Conceptual design of salt cavern and porous media underground storage site

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Revision History

Revision	Revision date	Summary of changes
0	22 June 2021	Initial version
1	21 April 2022	Revision based on early feedback and results, with focus on European context, and to include most likely assumptions in light of current knowledge

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1. Executive summary

As part of the Hystories project, funded by the EU under the Fuel Cells & Hydrogen Joint Undertaking Program (FCH-JU), WP7 – Ranking of geological sites will form a cornerstone between the technical / subsurface investigation work and the business / economic studies. This Work Package includes a conceptual design of an underground storage site along with Life Cycle Cost Analysis (LCCA). The costs estimate derived from this exercise will feed into WP5 – Modelling of the European energy system. Those costs estimates will also be one of the ranking criteria to build a prioritised list of prospects for hydrogen storage, along with technical criteria coming from WP1 to WP4 (WP1 – Geological assessment will, WP2 – Reservoir engineering and geochemistry, WP3 – Microbiology, WP4 – Material and corrosion). This detailed ranking of sites across Europe will then be used for a more detailed analysis of preselected sites within specific case studies in WP8 – European case studies.

In the absence of site-specific data (potential candidates have yet to be selected), the present document proposes a high-level description of the development and operation of an underground storage site of hydrogen in depleted fields, aquifers, and salt caverns. Most assumptions are either based on a statistical review of existing analogues for natural gas storage or based on engineering judgment in light of existing technical constraints. The Life-Cycle Cost Analysis and associated costs estimates (CAPEX, OPEX, and ABEX) will be treated in a subsequent deliverable (D7.2 - Life Cycle Cost Assessment of an underground storage site).

For an underground storage of hydrogen in salt caverns, the considered scenarios can be summarised as follows (low case resulting in a low investment i.e. low CAPEX, and vice versa):

- Cavern Free Gas Volumes (Low – Mid – High): 815,000 – 380,000 – 185,000 m^3
- Cavern Working Gas Inventory (Low – Mid – High): 62.5 – 31.3 – 15.6 million Sm^3
- Cavern Peak Gas rates (Low – Mid – High): 5.9 – 2.8 – 1.4 million Sm^3/d
- Cavern operating pressure range: 70 – 180 bar
- Storage site with Working Gas target of 250 million Sm^3 i.e. cavern / well count (Low – Mid – High): 4 – 8 – 16
- Well completion:
    - 30" conductor pipe
    - 20" surface casing string (cemented at 250 m assuming a top salt at 200 m)
    - 16" intermediate casing (contingent depending on top of salt depth)
    - 13 3/8" production casing string (last cemented casing shoe @ 1,000 m)
    - 10 3/4" x 7" leaching completion
    - 9 5/8" permanent gas completion run with production packer and Downhole Safety Valve (DHSV)

For an underground storage of hydrogen in aquifers or depleted fields, the considered scenarios can be summarised as follows (low case resulting in a low investment i.e. low CAPEX, and vice versa):

- Reservoir with Working Gas target of 550 million Sm^3
- Reservoir operating pressure range: 60 – 130 bar
- Storage Peak Gas rate: 8.3 million Sm^3
- Storage well count including inactive wells (Low – Mid – High): 5 – 24 – 71
- Auxiliary well count including inactive wells, water disposal wells, monitoring wells, etc. (Low – Mid – High): 1 – 6 – 34
- Well completion:
  - 20" conductor pipe
  - 13 3/8" surface casing string
  - 9 5/8" production casing string (cemented @ 1,200 m above the reservoir)
  - 6 5/8" sand screen set across the reservoir interval
  - 7" permanent gas completion run with production packer and Downhole Safety Valve (DHSV)

Finally, the key aspects for surface facilities have been considered. They will include all the required equipment to safely operate the storage facility (depleted field, aquifer, or salt caverns) during hydrogen injection and withdrawal phases. In particular, the surface facilities include:

- Hydrogen gas dehydration (molecular sieve systems based on the adsorption principle) and treatment units on the withdrawal train(s)
- A gas compression package (reciprocating compressors with electric drive) on the injection train(s) along with cooling units at compressor's discharge
- Filters and metering packages upstream/ downstream of the storage facility at the hydrogen transportation network
- Utilities e.g. fuel gas, gas venting, drains systems, firewater, etc.

2. Introduction

2.1. Background

According to EN 1918-1/2/3 (Gas infrastructure — Underground gas storage — Part 1/2/3), several types of underground media can be used for natural gas storage, which differ by storage formation and storage mechanism:

- Pore storage:
  - **storage in aquifers**
  - **storage in former gas fields**
  - **storage in former oil fields**
- Caverns:
  - **storage in salt caverns**
  - storage in rock caverns (including lined rock caverns)
  - storage in abandoned mines.

The three most widely used techniques (for natural gas – highlighted in bold above) are considered here for hydrogen storage: depleted oil and gas reservoirs, aquifers, caverns in salt formations (created by solution mining). Each of these has distinct geographic and geologic availability and physical characteristics which govern the suitability to a particular type of storage.

Depleted hydrocarbon gas reservoirs are porous and permeable formations that have typically produced most or all their economic reserves. The existing wells in the reservoir can be converted for hydrogen gas storage use and / or additional wells can be drilled to add to the hydrogen gas injection and withdrawal capability of the reservoir.

Aquifers are similar to depleted oil and gas reservoirs in terms of the nature of the porous rock media used to contain the stored gas and the methodology for assessing the reservoir. The difference is that aquifer reservoirs were originally filled with water and did not contain oil or gas.

The third principal type of underground natural gas storage facility is man-made caverns in salt formations. Salt caverns are created through the planned solutioning or dissolving of portions of naturally occurring salt formations.

2.2. Purpose

The key objectives as defined in Hystories Work Package #7 (WP) can be summarised as follows:

- To define a conceptual design with a focus on safe, affordable solutions to store hydrogen gas on a large scale (Task 7.1 – associated deliverable D7.1 i.e. present document).
- To provide insights regarding underground storage development costs for the preselected sites (Task 7.2 – associated deliverable D7.2).
- To conduct a high-level Life-Cycle Cost Analysis (LCCA) for the preselected sites (Task 7.3 – associated deliverable D7.3).

On that basis, the purpose of this document (D7.1) is to set the foundations for a common understanding of the principles that govern the design, development, and construction of an underground storage site of hydrogen.

As there is no specific site data available (potential candidates have yet to be selected), this document will cover the general engineering philosophy for the development and operation of an underground storage site of hydrogen in depleted fields, aquifers and salt caverns: it will be based on a set of key assumptions that are deemed « reasonable » from an engineering point of view. In other words, this document will provide a high-level conceptual design that is not constrained by site-specific requirements or constraints. Therefore, variations to the proposed engineering concept would be acceptable if dully supported by robust engineering work.

The output from this study will serve to highlight the principal aspects that drive the developments costs (also known as CAPital EXpenditure or CAPEX), the costs necessary to safely run the storage facility (also known as OPErating EXpenditure or OPEX) as well as the abandonment costs (also known as ABandonment EXpenditure or ABEX).

Once this common understanding has been established in D7.1, the Life-Cycle Cost Analysis and associated costs estimates (CAPEX, OPEX, and ABEX) will be treated in a subsequent deliverable (D7.2 - Life Cycle Cost Assessment of an underground storage site). As part of this analysis (to be conducted in D7.2), a simplified cost model will be developed based on the technical principles and key costs drivers outlined in the present report. The output from D7.2 will serve to conduct quick / high-level costs estimates for the potential candidates identified in WP1. Ultimately, this will help to complete the last task of WP7 i.e. Task 7.3 - Sites ranking and selection: the potential candidates will be ranked based on the findings from the other Work Packages and considering the Life-Cycle Cost criteria (cost estimates obtained from the costs model built in D7.2 and based on the engineering principles defined in D7.1).

2.3. Scope

The scope of this study includes the definition of a Basis of Design, along with a preliminary overall system configuration for hydrogen gas storage in salt caverns and porous media, focusing on:

- Preliminary production / injection and control wells architecture including outline drilling programme, completion concepts.
- High-level description of hydrogen gas processing, conditioning, compression, and metering facilities: review of input data and operating envelope, simplified block-flow diagram, modelling of key operating cases (injection/withdrawal) with PFD & process calculations.
- High-level description of surface facilities and connections with production / injection wells with surface plan and facilities layout, operating and control philosophy, conceptual description of utilities and safety equipment.
- Outline project development plan, associated schedule, and simplified project risk register.

An onshore location has been assumed in this study as the vast majority of the prospects identified in WP1 are located onshore. In addition, the subsurface engineering principles (geology, geophysics, reservoir engineering, etc.) remain fundamentally the same regardless of offshore / onshore environment except for the drilling engineering part. The key differences will be treated in the relevant section. The same applies to the « surface » engineering principles such as process engineering, electrical engineering and instrumentation, utilities, etc. The key differences will be briefly treated in the relevant section (facilities engineering, offshore flow assurance, offshore challenges, etc.).

3. Subsurface facilities | Salt caverns

3.1. Principle

According to API 1170 (Design And Operation Of Solution-Mined Salt Caverns Used For Natural Gas Storage).

Cavern solution mining is accomplished by drilling a wellbore into a suitable salt formation, dissolving the salt by circulating fresh or low-salinity water into the wellbore and withdrawing or returning the brine to the surface. As the salt is dissolved in a controlled fashion according to a specific plan, the wellbore grows to form a cavern in the salt formation. Once the geometrical design volume is reached, gas is injected into the cavern displacing and emptying the brine out of the cavern, making it ready for gas storage operations.

The wells previously drilled and completed as part of solution mining works are then recompleted to establish a controlled connection between the salt cavern and the surface facilities at the wellhead. They are used for gas storage service i.e. gas cycling with injection / withdrawal cycles based on business needs and storage operating strategy.

The walls of caverns formed in subsurface salt structures are practically impermeable to gas up to specific pressure thresholds, ensuring containment of the gas stored in the cavern. In addition, fractures and faults within the salt formation are healed by the viscoplastic behaviour of the salt under the overburden pressure.

The same principles are applicable for hydrogen gas storage.

3.2. Geological site characterisation

As per EN 1918-3, a geological exploration & appraisal programme shall be undertaken to obtain sufficient knowledge and to confirm the geological feasibility of the underground storage project by means of geological and geophysical surveys and drilling operations. Water supply and brine discharge options for the solution mining of the caverns should be investigated as well.

The available geological and geophysical data should be gathered along with regional and/or sedimentary basin level information e.g. gravimetric or magnetic maps, regional geological maps, existing seismic profiles, offset wells data, etc.

The requirements of the geological exploration & appraisal programme will largely depend on the level of maturity of prospect characterisation as well as the geological complexity of the prospect. Regardless, typical requirements may include:

- Geophysical surveys e.g. 2D or 3D seismic surveys covering the area of interest
- Exploration & appraisal wells with comprehensive formation logging & coring programmes
- Cores laboratory testing and analysis.

The acquired data in-situ, along with its analysis and interpretation, with laboratory testing on core samples will help to further characterise the geological prospect, with a focus on:

- Lateral & vertical extent i.e. envelope of the salt formation
- Local structural features such as fault patterns, tectonic zones, etc.
- Stratigraphic features of the salt formation (salt mineralogy, insoluble material content, permeable intra layers, hyper soluble material) and their distribution
- Mechanical strength of the salt and solubility in water
- Stratigraphic features of the overburden layers.

Comprehensive data analysis along with geological modelling shall be conducted in order to establish the technical feasibility of the site for the construction of salt caverns. This analysis shall also provide indications about the most suitable zones for caverns locations as well as caverns sizing and configuration.

3.3. Salt cavern design & performance

Based on EN 1918-3, caverns shall be designed to ensure long term integrity and containment, under a predefined operating envelope. As the salt rock surrounding the cavern may be subjected to a significant level of stress, their mechanical properties shall be evaluated on the basis of laboratory tests on core samples and/or in situ tests in the well(s). Analytical and/or numerical geomechanical modelling will be required to establish the cavern design and confirm the operating envelope. In addition, geomechanical modelling will help to evaluate and quantify mechanical disturbances such as:

- Stress distribution induced by the cavern in surrounding lithologies
- Salt creep inducing cavern closure and volume loss
- Surface subsidence induced by salt creep
- Magnitude of cavern shape change, especially salt strain at the last cemented casing shoe

The impact of cavern construction and operation with respect to neighbouring environment, in particular the magnitude of potential surface subsidence, shall be considered. On that basis, the key design parameters include:

- Cavern shape and size e.g. height, diameter, roof guard
- Cavern location e.g. depths, pillars, distances to top of salt, edge of salt, etc.
- Distance to subsurface neighbouring activities
- Minimum & maximum operating pressure
- Maximum pressure change rate.

