able to purchase such large quantities of storage that they will be able to manipulate both the primary auction and the development of the secondary market. It is ironic that often the original incumbent monopoly also feels exposed for the same reason. Ofgas, the UK regulator, has chosen to handle these concerns by limiting the availability of storage via the primary auction to 20%. This has the positive effect of limiting the market power of any one individual to 20% in the primary auction. If a large player requires more than 20%, they will need to go on to purchase this extra capacity in the secondary market. Not surprisingly, some large players might feel somewhat exposed under these arrangements as they will effectively be a distress buyer.

Avoiding hoarding

Another concern raised by some players in relation to auction is that the larger player may choose to hoard capacity, which could have two main effects. Firstly, those players who actually need the capacity to ensure an appropriate supply/demand match may not purchase adequate levels of storage and therefore incur security of supply problems. Secondly, by making storage a scarce resource the price of storage in the secondary market could rise considerably.

One of the main tools for minimising the impact of hoarding is the concept of 'Use-it-or-lose-it' (UIOLI). The basic principle behind UIOLI is exactly as the name indicates, in that spare storage that is not being used may be accessed in some way by other players on a daily firm rate or daily interruptible rate. The actual structure of the terms of UIOLI will vary from contract to contract, but the basic objective is to provide a disincentive for any player to hoard storage capacity since if they do they will lose it later anyway.

The provision of other services

Clearly, in a situation where a storage provider has auctioned all their capacity, their main task is to ensure that the storage facilities are adequately maintained and operated. However, commercial life is rarely that simple. For example, if not all the storage capacity has been sold in the primary auction, what does the storage provider do with the remaining capacity? If the storage provider is allowed to sell any spare capacity, what price is it sold at, and what type of service should it offer?

The answer to these questions will vary from country to country, and location to location. Nevertheless the primary objective must not be forgotten, which is to introduce competitively priced storage charges into a market previously dominated by a monopoly.

Chapter Six:

STORAGE PROJECTS

Introduction

This chapter is designed to provide an overview of the development of storage with particular reference to new projects in Europe. This will include an analysis of the background to the development of storage by the European Community, with an overview of the major projects taking place throughout the region. Following these brief descriptions four specific projects will be examined in more detail. These projects are currently at various stages of development and will be considered with regard to the project parameters, the operational need for the project, the commercial need for the project, and any problems associated with planning and completion.

Storage and the European Community

Article 129C of the treaty of the European Community has established guidelines on Trans-European Networks (TENS) which include the identification of projects of common interest. Underground storage facilities for natural gas, and facilities for the reception, storage and regasification of liquefied natural gas (LNG) are both identified as part of the main transportation infrastructure for natural gas.

The objectives of Energy TENS are:

- To contribute to the effective operation of an internal market in general, and an internal energy market in particular;
- To strengthen economic and social cohesion by reducing isolation of less favoured regions;
- To reinforce security in energy supply.

The priorities for Energy TENS include increasing both transportation and storage capacity for LNG and also underground storage capacity. Projects are of interest to the European Community if they correspond to the objectives and priorities of Energy TENS while also displaying potential economic viability. Inclusion is without prejudice to environmental impact. The European Community will promote technical co-operation as well as co-operation between member states, and ease authorisation procedures to reduce delays. With a TENS policy budget of 112 MECU, they will also provide financial support.

The criteria for approval of a project include:

- Degree of contribution to objectives and priorities;
- Economics: the project is both viable and potentially profitable;
- Maturity of the project;
- That Community support will have a stimulative effect;
- The soundness of the financial package;
- The socio-economic effects;
- The environmental consequences.

A summary of the main gas storage projects in the European Natural Gas network

These projects are divided into two areas:

- Storage projects of common interest, and
- Gas storage projects with external dimensions.

Storage projects of common interest

This group of projects is further sub-divided into two areas:

- Introduction of gas to new areas, and
- Increasing reception and storage capacity as necessary to satisfy demand.

Introduction of gas to new areas

Spain: As part of the setting up of gas networks in the regions of Galicia, Extremadura, Andalusia, Valencia South and Murcia, the LNG terminal at Huelva has been extended, with extensions to the terminal at Cartagena due for completion in 1999. The new terminal previously proposed at Galicia has been postponed.

Portugal: An LNG terminal is to be constructed on the Atlantic Coast.

Greece: As part of the setting up of a gas network in the country, an LNG terminal with storage facilities has been constructed in Revithoussa. Further underground storage, together with an LNG terminal for the island of Crete, are at the study stage.

Increasing reception and storage capacity as necessary to satisfy demand

Ireland: Development of natural gas storage facilities to supply the Irish network at Kinsale Head is at the study stage, with commissioning anticipated by the year 2000.

France: Extending the capacity of an existing LNG terminal at Lussagnet in Western France is currently at the study stage. There are also plans to extend underground storage capacities in the south-west of the country.

Italy: Construction of a new LNG terminal is under consideration, to allow diversification of supplies, particularly for power generation.

Spain: Development of underground storage capacities on the country’s north-south axis is being studied, in the following regions: Cantabria, Aragon, Castilla y León, Castilla La Mancha, and Andalusia. Commissioning of the projects is anticipated throughout the years up until 2005.

Development of underground storage capacities on the country’s Mediterranean axis is also being studied, in the areas of Catalonia, C.A. Valencia and Murcia. Commissioning would again be anticipated in the years leading up to 2005.

Portugal: Construction of an underground storage facility in the area of Monte Redondo is at the feasibility stage, with anticipated commissioning in the year 2000.

Belgium: Extending underground storage capacity at Loenhout in Northern Belgium has commenced, and will be completed in stages. Completion is expected to take until the year 2000.

Denmark: Extending underground storage capacity by increasing the capacity on the existing site at Stenlilleis is at the study stage. Also at the study stage is the possibility of creating new underground storage capacity at Toender, near the frontier with Germany.

Austria: Work on extending underground storage capacity by increasing the capacity on the existing site at Puchkirchen is due to be commissioned in 1999. Creating new underground storage capacity at Baumgarten is at the study stage.

Gas storage projects with external dimensions

Austria - Slovakia

Connection of Austria to underground storage in Slovakia.

Case studies on storage projects

The role and function of storage within Europe is changing, as can be seen clearly through the new projects.

The case study section of this chapter will look at four projects, three of which are in the UK and one in the Netherlands. These projects are:

- The development by Intergen of new salt caverns in East Yorkshire;
- The conversion by Scottish Power and Edinburgh Oil and Gas of an existing but depleted onshore gas field in South Yorkshire;
- The development by Utilicorp UK and Stavely of new salt caverns in Cheshire;
- The conversion by BP Amoco and its partners of an existing but depleted onshore gas field in the Western Netherlands.

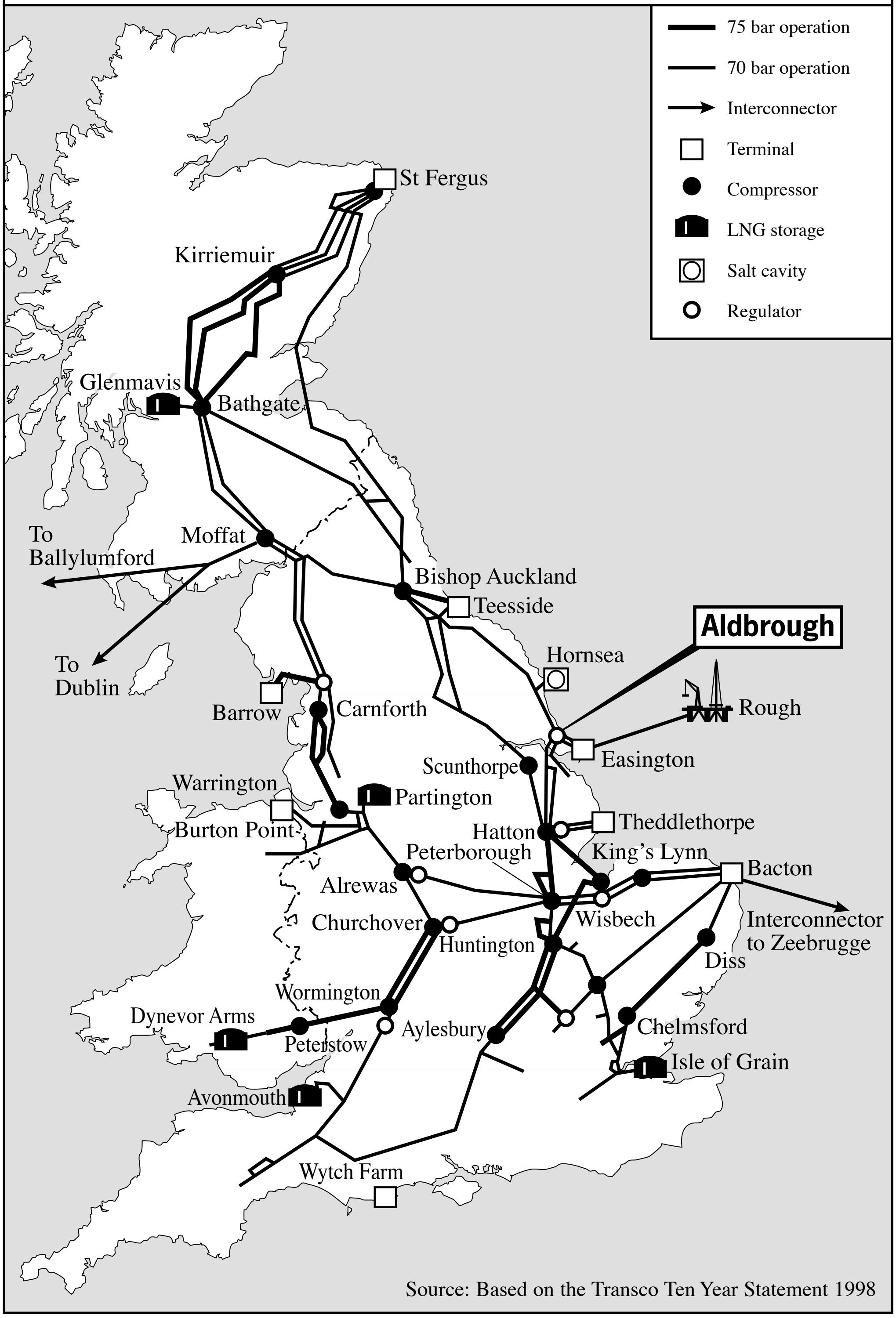
Case 1: The development by Intergen of new salt caverns in East Yorkshire

The project is to create three new salt caverns which will result in a total storage space of 170 Mcm, and above-ground facilities to provide a delivery capacity of 17 Mcm/d, with an injection rate of 2.8 Mcm/d. When complete the site will employ 12 full-time workers, and occupy a site of 3.5 hectares. Intergen anticipate a working life of 50 years for the facility.

During the decision-making process before work commenced, Intergen considered various types of storage. Conventional gas holders and linepack are used for diurnal storage, and depleted fields provide seasonal storage. LNG plants are expensive to build, expensive to operate, and have a limited cycle, taking long periods to refill (from six to seven months). Salt cavity was perceived as being the key to meeting peak seasonal demand. This is supported by the demand for the Hornsea salt cavity, which is over-subscribed and with a price increase of 50% for 1998 over the 1997 prices.

Due to the geological requirements of salt cavity storage it is not feasible to locate salt cavity storage adjacent to demand centres within the UK. Intergen considered five or six locations, but finally selected Aldbrough in the East Riding of Yorkshire, as it is located at the edge of the Zechstein salt formation. This salt formation runs from the UK under the North Sea to Poland, and several salt cavern storage systems are already located within the same bed across Northern Europe. The nearest of these is Hornsea, on the shore of the East Coast of England, operated by BG Storage. The salt layer is

Figure 6.1: UK National Transmission System – Aldbrough



Source: Based on the Transco Ten Year Statement 1998

500 to 600 metres thick, lies approximately 1,500 metres below ground level, and is said to be perfect for salt cavern storage.

The site is approximately 5 km from the National Transmission System, with an adequate power supply close by. This is essential as, due to the depth of the cavern, some compression will be required to inject the gas into the cavity, although none will be required to withdraw the gas.

The proximity of the North Sea (approximately 1 km) makes the project ideal for solution mining. Sea water will be used for mining, with the brine being returned to the North Sea. Drilling, subject to planning permission, is anticipated to commence in the first quarter of 1999, with a project completion date some 32 months later. Commercial operation is therefore expected to commence in 2001.

Intergen intends to fully finance the project. Discussion with lenders has indicated a keenness to ensure that risks are allocated to parties who can best control or mitigate them. The technical risks, for example, are mitigated by the fixed price turnkey contract to build the facility. The contract is time-bound, with liquidated damages relating to capacity and budget. Intergen is also using expertise from 'within the family', and have spent a number of years looking at the project.

Operational need for the project

Shippers need to match a variable demand with a variable supply, the demand in the UK being mainly a function of weather and temperature. Intergen see the gas bubble (i.e. the surplus of supply over demand) slowly disappearing over the next few years and being replaced with a shortfall in supply. This will be met by new production and, possibly, supplies via the Interconnector. However, any new production will take place further to the north in the North Sea at an increased depth and cost. These new fields will not deliver the same degree of swing, and contracts for these new fields will reduce swing from the current figure of 130% - 165% down to 110% - 120%. This will therefore increase the storage requirement within the UK.

The industry is making increasing demands for competition in storage. Ofgas, the national gas industry regulator, has a duty to promote competition in storage, and is supported in this role both by the Department of Trade and Industry and also the Gas Consumer Council. Transco's Network Code is currently proceeding through a process of modification in order to allow competition in storage to take place on a level playing field. A storage workstream is spearheading this process.

The 1995 modifications to the Gas Act introduced the concept of supplier daily balancing, and there is an increasing demand for flexibility. There is only a limited ability to increase interruptibility, whereas a four-fold increase in interruptibility would be needed to match demand swing. Also, due to the series of mild winters in recent years, interruptible customers have become complacent, assuming that interruption will not be required. In fact interruptible customers had come to believe that interruptible gas was just firm gas but cheaper! Within day matching has traditionally been met from linepack, but this is not an adequate answer to the situation.

The flexibility mechanism (or its replacement) offers opportunities for storage providers offering a flexible approach, and therefore storage is a key tool in the market.

Intergen plan to offer a variety of services of varying periods (5,10,15 and 30 days), and the design of the facility allows for rapid injection. Demand for the facility is keen, with 70% of the storage capacity already under long-term contract, and the remaining space expected to be committed by the first quarter of 1999. There is a competitive pricing structure, but as there are no established benchmarks for the pricing of long-term contracts there is a certain amount of scope within the contracts for adjustment over a period of time.

Commercial need for the project

Intergen consider themselves as a global developer of energy-related projects: power generation, pipeline operation, and gas storage. They also wish to be the leader in provision of competition to BG Storage. Potential sources of competition to this aim are those already existing sources (BG Storage, producer swing, the flexibility mechanism, and interruptible contracts) and new sources such as three other storage developments in the UK and swaps via the Interconnector.

Intergen see their customers (producers, marketers, suppliers etc.) as being right across the supply chain and who will use the storage service for different needs within their own portfolios. The project is large-scale, with competitive pricing. Intergen are prepared to make a long-term commitment to their customers, and extend the contracts as required.

Major barriers to the project

At the time of writing this report, Intergen were involved in the highly complex planning procedure, which appears to be the major barrier to the project. Preparation and filing of the permit submissions, response to queries, research, and legal fees all add to the costs of the project. There are a wide variety of permits and licences required at both local and national level, as described below:

- Local authority: exploration works, solution mining, ancillary developments, hazardous substances consent, above ground installations;
- Environment Agency: Integrated Pollution Control Authorisation/Brine discharge (IPC);
- Ministry of Agriculture and Fisheries: solids discharge;
- Department of Transport: Navigation consent;
- Department of Trade and Industry: Pipeline Construction Authorisation.

Of these, Intergen have already obtained the Brine discharge licence (IPC).

Planning consent is needed from the local authority, which was created by reorganisation some two years ago. Following this reorganisation, planning policies were revised to protect both the rural environment and the coastline from development, although this local plan takes into account the unique salt formation and the fact that Hornsea has been in existence for some 20 years. The local plan therefore allowed for the development of further salt cavities provided that the developments were environmentally sound, did not have an adverse impact on traffic or lifestyle, and were not associated with any large-scale industrial development. A further requirement, however, was that any development should be deemed to be essential to the national interest.

The original planning application was submitted to the Local Authority in August 1997. Protest was made by a local pressure group on the grounds of creeping industrialisation, traffic noise and visual intrusion, and the application was rejected in January 1998. Following this rejection, Intergen submitted a new application, which detailed the need for the project, while also appealing to the Department of the Environment, Transport and Regions (which has the ability to overturn local decisions) against the rejection of the original application. Intergen also embarked on an extensive public relations campaign but, despite this, the revised planning application was rejected in November 1998.

CASE 2: The conversion by Scottish Power and Edinburgh Oil and Gas of an existing but depleted onshore gas field in South Yorkshire

Hatfield Moors is located between Doncaster and Scunthorpe on the South Yorkshire/Lincolnshire border. The projected Hatfield Moors underground reservoir will be able to store enough gas to support almost 500,000 households, allowing approximately 4.1 Bcf of gas to be stored and then released as and when required.

The site is not currently connected to the National Transmission System, all gas that was previously extracted being transported via the local transmission system. Gas processing equipment using compression will inject gas into and withdraw gas from the field, and ensure that it conforms to the specification required by BG Transco. A 13 km pipeline will connect the site to the NTS (see Figure 6.2).

The project is subject to feasibility studies currently underway, and it is anticipated that the facility will be operational by the end of 1999. Scottish Power has signed an initial agreement with Edinburgh Oil and Gas (EOG), the owners and operators of the field.

Operational need for the project

EOG has extracted gas from the Hatfield Moors onshore field for the past 13 years. The reservoir is now reaching the end of its commercial life as a production field, and it is therefore intended to convert the gas field into a giant storage facility. In many respects the development of depleted onshore gas fields into storage facilities is an ideal extension of their use. With much of the processing and infrastructure facilities already being in place the costs tend to be lower than developing salt cavity facilities. However the development of onshore fields as a storage facility does have some limitations. For example, traditionally small onshore gas fields such as Hatfield Moors tend to have relatively slow injection and withdrawal rates. Such operational characteristics can limit the number of cycles that the facility can operate within any given year. It is possible to increase these injection and withdrawal rates by either drilling new wells (which is very expensive) or by increasing the capacity of existing wells (which is less expensive) through a process known as 'well fracture' which effectively cracks the geological infrastructure in the vicinity of the well and increases flow rates. (N.B. At the time of writing this report Scottish Power were unable to divulge detailed technical information on Hatfield Moors due to the commercial sensitivity of the information.)

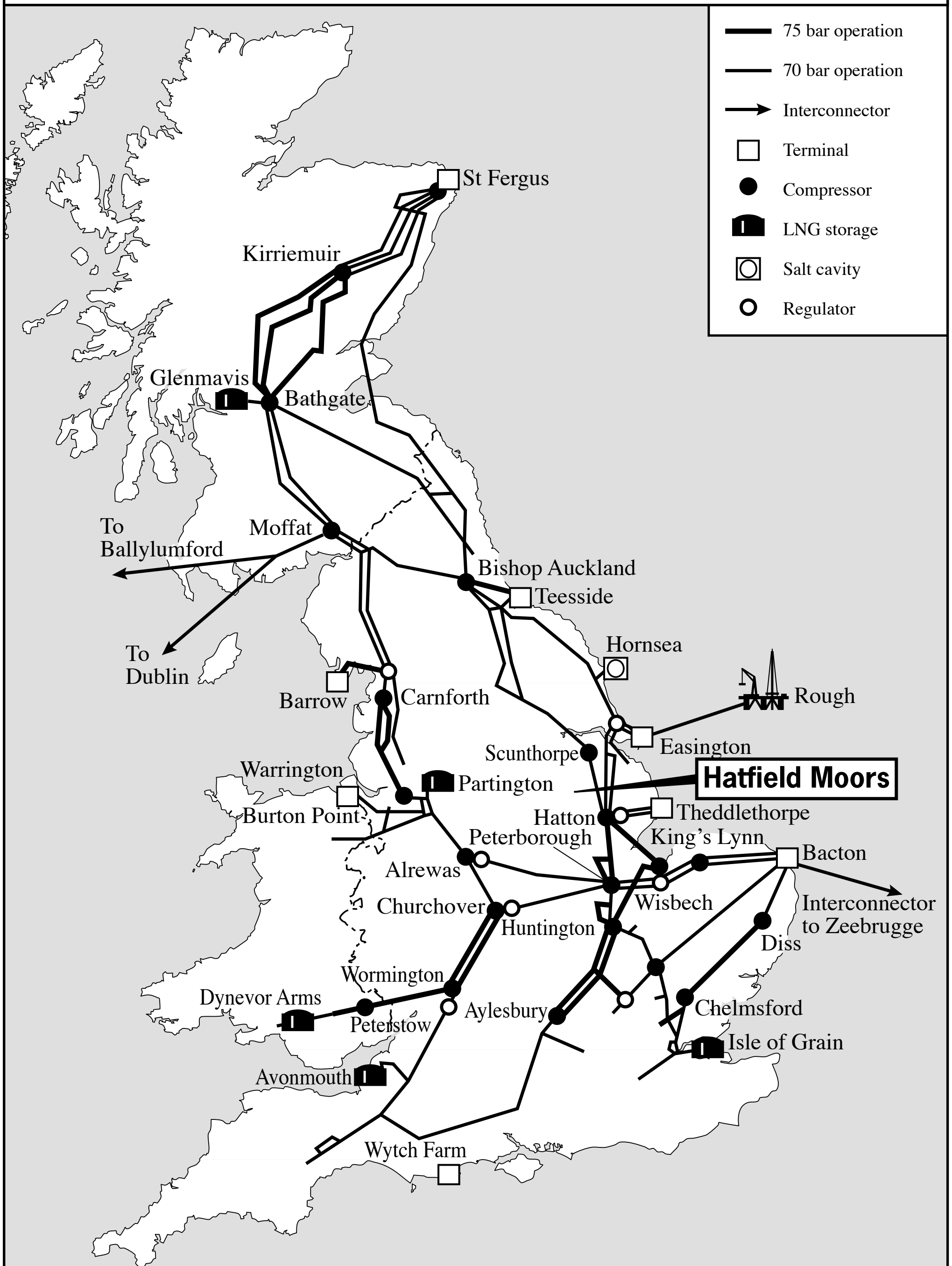
Commercial need for the project

For EOG, the prospect of extending the life of Hatfield Moor obviously enhances the value of the field. Scottish Power are a major user of gas for power generation, as well as a supplier of gas. The use of a storage facility will enable Scottish Power to manage both seasonal and daily swings in demand to best competitive advantage. Scottish Power are a significant player in both the electricity and gas business throughout the UK. In particular Scottish Power are developing their market power in the domestic gas and electricity markets. One of the significant operational characteristics of the domestic gas market is its sensitivity to temperature, with a swing of some 285%. Consequently the development of an onshore field such as Hatfield Moors into a depleted field storage facility is a strategic as well as commercial and operational addition to Scottish Power's portfolio of gas contracts.

Major barriers to the project

Although there are a number of planning hurdles to be overcome, especially with regard to the requirement to build a 13 km pipeline, as the facility has operated as a production field for a number of years the planning process is very much less complex than that for the Aldbrough project already described.

Figure 6.2: UK National Transmission System – Hatfield Moor



Source: Based on the Transco Ten Year Statement 1998

CASE 3: The Development by Utilicorp UK and Stavely of new salt caverns in Cheshire

The project is for the construction and operation of up to four storage cavities at Hole House Farm in Cheshire. Each cavity is designed to hold up to 150 million kWh of gas, with a peak deliverability (dependent on operational conditions) that could be as high as 30 million kWh per day. Hole House Farm is located at Minshull Vernon, south of Winsford on the Cheshire Plain, an area famous for salt extraction. The storage facility will be connected to the NTS to the north of Minshull Vernon, and will require some compression to inject gas into the salt cavities.

Drilling for the new cavities commenced in the summer of 1997, and it is expected that the storage facility will be fully operational in the gas year commencing October 1999. The necessary infrastructure is in the process of being installed, and environmental work at the site has been completed.

The partners in the project are Stavely Industries plc (Stavely) and United Gas, UtiliCorp United Inc's UK operation. United Gas will cover the full costs of the project, including the estimated £20 million cost of developing the cavities, while Stavely, through its subsidiary British Stasal, brings to the project almost 30 years of experience in the creation and operation of salt cavities in Cheshire for the purpose of salt extraction. United Gas is one of the UK's leading independent natural gas transportation management and trading companies, with an annual turnover in excess of £120 million, while Stavely has an annual turnover of some £400 million through its interests in technical services and salt.

Operational need for the project

The location of the site in the North West of the UK is important, in that it is in an area of high gas demand at a considerable distance from the principal entry points. Burton Point, the nearest terminal, is classified as both an entry point and an exit point from the system, as generally the terminal only provides gas for an adjacent power station. When insufficient gas is provided from this terminal, the power station uses gas from the NTS.

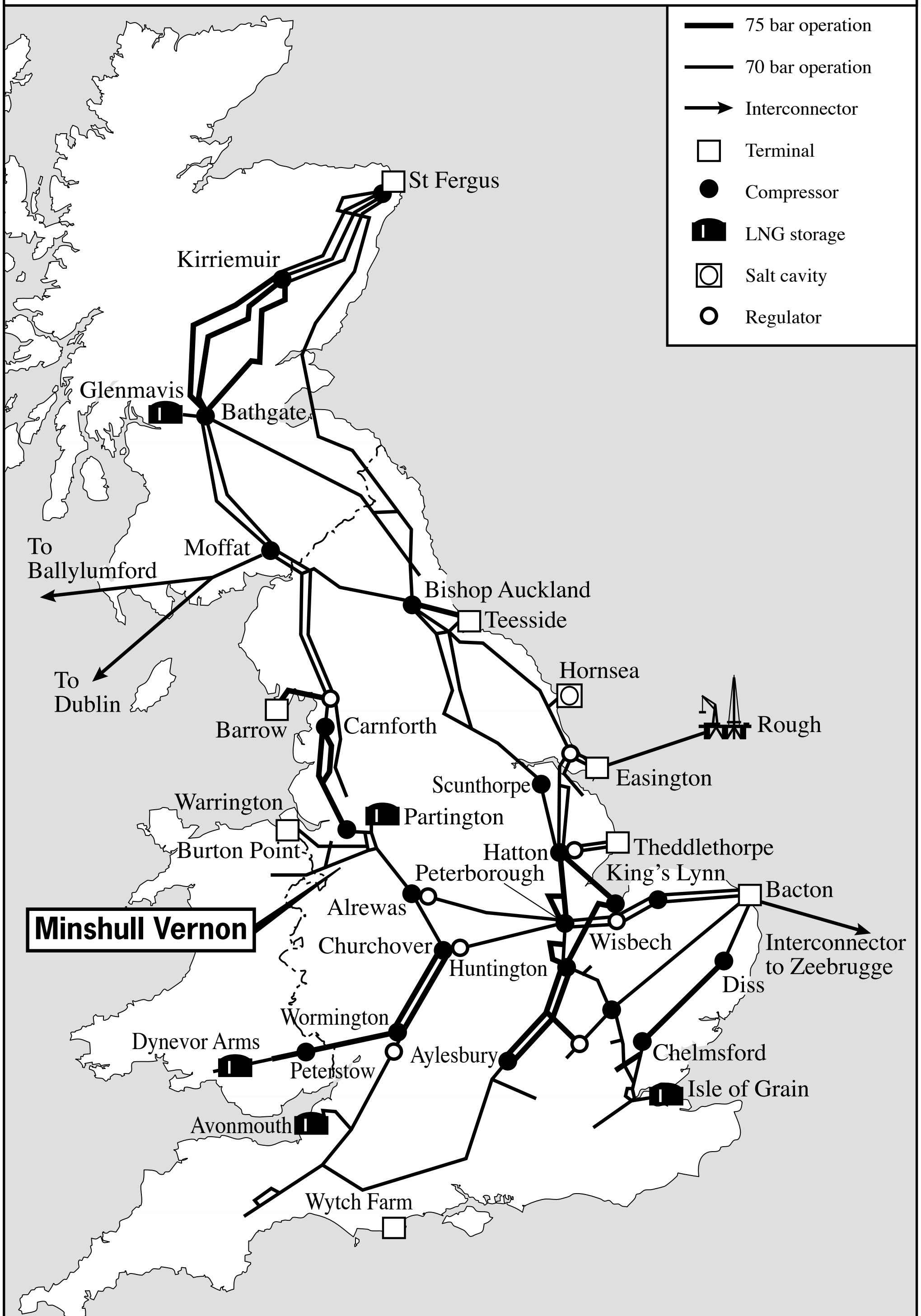
Commercial need for the project

The investment is directly linked to the UK growth strategy of United Gas. The development of an independent gas storage capability represents to United Gas an important step forward in the ability to be competitive in the UK storage market.

The agreement between United and Stavely, covering the construction and operation of the projected four storage cavities, gives Stavely an annual management fee for the three-year development stage of the first two cavities, and an index-linked annual rental once the storage becomes fully operational. In addition, Stavely will also benefit from receiving the brine from the new cavities, extending the life of the existing brine field operation and reflecting the company's strategic aim to exploit their salt deposit assets more fully.

Stavely and United Gas combined together in a joint venture to obtain the necessary regulatory and planning approvals for the storage project, and have now signed an agreement covering their commercial relationship for the full development of the storage site.

Figure 6.3: UK National Transmission System – Minshull Vernon



Source: Based on the Transco Ten Year Statement 1998

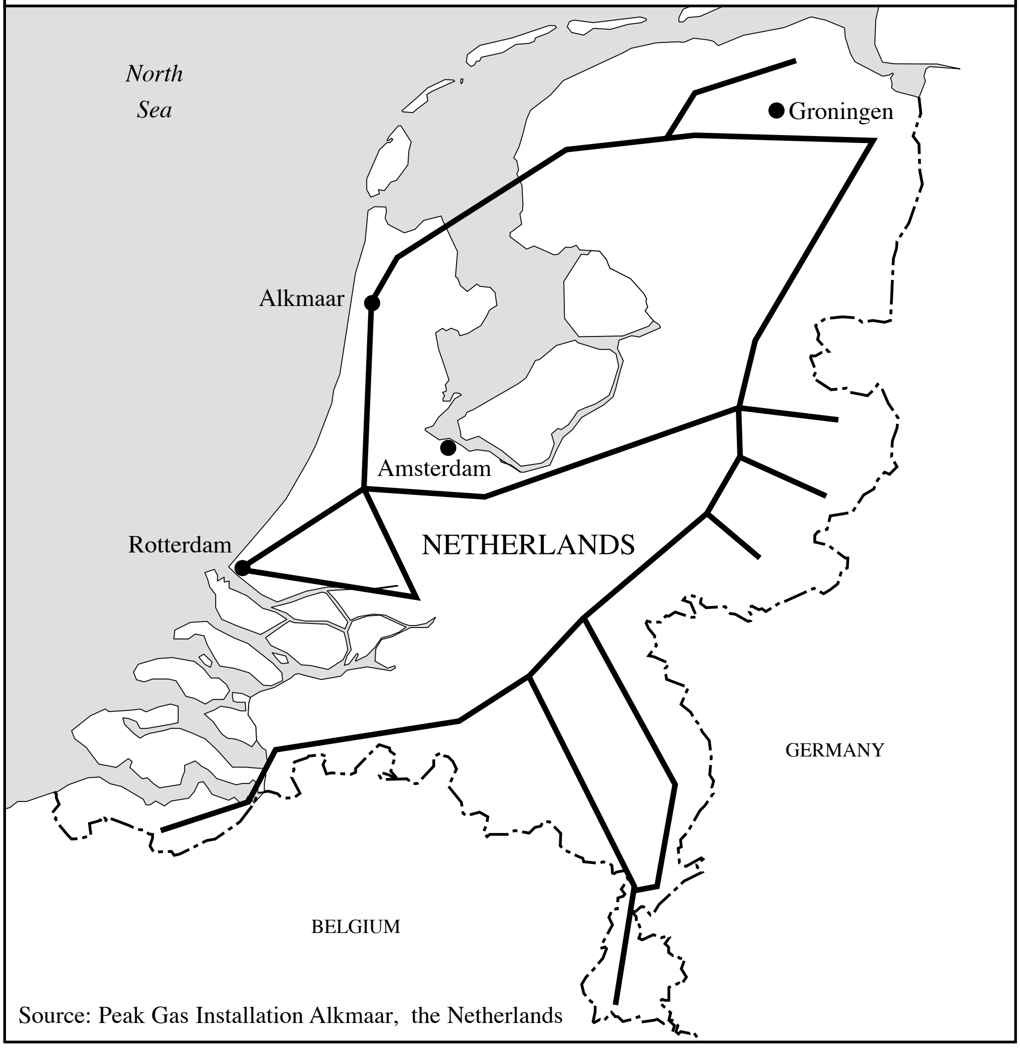
CASE 4: The conversion by BP Amoco and its partners of an existing but depleted onshore gas field in the Western Netherlands

The BP Amoco Peak Gas Installation Project (PGI) is one of the first underground gas storage projects to be built in the Netherlands, and the first in the western part of the country. The first phase was officially opened on 10 December 1997. BP Amoco also intends to expand the PGI. The Dutch authorities have granted all necessary licences.

The first phase involved the repressurisation of the depleted Alkmaar gas field by injecting gas owned by Gasunie and NAM. In order to achieve the capacity requirement, six new wells have been drilled in the field. Construction work started in July 1995, and the first gas was injected on 25 October 1996.

The site is located just outside the city of Alkmaar, in the industrial area of Boekelermeer.

Figure 6.4: Netherlands transmission system



Source: Peak Gas Installation Alkmaar, the Netherlands

The fact that this was an existing gas field located in an industrial area made planning consents relatively easy to achieve, although a number of key environmental issues had to be considered:

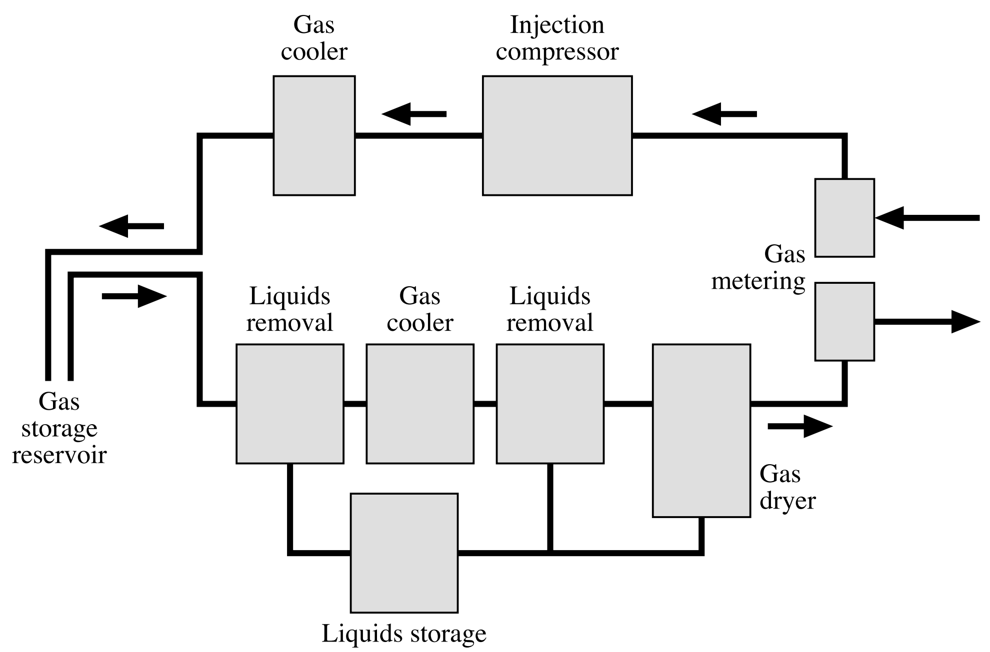
- The application of a high pressure protection system to prevent the emission of large quantities of gas to the atmosphere;
- The use of vapour recovery units on the storage tanks;
- Extensive noise abatement and insulation to meet strict noise regulations;
- Designing the drilling sites so that all drilling fluids were contained, ensuring that there was no environmental impact;
- The use of a liquid collection system for containing any spillage from routine maintenance;
- The use of a groundwater monitoring system.

The facility can currently provide a maximum capacity of 12 Mcmd, although when the reserves reach their original pressure the field will be capable of producing 24 Mcmd, with an annual working capacity of 250 Mcm. The expansion plan comprises the drilling of additional wells to give an increased capacity of 36 Mcmd. The site has been designed so that operations can commence within 75 minutes of a request for gas being made.

The feed gas injection rate is a maximum of 7 Mcmd, and by 15 January 1997 some 500 Mcm had been injected, rising to some 1.8 Bcm by mid-September 1997. Injection will continue until a further 1.4 Bcm has been added to fill the reservoir, at some time during 1999.

The existing Alkmaar reservoir is composed of porous rock some 2,000 metres underground. Although almost depleted, the site has the advantage of being already connected to the natural gas transmission system. The gas to be injected into the system is measured and compressed before being injected. When gas is required to be removed from storage it is recovered and processed at a gas treatment unit, ensuring that the gas is at the correct pressure, temperature and specification before being returned into the pipeline system.

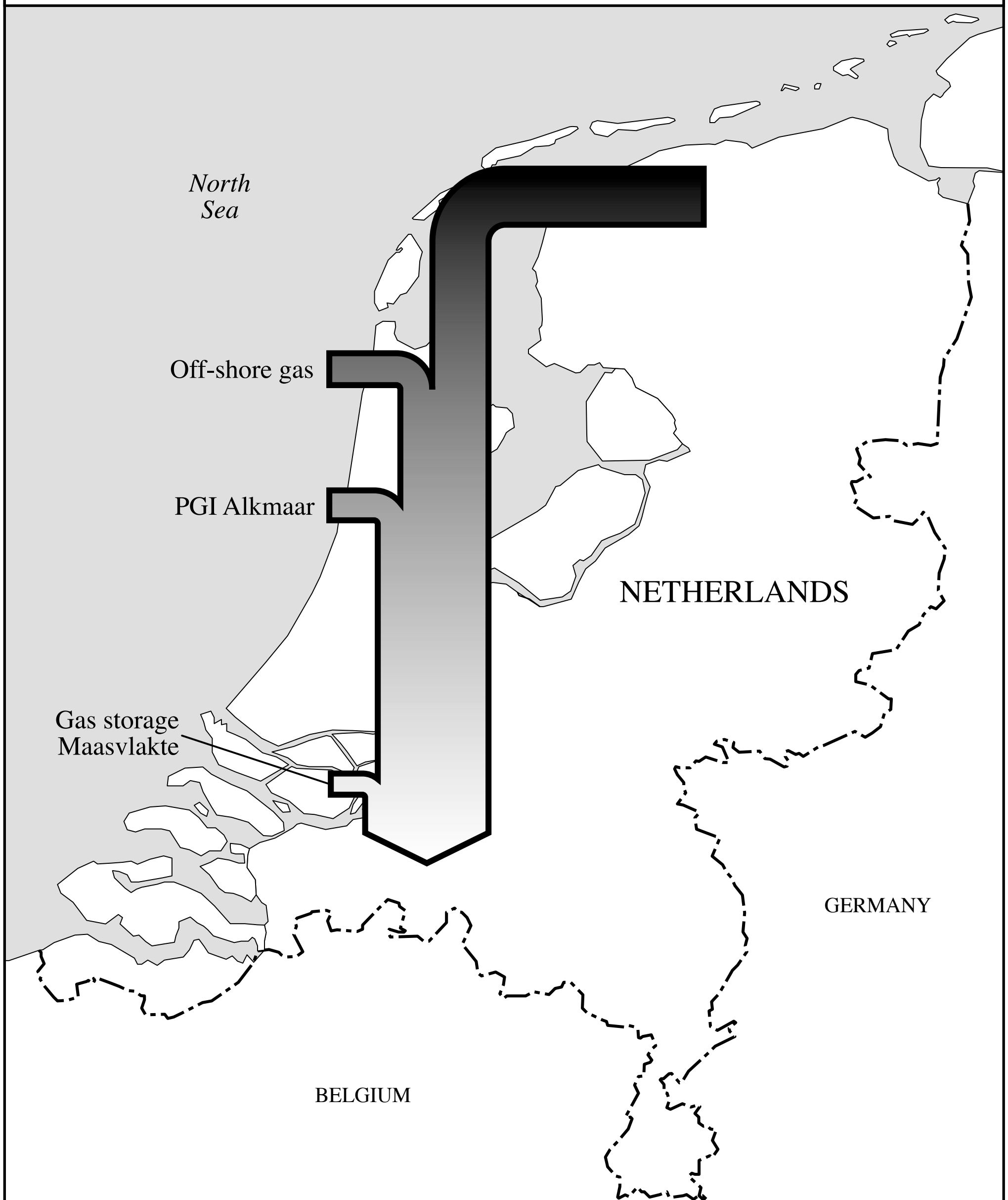
Figure 6.5: Gas treatment unit



Source: Peak Gas Installation Alkmaar, the Netherlands

The process of removing the gas from storage reduces the gas pressure from 200 bar to 75 bar. This produces a drop in temperature from 80°C to 40°C, and this results in the formation of water and other liquids which need to be separated from the gas. The gas is then dried and ‘scrubbed’ in silica gel columns, after which it is supplied to the pipeline system at a pressure of approximately 60 bar.

