Sustainable Hydrogen Project Development

An example of integrated project optimisation - March 2022

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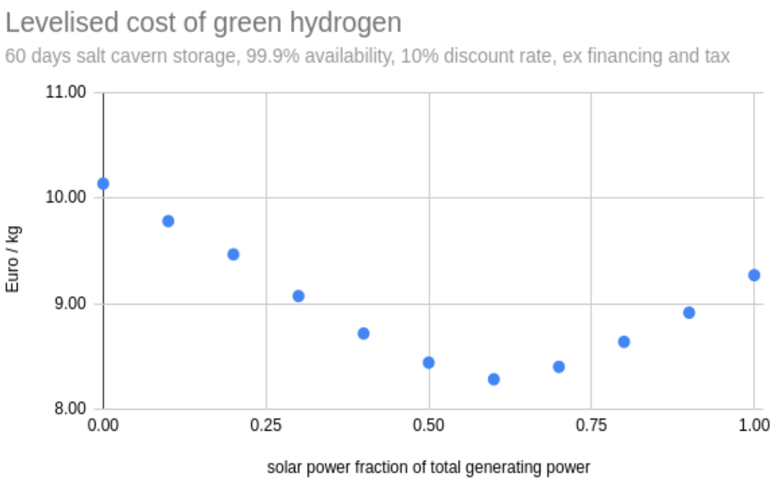
Executive Summary

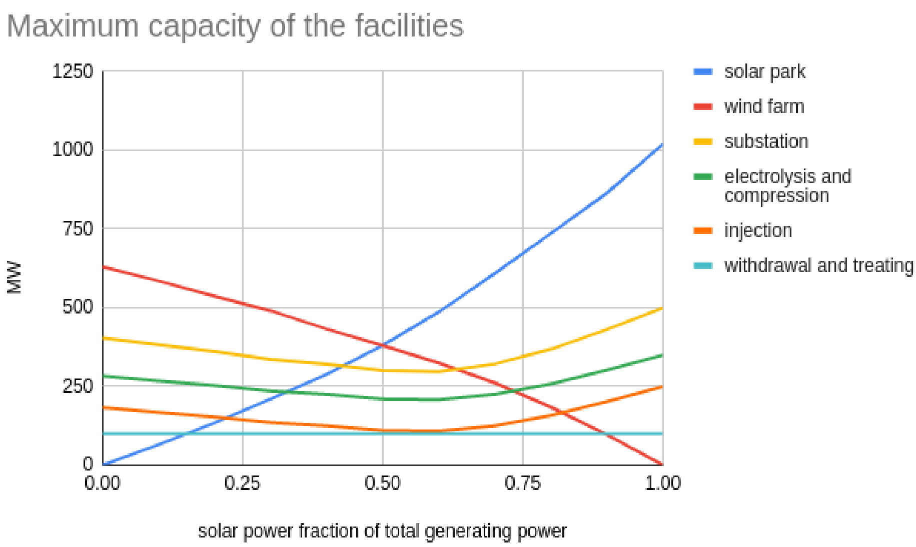
In their Global Renewable and Low-Carbon Gas Report, the International Gas Union concludes that green hydrogen is significantly more expensive than any other form of renewable gas, but costs are expected to fall. In that benchmark study, they provide a current price range for green hydrogen around 8 €/kg.

This study presents an example of integrated green hydrogen project development and shows what is needed to approach 8 €/kg, based on present-day cost assumptions and for a location in south France, near the Mediterranean coast. With the requirement of meeting the hydrogen demand of 100 MW for 99.9% of the time, this study optimises the maximum production capacity of the solar park, the wind farm, and all other facilities, and the underground storage size to achieve minimum hydrogen cost. The study fully considers the variability of the weather, based on ERA5 re-analysis data, and all other sources of unavailability, such as the reliability of the electrolyser stacks and the compressors, and quantifies the key role of the storage.

For the chosen location, the ratio between the production capacities of the solar park and the wind farm determine the hydrogen cost. Assuming a 10% discount rate for all facilities and excluding tax and financing, the levelised cost of hydrogen ranges from 8.28 €/kg to 10.14 €/kg. For the chosen location, the optimised project has about 60% of solar power and 40% of wind power. The levelised cost of hydrogen remains below 8.50 €/kg on the range from 50% to 75% of solar power.



The required availability of the final hydrogen supply determines the storage injection capacity, the storage size, and the capacity of all facilities upstream of the storage. For the continuous supply of 100 MW of hydrogen (99.9% of the time), the optimised project needs about 490 MW of solar park capacity, 320 MW of wind farm capacity, 300 MW of power transmission, 210 MW of electrolysis and compression capacity, and about 100 MW of underground storage injection and withdrawal capacity. The minimum required storage size is in the order of 100 GWh, that is about 2500 ton, of working gas at higher heating value.



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1 Study scope

1.1 Introduction

There is a growing interest in the role of green hydrogen in the energy transition in Europe.

Where the end-consumer of the green hydrogen is an industrial process that needs to operate continuously, the availability of the final hydrogen supply is of critical importance. Given the emphasis on moving industry to a sustainable basis, this is often the case. Options to secure supplies from alternative conventional hydrogen sources that do not qualify as sustainable are less desirable.

There are several ways to increase the availability of the final hydrogen supply, including provision of storage, diversification of hydrogen production methods and incorporation of redundancy into the design of plant facilities. These options all have different characteristics and costs. This requires a robust approach to system optimisation to avoid excessive costs and/or failure to meet the promised supply criteria.

The need to meet a customers requirement for supply availability is not new, natural gas and electricity delivery systems both face similar challenges with limited or expensive storage options. To understand and predict their performance, supply systems are typically modelled using packages such as ARTIS. These allow the system to be investigated to identify the main sources of downtime and identify cost effective changes to their design and operation that will deliver the required performance. This study shows how the same approach can be applied to a green hydrogen supply network, minimising the cost of the final hydrogen supply at near 100% availability of the final hydrogen supply.

Building on the findings of the HyUnder project, the Hystories studies are underway to examine the potential for the widespread implementation of hydrogen projects in Europe across the period 2025-2050. This includes (onshore and offshore) mapping of the proximity of suitable underground storage facilities with existing and future wind/solar farms, modelling the production of renewable hydrogen, associated gas compression and hydrogen pipeline networks to transfer hydrogen to and from storage, and identifying the profiles and amounts of renewable energy that can be buffered by such storage facilities to meet time-varying energy demands across all end use sectors.

The developed models identify how to match renewable supply with energy demand at all times by appropriately sizing and operating the technologies involved in producing, storing, and distributing renewable hydrogen.

Against this background, SecuoS and Geostock have carried out a complementary study to assess the integrated production availability of an agreed hypothetical project in the South of France near Marseille. The approach is readily transferable to other locations, designs, and production availability and reliability targets.

1.2 System description

The study investigates a hypothetical green hydrogen production, storage and distribution system located in the South of France that supplies an industrial customer. Electrical power is generated by a mix of wind and solar facilities. It is supplied via a substation to an electrolyser plant to produce hydrogen. The hydrogen is then compressed and supplied to a treatment plant. From there, it is transported by pipeline to the demand location. Excess hydrogen is compressed further and injected in salt caverns for storage. The stored hydrogen is available to make up for any shortfall arising from variations in wind and solar power and equipment downtime. The flows of wet hydrogen from the electrolyser plant and the underground storage to the treating facilities are commingled. The operation of the underground storage withdrawal and the treating facilities are controlled to produce a constant flow of 100 MW (HHV), that is 2540 kg/h, pure hydrogen for transport and consumption.

Figure 1.1 shows the integrated hydrogen project, with the solar park and wind farm, substation, electrolysis, compression, underground storage, treating and transport facilities, and the demand. The scope includes all facilities that are critical to supply of green hydrogen.