3.3.1. Assumptions

In the absence of specific site information, the following typical values are assumed for the cavern geometrical basis of design:

Table 1: Cavern geometrical features

Cavern geometry & salt features		
Cavern neck (m)	m	30
Last Cemented Casing Shoe Depth (m)	m	1,000
Roof angle (°)	°	20
Cavern height (m) (low – mid – high)	m	311 – 155 – 85
Cavern max. diameter (m)	m	80
Limit dissolution angle (°)	°	20
Shape factor (%)	% Vol.	70
Insoluble content (%)	% Vol.	10
Bulk factor	$V_{insoluble}$ (Bulk) / $V_{insoluble}$	1.8
Brine residual volume (%)	% Free Vol.	3.0
Solution mining parameters		
Brine flowrate (m^3/h)	m^3/h	300
Cavern closure during leaching (%)	% Leaching Time	10
Leached Vol. per Work-over	m^3	100,000
Start-up & saturation time	days	60
Downtime (%)	% Time	15
First Gas Fill (FGF) parameters		
Outages during FGF	h/d	2.0
Reduced capacity	%	15 %
Brine flowrate during FGF	m^3/h	250
Gas capacity parameters		
Max. Pres. Grad. @ Casing shoe	bar/m	0.18
Min. Pres. Grad. @ 2/3 cavern height depth	bar/m	0.06
Geothermal gradient	K/m	0.03
Delta T	degC	20
Standard Conditions P, T		
Standard Pressure	bara	1.01325
Standard temperature	degC	15.0

3.3.2. Cavern geometry

The parameters defined above are illustrated on the schematic below:

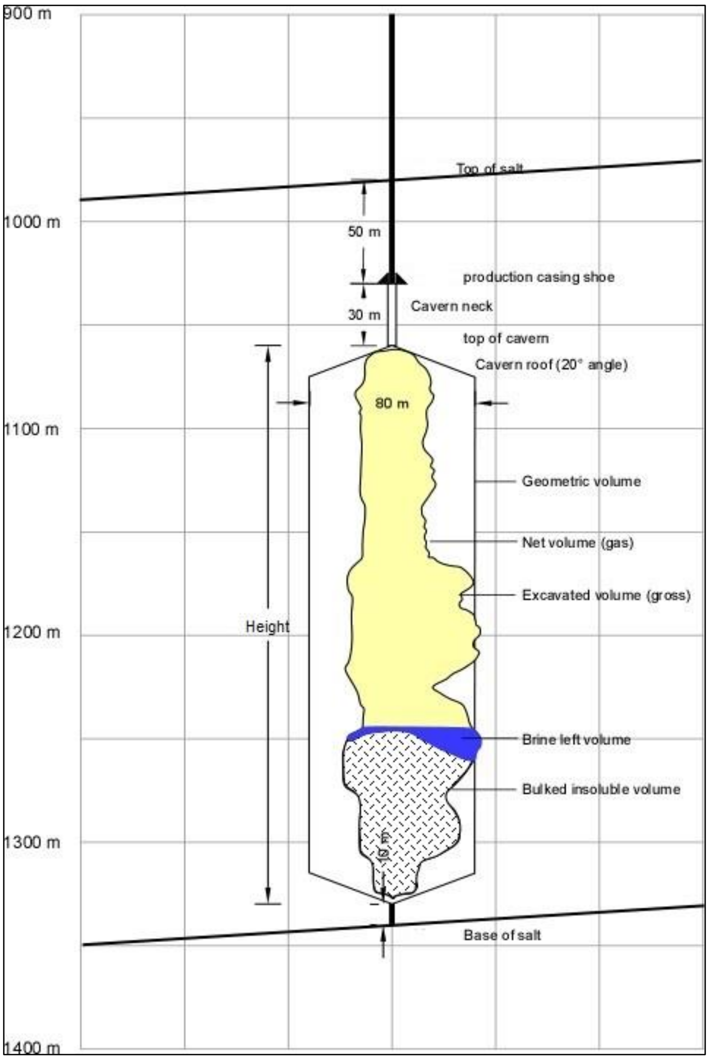

Figure 1: Cavern geometry & key parameters

3.3.3. Leaching duration

Using the assumptions listed above, one can derive a relationship between overall leaching time and free gas volume, usable for hydrogen gas storage:

$$Free\ Gas\ Volume = Net\ Cavern\ Volume - Brine\ Residual\ Volume$$

$$Dissolved\ Salt\ Volume = \frac{1\ -\ Insoluble\ Content}{1 - Insoluble\ Content\ x\ Bulk\ factor} * Free\ Gas\ Volume$$

$$Total\ Water\ Volume = R * Dissolved\ Salt\ Volume$$

Where R is the leaching ratio that reflects the leaching process efficiency: in other words, it represents the number of unit volumes of water that must be circulated downhole to dissolved one unit volume of salt rock. At the start of the leaching process when the cavern volume is reduced to the wellbore, R tends to be higher e.g. greater than 10 (and usually lower than 20). Depending on salt quality, R can then decrease and be as low as 8 towards the end of leaching process, when the cavern volume is large enough to enable the injected water to be fully saturated in salt.

In our case, a simple empirical law based on experience has been utilised: R can be influenced by a variety of parameters such as pressure, temperature, insoluble content, etc.

Once the total injected water volume is known for a specific Free Gas Volume, the leaching duration can be calculated assuming a standard leaching rate of 300 m^3/h:

$$Net\ leaching\ duration = \frac{Total\ Water\ Volume}{Water\ flowrate}$$

Facilities downtime, well integrity testing, cavern acceptance testing, saturation time as well as a work-over every 100 000 m^3 (to be confirmed as part of the detailed design phase) of cavern created have to be factored in, in order to derive the overall leaching duration.

A nominal leaching rate of 300 m^3/h is reasonable at these depths (circa 1,000 m below ground level) for standard casing and tubing sizes (see section on well architecture – 10 3/4" x 7" leaching strings with 13 3/8" production casing). With these values, the water / brine velocity remains below the erosional velocity of the leaching string tubulars. Finally, the pressure at the production casing shoe remains below the formation fracturing gradient.

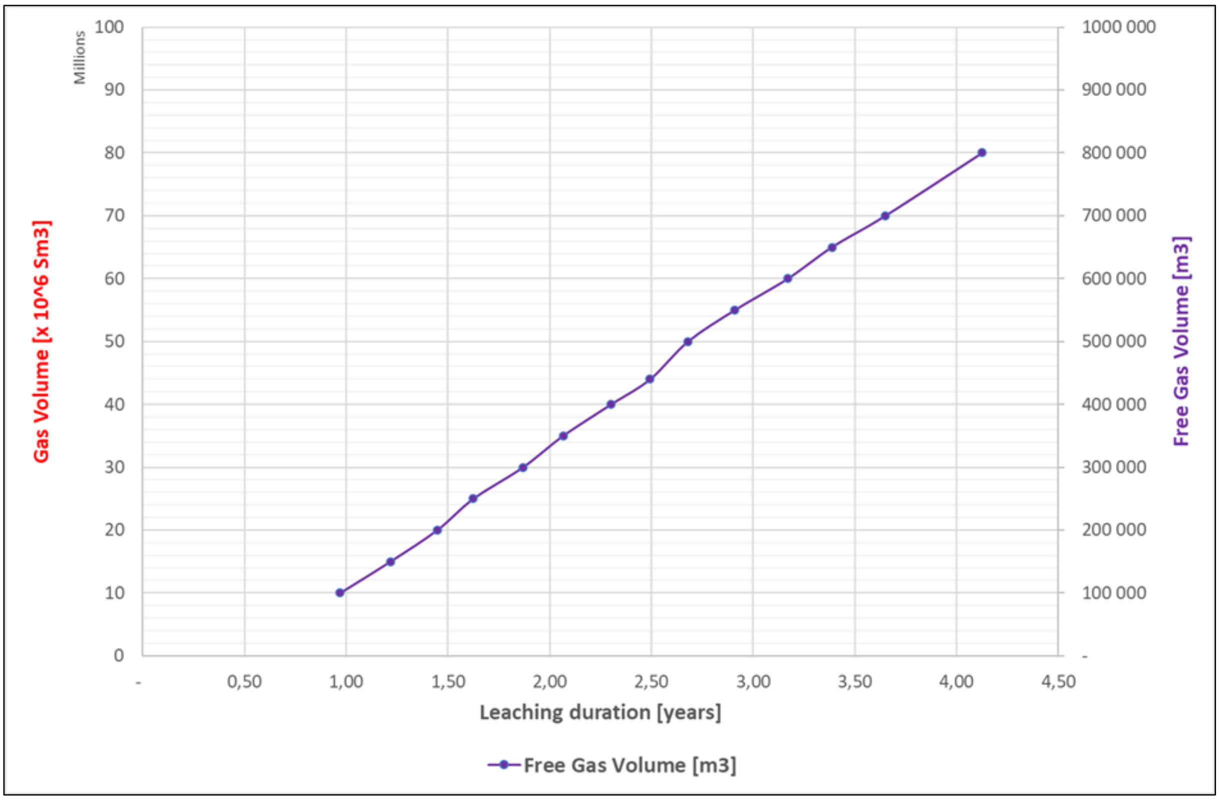

Figure 2: Free Gas Volume versus Leaching time

In the present case (no specific site data available, cavern design not constrained by local geology), a cavern with a Free Gas Volume ranging from 185,000 m^3 to 815,000 m^3 is deemed reasonable. From an economic point of view, excessively small caverns (and resulting from local geological conditions) tend to be marginal as some fixed costs are carried regardless of cavern size (leaching station construction and commissioning, connection to gas infrastructure, fixed drilling costs, etc.). From a technical point of view, excessively large caverns present some challenges too as they imply longer leaching durations, increased leaching rates, thereby requiring well tubulars with larger diameters (« exotic » casing specifications requiring increased lead times and costs, drilling challenges with unusually large sections regarding drill depths, drilling rigs rated for higher loads, increased mud pump capacity, etc.).

Table 2: Free Gas Volume Scenarios (low - mid - high)[1]

	Low case	Mid case	High case
Free Gas Volume (per cavern)	815,000 m^3	380,000 m^3	185,000 m^3

[1] Low case resulting in a low investment i.e. low CAPEX, and vice versa.

3.3.4. Gas capacity calculation

Using the ideal gas law (corrected with the compressibility factor), one can derive a relationship between Working Gas Volume and Free Gas Volume:

$$Cavern\ Gas\ Inventory(Pcav, Tcav, zcav) = \frac{Pcav}{Patm} * \frac{Tatm}{Tcav} * \frac{zatm}{zcav} * Free\ Gas\ Volume$$

This leads to:

$$Maximum\ Gas\ Inventory = Cavern\ Gas\ Inventory(Pmax, Tmax, z(Pmax, Tmax))$$

$$Maximum\ Gas\ Inventory = Cavern\ Gas\ Inventory(Pmin, Tmin, z(Pmin, Tmin))$$

Where,

$$Cushion\ Gas\ Volume = Minimum\ Gas\ Inventory$$

$$Working\ Gas\ Volume = Maximum\ Gas\ Inventory - Cushion\ Gas\ Volume$$

The maximum gas inventory in the cavern is calculated at Pmax, Tmax, z(Pmax, Tmax). The maximum allowable pressure in the cavern (Pmax) is calculated using the maximum pressure gradient at the last cemented casing shoe (0.18 bar/m in this case assuming a fracturing gradient typically equal 0.21 bar/m for a standard salt formation), which is the weakest point of the formation. As an approximation, a thermal equilibrium is assumed between the salt formation and the stored gas so that Tmax is derived using the geothermal gradient.

The minimum gas inventory in the cavern i.e. **Cushion Gas Volume** is calculated at Pmin, Tmin, z(Pmin, Tmin). Numerical geomechanical modelling is normally required to evaluate the minimum allowable pressure in the cavern (Pmin). Pmin is determined so that there is no risk of cavern wall collapse or excessive salt creep effects leading to significant cavern volume losses or excessive strain at the last cemented casing shoe that can lead to casing overstretch and pipe body or connections failures (a maximum cavern idle time at Pmin would also have to be defined in order to minimise the detrimental impact of salt creep). At this stage, it is common to calculate Pmin assuming a minimum pressure gradient of 0.06 bar/m, applied at 2/3 of the cavern height depth. Tmin (as well as Tmax) will largely depend on the injection / withdrawal cycles during gas storage operations. For simplicity, a standard temperature differential (Tmax – Tmin) of 20 degC has been applied.

The **Working Gas Volume** is eventually obtained by subtracting the Cushion Gas Volume to the maximum gas inventory. As a reminder, the Working Gas Volume is the volume of gas that can be cycled with injection / withdrawal movements. In turn, the Cushion Gas Volume, that helps maintaining the cavern above or at Pmin, can be considered as a « fixed asset » for the entire duration of the cavern design life.

