Viet Nam Technology Catalogue for Energy storage, Renewable fuels and Power-to-X

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Input for energy system modelling

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VIET NAM TECHNOLOGY CATALOGUE FOR ENERGY STORAGE, RENEWABLE FUELS, AND POWER-TO-X

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FOREWORD

Today, innovations and technological improvements in energy generation, storage and renewable fuels are advancing at a very rapid pace. At the same time, the cost, technical performance and environmental impacts of energy technologies remain highly context dependent and continue to evolve over time. Reliable and transparent information on these characteristics is therefore essential for sound long-term energy planning.

This Technology Catalogue provides a review-based technical foundation for a wide range of storage and renewable fuel technologies in the Vietnamese context. It aims at supporting evidence-based planning and analysis of Viet Nam's future power system. By presenting consistent data and assumptions on costs, performance and environmental impacts, the catalogue contributes to making energy system planning a central tool for unlocking the potential of new renewable-based technologies.

Through a multi-stakeholder involvement in the data and information collection process, all quantitative figures incorporated to this Technology Catalogue were thoroughly reviewed and scrutinized by a broad range of energy sector stakeholders in Vietnam, including Electricity Authority of Viet Nam (EAV), agencies under the Ministry of Industry and Trade (MOIT), Viet Nam Electricity (EVN), independent power producers, local and international experts, other development partners organizations, as well as energy branch associations and universities. This stakeholder engagement constitutes an essential element in the development process, to ensure that the Technology Catalogue is highly context specific, well anchored and legitimized by all relevant energy sector stakeholders.

The aim of this Technology Catalogue is therefore to serve as a key foundation for long-term energy and power modelling in Viet Nam, thus supporting government institutions, private energy companies, think tanks and others through a common and broadly recognized set of data for current and future electricity producing technologies in Viet Nam.

This Vietnamese Technology Catalogue builds on the approach of the Danish Technology Catalogues, which for many years have been developed by the Danish Energy Agency and Energinet through an open stakeholder process, serving as a key foundation for Denmark's long-term energy system planning.

Context

This publication is developed under the Danish-Vietnamese Energy Partnership Programme. The first Viet Nam Technology Catalogue for power generation and storage technologies was published in 2019, and subsequently updated in 2021 and 2023. In this edition, the publication focuses on a com-prehensive update of the chapters on pumped storage hydropower, lithium-ion batteries, vanadium redox flow batteries, and electrolysers. In addition, all cost data tables have been updated and con-verted to 2025 USD.

Acknowledgements

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Credits

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AMENDMENT SHEET

Under the Danish Energy Partnership Programme, the development of the Viet Nam Technology Catalogue has been a key activity since the first Technology Catalogue on Energy Generation technologies was published in 2019. The first edition of the Technology Catalogue on Energy Storage dates back to 2023. Since, the catalogue has undergone a series of updates to incorporate new technologies, revised data and methodological improvements, thereby strengthening its relevance for long-term energy planning in Viet Nam. The main amendments introduced between 2023 and 2026 are summarized in the following amendment sheet.

Version	Date	Reference	Description
	February 2026	7 Fuel cells	New chapter added
	January 2026	1 Hydro pumped storage 2 Lithium-ion batteries 3 Vanadium redox flow batteries 8 Electrolysers	Entire content of the chapters updated.
	January 2026	1-12	Water consumption added
	January 2026	Datasheet	All datasheets updated, costs converted to USD2025
	Mar ‘23	3 Vanadium Redox Flow Batteries 4 Hydrogen Storage 5 Compressed Air Energy Storage 6 Flywheels 7 Electrolysers 8 Green Ammonia synthesis 9 Methanol synthesis 10 Biomethanol from biomass gasification 11 Biogas production and upgrading 12 Green liquid fuels through Fischer-Tropsch synthesis	Chapters added compared to Viet Nam Technology Catalogue for power generation and Storage published in August 2021

CONTENT

ABBREVIATIONS

1. REF	Primary reformer (=SMR)
2. REF	Secondary reformer
AEC	Alkaline electrolysis cell
ASU	Air separation unit
ATR	Autothermal reformer
BAT	Best Available Technology
BFW	Boiler Feed Water
BOP	Balance of plant (utilities)
CC	Carbon capture
CO2rem	CO_2 removal unit
DeOX	De-Oxygenation unit
EIGA	European industrial gases association AISBL
EU	Electrolysis Unit
FG	Fuel gas
FT	Fischer Tropsch
FTS	Fischer Tropsch Synthesis
HC-feed	Hydrocarbon feed (normally fossil based but can also be bio-based)
HPS	High-pressure steam
HSE	Health safety and environment
HTS	High temperature shift (=high temperature water gas shift)
LNH3	Liquified NH_3
LTS	Low temperature shift (=low temperature water gas shift)
METH	MethanizationN2-EU Electrochemical synthesis NH_3
MOF	Metal organic framework
MTPD	Metric ton per day
NH3syn	NH_3 synthesis
NH3rec	NH_3 recovery unit
NH3reg	NH3 refrigeration unit
PEMEC	Proton Exchange Membrane electrolysis cell
PUR	Feed purification unit
RE	Renewable Energy
SOEC	Solid oxide electrolysis cell
SMR	Steam Methane Reforming (typically = 1.REF)
SSB	Solid State Battery
TPD	Tons per day
TRL	Technology readiness level
WGS	Water gas shift

INTRODUCTION

The catalogue consists of 13 chapters describing different technologies for energy storage and renewable fuels. The first 7 chapters are storage technologies and the remaining ones are technologies for the production of renewable fuels, including Power-to-X. This introduction outlines the scope, methodological principles and structure of this Technology Catalogue. A detailed description of the approach and methodological principles can be found in Appendix 1, 2 and 3 of this document.

Scope and Purpose

Reliable information on the cost, performance and environmental characteristics of energy technologies is essential for long-term energy planning. As energy technologies continue to rapidly evolve, their technical and economic performance varies across countries depending on local conditions, regulatory frameworks and market maturity. Thus, consistent and transparent information is needed to support the assessment of how energy storage and renewable fuel technologies might support the development of Viet Nam's evolving energy system. The purpose of this Technology Catalogue is therefore to provide a harmonized basis for assessing technologies, as well as to support long-term energy planning.

This catalogue compiles technical and economic information for a range of energy storage and renewable fuel technologies based on Vietnamese experience where available, and international evidence where necessary. By presenting harmonized assumptions for technology costs and performance parameters, the catalogue enables consistent comparisons across technologies and provides a common analytical foundation for planning and modelling. With this scope in mind, the catalogue is not intended to provide an exhaustive collection of specifications for all available technology variants. Rather, it presents selected and representative technologies to enable comparison between technologies with similar functions in the energy system.

For storage technologies in particular, the catalogue reflects that different technologies serve different applications across the power and energy system. Some technologies are better suited for power-intensive services, such as frequency support and short-duration balancing, while others are better suited for energy-intensive services, such as load shifting and longer-duration storage. The technologies are therefore compared not only on cost and performance, but also on their typical storage capacities, discharge durations and operational characteristics. Figure 1 provides an illustrative overview of how selected electricity storage technologies differ in terms of discharge duration and scale.

System boundaries and technological maturities

The technologies described in this catalogue cover for the most emerging technologies, which are expected to improve significantly over the coming decades, both with respect to performance and cost. This implies that the cost and performance of some technologies may be associated with an inherent level of uncertainty. Uncertainty ranges are thus provided for key parameters presented in this catalogue, such as investment costs. To further address the different maturity level of considered technologies, they have been grouped within one of four categories of technological development. This grouping is described in the section on research and development in Appendix 1 and reflects technological progress, future development perspectives and the uncertainty related to the projection of cost and performance data. As far as possible, technical parameters and investment costs are informed by Vietnamese project experience. At the same time, given the lack novelty of many hereby included technologies, as well as the lack of substantial storage and renewable fuel deployment in Vietnam so far, figures presented rely on authoritative international sources where necessary.

For all technologies, the presented cost and performance data refer to the technology asset and the associated infrastructure required to connect it to the relevant energy system. For storage technologies, performance is characterized through charging and discharging efficiencies, round-trip efficiency and, where relevant, storage losses over time. For renewable fuel technologies, the quantitative description reflects the relevant energy inputs, outputs and conversion efficiencies of the process.

Methodological principles and cost projections

To ensure comparability across technologies, all economic and technical data are reported using a common set of methodological assumptions. Economic data are expressed in constant 2025 U.S. dollars, excluding taxes such as value-added tax (VAT).

For most technologies, the catalogue provides cost and performance estimates for the future years in the timeframe between 2025 and 2050. For storage and renewable fuel technologies, future cost developments are primarily based on the learning curve approach and estimated based on technology learning rates and assumptions regarding future deployment. Appendix 2 and Appendix 3 provide detailed descriptions of the quantitative methodology for storage technologies and renewable fuel technologies, respectively.

Structure of the technology sheets

Each technology is described in a standardized manner consisting of two main elements.

- **The qualitative descriptions** provide a concise explanation of the considered technology, including its operating principles, key inputs and outputs, typical capacities, operational characteristics, advantages and disadvantages relative to alternatives, environmental characteristics including water consumption where relevant and research and development perspectives. Examples of current projects are included, with Vietnamese examples provided for technologies already applied in Viet Nam and international examples for technologies that are new to the Vietnamese market.
- The **quantitative sections** present technical and economic parameters for each technology. Tables contain data for 2025, 2030, 2040 and 2050 and include, among other, investment and operation and maintenance costs, efficiencies, technical lifetimes, construction times and other technology-specific performance parameters. For storage technologies, the quantitative description distinguishes clearly between energy-related and power-related characteristics. This includes the key parameters such as energy storage capacity and timescales (schematically presented in Figure 1), but also output and input capacity, charging and discharging efficiencies, round-trip efficiency, storage losses, response times and technical lifetime. Where relevant, investment costs are also distinguished between energy-related costs, capacity-related costs and other project costs, reflecting the specific cost structure of storage technologies. To account for the inherent uncertainty related to projected data, tables also include uncertainty spans, evaluated on a case-by-case basis.

Together, the qualitative and quantitative sections provide a consistent basis for presenting the storage and renewable fuel technologies included in this catalogue, and for assessing their potential role in Viet Nam's current and future energy system.

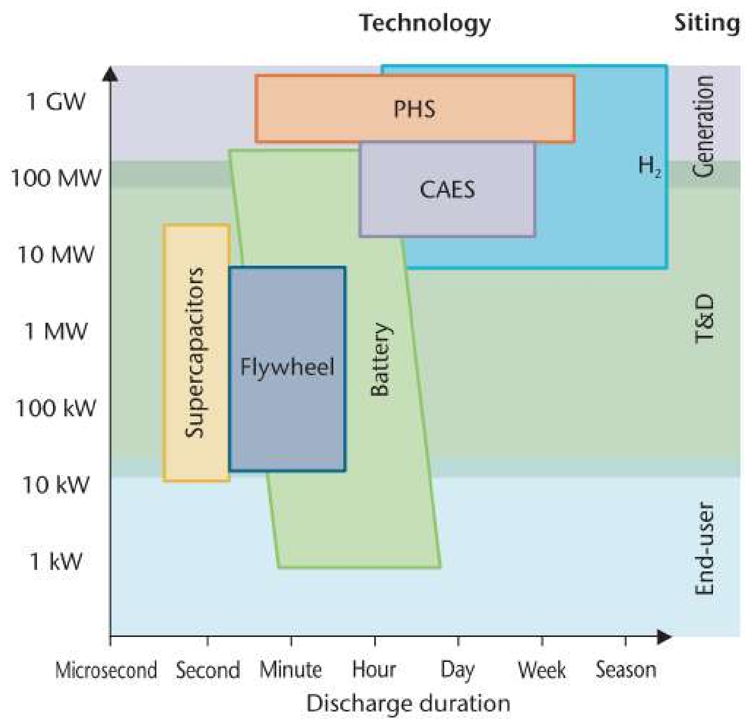

Figure 1: Capacity and discharge duration of electricity storage technologies (IEA 2015).

1. HYDRO PUMPED STORAGE

Brief technology description

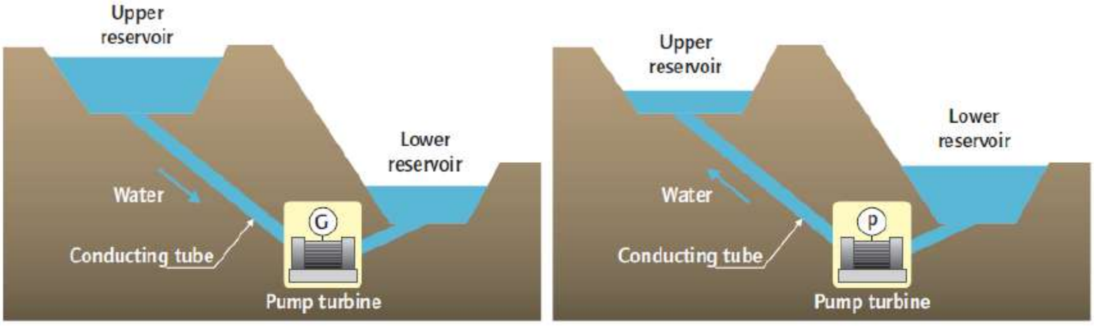

Figure 2: Hydro pumped storage

A typical pumped hydro storage (PHS) consists of two water reservoirs (lakes), tunnels that convey water from one reservoir to another, a reversible pump-turbine, a motor-generator, transformers, and transmission connection [1]. The amount of stored electricity is proportional to the product of the volume of water and the height between the reservoirs. For bulk electricity storage in utility grids, pumped hydro power plants dominate, with approximately 100 GW in service around the globe [2].

There are two main types of PHS facilities: off-stream PHS (closed cycle) uses water that was pumped to the upper reservoir, while hybrid PHS (combined) uses both the pumped water and natural flow water to generate electricity.

Greenfield PHS, including dams, have high capital expenditures and a long construction time. If an existing hydro plant is extended to also be a PHS, the investment per installed MW is significantly lower and the construction time varies between 2 and 3 years.

Pumped hydro storage involves a two-step process: pumping water to a higher elevation during periods of low electricity demand and releasing it to generate power during peak demand. This process inherently introduces energy losses. The efficiency of PHS systems typically ranges from 70-85 %, meaning that some energy is lost during the pumping phase and additional losses occur during the generation phase [1]. Despite these losses, PHS remains one of the most efficient large-scale energy storage methods available.

The primary advantage of PHS lies not in its raw efficiency but in its ability to store excess energy and provide grid stability. By storing energy during off-peak times and releasing it when demand is high, PHS helps balance supply and demand, integrate renewable energy sources, and enhance grid reliability. While less efficient than regular hydropower, PHS provides essential energy storage and flexibility benefits that are crucial for modern energy systems.

Pumped storage hydropower is one of the effective solutions to enhance power system flexibility, especially in systems with a high share of variable renewable energy sources such as wind and solar. Pumped storage hydropower can operate in two modes: (i) pumping mode (consuming electricity) during periods of low demand when there is surplus generation capacity; and (ii) generation mode during periods of high demand when there is a shortage of generation capacity. Pumped storage can support the power system with operational characteristics similar to conventional hydropower while also acting as a load to absorb excess generation during off-peak hours. It plays an important role in shifting the system generation profile and balancing supply and demand within the power system.

Input

The main energy input for a pumped hydro storage plant is electricity, typically drawn from the grid during off-peak periods when electricity is cheap or abundant (e.g., excess from wind, solar, or nuclear).

Output

Electricity.

Typical capacities

The capacity of a pumped storage hydropower project depends on site-specific conditions. Installed capacity can range from a few hundred megawatts up to around 1,000–1,200 MW. For locations with favourable reservoir construction conditions, project capacity can exceed 2,000 MW. However, for most pumped storage projects in Vietnam, the typical capacity range is around 300–1,200 MW. In addition to large variations in capacities PHS is also very diverse regarding characteristics such as the discharge time, which is ranging from several hours to a few days.

Ramping configuration

The primary intent of PHS is to provide peak power each day. However, their duty can be expanded to include ancillary service functions, such as frequency regulation in the generation mode. A variable-speed system design allows providing ancillary service capability in the pumping mode as well, which increases overall plant efficiency [2].

As Hydro Pumped Storage (HPS) installations offer greater flexibility than fixed-speed units, these plants provide additional services within the electrical grid beyond their primary purpose of energy storage, such as:

Peak levelling: An HPS system can be used for peak levelling to meet the highest demands in a short period of time.

Load balancing: Load levelling typically involves storing energy during light load periods (off-peak hours) in the system and delivering it during periods of high demand.

Shifting the generation profile: Pumped storage hydropower operates in charging mode (consuming electricity) when there is excess renewable energy, and later generates electricity to supply the load during peak hours when generation is insufficient. In this way, pumped storage hydropower helps shift the generation profile to better match the load curve.

Frequency regulation: It allows maintaining the frequency within given margins through continuous modulation of active power.

Fast start-up: When the power system experiences a fault or sudden loss of generation, pumped storage hydropower units — which are kept in standby mode — can switch from standby to generation within just a few minutes. Thanks to their ability to start using the gravitational energy stored in the upper reservoir, the units can deliver large output almost immediately without the warm-up time required by thermal power plants.

Backup reserve, spinning reserve: Reversible plants can provide an additional energy source that can be made available to the transmission system within seconds in case of unexpected load changes on the network.

Flexible and rapid ramps: Advances such as variable-speed turbines can provide flexible ramping capacity, allowing the generator to increase or decrease its output based on changes in net load forecasts. This is how some HPS can reach full load in less than 30 seconds.

Black start capability: These plants can operate with zero loads. When loads increase, additional energy can be rapidly charged.

Voltage support: These plants can control reactive power, thus ensuring that energy flows from generation to load.

Overall, pumped storage hydropower can support power system operation by providing ancillary services similar to those of conventional hydropower plants. However, HPS can additionally absorb energy surpluses (for example, from variable renewable energy - VRE) to meet demand peaks and fluctuations.

Advantages/disadvantages

Advantages:

- The water can be reused over and over again, and thus smaller reservoirs are suitable.
- The process of electricity generation has no emissions.
- Water is a renewable source of energy.
- Large volumes compared to other storages e.g. various batteries.