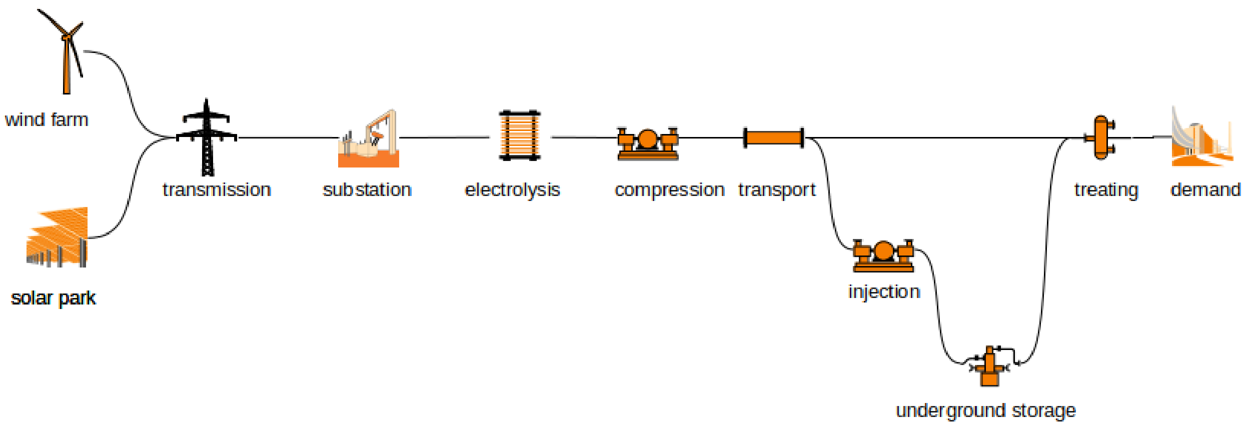

Figure 1.1: Integrated system overview showing hydrogen production, storage and distribution

This study assumes a coastal location north west of Marseille for the power generation, electrolysis, and first stage compression, and a location near Manosque for the injection compression, underground storage, and treating. These locations were chosen because the south east coast near Marseille presents good wind and solar energy potential and the underground near Manosque presents adequate geology to host salt caverns for hydrogen storage. Indeed, many salt caverns have already been constructed there for storing natural gas and liquid hydrocarbons. The hydrogen is transported between these locations, over a distance of about 100 km, by a dedicated bi-directional pipeline, at 100 bar.

This study is purely fictional, it does not correspond to any existing or proposed project.

1.3 System boundaries

The system boundaries cover all production-critical facilities from the green energy production at the solar parks and wind farms until the front gate of the final hydrogen consumption facilities. This includes the electrolysis, storage, treating, and hydrogen transport.

The subsurface facilities include the geological structure itself and associated physical and chemical processes.

The system is modelled in independent island mode, with no connection to the public electric power grid, batteries, or other electric storage. This is aligned with the EU directive that restricts the use of grid supplies for green hydrogen production. The exceptional case that the public grid supplies already fully meet the strict EU sustainability criteria is addressed as a sensitivity.

The study concerns the performance of the system once fully operational and does not include project delay, phasing or commissioning risks. The study does not address the accuracy of data and model simulations carried out by others and used as input.

The study scope encompasses all identified effects that might influence performance either positively, through opportunities, or negatively, through risks. This includes the market parameters such as supply/demand fluctuations, capacity profiles, and any contractual requirements. A key factor that affects system performance is equipment reliability resulting from degradation, failure, human error, other unplanned events, and the associated repair times. Alongside these are operational requirements for flushing, cleaning, regeneration, planned maintenance, inspections and other scheduled outages.

The impact of the surrounding natural environment is also included. This may arise for example from seasonal and daily weather effects on renewable power generation, ambient temperature on equipment performance, and any effect on repair times which may be linked to the time of day/year and manning strategy of the facility.

Data on the above are sourced from a number of different industry and public sources. One of the benefits of this type of study is that it allows uncertainties in data to be investigated via sensitivity analyses to understand the impact on overall system performance, so that the relative importance of data quality can be assessed.

1.4 Objectives

The aim of the study is to investigate:

- availability of the final hydrogen supply for the wind only Base Case for different storage capacities
- supply availability of the optimised system combining both wind and solar generation
- sources of system downtime, including breakdowns and criticality rankings for the Base Case and selected design alternatives
- identify possible improvements in the design, operation, and maintenance of the facilities
- make recommendations for finding the balance between equipment reliability and storage size that optimises economic value

The study models the hydrogen supply and demand inside the agreed system boundaries and evaluates and reports the curtailment to the producers and the availability of the final hydrogen supply. For the wind farm and solar park, this includes an assessment of the expected curtailment. All results are reported in terms of standard industry metrics, as averages over the study period and as functions of time.

The economic value is expressed in terms of LCoE estimates, based on cost data from open literature (IRENA, IAE, etc.). This includes a proposal for the definition of the 'Levelised Cost of Storage', consistent with the LCoE estimates.

1.5 Approach

1.5.1 ARTIS

The study uses the ARTIS (Availability and Reliability Tracking Information System) modelling platform, the in-house tool of SecuoS. ARTIS is a web based application for calculating the available capacity of a production system consisting of many process elements, each of which is subject to inspection, testing, failure, repair and maintenance. ARTIS is capable of handling time-varying production capacity profiles to give a period by period analysis of the production availability and system capacity. For instance, ARTIS can be applied to oil and gas projects, gas liquefaction plants and oil refineries.

ARTIS is web-based and fully transparent; no special software or detailed expertise is required for reviewing the model.

1.5.2 Ownership

Ownership of the tool (comprising the ARTIS model, ARTIS platform and any dedicated interface software) related to this study remains with SecuoS. Geostock has the right to use the ARTIS Cloud Service under the conditions of the ARTIS User Agreement, for this study.

All data used in the model remains the property of the data owner. Any confidential or commercially sensitive data used as input to the model or resulting from use of the model remains the property of the data owner. The ARTIS servers retain no data.

SecuoS provides free access to part of the ARTIS documentation. This access includes all aspect of the user interface, the online user manual, the database interface requirements, and syntax.

The ARTIS user interface is open source, but the engine is not. On request, SecuoS will make available test reports on some key functionality of the ARTIS engine.

2 System configuration and modelling

2.1 Introduction

A production availability model describes whether a system is able to operate at maximum capacity, able to operate at a reduced capacity, or unable to operate, depending on the status of its facilities. Rather than modelling the physical flow in a process flow scheme, the model reflects the time-dependent ability to produce, while respecting the mass and energy balances.

The system can comprise of many facilities, each with any number of equipment items. In the two most common and simple cases, the items are arranged in series, in a single train, or as a number of parallel trains. This arrangement reflects the impact on the facility when an item downtime event happens, such as an inspection or a failure (see [12] and [13]):

- Items that are arranged in series are critical to the train. That is, when such an item fails, the train can no longer operate.
- Items are arranged in parallel if, upon failure of one item, the parallel items and trains can continue production, and the whole system can continue to operate, possibly at a lower capacity.
- In general, systems cannot be modelled by serial and parallel nesting only; they must be modelled as a network of chains, each with individual nodes. In that case, each node is still critical to the performance of its chain, and the above two principles still apply.

The model can include both supply and demand.

The utilities like power generation and biological treatment of process water are just as much part of the model as are the production, conversion, transport and storage facilities. This implies that the model has a single unit of capacity for the whole system. In this study, the unit of power for all energy carriers is megawatt (MW) or gigawatt (GW) at higher heating value (HHV), as on the European natural gas markets. The unit of energy is megawatt-hour (MWh) or gigawatt-hour (GWh) and the unit of mass for CO_2 emissions is ton or kiloton (kton). The unit of pressure is bar.

This section describes the Base Case of the integrated hydrogen project.

2.2 Input data

The input parameters for the surface and subsurface facilities include:

- probability distributions of the wind farm and solar park generating capacity

  for the specific locations
- the maximum operating capacities of all surface and subsurface assets
- fuel use, conversion efficiencies, and round trip efficiencies
- the planned downtime events (maintenance, inspection, projects, withdrawals, ...) of all surface and subsurface assets
- parameters for the stochastic life- and downtime of all surface and subsurface facilities

- the hydrogen demand profiles, by final consumer

The study uses the standard definitions from relevant ISO standards.

2.3 Planned downtime

The hydrogen demand is assumed to have planned downtime, following a standard compressor inspection schedule:

- annual inspections: every year, 10 days
- intermediate inspections: every 3 years, 16 days
- major inspections: every 6 years, 30 days

This study assumes that all planned downtime in the hydrogen supply chain is aligned with this schedule.

2.4 Unplanned downtime and equipment reliability

This example study uses reliability data that has been collected by the oil & gas industry, under the OREDA Joint Industry Project [15]. Although the OREDA project does not consider hydrogen, no adjustments have been made for possible different failure modes, failure frequencies and repair times. The active repair times of OREDA have been used.

An average mobilisation delay of 12 hours has been added to all active repair times. By exception, the gas heater in the treating regeneration facility has a short average mobilisation delay of only 4 hours.

For the solar park, the PVGIS data [4] already includes a correction for unplanned downtime, see section 6.2.2. It is included in the system loss of 14%.

For the wind farm, it is assumed that the turbines' condition monitoring systems enable all repairs can be scheduled on an opportunity basis.

2.5 Operating flexibility

This study makes a number of assumptions on the operating flexibility.