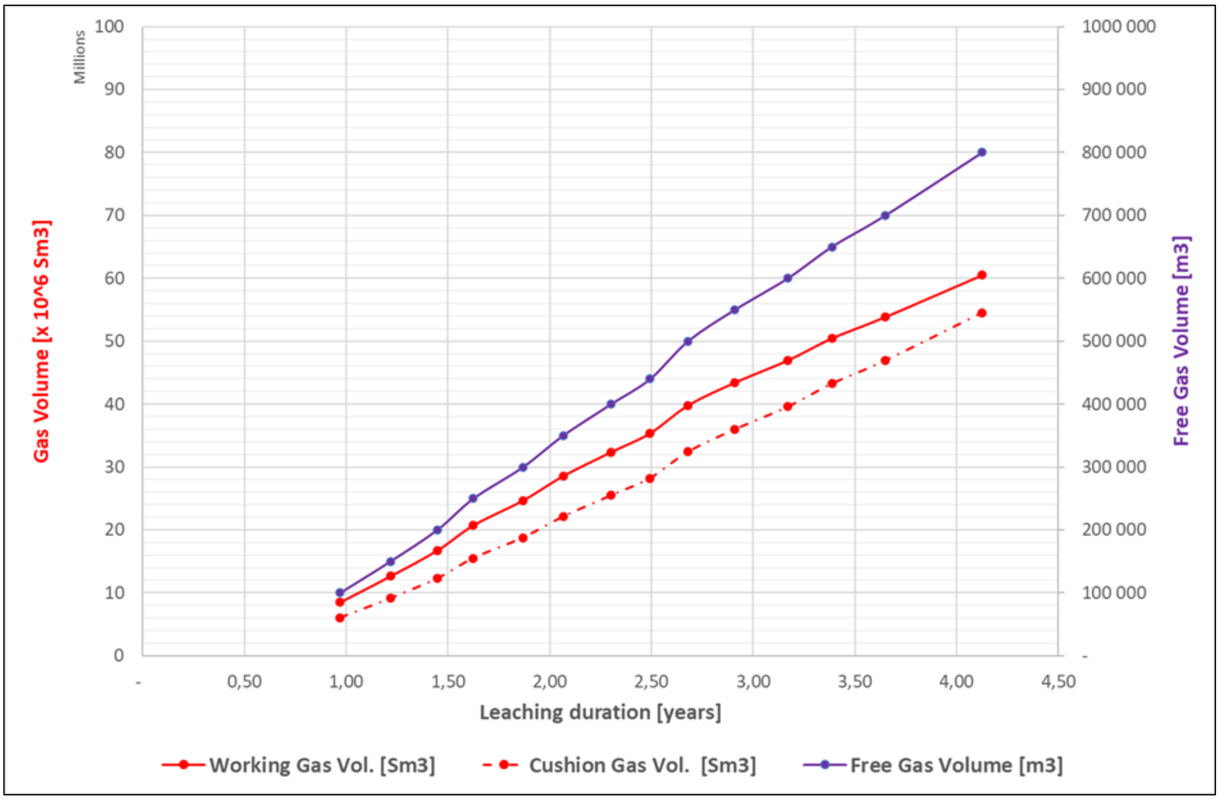

Figure 3: Free Gas Vol., Working Gas Vol. & Cushion Gas Vol. versus Leaching time

Assuming a cavern depth at circa 1,000 m (corresponding to Pmin ~70 bar and Pmax ~180 bar as a first approach), the working gas volume estimates, corresponding to the free gas volumes scenarios presented before, can be summarised as follows:

Table 3: Free Gas Vol., Working Gas Vol. & Cushion Gas Vol. Scenarios (low - mid - high)

Million Sm^3	Low case	Mid case	High case
Working Gas Vol. (per cavern)	62.5	31.3	15.6
Cushion Gas Vol. (per cavern)	55.1	23.7	11.1
Working Gas / Total Gas	53 %	57 %	59 %

As an example, cavern count estimates (based on the scenarios described above) are presented below for a total working gas target of 250 million Sm^3 (in line with base case scenario presented for porous media in section 4.4):

Table 4: Example | Cavern count for 250 million Sm^3 working gas target (low – mid – high)

250 million Sm^3 WGV target	Low case	Mid case	High case
Cavern & Well count	4	8	16

Maximum withdrawal gas rate

Specific gas operating cycles must be defined, and numerical simulation tools are required (in particular to evaluate heat transfers between the gas and the salt formation) to obtain a precise estimate of the maximum withdrawal rate.

However, similar to the approach chosen for gas capacity calculations, the ideal gas law (corrected with the compressibility factor) can be used to obtain a rough estimate of the maximum withdrawal rate:

$$Average\ Flowrate = \frac{Initial\ Gas\ Volume - Final\ Gas\ Volume}{Time}$$

In the absence of specific site data, it is common to assume a maximum pressure decrease of 10 bar / day when emptying the cavern at maximum speed, in order to preserve the integrity of the cavern. Nevertheless, it should be noted that this assumption would have to be validated during the detailed design phase by means of geomechanical and thermodynamical numerical modelling.

Going back to the three scenarios defined above, we have the following results:

Table 5: Maximum Withdrawal Rates (low - mid - high)

	Low case	Mid case	High case
Peak withdrawal rate (per cavern)	5,910,000 Sm^3/d	2,790,000 Sm^3/d	1,360,000 Sm^3/d
Total Peak withdrawal rate	23.6 $MMSm^3/d$	22.3 $MMSm^3/d$	21.8 $MMSm^3/d$

The figures presented above would have to be thoroughly checked against the actual tubing erosional velocity. However, hydrogen gas being much less dense than natural gas, erosional limits for hydrogen gas service are much higher than those for natural gas service. For instance, the erosional velocity for a standard 7" tubing (6" ID) ranges from 57 to 60 m/sec for the three scenarios above (with hydrogen gas). As a result, the erosional velocity is not anticipated to be a limiting factor for the maximum withdrawal gas rate in this case.

In a similar fashion, the figures presented above would have to be thoroughly checked against the hydrate formation envelope. Although hydrates can form with hydrogen gas, it is much less likely than with natural gas (methane hydrates).

3.4. Well design & construction

Well design shall be developed to meet the functional requirements of the well, while ensuring well integrity throughout the entire life cycle of the cavern. This work should be performed in order to identify potential hazards and to define appropriate barriers that are capable of controlling or mitigating these hazards and associated risks.

As part of the cavern construction process, the main well objectives are:

- To reach the salt section
- To enable the installation of a leaching completion to create the cavern (solution mining)
- To enable the installation of a temporary « debrining » string for the « first gas fill »
- To enable the installation of a permanent gas completion for gas storage service
- To safely operate the gas filled cavern for storage purpose.

Design of each hole section should consider the diameter and depth needed to allow for the installation of the last cemented casing i.e. production casing.

The first section consists of a **conductor pipe** that may be pile driven into the ground as part of civil engineering works to prepare the well pad. The setting depth may be adjusted depending on the pre-eminence of shallow hazards and/or unconsolidated formations at shallow depth.

The following section shall be cased off with the **surface casing** in order to isolate the wellbore from surface aquifers. The objective is two-fold: to avoid potential contamination of aquifers used for drinking water by drilling fluids and, to avoid wellbore fluids contamination and/or losses with aquifer water.

Depending on the in-situ conditions, an additional drilling section with an **intermediate casing** string may be required to isolate the well from anomalous zones including unstable or unconsolidated zones, lost circulation zones, and pressurised permeable zones.

During the last drilled section, the Last Cemented Casing (LCC) string i.e. **production casing** is running, set, and cemented in the well. The production casing should be set in a section of salt determined competent to provide a pressure-containing casing shoe.

In the absence of specific input data, the following typical well architecture has been assumed (no intermediate casing in this case):

- 30" conductor pipe
- 20" surface casing string (cemented at 250 m assuming top of salt at 200 m)
- 16" intermediate casing string (contingent: see details below)
- 13 3/8" production casing string (cemented at 1000 m within salt formation)
- 10 3/4" x 7" leaching completion
- 9 5/8" permanent gas completion run with production packer and Downhole Safety Valve (DHSV).

In most cases, two casing strings shall be set into the salt interval, namely the surface (or intermediate casing if the top salt lies deeper and that overlying formations need to be cased off e.g. shallow aquifers, lost circulation zones such as the salt cap rock in some instances) casing and the production casing in this case. Experience has shown that setting the casing ~50 m into the salt is necessary to achieve suitable isolation of the gas storage (to be confirmed by geomechanical analysis). Any design variance should be supported by robust engineering work in order to achieve the expected performance targets and ensure suitable integrity of the gas storage. The production casing setting depth usually results from a compromise between:

- Cavern long term geomechanical stability (greater depth often leads to increased impact of salt creep and cavern volume reduction)
- Required gas storage volume (pressure and gas storage volume will increase with depth)
- Pressure requirements at surface (gas infrastructure pressure, compressor sizing, etc.)

The production casing diameter is primarily selected based on leaching rates requirements and maximum gas injection / withdrawal rates during gas storage service.

3.5. Cavern solution mining strategy

As outlined above, fresh water (or undersaturated brine) is circulated downhole via a wellbore in order to dissolve the salt present in the formation, during the leaching process.

During the leaching operation, an inner and an outer leaching string are concentrically run into the well / cavern. Depending on the leaching phase, the fresh water can either be injected via the inner leaching string (direct mode or bottom injection) or via the annulus between inner and outer leaching string (indirect mode or top injection).

The cavern will be developed within the permitted geometrical limits. The shape of the cavern can be influenced by varying the:

- Leaching process mode (direct: bottom injection, indirect: top injection),
- Leaching flow rate (amount of water injected per hour),
- Setting depths of leaching strings,
- Depths of blanket interface,
- Duration of leaching intervals (leaching phases).

As part of this process, the upper part of cavern i.e. cavern roof is protected by a blanket medium. As a result of environmental considerations, nitrogen gas is commonly used as blanket medium (diesel may be used if required). The blanket is injected in the annulus of the production casing/outer leaching string and forms a barrier between the brine and the cavern roof. The blanket medium shall not dissolve the salt and the density must be sub-hydrostatic. The depth of the blanket / brine interface in the cavern is measured and « repositioned » at regular intervals by means of wireline logging tools. Nitrogen top-ups may be required to compensate for minor losses through time.

The cavern profile is developed from the bottom to the top by pulling the leaching strings and reducing blanket depth step by step.

The cavern construction typically consists in a three-stage leaching concept, starting with the sump development in direct injection mode, followed by the main development stages and the final stage in reverse mode to create the roof.

Sump leaching stage

The direct leaching mode will be used in this stage starting from the deepest point of the cavern to create an initial « pocket » to hold the insoluble residues. The leaching rate is increased by steps and produced brine concentration is low.

Main cavern development stage

Except for operational requirements, all subsequent leaching stages are based on reverse leaching mode. As the cavern volume rises and a typical flow rate of 300 m³/h is reached, the produced brine concentration increases. After each volume step of approx. gross volume 100.000 m³ a sonar survey must be done. Sonar measurements as well as leaching strings depths adjustments are carried out using a Workover rig.

Roof leaching stage

The roof leaching stage represents the last leaching step and aims to cap the cylindrical cavern shape with a dome-shaped roof.

The leaching phases and parameters are adjusted as the cavern construction progresses and based on the sonar measurements. The position of leaching strings and blanket interface is defined by the leaching engineer with the help of a dedicated leaching simulation package. Depending on salt quality, the number of workovers may be reduced with a positive impact on overall leaching duration and operational costs.

4. Subsurface facilities | Depleted fields and aquifers

4.1. Principle

In this case, hydrogen gas is stored underground in formations where a reservoir is available, i.e. a rock formation porous enough (to store the fluids) and sufficiently permeable (to allow fluid movement), with a geological seal forming a trap (to ensure containment of the fluids). These porous and permeable zones are typically hydrocarbon and/or water bearing in their native state, as in oil and gas fields, or water bearing only, as in aquifers.

Depleted oil and gas fields

Once the hydrocarbons are depleted in oil and gas fields, the porous zone can be used for hydrogen gas storage. Fluid containment up to the initial pressure conditions is demonstrated by the existence of the hydrocarbon accumulation itself over geological time.

The essential knowledge about the reservoir behaviour and properties is available from the exploration phase and from the production period of the oil and gas field. However, the storage integrity has to be analysed and demonstrated when reservoir pressures above initial pressures are applied. As such, it is more common and straightforward to select depleted gas fields for gas storage rather than depleted oil fields, as the feasibility assessment carries more risk and uncertainty in the latter case (well productivity and gas movement potentially impacted by unfavourable relative permeability conditions, seal competence for gas containment versus oil containment, etc.).

Aquifers

In the case of aquifers, the water bearing formation does not require any depletion before it can be converted for use as a hydrogen gas storage reservoir. As the gas accumulation is created artificially in originally water bearing structures, an extended exploration phase is required in order to prove its ability for the storage of gas. As reservoir pressures above initial pressures have to be applied for gas storage in aquifers, the containment of the originally water bearing structure under gas at anticipated operating pressures has to be demonstrated. The applied technologies for exploration, construction and operation are based on technologies in the oil and gas industry and are similar to technologies applied to gas storage in depleted oil and gas fields.

