Programme Area: Carbon Capture and Storage

Project: Hydrogen Turbines

# Title: Hydrogen Storage and Flexible Turbine Systems WP2 Report – Hydrogen Storage

## Abstract:

The purpose and focus of the Hydrogen Turbines project is to improve the ETI's understanding of the economics of flexible power generation systems comprising hydrogen production (with CCS), intermediate hydrogen storage (e.g. in salt caverns) and flexible turbines, and to provide data on the potential economics and technical requirements of such technology to refine overall energy system modelling inputs. The final deliverable (D2) comprises eight separate components. This document is D2 WP2 Report appendix – a more detailed review of salt cavern resources in the UK.

## Context:

This £300k project, led by global engineering and construction company Amec Foster Wheeler, in collaboration with the BGS, assessed the economics of a range of flexible power generation systems which involve the production of hydrogen (with CCS) from coal, biomass or natural gas, its intermediate storage (e.g. in salt caverns deep underground) and production of power in flexible turbines. The work included mapping of potentially suitable hydrogen storage salt cavern sites in and around the UK and provided the ETI with a flexible economic modelling tool to assess the range of possible options. The ETI's energy system modelling work suggests that systems such as these could provide a valuable contribution to the future energy mix, filling the gap between base load nuclear plant and low carbon power generation.

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# Hydrogen Storage and Flexible Turbine Systems
# WP2 Report – Hydrogen Storage

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# 1. EXECUTIVE SUMMARY

## 1.1 Introduction

Fossil fuel based power generation currently plays a key part in providing for the UK's energy demands. The development and implementation of Carbon Capture and Storage (CCS) technologies is an important option in reducing the associated CO2 emissions, but adding CCS to conventional power systems impacts their ability to respond to power demand fluctuations, since the column systems for CO2 removal work best at steady state conditions and are inefficient in turndown operation. Adding intermediate storage of hydrogen-rich fuel gas to a pre-combustion carbon capture scheme could be an attractive way of achieving flexible low-carbon power generation for the UK: the upstream carbon capture system would normally operate at a steady, base load capacity for maximum efficiency, while the hydrogen store would provide buffer capacity to allow the downstream hydrogen based power generation scheme to respond to demand fluctuations.

The purpose and focus of this project is:

- To improve the ETI's understanding of the economics of flexible power generation systems comprising hydrogen production (with CCS), intermediate hydrogen storage (e.g. in salt caverns) and flexible turbines; and
- To focus on the potential, economics and technical requirements for salt cavern storage and flexible turbines, to enable refinement of the ETI Energy System Modelling Environment (ESME) model in order to confirm or adjust ESME findings.

## 1.2 Scope

This report covers the work undertaken in the execution of WP2 – Hydrogen Storage.

The aim of WP2 is to provide a summary of suitable locations, costs, risks and schedule associated with creation and use of salt caverns for hydrogen storage.

The scope of WP2 consists of:

- Identification of potential salt cavern locations within UK and first 25 miles of UK Continental Shelf;
- Salt cavern cost structure;
- HSE challenges of cavern construction and operation;
- Managing loss of containment;
- Licensing and build timeline;
- Alternative cavern use; and
- Landscaping study of alternatives to salt caverns.

The scope of WP2 requires specialist geological knowledge which is provided by British Geological Survey (BGS), and included as Attachment 1.

## *1.3* Key Findings of Work Package 2 – Hydrogen Storage

The following items describe the key findings of this section of the Hydrogen Storage and Flexible Turbine Systems Project.

### 1.3.1 Identification of Potential Salt Cavern Locations within UK and first 25 miles of UK Continental Shelf

Following a review of the halite bearing locations within the UK and the first 25 miles of the UK continental shelf (UKCS), several locations have been identified as showing potential for the construction of salt caverns, whilst others have been ruled out as their potential is limited by one or more factors.

Table 1 reviews the main features of each potential storage location along with corresponding depths and thicknesses of Halite structures.

The Cheshire basin area in the North West of England shows good potential as an onshore location for construction of a new salt cavern, as the quality, depth and thickness of the halite are all favourable. Northwich halite is found at depths from 200-1800m and at thicknesses of 100-280 m in this area, which makes it highly suitable for salt caverns. For this reason, there are also other gas storage projects operating and under construction in the area. However, it does not have good access to sea, and the proximity to large population centres may make it less favourable for location of a large syngas plant.

The East Yorkshire area on the North East coast shows good potential for construction of salt caverns, with the Z2 Fordon Evaporites 150-200m thick at depths of ~1400m. These depths would need higher pressure storage and hence fewer caverns. There are existing gas storage projects at Hornsea and Aldborough, and the relatively remote rural location means there is potential for further development. The sites would benefit from a near-coastal location, limiting pipeline lengths for brine and sea cooling water, and giving direct links to the North Sea gas fields for CO2 export.

The Teesside area has a history of small brine caverns in the Z3 Boulby halite, some of which are currently used for storing hydrogen. The area is industrialised, near coastal and contains much of the infrastructure that the project may require. The halite here is at ~350m depth and with a thickness of 30-40m, a large number of small, low-pressure caverns would be required for a reasonable size of gas storage project.

The East Irish Sea offers the best offshore location, because of the thick layer of Preesall Halite, which covers much of the UKCS considered in this region. Thickness of halite can range anywhere from 100-600 m, meaning that in places there is potential for very large caverns. Offshore projects may also benefit from shorter periods in the planning phase. However, an offshore cavern location is more technically challenging and more expensive to develop than an onshore location.

## Table 1 - Review of Potential Salt Cavern Storage Locations as proposed by BGS

| Name of Halite Structure | Onshore/ Offshore | Location | Age | Depth (m) | Thickness (m) | Areal Extent ($km^2$) | Existing Underground Structures? | Potential Shown for Caverns? |
|---|---|---|---|---|---|---|---|---|
| **Z2 Fordon Evaporite** | **Onshore** | **Eastern England** | **Permian** | **1400** | **150-200** | **1980** | **Aldborough, Hornsea & Planned (Aldborough II)** | **Good** |
| **Z3 Boulby Halite** | **Onshore** | **Eastern England** | **Permian** | **350** | **30-40** | **4250** | **Teesside** | **Possible** |
| Larne Permian Halite | Onshore | Larne, Northern Ireland | Permian | 1500 | 250 | | Investigated | Part of area |
| **Northwich Halite** | **Onshore** | **Cheshire, NW England** | **Triassic** | **200-1800** | **100-283** | **760** | **Holford, Hole House, Hilltop Fm, Stublach & Planned (Kings St)** | **Good** |
| Wilkesley Halite | Onshore | Cheshire, NW England | Triassic | --- | 0-340 | | Yes | Possible |
| Dorset Halite | Onshore | Dorset, S England | Triassic | <2365 | <350 | | Planned (Portland) | Good - although licensing problems and deep |
| Preesall Halite | Onshore | Lancashire, NW England | Triassic | >300-500 | 240-300 | | Planned (Preesall) | Unlikely - permission problems - maybe smaller caverns only |
| Z2 Stassfurt Halite | Offshore | Southern North Sea | Permian | 700-3000 | 50-2500 | | Unknown | Possible - conditions very variable |
| Larne Permian Halite | Offshore | East Irish Sea | Permian | --- | >200 | | Unknown | Good |
| Fylde Halite | Offshore | East Irish Sea | Triassic | <1300 | <183 | | Unknown | Possible |
| Rossall Halite | Offshore | East Irish Sea | Triassic | <1200 | <143 | | Unknown | Unlikely - too thin |
| Mythop Halite | Offshore | East Irish Sea | Triassic | <1600 | 52-242 | | Unknown | Unlikely |
| **Preesall Halite** | **Offshore** | **East Irish Sea** | **Triassic** | **---** | **<100-600** | **4750** | **Planned (Gateway)** | **Good** |
| Warton Halite | Offshore | East Irish Sea | Triassic | 0-500 | 269+ | | Unknown | Possible |
| Röt Halite | Offshore | Southern North Sea | Triassic | --- | 100 | | Unknown | Unlikely - too thin |
| Upper Röt Halite | Offshore | Southern North Sea | Triassic | --- | <11 | | Unknown | No - too thin |
| Muschelkalk Halite | Offshore | Southern North Sea | Triassic | --- | 40-60 | | Unknown | Unlikely - too thin |

### 1.3.2 Salt Cavern Cost Structure

Once geologically suitable site locations have been identified, it is important to develop a method for evaluating the potential sites based on an understanding of cavern construction and operation processes, how the technical variables influence the project costs, and the key risk factors associated with the variables and hence influencing the costs.

The cavern construction process can be broken down as follows:

- Site characterisation:
    - Geological investigations of area;
    - Analysis of core samples in order to characterise the physical properties of the halite and enclosing beds; and
    - Development of geological model to define minimum and maximum storage pressures.
- Salt cavern construction:
    - Site preparation;
    - Drilling and well completion;
    - Construction of water/brine pipelines; and
    - Solution mining (leaching).
- Cavern commissioning:
    - Mechanical integrity testing;
    - De-brining; and
    - First gas fill.

The volume required for the salt cavern will depend on the project location, which governs the depth of halite and hence storage pressure, and the operating pattern, which sets the overall volume of gas to be stored. Leaching costs will vary approximately proportionally with the cavern volume. Drilling costs will vary approximately proportionally with the depth of drilling.

When operating an onshore salt cavern as a hydrogen/nitrogen buffer store, there will also be above ground equipment required, in order to condition the gas entering or leaving the cavern. This includes:

- Filter - to remove particulates
- Compressor - to overcome transfer losses and attain storage pressure
- Heater at cavern inlet - to avoid damaging cavern
- Metering stations - at inlet and outlet of cavern to measure losses
- Water wash column - to remove entrained salt
- Dehydration Unit - using TEG to avoid condensation in transfer pipeline
- Heating unit upstream of expansion turbine - to avoid condensation in expansion turbine
- Expansion turbine - to recover power from the high pressure gas

As such, an onshore cavern cost structure can be broken down as follows:

- Capital Costs:
  - Site characterisation costs;
  - Cavern construction cost;
  - Above ground/topside equipment costs;
  - Onshore gas pipeline cost; and
  - Cost of production of cushion gas.
- Operating costs.

The above cost breakdown is also applied to the offshore salt cavern. But the offshore system will require some additional aspects to construct and operate the cavern, which will affect the capital costs:

- Cost of hiring a drilling rig and specialised drilling equipment;
- Cost of a permanent structure to hold the topside equipment; and
- Offshore gas pipeline cost

Costing Scenarios

Based on the preferred locations suggested, the costs of constructing a single salt cavern in three different onshore locations (Teesside region, Cheshire Basin and East Yorkshire) and one offshore location (East Irish Sea Basin) have been estimated. The halite bed depth and thickness will govern the salt cavern depth and size, and hence the operating pressure and number of storage caverns required for a project with a known capacity in any one of these locations.

A comparison of separate storage caverns for hydrogen and nitrogen vs. storage of combined gas (mixed $H_2$ and $N_2$ gas) showed that the additional above ground equipment requirements and separate pipelines for transporting gas between the syngas plant, store and power island gave rise to additional costs for separate storage, with no real benefits envisaged. As such it is considered that combined storage options would be preferred.

Table 8 to Table 16 summarise the number of caverns required for a single gas turbine operating on full load under different operational regimes (diurnal, weekly, seasonal, etc) and for different storage pressures. It is evident from those tables that seasonal storage options give rise to excessive cavern numbers, so it is considered that weekly operating regime offers the best flexibility without entailing excessive cost.

Costs are therefore based on the typical hydrogen-rich syngas and nitrogen requirement of a single GE Frame 9FA syngas turbine operating at full load on a weekly operating regime (on weekdays, off weekends)

Capital Costs

Table 2 summarises the salt cavern location parameters and costs for a project supplying a single gas turbine operating on full load (GE Frame 9FA with nominal 308MWe output) under a weekly operating regime and using a combined gas storage for three onshore sites and one offshore storage site.

**Table 2 - Salt Cavern Location Parameters and Costs**

| | | Onshore | | | Offshore |
|---|---|---|---|---|---|
| | | **Teesside** | **Cheshire Basin** | **East Yorkshire** | **East Irish Sea** |
| Salt Cavern storage size | $m^3$ | 70,000 | 300,000 | 300,000 | 300,000 |
| Salt cavern depth | m | 370 | 680 | 1800 | 680 |
| Salt cavern operating pressure | bara | 45 | 105 | 270 | 105 |
| Number of cavern required for weekly operational mode and with combined storage | | 21 | 3 | 1 | 3 |
| Water/Brine pipeline length | km | 5 | 61 | 5 | 1 |
| **Costs** | | | | | |
| Jack-up drilling rig hiring cost | Million £ | - | - | - | 5.2 |
| Specialist drilling equipment hiring cost | Million £ | - | - | - | 1.2 |
| Geological Survey cost | Million £ | 3.0 | 3.0 | 3.0 | 6.0 |
| Salt Cavern Construction Cost | Million £ | 128.5 | 39.3 | 26.8 | 39.3 |
| Water pipeline cost | Million £ | 2.7 | 33.2 | 2.7 | 0.5 |
| Brine pipeline cost | Million £ | 2.7 | 33.2 | 2.7 | 0.5 |
| Costs of a 4 legged tower 'Jacket' structure | Million £ | - | - | - | 18.8 |
| Install Cost of Topside and above ground facility | Million £ | 97.1 | 130.2 | 205.9 | 350.8 |
| Land Costs (5%) | Million £ | 11.7 | 11.9 | 12.1 | 20.8 |
| Owners Costs (10%) | Million £ | 23.4 | 23.9 | 24.1 | 41.6 |
| Contingency (25%) | Million £ | 58.5 | 59.7 | 60.3 | 104.0 |
| Cost of production of Cushion gas | Million £ | 1.4 | 1.8 | 2.2 | 1.8 |
| **Total Project Cost** | **Million £** | **329.0** | **336.4** | **339.9** | **590.5** |
| **Cost per MW** | **Million £/MWe** | **1.07** | **1.09** | **1.10** | **1.92** |

It can be concluded from Table 2 that the total project cost of salt cavern development to supply hydrogen rich gas to one gas turbine operating on full load is comparable for the three different sites considered. Although the project costs are comparable, the number of caverns required is significantly higher for Teesside, which will require a large area of land to be available for development, and will bring complication in integration and networking between caverns.

The total project cost for the offshore cavern is significantly higher than onshore option, which makes the option less attractive.

It is worth noting that these costs are sensitive to pipeline assumptions which will be highly location specific.

Operating Costs

Operating costs for underground hydrogen storage are limited to energy and costs related to compressing the gas for storage and subsequent expansion for Gas Turbine operation, together with maintenance costs.

**Table 3 - Operating Costs Estimate Summary**

| Million £/yr | Onshore Cavern Storage Pressure 45 bara | | Onshore Cavern Storage Pressure 105 bara | | Onshore Cavern Storage Pressure 270 bara | | Offshore Cavern Storage Pressure 105 bara | |
|---|---|---|---|---|---|---|---|---|
| | Separate Storage | Combined Storage | Separate Storage | Combined Storage | Separate Storage | Combined Storage | Separate Storage | Combined Storage |
| **Fixed Costs** | | | | | | | | |
| Direct Labour | 0.95 | 0.95 | 0.95 | 0.95 | 0.95 | 0.95 | 0.95 | 0.95 |
| Administration / General Overheads | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 |
| Maintenance | 5.91 | 5.55 | 8.33 | 7.81 | 13.48 | 12.17 | 26.50 | 22.11 |
| Insurance & Local Taxes Allowance | 2.76 | 2.57 | 3.79 | 3.51 | 6.17 | 5.52 | 9.64 | 7.93 |
| **Total Fixed Costs** | **9.9** | **9.3** | **13.4** | **12.6** | **20.9** | **18.9** | **37.4** | **31.3** |
| **Variable Costs** | | | | | | | | |
| Fuel (Natural Gas) | 0.53 | 0.56 | 0.53 | 0.56 | 0.53 | 0.56 | 0.53 | 0.56 |
| Solvent and Chemicals | 0.16 | 0.16 | 0.24 | 0.23 | 0.39 | 0.35 | 0.24 | 0.23 |
| Waste Disposal | 0.16 | 0.16 | 0.24 | 0.23 | 0.39 | 0.35 | 0.24 | 0.23 |
| **Total Variable Costs** | **0.86** | **0.87** | **1.01** | **1.02** | **1.30** | **1.26** | **1.01** | **1.02** |
| **TOTAL OPERATING COSTS** | **10.8** | **10.2** | **14.4** | **13.6** | **22.2** | **20.2** | **38.4** | **32.3** |
| **£/MWhr** | **4.0** | **3.8** | **5.3** | **5.0** | **8.2** | **7.5** | **14.2** | **12.0** |

Table 3 shows that the operating costs are dominated by the maintenance cost and the cost for individual storage is higher than combined storage option. It also shows that operating costs for offshore projects are approximately double that of a comparative onshore project.

The above operating cost does not include the utility cost (electricity and water import costs) for operating the above ground facilities, as these will depend on the assumed price of electricity import/export. Utilities requirements are summarised in Attachment 9.

### 1.3.3 HSE Challenges of Cavern Construction and Operation

Water Sources

The construction of an underground storage cavern requires several years of leaching and hence, a large quantity of injection water is required. The salt saturation level of the injection water limits the effectiveness of the process, so fresh water is preferred in order to maximise efficiency and minimise water usage.

The source of injection water will vary depending on location associated and environmental factors, but can include fresh/saline aquifers, lakes, rivers, estuaries, reservoirs and the sea. In order to use water from any of these sources in the UK, it is first necessary to obtain a water abstraction licence from the Environmental Agency. Licensing acts to control the level of abstraction and therefore protects both water supplies and the environment from:

- Shortages in water supply;
- Increased river pollution due to reduced dilution of pollutants;
- Damage to fisheries and wildlife habitats; and
- Loss of rivers for recreation and enjoyment.

Depending on the specific Catchment Abstraction Management Strategy (CAMS), it may be that no more water is available for abstraction in the proposed area and in this case other alternatives should be considered.

Partially saturated water obtained from saline sources (e.g. the sea, saline aquifers) can be used (often, saline water is not fully saturated), although a larger volume of water is required to achieve a similar level of leaching as with fresh water. Land-locked locations, such as the recent projects proposed in Cheshire, incur significant costs from installation of pipelines to/from the sea.

Brine Transport and Disposal

During the construction phase of a salt cavern, a large amount of saturated brine (containing up to 30% salt) is produced, which upon removal from the cavern itself, requires disposal. Historically, brine has been used as a feedstock for local chemical plant applications. However, the UK brine market is now oversupplied, and as salt is a low-value, high-bulk commodity, there is neither a local nor export market, and recent projects have proposed brine disposal of to sea.

Again, for land-locked locations this can result in installation of long and expensive pipelines to/from the sea. The King St project in Cheshire is proposing a twin pipeline of over 61km out into the Mersey Estuary.

Discharge of brine from solution mining activities to sea has the potential to adversely impact marine ecology. In order to obtain a seawater discharge license, developers must comply with the various relevant legislation requirements associated with brine emissions to sea:

- Only consider discharge of brine to an underground reservoir or to sea as a last resort, where there is no chance of commercial re-use;
- Conduct bed surveys and wildlife habitat/marine surveys in order to analyse the impact to marine ecology;
- Model the saline discharge plume to demonstrate an effective dispersal pattern and provide evidence as to how quickly brine concentration drops to that of background sea water levels;
- Demonstrate that the discharged brine does not contain harmful levels of various toxic chemical species that may be present in halite beds; and
- Demonstrate the use of best available techniques for pollution prevention (if toxic compounds are present).

Well Integrity and Cavern Testing

Well integrity and storage tightness is very important, both in the construction of a salt cavern and its subsequent operation. Air and natural gas (and by extension hydrogen and nitrogen) are not poisonous from the perspective of underground-water protection. The most significant risk is the accumulation of flammable gas near the surface.

Three factors contribute to the problem of leakage in wells (Brouard & Bérest, 2013):

- Pressure distribution within the well;

  Gas pressures will exceed the geostatic pressure in the upper part of the well. The maximum pressure, below which a cement-filled annular space will not leak significantly, is a site-specific notion. This pressure must not be exceeded at the casing shoe, where the cement is in direct contact with the stored product.

- The geological environment;

  If the rock through which the well has been drilled is highly permeable, this may require special treatment. In contrast, soft impervious formations can have a favourable effect in that they naturally creep and improve the bond between the cement and the casing.

- Well architecture.

  Leakage through the wellbore has been indicated as a major risk in the storage of gas in salt caverns. Considering the extremely low permeability of the lithologies in the immediate vicinity of the caverns (rock salt, clays etc.), leakage through the cavern walls is highly unlikely under normal operating conditions.

  Special attention must be given to the parts of the well located directly at the entrance of the salt cavern, in particular the casing shoe and its cementation. Underground storage engineers work to a higher standard of cementing than is typical for most oil-industry operations, and use improved techniques (e.g. the use of admixtures, re-cementing and leak tests).

In general, during cavern testing, pressure is built up to a level slightly above the maximum operating pressure. Leaks are detected through visual inspection or, more accurately, through records of pressure evolution.

- Cavity Leak Testing

  After drilling has been completed, the cement and formation around the last cement casing shoe should be leak tested.

  Caverns should be tested before they are cleared for operation in order to verify pressure integrity and the capability of the cavern to store gas within the design limitations.

  Subsequent mechanical integrity testing (MIT) should be carried out every 10 years (or sooner).

- Acoustic Cavity Testing

  Sonar calliper logs are utilised to determine the size, shape and directional growth (if any) of a cavern. Sonar logs are maintained during solution mining of a cavern and at the start of cavern life.

Periodic sonar surveys should subsequently be carried out every 5 years (or sooner) to provide an indication of cavern growth over time compared to design and operating criteria.

- Geophysical Logs
- Subsidence Surveys – annual checks against a benchmark
- Cavity Monitoring - Wellhead pressures, temperature, stock and operating status of each cavity must be monitored continuously.

Additionally, gas detectors should be installed, securing possibilities to monitor any gas leakage in the surrounding area.

Finally, since human error is the primary cause of incidents at salt storage facilities, a robust management plan is essential that includes enough safeguards to minimize the probability of human error.

### 1.3.4 Managing Loss of Containment

Underground storage is considered to be the safest way to store large quantities of gas, for the following reasons:

- Stored gas is separated from the oxygen in the air (necessary for combustion) by several hundred meters of rock;
- The containment system is protected from fire, wilful damage and aircraft impact;
- The high storage pressures involved present no problem insofar as high pressure is the natural state of the fluids underground;
- Underground storage is extremely economical in terms of land area;

Further, salt caverns are considered to be the safest way of storing a combustible gas such as hydrogen underground, because;

- Depleted Wells and Aquifers may be fractured;
- Unlined mines / rock caverns may leak;
- Lined rock caverns are prohibitively expensive;
- The salt structure limits hydrogen molecules from permeating the halite; and
- Salt exhibits a viscoplastic behaviour, its tendency to creep makes caverns self-healing.

The geological failure risk is therefore virtually negligible - but stress modelling of high-frequency pressure fluctuations is essential to confirm long term cavern stability.

The “Engineered System” presents the greatest risk of leakage, especially for hydrogen projects, because:

- Hydrogen has very low viscosity, high diffusivity, high buoyancy;
- Hydrogen causes embrittlement of high strength steels and Ti / Al alloys;
- Hydrogen has a wide flammability range and low ignition energy.

As well as the fire and explosion risks associated with hydrogen-rich syngas leaks, there is also a significant asphyxiation risk associated with nitrogen leaks. Because of its colourless, odourless properties, nitrogen is a particularly common killer on process plants.

Appropriate measures to mitigate the risk of loss of containment include:

- Proper application of appropriate British Standards covering Salt caverns and Drilling operations;
- Well casings must be properly constructed and proven to be leak-tight - standard practices/procedures should be applicable to hydrogen, but with some additional materials selection criteria;
- Topside facilities must be designed for Hydrogen Service to minimise leaks;
- UK HSE/Land Use Planning considers failure of pipelines, onsite piping or wellhead giving rise to jet fires. Consequences of these must be assessed and safety (standoff) distances calculated;
  Safety distances are typically ~300m for natural gas storage projects;
  Preliminary calculations show minimum safety distances for hydrogen releases could be smaller than those for natural gas - due to low energy density and buoyancy of hydrogen.
- Use of low oxygen level monitoring for detection of nitrogen leaks.

### 1.3.5 Licensing and Build Timeline

The full project life cycle can be split into four main phases:

- Exploration and Planning - 3 - 4 years;

  This Phase is the most difficult to estimate due to the potential of several uncontrollable factors during the planning process that can jeopardize project deliveries schedule. Most recent applications for such caverns in the UK have gone to Public Inquiry, which introduces delays and uncertainty in planning practices. There is therefore a moderate level of uncertainty in the ability to gain planning consent for new proposed storage sites and hence investment.

- FEED - 1.5 years;

  Compilation of all the technical and commercial information required to allow a Final Investment Decision (FID) to be made.

- EPC Tender Award - 1 year;

  Evaluation of EPC contractors

- Execution EPC/Start-up - 6 years.
  - Site Preparation;
  - Wellhead and Drilling;
  - Leaching Facilities;
  - Cavern Construction;
  - Above Ground Facilities;
  - Pipelines; and
  - De-brining and Gas Introduction.

Various factors have been considered in order to determine the best and the most likely work sequences and durations.

Taking into account the possibility of parallel execution or at least a slight overlap of the above phases, the estimated duration of the Project from the start of exploration and planning activities through to a fully functional storage cavern is 10 years.

### 1.3.6 Alternative Cavern Use

The alternative salt cavern uses most likely to be competitive with hydrogen storage are:

- Natural gas storage;
- Carbon dioxide buffer storage; and
- Compressed air storage.

Table 4 provides a summary overview of the key information for each storage option.

**Table 4 - Salt Cavern Usage Options**

| Parameter | Hydrogen Storage | Natural Gas Storage | CO2 Storage | Air Storage |
|---|---|---|---|---|
| **Gas Source** | Dedicated production plant | National transmission network | CCS network | Atmospheric air |
| **Gas Destination** | Dedicated consumption plant | National transmission network | Sequestration well | CCGT combustor or atmosphere via expander |
| **Purpose** | Decarbonised “energy carrier” buffer storage | Fuel buffer storage | Flowrate buffer storage | Energy buffer storage |
| **Energy Density in Gas (MJ/m³/bar) (25°C)** | 12 (LHV basis)<br>6.5 (LHV basis, including $N_2$ storage) | 35 (LHV basis) | N/A | 0.1 (isothermal basis) |

The relative economics of salt cavern use as a store for hydrogen, natural gas, $CO_2$ or air are not straightforward to assess for the following reasons:

- All four uses provide the capacity to buffer a ‘system’ between peaks and troughs in demand, but the system buffered differs between uses. Hydrogen storage buffers decarbonised fuel “energy carrier” supply/demand; natural gas storage buffers conventional fuel supply/demand; carbon dioxide storage buffers CCS production/well capacity and air storage buffers power supply/demand.
- Since all four alternative salt cavern uses provide buffering, each is an inherent part of a larger system with a “topside” element. The topside elements for each option vary significantly in cost, and these costs depend upon location and will be impacted by climate change legislation.
- The scales of the “topsides” scope and caverns are not necessarily linked because the size, number and associated cost of the caverns depends significantly on the mode of operation of the system they serve: short term buffering requires much smaller cavern volumes than long term buffering.
- Three of the four storage options rely on the variation of market prices with supply and demand. Much of this variation and the value of buffer capacity to hedge against such variation is not publicly available, and will be impacted by climate change legislation.

Natural Gas Storage

Several natural gas filled salt cavern projects exist and are operating in the UK, and others are in various stages of planning.

Natural gas and hydrogen buffering are both means of storing fuel for subsequent conversion into power. In the case of natural gas buffering, the 'system topsides' consist of compression and pressure recovery equipment, pipelines, wells, control and monitoring systems and gas cleaning systems. Gas can be obtained from the national grid and supplied back to the national grid.

In the case of hydrogen buffering, the 'system topsides' are as outlined in WP1: a conventional reforming or gasification based syngas production plant and a gas turbine based power island designed to fire $H_2$-rich syngas.

The motivations for natural gas storage are security of supply and buffering of supply during short term peaks in demand. At present, storage capacity in the UK stands at around 5% of annual demand, compared with an average of around 20% in other Northern European countries. The need for additional natural gas storage in the UK is recognised by the UK government and a number of projects are currently under development. Suppliers of natural gas storage capacity may earn income based on a differential between purchase and selling prices, but they may also earn a fee based on the capacity they provide.

Unlike natural gas buffering, hydrogen buffering provides a decarbonised "energy carrier". In the absence of climate change legislation that provides a driver for power stations to apply CCS, hydrogen buffer storage can never compete with natural gas buffer storage: as well as the substantially greater topsides scope, conversion of carbon based fuels to hydrogen is inefficient and natural gas provides five times the volumetric energy density of hydrogen (taking account of the nitrogen storage required for hydrogen CCGT firing) requiring only one fifth of the cavern size for the same energy buffer capacity.

When climate change legislation does come into effect, power station $CO_2$ capture, compression, transport and storage schemes must be sized for a particular power output. Providing additional CCS capacity to meet demand peaks may be less cost effective than operating one of the plants proposed in WP1 (baseline syngas production plant with CCS, storage of the hydrogen, then operation of a decarbonised fuel based GT system to meet the demand peaks at times of high power demand).

Since the infrastructure for CCS is largely undeveloped and the future development of climate change legislation is unclear, it is not yet possible to determine how hydrogen storage and natural gas storage will compare.

Carbon Dioxide Storage

Although they differ in purpose, both hydrogen and $CO_2$ salt cavern storage require climate change legislation to become cost effective, as they both require adoption of CCS by conventional power plants and other large $CO_2$ producers.

The motivation for $CO_2$ storage in salt caverns is to avoid the cost and operating challenges of designing long transfer pipelines and sequestration wells for peak CCS flows. On this basis, their use will only be justified if they can be located close to the $CO_2$ source.

Unlike $CO_2$ storage caverns, hydrogen storage caverns do not need to be located close to large point sources of $CO_2$ with CCS: as the topsides for hydrogen storage are dedicated to the cavern, these can be situated close to the cavern rather than vice versa. Furthermore, while use of peak power generation from hydrogen fuel may shave some of the peaks in $CO_2$ production from other power stations, substantial cyclical loads will remain from other sources, meaning that salt caverns for hydrogen storage and $CO_2$ storage could easily co-exist.

The value of salt caverns for $CO_2$ storage will strongly depend upon the distance from the CCS network to salt cavern, the operating pressure range for the salt cavern compared with the $CO_2$ phase diagram, the distance from the CCS network to the sequestration wells, the scale of $CO_2$ transport and the variability and periodicity of the CCS network $CO_2$ flows.

Compressed Air Storage

Compressed air energy storage (CAES) and hydrogen buffer storage are similar in that they both provide an energy store for generation of electrical power at times of peak demand. Both options utilise a base loaded system generating the stored energy (a hydrogen production plant in the case of hydrogen storage; an air compressor in the case of CAES) and an intermittent system for power generation (a hydrogen fired GT for hydrogen storage and an expansion turbine or GT for CAES). Both systems aim to capitalise on the high value of power generated at times of peak demand.

Comparison of the energy density alone shows that CAES is a relatively poor method of energy storage, providing only 2% of the energy per unit volume that hydrogen storage can provide. CAES becomes attractive, despite its low energy density, when it is implemented as part of a GT system. In this case, the relatively small investment in an oversize air compressor, air pipeline and storage cavern provide the potential for significant power generation flexibility: the GT can operate continuously at design load, but the generator can be quickly switched from low to high power output at times of peak demand by turning off the air compressor and using stored air instead.

CAES is likely to become even more attractive following legislation requiring CCS from large power generation plants, since CAES allows GT or CCGT based power generation to operate at its design point (with a constant CCS load) while varying power output to suit the demand profile.

Because compressed air has a relatively low energy density, CAES is only practical for salt caverns located close to the associated compressor and turbine. For large power generation rates, the air pressure drop through the well and transfer pipeline can become significant and impact plant efficiency (the Huntorf CAES plant in Germany produces 60MW in compression mode and 290MW in turbine mode. For this capacity, the two salt caverns - both located within 1km of the power plant - each have a 20” production string).

### 1.3.7 Landscaping Study of Alternatives to Salt Caverns.

Geological Alternatives

Depleted oil and gas wells are the cheapest and most common form of underground gas storage around the world. There are two principal drawbacks of using depleted wells for hydrogen storage: firstly, hydrogen has a higher diffusivity than natural gas and is more likely to escape through microfractures in the caprock; secondly, depleted wells generally still contain large volumes of extractable material and any hydrogen put into the well for storage will be returned contaminated with a high level of natural gas and any other species present in the well, which could include higher hydrocarbons, nitrogen, $CO_2$, $H_2S$ and mercaptans.

Saline aquifers are more expensive to develop than depleted wells, as they require characterisation, do not have existing wells and topside infrastructure, and require a significant quantity of ballast gas to displace the water present and achieve the minimum operating pressure. Product hydrogen would be wet but otherwise uncontaminated. Although aquifers have been used for gas storage in other countries, they have not yet been commercialised in the UK and are unproven in hydrogen service, where there is a significantly greater risk of leakage.

Unlined mines and caverns have been considered in the past for gas storage, but have generally been troubled with gas leakage issues. They are also more expensive to develop than depleted wells or salt caverns.

Lined rock caverns can overcome the leakage issues, but represent the most expensive geological storage option.

Above Ground Containerised Storage

Use of spheres or bullets for hydrogen storage at the scale required for this project would require over 100 vessels to buffer diurnal operation. Notwithstanding the safety and plot space requirements, the cost of such a configuration would be an order of magnitude higher than salt cavern storage.

Semi-refrigerated storage would need to achieve and maintain a temperature of below -100°C to halve the ambient temperature storage volume. This would require considerable capital investment for the refrigeration packages and considerable energy to chill the hydrogen and re-heat on demand, with no scope for heat recovery between the two duties as they occur at different times. Moreover, the storage vessels costs may not drop significantly because more expensive alloys (rather than carbon steel) would be required for this temperature.

Liquefaction of hydrogen achieves a storage density of 71 kg/m$^3$, which is nine times the density achieved in a 105 bara salt cavern. However, refrigerated storage of liquid hydrogen requires a temperature of 20K, -253°C and to achieve temperatures so close to absolute zero is highly energy intensive and would severely impact the process energy efficiency.

Physical and Chemical Storage Technologies

Physical adsorption using materials such as activated carbon and chemical adsorption using materials such as metal hydrides have the potential to compete with pressurised hydrogen storage in automotive applications where gravimetric capacity is a key parameter and pressurised storage presents a significant hazard due to the risk of loss of containment in the event of a collision.

The main disadvantage of adsorption based media for bulk hydrogen storage is that the media is relatively expensive and the quantity required is proportional to the quantity of hydrogen stored. Hence, a large proportion of the storage cost is proportional to the volume stored. For pressurised storage, and particularly for salt cavern storage, there are significant economies of scale.

# 2. INTRODUCTION

The Energy Technologies Institute (ETI) is a public private partnership between global industry members - BP, Caterpillar, EDF, E.ON, Rolls-Royce and Shell with the UK government. The ETI brings together projects that accelerate the development of affordable, clean, secure technologies needed to help the UK meet its legally binding 2050 targets. The ETI's mission is to accelerate the development, demonstration and eventual commercial deployment of a focused portfolio of energy technologies, which will increase energy efficiency, reduce greenhouse gas emissions and help achieve energy and climate change goals.

The ETI's modelling, using its Energy System Modelling Environment ("ESME") shows that flexible power generation systems comprising hydrogen generation with Carbon Capture and Storage ("CCS"), intermediate storage (particularly using salt caverns) and flexible turbines are attractive components in a future UK Energy system. In such a system, hydrogen is supplied from coal and biomass fired gasifiers and steam methane reformers, with carbon dioxide ("$CO_2$") captured for storage. This permits the use at high load of capital intensive and relatively inflexible conversion and CCS equipment, filling hydrogen storage when power is not needed, and releasing hydrogen at short notice through turbines when power is at a premium. Superficially there are no barriers to using salt caverns as stores; as such stores are in use in the USA. However, these are for high value added applications and not for use in power where loss of efficiency is a more serious drawback. The ETI currently lacks sufficient data and knowledge to build a good representation of costs or efficiency (particularly relating to hydrogen storage) in ESME.

The purpose and focus of this project is:

- To improve the ETI's understanding of the economics of flexible power generation systems comprising hydrogen production (with CCS), intermediate hydrogen storage (e.g. in salt caverns) and flexible turbines; and
- To focus on the potential, economics and technical requirements for salt cavern storage and flexible turbines, to enable refinement of the ETI Energy System Modelling Environment (ESME) model in order to confirm or adjust ESME findings.

## 2.1 Scope of Study

The Hydrogen Storage and Flexible Turbine Systems Project is split into five work packages. The first three work packages (WP1, WP2 & WP3) are focused on data collection and research in order to derive a basis for techno-economic analysis in WP4. Using the output from the WP4 modelling, a representative system will be selected. In WP5, this representative system will be compared against a post combustion CCGT case:

- WP1 – Hydrogen Power Production;
- WP2 – Hydrogen Storage;
- WP3 – Supporting Studies;
- WP4 – Development of a Flexible Modelling Tool;
- WP5 – Identification of a Representative System and Comparison of CCGT with $CO_2$ Buffer Storage.

This report covers the work undertaken in the execution of WP2 – Hydrogen Storage.

## 2.2 Scope of WP2 – Hydrogen Storage

The activity in Work Package 2 is intended to find out where in the UK suitable salt structures exist, and how much storage there might be. “Suitability” will not just depend on rock quality, but on depth (pressure) and location. This will enable calculation of scalable costs for UK design types. This data will be of general use, to potentially examine the economics of different configurations around a store. It will be necessary to check, for example, whether or not use of a cavern as a hydrogen store represents better value than, say, a natural gas store or a $CO_2$ buffer store (which would also stabilise flows of captured $CO_2$ to storage).

The aim of WP2 is to provide a summary of suitable locations, costs, risks and schedule associated with creation and use of salt caverns for hydrogen storage.

The scope of WP2 consists of:

- Identification of potential salt cavern locations within UK and first 25 miles of UK Continental Shelf;
- Salt cavern cost structure;
- HSE challenges of cavern construction and operation;
- Managing loss of containment;
- Licensing and build timeline;
- Alternative cavern use; and
- Landscaping study of alternatives to salt caverns.

The scope of WP2 requires specialist geological knowledge which is provided by the British Geological Survey (BGS), and included as Attachment 1. The BGS scope includes GIS mapping of halite deposits within the target area, and provision of expert opinion on other aspects associated with geological storage of gas, particularly hydrogen.

The WP2 report forms a part of the Final Report deliverables for the Hydrogen Storage and Flexible Turbine Systems Project.

# 3. IDENTIFICATION OF POTENTIAL SALT CAVERN LOCATIONS

## 3.1 Objective

The objective of this section is to compare publicly available information on UK halite deposits and existing cavern locations against the salt cavern requirements for capacity, depth, location and quality in order to identify suitable site locations.

BGS take primary responsibility for this section of the scope, using their experience and existing geological databases to map the area and effective depth of the halite deposits with potential for development of caverns.

BGS also provide expert opinion on factors that may impact the suitability of such locations for storage of gas, particularly hydrogen.

## 3.2 Salt Cavern Locations Summary

Several UK locations contain salt deposits deep underground, created by the large scale evaporation of oceans and lakes. The resultant halite (salt) and other minerals left behind were covered by layers of mud, silt and rock and are now hundreds of metres underground. Salt is particularly suitable for gas storage on account of its impervious nature (gas cannot diffuse through). Pressure exerted on the body of salt from the layers of rock above it, makes the salt 'creep', which can be advantageous in a salt cavern, as geological faults or cracks in the salt effectively self-heal, thereby reducing the available pathways for gas escape. Storing gas in salt caverns is a proven technique used safely for many years all over the world.

BGS provides a comprehensive description of the various options available with regards to potential salt cavern locations within the UK and the first 25 miles of the UKCS in Section 2 of their report (Attachment 1).

A summary of the BGS findings is displayed below. For the purpose of the summary, emphasis is made on those options that show potential as a project location. Refer to the full report for a broad evaluation of all halites/locations.

### 3.2.1 Sedimentary Basins

Figure 1 and Figure 2 outline locations of UK onshore and offshore sedimentary basins, some of which are highlighted as potential locations for storage caverns.

For gas storage, there are important considerations and data that are needed to determine the suitability of the salt beds in which to create large voids for the purposes of storing gas at elevated pressures, including:

- Thickness of the halite beds - this sets the upper limit for potential cavern height that must include safe roof and bottom salt (pillar) thicknesses to include the cavern neck/roof shape below the final casing shoe point, which must be set in the salt beds;
- Depth of the halite beds –
    - As this increases, a greater force (lithostatic pressure) is exerted by the overlying rock (overburden) upon any potential void, which permits increasingly higher storage pressure and thus a greater mass of gas to be stored per unit cavern volume;
    - As this increases (and is accompanied by an increase in temperature), the salt beds show an increased rate of 'flow' (salt creep), which means a higher minimum cavern pressure must be

- maintained to prevent creep and resultant closure of the cavern/void, thereby maintaining cavern stability/integrity.
- This, together with the rock mechanical properties of the salt and mudstone inter-beds will also impact on the rates of injection and withdrawal, which must be such as to not compromise cavern wall stability and thus cavern integrity (including any associated tubings/casings etc).

- Level of impurities in the halite beds - important for cavern volumetrics and financial calculations, construction and safety considerations, including potential leakage pathway;
- Strength and creep characteristics of the main halite beds and any interbedded lithologies; and
- Presence of other salts, such as potassium salts that could lead to increased creep during operation or dissolution during cavern creation (which might lead to irregular and unstable cavern geometries).

The sedimentary basins outlined in Figure 1 and Figure 2 contain halite-bearing strata of different ages including Permian and Triassic deposits. These deposits have accumulated in many locations both onshore and offshore, as summarised below.

