Health and Safety Executive

Failure rates for underground gas storage

Significance for land use planning assessments

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Failure rates for underground gas storage

Significance for land use planning assessments

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The UK Government is considering the possibility of storing natural gas in a variety of underground gas storage (UGS) facilities. The Health and Safety Executive (HSE) has commissioned the British Geological Survey (BGS) to identify the main types of facilities currently in operation worldwide and any documented or reported failures and incidents which have led to release of stored product. Quintessa have been subcontracted by BGS to support this work by developing leakage scenarios for stored natural gas and carrying out simple scoping calculations to evaluate the likely significance of leakage. The Health and Safety Laboratory (HSL) has also been commissioned by HSE to carry out an assessment of UGS facilities to confirm whether or not the failure of the cavern itself through geological causes is significant enough to be considered for Land Use Planning (LUP) purposes.

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EXECUTIVE SUMMARY

Objectives

The UK Government is considering the possibility of storing natural gas in a variety of underground gas storage (UGS) facilities. The Health and Safety Executive (HSE) have commissioned the British Geological Survey (BGS) to identify the main types of facilities currently in operation worldwide and any documented or reported failures and incidents which have led to release of stored product. Quintessa have been subcontracted by BGS to support this work by developing leakage scenarios for stored natural gas and carrying out simple scoping calculations to evaluate the likely significance of leakage. The Health and Safety Laboratory (HSL) has also been commissioned by HSE to carry out an assessment of UGS facilities to confirm whether or not the failure of the cavern itself through geological causes is significant enough to be considered for Land Use Planning (LUP) purposes.

Main Findings

This report has summarised the findings from the BGS and Quintessa work and, using the information contained within their reports, estimated failure rates for different release scenarios from underground gas storage.

The failure rate for a geological failure of the storage cavity in a UGS facility is of the order of 10^{-5} failures per well year. The consequence of this type of failure is a slow release of stored gas with a mass flux of 10^{-6} to 10^{-7} $kgs^{-1}m^{-2}$. This flux is assumed to discharge over a fracture zone 100 m by 2 m in area. If it reached the surface as a point source it would equate to a discharge rate of the order of 10^{-4} kgs^{-1}. In major hazard terms this equates to a risk that can be considered negligible.

The risk is dominated by a release from the well connecting the storage cavity to the surface, which has a failure rate of a similar order (10^{-5} per well year) but would result in a rapid release up the well to the surface with a mass discharge rate calculated to be between 240 – 550 kgs^{-1}, i.e. the discharge rate is effectively 6 orders of magnitude higher than for geological failure of the storage cavity.

Recommendations

Failure of the well pipework is already considered in HSE's hazard based assessment of UGS facilities and as this failure scenario has been shown to dominate the risk, it therefore seems sensible for geological failures which result in a loss of integrity of the storage cavity to be ignored in HSE LUP assessments. However, this assumption is only valid for facilities that have demonstrated that they are operating in accordance with the relevant British Standard and have fully characterised the site prior to operation.

The BGS work concludes that a number of factors are critical to the success of underground natural gas storage projects and it is recommended that any underground gas storage facility demonstrates compliance with these factors, where appropriate, before commencing operation. These factors include ensuring that:

- the site provides strata deep enough for safe and economically viable storage (permitting high gas pressures),

- the site is adequately characterised, geologically,

- the facility is designed and operated with sufficient safety measures to ensure the storage reservoir or salt cavern cannot be inadvertently, or otherwise, overpressured,
- proper design, construction, monitoring and maintenance of injection/withdrawal wells,
- abandoned wells, in and around the proposed storage area, must be accurately located and previous completions checked for integrity and gas tightness.

1 INTRODUCTION

The UK Government is considering the possibility of storing natural gas in a variety of underground gas storage (UGS) facilities. The Health and Safety Executive (HSE) have commissioned the British Geological Survey (BGS) to identify the main types of facilities currently in operation worldwide and any documented or reported failures and incidents which have led to release of stored product. Quintessa have been subcontracted by BGS to support this work by developing leakage scenarios for stored natural gas and carrying out simple scoping calculations to evaluate the likely significance of leakage. The Health and Safety Laboratory (HSL) has also been commissioned by HSE to carry out an assessment of UGS facilities to confirm whether or not the failure of the cavern itself through geological causes is significant enough to be considered for Land Use Planning (LUP) purposes.

Risk assessment of geological storage of natural gas is not straightforward as in some cases no data or only limited data for frequencies or consequences are available. There are two main areas to consider: the engineered system, which includes the infrastructure bringing the gas to the storage facility (the above ground components); and the geological system in which the gas will be stored, which will include the man made/engineered infrastructure within the ground (boreholes, cements, valves, pipes etc.).

The geological system includes the reservoir rock, caprock, salt body nature and geological features such as thin non-halite interbeds, faults etc. (a thorough explanation of these terms is given in the BGS report [Evans, 2007]). However, the engineered system plays a major role in the development of any UGS facility and components are intricately linked with the geological system. The range of possible release scenarios for a given component may cover a wide range of events from a pinhole leak to catastrophic pipe failure, or rupture/failure of the storage environment (e.g. salt cavern) due to wear and tear, subsidence, communication with other caverns or inadvertent intrusion through boreholes due to poor planning and site characterisation.

1.1 CURRENT HSE LUP ASSESSMENT

HSE currently carry out hazard based assessments for LUP purposes in connection with gas storage sites. They consider the principle hazard of natural gas storage in underground caverns, to be failure of the above and below ground pipework associated with these installations. Failures of the underground pipeline feeding the site, the onsite pipework or the wellhead risers (pipework connecting the storage cavity to the surface) are assumed to give horizontal and/or vertical jet fires. The consequences associated with these scenarios are then assessed.

Failure of the integrity of the storage cavity itself is not currently considered in LUP assessments. That is, geological failure of the storage cavity is considered to be sufficiently unlikely that such risks do not affect the HSE assessment, assuming there is full regulatory compliance.