Regardless of the storage type (aquifer or depleted fields), special care must be dedicated to the impact of the stored fluid on adjacent and overlying strata (in particular permeable formations).

4.2. Geological site characterisation

As outlined in API 1170, the baseline geological reservoir characterisation is aimed at developing a practical understanding of the suitability of the reservoir and the adjacent stratigraphic environment prior to storage development or expansion. The main objectives are to confirm the presence of:

- A reservoir formation with adequate size, connectivity and petrophysical properties (porosity, permeability, etc.) to provide the desired storage capacity and productivity
- A sealing layer (fine-grained cap-rock) preventing vertical migration of fluids i.e. stored hydrogen gas at anticipated operating pressures
- A trapping mechanism (structural or stratigraphic) providing an adequate closure to ensure satisfactory containment of the gas-filled zone.

Along with the geological characterisation, the reservoir engineering studies shall aim to address secondary objectives such as:

- Reservoir connectivity and/or compartmentalisation
- Reservoir potential regarding pore storage volume
- Reservoir response to pressure cycles and flow rates
- Reservoir operating pressure envelope i.e. Maximum / minimum pressures
- Potential interactions between hydrogen gas and original reservoir fluids.

Similar to the exploration techniques in use for salt cavern feasibility assessments, the geological / reservoir characterisation shall be based on:

- Geophysical surveys e.g. 2D or 3D seismic surveys covering the area of interest
- Exploration & appraisal well data (MWD, mud logs, cuttings descriptions, LWD, etc.) along with open hole logs
- Production & development well data for depleted gas fields
- Water well test data analysis for aquifers
- Rock core samples analysis e.g. conventional and Special Core Analysis (SCAL) data
- Fluid samples analysis e.g. PVT studies.

Aquifers

Design of UGS in aquifers is mainly concerned with the demonstration of the ability of a structure and formation to be used for gas storage. The ability of a structure to ensure confinement of the stored hydrogen gas shall be demonstrated. The impact of the underground storage on water contained in the storage aquifer and in connected aquifers shall be acceptable. This requires the spreading of the gas zone to be known, the maximum operating pressure to be predicted.

Depleted oil and gas fields

In the case of depleted oil and gas fields, specific studies may be required regarding the technical integrity of existing and abandoned wells in order to prevent gas leakage at anticipated operating pressures. A number of existing and abandoned wells may pre-exist indeed. The status of these wells may vary from « active » e.g. producers, injectors or monitoring wells, temporarily suspended i.e. with retrievable deep-set plugs to permanently plugged or permanently abandoned (Xmas tree removed and completion pulled, wellhead cut at surface, several cement plugs present downhole).

4.3. Well design & construction

For the operation of an underground storage facility in depleted oil and gas fields or aquifers two principal types of wells may be used:

- Operating wells used for storage gas injection and withdrawal or for monitoring purposes.
- Monitoring wells in the storage formation and indicator horizons such as caprock, upper aquifers or oil and gas fields.

The well design principles for an underground storage in depleted oil and gas fields or aquifers are similar to those described above for salt caverns. As such, the production casing shall be set and cemented immediately above the reservoir formation. It should be noted that the integrity of the wells is even more critical in the context underground gas storage operations (potential vicinity of living areas, risk of contamination in overlying aquifers used for water consumption, etc.) than in the case of oil & gas production wells. As a result, ensuring adequate cementation of all the casing strings is of paramount importance.

In the absence of specific input data, the following typical well architecture has been assumed for operating wells (monitoring wells and auxiliary wells if any may be shallower thereby requiring less drill sections / casing strings):

- 20" conductor pipe
- 13 3/8" surface casing string
- 9 5/8" production casing string (cemented @ 1,200 m immediately above the reservoir)
- 6 5/8” sand screen set across the reservoir interval
- 7" permanent gas completion run with production packer and Downhole Safety Valve (DHSV).

Vertical wells only are assumed here.

A 7" tubing size is suitable to handle a large range of gas rates, including high gas rates typically experienced in the underground gas storage industry. Nevertheless, depending on specific site conditions (reservoir performance, geological characterisation), the tubing size may range from 2 7/8" up to 9 5/8" in some extreme cases.

Depending on the overburden features, one or several intermediate casing strings may be required, which will eventually lead to increased sizes for the shallower hole sections / casing strings (surface casing and conductor pipe).

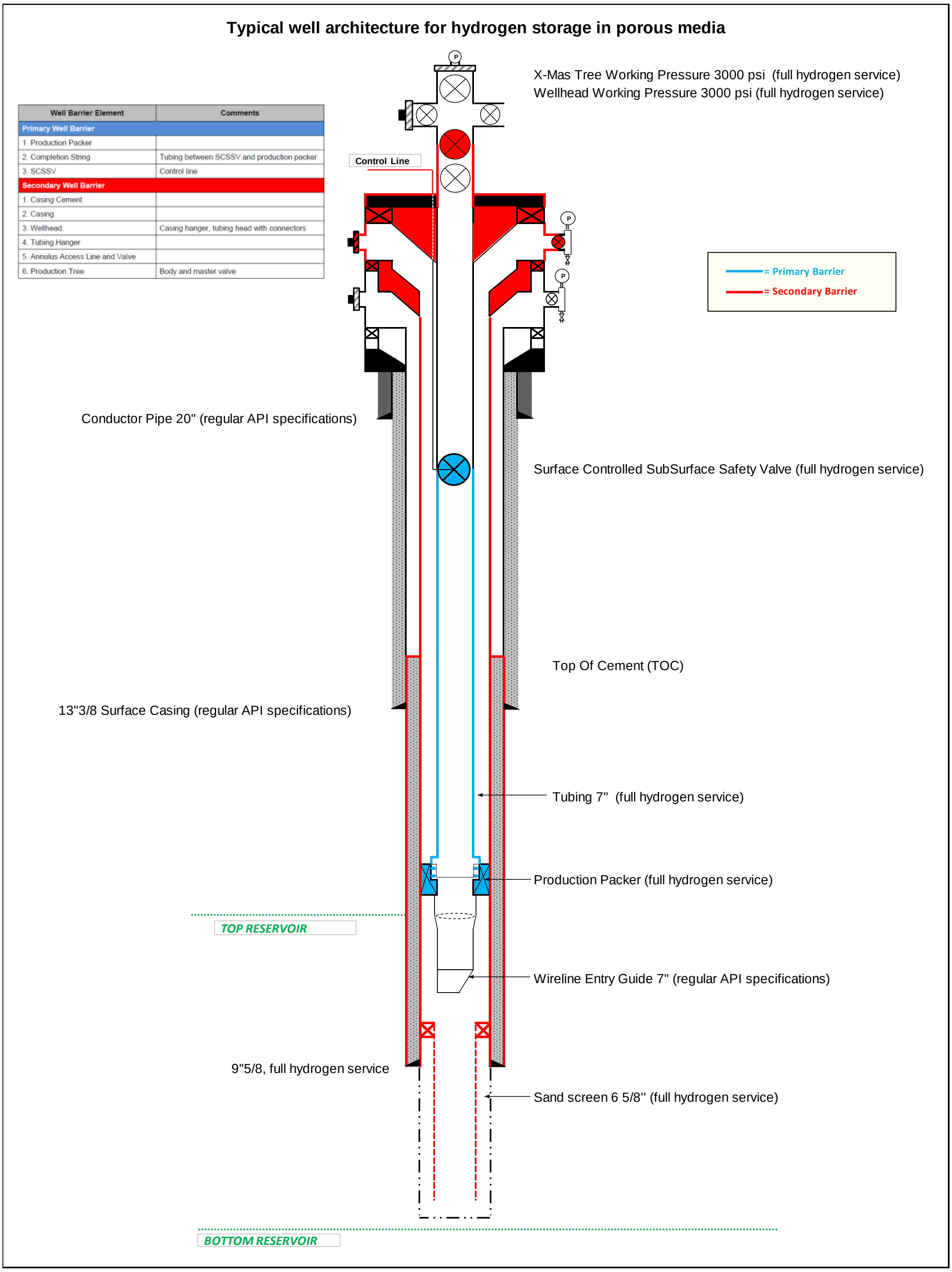

Figure 4: Typical well architecture for hydrogen storage in porous media

4.4. Basis of Design

As pointed out in section 2.2, the purpose of this document is to provide a generic conceptual design of an underground storage facility of hydrogen gas. As there is no specific site data available (potential candidates have yet to be selected), this document will be based on a set of key assumptions that are deemed « reasonable » from an engineering point of view. In other words, this document will provide a high-level conceptual design that is not constrained by site-specific requirements or constraints.

In light of this, a statistical approach was selected for the case of hydrogen storage in depleted fields or aquifers. Like for salt caverns, reasonable assumptions have been made regarding the reservoir size and the storage capacity. Indeed, they are based on the existing storage sites that are currently active in the world. The advantage of this approach is two-fold: both from the subsurface technical side, and from an economic / gas demand point of view, it provides a good basis to understand what a low case, middle case, and high case could look like.

4.4.1. Working Gas Capacity

According to the International Gas Union's (IGU) worldwide database for underground gas storages (2021 update, natural gas, filtering depleted fields and aquifers in operation in Europe), the distribution of natural gas storages in depleted fields and aquifers in Europe relative to their size is as follows:

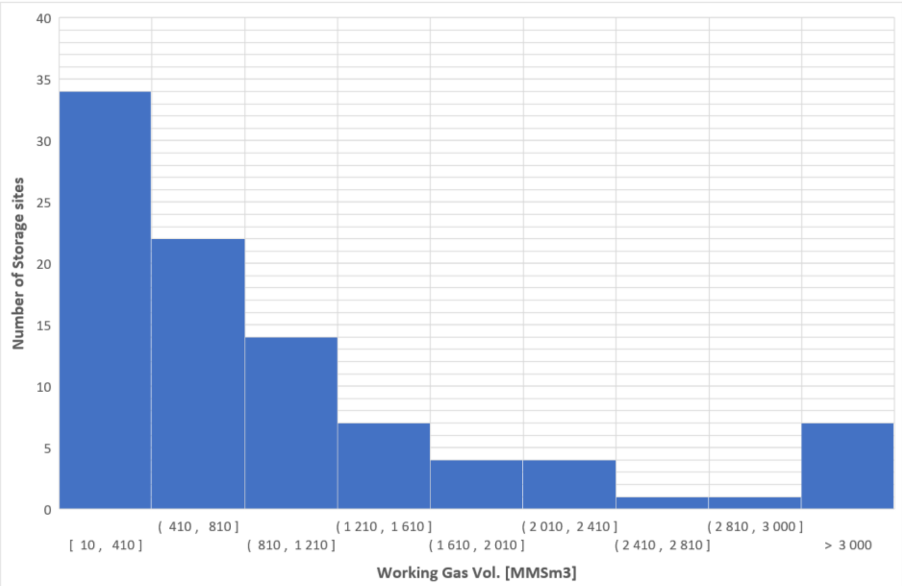

Figure 5: Working Gas Capacity distribution for depleted field and aquifer storages. Derived from IGU's 2021 database for European storages

The associated percentiles for existing natural gas storages in Europe (both aquifers and depleted fields in operation) are displayed below:

Table 6: Working Gas Capacity percentiles for depleted field and aquifer storages

Percentiles	10 %	20 %	30 %	40 %	**50 %**	60 %	70 %	80 %	90 %
Working Gas ($MMSm^3$)	90	169	321	479	**554**	794	980	1,495	2,248

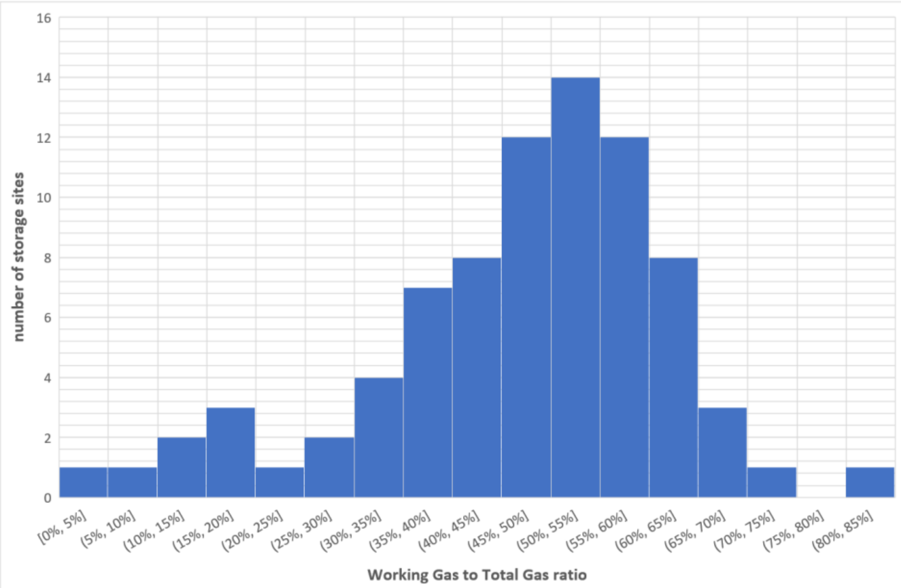

Figure 6: Working Gas / Total Gas distribution for depleted field and aquifer storages. Derived from IGU's 2021 database for European storages