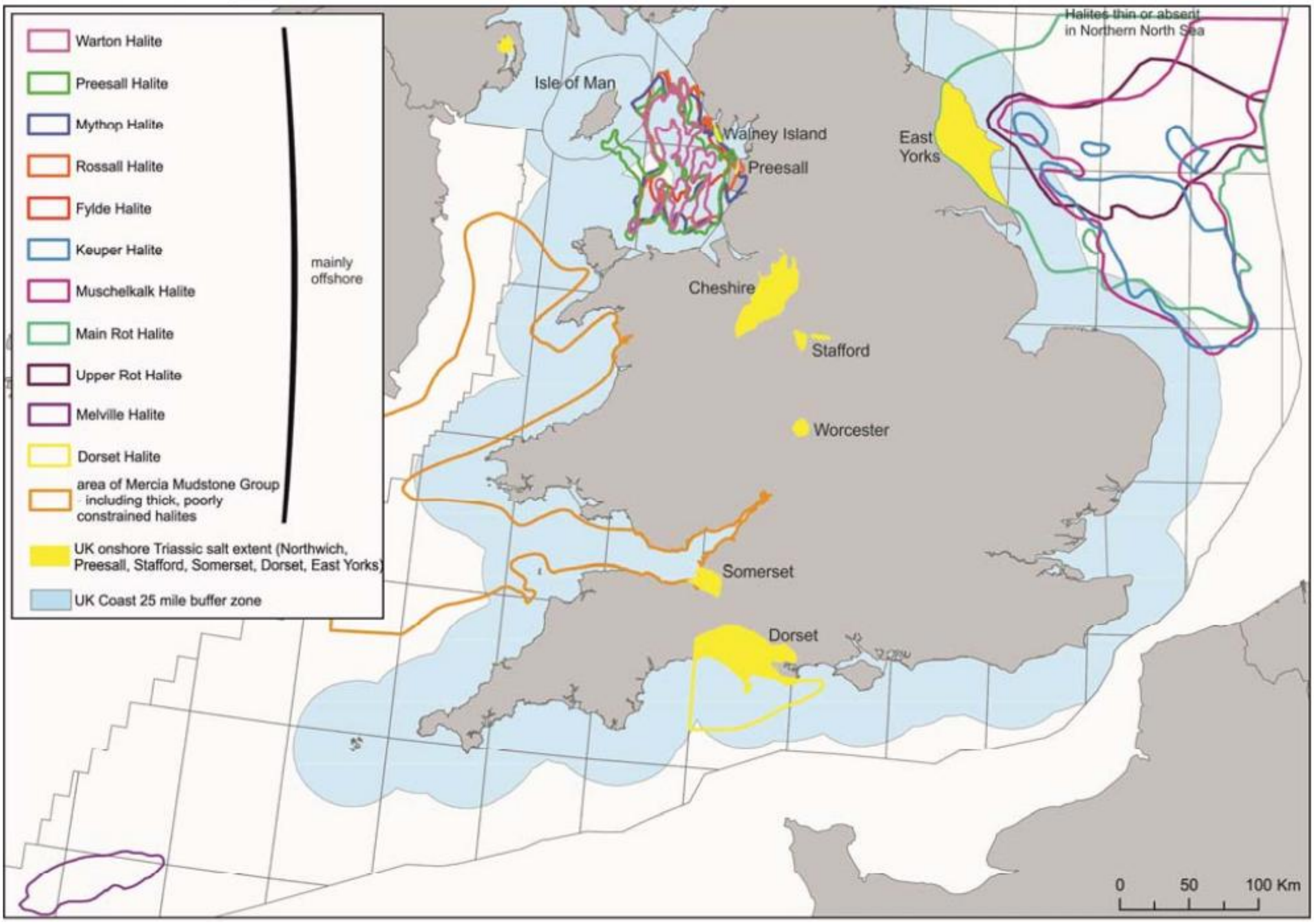



**Figure 1 - UK Triassic Sedimentary Basin Locations**

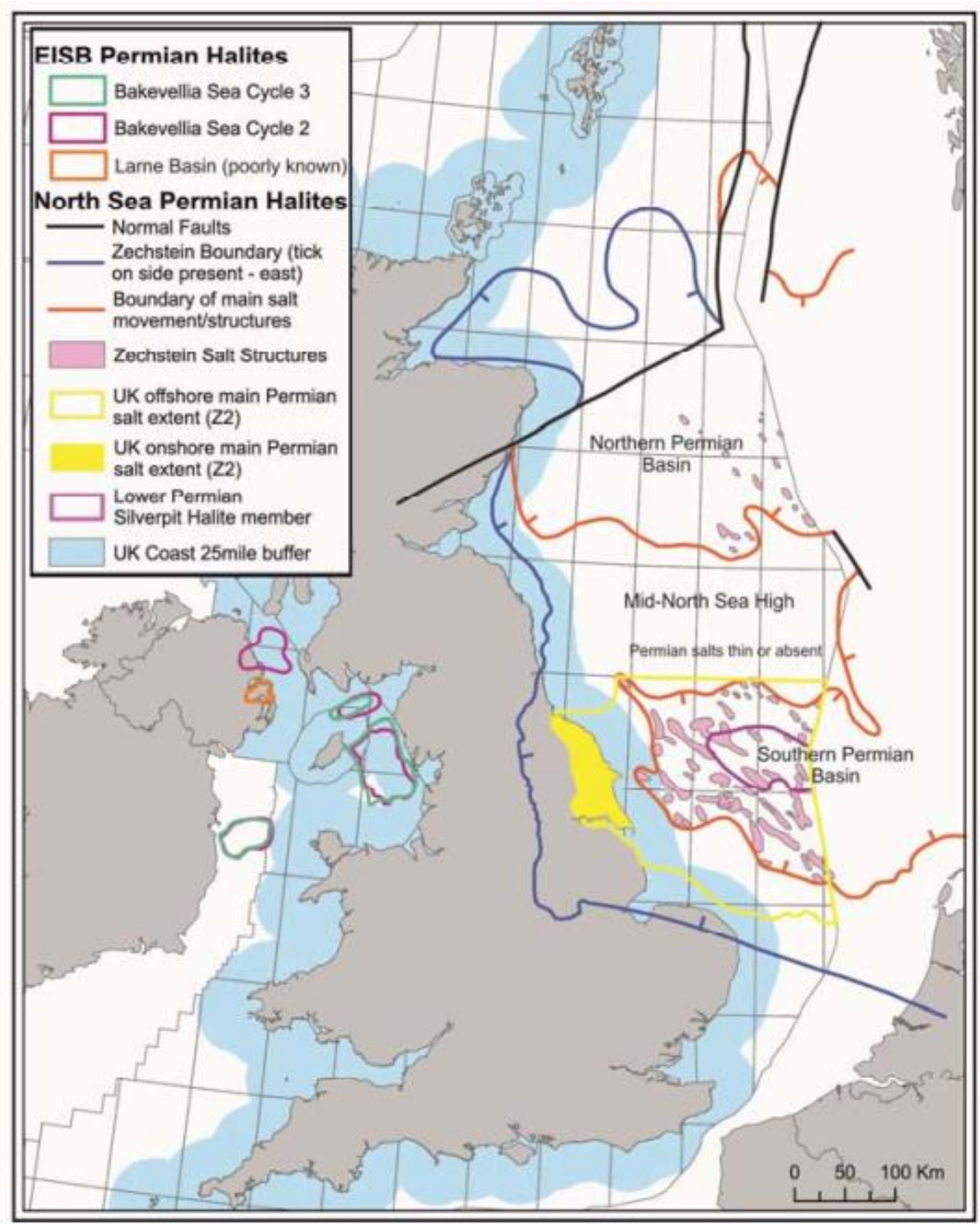



**Figure 2 - UK Permian (Zechstein) Sedimentary Basin Locations**

3.2.2 Summary of Onshore Halite-bearing Strata

<u>Permian Strata</u>

The main onshore Permian Halite deposits of interest are present at two locations:

- Eastern England:
  - *Z2 Fordon Evaporites* - Salt cavern-hosted gas storage facilities are already installed at Hornsea and Aldbrough in East Yorkshire. The main Z2 halite unit is found at a depth of ~1400 m and thickness ~150-200 m. The full areal extent of the Fordon Evaporites at thickness greater than 100m is approximately 1980 km$^2$. Rapid lateral changes, faulting and the presence of more soluble Halites have led

to problems with wells and cavern locations in the past at Hornsea, where wells have had to be abandoned. However, potential for further development is seen.

- *Z3 Boulby Halite* - Z3 Boulby Halite is said to be more restricted and shallower. The full areal extent of the Boulby formation at 500m below ordanance datum covers approximately 4250 $km^2$. Small former brine caverns leached by ICI in Teesside have been converted to and used for gas storage purposes since the 1970s. The caverns at Teesside are at ~350 m depth and are only 30-40 m in height.

- Northern Ireland:
  - *Larne Permian Halite* - Potential is seen in Permian salts lying beneath a thick sequence of Triassic halite beds. Deposits mapped at a depth of 1500 m and up to 250 m in thickness were originally proved usable in 1982 and described as good quality. However, the Permian halite in the onshore area to the west and southwest of Larne appears to have been ruled out by the recent joint investigations and poor initial results reported by BGE and Storengy.

<u>Triassic Strata</u>

The main onshore Triassic Halite deposits of interest are present at the locations outlined as follows:

- Cheshire:
  - *Northwich Halite* - At the northern end of the Cheshire Basin, several gas storage facilities are in operation and other new builds are planned. Halite deposits extend from outcrop to depths exceeding ~1800 m below ground level and attain thicknesses of over 250 m in places (the thickest: 283 m in the Byley borehole). The full areal extent of the Northwich Halite formation at depths of over 200m below ground level covers approximately 760 $km^2$. A large area of halite is available in the region, although log correlations show a shallowing and thinning of the Northwich Halite to the west (Winsford Mine area). Wet rockhead conditions may also be present in these shallower areas. Varying amounts of insoluble deposits such as mudstone are found, although in general halite deposits are of good quality. In places, the halite may reach depths of ~1700-1800 m, where it may be too deep for practical purposes.
  - *Wilkesley Halite* - Located to the south of Northwich Halite, this also shows potential for gas storage and has been worked in the past (shallow submergence and up to 340 m thickness, although dirty).
- Dorset:
  - *Dorset Halite* - Dorset contains a thick development of halite-bearing strata, which extends offshore into the English Channel within the 25 mile zone of interest (see section 3.2.3 below). Geophysical logs reveal the presence of some mudstone interbeds, although in general the halite is of good quality. The thickest deposit is 350 m in the Chickerell borehole. The deepest deposit is recorded as 2365 m and is 135 m thick (Portland #1 Borehole). Although Dorset Halite is generally deeply buried, prospects for hydrogen storage caverns appear good and deposits at Portland are already under

consideration for gas storage. However, the useful area of halite may already be bound up in the licence areas held by various oil and gas companies. Where this is not the case, halite may be too deeply buried for hydrogen storage purposes.

- North-Western Lancashire:
    - *Preesall Halite* - The Preesall Saltfield is the onshore extension of the thicker deposits of Preesall Halite offshore to the west in the East Irish Sea (section 3.2.3 below). The saltfield contains Halite at depths of 300-500m, thicknesses of 240-300m and thinner mudstone interbeds than that of Cheshire. Since 1993 it has been investigated for the construction of a gas storage facility. A large area of the saltfield remains un-worked, although the area has recently been the subject of a planning application for a natural gas storage facility. The application was rejected on 9th April 2013 due to an inadequate geological survey support for the predicted storage volumes and geological integrity, meaning that the developer must either seek a challenge to the decision, provide more supporting information or abandon the project in this location. Based on current information, it seems unlikely that consent would be granted for a hydrogen storage project.

Halite-bearing strata have been discovered and proved in a number of other locations, although their feasibility for construction of salt caverns is more limited because they are either too shallow, too thin or contain unacceptable levels of insoluble material. These areas include:

- Somerset;
- Worcestershire;
- Staffordshire;
- South Cumbria;
- Carlisle.

### 3.2.3 Summary of Offshore Halite-bearing Strata

Permian Strata

The main offshore Permian Halite deposits of interest are present in two main regions:

- Southern North Sea:
    - *Z2 Stassfurt Halite* - The Upper Permian Halite beds of the Southern Permian basin have potential for storage. Salt depth and thickness varies substantially throughout the body of the basin. A thin layer (approx. 50 m thick) of evaporite is found within the 25 mile area of consideration, at sea bed level to the north of Middlesbrough, which thickens and deepens eastwards offshore to depths of between 700 m and 2500-3000 m, and thicknesses of up to 2500 m in some of the major salt structures. Many of the thicker deposits are located further offshore (out of the 25 mile area of consideration) and are deeply buried, leaving the thinner areas of Halite available for development. In these areas, prospects for hydrogen storage are still good; similar to those of eastern England.

- West and south of the UK (East Irish Sea Basin):
  - *Larne Permian Halite* - Some of the purest halite in the East Irish Sea is located in the Larne basin. Salt structure thicknesses of over 200m have been mapped within the 25 mile zone of interest. In places, the Halite-bearing strata also contain sedimentary salt and mudstone deposits, although for the most part, significant potential for hydrogen storage cavern development is highlighted.
  - *St. Bees Evaporite Formation* - Another Halite-containing structure is highlighted here, although is restricted to the north of the East Irish Sea Basin, and is thought to show limited potential for gas storage.
  - *Manchester Marl Formation* - is deposited to the south of the East Irish Sea and thought to be relatively unsuitable for gas storage.

Halite-bearing strata have been discovered and proved in a number of other locations, although their feasibility for construction of salt caverns are more limited. These areas include:

- Upper Permian Strata of the Central North Sea;
- The Peel, Solway Firth, North Channel, Portpatrick-Larne and Kish Bank basins of the East Irish Sea;
- Northern North Sea;
- Moray Firth and Orkney; and
- Shetland.

<u>Triassic Strata</u>

The main offshore Triassic Halite deposits of interest are present in two main locations:

- East Irish Sea:
  - *Fylde Halite* - This halite formation, like the other offshore Triassic Halites highlighted here, has been proved by hydrocarbon exploration boreholes, is widespread, and is seen to attain significant thicknesses within the 25 mile limits of this study. Fylde Halite is present at depths of up to 1300 m and thicknesses of up to 183 m and may hold some potential for gas storage purposes.
  - *Rossall Halite* - This formation is a widely developed offshore unit of halite (with sequences of interbedded mudstones) proved at depths of up to 1200+ m and thicknesses of up to 148 m in the north and centre of the East Irish Sea basin. The Rossall Halite Member is commonly the thinnest halite unit in the East Irish Sea area and although salt beds forming the Rossall Halite are clean, they are probably not thick or laterally consistent enough to be considered one of the best subsurface storage prospects.
  - *Mythop Halite* - This Halite is also widely developed with significant intercalated mudstones. The formation is proved at depths of up to 1600+ m and ranges in thicknesses from ~52 m to 242 m in the north and centre of the East Irish Sea basin. Due to the significant presence of mudstones, the Mythop Halite Formation is unlikely to be considered one of the best subsurface storage prospects.

- *Preesall Halite* - This Formation is present throughout most of the East Irish Sea Basin and represents the thickest, most widespread and cleanest Triassic halite in the region. Although considerable thickness variations are seen within the basin, ranging from <100 m to over 600 m, Preesall Halite still represents the best prospects for gas storage within the 25 mile offshore UKCS area. The full areal extent of the Preesall Halite formation covers approximately 4750 $km^2$. The southern part of the basin perhaps represents the optimum location for subsurface storage due to the depth, thickness and purity levels in the halite and indeed, the proposed 1.5 billion $m^3$ Gateway Project has identified the Preesall Halite as a prospective storage horizon due to the structure's favourable characteristics.
- *Warton Halite* - This formation is mainly clean with numerous thin mudstone partings. The Halite bed has a maximum drilled thickness of 269 m and in places may be even thicker than the Preesall Halite, at depths ranging from near sea bed level 400-500 m. Because of the shallow nature of this formation, it suffers from wet rockhead conditions, which is likely to be detrimental to safe and commercial gas storage operations.

It should be noted that the location of the Triassic Halite beds in the East Irish Sea overlap with a mature hydrocarbon-producing region in which significant existing infrastructure is present. This in itself may limit short to medium term development of salt caverns, as potential areas are close to existing oil and gas fields, offshore wind farms, pipeline routes and perhaps shipping lanes.

- Southern North Sea:
  - *Röt Halite* - This Halite bed is one of three Halite Members which make up the Dowsing Dolomitic Formation. Röt Halite is between 60 and 80 m thick in most of the northern half of the Anglo-Dutch Basin and in places may be more than 100 m thick. The salt is reasonably pure, with a few thin mudstone layers.
  - *Upper Röt Halite* - Also part of the Dowsing Dolomitic Formation, this Halite bed is restricted to the northern half of the Anglo-Dutch Basin where it is thin (<11 m thick) and is, therefore, unlikely to provide gas storage potential.
  - *Muschelkalk Halite* – The last of three Halite Members forming the Dowsing Dolomitic Formation, Muschelkalk Halite is between 40 m and 60 m thick and is widespread.
  - *Keuper Halite* - Part of the Dungeon Saliferous Formation, Keuper Halite is largely restricted to the Sole Pit Basin in the centre of the southern North Sea. Halite beds are only reported at between 1 and 20 m thick and are interspersed with many mudstone interbeds, making the region unattractive for gas storage.

Although Triassic Halites in the southern North Sea basin can attain thicknesses of up to 100 m and are fairly pure, within the 25 mile zone of interest offshore, it is unlikely that such structures represent realistic potential for gas storage. Their thicknesses are generally too low to create viable and profitable caverns.

Halite-bearing strata have been discovered and proved in a number of other locations which are outside of 25 miles zone of interest for the present study and their feasibility for salt cavern construction are more limited, because they are too thin and involve basin margin facies/rocktypes. These areas include:

- The Central Graben;
- Northern North Sea;
- Southern North Sea, e.g. the Triton Anhydritic Formation;
- Moray Firth and Orkney-Shetland areas;
- Celtic seas; and
- South-western Approaches and English Channel:
    - Including the Cockburn Basin, Western Approaches Trough, the Little Sole (or Shelf Edge), Melville, St Mary's, South-Western Channel, Haig Fras and Plymouth Bay basins.

## *3.3* Other Location Factors

The geographical location of a large industrial syngas production plant and storage project within the context of the UK is also an important consideration, as a project will generally be more viable if it does not have to involve significant transportation of feedstocks, products, wastes or intermediates. Items to consider include proximity to:

- a location for brine sale or disposal at sea (within a reasonable distance);
- fuel source or fuel transportation infrastructure
    - national gas grid connection;
    - coal / biomass import terminal;
- electricity grid connection;
- $CO_2$ storage location, or connection to a $CO_2$ transportation hub;
- source of cooling water, sea water is preferred for maximum power plant efficiency.

Whilst Cheshire has been identified as having good potential for the salt cavern construction, it is not a coastal location, which causes complications with pipeline routings for brine during construction, sea water cooling (or hydrogen transport if the syngas production and/or power island are in a coastal location) during operation, and export of captured $CO_2$. It also seems unlikely that a syngas production facility would be able to be easily located close to the saltfield, which has large population centres nearby.

An East Yorkshire site would benefit from proximity to the sea, a relatively remote rural location, and direct links to the North Sea gas fields or saline formations for exported $CO_2$. The depth of halite here would require high pressures, and hence fewer caverns. The Fordon Evaporites of East Yorkshire are the thickest so could accommodate larger caverns.

A Teesside site would benefit from proximity to the sea, an industrially developed area, and links to the North Sea gas fields or saline formations for exported $CO_2$. The shallow depths of and limited thickness of the halite here would mean lower storage pressures, requiring many small caverns.

In addition, the UK's only current underground hydrogen storage facility using salt cavern is operating in Teesside. Sabic Petrochemicals is the operator for geological storage of hydrogen in what is known as 'The Tees Valley Hydrogen Project'. For over 25 years, the caverns have been used to store up to 1,000 tonnes of hydrogen for industrial use.

Further work will be carried out in WP4 to understand the impact of cavern depth on storage economics. Deeper caverns will operate at higher storage pressure which will result in smaller and potentially lower cavern construction cost, but higher capital and operating costs for cavern topsides equipment associated with gas compression and expansion. WP4 modelling will also include the ability to analyse the impact of pipeline costs on overall costs (i.e. for potential cases where storage is not co-located with the syngas plant/power island.

## *3.4* Conclusions

Following a review of the halite bearing locations within the UK and the first 25 miles of the UKCS, several locations have been identified as showing potential for the construction of salt caverns, whilst others have been ruled out as their potential is limited by one or more factors.

Table 5 reviews the main features of each potential storage location along with corresponding depths and thicknesses of halite structures.

The Cheshire basin area in the North West of England is believed to show good potential as an onshore location for construction of a new salt cavern project, as the extent, quality, depth and thickness of the halite are all favourable. Northwich halite is found at depths from 200-1800m and at thicknesses of 100-280 m in this area, which makes it highly suitable for salt caverns. For this reason, there are also other gas storage projects operating and under construction in the area. However, it does not have good access to sea, and the proximity to large population centres may make it less favourable for location of a large syngas plant.

The East Yorkshire area on the North East coast shows good potential for construction of salt caverns, with the Z2 Fordon Evaporites 150-200m thick at depths of ~1400m, and extending over an area of nearly 2000 km$^2$. These depths would necessitate higher pressure storage and hence require fewer caverns. There are existing gas storage projects at Hornsea and Aldborough, and the relatively remote rural location means there is potential for further development. The sites would benefit from a near-coastal location, limiting pipeline lengths for brine and sea cooling water, and giving direct links to the North Sea gas fields for CO2 export.

The Teesside area has a history of small brine caverns in the Z3 Boulby halite, some of which are currently used for storing hydrogen. The area is industrialised, near coastal and contains much of the infrastructure that the project may require. The halite here is at ~350m depth and with a thickness of 30-40m, a large number of small, low-pressure caverns would be required. The halite here extends over a large area, but much of that may be constrained by current urban/industrial areas.

The East Irish Sea offers a good offshore location, because of the thick layer of Preesall Halite, which covers nearly 5000 km$^2$, much of the UKCS considered in this region. Thickness of halite can range anywhere from 100-600 m, meaning that in places there is potential for very large caverns. Offshore projects may also benefit from shorter periods in the planning phase. However, an offshore cavern location is more technically challenging and more expensive to develop than an onshore location.

## Table 5 - Review of Potential Salt Cavern Storage Locations as proposed by BGS

| Name of Halite Structure | Onshore/ Offshore | Location | Age | Depth (m) | Thickness (m) | Areal Extent ($km^2$) | Existing Underground Structures? | Potential Shown for Caverns? |
|---|---|---|---|---|---|---|---|---|
| **Z2 Fordon Evaporite** | **Onshore** | **Eastern England** | **Permian** | **1400** | **150-200** | **1980** | **Aldborough, Hornsea & Planned (Aldborough II)** | **Good** |
| **Z3 Boulby Halite** | **Onshore** | **Eastern England** | **Permian** | **350** | **30-40** | **4250** | **Teesside** | **Possible** |
| Larne Permian Halite | Onshore | Larne, Northern Ireland | Permian | 1500 | 250 | | Investigated | Part of area |
| **Northwich Halite** | **Onshore** | **Cheshire, NW England** | **Triassic** | **200-1800** | **100-283** | **760** | **Holford, Hole House, Hilltop Fm, Stublach & Planned (Kings St)** | **Good** |
| Wilkesley Halite | Onshore | Cheshire, NW England | Triassic | --- | 0-340 | | Yes | Possible |
| Dorset Halite | Onshore | Dorset, S England | Triassic | <2365 | <350 | | Planned (Portland) | Good - although licensing problems and deep |
| Preesall Halite | Onshore | Lancashire, NW England | Triassic | >300-500 | 240-300 | | Planned (Preesall) | Unlikely - permission problems - maybe smaller caverns only |
| Z2 Stassfurt Halite | Offshore | Southern North Sea | Permian | 700-3000 | 50-2500 | | Unknown | Possible - conditions very variable |
| Larne Permian Halite | Offshore | East Irish Sea | Permian | --- | >200 | | Unknown | Good |
| Fylde Halite | Offshore | East Irish Sea | Triassic | <1300 | <183 | | Unknown | Possible |
| Rossall Halite | Offshore | East Irish Sea | Triassic | <1200 | <143 | | Unknown | Unlikely - too thin |
| Mythop Halite | Offshore | East Irish Sea | Triassic | <1600 | 52-242 | | Unknown | Unlikely |
| **Preesall Halite** | **Offshore** | **East Irish Sea** | **Triassic** | **---** | **<100-600** | **4750** | **Planned (Gateway)** | **Good** |
| Warton Halite | Offshore | East Irish Sea | Triassic | 0-500 | 269+ | | Unknown | Possible |
| Röt Halite | Offshore | Southern North Sea | Triassic | --- | 100 | | Unknown | Unlikely - too thin |
| Upper Röt Halite | Offshore | Southern North Sea | Triassic | --- | <11 | | Unknown | No - too thin |
| Muschelkalk Halite | Offshore | Southern North Sea | Triassic | --- | 40-60 | | Unknown | Unlikely - too thin |

# 4. SALT CAVERN COST STRUCTURE

## 4.1 Objective

The objective of this section is to describe the process of cavern construction and the resulting topside plant requirements, develop these requirements into a scalable cost estimate and outline the key risk factors influencing this cost estimate.

The cost estimate is developed from first principles and sense-checked against project experience. This includes insights into the effects of cavern depth (pressure), feasible unit size, pressure range (cushion gas), throughput and deliverability on capital and operating costs for a store.

BGS experience concerning practical constraints, including their knowledge of the UK brine market and potential barriers to disposal of brine to sea has been included.

## 4.2 Introduction

Once geologically suitable site locations have been identified, it is important to develop a method for evaluating the potential sites based on an understanding of cavern construction and operation processes, how the technical variables influence the project costs, and the key risk factors associated with the variables and hence influencing the costs.

The cavern construction process can be broken down as follows:

- Site characterisation:
    - Geological investigations of area;
    - Analysis of core samples in order to characterise the physical properties of the halite and enclosing beds; and
    - Development of geological model to define minimum and maximum storage pressures.
- Salt cavern construction:
    - Site preparation;
    - Drilling and well completion;
    - Construction of water/brine pipelines; and
    - Solution mining (leaching).
- Cavern commissioning:
    - Mechanical integrity testing;
    - De-brining; and
    - First gas fill.

The volume required for the salt cavern will depend on the project location, which governs the depth of halite and hence storage pressure, and the operating pattern, which sets the overall volume of gas to be stored.

When operating an onshore salt cavern as a hydrogen/nitrogen buffer store, there will also be above ground equipment required, in order to condition the gas entering or leaving the cavern.

As such, an onshore cavern cost structure can be broken down as follows:

- Capital Costs:
  - Site characterisation costs;
  - Cavern construction cost;
  - Above ground/topside equipment costs;
  - Onshore gas pipeline cost; and
  - Cost of production of cushion gas.
- Operating costs.

The above cost breakdown is also applied to the offshore salt cavern. But the offshore system will require some additional aspects to construct and operate the cavern, which will affect the capital costs:

- Cost of hiring a drilling rig and specialised drilling equipment;
- Cost of a permanent structure to hold the topside equipment; and
- Offshore gas pipeline cost

### 4.3 Site Characterisation

Site characterisation is the first process of cavern development, and is required to define the depth, thickness, structure, purity and rock mechanical properties of the salt body. This information is critical in calculating the safe pressure limits within which the cavern must operate in order to maintain its mechanical integrity.

Effective cavern design should consider:

- Geological and geographical information of the area;
- Mechanical and chemical properties of the salt and confining rock;
- Location of low permeability zones; and
- Inter-cavern spacing.

In order to develop an underground gas storage site, a number of geological investigations are required to provide detailed information regarding the geology and structure of the proposed site, as outlined in the HSE COMAH documentation (SPC 185). Geophysical measuring procedures based on seismic and gravimetric methods provide basic information about the location, extent and depth of salt deposits including whether there are salt layers (beds) or salt domes. Geological information is generally collected using the following methods:

- Seismic reflection study (either or both 2D and 3D) of the identified area; and
- Drilling of at least one exploration well to prove the nature and properties of the halite and enclosing strata.

Exploratory and subsequent cavern drilling produces drill cuttings and core samples. These provide additional information about the geological structure. Geophysical borehole measurements (logs) provide further information regarding the structure of salt formations that have been drilled through.

After sufficient geological samples have been obtained through exploration, the data must be interpreted and integrated into a geological modelling tool which then models the location, size, shape and composition of the salt beds in the immediate and surrounding areas. Any collected drill cuttings and core samples are analysed in the laboratory in order to characterise the physical properties of the halite and enclosing beds. Such characteristics include strength (compressive, shear and tensile) and permeability, the amount of insoluble material present, and the required leaching rate and other geochemical properties.

The geological modelling will also determine the exact depth of the storage caverns, thus defining minimum and maximum storage pressures.

## *4.4* Salt Cavern Construction

### 4.4.1 Drilling

Where the halite strata are deemed suitable for gas storage, underground caverns can be created using a process known as solution mining or leaching. Solution mining technology converts a simple borehole into a storage cavern through the injection and extraction of water.

Conventional solution mining for commercial salt use (including Cheshire at the Holford and Warmingham brinefields) forms a cavern shape that is not ideally suited to pressurised gas storage. The formation of a gas storage cavern requires careful planning and controlled construction to ensure that it will contain the pressurised gas and that there is a minimum distance (or wall thickness) between adjacent caverns, such that they can operate independently. Roof salt and bottom salt thickness must be retained for cavern integrity – the roof salt supports and protects the overlying strata from the effects of the brine and also the pressure cycling. Thicknesses will be dependent upon depths and thereby pressure ranges and cycling times.

Firstly, drilling equipment is used to create a borehole from the surface, through the rock salt formation, to the final required depth. The portion of the well above the salt formation is supported by several concentric layers of pipe known as casing to aid against ground water contamination and to prevent collapse of the well. This process is very similar to established oil and gas drilling practice.

### 4.4.2 Construction of Water/Brine Pipelines

Water and Brine Pipelines will be required to supply/dispose of the water during the leaching operation.

Water pipeline cost will depend on the availability of the water; and whether fresh water or brackish water (from saline aquifers or seawater) is being used.

For non-coastal locations, such as developments in Cheshire, significant costs will be incurred from installation of pipelines to/from the sea.

It is possible that brine may be used for salt recovery as a chemical feedstock, although the UK market for salt has been proven to be oversupplied, making salt virtually valueless. The brine outflow rate and residence time is carefully monitored if brine is required as a chemical feedstock and hence larger pipelines may be required.

Refer to Section 5.2 & 5.3 for more detail of water supply and brine disposal.

### 4.4.3 Solution Mining

A smaller-diameter pipe called tubing is lowered through the middle of the well. This arrangement creates separate pathways into and out of the well – the hollow tubing itself and the open space between the tubing and the final casing (the annulus).

To form a salt cavern, water is pumped in through one of the pipes, to the bottom of the borehole. As the fresh water comes in contact with the salt formation, the salt dissolves until the water becomes saturated, after which it is removed through the other pipe leaving an area of free space. The brine can be used for salt recovery or is otherwise disposed of. In order to protect the cavern roof from dissolution, a non-leaching blanket medium (typically nitrogen or air) is pumped in via the outer annulus, which sits on top of the brine in the cavern.

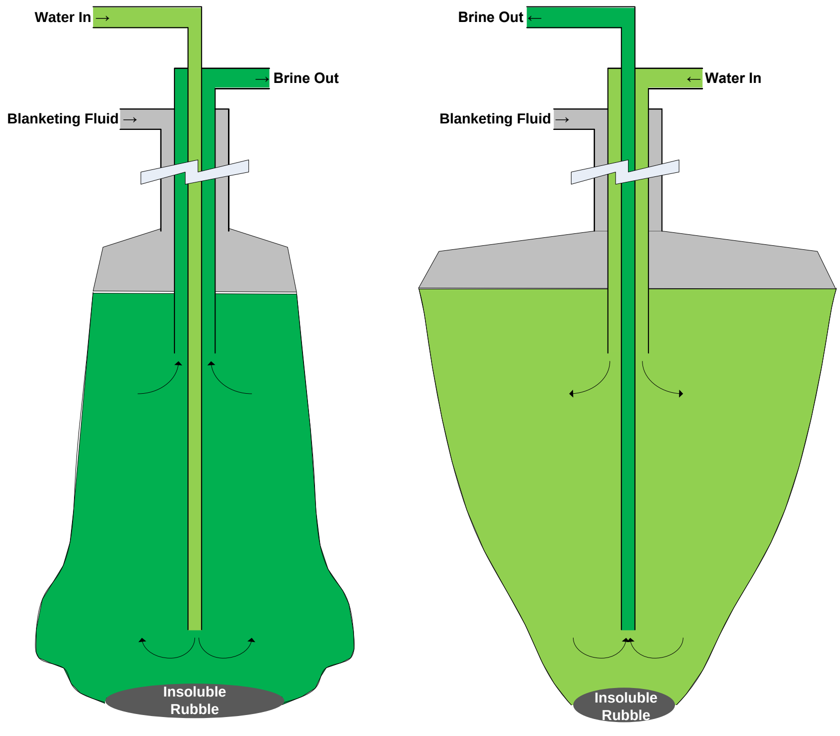
During the planning stage, the solution mining process is pre-modelled using a 3D leaching simulation software package. This model is then constantly altered and adjusted while the actual leaching operations are going on to ensure the process is on track.

Two different operational procedures are used to ensure the controlled development of cavern shape, as depicted in Figure 3:

- Direct leaching; and
- Indirect leaching.

In the direct method, water is introduced through the inner tube to the bottom of the cavern, where it flows down, around the walls and up to the brine collection point further up the cavern. The resultant saturated brine leaves through the inner annular space between the tube interior and the outer casing as an inert fluid. This method develops caves with larger diameters at the bottom of the cave.

In indirect solution mining (reverse circulation), water is introduced from the inner annular space at a position above the cavern floor, where it flows outwards and then down to the bottom of the cavern where the brine collection point collects the brine just above the sump. Saturated brine then leaves the cavern through the inner pipe. This method develops cavities with bigger diameters in the top.




Direct Circulation.
Salt dissolution occurs at bottom of cavern favouring lower cavern expansion

Reverse Circulation.
Salt dissolution occurs at top of cavern favouring upper cavern expansion

**Figure 3 - Direct and Indirect Solution Mining Process for Cavern Formation**

During the entire leaching phase, which ranges from 2.5 to 4 years, the shape of the cavern can only be influenced by the following parameters:

- The leaching rate, i.e. the amount of water injected;
- Mode of leaching, i.e. direct or indirect;
- Depth of the leaching strings;
- Depth of the blanket interface; and
- Duration of leaching intervals.

Rock-mechanical aspects that are relevant for safety as well as geological conditions are also taken into account here. A 3D simulation program is used to analyse the different cavern leaching phases. Cavern leaching requires thorough planning and constant monitoring. The development of cavern shape and size is monitored via constant analysis of brine and by collecting physical cavern dimension measurements with acoustic location monitoring (sonar) equipment. The process is generally continuous apart from short periods where leaching is suspended in order to perform acoustic surveys of the developing void. In this way, progress of cavern development is tracked.

To dissolve the rock salt in a controlled manner, an inert blanketing fluid which is non-reactive to salt must be used. One of the main characteristics of this fluid is that its density is lower than brine density to protect the roof of the cavity against uncontrolled dissolution and collapse. The most common fluids used are: nitrogen, diesel, natural gas and propane. If any of the blanketing fluids mentioned above is being proposed for storage, leaching of the cavern can continue even when it is already in operation; this can prove to be extremely useful if it is desirable to further increase the cavern volume.

Upon completion of the cavern structure, preparation is required to convert from brine to gas storage. Before any gas is introduced, an initial mechanical integrity test (MIT) is performed to confirm gas tightness of the uppermost salt and the well completion (casing, cement etc). See also section 5.5.2.

## 4.5 Cavern Commissioning

After the MIT is successfully completed, the first gas can be introduced in a process known as debrining, which essentially uses gas pressure to displace the brine contained in the cavern at the completion of solution mining. The debrining operation occurs after the excavation and completion of a salt cavern and before subsequent storage operations. This makes it the last step in the construction of a cavern storage facility.

For this purpose, the pumping head is assisted by an additional casing that allows the saturated brine to be removed. The so-called brine displacement string runs through the centre of the gas pumping casing and emerges just above the cavern sump. This ensures that as much brine as possible is removed from the cavern. The gas is pumped into the cavern through the annulus between the production casing and the brine displacement string. The injected gas exerts pressure on the brine in the cavern, displacing it up through the brine displacement string.

During this process, the gas and brine volumes are closely monitored in order to determine the real-time depth of the gas/brine interface. The measurement instrumentation is calibrated following completion of the initial gas filling process or by measuring the actual depth if required. When the gas first fill is completed, the brine displacement string is removed from the cavern using a lock. Subsequently, the full cross-section of the production casing is available for adding or removing gas.

The following technical and economic aspects must be taken into consideration when planning and carrying out the gas first fill:

- Availability of gas (cost, time);
- Transport capacity for removing the brine from site; and
- Planning possible additional measures such as gas or water lifting processes.

The duration of the debrining phase is generally in the region of 3 months. The volumetric flow of the gas is low but the pressure required is close to the eventual storage pressure.

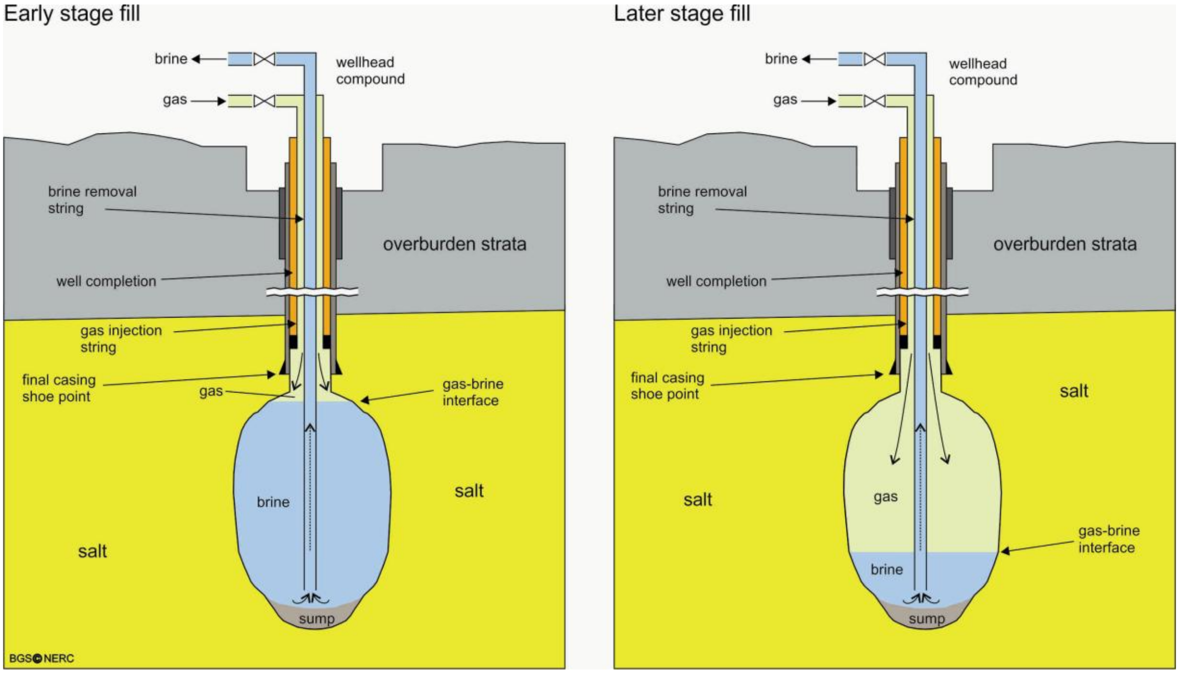



**Figure 4 - Initial Fill of a Cavern (BGS©NERC)**

The brine will contain some dissolved gas, which has to be removed before the brine is sent for disposal. If disposal is to sea, then this is relatively straightforward. If the brine is to be used as a chemical feedstock than removal of gas to low levels may be required, which can be accomplished using a stripping column. After completely filling the cavern with gas, the cavern is ready for operation.

The sump located at the bottom of the cavern will always contain some residue left over from the solution mining process; usually brine and insoluble particulates previously contained within the halite structure. The extraction pipe is never completely lowered to the bottom of the cavity in order to avoid a possible tube blockage.

## 4.6 Salt Cavern Operation Mode, Location and Pressure selection

### 4.6.1 Salt Cavern Operation mode

Salt caverns can be designed to operate in one of two modes:

- Constant pressure mode – caverns are maintained at constant pressure using brine displacement to vary the volume of gas within the cavern; or
- Variable pressure mode – cavern pressure varies depending upon the net flow of gas into/out of the caverns.

During constant pressure operation, gas will be withdrawn in brine compensated mode i.e. pressure of the cavern will be maintained by replacing gas by brine. Salt caverns used to store hydrogen in Teesside operate at constant pressure. The hydrogen storage facility in Teesside comprises three small, shallow, pancake-like salt caverns at a depth of 350-400m. Each cavern stores about 70,000m$^3$ of hydrogen gas. Storage operations do not involve compression and decompression of gas, but instead operate with brine pumped in from a surface pond, providing a constant pressure of approximately 45-50bar. This reduces the stress placed on the walls of the caverns. However, in caverns operated this way, the withdrawn gas will have a high proportion of dissolved water/salt.