1.2 STORAGE TYPES

1.2.1 Depleted Oil/Gas Fields

In the majority of oil/gas fields, the oil and/or gas is held in a porous rock, often a sandstone, which has spaces between the grains of sand, forming an interconnecting, permeable network between the grains. The porosity and permeability enables the hydrocarbons to move through the rock mass. As oil (and/or gas) is removed from the oil/gas field, the pressure in the reservoir depletes and water invasion occurs. Saline groundwater replaces the oil in the pore spaces due largely to hydrodynamic gradients. The existence of an oil/gas field demonstrates the capability of a structure and rock sequences to trap and successfully retain (commercial) quantities of hydrocarbons over significant periods of geological time (many millions of years). Depleted oil/gas fields therefore offer the potential for reinjecting and storing natural gas underground. Gas can be injected into the reservoir rock, displacing the water, to be stored, as was the oil, in the connected pore spaces. In many instances, re-injecting gas is associated with an increase in pressure within the reservoir, which can also lead to a period of increased oil recovery. Depleted oil and gas fields represent the most cost effective process and in the UK, represents the preferred method of underground storage [BSI, 1998a].

Gas storage in depleted oil and gas fields is the most widespread and generally the least expensive method of storing natural gas in large quantities. Worldwide, depleted reservoirs currently number around 480 storage facilities, providing around 70% of gas storage volume [Evans, 2007]. The first gas storage experiment was made in a gas field in Canada in 1915. The first gas storage facility in a depleted reservoir was built in 1916, using a gas field near Buffalo, New York (USA) and is still operational [WGC, 2006]. By 1930, there were nine storage facilities in six different American states and prior to 1950, virtually all natural gas storage facilities were in depleted reservoirs.

1.2.2 Aquifers

Aquifer storage is based upon the same concepts as depleted oil/gas fields, but is a more costly option as aquifers require conditioning and more preliminary work to prove their capability to hold and contain gas under pressure. They also need a greater investment in cushion gas as the reservoir formerly held saline waters [Oldenburg, 2002], [Favrez, 2003]. Consequently, aquifer storage is usually only used in areas where no nearby depleted hydrocarbon reservoirs exist and they are therefore not likely to be considered for storage in the UK.

1.2.3 Salt Caverns

Rock salt (halite) exhibits unique physical properties and mechanical behaviour and may exist in two forms: ‘thin bedded’ salt beds and, due to their rheological and deformation mechanisms, ‘massive’ salt domes (up to 1.6 km in diameter and anywhere between 5 and 9 km in height) formed by halokinetic movements.

Halite beds in situ are extremely soluble, highly incompressible, and are thought to be almost impermeable below about 300 m [Baar, 1977]. They are nonporous and thus represent a unique host material for the development of (large) caverns and storage of materials that do not cause dissolution of salt. Rock salt is also highly ductile and deforms readily by ductile (plastic) creep, forming a weak layer between other more competent rock structures. Under geological timescales and geostatic pressures, it deforms (‘flows’) plastically, much like a viscous fluid and salt is often viewed as a pressurised fluid.

As a result of these physical properties and characteristics, halite beds may provide both a storage medium and seal to economic accumulations of hydrocarbons. Underground salt formations, therefore, offer another option for the storage of hydrocarbon products (including liquefied petroleum gas (LPG) and natural gas), with salt cavities excavated in bedded salt layers or in halokinetic structures (salt pillows, diapirs, domes, walls etc.). Two scenarios exist for UGS in salt:

- Abandoned salt mines – generally shallow depth (few hundreds of metres) and not originally constructed (or operated) with gas storage in mind. Former salt mines, which are used in the US for underground fuel storage, tend to be at shallower depths than those at which solution mined cavities are constructed, with the inherent problems of thinner cap rock and possible groundwater interaction this gives rise to.

- Solution mined caverns – many early storage caverns were originally created by solution mining during the production of brine and chlorine products. They were then subsequently used to store products but the completed brine cavities were not, however, ideally designed or constructed (in terms of their shape or spacing) for high-pressure gas storage. Gas cavities should be spherical or cylindrical in shape with domed roofs and with a grid spacing related to their size (diameter).

In Canada, LPG has been stored in solution-mined caverns since the late 1940s (bedded salts) and early 1950s (salt domes), whilst LPG was first stored in Texas caverns in the 1950s [Tomasko et al., 1997], [Favrez, 2003]. At about this time crude oil was first stored in caverns in England. Natural gas was first stored in salt caverns in 1961 [Allen, 1972], [Tomasko et al., 1997]. In 1963, the Saskatchewan Power Corporation built the first salt cavern specifically designed and constructed for natural gas storage at Melville, Saskatchewan, Canada. The earlier cavern storage facilities utilised brine caverns created during the extraction of salt for the chemical industry. These earlier caverns were, therefore, created without a lot of the design and careful engineering that goes into the design and construction of present day gas storage caverns. Their stability and shape were therefore not always predictable.

1.3 BRITISH STANDARDS

The European Standard for underground gas storage, BS EN 1918, has five parts of which Part 3 – Functional recommendations for storage in solution-mined salt cavities, is one [BSI, 1998c]. The others have recommendations for storage in aquifers, storage in oil and gas fields, storage in rock caverns and surface facilities [BSI, 1998a], [BSI, 1998b].

The standards specify procedures and practices which are safe and environmentally acceptable. Part 3 covers the functional recommendations for design, construction, testing, commissioning, operation and maintenance of UGS facilities in solution-mined cavities up to and including the wing valve of the wellhead. The standard is not intended to be applied retrospectively to existing facilities.

1.3.1 Definitions

The following terms are defined in the standard and are used within this report:

- **Annulus** – space between two strings of pipes, or between the casing and the borehole.

- **Casing** – pipe or set of pipes that can be screwed or welded together to form a string which is placed in the borehole for the purpose of supporting the sides of the borehole and to act as a barrier preventing subsurface migration of fluids when the annulus between it and the borehole has been cemented.