Similarly, the associated percentiles for existing natural gas storages in Europe (both aquifers and depleted fields in operation) are displayed below:

Table 7: Working Gas / Total Gas percentiles

Percentiles	10 %	20 %	30 %	40 %	**50 %**	60 %	70 %	80 %	90 %
WG/TG ratio	29.3 %	36.1 %	41.4 %	48.1 %	**50.0 %**	51.7 %	55.8 %	59.1 %	61.8 %

4.4.2. Storage Pressure Envelope

According to the IGU worldwide database for underground gas storages (2021 update, natural gas, filtering depleted fields and aquifers currently in operation in Europe), the distribution of natural gas storages in depleted fields and aquifers relative to their operating pressure[2] envelope is as follows:

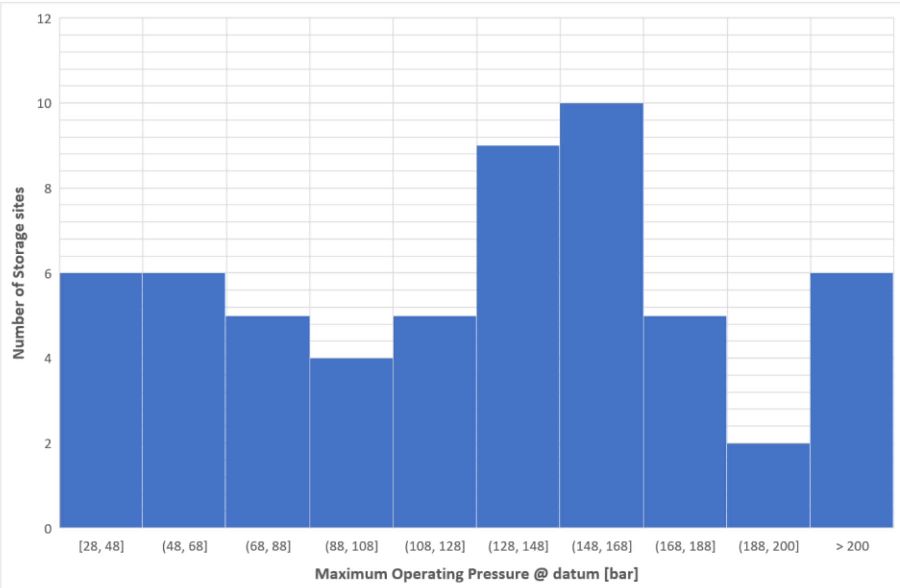

Figure 7: Max. Allowable Operating Pressure (MAOP) for depleted field and aquifer storages. Derived from IGU's 2021 database for European storages

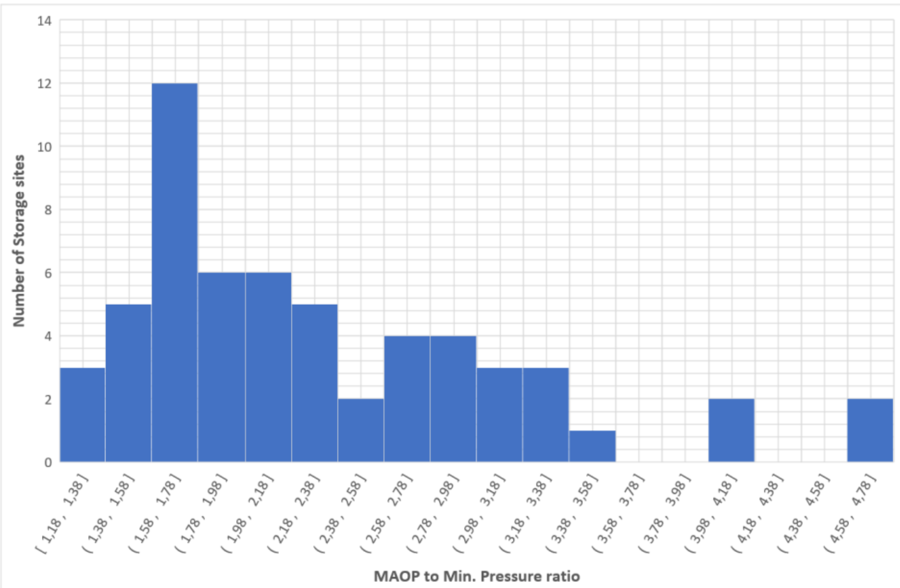

Figure 8: MAOP to Min. Storage Pressure ratio for depleted field and aquifer storages. Derived from IGU's 2021 database for European storages

2 Pressure taken at storage datum i.e. reference point at reservoir depth e.g. top of reservoir or similar.

Table 8: Min. / Max. Storage Pressure[3] percentiles

Percentiles	10 %	20 %	30 %	40 %	**50 %**	60 %	70 %	80 %	90 %
MAOP [bar]	50.3	66.0	92.5	115.8	**132.0**	148.2	151.8	171.2	204.6
MAOP / Min. Pres.	1.51	1.62	1.72	1.86	2.12	2.32	2.59	2.90	3.35

Based on the statistics presented above, one can see that the median case corresponds to approximately:

- Minimum operating pressure ~60 bar at surface
- Maximum allowable pressure ~130 bar at surface[4].

4.4.3. Peak Withdrawal Rate

As far as the Peak Withdrawal Rate is concerned, there is no generic scientific method to establish a reliable and accurate relationship between the latter and the Working Gas Capacity. The Peak Withdrawal Rate as well as the well count can only be derived from detailed geological characterisation combined with thorough reservoir modelling. In other words, every prospect (depleted field or aquifer) is unique with non-transferable properties.

To put the emphasis on this, it can be seen, according to IGU worldwide database (no filters applied), that there is no simple relationship or obvious correlation between Peak Withdrawal Rate and Working Gas Capacity:

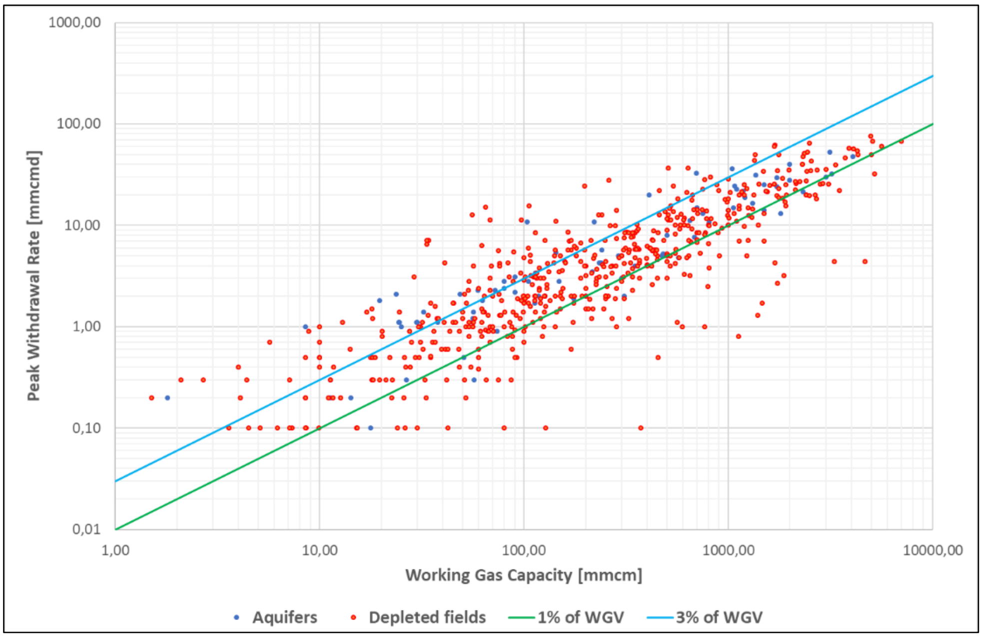

Figure 9: Peak Withdrawal Rate versus Working Gas Capacity

[3] Pressure taken at storage datum i.e. reference point at reservoir depth e.g. top of reservoir or similar.

[4] Hydrogen gas pressure gradient assumed to be constant (regardless of depth variations) as a result of very low specific gravity of hydrogen gas.

However, looking at the Peak Rate / Working Gas ratio distribution (same filters: porous media, currently in operation, in Europe), it can be seen that it typically ranges from 1 % to 3 % for most cases:

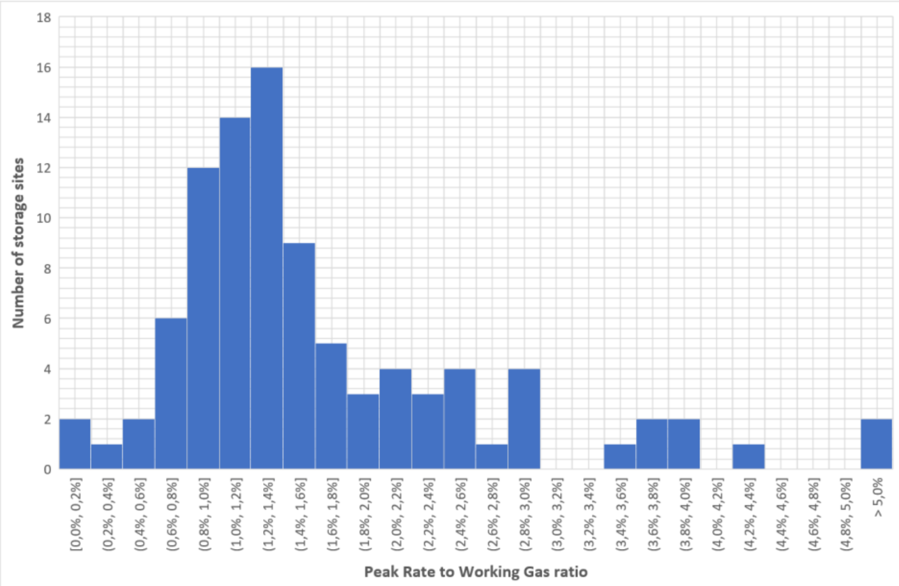

Figure 10: Peak Rate / Working Gas distribution in depleted fields and aquifers

Table 9: Peak Rate / Working Gas Ratio percentiles for depleted field and aquifer storages

Percentiles	10 %	20 %	30 %	40 %	**50 %**	60 %	70 %	80 %	90 %
Peak rate / WG	0.8 %	1.0 %	1.0 %	1.2 %	**1.3 %**	1.5 %	1.8 %	2.4 %	2.9 %

Using the same statistical method, the following distribution can be derived for storage well count and auxiliary well count per 100 $MMSm^3$ of Working Gas capacity, according to IGU worldwide database for underground gas storages (2021 update, natural gas, filtering depleted fields and aquifers currently in operation, in Europe):

Table 10: Well count per 100 $MMSm^3$ of Working Gas Capacity for depleted field and aquifer storages

Percentiles	10 %	20 %	30 %	40 %	**50 %**	60 %	70 %	80 %	90 %
Storage Well count / WG (/100 $MMSm^3$)	0.85	1.48	1.88	2.74	**4.42**	5.40	6.39	8.75	12.93
Aux. Well count / WG (/100 $MMSm^3$)	0.20	0.32	0.55	0.85	**1.10**	2.36	2.86	4.11	6.15

From the table above, it can be seen that in 80 % of cases, the well count is as follows:

- Storage well count (/100 $MMSm^3$) < 16
- Auxiliary well count (/100 $MMSm^3$) < 4.

It should be noted that in the case of hydrogen storage, one can expect the surveillance requirements for observation wells may be higher i.e. more observation wells due to the limited experience for pure hydrogen storage compared to natural gas storage.

4.4.4. Summary

Based on the statistical approach previously described, the following scenarios can be considered for a Working Gas Volume target of circa 550 million Sm^3 (which corresponds to the median value according to IGU for natural gas storages in depleted and aquifers currently in operation in Europe):

Table 11: Key results for aquifers & depleted fields (low - mid - high)

	Low case	Mid case	High case
Working Gas ($x10^6$ Sm^3)	550		
Operating Pressure Envelope (bar)	60 – 130 bar		
WG/TG ratio	50 %		
Cushion Gas ($x10^6$ Sm^3)	550		
Peak rate / WG	1.5 %		
Peak rate ($x10^6$ Sm^3/d)	8.25		
Storage Well count	5	24	71[5]
Aux. Well count	1	6	34[6]

It should be noted that the figures presented above are based on a statistical approach and can vary to a significant extent depending on the storage site and its geological properties. For instance, the cushion gas volume can only be derived by means of thorough geological characterisation and numerical reservoir modelling on a specific site. Likewise, accurate evaluation of peak withdrawal rates would require detailed nodal analysis on a predefined well completion design.