Disadvantages:

- PHS are significantly constrained by geographical requirements. These systems necessitate a specific topography characterized by the presence of two large reservoirs at different elevations; this allows for the movement of water between these elevations to generate or store energy
- The time it takes to construct is longer than other energy storage options.
- The construction of dams in rivers always has an impact on the environment.

When a new PHS is not built in connection with an existing hydropower plant there are also environmental concerns in flooding large areas.

Space requirement

Depending on the development site, pumped storage hydropower projects may require the construction of only one new reservoir (by utilizing an existing natural reservoir) or the construction of both the upper and lower reservoirs. Pumped hydropower storage systems offer a significant advantage in terms of spatial efficiency because they can be integrated into existing reservoir infrastructure without the need for additional space. This approach not only optimizes the use of available land but also reduces the ecological and social impacts of developing new large-scale infrastructure.

However, if the construction of an additional reservoir is required, the space requirement will be dependent on the topography and the desired storage level. The construction of a new reservoir could have adverse social and environmental impact and take up productive land use, as is the case of large-scale hydro.

Water consumption

Even as pumped hydropower storage systems do not require additional water to that used by the existing hydropower plant they are integrated with, they can pose challenges to downstream water flows, particularly regarding ecological flows.

These systems often manipulate water levels in reservoirs to optimize electricity generation, which can lead to significant fluctuations in water release schedules. Such alterations can disrupt the natural flow regimes that are critical for habitats, aquatic life, and nutrient cycling downstream. Operation of these systems must maintain the ecological flows essential to support the health and biodiversity of riverine environments. These flows ensure that sufficient water remains in rivers to sustain fish populations, riparian vegetation, and overall ecosystem functions.

Furthermore, during periods of high electricity demand or low natural inflow, the water held in upper reservoirs may not be released in adequate amounts, exacerbating water scarcity issues downstream. These impacts require careful management and potentially the integration of adaptive strategies that balance energy production needs with the ecological and water-use requirements of downstream communities and ecosystems.

Environment

The possible environmental impacts of pumped storage plants have not been systematically assessed. The water is largely reused, limiting extraction from external water bodies to a minimum. Using existing dams for pumped storage may result in political opportunities and funding for retrofitting devices and new operating rules that reduce previous ecological and social impacts [3]. PHS projects require small land areas, as their reservoirs will in most cases be designed to provide only hours or days of generating capacities.

Depending on the project location, the level of environmental and social impacts of pumped storage hydropower projects will vary. Detailed studies and surveys are required during the development phase to assess environmental impacts. Potential sites for pumped storage development in Vietnam are expected to involve significant social impacts (such as resettlement and loss of agricultural land) as well as impacts on the natural environment (such as loss or alteration of aquatic and terrestrial habitats). Agricultural land and forested areas may be affected by the construction of reservoirs. The impact on existing aquatic habitats will be significant at sites where new reservoirs are built by damming rivers and streams. The formation of the lower reservoir and changes in the flow regime will lead to a shift from river ecosystems to lake ecosystems, resulting in reduced biodiversity. In addition, dams will block the migration of fish and other aquatic organisms, creating a “barrier effect” that can cut off migration routes to upstream spawning areas [4].

Research and development

In the 1890's PHS was first used in Italy and Switzerland. After over 100 years of development PHS is a mature technology, but there are several developments around the world [1]:

- **Variable speed PHS**: Most existing systems are equipped with fixed-speed pumping turbines and can provide large-scale storage but can only offer frequency regulation during the discharge mode. New variable-speed technology allows facilities to regulate frequency during the pumping process. Japan has been a pioneer in the commercial use of this technology.
- **Saltwater PHS**: Japan was also a pioneer in this system in Okinawa. This plant uses the open sea as the lower reservoir. New projects have been proposed related to this technology, including the project by the Dutch consulting firm (DNV KEMA) that plans to use the sea as the upper reservoir and build a lower one by dredging and constructing a ring of dikes 50 meters below sea level.
- **Underground PHS**: Researchers have proposed the possibility of using underground caverns as lower reservoirs, but so far none have been built.
- **Compressed air PHS**: An innovative design plans to replace the upper reservoir with a pressurized water container. Instead of storing potential energy in elevated water, the proposed system stores energy in compressed air.
- **Submarine PHS**: Another innovative concept is to use the water pressure at the bottom of the sea to store electricity from offshore wind turbines. The system places pressure vessels submerged at the bottom of the sea.

A new (2009) Danish concept is storing electricity as potential energy by elevating sand. The sand is lifted by pumping water into a balloon underneath the sand, and then lowered by taking the water out through the pump, now acting as a turbine.

Currently, there are not many in-depth studies on pumped storage hydropower (PHS) in Vietnam, especially nationwide assessments and surveys of PHS potential. In 2004, the Vietnam Electricity (EVN), in collaboration with the Japan International Cooperation Agency (JICA), developed a master plan for pumped storage hydropower and peak load optimization in Vietnam [5]. Under Decision No. 3837/QĐ-BCN dated November 22, 2005, the Ministry of Industry approved the study on potential PHS projects in Vietnam, which proposed 10 feasible projects with a total expected capacity of around 10,000 MW. However, to date, only the Bac Ai Pumped Storage Hydropower Plant project (1,200 MW) has started construction. The total PHS capacity studied by localities reaches nearly 54 GW, but most of these projects have not yet been backed by concrete studies.

Examples of current projects

Bac Ai Pumped Storage Hydropower Plant is the first hydro pumped storage in Vietnam, located in West Bac Ai commune, Khanh Hoa province. As of 2025, it remains the only pumped storage hydropower project under construction in the country. The project has an installed capacity of 1,200 MW (four units of 300 MW each) and an average annual generation of 1,324 GWh. It plays an essential role in load regulation, energy storage, and facilitating the integration of renewable energy into the national power system.

The project includes two reservoirs: the upper reservoir with a catchment area of 2.8 km^2, useful storage of 9 million m^3, and a normal water level of 602.8 m; and the lower reservoir (Song Cai) with a catchment area of 750 km^2, total storage of 219.8 million m^3, of which 10.3 million m^3 is dedicated to pumped storage operation. The plant's maximum discharge flow is 351.3 m^3/s, with an average annual rainfall of approximately 1,685 mm.

The hydraulic structures include a main dam with an elevation of 197.5 m, a spillway system with five surface bays and three deep spillway bays, and a flood discharge capacity of more than 6,000 m^3/s. The upper dam is a CFRD type, 1,130 m long and 71.8 m high. The water conveyance system consists of two intake gates, a 1,242 m long pressure tunnel with a 7.5 m diameter, and a 377.6 m high surge shaft. The underground powerhouse accommodates four units, with a total length of 183 m and a design head of 399.1 m.

The project is being implemented in two phases. Phase 1 — the outlet structure located deep within the Song Cai Irrigation Reservoir — was constructed starting in January 2020 and completed in March 2021. Phase 2 includes all remaining project components. Unit 1 is scheduled to begin commercial operation in

2029, with full project completion expected by 2030. The total investment is estimated at approximately VND 21.1 trillion (around USD 900 million). Once operational, the Bac Ai pumped storage plant will enhance the flexibility of the power system, support large-scale renewable energy integration, and contribute to ensuring national energy security.

Investment cost estimation

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment cost [Million USD 2025 / MW]						
Sources	**2020**	**2025**	**2030**	**2035**	**2040**	**2050**
Technology Catalogue - Viet Nam Current		0.75	0.75		0.75	0.74
Technology Catalogue - Colombia 2025		1.23	1.23			1.22
Technology Catalogue - Indonesia 2024		1.27	1.27			1.27
Technology Catalogue - Vietnam 2023	1.13		1.13			1.13
NREL ATB 2024*		3.11	3.11	3.11	3.11	3.11
IRENA 2024**		2.60				
***NREL ATB 2024 - Class 1 PHS with 1020 MW avg. Cap, moderate scenario **Data from table 6.2**						

Additional remarks

There are frequently several hydro power plants on the same river, and the operation of these plants is to some degree interlinked. The benefits of a new PHS therefore depend also on the existing hydropower infrastructure.

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Data sheet

The following page contains the data sheet of the technology. All costs are stated in U.S. dollars (USD), price year 2025.

Storage pumped hydro - hybrid PSH (combined)											
Parameter	**Unit**	**2025**	**2030**	**2040**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
						Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data											
Generating capacity for one unit	MW_e	300	300	300	300	100	500	100	500	A	1
Generating capacity for total power plant	MW_e	1,200	1,200	1,200	1,200	100	4,000	100	4,000		1
Electricity efficiency, net, name plate	%	80	80	80	80	70	82	70	82		2, 3
Electricity efficiency, net, annual average	%	80	80	80	80	70	82	70	82		2, 3
Forced outage	%	4	4	4	4	2	7	2	7		3
Planned outage	%	5.8	5.8	5.8	5.8	2.0	11.5	2.0	11.5		3
Technical lifetime (years)	years	50	50	50	50	40	90	40	90		4
Construction time (years)	years	5	5	5	5	2.5	7.5	2.5	7.5	B	5
Space requirement	1000 m^2/MWe	30	30	30	30	15	45	15	45	B, C	5
Ramping configuration											
Ramping	% per minute	50	50	50	50	10	100	10	100		3, 6
Minimum load	% of full load	0	0	0	0	0	0	0	0		3
Warm start-up time	hours	0.1	0.1	0.1	0.1	0.0	0.3	0.0	0.3		3
Cold start-up time	hours	0.1	0.1	0.1	0.1	0.0	0.3	0.0	0.3		3
Economic data											
Specific investment	MUSD/MW	0.75	0.75	0.75	0.74	0.55	6.00	0.55	5.95	D, E, F, G	1
- of which equipment	%	30	30	30	30	20	50	20	50	D, E	7
- of which installation	%	70	70	70	70	50	80	50	80	D, E	7
- of which equipment	MUSD/MW	0.23	0.22	0.22	0.22	0.11	3.00	0.11	2.98	D, E	7
- of which installation	MUSD/MW	0.53	0.52	0.52	0.52	0.28	4.80	0.27	4.76	D, E	7
Fixed O&M	USD/MW-year	15,000	14,963	14,911	14,879	6,875	150,000	6,819	148,786	H	4
Variable O&M	USD/MWh	1.4	1.4	1.4	1.4	0.50	3.00	0.50	2.98		5, 7
Technology specific data											
Size of reservoir	MWh	6,000	6,000	6,000	6,000	3,000	20,000	3,000	20,000	I	1
Load/unload time	hours	5	5	5	5	4	12	4	12	I	1
Water consumption	L/MWh	0	0	0	0	-	-	-	-	J	

Notes:

A Size per turbine.

B Uncertainty (Upper/Lower) is estimated as +/- 50%.

C Space requirements for new sites is highly uncertain given the geographical dependency.

D Numbers are very site sensitive to geographical characteristics. There will be a limited improvement by learning curve development, but best, i.e. cheap locations will be utilized first. The investment largely depends on civil work.

E Cost are projected with a learning rate approach assuming a 1% learning rate for based on IEA's assumptions in their Global Energy and Climate Model, including capacity projections of the IEA's World Energy Outlook 2025, with Stated Policies Scenario (STEPS) for the central values and Current Policies Scenario (CPS) and Net Zero Emissions by 2050 as base for the upper and lower uncertainty range, respectively.

F Cost uncertainties in the short and long term indicate the spread of cost based on the examined cases. Costs are highly uncertain given the geographical characteristics.

G Based on an open loop system (hybrid PSH).

H Fixed O&M is assumed to be between 1% and 2.5%/year depending on the size of the plant in line with [4] with the central value to be approx. 1.25% for a plant at 1000 MW.

I The size of the total power plant and not per unit (turbine).

J Assuming a closed system with negligible water losses. Evaporation losses may occur as described under Hydro Power in the TC for power generation.

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2. LITHIUM-ION BATTERIES

Brief technology description

Lithium-ion batteries or Li-ion batteries (LIBs) are rechargeable batteries that store electric energy and provide electric power, typically for short durations (up to 6 hours) when used in relation to the power system. LIBs are a large family of technologies with several subgroups available, serving different applications depending on the power or energy requirements. The subgroups are typically defined by their inherent chemistry and new technologies are becoming available frequently. For energy storage, the NMC- or LFP-battery chemistries[1] are the dominating technologies. Non-rechargeable, or "primary", LIBs exist but are mainly used for low-current or long-duration storage applications and not for large-scale applications. Rechargeable, or "secondary", LIBs are applied in all kinds of consumer electronics, electric vehicles and large-scale electricity storage.

LIBs, and batteries in general, consist of battery cells, in which the energy is stored, which are assembled in modules and packed together into a battery system, as shown in Figure 3. The battery system also contains auxiliary components to ensure the battery operation. The battery system should not be confused with a grid-connected energy storage system (ESS), which is explained in the end of this section under "Components in a lithium-ion battery energy storage system".

The first lithium batteries were developed in the early 1970s, and Sony released the first commercial lithium-ion battery in 1991. Since then, LIBs have improved the performance of electrical applications in several fields from miniature electronics to electric vehicles to large-scale grid storage. As of 2024, the largest standalone facility in operation is located at Moss Landing with 3 GWh energy capacity and 0.75 GW rated power output, with options to expand to 6 GWh energy capacity and 1.5 GW rated power output [1].

LIBs can be used to supply system-level services covering nearly all current services depending on the functionality of the attached inverter and the size of the system with sub-millisecond response times making them ideal for services such as primary frequency regulation, voltage regulation and load shifting. As the technology is effective both at large and small scale it finds uses in both large grid services and small household applications typically allowing access to power during blackouts or optimizing usage of rooftop solar power.

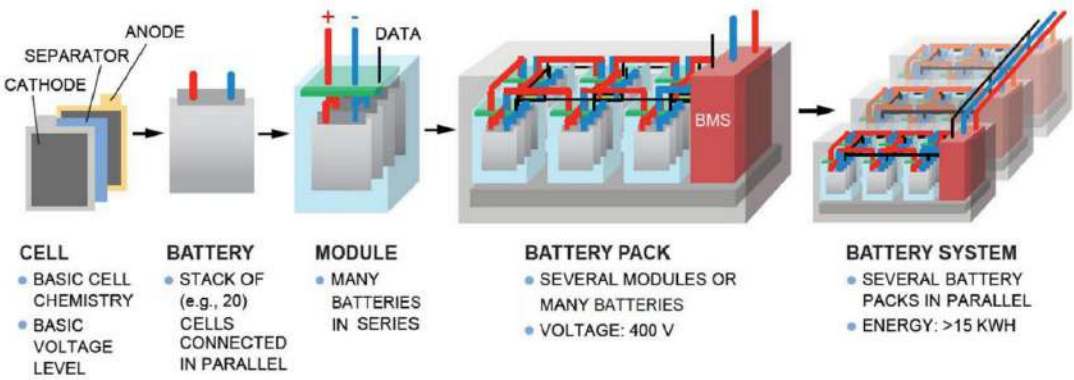

Figure 3: Basic components of a cell-based battery system from cell to system level.

The LIB electrochemical cell

A LIB cell contains two electrodes and a porous membrane as separator (see Figure 4). The materials used for the electrodes typically motivate the notation of the different LIBs. A liquid electrolyte fills the pores in the electrodes and membrane. Lithium salts (e.g. $LiPF_6$) are dissolved in the electrolyte to form Li^+ and PF_6^- ions. These ions can be released and absorbed by the electrodes from the electrolyte during charge and discharge. Alternatively polymer or solid electrolyte can be used but these are rarely seen in grid scale energy storage. The performance of the cell is determined by several factors with the chemistry of the anode and cathode electrodes being the main factor, but geometry, electrode thickness and electrolyte composition also influence the quality of the cell. Similarly, the cells architecture determine the ability to transfer heat out of the cell and avoid overheating from high power draw, since different materials or geometries show

[1] Detailed description of LIB chemistries can be found in Table 1.

different thermal capacity and conductivity. A schematic representation of a cell's internal components is shown in Figure below

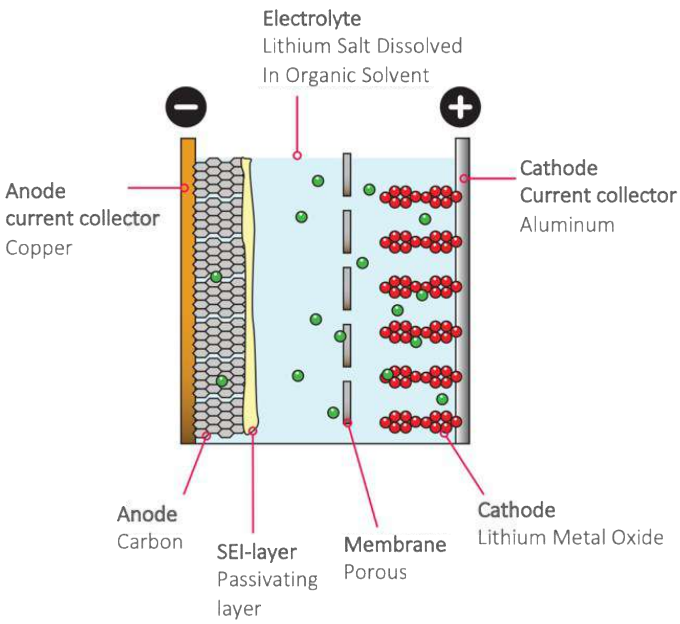

Figure 4: Schematic diagram of a typical LIB cell displaying the individual components in the battery. The membrane component is also known as the separator.

Each cell in a system provides a voltage and capacity with most LIB providing between 2 V and 5 V. In the case of the dominating NMC chemistry each cell provides about 3.6 V as nominal voltage. However, when fully charged each cell reaches 4.1 V to 4.2 V and once a load is used to discharge the battery the voltage drops until all the energy is consumed and the minimal voltage is reached. This minimum level varies from producer to producer and is typically between 2.5 V and 3 V.