Figure 6.6: Flow of gas to western Netherlands



Source: Peak Gas Installation Alkmaar, the Netherlands

The cost of the project is in the order of some $191 million, with the funding being provided by BP Amoco and its partners in the project Dyas B.V., Veba Oil Nederland B.V., and Energie Beheer Nederland B.V.

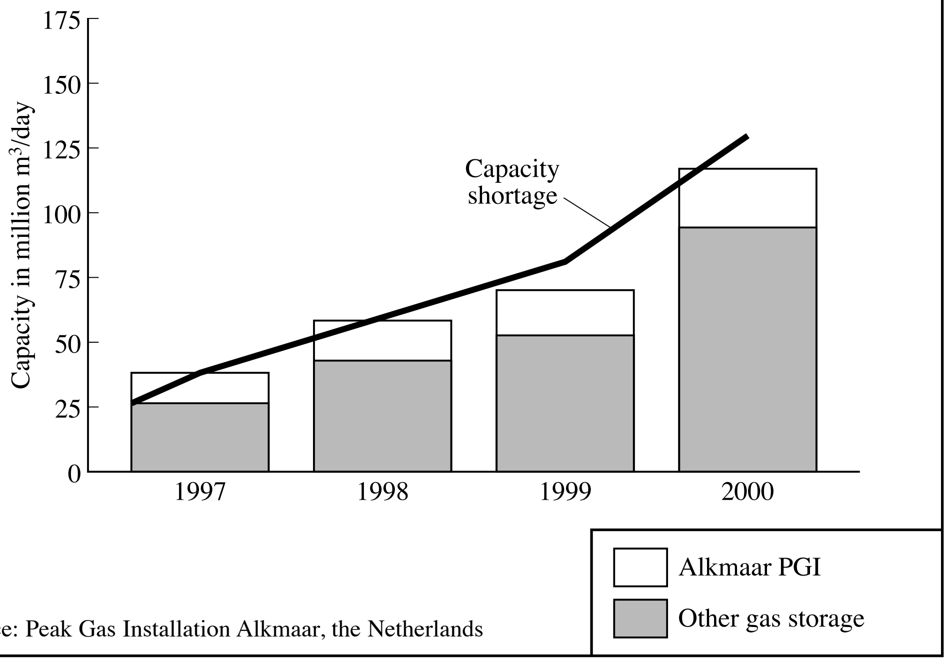
Operational need for the project

The Alkmaar gas field was chosen for this project as it was previously operated by

BP Amoco. Its size, proximity to the Gasunie pipeline and its geographical location near the gas market of the Western Netherlands were other major contributing factors to the decision to use this field.

The objective of the project is to allow Gasunie to meet demands during the winter in this area of the Netherlands.

Figure 6.7: PGI Alkmaar capacity contribution



Source: Peak Gas Installation Alkmaar, the Netherlands

Commercial need for the project

The project makes a significant contribution to BP Amoco's business plan in several ways, and is part of the company's European and wider strategy of capturing opportunities across the gas value chain. It also makes a significant impact on both operating cash flow and present value performance. Unlike traditional exploration and production ventures, the storage project does not decline over time. Investment risk is therefore reduced, and the site remains a key part of the BP Amoco operations in the Netherlands.

Chapter Seven:

STORAGE IN THE UK

Introduction

The purpose of this chapter is to describe the storage market in the UK, its operators, and the future changes planned by Ofgas. Storage of gas in the UK is divided into two categories, 'Diurnal storage' and 'Seasonal storage'.

Diurnal storage enables gas to be delivered into a system over a 24-hour period, and is not covered further here. Seasonal gas storage was traditionally used to reduce and even out the field demand in periods of high usage, and to put gas back into stock during periods of low demand. The increased usage of the gas supply system, and the increased commercialisation of the gas industry has created a demand for a more flexible seasonal storage system.

At the time of writing this report, the UK gas industry as a whole was involved in discussions over the introduction of storage auctions for seasonal storage. On 22 February 1999 the arrangements were finalised in a landmark agreement, with the introduction of auctions scheduled for the new gas storage year commencing 1 May 1999. The ensuing competition is expected to lead to lower gas prices in the winter as storing gas becomes cheaper. This chapter will examine how this situation arose, and therefore the areas covered in the chapter will include the following:

- Industry structure and ownership;
- Peak capacity and swing requirements;
- Overview of BG Storage;
- Regulation;
- Future arrangements for BG Storage.

Industry structure and ownership

The UK market

Since the introduction of the Network Code in 1996 the role of gas storage in the UK gas market has changed considerably. In order to understand these changes it is helpful to look at the history of storage and the way in which it has developed in the past.

Early gas field development in the Southern Basin of the North Sea indicated that if gas were to be extracted at excessive rates then its life cycle would be reduced. The original contracts for the supply of natural gas to the integrated British Gas reflected this, and included additional charges to compensate for excessive demand. British Gas therefore initially developed the interruptible gas market to assist in reducing peak demands. This reduction was enhanced by the construction of seasonal storage facilities. These storage facilities also had the benefit of increasing demand in the summer period.

In response to increasing commercial pressures and to privatisation, the gas business was refocused. Interruptible marketing concentrated on taking market share from heavy fuel oil. This resulted in increasing commodity throughput, exerting greater pressure on the system and storage facilities.

Initially the introduction of competition in the UK in 1990, with either monthly or annual balancing agreements, had little impact on the UK storage market since Transco (then British Gas plc) effectively provided a bundled balancing service, although there was some debate over cost allocation.

The introduction of the Network Code, and the separation and eventual demerger of the gas transportation and gas sales arms of British Gas (into BG plc and Centrica respectively) allowed a radical rethink of the way in which the transportation and storage of gas was operated. The subsequent separation, within BG plc, of transportation and storage into two business units, Transco and BG-Storage, allowed the costs, the role of storage, and the need for storage to be more clearly identified.

The gas supply chain

In order to understand the developing role of gas storage in the UK competitive gas market, it is first of all necessary to understand the structure of the UK gas market, and identify the various players and their roles. The various components of the UK gas chain can be described as follows:

- Gas producers (Mobil, BP, Texaco, BG E&P, Total, etc.);
- Gas transporters (BG Transco, and independent Public Gas Transporters);
- Storage (BG Storage, and independent storage operators);
- Shippers (United, Total Gas Marketing, etc.);
- Suppliers (gas marketing companies [Butler Fuels, Gas West, etc]);
- Consumers (power generation, industrial, commercial, domestic).

As can be seen from the above list, the gas supply chain in the UK is made up of a series of discrete interconnecting links, with increasing competition occurring at each link. The Office of Gas Supply (Ofgas), headed by the Director General of Gas Supply (DGGS), is responsible to the UK government for the development and control of competition in the gas industry. The general duties of the DGGS are set out in Sections 4 and 4A of the Gas Act. The DGGS must exercise his function in a manner that he considers is best calculated to secure that all reasonable demands for gas are met, that licence holders are able to finance their activities, and that there is effective competition in the shipping and supply of gas.

Subject to these primary duties the DGGS also has a duty to exercise his function in the manner considered to be best calculated to protect the interests of consumers, to promote efficiency and economy by licensees, and to secure effective competition in the carrying on of activities which are ancillary to shipping and supply (including storage). In doing so the DGGS has to take into account the effect on the environment of activities connected with the conveyance of gas through pipes. In addition, there are certain activities related to safety.

Gas producers

This is the term given to those organisations who see their main role as exploration for and the production of gas, primarily offshore in the North Sea and, increasingly, west of Shetland. They increasingly have an interest downstream in trading, shipping and marketing gas. Many different oil and gas producers operate on the UK Continental Shelf (UKCS). Most gas producers are subsidiaries or affiliates of oil producers. Producers' main reasons for trading are to sell physical oil or gas, to hedge against price falls, and to maintain an efficient and liquid market. They may also use derivatives to add value to their products by offering fixed prices.

Gas transporters

The main gas transporter in the UK at this time is Transco, one of eight businesses operated by BG plc. BG plc is a licensed Public Gas Transporter under the Gas Act 1995, and Transco manages the UK's national transportation network, which is one of the largest and most advanced in the world. The network contains 267,000 kilometres of gas main, and delivers an average of 200 Mcm of natural gas every day to some 19.5 million homes and businesses. Transco, under the legal and contractual framework of the Network Code agreed in 1996, physically balances the quantities of gas put into and taken out of the system daily, so ensuring the safety and security of the system. In addition, Transco acts as Network Emergency Co-ordinator on behalf of all gas shippers in the UK, and manages the 24-hour gas leak emergency service. Until 1 October 1997 Transco also managed the UK national storage system.

Shippers

Those organisations who buy gas from producers and sell it to end users or to other gas marketing organisations are known as gas shippers. Currently there are approximately 38 shippers operating in the UK natural gas market. Each shipper is licensed under the 1995 Gas Act to input and offtake natural gas from the Transco transportation system. This is predominantly carried out under the Network Code rules, although a certain amount of natural gas is transported under legacy agreements which are covered separately under the same Act. Shippers are commercially responsible for balancing their own supply and demand.

Storage

The main storage operator in the UK is BG Storage, a subsidiary of BG plc. The responsibility of BG Storage is to own and operate all the storage facilities that were previously part of Transco. These include salt cavity, LNG, and depleted field storage facilities. Although several independent companies are developing new facilities, none of these facilities were operational at the time of writing this report.

Gas suppliers

A supplier is an organisation that has a supplier's licence rather than a shipper's licence, and arranges to purchase gas from a shipper and then sells it on to end-users. It is not uncommon for a supplier also to be licensed as a shipper, although it is becoming increasingly common for suppliers not to be shippers.

Peak capacity and swing requirements

The purpose of this section is to examine the supply/demand match from the perspective of peak capacity and swing requirements. Unfortunately little credible work has been published on UK supply/demand other than the Transco 10-year

Statement and Base Plan Assumptions, which is the best information available. It is not the intention of this section to reproduce in detail the work published by Transco but to provide an overview of the key points associated with peak capacity and swing requirements.

Forecast supply and demand

Forecast demand

The 1999 Base Plan describes Transco's demand forecasting methodology. Under this methodology, Transco develops demand models based on the relationship between levels of demand and Composite Weather Variables (CWVs).

The general assumptions currently made by Transco for demand include the following:

- Economic growth in line with historic trends of around 2.5% per annum;
- Moderate inflation averaging around 3%;
- Consumer spending, initially supported by windfall payments before falling back to around 2.5% p.a.;
- No material change in crude oil prices relative to gas prices;
- No extension to the Review of Energy Sources for Power Generation (power station moratorium) beyond the original six months;
- Market prices for gas influenced by gas-on-gas competition and the continuing over-supply situation in the UK; and
- Competitive advantage for gas supplies in comparison with alternative fuels.

Transco bases its annual demand forecasts on a wide range of factors including: historic trends, local intelligence, the nomination of major new supply points by shippers, general economic factors, comparative fuel prices, conservation and environmental measures, potential growth areas, and possible taxation effects. Once the annual demand forecasts and daily demand models have been developed, Transco applies a simulation methodology, using historical weather data for each Local Distribution Zone (LDZ), in order to determine the peak day and severe winter demand estimates.

Annual demand

The amount of gas transported on which Transco can earn income is referred to as Formula Volume, whereas the total gas transported through the system is referred to as Throughput, with the difference being termed Shrinkage. Shrinkage covers gas used for transportation purposes, notably compressor usage. System leakage, theft, and lost energy caused by the difference between the actual calorific value of the gas and that used for billing purposes is also included in Shrinkage.

Throughput is expected to grow by nearly 30% over the ten years from 1998 to 2007. The majority of this growth is attributed to the European Interconnector, exports to Ireland, and the additional gas-fired power stations expected to be commissioned over that period. (NB: With gas flowing at present into the UK from Continental Europe via the Interconnector, this growth figure may well need to be revised.)

Business and Domestic

A favourable economic climate and highly competitive prices have supported strong growth in the business sector over the last few years. Although prices have started to rise in the business sector, probably as shippers endeavour to improve margins, the price differential is large enough for gas to remain competitive and support further growth in the business sector, particularly from Combined Heat and Power (CHP).

Growth in the domestic sector has fallen behind historical rates following the curtailment of mains extension projects. While fuel substitution played an important part in growing the business sector, it is unlikely to have a similar effect in the domestic sector following the liberalisation and convergence of the gas and electricity markets and the formation of 'energy' companies.

Power generation

A key driver in transportation volumes is the 23 gas-fuelled power stations currently connected to Transco's NTS, which consumed 15% of Transco's throughput in 1997. The forecasts assume the commissioning of 16 power stations (of which 13 have government approval) between 1997 and 2002. Power station consumption profiles and load factors are based on an assessment of the share of total power station market met by gas. However, there is uncertainty with respect to power station loads, and a number of issues will limit the impact of these new stations. These issues include:

- The open-ended nature of the gas moratorium under the Review of Energy Sources for Power Generation;
- Increased competition for the gas share of the generating market;
- Higher beach prices for gas.

These factors will result in lower load factors as more stations become less competitive. Nevertheless, the gas share of the generating market in England and Wales is forecast to grow from 30% in 1997 to around 43% by 2002, mainly at the expense of coal.

In 1997 there were five gas-fired power stations with their own pipelines delivering beach gas directly to the power station and thus by-passing Transco's system. These directly-supplied power stations accounted for 35% of total gas power generation demand. However, the directly-supplied share of the overall market is forecast to fall, as nearly all new stations are forecast to be connected to the NTS. An additional risk to Transco is the possibility that existing stations may decide to build their own pipelines in order to by-pass Transco's system, resulting in lost revenue and low system utilisation. However, for the purposes of these forecasts it has been assumed that existing stations will continue to take gas from Transco's system.

The Interconnectors

By October 1998 the NTS was connected to Continental Europe, Northern Ireland, and the Republic of Ireland. It was anticipated that, in the short-term, all three pipelines would export gas, although in fact the UK-Continental Interconnector has recently imported gas from the Continent to the UK. The designed export capacity of the 240 km 40 inch pipeline to Zeebrugge in Belgium is 20 Mcm per annum.

Exports to both Northern Ireland and the Irish Republic are expected to grow significantly over the forecast period as industrial and power station loads switch to gas, and Ireland's supply from Kinsale Head gas field depletes. In 1996 the gas share of primary energy consumption in the Irish Republic was 20%, compared to 36% in the UK.

The European Interconnector dominates planned growth in demand for gas from the UKCS. However, the annual demand forecasts assume a by-pass of the NTS at Bacton from October 1999 onwards, based on feedback from the Base Plan consultation process. Initially this by-pass will be 50%, growing to 70% once gas is landed in October 2000 from the Shearwater/Elgin Area Pipeline (SEAL). As Transco has committed to providing peak capacity for the Interconnector consequent to an advanced reservation of capacity process, this by-pass is not assumed to occur in peak conditions.

In spite of this, Transco forecasts that it will still need to incur the same capital costs to reinforce the system in order to bring gas south from St Fergus to replace Bacton supplies which would be diverted directly into the Interconnector.

Table 7.1a: Interconnector Annual Flows in relation to total UK demand (TWh)

	1997	1998	1999	2000	2001	2002
Total NTS flows	882	918	980	1,020	1,052	1,080
of which Moffat	22	30	35	40	45	48
of which Bacton	0	11	41	33	40	40
Interconnector flows as a percentage of NTS flows	2%	4%	8%	7%	8%	8%

Source: Transco Transportation Ten Year Statement 1998
Note: Figures for the Bacton demand are based on Transco's central case. This assumes that initially half of the annual demand for the Interconnector by-passes the NTS. Transco assumes that this by-pass will eventually represent some 70% of annual Bacton Interconnector demand.

Table 7.1b: Interconnector flows in relation to total UK peak demand (GWh/d)

	1997/98	1998/99	1999/2000	2000/01	2001/02	2002/03
Total NTS flows	4,872	5,262	5,556	5,939	6,195	6,284
of which Moffat	133	156	178	199	222	227
of which Bacton	0	250	300	420	490	500
Interconnector flows as a percentage of NTS flows	3%	8%	9%	10%	11%	12%

Source: Transco Transportation Ten Year Statement 1998
Note: At peak demand, all Bacton Interconnector demand is assumed to flow through Transco's network.

The demand forecasts include exports through the UK-Continental Interconnector. Deliveries via the SEAL pipeline to Bacton from 2000 onwards have been aggregated with other Bacton supplies. However, in order match to the Bacton by-pass expected from 1999, the reported annual supplies to Bacton have been reduced, starting with SEAL and then on a pro-rata basis. Any change to the demand forecasts for the Interconnector affects the sourcing of gas for the UK. However this is largely outside Transco's sphere of influence, and is determined by the Interconnector shippers.

Mild Weather Correction

Since 1987 the weather has been warmer than normal. This has equated to a loss of 25 TWh per annum against demand at normal conditions. (NB: Seasonal normal weather is currently based on the average of the last 65 years.) Consequently Transco has incorporated a Mild Weather Correction that takes account of the current series of warm winters. This correction is consistent with basing seasonal normal weather on the last 10 years, rather than the last 65 years. The result of this correction is to reduce LDZ demand at seasonal normal conditions by 2%, which equates to 13 TWh.

This correction only goes half-way to meeting the difference between actual demand and demand at seasonal normal temperatures, and therefore the forecasts remain optimistic. The effect on Transco's revenue could be significant, as the most weather sensitive load is the domestic sector which has the highest transportation charges and the highest allowed revenue.

Peak demand

Where annual demand is the main driver of Transco's income, peak day demand determines the system capacity required, and is consequently one of the key drivers for Transco's capital expenditure. Peak demand is forecast to increase by 1,427 GWh/d over a nine-year period (from 1998/99 to 2006/07). The majority of this growth is attributable to power stations and the European Interconnector, but an allowance has been made for interruptible consumers switching to firm.

Forecast supply

Supply forecasts are extremely difficult to develop, as there is a high level of uncertainty concerning new field developments, particularly associated with timing, location, landing point, and gas quality. In these circumstances a supply/demand match is achieved by assuming that the market will respond with longer-term supply developments. These might be imports through the Interconnector or from Norway, or from further UKCS developments. (NB: Supplies from existing and planned onshore fields have not been included on an individual basis, as their contribution to overall supplies is minimal.)

All fields have assumed production profiles and are classified into one of four supply categories:

- Production: fields in production;
- Development fields, where producers have committed to develop and which have been approved for development by the DTI;
- Appraisal fields, that producers are believed to be intending to develop within Transco's ten-year planning period;
- Additional Supplies, which are assumed developments at the end of the ten-year planning period to ensure an annual supply/demand match.

All Production and Development fields with their production profiles have been included as provided by producers or commercial sources. Appraisal fields have also been included, although their production profiles may shift or slip if any uncertainty surrounds their development. Additional supplies have only been assumed when necessary to achieve a supply/demand match.

Supply/demand match

Transco matches supplies to demand on an annual basis to create an exact match. Towards the end of their ten-year planning period additional supplies are needed to achieve the match, and these are sourced from all terminals on a proportionate basis. When additional supplies are necessary (from 2004/05) an aggregated annual supply of 5% above annual demand is assumed.

The supply/demand match is presented on a supply year basis, i.e. a year running from October to September.

Table 7.2: Summary of Annual Average Demands (TWh)

	1997/98	**1998/99**	**1999/2000**	**2000/01**	**2001/02**	**2002/03**	**2006/7**
0 - 73 MWh	364	367	371	372	374	376	384
>73 MWh	331	340	354	365	372	379	390
NTS PowerGen	135	147	165	179	194	201	222
NTS Industrial	27	26	26	26	26	26	26
Exports	28	86	81	87	87	89	93
Shrinkage	16	15	16	16	17	17	20
TOTAL	901	981	1,013	1,045	1,070	1,088	1,135

Source: Transco Transportation Ten Year Statement 1998

Table 7.3a: Summary of Annual Average Supplies - Low St Fergus Case (TWh)

	1997/98	**1998/99**	**1999/2000**	**2000/01**	**2001/02**	**2002/03**	**2006/7**
Producing	894	831	767	741	731	682	438
Development	7	150	180	178	166	163	85
Appraisal	0	0	46	127	173	253	283
Additional Gas	0	0	0	0	0	0	329

Source: Transco Transportation Ten Year Statement 1998

Table 7.3b: Summary of Annual Average Supplies - High St Fergus Case (TWh)

	1997/98	1998/99	1999/2000	2000/01	2001/02	2002/03	2006/7
Producing	894	831	787	741	708	672	445
Development	7	150	180	178	158	155	89
Appraisal	0	0	46	127	204	261	292
Additional Gas	0	0	0	0	0	0	309

Source: Transco Transportation Ten Year Statement 1998

For peak demand conditions, Transco assumes that all terminals supply at their maximum beach deliverability, with any shortfall being made up through storage, interruption or other supplies. For planning purposes they assume that interruption will be used before gas is taken out of storage, so for peak-day demand full interruption is assumed.

Table 7.4a: Summary of Peak Demands (GWh/d)

	1997/98	1998/99	1999/2000	2000/01	2001/02	2002/03	2006/7
LDZ Total	4,338	4,400	4,503	4,609	4,696	4,768	4,901
NTS PowerGen	297	347	463	597	?	671	713
NTS Industrials	56	56	56	56	56	56	56
Exports	133	406	478	619	712	727	745
Shrinkage	49	53	56	58	60	63	77
TOTAL	4,873	5,262	5,556	5,939	6,195	6,285	6,492

Source: Transco Transportation Ten Year Statement 1998

Table 7.4b: Summary of Peak Supplies - Low St Fergus Case (GWh/d)

	1997/98	1998/99	1999/2000	2000/01	2001/02	2002/03	2006/7
Producing	3,873	3,680	3,558	3,415	3,359	3,159	2,109
Development	22	561	665	935	930	921	525
Appraisal	0	0	167	476	646	907	1,203
Additional gas	0	0	0	0	0	0	1,328
Storage & Other	978	1,021	1,136	1,113	1,260	1,298	1,326

Source: Transco Transportation Ten Year Statement 1998

Table 7.4c: Summary of Peak Supplies - High St Fergus Case (GWh/d)

	1997/98	1998/99	1999/2000	2000/01	2001/02	2002/03	2006/7
Producing	3,873	3,680	3,588	3,415	3,358	3,236	2,042
Development	22	561	665	935	930	926	515
Appraisal	0	0	167	476	790	1,020	1,181
Additional gas	0	0	0	0	0	0	1,192
Storage & Other	978	1,021	1,136	1,113	1,117	1,103	1,561

Source: Transco Transportation Ten Year Statement 1998

Overview of BG storage

This section gives a detailed overview of the way in which the storage market was run over the last few years. Although the agreement to introduce storage auctions from May 1999 has completely altered the way in which the storage market will operate, an examination of the last few years will be useful to give an insight into how the storage industry has evolved.

Structure of BG Storage

The establishment of BG Storage as a separate business unit within BG plc took place on 1 October 1997, with Howard Higgins as Managing Director. Two further directors manage the areas of Customer Service and Business Development, with four Account Managers responsible for the management of services for individual shippers.

Standard Condition 2 of BG plc's licence requires BG plc to produce regulatory accounts for the storage business, and to consolidate those accounts into accounts for the Transco Business and the Transportation and Storage Business (if different from the Transco Business).

Types of storage available

Although Chapter 3 examines the various types of storage available in more detail, for the sake of clarity a brief description of the various types of storage facility used by BG Storage are described below. These facilities comprise:

- The Rough facility;
- The Hornsea facility;
- Liquefied Natural Gas (LNG).

Both Rough and Hornsea capacity will be auctioned for the next five years. LNG services will continue to be regulated, although during the course of 1999 a further review of LNG will take place.

The Rough facility

This is a partially-depleted offshore gas field, situated in the Southern Basin of the North Sea, off the coast of Yorkshire. Its unique feature is its huge size, able to store approximately 30 TWh, equivalent to 13 days supply for the UK market. It also has a high deliverability rate of 455 GWh/day. Rough forms an attractive alternative to the provision of new beach capacity, potentially enabling users to reduce the cost of peak supplies. Its disadvantage is its inability to change from withdrawal to injection and vice versa at short notice.

The Hornsea facility

The Hornsea facility, a group of salt cavities leached out from the Zechstein salt layer at a depth of 1800 metres, is situated on the North-East coast of England. The key advantage of this facility is the ability to inject or withdraw at short notice. The useable space is 3.5 TWh, and the cavities can deliver gas at a rate of 195 GWh/day. This enables shippers to fine-tune their load balances as well as being a flexible tool for the speculative trading of gas. Most third-party development of storage is focused in this type of facility.

Liquefied Natural Gas (LNG)

Facilities for the liquefaction of natural gas, and the storage and regasification of liquefied natural gas (LNG) have been situated at five strategic locations near to areas of high demand, or near to the extremities of the system. These facilities are situated at Glenmavis (near Glasgow), Partington (near Manchester), Dynevor Arms in South Wales, Avonmouth (near Bristol), and the Isle of Grain (to the south of the River Thames estuary). Their key feature is their high total deliverability rate of some 812 GWh/day, and their location in the network. As a result, LNG is able to provide a peak supply to shippers, and a supplement to network capacity for Transco, as well as being an insurance against emergencies such as system constraints, supply failures or end-user interruption. The disadvantage of the LNG facilities is the cost of space and the high liquefaction cost.

The LNG facilities at Dynevor Arms, Avonmouth, the Isle of Grain and Partington are currently designated as ‘constrained’, meaning that shippers who book storage services at these sites undertake an obligation to provide transmission support gas to Transco on days of very high demand. In recognition of this, they receive a transmission benefit in the form of a reduction to the system entry charge. (NB: Partington will not be constrained for the storage year 1999/2000.)

Storage operations

This section details the storage operations in place before the commencement of storage auctioning. The operations at Rough and Hornsea will be completely different from 1 May 1999. The information for LNG facilities is still current.

Injection is the transfer of gas from the National Transmission System (NTS) to a BG Storage facility (an offtake from the system), and withdrawal is the transfer of gas from the BG Storage facility to the NTS (a delivery to the system).

A shipper must have entered into a commercial arrangement with BG Storage, that is 'hold storage capacity' in a facility, in order to use that facility. Storage capacity comprises storage space and/or storage deliverability. Storage space is capacity which entitles the shipper to inject gas into and have gas in storage in a facility. Storage deliverability is capacity which entitles the shipper (provided it has gas in storage) to withdraw gas from a facility.

A firm service consists of space and deliverability in a set ratio known as the 'duration'. The term 'duration' does not define restrictions on the number of days when the customer can use the service. The duration of a service is the booked space divided by the booked deliverability. If the space is full of gas, then the duration is the number of days it would take to empty it by withdrawing at maximum rate.

Interruptible storage capacity is storage space in a facility which a shipper is registered as holding without being registered as holding storage deliverability. A shipper may only apply for storage space without deliverability at the Rough facility.

Services offered prior to the auction agreement

BG Storage offers annual storage under the Network Code. When an annual service is booked, a quantity of space and deliverability is reserved for a whole year. By booking space capacity a shipper secures the right to inject gas into the space. The cost of the capacity is invoiced in twelve monthly instalments over the year from May to April. In addition to the capacity charges, the customer pays a small commodity charge on the quantities of gas injected into storage, or on gas withdrawn from storage. The services presently offered by BG Storage are described below. Only the information on LNG services will continue to be current from 1 May 1999.

Firm services and Rough interruptible deliverability

Firm services are offered from the storage facilities at Rough, Hornsea and Glenmavis. The Rough firm service can be booked in any duration between 30 and 120 days, although shippers can extend the duration of the service by booking additional space with no deliverability. The Hornsea firm service is currently sold in any duration between 10 and 20 days. All LNG services have a fixed duration of 5 days. Partington will also offer a firm service for the storage year 1999/2000.

Space at Rough is not set aside for the interruptible service. However, shippers may book Rough space without booking deliverability. Rough shippers may withdraw up to one-fiftieth of their total space capacity on any one day on an interruptible basis. This is in addition to withdrawals made under any firm deliverability that they may have booked. BG Storage will only interrupt if there is insufficient deliverability, or if there are operational constraints. All space capacity carries with it equal rights to inject.

Constrained services

These are similar to firm services, with a duration of five days, and are offered at Dynevor Arms, Isle of Grain, Avonmouth and, until May 1999, Partington.

Tanker filling services

This service is offered at Glenmavis, where facilities exist for tanker filling to supply isolated towns in Scotland. The service is also offered to allow customers to use LNG for gas research, testing of equipment, fire fighting practice and fuelling LNG vehicles.

Storage prices

Before auctioning was introduced, shippers paid for the use of storage as follows:

- Storage Space Charge;
- Storage Deliverability Charge;
- Commodity Charge - Injection;
- Commodity Charge - Withdrawal.

However, they must also pay additional transportation charges in respect of moving the gas into and out from the NTS. Hence there are also system entry charges for each storage site but, in general, Transco makes no charge for NTS exit capacity at storage points, on the basis that the transportation service to the storage point is interruptible. When a firm transportation service is required, an NTS exit capacity charge will be payable.

BG Storage: service capacities

Table 7.5: Storage services and available capacities

	Space (GWh)	Deliverability (GWh/d)	Duration (Days)
Firm Services			
Glenmavis	551.45	110.29	5
Hornsea	3,494.50	195.00	10 to 20
Rough	30,333.68	455.00	30 to 120
Constrained Services			
Dynevor Arms	275.75	55.15	5
Isle of Grain	1,213.20	242.64	5
Avonmouth	827.20	165.44	5
Partington	1,194.85	238.97	5
TOTAL	37,890.63	1,462.49	

Source: BG Storage Services 1998/99

The following amounts of storage service are available:

The Rough space shown above can be booked with deliverability as a firm service, or without delivery as an interruptible service.

Injection capacities of the sites

Shippers who book the annual services secure injection rights when they book space capacity. The injection capabilities of the different sites are set out in the following table. Note that the attainable injection rate at Rough goes down as the facility fills up.

Table 7.6: Injection capabilities of the sites

Site	Number of days to fill	Average attainable from empty (GWh/d)
Rough	190	160.0
Hornsea	163	21.4
Avonmouth	318	2.6
Dynevor Arms	95	2.9
Glenmavis	150	3.7
Isle of Grain	226	5.4
Partington	229	5.2

Source: BG Storage Services 1998/99

BG Storage prices 1998/99

Table 7.7: BG Storage Prices 1998/99

	Reserved Space p/kWh/annum	Reserved Deliverability p/pdkWh/annum	Storage Injection p/kWh	Storage Withdrawal p/kWh/annum
Firm Services				
Glenmavis	1.37	0.986 (b)	0.279	0.010
Hornsea	0.29	8.0368 (b)	0.024	0.008
Rough	0.169 (a)	10.500 (b)	0.021	0.007
Constrained Services				
Dynevor Arms	2.27	1.452 (c)	0.198	0.017
Isle of Grain	0.95	0.730 (c)	0.290	0.019
Avonmouth	1.17	1.076 (c)	0.19	0.019
Partington (d)	0.86	0.795 (b)	0.258	0.017

Source: BG Storage Services 1998/99

Notes: (a) The Rough space price applies whether or not deliverability is booked with space. Rough customers may withdraw up to one-fiftieth of their total Rough space capacity on any one day on an interruptible basis.

(b) These prices do not include the NTS Entry Charge. Shippers will also need to book NTS entry capacity from Transco.

(c) These prices are shown before the transmission benefit has been subtracted.

The following table shows the prices for the BG Storage year from 1 May 1998 to 30

April 1999. For the purposes of BG Storage services, quantities of gas are measured by their energy value.

System entry capacity charges

Table 7.8: System entry capacity charges 1998/99

	Daily charge p/pdkWh/d	Annual charge p/pdkWh/annum
Rough	0.0024	0.876
Hornsea	0.0024	0.876
Avonmouth	-0.0011	-0.402
Dynevor Arms	-0.0099	-0.329
Glenmavis	0.0102	3.723
Isle of Grain	-0.0006	-0.219
Partington	0.0016	0.584

Source: Transco Gas Transportation Charges from 1 October 1998

Under the Network Code, shippers with storage deliverability need to book system entry capacity with Transco at the relevant storage site. The charges for 1998/99 are

Further development of BG Storage facilities

As part of the separation out of BG Storage, the company will use all reasonable endeavours to complete a robust internal physical, financial, information and systems separation of its storage business by 30 April 1999. BG Storage is also considering a number of possible enhancements of its assets, as outlined below.

Hornsea injection enhancement

This project would increase the amount of injection capacity available at Hornsea almost five-fold, in order to meet shippers' increased needs for flexibility. It will be possible to inject up to 120 GWh each day. The project is not economically viable in the present commercial and regulatory environment, and so the project is currently 'on hold'.

Salt cavity storage at Aldbrough

BG plc has submitted a planning application for the development of salt cavity storage at Aldbrough, which is eight miles south of the existing site at Hornsea. The planning application envisages six cavities, giving 188 GWh per day deliverability and 2,200 GWh of space.

Intergen have also submitted an application for a similar storage facility in the same region. At the time of writing, both applications have been rejected by the local council on environmental grounds, and both companies have appealed against this rejection.

Isle of Grain pre-treatment

The Bacton to Zeebrugge Interconnector is expected to reduce the quantity of low CO_2 gas entering the NTS at Bacton. As a result, the Isle of Grain will experience a greater proportion of gas landed at other terminals with a higher CO^2 content. Pre-treatment of the gas will be required before it can be liquefied. The project to build the pre-treatment plant is unlikely to affect site capacities or the service to shippers.

Further development of BG Storage services

BG is seeking to respond to the needs of the market place against the background of the Ofgas consultation on storage and the introduction of one year and five year storage contracts. Some of the actions taken to date by BG Storage are listed below. Further radical change may occur as a result of the auction process agreed in September 1998 and confirmed in February 1999:

- Rough and Hornsea will be removed from the Public Gas Transporters Licence, and so will no longer be regulated;
- Capacity will be sold by auction at Rough and Hornsea, with a reserve price;
- Injectability will be made available as a separate item from capacity and deliverability;
- The LNG situation will be subject to review during the 1999/2000 storage year, but is currently unchanged.

Top-up

Top-up ensures that there is adequate deliverability available in order to meet the 1 in 20 peak day demand, and also ensures that sufficient gas is available to meet a 1 in 50 severe winter. To determine the requirements for Top-up gas, Transco uses its projection of expected beach gas availability and storage bookings. Transco, in its role of Top-up Manager, procured storage services on behalf of the industry at an approximate cost of £30 million for the 1997/98 winter, and £3 million for 1998/99.

Ofgas has noted that one effect of a successful auction of storage services would be that shippers would book more firm deliverability than has been booked in recent years under the current arrangements, and this could reduce the need for Top-up bookings. In addition, a Network Code modification to prevent Top-up costs being passed on to the shipper while allowing Transco to retain any future revenues from Top-up gas, has been proposed by British Gas Trading, with proposed effect from the 1998/99 Top-up year. Ofgas was concerned that the existence of the Top-up regime distorts storage purchasing decisions and, subject to consideration of safety issues, supports its removal.

Regulation

History of storage regulation

In April 1998 Ofgas launched a detailed investigation into the market for gas storage and related services, and into the behaviour of the major participants. In July 1998 Ofgas published the findings of this investigation, and considered them sufficient evidence to request an enquiry by the Monopolies and Mergers Commission (MMC). However, in September 1998 Ofgas then published its final proposals in respect of future regulation of the storage market and this formed the basis of an agreement, subject to consultation, between Ofgas and BG plc. As this agreement will be implemented in full, the DGGS does not consider it will be necessary to refer these issues to the MMC.

The regulatory framework

The Gas Act

The Gas Act does not provide for the licensing of storage as a separate activity. However, in order to convey gas from a storage facility to a Public Gas Transporter's pipeline system, a storage provider requires a Public Gas Transporter (PGT) licence, unless it benefits from an exemption in the Gas Act or an exemption order. The Department of Trade and Industry is currently drafting an exemption order which would remove the requirement to hold a PGT licence for some forms of storage operation. In addition to duties under the Gas Act, the DGGS has a number of functions under the Fair Trading Act 1973 and the Competition Act 1980 (which are exercised concurrently with the Director General of Fair Trading).

The Public Gas Transporter's Licence

BG plc's PGT licence contains provisions relating to storage. These provisions are not contained in a discrete section of the licence, but are included in conditions throughout the licence. The standard conditions in the PGT licence particularly relevant to BG Storage include the following:

- Standard Condition 2, which requires BG plc to produce regulatory accounts for the storage business, and to consolidate those accounts into accounts for the Transco Business and the Transportation and Storage Business (if different from the Transco Business);
- Standard Conditions 3 and 4, which contain obligations relating to the determination of prices in accordance with the methodology statement, the publication and notification of prices to the DGGS, and procedures for modifying both the prices statement and the methodology statement;
- Standard Condition 7, which requires BG plc to create a Network Code, setting out the terms on which it will enter into transportation arrangements, including storage arrangements. Standard Condition 7 prescribes certain objectives, the achievement of which the Network Code is required to facilitate, and procedures for modifying the Network Code. BG plc is prohibited from entering into storage arrangements other than on the terms of the Network Code or with the DGGS's consent.
- Special Condition 8A, which requires BG plc to appoint a Managing Director of the Transco business, which includes the storage business, and makes provision for the separation of the Transco business from the rest of BG plc, the provision of resources to the Transco business, and for the Managing Director of Transco to make certain reports and returns to the DGGS;
- Special Condition 9D, which reflects the outcome of the 1996/97 MMC inquiry and imposes a cap on the revenues of the storage business;
- Standard Condition 11, which requires BG plc to conduct the transportation and storage business in such a way that neither it or any shipper or supplier obtains any unfair commercial advantage. It also contains provisions requiring BG plc to prevent certain flows of information relating to the transportation and storage business within BG plc, and to appoint a compliance officer to police those provisions;

- Standard Condition 12, which requires BG plc to comply with a direction by the DGGS to produce a long-term development statement;
- Standard Conditions 15 and 16, which require the provision of certain information to the Gas Consumers Council and to the DGGS;
- Standard Condition 25, which prohibits the sale of the storage assets of BG plc without the prior approval of the DGGS. This condition permits the transfer of the storage assets to a related person of BG plc without consent, so long as BG plc agrees to licence modifications which require it to secure that the related person complies with the provisions of the licence in relation to the storage of gas.

The DGGS has the discretion to remove licence provisions relating to storage on a category by category basis, having regard to the extent to which there is competition in relation to the storage of gas. In addition, the DGGS can decide to remove the requirements relating to storage from some of the licence conditions while maintaining the requirements relating to storage in other conditions. As part of the auction agreement, Rough and Hornsea will be removed from the PGT licence.

The Network Code

BG Storage's services are defined in Section R of Transco's Network Code. However, several changes will occur as a result of the auction agreement. A new section of the Network Code will be written to cover LNG, and the services at Rough and Hornsea will no longer be covered.

The Network Code also defines the arrangements for transportation to and from storage facilities. Transco claims that transportation services to and from storage facilities are managed in much the same way as transportation to any other system exit point, or from any other system entry point. Transco is planning to consult on changes to the method of charging for transportation services to storage facilities.

Future arrangements for BG storage

The Ofgas rationale

The primary aim of Ofgas is to ensure that all capacity is made available by BG Storage on non-discriminatory terms. Ofgas continues to believe that this aim can best be met by BG Storage being required to conduct an auction for storage rights, and to promote a competitive and liquid secondary market for such rights for services both at Rough and Hornsea.

BG Storage has been conducting an auction for Hornsea capacity for a number of years now, and therefore the extension of similar arrangements to Rough will not be without precedent. The establishment of an auction process will facilitate changes in regulatory arrangements that will provide a more stable medium-term policy environment for BG Storage.

Ofgas believes that secondary markets will offer customers the opportunity to purchase a range of contracts of shorter duration than five years. However they acknowledge the concerns of some potential customers concerning this point, and the associated desire to be able to acquire storage services on shorter duration contracts in the primary market (i.e. directly from BG Storage). Ofgas therefore proposes to require the auction of a proportion of capacity on annual terms, in addition to the auction for longer contracts. It is the view of Ofgas that 50% of capacity should be auctioned on an annual basis for each of the five years, although it will be open to BG Storage to auction these capacity rights for longer than one year, with the remainder of capacity being auctioned for five years from May 1999. Given the continued availability of LNG storage services (which account for 50% of BG Storage's physical deliverability capacity) on an annual basis, such an arrangement, coupled with secondary trading, should leave no storage customers short of their desired flexibility.