5 Storage well count may include inactive wells, suspended wells or abandoned wells.

6 Auxiliary well count may include water disposal wells, wells utilised for fuel gas, monitoring wells, etc.

5. Pre-design of surface facilities

5.1. Block flow diagram of the installation

Below is a typical block flow diagram of a storage installation:

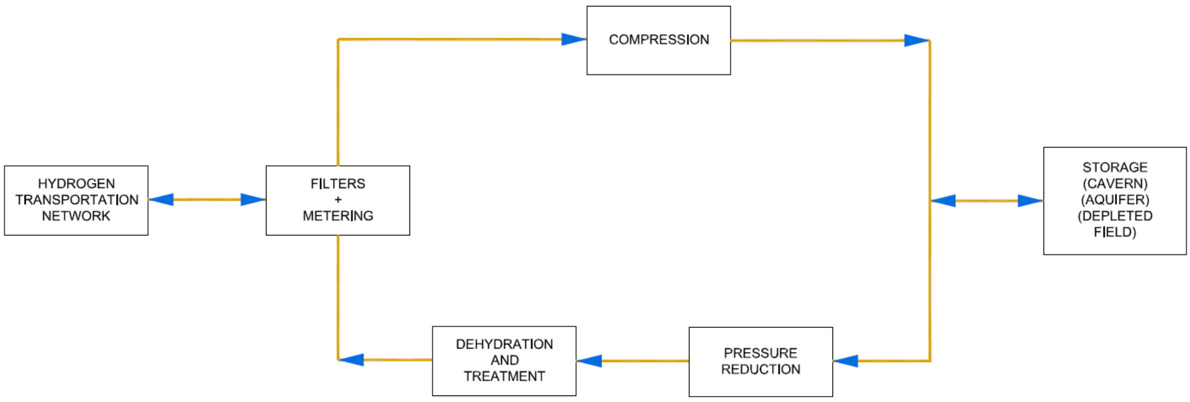

Figure 11: Block flow diagram of expected H2 storage

This block flow diagram illustrates the typical case, where the storage pressure is higher than that of the transportation network. In some cases, for caverns, aquifers or depleted fields at shallow depth, the storage pressure may be lower than that of the grid. In such rare cases, compression would be required for gas withdrawal.

The basic design data is listed below:

Gas composition at storage inlet (% mol):

Table 12: Gas composition

H_2:	99,93
O_2:	0,00
Water:	0,07

Maximum and minimum pressure of the storage:

- Maximum pressure at wellhead for porous media: 131 bara,
- Minimum pressure at wellhead: 61 bara.

The network pressure is fixed at 56 bara. This is the average value of the pressures proposed by the H2 Backbone report by Guidehouse (Wang et al., 2020). It mentions "*Discharge pressure 67-80 bar; Suction pressure 30-40 bar*".

The porous media case will be presented. The retained design flowrate is then 8.25 million Sm^3/d.

5.1.1. Injection phase description

A Process Flow Diagram (PFD) for hydrogen injection is given below:

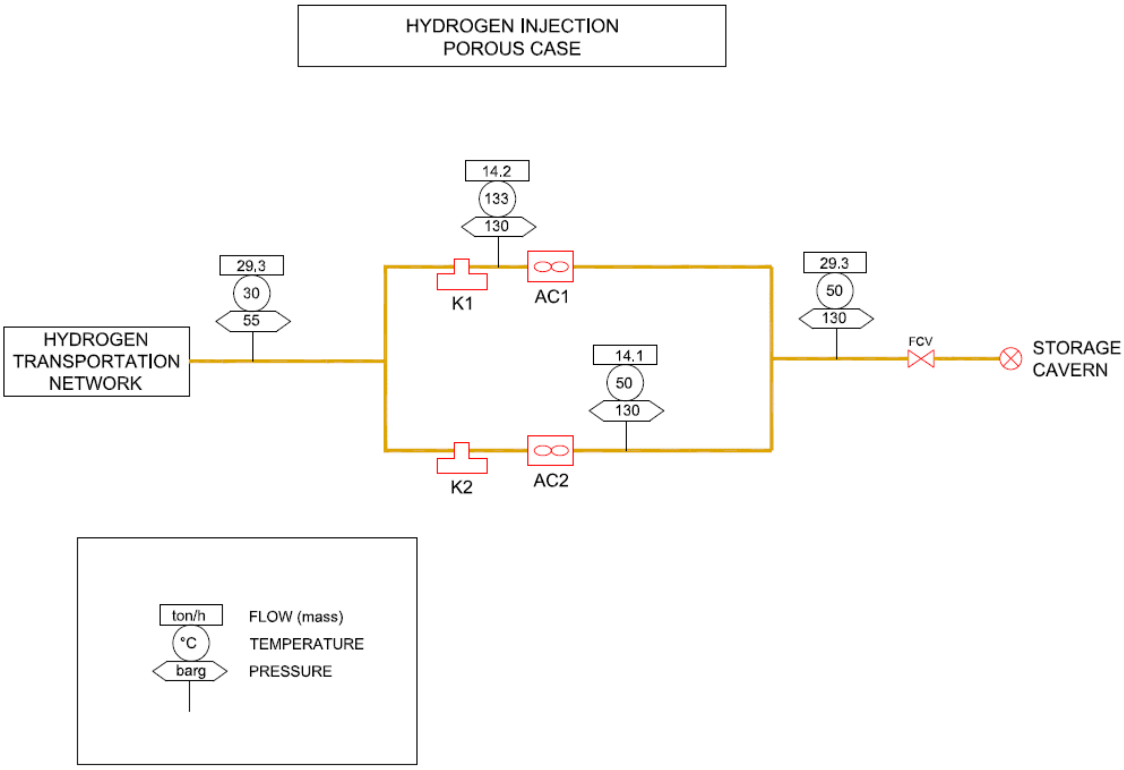

Figure 12: Process Flow Diagram of the injection

As indicated in the basic design data, the flowrate assumed for injection is 29.3 tons / hr at minimum pressure as well as at maximum pressure in the storage, corresponding to a “withdrawal to injection ratio” of 1 (site injection capacity equals site withdrawal capacity).

Hydrogen supply is out of the scope of this report but is assumed to be produced by electrolysis. Hydrogen is first filtered through a cartridge filter to remove any particles or droplets larger than 5 microns and is then counted to ensure an accurate material balance in storage. The counting can for example be carried out by ultrasonic flowmeters. Hydrogen is then delivered to a compression package. Hydrogen passes through a Knock-out drum before entering the compression package. This step is necessary to remove water droplets from the gas stream. In order to raise the gas pressure from 56 bara to 131 bara, it is necessary to have 1 compression stage in the base case for porous media.

Thermodynamics laws imply that the temperature of hydrogen increases when it is compressed. Due to constraints on steel grades, it is usual not to exceed 135 degC at the compressor outlet for hydrogen. Heat exchanger is installed at the compressor outlet.

Air exchanger (air cooler) could be used in this study.

The air inlet temperature is taken at 25 degC. Hydrogen outlet temperature is 50 degC . It is not necessary to further cool down the gas if the maximum temperature in the storage remains reasonable (below 60 degC) because the energy required to cool the hydrogen reduces the efficiency of the whole system.

The temperature approach (difference between hydrogen outlet temperature and air outlet temperature) will be at least 10 degC to obtain sufficient heat transfer within the heat exchanger.

The pressure drop in the heat exchanger cooler is taken at 0.2 bar.

Compressed hydrogen then enters the storage. A flowmeter and a control valve will allow the gas flow to be adjusted.

5.1.2. Withdrawal phase description

A Process Flow Diagram (PFD) upon hydrogen withdrawal period is given below:

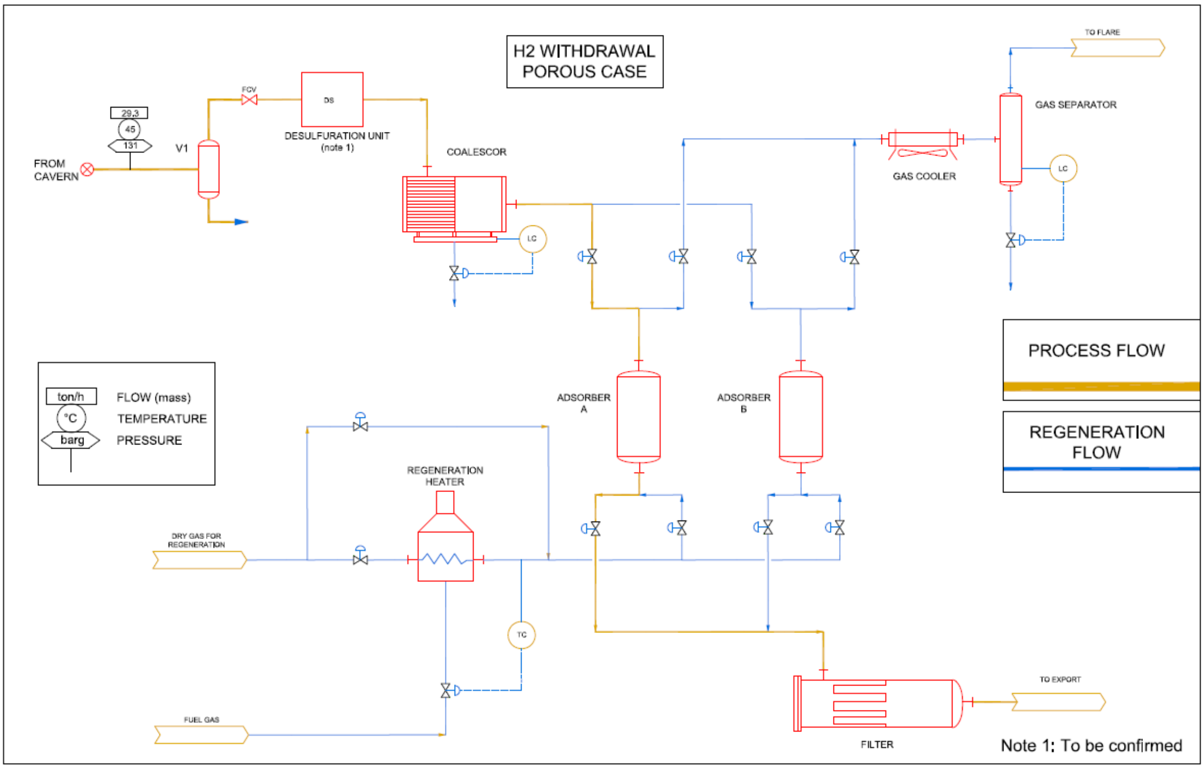

Figure 13: Process Flow Diagram of the hydrogen Withdrawal

As indicated in the basic data, the withdrawal flow rate is also 29.3 tons / hr, regardless of the storage pressure.

At the storage well outlet, the gas first flows through a slug catcher in order to separate any possible water outflows or condensed water. At the outlet of this tank, a valve and a flow meter are used to regulate the flow and the pressure. Hydrogen goes to the main station using the same lines as for injection.

Drying unit

Hydrogen dehydration can be done with Molecular Sieve systems typically composed of at least two adsorption columns. One is in the drying phase and the other in the regeneration phase. Adsorption of water from hydrogen occurs at high pressure and ambient temperature. The regeneration phase, which consists of desorbing the water contained in the zeolites, is carried out at low pressure and high temperature.

When leaving the drying unit, hydrogen contains less than 5 ppm by volume of water.

The main stream of hydrogen to be dried in the adsorption column is normally from the top to the bottom. In order to avoid contamination of the adsorbers by excess water, coalescing filters are often installed upstream of the adsorber, and gas filters for dust removal are generally installed downstream.

Regeneration of the adsorbers takes place in two successive phases: heating and cooling. During the heating phase, a flow of hot dry hydrogen releases the water retained by the desiccant. Since most of the water adsorbed during drying is at the top of the column, this flow is usually from the bottom to the top. During the cooling phase, the column is cooled by a « cold » flow in order to make it available for a new drying phase.

The regeneration phase is normally carried out at a lower pressure than that of drying. There is therefore a depressurisation of the absorbers before heating and a repressurisation after cooling.

These systems have notably proven their effectiveness for natural gas. However, in case of hydrogen storage in depleted fields or aquifers, other solutions may be more adapted. For instance, in the case of depleted fields, hydrogen will be partly loaded with hydrocarbons and water. Both water and hydrocarbons will be possibly removed by Silica gel adsorption process. The choice of treatment process will be dependent on the type of storage (depleted field, aquifer or salt cavern).

Fiscal metering and analysis

At the dehydration unit outlet, hydrogen is filtered, counted, and analysed to verify that it meets commercial specifications and/or hydrogen transportation network requirements. The counting and filtration units are the same as for injection.

Hydrate inhibition

It should be noted that unlike conventional storage of natural gas, it is not necessary to inject a hydrate formation inhibitor. Indeed, no formation of hydrate with hydrogen is envisaged. Positive temperatures (in degC) are sufficient to prevent ice build-up.

5.2. Engineering elements for the different packages

This part summarises the different methods used to carry out the sizing of the process packages.