As most stationary systems are build from modules with 24 V or 48 V, each module will typically be made of 6 or 16 cells in a series connection. On system level a voltage of 400 V, 600 V or 800 V is common, where 8, 12 or 16 individual 48 V-modules are connected in series to reach the system voltage. Thus common systems have 96, 144 or 192 cells in series through all modules. To increase the energy capacity without affecting the system voltage, cells are placed in parallel in the modules or whole systems are placed in parallel. This is typically presented as a 96_S2_P system, read as 96 cells in series and 2 in parallel. Parallel connections can be tens or hundreds of cells depending on the specific system. Generally, higher system voltages are common in applications with a higher power requirements and lower system voltages are found in compact low to medium power applications.

The operating range of a system in terms of voltage, temperature and power is determined by the architecture as descriped above. The entire system is protected from abuse by a battery management system (BMS) which controls the voltage, temperature and current the system is exposed to. If the limits of the system are exceeded the BMS must close down the system to protect the cells as voltage level, temperature or current outside of the limits can permanently damage the system and result in an increased safety risk.

Lithium-ion chemistry

Table 1 shows a comparison of the three most widely used LIB chemistries for grid-connected LIB systems and the major manufactures. The listed chemistries are NMC, LFP and LTO. Other LIB chemistries such as LCO[2], LMO[3] and NCA[4] are generally not used for grid electricity storage due to insufficient performance or high cost and are therefore not included in the table. The numbers in the table are from cell manufacturers

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[2] Lithium Cobalt Oxide.
[3] Lithium Manganese Oxide.
[4] Lithium Nickel Cobalt Aluminium Oxide.

or product and system suppliers.

NMC is the most widely used of the three chemistries, due to the increased production volume and lower prices led by the automotive sector. As mentioned above, a LIB contains an anode and a cathode, which are the two electrodes in the cell.

The LFP battery is the second dominating chemistry and is widely used for its high safety level, as it does not release oxygen from the cathode during fires. It has also found uses in the automotive sector for mid-range cars due to the development of cell-to-pack technology.

Both NMC and LFP batteries have graphite anodes. The main cause for degradation of NMC and LFP LIBs is graphite exfoliation and electrolyte degradation, which occur outside the voltage limit of operations.

LTO LIBs are the least used and most expensive cell chemistry among these three. In LTOs the graphite anode is replaced with a lithium-titanate anode. The cathode of an LTO battery can be NMC, LFP or other battery cathode chemistries. The LTO technology excels at ultra-high-power application with charge times below 1 minute in the most extreme cases, while maintaining a very long lifetime with more than 10,000 cycles. The main drawback for this technology is the significantly lower energy density and high price making its application limited.

Table 1: A comparison of three widely used LIB chemistries, with values based on the listed supplier's available data sheets for specific system.

Acronym	NMC[5]	LFP[6]	LTO[7]
Cell Chemistry	Lithium Nickel Manganese Cobalt Oxide	Lithium Iron Phosphate	Lithium Titanate
Energy Density (Wh/kg)	105 – 288 (Cell) 115 – 140 (System)	50 – 170 (Cell) 80 – 110 (System)	50 – 90 (Cell)
Energy Footprint[8] (kWh/m²)	~ 150	190 – 275	n/a
Cycle Life	1,500 – 8,000	4,000 – 12,000	20,000 – 25,000
Calendar Life	10 to 20 years	20 years	20 years
Exemplary Manufacturers	Samsung SDI, LG Chem, Panasonic, CATL, ATL	CATL, BYD, LG Chem, Panasonic, Ufine	Toshiba, Leclanche, Altairnano

Other type of battery

Lead–acid batteries

Lead–acid batteries, commonly referred to as accumulators, use lead as the electrode material and sulphuric acid as the electrolyte to store and release electrical energy. This is one of the oldest electrical energy storage technologies, dating back to the 19th century, and it is still in use today. In practice, lead–acid batteries are widely applied in motorcycles, automobiles, uninterruptible power supplies (UPS), legacy backup power systems, and some small-scale off-grid solar PV systems.

Lead–acid batteries operate based on a reversible chemical reaction between the lead plates and the sulphuric acid electrolyte. During discharge, the electrodes are converted into lead sulphate, releasing electrical energy. During charging, an external electric current reverses this process, restoring the original active materials for continued use. The technology is highly mature and has been commercially deployed since around 1880, with relatively low system costs (typically below USD 200/kWh). Lead–acid systems can deliver high discharge power and are available in a wide range of sizes and technical specifications,

[5] Cell and system values are taken from LG chem, TesVolt (using Samsung SDI), Panasonic, CATL websites.
[6] Cell and system values are taken from BYD, UFINE and CATLs websites.
[7] Cell and system values are taken from Toshiba and Leclanché websites.
[8] The energy footprint may vary significantly between suppliers, the numbers presented here are based on 4 systems from the listed suppliers. No values are given for LTO BESS systems as these were not available.

meeting diverse application needs.

However, lead–acid batteries have a low energy density compared to other battery technologies, at around 70 kWh/m³, resulting in significant space requirements. To store the same amount of energy (e.g., 1 kWh), a lead–acid battery may weigh approximately 25 kg, whereas an equivalent lithium-ion battery weighs only about 6.7 kg. In addition, the allowable depth of discharge for standard systems is relatively low (around 30–50%), and the use of toxic materials such as lead increases safety and environmental concerns. Battery lifetime is also limited, typically below 1,000 cycles, which negatively affects long-term economic performance.

Lead–acid and lithium batteries are currently the two most common battery types; however, lithium batteries are generally preferred due to their superior performance and better long-term economics. Compared with lead–acid batteries, lithium batteries offer higher energy efficiency, with charge/discharge efficiencies exceeding 90%, whereas lead–acid batteries experience higher energy losses. Owing to their higher energy density, lithium batteries are significantly lighter and more compact, saving installation space compared to the bulky lead–acid batteries. Moreover, lithium batteries have a much longer lifetime (approximately 3–5 times more cycles), allow deep discharge up to 80–100% of capacity, support fast charging, and require minimal maintenance, whereas lead–acid batteries are constrained in depth of discharge, charging speed, and require regular maintenance.

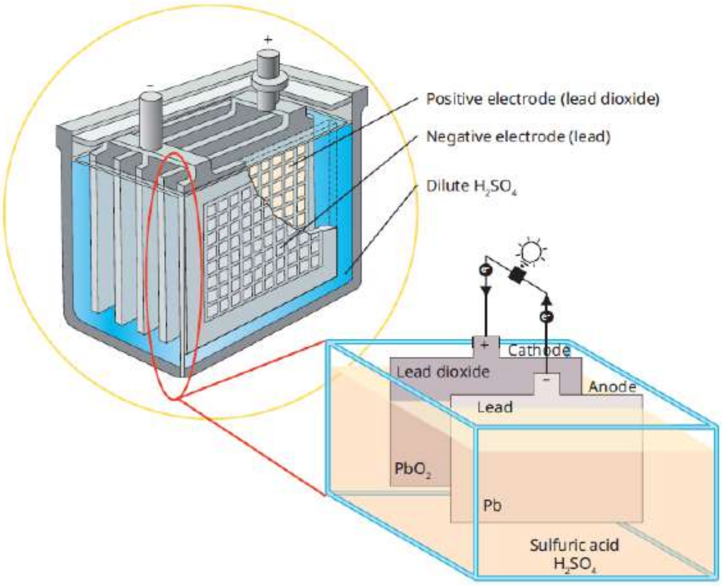

Figure 5: Structure of lead-acid battery

Sodium-ion batteries

There is a constant drive to develop new battery chemistries/technologies. While most never reach commercial success, a few promising technologies have shown the potential to complement or compete with the dominating LIB. Two promising technologies for industrial scaling are *sodium-ion batteries* (SIB) and solid-state batteries.

Sodium-ion batteries work as a simple substitution of lithium with sodium, but this minor change has caused complications, as the materials used in LIB must be reoptimized for the sodium ion before it can be commercialized. In contrast to lithium, sodium is less rare, geographically more abundant and cheaper, reducing the dependency on scarce resources for the battery system. SIBs operate on a similar principle, involving the movement of sodium ions between the anode and cathode during charge and discharge cycles. While they typically offer a lower energy density compared to lithium-ion batteries with CATL reporting energy densities of 160 Wh/kg based on a sodium Prussian white cathode chemistry. Their potential for lower costs makes them appealing for large-scale energy storage applications and midrange EVs. [2] However, it is unclear when sodium ion batteries will reach the necessary production scale to match the cost of LIB or succeed them. This technology is commercially available as of 2024 with several manufacturers on the market.

Solid-state batteries represent a broad family of batteries having a combined separator and electrolyte in one solid material. These batteries can be made with materials from both lithium and sodium ion technologies and use the same ions as the working principle. However, since the technologies does not rely on flammable liquid electrolytes, they promise a higher degree of safety as less fuel is available for a fire. However, this does not mean that they cannot catch fire, and safety concerns will remain. Additionally, since solid-state batteries allow for different electrode materials, there is greater possibility reaching higher energy densities, enabling longer battery life and improved performance in applications such as electric vehicles and portable electronics. Especially, if pure lithium metal anodes can be used safely not only in primary batteries, but this also greatly increases the energy density as the added weight of graphite can be removed. Despite these benefits, challenges remain in terms of manufacturing complexity and cost, especially as the manufacturing process is significantly different from LIB. Researchers are actively working to overcome these obstacles, aiming to make solid-state batteries a viable and widespread solution for future energy storage needs.

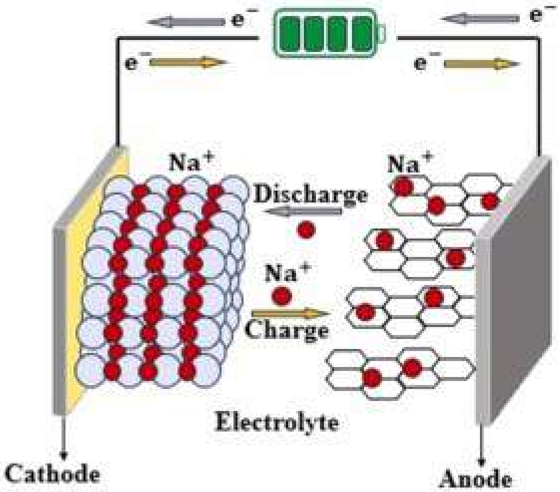

Figure 6: Principle of sodium-ion battery

Sodium–sulphur batteries

Sodium–sulphur (NaS, Sodium–Sulphur) batteries are a type of molten-salt battery that use liquid sodium (Na) and sulphur (S) as active materials. In recent years, sodium–sulphur batteries have attracted increasing attention as one of the most suitable technologies for long-duration energy storage. This energy storage system (ESS) is based on electrochemical charge–discharge reactions occurring between the positive electrode (cathode) and the negative electrode (anode). The cathode is typically made of molten sulphur, while the anode consists of molten sodium. The two electrodes are separated by a solid ceramic layer—sodium aluminate—which also acts as the electrolyte, allowing only positively charged sodium ions to pass through. In addition, the electrolyte reacts with sulphur to form sodium polysulfides according to the following reaction:

$$2Na + 4S = Na_2S_4$$

The battery system is equipped with independent heating units, as sodium–sulphur batteries must be maintained at a temperature of approximately 300–350°C to ensure that electrochemical reactions can occur and that both electrodes remain in the molten state.

Sodium–sulphur batteries have a high energy density of around 200 kWh/m^3. This technology is suitable for a wide range of ambient temperatures, particularly in hot climates, and offers a long lifetime—up to about 4,500 cycles or around 15 years for sealed systems—making it well suited for long-duration energy storage applications. However, sodium–sulphur batteries also have several drawbacks. They exhibit relatively high self-discharge when not in operation, as the high operating temperature must be continuously maintained. In addition, their instantaneous power output capability is relatively limited; they are typically optimized for discharge durations of around six hours and pose inherent safety risks due to the highly reactive nature of sodium when exposed to water. Furthermore, the potential for cost reduction remains uncertain, as the number of leading manufacturers in the market is still limited.

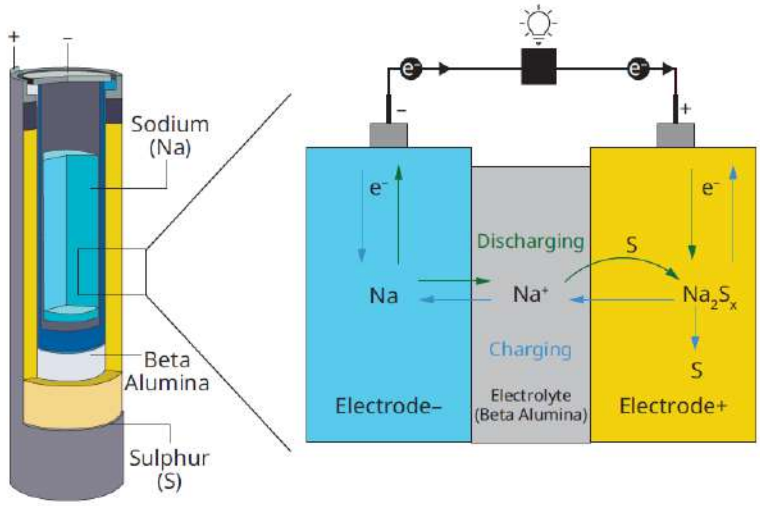

Figure 7: Principle of a sodium–sulphur battery

Sand battery

Sand battery is one of the thermal energy storage technologies currently being developed worldwide, different from lithium-ion batteries, which store energy in electrochemical form. The Sand Battery is a large-scale, high-temperature thermal energy storage system that uses sand or similar materials to store energy as heat. Its primary purposes are storing excess wind and solar energy, participating in grid balancing markets, and producing heat and power without combustion. This technology helps scale up renewable energy sources like wind and solar, enabling companies to meet their climate targets while significantly lowering energy costs.

The Sand Battery's storage unit is an insulated silo, typically 10 to 15 meters tall, with a diameter ranging from 4 to 30 meters, depending on capacity. Its modular structure allows for flexible storage capacity adjustments without extensive redesign. Charging and discharging occur via heat transfer pipes circulating air in a closed-loop system. The air is heated with resistive heaters, and the flow is controlled by industrial blowers and dampers. When discharging, the air is led through a heat exchanger. The output is hot water, steam, or air, with temperatures up to 400°C, suitable for 36% of industrial process heat needs. At present, sand batteries are used to store thermal energy and supply heat for small- and medium-scale industrial production as well as for building heating systems. However, the development of solutions to convert stored thermal energy back into electricity is still ongoing, promising the potential to compete with conventional electrical energy storage batteries. The pipes, buried in the storage medium, are maintenance-free and designed for longevity. From a thermodynamic standpoint, the roundtrip efficiency of these batteries is highly dependent on the maximum storage temperature, and the roundtrip efficiency is substantially lower than Li-ion batteries.

The world's first commercial sand battery was deployed in 2022 by the startup Polar Night Energy in Kankaanpää, Finland. It consists of a steel silo containing approximately 2,000 tons of crushed soapstone, which serves as the thermal storage medium. The system stores about 100 megawatt-hours (MWh) of energy, enough to heat the entire town centre. Capable of meeting local heating demand for nearly one month in summer and one week in winter, the system became fully operational in June 2025.

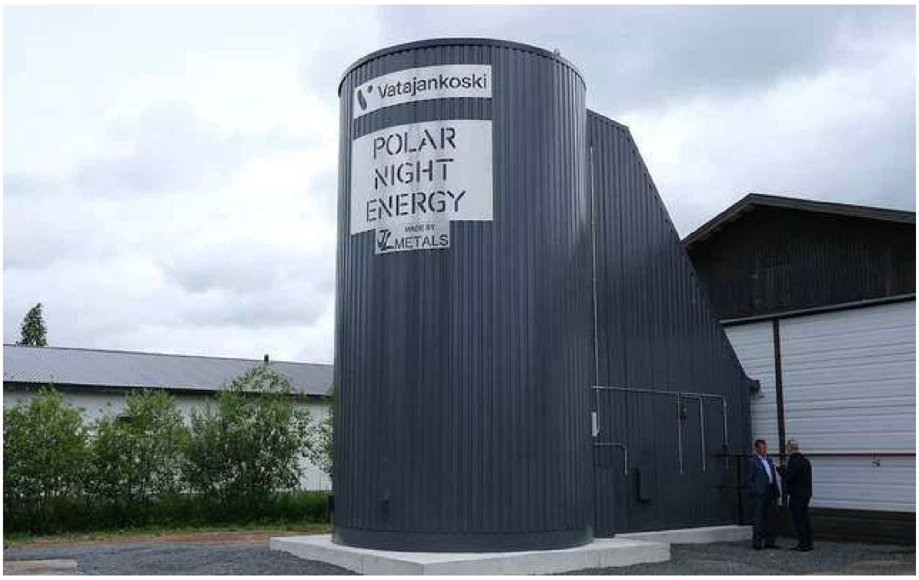

Figure 8: Sand battery project in Kankaanpää, Finland

Lithium-ion battery packaging

Battery cells come in various packaging styles—coin, cylindrical, pouch, and prismatic (Figure 9 and Figure 10) — each suited for different applications due to their unique characteristics. Coin cells are small and compact, perfect for low-power devices like watches and hearing aids. Cylindrical cells, known for their robust design and ease of manufacturing, are widely used in consumer electronics and electric vehicles, such as those made by Tesla, due to their enhancing safety and durability. Pouch cells are lightweight and flexible, making them ideal for applications where space and weight are critical, like in electric vehicles and portable electronics; however, their lack of rigid casing makes them more susceptible to physical damage. Prismatic cells have a rectangular shape that allows for easy stacking and efficient space use, making them suitable for electric vehicles and industrial energy storage systems. While they are more expensive to manufacture than cylindrical cells, prismatic cells offer better thermal management and higher capacity in a compact form. Each packaging type balances factors like size, energy density, cost, and application suitability to meet specific needs.