Ofgas considers that it is appropriate to put some form of limit on the amount of capacity that any individual bidder can purchase in the primary auction. Ofgas originally identified that BG Storage's control of facilities gave it short-term market power. They believe, therefore, that some form of constraint should be placed on bidders to prevent a simple transfer of market power from seller to buyer(s). Ofgas is in favour of keeping the auctions simple in order to avoid both delay and unnecessary complexity. Moreover Ofgas believes that the secondary markets will not only provide a satisfactory framework for price discovery, but will also have a powerful effect on the incentives for discovery of the actual products and services that parties wish to trade.

Ofgas therefore proposes that the auction should offer deliverability, space and injectability bundled together in proportions determined by current facility capacities (i.e. what is offered is, in effect, a share of the facility's capacity). The following reserve prices will be set in the auctions for bundled injectability, space and deliverability, expressed in terms of the price per unit of deliverability in the relevant bundle:

- Hornsea, 5 year: 2.564 p/pdkWh
- Hornsea, I year: 2.564 p/pdkWh
- Rough, 5 year: 10.989 p/pdkWh
- Rough, I year: 9.8890 p/pdkWh

The principal rationale for the Ofgas proposals to auction Rough capacity is to:

- Reduce BG Storage's market power;
- Prevent the withholding of capacity from the market;
- Create a market environment in which there exist a number of holders of longer-term tradeable capacity rights.

From this perspective, therefore, the charging mechanism is a secondary issue.

Ofgas recognises that the case for a uniform-price auction relative to a pay-as-you-bid system is not clear cut. Given that the charging mechanism is secondary in relation to Ofgas's objectives, and given that there is support for pay-as-you-bid from the industry, the final proposal from Ofgas is that the auctions should be based on pay-as-you-bid arrangements. They also consider that bids would be simple in form, with price and quantity only being required for either the one year or five year contracts, and bidders being allowed to choose to submit more than one price/quantity combination for the relevant contract length. Ofgas believe that BG Storage should be required to act so as to facilitate the development of a secondary market in storage services by:

- Ensuring that injectability, space and deliverability rights are defined in ways which allow them to be traded separately, and
- Establishing arrangements that allow for the transfer on a basis which is not

unreasonably restricted of all or any part of the rights purchased under the auctions described above at the request of the holders of those rights.

With such arrangements in place, Ofgas considers that secondary storage trading is likely to develop without any party adopting a formal market operator role. However, it has no objections to BG Storage developing a storage market if it saw a commercial opportunity to do so, provided that there is an internal separation from the operating of the facilities.

BG would be allowed to offer additional services so as to:

- Encourage rights holders not wishing to make full use of deliverability or injectability in a particular period to trade them on secondary markets and
- Ensure that, if rights holders do not do this for one reason or another, there will be an additional mechanism by which that capacity can be brought on to the market.

In particular, Ofgas considers that BG Storage should provide a use-it-or-lose-it regime in order to ensure that there will not be hoarding of capacity rights, and that unused capacity rights will be available to the market.

Auctions of Hornsea and Rough

BG will sell by auction firm rights to 100% of the maximum physical capacity to store gas, and the maximum physical capabilities to inject and deliver gas currently available at its Rough and Hornsea facilities up to and including the 2003/04 storage year. At each of those facilities, for the 1999/2000 storage year 50% of the firm capacity right will be sold for a term of five years, and 50% will be sold for a term of one year. The 50% of firm capacity rights auctioned for a one-year term at Hornsea and Rough will be re-auctioned on a one-year term in each subsequent year up to and including the 2003/04 storage year, although it will be open to BG to auction these capacity rights for periods of longer than one year.

Capacity rights auctions will be bundled together as injection, space and deliverability in a specified proportion. This is calculated by determining the total ratio, so that in effect shares of the overall capacity are sold. The following table illustrates this.

Table 7.9: Operational characteristics of Rough and Hornsea

	Space (GWh)	Deliverability (GWh/d)	Injectability (GWh/d)	Ratio Space: Deliverability: Injectability
Hornsea	3,494.50	195	21.4	18:1:0.11
Rough	30,333.68	455	160.0	67:1:0.35

Source: BG Storage Services 1998/99

Of course, once the auctions have taken place unbundling will occur on the secondary market. This will lead to separate trading of injectability, space and deliverability rights, giving each player the flexibility required.

No bidder or associated group of bidders will be allowed to buy more than 20% of the total deliverability across the four auctions. Bidders in the auctions will pay the price that they bid. Each auction will be subject to a reserve price which, if all firm capacity clears at each auction at its reserve price, will give BG at least the following revenues in the 1999/2000 storage year:

- 50% of firm rights to capacity at Hornsea, 5 year term: £2.5 million
- 50% of firm rights to capacity at Rough, 5 year term: £25.0 million
- 50% of firm right to capacity at Hornsea, 1 year term: £2.5 million
- 50% of firm right to capacity at Rough, 1 year term: £22.5 million

TOTAL £52.5 million

Any firm capacity rights offered for sale for five years but not sold will be included in the one year auction relating to that facility for that year, and auctioned on a long-term basis in the following year. Any other firm capacity rights offered for sale for more than one year but not sold will be included in the one year auction relating to that facility for that year, and auctioned in the following year. Any firm capacity unsold via the one year auctions will, for the duration of the relevant storage year, be offered for sale by BG at the reserve price relating to that facility.

Upon completion of the auctions in 1999, and each of the subsequent four years, the mechanics of the auction will be reviewed with the aim of agreeing any modifications to such mechanics, including reserve prices, warranted by that review.

Regulation

Prior to 31 January 1999, BG's licence was modified so that with effect from 1 April 1999 it will not apply to the Rough and Hornsea facilities.

Capacity in BG's LNG storage facilities will not be sold by auction, and those facilities will continue to be regulated under BG's PGT licence. BG will offer its LNG storage services for the 1999/2000 storage year at the same prices as it has offered them in the 1998/99 storage year. The storage revenue cap will be replaced with a licence condition freezing LNG prices at present nominal prices and, if practicable, all provisions relating to LNG will be placed in one licence condition. Ofgas will undertake a review of the regulation of LNG during 1999, with the intention of introducing new proposals effective from 1 April 2000.

The Network Code terms setting out the current basis on which Rough and Hornsea are sold will be removed from the Code. Appropriate provisions will be included in the terms of contract for the auctions and in the bidding rules to give effect to this agreement. Terms relating to the basis on which LNG storage is sold will be separately identified and consolidated in a separate section of the Network Code (Section Z).

Role of the Storage Workstream

Any set of business rules needs to change over time, as experience is gained and business conditions vary. The PGT Licence granted by Ofgas requires the transporter to define and operate a mechanism to control this process, and in the Network Code these are defined as the Modification Rules.

Under these rules a Modification Panel, consisting of representatives from Transco and its shippers, agree appropriate courses of action for each Modification Proposal. The Panel may refer a proposal to a Workstream for a review to gather information and/or pass the proposal for development.

In order to reflect the fact that BG has set up BG plc. Storage as a separate business unit within BG plc, and to admit top-ups, modifications to the Network Code will be required in the provisions which currently deal with the relationship between Transco and BG Storage, and also between BG Storage and shippers. The underlying principle of any modifications will be to provide rules which ensure the non-discriminatory treatment by Transco of any storage operator, including BG Storage, and separately define terms in the Code which cover the commercial relationships between BG Storage and shippers regarding LNG, with a view to ultimately removing them from the Network Code altogether. Network Code modifications are, therefore, presently being progressed.

A generic Storage Connection Agreement has been drafted by Transco as part of the Storage Workstream process. Ofgas has consulted on this agreement, and the business rules associated with storage separation at a future date, prior to granting approval.

Chapter Eight:

STORAGE IN THE US

Introduction

The world gas storage industry is dominated by the US, which has roughly two thirds of total worldwide gas storage capacity. This chapter outlines the development and use of storage in the US under the following headings:

- Industry structure;
- Peak capacity and swing requirement;
- Regulation of storage;
- Trends in US storage.

Industry structure

Physical gas chain

The US gas market is the largest gas market in the world and is characterised by diverse sources of supply and great distances between major producing areas and consuming markets. The US gas chain can be summarised as follows:

- Production;
- Gathering and processing;
- Transportation to market;
- Local distribution and marketing.

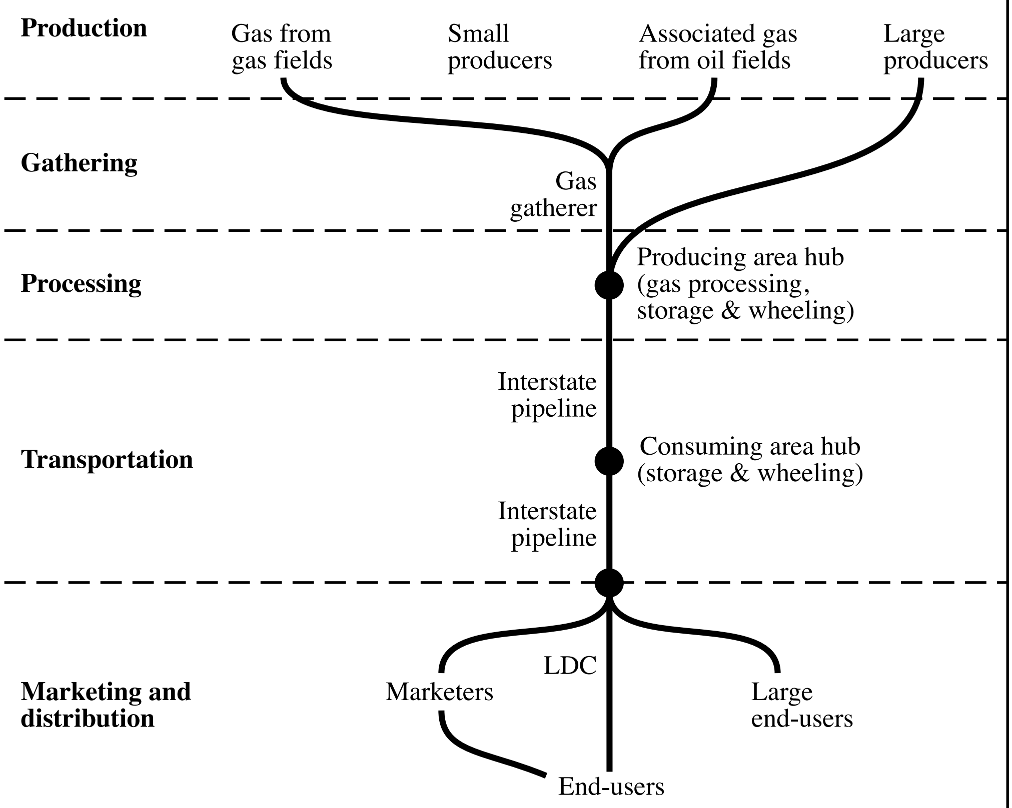
The primary agents at each stage of the gas chain are illustrated in Figure 8.1 overleaf.

Production

The US is one of the largest gas producers in the world, producing 19.6 Tcf (555 Bcm) of dry gas in 1996. Additional supplies are imported from Canada. Over half of US production comes from Texas and the Gulf of Mexico Outer Continental Shelf. Other major producing areas include Louisiana, New Mexico, Oklahoma and Kansas. There is some gas production in around half the states, although rarely in sufficient quantities to meet local demand.

Gas production is a very diverse industry in the US. Unlike gas production industries in most other countries, production in the US comes from a large number of small fields, both gas fields and oil fields offering associated gas. A collection of major producers operate in most producing areas. These companies are generally the large oil producers such as Texaco, Exxon and BP Amoco, as well as gas companies such as Enron. There are also a great number of smaller producers, termed independents. Independents range from medium-sized producers to very small companies, perhaps operating only one field. Gas producers may sell gas at the well-head to a gas gatherer or another producer, or may transport it closer to market. Many producers combine the roles of production, gathering and processing.

Figure 8.1: The US gas chain



Source: MJMCSL

Gathering and processing

As a consequence of the diverse nature of the US production industry, gas gatherers have an important role to play. Gatherers aggregate the supplies from a number of fields into gas 'packages' suitable for processing and sale. Gatherers operate in the gas producing areas and may sell gas on to pipelines for transportation to market. The major companies may operate as gatherers for smaller producers, although there are also independent gatherers.

Gas processing involves the removal of natural gas liquids such as methane, propane, butane and natural gasoline. These liquids can then be marketed separately. Gas processing plants typically form the interconnection between a gas gathering system and a high pressure pipeline for transporting gas to market. Such plants may be part of a producing area hub offering a variety of services including gas storage.

Transportation to market

Gas transportation is the role of pipeline companies. There are primarily two sorts of pipeline – interstate and intrastate. Interstate pipelines generally transport gas between states; a number of major pipelines span several thousand miles from producing areas to distant markets. Interstate pipelines are subject to regulation by FERC, the Federal Energy Regulatory Commission. Intrastate pipelines transport gas within states. They are mainly subject to regulation by State Public Utility Commissions (PUCs), although in some matters they may also be regulated by FERC.

The US has an extensive, complex and highly interconnected gas transmission grid. There is significant competition between pipelines, particularly as one city may be connected to several pipelines, thereby increasing security and flexibility of supply. Traditionally pipelines acted as merchant companies, buying gas from producers and selling bundled gas supply and transportation packages to customers. However, since the mid-1980s the pipelines' merchant role has been gradually decreasing. This was codified by FERC Order 636 in 1992 which required pipelines to offer open access to their transmission system based on unbundled rates for services such as gas transportation and storage. In addition, the pipelines were forced to unbundle their transmission and sales activities so that their merchant businesses operated in separate subsidiaries, and could not gain discriminatory access to transmission capacity. Effectively, pipelines now operate merely as transporters and charge shippers regulated rates to reserve capacity on, and to move gas through, their facilities.

Local distribution and marketing

Intrastate pipelines generally deliver gas to local distribution companies (LDCs), which then distribute to customers' meters. Some large customers may also be connected directly to transmission pipelines.

The gas supply market in the US is divided between wholesale and retail customers. The wholesale market has been open to competition since the mid-1980s. The period since then has seen the dramatic growth of the gas marketing industry, so that there are now over 300 gas marketers licensed by FERC in the wholesale market. Some marketers are independents, although most are affiliates of producers or other companies in the gas supply chain. Marketers compete with incumbent LDCs and pipeline merchant subsidiaries to supply wholesale customers, such as large process users (industrial and power generation loads). LDCs may also be supplied by marketers.

The retail market for residential, commercial and small industrial customers has until recently been served only by LDCs, generally offering bundled contracts. However, at present a number of pilot retail choice programmes are in operation in various states, in which retail customers may buy gas from the incumbent LDC or other marketers. LDCs remain responsible for retail distribution.

Regional production and markets

Regional differences in production and consumption of gas have shaped the US market. This is particularly important as regards gas transportation and storage. This is because the major producing areas are concentrated in the Southwest, especially Texas and the Gulf of Mexico, whereas the main population and industrial centres are in the Northeast, Midwest and California (the Midwest is also the area most greatly affected by cold weather in the winter). Most imports are from production in Western Canada. Table 8.1 displays production, consumption and net gas balance by regions in 1996.

Table 8.1: US production and consumption by region, 1996

Region	Production (Bcf)	Consumption (Bcf)	Net balance (Bcf)
Northeast[1]	368	3,736	–3,368
Southeast[2]	723	2,344	–1,621
Midwest[3]	366	4,416	–4,050
Central[4]	2,055	1,619	436
Western[5]	288	2,525	–2,237
Southwest[6]	15,451	6,876	8,576
Alaska and Hawaii	481	451	30
US total	19,751	21,967	–2,216

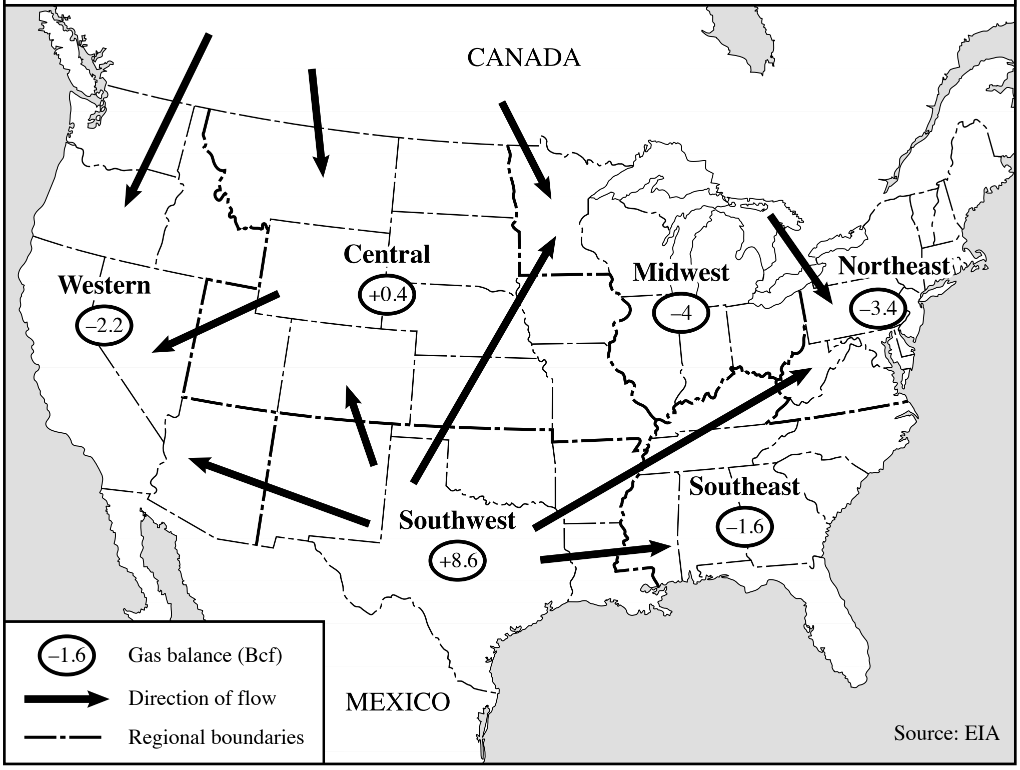
Notes:

1. Northeast includes Connecticut, D.C., Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, Virginia, and West Virginia.
2. Southeast includes Alabama, Florida, Kentucky, Mississippi, North Carolina, South Carolina and Tennessee.
3. Midwest includes Illinois, Indiana, Michigan, Minnesota, Ohio and Wisconsin.
4. Central includes Colorado, Iowa, Kansas, Missouri, Montana, Nebraska, North Dakota, South Dakota and Wyoming.
5. Western includes Arizona, California, Idaho, Nevada, Oregon and Washington.
6. Southwest includes Arkansas, Louisiana, New Mexico, Oklahoma, Texas and Utah.
7. Surplus gas from Alaska is generally exported to Canada.
8. US total net balance made up by imports from Canada (2,784 Bcf in 1996).
9. Production + imports do not equal consumption as some gas is used in transportation and gas stocks in storage may vary from year to year.

Source: EIA

The average distance of production from the market has increased significantly in recent decades as the former gas producing region in the Northeast, stretching from Pennsylvania to Illinois, has been largely exhausted and the bulk of production has moved westward to Texas, the Gulf of Mexico, the US Rocky Mountains and Western Canada. Only eleven US states are self-sufficient in gas supply (Alabama, Alaska, Colorado, Kansas, Louisiana, New Mexico, North Dakota, Oklahoma, Texas, West Virginia and Wyoming). Customers in states that are not self-sufficient must rely on gas imported from producing areas which may be over a thousand miles away. Figure 8.2 depicts net gas balances by region and general direction of gas flows between regions.

Figure 8.2: US regional gas balance and direction of gas flow, 1996



Transmission constraints are a major factor in the US market. The US lower 48 states have surplus gas productive capacity to meet gas monthly demand (even without imports from Canada). However, this is little use without sufficient pipeline capacity. Indeed, even though there may be enough gas production in the producing areas to meet winter demand in consuming regions, there is insufficient pipeline capacity to transport such quantities of gas to the Northeast and Midwest markets. In these circumstances storage plays a key role in ensuring sufficient deliverability to satisfy seasonal demand.

The position of storage within the industry

As noted in the section on the uses of storage, storage can be used for a variety of different purposes in both producing and consuming areas. Not surprisingly therefore, storage facilities are owned and operated by a variety of different groups within the gas industry. However, the dominant operators of storage are the interstate pipeline companies that traditionally used storage both to assist load balancing and system management and in support of their merchant role. Since the introduction of FERC Order 636 in 1992, pipelines have had to provide open access to much of their storage capacity. Interstate pipelines remain the largest storage operators. Until recently the only other storage owners in most areas have been LDCs, which have invested in storage to help meet their service obligations in the heating season. The only exception to this has been the Southwest producing area, where intrastate pipelines operate nearly 170 Bcf of working storage capacity. This is partly a function of the dual role of intrastate pipelines within the producing areas which includes gas gathering, processing and delivery to interstate pipelines as well as distribution to local customers.

As a result of the deregulation of the gas industry, a number of independent storage operators have entered the market. Independent operators include producers, large customers, hub operators and alliances made up of diverse interests. Many independent storage projects have been built with a particular eye to commercial rather than operational opportunities, and tend to focus on high deliverability facilities. Table 8.2 depicts storage facilities by region, type of reservoir, and operator.

Peak capacity and swing requirements

Heating and non-heating seasons

The gas industry in the US is highly seasonal. The heating season is considered to last from 1 November to 31 March, a period of 151 days (or 152 in leap years). The non-heating season is 1 April to 31 October (214 days). The gas transmission and storage markets are built on the assumption that winter demand in some regions will be several times summer consumption. The interaction of seasonal demand, transmission capacity and storage capacity is examined in more detail in the later section on uses of storage.

Productive capacity

There is significant surplus productive capacity in the lower 48 states of the US (i.e. excluding Alaska and Hawaii). Indeed in December 1996 dry gas productive capacity was estimated to be 66.9 Bcf/d (1.9 Bcm/d). Actual production was much lower, averaging 52.6 Bcf/d (1.5 Bcm/d) over the same period. This is typical of the US gas market which has been oversupplied since the early 1980s as a result of the incentive to drill wells provided by the deregulation of wellhead prices in the Natural Gas Policy Act of 1978. The oversupply of productive capacity has led to the most efficient wells (or those from which gas can most easily be brought to market) being produced. Although gas demand varies significantly on a seasonal basis, gas production remains largely consistent throughout the year, because of the use of seasonal storage to meet winter demand.

The distance of producing areas from major markets has a major effect on peak capacity and demand. Gas markets in some regions, particularly the Midwest and Northeast, are highly weather-sensitive, with demand in winter being several times summer consumption. Therefore pipeline capacity to transport gas from producing areas to markets is often a greater constraint than productive capacity. The total deliverability of gas through US interstate pipelines to market is estimated to be 74 Bcf/d (2.1 Bcm/d). Peak daily demand is estimated to be over 120 Bcf/d (3.4 Bcm/d). Storage near consuming centres plays a vital role in meeting the shortfall between peak day demand and pipeline deliverability. This shortfall may be further intensified by regional transmission constraints or weather conditions. In some states storage supplies significantly more than half of peak day demand.

Uses of storage

The US gas storage market is the most developed in the world. In January 1997 there were 410 storage sites in the US with a total working gas capacity of 3,765 Bcf (107 Bcm) and total deliverability of 74.5 Bcf/d (2.1 Bcm/d). US storage represents roughly two thirds of total world storage capacity. Most storage facilities in the US were constructed to meet operational needs. As the gas market in the US has been

Table 8.2: Storage facilities by region, type of reservoir, and operator

	Depleted Gas/Oil Field			Aquifer Storage			Salt Cavern Storage			Total		
Region/ Operator	**Number of Sites**	**Working Gas Capacity (Bcf)**	**Daily Deliverability (Mmcf/d)**	**Number of Sites**	**Working Gas Capacity (Bcf)**	**Daily Deliverability (Mmcf/d)**	**Number of Sites**	**Working Gas Capacity (Bcf)**	**Daily Deliverability (Mmcf/d)**	**Number of Sites**	**Working Gas Capacity (Bcf)**	**Daily Deliverability (Mmcf/d)**
Northeast												
Interstate	93	627	10,967	0	0	0	1	0	40	94	630	11,007
Intrastate	0	0	0	0	0	0	0	0	0	0	0	0
LDC	23	29	500	0	0	0	1	1	80	24	28	580
Independent	3	12	114	0	0	0	0	0	0	3	12	114
TOTAL	119	669	11,581	0	0	0	2	1	120	121	670	11,701
Southeast												
Interstate	7	114	2,164	0	0	0	1	15	1,500	8	129	3,664
Intrastate	0	0	0	0	0	0	0	0	0	0	0	0
LDC	17	27	520	2	6	67	1	2	260	20	34	848
Independent	3	4	38	0	0	0	2	6	670	5	10	708
TOTAL	27	145	2,722	2	6	67	4	23	2,430	33	173	5,220
Midwest												
Interstate	35	385	6,658	6	33	1,383	0	0	0	41	418	8,041
Intrastate	0	0	0	0	0	0	0	0	0	0	0	0
LDC	55	399	9,594	22	192	4,714	2	2	78	79	595	14,387
Independent	8	120	1,571	0	0	0	0	0	0	8	120	1,571
TOTAL	98	903	17,824	28	225	6,097	2	2	78	128	1,133	24,000
Central												
Interstate	21	380	3,726	7	88	1,215	0	0	0	28	466	4,941
Intrastate	0	0	0	0	0	0	0	0	0	0	0	0
LDC	17	83	534	1	10	350	0	0	0	18	90	884
Independent	2	4	51	0	0	0	1	2	160	3	6	211
TOTAL	40	467	4,312	8	97	1,565	1	2	160	49	562	6,037
Southwest												
Interstate	15	486	6,693	0	0	0	3	20	1,250	18	486	7,943
Intrastate	12	156	2,736	0	0	0	2	13	1,080	14	169	3,816
LDC	14	118	1,350	1	8	10	4	22	1,414	19	146	2,775
Independent	7	145	1,380	0	0	0	9	34	4,585	16	180	5,965
TOTAL	48	886	12,160	1	8	10	18	88	8,329	67	981	20,500
Western												
Interstate	0	0	0	0	0	0	0	0	0	0	0	0
Intrastate	0	0	0	0	0	0	0	0	0	0	0	0
LDC	10	222	6,565	1	15	550	0	0	0	11	239	7,115
Independent	1	7	5	0	0	0	0	0	0	1	7	6
TOTAL	11	229	6,570	1	15	550	0	0	0	12	246	7,120
US												
Interstate	171	1,971	30,209	13	120	2,598	5	35	2,790	189	2,129	35,597
Intrastate	12	156	2,736	0	0	0	2	12	1,080	14	169	3,816
LDC	136	880	19,065	27	231	5,692	8	26	1,832	171	1,132	26,590
Independent	24	291	3,159	0	0	0	12	41	5,415	36	335	8,574
TOTAL	343	3,299	55,171	40	351	8,290	27	116	11,117	410	3,765	74,579

Notes: Bcf = Billion cubic feet Mmcf/d = Million cubic feet per day LDC = Local distribution company
Depleted Gas/Oil field data includes one storage cavern facility classified as ‘other’. Totals may not equal sum of components because of independent rounding.
Source: EIA

deregulated the commercial opportunities provided by storage have also been recognised, and recent years have seen a surge in storage construction and expansion to seize commercial advantages offered by flexible storage. This section considers both operational and commercial uses of storage.

Operational uses of storage

Seasonal swing

Storage is used to allow the production and transmission system to operate at maximum efficiency by smoothing seasonal demand. Seasonal storage near consuming markets is injected with gas during the non-heating season. This gas can then be withdrawn in the heating season. Without seasonal storage it would be necessary to meet winter demand by increasing gas production in the cold months and decreasing it in the summer. It is more efficient to produce at a constant rate throughout the year. Similarly, pipeline capacity would need to be expanded to meet winter demand, a significant factor in the light of the costs involved in transporting gas across the continent. The expanded pipeline system would then operate less efficiently at a lower load factor in periods of low demand. Seasonal storage is generally a much cheaper option.

Seasonal storage is concentrated in major consuming areas, and particularly in the Midwest and Northeast. The existence of a former gas producing band stretching from Illinois to Pennsylvania has encouraged the extensive conversion of depleted fields to storage facilities. Depleted fields make good seasonal storage facilities because of their low cost and high working gas capacity. They are also likely to have some pipeline connections and well facilities already in place. In market areas where there are no potential depleted fields, some use of aquifer storage has been made. There are eight aquifer storage sites in Illinois, eight in Indiana, four in Iowa and eight others across five other states. However, most aquifers were developed in the 1970s when gas prices were very low. The high cost of base gas, and regulation to protect underground water sources, makes further aquifer development unlikely. Seasonal storage fields are generally designed to be injected slowly over most of the non-heating season, and to be drawn down over extended periods during the winter. They are generally characterised by high capacity and low deliverability.

Supply reliability and load balancing

Storage in producing areas can be used to increase security of supply in case of production constraints. If the temperature in producing regions drops significantly, wellheads may freeze up. Other difficulties in the area may also reduce production, such as storm damage to wells in the Gulf of Mexico. In such circumstances storage in producing areas may provide an emergency back-up supply. Producers may also use storage as a holding point to aggregate gas from different fields and repackage it in marketable quantities.

In addition, storage in producing areas and elsewhere enables pipelines to maintain pressure during periods of heavy system demand. Pipelines are required by FERC Order 636 to allow customers access to storage capacity that was formerly held by the pipelines to provide bundled supply. However, pipelines are allowed to retain a portion of storage capacity for their own use in this load balancing and system management role.

Peak swing

As noted above there is insufficient pipeline capacity to transport gas to market on average throughout the winter. This state of affairs is seriously compounded in periods of peak demand caused by exceptionally cold weather, when total US demand may be in excess of 120 Bcf/d (3.4 Bcm/d), possibly for several days at a time. In addition, gas demand generally varies during the day and may exceed deliverability from production and seasonal storage for a few hours of the day. There are a number of ways of providing peak swing, including linepacking, LNG or LPG, peak-shaving propane-air plant, and high deliverability underground storage. Of these linepack and underground storage are the cheapest, and only underground storage can economically meet peak demand over extended periods.

The continental climate of the US means that cold weather may seriously affect one region while demand in other regions remains normal. However, transmission constraints may restrict the ability of gas to be moved from one region to another in order to smooth peak demand across the continent. In such circumstances gas can be withdrawn from storage in the area of high demand, to be refilled with gas from less extended regions later.

The perceived advantages of high deliverability storage in providing peak swing have led to a surge in the construction of salt cavern storage sites in market areas (especially the Midwest and Northeast) in recent years. Salt cavern storage facilities may be cycled several times in one heating season, increasing their value as strategic peak supply tools. In addition, market areas have seen significant expansion of existing depleted field storage to improve deliverability, particularly in the absence of suitable salt formations for development. A major example of this is Columbia Gas Transmission's Market Expansion Project, whereby deliverability is being increased by 370 Mmcf/d (10.5 Mcm/d) at 14 existing depleted field sites over a period of three years from 1997 to 1999. Expansion of deliverability from storage is often driven by demands from customers, particularly LDCs and marketers anxious to meet service obligations.

Providing peak power generation fuel

Electricity cannot be stored. However, combined cycle gas turbines (CCGTs), with short starting up and ramping up times, can be used to meet peak electricity demand. In recent years a number of high deliverability storage facilities have been built to supply CCGTs with large quantities of gas at very short notice. In particular several salt cavern sites have been developed in Texas to meet peak summer electricity demand driven by the need for air-conditioning in hot weather.

Commercial uses of storage

Following the gradual deregulation of the US gas market from 1978, more and more companies have been exposed to the effects of gas price volatility. Even for companies that do not buy gas on the spot market, most long-term contracts are now spot-indexed. This has led to the development of a range of commercial uses of storage intended to reduce the exposure of storage capacity holders to peak gas spot market prices and, in some cases, to exploit commercial advantages provided by storage.

Reducing the cost of seasonal and peak demand

Gas spot prices are generally significantly higher in the heating season than the non-heating season. Gas prices vary considerably depending on market players' expectations of supply and demand fundamentals. In these calculations storage inventories are a major factor, particularly as they are the only part of the supply and demand equation for which reliable and transparent information is widely available. Statistics estimating working gas levels and other storage measurements are published weekly by the EIA, the American Gas Association and the Interstate Oil and Gas Compact Commission. Gas spot, and to a certain extent futures, prices will react to a combination of published storage statistics, temperature forecasts, and production and transmission expectations.

Therefore the commercial advantage of having gas available from storage can be significant. Gas buyers are protected from having to pay high spot gas prices in order to meet service obligations by withdrawing gas from storage. Storage facilities are generally injected during the non-heating season when prevailing gas prices are lower. Storage sites may also be injected with gas during periods of low demand in the heating season, particularly in the case of high deliverability salt caverns that may be cycled several times during the winter. The EIA estimates that the value of having gas available for immediate delivery during periods of stress can be greater than $1/MMBtu. Natural gas futures contracts may provide similar protection against price spikes. However, in many locations across the US storage gas may be a preferable hedging instrument, as local spot prices may vary considerably from futures prices at the three gas futures delivery points (the Henry Hub in Louisiana, the Permian Basin in Texas and the Nova pipeline in Alberta, Canada) due to regional weather systems and transmission constraints.

If the owner of the gas in storage does not need the gas for his own use, he can then release the gas and sell it on the spot market, potentially at a considerable premium. Overall, gas in storage provides the holder with added flexibility, either in terms of protection from high spot prices for gas for his own use, or the opportunity to sell storage gas and exploit high spot prices.

Arbitrage with futures contracts

The holder of storage gas and capacity within reasonable distance of a futures market can use storage to exploit risk-free arbitrage opportunities whenever there is a premium between spot and futures prices greater than the cost of storage and the time value of money.

If the market is in backwardation, that is the futures price is lower than the spot price, the storage-owner can sell spot gas and buy front-month futures gas to replace it. If the market is in contango, that is the futures price is higher than the spot price, the storage-owner can buy spot gas and sell futures contracts. It is worth noting that even if the gas in storage is being kept for the owner's own use to maintain supply throughout the heating season, the owner may still sell a portion of the gas to exploit arbitrage opportunities and replace it with futures gas. For example, at the beginning of the heating season the holder of storage gas might have 100 Mmcf in storage and want to have 60 Mmcf left at the beginning of January. The holder could still use 20 Mmcf in November, sell 60 Mmcf on the spot market at the beginning of December, replacing it with 60 Mmcf of January futures, and keep 20 Mmcf to meet unexpected demand during December. The 60 Mmcf of January futures will effectively refill the storage capacity sufficiently to cover demand over the three remaining months of the heating season.

Assuming that the storage user has not sold gas that he will want for his own needs before the futures contracts are delivered, the only real risk is the possibility of transmission constraints between the futures delivery point and the storage facility. In addition, costs that have to taken into account include the cost of keeping gas in storage and the cost of money in terms of interest that could have been gained on the money used to buy gas in storage.

Hub services supported by storage

Storage capacity can generally be leased from storage operators on a variety of firm and interruptible contracts similar to the contracts on offer for transmission capacity. However, storage operators also have the opportunity to offer hub services based on storage to aid customers in balancing supply and demand, such as parking (short-term storage of excess gas for a hub user), loaning (short-term supply of gas for hub user which is repaid in kind later), and balancing (the firm provision of the difference between a customer's nominations and actual demand). Storage can also support gas trading at a hub. These services are examined in more detail in the later section on market centres.

Regulation

Regulation of storage in the US is subject to the dichotomy that pervades all areas of US government: the balance of Federal and State authority. In general, storage facilities that are deemed to serve primarily the interstate market are regulated by FERC, whereas facilities that are deemed to serve the intrastate market are subject to regulation by the appropriate State Public Utility Commission. In practical terms the 189 storage facilities operated by interstate pipelines (57% of total US storage capacity) are subject to FERC, whereas almost all of the 171 facilities operated by LDCs (30% of total capacity) are State regulated, as are most of the 14 storage operations provided by intrastate pipelines (4%). Most of the 36 independent storage facilities (9%) are deemed to serve the interstate market and as such are regulated by FERC. This section will examine primarily Federal regulation as practised by FERC. It is worth noting, however, that state regulation by the PUCs is generally based on similar principles with certain regional variations.

Perhaps the key piece of current legislation governing storage operations is FERC Order 636. Passed in 1992 in order to codify the principles of non-discriminatory open access to gas transportation and storage facilities, it affects the pricing, competition, construction and operation of US storage and is the background to much of the regulation considered in this section.

Open access

Under the terms of FERC 636, storage operators must offer access to capacity and deliverability in their storage facilities on a non-discriminatory basis. They are permitted to file a number of rates and schedules but must accept bids for storage according to these published terms (although in some cases they may offer discounted rates to remain competitive). Since FERC 636, pipelines have only been allowed to retain a proportion of storage capacity for their own use in load balancing and system management. This proportion is regulated by FERC and is based on analysis of the pipeline's design requirements. In fact some pipelines have recently filed with FERC to reduce storage capacity reserved for their own use in order that they may sell more capacity on the open market.

Capacity release

In order to increase the efficiency of the gas storage and transmission system, FERC 636 also stipulated that pipelines and other storage operators allow re-trading of surplus storage capacity and set up electronic bulletin boards (EBBs) to facilitate a secondary market in released capacity. In effect, companies that have leased storage capacity from a storage operator may either use it themselves or sublet it to other companies on the capacity release market. This increases the efficiency and turnover of the storage system, as companies will generally acquire capacity on a medium to long-term basis, often for several years. Capacity release allows companies to gain some return from capacity that has been booked but is not in use, as well as enabling other companies without pre-booked storage capacity to take advantage of opportunities provided by storage facilities normally over a short period. EBBs specify the quantity of released capacity and deliverability on offer in real time and allow liquid secondary markets to develop.

Storage pricing

Sites that are subject to FERC regulation must submit rates schedules for FERC approval. There are two possible forms of storage rates: cost-of-service or market-based rates.

Most storage is operated on cost-of-service rates. These are rates authorised by FERC and set at a level expected to generate enough revenues to allow the company to recover its expenses plus an allowed rate of return on assets used. Effectively this sets a maximum limit on rates. However, storage operators may discount rates to encourage use during off-peak periods. Indeed, in areas where there is significant competition between nearby storage facilities, rates may often be offered at a discount.

Cost-of-service rates also apply to most pipelines for transportation and the two aspects are considered side-by-side, with many pipelines offering a range of services including bundled and unbundled transportation and/or storage tariffs.

A few storage facilities are permitted to offer market-based rates. In other words, rates are set by competitive bidding between customers, and the storage-operator's income is not regulated. This is intended to lead to greater efficiency and, in a freely competitive market, should do so. However, in many regions the storage market is not deemed to be sufficiently competitive to support market-based rates. Therefore companies wishing to offer market-based rates must file for FERC approval.

FERC approval of market-based rates is based on the applicant's ability to demonstrate that it lacks market power in that particular market. This requires a detailed analysis of the geographic situation of the storage facility and a comparison with alternative storage operations within that market. The study places considerable weight on analysis of the applicant's market share and the degree of market concentration. Market share is defined as the ratio of the applicant's working storage capacity to the total working storage capacity in that market. Market concentration is measured by the Herfindahl-Hirschman Index (HHI). A market's HHI is equal to the sum of the squares of each storage provider's market share; the lower the HHI, the lower the market concentration and the greater the competition in the market. In addition, for each service to be provided on a market-based rate the applicant must prove that a 'good alternative' from another operator is available soon enough, has a price that is low enough, and has a quality that is high enough to permit customers to substitute the alternative for the service offered by the applicant.

Obviously the difficulty in such calculations lies in defining the limits of the geographic market within which any one storage facility operates. In addition there may be difficulties related to isolating the market share of a storage operator from other affiliated companies. So far FERC has chosen to regard 'independent' storage operators that are in any way affiliated to other companies offering storage capacity in that market as part of one larger group for market share purposes, making it very difficult for them to gain approval. Therefore it is considerably easier for unaffiliated operators to file for FERC approval of market-based rates. There are also regional advantages in applying for such approval in areas such as the Southwest, where there is already a very low market concentration due to the large number of storage facilities and the degree of interconnectedness of the gas networks in the producing region.

Construction of storage facilities

Construction of storage facilities is subject to a number of constraints including local planning permission, environmental approval and FERC certification of public convenience and necessity. In this process storage developers must submit detailed plans to FERC. FERC also certifies the maximum capacity of storage facilities based on calculations of safe pressure levels within the storage reservoir. Companies wishing to expand or to increase the pressure in such reservoirs must seek FERC approval.

Additional regulations govern the construction of new aquifer storage. Due to concerns about the long-term availability of water in the continental US and the environmental impact of injecting gas into aquifer reservoirs, new gas storage facilities of this type are subject to strict regulation by the Environmental Protection Agency. In general the EPA will only permit the conversion of further aquifers to gas storage facilities if the water is deemed too salty for domestic or agricultural use.