- At any time, the project uses the full available capacity first to satisfy the full 100 MW hydrogen demand and then to inject all excess hydrogen into the underground storage.
- All items in the treating regeneration facility are assumed to have a grace period of 3 days to allow for continued operation of the active dehydration beds when the regeneration facility has an unplanned downtime event.
- The hydrogen pipeline is assumed to have enough line-pack only for limited operational storage. This could amount to about 10 minutes but this study does not include any hydraulic simulations to support that.

- The underground storage has a single well that is used both for injection and withdrawal. Depending on the diurnal cycle, the weather, and the line pack, the switches between the two operating modes will be frequent, often twice a day or more, and mostly predictable.
- The base case assumes that the initial volume of working gas is 80% of the full volume. This is taken to be a reasonable starting point because the underground storage is pressurised during the de-brining operation. The initial volume affects the assumed fixed working gas cost, see section 2.6, Table 1, but not any of the other study results.

2.6 Economics

This study optimises the maximum production capacity of the facilities and the underground storage size to achieve minimum hydrogen cost, under the condition of meeting the full 100 MW of hydrogen demand for 99.9% of the time, outside the planned downtime intervals. Based on cost density assumptions, this study calculates the Levelised Cost of Energy (LCoE) see [10], of green hydrogen.

Any available electric power above the project demand is assumed to have no value. The oxygen that is produced by the electrolysis is assumed to have no value either.

Table 1 presents an overview of the cost assumptions of the individual facilities in the hydrogen supply chain. Most cost assumptions derive from LCoE data, by assuming 100% utilisation. This study computes the utilisation, and the load factors, of the individual facilities.

facility	**cost density (€/kW)**	**source**
wind farm on land	1800	Fraunhofer, 2018
solar park	750	Fraunhofer, 2018
substation and transmission	333	Black & Veach, 2016
electrolysis	965	NREL, 2019
compression, 2x	894	Geostock, 2021
hydrogen pipeline	1200	Geostock, 2021
cavern, total	1536	Geostock, 2021
injection / withdrawal	58	Geostock, 2021
cushion gas	182	Geostock, 2021
working gas	253	Geostock, 2021
treating	269	Geostock, 2021

Table 1: cost density assumptions

The basis for the data in Table 1 is:

- The cost density data are preliminary assumptions and can be adjusted when new information is available.
- The electrolyser stacks have a limited life time; they are replaced every 8 years.

- Costs at the demand side, such as project development and refurbishment costs, are not considered.
- All LCoE data exclude all forms of subsidies and taxes.
- The assumed discount rate is 10%.

2.7 Assumptions and Uncertainties

As in any long-term planning context, assumptions on the timing of hydrogen project development are uncertain. In addition, there are large uncertainties around the future market developments and, in particular, future peak demand. To some extent, these uncertainties can be addressed by scenario analyses.

Access to data on the capacity and the historically achieved reliability of existing assets might be limited by lack of experience, confidentiality, consistency of definitions, and data quality. In many cases, data that were collected for natural gas facilities are taken to apply for hydrogen as well. At the present, this assumption cannot be validated.

On the other hand, there are significant EU-wide efforts to establish standard metrics, for example in the IRENA project.

3 Results

3.1 Base case

The base case has no solar park and no underground storage; all power is generated by a 630 MW wind park and when there is no wind, there's no hydrogen. The base case has only 100 MW, that is 2540 kg/h, of electrolysis and compression capacity. Figure 3.1 shows the cumulative available capacity of hydrogen, the base case is clearly inadequate.

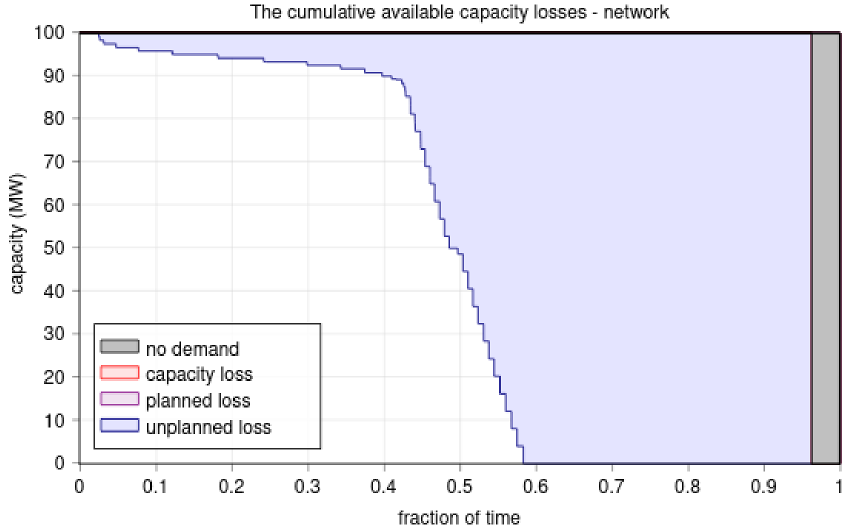

Figure 3.1: Base case: cumulative available capacity of hydrogen

It has an expected capacity of only 46.7%, that equals the white surface area. About 40% of the time there's no hydrogen at all.

The grey rectangle represents the planned downtime of hydrogen demand, it is 3.6%.

The blue area represents the unplanned loss, mostly when the wind speed is below 5 m/s, its size is 49.7%. The full demand of 100 MW hydrogen is only met about 3% of the time. Just below 100 MW, the losses from electrolyser downtime are visible. From 90 MW down, the steep steps reflect the wind speed and the small step at 50 MW corresponds to compressor downtime.

The subsequent sections address this problem in two ways: an underground hydrogen storage facility is added to provide backup and a solar park is added to reduce the variability of the power supply. This proceeds is three subsequent steps. First, a sufficiently large hydrogen underground storage facility is added to achieve a high production availability. Then, the optimum combination of solar park and wind farm capacities is determined by minimising the levelised cost of hydrogen, under the condition of 99.9% availability of the final hydrogen supply. After that, the size of the underground hydrogen storage is optimised to achieve further cost reduction, under the same condition.

3.2 Minimising the levelised cost of hydrogen by optimising the capacity balance

3.2.1 Base case with underground storage and extra capacity

This section adds a hydrogen underground storage facility, equivalent to 60 days at 100 MW, that is a working gas energy of 144 GWh, and a weight of 3660 ton.

In Figure 3.2, the blue curve shows the cumulative available capacity of the power from the 630 MW wind farm. The red line represents the electrical power demand at 156 MW, with the assumed electrolyser efficiency at 70%, and the reliability of the facilities upstream of the storage at 91.5%, based on the failure and repair assumptions referred to in section 2.4.

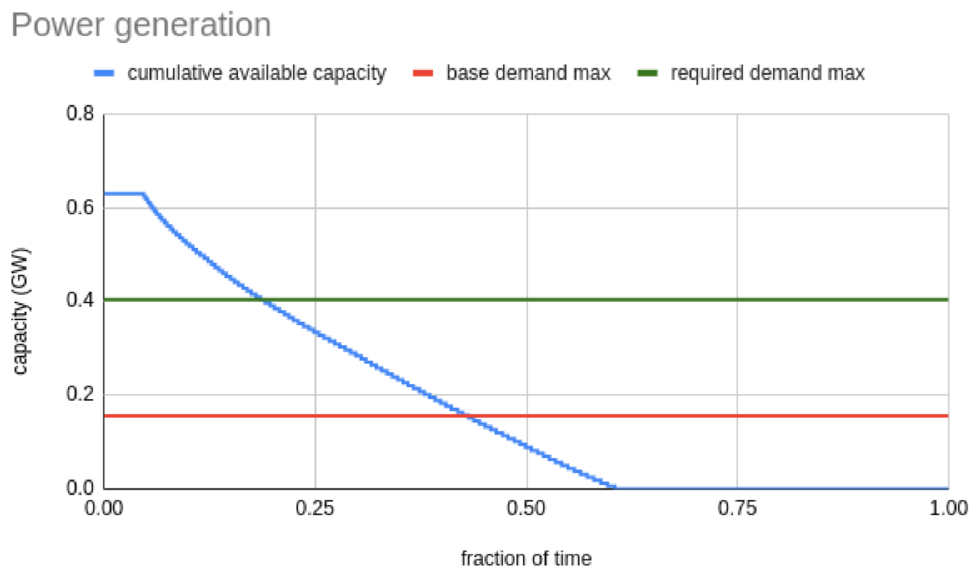

Figure 3.2: Base case - cumulative available capacity of electrical power

The area below the red line and above the blue curve, in the bottom right corner, reflects the base case loss of 49.2 MW hydrogen. The green line shows how much capacity the upstream facilities must have in order to capture enough power to fill the underground storage; the surface area gain below the green line and the blue curve and above the red line must equal or exceed the base case loss. This indicates the maximum demand for electric power, it must be at least 404 MW.