Figure 9: Examples of LIB cells. (a) Tesla 21700 cylindrical NMC LIB cell [3]. (b) Samsung SDI prismatic NMC LIB cells [4] (c) LG Chem pouch NMC LIB cell [5]

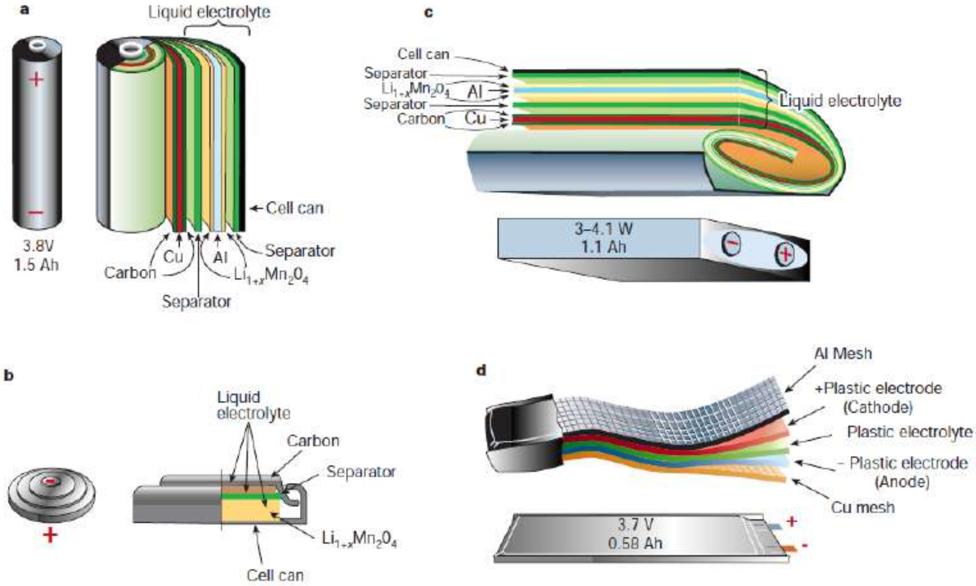

Figure 10: Schematic drawing showing the shape, packaging and components of various Li-ion battery configurations [6] (a) Cylindrical; (b) coin; (c) prismatic; and (d) pouch.

Components in a lithium-ion battery energy storage system

Figure 11 provides an overview of the components in a LIB storage system with an interface to the power grid. In LIB storage systems, battery cells are assembled into modules that are assembled into packs (see Figure 7). The battery packs include the BMS. The BMS is an electronic subsystem that monitors the battery conditions such as voltage, current, and temperature and protects the cells from operating outside the safe operating area. This is the main component responsible for the functional safety of the system. The BMS may be implemented as a single unit, but in the case of grid scale systems it is often distributed with local monitoring units in each module and 1 or 2 layers of control units in each rack or container and a system control for the whole site, this can be combined with the energy management system (EMS) in some cases.

A thermal management system (TMS) regulates the temperature for the battery and storage system. The TMS depends on the environmental conditions, e.g. whether the system is placed indoors or outdoors. Further, an EMS controls the charge/discharge of the grid-connected LIB storage from a system perspective. Depending on the application and power configuration the power conversion system (PCS) may consist of one or multiple power converter units (DC/AC link). For system coupling a transformer may be needed for integration with higher grid voltage levels.

Grid integration provides services to the grid such as increased reliability, load shifting, frequency regulation etc. The services are described further below in the section “Regulation ability and other system services”. Value generation and profit is created by selling services to grid transmission system operators (TSOs). Battery capacity may be sold to the TSOs in full or partially, allowing for alternate use of the remaining capacity, for example local load management, energy trading or distributed system operator (DSO) services. Appropriate sizing of the battery and power conversion systems is essential to maximize the revenue. Technical aspects of a battery storage system, system coupling, and grid integration are summarized in Table 2, Figure 11 and Figure 13.

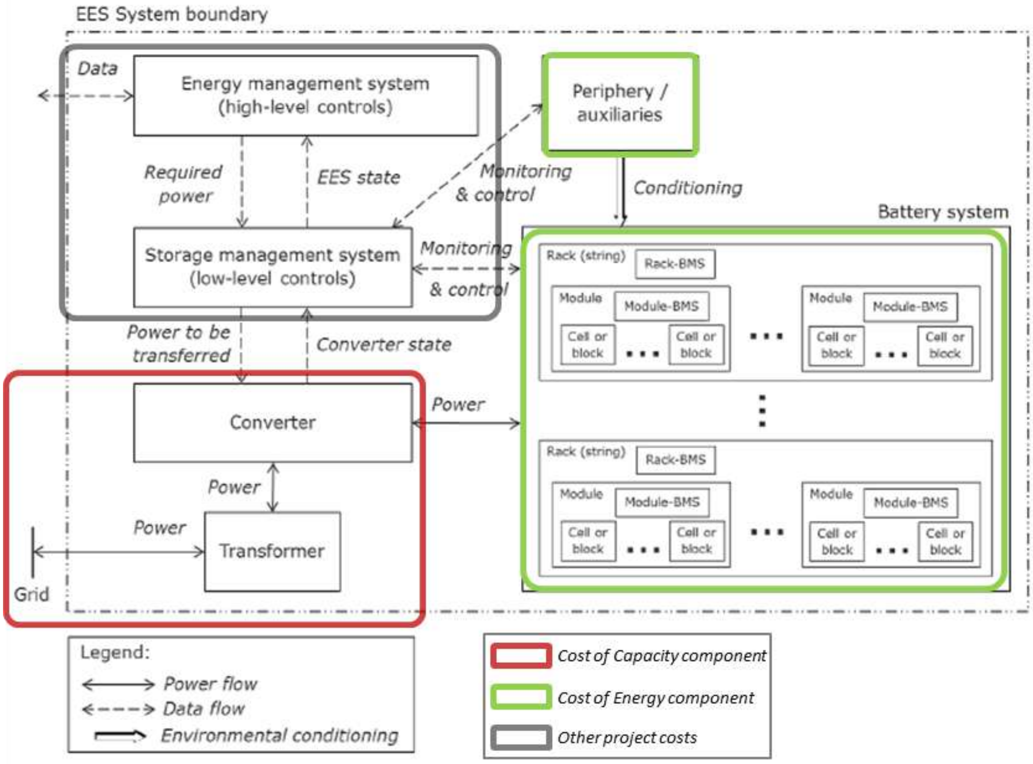

Figure 11: Components and their categorization of grid-connected battery energy storage systems, such as Li-ion. Modified from [7]

Input/output

Input and output are both electricity but must be converted in voltage and/or from AC to DC and vice versa depending on the local grid type with the battery side always requiring DC. In an AC grid this is done by an inverter which outputs AC current at a set frequency and voltage level. In a DC grid a converter is used to transform the variable DC voltage on the battery side to a fixed DC voltage on the grid side. The grid may require AC or DC, with AC being the most common. Electricity is stored in the cell as electrochemical energy during charge and converted back to electricity during discharge. Typically, with around 10% loss released as heat.

Energy balance

The losses in a LIB can be divided into operational and standby losses. The operational losses are first described, then the standby losses. Finally, total energy efficiency is discussed.

Operational losses

The operational losses occur when energy is discharged or charged to/from the grid. It includes the conversion losses in the battery and the power electronics.

The battery loses energy as heat during charge and discharge with a typical loss of $1-12\%$, depending on the current drawn, where higher current leads to higher losses. For a system discharging/charging over more than an hour, losses in the battery are typically below 4% for modern technologies. As this is related to the internal resistance of the cell, it will increase during the cell's lifetime typically reaching 200% of the initial value by *end of life* (EoL). However, the charge profile and temperature can heavily influence efficiency and for systems at extreme temperature and/or high power/energy ratios the efficiency obtained can be highly system specific and will need individual evaluation to accurately understand.

Power electronics is responsible for converting the stored energy in the battery into a usable AC system at the grid frequency and voltage. Inverters are designed with an optimal efficiency load, typically around $90-95\%$ of their rated capacity and are therefore the main source of losses.

The total round-trip efficiency is determined by the combination of losses in the inverter and the battery.

The total roundtrip efficiency includes losses in the AC system and DC system in addition to the standby losses making the total roundtrip efficiency typically ranging between 80% and 90%. The higher the power rating of a system the more important a high efficiency system is to avoid issues with handling waste heat.

Standby losses

LIB electricity storage system requires power to operate the auxiliary *balance of plant* (BOP) components, such as monitoring units, control systems and thermal management. Additionally, capacity components such as inverters have a standby consumption even at zero load that must be supported. This is often drawn directly from the battery itself.

The cells also experience self-discharge typically in the order of 0.1% per day depending on the environmental conditions. This arises from side reactions inside the cells, which are accelerated by increasing temperatures and therefore more important for systems in continuously warm climates. The standby losses are important for long-duration storage systems, as they are typically constant over time and not dependent on the number of charge/discharge cycles per day.

Ramping configurations

Grid-connected LIBs can absorb and release electrical energy almost instantly. The response time of grid-connected LIBs are strongly dependent on control components, EMS, BMS and TMS as well as the PCS. The fast response time and the ability of inverter to support grid services makes a BESS system capable of offering a wide range of services to the grid.

Table 2: Grid services relevant for grid systems.

Services	Notes
Frequency regulation	Frequency services are supplied in a fixed timeframe where the system must react to changes in the grid frequency. The service's price is based on the power available from the system. BESS can respond to changes in grid conditions accurately and precisely within milliseconds. The control system on the BESS rapidly adjusts the input or absorption of energy to help maintain or return the grid frequency to safe operational limits.
Energy shifting	Energy shifting is designed to minimize the peak power drawn from the local user or provide additional power during peaks hours on the utility scale. When providing load shifting, BESS can reduce the use of expensive peaking generation (Figure 8) and enable energy arbitrage.
Wholesale arbitrage	Wholesale arbitrage exploits price differences by buying energy when prices are low and selling when they are high.
Black start	Due to grid forming technology, in the inverter systems a BESS may be used to initiate the grid after a blackout. However not all inverters are designed for black start applications
Voltage support	Smaller BESS system may be placed in weak parts of the grid to provide or draw reactive power to influence the local voltage.
Increased self-consumption	For both large- and small-scale power production by wind or solar, a BESS may be used to avoid sending surplus energy to the grid when market prices are unfavorable. The energy can then be used locally or sold to the grid once prices are favorable.

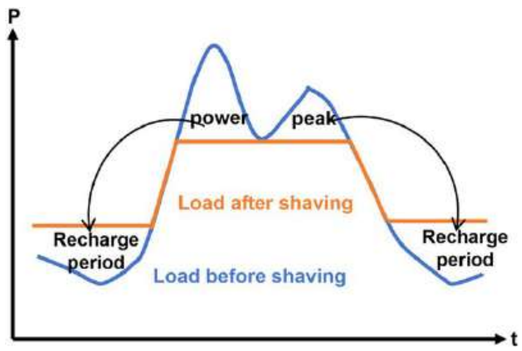

Figure 12: Peak shaving/shifting with BESS [8]

These grid services often have requirements to a minimum size, power or response time, and thereby limiting access to different markets depending on the system specifications. The market requirements are generally met during the design phase of centralized systems targeting specific markets. However, the rise of decentralized systems such as aggregated electric vehicles (EV) or aggregated residential BESS has meant that smaller units can be combined to meet market demands similar to a virtual power plant. However, virtual power plants typically comprise power production units such as photovoltaics (PV) or wind power, which are not needed in an aggregated BESS or EV system. These systems are harder to control as their primary use influences the availability of energy and power from the systems. Because of this, these systems typically target markets such as energy arbitrage or frequency regulation. Due to practical reasons, decentralized systems may not be suitable to offer black-start services or voltage stabilization services. They also suffer from unpredictability of the available capacity and energy as e.g. an EV may be unplugged by the owner while it is actively providing grid services. For this reason, vehicle-to-grid (V2G) will require a large number of EVs to be aggregated to get a statistical capacity that is robust against individual EVs losing connection.

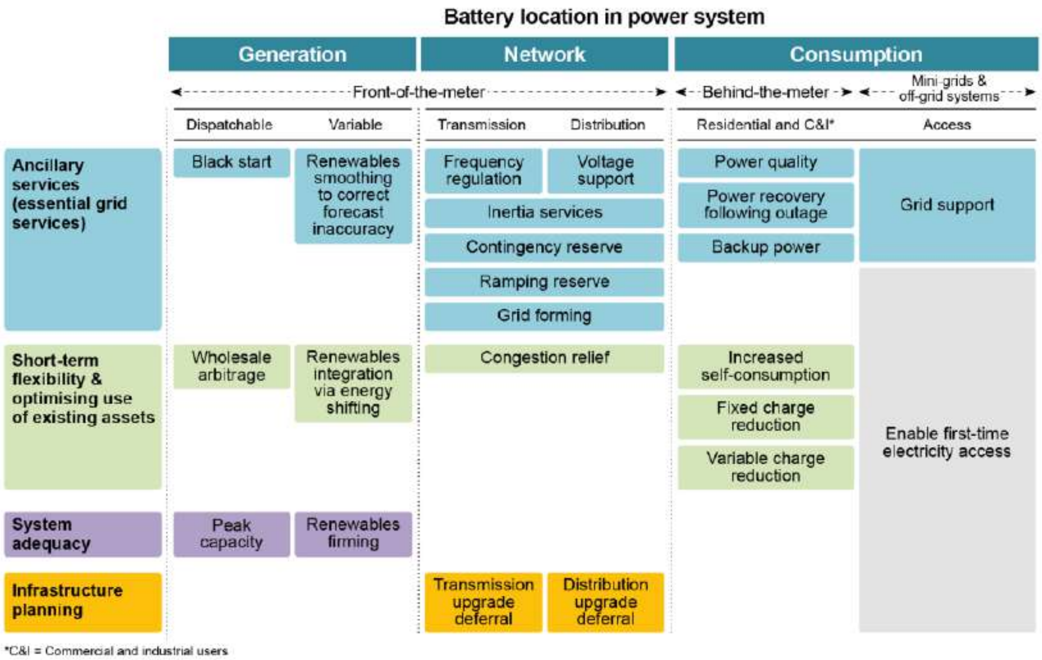

Figure 13: Battery storage can provide a broad range of services to a power system [9] Battery storage applications are represented along the dimensions: horizontal axis shows the location within a power system; vertical axis shows the type of services.

The BESS can further be used to provide inertia as a virtual spinning reserve. This can improve the integration of renewable energy. This service is rarely assessable by BESS system owners as it has historically been an inherent feature of the generators in central power plants and unless they are taken offline, it may not be necessary to provide such a service from a BESS system.

Otherwise, BESS can charge when VRE generation would be curtailed. This is beneficial when EVN has take-or-pay power purchase agreements (PPAs), where curtailed energy is already paid for. However, using BESS to reduce curtailment is not beneficial for EVN when the generator bears the lost revenue from curtailed power, and when the cost of curtailed renewables is higher than the system marginal price. BESS can provide deployable capacity located at key points of the transmission system, helping to optimize the use of existing transmission infrastructure. Its ability to rapidly store excess energy helps to reduce congestion.

Typical capacities

Most BESS systems are designed using the 19-inch rack standard or containerized solutions for easy installation. These racks can fit several modules in series and can often reach the full system voltage in a single rack. In this section we have taken 3 examples of commercially available BESS systems with 2 rack-based systems from Xolta and TesVolt and a containerized system from BYD see Table 3. Based on the available system, all have symmetric charge and discharge power rating and near $1C_1$ power to energy ratio. All systems are in the range of $0.075 - 0.12\ kWh/kg$ and $105 - 160\ kWh/m^2$ with the containerized solution generally having better performance. However, the rack does allow for more flexibility when dimensioning the size of the system as several racks or containers can be placed in parallel to increase the size of the system. The 20 ft. containerize solution is used in the data sheet as the default unit.

Currently, there is limited official information on the specific BESS models that will be used in renewable energy projects in Vietnam. These projects tend to deploy BESS modules with a capacity of around 5–15 MW, using LFP (Lithium Iron Phosphate) technology due to its high safety characteristics. The BESS units are typically installed in containerized form.

The Vietnamese market favors Chinese manufacturers such as CATL, Huawei, and BYD thanks to their competitive pricing and fast deployment capability. American and European brands like Tesla and Fluence, which are more expensive, are generally considered for projects with stricter technical standards.

Large-scale battery energy storage systems (BESS) are particularly sensitive to environmental conditions and operational modes. High ambient temperatures can increase internal resistance, accelerate cell degradation, and lead to faster capacity fade over time. Conversely, low temperatures reduce charge/discharge efficiency and power output capability. High humidity can also affect the reliability of power electronics and cooling systems. In addition, frequent charging and discharging at high capacity levels impose thermal and mechanical stress, shortening the actual system lifetime compared to the design specifications. Therefore, when planning and operating large-scale BESS, it is crucial to carefully assess local environmental conditions and adopt optimal operational strategies to extend system lifespan and maintain performance.

Typical storage period

Several aspects of LIB technology put an upper limit to the feasible storage period. The lifetime of the battery means that the cost per cycle becomes significantly higher for long term storage. The BOP power for standby operation adds parasitic losses to the system, which further limits the feasible standby time. This calls for shorter storage periods in order to obtain enough cycles to reach positive revenue. Most markets provide both favourable charge and discharge conditions within an $8 - 12\ hrs$ time window corresponding to the natural peaks loads during the day or the production from solar power farms. Therefore, most applications work well with a $2 - 6\ hrs$ system matching the time characteristic of the market. This does not necessarily apply to frequency services, which can have much shorter time characteristics of $15 - 60\ min$. While systems with longer storage times are possible, they are generally not cost competitive due to the high cost of the energy unit and the low number of cycles that can be realized within the system's lifetime.

Solar power projects are required to install battery energy storage systems with a minimum capacity equivalent to 10% of the project's installed capacity and a storage duration of 2 hours.

Advantages/disadvantages

LIB based BESS systems have the main advantage that the technology shares part of the same supply chain as the automotive sector, causing the scale up of production to occur much faster compared to most other storage technologies.

On the technical side, the technology has a very fast response time and ability to deliver both high power and large amounts of energy making it useful for most services needed in the grid as described in the chapter above. Additionally, low maintenance is expected, resulting in low operational cost for the system.

The battery system is installed in modular containerized form, allowing for easy expansion and installation at existing substations or power plants.

The main disadvantage is the inherent fire risk of the battery cells which results in high requirements for fire safety, which can greatly increase the footprint of the system due to safety zones around the racks or containers.

Table 3: Typical BESS characteristic for commercially available systems as of 2024.