During variable pressure operation, the operating pressure range should be limited to 0.3-0.8 of lithostatic pressure. The exact range will depend on the cavern geological structure. Maximum pressure should be typically 0.7-0.8 of lithostatic pressure, which ensures that the cavern is operating at a lower pressure than the fracturing pressure of the surrounding halite. The maximum pressure must be carefully controlled whenever gas is injected into the cavern. The minimum pressure is set to ensure the stability of the cavern, which is a function of the mechanical properties of the salt. The tightness of the cavern is ensured by the intrinsic tightness of rock salt. The plastic behaviour of these formations under the effect of geostatic pressure does not allow the propagation of cracking as long as the fracturing pressure is not exceeded. In variable pressure mode, a certain gas inventory must be reserved as cushion gas to maintain the minimum cavern pressure.

For the purposes of this study, it is considered that operating the cavern in variable pressure mode would be preferred, as this is the operating mode for the majority of current natural gas and compressed air storage projects.

### 4.6.2 Salt Cavern Location Parameters

Based on the preferred locations suggested in the previous section, project sites in three locations will be considered for potential onshore storage scenarios: Teesside, Cheshire Basin and East Yorkshire. As the depth and thickness of halite beds vary in these areas, the maximum cavern height and cavern operating pressure will also vary, which will affect the number of caverns required.

For offshore storage option, the Preesall Halite present throughout most of the East Irish Sea Basin represents the thickest, most widespread and cleanest Triassic halite in the region, and is the location chosen for the proposed Gateway gas storage project. It is equivalent in depth to the Cheshire Basin location, and as such, it represents a suitable scenario for comparison of offshore costs.

Underground storage caverns are only constructed in areas of sufficiently thick salt strata (salt layers or salt domes). According to Plaat et al. (2009), caverns created in salt domes usually range in size from 300,000m$^3$ to 700,000m$^3$, while those created in salt beds usually have volumes in the range of 100,000m$^3$ to 300,000m$^3$. Caverns can reach a height of 100-500m and 50-100m in diameter. Information from BGS indicates that the cavern volume of the existing salt cavern at Holford (Cheshire Basin) is 300,000m$^3$, and the volume of the salt cavern at Hornsea/Atwick site (East Yorkshire) is approximately 270,000m$^3$. The Teesside region halite bed is shallow and existing salt caverns storing hydrogen in Teesside are approx 70,000m$^3$.

The following location parameters have therefore been considered for the present study for developing a scalable cost structure of salt cavern formation:

**Table 6 - Salt cavern storage location parameters**

| Location | Reference | Cavern Depth (m) | Max Cavern Height (m) | Max Cavern Op Pressure (bara) | Max Cavern Volume (m3) |
|---|---|---|---|---|---|
| East Yorkshire (Z2 Fordon Evaporite) | Hornsea | 1800 | 200 | 270 | 300,000 |
| Teesside (Z3 Boulby Halite) | Sabic Teesside | 370 | 30 | 45 | 70,000 |
| Cheshire Basin (Northwich Halite) | EON Holford | 680 | 200 | 105 | 300,000 |
| East Irish Sea (Preesall Halite) | East Irish Sea | 680 | 200 | 105 | 300,000 |

## 4.7 Salt Cavern storage volume

Number of Salt Cavern requirement in three onshore storage sites

In the context of the current study, two additional options need to be considered:

- Individual storage of $H_2$-rich syngas and $N_2$ gas in separate salt caverns; and
- Combined storage of a mixture of $H_2$-rich syngas and $N_2$ in a single cavern.

Approximate storage volumes for the hydrogen-rich syngas, nitrogen and combined gas ($H_2$ + $N_2$ mix gas) have been calculated based upon flow rate requirements for a single gas turbine operating at full load.

Foster Wheeler experience has shown that the typical hydrogen rich syngas and nitrogen required for a single GE Frame 9F Syngas turbine at full load, is as follows:

**Table 7 - Typical Feed Rates of Hydrogen Rich Fuel and Dilution Nitrogen**

| | Hydrogen Rich Fuel | Dilution Nitrogen |
|---|---|---|
| Flow Rate | 12,287 kmol/h | 11,067 kmol/h |
| | 72,000 kg/h | 310,000 kg/h |
| Molecular Weight (kg/kmol) | 5.86 | 28.01 |
| Composition (mol %) | | |
| Hydrogen | 86.7 | 0.0 |
| Nitrogen | 6.7 | 100.0 |
| Carbon Monoxide | 4.0 | 0.0 |
| Carbon Dioxide | 1.8 | 0.0 |

The demand patterns identified in WP1 give rise to a range of operating regimes for the gas turbines, from diurnal operation up to seasonal operation.

Table 8, Table 9 & Table 10 summarise the number of caverns required to store hydrogen rich syngas, nitrogen gas and mixed gas at 45 bara with a cavern storage size of 70,000 m$^3$ for different operational modes.

Table 11, Table 12 & Table 13 summarise the number of caverns required to store hydrogen rich syngas, nitrogen gas and mixed gas at 105 bara with a cavern storage size of 300,000 m$^3$ for different operational modes.

Table 14, Table 15 & Table 16 summarise the number of caverns required to store hydrogen rich syngas, nitrogen gas and mixed gas at 270 bara with a cavern storage size of 300,000 m$^3$ for different operational modes.

The total storage volume includes the working gas volume and the cushion gas volume required for storage safety and also to maintain minimum storage pressure.

From information obtained from literature (Hart, 1997; Taylor et al., 1986) and also from existing operational facilities, it can be surmised that for facilities operating rapid cycling (so-called “fast churn”), the working volume available for withdrawal is a maximum of 10% of the total stored gas volume. For other operating modes, the cushion gas requirement will vary in the range of 40-80 % depending on the type of gas stored. In this study for diurnal operation, 90% cushion gas is used (as only a maximum of 10% withdrawal/day is possible) whereas for seasonal variation, the cushion gas requirement is set at 60%. For a weekly operational mode assuming daily withdrawal over 5 days, cushion gas is calculated to be 67% of the total stored gas; such that on 5$^{th}$ day of the withdrawal cycle, 10% of the total stored gas remaining in the cavern will be withdrawn.

As discussed above, there will be a sump at the bottom of each cavern which will fill with the insoluble material from within the halite. This sump cannot be removed or debrined, and so it will limit the gas volume. BGS identified that this is typically approximately 25% of the cavern size. Based on the actual cavern size (including sump), cavern diameter and length have been calculated with an assumption that caverns are approximately cylindrical and have a length to diameter ratio of 3. The exception is in Teesside, where the depth of halite limits the height of the cavern, resulting in caverns shorter than they are wide, so a L/D of 0.5 has been used.

An additional constraint to consider is the velocity of the gas within the production well. The maximum velocity should be restricted to avoid erosion/corrosion within the well based on API 14E guidelines.

Depending on the operational mode and the number of hours the gas turbine is offline for, the syngas plant capacity will vary substantially and so the amount of gas stored in the cavern will vary. When the gas turbine is in operation, hydrogen-rich syngas and nitrogen will come from both the syngas production plant and the salt cavern, which should satisfy the gas turbine’s requirement for full load operation. The tables clearly demonstrate the syngas production plant and air separation unit (ASU) capacity variation between different operating modes. For weekly and seasonal cases, it has been assumed that the gas turbine will be online for 24 hours.

**Table 8 - Calculated Volumes and Number of Salt Caverns (maximum cavern size 70,000 m$^3$) Required for $H_2$-rich Syngas at 45 bara and 45°C**

| **Operating Mode** | **Hours GT offline** | **Syngas Plant Capacity** | **Hydrogen Store Volume** | | | **Hydrogen Cavern Size** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (single GT) | | kg/h H2 rich fuel gas | Injection rate (m$^3$/hr) | Working Volume (m$^3$) | Total Volume (m$^3$) | no. of caverns | Actual Size of Cavern (m$^3$) | Cavern Size incl sump (m$^3$) | Cavern Diameter (m) | Cavern Length (m) | Rate of withdrawal (m$^3$/hr) | Syngas to GT (kg/hr) |
| Reference Case (GT 100% 24 hrs) | 0 | 72,000 | - | - | - | - | - | - | - | - | - | 72,000 |
| Diurnal (on 18 hours) | 6 | 54,000 | 5766 | 34,597 | 345,969 | 5 | 69,194 | 86,492 | 60 | 30 | 1,922 | 72,000 |
| Diurnal (on 15 hours) | 9 | 45,000 | 4805 | 43,246 | 432,461 | 7 | 61,780 | 77,225 | 58 | 29 | 2,883 | 72,000 |
| Diurnal (on 12 hours) | 12 | 36,000 | 3844 | 46,129 | 461,292 | 7 | 65,899 | 82,374 | 59 | 30 | 3,844 | 72,000 |
| Weekly (off weekends) | 48 | 51,429 | 5492 | 263,595 | 790,786 | 12 | 65,899 | 82,374 | 59 | 30 | 2,197 | 72,000 |
| Seasonal (off 4 months) | 2920 | 48,000 | 5125 | 14,966,364 | 37,415,910 | 535 | 69,936 | 87,420 | 61 | 30 | 2,563 | 72,000 |
| Seasonal (off 6 months) | 4380 | 36,000 | 3844 | 16,837,160 | 42,092,899 | 602 | 69,922 | 87,402 | 61 | 30 | 3,844 | 72,000 |

### Table 9 - Calculated Volumes and Number of Salt Caverns (maximum cavern size 70,000 $m^3$) Required for $N_2$ at 45 bara and 45°C

| **Operating Mode** | **Hours GT offline** | **ASU Capacity** | **Nitrogen Store Volume** | | | **Nitrogen Cavern Size** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (single GT) | | kg/h N2 | Injection rate ($m^3$/hr) | Working Volume ($m^3$) | Total Volume ($m^3$) | no. of caverns | Actual Size of Cavern ($m^3$) | Cavern Size incl sump ($m^3$) | Cavern Diameter (m) | Cavern Length (m) | Rate of withdrawal ($m^3$/hr) | N2 to GT (kg/hr) |
| Reference Case (GT 100% 24 hrs) | 0 | 310,000 | - | - | - | - | - | - | - | - | - | 310,000 |
| Diurnal (on 18 hours) | 6 | 232,500 | 4849 | 29,093 | 290,928 | 5 | 58,186 | 72,732 | 57 | 29 | 1,616 | 310,000 |
| Diurnal (on 15 hours) | 9 | 193,750 | 4041 | 36,366 | 363,660 | 6 | 60,610 | 75,763 | 58 | 29 | 2,424 | 310,000 |
| Diurnal (on 12 hours) | 12 | 155,000 | 3233 | 38,790 | 387,904 | 6 | 64,651 | 80,813 | 59 | 30 | 3,233 | 310,000 |
| Weekly (off weekends) | 48 | 221,429 | 4618 | 221,659 | 664,978 | 10 | 66,498 | 83,122 | 60 | 30 | 1,847 | 310,000 |
| Seasonal (off 4 months) | 2920 | 206,667 | 4310 | 12,585,332 | 31,463,330 | 450 | 69,919 | 87,398 | 61 | 30 | 2,155 | 310,000 |
| Seasonal (off 6 months) | 4380 | 155,000 | 3233 | 14,158,498 | 35,396,246 | 506 | 69,953 | 87,441 | 61 | 30 | 3,233 | 310,000 |

**Table 10 - Calculated Volumes and Number of Salt Caverns (maximum cavern size 70,000 $m^3$) Required for combined ($H_2$ + $N_2$) gas at 45 bara and 45°C**

| **Operating Mode** | **Hours GT offline** | **Mixed Gas Capacity** | **Combined Store Volume** | | | **Combined Cavern Size** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (single GT) | | kg/h H2 rich +N2 rich gas | Injection rate ($m^3$/hr) | Working Volume ($m^3$) | Total Volume ($m^3$) | no. of caverns | Actual Size of Cavern ($m^3$) | Cavern Size incl sump ($m^3$) | Cavern Diameter (m) | Cavern Length (m) | Rate of withdrawal ($m^3$/hr) | Combined gas to GT (kg/hr) |
| Reference Case (GT 100% 24 hrs) | 0 | 382,000 | - | - | - | - | - | - | - | - | - | 382,000 |
| Diurnal (on 18 hours) | 6 | 286,500 | 10702 | 64,214 | 642,137 | 10 | 64,214 | 80,267 | 59 | 29 | 3,567 | 382,000 |
| Diurnal (on 15 hours) | 9 | 238,750 | 8919 | 80,267 | 802,671 | 12 | 66,889 | 83,612 | 60 | 30 | 5,351 | 382,000 |
| Diurnal (on 12 hours) | 12 | 191,000 | 7135 | 85,618 | 856,182 | 13 | 65,860 | 82,325 | 59 | 30 | 7,135 | 382,000 |
| Weekly (off weekends) | 48 | 272,857 | 10193 | 489,247 | 1,467,741 | 21 | 69,892 | 82,366 | 61 | 30 | 4,077 | 382,000 |
| Seasonal (off 4 months) | 2920 | 254,667 | 9513 | 27,778,359 | 69,445,897 | 993 | 69,935 | 87,419 | 61 | 30 | 4,757 | 382,000 |
| Seasonal (off 6 months) | 4380 | 191,000 | 7135 | 31,250,654 | 78,126,634 | 1117 | 69,943 | 87,429 | 61 | 30 | 7,135 | 382,000 |

**Table 11 - Calculated Volumes and Number of Salt Caverns (maximum cavern size 300,000 $m^3$) Required for $H_2$-rich Syngas at 105 bara and 45°C**

| **Operating Mode** | **Hours GT offline** | **Syngas Plant Capacity** | **Hydrogen Store Volume** | | | **Hydrogen Cavern Size** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (single GT) | | kg/h H2 rich fuel gas | Injection rate ($m^3$/hr) | Working Volume ($m^3$) | Total Volume ($m^3$) | no. of caverns | Actual Size of Cavern ($m^3$) | Cavern Size incl sump ($m^3$) | Cavern Diameter (m) | Cavern Length (m) | Rate of withdrawal ($m^3$/hr) | Syngas to GT (kg/hr) |
| Reference Case (GT 100% 24 hrs) | 0 | 72,000 | - | - | - | - | - | - | - | - | - | 72,000 |
| Diurnal (on 18 hours) | 6 | 54,000 | 2526 | 15,154 | 151,543 | 1 | 151,543 | 189,429 | 43 | 129 | 842 | 72,000 |
| Diurnal (on 15 hours) | 9 | 45,000 | 2105 | 18,943 | 189,429 | 1 | 189,429 | 236,787 | 46 | 139 | 1,263 | 72,000 |
| Diurnal (on 12 hours) | 12 | 36,000 | 1684 | 20,206 | 202,058 | 1 | 202,058 | 252,572 | 48 | 143 | 1,684 | 72,000 |
| Weekly (off weekends) | 48 | 51,429 | 2405 | 115,462 | 346,385 | 2 | 173,193 | 216,491 | 45 | 135 | 962 | 72,000 |
| Seasonal (off 4 months) | 2920 | 48,000 | 2245 | 6,555,659 | 16,389,149 | 55 | 297,985 | 372,481 | 54 | 162 | 1,123 | 72,000 |
| Seasonal (off 6 months) | 4380 | 36,000 | 1684 | 7,375,117 | 18,437,792 | 62 | 297,384 | 371,370 | 54 | 162 | 1,684 | 72,000 |

**Table 12 - Calculated Volumes and Number of Salt Caverns (maximum cavern size 300,000 m$^3$) Required for $N_2$ at 105 bara and 45°C**

| **Operating Mode** | **Hours GT offline** | **ASU Capacity** | **Nitrogen Store Volume** | | | **Nitrogen Cavern Size** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (single GT) | | kg/h N2 | Injection rate (m$^3$/hr) | Working Volume (m$^3$) | Total Volume (m$^3$) | no. of caverns | Actual Size of Cavern (m$^3$) | Cavern Size incl sump (m$^3$) | Cavern Diameter (m) | Cavern Length (m) | Rate of withdrawal (m$^3$/hr) | N2 to GT (kg/hr) |
| Reference Case (GT 100% 24 hrs) | 0 | 310,000 | - | - | - | - | - | - | - | - | - | 310,000 |
| Diurnal (on 18 hours) | 6 | 232,500 | 2095 | 12,568 | 125,676 | 1 | 125,676 | 157,095 | 41 | 122 | 698 | 310,000 |
| Diurnal (on 15 hours) | 9 | 193,750 | 1745 | 15,709 | 157,095 | 1 | 157,095 | 196,368 | 44 | 131 | 1,047 | 310,000 |
| Diurnal (on 12 hours) | 12 | 155,000 | 1396 | 16,757 | 167,568 | 1 | 167,568 | 209,459 | 45 | 134 | 1,396 | 310,000 |
| Weekly (off weekends) | 48 | 221,429 | 1995 | 95,753 | 287,259 | 1 | 287,259 | 359,073 | 53 | 160 | 798 | 310,000 |
| Seasonal (off 4 months) | 2920 | 206,667 | 1862 | 5,436,637 | 13,591,592 | 46 | 295,469 | 369,337 | 54 | 162 | 931 | 310,000 |
| Seasonal (off 6 months) | 4380 | 155,000 | 1396 | 6,116,541 | 15,290,541 | 51 | 299,815 | 374,768 | 54 | 163 | 1,396 | 310,000 |

**Table 13 - Calculated Volumes and Number of Salt Caverns (maximum cavern size 300,000 m$^3$) Required for combined ($H_2$ + $N_2$) gas at 105 bara and 45°C**

| Operating Mode | Hours GT offline | Mixed Gas Capacity | Combined Store Volume | | | Combined Cavern Size | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (single GT) | | kg/h H2 rich +N2 rich gas | Injection rate (m$^3$/hr) | Working Volume (m$^3$) | Total Volume (m$^3$) | no. of caverns | Actual Size of Cavern (m$^3$) | Cavern Size incl sump (m$^3$) | Cavern Diameter (m) | Cavern Length (m) | Rate of withdrawal (m$^3$/hr) | Combined gas to GT (kg/hr) |
| Reference Case (GT 100% 24 hrs) | 0 | 382,000 | - | - | - | - | - | - | - | - | - | 382,000 |
| Diurnal (on 18 hours) | 6 | 286,500 | 4616 | 27,695 | 276,945 | 1 | 276,945 | 346,182 | 53 | 158 | 1,539 | 382,000 |
| Diurnal (on 15 hours) | 9 | 238,750 | 3846 | 34,618 | 346,182 | 2 | 173,091 | 216,364 | 45 | 135 | 2,308 | 382,000 |
| Diurnal (on 12 hours) | 12 | 191,000 | 3077 | 36,926 | 369,261 | 2 | 184,630 | 230,788 | 46 | 138 | 3,077 | 382,000 |
| Weekly (off weekends) | 48 | 272,857 | 4396 | 211,006 | 633,018 | 3 | 211,006 | 263,758 | 48 | 145 | 1,758 | 382,000 |
| Seasonal (off 4 months) | 2920 | 254,667 | 4103 | 11,980,452 | 29,951,130 | 100 | 299,511 | 374,389 | 54 | 162 | 2,051 | 382,000 |
| Seasonal (off 6 months) | 4380 | 191,000 | 3077 | 13,478,009 | 33,695,022 | 113 | 298,186 | 372,733 | 54 | 162 | 3,077 | 382,000 |

**Table 14 - Calculated Volumes and Number of Salt Caverns (maximum cavern size 300,000 $m^3$) Required for $H_2$-rich Syngas at 270 bara and 45°C**

| **Operating Mode** | **Hours GT offline** | **Syngas Plant Capacity** | **Hydrogen Store Volume** | | | **Hydrogen Cavern Size** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (single GT) | | kg/h H2 rich fuel gas | Injection rate ($m^3$/hr) | Working Volume ($m^3$) | Total Volume ($m^3$) | no. of caverns | Actual Size of Cavern ($m^3$) | Cavern Size incl sump ($m^3$) | Cavern Diameter (m) | Cavern Length (m) | Rate of withdrawal ($m^3$/hr) | Syngas to GT (kg/hr) |
| Reference Case (GT 100% 24 hrs) | 0 | 72,000 | - | - | - | - | - | - | - | - | - | 72,000 |
| Diurnal (on 18 hours) | 6 | 54,000 | 1052 | 6,312 | 63,121 | 1 | 63,121 | 78,901 | 32 | 97 | 351 | 72,000 |
| Diurnal (on 15 hours) | 9 | 45,000 | 877 | 7,890 | 78,901 | 1 | 78,901 | 98,627 | 35 | 104 | 526 | 72,000 |
| Diurnal (on 12 hours) | 12 | 36,000 | 701 | 8,416 | 84,161 | 1 | 84,161 | 105,202 | 35 | 106 | 701 | 72,000 |
| Weekly (off weekends) | 48 | 51,429 | 1002 | 48,092 | 144,277 | 1 | 144,277 | 180,346 | 42 | 127 | 401 | 72,000 |
| Seasonal (off 4 months) | 2920 | 48,000 | 935 | 2,730,567 | 6,826,417 | 23 | 296,801 | 371,001 | 54 | 162 | 474 | 72,000 |
| Seasonal (off 6 months) | 4380 | 36,000 | 701 | 3,071,888 | 7,679,719 | 26 | 295,374 | 369,217 | 54 | 162 | 711 | 72,000 |

**Table 15 - Calculated Volumes and Number of Salt Caverns (maximum cavern size 300,000 $m^3$) Required for $N_2$ at 270 bara and 45°C**

| **Operating Mode** | **Hours GT offline** | **ASU Capacity** | **Nitrogen Store Volume** | | | **Nitrogen Cavern Size** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (single GT) | | kg/h N2 | Injection rate ($m^3$/hr) | Working Volume ($m^3$) | Total Volume ($m^3$) | no. of caverns | Actual Size of Cavern ($m^3$) | Cavern Size incl sump ($m^3$) | Cavern Diameter (m) | Cavern Length (m) | Rate of withdrawal ($m^3$/hr) | N2 to GT (kg/hr) |
| Reference Case (GT 100% 24 hrs) | 0 | 310,000 | - | - | - | - | - | - | - | - | - | 310,000 |
| Diurnal (on 18 hours) | 6 | 232,500 | 882 | 5,290 | 52,901 | 1 | 52,901 | 66,126 | 30 | 91 | 294 | 310,000 |
| Diurnal (on 15 hours) | 9 | 193,750 | 735 | 6,613 | 66,126 | 1 | 66,126 | 82,658 | 33 | 98 | 441 | 310,000 |
| Diurnal (on 12 hours) | 12 | 155,000 | 588 | 7,053 | 70,535 | 1 | 70,535 | 88,168 | 33 | 100 | 588 | 310,000 |
| Weekly (off weekends) | 48 | 221,429 | 840 | 40,306 | 120,917 | 1 | 120,917 | 151,146 | 40 | 120 | 336 | 310,000 |
| Seasonal (off 4 months) | 2920 | 206,667 | 784 | 2,288,459 | 5,721,148 | 20 | 286,057 | 357,572 | 53 | 160 | 397 | 310,000 |
| Seasonal (off 6 months) | 4380 | 155,000 | 588 | 2,574,516 | 6,436,291 | 22 | 292,559 | 365,698 | 54 | 161 | 596 | 310,000 |

**Table 16 - Calculated Volumes and Number of Salt Caverns (maximum cavern size 300,000 m$^3$) Required for combined ($H_2$ + $N_2$) gas at 270 bara and 45°C**

| **Operating Mode** | **Hours GT offline** | **Mixed Gas Capacity** | **Combined Store Volume** | | | **Combined Cavern Size** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (single GT) | | kg/h H2 rich +N2 rich gas | Injection rate (m$^3$/hr) | Working Volume (m$^3$) | Total Volume (m$^3$) | no. of caverns | Actual Size of Cavern (m$^3$) | Cavern Size incl sump (m$^3$) | Cavern Diameter (m) | Cavern Length (m) | Rate of withdrawal (m$^3$/hr) | Combined gas to GT (kg/hr) |
| Reference Case (GT 100% 24 hrs) | 0 | 382,000 | - | - | - | - | - | - | - | - | - | 382,000 |
| Diurnal (on 18 hours) | 6 | 286,500 | 1940 | 11,638 | 116,385 | 1 | 116,385 | 145,481 | 40 | 119 | 647 | 382,000 |
| Diurnal (on 15 hours) | 9 | 238,750 | 1616 | 14,548 | 145,481 | 1 | 145,481 | 181,851 | 43 | 128 | 970 | 382,000 |
| Diurnal (on 12 hours) | 12 | 191,000 | 1293 | 15,518 | 155,179 | 1 | 155,179 | 193,974 | 44 | 131 | 1,293 | 382,000 |
| Weekly (off weekends) | 48 | 272,857 | 1847 | 88,674 | 266,022 | 1 | 266,022 | 332,527 | 52 | 156 | 739 | 382,000 |
| Seasonal (off 4 months) | 2920 | 254,667 | 1724 | 5,034,710 | 12,586,775 | 42 | 299,685 | 374,606 | 54 | 163 | 874 | 382,000 |
| Seasonal (off 6 months) | 4380 | 191,000 | 1293 | 5,664,049 | 14,160,122 | 48 | 295,003 | 368,753 | 54 | 162 | 1,311 | 382,000 |

It is evident from the above tables that for both 105 bara and 270 bara storage pressure scenarios, either diurnal and weekly operating modes of storage are feasible using a maximum of 3 caverns per GT for the 105 bar case and 2 caverns for the 270 bar case.

In the lower pressure scenario (45 bara), larger numbers of caverns are required. For example, weekly variation will need around 21 caverns.

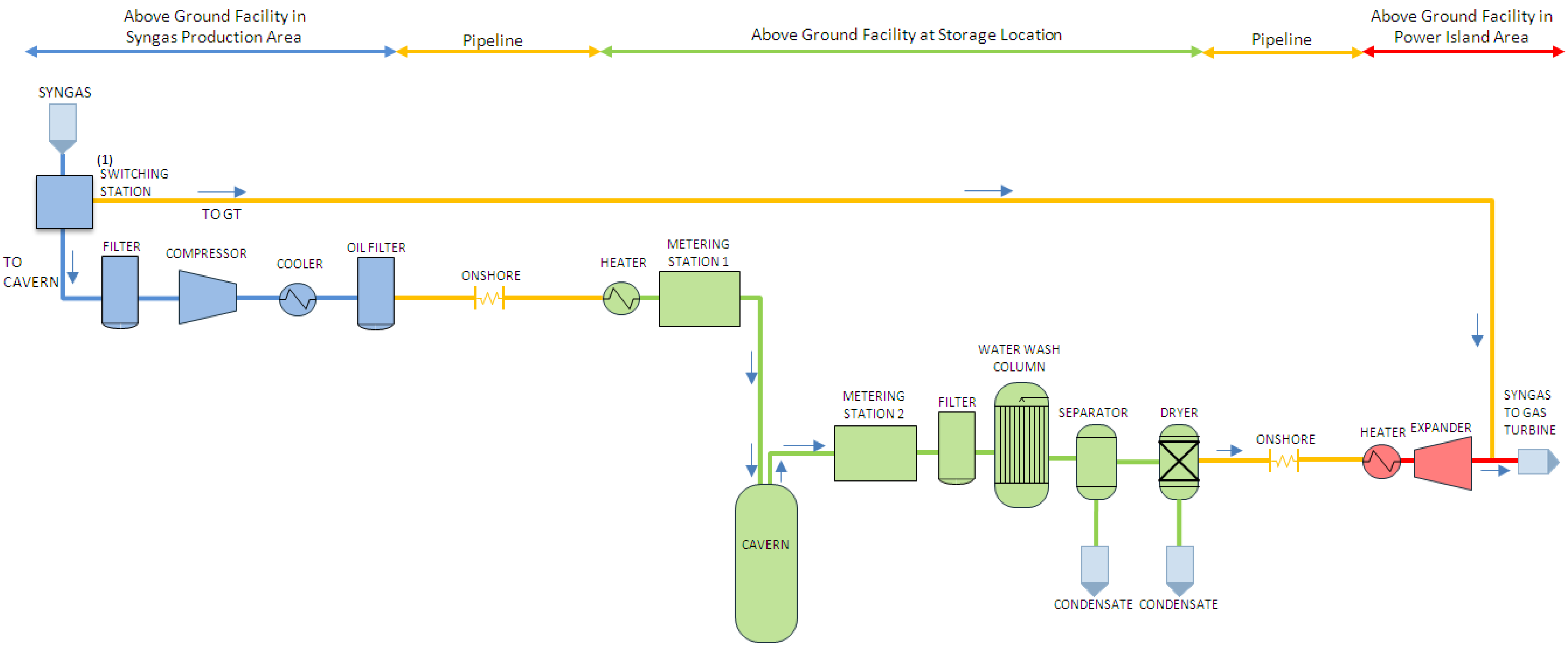
For seasonal cases, a large quantity of caverns is required for all operating pressure scenarios.

## *4.8* Above Ground / Topside Equipment

Above ground, the visible structure of an underground storage facility is mainly the solution mining and gas storage plants, operations and administrative buildings, cavern locations and associated cavern heads that are connected to the plants via field pipelines. The compression station / expansion turbine would be expected to be installed local to the syngas plant / power island respectively.

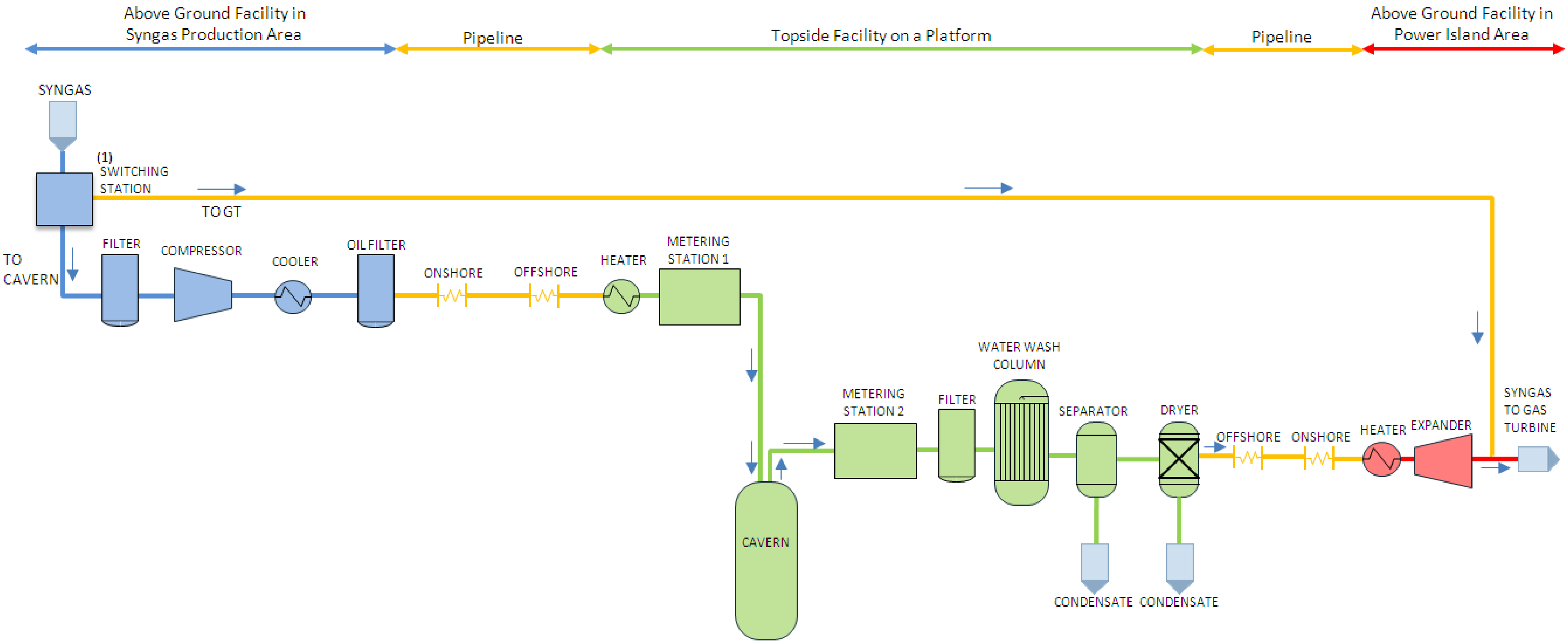
Figure 5 gives a schematic diagram of a typical above ground installation for an onshore salt cavern storing hydrogen-rich syngas supplied from a syngas plant (IGCC/ATR/SMR) and delivering to a gas turbine located in the Power Island. For simplicity, the scheme represents a combined gas storage case (such as would come from the ATR scheme). When hydrogen rich syngas and $N_2$ gas are stored separately, a second train of the inlet equipment will be required for the nitrogen gas. Though the gases would be stored separately, they would be mixed after extracting from individual caverns before entering the conditioning units above ground. Therefore, for both separate and combined storage options, gas conditioning units at the outlet of the salt caverns and above ground equipment in the Power Island are sized on the combined gas flow.

Figure 6 describes the topside equipment and other onshore facilities required for gas injection into, and extraction from, the underground salt cavern storage for an offshore project.




(1) When GT is offline, syngas from production plant is transferred to storage cavern only. When GT is online syngas is transferred from storage cavern and directly from production plant simultaneously.

**Figure 5 - BFD of a Typical Above Ground Installation for an Onshore Salt Cavern Storage Project**




(1) When GT is offline, syngas from production plant is transferred to storage cavern only. When GT is online syngas is transferred from storage cavern and directly from production plant simultaneously.

**Figure 6 - BFD of a Typical Topside Installation and Above Ground Facility for an Offshore Salt Cavern Storage Project**

The equipment displayed in Figure 5 and Figure 6 is explained below:

Filter

A filter is required to remove any solid particles from the gas stream that may damage downstream equipment.

Compression unit

Hydrogen-rich syngas from the syngas production plant will be at a much lower pressure (around 30 bar) than the storage pressures under consideration, so requires compression to a pressure slightly above the storage pressure (to overcome line pressure losses). The gas flows through one or more compressors (mainly centrifugal), which increases the pressure to the desired level.

As shown in Figure 5 (and Figure 6), the electric compressor system is located within the syngas production plant to allow integration with the syngas production plant and reduce the diameter of the transfer pipeline. A cooler downstream of the compressor reduces the temperature and hence the volume of the gas before transport. An oil filter is located downstream of the compressor to remove any entrained oil droplets.

Heater upstream of cavern

Salt cavern operating temperature is an important operating factor to consider in order to preserve the structural integrity of the storage facility. Caverns must be operated within a strict temperature envelope. The operating temperature of a Teesside salt cavern storing propane varies between -5 and +27°C, whereas a salt cavern storing butane varies between 0 and 29°C. Operation outside of these temperature ranges (and sudden changes in temperature) can increase the risk of cavern instability, resulting in roof collapse etc. Such damage has the potential to put affected cavities permanently beyond use. An existing natural gas salt cavern in operation in Portugal operates at 45°C. For this study, a cavern operating temperature of 45°C has been assumed.

As the compressed gas has to travel through an underground pipeline, the gas will experience significant cooling (to perhaps around 5°C) before arriving at the storage site. The extent of cooling will to some extent depend on the length of the distance between the syngas production plant and the salt cavern site. The gas needs to be heated to the approximate temperature of the storage cavity before being injected into the cavern.

Metering Station

The gas must be fiscally metered upon entry into the facility and upon exiting the facility. These metering stations are designed for simultaneous, continuous analysis of a quantity of the gas being transferred in the pipeline and require a straight length pipe upstream and downstream to ensure uniformity in the gas flow passing through the meter.

Water Wash Column

The cavern contains a heel of brine in the sump, which cannot be removed during the debrining operation. As the stored gas is in direct contact with the residual brine sump located in the bottom of the cavern, gas withdrawn from the cavern will contain some salt and will be saturated during an initial period of operation. The water wash column removes entrained salt in order to meet the gas turbine inlet specification.

Dehydration Unit

In each cavern, stored gas is in direct contact with the residual brine and will absorb water as a result. The longer the residence time, the higher the water content will be. Gas will potentially travel a considerable distance in a subterranean pipeline between the storage site and the Power Island. When saturated gas is discharged from the cavern and is cooled during transport, there is a risk of condensate formation.

The combined gas withdrawn from the caverns is therefore dried with triethylene glycol before entering the transfer pipeline to the Power Island to avoid condensate formation

N.B. A dehydration unit downstream of the syngas plant is not required as the syngas will be cooled to a controlled temperature of +4 $^{o}$C followed by separation of condensed water in the syngas production plant prior to compression, preventing formation of condensate as the gas re-cools.

Transfer Line Design

When the syngas production plant is serving a small number of caverns, it is possible to connect each well head individually to the plant. Inspection of the flowlines is via temporary pig launchers and receivers. Where a large number of caverns are required, care must be taken to ensure that the pipelines can be inspected and that liquid can be removed when necessary. If it is expected that liquid might accumulate in the flowline, this may give rise to large slugs of liquid if the flow is ramped up quickly. Drain points along the pipeline are not preferred.

Heating unit downstream of cavern

This is installed in the power island, downstream of the transfer pipeline, and upstream of the expansion turbine. The gas withdrawn from the cavern will cool down rapidly during expansion through the turbine, so the heating unit is required to ensure that the gas temperature after expansion does not fall lower than 15 ° C. This avoids the risk of very low temperature gas exiting the expansion turbine where there is a risk of condensate formation.

Expansion Turbine

An expansion turbine is typically a radial flow turbine through which the high pressure gas from the salt cavern is expanded to produce shaft work. Because shaft work is extracted from the expanding high pressure gas, the expansion is approximated by an isentropic process (i.e., a constant entropy process) and the low pressure exhaust gas from the turbine cools depending upon the operating pressure and gas properties.

The expansion turbine is placed in the Power Island to integrate the extracted power with the rest of the Power Island, and reduce the diameter of the transfer pipeline.

For Teesside storage case, as the gas is stored at low pressure (45 bara), an expansion turbine is not expected to be worthwhile.

Platform for topside facility and offshore Pipeline for Offshore Storage option

An Offshore storage scenario would require a permanent structure similar in design to a small gas platform to hold topside equipments. The platform will serve a dual role; initially to house the cavern leaching equipment, and then on cavern completion, to house the cavern gas well head and associated equipment (Figure 6). This substructure will be installed first and secured to the seabed by ‘screwing’ piles into the seabed.

A platform located over each cavern location allows for individual brine discharge dispersion units, which improves the dispersion efficiency of the brine discharges to sea during cavern construction (from Gateway Project). Once the cavern has been completed, the topsides will be installed using a crane from a jack-up barge. This will allow for simpler and safer operational maintenance, for example cavern re-entry 'work over' operations and equipment repair become greatly simplified if direct access is possible. The topside equipment that will be installed on the permanent structure offshore are displayed in Figure 6 as Topside Facility between two transfer pipelines.

The total topside operating weight of the equipments is estimated in the order of 2,000te and is potentially a Not Normally Manned Installation (NNMI) / Normally Unmanned Installation (NUI). FW suggest that for topsides of this size, the traditional approach to support this would be a 4 legged tower 'jacket' structure.

Traditional 4 legged jacket structures have been successfully installed for topside weights of up to 5,000te and there is a credible track-record globally for this approach. The jacket's legs would be braced with an upper, mid and lower plan and intermediate bracing as shown below.

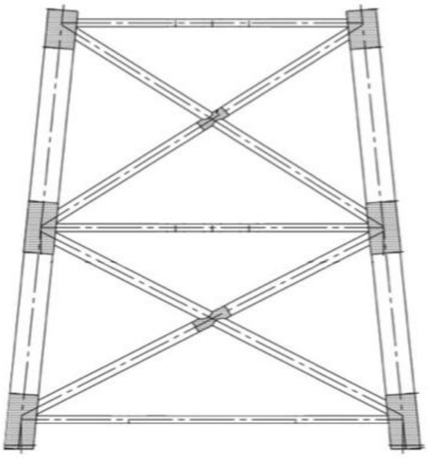


**Figure 7 - 4 Legged Tower Jacket Structure**

Based on the water depth, location and topside weights, a 4 legged jacket could be in the region of 1,500 to 2,000 te installed weight.

<u>Offshore Pipelines for Offshore Storage option</u>

Another important requirement to the offshore project is offshore transfer pipeline which will increase the total project cost significantly compared to an onshore project. In this study, it is assumed to be 25 km long (per Gateway project) and comprise two offshore import/export lines running from the storage site to the shore.

## 4.9 Capital Cost of Onshore Salt Cavern Storage Facilities

The capital cost of underground storage for gases in a salt cavern has three main components.

- CAPEX associated with development/construction of the cavern
- CAPEX associated with the above ground facilities to compress and condition the gas before injection into the cavern; and expand and condition the gas after withdrawal from the cavern.
- Cost of cushion gas required to maintain the minimum storage pressure. The syngas production plant will have to produce the substantial amount of cushion gas required, which cannot be extracted and will not contribute to power generation.

### 4.9.1 Capital Cost Associated with Geological Investigation and Modelling of the Cavern

Several geological investigations and laboratory tests on retrieved core samples from the proposed site will be required to provide detailed information regarding geological structure and integrity of the target site. As outlined in section 4.2, seismic reflection exploration (either 2D or 3D or both) and drilling of at least one exploration well will be required to understand the nature and properties of the halite and enclosing strata. Interpretation of the exploration data and integration with a geological model is essential to define the salt beds in the immediate and surrounding areas and to characterise the depth of storage available, thus defining the minimum and maximum storage pressures.

Much of this early site characterisation is required prior to Planning Application; it is only after award that preliminary site preparations and drilling wells for cavern development can really commence.

Salt cavern construction cost may be characterised as follows:

- Cost associated with geological investigation (either or both 2D and 3D seismic exploration cost and cost of drilling exploration well);
- Cost of laboratory testing of the core samples retrieved from the proposed site;
- Cost of drilling equipment, piping, casing, tubing, well valves, blow out preventer (BOP) etc. required to drill a hole from the surface to the depth of the salt formation; and
- Cost of solution mining – pumping water through the tube into the cavern and extracting brine.