Figure 3.3 shows the cumulative available capacity of hydrogen, with the increased capacities to handle the 404 MW of electric power the availability of the final hydrogen supply is 98.6%. This is a large improvement but still 1.3 MW short and below the 99.9% target.

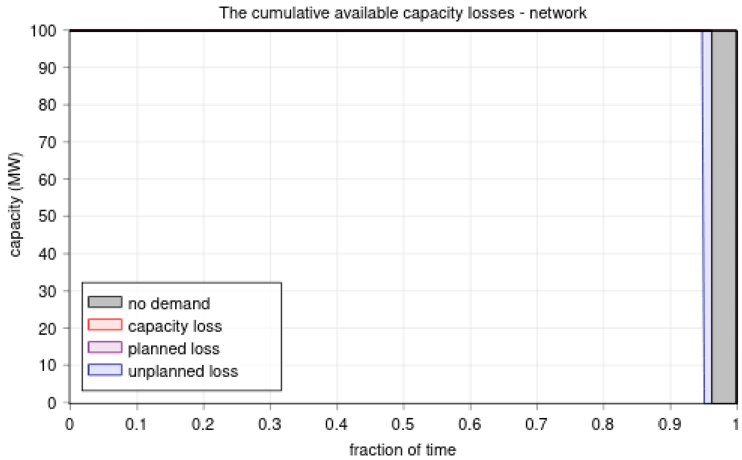

Figure 3.3: Only wind power, with storage: cumulative available capacity of hydrogen

The grey rectangle represents the planned downtime of hydrogen consumption. The blue rectangle represents the situation that the wind speed is below 5 m/s and the storage is empty.

3.2.2 Optimising the capacity balance

For reaching the 99.9% availability of the final hydrogen supply and minimising the levelised cost of hydrogen, a series of 11 cases has been set up, each one with a different solar park capacity as a fraction of total generating capacity. The first one is identical to the one described in section 3.2.1. For each case, the additional capacity required to produce and inject hydrogen has been determined, in the same way as described in section 3.2.1. Table 2 lists the 11 cases with the capacities that are required for achieving 99.9% availability of the final hydrogen supply, assuming that the underground storage is large enough.

capacity fraction	capacity, MW						
solar	generation	solar park	wind farm	substation	electrolysis and compression	injection	withdrawal and treating
0	630	0	630	404	283	183	100
0.1	650	65	585	382	267	167	100
0.2	670	134	536	361	253	153	100
0.3	700	210	490	336	235	135	100
0.4	720	288	432	321	225	125	100
0.5	760	380	380	300	210	110	100
0.6	810	486	324	297	208	108	100
0.7	870	609	261	321	225	125	100
0.8	920	736	184	368	258	158	100
0.9	960	864	96	431	302	202	100
1	1020	1020	0	499	349	249	100

Table 2: The 11 cases used for minimising the levelised cost of hydrogen

Figure 3.4 shows these capacities. .

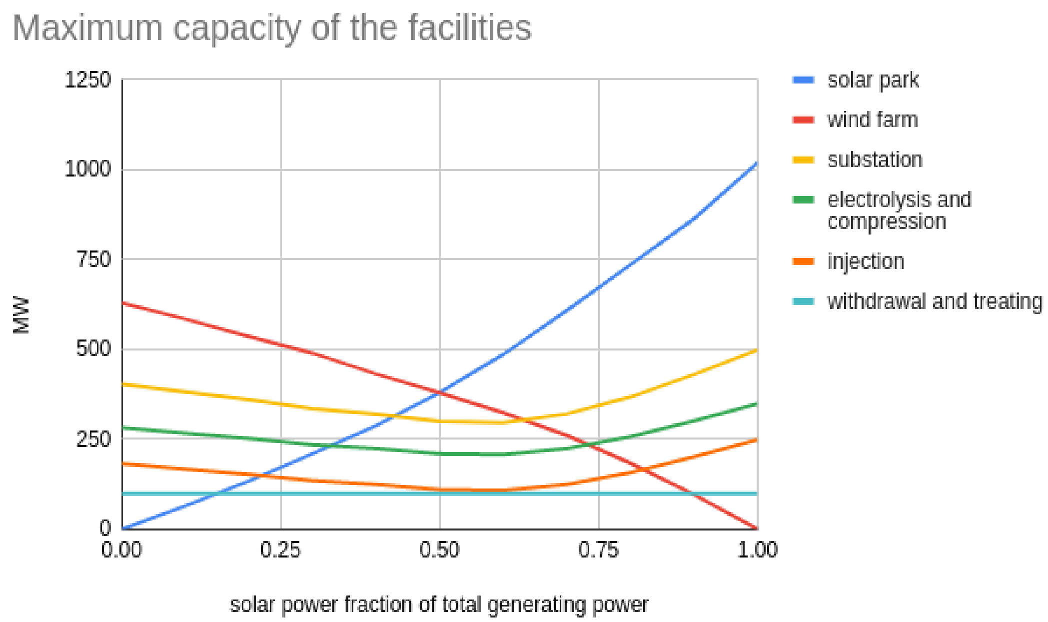

Figure 3.4: Capacity of the facilities as a function of the solar power fraction

Table 3 shows the levelised cost of hydrogen, based on the capacities in Table 2 and the cost assumptions in Table 1,

capacity fraction	cost of hydrogen	
solar	**€ / MWh**	**€ / kg**
0	257	10.14
0.1	248	9.78
0.2	240	9.47
0.3	230	9.07
0.4	221	8.72
0.5	214	8.44
0.6	210	8.28
0.7	213	8.40
0.8	219	8.64
0.9	226	8.91
1	235	9.27

Table 3: Levelised cost of hydrogen

The cost of hydrogen ranges between 8.28 and 10.14 €/kg and the case with 60% solar power and 40% wind power achieves the minimum. Figure 3.5 shows the cost curve.

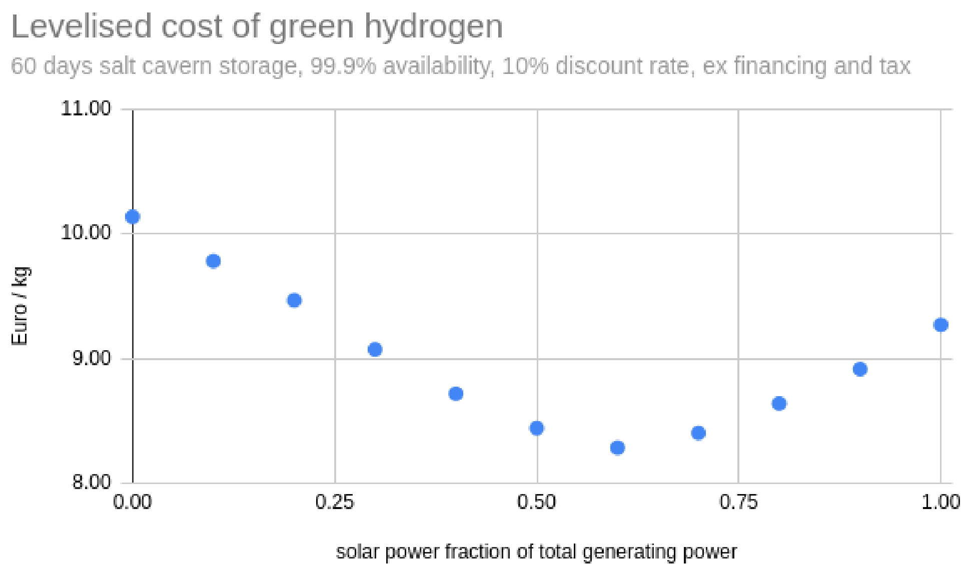

Figure 3.5: Levelised cost of hydrogen, as a function of the solar power fraction

The case with the lowest levelised cost of hydrogen is the one with 60% solar power (486 MW) and 40% wind power (324 MW). This is the optimised case, further analysed in section 3.3.

3.3 Optimised case

3.3.1 Capacity requirements

In Figure 3.6, the blue curve shows the cumulative available capacity of the power for the optimised case, with 60% solar and 40% wind power. The red line represents the electrical power demand at 156 MW, with the electrolyser efficiency at 70% and the reliability of the facilities that are upstream of the storage at 91.5%.