Advantages	Disadvantages
Short response time	Fire risks
Scales to large and small sizes	High voltage risks

High energy efficiency	Large investment cost
Proven technology	
Long lifetime	
Low maintenance	
Low cost per kWh/cycle	

Space requirement

The racks and battery packs are typically assembled in containers and the energy per 20 feet container (including LIB system and excluding power conversion system) is 3-4 MWh for NMC and LFP batteries. The footprint of a 20-feet container is 14.86 m^2, which gives a space requirement around 3.7 - 5 m^2/MWh.

Water consumption

Utility-scale lithium-ion energy systems typically do not require external water for their electrochemical operations. Some BESS advanced liquid cooling technologies that operate in a closed cycle, where water or another coolant circulates within a sealed system to transfer heat away from the battery cells efficiently. This method enhances system efficiency and longevity by maintaining optimal operating temperatures without the need for constant water replenishment.

Environment

Like all storage technologies, LIB adds additional *greenhouse gas* (GHG) emissions on the electricity that is stored. These emissions arise from manufacturing, recycling and losses during the use phase. However, energy storage in LIBESS can still provide a net reduction in GHG emissions of electricity by displacing high-emissions power sources, such as coal or gas based powerplants, with stored energy generated from low emissions sources such as wind or solar. The emissions from a BESS are determined in a *life cycle analysis* (LCA), typically taking all the above-mentioned contributions into account, i.e. emissions from production and avoided emissions from integration of *renewable energy* (RE). However, it is difficult to estimate the impact of RE-integration, since it is highly dependent on the actual usage of a BESS and the energy system in which it is integrated and may therefore vary significantly from case to case [9]. In a case study of a grid-scale BESS in Normandy it was estimated that with optimized control strategies, the BESS may displace up to 3 times the GHG emissions produced in its manufacturing and recycling phase [9]. Additionally, LCA analysis has shown that the choice of battery chemistry has a minimal impact on the total emissions. The main impact on the emissions per kWh stored comes from how intensely the BESS is utilized. More charging/discharging cycles per operating time reduces the emissions per kWh energy stored, an optimum lies typically around 1 full cycle per day. At frequencies above 1 cycle/day minimal additional improvement is achieved. External factors also affect the emissions intensity, especially the grid mix. When comparing the US grid mix with a pure PV source, the emission intensity drops from $0.55\ kg_{CO2eq}/kWh$ to $0.1\ kg_{CO2eq}/kWh$, respectively [10], [11]. Based on common LIB technologies, it can be expected that BESS storage system in 2020 has an emission intensity of $200\ kg_{CO2eq}/kWh$ of installed capacity, resulting in a $43 - 84\ g_{CO2eq}/kWh$ stored energy through the systems lifetime if the system is used effectively [11].

Fire protection and safety requirements and standards

Lithium battery systems must be ensured safe through the application of appropriate design principles, safety measures, protection mechanisms, and proper component selection. The overall safety of a battery energy storage system (BESS) is based on functional safety concepts and is implemented through a multi-layered approach, including the following levels:

- Cell level: Selection of cell chemistry and cell design best suited to the load profile and boundary conditions of the specific application. Cell design incorporates basic mechanical protection measures, such as vent disks, as well as other protective elements to mitigate internal cell faults.

- Module level: The module must be compatible with the thermal and mechanical protection concept of the battery rack. It also integrates a layer of the battery management system (BMS), which ensures that each cell operates within a safe window by collecting data such as cell current, voltage, and temperature.

- Rack level: This includes a rack-level BMS, electrical protection devices such as fuses and circuit breakers to protect against external faults, as well as passive protection measures against mechanical impacts and active protection measures against thermal risks.

- System level: This level includes the system controller, which coordinates internal interactions among components and serves as the interface with the external environment. During operation, environmental sensors continuously monitor for abnormal conditions around the BESS. When an incident is detected, sensors send alerts to the thermal management controller to initiate cooling or ventilation and notify the safety monitoring system. In addition, fire suppression systems are essential components to prevent the ignition and propagation of fires within the BESS.

Many countries have issued regulations and legal requirements for the safety of battery energy storage systems and have provided guidelines to mitigate potential operational risks. In general, there are four main groups of safety standards: those developed by Underwriters Laboratories (UL), the International Electrotechnical Commission (IEC), the United Nations (UN), and the U.S. National Fire Protection Association (NFPA).

UL standards: UL is a U.S.-based organization fully authorized by the Occupational Safety and Health Administration (OSHA) to develop safety standards. Several UL standards play a foundational role for BESS and are widely recognized in the industry. UL 1973, UL 1642, and UL 9540A are commonly required for battery-level safety. Unlike UL 9540A, both UL 1973 and UL 1642 are direct certification standards. UL 1973—Standard for batteries for use in light electric rail (LER) and stationary applications—ensures that BESS operate safely and reliably under real-world conditions (e.g., when integrated with solar PV). UL 1642—Standard for lithium batteries—covers both primary and secondary lithium batteries used as power sources for products, aiming to reduce safety risks.

UL 9540A was developed by UL as a standardized test method to evaluate fire propagation resulting from thermal runaway in BESS. It allows manufacturers to demonstrate compliance with new regulations. UL 9540A testing can be conducted at multiple BESS levels and also addresses system installation safety. UL 9540A is referenced in UL 9540, the Standard for Energy Storage Systems and Equipment. UL 9540 is an overarching standard on system compatibility and safety and does not apply to individual components (e.g., cells). It provides a general framework to ensure safe and reliable BESS operation.

IEC standards: IEC is a Switzerland-based standards organization closely associated with the International Organization for Standardization (ISO). IEC 62619 (often used in conjunction with IEC 63056) specifies requirements and tests to ensure the safe operation of lithium-ion batteries used in industrial applications, including stationary applications. At the BESS installation level, IEC 62933-5-1 and IEC 62933-5-2 specify, respectively, safety considerations (e.g., hazard identification, risk assessment, and risk mitigation) and safety requirements (e.g., protection of personnel and, where applicable, safety aspects related to the surrounding environment and living organisms) for grid-integrated electrical energy storage systems.

UN standards: Another important aspect of battery safety is compliance with United Nations transport regulations, commonly referred to as UN 38.3. This standard enables testing and certification of batteries at various levels, from cell to module, to ensure safety during transportation.

NFPA standards: NFPA is a U.S.-based standards organization focused on fire prevention and risk mitigation. Numerous NFPA standards and codes address different safety aspects of BESS, including fire prevention, fire suppression, and explosion mitigation. For example, NFPA 855 is the standard for the installation of BESS, providing comprehensive criteria for fire protection and ensuring that systems are installed in an appropriate and safe manner.

Vietnam has issued a set of 15 national standards, TCVN 14499, on Battery Energy Storage Systems (BESS). Among these, Parts 5-1, 5-2, and 5-3 focus on safety requirements for grid-integrated Electrical Energy Storage (EES) systems. These standards are primarily based on the previously published IEC 62933 standards.

Critical and strategic raw material aspects

LIB technologies rely on critical raw materials (CRM). To classify as a CRM, according to the EU, material needs to be both economically important to the EU and have a certain risk in supply. Specifically, the so-called supply risk score must be over 1 and the economic importance be over 2.8. The score of relevant materials is published in the Study of critical raw materials for the EU in 2023. There were 32 identified CRMs out of 87 screened, additionally copper and nickel are considered strategic materials but do not meet the criteria for CRM. As shown in Table 4, all of the LIB technologies rely on CRMs and production is typically centralized in a few countries with China, Australia, Russia and Chile playing key roles in the global supply chains. In all CRMs recycling of EoL equipment cannot meet the current demand and as demand increases, this situation will likely persist in the future. The future demand toward 2040 is expected to rise significantly and will, even with optimized recycling rates, require additional production capacity of virgin materials, especially for nickel, cobalt and lithium [12]. In theory, there are enough CRM available globally to realize the current production targets for LIB. Mining and processing of these materials, however, has considerable negative ecologic as well as economic impact on the global energy transition and the sustainable development goals. Therefore, both recycling of LIB materials and alternative battery chemistries should be exploited in near future.

The raw material price of these materials is highly volatile and can shift significantly year to year. Especially 2022 and 2023 saw historical high pricing of lithium reaching 78 kEUR in November 2022 up from its historical low in Oct. 2020 of just 5 kEUR. [13] This volatility is drastically reduced when going from raw materials to full scale systems. This can be seen in the peak price of lithium, dropped 35.9% between April 2023 and April 2024. In the same period battery pack pricing dropped only 14 % driven by both innovation and price drop. The price volatility is further reduced by long term contract across the battery value chain. As a result, the volatility in raw material market is unlikely to have high impact on pack pricing in the short term [14].

Table 4: Overview of key materials used on the different storage technologies.

CRM	Technologies	Biggest and second biggest producers	Supply risk/Economic impact[9]	Recycling share[10]
Aluminum	LIB (NMC, LFP, LTO), SIB[11]	Australia (28%) China (21%)	1.2(+)/5.8(+)	32 %
Cobalt	LIB (NMC, LTO)	DRC (63 %) Russia (7 %)	2.8(+)/6.8(+)	22 %
Copper	LIB (NMC, LFP, LTO)	Chile (28 %) Peru (12 %)	0.1(-)/4.0(-)	55 %
Graphite	LIB (NMC, LFP, LTO), VRFB	China (67 %) Brazil (8 %)	1.8(-)/3.4(+)	3 %
Lithium	LIB (NMC, LFP, LTO)	China (56 %) Chile (32 %)	1.9(+)/3.9(+)	0 %
Manganese	LIB (NMC, LFP, LTO), SIB	South Afrika (29 %) Australia (16 %)	1.2(+)/6.9(+)	9 %
Nickel	LIB (NMC, LTO)	China (33%) Indonesia (12%)	0.5/5.7(+)	16 %
Vanadium	VRFB	China (62 %) Russia (20 %)	2.3(+)/3.9(-)	1 %

Operation of the BESS will not produce any air pollution, nor any significant noise, significant solid or liquid waste. It will be a contractual requirement that faulty, or waste batteries will be collected, transported and recycled in appropriate facilities by the battery suppliers. Given that batteries carry the risk of fire and explosions in cases of overcharging, over-discharging, excess current, or short circuits, adequate fire-protection systems need to be carefully designed during the planning stage. To mitigate risk, safety must be an important aspect of design, not only at the cell level, but also at the module, pack, and final product levels. BESS design therefore will first and foremost adhere to prevailing regulations on firefighting and have an approved firefighting plan before going into construction and operation. A battery-protection system is an important way to improve safety and to minimize the severity of accidents if they do occur.

[9] (+) is used for values that have increased from the 2020 assessment and (-) is used for values that have decreased. No sign indicates that the value is stable in the period.
[10] Recycling share of the total market demand.
[11] Based on Prussian White technologies.

Viet Nam currently depends on imports for up to 80% of its lithium and cathode supply. Although the country possesses potential lithium ore reserves of several million tons in some central provinces, large-scale mining and processing have not yet been developed. Nevertheless, Viet Nam still has significant potential to gradually localize the battery supply chain. In 2024, Viet Nam ranked 20th out of 30 countries in the global battery supply chain ranking. The country's battery supply chain is still in its early stage, facing many challenges. The target by 2030 is to meet domestic battery demand of approximately 46.9 GWh and move toward becoming a regional battery manufacturing hub. However, to achieve this goal, Viet Nam needs to address several constraints, including low investment in research and development, limited mineral refining capacity, and the lack of fully integrated production value chains. Increasing investment in advanced processing technologies for critical minerals such as nickel, cobalt, and lithium, while expanding international cooperation through trade agreements and strategic partnerships, will play an important role in enhancing localization capacity and reducing future supply chain risks. Viet Nam should implement sustainable development strategies to participate more deeply in the global battery supply chain. These strategies include diversifying raw material supply sources, investing in advanced battery manufacturing technologies, developing infrastructure, strengthening international cooperation, and ensuring environmental standards, among others.

Research and development

Development is currently focusing on addressing a few key challenges

1. Lower LCOS
2. Development of new cell technology such as solid state and metal-based anodes
3. Increased sustainability
4. Increased safety

Lowering the LCOS has been done by either increasing the lifetime of the battery to spread the large capex cost over more cycles or a longer period. Or by lowering the CAPEX cost with improved production technologies such as dry coating of the electrodes. Eliminating the need for drying and solvent recovery. These technologies are currently near adoption with a maturity level in category 2 [15].

There are several promising materials that can provide a significantly higher capacity compared to current technology. Some of the most promising materials were Lithium sulphur, silicon and solid-state materials. Sulphur and silicon-based material have been in commercialization by companies such as Oxis and Amprius respectively, promising capacities up to $500\ Wh/kg$ and $1{,}300\ Wh/L$ with charge times below 6 minutes. [16], [17] However, Oxis has since filed for bankruptcy. Solid state technologies or semi solid-state technologies are also entering the commercialization state and have been announced by several companies such as 24M claiming to be able to make battery packs that can provide ranges in EV of up to $1{,}600\ km$ per charge and costs down to $80\ US\$/kWh$ [18]. The solid-state technology also reduces or eliminates the use of flammable electrolyte reducing the safety risk associated with the cells. However, more needs to be studied on the safety of solid-state technologies before the risk associated with the technology is fully known. While these technologies all are at a maturity level in category 2, they have yet to meet the pricing requirements to compete with existing technologies.

Examples of current projects

Examples for Vietnam:

On August 31, 2023, the JETP Implementation Plan was approved under Decision No. 1009/QĐ-TTg [19]. Accordingly, during the 2024–2029 period, pilot energy storage investment projects will be implemented in Vietnam, including:

- A 50 MW battery storage pilot project.
- A 7 MW battery storage pilot project integrated into a 50 MW solar farm.
- A 105 MW battery storage pilot project integrated into a 400 MW solar farm.

To accommodate the high share of renewable energy sources—especially wind and solar power—many large-scale BESS projects have been approved. Details are presented in the table below.

Table 5: BESS project approved to develop

No	Project	Capacity (MW)	Expected operation period
1	50 MW battery storage project	50	2025-2030
2	7 MW battery storage project integrated into a 50 MW solar farm	7	2025-2030
3	105 MW battery storage project integrated into a 400 MW solar farm	105	2025-2030
4	Other battery storage projects	138	2025-2030
5	Installation of a BESS system at the Krông Pa solar power plant	7	2025-2030
6	Installation of a BESS system at the Krông Pa 2 solar power plant	7	2025-2030
7	Hai Anh wind power plant BESS project	4	2025-2030

To meet peak demand and ensure power supply capacity during the 2026–2030 period, Vietnam Electricity (EVN) has assigned its Power Corporations to carry out procedures for investing in the installation of BESS on the distribution grid with a total capacity of approximately 1,200 MW (including 50 MW installed on the distribution grid in Hanoi). The minimum storage duration is 2 hours, in line with current regulations.

Global examples:

- Globally the three largest grid-scale LIB storage systems are the Moss Landing BESS operated by Vistra energy of $750\,MW$ and $3{,}000\,MWh$ with plans to expand to $1{,}500\,MW$ and $6{,}000\,MWh$,[21] the Mira Loma Substation in California which features $20\,MW$ and $80\,MWh$ using 400 Tesla Powerpack 2 [22], [23] and the Neoen's Hornsdale Wind Farm which features $100\,MW$ and $129\,MWh$ [23], both systems provide peak shaving.
- The Laurel Mountain, West Virginia, USA grid-scale LIB storage system at $32\,MW$ and $8\,MWh$ [24] is designed for frequency regulation and with high power to energy ratio compared to the Tesla grid-scale LIB storage systems, which are designed for peak shaving with a lower power to energy ratio.

Investment cost estimation

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment costs [MUSD2025/MWh]		2020	2025	2030	2040	2050
This Technology Catalogue			0.36	0.24	0.20	0.18
Technology Catalogue – Vietnam 2023		0.95		0.54		0.25
Technology Catalogue – Indonesia 2023			0.50	0.35		0.24
Technology Catalogue – Denmark 2025*			0.39	0.38	0.40	0.43
NREL ATB			0.33	0.29	0.23	0.18
Lazard, 2025			0.16-0.40			
	Global average		0.20			

Investment costs [MUSD2025/MWh]		2020	2025	2030	2040	2050
IRENA, 2025	China		0.11			
	United States		0.31			
	Europe		0.34			
IEA, 2024 - STEPS				0.20	0.17	0.15
***The Danish TC assumes the rate of growth will slow down between 2040 - 2050, because of competition with post-LIB or new battery technologies, which explains the higher investment cost in projected years.**						

Prediction of performance and cost

CAPEX

The projection of the capital cost for a 1 MW and 4 MWh lithium-ion battery energy storage system (LI-BESS) is divided into the following elements:

- Battery cells
- Packaging of the cells into battery packs with a Battery Management System (BMS)
- Procurement of battery packs in racks within containers, which includes thermal management systems (TMS) and a fire suppression system (FSS)
- Labour for installation and assembly
- Balance of System (BOS), which includes wiring and electrical support equipment
- Power Conversion System (PCS), which converts bidirectionally between the DC current for the battery system and the AC current for the grid
- Cost of connecting the BESS to the grid, which includes a transformer
- Cost of Engineering, Procurement, and Construction (EPC), which encompasses site-specific engineering work, procurement of materials and construction equipment, as well as siting, installation, and commissioning of the BESS.

The cell- and pack-cost are projected from a learning curve based on recent industry average LIB pack cost forecast from BloombergNEF's annual battery price survey [43], BloombergNEF's annual energy storage system cost survey [44] from 2025 and the prediction for added capacity in the future is taken from IEA's World Energy Outlook 2025 [45].

The resulting learning rates are 23% on the battery cells, 24% on the battery packs, 12% on PCS and 10% on BOS and EMS.

Scaling with system size

As with most other modular technologies, there is an impact on price as customers purchase larger volumes. The capacity component cost receives a 10% price break for a tenfold increase in system size. Energy components receive a 5% price break for a tenfold increase in system size [46].

Table 6: Scaling factor by capacities

4h system, 2025	1-10 MW	10-100 MW	100-1000 MW
Energy component scaling factor	1	0.92	0.88
Capacity component scaling factor	1	0.89	0.81

Cost examples

The aim of this technology catalogue is to provide a brief insight into the technical aspects, current status, and forecasted price level of LIB BESS technology. In relation to this, and to help the reader obtain realistic prices indications, we provide two simple installation cost calculation examples below. One for frequency regulation in 2020 and one for energy integration in 2030. The examples are based on the data in the Data sheet. For simplicity neither O&M expenses nor interest rates are included in the calculations.