- **Cavity** – leached volume in the salt below the bottom end of the last cemented casing.
- **Cementing** – operation whereby a cement slurry is pumped and circulated down a well through the casing and then upwards into the annular space between the casing and the open or cased hole.
- **Completion** – technical equipment inside the last cemented casing for leaching, first gas filling or production/injection.
- **Drilling** – all technical activities connected with construction of a well.
- **Gas tightness** – adherence to a minimum leakage rate in an approved test procedure.
- **Leaching, solution mining** – the controlled supply of water into the salt strata and the production of brine in order to construct a salt cavity.
- **Master valve** – valve at the wellhead, vertically above the well, designed to close off the well in case of emergency or maintenance.
- **String** – set of casing or tubing pipes plus additional equipment screwed or welded together for a defined purpose.
- **Subsurface safety valve** – valve installed in tubing or casing beneath the wellhead for the purpose of stopping the flow of gas in an emergency.
- **Well** – technical equipment of a wellbore from the wellhead to the bottom of the hole.
- **Wellhead** – equipment supported by the top of the well casings, including tubing head, shut-off and flow valves, flanges and auxiliary equipment.

1.3.2 Key requirements

The European Standard [BSI, 1998c] states that the storage facility must be designed to ensure the long-term containment of the stored products. It presupposes:

- adequate prior knowledge of the geological formation in which storage is to be developed and of its geological environment,
- acquisition of all relevant information needed for specifying parameter limits for construction and operation,
- demonstration that the storage is capable of ensuring long-term containment of the stored product through its hydraulic and mechanical integrity.

The standard details the geological exploration and mechanical property testing of the salt required to ensure adequate site characterisation is carried out.

Another requirement of the standard is a master isolation valve which isolates the wellhead from the cavity in the event of an emergency or during maintenance. Major offtakes and intakes of the wellhead should also have a manual and/or actuated valve (which may be the subsurface safety valve if fitted). The wellhead has to be equipped with devices to automatically shutdown the well in case of unallowable operation or emergency.

Monitoring systems need to be designed to verify gas containment and storage reservoir integrity while the facility is operating. Data should be collected on cavity volumes, cavity pressures and annuli pressures, injected and produced gas volumes and qualities.

During construction, the standard requires that the leaching process is monitored and the cavity shape development is controlled. Once the required cavity dimensions are reached, the actual cavity shape must be confirmed and documented by a final survey.

2 INCIDENT SUMMARY

A thorough review of incidents relating to UGS has been carried out by BGS [Evans, 2007]. This section summarises that review and highlights those incidents particularly relevant to geological failure of possible storage scenarios in the UK.

Overall, 64 instances of problems at UGS facilities have been found. Of these, 27 have been at salt cavern facilities, 16 at aquifers and 16 at depleted oil/gas fields. Only eight deaths related to UGS have been found reported in the literature, with around 61 injured and circa 6700 evacuated. All reported deaths have occurred at salt cavern facilities and all of these have been in America. Indeed, 53 of the reported incidents have occurred in America, with California (12) and Illinois and Texas (10) having the highest numbers. The 64 incidents have, however, been of varying cause, severity and nature, with some involving only minor problems that were quickly rectified and at no stage threatened failure of the facility or release of product. However, in four of these incidents all involving storage in salt, a total of eight people have been killed as a result of the release of the stored product.

Incidents have been categorised according to their cause. Failure of the storage cavity relates to failure of the integrity of the cavity (i.e. geological failure) and includes migration of the gas out of the original cavity through either rock mass discontinuities or faults, failure of the cavity roof and salt creep leading to reduced cavity capacity. The consequences of this type of failure are represented by the viscous dominated release in the Quintessa work [Watson et al., 2007].

Well failures include releases through failed or leaky boreholes, casing failure and well valve failure (this type of failure therefore includes failure of the pipework connecting the storage cavity to the surface). The consequences of well failures are represented by the rapid advective release in the Quintessa work [Watson et al., 2007]. Inadvertent intrusion will also produce similar consequences.

Of the 16 depleted oil and gas field incidents, 6 were caused by failure of the storage cavity, 5 were caused by well failures and 3 were due to the above ground infrastructure. Of the 27 salt cavern incidents, 7 were caused by failure of the storage cavity, 11 were caused by well failures and 7 were due to the above ground infrastructure.

2.1 IDENTIFIED INCIDENTS RESULTING FROM FAILURE OF THE STORAGE CAVITY IN DEPLETED OIL/GAS FIELDS

Table 1 shows all incidents detailed in the BGS report [Evans, 2007] which relate to failure of the integrity of the storage cavity in depleted oil/gas fields. All of the incidents are caused by gas migrating from the original injection footprint into adjacent cavities.

Table 1 Failure of storage cavity integrity in depleted oil/gas fields

Facility	*Date*	*Summary*
Castaic Hills and Honor Rancho, California, USA	1975 - present	Gas migrated from Castaic reservoir, via faults, to adjacent shallower reservoirs and subsequently to surface
Montebello, LA, California, USA	1950s - 1980s	Gas migrated from injection area and lost over extended period
Playa del Rey, LA, California, USA	1940s - present	Gas migrated from Playa del Rey structure into a neighbouring structure from earliest days. Cause partly due to faults
Epps, Louisiana, USA	1980s - 1990s	Gas migrated away from injection footprint and produced elsewhere
East Whittier, California, USA	1970s	Gas migrated from original injection site and produced by another company
El Segundo, California, USA	1970s	Gas migrated from reservoir to surface

2.1.1 Discussion

Underground fuel storage facilities in California account for the majority of the documented problems in depleted oil and gas fields. The BGS report [Evans, 2007] discusses the fact that California represents a special area for the following reasons:

- it is a highly petroliferous area, developed in (relative to the UK) young (Cainozoic) sedimentary rocks,
- it is an area of ongoing seismic activity associated with transpressional tectonics that has resulted in the formation of many traps formed by (faulted) folds and still produces numerous surface rupturing faults that have contributed to fracturing of large areas of strata,
- it has a long history of (often unregulated) oil exploration dating back to the late 1800s, with many thousands of wells having been drilled across the state,
- as a consequence, the locations of many wells are not known accurately, with many not known at all and also many of the older wells now having old and deteriorating well completions (casings and cement).

Consequently, California provides a high number of incidents associated with UGS and distorts the data. Whilst the data provide important information on problems encountered and modes of failure of UGS infrastructure for planning and risk assessment, many of the problems and geological factors encountered in California would not necessarily be applicable or relevant to assessment of UGS in the UK situation.