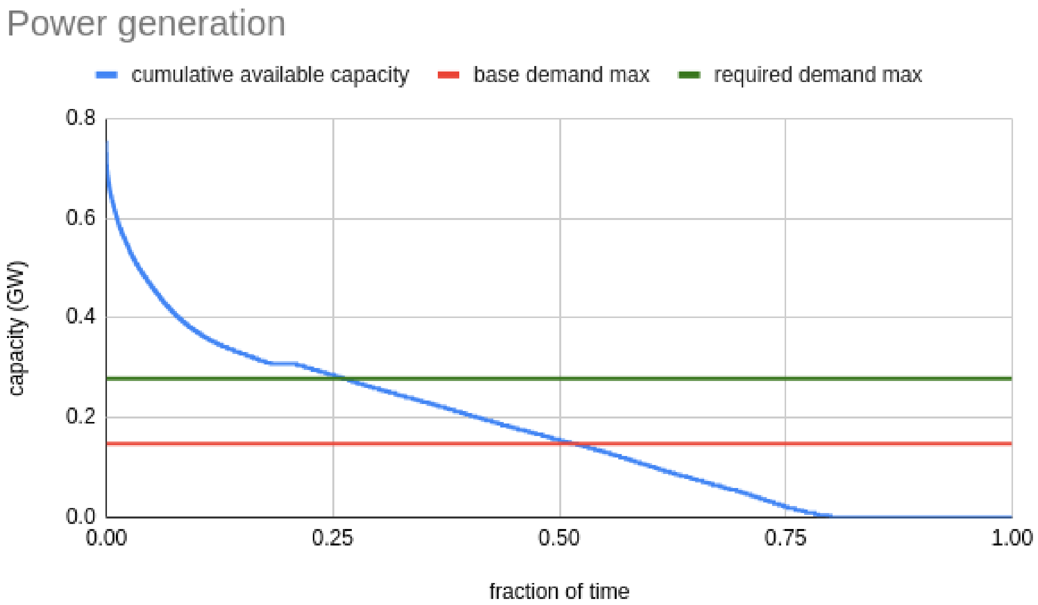

Figure 3.6: Optimised case - cumulative available capacity of electrical power

The blue curve can be understood as follows.

- On the interval [0, 0.18], that is 18% of the time, it is daytime with plenty of sun and wind.
- On the interval [0.18, 0.22], it is nighttime and the wind farm operates at plateau, with wind speeds between 15 and 25 m/s.
- On the interval [0.22, 0.52], there is enough electrical power for meeting the full hydrogen demand while also injecting into underground storage.
- On the interval [0.52, 0.8], there is still some generating capacity, but not enough to produce the full 100 MW of hydrogen.
- On the interval [0.8, 1.00], that is 20% of time, there is no power at all.

This already explains that the underground storage will operate in withdrawal mode for 48% of the time, of which 20% of the time at the maximum of 100 MW.

The area below the red line and above the blue curve, in the bottom right corner, reflects the amount of hydrogen that passes through the underground storage, the utilisation is 34.5 MW. The green line shows how much the capacity the upstream facilities must have in order to capture enough power to fill the underground storage. This indicates the maximum demand for electric power and the capacity of the substations, it is 297 MW. The capacity of the electrolysis and the compression is 70% of that. Table 2 in section 3.2.2 shows the capacity of the facilities.

The area below the blue curve and above the green line, in the left top corner, reflects 27 MW of expected generating capacity that the project cannot use. This study does not put a value on it.

3.3.2 Underground storage size requirement

The optimised case needs a sufficiently large underground storage, see section 3.2.2. The storage must never get full and never get empty, in order not to constrain the optimisation.

Figure 3.7 shows the relation between the underground storage size and the availability of the final hydrogen supply, both for the optimised case and the case with only wind energy.

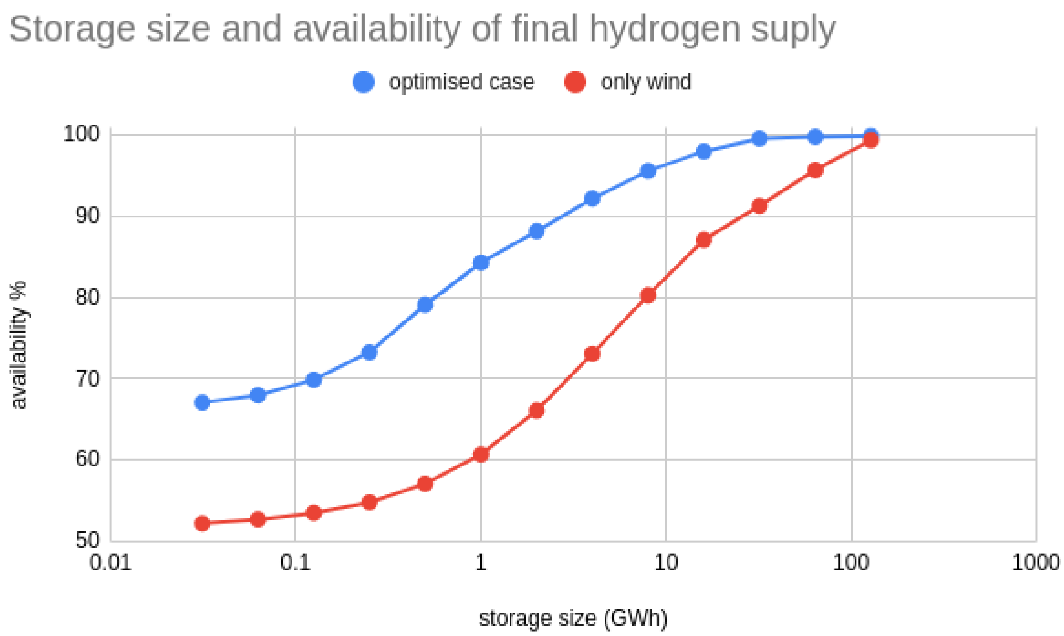

Figure 3.7: Storage size and availability of the final hydrogen supply

The 99.9% availability of the final hydrogen supply requires a storage size in the order of 100 GWh, about 2500 ton, as a minimum, in both cases.

This minimum value does depend on the chosen location of the power generation facilities and the local weather data.

All cases other than the optimised one, with different solar power fractions, see section 3.2.2, have more variation in available power generation. Hence, these cases require larger storage sizes in order to achieve the same availability of the final hydrogen supply. For salt caverns, increasing the size of the storage comes at only a margin cost.

3.3.3 Utilisation and load factors

Table 4 and Figure 3.8 show the utilisation and load factors of the facilities. They does not distinguish between the solar park and the wind farm and do not account for any planned downtime.

optimum case facility	capacity MW	utilisation MW	load factor ex planned downtime
power generation	810	143	17.6%
substation	297	143	48.1%
electrolysis	208	99.9	48.1%
compression	208	99.9	48.1%
pipeline	108	69	63.9%
injection	108	34.5	32.0%
withdrawal	100	34.5	34.5%
treating	100	99.9	99.9%

Table 4: Optimised case - utilisation and load factors

The pipeline utilisation is about double the injection and withdrawal utilisation because the hydrogen flows in both cases, in opposite directions.

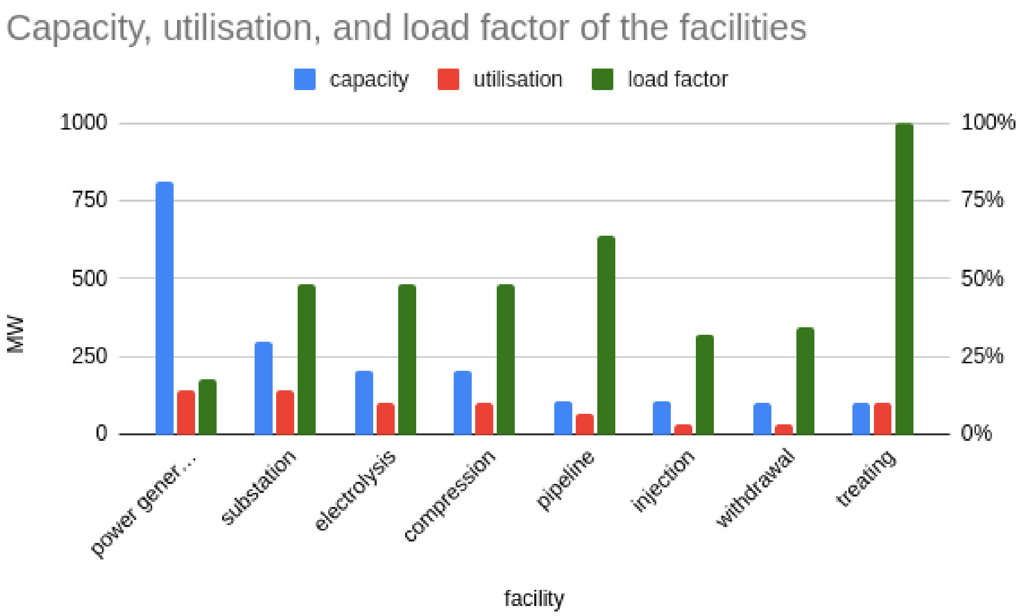

Figure 3.8: Optimised case - utilisation and load factors

3.3.4 Reliability of the facilities

Figure 3.9 shows the breakdown of the unplanned losses, relative to the demand, without the underground storage, for the optimised case.