Frequency regulation in 2025: 4C-rate, 2 MWh BESS system. 20 years operation time.

Cost items:

2 MWh “energy component”, year 2025 at 0.13 $M\$/MWh$

2 MWh “other project costs”, year 2025 at 0.20 $M\$/MWh$

8 MW PCS “capacity component”, year 2025 at 0.12 $M\$/MW$

Scale factor of 1 for both capacity and energy

CAPEX: 2$*$ (0.13 $M\$$+0.20 $M\$$) + 8$*$ 0.12 $M\$$ = 1.62 $M\$$

Energy integration in 2030: ¼C-rate, 16 MWh BESS system. 25 years operation time.

Cost items:

16 MWh “energy component”, year 2030 at 0.8 $M\$/MWh$

16 MWh “other project costs”, year 2030 at 0.16 $M\$/MWh$

Energy component scaling factor of 0.92

4 MW PCS “capacity component”, year 2030 at 0.09 $M\$/MW$

CAPEX: 16$*$ 0.92$*$ (0.16 $M\$$+0.08$M\$$)+ 4$*$ 0.09 $M\$$ = 3.89 $M\$$

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Data sheet

The following page contains the data sheet of the technology. All costs are stated in U.S. dollars (USD), price year 2025.

Storage utility scale Li-Ion											
Parameter	**Unit**	**2025**	**2030**	**2040**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
						Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data											
Form of energy stored		Electricity									
Application		System, power- and energy-intensive									
Energy storage capacity for one unit	MWh	4	4	4	4	4	4	4	4	A, B, C	
Output capacity for one unit	MW	1	1	1	1	1	1	1	1	A, B, C	
Input capacity for one unit	MW	1	1	1	1	1	1	1	1	A, B, C	
Storage capacity	MWh	4	4	4	4	4	4	4	4	A, B, C	
Discharge time	hours	4	4	4	4	4	4	4	4	A, B, C	
Round trip efficiency	%AC	91	92	92	92					D	1, 3, 4, 6
Round trip efficiency	%DC	95	96	96	96					D	1, 3, 4, 6
- Charging efficiency	%	98	98.0	98.5	98.5						7
- Discharge efficiency	%	97	97	97.5	97.5						7
Self-discharge rate	%/day	0.1	0.1	0.1	0.1					E	9
Forced outage	%	0.38	0.35	0.30	0.25					F	
Planned outage	%	0.38	0.38	0.19	0.19					F	
Technical lifetime	cycles	5,000	6,000	12,000	20,000						1, 3
Technical lifetime	years	15	20	30	30					G	1, 3, 10
Construction time	years	0.25	0.20	0.20	0.20					H	
Ramping configuration											
Response time from idle to full-rated discharge	s	0.08	0.08	0.08	0.08					I	11
Response time from full-rated charge to discharge	s	0.08	0.08	0.08	0.08					I	11
Economic data											
Specific investment	MUSD/MWh	0.36	0.24	0.20	0.18	0.28	0.45	0.14	0.25	J	1, 12, 13, 14, 15
- energy component	MUSD/MWh	0.128	0.07	0.05	0.04	0.10	0.17	0.03	0.07	K	
- power component	MUSD/MW	0.116	0.08	0.07	0.07	0.10	0.14	0.06	0.09	K, L	16
- other project costs	MUSD/MWh	0.203	0.16	0.14	0.13	0.15	0.25	0.09	0.16	K, M	
Fixed O&M	USD/MW-year	12,000	9,269	8,035	7,592	10,000	32,000	6,327	20,245	N	1
Variable O&M	USD/MWh	2.0	1.54	1.34	1.27	2.00	2.60	1.27	1.64	O	1, 17
Technology specific data											
Energy storage expansion cost	MUSD/MWh	0.33	0.24	0.20	0.19	0.25	0.38	0.14	0.21	P	

Storage utility scale Li-Ion											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Power expansion cost	MUSD/ MW	0.12	0.09	0.08	0.07	0.10	0.13	0.06	0.08	Q	
Alternative Total investment cost	MUSD/ MW	1.44	1.04	0.87	0.81	1.10	1.65	0.62	0.93		
Energy density	kWh/m^3	100	110	130	150					R	18, 19
Water consumption	L/MWh	0	0	0	0	-	-	-	-		

Notes:

A One unit is defined as a 20 feet container including LIB system and excluding power conversion system. The Specific investment cost under Economic data is the total cost for a 4MWh/1MW BESS, which is the typical size of grid-scale BESS in 2025. (Some specific BESS might have lower energy capacity and higher power capacity or vice versa).

B A 4-hour battery has been picked as a reference, as there is more data available for this power-to-energy ratio in the references listed.

C Power and energy output can be scaled linearly by utilizing many modules (up to 250 MW has been demonstrated (https://www.pv-magazine-australia.com/2023/08/10/battery-capacity-overtakes-pumped-hydro-in-nem/). Output capacity expansion can be done reprograming the management unit without any new battery module. For Utility batteries the ratio between energy storage and capacity is in general between 1 and 10 (C-rate between 1/10 and 1), only rarely the ration will be below 1.

D The gradual change towards lower C-rates following the transition from frequency regulation to renewable integration promotes lower C-rates. Therefore, the average DC roundtrip efficiency is expected to increase slightly. . The AC roundtrip efficiency includes losses in the power electronics and is 2-4 % lower than the DC roundtrip efficiency. The total roundtrip efficiency further includes standby losses making the total roundtrip efficiency typically ranging between 80 % and 90 % [1,8].

E Lithium-ion battery daily discharge loss. The central estimates for self-discharge of Li-ion batteries range between 0,05% and 0,20% a day in 2025 and are expected to stay flat to 2050.

F The main source of outage of the battery cells is caused by extreme heat or cold as this may push the cells beyond their operational limits. However, these are considered rare events and for many system may never occur. Outages may however happen due to the power electronic or thermal management which will also need yearly maintenance causing planned outage. In total this is expected to remain below a few days per year and is unlikely to change significantly over time.

G Samsung SDI 2016 whitepaper on ESS solutions provide 15-year lifetime for current modules operating at C/2 to 3C. Steady improvement in battery lifetime due to better materials and battery management expected. Number of cycles can be a more meaningful lifetime indicator.

H Construction time of a BESS varies widely from site to site. Construction of the BESS system alone may only take a few months, but getting approval to connect to the grid and potential upgrade to the grid may delay start of operations by as much as 18 months [4]. However, this may differ significantly from country to country.

I The response time is obtained from simulated response time experiments with hardware in the loop [13].

J The specific investment cost is the total cost of a 4 MWh/1 MW BESS, which is the typical grid-scale battery. However, size and Power to Energy ratio may vary significantly from system to system and must be calculated based on the expected system specifications.

K A learning rate of 24 % is assumed for the energy component, 12 % for the power component and 10 % for other costs, according to BNEF [14][15] and IEA [6].

L Power conversion cost is strongly dependent on scalability and application. The PCS cost is based on references and reflects the necessity for high power performance and compliance to grid codes to provide ancillary services, bidirectional electricity flow and two-stage conversion, as well as the early stage of development and the fact that few manufacturers can guarantee turnkey systems. Inverter replacement is expected every 10 years.

M Other costs include construction costs and entrepreneur work. These costs are heavily dependent on location, substrate and site access. Power cables to the site and entrepreneur work for installation of the containers are included in other costs. Therefore, other costs are assumed to roughly correlate with the system size. Automation is expected to decrease other costs from 2030 and onwards.

N Fixed O&M is assumed to be 3 $/kW-year in 2025 based on [1].

O Cost per MWh of energy discharged from the battery.

P Since multi-MWh LIB systems are modularly scalable, the energy storage expansion cost is here estimated to be equal to the energy component plus 20% of the respective “other costs”.

Q Since multi-MW LIB systems are modularly scalable, the capacity expansion cost equals the capacity component cost plus 20% of the respective “other costs”.

R Energy density is reported at container/enclosure level (nominal kWh divided by container volume based on external dimensions). It includes space for internal equipment and auxiliaries and is not cell/pack/rack-level.

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3. VANADIUM REDOX FLOW BATTERIES

Brief technology description

A redox flow battery (RFB), or simply flow battery, is a special type of secondary (i.e., rechargeable) batteries for electrical energy storage systems. A flow battery stores electrical energy in chemical compounds, whereby the reactants are present in dissolved form. These two reactants act as energy carriers and circulate in separate circuits, between which ion exchange takes place in galvanic cells consisting of two electrodes and a separating membrane. In these cells, the dissolved reactants are chemically reduced and oxidized[12] to either absorbing or releasing electrical energy in form of electrons. The electrolyte that is reduced (i.e., the reductant) at the negative electrode of the galvanic cells (i.e., the anode) is also referred to as negolyte or anolyte. The electrolyte that is oxidized (i.e., the oxidant) at the positive electrode of the galvanic cells (i.e., the cathode) is also referred to as posolyte or catholyte. A principal diagram of a general RFB is shown in Figure below.

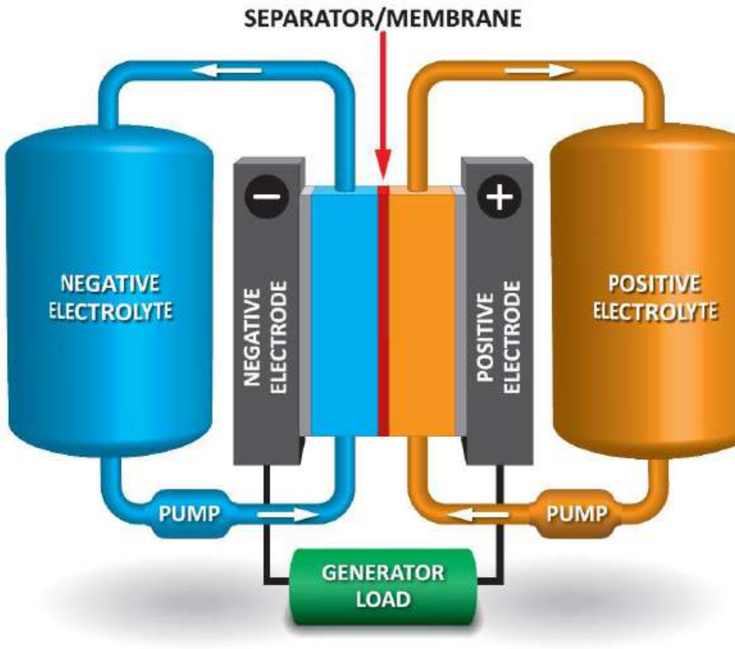


Figure 14: Principal diagram of a redox flow battery.

The number and sizes of the electrolyte tanks determine the energy capacity of an RFB, whereas the number and size of the galvanic cells determine its power capacity. Due to the possibility to scale their rated energy and power independently of each other, RFBs are today primarily used within stationary electrical energy storage systems (EESS) for short-term (< 6 hours) and medium-term storage periods (< 24 hours). Figure 11 illustrates the general architecture of an EESS with a redox flow-based battery system including the cell stack, two electrolyte tanks, necessary pipes and pumps as well as a battery management system (BMS). The remaining components of such a system can be directly related to other types of battery energy storage systems (BESS), for example, Lithium-based BESS.

12 The term redox originates from the electrochemical processes of reduction and oxidation.

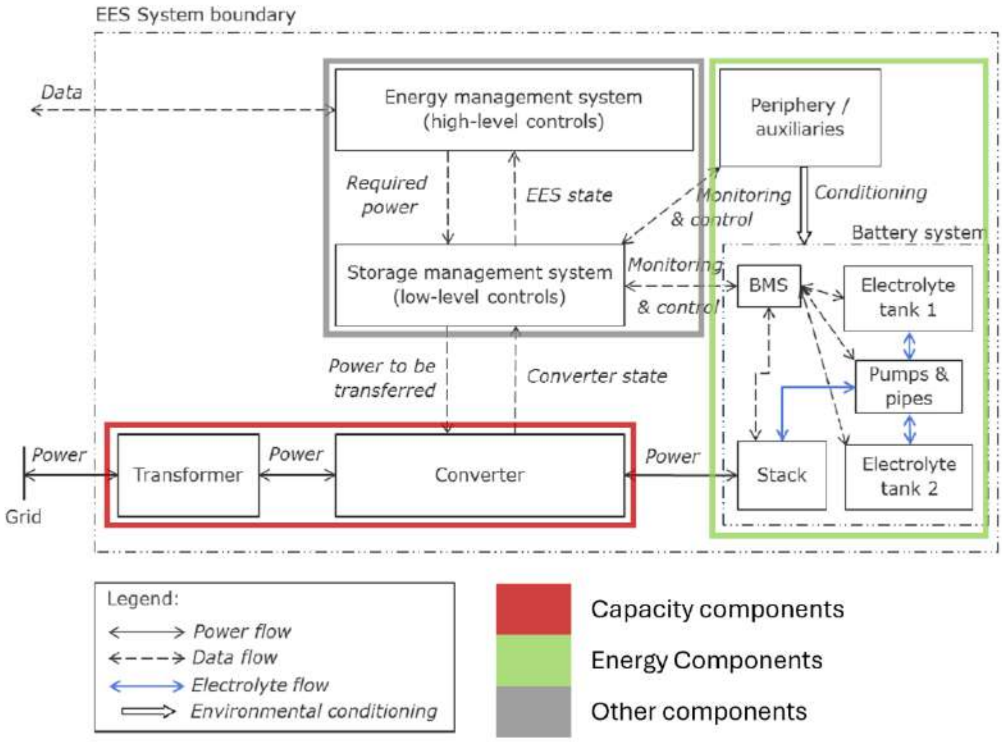


Figure 15: General architecture of a redox flow-based battery energy storage system (Modified from [1]).

Vanadium redox flow batteries (VRFB), sometimes also known simply as vanadium redox batteries (VRB) or vanadium flow batteries (VFB), are currently both the most common and mature technical realizations of RFBs. A VRFB utilizes the ability of vanadium to adopt four different oxidation states in solutions, so that only one electroactive element is required for these RFBs instead of two as redox pairs of vanadium can be used for both electrolytes. The electrodes of VRFBs are made of carbon, the structure of which has a significant influence on the properties. The electrodes and the two electrolyte reservoirs are separated by a membrane that ideally only allows hydrogen ions to pass through. This makes the VRFB-technology ideal for exploiting in the cell stack (and for other subsystems) materials, components and processes originally developed for hydrogen fuel cells. Figure 16 shows the principal electrochemical reactions inside a VRFB.

VRFBs use redox pairs of vanadium in both half-cells of the cell stack. The posolyte reactive species contains vanadyl sulphate (i.e., vanadium(IV) oxide sulphate, $VOSO_4$), which can be oxidized to the pentavalent ion. The corresponding half-cell reaction at the cathode is:

$$VO^{2+}+H_2O \rightleftharpoons VO_2^{+}+2H^{+}+e^{-} \qquad (E^0=0.995 \text{ V vs. SHE}),$$

where VO^{2+} is the oxovanadium(IV) cation vanadyl and VO_2^{+} is pervanadyl, an oxycation of vanadium(V). The negolyte reactive species contains vanadium(III) sulphate (i.e., $V_2(SO_4)_3$), which can be reduced to the bivalent vanadium salt. The corresponding half-cell reaction at the anode is:

$$V^{3+}+e^{-} \rightleftharpoons V^{2+} \qquad (E^0=-0.255 \text{ V vs. SHE}).$$

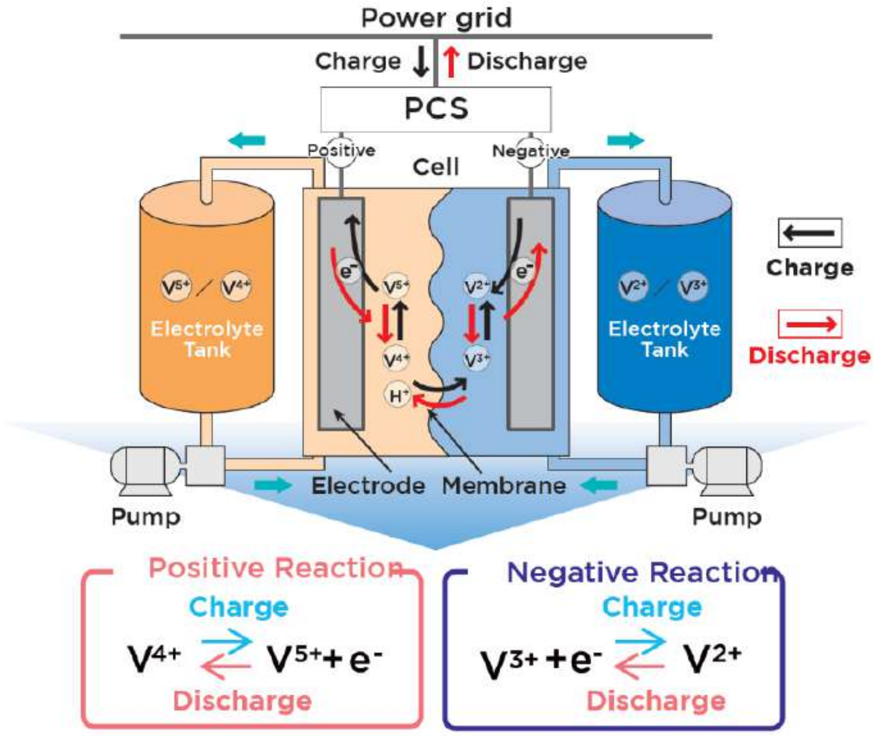


Figure 16: Principal electrochemical reactions inside a vanadium redox flow battery [2].

Hence, the full-cell reaction is:

$$VO^{2+}+H_2O+V^{3+} \rightleftharpoons VO_2^{+}+2H^{+}+V^{2+}$$

and provides a cell voltage of 1.25 V at standard environmental conditions. The source voltage per cell (voltage without load) is between 1.15 V and 1.55 V. At 25℃ it is 1.41 V. Traditionally, the reactive species have been dissolved with concentrations of $1.5 - 2$ M in aqueous sulphuric acid solutions with an acid concentration of $2 - 5$ M [2].