Trends in US storage

The US experience provides a fascinating insight into the development of gas storage in a highly competitive gas market. This section highlights a number of trends that have emerged following FERC 636 which may point the way for the development of storage in other gas markets.

Growth of storage to meet seasonal and peak demand

The deregulation of the US gas market, coupled with growing energy demand and rising appreciation of the environmental advantages of gas as a power generation and industrial feedstock, has led to consistent growth of US gas consumption in recent years. This growth is projected to continue at a rate of roughly 2% p.a. in the foreseeable future, requiring an additional 4 Tcf (110 Bcm) of annual supply by 2010 according to the US Department of Energy. It is not surprising, therefore, that total US storage capacity increased by 206 Bcf (5.9 Bcm) or 6% between 1992 and 1996. At the beginning of 1997 at least 104 storage projects were planned for completion by 2004, adding a further 393 Bcf (11.1 Bcm) of capacity, although it is not expected that all of these projects will come to fruition. Table 8.3 summarises proposed storage facilities by region, type of reservoir and operator.

It should be noted that meeting extra demand is not simply a matter of increasing storage in proportion to demand. Any rise in total demand may also require additional pipeline capacity into a market. In fact there is significant trade-off between new pipeline and storage capacity. In the foreseeable future at least, US and Canadian gas production is theoretically sufficient to meet extra demand merely by expansion of pipeline capacity. On the other hand, as many pipelines still operate at comparatively low load factors during the non-heating season, it should be possible to meet growing demand by storage expansion with only minor changes to the pipeline system. In reality both pipeline and storage capacity will be expanded to meet growing demand, as demonstrated by the 104 storage projects on the table and a number of major pipeline projects currently under construction or planned. The degree to which storage capacity is expanded in preference to transmission capacity will depend on the comparative economics of each option. At present it seems likely that the proportion of peak and seasonal demand that is met by storage gas will increase, because in many areas it will prove a cheaper way to cater for extra demand than by expanding pipeline capacity into the region.

Benefits of high deliverability storage

As noted above, total storage capacity increased by 206 Bcf (5.8 Bcm) over the period 1992 to 1996, a rise of 6%. Over the same period total deliverability from US storage increased by 8 Bcf/d (227 Mcm/d) or 12%. Storage projects proposed for completion between 1997 and 2004 are scheduled to increase capacity by 393 Bcf (11.1 Bcm/d), which is just over 10% on 1997 levels, but deliverability by 11 Bcf/d (0.31 Bcm/d) which is nearly 15%. This is a sign of the growing recognition of the benefits of high deliverability storage. Traditionally, US gas storage facilities have focused on meeting seasonal demand and are designed for comparatively steady withdrawal over the winter period. However, many new storage projects and expansions are designed to allow rapid withdrawal at short notice. The benefits of high deliverability storage include:

- The ability to meet peak demand, replacing other peak-shaving tools;
- Use as a market tool to exploit arbitrage opportunities;
- Cycling to increase efficiency of operation and effective capacity over the course of the heating season;
- The ability to switch rapidly between injection and withdrawal and to operate as a load balancing tool, either for own use or for sale to customers.

High deliverability salt storage

The most obvious form of high deliverability storage involves the use of salt caverns. Salt cavern storage facilities can typically be drawn down completely in around 10 days and re-injected in 20 days. In addition, some salt cavern storage facilities can switch from injection to withdrawal in as little as 15 minutes, providing great flexibility as a peak supply and balancing tool. At the beginning of 1997 there were 27 operational salt cavern storage facilities in the US, providing only 3% (116 Bcf or 3 Bcm) of total US storage capacity, but 15% (11 Bcf/d or 0.31 Bcm/d) of total

Table 8.3: Proposed storage facilities by region, type of reservoir and operator

	Depleted Gas/Oil Field			Aquifer Storage			Salt Cavern Storage			Total		
Region/ Operator	Number of Sites	Working Gas Capacity (Bcf)	Daily Deliverability (Mmcf/d)	Number of Sites	Working Gas Capacity (Bcf)	Daily Deliverability (Mmcf/d)	Number of Sites	Working Gas Capacity (Bcf)	Daily Deliverability (Mmcf/d)	Number of Sites	Working Gas Capacity (Bcf)	Daily Deliverability (Mmcf/d)
Northeast												
Interstate	23	15	250	0	0	0	7	8	870	30	22	1,120
Intrastate	2	18	134	0	0	0	0	0	0	2	19	134
LDC	0	0	0	0	0	0	1	1	64	1	1	64
Independent	1	5	70	0	0	0	3	7	700	4	11	770
TOTAL	26	39	454	0	0	0	11	16	1,634	37	54	2,088
Southeast												
Interstate	1	6	100	0	0	0	0	0	0	1	6	100
Intrastate	0	0	0	0	0	0	0	0	0	0	0	0
LDC	0	0	0	0	0	0	0	0	0	0	0	0
Independent	6	26	270	0	0	0	1	4	400	7	30	670
TOTAL	7	32	370	0	0	0	1	4	400	8	36	770
Midwest												
Interstate	22	14	189	0	0	0	0	0	0	22	14	189
Intrastate	0	0	0	0	0	0	0	0	0	0	0	0
LDC	1	17	200	0	0	0	0	0	0	1	17	200
Independent	3	48	885	2	6	15	1	15	350	5	69	1,290
TOTAL	26	79	1,274	2	6	15	1	15	350	28	100	1,679
Central												
Interstate	3	2	200	0	0	0	1	5	500	4	6	700
Intrastate	0	0	0	0	0	0	0	0	0	0	0	0
LDC	0	0	0	0	0	0	0	0	0	0	0	0
Independent	1	4	120	0	0	0	4	6	500	5	9	620
TOTAL	4	5	320	0	0	0	5	11	1,500	9	15	1,320
Southwest												
Interstate	0	0	0	0	0	0	1	7	600	1	7	600
Intrastate	0	0	0	0	0	0	1	3	350	1	3	350
LDC	0	0	0	0	0	0	1	4	150	1	4	150
Independent	3	90	1,350	0	0	0	6	6	700	9	95	2,050
TOTAL	3	90	1,350	0	0	0	9	20	1,800	12	109	3,150
Western												
Interstate	0	0	0	0	0	0	0	0	0	0	0	0
Intrastate	0	0	0	0	0	0	0	0	0	0	0	0
LDC	4	12	180	1	3	50	0	0	0	5	15	230
Independent	4	64	1,900	0	0	0	0	0	0	4	64	1,900
TOTAL	8	76	2,080	1	3	50	0	0	0	9	79	2,130
US												
Interstate	49	36	739	0	0	0	9	19	1,970	58	55	2,709
Intrastate	2	19	134	0	0	0	1	3	350	3	22	484
LDC	5	29	380	1	3	50	2	4	214	8	36	644
Independent	18	237	4,595	2	6	55	15	37	2,650	35	279	7,300
TOTAL	74	321	5,848	3	9	105	27	64	5,184	104	393	11,137

Note: Salt Cavern Storage includes one proposed mine cavern facility in New York.
Totals may not equal sum of components because of independent rounding.
Source: EIA

deliverability. In the period 1997 to 2004 a further 27 salt storage construction or expansion projects are planned, adding 64 Bcf (1.8 Bcm) of capacity and 5 Bcf/d (140 Mcm/d) of deliverability.

At present 18 of the 27 US salt storage facilities are located in the Southwest producing region, 13 of these being in Texas and 5 in Louisiana. These storage facilities generally serve a dual purpose, having both a traditional storage role and also providing fuel for peaking CCGT plant. The Southwest is an ideal geological location for the construction of salt storage sites due to large salt dome formations in the region. A further 9 such facilities are planned in the Southwest by 2004. The other 9 existing storage facilities are spread through the remaining areas, with the exception of the Western region which does not have suitable geology. Major growth in salt storage is expected in the Northeast and Central regions, where 11 and 5 projects are planned respectively.

Expansions to deliverability at depleted field storage facilities

In many areas there are no suitable salt dome or bed formations in which to build storage facilities. An alternative approach to providing high deliverability storage involves expansion of existing depleted field facilities. The deliverability of a reservoir depends on the porosity and permeability of the rock as well as the number of wells and power of compression facilities. Salt caverns have naturally high deliverability as the cavern effectively functions as one large ‘pore’. Various methods exist to increase the porosity and permeability of depleted field reservoirs, such as cracking the rock or using horizontal drilling to permit greater movement of gas. Retrofitting depleted fields with additional wells and compression also allows operators to withdraw and inject gas at a greater rate.

Significant expansions of deliverability from depleted fields are planned from 1997 to 2004 in all regions, but especially in the Northeast, Midwest and Southwest. If all these projects are completed, total depleted field capacity will increase by 321 Bcf (9 Bcm) and deliverability by nearly 6 Bcf/d (170 Mcm/d), increases of 9.7% and 10.6% respectively. Although the average withdrawal period for depleted fields is over 50 days, a number of high deliverability depleted field facilities exist where stocks can be entirely drawn down in under 10 days. A major example of this is Columbia Gas Transmission’s Market Expansion Project whereby deliverability at 14 fields is being increased by a total of 370 Mmcf/d (10 Mcm/d) by enhancing 277 existing wells, drilling 38 new wells, increasing capacity by 10 Bcf (280 Mcm) in one reservoir and adding 4700 horsepower of storage compression. The increased deliverability should also lead to increased use of capacity, so the Market Expansion Project of Columbia Gas Transmission forecasts that seasonal storage turnover will be increased by 18 Bcf (500 Mcm).

Cycling

Cycling refers to the number of times a storage facility is emptied and refilled in the course of a year. As noted above, US storage sites have traditionally been designed to be steadily injected from April to October and drawn down from November to March. There is some flexibility, as few reservoirs require the full non-heating season for re-injection, and storage operators may delay injection if gas prices are high in early summer. However, one of the benefits of high deliverability salt storage is its potential to be drawn down and re-injected many times within one year. Indeed, in terms of technical feasibility, many salt caverns could be cycled up to 10 times annually. In effect, cycling multiplies the working capacity of a storage facility: a salt cavern with an actual capacity of 2 Bcf could in some ways do the work of a depleted field with a capacity of 20 Bcf!

In practice the level of cycling is much lower, with most salt facilities rarely cycled more than two or three times a year. However, recent years have seen large increases in partial cycling as companies choose to withdraw gas from storage in summer or inject in winter, particularly to take advantage of high prices in part of the non-heating season or low prices for a few weeks of the heating season. Arbitrage of spot and futures markets also contributes to cycling. Market-based rates for storage services are thought to incentivise storage operators to facilitate cycling while, conversely, the cost-of-service rates charged by most storage operators may place a disincentive on storage operators to encourage greater use of their facilities because they can earn as much as they are permitted to without cycling.

Independent storage

Traditionally the major owners and operators of storage have been the interstate pipelines with a smaller proportion of facilities operated by LDCs and intrastate pipelines. In recent years, and particularly since the implementation of FERC 636, a number of ‘independent’ storage projects have been built. Independents may be oil or gas producers (particularly in the case of depleted field storage), marketers, customers or other interested groups. Some independents are alliances of companies from various sectors of the industry.

In January 1997 there were 36 existing independent storage facilities, of which 12 were salt caverns and 24 were depleted fields. Independent storage provided in total 335 Bcf (9.5 Bcm) of capacity (9% of US capacity) and 8.6 Bcf/d (240 Mcm/d) of deliverability (11% of US deliverability). Independent storage is most prominent in the Southwest where there are 16 such facilities, with another 8 in the Midwest, 5 in the Southeast, 3 each in the Northwest and Central regions and one in the Western region. In June 1997 the California Public Utility Commission approved the Wild Goose storage facility, the first independent storage operation in the state. This is likely to open the door for further independent storage in the Western region. Of the 104 known storage proposals in January 1997, 35 for were independent storage operations, spread fairly evenly across the US. These storage projects accounted for 71% of proposed capacity additions (279 Bcf or 7.9 Bcm) and 66% of proposed deliverability additions (7.3 Bcf/d or 210 Mcm/d). However, independent storage projects may lack the financial backing of interstate pipeline storage projects and it is doubtful that all proposed independent storage projects will be completed.

The emergence of market hubs and market centres

A key development in the US gas industry in recent years has been the emergence of market hubs and market centres. FERC 636 promoted the market centre concept as a means to provide the services that had previously been bundled by pipelines. Readily available and preferably high deliverability storage capacity is a vital part of most hubs and market centres, and therefore the development of these facilities has had a major effect on the use and expansion of US storage.

There are now at least 39 active hubs or market centres in North America, 7 of which are in Canada and the remaining 32 in the US. Of these facilities, 27 have become operational since the enactment of FERC 636 in 1993. A number of further hub operations are presently planned or under construction. Hubs and market centres allow companies to manage their gas supply, using services such as parking, loaning and balancing to tailor supply to meet demand on a short-term basis. They also facilitate the transfer of gas from different pipelines, production sources or storage facilities to market. Finally, hub operations assist trading of surplus commodity, pipeline capacity and storage capacity, thus leading to more efficient utilisation of the system.

Physical hubs, market hubs and market centres

Hubs can be defined as physical hubs, market hubs or market centres depending on the services provided and the physical infrastructure of the facility:

- A physical hub is a point at which gas can be transferred from one pipeline to one or more others. Physical hubs may also offer storage and gas processing as in the case of the Aqua Dulce Hub in Southeast Texas;
- A market hub is a facility that complements the transfer facilities offered by a physical hub with hub services to facilitate the buying, selling and transportation of gas within the local facility. Typically such services may include storage, processing, peaking supply, title-tracking, EBB trading, wheeling and transportation. These hub services are explained further below. Examples of the market hubs include the Henry Hub in Louisiana and the Katy Hubs in East Texas;
- A market centre offers the services of a market via the physical infrastructure of one or more pipeline systems. Effectively an entire interconnected pipeline can operate as a market centre, facilitating trading, storage operations, balancing and transportation at any point or between any two points on the system. The Columbia Market Center in the US Northeast is an example of a market centre. The term 'market centre' is sometimes used as a generic term to include both hubs and market centres.

The types of service offered by market centres vary, and no two operations are identical in the services they provide. The various services that may be offered by hubs are summarised below. The definitions are taken from The Federal Energy Regulatory Commission's Office of Economic Policy.

Wheeling: Essentially a transportation service. Transfer of gas from one interconnected pipeline to another through a header (hub), by displacement (including exchanges), or by physical transfer over the transmission of a market centre pipeline.

Parking: A short-term transaction in which the market centre holds the shipper's gas for redelivery at a later date. Often uses storage facilities, but may also use displacement or variations in linepack.

Loaning: A short-term advance of gas to a shipper by a market centre that is repaid in kind by the shipper a short time later. Also referred to as advancing, drafting, reverse parking, and imbalance resolution.

Storage: Storage that is longer than parking, such as seasonal storage. Injection and withdrawal operations may be separately charged.

Peaking: Short-term (usually less than a day) sales of gas to meet unanticipated increases in demand or shortages of gas experienced by the buyer.

Balancing: A short-term interruptible arrangement to cover a temporary imbalance situation. The service is often provided in conjunction with parking and loaning.

Gas Sales: Sales of gas that are used mainly to satisfy the customer's anticipated load requirements or sales obligations to others. Gas sales are also listed as a service for any market centre that is a transaction point for electronic gas trading.

Title Transfer: A service in which changes in ownership of a specific gas package are recorded by the market centre. Title may transfer several times for some gas before it leaves the centre. The centre is merely recording an accounting or documentation of title transfers that may be done electronically, by hard copy, or both.

Electronic Trading: Trading systems that either electronically match buyers with sellers or facilitate direct negotiation for legally binding transactions. A market centre or other transaction point serves as the location where gas is transferred from seller to buyer. Customers may connect with the hub electronically to enter gas nominations, examine their account position and access e-mail and bulletin board services.

Administration: Assistance to shippers with the administrative aspects of gas transfers, such as nominations and confirmations.

Compression: Provision of compression as a separate service. If compression is bundled with transportation, it is not a separate service.

Risk Management: Services that relate to reducing the risk of price changes to gas buyers and sellers, for example exchange of futures for physicals.

Hub-to-hub Transfers: Arranging simultaneous receipt of a customer's gas into a connection associated with one centre and an instantaneous delivery at a distant connection associated with another centre. A form of 'exchange' transaction.

The use of storage at market centres and hubs

Of the 13 hub services outlined above, at least 5 generally require some means of storing gas (parking, loaning, storage, peaking and balancing). It is noticeable that these services (together with wheeling) are primarily operational, and form the central business of most hub operators. Storage capacity is therefore of great value to hub operators in carrying out their most important functions. Hub operators may provide short-term storage by linepacking, or use LNG or propane-air to meet peak supply. However, most rely on underground reservoirs to provide gas storage. There are three hub operators that use only linepack for storage, and six presently have no storage facilities (these are all in the producing areas and are mostly used for gathering, processing and packaging of gas for interstate transportation). The remaining 30 hubs have access to a total of 2,006 Bcf of storage capacity (47% of US total) and 30,149 Mmcf/d (39% of US total). Almost all high-deliverability salt storage can be accessed from operational hubs or market centres.

In recent years, significant developments of hubs and market centres have often focused on increasing nearby storage capacity or deliverability. One example of this is Equitable Storage's Jefferson Island storage facility in Erath, Louisiana. Until the commissioning of Jefferson Island in 1996, there was no gas storage facility directly linked to the Henry Hub, delivery point for the world's most liquid gas futures contract. The addition of such storage is perceived to have a high strategic value providing arbitrage opportunities in futures trading.

A further recent development has been the construction of hubs based on storage reservoirs. Market Hub Partners is a key proponent of this mode of hub operation. MHP has built the following high deliverability storage facilities: Moss Bluff in Liberty, Texas; Egan in Acadia Parish, Louisiana; MS-1 in Copiah County, Mississippi, and is presently pursuing other similar projects including NE-1 in Tioga County, Pennsylvania. MHP aspires to offer a network of strategic market hubs based on storage and accessed via a unified EBB system.

Chapter Nine:

AN OVERVIEW OF STORAGE IN CONTINENTAL EUROPE

Introduction

The European gas market is entering one of the most dynamic phases in its history. The next 20 years will see rapid growth in both domestic and industrial markets. Competition and liberalisation are developing alongside wide-ranging European legislation. The Interconnector has, for the first time, allowed the highly competitive UK market access to the more regulated Continental markets and, as recent experience has shown, the existing players on the Continent have gained access to the UK gas market. The environmental benefits of gas over other fossil fuels in the generation of electricity have also given greater impetus to the production of gas-fired power stations and the convergence of gas and electricity industries.

Western Europe is currently in gas surplus, but increasing demand will necessitate the import of gas supplies from more distant locations. There will therefore be a need for greater storage capacity and flexibility and, with the development of hub services, storage will come into its own as a tool in the hands of commercial managers. This chapter highlights the changing European gas market and the developments taking place in storage throughout the region. Particular attention is paid to the development of liberalisation, with the leading role of the EU, and to how these commercial and legislative measures are having a direct effect on storage planning.

Industry structure and ownership

The structure of the gas market in the different European countries varies considerably from the liberalised and highly competitive UK situation to the monopolistic controlled situation in France, with all shades of opinion between these two extremes. The different industry and market structures are described in the country-specific chapters of the remainder of this report.

The forces for and against liberalisation of the market include political, legislative, commercial, physical and technical factors, and the relative weight of these factors varies from country to country. A previous EJC Energy report, *Natural Gas Trading in Europe*, has examined the issue of European market liberalisation in some detail. Table 9.1 summarises the current position of each country's gas industry and the factors influencing its future development.

Table 9.1: Forces for and against liberalisation in Continental Europe

Country	Forces for liberalisation	Forces against liberalisation	Gas trading developments	Potential trading hubs
Austria	Pressure from industrial consumers. Competition from new market entrants such as Ruhrgas and Bayernwerk. EU Directive.	Dominance of OMV and the regional companies. No third party access (TPA).	Summer trading at Baumgarten.	Potential for an integrated central European trading hub, including Austria.
Belgium	Opening of Interconnector. Pressure from industrial consumers. EU Directive.	Dominance of Distrigaz. No TPA.	Spot trading at Zeebrugge from late 1998 could be followed by basis trading at Belgian border points.	Zeebrugge may become hub for north west Europe.
Germany	Pressure from industrial consumers and power generators. Opening of Interconnector. Passing of energy law.	No TPA. Cross-ownership structure and increasing horizontal and vertical integration.	Summer trading at Emden and other border points.	Potential for Zeebrugge or NBP basis trading at Aachen and Emden. Potential for an integrated central European trading hub, including south west Germany.
Italy	Pressure from power generators and eventually other large industrial consumers. EU Directive.	Dominance of ENI Group. Very limited TPA. Access to supplies difficult for new entrants due to SNAM over contracting supplies.	Separate import contracts by ENEL. Edison looking to purchase foreign supplies directly.	None in the foreseeable future.
Netherlands	Opening of the Interconnector. Pressure from distributors, industrial consumers and power generators.	Dominance of Gasunie in supply, distribution and domestic gas purchases. Access to transportation grid offered on restrictive terms. No TPA for storage or blending stations. Different gas qualities.	Short-term electricity market now developing may impact on gas.	Hub Holland i.e. the Dutch gas infrastructure including Groningen.

Table 9.1: Forces for and against liberalisation in Continental Europe (cont.)				
Country	**Forces for liberalisation**	**Forces against liberalisation**	**Gas trading developments**	**Potential trading hubs**
Spain	Pressure from power generators and large consumers. New Royal Decree and Hydrocarbons Bill. Power of autonomous governments.	Dominant position of Gas Natural/Enagas. Availability of supplies. Financial guarantees needed to support network development.	One year trades for LNG. Short-term electricity market unlikely to have direct impact on gas.	None in the foreseeable future.
France	Opening of the Interconnector. Pressure from industrial consumers. EU Directive.	GDF's legal monopoly on imports and control of transportation and distribution. No TPA. Government supports status quo. Low population density.	GDF may trade gas at the margin.	None in the foreseeable future.
Source: EJC Energy				

The changing face of the European gas industry will have a huge impact on storage. New players will be far more efficient in their use of storage, and the development of trading hubs brings storage into the realm of commercial and competitive advantage. Players that provide the most flexibility will be the winners, and improved flexibility demands increased storage. Currently, gas is stored in a variety of ways across Europe, including liquefied natural gas (LNG) in receiving terminals and peak shaving units, depleted field storage, aquifers, salt cavities and disused mines. The numbers of these facilities is given in Table 9.2.

Table 9.2: Number of gas storage facilities in Europe	
Type of facility	**Numbers**
LNG receiving terminals	7
LNG peak shaving units	10
Depleted field storage	32
Aquifer storage	21
Salt cavity storage	18 (plus 2 under development)
Disused mines	2
Source: Various	

Peak capacity and swing requirements

The European Union gas trade market is likely to grow dramatically over the next 10 to 20 years. The past five years have seen a 26% increase in gas consumption. However, there is still much debate and disagreement over the amount of growth to be expected. In 1996 gas accounted for 22.1% of primary energy consumption in the EU, second only to oil at 42%. Deregulation of the electricity sector and the growing propensity for electricity generators to use gas could mean that the gas share of the EU energy market rises to over 25%. This increase is subject to a number of forecast and planned power generation projects going ahead. (NB: In many respects the forecasts for the market share in the European gas market are highly sensitive to external market forces. For example, the current low oil price of $10 - $11 per barrel had not been forecast, nor had its impact on gas prices. As a result of oil-based indexation on most long-term gas purchase contracts in Continental Europe, gas prices on the Continent are currently lower than those in the UK. The current restriction on the use of gas in power generation in the UK has also had an impact on the size of the UK market.)

There is a large difference between growth rates in the northern countries (Austria, Belgium, Denmark, France, Finland, Germany, Holland, Sweden, UK) and those in the south, whose markets are still developing (Greece, Ireland, Italy, Portugal, Spain). Over the next 15 years it is expected that the southern countries will experience growth of between 100% - 150%, whereas gas markets in the northern countries will grow by about 60% in the same period.

Growth of commercial and domestic demand

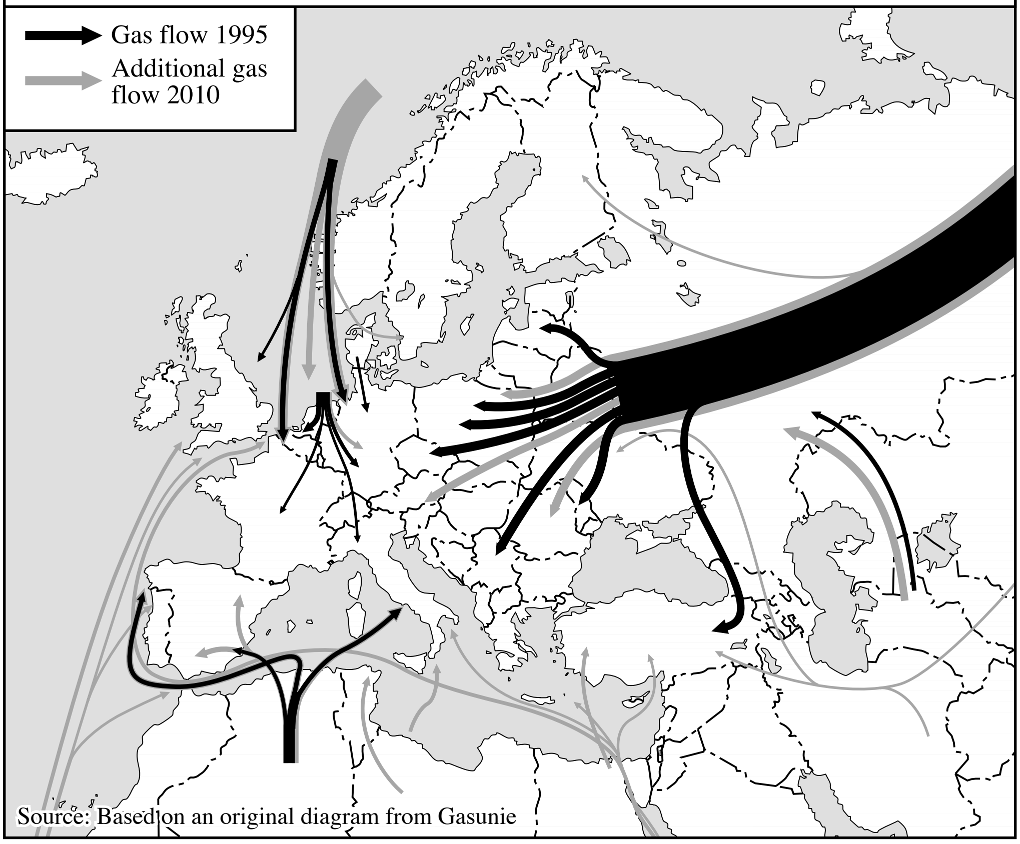
Despite the fact that the majority of gas markets in Western Europe are already fairly mature, the gas market within Europe continues to grow. This is due to two main reasons:

- The environmental benefits of gas over other fuels, and
- The development of new markets such as Greece and Ireland.

The environmental benefits

The perception of gas as a 'clean' fuel, and its relatively low cost, has done much to promote the expected increase in domestic demand over the next decades. Industrial demand is set to rise dramatically as improved gas turbine technology has increased efficiency and reduced construction time and capital cost. Technological advances have been encouraged by the relaxation of European directives on the construction of gas-fired power stations. The availability of large reserves both in Western Europe and further afield have given the industry renewed confidence, and the political changes in Eastern Europe have provided the foundations for a much more closely integrated pan-European gas market. Figure 9.1 shows the expected differences in gas flows into Europe between 1995 and 2010.

Figure 9.1: Differences in gas flows into Europe between 1995 and 2010



Source: Based on an original diagram from Gasunie

In 1997 total gas supply to Western Europe from indigenous production and imports was 360 Bcm. Imports from Russia and Algeria accounted for 17% and 12% of the total supply respectively. Indigenous production, mainly from Norway, UK and the Netherlands, accounted for 70% of the supply.

The development of new markets

New developments in European infrastructure, such as the UK - Ireland Interconnectors, have fuelled a growth in demand as domestic and industrial users sign up for the cheaper and more convenient gas supply. The expansion of the electricity market in a new competitive era has resulted in increased developments of independent power projects in Europe using gas as the primary fuel due to the fact that it is cheaper, easier and quicker to develop a gas-fired power station than a coal or nuclear station.

There is considerable variation in the estimates of future supply and demand in Western Europe. Most estimates up to the year 2010, however, expect surplus supplies due to increased indigenous production, particularly in the North Sea. It is estimated that indigenous production will double by the year 2010. Estimates of supply and consumption data are given in Table 9.3.

Table 9.3: Estimates of Western European gas supply and demand 2000 - 2010		
Year	**Consumption (Bcm)**	**Supply (Bcm)**
2000	365 – 385	370 – 380
2005	430 – 440	440 – 450
2010	430 – 500	500 – 510
Source: Gasunie		

Increased dependency on imports

Although indigenous production in the EU is set to increase, it is expected that this will be outstripped by demand by the year 2010. The Interconnector has been developed partly out of a desire to ensure secure alternative supplies, but it remains a fact that Europe will become increasingly dependent on regions outside its borders for its gas supply. Large quantities of cheap gas may become available through the Yamal pipeline from the former Soviet Union and from other distant and less secure sources. In addition, the LNG market is undergoing a period of growth and is looking for new markets.

Liberalisation

Britain has led the way in terms of liberalising the European gas market. Continental Europe, which has long been a bastion of gas monopoly and long-term contracts, is set to change over the next few years. With the opening of the Bacton-Zeebrugge Interconnector there is, for the first time, a physical connection between the highly competitive, volatile, short-term commodity markets of Great Britain and the more stable managed Continental system. There are a number of additional pressures, including consumer demand and European legislation, that are paving the way for a much more open European gas market.

Open access and unbundling

Unbundling is a term with slightly different meanings depending on the country in which the term is being used. In the UK it is essentially the philosophy ensuring that competition can reach every part of the gas industry. In Continental Europe it is perhaps a more formal concept enshrined in recent European legislation, where gas companies in the EU will have to hold separate accounts for generation, transmission, distribution and other undertakings. This will ensure that distortion of competition cannot take place, particularly where a company holding a monopoly in one area uses that to support its activities in the competitive market.

Open access to the gas market is being encouraged through the Gas Directive. For instance, Member States must designate gas-fired power generators as eligible customers. Additionally, Member States must progressively open supply markets based on a minimum percentage as well as a consumption threshold.

New market entrants

As the European market liberalises, new players are emerging to take advantage of commercial opportunities. UK players are already active in selling gas into the Netherlands, and there are power generation opportunities for the future. As the market develops it is likely that these players will want to acquire storage facilities.

Energy aggregators are already developing in the electricity market, and are likely to play an important role in the gas market as the two industries begin to converge. These aggregators sum the load of a number of individual customers (wholesale and retail) in the same geographical area into a large block with desirable characteristics such as high load factor, and then source other utilities that will serve the load cheaply. If the UK experience is anything to go by, the role of aggregators will be resisted by the incumbent monopoly since it effectively allows new market entrants to beat the threshold limits.

Customer pressure

In such a rapidly changing market the power of the customer should not be underestimated. If large industries find their gas costs unacceptable due to the unwillingness of government to speed up liberalisation, they may well bring pressure to bear by considering relocation to countries where the energy market is more competitive. In a recent discussion with a large French gas user, the user commented that it would actually be cheaper for them to build an independent pipeline to Germany and purchase their gas from Germany than it would be for them to purchase their gas in France.

New infrastructure

The first 25 years of the European gas industry (1970 - 1995) saw a concentrated focus on developing the industry's infrastructure. The main gas routes in the mature Western European gas market have now been created, and future infrastructure developments will centre on expanding these major routes and creating interconnections between them. For instance, the Statpipe, Zeepipe (Belgium) and Europipe lines from Norway are being supplemented by the NorFra pipeline (Belgium) and Europipe II. The Bacton-Zeebrugge Interconnector has just been opened, with potential plans for an interconnector into the Netherlands. A number of German pipelines are also under construction. The Balkan systems linked Bulgaria to Macedonia in 1995, and to Greece in 1996. These developments have ensured that there is a fully integrated pan-European gas network rather than independent national networks, and paves the way for liberalisation in a similar way to that seen in the US market.

Liquefied natural gas (LNG) transported by marine tanker continues to play an important role, although volumes remain small in comparison with pipeline gas. LNG is particularly important for countries such as France, Greece, Spain and Turkey where construction of pipelines to geographically remote sources still proves too difficult and expensive.

Development of spot and futures markets

The UK has seen spot trading, that is short-term contracts of less than one year, taking place since 1992/93 when power generators with surplus gas began to look for buyers.

These early transactions were small volume fixed-price deals conducted over the telephone (so-called Over-the-Counter [OTC] deals). However, in 1995 over-supply in the UK worsened, and gas prices began to fall, with a subsequent increase in gas trading.

At this time there was much discussion about the possibility of Bacton becoming the gas trading hub of Europe. It was situated at the UK end of the Bacton-Zeebrugge Interconnector, and there was the possibility of a screen-based gas trading market being established at Bacton by the International Petroleum Exchange (IPE).

The introduction of the Network Code in March 1996 began the move from a monthly gas balancing regime to a daily system, with much tighter financial constraints. Alongside this came the development of the National Balancing Point (NBP) which is the notional point on the Transco national transmission system through which all gas is deemed to flow, and about which all gas is balanced. This established the first gas trading system hub in the UK.

The introduction of a natural gas futures contract by the IPE in January 1997 has strengthened the futures market in the UK. Further physical gas trading hubs are beginning to develop at Moffat and Bacton, although no other hubs have been able to compete with the volume, liquidity and confidence that has been achieved at the NBP. The IPE market offers the benefits of price transparency, regulation and reduced counter-party risk, and is growing in size and strength.

This activity in the UK is yet to have a major impact on the European market, but the various legislative and commercial pressures mentioned earlier in this section are coming to bear on the European market as a whole. The development of a European spot gas trading market is on the horizon, and Table 9.4 describes a number of areas that have been identified as possible physical trading hubs.

Table 9.4: Possible European gas trading hubs

Potential European gas trading hub	Description
Moffat	UK shippers and producers competing to sell gas into the developing Irish gas market.
Bacton	Strategic European location at the landing point of the Bacton-Zeebrugge Interconnector. Still a popular location for OTC trading. IPE considering developing a natural gas futures contract for Bacton.
Zeebrugge	The more logical end of the Interconnector for development of European gas trading hub due to proximity and size of local market.
Spanish/French border	Growth of Spanish independent power projects has initiated discussion on a spot gas market somewhere in southern Spain or northern France.
Russian/German interface	The Yamal pipeline offers great potential for Russian gas to flow into Europe with development of a spot market, although commentators are pessimistic about this scenario.

Source: EJC Energy

The EU Gas Directive

During the course of writing this report discussions were held with a number of players in the European gas market. Most countries, it appears, see themselves at the centre of the European gas market, running either a ‘locational’ gas hub or a ‘system based’ gas hub that sets prices for a large part of Europe. However, while physical gas trading hubs may develop at some or all of the locations listed in the above table, it seems unlikely that any of these potential hubs would be able to compete with the UK’s NBP gas hub which, as previously mentioned, is home to the IPE natural gas futures contract as well as a large volume of OTC trades. It therefore seems likely that any emerging European gas hubs will trade at a basis to the NBP to take into account European transit charges and local market conditions.

The European Commission and Directorate General for Energy (DG XVII) worked hard during the 1980s and 1990s to build up a consensus on energy policy for the EU. This has not been an easy task, with most Member States preferring the status quo rather than liberalisation. However, a series of liberalising directives (as detailed in Table 9.5), culminating in the most recent Electricity and Gas Directives, have paved the way for change across the EU.

Table 9.5: The process of energy liberalisation in the EU	
Directive	**Description**
90/377/EEC	Legislation ensuring transparency and comparability of electricity and gas prices to large consumers in the different Member States and regions within the States. This standardisation began to lay the foundations for the single market.
90/347/EEC and 91/296/EEC	Directives establishing a framework for electricity and gas transit respectively.
91/148/EEC	Permitted the use of gas in power generation, previously forbidden under Directive 74/404/EEC. Gas is now the second most important fuel for thermal power generation in Europe, after coal
94/22/EC	Allowed access of EU companies to upstream hydrocarbons sector in European Economic Area (EU15 countries plus Norway, Iceland and Liechtenstein) creating the internal market in upstream exploration and production.
Source: Various	

The Electricity Directive 96/92/EC was adopted by the Council of Ministers on 19 December 1996, and came into force on 19 February 1997. Some of the key provisions in the Directive are included in Table 9.6.

Table 9.6: Features of the Electricity Directive 96/92/EC	
Unbundling	Companies must have separate (unbundled) accounts for generation, transmission and distribution. This will avoid any distortion of competition and cross-subsidisation.
Generation	Rights to build generating plant must be offered on an objective and non-discriminatory basis, with Member States having to choose between authorisation and tendering to govern construction of new facilities.
Access	Member States to provide open non-discriminatory access to transmission and distribution networks.
Transmission and distribution	Member States must designate Transmission and Distribution System Operators to dispatch generation and distribution of electricity based on objective, published and non-discriminatory criteria.
Regulation	Little guidance on regulatory mechanism. Although tariffs must be non-discriminatory and transparent there is little guidance on calculation methodology.
Source: Various	

The Gas Directive was adopted by the Council of Ministers in February 1998 and has been ratified by the European Parliament. It contains many of the same principles as the Electricity Directive, but there are some important differences. Member States can choose between 'regulated access' and 'negotiated access' for third parties (Article 14). 'Regulated access' gives eligible customers the right to use gas transport systems on payment of regulated tariffs (Article 16), whereas 'negotiated access' involves the transportation owners and eligible companies wanting to use the system having to negotiate 'voluntary commercial agreements in good faith'.

Member States are required to designate gas-fired power generators as eligible customers. They must also begin to open supply markets based on a minimum percentage and consumption threshold (Article 18). This will result in a progressive opening of 33% of the national markets by the year 2010 (see Table 9.7).

Table 9.7: Progressive consumption thresholds in the EU Gas Directive

Date	Percentage of national consumption	Consumption threshold per annum
June 2000	20	>25 Mcm
June 2005	28	>15 Mcm
June 2010	33	>5 Mcm

Source: EU Gas Directive

In the new competitive market, some companies currently enjoying a monopoly position will suffer declining market share and may have difficulty in meeting take-or-pay commitments. These companies can request a derogation (temporary exemption) from access provisions (Article 25) from Member States, subject to European Commission approval.

Emergent markets are also given protection under the Directive. These countries must not be connected to the interconnected system of another Member State, and must have only one external supplier (with a market share of 75% or more). Only Greece and Portugal qualify as emergent markets, although certain regions in other Member States may also be eligible if there is no established gas infrastructure.

A decade of intense debate and negotiation has produced a Directive that will have some positive impact on the European gas market, but it will be a less forceful impetus for change and liberalisation than had been anticipated. What remains to be seen is how individual Member States interpret the new legislation and transfer it into national policy.

Themes in European Storage

Storage, like everything else in the European gas industry, is being directly affected by liberalisation and competition. What was once a technical and operational issue, and the domain of the engineer, has now moved firmly into the commercial arena. Storage is already being used as a competitive tool, providing advantages of flexibility and secure supply. The role for gas storage in Europe will slowly emerge as member states of the EU embrace competition and implement the EU Gas Directive.

Independent storage

Existing European storage facilities have been designed for use in a monopoly situation. As the market liberalises, new players will be able to use storage facilities in a far more cost-effective way.

Storage has traditionally been used to bridge the gap between peak availability of gas supply and peak demand requirement of the gas supply system. During the summer months and well into the winter there is more than enough gas to meet demand, but as the winter progresses demand exceeds supply and additional supplies must be found. Large storage facilities such as depleted fields, aquifers and disused mines have provided the bulk of this extra supply. Other storage facilities such as salt cavities and LNG provide additional short-term storage with higher withdrawal rates.

Today storage gives gas traders and gas operations controllers trading opportunities to buy at low prices and sell high. Storage also gives them the ability to keep balancing charges to a minimum. Insecure supplies from countries such as Russia and the CIS can also be made more secure by twinning the supply with large existing storage facilities in Europe.

Development of gas hubs and hub services

Gas trading hubs are well established in the US, and there has been much talk of the development of hubs in Europe. It seems likely that the next few years will see a number of hubs established throughout the Continent where gas is physically traded. One of the major features of a gas hub is its ability to maintain a secure and flexible supply of gas, and this demands large storage facilities. It therefore seems likely that most hubs will be situated close to areas of large storage capacity.

The following two definitions cover the range of descriptions of a gas trading hub:

- A physical location on a pipeline system where a number of pipelines converge, a local market is available, and where there is a demand for gas trading by the market, and
- A system hub, such as the National Balancing Point in the UK, where services associated with that system are offered at any point on the system.