5.2.1. Thermodynamic model choice

The thermodynamic model is chosen in accordance with the composition of the gas studied. Following a flowchart of choice proposed by IFP Training (D TH 1406B), the thermodynamic model is the Grayson Streed model. However, a classic model like SRK or PR would also be suitable. A check should nevertheless be carried out by consulting: SELECT THERMODYNAMIC MODELS FOR PROCESS SIMULATION, A Practical Guide using a Three Steps Methodology.

5.2.2. Water content versus temperature and pressure

UniSim process simulation software calculates the equilibrium water content in the withdrawn hydrogen for a wide range of temperatures and pressures.

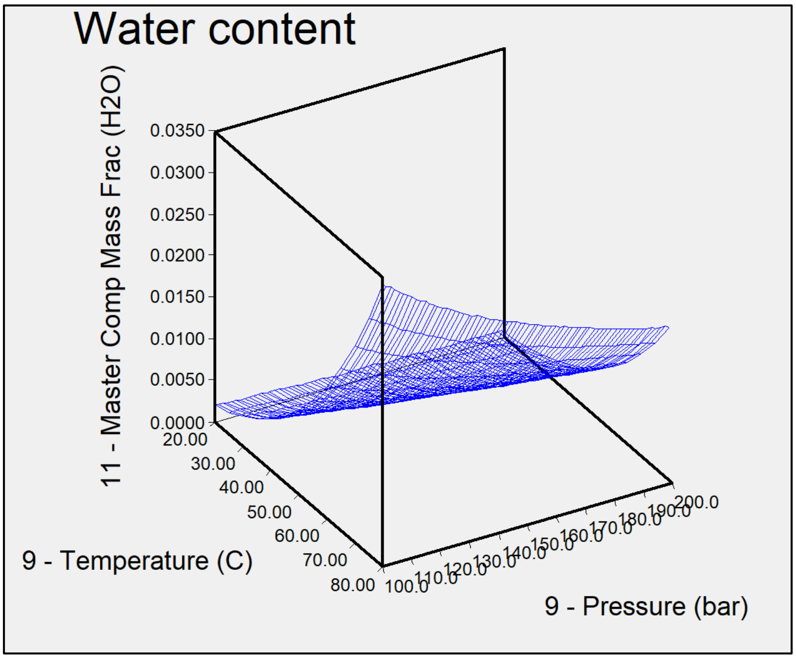

Figure 14: Saturation water content of pure hydrogen stream

One can see that hydrogen water content increases with temperature and decreases with pressure. This behaviour is similar to that observed for natural gas.

It was considered that the hydrogen flow leaving the electrolyser was saturated with moisture. To do this in the simulation, a flow of water is brought into contact with the flow of hydrogen. This mixture is then separated in a flash drum. The gas flow exiting the separator head corresponds to hydrogen saturated with water.

Due to the presence of water within porous media storage, the same saturation device is made to simulate the withdrawn gas. In this case, the saturation takes place under the temperature and pressure conditions of the storage.

5.2.3. Cooler design at compressor discharge

5.2.4. Compressor efficiency

The compressors selected are reciprocating compressors. The simulation software offers classic efficiency depending on the type of compressor selected. In order to be closer to what manufacturers can offer, Dresser Rand's online compressor selector software was used. For the given operating cases, an efficiency between 83 % and 85 % is proposed. This efficiency will be used for the simulation.

5.2.5. Line sizing criteria

Maximum speed and vibration criteria were retained. These criteria are standard in the gas industry. We will seek to have:

Compressor suction:

- Pressure drop lower than 0.7 bar/km,
- Velocity lower than 20 m/s,
- Rhox v^2 lower than 7500 Pa.

Compressor discharge:

- Pressure drop lower than 1.15 bar/km,
- Velocity lower than 20 m/s,
- Rhox v^2 lower than 10 000 Pa.

5.2.6. Impact of compression ratio

Generally, the temperature of 135 degC should not be exceeded at the hydrogen compressor outlet to avoid additional costs associated with changing the grade of steel used and linked to API 618 requirement. For salt cavern case due to high compression ratio (high Maximum Operating Pressure of the cavern), two stages of compression should be installed to fulfil the criteria of discharge temperature of 135°degC.

Compression ratio is the ratio between discharge pressure and suction pressure. In our case of Hydrogen compression limited to 135°degC, above a compression ratio of 2.3, two stages should be installed.

5.2.7. Drying unit

Hydrogen dehydration can be done with Molecular Sieve systems typically composed of at least two adsorption columns. One is in the drying phase and the other in the regeneration phase. Adsorption of water from hydrogen occurs at high pressure and ambient temperature. The regeneration phase, which consists of desorbing the water contained inside the zeolites, is carried out at low pressure and high temperature.

When leaving the drying unit, the hydrogen contains less than 5 ppm by volume of water.

In practice, these systems can be composed of more than two columns.

In these systems, the hydrogen flow is dried continuously, although the drying / regeneration cycle is inherently discontinuous.

The sizing of Molecular Sieve systems is complex and cannot be done with basic process simulators. It is therefore necessary to call on the desiccant manufacturer to size them with their proprietary software. In our case, the simulation under UniSim simply corresponds to a « component splitter » which allows a certain amount of water to be removed in order to meet the specification of 5 ppm vol.

The pressure drop across the drying unit (coalescer and adsorber) is taken equal to 0.5 bar in the simulation.

The desiccant used in Molecular Sieves is often composed of zeolites with clay.

There is no maximum pressure intrinsic to the equipment. The maximum pressure will depend mainly on the enclosure to be considered and the height of desiccant in the columns. These parameters must be included in the economic optimisation of the whole. A design pressure of 200 bar is considered, and to achieve a remaining water quantity of less than 5 ppmv at the outlet, an adsorption pressure of 80 bar minimum is used, this value maximising the water saturation in the flow entry. The flow temperature is assumed to be 40 degC maximum. These preliminary values must be confirmed in order to optimise the dehydration system. By dimensioning the dehydration unit at 200 bar we avoid reducing the pressure and therefore having to recompress at the outlet of this unit.

5.2.8. Design basis of air cooler

Air exchangers (air cooler) were used in this study. In fact, heat is not usually recovered at the outlet of the compressors because the investment to set up a water circuit serving shell and tube exchangers is relatively large. In addition, a use for this heat must be found.

The advantage of using cooling water is that a lower gas temperature can be achieved. This improves the efficiency of the compression system.

The air inlet temperature is taken at 25 degC. The hydrogen outlet temperature is 50 degC. It is not necessary to cool more at the exit because the geothermal temperature of the storage is quite high. Energy spent cooling the hydrogen too low would be wasted.

The temperature approach (difference between hydrogen outlet temperature and air outlet temperature) will be at least 10 degC to obtain sufficient heat transfer within the exchanger.

The pressure drop in the exchanger is taken equal to 0.2 bar on the hydrogen side.

The power of the dry cooler blower motor can be calculated using the method presented in « Manual of economic evaluation of processes » by A. Chauvel, 2003

Thus in our case, we find powers of less than 100 HP (75 kW).

The overall transfer coefficient for hydrogen has been regressed using data from « Practical thermal design of air-cooled heat exchanger ».

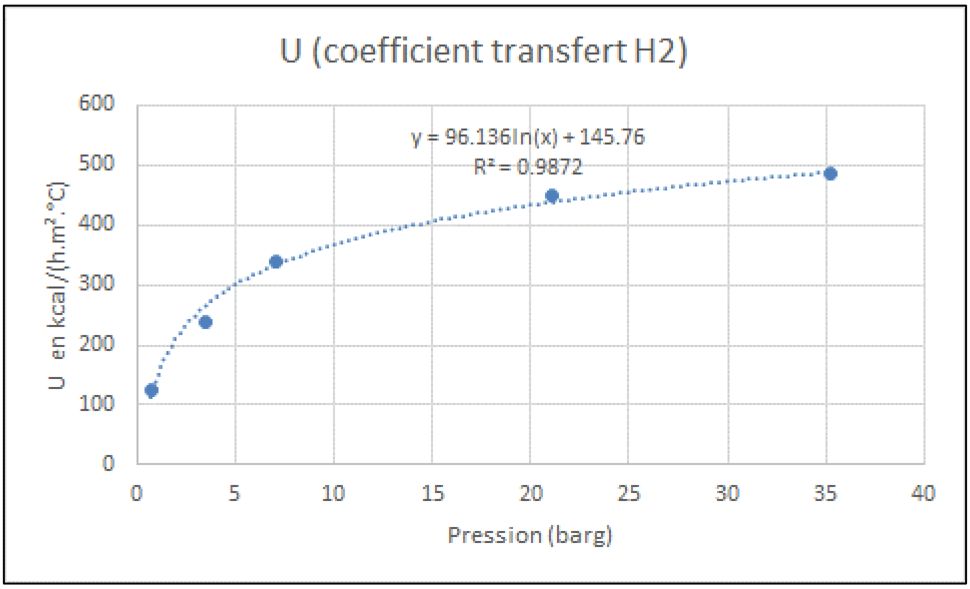

Figure 15: Heat transfer coefficient for H2

5.2.9. Injection compressor

The maximum power requirements are presented for both porous media and salt cavern cases.

Table 13: Compression power results for aquifers & depleted fields (low - mid - high)

	Low case	Mid case	High case
Working Gas (x10^6 Sm^3)	550		
Operating Pressure Envelope (bar)	60 – 130 bar		
Total Peak rate (x10^6 Sm^3/d)	8.25		
Storage Well count	5	24	71[7]
Total Installed Compression Brake power (MW)	13.0		

[7] Storage well count may include inactive wells, suspended wells or abandoned wells.

Table 14: Compression power results for salt caverns (low – mid – high)

	Low case	Mid case	High case
Working Gas (x10^6 Sm^3)	250		
Operating Pressure Envelope (bar)	70 – 180 bar		
Total Peak rate (x10^6 Sm^3/d)	23.6	22.3	21.8
Storage Well count	4	8	16
Total Installed Compression Brake power (MW)	49.2*	46.5*	45.3*
Note : * 2 compression stages required			

Plant reliability will be a key input to define the level of equipment redundancy. It was decided to split the flow in two in order to have a 50 % availability if one of the compressors were to be offline.

It has to be noted that for the current study maximum flow and maximum discharge pressure (maximum compression ratio) have been selected to size the compressor. It leads to an overdesign of the compressor power. The compressor design should be optimized in accordance with geological and costs constraints.

Furthermore, WTIR (Withdrawal-to-injection capacity ratio (flowrates) has been selected in this conceptual study equal to 1. However surface CAPEX rate (see D7.2 report) per withdrawal flowrate capacity is highly dependent on the installed compression power (ratio WTIR).
WTIR is a techno-economic parameter set by defining the cycling with injection / withdrawal cycles based on business needs and storage operating strategy. Generally WTIR is around 2 on underground natural gas storage. This means that the injection flow is only the half of the withdrawal. It is then obvious that the selected WTIR in this study is very conservative in terms of compression power requirement and in terms of costs.

Compression unit's selection

Centrifugal compressors will require recycling gas to avoid surging during part of the injection process.

At this stage of the design, it is proposed to select reciprocating compressors ONLY, which are more flexible (use of unload or partial load of the cylinders) and will be suitable for operation requirements given above. This selection should be confirmed at the next design stages.

The selection of the compressor type will be dependent on the site, the flowrate and the pressure increase to be reached. Usually in Europe, for gas storage underground, the most selected compressor type is the reciprocating type.

Compressor drive type selection

The selection of the compressor drive, gas-powered or electrically powered is another design issue. Due to expected constraints on fuel gas emission, electrical motors with variable speed were selected for this project. The final selection of compressor and drive type shall be made during the next development stages.

Further details are given here on the different types of groups:

- **<u>Moto-compressors (thermal engine gas fired)</u>**
  - Good global energy performance,
  - Quite flexible in terms of flowrate and compression rate,
  - Problems with emissions of NOx,
  - High degree of maintenance is needed which implies a high cost (engine and compressor),
  - Need of fuel gas with a minimum of C5+,
  - Typical operation speed between 600-1200 rev/min which implies the installation of an ISO 13631 compressor (medium to high speed),
  - It does not need an important electric power source nearby.

- **<u>Turbo-compressors (thermal engine gas fired)</u>**
  - Group compactness / high developed power,
  - Sensible maintenance levels are needed (nevertheless higher than for an electric driver),
  - Turbines reduced working zone with low emissions,
  - Generally chosen for facilities which need power greater than 5 MW,
  - Input air must be filtered as well as output silencers are to be installed,
  - Need of clean and dry fuel gas,
  - Problems with emissions of NOx in smoke emitted.

- **<u>Electro-compressors (electric engine)</u>**
  - There are no emissions into the atmosphere,
  - Quite flexible in terms of flowrate and compression rate,
  - Low maintenance is required: low cost,
  - Not noisy,
  - Available either on API618 or ISO 13631, regarding the operating speed chosen,
  - Motor driver with available variable speed to match requested operating conditions,
  - Modes of functioning.