The geological investigation process takes around 2 years with an additional 4 years for solution mining (with the main leaching process taking approximately 2.5 out of the 4 years). BGS has provided indicative cost data for the investigation process for an onshore hydrocarbon exploration venture as follows:

- 2D seismic data - for reasonable size programme (> 50 km) - £8-10K/km with an additional £1K for processing; and/or
- 3D onshore - for a programme of say 50 $km^2$ plus - £12-20K/$km^2$ with an additional £2K for basic processing - depends upon the required surface effort and fold at target - (shallower targets require more source effort).
- A vertical land well to 2000m is in the range of £2 to £3 million depending on TD hole size (6” or 8 ½”) and the number of casing points required for

isolation of aquifers etc. Coring will increase costs due to the need to stop drilling (‘trips’), in order to change the drilling assembly to include the core barrel (generally 9 m or longer) and then return to the bottom of the hole, drill on further then retrieve the core barrel, change and recommence until coring is completed. These ‘trips’ can take days to complete and add to the cost of drilling operations. In addition, down hole geophysical logs and in situ pressure tests of the storage formation are required to provide information on the strata at depth.

### 4.9.2 Capital Cost Associated with Onshore Salt Cavern Construction

The depth of the salt cavern has a significant impact on cost as the drilling equipment hire cost and tubing/casing cost increase with depth. The salt cavern volume has a minimal influence on cost as when the drilling is completed; the only significant cost is pumping the water in and brine out from mined cavern during solution mining. It is therefore sensible to mine the largest caverns that the structural integrity of surrounding halite beds permit.

Taylor et al. (1986) estimated solution mining costs as $23/m$^3$ whereas hard rock mining costs were estimated at $34-$84/m$^3$ depending on the depth. New York State Electric & Gas completed an underground natural gas storage system consisting of 89 km of high-pressure pipeline, a 1,930 kW compressor and a solution mined cavern with a 22.6 million Nm$^3$ working volume (roughly equivalent to 2 million kg of H2) in 1996. The complete project cost was $57.2 million (NYSEG, 1996b; NYSEG, 1996c). The cost included both cavern construction cost and cost of above ground facilities.

<u>Base Case Parameters and Costs</u>

Foster Wheeler has in-house cost data for an onshore natural gas storage project using salt caverns in Southern Europe. This information is used as the basis from which to scale for the present study.

**Table 17 - Base Case Parameters and Cost**

| **Parameters** | **Value** | **Unit** |
|---|---|---|
| Salt cavern storage size | 400,000 | m$^3$ |
| Salt cavern depth | 1,000 | m |
| Distance from sea | 5 | km |
| Length of Brine Pipelines | 10 | km |
| Year of construction of one cavern | 2001-2004 | |
| Total cost to mine one salt cavern | 15<br>18.4 (1) | Million Euro<br>Million GBP |

(1) 45% forward escalation has been used to convert cost from 2001 to Q1 2010. A currency conversion factor of 0.86 is used to convert Euro to Pound.

The cost takes account of construction and testing phases, including drilling, piping, well valves, casing and BOP, with a 4 year construction period using brackish water.

The solution mining cost is assumed to include leaching plant facilities like water injection pumps, the brine production/disposal station, completion of leaching and first gas fill. The costs of leaching field pipelines are not included.

The cost does not account for the geological survey cost, which was performed during a 2 year period (1998-1999) in order to select a suitable location for the cavern. Information provided by BGS gives an indication of the cost required for the geological survey (both the 2D/3D seismic exploration cost and the cost of drilling an exploration well) which is in the region of £3 million.

The cost does not include any above ground facilities (e.g. compression and expansion, gas metering, dehydration etc.).

An indicative breakdown of the salt cavern construction cost into different phases was provided by KBB (an independent engineering company specific expertise in solution mining) for the HyUnder project. This has been used in Table 18.

**Table 18 - Cost Breakdown of Construction of an Onshore Salt Cavern**

| Cost Breakdown | % of Total cost | Million GBP |
|---|---|---|
| Project Preparation (Project Management, Engineering, Civil Works & Construction) | 30 | 5.5 |
| Drilling Subcontract | 15 | 2.8 |
| Well Completion and Testing | 15 | 2.8 |
| Construction Contingency (Underground Risks) | 10 | 1.8 |
| Solution mining | 30 | 5.5 |
| | **100** | **18.4** |

The reference project is approximately 5 km from the coast and has two 10 km long seawater/brine pipelines. The cost of the brine pipeline is summarised in Attachment 2. For a CS 16 inch pipeline of 10 km length, the cost of a single pipeline will be £5.5 million.

Table 19 summarises the total installed cost of constructing a reference cavern of 400,000 $m^3$ size.

**Table 19 - Total Cost (Installed) of Construction of a 400,000 $m^3$ Onshore Salt Cavern at 1000 m depth**

| | Million GBP |
|---|---|
| Geological Survey cost | 3.0 |
| Cavern Construction Cost | 18.4 |
| Water pipeline cost (CS, 10 km) | 5.5 |
| Brine pipeline cost (CS, 10 km) | 5.5 |
| **Total cost** | **32.4** |

Cost Scaling

The cost breakdowns listed in Table 18 & Table 19 are used to develop the scalable cost estimate.

DEEP (an independent engineering company with specific expertise in underground storage and solution mining) have confirmed that solution mining cost increases proportionally with cavern storage volume. Table 20 shows the variation of solution mining cost based on the storage volume.

**Table 20 - Solution Mining Cost Variation with Storage Volume**

| Cavern storage volume, $m^3$ | Application | Million GBP |
|---|---|---|
| 70,000 | Teesside | 1.0 |
| 300,000 | Cheshire, E. Yorkshire, East Irish Sea | 4.1 |
| 400,000 | Base Case (S. Europe) | 5.5 |
| 700,000 | Salt Dome Applications | 9.7 |

Drilling/well completion/construction cost will depend on the depth of the salt cavern. From Foster Wheeler's in-house experience, it is anticipated that this cost will vary proportionally with drilling depth by around £1 million/100 m. Table 21 shows the variation of project cost with cavern depth.

**Table 21 - Variation of Cavern Construction Cost with Storage Depth**

| Salt cavern depth, m | Application (1) | Million GBP |
|---|---|---|
| 370 | Teesside | 10.7 |
| 680 | Cheshire | 14.5 |
| 1000 | Base Case (S. Europe) | 18.4 |
| 1800 | E. Yorkshire | 28.2 |

(1) Based on a 400,000m$^3$ cavern volume

4.9.3 Capital Cost of Onshore Salt cavern above ground facilities

The full list of above ground equipment is shown in Figure 5.

The major contributors to the cost of the above ground facilities include:

- compressor (to pressurise gas up to cavern storage pressure);
- expansion turbine (to recover power from decompression of the stored gas);
- dehydration unit (to remove moisture on withdrawal and avoid condensation in the pipeline).

Reciprocating compressors are most commonly used for hydrogen applications, but centrifugal compressors may also be an option. Reciprocating compressors cost about 50% more than a comparable centrifugal compressor, but have higher efficiencies (Timmerhaus & Flynn, 1989). The capital cost of both compressor types are subject to a sizing exponent of 0.80. High operating pressure also adds to the cost of a compressor.

An expansion turbine is typically a radial flow turbine through which a high pressure gas is expanded, producing shaft work. Refer to WP1 Report, section 6.3 for more details on expansion turbines.

<u>Estimate Format</u>

Estimates have been prepared for 45 bara, 105 bara and 270 bara pressures in the form of four cases, which are as follows:

- Case 1: $H_2$-rich syngas inflow for storage in a salt cavern;
    - Including two hot water pumps and two commercial hot water boilers
- Case 2: $N_2$ inflow for storage in a salt cavern;
    - Including two hot water pumps and two commercial hot water boilers
- Case 3: Combined gas ($H_2$-rich syngas + $N_2$) inflow for storage in a salt cavern;
    - Including three hot water pumps and three commercial hot water boilers
- Case 4-Outlet: Combined gas outflow from a salt cavern.

- At 45 bara pressure, no Expansion Turbine is required; a small booster compressor has been included to maintain the gas pressure inlet to Gas Turbine
- At 105 bara pressure, one 14.6 MW Expansion Turbine is required; and
- At 270 bara pressure, two 16.0 MW Expansion Turbines are required.

When $H_2$ and $N_2$ gas are individually stored, the gases will be mixed at the outlet of the storage site in order to ensure that a mixed gas always flows to the Power Island.

It has been assumed for this study that syngas production plant is approximately 10 km away from salt cavern site and Power Island is also 10 km away from salt cavern facility. For each of the gas inflow cases (Case 1, Case 2 and Case 3), 1x10 km carbon steel subterranean pipeline will be required to link the syngas production plant and above ground salt cavern facility. A further 10 km carbon steel pipeline is required to transfer the combined gas from the salt cavern site to the heater and expansion turbines located in Power Island (Case 4-outlet). Table 22 shows the calculated pipeline diameter for different storage pressure scenarios for these pipelines. The pipeline diameter is calculated for each storage scenario maintaining the gas velocity within a limit of 10 m/s in the pipeline to avoid corrosion/erosion issues and such that the overall pressure drop in the 10km line is below 15 bar.

**Table 22 - Transfer pipeline diameter for different storage options**

| Storage Pressure, bara | **Pipeline diameter, inch** | | | |
|---|---|---|---|---|
| | **Case 1** | **Case 2** | **Case 3** | **Case 4-Outlet** |
| 45 | 20 | 24 | 30 | 30 |
| 105 | 12 | 16 | 20 | 20 |
| 270 | 10 | 14 | 16 | 16 |

The Work Breakdown Structure (WBS) used for each Case estimate is as follows:

- Above ground facility at Syngas Production Unit;
- Pipelines between syngas production plant and cavern site;
- Above ground facility upstream to salt cavern at the cavern site;
- Above ground facility downstream of salt cavern at the cavern site;
- Pipelines between cavern site and Power Island; and
- Above ground facility at Power Island.

<u>Summary of Capital Cost Estimate - Onshore Salt Cavern Above Ground Facilities</u>

Capital Costs Summaries for the 3 storage pressure and 4 cases defined above are provided in the following Attachments:

- Attachment 3; Above Ground Facility Capital Cost Summaries @ 45bara
    - Case 1;
    - Case 2;
    - Case 3;

    - Case 4-Outlet
- Attachment 4; Above Ground Facility Capital Cost Summaries @ 105bara
    - Case 1;
    - Case 2;
    - Case 3;
    - Case 4-Outlet
- Attachment 5; Above Ground Facility Capital Cost Summaries @ 270bara
    - Case 1;
    - Case 2;
    - Case 3;
    - Case 4-Outlet

Refer to Section 4.9.4 for details of the Cost Estimating Basis.

No allowance is included for pipe bridges or other similar crossings.

The Capex of a given option is summarised in Table 23 by combining the data as follows:

1. Individual Storage Scenario: Case 1 + Case 2 + Case 4-Outflow; and
2. Combined Storage Scenario: Case 3 + Case 4-Outflow.

The cost of hydrogen-rich syngas pipeline for three different storage pressures is provided in the following Attachment:

- Attachment 6; Hydrogen rich gas pipeline cost - Onshore

These same pipeline design and cost estimates are also considered applicable for $N_2$ and combined gas pipelines. The cost of gas pipelines decreases as storage pressure increases due to volumetric flow change. Table 22 represents the pipeline diameters for the three different storage options.

It is evident from Table 23 that as the cavern storage pressure increases; the cost of above ground facilities also increases. These notable increases in cost associated with high pressure storage are a combination of the cost of the compressor, cost of expansion turbine, and cost of the heater requirement before gas expansion to avoid condensation after the expansion turbine.

Table 23 also shows that capital cost for combined storage is lower than for individual storage in all cases. From this analysis, it is clear that combined storage is a more cost effective option as it only requires a single set of above ground equipment.

**Table 23 - Capital Costs Estimate - Summary of Onshore Salt Cavern Above Ground Facilities for Individual and Combined Storage Scenarios**

| | Cavern Storage Pressure 45 bara | | Cavern Storage Pressure 105 bara | | Cavern Storage Pressure 270 bara | |
|---|---|---|---|---|---|---|
| **DESCRIPTION** | **Individual Storage Scenario** | **Combined Storage scenario** | **Individual Storage Scenario** | **Combined Storage scenario** | **Individual Storage Scenario** | **Combined Storage scenario** |
| | Million GBP | Million GBP | Million GBP | Million GBP | Million GBP | Million GBP |
| MAJOR EQUIPMENT | 32.7 | 31.1 | 47.8 | 45.6 | 76.9 | 70.1 |
| DIRECT BULK MATERIALS | 11.7 | 11.1 | 20.3 | 19.1 | 37.5 | 33.6 |
| DIRECT MATERIAL & LABOUR CONTRACTS | 42.0 | 37.6 | 42.8 | 37.4 | 62.5 | 54.9 |
| LABOUR ONLY CONTRACTS | 10.7 | 10.3 | 19.0 | 18.0 | 35.7 | 32.2 |
| INDIRECTS | 2.7 | 2.5 | 4.0 | 3.9 | 6.7 | 6.1 |
| EPC CONTRACTS | 5.6 | 4.4 | 8.0 | 6.2 | 12.0 | 9.0 |
| **INSTALLED COST** | **105.4** | **97.1** | **142.0** | **130.2** | **231.2** | **205.9** |
| LAND COSTS (5%) | 5.3 | 4.9 | 7.1 | 6.5 | 11.6 | 10.3 |
| OWNERS COSTS (10%) | 10.5 | 9.7 | 14.2 | 13.0 | 23.1 | 20.6 |
| CONTINGENCY (25%) | 26.4 | 24.3 | 35.5 | 32.5 | 57.8 | 51.5 |
| **TOTAL PROJECT COST** | **147.6** | **136.0** | **198.8** | **182.2** | **323.7** | **288.3** |

### 4.9.4 Capital Cost Estimating Basis

Estimates contained within this study report are based on the technical definition for each of the benchmark cases considered. The estimate methodology is largely based on in-house data or sourced quotations from previous projects of a similar nature.

For all of the cases reported, the source estimate data has been adjusted to provide consistent figures which are comparable on a Q1 2010 UK basis.

Capital cost estimates prepared using this methodology and associated qualifications/exclusions are normally considered to have an accuracy of +/-40% at best. This accuracy is considered on the overall project cost (not individual lines items on the summary).

Estimate Basis

Estimates are produced using the Aspentech Capital Cost Estimator (ACCE) estimating program indexed to reflect Foster Wheeler's experience of market conditions.

Currency

The estimates are reported in GB Pounds (GB£).

When in-house data is available in a different currency, the following currency conversion rates have been used for conversion:

GB£ 1.00 = US$ 1.52

GB£ 1.00 = EUR 1.12

Escalation

The estimates have been escalated to the date of the reference project (1Q 2010), based on Foster Wheeler experience. No allowance has been made for future escalation.

Major Equipment

The majority of equipment item costs have been generated using the Aspentech Capital Cost Estimator estimating program, indexed to reflect Foster Wheeler's experience of market conditions.

For some specialist major equipment items not covered by the ACCE database (such as the Dryers), costs have been based on in-house data and budget prices from suppliers or licensors. The cost of the Dryer unit downstream of cavern is based on a budget quote from a similar project and adjusted to reflect the required capacity used in each Case.

Direct Materials

The estimated material costs reflect worldwide procurement, therefore no allowance for possible savings by local purchasing of direct materials and associated reductions in shipping costs have been made.

Bulk Materials

Bulk material costs have been factored from the major equipment costs using TIC factors derived from similar equipment used in previous projects. Costs take account for above ground Piping, Instrumentation and Electrical components.

No allowance is included for pipe bridges or other similar crossings.

Spare Parts

Commissioning Spares have been estimated using historical percentage factors.

Shipping and Freight

Shipping & Freight costs have been estimated using historical percentage factors. Import duties have been excluded.

Construction Costs

These costs include Material and Labour Sub Contracts (Civils, Steelwork and Protective Cover) and Labour-only Sub Contracts, have been derived using TIC factors adjusted for a UK location.

Indirect Costs

These costs include for temporary facilities, heavy lifts, commissioning services and vendors engineers and have been factored from projects of a similar nature.

EPC Contracts

These costs include for home office engineering and procurement and construction management and have been factored from projects of a similar nature.

Land / Site costs

No Site specific costs have been included. The site has been assumed to be a generic site clear and level and free from underground obstructions.

Land costs have been included (as specified by ETI) at a rate of 5% of the total installed costs for all cases.

Owner's Costs

Owner's costs have been included (as specified by ETI) at a rate of 10% of the total installed costs for all cases.

Contingency

Contingency has been included (as specified by ETI) at a rate of 25% of the total installed costs for all cases.

Exclusions

The following costs have been specifically been excluded from this estimate:

- Import duties;
- Capital / insurance spares;
- Financing;
- Royalties & process guarantees;
- Piling;
- Removal of unseen/unidentified underground obstructions;
- Operating costs; (which are covered separately)
- Statutory authority & utility company costs & permits;
- Currency fluctuations;
- PMC costs;
- Contractors all risk insurance;
- Taxes;
- Metal pricing movements.

#### 4.9.5 Capital Cost of Cushion Gas

Depending on the frequency of gas withdrawal, cushion gas requirement may vary from 90% (fast-churn daily extraction) to 60% (seasonal withdrawal). Brine can be used to displace this gas at an additional expense for pumping and storing the brine solution (Taylor et al., 1986).

For the proposed application, dry cavern operation is assumed, as this avoids ongoing issues with gas saturation and salt contamination that occur when operating under brine displacement mode.

An additional expense for underground storage facilities is the cost of the cushion gas which remains inside the cavern facility when the storage system is at the end of its discharge cycle. Before operation of the cavern, the syngas production plant must operate for a certain period of time in order to charge the cavern with the required volume of cushion gas.

The cost of producing the cushion gas includes the cost of operating the syngas production plant and the cost of operating the above ground facility for that period of time, including any required electricity import requirements.

As discussed in Section 4.7, the percentage of cushion gas in the cavern will depend on the proposed operating regime, as there is a limitation of 10% withdrawal of working gas/day. Table 24 summarises the capital cost associated with production of cushion gas with for different operating regimes in the 105 bara storage pressure case.

**Table 24 - Costs of Cushion Gas for Hydrogen Rich Syngas Storage (105 bara)**

| Operating Mode | Syngas plant capacity, kg/h of $H_2$ rich fuel gas | % of Cushion gas | Cushion gas volume ($Am^3$) | Hours syngas plant running for cushion gas production | Cost of cushion gas production, Million £ |
|---|---|---|---|---|---|
| Reference Case (GT 100% 24 hrs) | 72,000 | - | - | - | - |
| Diurnal (on 18 hours) | 54,000 | 90% | 136,389 | 54 | 1.0 |
| Diurnal (on 15 hours) | 45,000 | 90% | 170,486 | 81 | 1.5 |
| Diurnal (on 12 hours) | 36,000 | 90% | 181,852 | 108 | 2.0 |
| Weekly (off weekends) | 51,429 | 67% | 230,923 | 96 | 1.8 |
| Seasonal (off 4 months) | 48,000 | 60% | 9,833,489 | 4,380 | 83.0 |
| Seasonal (off 6 months) | 36,000 | 60% | 11,062,675 | 6,570 | 124.6 |

As shown in the table, cushion gas capital cost is significantly higher for the seasonal operating scenario because of the large number of caverns. This is seen to be a significant barrier to seasonal storage projects storing syngas.

For the other two pressure cases, the cost of running the syngas production plant will be same as for the 105 barg case, but the cost of running the above ground facility will be different. Table 25 summarises the cost of cushion gas production for three different storage pressure scenarios.

**Table 25 - Costs of Cushion Gas for Hydrogen Rich Syngas Storage for different storage pressure scenarios**

| Operating Mode | Cost of cushion gas production for 45 bara cavern, Million £ | Cost of cushion gas production for 105 bara cavern, Million £ | Cost of cushion gas production for 270 bara cavern, Million £ |
|---|---|---|---|
| Reference Case (GT 100% 24 hrs) | - | - | - |
| Diurnal (on 18 hours) | 0.8 | 1.0 | 1.2 |
| Diurnal (on 15 hours) | 1.2 | 1.5 | 1.9 |
| Diurnal (on 12 hours) | 1.6 | 2.0 | 2.5 |
| Weekly (off weekends) | 1.4 | 1.8 | 2.2 |
| Seasonal (off 4 months) | 65.9 | 83.0 | 101.0 |
| Seasonal (off 6 months) | 98.9 | 124.6 | 151.6 |

### *4.10* Capital Cost of Offshore Salt Cavern Storage Facilities

In addition to the three aspects of capital cost which apply to onshore projects as described in Section 4.9, there will be additional factors related to offshore drilling and installation of a permanent offshore structure to hold the injection facility that will increase the cost of an offshore project:

- Cost of hiring a Jack-up drilling rig to drill into the salt formation. The drilling rig will be very similar to those used to drill oil and gas wells;
- Cost of hiring the specialist drilling equipment;
- CAPEX associated with development/construction of the cavern offshore;
- CAPEX for a permanent offshore structure (4 legged tower 'Jacket' structure) similar in design to a small oil and gas platform.
- CAPEX associated with the above ground facilities and offshore topsides to compress and condition the gas before injection into the cavern; and expand and condition the gas after withdrawal from the cavern.
- Cost of cushion gas required to maintain the minimum cavern pressure.

#### 4.10.1 Costs of hiring a Jack-up drilling rig

For each cavern site, a well needs to be drilled into the salt formation. The wells will be drilled from a jack-up drilling rig similar to those used to drill oil and gas wells. Each well drilled as part of the proposed Gateway project is expected to take approximately 15 days to complete (Gateway Gas Storage Project, 2007).

Using FW in-house information, it has been assumed that the jack-up will be of an independent legged cantilevered type, capable of operating in the exposed offshore environment of the Southern North Sea.

Using information from Rigzone (an independent company specializing in drilling operations), an average day hire rate of £87,000 per day has been assumed. Additional charges will apply for mobilisation and demobilisation which has been assumed to take 5 more days; at a cost of £435,000. The total jack-up rig hire rate for a 15 days period is estimated as £1,740,000.

#### 4.10.2 Costs of specialist drilling equipment hire

Schlumberger (an independent company specializing in offshore drilling) has provided the hiring cost of drilling equipment required to drill a well through to the salt structure. The main items that need to be hired for drilling would include the drill bit, directional drilling (DD) and BHA tools and Measurement While Drilling (MWD) and Logging While Drilling (LWD) tools. These equipments typically cost around £400,000 for 15 days hiring for offshore wells.

#### 4.10.3 Capital Cost associated with Offshore Salt Cavern Construction

As discussed in Section 4.9.1 for onshore cavern construction, the same strategy applies for offshore gas storage site selection and cavern construction. Several geological investigations will need to be carried out to provide detailed information regarding the geological structure and integrity of a proposed offshore site.

Offshore salt cavern construction cost may be characterised as follows:

- Cost associated with geological investigation (either or both 2D and 3D seismic exploration cost and cost of drilling exploration well). The cost will be higher for offshore survey as to drill an exploration well for geological investigation drilling rig will need to be hired;

- Cost of bulk material such as piping, casing, tubing, well valves, blow out preventer (BOP) etc. required to create a structured borehole from the permanent offshore 'Jacket' structure to the depth of the salt formation; and
- Cost of solution mining: pumping seawater through the tube into the cavern and extracting brine out.

The same timescale has been assumed for offshore development as onshore cavern construction. The geological investigation process is assumed to take 2 years with additional 4 years for solution mining. In the absence of detailed information specifically related to offshore construction cost, data provided in Table 17 & Table 18 have been assumed to be applicable for offshore caverns.

The geological survey cost for offshore system is assumed to be approximately double that of an onshore cavern as it requires hiring a drilling rig and specialist drilling equipment for exploration wells.

Conversely, pipeline costs associated with water intake and brine disposal will be considerably reduced for offshore cavern construction as seawater can be used for solution mining and brine will be disposed in the sea. Based on the brine pipeline cost data in Attachment 2, a nominal cost of £1m is allowed for seawater intake and brine disposal pipework.

Table 6 in section 4.6.2 describes the salt cavern location parameters for our offshore scenario. Based on the cost data given in Table 20 & Table 21, the construction cost for an onshore salt cavern of 300,000 $m^3$ storage volume at a depth of 680 m will be £13.1 million.

Table 26 summarises the estimated total cost of constructing an offshore cavern.

**Table 26 - Total Cost of Construction for a 300,000 $m^3$ Offshore Salt Cavern at 680 m depth**

| | **Million GBP** |
|---|---|
| Jack-up drilling rig hiring cost | 1.7 |
| Specialist drilling equipment hiring cost | 0.4 |
| Geological survey cost | 6 |
| 1 x Cavern construction cost | 13.1 |
| Seawater /Brine pipeline cost (1 km) | 1.0 |
| **Total cost** | **22** |

Note 1: The onshore cavern construction cost variation with cavern storage volume and depth is listed in Table 20 & Table 21 and are assumed to be applicable for offshore cost scaling.

### 4.10.4 Costs of a 4 Legged Tower 'Jacket' Structure for Topside Equipment

As discussed, the topside equipments will be installed on a 4 legged tower 'Jacket' structure. This will have a dual role; initially to house the cavern leaching equipment, and then on cavern completion, to house the cavern gas well head and associated equipments. From Foster Wheeler in-house data, an estimated cost associated with the structure is presented in Table 27.

**Table 27 - Total Cost of a 4 Legged Tower 'Jacket' Structure**

| | **Million GBP** |
|---|---|
| Engineering cost | 2 |
| Fabrication cost | 12 |
| Installation cost | 5 |
| **Total cost** | **19** |

Engineering costs for this structure includes FEED and Detailed Design. Fabrication Costs is heavily dependent on fabrication location, yard capabilities and steel prices at time of construction. Installation costs are based on mobilisation from Northern European ports.

4.10.5 Capital Costs of Above Ground Facilities and Offshore Topside Equipment

The full list of above ground and topside equipment for offshore project is shown in Figure 6.

The major equipment items contributing to the cost of the above ground / topside facilities are described in Section 4.8, including:

- compressor (to pressurise gas up to cavern storage pressure);
- expansion turbine (to recover power from decompression of the stored gas);
- dehydration unit (to remove moisture on withdrawal and avoid condensation in the pipeline).

For the offshore scenario, it has been assumed that the syngas plant and Power Island will be 10km from the shore, and the storage caverns will be a further 25km offshore.

Therefore for Case 1, Case 2 and Case 3, 1x10 km carbon steel subterranean onshore pipeline and 1x25 km offshore pipeline will be required for each case to link the syngas production plant and topside facility offshore. A further 35 km of pipeline is also required to transfer the combined gas from the salt cavern site to Power Island (Case 4-outlet).

The pipeline diameter is calculated for each storage scenario maintaining the gas velocity within a limit of 10 m/s in the pipeline to avoid corrosion/erosion issues and such that the overall pressure drop in the 10km line is below 15 bar. The pipeline diameter is calculated as 16 inches for Case 1, 22 inch for Case 2 and 30 inch for Case 3 and Case 4-outlet.

Order of magnitude capital cost estimates for the offshore pipeline of 25 km long are summarised in Attachment 7.

The inclusions to the offshore pipeline cost estimation are as follows:

- Pipeline material cost
- Corrosion coating
- Weight coating
- Pig launcher / receiver
- Spools, flanges, fittings
- Freight
- Pipe lay Vessel / barge costs - pipe laying, Diving spread etc.

- Pipe supply vessel
- Routing surveys
- Pre-lay survey
- Trenching spread
- Near shore survey
- Testing and pre-commissioning
- Engineering

As discussed earlier, the offshore storage scenario is based on a East Irish Sea location with a storage pressure of 105 bara, and should be directly comparable with the onshore Cheshire scenario. The cases referred to below match those described for the onshore scenarios in Section 4.9.3.

Capital Cost Summaries for 4 cases operating with 105 bar storage pressure are provided in Attachment 8, Above Ground & Topsides Facilities Capital Cost Summaries Offshore. The cases are:

- Case 1 – $H_2$ rich syngas inflow;
- Case 2 – Nitrogen inflow;
- Case 3 – Combined syngas and nitrogen inflow;
- Case 4 – Gas outflow.

The Cost Estimating Basis used in development of these cases in given in section 4.9.4.

The overall topsides capital cost for two design scenarios is summarised in Table 28:

1. Individual Storage Scenario: Case 1 + Case 2 + Case 4; and
2. Combined Storage Scenario: Case 3 + Case 4.

It is evident from Table 28 that the cost of combined offshore storage is approximately 19% lower than individual storage option.

It is also clear that total cost of topside, transfer pipelines and above ground facility is approximately 2.7 times higher for the combined offshore storage scenario compared to onshore storage at same pressure. The significant cost increase is primarily due to the 25 km offshore transfer pipeline and larger diameter onshore pipeline. The distance of salt cavern site from shore and hence the offshore pipeline length has major impact on the offshore project cost compared to its onshore option.

**Table 28 - Capital Costs Estimate Summary of Above Ground Facilities for Individual and Combined Storage Scenario**

| | Onshore Cavern Storage Pressure 105 bara | | Offshore Salt Cavern Storage Pressure 105 bara | |
|---|---|---|---|---|
| **DESCRIPTION** | **Individual Storage Scenario** | **Combined Storage scenario** | **Individual Storage Scenario** | **Combined Storage scenario** |
| | Million GBP | Million GBP | Million GBP | Million GBP |
| MAJOR EQUIPMENT | 47.8 | 45.6 | 47.8 | 45.6 |
| DIRECT BULK MATERIALS | 20.3 | 19.1 | 20.3 | 19.1 |
| DIRECT MATERIAL & LABOUR CONTRACTS | 42.8 | 37.4 | 335.1 | 258.0 |
| LABOUR ONLY CONTRACTS | 19.0 | 18.0 | 19.0 | 18.0 |
| INDIRECTS | 4.0 | 3.9 | 4.0 | 3.9 |
| EPC CONTRACTS | 8.0 | 6.2 | 8.0 | 6.2 |
| **TOTAL INSTALLED COST** | **142.0** | **130.2** | **434.3** | **350.8** |
| LAND COSTS (5%) | 7.1 | 6.5 | 21.7 | 17.5 |
| OWNERS COSTS (10%) | 14.2 | 13.0 | 43.4 | 35.1 |
| CONTINGENCY (25%) | 35.5 | 32.5 | 108.6 | 87.7 |
| **TOTAL PROJECT COST** | **198.8** | **182.2** | **608.0** | **491.1** |

4.10.6 Capital Costs of Cushion Gas

Capital cost for cushion gas will remain same for both onshore and offshore storage cases provided both at same storage pressure and operating at same operational mode. Table 24 summarises the capital cost associated with cushion gas for different operational modes for a storage pressure of 105 bara.

## *4.11* Summary Comparison of Capital Costs of Storage Facilities for Onshore and Offshore Cavern Locations

In Sections 4.9 and 4.10, the costs of constructing a single salt cavern in three different onshore locations (Teesside region, Cheshire Basin and East Yorkshire) and one offshore location (East Irish Sea Basin) have been estimated. The halite bed depth and thickness will govern the salt cavern depth and size, and hence the operating pressure and number of storage caverns required for a project with a known capacity in any one of these locations.

A comparison of individual storage scenarios vs storage of combined gas showed that the additional above ground equipment requirements and separate pipelines for transporting gas between the syngas plant, store and Power Island gave rise to additional costs for separate storage, with no real benefits envisaged. As such it is considered that combined storage options would be preferred.

Table 8 to Table 16 summarise the number of caverns required for a single gas turbine operating on full load under different operational regimes (diurnal, weekly, seasonal, etc) for different storage pressures. It is evident from those tables that seasonal storage options give rise to excessive cavern numbers, so it is considered that weekly operating regime offers the best flexibility without entailing excessive cost.

Table 29 summarises the salt cavern location parameters and costs for a project supplying a single gas turbine operating on full load (GE Frame 9FA with 308MWe nominal output) under a weekly operating regime using combined gas storage for three onshore locations and one offshore storage location.

**Table 29 - Salt Cavern Location Parameters and Costs**

| | | Onshore | | | Offshore |
|---|---|---|---|---|---|
| | | **Teesside** | **Cheshire Basin** | **East Yorkshire** | **East Irish Sea** |
| Salt Cavern storage size | $m^3$ | 70,000 | 300,000 | 300,000 | 300,000 |
| Salt cavern depth | m | 370 | 680 | 1800 | 680 |
| Salt cavern operating pressure | bara | 45 | 105 | 270 | 105 |
| Number of cavern required (weekly operational mode, combined gas storage) | | 21 | 3 | 1 | 3 |
| Water/Brine pipeline length | km | 5 | 61 | 5 | 1 |
| **Costs** | | | | | |
| Jack-up drilling rig hiring cost | MM GB£ | - | - | - | 5.2 |
| Specialist drilling equipment hiring cost | MM GB£ | - | - | - | 1.2 |
| Geological Survey cost | MM GB£ | 3.0 | 3.0 | 3.0 | 6.0 |
| Salt Cavern Construction Cost | MM GB£ | 128.5 | 39.3 | 26.8 | 39.3 |
| Water pipeline cost | MM GB£ | 2.7 | 33.2 | 2.7 | 0.5 |
| Brine pipeline cost | MM GB£ | 2.7 | 33.2 | 2.7 | 0.5 |
| Costs of a 4 legged tower 'Jacket' structure | MM GB£ | - | - | - | 18.8 |
| Installed Cost of Topside and above ground facility | MM GB£ | 97.1 | 130.2 | 205.9 | 350.8 |
| Land Costs (5%) | MM GB£ | 11.7 | 11.9 | 12.1 | 20.8 |
| Owners Costs (10%) | MM GB£ | 23.4 | 23.9 | 24.1 | 41.6 |
| Contingency (25%) | MM GB£ | 58.5 | 59.7 | 60.3 | 104.0 |
| Cost of production of Cushion gas | MM GB£ | 1.4 | 1.8 | 2.2 | 1.8 |
| **Total Project Cost** | **MM GB£** | **329.0** | **336.4** | **339.9** | **590.5** |
| **Cost per MW** | **MM GB£ per MWe** | **1.07** | **1.09** | **1.10** | **1.92** |

It can be summarised from Table 29 that the total project cost of salt cavern development to supply hydrogen rich gas to one gas turbine operating on full load is comparable for three different site considered. Although the project costs are comparable, the number of caverns required is significantly higher for Teesside, which will require a large area of land to be available for development, and will bring complication in integration and networking between caverns.

The total project cost for the offshore cavern is significantly higher than onshore option, which makes the option less attractive.

It is worth noting that these costs are sensitive to pipeline assumptions which will be highly location specific. An additional opportunity would present itself if the syngas production plant could be co-located with the power island, allowing integration of these two plant items, and if combined gas was being stored, only a single pipeline between the plant and store would be necessary, as it could operate in a push/pull mode.

BGS has reported costs of construction of salt cavern for different existing projects. Estimated cost of construction of 9 salt caverns at Aldbrough, East Yorkshire is reported as £290m (£32m per cavern) whereas estimated cost of construction of 24 offshore salt caverns developed by Gateway project is reported as £600m (£25m per cavern). Cost breakdown of such projects are not available and hence it is difficult to compare the cost directly with the East Yorkshire and East Irish Sea development project costs reported in Table 29. However, on the assumption that the published data for existing projects only considers cavern construction cost, these costs are broadly consistent with the data in Table 29, which yields a per cavern cost range (excluding topsides) of £30m-£50m. The published data are for projects involving a larger number of caverns so economies of scale would be expected to reduce the per cavern cost somewhat.

## *4.12* Operating Costs for Salt Cavern Facilities

Operating costs for underground hydrogen storage are limited to energy and costs related to compressing the gas for storage and subsequent expansion for Gas Turbine operation, together with maintenance costs.

O&M costs are generally allocated as variable and fixed costs.

### 4.12.1 Variable costs

Variable costs include the consumption of solvents and fuel (natural gas) for heating. These costs are annual, based on the expected equivalent availability of the plant. Variable costs mainly include the following:

- Fuel (natural gas);
- Solvent consumption for drying; and
- Waste disposal.

The cost of natural gas has been specified by the ETI for this project as $6.6/MMBTU (1.5p/kWh).

In the absence of detailed technical data of package equipment, costs for solvent and waste disposal processes have been estimated as 0.5% of the total major equipment cost.

<u>Utility Costs</u>

The largest operating cost for above-ground gas storage is the energy required to compress the hydrogen. The exact energy requirements will depend on the final pressure, but because compression work applied is an exponential function of pressure, a high final storage pressure requires minimal power compared to the initial compression of the gas.

The efficiency of the compressor will also affect the economics. Small compressors may have efficiencies as low as 40% - 50%, however larger alternating, double-action compressors may have efficiencies in the 65% - 70% range (Zittel & Wurster, 1996; Cuoco et al., 1995). The energy required to compress hydrogen from 1 to 150 - 200 bara can be 8%-10% of the energy content of the hydrogen (Cuoco et al., 1995).

Utility costs for hydrogen storage consist of electricity (and cooling) for all processes shown in Figure 5. The utilities requirements are summarised in Attachment 9 for each of the locations. In order to calculate the operating cost of these utilities, a price for electricity imported / exported electricity must be assumed. This is the subject of the economic modelling calculations within WP4. As such, the operating costs shown below do not include the utility cost (electricity and water import costs) for operating the above ground facilities.

4.12.2 Fixed costs

Fixed costs mainly include the following:

- Direct labour;
- Administrative and general overheads; and
- Maintenance.

Direct Labour

The yearly cost of direct labour has been calculated assuming, for each individual, an average cost equal to £50,000 / year is applicable. Table 30 shows the number of personnel required for operation of the underground storage facility (including above ground facilities). This is applicable to both the individual storage scenario and the combined storage scenario.

**Table 30 - Personnel Basis for Underground Storage**

| Operation | Total | Notes |
|---|---|---|
| Area Responsible | 1 | daily position |
| Assistant Area Responsible | 1 | daily position |
| Electrical Assistant | 1 | 1 shift position |
| Shift Supervisor | 4 | 1 shift position |
| Control Room Operator | 4 | 2 shift position |
| Field Operator | 4 | 2 shift position |
| **Subtotal** | **15** | |
| **Maintenance** | | |
| Mechanical group | 1 | daily position |
| Instrument group | 1 | daily position |
| Electrical group | 1 | daily position |
| **Subtotal** | **3** | |
| **Laboratory** | | |
| Superintendent + Analysts | 1 | daily position |
| **Total** | **19** | |

Administrative and General Overheads

These costs include all other Company services not directly involved in the operation of the Complex, including:

- Management;
- Personnel services;
- Technical services; and
- Clerical staff.

These services vary widely from company to company and are dependent on the type and complexity of the operation.

Based on an EPRI study, Technical Assessment Guide for the Power Industry, an amount equal to 30% of the direct labour cost has been considered for this purpose.

Maintenance

A precise evaluation of the cost of maintenance would require an in-depth breakdown of the numerous items of equipment and packages contained in the complex. Since these costs are all strongly dependent on the type of equipment selected and statistical maintenance data provided by the selected supplier, this type of maintenance cost evaluation is premature at this stage.

A portion of these maintenance costs will be associated with regular sonar surveys and mechanical integrity testing to ensure the structural integrity of the storage site.

The shape and extent of the cavern should be monitored using sonar, at intervals of at least every 5 years. BGS have advised that a typical cavern sonar surveys cost is in the region of £9000 per cavern, and there will be a small mobilization/demob charge.

BGS has also provided the cost of borehole mechanical integrity tests which will be required every 10-20 years. The following breakdown applies to three in situ borehole mechanical integrity tests:

- Project preparation - ~ £45,000
- Mobilise/demobilise - ~ £18,000
- Field operations (tests) - ~ £170,000
- Reporting and interpretation - ~ £27,000
- Total costs for borehole pressure tests therefore ~ £270,000 for one borehole.

The annual maintenance cost of the complex has been estimated as a percentage of the installed capital cost of the facilities and major equipment cost.

Different percentage factors have been applied to the different units, based on the following criteria:

- 2.5% of the installed capital cost for gaseous and liquid handling units; and
- 10% of the major equipment cost for utilities and offsites

### 4.12.3 Operating Cost of an offshore salt cavern storage

The same logic is applied to the development of OPEX for offshore salt cavern. The main difference between the offshore and onshore operating cost for a similar storage pressure cavern is the maintenance cost related to topside equipments on an unmanned permanent structure. Different percentage factors have been applied to determine the maintenance cost of the topside and onshore injection facilities as follows:

- 5% of the installed capital cost for gaseous and liquid handling units; and
- 10% of the major equipment cost for utilities and offsites.

### 4.12.4 Summary of Operating Cost Estimates

Table 31 summarises the operating costs for a project with a single gas turbine operating on full load (GE Frame 9FA with 308MWe nominal output) under a weekly operating regime using combined gas storage.

The data shows that the operating costs are dominated by the maintenance cost and the cost for individual storage is higher than combined storage option. It also shows that operating costs for offshore projects are approximately double that of a comparative onshore project.

**Table 31 - Operating Cost Estimate Summary**

| Million UK£ p.a | Onshore Cavern Storage Pressure 45 bara | | Onshore Cavern Storage Pressure 105 bara | | Onshore Cavern Storage Pressure 270 bara | | Offshore Cavern Storage Pressure 105 bara | |
|---|---|---|---|---|---|---|---|---|
| | Separate Storage | Combined Storage | Separate Storage | Combined Storage | Separate Storage | Combined Storage | Separate Storage | Combined Storage |
| **Fixed Costs** | | | | | | | | |
| Direct Labour | 0.95 | 0.95 | 0.95 | 0.95 | 0.95 | 0.95 | 0.95 | 0.95 |
| Administration / General Overheads | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 | 0.29 |
| Maintenance | 5.91 | 5.55 | 8.33 | 7.81 | 13.48 | 12.17 | 26.50 | 22.11 |
| Insurance & Local Taxes Allowance | 2.76 | 2.57 | 3.79 | 3.51 | 6.17 | 5.52 | 9.64 | 7.93 |
| **Total Fixed Costs** | **9.9** | **9.3** | **13.4** | **12.6** | **20.9** | **18.9** | **37.4** | **31.3** |
| **Variable Costs** | | | | | | | | |
| Fuel (Natural Gas) | 0.53 | 0.56 | 0.53 | 0.56 | 0.53 | 0.56 | 0.53 | 0.56 |
| Solvent and Chemicals | 0.16 | 0.16 | 0.24 | 0.23 | 0.39 | 0.35 | 0.24 | 0.23 |
| Waste Disposal | 0.16 | 0.16 | 0.24 | 0.23 | 0.39 | 0.35 | 0.24 | 0.23 |
| **Total Variable Costs** | **0.86** | **0.87** | **1.01** | **1.02** | **1.30** | **1.26** | **1.01** | **1.02** |
| **TOTAL OPERATING COSTS** | **10.8** | **10.2** | **14.4** | **13.6** | **22.2** | **20.2** | **38.4** | **32.3** |
| **£/MWhr** | **4.0** | **3.8** | **5.3** | **5.0** | **8.2** | **7.5** | **14.2** | **12.0** |

The above operating costs do not include the utility cost (electricity and water import costs) for operating the above ground facilities, as these will depend on the assumed price of electricity import/export. The utilities requirements are summarised in Attachment 9 for each of the locations.