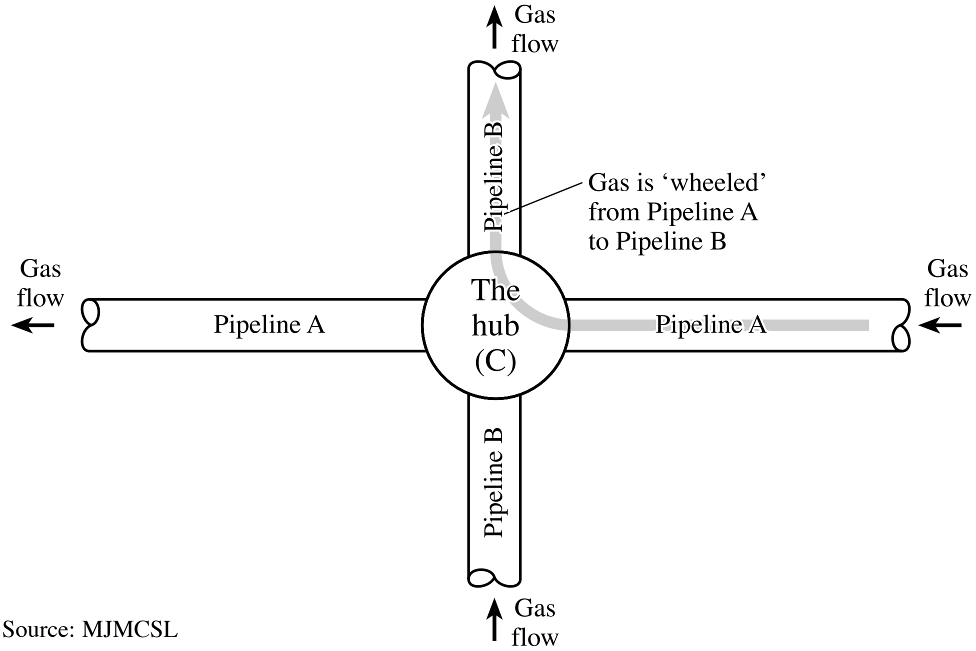
It is likely that Continental gas markets will evolve on the basis of negotiated access for the time being, and therefore trading will be limited to locations where there are sufficient buyers and sellers.

A number of services develop at a gas trading hub to serve the needs of the local market. These services include wheeling, parking, loaning, title transfer and electronic trading.

Wheeling

Wheeling is the movement of gas through a hub from one pipeline into another. This can either be the physical movement of gas (i.e. from pipeline A into pipeline B via the hub C, as shown in Figure 9.2), or virtual wheeling where gas is redelivered to a different point by the hub administrator swapping gas in the various pipeline systems on behalf of the shipper.

Figure 9.2: Hub services – wheeling

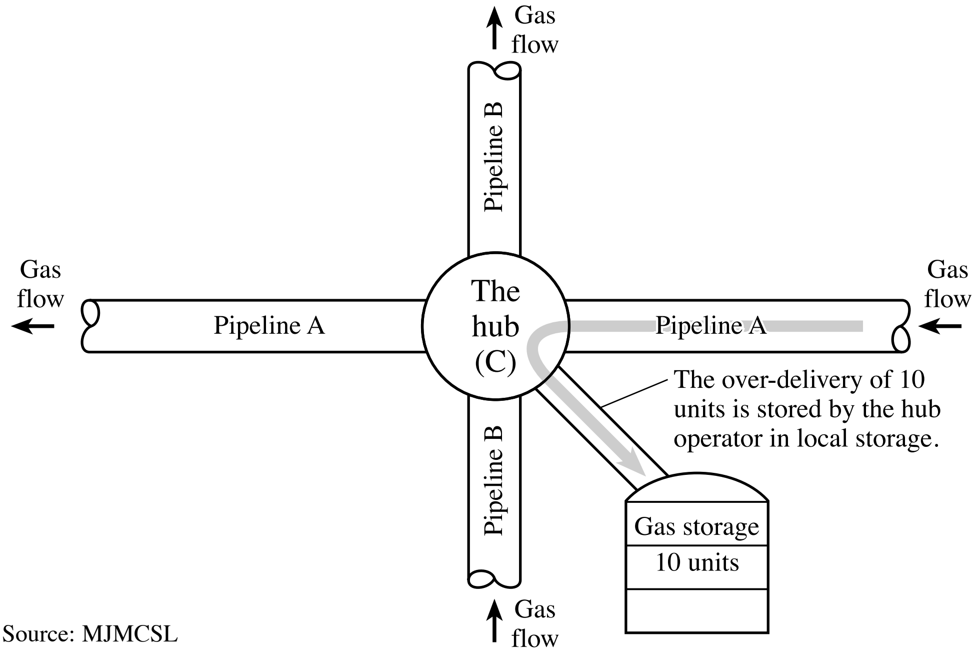


Source: MJMCSL

Parking

Parking is where a shipper stores surplus gas on a temporary basis at the hub. This service employs local storage facilities or gas swaps between shippers to allow those with surplus gas to avoid balancing charges. In Figure 9.3 shipper A has a surplus of 10 units a day. The hub service provider is able to store surplus gas for a small charge, limiting shipper A's exposure to balancing charges. On some occasions the hub service provider can swap this surplus gas with another supplier which has under-delivered.

Figure 9.3: Hub services – parking

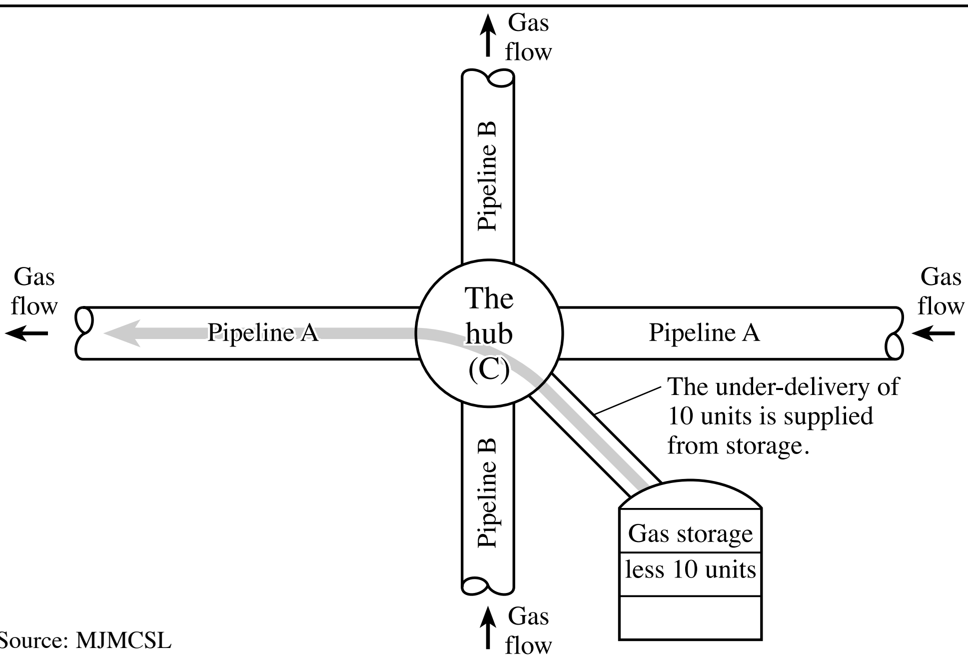


Source: MJMCSL

Loaning

A hub service provider can loan gas on a short-term basis to a shipper that has insufficient gas on a particular day but is expecting additional deliveries or a reduction in demand on the following day. This will help the shipper to avoid balancing charges. Loaning can be considered a peak shaving service when it takes place on days of peak demand. Figure 9.4 shows shipper A to be 10 units short of its required supply, and hub service provider C loaning 10 units of gas to make up the shortfall and help shipper A avoid balancing charges.

Figure 9.4: Hub services – loaning



Source: MJMCSL

Title transfer or title tracking

As the pipeline system becomes longer and more complex, there is an increasing need to track gas accurately in order to ensure the commercial integrity of the network. A hub service provider would take responsibility to track the title of the gas through the system and allow correct allocation from one pipeline to another.

Electronic trading

Gas hubs in the US have been crucial for the development of electronic trading. The New York Mercantile Exchange (Nymex) futures contract at the Henry Hub is a good example of this. The IPE's gas futures market at the NBP in the UK is another example of trading developing at a virtual, rather than a physical, hub.

The potential development of hubs at locations around Europe will have a major impact on storage. The hubs, by definition, require large amounts of storage capability, so there will be a resulting increase in the amount of storage required in Europe.

Exporting flexibility

There is a growing trend towards large diameter pipes bringing gas long distances into Continental Europe from countries such as Algeria, Norway and Russia. These pipelines operate at high load factors, increasing the need for storage, balancing and other gas services close to the market.

A number of major European companies are doing their best to maximise their export flexibility by maintaining large and flexible portfolios enabling them to sell short-term gas to other countries. The obstacle of lack of Third Party Access, however, remains. Gasunie in the Netherlands is particularly well-placed to become a gas trader and to offer balancing services alongside its more traditional role. Average yearly load factors for Dutch exports are only 35%, compared with 80% - 90% for the other major exporters mentioned earlier. Some German companies are already selling small volumes of gas into Poland and the Czech Republic. Other companies, such as Shell, are investigating the possibility of larger diameter pipelines operating at higher pressures of up to 150 bar rather than the normal 80 bar. Operating these pipelines at lower loads would give added flexibility.

The Interconnectors

The connection of the Irish and British gas transportation systems to the Continent via the Interconnectors (Britain to Belgium, Great Britain to Northern Ireland, and Great Britain to the Irish Republic) is a significant development in the production of a vast, integrated pan-European pipeline network. The Interconnectors are more than just a physical connection between countries, they have been the means for opening up competition and speeding the process of liberalisation in some of the more entrenched Continental markets. As the market begins to open up, it is likely that trading hubs will emerge at key connections, such as Zeebrugge.

Arbitrage opportunities

Now that the Bacton-Zeebrugge Interconnector is open there are significant opportunities for arbitrage between the regulated stable prices on the Continent and the more volatile spot prices in the UK. Although it was widely expected that gas would flow in one direction, from the UK to the Continent, for the first years of the Interconnector's life, flow into the UK is already taking place due to low European gas prices.

Dealing could take place in a number of ways, including increased exports in summer when British prices are lower than the Continent's, or reducing exports in order to sell at a higher price on the UK spot market during winter or on a price spike day. This would require complex agreement between the UK seller and the Continental buyer, who would have to find an adequate alternative supply.

The future shows promise for geographical swaps, and one Western European country is already in negotiation with Gazexport for supplies to Polish power stations in exchange for UK gas delivered at Zeebrugge or Bacton.

Storage tariffs

One of the main questions asked by players in the European gas market is how much are the storage tariffs in a particular country. However, with the exception of the UK, none of the European countries publish storage tariffs in the public domain, although a few are now beginning to publish transportation tariffs. In many ways this mirrors the UK experience, where the publication of any form of storage tariff came several years after the publication of transportation tariffs. However, once storage tariffs do begin to be published in Europe, the integrated nature of the European transmission network will open up the opportunity for competition between existing storage providers in various parts of Europe, as well as new market entrants.

Storage regulation

At the time of writing this report, various representatives of the European Commission were meeting with member states to discuss the implementation of the EU Gas Directive. With the negotiations over, the discussions on implementation will centre around the interpretation of the legal text. One interpretation of the Gas Directive is that not only would transportation and storage be unbundled from gas sales, but that transportation and storage would also be separated. If this does happen in a coherent and consistent fashion, then the EU may see higher levels of competition in storage than previously envisaged.

Chapter Ten:

AUSTRIA

Introduction

Although it is a comparatively small gas market in itself, Austria is a key part of the European gas network and is the gateway for Russian gas entering into Western Europe. At present underground gas storage plays an important role in meeting seasonal demands and, in the future, storage facilities in Austria may provide hub services for a number of Western European countries. This chapter briefly outlines the structure of the Austrian gas industry, and examines the state of storage within the industry.

Industry structure

Austria — the gateway for Russian gas

In order to understand the structure of the Austrian gas industry it is vital to grasp the key role played by gas transit. Approximately 70% of the gas that enters Austria is transported across the country and exported to other Western European nations, in particular to Italy, Germany and France. This has been a major influence on the design of the pipeline infrastructure in recent years, when significant pipelines have been built for the purpose of international gas transportation rather than for load distribution.

In a European context, the Austrian pipeline system is of vital importance. Western Europe imports increasing quantities of gas from Russia. With the single exception of a pipeline to Finland, all Russian gas destined for Western Europe is transported via the Ukraine and Slovakia at present to what is effectively a Central European hub at Baumgarten in Eastern Austria. However an important phase of the Yamal pipeline will be completed at the end of 1999 which will provide an alternative route for Russian gas via Poland. At Baumgarten, Russian gas is wheeled to a number of different pipelines for onward transportation within Austria and onward to Italy, Germany, France, the Czech Republic, Slovenia, Croatia and Hungary. Austria's position as a gateway to Europe for Russian gas affords great opportunities for the development of underground storage facilities to serve the European market: opportunities which, at the present moment, are not being seized.

Pipeline infrastructure

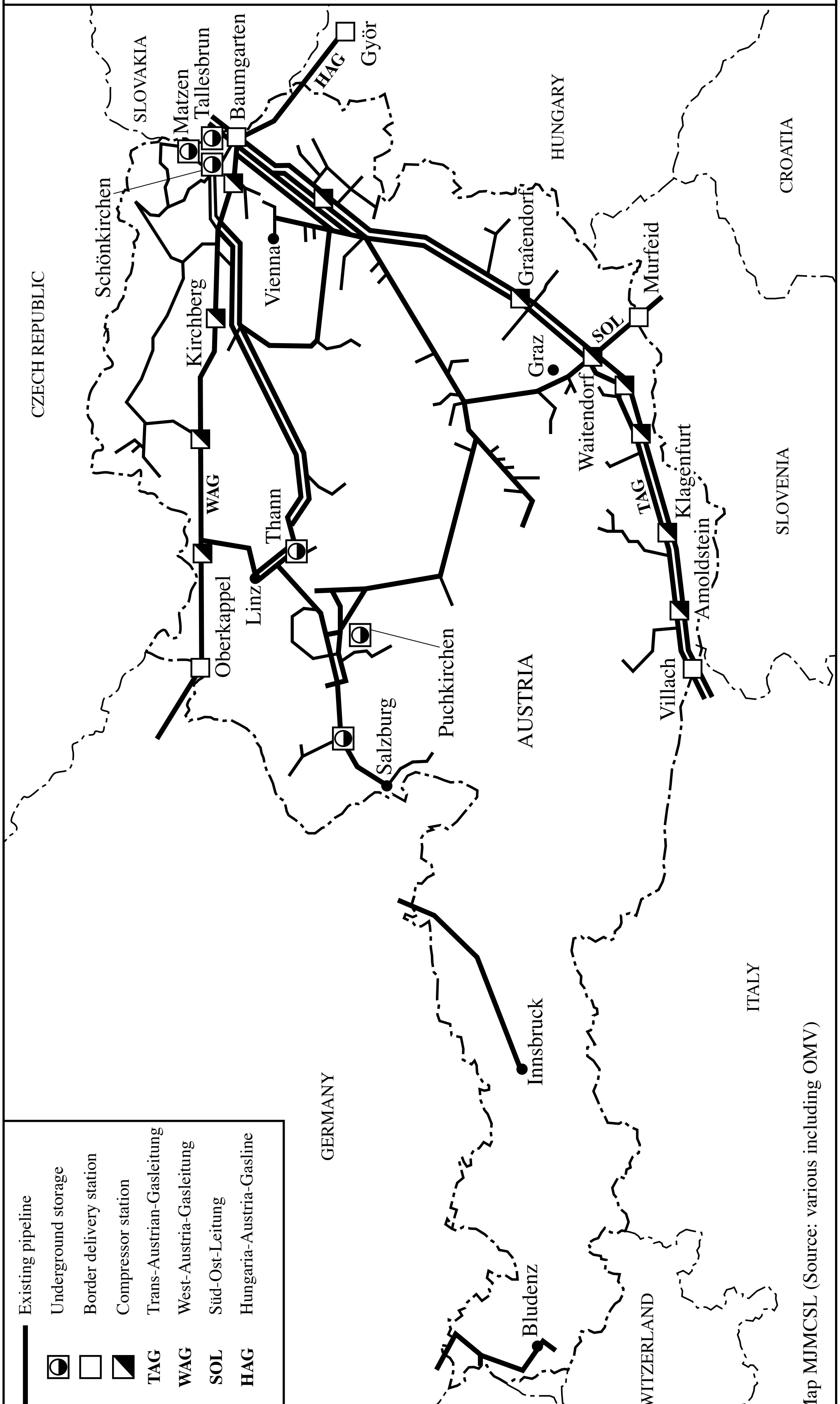
The international hub at Baumgarten has been of major importance to the Austrian gas market since 1968, when Austria signed the first contract by a Western nation to import gas from the USSR. Pipelines radiate north, west and south from Baumgarten. Most Austrian pipelines are designed primarily for international transit but also serve a secondary role of domestic gas supply, with a number of terminals within Austrian territory. For example, 90% of capacity in TAG has been sold under long-term contracts to the Italian company SNAM, but the Austrian transporter OMV retains 10% of the capacity to meet domestic demand.

Table 10.1: Transit pipelines in Austria

Pipeline	Entry Point	Exit Point	Distribution of gas	Capacity (Bcm)	Ownership	Notes
WAG	Baumgarten	Oberkappel (German border)	France and Germany	6	OMV 51% GDF 44% Ruhrgas 5%	
TAG	Baumgarten (Italian border)	Arnoldstein	Italy	23 (30 by 2007)	OMV 100%	
SOL	Graz (TAG)	Murfeld (Slovenian border)	Slovenia and Croatia	3	OMV 100%	SOL is a branchline of TAG
HAG	Baumgarten	Györ (Hungary)	Hungary	4.5	Austrian section: OMV 100%, Hungarian section MOL 100%	Potential alternative route for supplies of Russian gas if gas flow were reversed
Penta West	Oberkappel	Mauerkirchen and Burghausen (German border)	Bavaria	7	OMV 100%	Under construction. As well as delivering gas to Southern Germany, Penta West could operate on a North-South link in the OMV grid, giving European countries access to North Sea gas.
OB	Puchkirchen	Wildenramer (German border)	Bavaria	?	RAG Ruhrgas ? Bayenwerk	RAG has been granted a concession by the MEA to construct a pipeline from Puchkirchen to Bayenwerk's grid in Southern Germany. Following a similar route to Penta West, OB could compete as a North-South link. RAG also has a deal to provide 253 Mcm of storage capacity to Ruhrgas from 1999. This would be accessed via OB or an alternative pipeline built by Ruhrgas.

Source: Various

Figure 10.1: The Austrian pipeline system



Map MIMCSL (Source: various including OMV)

The major extant and proposed Austrian pipelines are described in Table 10.1.

Major players

The producers

The Austrian gas industry is dominated by OMV, the state oil and gas company. OMV is the sole importer and the major transporter of gas in Austria. It is also responsible for over 60% of indigenous gas production. All but one of Austria's significant gas storage facilities are operated by OMV.

Gazprom is the major seller of gas to Austria, although in 1993 a contract was signed for Norwegian gas from the Troll Field. Russian gas sales are handled by GWH, an equal joint venture between OMV and Gazexport (Gazprom's marketing arm), which negotiates with Austria Ferngas (AFG), the trade association of the regional distribution companies.

The only other significant gas producer is RAG, which produces 30% - 40% of Austrian indigenous gas supply. Major shareholders in RAG include Shell (25%), Mobil (25%), EVN (20%) and, indirectly, Bayenwerk (20%). RAG also operates one underground gas storage facility, the depleted field reservoir at Puchkirchen.

The regional distribution companies

Neither OMV or GWH sell gas directly to end-users in Austria. All gas destined for the Austrian market is sold to the eleven regional distribution companies or Ländes Ferngas Gesellschaften (LFGs). Each LFG has a monopoly on distribution and supply in its regional franchise area. The four largest and most influential LFGs are Wiener Stadtwerke, Oberösterreichische Ferngas (in which OMV is the major shareholder), EVN and Steirische Ferngas. The interests of the LFGs are generally represented in negotiations with gas sellers by their trade association, Austria Ferngas. In a similar fashion storage capacity is contracted from OMV and allocated to the various LFGs by internal negotiation.

External players

As a result of OMV's major international transit business, as well as Austria's strategic position, bordering as it does seven other European countries, a number of external companies have an important influence in the Austrian gas industry. The role of Gazprom has already been discussed but, in addition, companies such as SNAM, GDF, Ruhrgas and Bayenwerk (the Bavarian utility) have interests in Austria. GDF and SNAM are major buyers of Russian gas which is transported via Baumgarten and OMV's pipeline system. Ruhrgas and Bayenwerk import some Russian gas via Austria, but also have other interests in the Austrian gas industry. Ruhrgas has struck a deal with RAG to lease storage capacity from Puchkirchen. Bayenwerk is also said to be interested in storage facilities in Austria to supply its expansion of gas-fired generation in Bavaria. Both companies may choose to challenge OMV's de facto transportation monopoly by building pipelines from Southern Germany into Austria. The remote western provinces of West Tyrol and Vorarlberg are not connected to the Austrian grid and are supplied from Germany.

Peak capacity and swing requirements

Average annual gas demand in Austria is around 7 Bcm. Indigenous production has dropped to less than 1 Bcm (0.7 Bcm in 1996). Therefore Austria is heavily dependent on imports (6.4 Bcm in 1996), the majority of which come from Russia (5 to 6 Bcm), although since 1995 Austria has also imported small quantities of Norwegian gas and gas is also imported from Germany to supply West Tyrol and Vorarlberg. Gas may also be brought from Germany on a spot basis to meet unexpected demand. In 1996 Russian imports amounted to 5.7 Bcm, Norwegian imports 0.4 Bcm, and imports from Germany 0.3 Bcm. In addition, 17.6 Bcm of Russian gas was transported through Austria to Italy, France, Slovenia, Croatia, Hungary and Germany.

Russian gas is delivered at a fairly constant rate at Baumgarten, enabling Gazprom's pipelines to operate at a high load factor throughout the year. However, monthly gas demand in winter may be three times that for the summer months. Seasonal supply is guaranteed by significant use of underground storage. This is illustrated by Table 10.2 which compares supply and disposal of gas in Austria during January and June 1996.

Table 10.2: Supply and demand of gas supply winter and summer 1996

	January (Mcm)	June (Mcm)
Indigenous production	131	112
Imports	540	479
Storage withdrawals/(injections)	373	(228)
TOTAL CONSUMPTION	1,044	363

Source: IEA

As can be seen from the above table, roughly one-third of peak month supply is met by the use of stored gas. With the majority of Austria's gas supply imported from distant Russian fields, almost all short-term flexibility must be provided by storage in Austria. The present national storage capacity of 2.8 Bcm and deliverability of 28.6 Mcmpd is largely reserved to meet Austrian swing requirements. Further expansion of capacity and deliverability would probably be necessary if OMV were to offer storage services to clients outside the national boundaries.

Storage facilities available

Types and location of storage

All underground gas storage facilities in Austria are depleted field reservoirs. At present there are five storage operations, four owned by OMV and one owned by RAG. Three of the reservoirs (Matzen, Tallesbrun and Schönkirchen) are located in a cluster within Eastern Austria, near to the international switching point at Baumgarten, the Slovak border, and to OMV's operations centre at Auerstal. The other two sites are located in the industrial region of Upper Austria, being OMV's Thann reservoir near Linz and RAG's Puchkirchen facility near Salzburg. Table 10.3 details the capacity and deliverability of the five storage reservoirs.

Table 10.3: Austrian storage reservoirs			
Site	Ownership	Working Capacity (Mcm)	Daily Deliverability (Mcmpd)
Matzen	OMV	280	2.9
Tallesbrun	OMV	300	3.8
Schönkirchen	OMV	1,490	17.9
Thann	OMV	250	3
Puchkirchen	RAG	735	-
Source: Various including Cedigaz and from the organisations concerned			

Availability of storage

The Austrian storage system is unusual for European gas markets in that in general gas in storage has already been sold to the regional distribution companies but is held in storage by OMV on their behalf. Allocation of storage capacity between the LFGs is negotiated by AFG.

Following major expansion work, storage capacity at Puchkirchen has been leased by RAG to Ruhrgas. Additional storage capacity may also become available to the Austrian and the international market across the German border and, perhaps more significantly, at the Lab site in Slovakia run by Nafta Gbely. Lab and Baumgarten are connected by the March-Baumgarten pipeline.

New storage projects

Expansion of Puchkirchen

In recent years capacity at RAG's Puchkirchen facility has been expanded significantly, from 90 Mcm to 735 Mcm. RAG has made use of this extra capacity by striking a deal with Ruhrgas to provide the German company with 253 Mcm of storage capacity per year from 1999.

Eurostorage Baumgarten

In the mid-1990s OMV had been searching for an international partner to help finance its ambitious plan known as Eurostorage Baumgarten. This proposal entailed development of the Zwerndorf depleted field directly beneath Baumgarten into a major storage facility with a capacity of around 3 Bcm. Linked with OMV's existing storage reservoirs near Baumgarten such a development could offer unparalleled storage services to a range of European customers. In the future it might also enable gas from Turkmenistan, Kazakhstan and Astrakhan to be exported into Central Europe via Baumgarten as Gazprom might be prepared to allow Turkmen and Kazakh gas through its pipelines during the summer months, increasing the pipe's load factor. Some of this gas could then be stored at Baumgarten and transported to market in the winter. At present the scheme has been dropped owing to OMV's failure to attract a partner with sufficient financial backing. A smaller development of Zwerndorf is now planned, although it is still scheduled to provide around 1 Bcm of storage capacity by 2001. New storage projects in Austria by other companies seem unlikely at present.

Storage tariffs

AFG negotiates storage tariffs with OMV on behalf of the regional distribution companies. AFG then allocates storage capacity to the regional distributors according to an agreed formula. The companies are charged for booking withdrawal capacity on a standard price per m^3/hour for each month. The price is calculated by OMV on a cost recovery plus margin basis. There is no commodity charge for storing gas unless a company exceeds its booked capacity. Traditionally OMV has been able to secure storage contracts with a 20-year duration, but the rapid changes in the European gas industry and the development of storage at Lab in Slovakia may affect AFG's willingness to sign such long-term contracts in future.

Uses of storage

As noted above, the major use of storage in Austria is to provide seasonal and peak supply for the Austrian market. In recent years this has been augmented by significant summer spot purchases from Gazprom. Under the LFG's contract terms they are permitted to buy up to 10% of their annual contracted quantity on a spot basis. During the summer of 1997 Russian spot gas prices were low and the Austrian distributors purchased the permitted 10% of their contracted volume on spot rather than under long-term negotiated prices. They then stored the gas for winter use. Gazprom has encouraged this practice in order to increase the load factor of its pipelines during the summer months. If more storage in Austria were developed and utilised, summer purchase and storage of Russian gas transported at a higher load factor could offset demands for new pipeline infrastructure stretching from Russia to Central Europe.

Alternatives to storage

Swing by major suppliers

The great distances from Austria's major suppliers, Russia and Norway, decrease the pragmatic and economic feasibility of replacing storage in Austria with swing from supplies. However, spot purchases in Germany may be used to cover short-term needs.

Regulation

The Austrian gas industry has traditionally had a high level of state ownership at both national and provincial level. As a result of this, regulation is generally light. Due to the federal nature of Austria jurisdiction is divided between the Ministry of Economic Affairs (MEA) and the governments of the Länder (provinces) which oversee the affairs of the LFGs.

Legislation

The production and storage of gas are regulated by the Mining Act, 1975 (Berggesetz). This act requires that companies wishing to produce or store gas seek a licence from the MEA. The Energy Act, 1939 (Energiewirtschaftsgesetz) and the Pipeline Act, 1975 (Rohrleitungsgestetz) lay out the authorisation and licences necessary from the LEA to import and distribute gas, and to build high pressure pipelines, respectively.

Encouraging competition in storage

At present there are few, if any, measures in Austrian regulation encouraging competition in gas storage. However, this may be changed by the enactment of the EU Gas Directive which requires some form of Third Party Access to gas storage facilities. The exact nature of the transposition of the Directive into national law is unclear.

Chapter Eleven:

BELGIUM

Introduction

The Belgian gas market is quite a small one, consuming just over 13 Bcm in 1997, compared to more than 100 Bcm consumed each year by both Germany and the UK. But within Belgium gas usage is quite significant, accounting for 23% of primary energy consumption in 1996. Belgium has no gas producing fields of its own, which makes its gas supply completely dependent on imports.

However Belgium occupies a key position in Europe. It is adjacent to Germany and the Netherlands, which both produce gas, and has connections to the UK and Norway, which both produce gas from the North Sea. Belgium can also import Russian gas, as the new Wedal pipeline connects Belgium to the European mainline system linking Germany, Poland and Russia. Therefore Belgium has a very diverse gas supply, and gas storage is only required to help balance variations in seasonal demand.

The role of gas transit is growing, and in 1997 17 Bcm was transported across Belgium, mostly to France and Spain. This trend has increased with the arrival of the UK Interconnector and the completion of various new pipeline projects in Belgium and countries nearby.

Industry structure

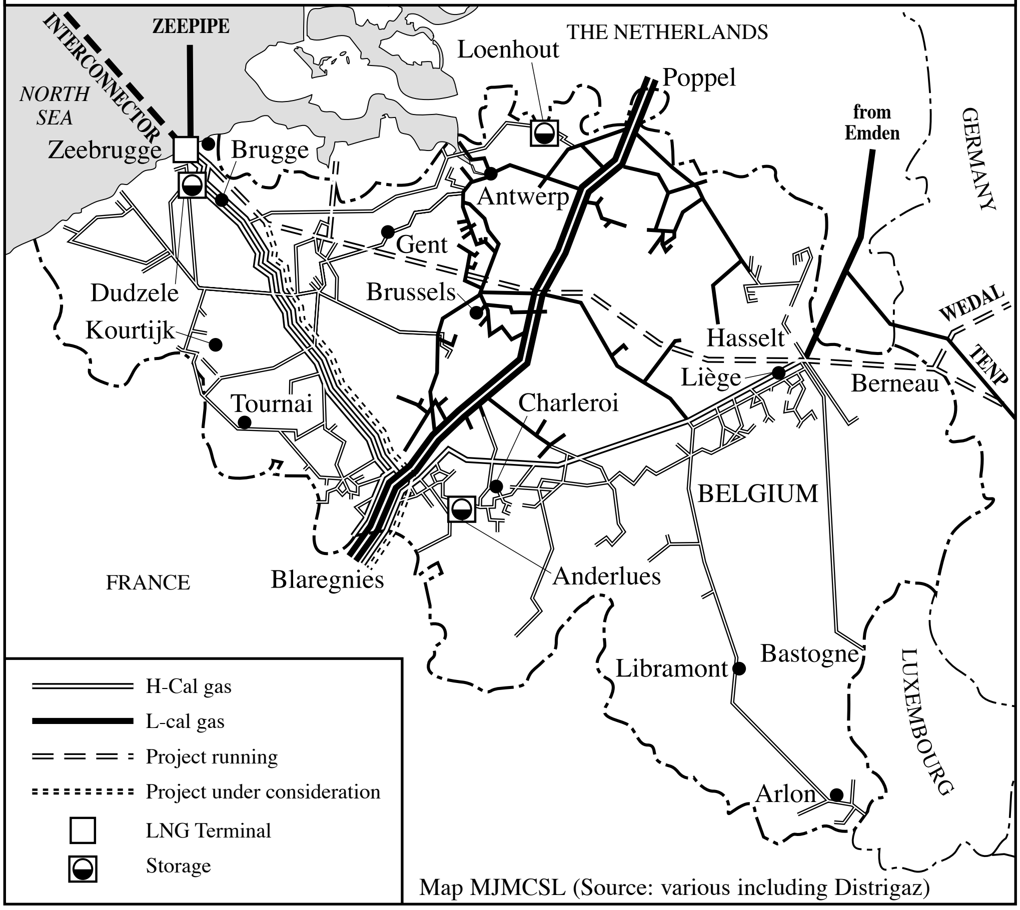
Distrigaz is the largest gas company in Belgium. It has a legal monopoly on transmission and storage, and a de facto monopoly on imports. All the largest gas consumers are supplied directly by Distrigaz, but the rest are supplied by local distribution companies, each with exclusive supply rights in their own regions. These companies all have long-term contracts with Distrigaz for their gas supply.

Major Players

Distrigaz is the only major gas company in Belgium. As mentioned above, it has monopolies on imports, transmission and storage which makes it solely responsible for supplies to Belgium. Distrigaz was privatised in 1998, with the government retaining a ‘golden share’ enabling it to veto key decisions. At present no Third Party Access is offered to pipelines or storage, although current European law requires negotiations to be entered into upon request. A few such arrangements have been made, but Distrigaz’s position as supplier to Belgium is still very secure.

Electrabel, the largest electricity utility, is another major player in the gas market, both through its holdings in the local distribution companies and as a major consumer in Belgium. It is able to participate in negotiations concerning gas supplies for power generation. Recently a joint regasification and electricity plant was built at Zeebrugge with Distrigaz, which increased the efficiency of both companies’ operations.

Figure 11.1: Map of gas network in Belgium



Map MJMCSL (Source: various including Distrigaz)

Pipelines

There are separate pipeline systems in Belgium for low and high calorific gas. Low calorific gas is imported from the Netherlands and transported across the country to France and Spain. The high calorific system is a more extensive system, and takes gas from Norway and the UK to Germany. The role of gas transit in Belgium has grown with the arrival of UK gas from the recently opened Interconnector, which joins Bacton to Zeebrugge. In order to distribute this gas, Distrigaz is investing in its high pressure network, with the so-called "vTn/rTr" project. This links the Belgian system with Zelzate and Gravenvoeren on the Dutch border, and Eynatten on the German border. In the next five years, Distrigaz is intending to invest heavily in transport and pipeline projects.

Peak capacity and swing requirements

The residential/commercial sector consumes over half of the total gas used in Belgium. Since this gas is mainly used for heating, the seasonal variation in gas demand is very high in comparison with the total gas consumed. The table below shows that the gas consumed in January 1997 was nearly three times greater than in July of the same year. On the coldest day, however, the local distribution companies used eleven times more gas than on the warmest day.

Table 11.1: Monthly gas usage in Belgium (Mcm)					
	January 1997	**July 1997**	**Maximum**	**Average**	**Minimum**
Imports	1,651	773	1,651	1,010	733
Injections/ (Withdrawals)	(134)	99	(134)	19	204
Total consumption	1,801	677	1,801	1,105	677
Source: Natural Gas Information, IEA.					

This shows that there is a great need for gas storage, as the current storage capacity is only 500 Mcm, which would be about 9 days supply in January. From the table above it can be seen that gas from storage provides less than 10% of peak winter demand. The rest of the need can be met either by swing from the suppliers, or by short-term “spot” deals. Another option is to rent storage from neighbouring countries with much greater capacities.

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Storage facilities available

Types and Location of Storage

Underground Storage

Belgium has only two underground storage facilities, with a combined capacity of just over 1 Bcm and deliverability of 0.4 Mcm/hour. Their main purpose is to balance seasonal demand variations, and guarantee some supply security against technical problems. However any major supply problem of more than a week in winter, or more than three weeks in summer, will exhaust the entire storage capacity.

Both the storage facilities are owned and operated by Distrigaz. When needed, storage capacity in the Netherlands and in France is rented.

Table 11.2: Underground storage facilities in Belgium					
Location	**Start date**	**Storage type**	**Depth (m)**	**Working gas volume ($10^6 m^3$)**	**Maximum withdrawal rate ($10^3 m^3/h$)**
Anderlues	1975	Depleted mine	120–1,100	164	42
Loenhout	1985	Aquifer	1080-1260	900	354
Source: Distrigaz, Cedigaz.					

Other - LNG

In 1991 a LNG receiving terminal was opened in Zeebrugge with 261,000 m^3 of LNG storage capacity (156 Mcm natural gas). This capacity can be increased if the need should arise. Already an additional above-ground LNG storage facility has been built at Dudzele, near Zeebrugge. This can hold the equivalent of 66 Mcm of natural gas. However it is probably easier, and cheaper, to arrange extra deliveries of LNG when required than to build extra LNG storage facilities.

New Projects

Studies are underway to increase the working capacity of the storage facility at Loenhout. It is thought that the facility can be extended to a maximum of 1.4 Bcm. Distrigaz plans to invest BF 0.8 billion over the next five years in improving its storage facilities.

Alternatives to storage

Apart from storage, peak winter demand can be met by interruptible contracts, supply swing, or short term spot purchases of additional gas. Previously the short-term purchases have brought in some LNG to meet requirements during winter. About 10% of the gas sold by Distrigaz is under interruptible contracts. Further details of contracts, availability of swing gas or storage costs are confidential, the latter being incorporated into the price of the gas.

Regulation

Legislation

There are two laws that affect the Belgian gas industry:

- Law of 12 April 1965, as amended, a general law on gas transportation, and
- Law of 29 July 1983, which grants Distrigaz an exclusive concession to the transport and storage of gas.

The national government, through the Ministry of Economic Affairs, plays a major role in the gas sector since it holds a ‘golden share’ in Distrigaz. This allows it to veto decisions made by the company’s board that are deemed to be against the government’s energy policy. These rights are granted to the government under the Royal Decree of 16 June 1994. However some changes are likely to be enforced when the EU Gas Directive comes into play.

Encouraging competition in storage

It is unlikely that there will be any competition at all on the Belgian gas market unless it is enforced by European Law. The European Commission is looking to introduce competition into the European gas markets, but this is still a long way off.

Chapter Twelve:

FRANCE

Introduction

Gas plays a relatively minor role as a fuel in France, accounting for only about 14% of primary energy consumption, a figure well below the European average. The residential and commercial market accounts for nearly 60% of gas demand, which is not surprising as almost 40% of French homes are heated by gas. This demand is expected to grow by around 2.5% per year over the next few years. Therefore there is an obvious need for storage, to balance out seasonal variations in gas demand. The future of gas in power generation depends on whether the government continues to support nuclear power, which now accounts for almost 80% of the country's electricity production. A recent government study has shown that gas powered generation is the most competitive, and more power stations are being converted to run on gas.

Gas storage plays a key security of supply role, as domestic gas reserves are declining and now account for only 7% of the gas consumed in France. The rest is made up by imports, the major suppliers being Russia (30%), Norway (28%), Algeria (20%) and the Netherlands (14%). There has been considerable investment in research and development of new storage techniques, and France has extensive storage capacity both at home and abroad.

This storage capacity is also a major asset when the position of France as a gas transporter is considered. Currently gas is transported across France to Spain and Portugal. The ability to take LNG has helped in a recent complex swap deal where France has taken delivery of Nigerian LNG for Italy, some of which will be transported to Italy, the rest being made up of volumes of gas from Russia. The storage facilities owned in Europe increase France's options in such deals, and the large capacity available at home gives the choice to divert imports from elsewhere.

Industry Structure

Local distribution is carried out by companies holding a long-term concession granted by the local municipality. These concessions confer exclusive rights and obligations on the holder to distribute gas in a defined area, generally a single commune, or a few communes. (NB: A commune is a small localised community of gas users.)

In many cases, gas and electricity distribution services are horizontally integrated. The largest company, Gaz de France, runs over a hundred regional distribution centres with Electricité de France, the state-owned electricity monopoly. As a result of a strategic alliance with Elf, a leading gas producer, Gaz de France has also become more vertically integrated.

Primary responsibility for regulation of the gas industry lies with the Ministry of Industry, the Ministry of Economy and the Ministry of Budget. Gas prices in all sectors are controlled by the Ministry of Finance through an agreement with Gaz de France.

'Competition' is due to be introduced in all areas which have no supply, but after new coverage plans are drawn up Gaz de France will have three years to take the first pick, thereby ensuring it will retain total domination.

Major players

The French gas industry is dominated by Gaz de France (GdF), which has a legal monopoly on imports and controls most of the transmission and distribution networks. It also owns 13 of the 15 gas storage facilities in France, and has the use of one of the others. Like its sister company, Electricité de France, GdF is fully state-owned, and both have strong government support to keep their dominant positions.

To date, GdF's upstream participation includes ownership of the Trois Fontaines gas field, and a 50% share of the Paris-basin oil field St Martin de Bossenay. These assets will be very valuable in the long term, as it will soon be possible to convert both into storage. These will be France's first gas storage facilities to use depleted fields, the cheapest form of storage, and should significantly increase the total storage capacity in France. The Trois Fontaines field is likely to yield over 0.4 Bcm of working gas when converted.

GdF has extensive gas production, storage and distribution interests in many countries in Central and Eastern Europe, including Slovakia, Germany, Hungary, Slovenia, the UK North Sea and Austria. Further afield GdF has invested in storage projects in Canada and Uruguay. This, together with its investment in research and development, gives it considerable knowledge and experience in storage techniques.