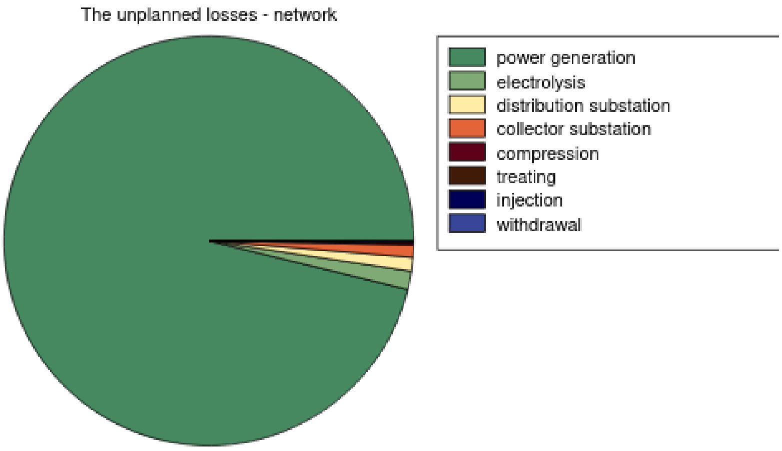

Figure 3.9: Optimised case - breakdown of the unplanned losses

The unplanned losses from the electrolyser and compression downtime is small because of their large capacities. Although the power generation facilities dominate the unplanned losses, all facilities are critical to the availability of the final hydrogen supply.

3.3.5 Cost breakdown

Figure 3.10 shows the cost breakdown of the optimised case.

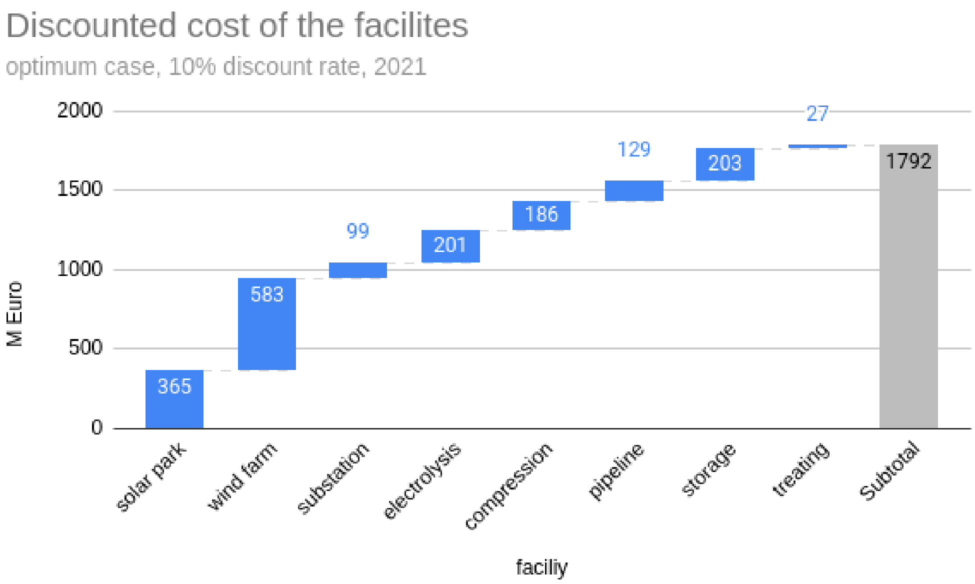

Figure 3.10: Discounted cost of the facilities, 10% discount rate, 2021

The total discounted cost of the optimised case is 1792 M Euro. Although the wind farm provides only 40% of the electric power, it still accounts for almost one third of the total project cost.

3.4 Green power import from the grid - only when the sustainability criteria are met

The EU has now published its draft guidance on the criteria that a "renewable liquid and gaseous transport fuel of non-biological origin", such as green Hydrogen, will have to satisfy. Whilst the criteria is for transport fuels, it is being viewed more widely by the industry as the standard for green hydrogen in Europe, see statement from Hydrogen Europe.

For most of the proposed green Hydrogen projects, power supplies from the local grid will only occasionally satisfy these criteria. Generally, the public grid cannot serve as a primary or even a back-up power source. Hence, this section addresses the exceptional case that the public grid supplies already fully meet the strict EU sustainability criteria.

All cases considered so far generate all electric power required for the electrolysis themselves, by solar and wind. For the optimised case, alternative green power supply from the public grid has been considered as a sensitivity. It is assumed that the green power import contract provides for the continuous supply at a constant price over the whole evaluation period.

Figure 3.11 shows that the levelised cost of hydrogen reduces with increasing green power import at an assumed import price of 50 €/MWh.

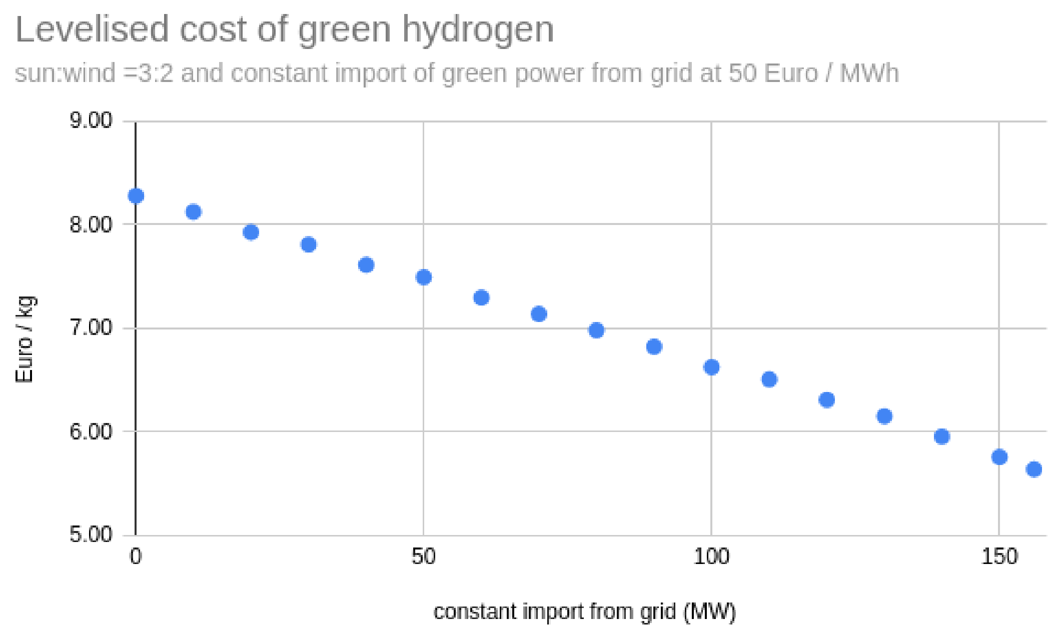

Figure 3.11: Sensitivity of the optimised case with green power import from the public grid

In the sensitivities with green power import, the integrated project can achieve the target 99.9% availability of the final hydrogen supply with smaller facilities upstream of the salt cavern. This leads to the cost reductions.

Above a price of 90 €/MWh, there is no longer any gain from power import.

4 Conclusions and recommendations

On sustainable project development

1. Project studies along the lines of this example study are key for optimising the capacity balance of the integrated hydrogen supply chain and for achieving minimum hydrogen cost. Most importantly, they help with optimising the capacities of the facilities upstream of the storage, under the condition of high availability of the final hydrogen supply, close to 100%.
2. Such studies provide an objective and quantitative basis for project integration, commercial negotiations, transfer pricing, and obtaining project subsidies and financing.
3. Having developed a robust modelling methodology, it is recommended to further evaluate locations with more favourable wind and solar conditions while ensuring suitable underground storage capacity, possibly at some distance, if so if required.
4. For each new location, the data on the local weather must be used and the assumptions must be updated in order to optimise the capacity balance.