# 5. HSE CHALLENGES OF CAVERN CONSTRUCTION AND OPERATION

## 5.1 Objective

The objective of this section is to review the key HSE challenges of cavern construction and operation, including:

- water sources;
- brine transport and/or disposal; and
- well integrity and cavern testing;

and explore measures necessary to mitigate such challenges.

## 5.2 Water Sources

The construction of an underground storage cavern requires the sustained application of the solution mining process over a number of years (as discussed in previous sections) and thus, a large quantity of injection water is required for leaching of the subterranean halite formation being developed.

The mechanism of leaching involves the near full salt saturation of un-saturated injected water, resulting in the production of brine, which is then removed from the cavern. The salt saturation level of the injection water limits the effectiveness of the process, so fresh water is preferred in order to maximise efficiency and minimise water usage. However, limitations such as location and availability of fresh water reserves often results in fresh water being unavailable for leaching. Partially saturated water obtained from saline sources (e.g. the sea, saline aquifers) can be used (often, saline water is not fully saturated), although a larger volume of water is required to achieve a similar level of leaching as with fresh water. For these reasons, land-locked locations, such as the King Street gas storage development in Cheshire, will incur significant costs from installation of pipelines to/from the sea.

The source of injection water will vary depending on location associated and environmental factors, but can include fresh/saline aquifers, lakes, rivers, estuaries, reservoirs and the sea. In order to use water from any of these sources in the UK, it is first necessary to obtain a water abstraction licence from the Environmental Agency. The following key points should be noted in terms of abstraction licences (Environment Agency, 2013):

- A licensing system is in place to ensure that the following impacts of persistent over-abstraction of watercourses do not come to pass. Licensing acts to control the level of abstraction and therefore protects both water supplies and the environment from:
  - Shortages in water supply;
  - Increased river pollution due to reduced dilution of pollutants;
  - Damage to fisheries and wildlife habitats; and
  - Loss of rivers for recreation and enjoyment.
- If a proposed application plans to abstract or impound more than 20 $m^3$/day water from a surface or underground source (such as a river, stream, reservoir, lake, pond, canal, spring, borehole, dock, channel, creek, bay, estuary or arm of the sea), then an abstraction licence is required.

- Applications are made to the Environment Agency, require substantial supporting evidence and can take months, but if successful result in the allocation of a certain volume of water from the source for the proposed application. An annual cost is usually associated with this.
- Water may not always be available and depends largely on the Catchment Abstraction Management Strategy (CAMS) for the proposed area, which describes the availability of water for abstraction. It may be that no more water is available for abstraction in the proposed area and in this case other alternatives should be considered.
- Variations in available source water often occur due to weather and seasonal changes. Therefore, most abstraction licenses now contain conditions where the license holder has to reduce or stop taking water once the river has dropped to a certain level or flow. These are known as Hands off Flow (HoF) conditions and protect other river users and the environment.

As such, it is essential to consider and manage the risks and potential delays in the project schedule brought about by a lengthy abstraction licence application process, and/or temporary HoF conditions during leaching operations.

## *5.3* Brine Transport and Disposal

### 5.3.1 Examples of Brine Usage and Disposal

During the construction phase of a salt cavern, a large amount of un-saturated 'leaching' water is required during the solution mining process as described above. Consequently, a large amount of saturated brine (containing up to 30% salt) is produced, which upon removal from the cavern itself, requires disposal. Table 32 (from BGS report, section 5.1) outlines the method of brine use or disposal adopted during the construction of a number of caverns dating from 1959 up to the present day.

As can be seen, brine produced from a number of caverns including those at Teesside, Holford, and Hole House has historically been used as a feedstock for local chemical plant applications. Unfortunately, following these applications, a dramatic fall in demand for salt in the chemicals industry occurred, resulting in the oversupply of the UK brine market. As salt is a very low value, high bulk commodity, no economic incentive exists for overseas export of brine to foreign markets, therefore one of the few options left to salt cavern developers is to dispose of the brine to sea.

Brine from the developments of Hornsea and Aldbrough (Phase I) has for many years been discharged to the North Sea, via the use of subsea brine diffuser structures and indeed most planned and current developments have proposed sea water discharges.

This is often an unnecessary inconvenience for cavern developers and tends to complicate matters, especially for land-locked locations such as King Street in Cheshire. In this case, the lack of a local market for brine has forced developers to propose the construction of a 61 km-long dual brine and seawater pipeline from Cheshire to the Mersey Estuary. This type of structure is expensive, although is in this case unavoidable.

In addition, in these areas where there has traditionally been a brine industry, there is often local concern that a natural mineral resource is being disposed of without realising its inherent value. This has been a feature of planning applications, where a balance needs to be reached between security of energy supplies and salt value.

**Table 32 - Brine use in Operational or Proposed Salt Cavern Storage Facilities in England (from BGS Report, Section 5.1)**

| Facility | Development stage | Actual use or proposed method of brine disposal |
|---|---|---|
| Saltholme, Teesside | Operational since c. 1959 | Brine used at site |
| Hornsea, E Yorks | Operational (since 1979) | Discharged to North Sea |
| Holford H165 | Operational since 1984 | Gas storage cavern created by ICI within Holford Brinefield, with brine having been used in the chemical industry |
| Aldbrough – phase I, E Yorks | Fully operational 2012 | Discharged to North Sea |
| Holford (Byley), Cheshire | Operational February 2013 | Supplied to Ineos Enterprises Ltd at Holford Brinefield |
| Hole House, Cheshire | Fully operational from end 2008 | Supplied to British Salt at Warmingham Brinefield |
| Hill Top, Cheshire | First caverns operational early 2013 | To be supplied to British Salt at Warmingham Brinefield |
| Stublach, Cheshire | Under construction, first caverns operational end 2013 | Supplied to Ineos Enterprises Ltd at Holford Brinefield |
| Aldbrough – phase II, E Yorks | Planning approval, awaiting FID | Discharged to North Sea |
| Parkfield Farm, Cheshire | Planning Approval granted | To be supplied to British Salt at Warmingham Brinefield |
| King Street, Cheshire | Planning approval, awaiting FID | To be transported by pipeline and discharged to East Irish Sea via the Mersey Estuary |
| Whitehill, E Yorks | Planning approval, awaiting FID | Discharged to North Sea |
| Preesall, Lancashire | Awaiting decision by Secretary of State following IPC recommendation | Discharged to Irish Sea |
| Isle of Portland, Wessex | Planning approval, awaiting FID | Discharged to English Channel |
| Gateway Storage, East Irish Sea | Planning approval, awaiting FID | Discharged to Irish Sea |
| Islandmagee, Larne, Northern Ireland | Planning approval, awaiting FID | Discharged to Irish Sea |

### 5.3.2 HSE Factors

Discharge of brine from solution mining activities to sea has the potential to adversely impact marine ecology. In this regard, it is imperative that developers comply with the various relevant legislation requirements associated with brine emissions to sea. (Refer also to BGS report, section 5.2.1).

In summary, developers are required to:

- Only consider discharge of brine to an underground reservoir or to sea as a last resort, where there is no chance of commercial re-use;
- Conduct bed surveys and wildlife habitat/marine surveys in order to analyse the impact to marine ecology;
- Model the saline discharge plume to demonstrate an effective dispersal pattern. Local knowledge of water behaviour such as tidal effects as well as worst case scenario cases (including spring and neap tides) should be considered in order to provide evidence as to how quickly brine concentration drops to that of background sea water levels;

- Demonstrate that the discharged brine does not contain harmful levels of various toxic chemical species that may be present in halite beds; and
- Demonstrate the use of best available techniques for pollution prevention (if toxic compounds are present).

In fulfilling these requirements, developers aim to obtain a sea water discharge licence, issued by the Environment Agency. A similar application process to the water abstraction licence process applies here.

## *5.4* Well Integrity and Storage Tightness

Well integrity and storage tightness is very important, both in the construction of a salt cavern and its subsequent operation. In the first instance, the cavern must be completely impervious to brine and the blanket gas; and in the second instance, to hydrogen-rich syngas and/or nitrogen (Pierre & Benoit, 2003).

Tightness is a fundamental prerequisite for any underground works where bare minimum product leakage needs to be ensured. However, air and natural gas (and by extension hydrogen and nitrogen) are not poisonous from the perspective of underground-water protection: a leakage of sufficiently diluted natural gas into underground water has minor consequences for water quality (Pierre & Benoit, 2003).

From the perspective of ground-surface protection, the most significant risk is the accumulation of flammable gas near the surface. In this situation, gases that are heavier than air are more dangerous than natural gas and syngas, but a recent accident in Hutchinson, Kansas, proved that the accumulation of gas in shallow water-bearing formations can lead to severe consequences (Pierre & Benoit, 2003).

Loss of containment issues are considered further in Section 6.

### 5.4.1 Main Factors in the Onset of Well Leakage

Three factors contribute to the problem of leakage in wells (Pierre & Benoit, 2003):

- Pressure distribution within the well;
- Geological formations; and
- Cementing workmanship and well architecture.

These factors are discussed below:

<u>Pressure Distribution within the Well</u>

The operating pressure range of a salt cavern is often quoted as a fraction of the geostatic (or lithostatic) pressure at the depth of the well. The standard density used for calculation of geostatic pressure is 2200 kg/m³, so that the geostatic pressure increases at a rate of roughly 1 bar every 4.6 metres. Hence, at a depth of 1000m, the geostatic pressure would be 215 barg.

Assuming a maximum operating pressure of 80% of geostatic pressure and with reference to Figure 8 (which shows the pressure profile for a salt cavern with its top at a depth of 1000m and its base at a depth of 1150m), three key points need to be taken into consideration during cavern operation:

1. As geostatic pressure variation with depth is greater than for any likely stored fluid, the key point for assessment of maximum operating pressure is at the casing shoe – the highest point in the cavern where the well casing is

cemented to the cavern wall. Setting the operating pressure based on the bottom of the cavern will result in excessive pressure at the casing shoe.

2. The operating pressure at the casing shoe is not the same as the operating pressure at the surface due to the pressure of the column of fluid below the surface. This has a relatively small impact with hydrogen, but a large impact with saline solution.

3. Although the key pressure is at the casing shoe, it is important to note that the well pressure above the casing shoe is significantly greater than the surrounding geostatic pressure, particularly with hydrogen, and the well casing is required to contain this pressure.

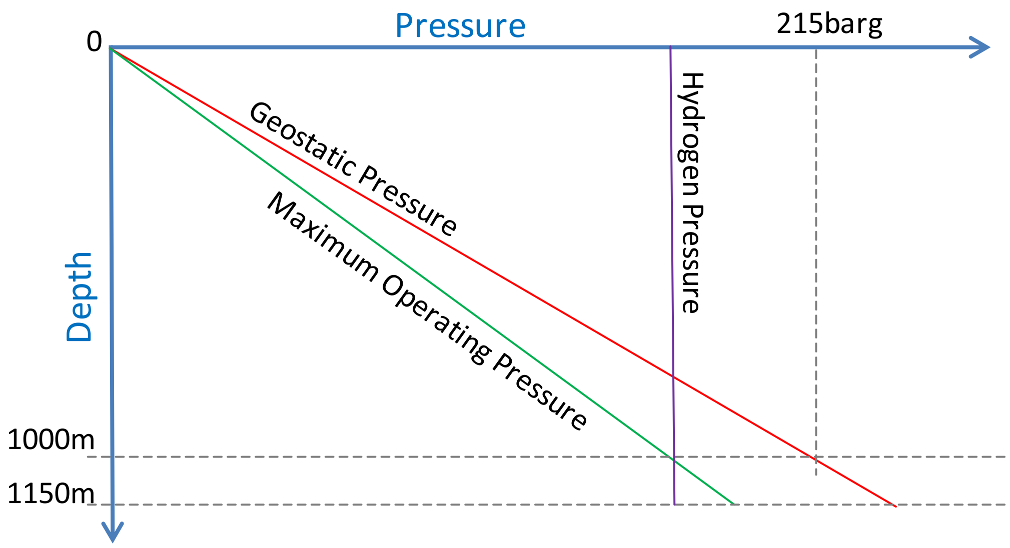



**Figure 8 - Pressure Distribution inside a Salt Cavern and Well**

<u>Geological Formations</u>

If most of the rock formations through which the well crosses are impervious, the situation is of course, extremely favourable. Salt domes are frequently surmounted by a very permeable zone (called caprock) where brine easily circulates between the pieces of rock left over from solution mining of the top of the salt dome. This situation requires special treatment. In contrast, soft-impervious formations can have a very favourable effect in that they naturally creep and tend to tighten around the well, improving the bond between the cement and the casing.

<u>Cementing Workmanship and Well Architecture</u>

Cementing in oil and gas wells is a “rough and ready” operation, but underground storage engineers work to a higher standard than is typical for most oil-industry operations. This has led to many improvements in the techniques usually employed in oil drilling (e.g. the use of admixtures, re-cementing and leak tests).

The architecture of the well and the number and length of steel casings are generally selected with reference to the actual objectives of the drilling operations. These may be to maintain integrity of a hole through weak strata or to prevent communication between two aquifers at distinctly different pressures. Clearly, the objectives must also include leak prevention and may require a more complicated architecture to isolate a stratum that was not troublesome for the driller but which might later promote leakage through a single damaged casing.

Leakage through the wellbore has been indicated as a major risk in the storage of gas in salt caverns. Special attention must be given to the parts of the well located directly at the entrance of the salt cavern, in particular the casing shoe and its cementation. Considering the extremely low permeability of the lithologies in the immediate vicinity of the caverns (rock salt, clays etc.), leakage through the cavern walls is highly unlikely under normal operating conditions (minimal pressure change). Stress gradients in salt pillars due to different pressures inside neighbouring caverns can be prevented by maintaining a minimum distance between caverns, which is determined through modelling.

Furthermore, leakage through potential faults that may be present in the salt is not likely. Such faults will be non-permeable due to the viscoplastic behaviour of salt, and therefore will not allow fluxes between caverns or to shallower layers.

## *5.5* Cavern Testing and Surveying

In general, during pressure vessel testing, pressure is built up to a level slightly above the maximum operating pressure. Leaks are detected through visual inspection or, more accurately, through records of pressure evolution. A dramatic pressure fall is a clear sign of poor tightness. A key question concerns the allowable rate of pressure decrease; it is usually fixed according to experience rather than through a more scientific understanding of the mechanisms of pressure decrease (Pierre & Benoit, 2003).

Selecting too high a test pressure is not recommended, even if such a choice provides better confidence in cavern tightness. For example, when storing gas in an underground facility, the maximum operating pressure tends to be close to the geostatic pressure. In this case, only a small margin is left for selecting a test pressure. When a vessel is decompressed after testing, the pressure decrease rate is also a matter of concern. This rate can be high, especially when a stiff test fluid is used; however, too fast a pressure release induces large tensile stresses and pore pressure gradients, which can be damaging to the rock formation or cemented wells. A moderate post-test pressure decrease rate is therefore recommended (Pierre & Benoit, 2003).

### 5.5.1 Cavity Leak testing

After drilling has been completed, the cement and formation around the last cement casing shoe must be leak tested, before the cavern is cleared for operation, in order to verify pressure integrity and the capability of the cavern to store gas within the design limitations. Subsequent integrity testing should be carried out every 10 years or sooner.

### 5.5.2 Cavern Mechanical Integrity Testing

A Mechanical Integrity Test (MIT) is used to test cavern tightness. Two types of MIT are currently used (Pierre & Benoit, 2003):

- The Nitrogen Leak Test (NTL); and
- The Fuel-Oil Leak (FLT) Test.

The collection of precise pressure data is required, which can last several days depending upon cavern size, cavern stability and the fluid type.

The Nitrogen Leak Test (NLT) consists of lowering a nitrogen gas column into the annular space below the last cemented casing. The central string is filled with brine and a logging tool is used to measure the brine/nitrogen interface location. Two or three measurements, generally separated by a 24 hour interval, are performed; an upward movement of the interface is deemed to indicate a nitrogen leak. Pressures are measured at ground level and temperature logs are performed to allow the precise calculation of nitrogen seepage.

The Fuel-Oil Leak Test (FLT) is more popular in Europe than in the United States. It consists of lowering a fuel-oil fluid column into the annular space. During the test, attention is paid to the evolution of brine and fuel oil pressures as measured at the well head. A severe pressure-drop rate is a clear sign of poor tightness. In addition, the fuel-oil is withdrawn after the test and weighed, allowing comparison with the weight of the injected fuel-oil volume.

The FLT is generally used before the cavern is leached out; the NLT is used for full-size cavern testing.

#### 5.5.3 Acoustic Cavity Testing

Sonar calliper logs are utilised to determine the size, shape and directional growth of a cavern. Sonar logs are maintained during solution mining of a cavern and at the start of cavern life. Periodic sonar surveys should subsequently be run to provide an indication of cavern growth over time compared to design and operating criteria. Particular attention should be paid to the location and configuration of the cavern top and bottom, to reveal any upward thinning or roof falls. In addition lateral dissolution of the cavern sides should be monitored to detect any degradation of the integrity of adjacent caverns. When fully operational, a sonar survey should be carried out for each cavern every 5 years or sooner.

#### 5.5.4 Geophysical Logs

Periodic geophysical logging of the cavern may be undertaken to determine the position and thickness of the salt roof. Logs can be run to locate the cavern floor, bottom of the tubing strings, gas/brine interfaces, bottom of production casing and to determine washouts below the production casing shoe.

#### 5.5.5 Subsidence Surveys

Annual surveys at approximately the same time of year provide the most accurate data for detecting or measuring subsidence. Control surveys should be tied into a bench mark e.g. Ordnance Survey bench mark. Periodic surveys over the life of the cavern will determine if subsidence is occurring.

#### 5.5.6 Cavity Monitoring and Maintenance

The operating pressure of each cavern must be measured continuously at the wellhead or in the hole. Wellhead pressures, temperature, stock and operating status of each cavity must be monitored.

To check for gas leakage to the annulus, the annuli pressures must be measured, and any build up of pressure in the annulus safely vented. A routine inspection and maintenance schedule for surface and subsurface safety equipment must be prepared and followed. If a well repair is carried out, datum logs for the wall thickness of the production casing string and the quality of the cementation should be run.

For each selected storage cavern a cavern-specific, semi-quantitative, risk analysis should be done using all specific information available on the cavern, surrounding area and wells. Though the risk of leakage associated with gas storage in salt caverns is low, an extensive monitoring plan should be formulated to ensure the long-term stability and containment of the gas in the caverns and wells. Pressure in the well tubing, pressure and flow in the well annulus, gas level as well as brine and gas inflow and outflow should be monitored continuously to detect any breach of containment at an early stage. Additionally, the shape and extent of the cavern should be monitored using sonar, at intervals of at least every 5 years (as mentioned above) and ideally before initial gas injection and after each gas extraction. Industry standard MITs should be performed prior to the start of the storage operation to assess the integrity of the well and such integrity should be evaluated at regular intervals (every 10-20 years, as mentioned above) during the storage operation to ensure that the cavern structure is not compromised. Additionally, gas detectors should be installed, securing possibilities to monitor any gas leakage in the surrounding area. Finally, since human error is the primary cause of incidents at salt storage facilities, a robust management plan is essential that includes enough safe guards to minimize the probability of human error.

# 6. MANAGING LOSS OF CONTAINMENT

## 6.1 Objective

The objective of this section is to investigate the statistics and potential consequences of loss of containment, together with the design, construction and operating procedures required to minimise the likelihood of such loss.

BGS experience of leakage risks and land use planning for natural gas storage is included with the Health and Safety Executive/Health and Safety Laboratory and likely courses of containment and remediation.

## 6.2 Underground Gas Storage

### 6.2.1 Hydrogen Storage

As outlined in WP1, WP3 and BGS reports, hydrogen is a challenging substance to handle. It causes embrittlement of some materials; it has a high propensity to leak from the smallest of holes due to its low viscosity, very high diffusivity and high buoyancy; and has a high propensity to ignite given its wide flammability range, very low ignition temperature and spontaneous ignition properties. The consequences of a hydrogen ignition are more serious than other flammable gases; hydrogen burns rapidly in air and is more likely to detonate, which can cause a large amount of damage (the BGS report section 6.1 explores this subject in greater detail).

As such, when designing a hydrogen storage cavern, it is critical to assess whether any of the exceptional properties of hydrogen will affect construction and operational safety.

### 6.2.2 Underground Storage of Gas

Underground storage is considered to be the safest way to store large quantities of gas (Pierre & Benoit, 2003). Underground storage facilities are much better in terms of safety and environmental protection than above ground storage spheres/bullets:

- Gas stored underground is separated from the oxygen in the air (necessary for combustion) by several hundred meters of rock;
- This natural barrier protects them from fire, wilful damage and aircraft impact;
- The high storage pressures involved present no problem insofar as high pressure is the natural state of the fluids underground; and
- Underground storage is extremely economical in terms of land area (Pierre & Benoit, 2003)

BGS describe (in section 6.2 of their report) how a hydrogen storage cavern must comply with European standard EN 1918-3 “Underground storage of gas – functional recommendations for storage in solution mined salt caverns”.

A storage cavern is a pressure vessel: high pressure fluids are contained in a stiff impervious envelope and a system of valves allows the cavity to be sealed off. However, caverns differ from standard pressure vessels in two respects:

- The “container” consists of the well and the cavern proper (typically, the height of such a system is 1 km). The well is equipped with several tubes containing various fluids (brine/gas/hydrocarbons). Even a small difference in fluid density results in very different column weights. At the same depth, the gap between fluid pressures can be several MPa large. This gives rise to potential for unstable situations if the various fluids come into direct contact accidentally.

- The volume of a cavern body can be very large (up to 800,000 $m^3$). Even a small pressure drop results in a significant change in the volume of the stored product. Liquid compressibility, an often negligible notion in most above-ground vessels, plays a significant role when large underground caverns are considered.

## *6.3* Loss of Containment - Key Challenges

### 6.3.1 General

Poorly designed or operated underground storage facilities can lead to severe accidents. Much has been learned from hundreds of caverns operated for decades; case histories of accidents providing the best lessons for preventing further problems.

Problems have inevitably occurred with the use of salt caverns, ranging from undesirable cavern behaviour to disastrous explosions on the ground surface. Large volume losses (i.e. cavern closure) due to salt creep have occurred in natural gas storage caverns. Examples include the Eminence dome, U.S., with loss of 40% between 1970-72 and at Tersanne, France, with loss of 30% between 1970-80. Such losses represent costly reductions in storage capacity. Following these early problems, appropriate adjustments were made in cavern depths and minimum operating pressures, so that gas storage continues at both sites today (Pierre & Benoit, 2003).

Assessing the risk associated with the loss of containment from geological storage of gas is not straightforward as in some cases no or only limited data for frequencies or consequences are available. There are two main areas to consider:

- The geological system - which includes the salt cavern itself (i.e. reservoir rock, caprock, salt body nature and features such as thin non-halite interbeds and faults), borehole and all other associated natural structures; and
- The engineered system, which includes all man-made/engineered infrastructure within the ground (wellhead, injection/extraction casings, cement, valves, pipes etc.) as well as all man-made/engineered infrastructure used to transport and process fluids on the surface (i.e. Above ground/Topsides facilities including pipework/pipelines, valves, seals, filters, columns, compressors, expansion turbines etc.).

### 6.3.2 Key Challenges - The Geological System

Complications with the geological system tend to be associated with rupture/failure of the storage environment (i.e. salt cavern) due to wear and tear, subsidence, communication with other caverns or inadvertent intrusion through boreholes due to poor planning and site characterisation.

<u>Design Considerations</u>

In selecting sites for salt caverns, one should account for:

- 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;
- Distance to populated areas;
- Proximity to other industrial facilities;
- Current and future use of adjacent properties that may withdraw large amounts of groundwater and potentially increase subsidence rates;
- Handling of brine;
- Proximity to environmentally sensitive wetlands, streams, and drinking water aquifers;
- Proximity to salt boundary; and
- Proximity to other active or abandoned subsurface activities;
- Inter-cavern spacing (typically, free space to diameter ratio should be >2:1).

BGS report that from a geological point of view, the key considerations in terms of factors controlling and presenting challenges to the storage of hydrogen gas in salt caverns are likely to be related to:

- Permeability to gas and hydrogen mobility - relative to both the natural system (e.g. the porosity and permeability of the halite and entrained insoluble material) and man-made materials (cements, well casings etc.);
- Presence and percentage of other interbedded lithologies other than halite (rocksalt) - including other evaporites (e.g. more soluble, higher potassium salts), carbonates and both fine- and coarse-grained siliciclastics and the effect of hydrogen on rock properties and embrittlement of components;
- The strength of the rocksalt in terms of the creep rate, tensile/compressive strength and cavern stability, which will all be related to the depth - the deeper the halite beds are, the more the salt will deform and flow. This will affect storage cavern stability and determine the operational cyclical loading storage pressures and possible injection cycles and/or the interaction of hydrogen with rocks of differing composition in the cavern walls and roof areas that could cause elevated stresses leading to microcracks and fracturing to produce an increase in permeability and the potential for cavern failure and escape of hydrogen;
- Temperature of the injected gas - also important to cavern stability, as thermal shock can weaken and cause fracturing of the halite in the cavern walls/roof;
- Chemical reaction to non-salt lithologies and some more exotic salt species; and
- Depth of the halite beds and potential for salt creep leading to damage to well casings and completions.

### 6.3.3 Key Challenges - The Engineered System

The engineered system includes all man-made subterranean infrastructure as well as all above ground/topsides infrastructure associated with transporting process fluids on the surfaces, as described above. 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.

Complications in the operation of underground hydrogen storage caverns typically arise due the exceptional penetrative nature of hydrogen gas. As described in section 6.2.1, hydrogen has very low viscosity, high diffusivity, high buoyancy, causes hydrogen embrittlement of high strength steels and Ti / Al alloys, has a wide flammability range and low ignition energy. These properties of hydrogen make the use of an underground storage cavern designed for another gas such as natural gas, potentially unsuitable and even dangerous for hydrogen service. In particular, those components containing metallic materials should be assessed for resistance to hydrogen penetration:

- The completion (cavern head, production strings, safety valve); and
- The casings (last cemented casing string).

In general, such complications are mitigated via use of appropriate design codes and practices. There are several standard measures that are generally put in place to account for hydrogen service, as well as best operating practices for hydrogen plant. This being said, the engineered system is still highlighted as the most likely area to encounter a situation leading to a leakage.

### 6.3.4 Failure of Underground Storage Systems

For most gas storage facilities, minimal brine is left at the bottom of the cavern and brine movement is not managed when injecting or withdrawing gas. Gas pressure builds up when gas is injected and drops when gas is withdrawn. In the case of a wellhead failure, the entire gas volume of the cavern would be expelled. This phenomenon probably would be spread over several weeks, depending upon the initial gas pressure and head losses through the well. The eruption would be spectacular, but probably far less dangerous than an LPG eruption, because syngas and natural gas are significantly less dense than air. The gas cloud would move upward rapidly and disperse in the higher atmosphere. In some cases, the cloud could kindle at an early stage, but, if it does not, the risk of explosion would be small.

Aside from the more obvious risk of fires and explosions of hydrogen-rich syngas leaks, there is also a significant risk associated with storage of large volume of nitrogen (and/or other gas which does not contain oxygen). Nitrogen is an asphyxiant, and if it were to escape from storage in sufficient quantities, it may reduce the available oxygen content in the surrounding air enough to be fatal.

As nitrogen is a colourless, odourless gas with a density approximately the same as air, it is very difficult to detect and can also collect in pits and trenches. Accidental asphyxiation of personnel in nitrogen inerted atmospheres is often a cause of fatalities on process plants worldwide.

In the light of this, a quantitative assessment of the risks associated with a nitrogen leak should be undertaken based on failure scenarios and atmospheric dispersion modelling. If appropriate, exclusion zones should be defined and enforced to mitigate the risk of asphyxiation. Consideration should be given to the installation of permanent oxygen monitors to detect and alarm low oxygen levels and initiate an emergency response.

Previous incidents at underground fuel storage facilities suggest well complications are amongst the most likely cause of loss of containment in salt cavern storage (Evans, 2003). Such complications can include:

- Breaks/faults in the casing, joints or defective/poor quality cementing of casings, leading to leakage through new or ageing injection well completions;
- Presence of unknown wells arising from inadequate site characterisation;
- Inadequate isolation during re-entry, repair or maintenance work to cavern;
- Inconsistent or inadequate monitoring of injection wells, groundwater in overlying formations and leakage from cavern; and
- New caverns drilled in poorly characterised/investigated areas and intersecting old mines, or existing facilities.

A report published by the HSE (2008) on “Failure rates for underground Gas Storage” (Keeley, 2008) stated that the geological failure rate in underground storage (UGS) facilities is of the order of $10^{-5}$ failures per well year. The consequence of this type of failure is a slow release of stored (natural) gas with a mass flux of $10^{-6}$ to $10^{-7}$ kg/s/m$^2$. This flux is assumed to discharge over a fracture zone 100 m by 2 m in area. If this release reaches the surface as a point source it will equate to a discharge rate of the order of $10^{-4}$ kg/s. In major hazard terms this equates to a risk that can be considered negligible. The risk is dominated by a release from 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 (of natural gas) calculated to be between 240 – 550 kg/s, 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 Land use Planning (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.

#### 6.3.5 Summary of Likely Failures

The Engineered System is much more likely to develop complications leading to a failure than the Geological System.

The Geological System can experience salt creep (especially at significant depths), or other effects such as gas loss due to the presence of unknown wells etc. Correct design measures and effective cavern location selection should eliminate this; therefore the risk of leakage is considered minimal.

The Engineered System is more likely to develop complications leading to a gas leak, as it contains mechanical equipment with moving parts (valves, compressors, expansion turbines etc.), as well as pipe work, filters, columns and other man-made equipment. Due to the exceptional properties of hydrogen, leakage of hydrogen is possible. Use of appropriate design codes created specifically for hydrogen service and effective monitoring of the system should mitigate the risk of chronic and acute (catastrophic) release of hydrogen.

## *6.4* Loss of Containment - Mitigation Considerations

A number of general loss of containment mitigation considerations are outlined below. For greater detail, reference should be made to section 6.2 of the BGS report.

### 6.4.1 Halite Permeability

In order to effectively store hydrogen gas inside a void created in a halite structure, it is necessary to determine the extent of halite permeability to hydrogen gas. BGS suggest the use of cavern hydrogen diffusivity or mechanical integrity tests (MIT) to determine the gas tightness of the salt cavern structure to hydrogen.

### 6.4.2 Salt Microstructure

In order to fully predict the behaviour of the halite structure, BGS emphasise that obtaining a detailed 3D geological model is imperative, in supporting the proposal to develop a site, the design of the caverns and for the leaching programme. The model is used to pick optimum depths and thicknesses, to establish operating pressure ranges as well as permissible injection rates and cycling times to avoid fatigue on the salt and the potential for loss of cavern integrity and potential failure. Salt microstructure should also be established in order to discover its properties such as its level of deformity and re-crystallisation ability.

### 6.4.3 Cycle Loading (Operating Regime)

Historically, salt caverns have been used for applications whereby gas is charged and discharged over a lengthy period of time. This operating mode ensures that cavern pressure change remains at a manageable level (1-2 MPa/day pressure drop during discharge), thus ensuring integrity of the salt cavern structure. More recently there has been a drive toward more aggressive operating modes (so called High-Frequency Cycled Gas Storage Cavern, or HFCGSC).

Typically, high-deliverability gas storage salt caverns can be emptied in 10 days and refilled in 30 days or less. This change in operation mode means that maximum pressure-drop rates are expected to become faster. This puts more strain on the salt cavern structure itself, so care must be taken to ensure that modern caverns are designed accordingly.

### 6.4.4 Halite Bed Thickness

The BGS report explains that in the USA and Europe, halite beds regularly range up to several kilometres thick. This allows for the construction of very large salt caverns of a uniform, stable shape. UK geology unfortunately does not offer the same benefits and many salt caverns created will be in much shallower halite deposits. In some cases, in order to still produce caverns of sufficient volumes, cavern diameter is larger than cavern height. This is a more unstable design and especially with possible high cycle loading applications planned, care must be taken to ensure that cavern integrity is not compromised; resulting in loss of containment. One option could be the development of horizontal caverns, which are described in section 6.2.4 of the BGS report.

### 6.4.5 Chemical Reactions

BGS highlight that the interaction of hydrogen with chemical species present in the halite beds is another possible issue to consider. Possible chemical reactions could cause the production of toxic gas as well as the loss of hydrogen. Reactions are possible with sulphide, sulphate, carbonate, and oxide minerals that may be present in non-halite lithologies or more exotic, more soluble salts. Therefore, it is essential that the halite bed to be developed is chosen based on a fully characterised halite sample, ahead of development.

### 6.4.6 HSE LUP Assessment

The HSE currently carry out hazard based assessments for Land Use Planning (LUP) purposes in connection with gas storage sites. They consider the principle hazard of 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. The same assessment will be applied to any flammable gas storage (HSE, 2013).

### 6.4.7 Safety Distances

During installation and inspection of the above ground facility and surrounding area, calculation of safety distances is essential to ensure minimum risk to assets, operators and the environment (HSE, 2013).

In this study, hydrogen storage safety distance calculations are approached according to two different methods:

- *Level A* - This method takes into consideration the facility as a whole, based on the storage inventory and provides conservative safety distances as a result of considering consequences of the most harmful plant complication possible. The outcome of this method is generally useful in the preliminary stages of a project, when it is necessary to assess the maximum impact of the installation on the local environment, residential areas and industrial establishments etc. This method does not provide detailed information about specific incidental scenarios.
- *Level B* - Conceptually similar to the traditional Quantitative Risk Assessment approach, this method analyses in detail the main equipment, determines a specific release scenario, identifies the relative consequences and provides specific values of the safety distances. It is much more accurate, if general. Part of this approach explores jet fire impact on equipment and people. Consequence modelling can then be carried out using worst case scenario parameters, (e.g. large hole/rupture size etc.) to determine possible consequences of such a loss of containment.

For a gas pressure of 100 bara, the safety distance is calculated (using the above methods) as 100 m. Information obtained from the Teesside salt cavern storage site reports the horizontal distance between the salt cavern and the above ground facility of around 400 m.

When a multi-cavern site is developed, the caverns themselves should be constructed with reasonable clearance distances. This ensures that they operate independently and that the structural integrity of the individual caverns is maintained. Information obtained from a project operating in Southern Europe shows that the distance between cavern centre-points for a cavern size of 400,000 $m^3$ is approximately 300 m. This is larger than the separation distance of the Teesside caverns, which is approximately 110 m.

In summary, minimum safety (standoff) distances of around 300m are seen for representative natural gas storage projects. Preliminary calculations by Foster

Wheeler show minimum safety distances for hydrogen releases could be smaller than those for natural gas due to low energy density and buoyancy of hydrogen. However, a conservative approach using 300m separations is considered wise at this stage.

### 6.4.8 Codes and 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. Standards of this type 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 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; and
- 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.

A master isolation valve is required, to isolate the wellhead from the cavity in the event of an emergency or during maintenance. Major off takes 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. After the desired cavity dimensions are reached, the actual cavity shape must be confirmed and documented by a final survey.

<u>A Focus on Safety</u>

Developed facilities should consider a range of core safety features including:

- Sonar surveys of caverns to confirm shape conforms to design criteria;
- Pressure tests of caverns and wells before the gas is introduced;
- Steel well casings cemented to rocks to ensure a gas-tight seal;
- Production tubing sealed inside casings to provide double containment;
- Monitoring of space between casings and production tubes to allow for immediate detection of leaks;

- Sub-surface safety valve which shuts off the gas in the event of any surface incident; and
- Duplicate/backup critical safety control and monitoring systems to ensure safety.

Furthermore, the plant should be designed, built and operated in compliance with all Codes and Standards relating to good engineering practice. It is critical that the site development team works alongside the relevant regulatory authorities to ensure the plant meets the strict rules which govern gas storage sites including:

- *The Health and Safety Executive* **-** In the UK, the HSE's primary role and regulatory responsibilities are to ensure the safe application of design, construction, operation and decommissioning activities for salt cavern sites and to ensure appropriate emergency plans are developed;
- *COMAH (Control of Major Accident Hazards* **-** During start-up of an installation, safety is achieved through compliance with the COMAH regulation. COMAH is enforced by the HSE and the Environment Agency (EA). A pre-construction safety report (PCSR) and a pre-operational safety report (POSR) must be submitted to the HSE. The on-site emergency plan must also be issued before gas is injected in the cavern, which will be a comprehensive review of potential incidents and the control measures put in place to minimise risk to operators, assets and the environment;
- *Hazardous Substances Consent* **-** All underground caverns storing more than 15 tonnes of hydrogen must apply to the Hazardous Substance Authority (HAS) for consent;
- *Borehole Sites and Operations Regulations 1995 (BSOR)* **-** These regulations apply from the start of operation and continue until the cavern is abandoned; and
- *Pipeline Safety Regulations* **-** When hydrogen is transported in a pipeline at a pressure above 7 bar, it is classified as a major accident hazard pipeline and the regulations apply. The HSE should be notified 6 months before construction of the route and they will need to complete their review 14 days before the gas is introduced.

Many of these measures are common engineering practice and will apply as standard during the implementation of such a project.

HSE challenges associated with cavern construction and operation for hydrogen rich syngas are discussed in detail in the BGS report, section 6.

# *7.* LICENSING AND BUILD TIMELINE

## *7.1* Objective

The objective of this section is to investigate the licensing requirements and likely timeline for licensing and solution mining of the required salt cavern development.

BGS add their experience of natural gas storage projects both on and offshore, data acquisition requirements and site characterisation timescales.

## *7.2* Project Life Cycle Phases

The full project life cycle can be split into four main phases as outlined below. Each phase is different in terms of complexity and criticality and various factors have been considered in order to determine the best and the most likely work sequences and durations.

The full life cycle project execution phases are:

1. *The "Exploration and Planning" Phase* **-** This phase involves selecting a suitable site for salt cavern construction and applying for planning permission to relevant governing authorities. Upon completion of this phase, a site will be selected with an understanding of depth and storage pressure of the proposed salt cavern. This phase will also identify the main contractor/technology providers for the main packages of the project and will produce an assessment of the time and cost of the project approximated to +/-30%. The shareholders will receive sufficient information related to economics/finance to decide whether or not to proceed to the next phase.
2. *The "FEED" Phase* **-** In this phase, the design is developed in more detail. The design data produced enables the project team to achieve an approximation of the project time and costs to +/- 15%. As part of this phase, the ITB package to be sent to potential main contractors for the EPC bid phase is also defined.
3. *The "EPC Tender Award" phase* - In this phase, the ITB package is sent out to potential main contractors for the EPC phase, bids are received back and contracts are awarded depending on the relative attractiveness of the bids. At the end of this stage, the main workforce for the EPC phase will be defined and the scope split as such, providing a basis for detailed engineering and construction work to commence.
4. *The "Execution EPC/Start-up" Phase* **-** This phase refers to project execution activities from start of Detailed Design up to Construction and Commissioning of the salt cavern ready for storage operations, through materials procurement, subcontracting and construction.

## *7.3* Qualifications and Assumptions

The following explanation describes the main qualifications and assumptions used during assessment of the Overall Project Duration.

### 7.3.1 Phase 1 - Exploration and Planning

This Phase is the most difficult to estimate due to the potential of several uncontrollable factors during the planning process that can jeopardize project deliveries schedule.

Exploration Phase

One of the most critical activities to be executed in this phase is the Initial Site Investigation. The following main activities are scheduled:

- Subsurface Mapping;
- Seismic Survey (either or both 2D and 3D) of the identified area;
- Drilling of at least one exploration well to prove the nature and properties of the halite and enclosing strata;
- Laboratory test of drill cuttings and core samples; and
- Interpretation and integration of data into a geological model which then will provide necessary information regarding the location, size, shape and composition of the salt beds in the immediate and surrounding areas.

Based on the data obtained following exploration activities, cavern development modelling should be performed which includes:

- Determination of a suitable depth for the cavern;
- Evaluation of operational size of the cavern;
- Pressure limits for storage; and
- Leaching programme.

Planning Phase

The BGS report, Section 7 and also relevant case studies note that most applications for such caverns have gone to Public Inquiry, which introduces unnecessary delays and therefore uncertainty in planning practices. A recent history of projects developed in the UK shows multiple delays to scheduled activities due to the planning application process.

There is therefore a moderate level of uncertainty in the ability to gain planning consent for new proposed storage sites and hence investment.

Considering the aforementioned criticalities, a duration of four years has been estimated to deliver this phase, taking in to consideration the historical data available in the BGS report and FW benchmark, although it is possible that the total duration of the exploration and planning phase could be 6-7 years.

### 7.3.2 Phase 2 - FEED

A FEED stage is necessary in order to compile all the technical and commercial information leading to a determination of the CAPEX with an accuracy of +/- 15%. The Invitation to Bid (ITB) package falls as part of the scope of this phase, which aims to assess the best technical and commercial offer related to the EPC Project Execution.