Elf Aquitaine is the largest gas producer in France, and a subsidiary of Elf. It owns the Lacq production field (the largest in France) and the nearby storage facility at Lussagnet in south-west France. It also owns 70% of Gaz du Sud-Ouest (GSO), the owner and operator of the transmission network in south-west France. GSO supplies about 10% of gas sold in France but is not involved in local distribution. The other major gas producer is Total, which also owns shares in a few smaller French companies.

Pipelines

The rate of grid expansion has markedly slowed in recent years, since most urban areas are already connected. According to the IEA, about 70% of the population in urban areas are within the supply area, and about 40% of households within that area are connected.

GdF has agreed to share the cost of a submarine pipeline with it's Norwegian partners (NorFra) from the Norwegian area of the North Sea to Dunkerque on the French coast, and this pipeline is currently under construction. GdF has transit deals, either for current or future supplies, to carry this Norwegian gas to Spain and Italy, and is improving its infrastructure to cope with the larger imports. The planned Les Marches du Nord-Est, linking Northern France with Alsace, will join the Belgian and Swiss systems, and constitute an essential element in strengthening France's position in natural gas transit across Europe.

GdF's monopoly is likely to come under threat as a result of cheap UK gas flowing through the Bacton-Zeebrugge Interconnector. Both Elf and the larger industrial customers want to import gas directly. Elf in particular needs to find alternative supplies for the south west to replace its declining domestic reserves.

Peak capacity and swing requirements

Present storage capacity represents just under one-third of the gas consumption for an average climatic year, and also serves to guarantee very high instantaneous outputs. On the coldest day of the year, consumption could be ten times that of the warmest day. Table 12.1 shows how marked this difference is even on a monthly basis. Proof of the importance of holding substantial gas stocks is that on 2 January 1997, when the average temperature was -6.2°C, demand reached GdF's absolute record, and it had to call on underground storage to supply 52% of consumption.

As already mentioned, the bulk of gas is used in heating, and with domestically-produced gas volumes becoming less and less significant, France is very dependent on swing gas and gas from storage to meet the winter demand. In January 1997 consumption was nearly twice the average figure. Gas from storage made up 60% of this extra demand, the remainder coming from swing negotiated with the suppliers, and from slightly increased domestic production. A swing factor of 125% is common, although details of the contracts agreed are confidential.

Table 12.1: Monthly gas usage in France (Mcm)

	January 1997	July 1997	Maximum	Mean	Minimum
Indigenous Production	238	252	252	219	166
Imports	3,617	2,844	3,617	2,945	2,383
Injections/ (Withdrawals)	(1,684)	1,147	(1,684)	18	1,419
Total consumption	5,874	1,561	5,874	3,034	1,313

Source: Natural Gas Information, IEA

Storage facilities available

Types and location of storage

Underground storage

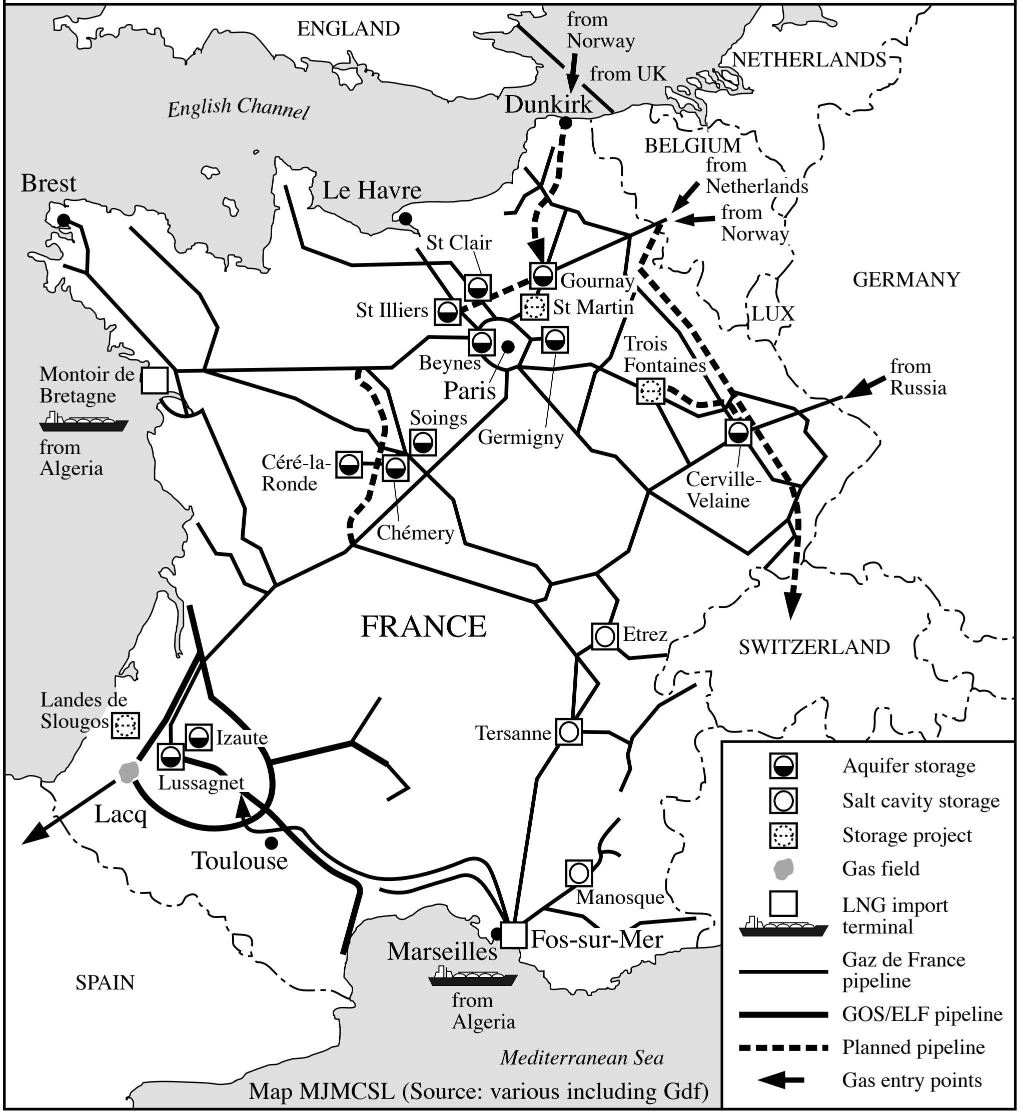
There are 15 underground storage sites in France in deep rock or salt formations, with a working volume of 10.5 Bcm. GdF owns 13 of the sites, and has the use of one of the other two, both of which belong to Elf Aquitaine. Of the 15 storage locations, 12 are aquifers and three are salt caverns. France is unusual in that there is at this time no storage in depleted fields, and aquifers and salt cavities are relatively expensive to develop. However, these storage sites in France are used to their full potential. The aquifers have enough capacity to be able to balance out the seasonal demands, and the salt cavities are able to meet any peak flow requirements. The following table summarises the information about the sites.

Table 12.2: Details of underground storage facilities in France					
Location	**Start date**	**Storage type**	**Depth (m)**	**Working gas volume (10^6m^3)**	**Maximum withdrawal rate ($10^3m^3/h$)**
Beynes Supérieur	1956	Aquifer	405	210	188
Lussagnet	1957	Aquifer	600	720	625
St Illiers	1965	Aquifer	470	730	667
Chémery	1968	Aquifer	1,120	3,500	1,771
Tersanne	1970	Salt cavities	1,400	230	675
Cerville-Velaine	1970	Aquifer	470	700	200
Beynes Profond	1975	Aquifer	740	400	375
Gournay sur Aronde	1976	Aquifer	750	1,000	729
Etrez	1979	Salt cavities	1,400	430	833
St Clair sur Epte	1981	Aquifer	742	325	167
Izaute	1981	Aquifer	487	1,250	375
Soings	1981	Aquifer	1,135	215	75
Germigny	1982	Aquifer	892	680	292
Manosque	1993	Salt cavities	1,250	300	7881
Céré-la-Ronde	1993	Aquifer	900	100	458
Source: Various, including,Cedigaz, GdF					

Other - LNG

France has two LNG terminals, one at Montoir and one at Fos, which are used to import LNG from Algeria, and recently from Nigeria on behalf of Italy. There are two LNG storage tanks which together store the equivalent of 0.5 Bcm of natural gas.

Figure 12.1: Map of French gas network



New projects

Several improvements are being made to existing facilities. Both the Gournay sur Aronde and Germigny sites are near to Dunkirk, where the NorFra pipeline enters the French system, and enhancements are planned in order to improve the transit services that can be offered. The aquifer at Chémery is the second largest in the world, and can be made larger still. It is hoped to increase the total capacity by 400 Mcm. Additional salt cavities are planned at Etrez and Manosque.

In July 1995 GdF and Geopetrol purchased the Saint Martin de Bossenay oil field from Shell and Elf. The field will be converted into a storage facility by GdF when it is depleted, probably during 1999. In 1994, GdF purchased a gas field at Trois Fontaines which should be converted for storage by the year 2000.

A large new aquifer is planned for Landes de Siougos, which will be able to store almost 3 Bcm of working gas. It will be well placed near the pipeline to Spain, which already purchases storage capacity from France.

GdF has invested a great deal in research and development. Much of this has been in experimenting with new techniques of gas storage. One successful experiment involves replacing the first 20% of the expensive cushion gas in a storage facility with an inert gas such as nitrogen. This technique has already been implemented in three of the French storage facilities. Other areas of research have looked towards enabling storage facilities to be developed where the geological structure would not normally support this. An experiment has been conducted by GdF in Sweden as to the possibility of storing gas in steel-lined caverns. Tests on this are still underway, as also are tests on the possibility of storing gas in salt layers only 100 metres thick as opposed to the previous requirement for layers 250 metres thick.

Storage tariffs

Due to the fact that at this time there is no gas-to-gas competition in France, and unbundling of transportation and storage has not occurred, no storage tariffs are available.

Alternatives to storage

Interruptible contracts

Large industrial customers have the option of firm or interruptible contracts. The tariffs contain a small standing charge, which is uniform throughout France, and a load factor charge which varies by region, pipeline type, volume, season and the cost of alternative fuels. Prices to large customers are confidential. Contracts are typically 80% take-or-pay.

Large interruptible customers can make one-off spot trades with GdF. New interruptible customers can have contracts that allow them to switch between gas and alternative fuels as market signals dictate. Interruptible customers are rarely, if ever, interrupted. It has been estimated that, with the current amount of gas in storage, France could withstand a whole year of one of its major sources of gas supply being cut off.

Regulation

Legislation

Gaz de France (GdF) was established as the national gas utility under the 1946 Nationalisation Law (46-628). This granted GdF a legal monopoly on imports and exports, and control over most of the transmission network. In addition GdF was granted an exclusive right to distribute gas in France apart from areas already covered by the local distribution companies.

According to the 1946 law, primary responsibility for regulation of the gas industries lies with the Ministry of Industry, Post and Telecommunications, the Ministry of Economy and the Ministry of Budget. These ministries are also represented on GdF's board of directors.

The Direction du Gaz, de l'Electricité et du Charbon, a department in the Ministry of Industry, is responsible for formulating and implementing energy policy. It is also responsible for supervising the activities and operations of the state-owned energy companies. The Ministry of Economy and the Ministry of Budget supervise tariffs, capital expenditure and the macroeconomic impact of energy policy.

All gas transporters operate under exclusive concessions granted by the Ministry of Industry. Under the 1993 Privatisation Law, gas transportation can only be carried out by companies that are at least 30% state-owned. Before that time gas transportation companies were required to have a majority state holding. The rights and obligations of the concession are outlined in Decree No 85-1108 of October 1985, which obliges transporters to guarantee continuity of supply, to comply with tariff rules contained in the license, and to treat all customers in a non-discriminatory way.

A licence is required to construct and operate storage facilities. However, since storage does not fall under the scope of the Nationalisation Law, there is no minimum state shareholding. The terms and conditions of a storage licence are laid out under Decree No 85 of 1985.

Encouraging competition in storage

Any changes to French legislation are likely to be driven by the EU Gas Directive. However, any undermining of the monopolies of the French state-owned energy companies, Gaz de France and Electricité de France, is being fought against by the French government, which has already succeeded in ‘watering down’ the liberalisation enforced by the EU directive. Since the European Commission is finding it very difficult to get any notion of competition into the French gas market, any sort of competition in storage is unlikely in the foreseeable future.

Chapter Thirteen:

GERMANY

Introduction

The German gas market is the second largest in Europe, behind the UK, and its central position in Europe means that changes in Germany are felt all over Europe. In 1997 natural gas accounted for 21% of primary energy requirements. At the moment gas storage is used almost exclusively in order to balance out seasonal demand variations, and capacity is being increased to guard against possible future supply interruption. However, some gas is bought and stored in Germany over the summer, then sold on to other countries in the winter, particularly to countries in Central Europe which have high swing requirements, such as the Czech Republic. Germany has relatively little storage compared to consumption. In 1997 100 Bcm was consumed, compared to 16 Bcm current storage capacity.

Industry structure

There are many different gas companies involved in the German gas industry at every level. Companies are both private and publicly owned and privatisation is on-going, with some municipalities looking to sell off their shares. There is a high degree of cross-ownership, which makes the market very complex.

In Germany there are 11 domestic gas producers, 18 gas merchant companies, and over 700 local or regional gas distribution companies. The market is dominated by the largest merchant companies, who own extensive pipeline networks. They buy gas from domestic and foreign producers, and sell it on to local distribution companies, industry, and power stations.

Virtually all contracts are long term Take-or-pay, and much emphasis is placed on security of supplies for the future. Therefore Germany has a number of long-term commitments to a wide variety of countries including Russia, Norway, Denmark and the Netherlands.

Regulation is light, and there are no controls on pipelines or storage. There is no obligation on pipeline owners to offer Third Party Access (TPA), although in some cases agreements have been negotiated. The main laws are the new Energy Law, which was passed in March 1998, and the Competition Law, but more legislation will be required when the EU Gas Directive finally comes into force.

Major players

Ruhrgas is by far the most important company, and is responsible for nearly half of German gas imports/production, supplying almost two-thirds of the market. It is a gas merchant company, with its own extensive pipeline network. This gave it a virtual transport and supply monopoly until Wingas was formed in 1992. Ruhrgas's operations are concentrated in the industrial north-west, where most of its pipeline network is laid (see Figure 13.1), although Ruhrgas is also involved right across Germany. It owns 12 underground storage facilities, with a combined capacity of over 5 Bcm. This will be increased by 0.5 Bcm when the sites are completed. Ruhrgas has stakes in many gas companies within the German market, and co-operates closely with many others.

Wingas, another merchant company, is the main competitor to Ruhrgas. A joint venture between Wintershall and Gazprom, it started building its own pipeline network in 1993 (see Figure 13.2). It has been expanding ever since, and now holds a market share of over 10%. It is looking to increase this share to 15% by 2005. Wingas owns one storage facility, at Rehden, now undergoing expansion work which will increase the capacity to over 4 Bcm. Wingas has also invested in several new storage projects, and when all are completed will have a total storage capacity of about 5 Bcm.

BEB is the largest domestic gas producer, and also held the largest underground storage facility until Wingas expanded its Rehden unit. Now it owns at least part of 4 storage sites, which have a total capacity of 3 Bcm and which after completion will store over 4 Bcm.

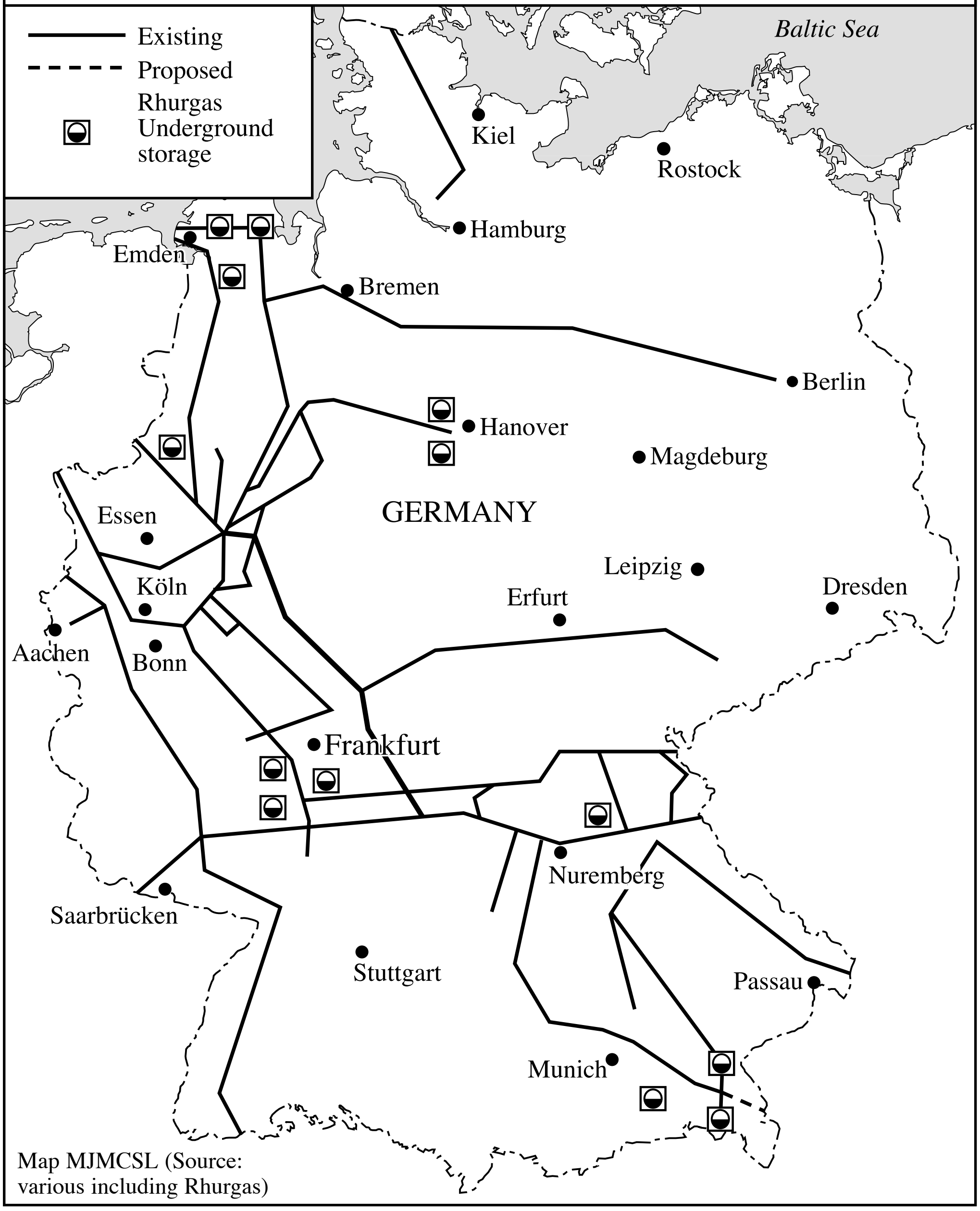
Verbundnetz Gas (VNG) is the largest East German supplier, previously holding a 90% market share in the former East Germany. Five years ago it owned all the underground storage sites in former East Germany, but more recently other companies have developed new sites there. VNG currently operates seven storage sites, and is developing two more. This gives it over 2 Bcm current storage capacity, which will increase to 4 Bcm by 2005. VNG was privatised in 1990, and its main shareholders are Ruhrgas and Wingas.

Thyssengas co-operates with Ruhrgas in the Rhineland, and has agreed separate supply areas with Ruhrgas. The recently-amended Energy Law has since made such agreements illegal. Although it owns three storage sites, the total capacity is less than 0.7 Bcm. The sites are being expanded, and Thyssengas will increase its capacity to nearly 1.5 Bcm.

Pipelines

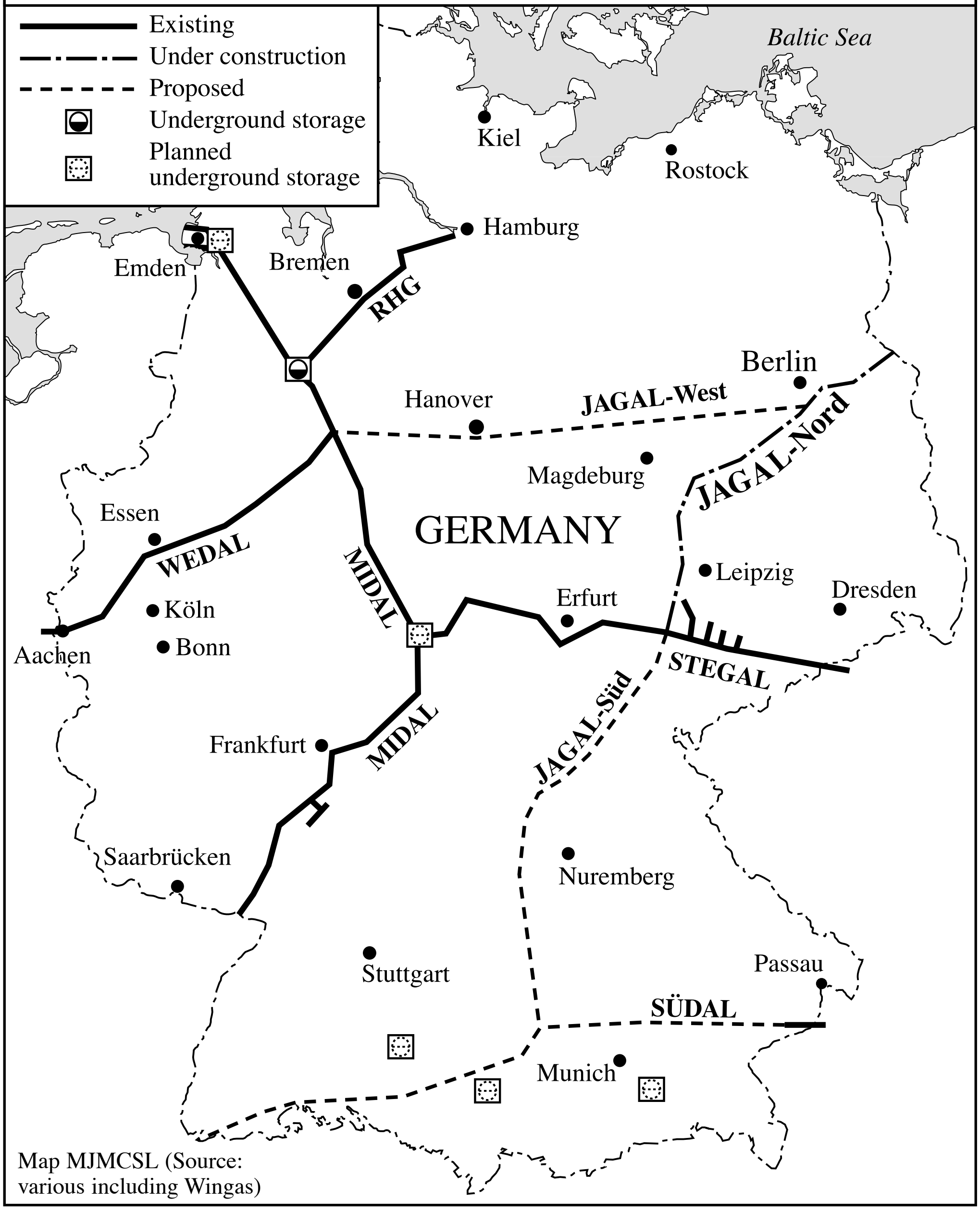
There are two major pipeline networks in Germany. Ruhrgas owns and operates the larger, which is more concentrated in the industrial north-west. Figure 13.1 shows the larger pipes of this network, and the company's dominance in the west. Through this network Ruhrgas supplies 60% of the German gas market. Since Ruhrgas will not allow Third Party Access to its pipelines, the only way to compete with Ruhrgas is through an independent network. Therefore Wingas have recently constructed a more widespread network, which is still expanding quickly as more customers are added. It brings direct gas-to-gas competition in the locality of the network. There are three planned long-distance connections that will soon be added to the Wingas system. From Figure 13.2 it can be seen that on completion of these pipelines Wingas will have a centralised efficient network, and will be in a position to challenge the market dominance of Ruhrgas.

Figure 13.1: Map of Ruhrgas gas network



Map MJMCSL (Source: various including Rhurgas)

Figure 13.2: Map of Wingas gas network



Peak capacity and swing requirements

In 1997 gas consumption in Germany was about 100 Bcm, of which just over 20% was produced domestically. Therefore it can be seen that Germany is heavily dependent on imports, and Ruhrgas in particular is actively seeking to diversify its supply sources in order to maintain security of supply well into the next millennium.

The residential and commercial sector consumes almost half of the total gas on the market, and uses much of this for heating. As a result of this, demand for gas varies greatly with the outdoor temperature and therefore the time of year. From the Table 13.1 it can be seen that in Germany as a whole, gas consumption was over four times greater in January than in July during 1997. The demand in January was over 5 Bcm more than the mean demand. Nearly two-thirds of this extra gas was provided by gas storage.

Table 13.1: Monthly gas usage in Germany during 1997 (Mcm)					
Monthly gas usage	**January 1997**	**July 1997**	**Maximum**	**Average**	**Minimum**
Indigenous Production	2,409	1,426	2,409	1,840	1,383
Imports	8,612	6,352	8,787	7,240	5,538
Exports	446	247	446	330	214
Injections/ (Withdrawals)	(3,042)	2,311	(3,042)	270	2,311
Total consumption	13,724	3,279	13,724	8,351	3,279
Source: Natural Gas Information, IEA					

The rest of the additional gas required came from swing gas negotiated with each supplier. This is agreed confidentially at the start of the supply contract. Looking at the above table, however, it seems that the usual amount of swing gas supplied is 20%. Germany's own gas production is 30% greater in winter than on average.

In the future, some cheap spot gas may be available in the summer from the UK via the Interconnector, and stored in Germany for use in the winter. This will further increase the role of gas storage in the gas industry. Already some seasonal gas is being bought on the German border from foreign companies who have spare capacity in the pipelines over the summer. This gas is then stored for use in the winter. The details of these deals are not published, although the gas is sold within the framework of the existing long-term contracts.

Storage facilities available

Types and location of storage

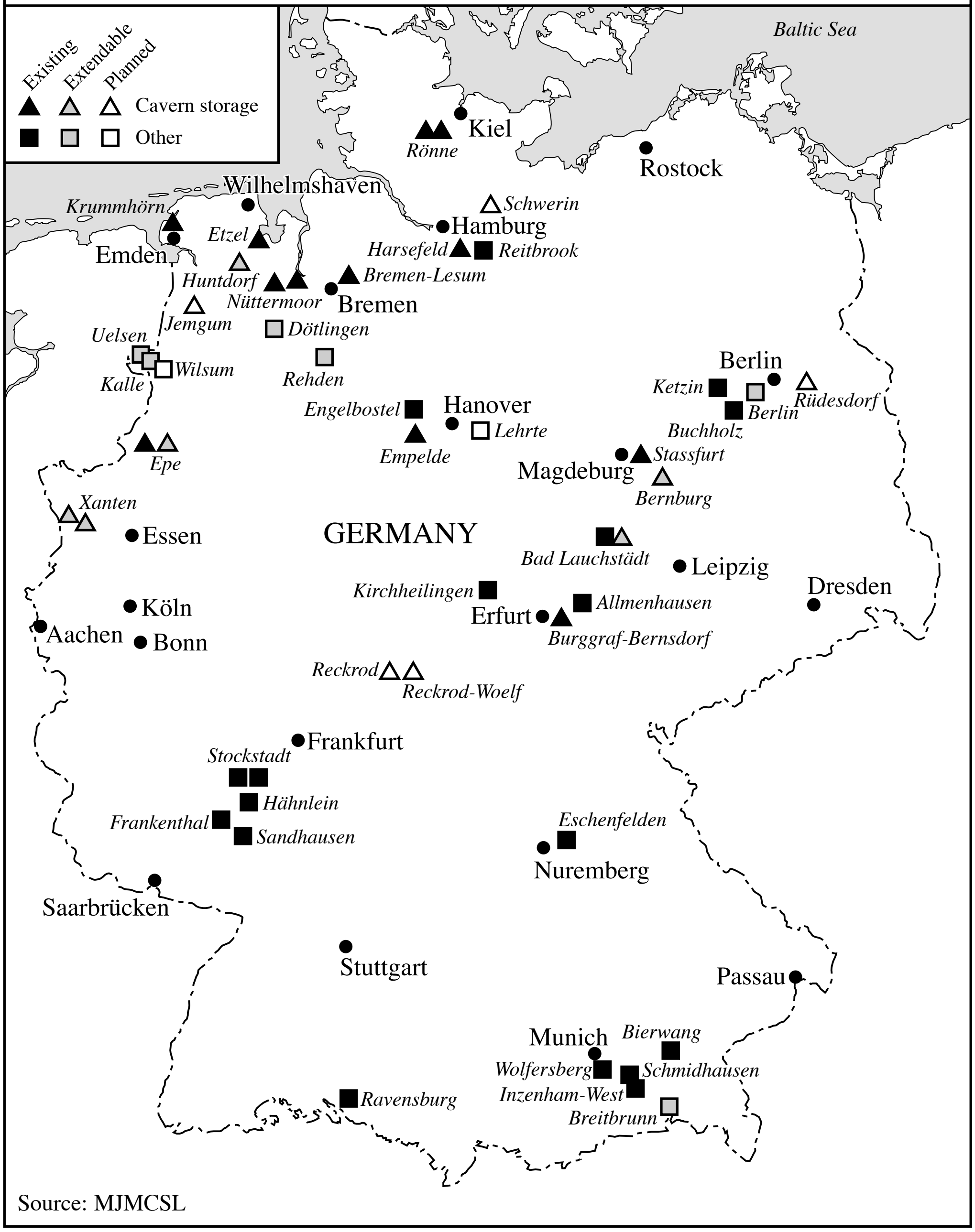
Underground storage

The situation of each of the former Germanies is very different and, although Germany has been unified for some time, these differences are still very marked. In former East Germany the use of gas for heating has been rising, and so larger seasonal variations in gas demand have been occurring. This has led to the storage capacity in former East Germany increasing by some 50% over the last five years in terms of working gas, and now totals nearly 2.7 Bcm. However, the former East Germany is still a long way from catching up with the former West Germany in terms of storage capacity.

Industry has played a greater part in the former West Germany, and the residential/commercial sector also consumes larger quantities of gas. Since geological structures limit the possibilities for storing large amounts of gas, many medium-sized storage facilities have been developed. These are mainly concentrated in the north-west, where the need for storage is greater due to the higher consumption of gas by heavy industry. The share of natural gas in the energy market is increasing, and storage capacity has risen rapidly from about 8.5 Bcm in 1994 to over 16 Bcm at the present time.

Currently in Germany there are 42 storage sites in operation. Of these sites 17 are in salt caverns, 14 in depleted fields (including two in depleted oil fields), 10 in aquifers and one in a former salt mine. Of these sites, six are being expanded and there are also six new projects under consideration/construction. Figure 13.3 shows that although there are sites all over Germany, the bulk of the facilities are concentrated in the industrial north-west. Because of the geology of Germany, the salt caverns and aquifers tend mostly to be located in the north of this region, where the rock structure is more suited to that kind of gas storage. Tables 13.2 and 13.3 outline the characteristics of the existing and planned storage facilities respectively.

Figure 13.3: Map of showing location of storage facilities



Source: MJMCSL

Table 13.2: Operational underground storage facilities

Name/place of storage	Location	Year opened	Owner/operator	Storage type (no. caverns)	Depth (m)	Current (working gas) volume (10^6m_3) (Mcm)	Current (working rate) (10^3m^3/h) (Mcm)	Future (working gas) volume (10^6m_3) (Mcm)	Future (working rate) (10^3m^3/h) (Mcm)
Allmenhausen	Thuringia	1996/7	Contigas	Depleted field	350–400	30	24	30	24
Bad Lauchstädt		1978	Verbundnetz Gas	Depleted field	800	426	238	426	238
Bad Lauchstädt		1979	Verbundnetz Gas	16 caverns	780–950	709	833	790	833
Berlin		1994	GASAG	Aquifer	800–1,000	339	360	800	–
Bernburg		1974	Verbundnetz Gas	26 caverns	500–700	769	1,250	1,134	1,250
Bierwang	nr Munich	1975	Ruhrgas	Depleted field	1,560	1,500	800	1,500	1,200
Breitbrunn		1997	RWE-DEA (Ruhrgas)	Depleted field	1,900	550	250	1,080	500
Bremen-Lesum			Stadtwerke Bremen	2 caverns	1,090–1,320	–	–	82	80
Buchholz		1976	Verbundnetz Gas	Aquifer	570–610	125	58	125	58
Burggraf-Bernsdorf		1970	Verbundnetz Gas	Former mine	580	3	40	3	40
Dötlingen	Oldenburg	1983	BEB/MEEG	Depleted field	2,650	2,000	790	2,800	840
Empelde	nr Hanover	1982	GHG	3 caverns	1,300–1,800	150	300	150	300
Engelbostel	nr Hanover	1954	Ruhrgas	Aquifer	200	40	65	40	65
Epe	nr Münster	1976	Ruhrgas	32 caverns	1,090–1,420	1,500	1,500	1,500	1,500
Epe	nr Münster		Thyssengas	5 caverns	1,200	196	380	603	520
Eschenfelden	Nuremberg	1974	Ruhrgas/EWAG	Aquifer	600	72	130	72	130
Etzel	Wilhelmshaven	1993	Ruhrgas/EGL	9 caverns	1,100–1,700	500	1,310	500	1,310
Frankenthal	nr Worms		Saar Ferngas	Aquifer	600			650	100
Hähnlein	nr Darmstadt	1960	Ruhrgas	Aquifer	500	80	100	80	100
Harsefeld	nr Stade	1994	BEB	2 caverns	1,150–1,450	150	300	150	300
Huntdorf	Wesemarsch	1975	EWE	4 caverns	650–850			160	350
Inzenham-West	Rosenheim	1982	RWE-DEA (Ruhrgas)	Depleted field	900	500	280	500	280
Kalle	nr Bentheim		Thyssengas	Aquifer	2,100	305	350	400	350
Ketzin		1964	Verbundnetz Gas	Aquifer	230	135	79	135	79
Kirchheilingen		1976	Verbundnetz Gas	Depleted field	900	170	187	170	187
Krummhörn	nr Emden	1977	Ruhrgas	3 caverns	1,500–1,800	110	250	110	250
Neuenhuntorf			NWK	2 caverns					
Nüttermoor	nr Leer		EWE	15 caverns	950–1,300	1,180	950	1,180	950
Nüttermoor	nr Leer		Ruhrgas	1 cavern	900	110	100	110	100
Ravensburg	Fronhofen	1997	PEG/GVS	Dep. oil field	1,750–1,800	70	70	70	70
Rehden	nr Diepholz	1994	Wingas	Depleted field	1,900–2,100	2,650	1,950	4,200	2,400
Reitbrook	nr Hamburg	1986	PEG/Mobil	Dep. oil field	640–725	350	350	350	350
Rönne	nr Kiel 101	1971	Stadtwerke Kiel	1 cavern	1,300–1,400	2	50	2	50
Rönne	nr Kiel 102	1996	Stadtwerke Kiel	1 cavern	1,400–1,600	60	100	60	100
Sandhausen		1994	Ruhrgas	Aquifer	600	26	45	26	45
Schmidhausen	nr Munich		PEG/BEB/Mobil	Depleted field	1,000–1,100	150	150	150	150
Stassfurt		1996	VEW	1 cavern		20		20	
Stockstadt	nr Darmstadt	1991	Ruhrgas	Depleted field	500	45	45	45	45
Stockstadt	nr Darmstadt		Ruhrgas	Aquifer	460	90	90	90	90
Uelsen		1997	BEB	Depleted field	1,500	750	450	1,000	450
Wolfersberg	nr Munich	1973	RWE-DEA	Depleted field	2,930	320	210	320	210
Xanten	Niederrhein	1984	Thyssengas	8 caverns	1,000	192	280	460	560
					TOTAL	**16,374**	**14,714**	**22,073**	**160,454**

Source: Various including; International Gas Report, Cedigaz and direct contact with companies.

Table 13.3: Planned underground storage facilities

Name of site	Location	Year due open	Owner/operator	Storage type (no. caverns)	Depth (m)	Maximum working gas volume (Mmcm) after completion	Maximum working rate (Mmcm) after completion
Bad Lauchstädt		2005	Verbundnetz Gas	2 caverns	780–950	(790)	
Bernburg		2005	Verbundnetz Gas	10 caverns	500–700	(1,134)	
Epe	nr Münster		Thyssengas	8 caverns	1,200	(603)	
Holtgaste	Jemgum		Wintershall	12 caverns	1,000–1,450	720	
Huntdorf	Wesermarsch		EWE	2 caverns		(100)	–
Lehrte	nr Hanover	1999	PEG	Depleted field	1,000	74	130
Reckrod-Woelf			Wingas	3 caverns	700–1,100	120	–
Reckrod	nr Fulda	2002	Gas Union	2 caverns	700–1,100	300	600
Rehden	nr Diepholz	2000	Wingas	Depleted field	1,900–2,100	(4,200)	(2,400)
Rüdesdorf	nr Berlin		EWE	4 caverns		300	
Schwerin		2000/4	Hein Gas	2 caverns	430		
Wilsum	nr Bentheim		VEW	Aquifer	1,900	250	
Xanten			Thyssengas	5 caverns	1,000	(450)	
				TOTAL NEW STORAGE		1,764	730

Source: Various including, International Gas Report, Cedigaz, and direct contact with storage providers.
Note: Bracketed figures indicate storage extension, and are not included in the total.
Due to the commercial and operational sensitivities associated with some of these projects, not all the relevant information was publicly available.

LNG and pipeline storage

There was a minor gas supply crisis in Germany some 25 years ago, as a result of which plans to construct an LNG terminal were drawn up. The crisis, however, was resolved before any work started on the terminal, which would have been situated in the port of Wilhelmshaven. The plans are still considered as being up-to-date and ready for use if another crisis should occur. The projected LNG terminal would give Germany the ability to import LNG, and provide 144 Mcm of storage.

Technischewerke Stuttgart has operated an underground LNG storage facility for the last 25 years. This holds the equivalent of 18 Mcm of gas. A similar unit is operated by Thyssengas near Neuss.

Competing pipelines may have excess capacity, and can store gas under pressure when they are otherwise not in use. The largest example of this is a pipeline being constructed by Stadtwerke Paderborn in the north of Rhine-Westphalia which, on completion, will be able to store 300 Mcm of gas when it is not in use.

Availability of storage

Storage facilities, like the pipeline networks, are not normally used by third parties. Wingas has sold virtual storage to Czech and Slovak companies. Small quantities of Russian gas purchased by these companies in the summer are stored at Rehden, and then taken back from Wingas volumes passing through the Czech Republic and Slovakia in the winter. Ruhrgas uses its storage solely for its own purposes.

New projects

Even if no new projects are added, storage capacity will increase by 50% over the next 10 years. If capacity continues to increase at the current rate, then storage capacity could well be doubled by the year 2005. However, even with a storage capacity of 30 Bcm, Germany will still be heavily dependent on imports, and a major supply interruption of more than a few months will cause serious problems for industry.

Storage tariffs

These are confidential, and are individually negotiated on the rare occasions storage is offered to third parties. The everyday cost of operating the storage facilities is incorporated into the price of the gas. Details of the alternatives, such as swing from suppliers or interruptible contracts, are also unavailable.

REGULATION

Legislation

Regulation has always been light, but this may have to change if the policy of the EU towards the liberalisation of gas markets is pursued. So far there are two main laws that affect the gas industry:

- The Energy Law of 1935 (partly replaced by the new Energy Law of March 1998), and
- The Competition Law of 1957 (amended in 1990).

The Energy Law consists of the basic requirements i.e. the licensing and publication of certain information as required by the governing authorities from any company wishing to supply energy.

The Competition Law gives ultimate oversight on competition matters to the Federal Cartel Office (FCO). The industry is not regulated to ensure competition, but instead the FCO has power to prohibit abuse of a market-dominant position and to prevent mergers.

The Competition Law allowed the energy companies to agree exclusive supply zones to limit competition between them in certain areas. However, the new Energy Law has since made such agreements illegal. The new Energy Law also facilitates some form of Third Party Access (TPA) to the electricity grid, and increases the priority of environmental issues in the energy industry. A further law regarding TPA to the gas pipelines will be necessary in order to comply with the EU Gas Directive.

Encouraging competition in storage

As in the UK, before competition emerges in storage there must be a competitive gas market. At present this is not the case in Germany, as lack of TPA means that the only way to compete in the market is to build an independent pipeline system. However the EU Gas Directive, when integrated into German law, will require increased TPA, especially to storage facilities. Ruhrgas, and some other major companies who have benefitted the most from having no competition, are strongly opposed to any form of liberalisation. Wingas, major gas consumers and much of the German government are seeking to encourage liberalisation. Therefore, any progress will be slow, and many compromises will need to be reached before competition emerges in the German gas market.