2.2 IDENTIFIED INCIDENTS RESULTING FROM FAILURE OF THE STORAGE CAVITY IN SALT CAVERNS

Table 2 shows all incidents detailed in the BGS report [Evans, 2007] which relate to failure of the integrity of the storage cavity in salt caverns. In two incidents storage gas has migrated away from the original storage area. In the remaining incidents, no release of gas has occurred; however, they are included as the capacity of the cavity has changed and there was the potential for an incident to occur if the problem had not been detected, e.g. overfilling if the reduced capacity had not been identified.

Table 2 Failure of storage cavity integrity in salt caverns

Facility	*Date*	*Summary*
Conway, McPherson County, Kansas, USA	1980s - 2002	Gas found in wells and local groundwater possibly caused by wet rockhead
Mineola, E. Texas, USA	1995	Cavern operations led to connection between adjacent caverns, pressure build up and casing leak
Eminence, Mississippi, USA	1972	Salt creep caused by operating at too low pressure, capacity lost
Kiel, Germany	1960s – present	Salt creep leading to lost capacity
Tersanne, France	1970 – 1979	Salt creep leading to lost capacity
Clovelly, Louisiana, USA		Cavern leaching in the salt overhang. Insufficient thickness of salt to act as a barrier
Napoleanville, Louisiana, USA		Shale layers of salt dome side encountered in some caverns leading to insufficient buffer salt.

2.2.1 Discussion

Two cases of problems encountered at salt cavern facilities (Clovelly and Napoleanville, Louisiana) were due to insufficient site characterisation [Evans, 2007], with the caverns having been built too close to the edge of a salt dome such that there was not enough salt ‘buffer’. In terms of the UK, this is not really an issue onshore, as there are no halokinetic structures developed. However, similar problems may be caused in cases with a previously unknown large fault, producing an offset of the bedded salt beds, that might be close by a facility, potentially intersecting or impacting on the cavern walls.

In several of the other incidents, where no release occurred, the shape of the cavity has changed over time due to the operating technique employed at those particular sites. Had operators been monitoring data such as the cavity volume, cavity pressure or stored gas volumes, these situations may not have occurred. Adherence to the European Standard [BSI, 1998c] would require a facility operator to monitor and record these data.

2.3 OPERATING EXPERIENCE

The BGS report [Evans, 2007] gives the numbers of the different types of UGS sites worldwide, depleted oil and gas fields, salt caverns and aquifers; this is summarised in Table 3.

The first gas storage facility in a depleted oil and gas reservoir was built in 1916 near Buffalo, New York and is still operational today [WGC, 2006]. By 1930, nine storage facilities in six different US states were operational. Storage in solution mined salt caverns was reportedly first conceived in Canada in the early 1940's and storage of LPG and other light hydrocarbons spread rapidly in the early 1950's in North America and Europe. Conversion of depleted brine caverns for gas storage began in the early 1960s.

Table 3 Summary of UGS sites worldwide

	Type and number of UGS sites				
Area	*Gas & Oil Fields*	*Aquifers*	*Salt Caverns*	*Other*	*Total*
Europe	64	23	27	3	**117**
Former Soviet Union	36	13	1		**50**
USA	320	44	30		**394**
Canada	44		8		**52**
South America	2				**2**
Asia	7				**7**
Australia	5				**5**
Total	**478**	**80**	**66**	**3**	**627**

Papanikolou et al. [2006] reviewed data from the 1970s onwards to identify accidents associated with fugitive emissions of gas from UGS facilities. They calculated the cumulative years of UGS site and well operations to be 20,271 years and 791,547 years, respectively. Seventeen accidents were identified and of these sixteen were associated with underground causes, principally well failures. Incident frequencies were calculated from this information to give the frequency of a major incident from a UGS facility to be 8.4 x 10^{-4} per year and the frequency of a major incident from a UGS well to be 2.0 x 10^{-5} per year.

The paper also compared these incident rates to data from an offshore blowout study [Holand, 1997], which gave a production blowout frequency of 5 x 10^{-5} per well year.

A working group was set up in 1998 to exchange information on UGS operations [Joffre and LePrince, 2002]. Eight European companies participated and an accident database was established for incidents which are reportable under the Seveso Directive. The eight companies taking part in the study owned 42 sites in total which corresponds to 845 wells. Operating experience was estimated for these 42 sites and calculated to be 100,155 well years. Eleven incidents were reported, six occurring on the surface engineering structure and five on the wells. The probability for a major accident was calculated to be 6 x 10^{-3} per site year for surface failures and 5 x 10^{-5} per well year for well failures. The paper states that this is probably an overestimate of the failure frequency as it is likely that the operating experience is greater than that estimated.

The operating experiences used in the references above do not distinguish between the different types of UGS sites. However, it is possible to calculate estimates for the operating experience of the different types of site from the above data. Three different methods have been used to calculate this.

Method 1: From the Joffre and LePrince [2002] report, the 42 European sites had 100,155 well years experience in total. The BGS report states that there are currently 117 sites in Europe. Assuming that the 42 sites are representative of the other sites in Europe (i.e. each site has a similar number of wells and has been operating for a similar number of years), then this would give a total operating experience in Europe for all types of site of 280,000 well years. 27 sites in Europe are salt cavern storage and 64 sites are depleted oil and gas fields giving 65,000 well years and 153,000 well years, respectively. As stated previously, the Joffre and LePrince [2002] report is likely to have underestimated the operating experience and therefore this method is also likely to produce an underestimate of operating experiences.

Method 2: The Papanikolau et al. [2006] paper gives the operating experience for all UGS sites worldwide since 1970 to be 791,547 well years. The BGS report states that there are currently 627 sites worldwide. Using similar assumptions to above, this would mean that: the 27 European salt cavern sites account for 34,000 well years experience, the 64 European depleted oil and gas field sites account for 81,000 well years experience, the 66 worldwide salt cavern sites account for 83,000 well years experience, and the 478 worldwide depleted oil and gas field sites account for 603,000 well years experience. The Papanikolau et al. [2006] paper only includes operating experience from 1970 to 2006 and this will therefore lead to this method producing an underestimate of operating experiences.