The selection of the engine (gas engine or electric motor) is made considering the environmental constraints related to the emissions. In addition, electric motors are often variable speed and can therefore adapt to changing flow conditions. Finally, it is likely that the injection will take place when the electric current is abundant and at low cost.

An electrical motor is thus recommended.

5.2.10. Utilities

In addition to the equipment mentioned in the previous paragraphs, the following utilities will certainly be necessary to operate the storage:

- A fuel gas network: the gas can come from the storage and will supply the heater used for the regeneration of molecular sieves.
- A vent and a depressurization management unit: in an emergency, it will be necessary to reduce the pressure in the various workshops.
- Pig stations if the hydrogen comes from a pipeline,
- A power supply and a generator in case of emergency,
- A gas analyser,
- A fire network with pumps and dedicated storage,
- Instrument air,
- A drinking water and freshwater network,
- A drain system,
- A control and supervision system,
- A gas and fire detection system,
- A water collection and possible treatment system (degassing water from the demisters),
- Buildings (administrative, operation, electrical, maintenance, warehouse, firefighting, guard post).

<u>Factors influencing the project CAPEX</u>

The following table has been developed to summarise the main process factors that will impact the CAPEX of the project.

For withdrawal:

Table 13: Withdrawal - Process factors impacting CAPEX

<table>
<tr><th>Type of storage</th><th>Salt cavern</th><th>Aquifer</th><th>Depleted field</th></tr>
<tr><td colspan="4">Low impurities content: H_2O and possibly H_2S</td></tr>
<tr><td colspan="3">Dehydration required and H_2S treatment</td><td>HC dew point unit
+ Dehydration unit
+ H_2S treatment</td></tr>
<tr><td colspan="4">Units will be sized by flowrate</td></tr>
<tr><td colspan="3">Dehydration size will also be dependent on water content specification
Technology choice will be function of water content and pressure</td><td>Dehydration size will also be dependent on water content specification as well</td></tr>
</table>

For Injection:

Table 14: Injection - Process factors impacting CAPEX

	Salt cavern	Aquifer	Depleted field
Filtering and metering	Both units will be function of the flowrate. Each XX Nm^3/h new train of filtering and metering is required		
Compression	Direct function of power consumed. Power is function of flowrate and pressure difference between suction pressure (pipeline or electrolyser pressure) and injection pressure		

5.3. Technical considerations for offshore hydrogen gas storage

5.3.1. Subsurface engineering

As pointed out in section 2.3 – Scope, the subsurface engineering principles (geology, geophysics, reservoir engineering, etc.) remain fundamentally the same regardless of offshore or onshore environment, to the exception of the drilling engineering part. As far as geologic characterisation and reservoir modelling are concerned, the key difference between onshore and onshore environment relates to the costs associated to data acquisition (in particular for seismic data and downhole data obtained from offshore wells).

During the exploration and appraisal phase and in the absence of pre-existing infrastructure or offshore installations, subsea exploration and appraisal wells will be drilled i.e. wells with a wellhead lying on the seabed and connected to surface through a riser. This will necessitate a Mobile Offshore Drilling Unit (MODU): depending on Met Ocean conditions (meteorology / oceanography), a jack-up rig may be used in shallow waters for instance, whilst a semi-submersible rig or even a drillship may be preferred for greater water depths. Once the exploration / appraisal phase is complete, the exploration and appraisal wells will be either permanently plugged and abandoned or temporally suspended to allow well re-entry. Once the exploration and appraisal wells have been secured, the riser can be disconnected and the MODU can be demobilised.

During the development phase, the storage wells may be drilled either as subsea wells by means of a MODU, or as platform wells with dry Xmas trees using a jack-up rig above the platform (if any) or using the platform rig (if any).

5.3.2. Surface facilities

With respect to the « surface » facilities, the engineering principles such as process engineering, electrical engineering and instrumentation, utilities, etc. will not significantly differ either, between onshore and onshore environment.

Nevertheless, multiple development options may be envisaged depending on project requirements. This may range from minimal offshore facilities and structures (i.e. process equipment and utilities located onshore and connected to offshore subsea wells via a subsea multiphase pipeline), to minimal onshore facilities (i.e. manned offshore installation equipped with full process equipment, utilities and a drilling rig and connected to the grid via a subsea gas pipeline).

Depending on project requirements (drilling, storage operations, fluid processing, power requirements, hydrogen export/import to/from shore, etc.), the platform may take on various forms: from fixed steel jackets with seabed foundations to floating units anchored on the seabed.

Similarly, environmental conditions will affect the solution retained during the development phase. These include (but are not limited to):

- Geographic location – distance to shore, distance to grid or pipeline network, etc.
- General Meteorological and Oceanographic Considerations affecting offshore site – Waves, Tides, Currents, Winds, Ice, etc.
- Active geologic processes – earthquakes, movement of near-surface sediments, seafloor instability, scour, shallow gas, etc.

6. Outline development schedule and key risks

6.1. Outline development schedule

The main project steps are presented in the simplified timeline below:

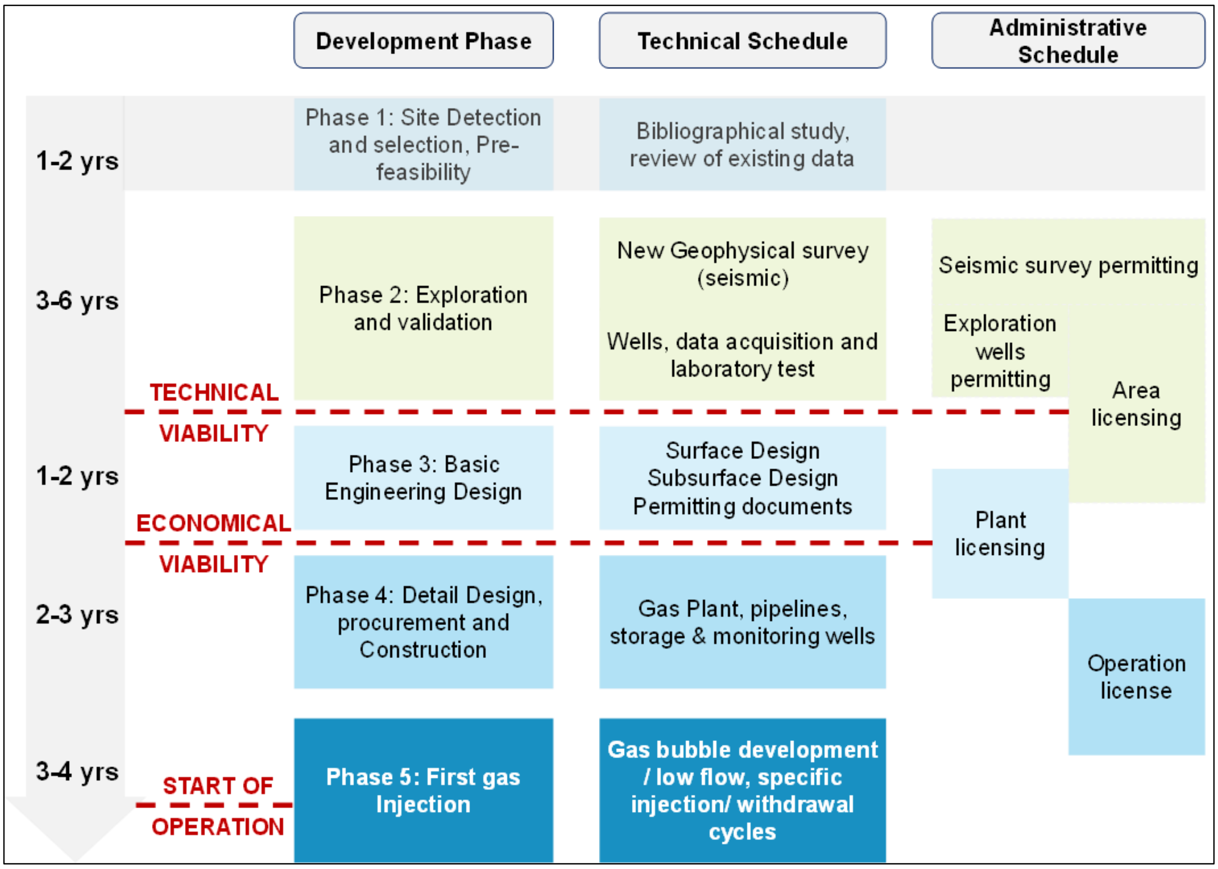

Figure 16: Main project steps – Simplified timeline

The steps and durations described above are indicative: delays can vary to a large extent, depending on various factors e.g. geological uncertainty, infrastructure access challenges, complex permitting process (vicinity of living areas, protected zones, etc.).

After the exploration phase and the GO / NO GO decision(s), it will be necessary to perform a basis design engineering of the project (subsurface and surface plant) to evaluate its cost. After this stage, it will be possible to evaluate if the project economics are compatible with market needs.

Then, for the Surface plant, a Front-End Engineering Design (FEED) will be needed. The licensing of the facility will be performed jointly. Finally, there will be the plant construction. On the subsurface standpoint, a detailed engineering of the well and the preparation of the drilling campaign will be needed, then the well drilling campaign will be performed during the plant construction. The Cushion gas injection shall start as early as possible and as soon as the subsurface part is ready. This will allow to reduce the delay for start of operation.

6.2. Key typical risks & uncertainties

The top generic risks and uncertainties that need to be addressed as part of an underground storage of hydrogen are listed below for depleted fields and aquifers:

- Data quality
  - Field description (technical reports, production history for depleted fields, etc.)
  - Geophysical data (2D / 3D seismic, gravimetric surveys, etc.)
  - Well data (logging data, cores descriptions, drilling reports, etc.).
- Reservoir characterisation (size and compartmentalisation)
  - Trapping mechanism
  - Reservoir structure, closure, and boundaries
  - Sealing capacity of surrounding formation and boundary faults
  - Reservoir sedimentology (petrophysical properties, continuity, extension, etc.)
  - Porosity and permeability horizontal / vertical distribution
  - Fault pattern and associated transmissibility / sealing potential
  - Type and strength of the drive mechanism
  - Spill point and lateral gas migration.
- Determination of maximum operating pressure
  - Risk of mechanical disturbance of cap-rock
  - Risk of gas penetration through cap-rock
  - Risk of uncontrolled lateral spread of gas.
- Wells
  - integrity status and condition of existing wells
  - Performance and productivity of existing wells
  - Wells planning uncertainties (Well location, Completion design, Integrity of the storage reservoir, Gas tightness of the subsurface installations, Pressure and temperature during cycle, Gas composition - Corrosion prevention, Protection of the formations above the storage reservoir, Planned lifetime)
  - Neighbouring subsurface activities
  - Presence of wells in the basin: interference with hydrogen storage
  - Presence of wells in the basin: industrial and public acceptance.

In the case of salt caverns, the top generic risks and uncertainties that need to be addressed as part of an underground storage of hydrogen are listed below:

- Data quality
  - Prospect description (technical reports, offset wells, regional geology, etc.)
  - Geophysical data (2D / 3D seismic, gravimetric surveys, etc.)
  - Well data (logging data, cores descriptions, drilling reports, etc.).
- Structural risk
  - Lateral extension of salt structures impacting number of caverns and ultimately gas storage volume
  - Vertical extension and depth of salt structures impacting caverns volumes and volume of gas stored in each cavern
  - Regional / local geological constraints e.g. fault patterns impacting caverns' tightness and integrity.
- Stratigraphic / Petro-physical uncertainty
  - Salt interval homogeneity / continuity e.g. presence of insoluble or hyper-soluble strata within saline massif impacting leaching time and caverns volumes
  - Salt quality and purity e.g. hyper-soluble insoluble elements within salt matrix impacting leaching time and caverns volumes.
- Geomechanical uncertainty
  - Salt creep impacting leaching time and free gas volume over time (cavern volume reduction).
- Determination of operating envelope versus cavern / well limitations
- Wells
  - integrity status and condition of existing wells (if any)
  - Wells planning uncertainties (well location, completion design, cavern integrity and, pressure and temperature during cycle, gas composition - corrosion prevention, protection of the formations above the cavern, planned lifetime).
- Leaching strategy
  - Alternatives for cost / time optimisation in relation to the development of the leaching strategy (quantity of cavities)
  - Leaching station design and construction
  - Water supply / brine discharge.

Regardless of the storage solution (salt cavern or depleted field / aquifer), some of the key surface facilities risks and uncertainties that need to be addressed as part of an underground storage of hydrogen are listed below:

- Site implementation
  - Location constraints (authorisations, land acquisition, etc.)
  - environmental (deforestation, topography, soil quality, etc.)
  - Gas pipeline connection
  - Electrical supply
  - Climate conditions
  - seismicity.
- Design of operating facilities
  - Site operating conditions (operating cycles, etc.)
  - Stored gas commercial specifications (network pressure, temperature, gas quality, etc.).

7. References

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