On this example study

5. Despite the large capacities of the facilities upstream of the underground storage, the optimised case is lean. Any increase in their assumed downtime has a delayed impact on the availability of the final hydrogen supply. Any change in their assumed downtime must be compensated by a corresponding change in the capacities of <u>all</u> upstream facilities.
6. For all facilities downstream of the storage, their reliability has a direct impact on the final hydrogen supply. Hence, the downstream facilities, including the withdrawal facilities, must be close to 100% reliable. The addition of a second well would provide further flexibility in managing the injection and withdrawal cycles of the hydrogen and its metering.

On risk management

7. Since the weather risk dominates the project cost, it pays off to diversify that risk, by realising geographical spread or by providing backup power, from nuclear or other renewable sources. The high investment required for the power generation capacity – which exceeds the demand by an order of magnitude – justifies the investigation of possible win-win integration options with other renewable power producers . However, the opportunities will be constrained by the EU definitions of green hydrogen.
8. The minimum required storage size depends on the assumed weather data. Since the future weather will differ from historical data, an as-yet unknown margin must be adopted.

On data collection

9. This study uses historical local correlated weather data, hour-by-hour and over a period of 12 years. But longer periods are better. The ERA5 re-analysis data is a most useful source.
10. The Oil & Gas Industry has developed the ISO 14224 standard for the collection and exchange of reliability and maintenance data for equipment. This is a practical standard, based on the data collection process of the industry leading Offshore REliability DAtabase (OREDA) Joint Industry Project [15]. The standard can be adjusted for the hydrogen Industry to capture equipment reliability data on a complete and consistent basis. The Hydrogen Reliability Database must be arranged through a new international long-term mutual industry effort.

5 References

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6 Appendices

6.1 Measurement units

GJ	gigajoule
GWh	gigawatt hour
g/kWh	gram per kilowatt hour
h	hour
HHV	higher heating value
kT	kiloton
kV	kilovolt
kWh	kilowatt hour
LCoE	levelised cost of energy
MJ	megajoule
MT	megaton
bar	100 kilopascal

6.2 Model details

6.2.1 Power generation

Both the wind farm and the solar park are modelled as single blocks each with an hourly event trace that represents all aspects that impact on the available capacity. Section 3 optimises their peak capacities.

The local weather fully dominates the available capacity of electric power from the solar park and the wind farm. This study handles this source of variability by using the correlated historical weather data generated by the ERA5 project [5] of the European Centre for Medium-Range Weather Forecasts, ECWMF, for the example location, hour by hour, for the 12-year period from 2005 until 2016.

6.2.2 Solar park

The solar park is modelled as a single block, with the hourly data downloaded from the Photovoltaic Geographical Information System (PVGIS) [4]. These data include the impacts of hourly solar radiation and ambient temperature, cloud cover, panel orientation and efficiency, and system losses.

In the ARTIS model, the PVGIS-ERA5 data are scaled with the peak capacity of the solar park. This study assumes that the hourly historical data applies, as is, to the future period from 2025 until 2036.

6.2.3 Wind farm

The wind farm is also modelled as a single block, with capacities based on the hourly wind speed data of the Copernicus Project of the European Centre for Medium-Range Weather Forecasts (ECMWF)[5]. The download details are:

- source: ERA5 hourly data on single levels from 1979 to present
- type: reanalysis
- wind: 100m u-component and 100m v-component
- year: 2005 - 2010 and 2011 - 2016, separately in 2 downloads
- month, day, and time: all
- geographical area: latitude 5.2 - 5.3, longitude: 43.3 - 43.4
- format: GRIB

After download, the wind speed data have been corrected for an assumed altitude of 160 m using the commonly applied power law with coefficient 1/7. The wind turbines are assumed to have a piece-wise linear capacity curve with simplified parameters:

- cut-in wind speed: 5 m/s
- capacity plateau starts at 15 m/s
- cut-out wind speed: 25 m/s

In the ARTIS model, the resulting capacity data are scaled with the peak capacity of the wind farm. This study assumes that the hourly historical data applies, as is, to the future period from 2025 until 2036.

6.2.4 Power collection, transmission and distribution

The wind farm and the solar park are in the same area and they are connected to a single substation. The substation transforms the voltage from 33 kV to a lower level suitable for supplying the rectifiers of the electrolyser stack modules.

Figure 6.1 shows the substation diagram, based on a published design [6].

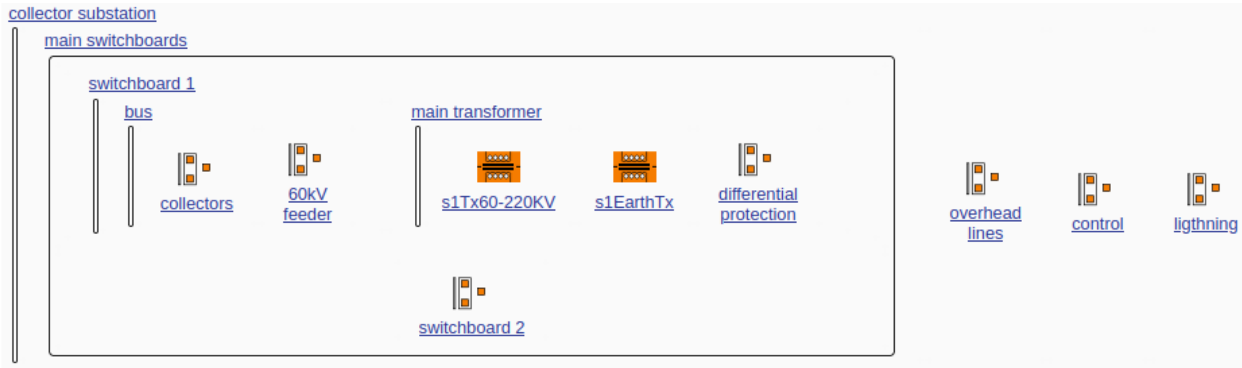

Figure 6.1: diagram of the substation

The power transmission cables that connect the substation to the electrolysis plant are assumed to have sufficient capacity and no downtime.

6.2.5 Electrolysis

The electrolysis plant produces hydrogen and oxygen from demineralised water, by electrolysis. The outline of the electrolysis plant is taken from the IRENA study on green hydrogen cost reduction [2]. It is based on the Polymer Electrolyte Membrane (PEM) technology. Figure 6.2 shows the model diagram for the example system design, with 6 modules of 20 stacks, each with the same capacity. In the optimisation, Figure 3.4, the total capacity of the electrolysis plant ranges from 200 to 300 MW.

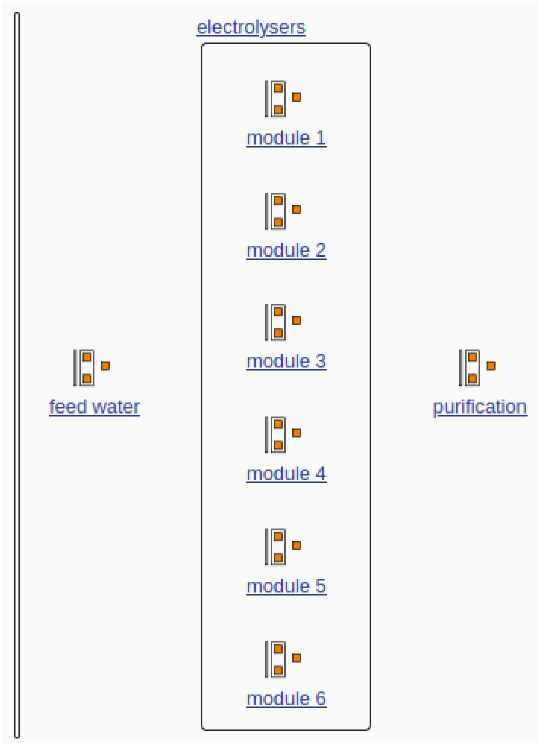

Figure 6.2: diagram of the electrolysis plant

The electrolysis is assumed to have an efficiency of 70%.

PEM systems typically require the use of feed water circulation pumps, heat exchangers, pressure control and monitoring only at the anode (oxygen) side. At the cathode side, a gas-separator, a de-oxygenation component to remove remnant oxygen, and a gas dryer. The oxygen is considered not to be of value and is released to the atmosphere.

Figure 6.3 shows the diagram of the feed water facilities.