VRFBs have lower energy density of approximately 15 Wh/l to 35 Wh/l of liquid electrolyte, compared to lithium-ion batteries. The energy density by mass is therefore between 20 Wh/kg and 32 Wh/kg electrolyte [2].

As with all redox flow batteries, one of the main advantages of the vanadium redox accumulator is that, unlike conventional secondary cells, the power and capacity are independent of each other. The power can be regulated primarily by the electrode surface, the storage capacity by the amount of electrolyte. Full discharge to 0% state of charge (SoC) is also harmless. The modular and scalable design of a VRF-BESS is illustrated in Figure 17. Further advantages of VTFBs include cycle stability and ‘charging’ via electrolyte exchange. According to a study from 2016 [3], such a battery completed over 200,000 charge/discharge cycles within a three-year test.

The main disadvantage of vanadium redox accumulator technology, in addition to the poor volume-energy storage ratio, is the more complicated overall structure compared to conventional accumulators, which also includes pumps and storage tanks.

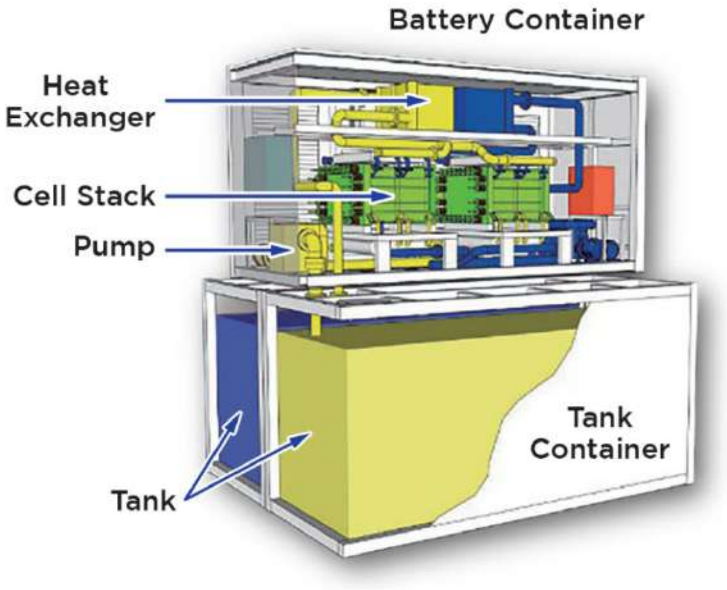


Figure 17: Illustrations of the modular and scalable nature of VRFBs (©Sumitomo Electric, 2019).

When pumped into the reaction cell the anolyte and catholyte will be separated by a proton conducting (polymer) membrane. An illustration of reaction cell components and a full reaction stack can be seen in Figure below.

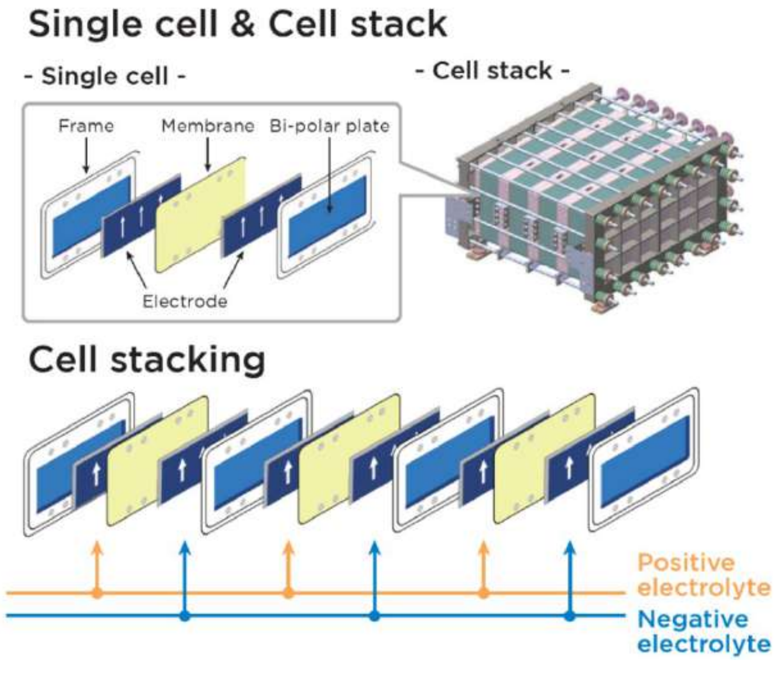
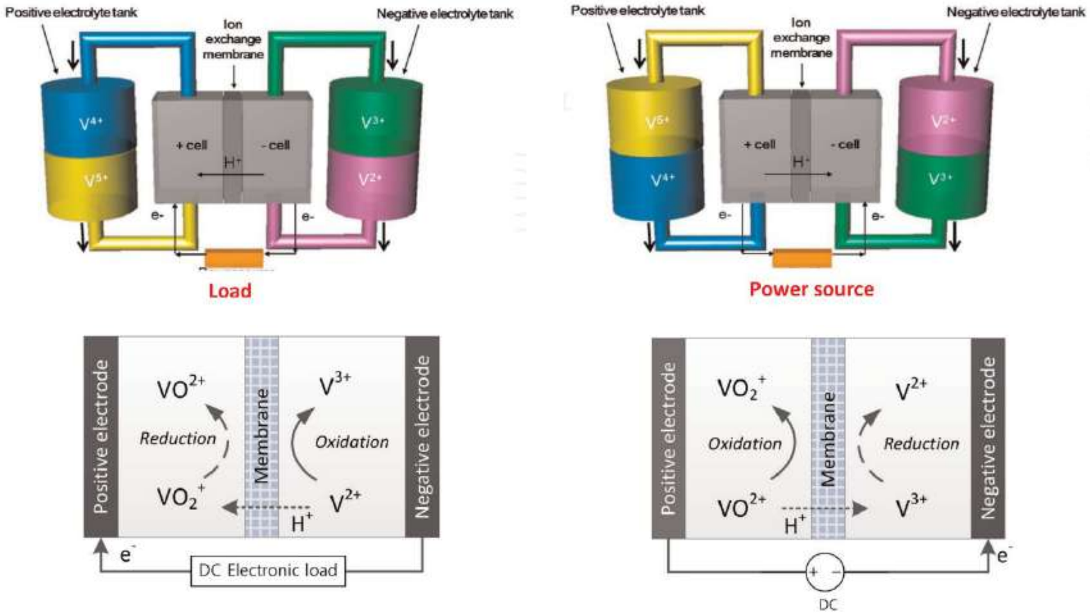


Figure 18: Illustration of a single cell, a cell stack and the respective cell stacking for a VRFB (©Sumitomo Electric, 2019).

Input/output

As is common for BESS, the primary input as well as output of VRFBs is electrical energy. Electrical energy is converted electrochemically into chemical energy during charge and converted back to electrical energy during discharge in the reaction process described above. Figure 19 illustrates energy conversion of both input and output energy in a VRFB.



(a) (b)

Figure 19: Illustrations of the energy conversion processes in a VRFB during discharging (a) and charging (b).

The cell stacks of VRFBs operate typically with direct current (DC). When operated with alternating current (AC) as input/output power, this must be converted accordingly by appropriate power electronics.

Secondary input or output power in the form of thermal energy can generally be neglected for VRFBs. Due to their operating temperatures being close to average ambient temperature, waste heat of VRFBs is not of high value. At the same time, most VRFBs do not require auxiliary cooling for the cell stacks due to the large thermal mass of the electrolyte itself [2].

Energy balance

Like all other energy conversion technologies, certain loss mechanisms also occur with the practical operation of VRFBs. The losses in VRFBs can be divided into operational losses and standby losses. The total energy efficiency is a combination of these effects.

Operational losses

The operational losses of a VRF-BESS comprise all the losses that occur during charging and discharging.

Voltage efficiency is the ratio of average discharge voltage to the average charge voltage. In VRFBs, voltage efficiency typically ranges from 75% to 90%. This efficiency is affected by factors such as internal cell resistance and overpotentials during operation. Coulombic efficiency is the ratio of the total charge discharged to the total charge initially charged. VRFBs generally have high Coulombic efficiencies, often exceeding 95%, because the vanadium ions do not cross-contaminate between the two half-cells which minimizes side reactions. Energy efficiency is the product of voltage efficiency and Coulombic efficiency. It represents the overall efficiency of a battery in converting the input electrical energy into electrical energy stored and back into electrical energy. For VRFBs, energy efficiency typically ranges from 70% to 85%.

In practice, the use of electric pumps and valves in the VRF battery system results in additional losses due to the consumption of these peripherals. Added to this are the peripheral consumptions of communication, controls and other central subsystems. These losses add up to below 2% during operation. Furthermore, the central power electronics are designed with rated efficiencies typically rated around 95% which results in additional losses during operating VRF-BESS.

The overall roundtrip efficiency of a complete VRF-BESS can be expected to be in the range between 75% and 90% on the DC-side alone. The respective losses of between 10% and 25% are released in the form of thermal energy.

Standby losses

The standby losses of a VRF-BESS comprise all the losses that occur in periods when not operated (i.e., neither charging nor discharging).

Electrolyte left in the cell stack after operation will self-discharge during idle/standby due to diffusion of vanadium ions across the membrane separating the two half-cells. These losses are comparatively low for VRFBs, often between 1% and 3% per day, and affect only the amount of electrolyte within the cell stacks. Small volumes and/or closing valves close to the input/output of the cell stacks can minimize the losses.

Any standby consumption of other subsystems and peripherals of a VRF-BESS (e.g., communication and controls) can be considered additional losses. The losses are typically below 1% per day.

Ramping configurations

The response time is an important characteristic that determines how fast a battery can respond to changes in load demand during discharging or input power during charging. VRFBs are known for their relatively fast response times below $100\ ms$ if electrolyte is already present within the cell stack, below $1\ s$ if the electrolyte must first be pumped into the cell stack (idle/standby), and below $1\ min$ if the whole VRF-BESS is shut down.

This fast response time, together with low self-discharge and a high number of lifetime cycles, allow VRFBs to be both effectively and efficiently exploited for most grid-scale applications of EESS. Table 7 and Figure 20 collect possible applications for grid-connected VRF-BESS.

Table 7: Possible applications for grid-connected BESS.

Services	Notes	Location
Frequency regulation	Frequency services are supplied in a fixed timeframe where the system must react to changes in the grid frequency. The service price is based on power available from the system.	Front-of-the-meter
Peak shaving	Peak shaving is designed to minimize the peak power drawn from the local user or provide additional power during peaks hours on utility scale.	Front-of-the-meter
Energy arbitrage	Energy arbitrage exploits price differences by buying energy when prices are low and selling when they are high.	Front-of-the-meter
Black start	Due to grid forming technology in the inverter systems a BESS may be used to initiate the grid after a blackout. However not all inverters are designed for black start applications	all
Voltage support	Smaller BESS system may be placed in weak parts of the grid to provide or draw reactive power to influence the local voltage.	all
Optimized self-consumption	For both large- and small-scale wind or solar power production a BESS may be used to avoid sending surplus energy to the grid when marked prices are unfavorable. The energy can then be used locally or sold to the grid once prices are favorable.	Behind-the-meter

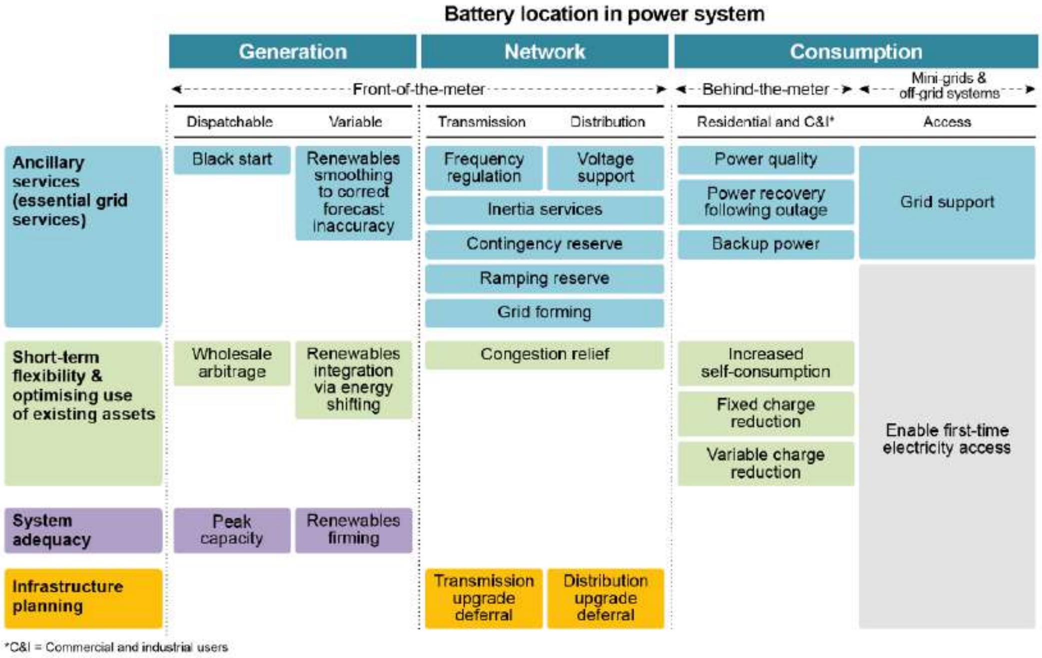


Figure 20: BESS applications along the dimensions of the power grid; horizontal axis shows the location; vertical axis shows the service (©IEA, 2024).

Most possible applications for BESS primarily place demand on the central power electronics, as these ensure the connection to the grid. However, the BMS is responsible for ensuring that the actual battery system can follow the power electronics. This is typically ensured in the design phase of the BESS. With the help of an appropriate BMS, VRFBs can deliver up to 1.5 times their rated nominal power for shorter periods (as long as membranes in the stacks are not overheated).

Typical capacities

Examples of recently commissioned grid-scale VRB installations are listed Table below.

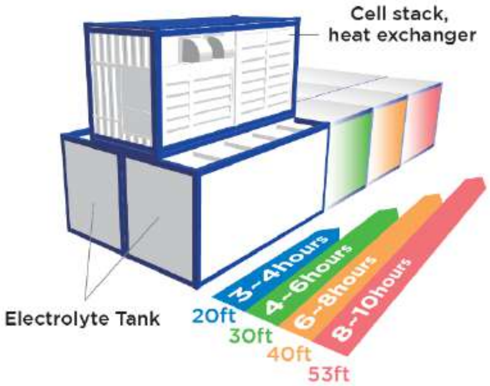
Table 8: Selective list of the largest VRF-BESS installations worldwide.

Name	Commission Date	Energy (MWh)	Power (MW)	Discharge (Hours)	Country
Minami Hayakita Substation	December 2015	60	15	4	Japan
Pfinztal, Baden-Württemberg	September 2019	20	2	10	Germany
Woniushi, Liao-ning		10	5	2	China
Tomamae Wind Farm	2005	6	4	1.5	Japan
Zhangbei Project	2016	8	2	4	China
SnoPUD MESA 2 Project	March 2017	8	2	4	USA
San Miguel Sub-station	2017	8	2	4	USA
Pullman Washing-ton	April 2015	4	1	4	USA
Dalian Battery	October 2022	400 (800)	100 (200)	4	China

Typical storage period

The typical energy storage period for BESS depends on both their application, design, and operation. The storage period for VRFBs is principally not limited as their modular nature and scalability allow for flexible deployment to meet the needs of different applications. It ranges from minutes for grid services to weeks for energy storage.

Due to their low self-discharge, minimal degradation, and the favorable levelized cost of storage (LCOS) for high energy/power-ratios, VRF-BESS have general benefits for storage periods larger than that for Li-BESS. Figure below illustrates typical storage periods for VRF-BESS.



Type (hours)	Output	Capacity
20ft (3~4h)	250kW	750kWh~1,000kWh
30ft (4~6h)	250kW	1,000kWh~1,500kWh
40ft (6~8h)	250kW	1,500kWh~2,000kWh
53ft (8~10h)	250kW	2,000kWh~2,500kWh

Figure 21: Illustration of typical storage periods for VRF-BESS (©Sumitomo Electric, 2019).

Advantages/disadvantages

General advantages and disadvantages of VRFBs in comparison to other EESS technologies are listed in table below.

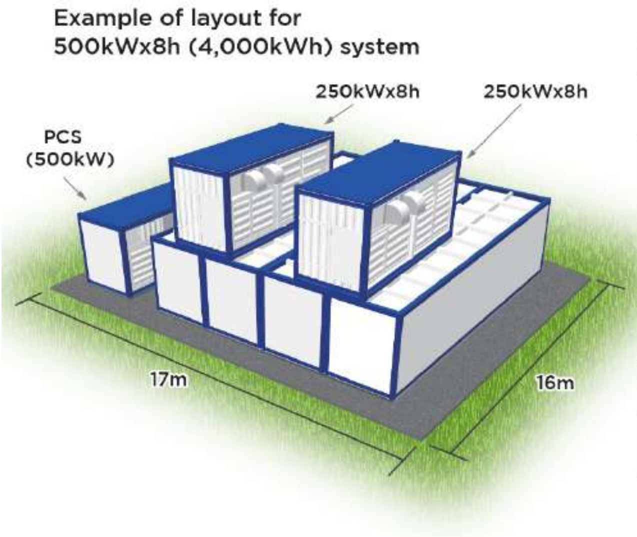
Table 9: General advantages and disadvantages of VRFBs.

Advantages	**Disadvantages**
Energy and power capacity can be scaled independently of each other	Heavy weight of electrolyte solution
High tolerances for deep discharge	Toxicity of vanadium compounds
Mixing electrolytes causes no damage	Noble materials in cell stack
Single charge state across the electrolyte avoids capacity degradation	Extra active peripherals in the form pumps and valves
Non-flammable and non-explosive aqueous electrolyte	Relatively low energy density (compared to LiB)
Low noise and emissions during operation	Relatively poor roundtrip efficiency (compared to LiB)
Energy and power capacity upgradeable during the whole lifetime	Small operating temperature range (~5 °C to 50 °C)
Passive cooling possible	
High lifetime cycles (> 20.000)	
High lifetime (> 20 years)	
Low LCOS (~ 0.05 €/kWh)	

Space requirement

Due to their modular nature and scalability, the space requirement for VRF-BESS strongly depends on individual boundary conditions. From actual VRF-BESS in operation land use between 17 m^2/MWh and 140 m^2/MWh is reported [4].