Method 3: From the Papanikolau et al. [2006] paper there are 20,271 site years of operation worldwide for all UGS sites. There are also 791,547 well years of operation which suggests that the average number of wells per site is 40. The BGS report states that there have been approximately 45 years of well operations at salt cavern sites. So, 45 years ago there were no wells and now there are approximately 40 wells per site, giving an average of 20 wells per site over the 45 years (a similar assumption is used in the Joffre and LePrince [2002] report to calculate operating experience). This would mean that for the 27 salt cavern sites in Europe, there are 45 years x 20 wells x 27 sites = 24,000 well years operating experience. Similar calculations give operating experience of 59,000 well years for the 66 salt cavern sites worldwide, 115,000 well years for the 64 depleted oil and gas fields in Europe and 860,000 well years for the 478 depleted oil and gas fields worldwide (assuming depleted oil and gas fields have been operational for 90 years). As stated, this method uses a similar assumption to that used in the Joffre and LePrince [2002] report and this is likely to also produce an underestimate of operating experience.

Table 4 summarises the estimated operating experience for the different types of UGS. As has been discussed previously, all three methods are likely to produce underestimates of the different operating experiences calculated and this may result in the corresponding failure rates being overestimated.

Table 4 Estimates of operating experience (well years) at UGS sites

Method	*Salt caverns - Europe*	*Salt caverns - worldwide*	*Oil and gas fields – Europe*	*Oil and gas fields - worldwide*
1	65,000		153,000	
2	34,000	83,000	81,000	603,000
3	24,000	59,000	115,000	860,000

2.4 SUMMARY AND DISCUSSION

Although many of the incidents have occurred in the US and very few failures have been experienced in Europe, identification of typical incident causes allows us to consider the necessary safety measures that need to be in place to prevent accidents.

From the reviews of each incident in the BGS report, it is clear that in the vast majority of cases, the incident or problem experienced at any particular facility has not been the result of a failure of the geology. The exception in storage facilities relevant to this work, where the geology has apparently been linked to the failure of one salt cavern facility, is where connection of caverns occurred in Mineola, USA, although human error was ultimately to blame for this failure.

Instead, most typically incidents most relevant to UK development have resulted from a failure of either the man-made infrastructure (well casings, cement, pipes, valves, flanges, compressors etc.), or human error, which has included overfilling of caverns and inadvertent intrusion. Problems have also arisen from (extreme) natural events (seismic activity). The causes, scale, and severity of the accidents are also extremely variable and have in some cases been the result of a combination of factors.

It has been shown that the majority of incidents in UGS facilities in depleted oil and gas fields have occurred in California and the reasons for this have been discussed in Section 2.1.1. These historical problems and geological factors are not considered applicable or relevant to UGS in the UK.

A paper summarising the history of salt cavern use [Thoms and Gehle, 2000] states that early salt cavern storage in the US was done in brine wells that had been solution mined without consideration for subsequent storage in the depleted caverns. This practice sometimes resulted in later problems for storage operations in retrofitted brine caverns. Because of this, it would be expected that new purpose built salt caverns would be less likely to fail compared to the ones that had been retrofitted for gas storage.

Operating experience has been estimated for salt caverns and oil/gas fields both in Europe and worldwide. Different methods have been used to calculated these operating experiences although all methods are likely to lead to an underestimate when compared to actual operating experience. It can be seen from Table 4 that the methods provide estimates that are relatively consistent, i.e. approximately within an order of magnitude.

3 CALCULATED ACCIDENT RATES

The following two sections calculate failure rates for different types of failure of the underground storage system, failure of the integrity of the storage cavity and failure of the well and its associated equipment. The failure rates were calculated using the incidents described in the BGS report [Evans, 2007] and the operating experience estimated in Section 2.3. For comparison, previous work has derived failure rates for the subsurface storage system and calculated it to be 2 x 10^{-5} per well year [Papanikolau et al., 2006] and 5 x 10^{-5} per well year [Joffre and LePrince, 2002].

3.1 STORAGE CAVITY FAILURES

The BGS report [Evans, 2007] identifies 6 failures in depleted oil and gas fields and 2 failures in salt caverns (only incidents which resulted in a release of gas have been included), which were caused by failure of the storage cavity. Using the operating experiences estimated in section 2.3, failure rates for storage cavity failure can be calculated for the different types of UGS sites; these are shown in Table 5. European and worldwide failure rate ranges have been calculated using the highest and lowest operating experience estimates. No relevant storage cavity failures in European oil and gas fields or salt caverns have been recorded, so one failure has been assumed when calculating the failure rate. This assumption is pessimistic and therefore may result in an overestimate of the failure frequency.

The consequences of this type of failure are represented by the viscous dominated release in Section 4.

Table 5 Calculated failure rates for storage cavity integrity failure

		Salt caverns - Europe	*Salt caverns - worldwide*	*Oil/ gas fields - Europe*	*Oil/ gas fields - worldwide*
Number of cavity failures		1	2	1	6
Operating experience (well years)	Upper	65,000	83,000	153,000	860,000
	Lower	24,000	59,000	81,000	603,000
Failure rate (per well year)	Lower	1.5 x 10^{-5}	2.4 x 10^{-5}	6.5 x 10^{-6}	7.0 x 10^{-6}
	Upper	4.1 x 10^{-5}	3.4 x 10^{-5}	1.2 x 10^{-5}	9.9 x 10^{-6}

3.2 WELL FAILURES

The BGS report [Evans, 2007] identifies 5 failures in depleted oil and gas fields and 11 failures in salt caverns which were caused by failure of either the well or its casing. Using the operating experiences estimated in section 2.3, failure rates for well/casing failure (i.e. the pipework connecting the storage cavity to the surface) can be calculated for the different types of UGS sites; these are shown in Table 6. European and worldwide failure rate ranges have been calculated. No relevant well failures in European oil and gas fields have been recorded so one failure has been assumed when calculating the failure rate. As stated in the previous section, this assumption is pessimistic and therefore may result in an overestimate of the failure frequency.

The consequences of this type of failure are represented by the rapid advective release in Section 4.