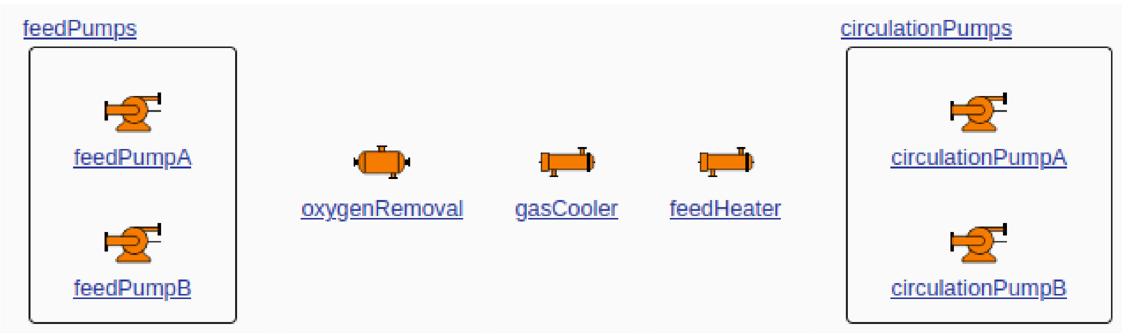

Figure 6.3: diagram of the feed water facilities

Figure 6.4 shows the diagram of the hydrogen purification facilities.

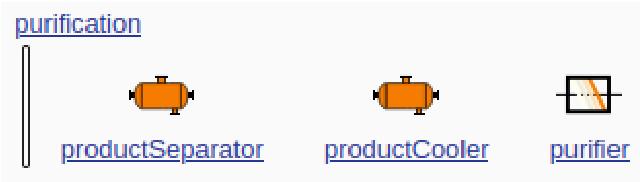

Figure 6.4: diagram of the hydrogen purification facilities

6.2.6 Compression

The model of the compression facilities is based on the Hystories concept document [1]. There are 2 compression stations, one at the electrolyser plant for compression to transport and treating pressure, at 100 bar, and one at the underground storage location for further compression to injection pressure, at 200 bar.

Figure 6.5 shows the diagram of the 2 trains of the 100 bar compressor station. Each train has 50% capacity. The compressors are of the reciprocating type. Each compressor has an electric driver.

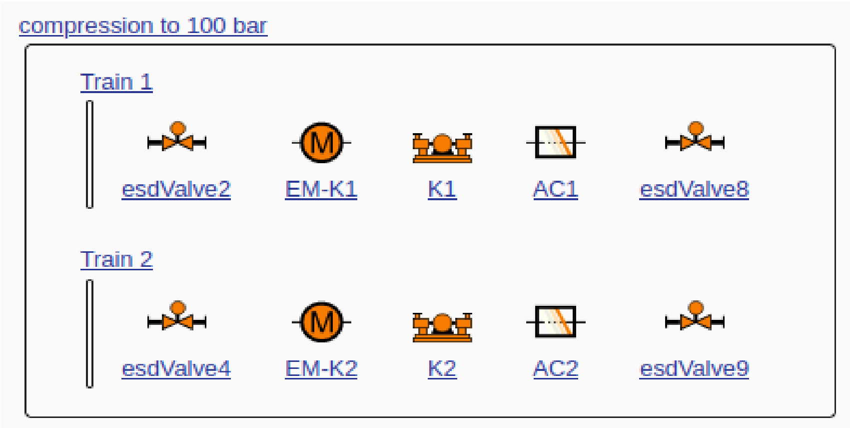

Figure 6.5: diagram of the hydrogen compression facilities

The compressor drivers are powered from the public grid.

6.2.7 Underground storage

The model of the underground facilities is based on the parameters for the large salt cavern that the Hystories concept document [1] provides. It covers the salt cavern, the well and associated completion, and the wellhead.

The storage is intended to store the required amount of hydrogen and it acts as a buffer to improve the availability of the final hydrogen supply.

A typical well architecture would be :

- 30" conductor pipe
- 20" surface casing string

- 13 3/8" production casing string (Last Cemented Casing)
- 9 5/8" gas completion run with packer/tubing anchor seal assembly and Downhole Safety Valve

6.2.8 Treating

The model of the treating facilities is based on the Hystories concept document [1]. Figure 6.6 shows its model diagram.

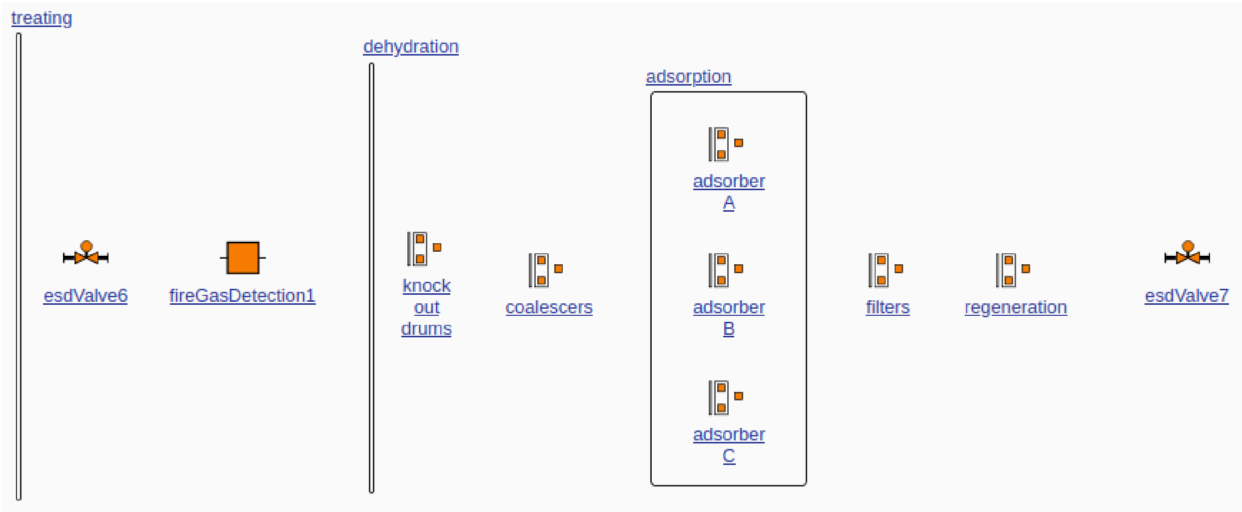

Figure 6.6: Diagram of the treating facilities

In salt caverns, the remaining brine will slowly evaporate into the hydrogen. When the hydrogen is withdrawn from the salt cavern, it flows to the treating facilities for removing the water traces from it. This study assumes that is done by adsorption.

6.2.9 Transport

The hydrogen pipeline between the electrolyser plant near Marseille and the underground storage near Manosque is assumed to have sufficient capacity and no downtime. The pipeline is bi-directional.

6.2.10 Demand

The demand is assumed to be at a location near Marseille, at 100 MW, that is 2540 kg/h.

6.3 Brief explanation of availability modelling terminology

A **production availability model** is a stochastic representation of the facilities and equipment items of a production system, showing their impact on the system availability. The production availability model availability shows how the system depends on each all items for its proper functioning. The diagram availability is <u>not</u> a process flow scheme, it does not show the flow of product. Items from different systems may be shown connected. Items do not need to be shown in the order in which they sit in the process.

- Items are in **series** when their proper functioning is vital for plant performance; if one item fails, the entire process stops.
- Items are placed in **parallel** if upon failure of one item, the other parallel item(s) can (partly) take over and the process continues, possibly at a lower capacity. Parallelism is not restricted to single items, e.g. the compression trains in LNG liquefaction are placed in parallel, each containing several compressors, heat exchangers and knock out drums.
- an item has a maximum production capacity and inherits its downtime data from a **unit**

Each unit represent a set of comparable items and it has the following data:

- bypass capacity upon failure (e.g. a manual bypass on a valve)
- failure data: Mean Time To Failure (MTTF) and Mean Time To Repair (MTTR)
- Optionally: preventive maintenance strategy

For the analysis, time is split into 4 different categories: operation, standby, preventive maintenance and breakdown maintenance

An item is **available** if it is either in operation or on standby, not while down, either planned or unplanned:

Availability = (operation time + standby time) / total time

The **reliability** of a unit is defined as the fraction of time that the unit is working when required. Hence reliability is based on time excluding preventive maintenance:

Reliability = (operation time + standby time) / (total time - preventive maintenance time)

Reliability always excludes preventive maintenance and availability includes preventive maintenance.

With parallel items and bypass capacities, a system may have several capacity levels at which it can operate. The concept of availability (and reliability) is extended to **Available Capacity**: a table of all attainable capacity levels and the fraction of time spent at each level:

Capacity level	Available capacity
0%	Fraction of time spent at 0% capacity
x%	Fraction of time spent at x% capacity
100%	Fraction of time spent at 100% capacity

From the available capacity we can derive how much capacity can be expected from the system in one year's time. This is called **Effective Capacity**:

Effective Capacity = Σ capacity$_i$ * (fraction of time spent at capacity$_i$)

Stream-days can be computed directly from Effective Capacity:

Stream-days = effective capacity * 365.25 / 100