Chapter Fourteen:

ITALY

Introduction

Italy has one of the greatest needs in Europe for gas storage. Gas accounts for 26% of primary energy consumption, and this is expected to grow to 33% by the year 2000. This makes Italy the third largest gas user in Europe, behind the UK and Germany. However, domestic gas reserves are diminishing and, at present, two-thirds of gas supplies are imported. This figure is increasing, making Italy ever more dependent on imports.

The main problem is that Italy is far from any major gas producing countries, and the cost of transporting gas over long distances is high. Also, political instabilities in some of the producing countries and the countries that the gas is transported through en route to Italy cause concern for supply security. Therefore storage plays a major role in smoothing over any temporary supply interruptions.

In addition to this, the greatest demand for gas within Italy comes from the residential/commercial sector and is mainly used for heating. This puts a large seasonal variation on gas requirements, and storage capacity is needed in order to even out the load during the year.

Therefore it is no surprise that Italy has one of the largest storage capacities in Europe, with a total capacity of nearly 15 Bcm and deliverability of about 170 Mcm per day.

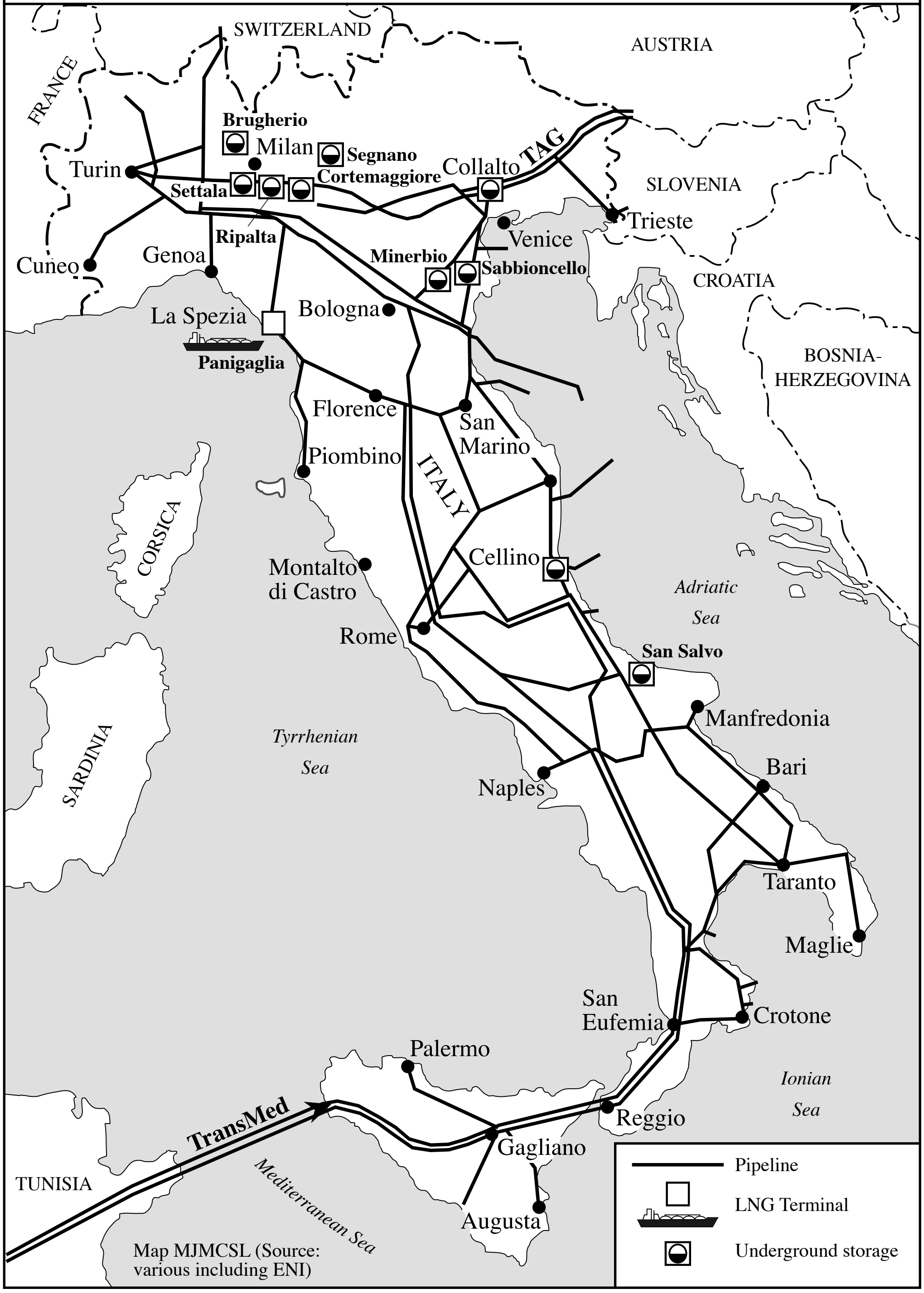
Industry structure

Major Players

The Italian gas industry is dominated by ENI, the state controlled oil and gas group, which has recently been privatised. The government has retained a golden share. During the privatisation, two subsidiaries were formed, Agip and Snam, to take care of some of ENI's operations. Both Agip and Snam are wholly owned by ENI. Agip looks after the exploration and production of oil and gas, and also runs most of the storage sites. It dominates domestic production (90%) and has a virtual monopoly on gas storage. Snam now owns and operates the transmission system, including the LNG facilities. It has a de facto monopoly on imports and transmission.

Edison is a fully privatised company and an affiliate of the Montedison chemical group. It produces gas domestically, and has converted two depleted fields into storage facilities. However, although these could be expanded, their working gas total only makes up 1% of all the available working gas in storage facilities in Italy. Edison has recently been foiled in an attempt to bring more Russian gas onto the market through the planned Volta pipeline. Plans for the Volta pipeline have been shelved since Snam's recent contract with Gazprom. It is in Gazprom's interests to delay competition, as gas prices are kept higher.

Figure 14.1: Map of Italian gas network



Italgas is a group of distribution companies, owned partly by ENI. It controls distribution in cities such as Rome, Florence and Venice.

Enel is the state-owned electricity monopoly, and is the largest single user of gas in Italy. It is supplied mostly by Snam, but also negotiates some of its own supplies independently. However it is still reliant on Snam to import and transport the gas.

Pipelines

The pipeline systems carrying gas to Italy are expanding as a North Italy ‘hub’ is planned. Already there are several long-distance pipelines which are being upgraded to handle greater capacities:

- Trans-Mediterranean Pipeline (TransMed) carrying gas from Algeria via Tunisia;
- Trans-Austria Gasleitung (TAG) carrying gas from Russia via Slovakia and Austria;
- Transitgas carrying Dutch gas from the Trans-Europa Naturgas Pipeline (TENP) via Switzerland.

ENI has interests in all of these pipelines via Snam, and is also committed to developing pipelines to Croatia and Greece. The domestic transmission system has also been improved, but as yet there is no competition at all. Although other parties are legally allowed to construct their own facilities to import gas, no successful attempt has been made to do so. ENEL had plans to construct its own LNG terminal, which would have made it less dependent on Snam, but the plans were refused on environmental grounds.

Peak capacity and swing requirements

There are large seasonal variations in gas demand throughout the year, as most gas is going to the residential/commercial sector for heating purposes. However, the proportion of gas used for power generation is increasing, and this trend is forecast to continue into the foreseeable future. As a result of this, the variations in demand have become less dramatic over the last few years. The table below shows that Italy is largely dependent on imports for its winter supply, with domestic production and stored gas providing only 23% and 18% of this respectively. The rest of the winter demand must be met either by short term spot purchases, or by swing from suppliers.

Table 14.1: Monthly gas usage in Italy (Mcm)

	January 1997	July 1997	Maximum	Average	Minimum
Indigenous Production	1,734	1,632	1,748	1,606.0	1,374
Imports	4,434	2,592	4,434	3,259.0	2,131
Exports	7	1	8	3.5	1
Injections/ (Withdrawals)	(1,335)	654	(1,335)	20.0	955
Total consumption	7,447	3,530	7,447	4,823	2,525

Source: Natural Gas Information, IEA.

Storage facilities available

Types and Location of Storage

Underground Storage

In Italy, storage locations are developed not just to help meet seasonal variation in demand but also for strategic protection against possible supply interruptions. As mentioned already, interruptions need to be taken into account because of the political instability in some key countries, and the fact that imported gas has to travel long distances to reach Italy. For example, the reservoir with the greatest capacity is situated near the TransMed pipeline used to import Algerian gas, and can cope with a temporary suspension of deliveries. All of the storage facilities have been constructed using depleted fields, the cheapest form of storage.

Table 14.2: Underground storage facilities in Italy

Location	Date	Operator	Depth (m)	Current working gas volume ($10^6 m^3$)	Current withdrawal rate ($10^3 m^3/h$)
Cortemaggiore	1964	Agip	1,500	930	514
Sergnano	1965	Agip	1,300	2,400	1,404
Brugherio	1966	Agip	1,100	680	204
Ripalta	1967	Agip	1,500	1,350	833
Minerbio	1975	Agip	1,300	3,300	1,512
San Salvo	1982	Agip	1,050	3,300	1,200
Cellino	1985	Edison	600–1,000	75	33
Sabbioncello	1985	Agip	1,100	1,140	540
Settala	1986	Agip	1,150	1,600	756
Collalto	1994	Edison	1,500	45	13
			TOTAL	14,820	7,009

Source: ENI, Edison

Other - LNG

There is one LNG site currently operating in Italy, at Panigaglia. Several attempts have been made to build another on the mainland but all have failed on environmental grounds. However, if the new plans for an offshore LNG terminal are approved, then the role of LNG will substantially increase.

New Projects

As gas fields run down, ENI is always seeking to convert them into storage fields. Its aim is to increase its working gas capacity to 18 Bcm by the year 2000. There are a number of such fields under study, but no definite information about any new storage projects under construction.

Edison is currently expanding its Collalto facility. Within five years the working gas capacity should have reached 515 Mcm, with a peak withdrawal rate of 200,00 m^3 per hour.

An offshore LNG plant is planned by Mobil/Edison. It will be located near the Po delta, an area already rich in gas fields, and therefore with an existing pipeline infrastructure. If this goes ahead the terminal will be able to provide 4 Bcm a year from 2001.

Alternatives to storage

There have been some short term ‘spot’ deliveries of LNG to the Panigaglia terminal which have helped meet the winter demand. There is not the spare capacity at this terminal for this to become a major alternative to storage, but if another LNG terminal were built, then extra deliveries would help to ease the winter demand, and also serve as insurance against supply interruptions.

Interruptible contracts are very important, and form a significant amount of sales. As the bulk of Italy’s gas comes long distances, the supply level is not very flexible.

Regulation

Legislation

There is no single legal framework for the Italian gas industry. The key laws are the following:

- ENI charter of 1953;
- Law 170 of April 1974 on storage operation;
- Law 359 of August 1992 on privatising ENI;
- Law 9 of January 1991 on limited TPA;
- Law 481 of November 1995 on establishing fully autonomous public service regulators;
- Law 625 of November 1996 which ended Agip’s long-standing monopoly on production and storage in the Po Valley and nearby Adriatic Sea. It also removed Snam’s exclusive right to construct and operate pipelines for domestically produced gas in the same areas.

The last of these laws abolished the legal monopoly on production and storage in the Po Valley and Adriatic Sea previously granted to Agip by the ENI charter of 1953. In real terms, Agip make some concessions, although it is difficult to envisage that anything of any great value will be released. The law is therefore unlikely to achieve anything other than changing Agip’s monopoly from a legal monopoly to a de facto monopoly.

This change does not affect the restrictive law on storage. Under the law of April 1974, storage can only be carried out by companies that hold a concession to exploit hydrocarbons. In practice Agip, which carries out 90% of production, will continue to operate all the storage facilities.

A new National Energy Plan (PEN) along with a new energy law was due to be submitted to Parliament during the summer of 1998. However the gist of the plan is to continue government involvement, and it therefore does little to facilitate the introduction of any meaningful competition.

Encouraging competition in storage

No storage issues are touched by European law and, until they are, storage in Italy will remain under the control of ENI. Pressure concerning the opening up of storage facilities is being applied by other gas companies, such as Edison. However, as mentioned above, the Italian government is reluctant to introduce any real competition into the energy industry since that will bring about job losses. Until the other aspects of the gas industry are competitive, it is unlikely that competition in storage will emerge. But, as noted above, if Agip do let anything of real value go when relinquishing their acreage in the Po Valley area, then competition in storage could emerge.

Chapter Fifteen:

THE NETHERLANDS

Introduction

The Netherlands is the largest producer of natural gas in the European Union. The country has about 2,475 Bcm of reserves when existing fields, estimates of new fields, and planned imports are taken into account. Natural gas accounts for about 52% of total primary energy supply (TPES), being the highest figure for any country in the world (the average OECD country gas share of TPES is 20%). The key physical asset in the Netherlands is the highly flexible Groningen field. The flexibility and size of Groningen is the basis for the as yet still theoretical 'Hub Holland'. Gasunie is developing the Hub Holland concept in response to a declining market share, with the aim of becoming the major European gas trader and provider of flexibility and other services. Three new storage facilities have been developed in response to falling pressure in the Groningen field and the projected Hub Holland strategy. There has also been talk of an Interconnector between the Netherlands and the UK, but with current UK prices being higher than those on the Continent it seems likely that such a project will remain as no more than talk for a long time to come. This chapter reviews the main features of the Dutch gas industry, and highlights the role of storage in the country.

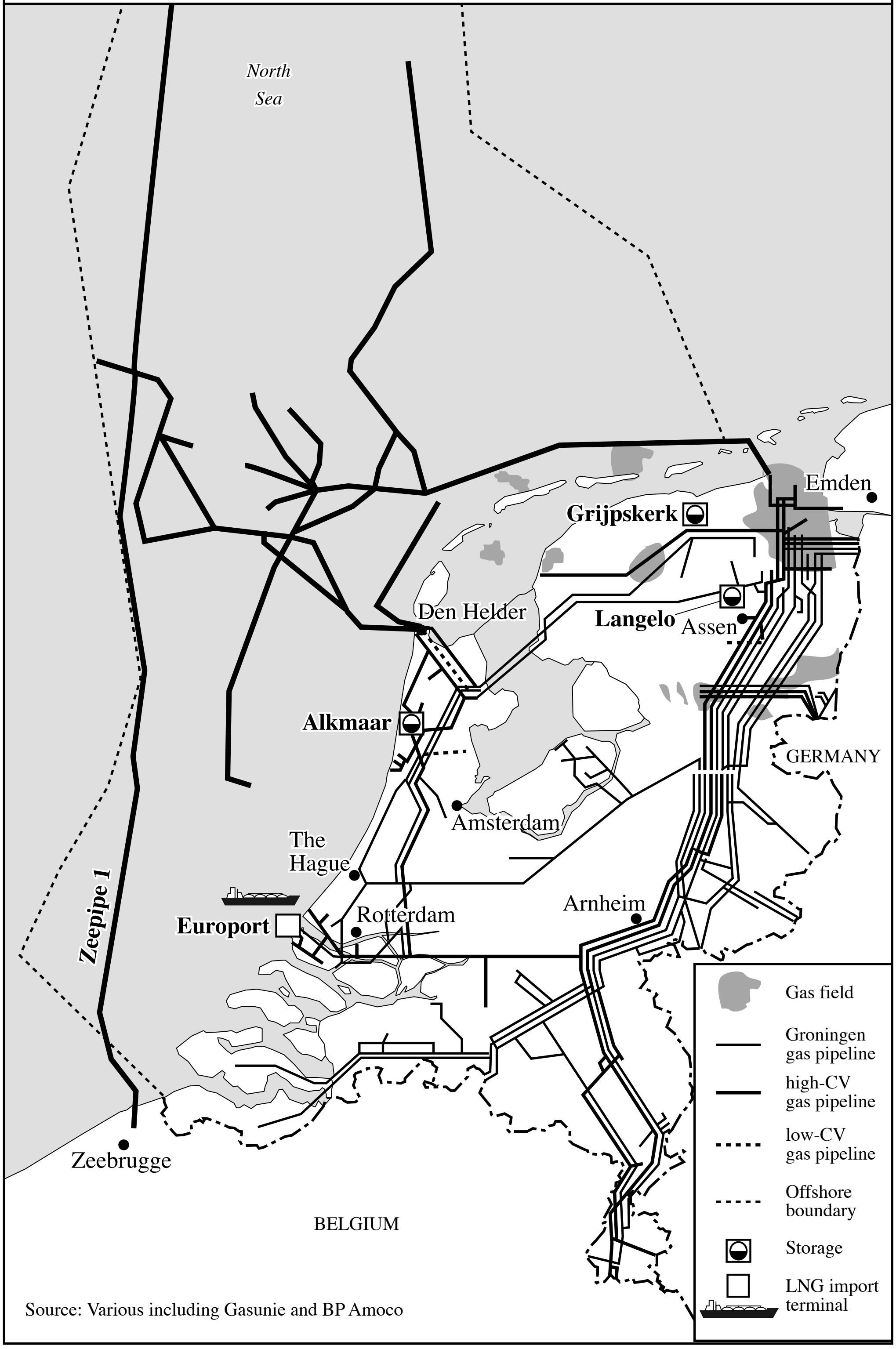
Industry structure

The Dutch gas industry remains fairly resistant to competition, but pressure is increasing both at home and abroad to introduce liberalisation. Government exerts its influence through a private agreement between Shell and Esso in relation to the Groningen regime. The government is also able to influence the industry through its 10% stake in Gasunie, and through its ownership of Energie Beheer Nederland BV (EBN BV), the holding company for the state's interests in oil and gas production.

Fundamentally Dutch policy is to harmonise the production of gas with the sale of gas in the domestic market and beyond. The 'small fields policy' is an example of this, where the purpose of the policy is to encourage production from the numerous small fields in order to prolong the life of the large Groningen field. This 'small fields policy' has developed fields which would not have been considered economically viable in other countries, and has further strengthened the Dutch gas reserves position and underground storage potential.

The Netherlands has a complex gas infrastructure due to the variation in gas quality from the various gas fields. Groningen gas is typically of low calorific value, and two pipeline networks are required to transport gas of different calorific value. Blending stations mix the different gases to ensure they meet domestic and export specifications.

Figure 15.1: Map of Dutch gas network



Source: Various including Gasunie and BP Amoco

The major players

NV Nederlands Gasunie dominates the Dutch gas industry and is responsible for purchasing, transport, and sales to distribution companies, power stations and other large industries. The company still has a virtual monopoly on purchase of domestic gas, transmission and exports, although pressure to liberalise the market is increasing both at home, from Dutch large users, and also from distributors wanting cheaper foreign supplies. The introduction of the competitive ethos from the UK via the Interconnector, combined with the liberalising ethos of the EU Gas Directive, puts further pressure on Gasunie. The company faces what is effectively a fixed volume of gas sales of approximately 80 Bcm per year, implying a declining market share. In response to this situation Gasunie has developed the 'Hub Holland' concept.

Hub Holland is the term being used to describe the flexibility of the Dutch gas infrastructure and the security of volume, capacity and supply that Gasunie offers to other companies who rely on mainly base-load supplies. Gasunie is set to have a strategic role in the transit of gas between Russia, the UK and other European countries. In 1997 Gasunie carried 10.8 Bcm of gas for third parties, compared with 9.8 Bcm in 1995.

In 1997 Gasunie purchased 95% of its supply from domestic fields, plus small quantities from Norway (4%) and the UK (1%). The largest producer in Holland is Nederlandse Aardolie Maatschappij (NAM BV), which owns 64% of onshore exploration and production concessions, including the huge Slochteren field near Groningen. The company also owns 24% of the offshore concessions, competing with other major suppliers such as BP Amoco, Occidental, and Elf. Overall, 15 consortia (including Shell and Esso) supply Dutch gas to Gasunie.

The country has 33 gas distribution companies, with over half the sales being made by five large distributors. These are publicly-owned companies, which are often horizontally integrated, supplying gas, electricity and sometimes district heating. The number of distribution companies is likely to fall with the ongoing merger process. A new organisation called EnergieNed represents the distributors in negotiations with Gasunie, the government, the EU, and other organisations. However, the position of EnergieNed is under review, as some companies are pushing to decentralise the negotiation process in the run-up to liberalisation. Strategic regional alliances such as Energie Holland, which comprises the three largest distributors in the west of the country, are a new feature in the changing market.

Peak capacity and swing requirements

Domestic demand in 1997 was 43.9 Bcm (46.7 Bcm in 1996). Gasunie has estimated that demand will grow to about 50 Bcm in 2000, and to approximately 60 Bcm in 2010. Domestic production is likely to fall until 2000 and then level out. Exports, which have recently been increased to counteract loss of market share at home, will also reduce.

In 1997 Gasunie purchased 84 Bcm of gas, down 10% on the previous year due to higher average temperatures. Of the total amount, 52% went for domestic consumption and 48% for export. Table 15.1 shows a breakdown of users in 1996 and 1997, with forecasts for the years 2000 and 2010. Of the exports, 59% went to Germany, 14% to Italy, 13% to France, 12% to Belgium and 2% to Switzerland. Gasunie is developing its export market, with contracts under negotiation with Poland, the Czech Republic, Slovakia and Spain. In February 1997 Gasunie signed a letter of intent to supply 2 Bcm per year of gas to Poland for the next 15 years.

Table 15.1: Gas supply and demand in The Netherlands 1997–2010 Bcm/year (%)				
	1996	**1997**	**2000**	**2010**
Domestic production	90.2	79.8	75.3	79.4
Imports	3.6	4.2	11.2	14.0
Exports	– 45.9	– 40.1	– 38.3	– 38.8
Total domestic supply	47.9	43.9	48.2	54.6
Residential/commercial	18.4 (39%)	15.5 (35%)	18.7 (39%)	19.5 (36%)
Industry	18.2 (38%)	19.1 (44%)	18.2 (38%)	20.9 (38%)
Power stations	6.1 (13%)	5.2 (12%)	6.6 (14%)	9.4 (17%)
Greenhouse growers	4.8 (10%)	4.1 (9%)	4.7 (10%)	4.8 (9%)
Surplus/deficit	0	0	0	0
Total domestic demand	47.9	43.9	48.2	54.6
Source: Gasunie				

Availability of swing gas

Gas demand in winter is normally about 530 Mcm/day, but on 2 January 1997 demand reached a maximum of 558 Mcm, due to prolonged cold temperatures. The fact that the gas supply in the Netherlands was able to accommodate such a large increase in the normal peak day load is a testimony to the inherent flexibility and security of supply that the designers and operators of the system have been able to achieve. It is this flexibility and security of supply that enables the Netherlands to offer a high degree of flexibility both to domestic customers and in terms of export supply.

The swing requirement in 1998 is illustrated in Table 15.2, showing supply figures from January and July.

Table 15.2: Comparison between sales figures for January and July 1998

	January 1998 (Mcm)	July 1998 (Mcm)
Domestic sales	5,334	2,265
Export	4,821	1,614
TOTAL	**10,155**	**3,879**

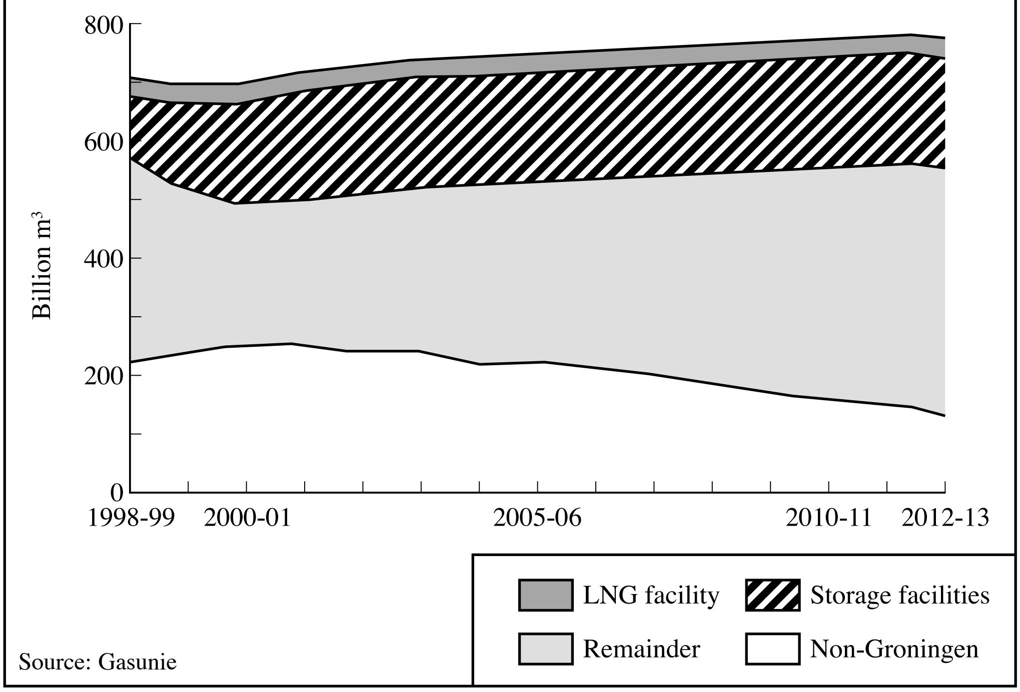
Source: Gasunie

Future delivery capacity

Up until now the Groningen field has been used to balance delivery capacity. However, as pressure in the Groningen field falls, new steps have been taken to ensure ample swing capacity. Firstly, three underground storage facilities have been constructed (see Storage Facilities section) and, secondly, compressors are being installed in the Groningen field, beginning with a compressor on the Tjuchem well cluster. This compressor is due to enter service at the end of 1999. In the future some of the depleted smaller gas fields will be available for underground gas storage.

The Netherlands offers far greater flexibility in terms of supply capacity than other large scale producers for the European gas market. Russia, Norway and Algeria supply under high load factors (low swing), typical of long distance suppliers, of between 7,200 - 8,000 hours in order to meet annual contracts. Gasunie is a low load factor supplier, with a transmission system load of only 3,000 hours providing far greater flexibility. Annual export capacity is significantly higher than average export levels of about 40 Bcm per year. Back-up supply agreements covering additional capacity of another 20 Bcm are maintained with Germany and Belgium. Dutch export capacity is limited by pipeline dimensions rather than production capacity at this time. However, as pressure falls in the Groningen field, export capacity will be reduced unless production from other fields increases.

Figure 15.2: Future delivery and production



Source: Gasunie

Figure 15.2 shows how delivery and production capacity is forecast by Gasunie to change over the period 1998 to 2013. The top line shows the required delivery capacity, which is a function of the demand for gas both from local gas markets and gas exports. The current methodology used by Gasunie in calculating demand is on the basis of a minimum effective temperature (including the effect of wind-chill) of -17°C for the domestic market, combined with the contractual capacity required for industrial customers and for exports. What is interesting to note is the decline in delivery capacity provided by non-Groningen fields. Whether this is a realistic drop-off in availability of non-Groningen gas or just a function of the exploration and production time horizon remains unclear. What is clear is the willingness of the Netherlands to invest both in compressors and storage to ensure adequate supply availability.

Alternatives to storage

The purpose of this section is to identify the actual or potential alternatives to storage. Clearly, due to the availability of swing from the Groningen field combined with the storage facilities already in existence or planned for development in the near future, the need for alternatives to storage is limited. However, the most common tool used apart from swing and storage is interruptible contracts to power generators as described below.

Interruptible contracts

As mentioned in Chapter 4, the ability to interrupt large end-users does provide an alternative to storage. In fact, deliveries to power generators in the Netherlands are routinely interrupted when the temperature drops below -5°C. In this way approximately a quarter of industrial demand could be cut for a short period of time. Interruption of this type assists the gas supply system in the Netherlands in two ways. Firstly, it enables the seasonal supply/demand match to be managed on the small number of peak gas demand days that occur during a cold winter. Secondly, the interruption of these large process users enables the designers of the pipeline system in the Netherlands to maximise the utilisation of the pipeline system in an economic fashion.

Swing offered by suppliers

Clearly, another alternative to storage is the purchase of additional swing from suppliers. However, since imports come via long supply pipelines designed to have little spare capacity, additional swing from these sources of supply is often expensive and therefore uneconomic when compared to existing swing contracts or local storage facilities.

Storage facilities

The Netherlands has three storage facilities. These are based at Grijpskerk, Langelo (Norg) and Alkmaar. There is also a small LNG storage terminal at Europoort. Total delivery rate from these facilities is estimated at 200 Mcm/day. The Groningen field is the key balancing tool used by Gasunie to balance seasonal variations in demand and to manage swing. Table 15.3 gives details of the ownership, capacity and deliverability of the storage facilities.

Table 15.3: Gas storage facilities in the Netherlands

Site	Start Date	Ownership	Working capacity (Mcm)	Working rate (Mcm/day)	Supply
Grijpskerk	1997	NAM BV	1,500[1]	80	Can supply high calorific gas for several weeks
Langelo (Norg)	1998	NAM BV	3,000[2]	80	Can supply Groningen gas for almost a month
Alkmaar	1998	(BP Amoco and partners, Energie Beheer,Nederland BV,Veba Oil BV, and Dyas BV)	500	24	Peak-shaving facility. Can supply Groningen gas for short-term peaks (several days)
Europort (Maasvlakte) (LNG storage)	1977		75	31	

Source: Gasunie

Notes: 1 Working capacity of Grijpskerk site. Maximun possible capacity is 3,000

2 Working capacity of Langelo (Norg) site. Maximun possible capacity is 4,500

Future plans for storage

At the time of writing this report it was unclear what additional plans Gasunie or other users or marketers might have for storage in the Netherlands. There are, however, three possible scenarios where existing storage facilities might be developed or new storage facilities built.

Development of new suppliers other than Gasunie

As the competitive market begins to develop in the Netherlands and new players enter the market to sell gas to end-users, either via the existing Gasunie pipeline infrastructure or via new independent pipelines, so the need for new independent storage facilities will become apparent. Therefore it is quite possible that some of the new players in the market will feel the need to develop their own storage facilities rather than rely on the flexibility provided by Gasunie.

Hub Holland becomes a successful strategy

Another possible scenario is that Hub Holland ceases to be a concept discussed at conferences, and that the Netherlands does actually develop as a significant gas hub within the European context. In this scenario the Netherlands provides a variety of hub services associated both with the transit of gas through the country to a variety of locations within Europe, and with the facilitating of competition within the Netherlands itself.

Sales of storage to the UK

Yet another possible scenario is that the Netherlands becomes actively involved in the UK storage market by purchasing gas from the UK in the summer months when commodity prices are low, and then selling that gas back to players in the UK as an alternative to storage when prices are high. Initially such a strategy is likely to be based on the spare marginal capacity available in Gasunie's storage facilities, but there is no reason why sales of this type of service to the UK should not increase if there is a market for it and, as a consequence, drive the development of additional storage facilities. At the time of writing this report, discussions were continuing on the construction of a second interconnector linking the UK with Continental Europe. This link could be used to store UK gas in the Netherlands during the summer and then pipe it back to assist UK winter peak demands.

Regulation

As mentioned earlier, the government in the Netherlands exerts influence mainly through indirect means, such as its shareholding in Gasunie, rather than through direct legislation. There is no Gas Act, although one is planned and is already in draft form, and government policy is based on the Nota de Pous (1961), which states that the exploitation of Dutch gas reserves should be harmonised with the sale of such gas, and that gas supply should be a government task.

A government White Paper, the Third Energy Memorandum (published in December 1995), proposed more rapid and extensive deregulation of the gas market. Gasunie's position is that it is confident of meeting the challenges presented by the proposals, providing that the Netherlands does not go further than other EU countries in the implementation of the new European directive. At the end of 1997 the Ministry for Economic Affairs published a 'Gasstromen' (gas streams) working paper in preparation for future legislation to ensure a phased and controlled deregulation process.

Storage pricing

Despite attempts by the author and EJC Energy to obtain storage tariffs for the Netherlands, at the time of writing this report no such information was available in the public domain.

Future developments

Gasunie will lose some domestic market share with the arrival of gas through the Interconnector. However, the company has the experience and the flexibility, with the advantage of a stable reserve capacity and a strategic geographical position, to be one of Europe's leading gas hubs in the new millennium.

Chapter Sixteen:
SPAIN

Introduction

Spain has one of the fastest growing gas markets in Europe, although the market as yet is very small by European standards. In 1997 13 Bcm of natural gas was consumed (an increase of some 3.4 Bcm over 1996 figures), which accounted for 8.3% of primary energy use. Consumption is expected to double by 2005, as new energy policy is to encourage the use of gas, particularly as a fuel for use in power generation. Demand is forecast to rise in all other sectors as well.

The gas industry is still very much under government control, the government having retained the power to set prices and authorise the building of any type of gas facilities. The passing of the new Hydrocarbon Law provides the framework for implementing the EU Gas Directive, as well as enforcing the government's policy of gaining market security by diversifying supplies.

Domestic production is running down, and has little role to play in meeting Spain's gas demand. Therefore Spain is totally dependent upon imports, which currently consist of LNG from Algeria, Nigeria, and Trinidad & Tobago into Spain's three receiving terminals, or gas imported along new pipelines from Norway via France and from Algeria via Morocco.

Not a great deal of gas is used for heating, so the seasonal variation in gas demand is not sufficient to call for an enormous storage capacity. However, with domestic reserves declining and no nearby gas producer, gas storage is required to guard against temporary supply interruptions, pipeline failure or LNG delivery problems. In addition to this, the new Hydrocarbon Law requires large traders and users to have at least 35 days of storage capacity in order to ensure supply security. To meet this requirement Spain is looking to increase its storage capacity.

Industry structure

Major players

The principal player in the market is the Gas Natural group, which is the fourth largest gas group in the EU. It supplies 90% of the market in Spain, with a majority stake in 12 regional distribution companies (RDCs), and a minority stake in three others. There are four other RDCs which are owned by municipalities.

Enagas is the sole importer of natural gas, and owns and operates the transmission network and the storage facilities. It supplies the RDCs, and also some large consumers directly. Enagas is wholly owned by Gas Natural.

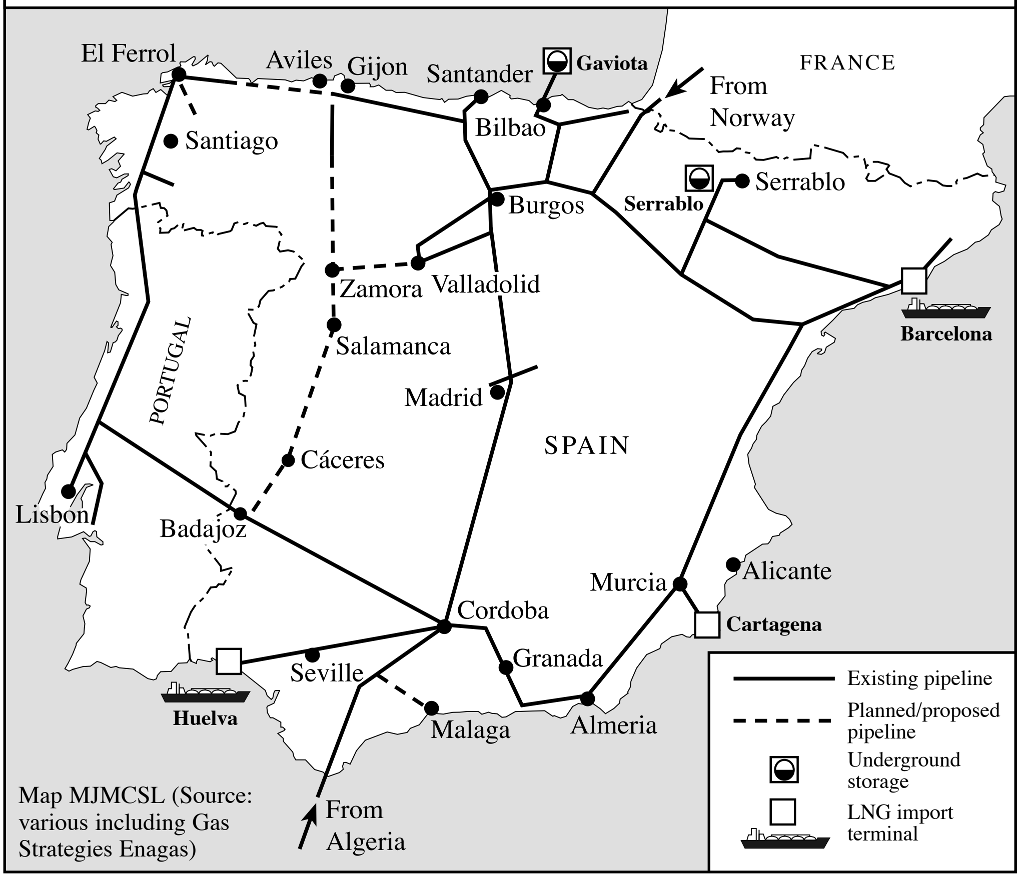
Pipelines

Besides the three LNG terminals, there are two other main points of entry for gas imports. In 1993 the Spanish grid was linked to Lacq on the French system, via the Pyrenees. Some Norwegian gas has since been imported via this link. This pipeline has also enabled Enagas to rent some French storage capacity when required.

Three years later the Maghreb-Europe pipeline was built, connecting Algeria and Spain across the Straits of Gibraltar via Morocco. This link supplied 38% of gas imported in 1997, and imports can be increased up to a maximum of 8 Bcm per year. This figure can be increased even further as more compressor stations are added along the line.

The internal pipeline network is under expansion as more connections to the major import lines are constructed. A limited form of Third Party Access (TPA) to the grid is available, but only for the larger consumers who, under the new law, are able to choose their supplier. It is intended to open up the whole grid for TPA gradually, under the government's supervision.

Figure 16.1: Map of Spanish gas network



Map MJMCSL (Source: various including Gas Strategies Enagas)

Peak capacity and swing requirements

The new Hydrocarbon Law ensures that no country can supply more than 60% of Spain's gas requirements, therefore Spain is dependent on more than just Algeria for it's gas. This makes managing the supply/demand match very difficult, as the largest gas supplier cannot legally supply any additional gas since Algerian imports already make up almost 60% of gas required! To deal with this, Spain invested in a project in Trinidad & Tobago in order to secure enough supplies from elsewhere.

As a result of Spain being unable to take any more gas from Algeria for legal reasons, there is a considerable need for storage against temporary supply interruptions from the smaller suppliers.

Since the climate in Spain is relatively mild, and not a great deal of gas is used for heating, the seasonal variation in gas demand is not as marked as in other European countries. This can be seen from Table 16.1, which shows that the maximum monthly gas consumption is only 60% higher than the minimum. Therefore there is not much need for storage to balance out the seasonal loads, as a small amount of swing from each supplier and the occasional extra delivery of LNG would be adequate. However, with the forecast growth in the market, there may well be much more of a demand for storage for load balancing purposes in the future.

Table 16.1: Monthly gas usage in Spain (Mcm)

	January 1997	July 1997	Maximum	Mean	Minimum
Indigenous Production	4	7	49	12	4
Imports	1071	961	1,075	979	837
Injections/ (Withdrawals)	(80)	17	(85)	28	123
Total consumption	1,155	950	1,164	961	720

Source: Natural Gas Information, IEA

Storage facilities available

Types and location of storage

Underground storage

Spain has only three underground storage facilities: two depleted fields at Serrablo near the Pyrenees, and a semi-depleted gas field off the Spanish Basque coast at Gaviota. All these facilities are operated by Enagas. The current working gas capacity is just under 1.3 Bcm, but this will be increased threefold as Gas Natural is aiming to enlarge its storage capacity to cover 90 days of consumption.

Table 16.2: Details of underground storage facilities in Spain

Location	Start date	Storage type	Depth (m)	Working gas volume ($10^6 m^3$)	Maximum withdrawal rate ($10^3 m^3/h$)
Gaviota	1994	Depleted field		779	229
Serrablo Aurin	1992	Depleted field	1,500	160	104
Serrablo Jaca	1992	Depleted field	2,700	335	63

Source: Gas Natural

Other - LNG

The LNG terminals have recently been refurbished, although plans for a new terminal at El Ferrol have been scrapped as a new pipeline to Portugal is being planned. The Cartagena and Huelva terminals have been upgraded and their capacity increased in order to enable the terminals to handle larger tankers. The storage capacity at Huelva is now 160,000 m^3.

New projects

Three are four or five new underground storage areas planned for development over the next few years. Gas Natural plans to build two or three salt cavity storage facilities before the year 2000, to be followed later by a couple of aquifer storage facilities. No further information is available.

Enagas has been granted a concession to develop the near-depleted Amposta oil field into a gas storage facility. At first the working gas capacity is likely to in the region of 1 Bcm, but on completion it could yield a working gas capacity of well over 5 Bcm.

Alternatives to storage

Interruptible contracts

So far interruptible contracts have been little used, but this position is certain to change under the new Hydrocarbon Law. As large consumers can negotiate their own contracts with suppliers independently, there is no guarantee that gas bought by Gas Natural or other distribution companies under Take-or-pay obligations will be required. There is no information available about the amounts of swing gas agreed with suppliers.