Table 6 Calculated failure rates for well failure

		Salt caverns - Europe	*Salt caverns - worldwide*	*Oil/ gas fields - Europe*	*Oil/ gas fields - worldwide*
Number of well failures		1	10	1	5
Operating experience (well years)	Upper	65,000	83,000	153,000	860,000
	Lower	24,000	59,000	81,000	603,000
Failure rate (per well year)	Lower	1.5×10^{-5}	1.2×10^{-4}	6.5×10^{-6}	5.8×10^{-6}
	Upper	4.1×10^{-5}	1.7×10^{-4}	1.2×10^{-5}	8.3×10^{-6}

3.3 COMPARISON WITH FAILURE RATES FOR PIPEWORK, ABOVE GROUND STORAGE, AND OFFSHORE BLOWOUTS

The following sections have been included for comparison purposes. HSE currently take a hazard based approach to the assessment of salt cavern storage facilities on the basis of a worst case failure from the largest above ground pipe. This could include the on-site pipework or the pipework connecting the storage cavity to the surface (i.e. the well). Failures are assumed to give horizontal or vertical jet fires. The likelihood of failure of the integrity of the salt cavity (where there is full regulatory compliance) is considered to be sufficiently low that such risks do not affect the HSE assessment. The failure frequency of the pipework is considered in Section 3.3.1 to allow comparison between it and the failure frequencies calculated in Section 3.2 for the underground system.

3.3.1 Pipework

HSE currently assess pipework failure rates according to the pipe diameter, pipe length and hole size. The pipework from the cavity to the wellhead of a salt cavern storage facility could be around 250 mm diameter and 300 m long [Watson et al., 2007]. HSE assume that the failure rate for guillotine failures for pipework diameter 150 mm – 299 mm is 2×10^{-7} /m/yr and that the failure rate for small holes (4 mm) in pipework of diameter 150 mm – 299 mm is 1×10^{-6} /m/yr [HSE, 2004].

Therefore, the pipework connecting the cavity to the surface of a salt cavern storage facility would be assigned failure rates of 6×10^{-5} /yr for guillotine failures and 3×10^{-4} /yr for small holes. It might also be expected that given the environment of the pipework (i.e. salt rich), failures due to corrosion would be higher than average.

3.3.2 LNG storage tanks

Current energy demands necessitate that liquefied natural gas (LNG) is stored in the UK. An alternative method of storage to underground gas storage is using above ground refrigerated storage tanks. For storage tanks that have double walls, HSE currently assign a failure rate of 5 x 10^{-7} per tank year for catastrophic failure and 3 x 10^{-5} per tank year for minor (300 mm) failures [HSE, 2004].

3.3.3 Offshore blowouts

The Papanikolau et al. [2006] paper also compared incident rates at salt cavern storage facilities to data from an offshore blowout study [Holand, 1997], which gave a production blowout frequency of 5 x 10^{-5} per well year. HSE also recommend the use of this value for the failure frequency of production well blowouts.

3.3.4 Summary

Failure rates for pipework failure, above ground LNG storage and offshore blowouts have been presented in the preceding sections. These failure rates are shown in Table 7 alongside the calculated failure rate for a European salt cavern storage facility. This allows the calculated failure rates to be shown in context and also allows comparison with the failure rates that would be used in current HSE LUP assessments for above and underground gas storage, if the assessment was risk based. It can be seen that the failure rates are of a similar magnitude except for the catastrophic failure of an above ground LNG storage tank, which is much lower. However, the potential consequences following catastrophic failure of an LNG tank are more severe.

Table 7 Summary of failure rate comparison

	Failure Rate (per equipment year)	
	Catastrophic failure	***Minor failure***
Salt caverns (Europe)	4 x 10^{-5} (all failures)	
Offshore blowouts	5 x 10^{-5}	
Pipework (well riser)	6 x 10^{-5}	3 x 10^{-4}
LNG tanks (double walled)	5 x 10^{-7}	3 x 10^{-5}

4 CONSEQUENCES OF CAVERN FAILURE

The Quintessa report [Watson et al., 2007] identifies three basic geological scenarios which are representative of existing or potential onshore UGS facilities in the UK:

- cavern storage in which the overlying geosphere is composed entirely of low permeability rock formations,
- cavern storage in which the overlying geosphere contains varied low permeability and high permeability formations,
- depleted hydrocarbon reservoir storage in which the overlying geosphere contains varied low permeability and high permeability formations.

Three release pathways were described which account for the range of cavern failures identified:

- **Rapid advective** release through a failed or leaky borehole (well/casing) impacting on the area immediately adjacent to the borehole works. This case also includes borehole valve failure and inadvertent intrusion via drilling into the gas cavern.
- **Viscous dominated** release via rock mass discontinuities and/or fault zones, which covers cases where heterogeneities become routes for viscous gas migration of free gas or advection of dissolved gas through natural transmissive features. This case also covers failure of the cavern roof resulting in the disappearance of the impermeable salt barrier.
- **Diffusive** release via dissolution of natural gas into brine surrounding the salt cavern or the porewater in the caprock, diffusion within the brine/ porewater, and subsequent exsolution and hence release to near-surface.

One other significant pathway, **near-surface exsolution**, exists when higher permeability materials are present. A pre-existing old borehole or massive cavern collapse could form a pathway enabling gas to migrate and dissolve in a near-surface aquifer. Once the gas has reached the aquifer, several possibilities exist for how the gas comes out of solution and migrates to the surface over a wide area (120 m by 10 m).

The Quintessa report [Watson et al., 2007] calculated methane leakage rates, areas of discharge, mass fluxes and the time taken to empty the cavern space, for each pathway for the three geological scenarios. The report also provides a semi-quantitative assessment of the likelihood of occurrence for each release scenario. These results are summarised in Table 8.

The mass flux from a rapid advective release has not been calculated, as the release is effectively a point source. The diffusive release for the salt cavern (mixed permeability) storage scenario was not calculated by Quintessa. It was assumed to be negligible as it would be of the same order of magnitude, albeit slightly higher, as that calculated for the low permeability salt cavern. The viscous dominated release is calculated for two depths of depleted oil and gas fields, 400 m and 1500 m.

The time to empty a hypothetical 100 m diameter spherical cavern has also been estimated. This shows that only the rapid advective type release is capable of emptying a cavern on the timescale of operation of a UGS facility. However, the rate of loss through the viscous dominated pathway could potentially be economically significant even if there are no safety implications associated with this type of release.