The latter part of the FEED phase is devoted to the decision to move ahead with the Execution Phase with the Final Investment Decision (FID) Milestone. A timescale in the region of 1.5 years is envisaged for delivery of this phase.

### 7.3.3 Phase 3 - EPC Tender Award

During this phase, a technical/commercial evaluation of potential EPC contractors will be carried out. An upgrade of the engineering documents is also planned in order to fully align to technical clarifications raised during the bid phase. A duration of 1 year is envisaged.

### 7.3.4 Phase 4 - Execution/EPC

The EPC phase consists of three main sub-phases:

- Engineering;
- Procurement; and
- Construction - including final testing of the cavern ready for operation.

Each Sub-Phase can be further split according to main Process/Area blocks in line with the Construction sequence.

The main Process/Area blocks identified are:

- Site Preparation;
- Wellhead and Drilling;
- Leaching Facilities;
- Cavern Construction;
- Above Ground Facilities;
- Pipelines; and
- De-brining and Gas Introduction.

The Engineering phase duration has been estimated in the range of 2.5 years, based on Foster Wheeler's in-house statistical data available concerning similar projects.

The Procurement phase duration has been estimated in the range of 4 years, from the first enquiry issue to the last material delivered at site. The first materials to be ordered will be those considered critical in terms of prospective lead time or related to the site preparation, well construction, wellhead, leaching facilities, water/brine pipelines, pumping stations and above ground facilities.

The construction phase duration has been estimated in the range of 5 years. Due to the nature of necessary underground works in an unknown/superficially explored area, the total duration could vary from 5 - 6 years depending on potential issues faced during the cavern formation phase.

These three sub-phases can be run in parallel to some degree, with the total EPC phase expected to last 6 years.

The main construction Process/Area blocks identified are listed below in order to outline the works necessary to progress alongside the project schedule:

<u>Site Preparation</u>

- Area Clearance and Landscaping;
- Access Roads;
- Temporary Construction Facilities;
- Connection to Power and Water grid;
- Warehouses;
- Disposal Areas (if required); and
- Pre-assembly Shops.

Wellhead and Drilling

- Construction and Installation of the facilities related to drilling of the boreholes to a designated depth below grade;
- Installation of the Leaching tubes (water and brine), Inlet/Outlet gas tube and Wellheads; and
- Installation of gas tubes for working gas.

Leaching Facilities

- Construction of Pumping Station for solution mining;
- Construction of Control Station; and
- Installation of Balance of Plant services (BOP - including Piping, E&I etc.).

Cavern Formation

- Introduction of injection water through the strings previously installed during the Drilling phase;
- Injection of Nitrogen gas blanket gas to control the cavern shape; and
- Extraction of Brine.

Above Ground Facilities

- Installation of all above ground facilities (e.g. Compressor, dryer, expansion turbine etc);
- Construction of Control Station; and
- Installation of Balance of Plant services (BOP - including Piping, E&I etc.).

Seawater and Brine Pipelines

- Installation of dual pipelines for water injection and brine extraction.

Hydrogen Pipelines

- Installation of two pipelines (of approximately 10 km each) to transport hydrogen from the syngas production plant to the storage cavern(s) and from the storage cavern(s) to the Power Island.

De-brining and Hydrogen Introduction

- Gas introduction for brine removal (through strings previously installed during the drilling phase); and
- Brine removal (through strings previously installed during the drilling phase).

7.3.5 Further Information

For further explanation and justification for the timescales outlined above, reference should be made to the following Attachments:

- Attachment 10; Project Execution Schedule; and
- Attachment 11; Construction works flow and duration assessment chart.

The Construction works flow and duration assessment chart aims to provide a fundamental outline of the relationships shown between the different construction phases. Specific project case studies used to estimate the duration of each phase and the overall Project duration are outlined. The relationships highlighted in red are related to the critical path and to the longest path. The duration of the activities shown may vary considerably depending on the period in which the project will be actually executed. This is due mainly to variations in market conditions, which in turn may lead to materials supply and manpower availability deviations. The Project Execution Schedule outlines the envisaged timescale of the Project in a different format.

The following references were consulted:

- BGS report - Example projects in the UK:
  - Holford (H165), Cheshire (Triassic halite), England;
  - Hole House, Cheshire (Triassic halite), England;
  - Hilltop Farm, Hole House, Cheshire (Triassic halite), England;
  - Parkfield Farm, Hole House, Cheshire (Triassic halite), England;
  - Holford (formerly Byley), Cheshire (Triassic halite), England;
  - Stublach, Cheshire (Triassic halite), England;
  - King Street (Rudheath), Cheshire (Triassic halite), England;
  - Preesall, NW Lancashire (Triassic halite), England;
  - Portland, Dorset (Triassic halite), England;
  - Gateway (Triassic halite), East Irish Sea;
  - Hornsea/Atwick, East Yorkshire (Permian halite), England;
  - Aldbrough – phases I & II, East Yorkshire (Permian halite), England;
  - Whitehill, East Yorkshire (Permian halite), England;
  - Teesside: Billingham (Saltholme) and Wilton (Permian halite);
  - Islandmagee, Antrim (Permian halite), N Ireland; and
  - BGE & Storengy, NE Storage Project Larne, Antrim (Permian halite), N Ireland.
- Foster Wheeler in-house information - Example projects outside the UK:
  - Carrico Gas Storage Project, Portugal;
  - Gas Storage Zuidwending, Netherland; and
  - Poederlee Gas Storage, Belgium.

## *7.4* Conclusions

The full project life cycle can be split into four main phases:

- Exploration and Planning **–** 3 - 4 years;
- FEED - 1.5 years;
- EPC Tender Award - 1 year;
- Execution EPC/Start-up **-** 6 years.

Various factors have been considered in order to determine the best and the most likely work sequences and durations. Taking into account the possibility of parallel execution or at least a slight overlap of the above phases, the estimated duration of the Project from the start of exploration and planning activities through to a fully functional storage cavern is 10 years.

# 8. ALTERNATIVE CAVERN USE

## 8.1 Objective

The objective of this section is to carry out a high-level, qualitative techno-economic comparison of alternative potential uses of salt caverns including buffer storage of other gases including natural gas, dense phase carbon dioxide and air.

## 8.2 Alternative Technologies

This section aims to determine whether there might be other uses for salt caverns which would be more economically attractive than using the cavern to store hydrogen for peak power generation.

The alternative salt cavern uses considered most likely to be competitive with hydrogen storage are:

- Natural gas storage;
- Carbon dioxide buffer storage; and
- Compressed air storage.

The technical basis for each of these storage strategies is explored, then the relative economics are considered.

## 8.3 Technical Comparison of Storage Options

### 8.3.1 Natural Gas Storage

Natural gas storage is an essential part of any natural gas supply infrastructure, helping to ensure that supply can meet demand at all times by providing additional gas to the grid during high demand which had been stored away during periods of low demand.

Other countries have significantly more gas storage capacity than the UK, largely because until relatively recently, the UK was able to vary its significant North Sea production in order to meet fluctuating demand. Germany, Italy and France have approximately 69, 59 and 87 days of natural gas storage respectively compared to 14 days storage in the UK (Chadwick & Evans, 2009).

At present, storage capacity in the UK stands at around five percent of annual demand, compared with an average of around twenty percent in other Northern European countries. The need for additional natural gas storage in the UK, to prevent shortfalls in supply and to protect consumers from extreme price spikes during high demand, is recognised by the UK government and a number of projects are currently under development.

Natural gas can be stored in a number of types of formations including partially depleted oil and gas reservoirs, aquifers and salt caverns. Furthermore, it can be liquefied and stored as LNG, with a density of 10-20 times that of compressed gas. Salt caverns represent an attractive option because of their high deliverability, despite their relatively small storage capacity compared to a reservoir. Several natural gas filled salt cavern projects exist and are operating in the UK. The Gateway offshore salt cavern development proposed for the East Irish Sea is also for natural gas storage and would help to improve the security of energy supplies for the UK markets.

8.3.2 Carbon Dioxide Buffer Storage

Capture and storage of carbon dioxide from large point sources such as power stations will be required if the UK is to reduce its emissions and achieve its climate change targets. The rate of carbon dioxide production from power stations will vary due to the cyclical nature of power demand. Design of long pipelines and wells for the peak $CO_2$ flow is undesirable, since larger diameters would be required and operating frictional pressure drops will vary – something that should be avoided if possible due to the complex phase behaviour of $CO_2$.

Salt caverns do not offer sufficient capacity to present a long term solution for $CO_2$ sequestration: their intended use is as a short term $CO_2$ storage buffer to maintain a relatively constant flowrate in long $CO_2$ pipelines and wells into sequestration reservoirs. This would be achieved by routing $CO_2$ into local salt cavern storage during times of peak production and routing $CO_2$ from the salt cavern to the sequestration reservoirs during periods of low production, as illustrated in Figure 9.

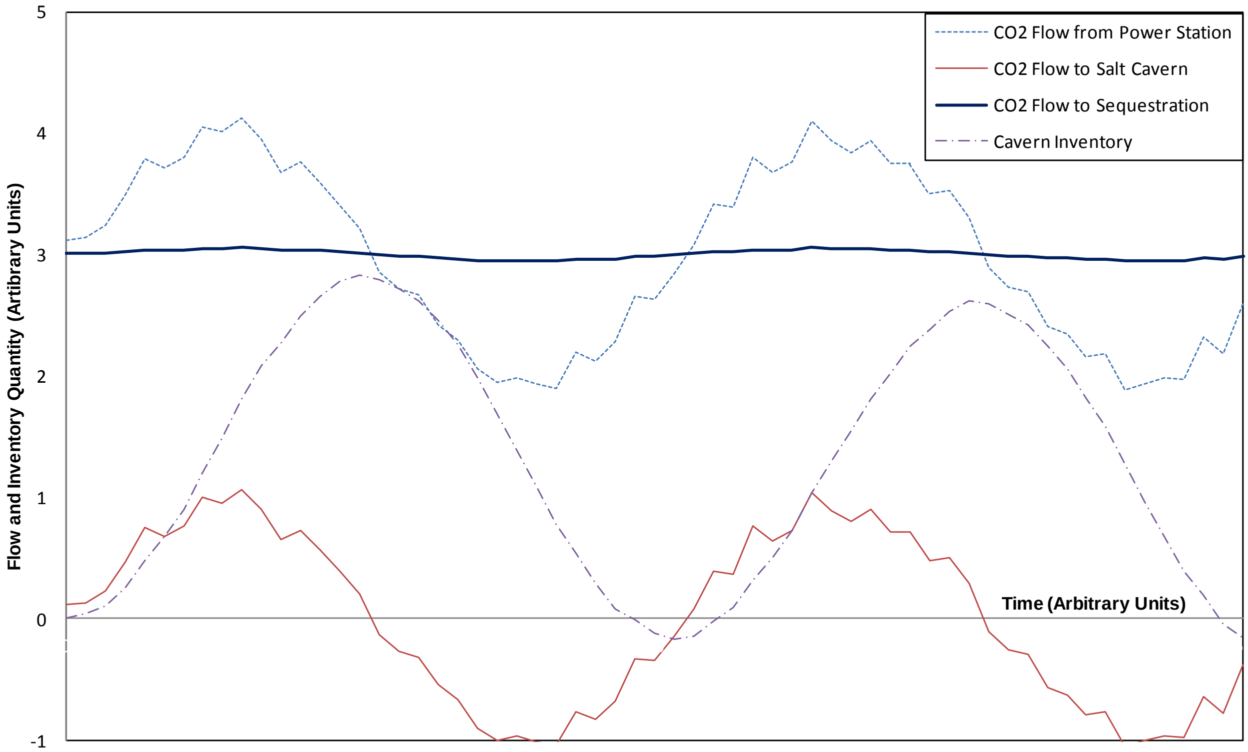



**Figure 9 – Illustrated Operation of $CO_2$ Buffer Salt Cavern**

Salt caverns are an attractive option for buffer storage of $CO_2$ because of their high deliverability and low impact on stored product composition (assuming a dry cavern is used rather than brine displacement).

The most economic model for transporting $CO_2$ to storage is achieved when a number of $CO_2$ sources (such as power stations, cement works, oil refineries etc.) are connected into a local/regional $CO_2$ hub which has a local salt cavern to damp short-term variations in production and a pipeline designed for the damped flow leading to sequestration wells.

Such a network-hub scheme may require the full $CO_2$ transport network to operate in the dense (supercritical) phase, or it may use gas phase $CO_2$ transport where possible with booster stations to raise the pressure at some distance between the collected $CO_2$ and the $CO_2$ stores, as shown in Figure 10.

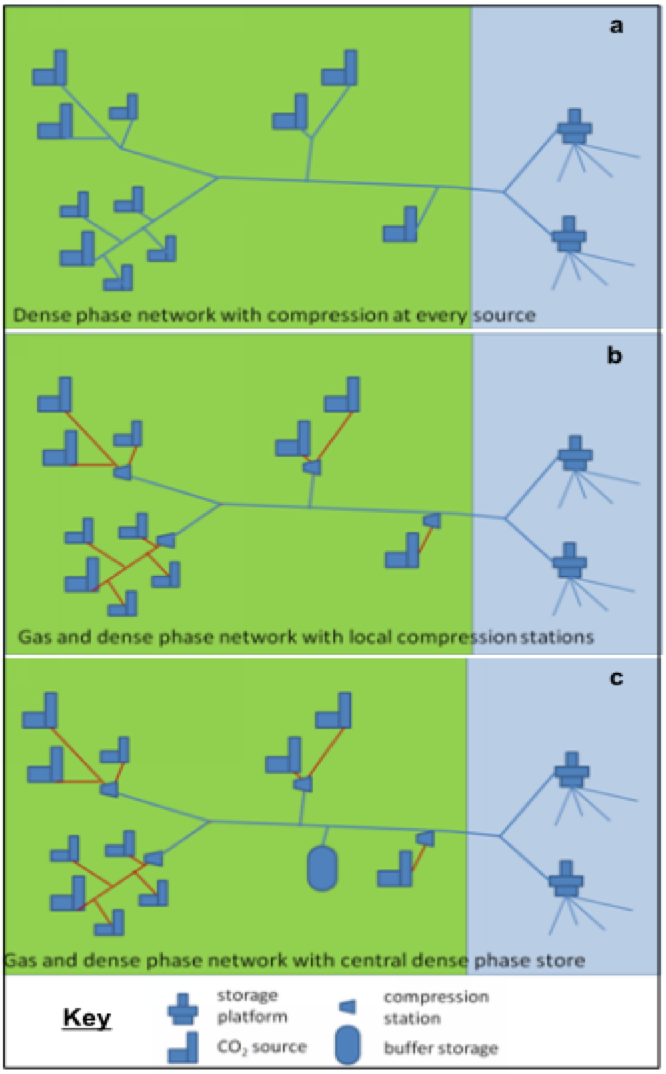



**Figure 10 - Possible $CO_2$ Network Configurations**

As shown in Figure 11, transport and storage of $CO_2$ in a dense (supercritical) phase requires the pipeline and storage cavern to operate at above the critical point, which occurs at 74 bar (abs) and 31°C. As the acceptable pressure range for salt cavern operation is a function of depth, the technical feasibility of storing $CO_2$ in a salt cavern depends on the depth of the cavern. This would have the following impact for the three proposed locations:

| | |
|---|---|
| Teesside | With operating pressures of up to 45 bara, these caverns would only be suitable for gas phase storage. |
| East Yorkshire | With operating pressures between 120 – 270 bara, these caverns would be suitable for supercritical $CO_2$ storage. |
| Cheshire | With operating pressures between 40 – 105 bara, these would be more difficult for $CO_2$ buffer storage: if the temperature is below 31°C, the $CO_2$ would be liable to change phase from liquid to gas as the pressure drops below approximately 74 bara, creating operational issues. To avoid this, the cavern would only be able to use a limited part of their operating range:<br>● 40 - 70 bara for gas phase storage, or<br>● 80 to 105 bara for supercritical $CO_2$. |

However, as noted in section 4.7, 90% cushion gas is recommended for facilities with ‘fast-churn’ pressure cycles. Hence, the cavern would only operate in the 94 to 105 bara range if used for damping of diurnal $CO_2$ production cycles, which is the most likely scenario.

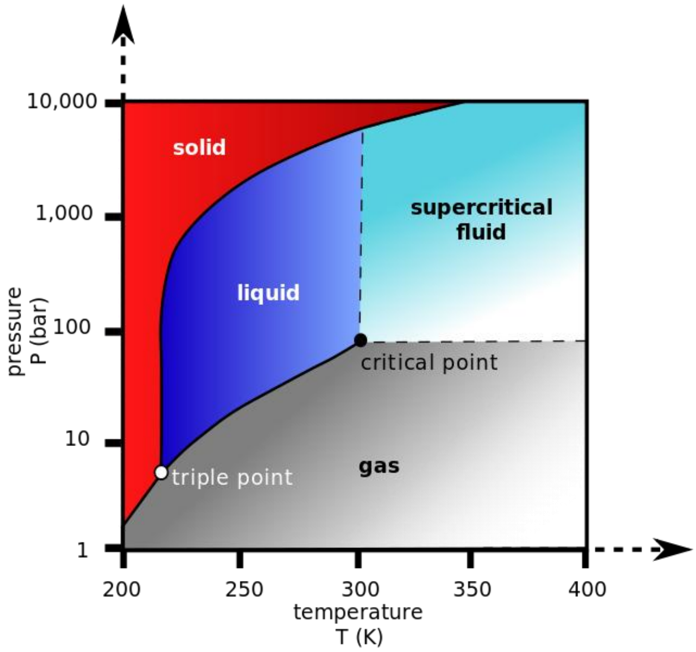



**Figure 11 - $CO_2$ Phase Diagram**

8.3.3 Compressed Air Energy Storage

Compressed Air Energy Storage (CAES) is an energy storage technology. Power is used to pack air into a fixed volume reservoir at times of low electrical power demand, resulting in an increase in the operating pressure of that reservoir. At times of high electrical power demand, the reservoir is unpacked by releasing the air to perform useful work.

A compressed air storage system with an underground cavern was patented in 1948, and the first CAES plant using salt caverns for storage has been operating in Huntorf, Germany, since 1978 (Seamus, 2011) at an efficiency of 42% (Makansi, Energy Storage Council). Salt caverns are preferable to surface storage options due to their very large volume and thus the large quantity of energy that can be stored with only a small pressure change.

The efficiency of CAES is limited by the efficiency of conversion of power into pressure energy and vice versa. When compressing air, much of the energy is converted into heat as well as pressure, and this heat has to be removed to maintain acceptable compressor and cavern operating pressures. Conversely, heat is lost in air expansion and feed air has to be heated to maintain acceptable expander outlet temperatures. RWE and its R&D partners are currently working on a more advanced design using adiabatic compressed air storage. In this system, the heat of compression is removed from the air during compression and stored, then reused to heat the expanding air as it is released. This plant is hoped to achieve efficiencies of between 75% and 85%.

Packing and unpacking of the reservoir air can be undertaken using a dedicated compressor/expansion turbine generator, but a more cost effective solution is to combine CAES with gas turbine (GT) power generation.

<u>CAES combined with GTs</u>

At present, there are only 2 CAES plants in the world at commercial scale: the 290 MW plant belonging to E.N Kraftwerke, Huntorf, Germany, built in 1978, and the 110 MW plant of AEC (Alabama Electric Corporation) in McIntosh, Alabama, USA, commissioned in 1991. Both of these have integrated the CAES with gas turbines.

During off-peak load periods when power has low value, power is used to compress and store air in the underground salt caverns. Later, during peak load periods, the process is reversed; the compressed air is returned to the surface; this air is used for combustion, eliminating the air compression load that is normally a significant part of the GT output.

Both ‘pure’ and ‘GT hybrid’ CAES projects are referred to as CAES in the literature, making published data relating to compressed air energy storage difficult to interpret.

8.3.4 Technical Storage Option Summary

The following table summarises the key technical parameters for each potential salt cavern use

**Table 33 – Salt Cavern Usage Options**

| Parameter | Hydrogen Storage | Natural Gas Storage | CO2 Storage | Compressed Air Storage |
|---|---|---|---|---|
| **Gas Source** | Dedicated production plant | National transmission network | CCS network | Atmospheric air |
| **Gas Destination** | Dedicated consumption plant | National transmission network | Sequestration well | CCGT combustor or atmosphere via expander |
| **Purpose** | Decarbonised “energy carrier” buffer storage | Fuel buffer storage | Flowrate buffer storage | Energy buffer storage |
| **Energy Density in Gas (MJ/m³/bar) (25°C)** | 12 (LHV basis)<br>6.5 (LHV basis, including $N_2$ storage) | 35 (LHV basis) | N/A | 0.1 (isothermal basis) |

## *8.4* Economic Comparison of Storage Options

8.4.1 Overview

The relative economics of salt cavern use as a store for hydrogen, natural gas, $CO_2$ or air are not straightforward to assess for the following reasons:

- All four uses provide the capacity to buffer a ‘system’ between peaks and troughs in demand, but the system buffered differs between uses. Hydrogen storage buffers decarbonised fuel “energy carrier” supply/demand; natural gas storage buffers conventional fuel supply/demand; carbon dioxide storage buffers CCS production/well capacity and air storage buffers power supply/demand.
- Since all four alternative salt cavern uses provide buffering, each is an inherent part of a larger system with a “topside” element. The topside elements for each option vary significantly in cost, and these costs depend upon location and will be impacted by climate change legislation.
- The scales of the “topsides” scope and caverns are not necessarily linked because, as demonstrated in section 4.7 of this report, the size, number and associated cost of the caverns depends significantly on the mode of

operation of the system they serve: short term buffering requires much smaller cavern volumes than long term buffering.

- Three of the four storage options rely on the variation of market prices with supply and demand. Much of this variation and the value of buffer capacity to hedge against such variation is not publicly available, and will be impacted by climate change legislation.

8.4.2 Economic Comparison of Natural Gas and Hydrogen Buffering

Natural gas and hydrogen buffering are both means of storing fuel for subsequent conversion into power.

In the case of natural gas buffering, the ‘system topsides’ consist of compression and pressure recovery equipment, pipelines, wells, control and monitoring systems and gas cleaning systems. Gas can be obtained from the national grid and supplied back to the national grid.

In the case of hydrogen buffering, the ‘system topsides’ are as outlined in WP1: a conventional reforming or gasification based syngas production plant and a gas turbine based power island designed to fire $H_2$-rich syngas.

The motivations for natural gas storage are security of supply and buffering of supply during short term peaks in demand. Suppliers of natural gas storage capacity can earn income based on a differential between purchase and selling prices, but they may also earn a fee based on the capacity they provide.

Unlike natural gas buffering, hydrogen buffering provides a decarbonised “energy carrier”. In the absence of climate change legislation that provides a driver for power stations to apply CCS, hydrogen buffer storage can never compete with natural gas buffer storage: as well as the substantially greater topsides scope, conversion of carbon based fuels to hydrogen is inefficient and natural gas provides five times the volumetric energy density of hydrogen (taking account of the nitrogen storage required for hydrogen GT firing) requiring only one fifth of the cavern size for the same energy buffer capacity.

When climate change legislation does come into effect, power station $CO_2$ capture, compression, transport and storage schemes must be sized for a particular power output. Providing additional CCS capacity to meet demand peaks may be less cost effective than operating one of the plants proposed in WP1 (baseline syngas production plant with CCS, storage of the hydrogen, then operation of a decarbonised fuel based GT system to meet the demand peaks at times of high power demand).

Since the infrastructure for CCS is largely undeveloped and the future development of climate change legislation is unclear, it is not yet possible to determine how hydrogen storage and natural gas storage will compare.

8.4.3 Economic Comparison of Carbon Dioxide and Hydrogen Buffering

Although they differ in purpose, both hydrogen and $CO_2$ salt cavern storage require climate change legislation to become cost effective, as they both require adoption of CCS by conventional power plants and other large $CO_2$ producers.

The motivation for $CO_2$ storage in salt caverns is to avoid the cost and operating challenges of designing long transfer pipelines and sequestration wells for peak CCS flows. On this basis, their use will only be justified if they can be located close to the $CO_2$ source.

Unlike $CO_2$ storage caverns, hydrogen storage caverns do not need to be located close to large point sources of $CO_2$ with CCS: as the topsides for hydrogen storage are dedicated to the cavern, these can be situated close to the cavern rather than vice versa. Furthermore, while use of peak power generation from hydrogen fuel may shave some of the peaks in $CO_2$ production from other power stations, substantial cyclical loads will remain from other sources, meaning that salt caverns for hydrogen storage and $CO_2$ storage could easily co-exist.

The value of salt caverns for $CO_2$ storage will strongly depend upon the distance from the CCS network to salt cavern, the operating pressure range for the salt cavern compared with the $CO_2$ phase diagram, the distance from the CCS network to the sequestration wells, the scale of $CO_2$ transport and the variability and periodicity of the CCS network $CO_2$ flows (refer to Attachment 12 for further analysis of these issues).

### 8.4.4 Economic Comparison of CAES and Hydrogen Buffering

Compressed air energy storage (CAES) and hydrogen buffer storage are similar in that they both provide an energy store for generation of electrical power at times of peak demand. Both options utilise a base loaded system generating the stored energy (a hydrogen production plant in the case of hydrogen storage; an air compressor in the case of CAES) and an intermittent system for power generation (a hydrogen fired GT for hydrogen storage and an expansion turbine or GT for CAES). Both systems aim to capitalise on the high value of power generated at times of peak demand.

Comparison of the energy density alone shows that CAES is a relatively poor method of energy storage, providing only 2% of the energy per unit volume that hydrogen storage can provide. CAES becomes attractive, despite its low energy density, when it is implemented as part of a GT system. In this case, the relatively small investment in an oversize air compressor, air pipeline and storage cavern provide the potential for significant power generation flexibility: the GT can operate continuously at design load, but the generator can be quickly switched from low to high power output at times of peak demand by turning off the air compressor and using stored air instead.

CAES is likely to become even more attractive following legislation requiring CCS from large power generation plants, since CAES allows GT or CCGT based power generation to operate at its design point (with a constant CCS load) while varying power output to suit the demand profile.

Because compressed air has a relatively low energy density, CAES is only practical for salt caverns located close to the associated compressor and turbine. For large power generation rates, the air pressure drop through the well and transfer pipeline can become significant and impact plant efficiency (the Huntorf CAES plant in Germany produces 60MW in compression mode and 290MW in turbine mode. For this capacity, the two salt caverns - both located within 1km of the power plant - each have a 20” production string).

Further literature on the economic attractiveness of CAES is provided in Attachment 13.

# 9. LANDSCAPING STUDY OF ALTERNATIVES TO SALT CAVERNS

## 9.1 Objective

The objective of this section is to perform a high level review of alternative methods of hydrogen storage including cost, practicality, level of development/implementation and risk. Likely alternatives include:

- Physical storage methods; and
- Chemical storage methods.

Alternative forms of geological storage and their applicability for hydrogen storage will be reviewed by BGS and summarised here. Likely alternatives include:

- Depleted fields;
- Aquifers; and
- Other mined voids in soft or hard rock for both lined and unlined cavities.

## 9.2 Hydrogen Storage Targets

The US Department of Energy (DoE) has set targets for vehicular hydrogen storage based on the weight of hydrogen inventory as a proportion of the overall fuel container weight (gravimetric capacity), with the aim of challenging petrol and diesel in terms of gravimetric storage efficiency. The original targets were 6% by 2010 and 9% by 2015. However, following a concentrated research effort, these targets were reassessed in 2009 and to 4.5% by 2010 and 5.5% by 2017, with an eventual ultimate goal of 7.5% (Fuel Cell Technology, Hydrogen Storage, 2013).

The UK Sustainable Hydrogen Energy Consortium (UK-SHEC) was established in 2003 as part of the Engineering and Physical Sciences Research Council (EPSRC) SUPERGEN initiative and over the past few years has worked to encourage the development of sustainable power generation and supply (United Kingdom Sustainable Hydrogen Energy Consortium, 2013). Their findings for current gravimetric capacities are summarised in Table 34.

**Table 34 - Gravimetric Capacities for Hydrogen Storage Options**

| Storage Form | Current Gravimetric Capacity |
|---|---|
| Complex Hydrides | 1.5-2.5% |
| Chemical Hydrides | 2.5-3.5% |
| 350 bar Compressed | 3-4% |
| 700 bar Compressed | 2.5-4.5% |
| Cryo Compressed | 5-6% |
| Liquid Hydrogen | 5-7% |

## 9.3 Bulk Storage Options

Conventional methods of hydrogen storage include compressed high and low pressure gaseous hydrogen and liquefied hydrogen at cryogenic temperatures. These, as well as other alternative methods are discussed below.

9.3.1 Full Pressure Storage

At atmospheric conditions, hydrogen gas has a very low volumetric energy density. One way of increasing it is to use compression: 350 or 700 barg are typically used for transportation applications: 3.94 kg can be stored in the 350 barg tank of a Honda FCX Clarity vehicle.

Pressurised storage of hydrogen is seldom used in industry as the low density results in a very low gravimetric capacity and high costs, as demonstrated by the two case studies below.

Compressed Storage Spheres

As a high-level demonstration of the volume of compressed gas storage required to replace a salt cavern, storage spheres are considered in the following model. An analysis of two gas storage sphere specifications from previous in-house projects is made below. A hybrid case is also explored below using the design and operating conditions from Case 1 with the larger diameter from Case 2. The reference projects were designed for propane storage, so costs for hydrogen storage may be higher due to additional measures required to avoid hydrogen embrittlement.

It should be noted that the usual practice is to use spherical tanks for storage of pressurised liquids at their bubble point. It is impractical to achieve conditions at which hydrogen becomes liquid without refrigeration, and refrigerated storage is considered later in sections 9.3.2 and 9.3.3 of this report.

**Table 35 – Hydrogen Sphere Specification Options**

| | | **Case 1** | **Case 2** | **Hybrid** |
|---|---|---|---|---|
| ID | m | 14.55 | 25.00 | 25.00 |
| Working volume | $m^3$ | 1612 | 4500 | 4500 |
| Design temperature | °C | 75 | 85 | 75 |
| Design Pressure | barg | 16.7 | 7.0 | 16.7 |
| Operating temperature | °C | 50 | 60 | 50 |
| Operating pressure | barg | 15.4 | 6.3 | 15.4 |
| Material | | LTCS | | |

Assuming a minimum operating pressure of 1 barg in each sphere, the following storage capacity and number of spheres would be required to store the volume of hydrogen required to supply a single gas turbine (72,000 kg/h $H_2$):

**Table 36 - Hydrogen Sphere Requirements**

| **Case 1** | | $H_2$-rich Syngas | Nitrogen | **TOTAL** |
|---|---|---|---|---|
| Density @ 60 °C 15.4 barg | $kg/m^3$ | 3.47 | 16.6 | |
| Density @ 60 °C 1.0 barg | $kg/m^3$ | 0.42 | 2.0 | |
| Available inventory per sphere | kg | 4917 | 23535 | |
| Flow rate required | kg/h | 72000 | 310000 | |
| No. of spheres for 12 hours diurnal operation | # | 176 | 158 | **334** |
| **Case 2** | | $H_2$-rich Syngas | Nitrogen | |
| Density @ 60 °C 6.3 barg | $kg/m^3$ | 1.54 | 7.38 | |
| Density @ 60 °C 1.0 barg | $kg/m^3$ | 0.42 | 2.0 | |

| | | | | |
|---|---|---|---|---|
| Available inventory per sphere | kg | 5373 | 24210 | |
| Flow rate required | kg/h | 72000 | 310000 | |
| No. of spheres for 12 hours diurnal operation | # | 161 | 154 | **315** |
| **Hybrid** | | $H_2$-rich Syngas | Nitrogen | |
| Density @ 60 °C 15.4 barg | kg/m$^3$ | 3.47 | 16.6 | |
| Density @ 60 °C 1.0 barg | kg/m$^3$ | 0.42 | 2.0 | |
| Available inventory per sphere | kg | 13725 | 65700 | |
| Flow rate required | kg/h | 72000 | 310000 | |
| No. of spheres for 12 hours diurnal operation | # | 63 | 57 | **120** |

Approximate costs for the spheres are estimated as follows:

**Table 37 – Hydrogen Sphere Costs**

| Case | Cost of Syngas Storage (Million £) | | | |
|---|---|---|---|---|
| | Single Sphere | Total Spheres | TIC Factor | TIC Cost |
| **Case 1** | 1.2 | 400 | 3 | 1200 |
| **Case 2** | 4.0 | 1260 | 3 | 3780 |
| **Hybrid** | 6.5 | 780 | 3 | 2340 |

Given that the 12 hour diurnal operation case can be accommodated by 2 salt caverns with an installed cost of approximately £150m, use of spheres is an order of magnitude more expensive as well as requiring a large land area (~8 hectares) and presenting a significant safety hazard.

Bullets

Bullets are an alternative to spheres for storage of pressurised gases or bubble point liquids. They are normally installed horizontally and are frequently partially or fully covered with earth (buried or covered with an earth mound) for safety reasons.

The practical upper limit for bullet size is as follows:

- Diameter – 8 m
- Length to diameter ratio – 8
- Volume – 3500 m$^3$

Assuming a working volume of 3500 m$^3$ and similar operating conditions to the sphere case leads to the following specification:

**Table 38 – Hydrogen Bullet Specification**

| | |
|---|---|
| ID | 8.00 m |
| Working volume | 3500 m$^3$ |
| Design temperature | 85 °C |
| Design Pressure | 16.7 barg |
| Assumed operating temperature | 60 °C |
| Assumed operating pressure | 15.4 barg |

Assuming a minimum operating pressure of 1 barg in each bullet, the following storage capacity and number of bullets would be required to store the volume of hydrogen required to supply a single gas turbine (72,000 kg/h $H_2$):

**Table 39 – Hydrogen Bullet Requirements**

| | | $H_2$-rich Syngas | Nitrogen | **TOTAL** |
|---|---|---|---|---|
| Density @ 60 °C 15.4 barg | $kg/m^3$ | 3.47 | 16.6 | |
| Density @ 60 °C 1.0 barg | $kg/m^3$ | 0.42 | 2.0 | |
| Mass of gas stored | kg | 10675 | 51100 | |
| Flow rate | kg/h | 72000 | 310000 | |
| No. of bullets for 12 hours diurnal operation | # | 81 | 73 | **154** |

Approximate costs for the bullets are estimated as follows:

**Table 40 – Hydrogen Bullet Costs**

| **Cost of Syngas Storage (Million £)** | | | |
|---|---|---|---|
| **Single Bullet** | **Total Bullets** | **TIC Factor** | **TIC Cost** |
| 2.6 | 400 | 3 | 1200 |

The analysis above indicates that bullets offer a hydrogen storage price similar to that of spheres, and the saving of space and potential to bury these bullets for safety reasons would favour their use in a UK application. However, the cost remains an order of magnitude greater than salt cavern storage.

### 9.3.2 Semi-Refrigerated Storage

In order to increase the gravimetric and volumetric storage capacities of compressed gas tanks it is possible to use semi-refrigerated / cryo-compressed vessels.

In this type of vessel, gaseous hydrogen is stored at high pressure and sub-ambient temperature. As the density of a gas is inversely proportional to absolute temperature, reducing temperature leads to increased storage density.

Increased storage density means that hybrid insulated pressure vessels used for semi-refrigerated storage can be more compact than ambient-temperature, high-pressure vessels. Furthermore, because hydrogen remains as a gas, power demand for liquefaction and regasification is avoided and as the temperatures involved are not as low as for liquid hydrogen storage, ambient heat gain is lower than for fully-refrigerated tanks. Disadvantages of semi-refrigerated storage include larger capital cost compared to compressed tanks and a larger amount of associated equipment for operation.

Generic cost estimation for a semi-refrigerated hydrogen storage case is difficult, since the storage temperature can be adjusted to suit the application. However, to halve the number of spheres/bullets required to supply one gas turbine for 12 hour diurnal operation would require chilling to half of the assumed operating temperature. 60°C = 333K, so half this temperature is -106.5°C. At best this would reduce the storage cost by half to around £600m, but in fact the materials of construction of the vessels would need to change from carbon steel to alloy and chillers with recirculating cooling would need to be added. The final cost might be somewhere between £600m and £1200m, but still far greater than salt cavern storage.

In addition, the energy cost for semi-refrigeration would be high, as energy is required for chilling and for re-heating when the hydrogen is fired. As the chilling and re-heating duties will occur at different times, there is limited opportunity for heat recovery between these two duties.

### 9.3.3 Fully-Refrigerated Storage

In fully-refrigerated storage tanks, gas is stored as a liquid at its bubble point, at near atmospheric pressure. The temperatures used for volatile gases such as LPG and methane are usually cryogenic, meaning large amounts of energy must be expended by refrigeration packages in order to liquefy the gases and remove the energy transferred to the cryogenic liquid from the warmer environment.

Natural gas is routinely stored at around -162°C (111K) as liquefied natural gas (LNG), but hydrogen has a much lower boiling point than natural gas (-253°C, 20K), and this proximity to absolute zero makes it hard to liquefy. Moreover, hydrogen occurs in two spin states and the spontaneous switching from the more prevalent orthohydrogen state to parahydrogen releases heat that adds to the maintenance load normally required to counter ambient heat gain for liquefied gases.

Liquefaction of hydrogen results in a fluid with a density of 71 kg/m$^3$. By comparison, hydrogen gas at 105 bara and 45°C (salt cavern conditions) has a density of 7.9 kg/m$^3$. While this nine-fold increase in density is desirable, the capital cost of the the liquefaction equipment for this difficult duty is very high and the energy cost can be as high as 30% of the energy content of the hydrogen. Combined with the additional energy that would be required to heat the hydrogen back to ambient temperature for firing and the specialist materials required for operation at 20K, cryogenic storage of hydrogen for diurnal power generation cycles is not considered to be practical, efficient or cost effective.

Cryogenic storage continues to be investigated for automotive hydrogen fuel, as this offers the greatest potential gravimetric capacity. Potential issues for this storage option are hydrogen losses through ambient heat gain, particularly during filling, and safety issues associated with venting of boil-off hydrogen in an enclosed space such as a garage.

## *9.4* Physical / Chemical Adsorption Storage Mechanisms

The physical and chemical methods of high hydrogen syngas storage discussed below all take advantage of one or more of the following storage mechanisms:

- Physical Adsorption;
- Chemical Adsorption.

Adsorption is a surface phenomenon whereby gas or liquid molecules (adsorbate) accumulate or concentrate over the surface of a solid or liquid (adsorbent), forming a high density surface layer. There are two variations of adsorption:

- Physical adsorption or physisorption occurs where adsorbate molecules are attracted by weak van der Waals forces towards the adsorbent molecules. Interactions are reversible, non-specific and form a multilayer of adsorbate molecules on the adsorbent surface. Physisorption is exothermic, so adsorption is favoured by lower temperatures and high partial pressures of adsorbate. The capacity of the adsorbent increases with surface area.
- Chemical adsorption or chemisorption occurs where adsorbate molecules bind to the surface of adsorbent molecules via the formation of chemical bonds. Interactions are highly specific and adsorbate molecules form a monolayer of irreversibly bound particles on the adsorbent surface. Although chemisorption is also exothermic, there is often an activation energy barrier

to overcome, meaning more effective adsorption interactions occur at high temperatures. Unlike physisorption, the extent of chemisorptions is not a strong function of adsorbate partial pressure. The capacity of the adsorbent increases with surface area.

The following physical adsorption options are considered:

- Carbon-based physical adsorption;
- Metal organic frameworks;
- Other physical adsorbents.

Chemical adsorption is considered separately in section 9.5.

### 9.4.1 Carbon-based Physical Adsorption

Many carbon-based variants are available for storage of hydrogen gas via physical adsorption. The main types are carbon nanotubes and activated carbon beads, powder, granules, fibres and monoliths.

Activated carbon is a highly porous, modified synthetic carbon containing crystallized graphite and amorphous carbon. It has a very high specific surface area (~1000$m^2$/g).

Although carbon based physical storage is still in the research and development phase, many carbons (particularly activated carbons) are considered as potential candidates for hydrogen storage because they are relatively cheap and accessible on a commercial scale. Carbon nanotubes are also receiving a large amount of interest from the research community as storage structures for hydrogen fuelled automobiles.

### 9.4.2 Metal Organic Frameworks

Metal organic frameworks (MOFs) are crystalline structures consisting of metal ions and an organic molecule (ligand) known as the linker (MOF Technologies, 2013). The resulting frameworks provide the highest surface area of any known substance (1000-6000$m^2$/g) and the metal ions can provide sites for physical adsoption of hydrogen. Operating at pressures of 10-100bar, MOFs can currently provide gravimetric densities of 2.5-7.5% when operating at liquid nitrogen temperatures, but this is an impractical temperature for most applications and room temperature capacities peak at around 1.4%.

Though gravimetric capacity currently does not compare favourably with pressurised storage and the MOFs themselves are expensive to produce, they offer the potential for safer storage of hydrogen in automotive applications.

### 9.4.3 Other Physical Adsorbents

A large range of other physical adsorbent materials exist, including zeolites and clathrate hydrates, as well as glass-based systems such as glass capillary arrays and glass microspheres.

Zeolites are hydrated microporous crystalline aluminosilicates with internal surface areas of up to 1000 $m^2$/g and although they are classic absorbents, do not perform as well as either carbons or MOFs for gas adsorption, so are not worth considering in this study.

Although clathrate hydrates have shown potential as possible hydrogen storage vectors, they are in the research and development stage at present. Glass systems present an interesting alternative to conventional adsorbents. Under the right conditions they have been shown to adsorb moderate quantities of gas.

#### 9.4.4 Summary

Physisorption of hydrogen onto adsorbent materials continues to be a subject of research and development, but is currently unable to compete with compressed storage in terms of cost or gravimetric capacity. When fully developed, adsorbents may find application in automotive applications where gravimetric capacity is important and collision risk is a key safety concern, but they are highly unlikely to find application for large scale bulk hydrogen storage.