Regulation

Legislation

The Spanish Parliament passed a new Hydrocarbon Law in September 1998. This has replaced most of the previous legislation, and provides the framework for the implementation of the EU Gas Directive. The main points of the law which affect the gas industry are:

- Regulation of transporter, trader and manager;
- Large users must have 35 days of storage capacity available in order to ensure

security of supply;
- Gas imports from any one country must not exceed 60% by any trader;
- The previous granting of concessions in certain areas has been replaced by an authorisation procedure;
- Regulated access to gas grid guaranteed by new public regulator;
- Financial unbundling of charges;
- Largest users able to choose their own supplier.

Gas Natural retains its transportation monopoly, as the government is protecting its investments in the gas infrastructure by preventing the laying of new lines or building of new facilities by other companies. The government has set upper limits on prices for access to the grid. Gas Natural estimates that 45% of the market will be opened as the largest users are allowed to choose their own suppliers. This percentage will gradually increase to 100% over the next 15 years. However, as there is a lack of viable alternative suppliers, it remains to be seen if Gas Natural's supply dominance will be challenged.

Encouraging competition in storage

Under the new law outlined above, companies must apply for authorisation before constructing gas facilities in any area. As there is plenty of opportunity for new storage facilities in Spain, and the new law creates a greater demand for storage, there is the potential for competition in storage as soon as Gas Natural's monopoly is gone. This remains entirely in the hands of the government. However, the government intends to protect Gas Natural's investments in the gas infrastructure by preventing any pipeline competition, and it is unlikely to allow any competing storage facilities to be built before the market has been totally opened up. This will be phased in over the next 15 years, which is earlier than the EU Gas Directive will require.

Chapter Seventeen:

THE CZECH REPUBLIC

Introduction

Since the Czech Republic separated from Slovakia five years ago, the gas industry has been growing at a fast rate. This has been largely due to a sharp rise in demand from the residential and small business sector. Since the proportion of gas consumption in the residential/commercial sector is nearly 40%, and about 20% of gas use is for district heating, the variation in seasonal demand is very marked. As domestic gas production is almost negligible there is a need for gas storage to even out the seasonal loads on the import pipelines.

The energy industry is still totally subject to state regulation. The main player is, Transgas, which has a 'state ensured' monopoly on imports, transportation and storage, and is wholly state owned and controlled. Recently the government has been looking to diversify its sources of gas, as previously Russia has been the sole supplier of gas to the Czech Republic. However, even with some Norwegian gas now arriving on the market, Russian gas is still heavily relied upon. Therefore, there is a need for storage in order to provide security of supply, as any interruption of the main supply would cause severe gas shortage.

As well as for supply security, storage is required for balancing out the seasonal variation in gas demand. At present there is 2.8 Bcm of working gas available in the five operational storage facilities. In addition to this, some storage is leased from nearby countries, and another 0.5 Bcm of storage is in the planning stage.

Industry structure

Major Players

Transgas is the largest gas company. As mentioned above, it is state controlled and responsible for imports, transportation, storage and sales to the eight smaller regional distribution companies and a few large industries. It also carries Russian gas across to Western Europe. Until 1997 it held a legal monopoly on imports. However, since the legal monopoly expired, the government has blocked attempts by the distribution companies to import gas directly, effectively continuing Transgas's monopoly.

Recently Transgas has been incurring huge losses, and has had to lay aside most investment programmes. This is mainly due to the fact that the government is enforcing the subsidising of household gas, so that Transgas has to sell the gas on to the distribution companies at a lower-than-cost price.

The smaller regional distribution companies are to a large extent government controlled, although they have been partially privatised. More shares are likely to be given up by the government, but it intends to retain a blocking minority (34%) in each. Each company has a licence to operate in a certain region, which effectively gives each a monopoly in that region. The legislation on the issuing of licences is unclear, so the possibility of any competition emerging in any region is entirely determined by the government.

Pipelines

Transgas owns and operates the 4,300 km of high pressure pipelines in the Czech Republic. Much of the infrastructure has been geared towards transit, but since the break up from Slovakia, all the gas transit to Austria has been lost. A new pipeline to deliver Russian gas to Germany is being built, which should allow one of the older transit lines to be used for domestic deliveries.

Peak capacity and swing requirements

The largest proportion of gas consumed is used for heating, and as a result over 70% of gas consumption occurs during the winter half of the year. In January 1997, gas from storage met over 40% of the total demand, with the rest of the demand being met by imports (see Table 17.1). As the residential/commercial sector is the fastest growing sector, the need for storage will rise even further.

Table 17.1: Monthly gas usage in Czech Republic (Mcm)

	January 1997	July 1997	Maximum	Mean	Minimum
Indigenous Production	8	9	9	8.4	7
Imports	870	776	870	78.1	636
Injections/ (Withdrawals)	(630)	469	(630)	11.0	447
Total consumption	1,510	315	1,510	779.0	310

Source: Natural Gas Information, IEA

Storage facilities available

Types and Location of Storage

Underground Storage

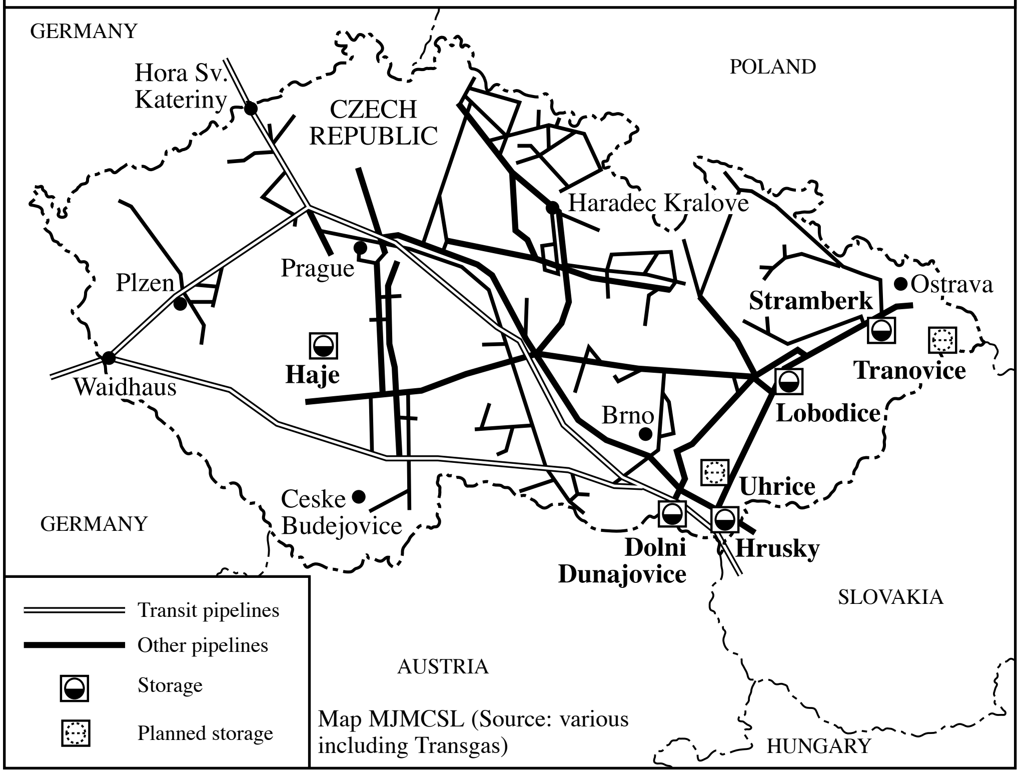
Currently five storage sites are in operation, and several more are being developed. Transgas is responsible for building and operating all the facilities, except for Poddorov, which is being constructed by CPP, a local distribution company operating in Bohemia. Storage is also leased from Slovakia's LAB site, and from Wingas's Rehden facility, with the Czech Republic taking in the region of 0.5 Bcm per year from both.

Table 17.2: Storage facilities in the Czech Republic

Location	Start date	Storage type	Depth (m)	Working gas volume ($10^6 m^3$)	Maximum withdrawal rate ($10^3 m^3/h$)
Dunajovice	1989	Depleted field	1,150	700	350
Haje (Pribam)	1998	Cavern storage	950	55	250
Lobodice	1965	Aquifer	400 - 500	140	112
Stramberk	1983	Depleted field	440 - 540	420	250
Tvrdonice (Hrusky)	1973	Depleted field	1,050 - 1,600	495	250
Poddorov	-	Depleted field	1,700	150	
Uhrice	2000	Depleted field	1,600	180	250
Tranovice (Zukov)	2001	Depleted field	400 - 460	140	50

Source: Transgas

Figure 17.1: Map of Czech Republic gas network



New Projects

Most new projects have been put on hold as Transgas are suffering massive financial losses due to the enforced subsidising of household gas mentioned earlier. Current work is mainly being done on reinforcing the existing facilities. However several new storage projects were already being developed, and when finished they will greatly increase the storage capacity available.

Among the current projects are the development of a storage site at Tranovice and the development of the Poddorov and Uhrice fields. The converting of the latter fields to storage remain very much in the planning stage, and no definite date for completion of construction has been given.

Alternatives to storage

The seasonal variations in gas demand in the Czech Republic have been so severe that, in the last couple of years, short-term contracts have been signed with German companies to supply extra gas during the winter. In 1997 a contract was signed with BEB Erdgas and Verbundnetz Gas (VNG) to provide around 25 - 30 Mcm between November and February at a peak daily volume of 2 Mcm from BEB, plus gas from VNG if required. The rest of the details of the contract are confidential, but gas would only be delivered if the weather was severe. Also, a supply contract with Wingas contains a clause allowing for extra deliveries in the winter, if required.

Interruptible Contracts

The Ministry of Finance has yet to agree to interruptible contracts.

Swing Offered by Suppliers

No information is available. From the supply table it seems to be in the region of 5-10%.

Regulation

Legislation

The only relevant legislation on the Czech gas industry is the Czech Energy Act which came into effect in 1995. This creates a framework for enterprises entering the industry, and establishes a regulator for the industry (albeit one controlled by the state). It goes no further than merely confirming that the energy industry is subject to state regulation and provides that the Ministry of Industry and Trade is the sole body authorised to submit pricing proposals to the Ministry of Finance.

Encouraging Competition in Storage

This will only come when the Czech gas market has been opened up to competition. This is likely only if the Czech Republic seeks EU membership, and therefore alters its legislative framework so that the energy industry is run in a way that complies with EU law. At the moment there is no TPA within the Czech network. LDCs operate under license to supply gas in certain areas, and the legislation on licensing is not clear. Therefore competition is very much under the control of the government.

Chapter Eighteen

HUNGARY

Introduction

The Hungarian gas market is dominated by Mol, the largest gas company, which has a monopoly on domestic production and supply. With domestic gas production declining and gas demand rising, particularly in the residential sector, there is a greater need for gas storage. Gas usage is becoming ever more popular, and the percentage of gas in primary energy consumption has risen to about 40%. One third of this gas is produced domestically, and this fraction is decreasing. Currently gas storage can provide about 112 days of peak winter imports, and this will be increased further by the turn of the century.

Gas prices are determined by government, and in the year 1994/95 large losses were made by Mol, because it was forced to sell gas cheaply to the Hungarian market. Privatisation began in 1995, and all energy companies have now been partly privatised. Since privatisation, investors have been demanding price rises, and now the prices have risen almost to a standard world level.

Industry structure

Major Players

Mol is the only fully integrated oil and gas company in Hungary, as well as the largest. It has a de facto monopoly on domestic production and supply, but in 1994 its exclusive import rights were abolished by the government, and control of Russian imports was passed to Panrusgaz. Mol is partly privatised, although the state holds a 50% plus one controlling share and intends to retain a blocking minority when further privatisation takes place.

Panrusgaz, a Russian/Hungarian joint venture, was set up in 1994 to control the bulk of imports. Basically, Panrusgaz buys Russian gas and sells it on to Mol at a profit. However Mol still buys a small amount of gas directly from Russia. The shareholders of Panrusgaz are Mol (50%), Gazprom (40%) and Gazexport (10%).

There are nine smaller local distribution companies which operate under a licence. They are partly privatised, with the state retaining at least a blocking share in each. Most buy their gas from Mol and distribute it to the area where they are licensed.

Pipelines

Hungary’s internal pipeline system has been growing rapidly to keep up with the rapidly expanding residential market. This trend should continue to increase into the next decade, albeit not quite so fast. The HAG pipeline was built two years ago connecting Hungary to Western Europe. The intention was to help diversify supplies away from total dependence on Russia. Gas now comes in from Ruhrgas and Gaz de France. Ironically, much of this is Russian gas anyway.

A new pipeline is planned to help supply gas to Bosnia under a new transit deal signed in April 1998.

The Volta pipeline project, which was planned to take Russian gas across Hungary to Northern Italy has been put on hold. This means another threat to Mol's supply monopoly has been (at least temporarily) removed, as the pipeline could have supplied Russian gas directly to large industrials within 70 km of the pipeline.

Peak capacity and swing requirements

The recent growth in gas use by the residential sector has sharpened the seasonal variation in gas demand in the winter. The figures in Table 18.1 are distorted by the fact that the Zsana storage facility started up in 1996 with a capacity of 600 Mcm. As a result, in 1997 nearly 1 Bcm of gas was injected into storage over the year. However in 1996 70% of gas consumption occurred during the six winter months, and daily winter consumption is about five to six times higher than in the summer. In December 1997 gas from storage only made up 25% of total consumption. Although increased domestic production of 80 Mcm above the monthly average helped to make up another 25% of total consumption, as gas reserves are diminishing and demands increasing this figure will become steadily less significant. Therefore Hungary is very much dependent on swing gas from suppliers to meet winter demand.

Table 18.1: Monthly gas usage in Hungary (Mcm)

	January 1997	July 1997	Maximum	Mean	Minimum
Indigenous Production	540	291	540	366	226
Imports	646	786	868	646	569
Injections/ (Withdrawals)	0	617	(756)	80	617
Total consumption	1,186	460	1,753	988	442

Source: Natural Gas Information, IEA

Storage facilities available

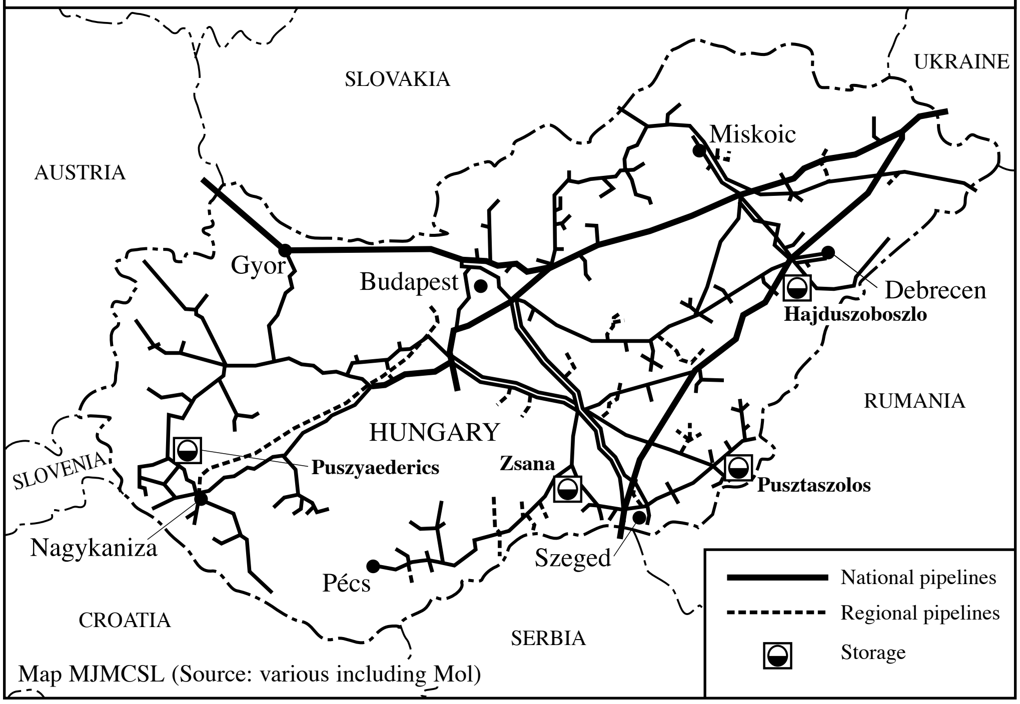
Types and Location of Storage

Underground Storage

There are four underground storage sites in Hungary, with a total capacity of about 2.6 Bcm, and a deliverability of 33 Mcm daily. Storage has recently been increased to help balance pipeline loads throughout the year, as the daily gas demand in the winter months is many times greater than during the summer months.

Table 18.2: Storage facilities in Hungary					
Location	**Start date**	**Storage type**	**Depth (m)**	**Working gas volume ($10^6 m^3$)**	**Maximum withdrawal rate ($10^3 m^3/h$)**
Hajduszoboszlo	1979	Depleted field	920 - 947	1400	750
Pusztaszolos	1979	Depleted field	1,087 - 1,242	240	140
Puszyaedrics	1979	Depleted field	1,400 - 1,500	330	120
Zsana	1996	Depleted field	1,820 - 1,850	600	375
Source: MOL					

Figure 18.1: Map of Hungarian pipeline and storage facilities



Map MJMCSL (Source: various including Mol)

New Projects

Hungary is well supplied with oil and gas fields that are running relatively low and would be suitable for conversion into underground storage facilities. At the moment, the only project going ahead is the expansion of the Zsana facility. The capacity there is expected to be double by the year 2000.

Alternatives to storage

Interruptible contracts

Three years ago storage and flexibility of domestic production were sufficient to accommodate the seasonal variations in gas demand. As all contracts are still long-term Take-or-pay, interruptible contracts are very much a recent alternative. However gas storage remains the main tool for load balancing, and the ongoing development of the Zsana site illustrates this.

Regulation

Legislation

Hungary was the first Eastern European country to establish a legal and regulatory framework for the gas industry, including an energy regulator. The main pieces of legislation are

- Act XLVIII of 1993 on mining, and
- Act XLI of 1994 on gas supply.

The Mining Act outlines the rules and conditions for granting concessions for the exploration and production of minerals (including hydrocarbons), the construction and operation of pipelines for hydrocarbons and the exploration of underground storage for hydrocarbons.

The Gas Act abolished the exclusive gas import rights of Mol, and passed them on to Panrusgaz. As Third Party Access does not exist, Panrusgaz has to sell all gas to Mol at the Hungarian border. This Act also set up the Energy Office as the regulator.

In addition to appointing and supervising the regulator, the state retains overall control of the sector through its ‘golden shares’ in the distribution companies and Mol. Whatever further privatisation occurs, the state intends to keep at least a blocking minority in each company.

Encouraging competition in storage

There is unlikely to be any competition in storage before the Hungarian gas market is opened up to competition. At present Mol is doing everything it can to keep its supply monopoly, and has no serious threats now that the proposed Volta pipeline has been postponed indefinitely.

Chapter Nineteen:

POLAND

Introduction

Poland is the largest country in Central Europe, and is the most likely to be granted EU entry. It has one of the smallest gas industries in the region, largely due to the continued dependence on coal. National gas consumption is only about 13 Bcm per year, representing just under 9% of primary energy use. Just over half of the gas is imported from Russia, and the rest is produced domestically. Gas consumption is expected to double by the year 2010, with the areas of greatest growth being the residential sector and power generation.

Poland has an important role in the transit of Russian gas to Western Europe. This should increase over the next decade as the construction of the Yamal-Europe pipeline is completed.

Most of the current gas demand comes from the residential and commercial sector. Storage is needed primarily to cover peak winter demand, although when there is sufficient capacity to do this then there are plenty of opportunities to develop sites on the major transit routes to ensure security of supply.

Industry structure

Major players

The Polish Oil and Gas Company (POGC) is responsible for the entire natural gas sector, from exploration and production to transmission, storage and distribution. It is wholly owned by the Treasury, but is controlled by the Ministry for the Economy. It is being restructured and partially commercialised, but as yet no privatisation is taking place.

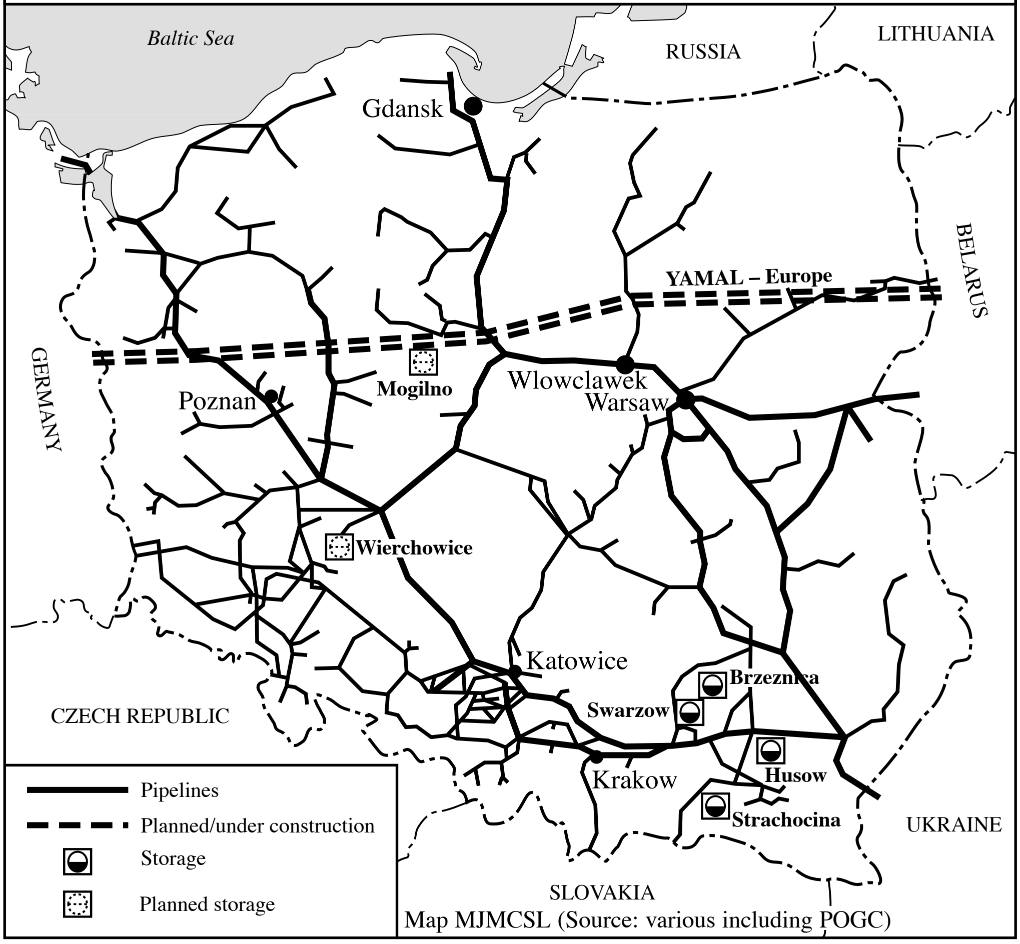
Europol Gas is a Russian/Polish joint venture that is building and operating the Polish section of the Yamal pipeline. It is owned by POGC (48%), Gazprom (48%) and Gas Trading (4%).

Pipelines

The Yamal-Europe pipeline is still under construction. When completed by the year 2010 it should carry 67 Bcm per year of gas from Russia to Western Europe. Poland will be entitled to 14 Bcm of this gas.

Poland's internal transmission network is owned and operated by POGC. A new high pressure pipeline is being constructed from the Mogilno storage facility to the distribution hub at Wloclawek, where a pipeline to Kutno via Lodz was connected in 1996. POGC are also seeking to refurbish the pipeline from Wloclawek to Gdansk, which will enable links to be made with Wabrzezno and Brodnica.

Figure 19.1: Map of Polish pipeline and storage facilities



Peak capacity and swing requirements

As the gas industry grows, the variation in demand over the year will increase. In 1997 the consumption of gas did not vary hugely over the year, as Table 19.1 shows. When gas demand has doubled, and most of it comes from heating requirements, there will be a considerable need for storage to even out winter loads, particularly in colder years. The current storage capacity is not sufficient to cope with this, so swing gas will play a more important role while storage sites are developed. Domestic production is declining, and so will not be able to help balance the annual loads.

There has been a gas shortage in previous cold winters, when demand has been high and Russian gas supplies have been disrupted. As a result, gas supplies had to be cut off from several large industrial companies.

Table 19.1: Monthly gas usage in Poland (Mcm)					
	January 1997	**July 1997**	**Maximum**	**Mean**	**Minimum**
Indigenous Production	455	386	455	425	386
Imports	650	600	771	675	600
Injections/ (Withdrawals)	(207)	(216)	(216)	(468)	220
Statistical difference	34	44	49	44	34
Total consumption	1,273	1,157	1,273	1,092	817
Source: Natural Gas Information, IEA					

Storage facilities avalible

Types and location of storage

Underground storage

There are four underground storage facilities in operation, and a further two sites are under construction. Several more are planned in order to deal with the forecast rapid growth of the Polish gas industry. Some storage capacity also been leased in the Ukraine and Belarus.

Table 19.2: Storage facilities in Poland							
Location	**Start date**	**Storage type**	**Depth (m)**	**Current working gas capacity (10^6m^3)**	**Current withdrawal rate ($10^3m^3/h$)**	**Eventual working gas capacity (10^6m^3)**	**Eventual withdrawal rate ($10^3m^3/h$)**
Brzeznica	1980	Depleted field	390 - 410	69	54		
Husow	1982	Depleted field	1,260 - 1,300	422	154	772	595
Strachocina	1987	Depleted field	900 - 110	63	63	600	
Swarzow	1979	Depleted field	640 - 660	100	51		
Mogilno	2000	Caverns		400		1,000	
Wierchowice	2000	Depleted field		2,000		4,000	2,208
Source: POGC							

Other - LNG

Construction of an LNG terminal at the port of Gdansk is under consideration. This would provide an alternative supply of gas, and would protect against temporary main pipeline supply interruption. It would also give a different means of balancing the seasonal demand by ‘one-off’ deliveries of LNG. Another possible site for the terminal is also being considered, further west along Poland’s shoreline.

New projects

Poland has numerous sites suitable for constructing storage facilities, including salt caverns, aquifers and depleted fields. The only barrier preventing rapid development is finance. POGC hope that the amount of gas in storage should increase to about 3 Bcm by the year 2000, and to about 5 Bcm by 2010, provided that they get enough financial support. This should ensure sufficient capacity for about three to four months of consumption.

The Mogilno facility is being constructed by Asea Brown Boveri under contract from POGC. The project is being financed with World Bank credits. Development of the Wierchowice storage site has been contracted out to Sofregaz, an engineering subsidiary of Gaz de France.

Alternatives to storage

Due to the nature of the market, little information is publicly available about the type and costs of alternatives to storage. Based on the little information available, swing appears to be in the range of 10%.

Regulation

Legislation

The draft energy law, which grants Third Party Access to Polish gas companies, was passed in early 1997. This supplements the existing Geological and Mining Law of 1994, and replaces the out-dated Energy Act of 1984. It also moves the Polish energy industry more into line with the EU.

The Geological and Mining Act outlines the terms and conditions for the granting of concessions for the exploration, production and storage of minerals, including oil and gas.

Unlike previous legislation, the role of the state is greatly reduced, and no distinction is made between foreign and domestic companies. The legislation is used as a basis for individual contracts on oil and gas exploration and production negotiated with the Ministry of Environmental Protection, Natural Resources and Forestry.

The new energy law establishes an Energy Regulatory Agency (URE) to award licences and regulate prices for gas, electricity, and district heating suppliers. The URE is appointed by and reports directly to the Prime Minister. The Ministry of Finance, however, will continue to set prices for the next two or three years.

Encouraging competition in storage

There is little chance of any real competition in the gas industry in the foreseeable future, even with the new energy law. If Poland is granted entry into the EU, then as EU gas policy is implemented in European law, Poland will have to comply. Much of the EU gas policy is geared towards introducing competition into every area of the domestic gas market, including storage.

Chapter Twenty:

SLOVAKIA

Introduction

The Slovak gas industry is dominated by Slovensky Plynarensky Preimysel (SPP), the state-owned gas transmission and distribution company. The development of the domestic market is being held up by slow progress in enacting a draft energy law and price reform.

Slovakia occupies a key position for the transit of Russian gas to Western Europe. Four high pressure pipelines run from the Ukranian border across the country to the Czech Republic and Austria, and from there to Germany and the rest of Western Europe. There are also connections to Hungary and Slovenia.

When Slovakia separated from the Czech Republic in 1993, it took with it the Lab facility, which was the biggest storage site in the former Czechoslovakia. This site has since been expanded, and further expansion is being considered. Slovakia is also looking into laying more high pressure pipelines and developing new storage sites in a bid to become the major hub for the transit of Russian gas to Europe, and a provider of storage services for neighbouring countries.

Industry structure

Major players

SPP holds a monopoly on the import, transmission and distribution of gas in Slovakia. It is now divided up into four divisions to deal separately with transit, investment and trading, distribution, and domestic transmission. Not content with this, SPP has made it known that it would like its storage back, even if this means ‘absorbing’ Nafta Gbely, the company currently holding the storage monopoly.

Pozagas is a joint venture set up to build, operate and lease the storage at the new Lab IV facility. It is owned by SPP (35%), Nafta Gbely (35%) and Gaz de France (30%).

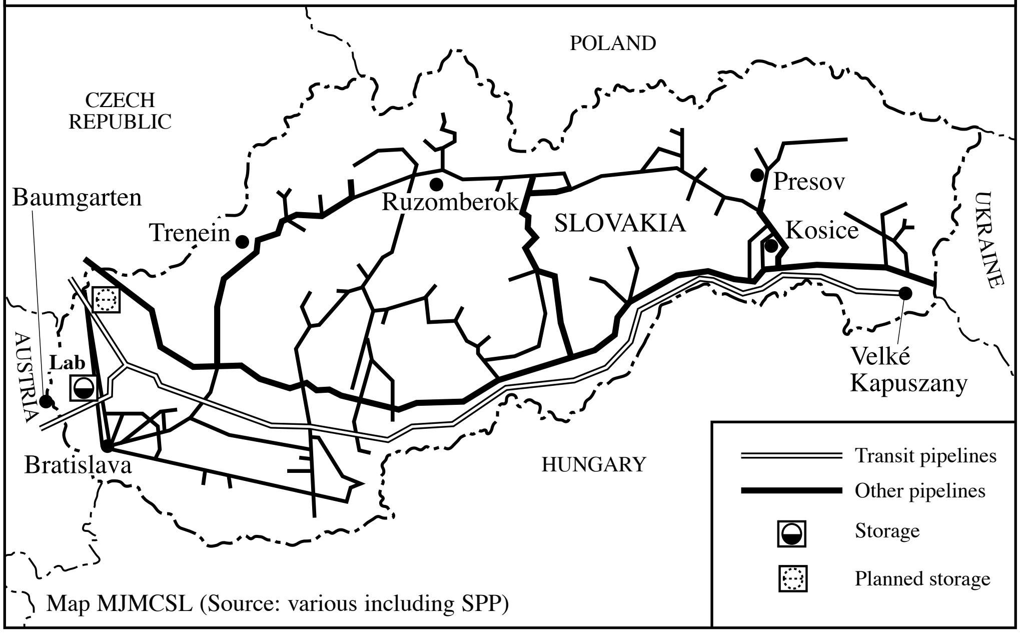
In 1993 SPP’s monopoly on gas storage ended when Nafta Gbely was given exclusive control and took over the existing Lab facility. The company was privatised in 1996 and is totally in the private sector. It is looking to develop new projects elsewhere.

Pipelines

Slovakia currently operates part of the main transit route for Russian gas flowing into Europe. However, this will be less significant when the Yamal pipeline is completed. The Yamal line runs across Poland to Germany, and will compete directly with the route through Slovakia. There are four major transit lines across Slovakia, and another pipeline is being built alongside these. This will increase the transit capacity to some 90 Bcm per year by the millennium. Some SK56 billion will be invested in the gas sector between 1996 and 2005, and this will go towards extending and enhancing the pipeline infrastructure as well as increasing the storage capacity.

A new pipeline connecting Baumgarten in Austria to Lab IV was completed at the end of 1996. It runs under the Moravia River, and will enable Austria to purchase storage capacity more easily.

Figure 20.1: Map of the pipeline and storage facilities in Slovakia



Map MJMCSL (Source: various including SPP)

Peak capacity and swing requirements

Gas plays a major role in Slovakia. It accounts for 33% of primary energy consumption. The largest consuming sector is industry (taking just over 75% of the gas). The residential sector has not taken to gas as a form of heating, and growth is predicted to rise only at a very slow rate. A small amount of gas is produced domestically, and this helps to balance out the seasonal variations in gas demand. The variation is not great, however, as such a small amount is used for heating. As domestic consumption increases, more storage will be required for balancing, but as storage capacity is growing far faster than domestic gas usage this will not cause any problems.

Slovakia also has the option of short-term ‘winter’ contracts to cover any shortages or extra demand that may arise. In previous winters it has bought in volumes of gas from VNG, a German gas company.

Storage facilities available

Types and location of storage

Underground storage

Currently there is only one storage site in operation, although Slovakia as a whole has large potential for underground gas storage. The storage facility is called Lab, and is situated on the Czech/Slovak border. It uses a depleted gas field, and the storage capacity has been developed in stages. The third stage is now complete, and a fourth stage (Lab IV) is under construction. This latest site is already in operation, although maximum capacity is not due to be reached until 2003.

Table 20.1: Storage facilities in Slovakia

Location	Start date	Storage type	Depth (m)	Current working gas capacity (10^6m^3)	Current withdrawal rate ($10^3m^3/h$)	Eventual working gas capacity (10^6m^3)	Eventual withdrawal rate ($10^3m^3/h$)
Lab I - III	1972	Depleted field		1,700	1,025	1,950	
Lab IV	2003	Depleted field	630 -1,070			800	354
Lab V		Depleted field				1,250	542

Source: Pozgas, Cedigas

New projects

The fifth stage of development at the Lab storage site is under study, and preparations are said to be 'encouraging'. The figures shown for Lab V in the above table are the results from a preliminary study by Nafta. Construction of this stage has yet to be started.

There are many other suitable sites for developing storage facilities. As yet there are no definite plans to construct another facility, but since Slovakia is looking to increase its storage capacity well beyond what is possible at Lab, it is highly likely that there will be new developments soon.

Storage tariffs

No information is available, although storage is leased to Transgas, Gaz de France and some German companies.

Alternatives to storage

As with other developing markets, no information is publicly available on potential alternatives to storage.

Regulation

Legislation

The gas industry is still subject to laws dating back to communist times, the key legislation being the Act on Production, Distribution and Consumption of Gas Fuels. This gives the Ministry of Economy overall responsibility for the gas sector.

An energy law has been drafted for the production, distribution and supply of gas, electricity and district heating. However, progress on enacting the law has been slow. This law, which will supersede previous legislation, will introduce a licensing system for energy activities, effectively ending SPP's legal monopoly. In practice, though, SPP will retain a de facto monopoly.

Unlike the case with electricity, SPP will not be required to offer Third Party Access. However, as Slovakia wishes to join the EU, this rule may have to be changed in order to come into line with European law when the EU gas directive is enforced.

Encouraging competition in storage

There is no sign of competition at the moment. However, as with the introduction of Third Party Access, this situation could change if Slovakia joins the EU and the EU policy on market liberalisation comes into play.

GLOSSARY AND ABBREVIATIONS

Aquifer	A geological structure that can be used to store gas. It consists of a deep, dome-shaped, water-saturated bed of rock capped by a layer of impermeable rock.
Annual contract quantity (ACQ)	Amount of gas specified in a buyer's nomination purchase contract for one year.
Arbitrage	Difference in the price of a commodity (or commodities) in different geographical locations, markets, grades or forms; trading to exploit these differences.
Balancing	Making up gas under-deliveries or marketing over-deliveries. The UK Network Code requires daily balancing (i.e. shippers must balance their inputs to and offtakes from the NTS on a daily basis).
Bcf	Billion cubic feet (35.3 Bcf = 1 Bcm).
Bcm	Billion cubic metres (standard or normal), i.e. 10^9 m^3.
Beach terminals	(UK) Onshore terminals from which gas enters the NTS.
Blending	Mixing of gas of different specifications to produce one with the required specification.
Bundling	A combined charge for the provision of two or more services, e.g. the cost of transportation and storage of gas.
CCGT	See Combined cycle gas turbine.
CHP	See Combined heat and power.
Calorific value	A measure of the energy released when a fuel is burned.
Capacity charge	Price set on reserved capacity or measured demand (e.g. in a pipeline).
Capacity trading	Where a player with spare capacity in a storage facility or pipeline system sells or leases his right to use that capacity. Often this is facilitated by the use of electronic bulletin boards.
Co-generation	See Combined heat and power.
Combined cycle gas turbine	An energy efficient gas turbine where the first turbine generates electricity from the gas produced during fuel combustion. The hot gases then pass through a boiler and then on into the atmosphere. The steam from the boiler drives a second electricity generating turbine.
Combined heat and power	Electricity generated using a Combined cycle gas turbine. (Also known as Co-generation.)
Deliverability	Rate at which gas can be supplied from storage in a given period (usually per hour or per day).
Depleted field	A gas or oil field for which it is no longer economic to continue production.
Distribution	Delivery of gas from a high-pressure transmission system to the customers' meters.

Dual-firing	Where two different fuels can be used alternatively to power one piece of plant (e.g. gas and oil in the case of some power stations).
EU	European Union.
EU Gas Directive	An agreement signed provisionally in December 1997 setting a timetable for the opening up of the gas markets in the EU.
FERC	Federal Energy Regulatory Commission. The US government body whose responsibilities include the regulation of the gas industry and interstate electricity rates.
Firm (uninterruptible)	Gas for which the full price has been paid on the understanding that it will be delivered continually throughout the contract period; contrasts with interruptible.
Forward contract	Commodity trading ahead of physical loading, generally at least one month ahead.
Gas bubble	Oversupply of gas.
Hub	1. Physical hub: area where gas purchases and sales occur at the intersection of different pipelines (e.g. Henry Hub, USA). 2. System hub: notional point where gas is traded (e.g. the NBP, UK).
IPE	International Petroleum Exchange. London-based Exchange that offers various contracts at the NBP.
Injectability	Rate at which gas can be input into a storage facility.
Interconnector	The 20 Bcm a year pipeline connecting Bacton (UK) to Zeebrugge (Belgium). Two other Interconnectors link the UK to Ireland.
kWh	Kilowatt hour (10.8 kWh = 1 m3 of natural gas).
LDC	1. Load distribution curve. 2. Local distribution company: company that distributes gas in a particular area.
Linepack	Raising the pressure within a gas pipeline system to increase the storage in the system.
Liquidity	A measure of the ease with which trades can be executed and positions closed out. Liquid markets are easy to enter and exit. Measures of liquidity include trading volumes and market concentration.
Load factor	Ratio between the average and peak usage of gas.
Mcf	Million cubic feet (35.3 Mcf = 1 Mcm).
Mcm	Million cubic metres, i.e. 10^6 m^3.
Mmbtu	Million British thermal units. Measurement used to compare the heat-producing value of different fuels (1 Mmbtu = 10 Therms = 292.7 kWh = 27.1 m^3 of natural gas).
NBP	(UK) National Balancing Point.
NTS	(UK) National Transmission System.
NYMEX	(US) New York Mercantile Exchange.

Network Code	(UK) Published code containing the terms and conditions under which shippers can use Transco's transportation network (and BG Storage's facilities) on a fair, equal and transparent basis.
Ofgas	Office of Gas Supply. UK gas regulator.
Peak shaving	Reduction in the load placed on a transmission system during a period of high demand (e.g. by LNG storage located near to a demand centre).
Salt cavity	A cavity leached out from a deep layer of salt by pumping down fresh water and removing the resulting brine. The cavity can then be used to store gas.
Shipper	1. A company that transports gas through a pipeline system. 2. (UK) A company holding a shipper's licence to buy gas from producers, sell gas to suppliers, and employ Transco to transport the gas to end users.
Spot market	Generic term encompassing the entire short term or commodity market; contracts of less than one year in duration.
Storage capacity	The maximum volume of gas that can be stored.
Swing	1. Variations in gas demand. 2. Flexibility to vary nominations in a gas purchase agreement.
Swing factor	Measure of swing, usually expressed as a percentage of peak to average supplies.
TPA	See Third Party Access.
Take-or-pay	Where the buyer agrees to pay for a specified amount of gas, whether this amount is taken or not.
Therm	A unit of heat (1 Therm = 29.27 kWh = 2.71 m3 of natural gas).
Third Party Access	Access to gas infrastructure by eligible third parties. Third Party Access may either be regulated (subject to published terms and conditions) or negotiated between the parties involved.
Transco	Subsidiary of BG plc. Transco owns and operates the UK National Transmission System.

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EC Energy Monthly, FT
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European Gas Markets, PH Energy Analysis
Financial Times
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