Table 8 Consequences of storage failure scenarios

Storage scenario	*Release pathway*	*Mass discharge (kg/s)*	*Area of discharge (m^2)*	*Mass flux ($kg/s/m^2$)*	*Time to empty 100 m dia. cavern*	*Probability of occurrence*
Salt cavern – low permeability	Rapid advective	250	0.05	N/A	1.7 days	Low
	Viscous dominated	2.32E-4	200	1.16E-6	5000 years	Intermediate
	Diffusive	1.76E-11	7854	2.2E-15	4.4E+10 years	High
Salt cavern – mixed permeability	Rapid advective	550	0.05	N/A	2.6 days	Low
	Viscous dominated	3.44E-4	200	1.72E-7	6400 years	Intermediate
	Diffusive	Negligible				High
	Near-surface exsolution	5.9E-7	1200	4.9E-10	N/A	Intermediate
Depleted oil/gas fields – mixed permeability	Rapid advective	240	0.05	N/A	1.4 years	Low
	Viscous dominated – 400 m deep	9.89E-5	200	4.95E-7	9.9E+12 years	Intermediate
	Viscous dominated – 1500 m deep	2.73E-4	200	1.37E-6	3.7E+13 years	Intermediate
	Diffusive	1.12E-7	2.5E+5	4.5E-13	1.2E+18 years	High
	Near-surface exsolution	5.9E-7	1200	4.9E-10	N/A	Intermediate

The different release scenarios are assigned low, intermediate and high probabilities. Rapid advective releases are considered to be low probability as they are largely controlled by the highly regulated working practices of the facility operator, and adequate site characterisation should have ensured that all pre-existing boreholes have been located and appropriately sealed. Quintessa estimate that the failure rate of wells associated with UGS facilities is approximately once per 20,000 to 50,000 years of well operations [Watson et al., 2007]. These failure rates are taken from the Joffre and LePrince paper [2002] and the Papanikolau et al. paper [2006].

The diffusive release pathway is considered to have a high probability because the features and processes necessary for this pathway to occur are common to the geology found in the UK. In effect, this process is certain to occur anywhere that a concentration gradient is present. However, diffusive transport will be extremely slow and the corresponding fluxes of gas will be extremely small and reach the surface millions of years into the future.

The viscous dominated release pathway is regarded to have an intermediate probability of occurrence as the physical features required for this type of release are not expected to be present or well developed in the UK geology. For new sites, it is expected that any potentially transmissive features would be detected during site characterisation and therefore avoided.

Potential releases via the near-surface exsolution pathway are significantly lower than releases via the viscous dominated pathway. The near-surface exsolution pathway may lead to very small releases that are a significant distance from the UGS facility footprint.

Quintessa therefore conclude that only rapid advective type releases could potentially result in significant gas emissions at the surface [Watson et al., 2007]. However, they note that this type of release pathway would be unlikely if the storage site is properly investigated prior to commissioning and adequately managed during operations.

4.1 GAS MIGRATION RATES

Whilst subsurface oil and gas accumulations demonstrate the sealing capabilities of overlying caprock strata, no reservoir cap rock or trap has ever been shown to be a perfect seal to hydrocarbon migration [Nelson and Simmons, 1995]. Natural pathways and mechanisms exist that include faults, fractures, microfractures and pore space in the caprock, which preclude a perfect seal and result in hydrocarbon liquids and gases reaching the earth's surface. Studies have shown that migration of hydrocarbons to the surface is more common than might generally be thought or presumed, with petroleum leakage to the surface presently occurring in at least 126 of the 370 petroleum-bearing basins worldwide [Clarke and Cleverley, 1991]. However, it is relatively rare for seeps to overlie major fields [MacGregor, 1993].

The caprock, therefore, only retards hydrocarbon migration, permitting the temporary (on geological timescales) accumulation of reserves within the underlying reservoir rock. It is, therefore, the rate of hydrocarbon flux across the field, achieved by migration along faults, fractures and microfractures, or by capilliary action through the pore space that is of interest to the study of residence (or retention) time in any particular trap or field. If a concentration gradient (chemical potential gradient) exists, then molecular diffusion (by capilliary action) is always present [Bockris and Reddy, 1970]. This is generally regarded as the slowest loss mechanism and represents the minimum rate of loss from a reservoir over geological time [Nelson and Simmons, 1995]. The implication is that losses or flux rates must be higher if other migration routes are present.

The BGS report [Evans, 2007] reviewed background seepage rates for hydrocarbon bearing basins around the world. A summary table of this review is given in Appendix 6 of the BGS report. Mass fluxes for these hydrocarbon bearing basins range from 1.9×10^{-8} to 3.2×10^{-15} $kg/m^2/s$. These rates are comparable with the diffusive release pathways fluxes calculated by Quintessa [Watson et al., 2007] (10^{-10} to 10^{-15} $kg/m^2/s$) and are one or two orders of magnitude lower than the viscous dominated releases (10^{-6} to 10^{-7} $kg/m^2/s$).

Another source of information, which allows us to put the release rates of stored gas into context, is the migration of methane gas from landfill sites. Various experiments have been carried out to measure the methane flux from landfills and the results range from around 10^{-7} to 10^{-11} $kg/m^2/s$ [Boeckx et al., 1996], [Chan and Parkin, 2001]. These fluxes are comparable to those reported found in hydrocarbon bearing basins although in general they are slightly higher. Landfill fluxes are also higher than the diffusive mass fluxes predicted by Quintessa [Watson et al., 2007] and slightly lower than the viscous dominated releases.

5 SUMMARY AND DISCUSSION

This report has summarised the findings from the BGS [Evans, 2007] and Quintessa [Watson et al., 2007] reports and, using the information contained within those reports, estimated failure rates for different release scenarios from underground gas storage. The failure rates calculated are shown in Table 9 and are compared to the failure rate HSE would assume for pipework failure, if carrying out a risk based assessment. For storage cavity and well failures the upper failure rate calculated has been used.