A further key issue with hydrogen adsorbents is that many of them can be poisoned or performance adversely affected by the impurities present in hydrogen. Whilst the microscopic pore structure of an adsorbent is perfect for the very high diffusivity of hydrogen molecules, larger molecules such as CO or $CO_2$ could block the pores of the material, leading to reduced hydrogen storage capacity. Hydrogen produced by reforming or gasification will contain such impurities and increasing purity will reduce yield and increase production costs.

### *9.5* Chemical Storage Options

Chemical storage of hydrogen gas is another option which has benefited from significant research efforts in the recent past. In general, chemical storage methods are able to store a larger volume of hydrogen than physical adsorption based methods. However, because chemical reaction-like interactions occur during charging of the chemical storage media, stored hydrogen is harder to release when required.

The following chemical adsorption options are considered:

- Metal hydrides;
- Chemical hydrides;
- Other chemical storage options.

#### 9.5.1 Metal Hydrides

Metal hydrides are formed from a combination of metal ions and multiple hydride ions, producing an ordered crystalline structure. They tend to form strong bonds with hydrogen and so have shown potential for reversible storage and release of hydrogen at relatively mild conditions (<120 °C and 1-10 atm) (FCT Hydrogen Storage, 2013). They fall in two different groups: simple and complex metal hydrides.

<u>Simple Metal Hydrides</u>

Simple hydrides such as $LaNi_5H_6$ chemically adsorb hydrogen into their crystal structures and can function at near ambient temperatures and pressures. However, the specific surface area of such hydrides is low, resulting in low gravimetric storage capacity (~1.3 wt.%). Moreover the cost of these hydrides is high (FCT Hydrogen Storage, 2013).

<u>Complex Metal Hydrides</u>

Complex metal hydrides such as $NaAlH_4$ and $LiAlH_4$ can typically store a larger quantity of hydrogen than simple hydrides, but release has to be catalysed with titanium dopants. The theoretical material limit for gravimetric capacity in $NaAlH_4$ is

5.5%, but practical limits are lower and slow kinetics of release make hydrogen delivery rate an issue.

High cost and low volumetric capacity are two other issues with complex metal hydrides. Moreover, slow adsorption rates and a high heat of adsorption present difficulties when considering complex hydrides for automotive fuel applications (FCT Hydrogen Storage, 2013).

### 9.5.2 Chemical Hydrides

A number of chemical substances can be used whereby a chemical reaction is exploited, producing hydrogen. This differs from other methods discussed in this study, as the storage media cannot be refilled from a hydrogen source: once spent, the storage medium has to be removed and regenerated before being used again.

Three classes of reaction are described below:

- Hydrolysis;
- Hydrogenation/Dehydrogenation;
- Alcoholysis

<u>Hydrolysis</u>

Chemical hydrides such as $NaBH_4$ and $MgH_2$ can be oxidised in the presence of water to produce hydrogen.

Typically, a slurry formed from an inert stabilizing liquid protects the hydride from contact with moisture and makes the hydride pumpable. At the point of use, the slurry is mixed with water and the consequent reaction produces high-purity hydrogen.

While sodium borohydride hydrogen capacity can be high (values of 4% are reported) and hydrogen release kinetics fast, high cost, high regeneration energy requirements, and challenging regeneration logistics are issues that have to be resolved.

<u>Hydrogenation/Dehydrogenation</u>

Hydrogenation and dehydrogenation reactions have been studied for many years as a means of hydrogen storage. For example, the decalin-to-naphthalene reaction can release 7.3 wt% hydrogen at 210°C using a platinum-based or noble-metal-supported catalyst to enhance hydrogen evolution kinetics.

Recently, a new type of liquid-phase material has been developed by Air Products and Chemicals, Inc., which has shown 5.0 – 7.0 wt% gravimetric hydrogen storage capacity and a volumetric capacity greater than 0.050 kg/L hydrogen. Future research is directed at lowering dehydrogenation temperatures. The advantages of such a system are that unlike other chemical hydrogen storage concepts, dehydrogenation does not require water. However regeneration efficiency and cost are important factors (FCT Hydrogen Storage, 2013).

<u>Alcoholysis</u>

Alcoholysis is a recently reported variation of hydrolysis in which lightweight metal hydrides such as LiH, NaH, and $MgH_2$ are reacted with methanol or ethanol instead of water. Alcoholysis reactions are hoped to provide controlled and convenient hydrogen production at room temperature and below.

As is the case with hydrolysis reactions, alcoholysis reaction products cannot be regenerated in situ and a constant supply of alcohol must also be available, which impacts system complexity and cost (FCT Hydrogen Storage, 2013).

### 9.5.3 Other Chemical Storage Options

A number of other chemical storage methods are currently under investigation including:

- Synthesised hydrocarbons;
- Liquid Organic Hydrogen Carriers (LOHC);
- Ammonia;
- Amine-borane complexes;
- Formic acid;
- Imidazolium ionic liquids;
- Phosphonium borate;

These storage methods are generally variations of the methods previously described. They do not currently offer any significant advantages and they share the same common drawbacks.

### 9.5.4 Summary

Though some of the chemical storage methods, such as metal hydrides, have potential for medium term application in small scale applications such as automotive hydrogen fuel storage, scale-up of these technologies for bulk industrial hydrogen storage is impractical. Furthermore, as the storage medium is relatively expensive and the quantity required is proportional to the quantity of hydrogen to be stored, the economies of scale available from large pressurised storage systems such as salt caverns do not exist for chemical storage media.

As with physical storage techniques, a critical uncertainty is whether impurities contained within hydrogen generated via syngas (such as $CO_2$ and CO) will adversely affect the chemical storage media.

### 9.5.5 Hydrogen Adsorption for Storage Applications

A comparison of physical and chemical storage with pressurised and refrigerated storage options is provided in Table 41.

**Table 41 –** Hydrogen Storage Methods - adapted from Züttel, 2004

| **Method of Storage** | **Comments** | **Pressure (bar)** | **Temperature (°C)** | **Gravimetric Capacity (mass%)** | **Volumetric Capacity (kg $H_2/m^3$)** |
|---|---|---|---|---|---|
| High-pressure gas cylinders | Metal cylinders | 350-700 | Ambient | 3-5 | <50 |
| High-pressure gas cylinders | Lightweight composite instead of metal cylinders | 350-700 | Ambient | 10-15 | <40 |
| Cryogenic storage of liquid $H_2$ | Large insulation volume. Boil-off due to ambient gain | Atm | -252 | 5-10 | 70 |
| Physically Adsorbed $H_2$ | Materials include activated carbon. High specific area required | 100 | -80 | ~2 | 20 |
| Chemically Adsorbed $H_2$ | Materials include metals. High specific area required | 1 | Ambient | ~2 | 150 |

Though physical storage methods can achieve reasonable volumetric storage density, the key gravimetric capacity measure for transport applications is currently relatively poor.

Based on Table 41, to supply the hydrogen required for 12 hour diurnal operation of a single gas turbine (72,000 kg/h $H_2$), the volume of adsorbent required would be approximately 45000 $m^3$ at 100 bar and -80°C for physical adsorbent media, or 6000 $m^3$ at ambient conditions for chemical adsorbent media. However, when considering these media for storage of bulk hydrogen for turbine power generation, the following points need to be taken into account:

- The density of hydrogen at 100 bar and -80°C is 12.5 kg/$m^3$, so activated carbon only appears to increase volumetric capacity by a factor 2. Based on the calculations in section 9.3.1, vessel based storage is almost an order of magnitude more expensive that salt cavern storage, so halving the volume will not make above ground storage more attractive than salt caverns, particularly when the cost of carbon is taken into account.
- Figures shown are hydrogen capacity figures, not working volumes. The volume of hydrogen available is a function of the operating pressure range. It is likely that the working volume are roughly 50% of the adsorbed volume (representing 50% “cushion gas” volume) which would double the media volume required.
- Impurities present in the hydrogen will adversely affect the adsorbent performance and may require greater levels of purification which will increase cost and reduce yield.
- Although ambient conditions are quoted for chemical adsorbent option, higher pressure will be required to achieve adsorption and high temperatures will be required to cause desorption.
- Nitrogen is still required as a diluent for hydrogen GT firing and will still need to be stored. Nitrogen could also be stored using physical adsorption, but the scope for chemical adsorption is less than for hydrogen.

## *9.6* Geological Storage Options

The following section summarises information supplied by BGS concerning alternative geological methods of hydrogen storage. For full detail, refer to the BGS report, Section 8.

Table 42 outlines the number of underground natural gas storage facilities, working volumes and deliverability worldwide. The vast majority of underground gas storage (UGS) facilities are developed in depleted (or depleting) oil/gasfields, with the next most common locations being aquifers and then salt caverns. Other facilities (abandoned mines or lined rocks caverns) are very rarely used.

Most salt cavern facilities are designed with the intent of cycling the entire working gas capacity 5 to 10 times each year. Typical injection periods are in the range of 20 days. In contrast, more traditional storage, such as storage in depleted reservoirs, is normally cycled only once each year and typically requires between 70 and 200 days to refill.

**Table 42 – Summary of underground natural gas storage facilities worldwide (BGS report, Section 8.2)**

| Area | Type and Number of UGS facilities (2005) | | | | | Working Volume | Deliverability |
|---|---|---|---|---|---|---|---|
| | *Gas & Oil Fields* | *Aquifers* | *Salt Caverns* | *Other* | *Total* | *($x10^9m^3$)* | *($x10^6m^3/d$)* |
| *Europe* | 64 | 23 | 27 | 3 | **117** | 75 | 1,448 |
| *Former Soviet Union* | 36 | 13 | 1 | | **50** | 110 | 983 |
| *U.S.A.* | 320 | 44 | 30 | | **394** | 113.5 | 2,389 |
| *Canada* | 44 | | 8 | | **52** | 17 | 279 |
| *South America* | 2 | | | | **2** | 0.2 | 2 |
| *Asia* | 7 | | | | **7** | 2.6 | 14 |
| *Australia* | 5 | | | | **5** | 1.0 | 10 |
| **Total (%)** | **478 (76)** | **80 (13)** | **66 (11)** | **3 (<1)** | **627** | **319.3** | **5,105** |

The factors that determine whether or not a reservoir or salt cavern storage facility will make a suitable storage facility are both geographical and geological. Geographically, potential sites would, ideally, be relatively close to the consuming regions or industry. They must also be close to transport infrastructure, including main and trunk pipelines and distribution systems. Geologically, pore storage options (depleted oil-/gas-fields and aquifers) require good porosity and permeability. The porosity of the formation determines the amount of gas that it may hold. The permeability determines the rate at which gas flows through the rock formation, which in turn determines the achievable rate of injection and withdrawal of working gas.

Together, the porosity and permeability of reservoirs determine the effectiveness or performance and thus economic viability of any specific site. Depleted hydrocarbon reservoirs, because they have held and produced hydrocarbons, tend to have high permeability and porosity. They have also proved the integrity of the trap to retain hydrocarbons over geological time (millions of years). This is different for aquifer storage, where the porosity, permeability and cap rock all have to be proven, which is more expensive and impacts upon the viability of any proposed development.

Underground storage is the most inexpensive means of storing large quantities of hydrogen (Amos, 1998). Capital costs vary depending on whether there is a suitable natural cavern or rock formation available, or whether a cavern must be mined. Use of abandoned natural gas/oil wells is the cheapest option, followed by solution salt mining and hard rock mining.

### 9.6.1 Depleted Oil/Gasfields

Depleted gas and oil reservoirs provide the greatest storage volumes and have been the most prominent and commonly used storage type for natural gas storage to date. They are also generally the least expensive method of storing natural gas in large quantities. Worldwide, depleted reservoirs currently number around 480 storage facilities, representing over 75% of known UGS facilities.

Although the use of depleted hydrocarbon reservoirs is much more common in the US; natural gas is already stored in depleted reservoirs in the UK, in locations such as the Rough Field in the Southern North Sea.

Essentially, oil/gas fields comprise a reservoir with high porosity and permeability and an impermeable caprock, which acts to trap the oil/gas in situ. The high permeability and porosity allows large volumes of gas to be more readily injected, stored and withdrawn. The operating concept is simple: on field depletion, gas is injected into the pore spaces left after removal of the original oil or gas. Generally, the reservoirs are easy to develop, operate, and maintain due to existing infrastructure. Geologically, they represent ideal storage types (and are the preferred storage type in the British & European Standards documents) for a number of reasons:

1. They comprise a known, viable and proven structure or trap that has retained hydrocarbons for many millions of years;
2. The performance of the reservoir rock is known from the production history, which makes modelling, constraining and verifying the gas injection, storage cycles and area of injected gas simpler; and
3. The caprock is known to be suitable and to retain hydrocarbons, although studies are required to assess any damage that might have arisen due to field development such as reduced reservoir pressure and damaged wells.

Despite numerous advantages it is essential that the reservoir is suited to storing gas at high pressure. In some cases, there is a caprock threshold pressure - the pressure required for gas to displace capillary water - above which stored gas will be lost. If not recognised, loss of injected/stored gas inventory can occur when operating pressure exceeds this threshold pressure. Additional loss of injected product may also occur through fingering of gas – escape of gas from the main body of the reservoir into lower pressure regions from which it is not recoverable.

Not all depleted fields have storage potential: low original porosities and permeabilities, reservoir damage such as decreasing porosity/permeability arising from pressure drops and reservoir collapse during production, or water invasion all have the potential to render reservoirs unsuitable for UGS.

With regards to hydrogen storage, depleted fields will require considerable work to demonstrate sufficient sealing capacity of the caprock to ensure hydrogen remains within the reservoir horizon. The caprock will have undergone some fracturing and microfracturing as a result of depressuring the underlying reservoir during production. Even if halite beds are present just above the cap rock, it will have to be shown that the other lithologies have the required low porosities and permeabilities to prevent hydrogen migrating up and out of the structure.

Careful site characterisation would be required to prove the integrity of the structure and even after this it is likely that structures will be unsuitable for hydrogen storage.

Another key potential issue with hydrogen storage in depleted oil and gas wells is contamination. Even when oil and gas fields are depleted to the point where they become uneconomic, a large amount of extractable material remains and this will mix with the hydrogen injected for storage, resulting in an extracted gas containing relatively high levels of methane, higher hydrocarbons and potentially nitrogen, $CO_2$, $H_2S$ and mercaptans. If the hydrogen is produced from fossil fuels (possibly natural gas) to provide a decarbonised fuel, it seems counterproductive to mix the resulting hydrogen with natural gas and other contaminants through temporary storage in a depleted oil or gas well.

### 9.6.2 Aquifers and Permeable Strata, including Limestone

Gas storage in aquifers is based on the same concepts as depleted oil-/gas-fields. The principle of aquifer storage is to create an artificial gas-field by ‘reconditioning’ the water-bearing, porous and permeable formations (aquifers) and injecting gas into the water-bearing pore spaces. A knock on effect of this intimacy with water is that upon extraction, gas typically must be dehydrated prior to transport. This requires specialized process plant on site near the wellhead and extra expense.

Around 80 gas storage aquifers are in operation around the world today, most of which are in the United States, the former Soviet Union and Western Continental Europe. The UK has no operating aquifer storage facilities.

Although aquifers typically occur in rocks such as sandstone, other structures may comprise chalk and fractured hard rock types such as limestones or igneous rocks. A potentially suitable aquifer for storage will have geology similar to depleted gas reservoirs, requiring an existing formation pressure, good trapping configuration, and high porosities and permeabilities that provide large reservoir volume and flowrate capacity.

Hydrogen or syngas withdrawn from aquifer storage will require dehydration, but will not suffer the same purity issues associated with storage in depleted oil or gas wells, since aquifers do not contain naturally occurring gas.

Aquifer storage represents a more costly option than depleted reservoirs as aquifers require the following additional investment:

1. Conditioning and more preliminary work to prove the presence and capability of a structure to hold and contain gas under pressure.
2. Construction of above ground infrastructure - equipment such as wells, pipelines, injection and dehydration systems;
3. Cushion gas to displace the original water and reach the minimum operating pressure.

Small gas losses may occur through the caprock, by dissolution into connate water and diffusion into the surrounding groundwater. As in depleted fields, some gas may also become lost through fingering.

Applicability to the UK

In the UK context (and generally), aquifer storage represents the most expensive type of storage facility for natural gas for the reasons outlined above. Aquifer storage facilities are usually used only in areas where no nearby depleted hydrocarbon reservoirs exist, so should only be considered if other options are limited.

Salt caverns have been used commercially in the UK for natural gas and hydrogen storage whereas aquifer storage has not been commercialised in the UK for either use. This would suggest that salt caverns have a techno-economic advantage over aquifers for UGS. Hydrogen is more valuable than natural gas and a more difficult gas to store due to its high diffusivity. As halite is one of the few lithologies that self-heals to remove cracks through which hydrogen might escape, this gives salt caverns a further advantage over aquifers for hydrogen UGS.

### 9.6.3 Other Mined Voids

Abandoned/reconditioned Coal Mines

Abandoned coal mines offer potential in terms of gas storage and have been used to store natural gas underground in the past, including two mines in Belgium, one in Colorado and one in Illinois - all have now been decommissioned. To ensure gas containment, the mined coal seam needs to be surrounded by impermeable layers and the geology and hydrostatic pressure will determine the pressure at which the mine can be operated. The volume of gas that can potentially be stored in a coal mine is based not only on the volume mined, but also on the adsorption rate of the unmined coal: gas is adsorbed on to the coal, which it was estimated in the Belgium example increased the (natural) gas storage by a factor of ten.

In both the Belgium and Colorado locations mentioned above, problems with leakage through either the caprock or overburden was encountered. This is often due to fracturing and microfracturing of the rock structure caused during mining activities, which lead to a loss of sealing integrity.

Given their operating record, great care should be taken to undertake a thorough survey of the mining history as well as the surrounding/enclosing geology prior to use of coal mines for UGS. Furthermore, as hydrogen has a higher diffusivity than natural gas, it is more likely for leaks to occur.

Abandoned Salt Mines

Abandoned salt mines have been used quite widely to store fuel products, particularly LPG and crude oil as part of the American Strategic Petroleum Reserve in America. They are based upon the same principals as abandoned coal mine storage, but are however, generally at shallow depths and have encountered problems in retaining the stored product.

These formations are thus deemed unsuitable for hydrogen storage.

Unlined Rock Caverns

Unlined rock caverns have been used for decades to store a wide range of low vapour pressure products, mostly liquids such as crude oil, butane, and propane. Around 70 mined LPG storage facilities have been commissioned in the USA and around 20 in Europe, including the Killingholme LPG storage site in North Lincolnshire. Few operational unlined cavern facilities store natural gas.

Abandoned limestone mines have in the past been converted for gas storage purposes. An example is a Compressed Air Energy Storage (CAES) plant which is located in an old limestone mine 670 m below ground in Ohio. The mine covers an area about 2130 m by 1220 m and has a capacity of 9.6 million cubic metres. Although well below the water table, the mine is said to be virtually dry. The limestone is a dense rock with few fractures, tests revealing it is capable of withstanding the planned operating pressure range of 55-110 bar.

Limestone cavern storage as a concept is still at the research stage with many factors requiring further investigation. These include the issues of gas tightness, cavern stability and the disposal of large amounts of carbon dioxide that is generated by the dissolution of the limestone during construction. Whilst unlikely to be of immediate interest to developers in the UK, it could potentially have applications using materials such as chalk.

The gas tightness of limestone or chalk in hydrogen storage service would require investigation, and the $CO_2$ released during creation of the storage cavern should also be considered in the footprint of a low carbon power generation facility.

Refrigerated Unlined Rock Caverns

The concept of refrigerated cavern storage stems from the fact that as gas temperature is lowered it becomes more dense.

The development of refrigerated mined caverns would reduce the cost of construction by reducing the amount of rock that must be excavated. The caverns represent plausible substitutes for salt storage where salt deposits are not available. However, compared to other options, hard rock caverns are generally economically unattractive.

Lined Rock Cavities/Caverns

In countries and regions where porous sandstone and salt are absent, lined rock cavities (LRC) provide modest storage capacities where crystalline and metamorphic strata form the majority of rocks at outcrop. LRCs are generally large voids excavated out of the country rock with steel plate or polypropylene plastic linings constructed inside the void to act as an impervious layer, completely containing the gas and ensuring gas tightness. This steel or plastic 'vessel' is then cemented in place, with the cement providing a further barrier to gas migration and also filling the gap between the steel/plastic vessel and the rock walls to provide stability and protect the lining from damage against the host rock. LRCs are more expensive than unlined rock caverns, but in countries lacking deep sedimentary basins with suitable reservoir and caprock sequences, may offer the more economical solution for high volume gas storage.

In the UK, use of LRCs is unnecessary, since many cheaper alternatives are available.

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# ATTACHMENT 1
# BGS REPORT

# ATTACHMENT 2
# COST OF BRINE PIPELINES

Project No: 13058
Client: ETI
Project: H2 Storage & Flexible Turbines
Location: Generic NE England

# BRINE PIPELINES SUMMARY

## B31.4 CODE, BRINE 40C & 20BAR
## DESIGN FACTOR 0.5, 0.6 or 0.72

Rev : 01
Date : 14-Mar-13
By : KSW

| Nom. Dia in. | MATERIAL OF CONSTRUCTION | Pipeline Size OD in. | Wall Thickness mm | PIPELINE MATERIALS GBP/km | PIPELINE CONSTRUCTION GBP/km | PIPELINE CROSSINGS GBP/km | PIPELINE SERVICES GBP/km | OVERALL TOTAL GBP/km |
|---|---|---|---|---|---|---|---|---|
| 6 | API 5L GRB | 6.63 | 7.11 | 77,900 | 126,000 | | 22,700 | 227,000 |
| 8 | API 5L GRB | 8.63 | 8.18 | 104,700 | 164,000 | | 29,900 | 299,000 |
| 10 | API 5L GRB | 10.75 | 9.27 | 132,600 | 204,000 | | 37,400 | 374,000 |
| 12 | API 5L GRB | 12.75 | 9.53 | 156,400 | 242,000 | | 44,300 | 443,000 |
| 14 | API 5L GRB | 14.00 | 7.92 | 160,100 | 266,000 | | 47,300 | 473,000 |
| 16 | API 5L GRB | 16.00 | 7.92 | 186,100 | 304,000 | | 54,500 | 545,000 |
| 18 | API 5L X65 | 18.00 | 7.92 | 222,100 | 342,000 | | 62,700 | 627,000 |
| 20 | API 5L X65 | 20.00 | 9.53 | 262,200 | 380,000 | | 71,400 | 714,000 |
| 22 | API 5L X65 | 22.00 | 9.53 | 296,100 | 418,000 | | 79,300 | 793,000 |
| 24 | API 5L X65 | 24.00 | 9.53 | 334,000 | 455,000 | | 87,700 | 877,000 |
| 30 | API 5L X65 | 30.00 | 9.53 | 468,800 | 569,000 | | 115,300 | 1,153,000 |
| 32 | API 5L X65 | 32.00 | 9.53 | 516,700 | 607,000 | | 124,900 | 1,249,000 |
| 36 | API 5L X65 | 36.00 | 9.53 | 602,500 | 683,000 | | 142,800 | 1,428,000 |
| 42 | API 5L X65 | 42.00 | 12.70 | 862,300 | 797,000 | | 184,400 | 1,844,000 |
| 48 | API 5L X65 | 48.00 | 12.70 | 1,029,500 | 911,000 | | 215,600 | 2,156,000 |
| 60 | API 5L X65 | 60.00 | 12.70 | 1,262,800 | 1,138,000 | | 266,800 | 2,668,000 |

FOSTER WHEELER

| | | | |
|---|---|---|---|
| Project No: 13058<br>Client:ETI<br>Project: H2 Storage Study<br>Location: Generic NE England | **ETI H2 STORAGE STUDY**<br>**OVERALL HDPE PIPELINES SUMMARY - BRINE 20BAR** | Rev :<br>Date :<br>By :<br>Printed: | '0'<br>13-May-13<br>KSW<br>15-May-13 |

| Nom Dia in. | MATERIAL OF CONSTRUCTION | Pipeline Size OD in. | Wall thkness mm | PIPELINE MATERIALS GBP | PIPELINE CONSTRUCTION GBP | PIPELINE CROSSINGS GBP | PIPELINE SERVICES GBP | OVERALL TOTAL GBP |
|---|---|---|---|---|---|---|---|---|
| 6 | HDPE | 6.63 | 17.90 | 42,200 | 104,000 | | 16,200 | 162,000 |
| 8 | HDPE | 8.63 | 25.20 | 60,300 | 135,000 | | 21,700 | 217,000 |
| 10 | HDPE | 10.75 | 27.90 | 69,800 | 167,000 | | 26,300 | 263,000 |
| 12 | HDPE | 12.75 | 35.20 | 91,400 | 198,000 | | 32,200 | 322,000 |
| 14 | HDPE | 14.00 | 39.70 | 110,200 | 218,000 | | 36,500 | 365,000 |
| 16 | HDPE | 16.00 | 44.70 | 136,300 | 248,000 | | 42,700 | 427,000 |
| 18 | HDPE | 18.00 | 50.30 | 176,600 | 280,000 | | 50,700 | 507,000 |
| 20 | HDPE | 20.00 | 55.80 | 203,100 | 311,000 | | 57,100 | 571,000 |
| 22 | HDPE | 22.00 | 62.20 | 248,800 | 342,000 | | 65,600 | 656,000 |

FOSTER WHEELER

| | | | |
|---|---|---|---|
| Project No: 13058<br>Client:ETI<br>Project: H2 Storage Study<br>Location: Generic NE England | **ETI H2 STORAGE STUDY**<br><br>**OVERALL HDPE PIPELINES SUMMARY - BRINE 5BAR** | Rev :<br>Date :<br>By :<br>Printed: | '0'<br>13-May-13<br>KSW<br>15-May-13 |

| Nom Dia in. | MATERIAL OF CONSTRUCTION | Pipeline Size OD in. | Wall thkness mm | PIPELINE MATERIALS GBP | PIPELINE CONSTRUCTION GBP | PIPELINE CROSSINGS GBP | PIPELINE SERVICES GBP | OVERALL TOTAL GBP |
|---|---|---|---|---|---|---|---|---|
| 6 | HDPE | 6.63 | 4.90 | 33,700 | 104,000 | | 15,300 | 153,000 |
| 8 | HDPE | 8.63 | 6.90 | 43,300 | 135,000 | | 19,800 | 198,000 |
| 10 | HDPE | 10.75 | 7.70 | 48,800 | 167,000 | | 24,000 | 240,000 |
| 12 | HDPE | 12.75 | 9.70 | 58,400 | 198,000 | | 28,500 | 285,000 |
| 14 | HDPE | 14.00 | 10.90 | 68,200 | 218,000 | | 31,800 | 318,000 |
| 16 | HDPE | 16.00 | 12.30 | 83,200 | 248,000 | | 36,800 | 368,000 |
| 18 | HDPE | 18.00 | 13.80 | 106,100 | 280,000 | | 42,900 | 429,000 |
| 20 | HDPE | 20.00 | 15.30 | 120,000 | 311,000 | | 47,900 | 479,000 |
| 22 | HDPE | 22.00 | 17.20 | 145,300 | 342,000 | | 54,100 | 541,000 |
| 24 | HDPE | 24.00 | 18.00 | 170,500 | 373,000 | | 60,400 | 604,000 |
| 30 | HDPE | 30.00 | 23.10 | 281,400 | 467,000 | | 83,200 | 832,000 |
| 32 | HDPE | 32.00 | 24.50 | 322,600 | 498,000 | | 91,200 | 912,000 |
| 36 | HDPE | 36.00 | 27.60 | 396,400 | 560,000 | | 106,300 | 1,063,000 |
| 42 | HDPE | 42.00 | 32.00 | 573,900 | 654,000 | | 136,400 | 1,364,000 |
| 48 | HDPE | 48.00 | 36.70 | 704,800 | 746,000 | | 161,200 | 1,612,000 |
| 60 | HDPE | 60.00 | 45.00 | 966,100 | 933,000 | | 211,000 | 2,110,000 |

# ATTACHMENT 3
# ABOVE GROUND FACILITY CAPITAL COST SUMMARIES @ 45bara

| | |
|---|---|
| Project: No 13058 | Rev : 0 |
| Client : ETI | Date : |
| Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW |
| Location : UK | Printed: 08/05/2013 |

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 1 45 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SYNGAS UNIT | ABOVE GROUND FACILITY IN SALT CAVERN SITE | PIPELINE, 10 km (20 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 5,881,000 | 1,255,000 | | 7,136,000 |
| | DIRECT BULK MATERIALS | | 2,843,000 | 678,000 | | 3,521,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 3,088,000 | 605,000 | 7,170,000 | 10,863,000 |
| | LABOUR ONLY CONTRACTS | | 2,643,000 | 534,000 | | 3,177,000 |
| | INDIRECTS | | 510,000 | 107,000 | | 617,000 |
| | EPC CONTRACTS | | 1,259,000 | 787,000 | | 2,046,000 |
| | **INSTALLED COST** | | 16,224,000 | 3,966,000 | 7,170,000 | 27,360,000 |
| | LAND COSTS | 5% | 811,200 | 198,300 | 358,500 | 1,368,000 |
| | OWNERS COSTS | 10% | 1,622,400 | 396,600 | 717,000 | 2,736,000 |
| | CONTINGENCY | 25% | 4,056,000 | 991,500 | 1,792,500 | 6,840,000 |
| | **TOTAL PROJECT COST** | | 22,713,600 | 5,552,400 | 10,038,000 | 38,304,000 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

Project: No 13058
Client : ETI
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES
Location : UK

Rev : 0
Date : 09/04/2013
By : KSW
Printed: 08/05/2013

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 2 45 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SYNGAS UNIT | ABOVE GROUND FACILITY IN SALT CAVERN SITE | PIPELINE, 10 km (24 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 4,515,000 | 1,275,000 | | 5,790,000 |
| | DIRECT BULK MATERIALS | | 2,115,000 | 539,000 | | 2,654,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 2,290,000 | 526,000 | 9,040,000 | 11,856,000 |
| | LABOUR ONLY CONTRACTS | | 1,948,000 | 438,000 | | 2,386,000 |
| | INDIRECTS | | 388,000 | 108,000 | | 496,000 |
| | EPC CONTRACTS | | 1,176,000 | 545,000 | | 1,721,000 |
| | **INSTALLED COST** | | 12,432,000 | 3,431,000 | 9,040,000 | 24,903,000 |
| | LAND COSTS | 5% | 621,600 | 171,550 | 452,000 | 1,245,150 |
| | OWNERS COSTS | 10% | 1,243,200 | 343,100 | 904,000 | 2,490,300 |
| | CONTINGENCY | 25% | 3,108,000 | 857,750 | 2,260,000 | 6,225,750 |
| | **TOTAL PROJECT COST** | | 17,404,800 | 4,803,400 | 12,656,000 | 34,864,200 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

Project: No 13058
Client : ETI
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES
Location : UK

Rev : 0
Date : 09/04/2013
By : KSW
Printed: 08/05/2013

# ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 3 45 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SYNGAS UNIT | ABOVE GROUND FACILITY IN SALT CAVERN SITE | PIPELINE, 10 km (30 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 9,000,000 | 2,350,000 | | 11,350,000 |
| | DIRECT BULK MATERIALS | | 4,503,000 | 1,076,000 | | 5,579,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 4,920,000 | 1,073,000 | 12,310,000 | 18,303,000 |
| | LABOUR ONLY CONTRACTS | | 4,273,000 | 944,000 | | 5,217,000 |
| | INDIRECTS | | 790,000 | 203,000 | | 993,000 |
| | EPC CONTRACTS | | 1,455,000 | 1,091,000 | | 2,546,000 |
| | **INSTALLED COST** | | 24,941,000 | 6,737,000 | 12,310,000 | 43,988,000 |
| | LAND COSTS | 5% | 1,247,050 | 336,850 | 615,500 | 2,199,400 |
| | OWNERS COSTS | 10% | 2,494,100 | 673,700 | 1,231,000 | 4,398,800 |
| | CONTINGENCY | 25% | 6,235,250 | 1,684,250 | 3,077,500 | 10,997,000 |
| | **TOTAL PROJECT COST** | | 34,917,400 | 9,431,800 | 17,234,000 | 61,583,200 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

| | | | |
|---|---|---|---|
| Project: No 13058 | | Rev : | 0 |
| Client : ETI | | Date : | 09/04/2013 |
| Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | | By : | KSW |
| Location : UK | | Printed: | 08/05/2013 |

# ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 4-OUTLET 45 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN POWER ISLAND | PIPELINE, 10 km (30 inch) | TOTAL |
|---|---|---|---|---|---|
| | | | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 19,789,000 | | 19,789,000 |
| | DIRECT BULK MATERIALS | | 5,556,000 | | 5,556,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 6,973,000 | 12,310,000 | 19,283,000 |
| | LABOUR ONLY CONTRACTS | | 5,129,000 | | 5,129,000 |
| | INDIRECTS | | 1,549,000 | | 1,549,000 |
| | EPC CONTRACTS | | 1,833,000 | | 1,833,000 |
| | **INSTALLED COST** | | 40,829,000 | 12,310,000 | 53,139,000 |
| | LAND COSTS | 5% | 2,041,450 | 615,500 | 2,656,950 |
| | OWNERS COSTS | 10% | 4,082,900 | 1,231,000 | 5,313,900 |
| | CONTINGENCY | 25% | 10,207,250 | 3,077,500 | 13,284,750 |
| | **TOTAL PROJECT COST** | | 57,160,600 | 17,234,000 | 74,394,600 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

# ATTACHMENT 4
# ABOVE GROUND FACILITY CAPITAL COST SUMMARIES @ 105bara

Project: No 13058 | Rev : 0
Client : ETI | Date : 09/04/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW
Location : UK | Printed: 08/05/2013

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 1 105 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SYNGAS UNIT | ABOVE GROUND FACILITY IN SALT CAVERN SITE | PIPELINE, 10 km (12 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 9,785,000 | 1,255,000 | | 11,040,000 |
| | DIRECT BULK MATERIALS | | 5,219,000 | 678,000 | | 5,897,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 5,564,000 | 605,000 | 5,250,000 | 11,419,000 |
| | LABOUR ONLY CONTRACTS | | 4,898,000 | 534,000 | | 5,432,000 |
| | INDIRECTS | | 870,000 | 107,000 | | 977,000 |
| | EPC CONTRACTS | | 1,996,000 | 787,000 | | 2,783,000 |
| | **INSTALLED COST** | | 28,332,000 | 3,966,000 | 5,250,000 | 37,548,000 |
| | LAND COSTS | 5% | 1,416,600 | 198,300 | 262,500 | 1,877,400 |
| | OWNERS COSTS | 10% | 2,833,200 | 396,600 | 525,000 | 3,754,800 |
| | CONTINGENCY | 25% | 7,083,000 | 991,500 | 1,312,500 | 9,387,000 |
| | **TOTAL PROJECT COST** | | 39,664,800 | 5,552,400 | 7,350,000 | 52,567,200 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

Project: No 13058 | Rev : 0
Client : ETI | Date : 09/04/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW
Location : UK | Printed: 08/05/2013

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 2 105 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SYNGAS UNIT | ABOVE GROUND FACILITY IN SALT CAVERN SITE | PIPELINE, 10 km (16 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 7,689,000 | 1,275,000 | | 8,964,000 |
| | DIRECT BULK MATERIALS | | 4,089,000 | 539,000 | | 4,628,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 4,328,000 | 526,000 | 7,090,000 | 11,944,000 |
| | LABOUR ONLY CONTRACTS | | 3,818,000 | 438,000 | | 4,256,000 |
| | INDIRECTS | | 682,000 | 108,000 | | 790,000 |
| | EPC CONTRACTS | | 1,866,000 | 545,000 | | 2,411,000 |
| | **INSTALLED COST** | | 22,472,000 | 3,431,000 | 7,090,000 | 32,993,000 |
| | LAND COSTS | 5% | 1,123,600 | 171,550 | 354,500 | 1,649,650 |
| | OWNERS COSTS | 10% | 2,247,200 | 343,100 | 709,000 | 3,299,300 |
| | CONTINGENCY | 25% | 5,618,000 | 857,750 | 1,772,500 | 8,248,250 |
| | **TOTAL PROJECT COST** | | 31,460,800 | 4,803,400 | 9,926,000 | 46,190,200 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation,  Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

Project: No 13058 | Rev : 0
Client : ETI | Date : 09/04/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW
Location : UK | Printed: 08/05/2013

# ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 3 105 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SYNGAS UNIT | ABOVE GROUND FACILITY IN SALT CAVERN SITE | PIPELINE, 10 km (20 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 15,443,000 | 2,350,000 | | 17,793,000 |
| | DIRECT BULK MATERIALS | | 8,153,000 | 1,076,000 | | 9,229,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 8,804,000 | 1,073,000 | 8,110,000 | 17,987,000 |
| | LABOUR ONLY CONTRACTS | | 7,767,000 | 944,000 | | 8,711,000 |
| | INDIRECTS | | 1,374,000 | 203,000 | | 1,577,000 |
| | EPC CONTRACTS | | 2,340,000 | 1,091,000 | | 3,431,000 |
| | **INSTALLED COST** | | 43,881,000 | 6,737,000 | 8,110,000 | 58,728,000 |
| | LAND COSTS | 5% | 2,194,050 | 336,850 | 405,500 | 2,936,400 |
| | OWNERS COSTS | 10% | 4,388,100 | 673,700 | 811,000 | 5,872,800 |
| | CONTINGENCY | 25% | 10,970,250 | 1,684,250 | 2,027,500 | 14,682,000 |
| | **TOTAL PROJECT COST** | | 61,433,400 | 9,431,800 | 11,354,000 | 82,219,200 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

Project: No 13058 | Rev : 0
Client : ETI | Date : 09/04/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW
Location : UK | Printed: 08/05/2013

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## OUTLET FROM SALT CAVERN 105 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SALT CAVERN SITE | ABOVE GROUND FACILITY IN POWER ISLAND | PIPELINE, 10 km (20 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 22,245,000 | 5,593,000 | | 27,838,000 |
| | DIRECT BULK MATERIALS | | 6,654,000 | 3,167,000 | | 9,821,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 8,065,000 | 3,227,000 | 8,110,000 | 19,402,000 |
| | LABOUR ONLY CONTRACTS | | 6,255,000 | 3,046,000 | | 9,301,000 |
| | INDIRECTS | | 1,759,000 | 514,000 | | 2,273,000 |
| | EPC CONTRACTS | | 1,962,000 | 847,000 | | 2,809,000 |
| | **INSTALLED COST** | | 46,940,000 | 16,394,000 | 8,110,000 | 71,444,000 |
| | LAND COSTS | 5% | 2,347,000 | 819,700 | 405,500 | 3,572,200 |
| | OWNERS COSTS | 10% | 4,694,000 | 1,639,400 | 811,000 | 7,144,400 |
| | CONTINGENCY | 25% | 11,735,000 | 4,098,500 | 2,027,500 | 17,861,000 |
| | **TOTAL PROJECT COST** | | 65,716,000 | 22,951,600 | 11,354,000 | 100,021,600 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

# ATTACHMENT 5
# ABOVE GROUND FACILITY CAPITAL COST SUMMARIES @ 270bara

Project: No 13058 | Rev : 0
Client : ETI | Date : 09/04/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW
Location : UK | Printed: 08/05/2013

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 1 270 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SYNGAS UNIT | ABOVE GROUND FACILITY IN SALT CAVERN SITE | PIPELINE, 10 km (10 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 16,217,000 | 1,340,000 | | 17,557,000 |
| | DIRECT BULK MATERIALS | | 8,983,000 | 730,000 | | 9,713,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 9,451,000 | 642,000 | 5,450,000 | 15,543,000 |
| | LABOUR ONLY CONTRACTS | | 8,464,000 | 589,000 | | 9,053,000 |
| | INDIRECTS | | 1,456,000 | 112,000 | | 1,568,000 |
| | EPC CONTRACTS | | 3,357,000 | 787,000 | | 4,144,000 |
| | **INSTALLED COST** | | 47,928,000 | 4,200,000 | 5,450,000 | 57,578,000 |
| | LAND COSTS | 5% | 2,396,400 | 210,000 | 272,500 | 2,878,900 |
| | OWNERS COSTS | 10% | 4,792,800 | 420,000 | 545,000 | 5,757,800 |
| | CONTINGENCY | 25% | 11,982,000 | 1,050,000 | 1,362,500 | 14,394,500 |
| | **TOTAL PROJECT COST** | | 67,099,200 | 5,880,000 | 7,630,000 | 80,609,200 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

| | | | |
|---|---|---|---|
| Project: No 13058 | | Rev : | 0 |
| Client : ETI | | Date : | 09/04/2013 |
| Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | | By : | KSW |
| Location : UK | | Printed: | 08/05/2013 |

# ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 2 270 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SYNGAS UNIT | ABOVE GROUND FACILITY IN SALT CAVERN SITE | PIPELINE, 10 km (14 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 13,582,000 | 1,348,000 | | 14,930,000 |
| | DIRECT BULK MATERIALS | | 7,544,000 | 583,000 | | 8,127,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 7,880,000 | 557,000 | 7,960,000 | 16,397,000 |
| | LABOUR ONLY CONTRACTS | | 7,088,000 | 485,000 | | 7,573,000 |
| | INDIRECTS | | 1,219,000 | 113,000 | | 1,332,000 |
| | EPC CONTRACTS | | 3,191,000 | 545,000 | | 3,736,000 |
| | **INSTALLED COST** | | 40,504,000 | 3,631,000 | 7,960,000 | 52,095,000 |
| | LAND COSTS | 5% | 2,025,200 | 181,550 | 398,000 | 2,604,750 |
| | OWNERS COSTS | 10% | 4,050,400 | 363,100 | 796,000 | 5,209,500 |
| | CONTINGENCY | 25% | 10,126,000 | 907,750 | 1,990,000 | 13,023,750 |
| | **TOTAL PROJECT COST** | | 56,705,600 | 5,083,400 | 11,144,000 | 72,933,000 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

Project: No 13058 | Rev : 0
Client : ETI | Date : 09/04/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW
Location : UK | Printed: 08/05/2013

# ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 3 270 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SYNGAS UNIT | ABOVE GROUND FACILITY IN SALT CAVERN SITE | PIPELINE, 10 km (16 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 23,174,000 | 2,491,000 | | 25,665,000 |
| | DIRECT BULK MATERIALS | | 12,765,000 | 1,238,000 | | 14,003,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 13,447,000 | 1,134,000 | 9,760,000 | 24,341,000 |
| | LABOUR ONLY CONTRACTS | | 12,121,000 | 1,039,000 | | 13,160,000 |
| | INDIRECTS | | 2,080,000 | 212,000 | | 2,292,000 |
| | EPC CONTRACTS | | 3,790,000 | 1,091,000 | | 4,881,000 |
| | **INSTALLED COST** | | 67,377,000 | 7,205,000 | 9,760,000 | 84,342,000 |
| | LAND COSTS | 5% | 3,368,850 | 360,250 | 488,000 | 4,217,100 |
| | OWNERS COSTS | 10% | 6,737,700 | 720,500 | 976,000 | 8,434,200 |
| | CONTINGENCY | 25% | 16,844,250 | 1,801,250 | 2,440,000 | 21,085,500 |
| | **TOTAL PROJECT COST** | | 94,327,800 | 10,087,000 | 13,664,000 | 118,078,800 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

Project: No 13058 | Rev : 0
Client : ETI | Date : 09/04/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW
Location : UK | Printed: 08/05/2013

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## OUTLET FROM SALT CAVERN 270 BAR PRESSURE

| COST CODE | DESCRIPTION | | ABOVE GROUND FACILITY IN SALT CAVERN SITE | ABOVE GROUND FACILITY IN POWER ISLAND | PIPELINE, 10 km (16 inch) | TOTAL |
|---|---|---|---|---|---|---|
| | | | GBP | GBP | GBP | GBP |
| | MAJOR EQUIPMENT | | 24,643,000 | 19,810,000 | | 44,453,000 |
| | DIRECT BULK MATERIALS | | 8,411,000 | 11,203,000 | | 19,614,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 9,499,000 | 11,267,000 | 9,760,000 | 30,526,000 |
| | LABOUR ONLY CONTRACTS | | 8,154,000 | 10,906,000 | | 19,060,000 |
| | INDIRECTS | | 1,995,000 | 1,788,000 | | 3,783,000 |
| | EPC CONTRACTS | | 2,163,000 | 1,964,000 | | 4,127,000 |
| | **INSTALLED COST** | | 54,865,000 | 56,938,000 | 9,760,000 | 121,563,000 |
| | LAND COSTS | 5% | 2,743,250 | 2,846,900 | 488,000 | 6,078,150 |
| | OWNERS COSTS | 10% | 5,486,500 | 5,693,800 | 976,000 | 12,156,300 |
| | CONTINGENCY | 25% | 13,716,250 | 14,234,500 | 2,440,000 | 30,390,750 |
| | **TOTAL PROJECT COST** | | 76,811,000 | 79,713,200 | 13,664,000 | 170,188,200 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

# ATTACHMENT 6
# HYDROGEN RICH GAS PIPELINE COSTS - ONSHORE

FOSTER WHELER

| | |
|---|---|
| Project No: 13058<br>Client:ETI<br>Project: H2 Storage Study<br>Location: Generic NE England | **ETI H2 STORAGE STUDY**<br>**OVERALL PIPELINES SUMMARY B31.8 CODE - GAS 45C & 50BAR - DESIGN FACTOR 0.5** |
| Rev : '0'<br>Date : 30-Apr-13<br>By : KSW<br>Printed: 30-Apr-13 | |

| Nom Dia in. | MATERIAL OF CONSTRUCTION | Pipeline Size OD in. | Wall thkness mm | PIPELINE MATERIALS GBP/km | PIPELINE CONSTRUCTION GBP/km | PIPELINE CROSSINGS GBP | PIPELINE SERVICES GBP/km | OVERALL TOTAL GBP/km |
|---|---|---|---|---|---|---|---|---|
| 6 | API 5L GRB | 6.63 | 7.18 | 77,900 | 126,000 | | 22,700 | 227,000 |
| 8 | API 5L GRB | 8.63 | 8.45 | 105,600 | 164,000 | | 30,000 | 300,000 |
| 10 | API 5L GRB | 10.75 | 9.79 | 136,400 | 204,000 | | 37,800 | 378,000 |
| 12 | API 5L GRB | 12.75 | 11.05 | 168,900 | 242,000 | | 45,700 | 457,000 |
| 14 | API 5L GRB | 14.00 | 11.84 | 193,600 | 266,000 | | 51,100 | 511,000 |
| 16 | API 5L GRB | 16.00 | 13.10 | 237,800 | 304,000 | | 60,200 | 602,000 |
| 18 | API 5L X65 | 18.00 | 9.12 | 235,600 | 342,000 | | 64,200 | 642,000 |
| 20 | API 5L X65 | 20.00 | 9.80 | 265,200 | 380,000 | | 71,700 | 717,000 |
| 22 | API 5L X65 | 22.00 | 10.48 | 309,500 | 418,000 | | 80,800 | 808,000 |
| 24 | API 5L X65 | 24.00 | 11.16 | 358,900 | 455,000 | | 90,400 | 904,000 |
| 30 | API 5L X65 | 30.00 | 13.20 | 538,600 | 569,000 | | 123,100 | 1,231,000 |
| 32 | API 5L X65 | 32.00 | 13.88 | 605,600 | 607,000 | | 134,700 | 1,347,000 |
| 36 | API 5L X65 | 36.00 | 15.24 | 734,500 | 683,000 | | 157,500 | 1,575,000 |
| 42 | API 5L X65 | 42.00 | 17.28 | 985,700 | 797,000 | | 198,100 | 1,981,000 |
| 48 | API 5L X65 | 48.00 | 19.32 | 1,233,200 | 911,000 | | 238,200 | 2,382,000 |
| 60 | API 5L X65 | 60.00 | 23.40 | 1,675,900 | 1,138,000 | | 312,700 | 3,127,000 |

FOSTER WHELER

Project No: 13058
Client:ETI
Project: H2 Storage Study
Location: Generic NE England

# ETI H2 STORAGE STUDY

## OVERALL PIPELINES SUMMARY B31.8 CODE - GAS 45C & 120BAR - DESIGN FACTOR 0.5

Rev : '0'
Date : 30-Apr-13
By : KSW
Printed: 30-Apr-13

| Nom Dia in. | MATERIAL OF CONSTRUCTION | Pipeline Size OD in. | Wall thkness mm | PIPELINE MATERIALS GBP/km | PIPELINE CONSTRUCTION GBP/km | PIPELINE CROSSINGS GBP | PIPELINE SERVICES GBP/km | OVERALL TOTAL GBP/km |
|---|---|---|---|---|---|---|---|---|
| 6 | API 5L GRB | 6.63 | 11.37 | 94,100 | 126,000 | | 24,500 | 245,000 |
| 8 | API 5L GRB | 8.63 | 13.89 | 133,300 | 164,000 | | 33,000 | 330,000 |
| 10 | API 5L GRB | 10.75 | 16.57 | 179,500 | 204,000 | | 42,600 | 426,000 |
| 12 | API 5L GRB | 12.75 | 19.10 | 230,100 | 242,000 | | 52,500 | 525,000 |
| 14 | API 5L GRB | 14.00 | 20.68 | 268,200 | 266,000 | | 59,400 | 594,000 |
| 16 | API 5L GRB | 16.00 | 23.20 | 334,300 | 304,000 | | 70,900 | 709,000 |
| 18 | API 5L X65 | 18.00 | 15.24 | 304,400 | 342,000 | | 71,800 | 718,000 |
| 20 | API 5L X65 | 20.00 | 16.60 | 350,200 | 380,000 | | 81,100 | 811,000 |
| 22 | API 5L X65 | 22.00 | 17.96 | 412,800 | 418,000 | | 92,300 | 923,000 |
| 24 | API 5L X65 | 24.00 | 19.32 | 481,300 | 455,000 | | 104,000 | 1,040,000 |
| 30 | API 5L X65 | 30.00 | 23.40 | 730,800 | 569,000 | | 144,400 | 1,444,000 |
| 32 | API 5L X65 | 32.00 | 24.76 | 823,600 | 607,000 | | 159,000 | 1,590,000 |
| 36 | API 5L X65 | 36.00 | 27.48 | 1,010,800 | 683,000 | | 188,200 | 1,882,000 |
| 42 | API 5L X65 | 42.00 | 31.56 | 1,362,400 | 797,000 | | 239,900 | 2,399,000 |
| 48 | API 5L X65 | 48.00 | 35.64 | 1,725,700 | 911,000 | | 293,000 | 2,930,000 |
| 60 | API 5L X65 | 60.00 | 43.80 | 2,446,700 | 1,138,000 | | 398,300 | 3,983,000 |

FOSTER WHEELER

Project No: 13058
Client:ETI
Project: H2 Storage Study
Location: Generic NE England

# ETI H2 STORAGE STUDY

## OVERALL PIPELINES SUMMARY B31.8 CODE - GAS 45C & 285BAR - DESIGN FACTOR 0.5

Rev : '0'
Date : 30-Apr-13
By : KSW
Printed: 30-Apr-13

| Nom Dia in. | MATERIAL OF CONSTRUCTION | Pipeline Size OD in. | Wall thkness mm | PIPELINE MATERIALS GBP/km | PIPELINE CONSTRUCTION GBP/km | PIPELINE CROSSINGS GBP | PIPELINE SERVICES GBP/km | OVERALL TOTAL GBP/km |
|---|---|---|---|---|---|---|---|---|
| 6 | API 5L GRB | 6.63 | 22.87 | 134,300 | 126,000 | | 28,900 | 289,000 |
| 8 | API 5L GRB | 8.63 | 28.87 | 202,200 | 164,000 | | 40,700 | 407,000 |
| 10 | API 5L GRB | 10.75 | 35.24 | 286,600 | 204,000 | | 54,500 | 545,000 |
| 12 | API 5L GRB | 12.75 | 41.24 | 381,200 | 242,000 | | 69,200 | 692,000 |
| 14 | API 5L GRB | 14.00 | 44.99 | 450,800 | 266,000 | | 79,600 | 796,000 |
| 16 | API 5L GRB | 16.00 | 50.98 | 574,400 | 304,000 | | 97,600 | 976,000 |
| 18 | API 5L X65 | 18.00 | 32.07 | 483,200 | 342,000 | | 91,700 | 917,000 |
| 20 | API 5L X65 | 20.00 | 35.30 | 572,100 | 380,000 | | 105,800 | 1,058,000 |
| 22 | API 5L X65 | 22.00 | 38.53 | 680,500 | 418,000 | | 122,100 | 1,221,000 |
| 24 | API 5L X65 | 24.00 | 41.76 | 800,700 | 455,000 | | 139,500 | 1,395,000 |
| 30 | API 5L X65 | 30.00 | 51.45 | 1,230,900 | 569,000 | | 200,000 | 2,000,000 |
| 32 | API 5L X65 | 32.00 | 54.68 | 1,393,600 | 607,000 | | 222,300 | 2,223,000 |
| 36 | API 5L X65 | 36.00 | 61.13 | 1,731,800 | 683,000 | | 268,300 | 2,683,000 |
| 42 | API 5L X65 | 42.00 | 70.82 | 2,344,500 | 797,000 | | 349,100 | 3,491,000 |
| 48 | API 5L X65 | 48.00 | 80.51 | 3,009,900 | 911,000 | | 435,700 | 4,357,000 |
| 60 | API 5L X65 | 60.00 | 99.89 | 4,454,800 | 1,138,000 | | 621,400 | 6,214,000 |

# ATTACHMENT 7
# HYDROGEN RICH GAS PIPELINE COSTS - OFFSHORE

| FW Estimating Dept. | | FOSTER WHEELER | Date : | |
|---|---|---|---|---|
| Client : | ETI | | Prep. By : | KSW |
| Project : | | | | |
| | Salt cavern | | Rev. No. : | 0 |
| Contract No. : | 13058 | | Printed : | 03-May-13 |

| Description | Option | 105 bar | 105bar | 105bar | 105bar | 105bar | 105bar | 105bar | 105bar | 105bar | 105bar | 105bar | 105bar | 105bar | 105bar |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Pipeline | Offshore | Offshore | Offshore | Offshore | Offshore | Offshore | Offshore | Offshore | Offshore | Offshore | Offshore | Offshore | Offshore | Offshore |
| | Line Diameter (inches) | 10 | 12 | 14 | 16 | 18 | 20 | 22 | 24 | 30 | 32 | 36 | 42 | 48 | 60 |
| | Length (km) each | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| | No of Lines | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| | Length (km) total | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 | 25 |
| | | GBP | GBP | GBP | GBP | GBP | GBP | GBP | GBP | GBP | GBP | GBP | GBP | GBP | GBP |
| Overall Total Pipeline | | 79,000,000 | 81,000,000 | 84,000,000 | 86,000,000 | 87,000,000 | 89,000,000 | 93,000,000 | 96,000,000 | 105,000,000 | 107,000,000 | 117,000,000 | 130,000,000 | 148,000,000 | 183,000,000 |
| USE | £ m/km | 3.16 | 3.24 | 3.36 | 3.44 | 3.48 | 3.56 | 3.72 | 3.84 | 4.20 | 4.28 | 4.68 | 5.20 | 5.92 | 7.32 |

# ATTACHMENT 8

## ABOVE GROUND & TOPSIDES FACILITIES CAPITAL COST SUMMARIES OFFSHORE @ 105bara

| | | | |
|---|---|---|---|
| Project: No 13058 | | Rev : | 0 |
| Client : ETI | | Date : | |
| Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | | By : | KSW |
| Location : UK | | Printed: | 08/05/2013 |

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 1 105 BAR PRESSURE (OFFSHORE STORAGE)

| COST CODE | DESCRIPTION | | ABOVE GROUNG FACILITY IN SYNGAS UNIT GBP | TOPSIDE INJECTION FACILITY FOR SALT CAVERN GBP | ONSHORE PIPELINE, 10 km (16 inch) GBP | OFFSHORE PIPELINE, 25 km (16 inch) GBP | TOTAL GBP |
|---|---|---|---|---|---|---|---|
| | MAJOR EQUIPMENT | | 9,785,000 | 1,255,000 | | | 11,040,000 |
| | DIRECT BULK MATERIALS | | 5,219,000 | 678,000 | | | 5,897,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 5,564,000 | 605,000 | 7,090,000 | 86,000,000 | 99,259,000 |
| | LABOUR ONLY CONTRACTS | | 4,898,000 | 534,000 | | | 5,432,000 |
| | INDIRECTS | | 870,000 | 107,000 | | | 977,000 |
| | EPC CONTRACTS | | 1,996,000 | 787,000 | | | 2,783,000 |
| | **INSTALLED COST** | | **28,332,000** | **3,966,000** | **7,090,000** | **86,000,000** | **125,388,000** |
| | LAND COSTS | 5% | 1,416,600 | 198,300 | 354,500 | 4,300,000 | 6,269,400 |
| | OWNERS COSTS | 10% | 2,833,200 | 396,600 | 709,000 | 8,600,000 | 12,538,800 |
| | CONTINGENCY | 25% | 7,083,000 | 991,500 | 1,772,500 | 21,500,000 | 31,347,000 |
| | **TOTAL PROJECT COST** | | **39,664,800** | **5,552,400** | **9,926,000** | **120,400,000** | **175,543,200** |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

| | | | |
|---|---|---|---|
| Project: No 13058 | | Rev : | 0 |
| Client : ETI | | Date : | |
| Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | | By : | KSW |
| Location : UK | | Printed: | 08/05/2013 |

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 2 105 BAR PRESSURE (OFFSHORE STORAGE)

| COST CODE | DESCRIPTION | | ABOVE GROUNG FACILITY IN SYNGAS UNIT GBP | TOPSIDE INJECTION FACILITY FOR SALT CAVERN GBP | ONSHORE PIPELINE, 10 km (22 inch) GBP | OFFSHORE PIPELINE, 25 km (22 inch) GBP | TOTAL GBP |
|---|---|---|---|---|---|---|---|
| | MAJOR EQUIPMENT | | **7,689,000** | **1,275,000** | | | **8,964,000** |
| | DIRECT BULK MATERIALS | | **4,089,000** | **539,000** | | | **4,628,000** |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | **4,328,000** | **526,000** | **9,230,000** | **93,000,000** | **107,084,000** |
| | LABOUR ONLY CONTRACTS | | **3,818,000** | **438,000** | | | **4,256,000** |
| | INDIRECTS | | **682,000** | **108,000** | | | **790,000** |
| | EPC CONTRACTS | | **1,866,000** | **545,000** | | | **2,411,000** |
| | **INSTALLED COST** | | **22,472,000** | **3,431,000** | **9,230,000** | **93,000,000** | **128,133,000** |
| | LAND COSTS | 5% | **1,123,600** | **171,550** | **461,500** | **4,650,000** | **6,406,650** |
| | OWNERS COSTS | 10% | **2,247,200** | **343,100** | **923,000** | **9,300,000** | **12,813,300** |
| | CONTINGENCY | 25% | **5,618,000** | **857,750** | **2,307,500** | **23,250,000** | **32,033,250** |
| | **TOTAL PROJECT COST** | | **31,460,800** | **4,803,400** | **12,922,000** | **130,200,000** | **179,386,200** |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

Project: No 13058 | Rev : 0
Client : ETI | Date :
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW
Location : UK | Printed: 08/05/2013

## ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 3 105 BAR PRESSURE (OFFSHORE STORAGE)

| COST CODE | DESCRIPTION | | ABOVE GROUNG FACILITY IN SYNGAS UNIT GBP | TOPSIDE INJECTION FACILITY FOR SALT CAVERN GBP | ONSHORE PIPELINE, 10 km (30 inch) GBP | OFFSHORE PIPELINE, 25 km (30 inch) GBP | TOTAL GBP |
|---|---|---|---|---|---|---|---|
| | MAJOR EQUIPMENT | | 15,443,000 | 2,350,000 | | | 17,793,000 |
| | DIRECT BULK MATERIALS | | 8,153,000 | 1,076,000 | | | 9,229,000 |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | 8,804,000 | 1,073,000 | 14,440,000 | 105,000,000 | 129,317,000 |
| | LABOUR ONLY CONTRACTS | | 7,767,000 | 944,000 | | | 8,711,000 |
| | INDIRECTS | | 1,374,000 | 203,000 | | | 1,577,000 |
| | EPC CONTRACTS | | 2,340,000 | 1,091,000 | | | 3,431,000 |
| | **INSTALLED COST** | | 43,881,000 | 6,737,000 | 14,440,000 | 105,000,000 | 170,058,000 |
| | LAND COSTS | 5% | 2,194,050 | 336,850 | 722,000 | 5,250,000 | 8,502,900 |
| | OWNERS COSTS | 10% | 4,388,100 | 673,700 | 1,444,000 | 10,500,000 | 17,005,800 |
| | CONTINGENCY | 25% | 10,970,250 | 1,684,250 | 3,610,000 | 26,250,000 | 42,514,500 |
| | **TOTAL PROJECT COST** | | 61,433,400 | 9,431,800 | 20,216,000 | 147,000,000 | 238,081,200 |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

Project: No 13058 | Rev : 0
Client : ETI | Date :
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : KSW
Location : UK | Printed: 08/05/2013

# ORDER OF MAGNITUDE ESTIMATE SUMMARY
## CASE 4-OUTLET 105 BAR PRESSURE (OFFSHORE STORAGE)

| COST CODE | DESCRIPTION | | ABOVE GROUNG FACILITY IN POWER ISLAND GBP | TOPSIDE INJECTION FACILITY FOR SALT CAVERN GBP | ONSHORE PIPELINE, 10 km (30 inch) GBP | OFFSHORE PIPELINE, 25 km (30 inch) GBP | TOTAL GBP |
|---|---|---|---|---|---|---|---|
| | MAJOR EQUIPMENT | | **22,245,000** | **5,593,000** | | | **27,838,000** |
| | DIRECT BULK MATERIALS | | **6,654,000** | **3,167,000** | | | **9,821,000** |
| | DIRECT MATERIAL & LABOUR CONTRACTS | | **8,065,000** | **3,227,000** | **12,420,000** | **105,000,000** | **128,712,000** |
| | LABOUR ONLY CONTRACTS | | **6,255,000** | **3,046,000** | | | **9,301,000** |
| | INDIRECTS | | **1,759,000** | **514,000** | | | **2,273,000** |
| | EPC CONTRACTS | | **1,962,000** | **847,000** | | | **2,809,000** |
| | **INSTALLED COST** | | **46,940,000** | **16,394,000** | **12,420,000** | **105,000,000** | **180,754,000** |
| | LAND COSTS | 5% | **2,347,000** | **819,700** | **621,000** | **5,250,000** | **9,037,700** |
| | OWNERS COSTS | 10% | **4,694,000** | **1,639,400** | **1,242,000** | **10,500,000** | **18,075,400** |
| | CONTINGENCY | 25% | **11,735,000** | **4,098,500** | **3,105,000** | **26,250,000** | **45,188,500** |
| | **TOTAL PROJECT COST** | | **65,716,000** | **22,951,600** | **17,388,000** | **147,000,000** | **253,055,600** |

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneous 1 Q 2010

## ATTACHMENT 9

## UTILITIES SUMMARY – STORAGE SCENARIOS AT 45bara, 105bara & 270bara

**FOSTER WHEELER ENERGY LIMITED**
**UTILITIES BALANCE SUMMARY**

**Work Package 2**

**CLIENT:** The Energy Technologies Institute
**CONTRACT:** 13058
**NAME:** Hydrogen Storage and Flexible Turbine System

SHEET 1 OF 1

| | DESCRIPTION | Steady State Averaged Power kW | Hot Water Supply t/h | Sea Water t/h | Fresh Cooling Water t/h | Natural Gas Fuel $Nm^3/h$ | Process Water t/h | REMARKS | REV |
|---|---|---|---|---|---|---|---|---|---|
| | **Storage (Note 1) - 45 bara** | | | | | | | | |
| | Hydrogen Compression in Syngas Plant | -6584 | | -804 | -663 | | | | |
| | Nitrogen Compression in Syngas Plant | -5834 | | -740 | -572 | | | | |
| | Fresh Cooling Water in Syngas Plant | | | | 1235 | | | | |
| | Seawater to Syngas Plant | | | 1544 | | | | | |
| | Water Wash at Cavern Outlet | | | | | | | | |
| | Gas Heating at Cavern Inlet | | | | | -48 | | | |
| | Water Wash at Cavern Outlet | | | | | | -10 | | |
| | Fuel Gas Drying at Cavern outlet | -500 | | | | -174 | | | |
| | Net Power Supply from Power Island | 12918 | | | | | | | |
| | Natural Gas Import | | | | | 222 | | | |
| | Storage Total | 0 | 0 | 0 | 0 | 0 | -10 | | |
| | **Storage (Note 1) - 105 bara** | | | | | | | | |
| | Hydrogen Compression in Syngas Plant | -19064 | | -1796 | -1437 | | | | |
| | Nitrogen Compression in Syngas Plant | -16837 | | -1715 | -1372 | | | | |
| | Fresh Cooling Water in Syngas Plant | | | | 2809 | | | | |
| | Seawater to Syngas Plant | | | 3511 | | | | | |
| | Gas Heating at Cavern Inlet | | | | | -88 | | | |
| | Water Wash at Cavern Outlet | | | | | | -10 | | |
| | Fuel Gas Drying at Cavern outlet | -500 | | | | -274 | | | |
| | Fuel Gas Heating in Power Island | | -139 | | | | | | |
| | Fuel Gas Expander | 14460 | | | | | | | |
| | Net Power Supply from Power Island | 21941 | | | | | | | |
| | Hot Water from Power Island | | 139 | | | | | | |
| | Natural Gas Import | | | | | 362 | | | |
| | Storage Total | 0 | 0 | 0 | 0 | 0 | -10 | | |
| | **Storage (Note 1) - 270 bara** | | | | | | | | |
| | Hydrogen Compression in Syngas Plant | -31016 | | -3005 | -2404 | | | | |
| | Nitrogen Compression in Syngas Plant | -27274 | | -2915 | -2332 | | | | |
| | Fresh Cooling Water in Syngas Plant | | | | 4736 | | | | |
| | Seawater to Syngas Plant | | | 5920 | | | | | |
| | Gas Heating at Cavern Inlet | | | | | -44 | | | |
| | Water Wash at Cavern Outlet | | | | | | -10 | | |
| | Fuel Gas Drying at Cavern outlet | -500 | | | | -137 | | | |
| | Fuel Gas Heating in Power Island | | -156 | | | | | | |
| | Fuel Gas Expander | 31870 | | | | | | | |
| | Net Power Supply from Power Island | 26920 | | | | | | | |
| | Hot Water from Power Island | | 156 | | | | | | |
| | Natural Gas Import | | | | | 181 | | | |
| | Storage Total | 0 | 0 | 0 | 0 | 0 | -10 | | |
| | **Offsites & Utilities - All Cavern Pressures** | | | | | | | | |
| | Demin Plant | -50 | | | | | 10 | | |
| | Utility water | -30 | | | | | | | |
| | Fire Water System | -200 | | | | | | | |
| | Waste Water Treatment | -50 | | | | | | | |
| | Buildings | -200 | | | | | | | |
| | Offsites & Utilities Total | -530 | 0 | 0 | 0 | 0 | 10 | | |
| | **Grand Total** | **0** | **0** | **0** | **0** | **0** | **0.0** | | |

NOTES 1. All figures except for electric power represent the steady state average flow at the capacity of one GT.

# ATTACHMENT 10
# PROJECT EXECUTION SCHEDULE – CAVERN CONSTRUCTION

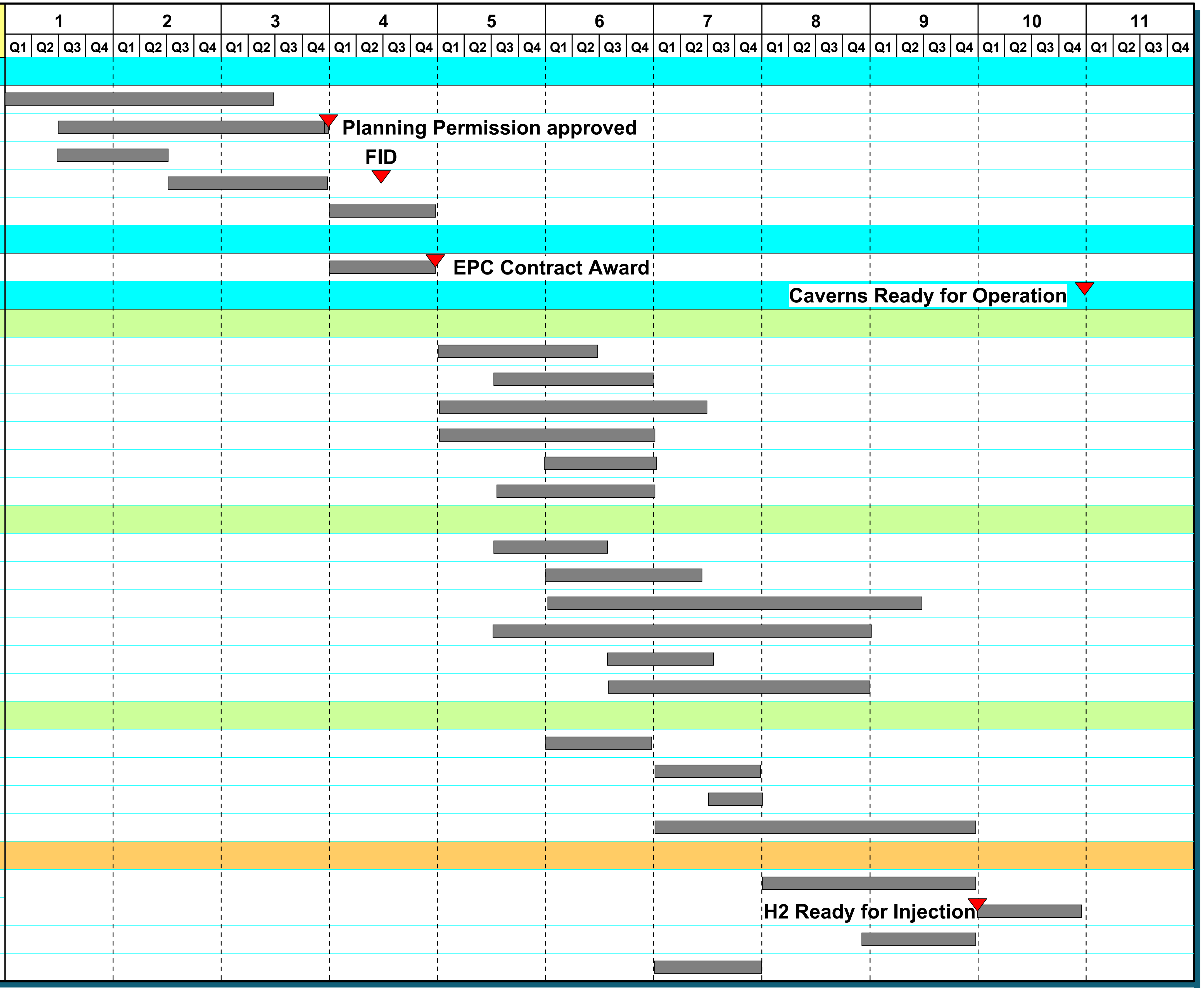
# WP2 - Hydrogen Storage
## Onshore Salt Cavern Facilities
*Project Schedule*

Rev. 0

**Client : ETI**
**Project No. 13058**
**Location : UK**



| Task Num | TASK |
|---|---|
| 1 | **PLANNING PHASE** |
| 2 | Environmental Permits (EIA&ESIA) |
| 3 | Spatial Planning Permits |
| 4 | Initial Site Investigation |
| 5 | FEED |
| 6 | Evaluation and Sanction |
| 7 | **EPC tender Phase** |
| 8 | Bids and Tabulations |
| 9 | **Execution EPC** |
| 10 | **Engineering** |
| 11 | Site Preparation and Drilling |
| 12 | Leaching Facilities |
| 13 | Pipelines |
| 14 | Gas Facilities |
| 15 | Wellhead |
| 16 | Utilities, Infrastructures and Control |
| 17 | **Procurement** |
| 18 | Site Preparation and Drilling |
| 19 | Leaching Facilities |
| 20 | Pipelines |
| 21 | Gas Facilities |
| 22 | Wellhead |
| 23 | Utilities, Infrastructures and Control |
| 24 | **Construction** |
| 25 | Site Preparation |
| 26 | Leaching Facilities |
| 27 | Wellhead and Drilling |
| 28 | Gas Facilities |
| 29 | **Caverns Leaching** |
| 30 | Caverns Formation |
| 31 | Debrining and H2 Introduction |
| 32 | H2 Pipelines and Facilities |
| 33 | Seawater and Brine Pipelines |

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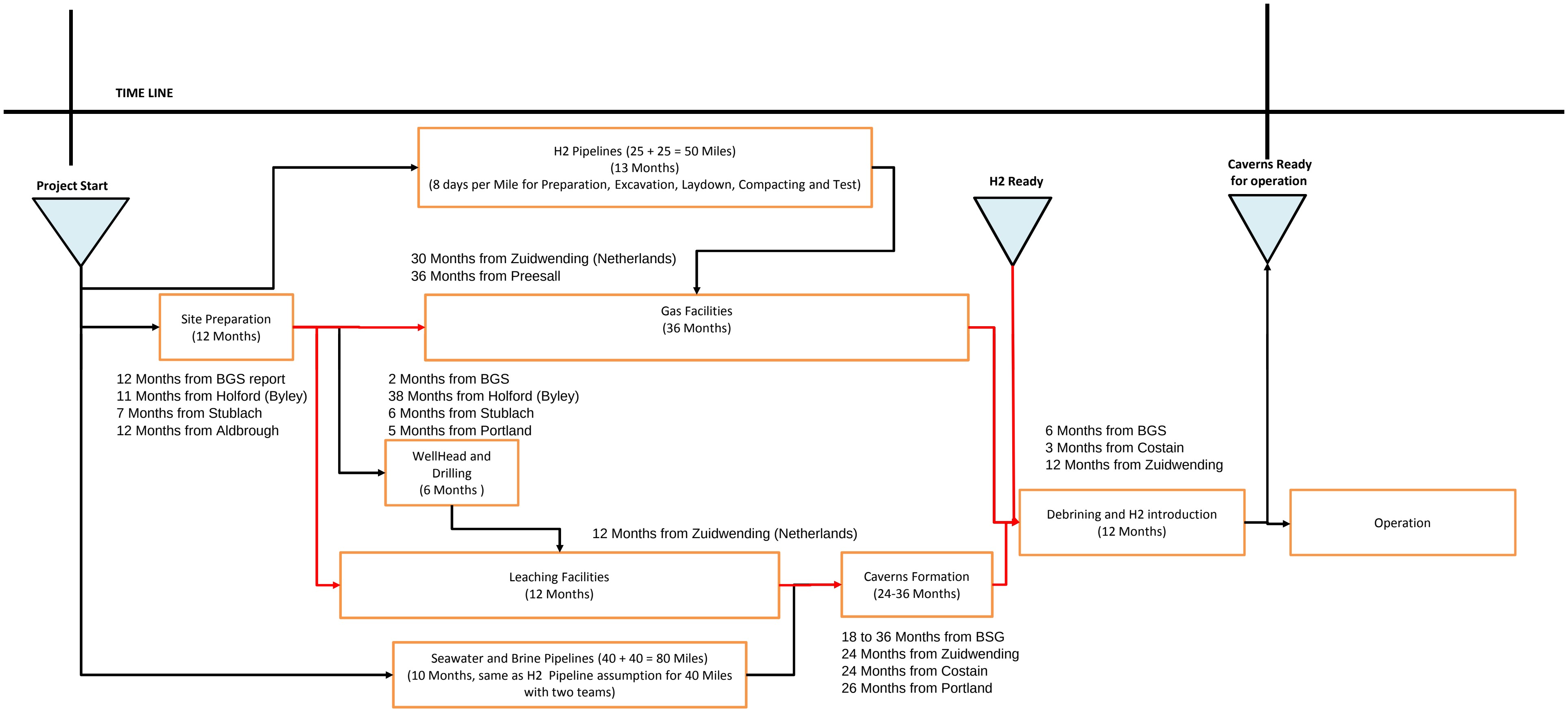
# ATTACHMENT 11
# CONSTRUCTION WORKS FLOW AND DURATION ASSESSMENT CHART

# WP2 - Hydrogen Storage

## Construction Works Flow and Duration Assessment Chart

Rev. 0

**Client : ETI**
**Project No. 13058**
**Location : UK**



# ATTACHMENT 12

# SUPPLEMENTARY ECONOMIC EVALUATION OF $CO_2$ STORAGE IN SALT CAVERNS

One method of assessing the economic merit of salt cavern use for $CO_2$ storage is to assume that a significant proportion of captured $CO_2$ comes from diurnally operated plants, such as gas fired CCGTs or pulverised coal plants with post-combustion carbon capture.

Two possible $CO_2$ network configurations are considered for this assessment:

- *Case A* - represents the solution without buffer storage. Here, gaseous $CO_2$ is produced and compressed into supercritical form either at source or at a compressor station within the network hub. It is then transported by pipeline to sequestration.
- *Case B* – represents the solution with buffer storage. Here, gaseous $CO_2$ is produced and compressed into supercritical form either at source or at a compressor station within the network hub. Compressed $CO_2$ is transported by pipeline to sequestration, but a local salt cavern is used to accommodate part of the $CO_2$ production during the day and release this $CO_2$ into the sequestration pipeline during the night.

For Case A, the flow in the $CO_2$ pipelines will fluctuate on a diurnal basis. This can be approximated to a pattern of 12 hours at 100% flow and 12 hours at 0% flow. In this case, the whole pipeline network would need to be sized for the 100% flow, resulting in under-utilisation of the capital intensive network system for the 12 hours during the night. For Case B with sufficient buffer storage, the $CO_2$ flow rate through the pipeline can be designed for the daily average expected $CO_2$ flow rate, which in the simplified case would correspond to 50% flow.

<u>Estimation of cost impact of using a buffer storage of $CO_2$</u>

The information used in this section on the typical pipeline diameter, cost of $CO_2$ pipeline, storage well and injection facilities was provided by ETI.

ETI estimated that a typical 500 MW coal-fired power station might create a $CO_2$ flow to storage of 6Mt/a by day (12 hour operation per day) and 0Mt/a by night. With a buffer storage facility, the $CO_2$ flow to storage could be a steady rate of 3Mt/a.

The $CO_2$ pipeline diameter required for 6Mt/a of $CO_2$ flow (i.e. 685 te/hr) is calculated as 14”, whereas that required for 3Mt/a of $CO_2$ flow (i.e. 342.5 te/hr) is calculated as 10”.

It can be seen from Table 43 that the overall CAPEX saving achievable through use of a buffer storage facility is approximately £77 million.

**Table 43 - Cost of $CO_2$ pipeline and storage well with and without a Buffer Storage Facility (Information provided by ETI)**

| Parameter | Without Buffer Storage | With Buffer Storage |
|---|---|---|
| $CO_2$ Flow Rate | 6 Mt/a (day)<br>0 Mt/a (night) | 3 Mt/a |
| Pipeline Diameter Required | 14” | 10” |
| Pipeline Cost (100 km) | £117 million | £100 million |
| Storage Well Cost (Assuming well in Southern North Sea) | £60 million | £30 million |
| Injection Facility | £100 million | £70 million |
| **Total Cost** | **£277 million** | **£200 million** |

Salt Cavern - $CO_2$ Buffer Storage Feasibility and Associated Cost

A salt cavern capable of providing supercritical $CO_2$ buffer storage for a 500 MW coal-fired power station would therefore need to be able to receive (and deliver) $CO_2$ for 12 hours at a rate of 3Mt/a - a total of 4110te. As discussed above, salt cavern in East Yorkshire region will be more suitable for buffer storage of supercritical $CO_2$, and suits our proposed storage scenario in the Southern North Sea.

At 45°C and 270 bara, this is a daily working volume of 4,691m$^3$ and total storage volume will be of 46,913m$^3$ assuming 90% cushion gas. With a cavern storage size of 300,000 m$^3$, one salt cavern is sufficient to buffer the $CO_2$ production from six 500 MW coal-fired power stations.

Table 44 summarises the approximate total project cost of salt cavern for $CO_2$ buffer storage.

**Table 44 –Cost of $CO_2$ Buffer Storage**

| Parameter | Onshore Salt Cavern East Yorkshire | |
|---|---|---|
| | Cost to Serve 1 x 500 MW power station | Cost to Serve 6 x 500 MW power station (or equivalent) |
| Geological Survey cost | £3 million | £3 million |
| 1 x Salt Cavern Construction Cost | £27 million | £27 million |
| Installed cost of Water pipeline (5 km) | £3 million | £3 million |
| Installed cost of Brine pipeline (5 km) | £3 million | £3 million |
| Cost of above ground facilities - $CO_2$ compressor & expansion turbine | £45 million | £200 million |
| Land cost, Owner Cost and Contingency cost for the project (40% of total installed cost) | £32 million | £93 million |
| **Total Buffer Cost** | **£112 million** | **£329 million** |

From Table 43 and Table 44, it is evident that the cost saving of £77 million due to reduced peak flow to sequestration is exceeded by the £112 million cost of the buffer storage system. However, as the buffer storage system can accommodate six times the capacity at approximately three times the cost, provision of buffer capacity may become economic if it served a hub with a daily average $CO_2$ production rate of nearer 20 Mt/a.

The evaluation above is simplistic and economic benefits of salt cavern $CO_2$ buffer storage will depend on several additional factors, including:

- Water/brine pipeline length for solution mining
- Distance of the salt cavern site from the $CO_2$ point sources
- Ratio of peak to average $CO_2$ production rate
- Difference between buffer storage and sequestration well pressure
- Distance of the salt cavern from shore
- Distance of offshore well from shore

Even if there is no clear economical driver for provision of salt cavern $CO_2$ buffer storage, it is always preferable from an operational point of view to have a constant flow of $CO_2$ to the permanent storage facility, in order to avoid pressure fluctuations in the pipeline and wells and provide operational flexibility.

# ATTACHMENT 13

# SUPPLEMENTARY ECONOMIC EVALUATION OF CAES USING SALT CAVERNS

CAES Storage Feasibility and Associated Cost

A recent study (Fertig & Apt, 2011) suggests that the general daily difference in electricity price between day and night in the USA is insufficient to economically run a CAES plant, and that cost optimised modelling has shown that the plants would only run during the very high price spikes experienced when something unusual happens on the grid:

*"With 2008 hourly prices and load in Houston, the economically optimal CAES expander capacity is unrealistically large - 24 GW - and dispatches for only a few hours per week when prices are highest; a price cap and capacity payment likewise results in a large (17 GW) profit-maximizing CAES expander. Under all other scenarios considered the CAES plant is unprofitable."*

However, this appears to relate to an expander based CAES system rather than a GT based system. Moreover, the power demand pattern and value of peak demand power differ in the UK and the price differential at peak demand is likely to increase if CCS is required for large power stations.

Fertig and Apt estimated that a salt cavern based CAES system would cost from £0.3m-£1.0m per MW at 100MW capacity, dropping to £0.3m-£0.5m at 400MW capacity, though the duration of supply at this power level are not reported.

An alternative study performed by EPRI (Electric Power Research Institute) (Schainker, 2010), proposes similar costs of £0.4m-£0.5m per MW at 100-300MW scale based on 10 hours of power production.

The operating cost for CAES plants will depend on the source of power for compression of the air. Cheap compression power could be obtained directly from wind turbines during periods of low power demand.

As noted previously, air compression combined with GT power generation appears to offer a more cost effective form of power generation than "stand-alone" CAES: with a combined GT solution, the generator set, compressor driver and all ancillaries are already present, meaning that the CAES incremental cost is limited to the storage cavern and associated pipework and the marginal cost of a larger air compressor, additional drive shaft clutches and air flow controls.