Table 9 Summary of calculated failure rates

	Failure scenario	*Salt caverns - Europe*	*Salt caverns - worldwide*	*Oil/ gas fields - Europe*	*Oil/ gas fields - worldwide*
Failure rate (per well year)	Storage cavity	4.1×10^{-5}	3.4×10^{-5}	1.2×10^{-5}	9.9×10^{-6}
	Well	4.1×10^{-5}	1.7×10^{-4}	1.2×10^{-5}	8.3×10^{-6}
	Pipework	Guillotine – 6×10^{-5} Small holes – 3×10^{-4}			

It should be noted that these calculated failure rates are likely to be pessimistic for a number of reasons. One of these reasons is the use of accident data from the US which has a high number of depleted oil/gas field incidents and distorts the data as many of the problems and associated geological factors are not necessarily applicable or relevant to the UK situation. Similarly, much of the early salt cavern storage in the US was done in retrofitted caverns which had not been solution mined with consideration for future storage. Problems resulting from this would not be expected in newly mined salt caverns in the UK.

In addition, as stated in Section 2.3, it is probable that all the estimates of operating experience are lower than their true values. This will result in the calculated failure rates being higher than is actually the case. Another factor is that no relevant failures were found in the literature for storage cavity failures in European oil/gas fields or salt caverns, or for well failures in European oil/gas fields. To enable a failure rate to be calculated for these types of site, one failure has pessimistically been assumed. This will also result in an overestimate of the failure rate. This assumption has prevented a comparison between the relative failure rates for the storage cavity and well being carried out as the same failure rate has been estimated for both. However, worldwide failure rates for cavity failure in salt caverns are less than for well failure. These results do at least allow us to predict that the failure rate for the integrity of the storage cavity will be no greater than the failure rate for well failures.

From the reviews of each incident in the BGS report [Evans, 2007], it is clear that in the vast majority of cases, the incident or problem experienced at any particular facility has not been the result of a failure of the geology. The exceptions, where the geology has apparently been linked to the failure, are one salt cavern facility where connection of caverns occurred (Mineola, USA), although human error was ultimately to blame for this failure, and a case where a well appears to have been crushed due to faulting (in a seismically active area, with little similarity to the UK environment).

In general, incidents most relevant to UK development have resulted from a failure of either the man-made infrastructure (well casings, cement, pipes, valves, flanges, compressors etc.), or human error, which has included overfilling of caverns and inadvertent intrusion. Problems have also arisen from (extreme) natural events (seismic activity). The causes, scale, and severity of the accidents are also extremely variable and have in cases been the result of a combination of factors.

BGS also conclude [Evans, 2007] that previous incidents at underground fuel storage facilities suggest that the biggest risks in both depleted oil/gas field facilities and salt cavern storage arise from well problems:

- breaks/faults in the casing, joints or defective or poor quality cementing of casings, leading to leakage through new or ageing injection well completions and leakage up abandoned wells,
- presence of unknown wells arising from inadequate site characterisation,
- during re-entry, repair or maintenance work to wells,
- inconsistent or inadequate monitoring of injection wells, groundwater in overlying formations and leakage from abandoned wells,
- new oil or gas exploration wells drilled in poorly characterised/investigated areas and intersecting old mines, or existing facilities.

6 CONCLUSIONS AND RECOMMENDATIONS

The failure rate for a geological failure of the storage cavity in a UGS facility is of the order of 10^{-5} failures per well year. The consequence of this type of failure is a slow release of stored gas with a mass flux of 10^{-6} to 10^{-7} $kgs^{-1}m^{-2}$. This flux is assumed to discharge over a fracture zone 100 m by 2 m in area [Watson et al., 2007]. If it reached the surface as a point source it would equate to a discharge rate of the order of 10^{-4} kgs^{-1}. In major hazard terms this equates to a risk that can be considered negligible.

The risk is dominated by a release from the well connecting the storage cavity to the surface (i.e. the pipework connecting the storage cavity to the surface), which has a failure rate of a similar order (10^{-5} per well year) but would result in a rapid release up the well to the surface with a mass discharge rate calculated to be between 240 – 550 kgs^{-1}, i.e. the discharge rate is effectively 6 orders of magnitude higher than for geological failure of the storage cavity.

Failure of the well pipework is already considered in HSE's hazard based assessment of UGS facilities and as this failure scenario has been shown to dominate the risk, it therefore seems sensible for geological failures which result in a loss of integrity of the storage cavity to be ignored in HSE LUP assessments. However, this assumption is only valid for facilities that have demonstrated that they are operating in accordance with the relevant British Standard and have fully characterised the site prior to operation.

The BGS report [Evans, 2007] concludes that a number of factors are critical to the success of underground natural gas storage projects and it is recommended that any underground gas storage facility demonstrates compliance with these factors, where appropriate, before commencing operation. These factors include ensuring that:

- the site provides strata deep enough for safe and economically viable storage (permitting high gas pressures),
- the site is adequately characterised, geologically,
- the facility is designed and operated with sufficient safety measures to ensure the storage reservoir or salt cavern cannot be inadvertently, or otherwise, overpressured,
- proper design, construction, monitoring and maintenance of injection/withdrawal wells,
- abandoned wells, in and around the proposed storage area, must be accurately located and previous completions checked for integrity and gas tightness.

For oil/gas field storage, site characterisation requires adequate knowledge of:

- the sedimentary model providing information of:
  - porosity and permeability – distribution across the area,
  - thickness and extent of storage reservoir,
  - interconnection or isolation of sandbodies.
- caprock integrity – thickness and distribution,
- geological structure – including presence of faults in reservoir or caprock,

- lithology.

For salt cavern storage, site characterisation requires adequate knowledge of:

- the thickness and extent of the salt beds,
- presence and nature/distribution/thickness of non salt interbeds,
- presence and nature of more soluble evaporite beds,
- geological structure, including the likely presence of faulting.

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Failure rates for underground gas storage

Significance for land use planning assessments

The UK Government is considering the possibility of storing natural gas in a variety of underground gas storage (UGS) facilities. The Health and Safety Executive (HSE) has commissioned the British Geological Survey (BGS) to identify the main types of facilities currently in operation worldwide and any documented or reported failures and incidents which have led to release of stored product. Quintessa have been subcontracted by BGS to support this work by developing leakage scenarios for stored natural gas and carrying out simple scoping calculations to evaluate the likely significance of leakage. The Health and Safety Laboratory (HSL) has also been commissioned by HSE to carry out an assessment of UGS facilities to confirm whether or not the failure of the cavern itself through geological causes is significant enough to be considered for Land Use Planning (LUP) purposes.

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