A reasonable average value for space requirement for a VRF-BESS results from a modular design based on standard ISO containers as shown in Figure 22. This results in land use between 45 m^2/MWh and 65 m^2/MWh, with lower values for higher energy/power ratios.



Sample footprint

Output	Capacity	LxW
1MW	4MWh	15m×17m
1MW	6MWh	21m×17m
1MW	8MWh	27m×17m
10MW	40MWh	85m×27m
10MW	60MWh	103m×27m
10MW	80MWh	131m×27m

Figure 22: Illustration of typical land use for VRF-BESS (©Sumitomo Electric, 2019).

Water consumption

In vanadium redox flow batteries (VRFBs), water is an integral part of the electrolyte and directly participates in the electrochemical reactions, particularly at the positive half-cell. During charge and discharge, protons are consumed and produced, and water is involved through proton exchange and hydration effects associated with the vanadium redox couples. However, this does not constitute net water consumption during normal operation, as water is neither permanently consumed nor generated in the overall cell reaction.

Water losses are mainly associated with secondary effects such as evaporation, electrolyte handling, maintenance activities, and, in some system designs, cooling. These losses are typically small and can be managed through sealed systems and periodic electrolyte rebalancing. As a result, VRFBs exhibit low operational water consumption compared to many other energy technologies, with water requirements largely limited to initial electrolyte preparation and infrequent make-up over the system lifetime.

Environment

The environmental footprint of VRF-BESS can be considered in the range of between 160 kg_{CO2eq}/kWh and 190 kg_{CO2eq}/kWh (with a median at about 180 kg_{CO2eq}/kWh), due to the energy-intense production of V_2SO_5 and low production volumes but should be compensated during normal operation by a high lifetime and cycle number. This is considerably higher than the average environmental footprint of about 105 kg_{CO2eq}/kWh for LIB-BESS, but here the range spans between 80 kg_{CO2eq}/kWh and 230 kg_{CO2eq}/kWh. The majority of the components and materials used in a VRF-BESS can be recycled, including the electrolyte which is often directly reused. [8]

Nevertheless, vanadium ions might pose environmental risks that are not fully determined yet [2] and components of the cell stack might be highly acidic or alkaline at end of life, hence, to be treated as corrosive material during recycling and disposal [2].

Research and development

The area of VRFB and RFB in general is under heavy development. This is due to the fact that electrical energy storage becomes more important as the penetration with renewable energy supply like wind and solar increases, requiring measures to integrate the fluctuating production of electricity into the grid.

The primary goal of research and development is currently to scale production of VRFBs to reduce LCOS by economy of scale. Here, similar scaling effects like LiB are expected [5].

More specifically, research and development focusses on the following aspects:

1. Electrolytes that are less energy-intense (cheaper) to produce
2. Electrolytes that transfer more electron per molecule (higher energy density)
3. Electrolytes that operate stable in a wider temperature range
4. Non-aqueous, organic, and/or metallic electrolytes
5. Alternative materials to Nafion for the proton exchange membrane (cheaper, PFAS-free)
6. Catalysts to increase exchange current density (higher efficiency)
7. BMS to optimize oxygen generation at the electrodes

Examples of current projects

Grid-scale VRF-BESS are commercially available from several companies and in operation in different countries. A non-exhaustive list of VRFB manufacturers can be found in table below. The market for VRFBs is different to that for LiB as large VRF-BESS are typically electrochemical process plants and therefore designed and installed by different industries.

Table 10: Exemplary manufacturers of VRFBs.

Name	Origin	Link
VFlow Tech	Singapore	www.vflowtech.com
VoltStorage	Germany	www.voltstorage.com
VRB Energy	China	www.vrbenergy.com
UniEnergy Technologies	USA	www.uetechnologies.com
Ashlam Energy	USA	www.ashlamenergyllc.vom
NEXTracker	USA	www.nextracker.com
CellCube Energy Storage	Canada	www.cellcube.com
Delectrik Systems	India	www.delectrik.com
V Sun Energy	Australia	www.vsunenergy.com
Rongke Power	China	www.rongkepower.com
VisBlue	Denmark	www.visblue.com
H_2 Inc.	South Korea	www.h2aec.com
Green Energy Storage	Italy	www.greenenergystorage.com
meeco (sun2live)	Switzerland	www.meeco.net
Sumitomo Electric	Japan	www.globa-sei.com
redT energy	Ireland	www.redtenergy.com
Solibra energy Storage	Germany	www.vanadiumredoxflow.com

Investment cost estimation

The data from the different sources in the table below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment costs [MUSD2025/MWh]	2020	2025	2030	2040	2050
This Technology Catalogue		0.72	0.74	0.53	0.43
Technology Catalogue – Vietnam 2023	0.82		0.56		0.45

Additional remarks

Even though VRFBs and other RFBs have high commercial potential, rapid cost reduction of alternative storage solutions (e.g., LiB) might halter their commercial deployment and technological development. This can prevent VRB and other flow batteries from reaching full commercial potential.

On the other hand, the modularity and scalability of RFBs make them a promising candidate for stationary EESS for storage periods above 6 hours, especially with an electrolyte with low environmental impact over the whole value chain.

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Data sheet

The following page contains the data sheet of the technology. All costs are stated in U.S. dollars (USD), price year 2025. The *uncertainty* it related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Vanadium Redox Battery (VRB)											
Parameter	**Unit**	**2025**	**2030**	**2040**	**2050**	**Uncertainty (2030)**		**Uncertainty (2050)**		**Note**	**Ref**
						Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data											
Form of energy stored		Electricity									
Application		System, power- and energy-intensive									
Energy storage capacity for one unit	MWh	0.5	0.6	0.65	0.75	0.5	0.7	0.7	0.8	A, Q	1, 2, 3, 4
Output capacity for one unit	MW	0.25	0.5	0.5	0.5	0.4	0.6	0.4	0.6	A, Q	1, 2, 3, 4
Input capacity for one unit	MW	0.25	0.5	0.5	0.5	0.4	0.6	0.4	0.6	A, Q	1, 2, 3, 4
Round trip efficiency	%DC	78	80	83	85	75	85	80	90	B	1, 2, 3, 4
- Charge efficiency	%	-	-	-	-	-	-	-	-		
- Discharge efficiency	%	-	-	-	-	-	-	-	-		
Energy losses during storage	%/day	0.25	0.2	0.15	0.1	0.15	0.25	0.05	0.15	C	1, 2, 3, 4
Forced outage	%	0.4	0.2	0.2	0.2	0.2	0.5	0.1	0.4	D, Q	1, 2, 3, 4
Planned outage	%	0.2	0.1	0.1	0.1	0.1	0.25	0.05	0.2	D, Q	1, 2, 3, 4
Technical lifetime	years	25	30	35	40	25	35	30	50		1, 2, 3, 4, 5, 6
Construction time	years	0.5	0.25	0.2	0.15	0.15	0.5	0.1	0.2	E, Q	7
Ramping configuration											
Response time from idle to full-rated discharge	s	0.2	0.1	0.1	0.1	0.05	0.25	0.05	0.2	F, G	8
Response time from full-rated charge to full-rated discharge	s	0.1	0.1	0.1	0.1	0.05	0.2	0.05	0.2	F, G, Q	8
Economic data											
Specific investment	MUSD/ MWh	0.72	0.74	0.53	0.43	0.63	0.89	0.25	0.52	H	7, 8, 9, 10, 11
- energy component	MUSD/ MWh (or %)	0.26	0.19	0.10	0.06	0.15	0.26	0.04	0.09	H, I	7, 8, 9, 10, 11
- power component	MUSD/ MW (or %)	0.51	0.45	0.34	0.31	0.38	0.51	0.20	0.34	H, J	7, 8, 9, 10, 11

Vanadium Redox Battery (VRB)											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2030)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
- other project costs	MUSD/ MWh (or %)	0.20	0.18	0.17	0.16	0.18	0.19	0.09	0.18	H, K	7, 8, 9, 10, 11
Fixed O&M	USD/M W/year	5,369	5,521	3,954	3,225	3,133	8,856	1,003	5,234	H, L	7, 8, 9, 10, 11
Variable O&M	USD/M Wh	-	-	-	-	-	-	-	-	M	7, 8, 9, 10, 11
Technology spe-cific data											
Energy storage expansion cost	MUSD/ MWh	0.27	0.20	0.11	0.07	0.16	0.27	0.41	0.16	H, N	7, 8, 9, 10, 11
Power expansion cost	MUSD/ MW	0.54	0.47	0.36	0.34	0.41	0.54	0.20	0.54	H, O	7, 8, 9, 10, 11
Lifetime in total number of cycles	None	>20,000	>40,000	100,000	>100,000	20,000	40,000	40,000	200,000	P	8
Specific power	W/kg	8.25	16.5	16.5	16.5	8.25	16.5	8.25	16.5	A, Q	8
Power density	W/m^3	3,704	7,407	7,407	7,407	3,704	8,889	3,704	8,889	A, Q	8
Specific energy	Wh/kg	16.5	19.7	23.4	24.6	16.5	24.6	23	26.25	A, Q	8
Energy density	Wh/m^3	7,407	8,880	9,996	11,111	7,407	11,111	10,370	11,852	A, Q	8
Water consump-tion	L/MWh	0	0	0	0	-	-	-	-		

Notes:

A One unit defined as a 40 feet ISO container including VRFB system (cell stacks, electrolyte tanks, and control system) and excluding power conversion system. Based on data from existing and/or available VRFB systems.

B Efficiency varies considerably between different VRFBs, depending on control system and use cases.

C Energy losses depend on idle situation. If pumps are off and electrolyte not present in the reaction stack no energy loss occurs. This increases response time (see below). Self-discharge only occurs for electrolyte inside the reaction stack. This is a relatively small volume and the self-discharge will be at most 1% for 40ft unit. Losses related to stand-by energy consumption of pumps are not included.

D Some companies guarantee at least 99.5% uptime.

E Depends highly on the installation.

F Time is less than 100 ms for idle situation with electrolyte in reaction stack and pumps on [4]. Less than 1 s if electrolyte must first be pumped [5]. Less than 1 min if pumps are not on [5]. PCS might be limiting the response time.

G Might in practice be limited by PCS.

H Valid for installations with rated discharge times of 2 hours. This relates to a C-rate 1.0 for a 40ft unit system (i.e., 250 kW with 500 kWh). The price development is strongly dependent on competition with other energy storage technologies as a high market share will be needed to reach a low cost.

I Composed of electrolyte and tank infrastructure for a unit system cost at around 250 USD/kWh.

J Composed of stack and other power capacity related cost of about 1175 USD/kW for the 40ft unit system.

K Other costs include construction costs and entrepreneur work. These costs are heavily dependent on location, substrate and site access. Power cables to the site and entrepreneur work for installation of the containers are included in other costs. Therefore, other costs are assumed to – roughly – correlate with the system size. Automation is expected to decrease other costs from 2030 and onwards. Estimates are aggregated from the literature.

L Fixed O&M is assumed to be constant at around 1% for a 2 to 8h system. O&M depends on the energy to power ratio. Most suppliers define O&M below 15% of Capex over lifetime of > 20 years.

M Variable O&M is assumed to be 0 USD/MWh, as a fixed use pattern is assumed throughout the VRFB calendar life, and all replacement and maintenance is accounted for under fixed O&M.

N Since multi-MWh VRFB systems are modular and scalable, the energy storage expansion cost is basically electrolyte cost plus the required tank infrastructure and the cost in MUSD/MWh will therefore decrease with longer storage durations.

O Since multi-MW VRFB systems are modular and scalable, the capacity expansion cost equals the stack system component cost plus required installation material and the specific investment cost in MUSD/MWh will therefore decrease with larger capacities.

P Cyclic lifetime of up to 200.000 cycles has already been demonstrated for VRFBs, but might still require refurbishment in practical operation.

Q Uncertainties are based on a qualified guess for VRFB, based on their scientific principles.

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4. HYDROGEN STORAGE

Brief technology description

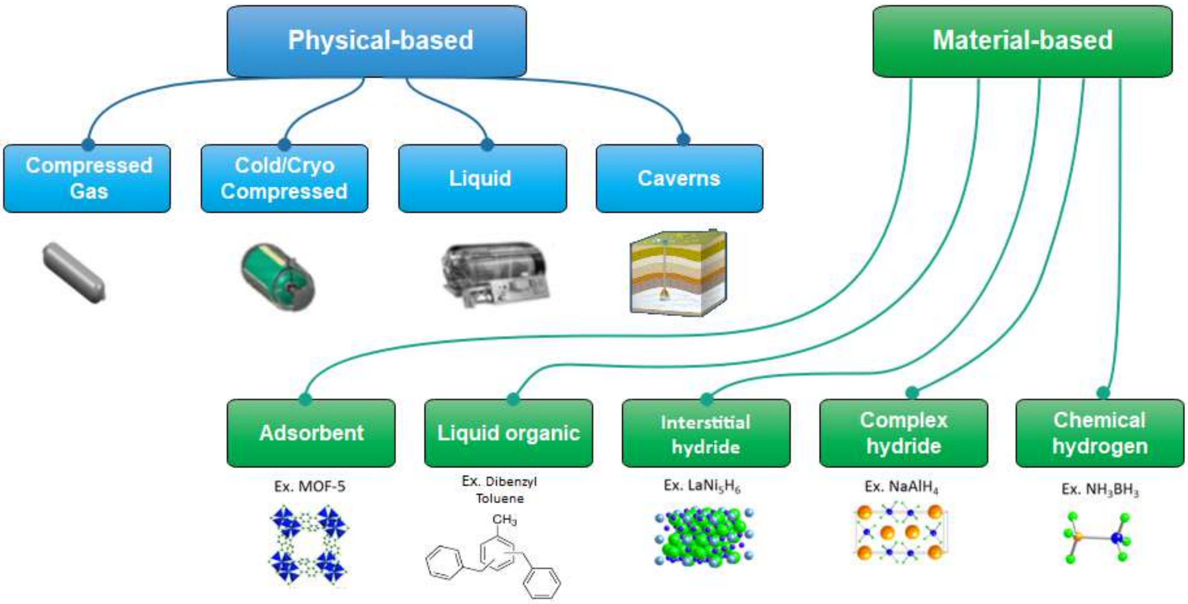

Figure 23: Hydrogen storage categories (icons from [6])

Hydrogen is currently being used in a wide range of applications, mainly for industrial purposes in chemical production and refining. Today, more than 95% of its production globally (96% in 2008, [1]) comes from hydrocarbons and mainly from reforming of methane. However, hydrogen has been seen as a mean for energy storage of renewable energy surplus since the 1920s [2]. It has recently drawn a lot of attention due to the rapid spreading of the renewable energy industry all around the world and due to the steady growth of the hydrogen fuel cells industry. Large scale hydrogen production from surplus of renewable energy sources is believed to help sector coupling in the energy-supply system with power-to-gas and power-to-fuel technologies [1]. Moreover, technologies running on hydrogen (applications in the transportation sector, energy production sector etc.) are expected be a significant part of the green energy transition.

Hydrogen is the most abundant element in the universe, making up for more than 90% of all known matter. It is also the simplest element, consisting of only one proton and one electron, making it the smallest and lightest element of the periodic table. Its small size and its properties make hydrogen difficult to store in large quantities. Typically, hydrogen is stored as hydrogen gas (H_2). Hydrogen is also a suitable storage medium owing to its high gravimetric energy density of 120 MJ/kg or 33.33 kWh/kg [3]. For a large-scale storage, hydrogen can serve valuably while batteries are more suitable for small scale storage. However, due to its molecule size, its volumetric energy density is comparatively low at 2.8-4.7 MJ/L or 0.78-1.31 kWh/L[4] when it is pressurized between 350-700 bar. At atmospheric pressure the energy density is only 0.012 MJ/L or 0.003 kWh/L and for this reason hydrogen must be pressurized for energy storage purposes. This low volumetric energy density has pushed the industry to develop different methods and technologies for small, medium, and large-scale hydrogen energy storage which will be explained in the following sections.

How can hydrogen be stored?

State-of-the art technology for hydrogen storage in bulk is observed in the form of hydrogen tanks. For instance, hydrogen is used mainly in chemical industries and specifically in steel making where the pressurized hydrogen stored in tanks is utilized. Caverns are useful for long-term large-scale storage. However, only a few caverns for hydrogen storage exist currently.

The most important hydrogen storage methods and technologies can be divided into two main categories: Physical-based and Material-based hydrogen storage, with each having different technologies as shown in Figure 13. Some of them are industrialized, reliable and proven over lengthy periods of time, while others are promising state-of-the-art experimental technologies.

Physical-based hydrogen storage

Physical-based hydrogen storage technologies include methods based on compression cooling or a combination of the two for storing the hydrogen into some form of vessels [7]. These vessels can be either man-made pressurized tanks and salt caverns or naturally occurring aquifers. The principle behind all the different forms of physical storage relies on storing compressed/cooled hydrogen in gaseous or liquid form in a vessel-like contraption.

In the case of hydrogen gas, it is being compressed and stored either at low pressure (up to 45 bar), at medium pressure (up to 500 bar) or at high pressure (up to 1,000 bar or even more) into hydrogen storage vessels. For the pressure ranges medium and high, there is a temperature gradient inside the vessel due to the heat of compression and the hydrogen may need to be cooled to prevent the failure of the materials of the vessels. This is typically observed in hydrogen fueling stations for hydrogen fuel cell cars. For hydrogen storage in the fueling stations, many low-pressure tanks operating at ambient temperatures are utilized. The hydrogen stored as such is then compressed to high pressure and stored in tanks. This pressurized hydrogen is used for fueling at cooler temperatures to reach the desired pressure levels [8]. The pressurized vessels or hydrogen tanks are usually made from seamless steel or composite wrapping with steel or polymer (plastic) liners. The materials of the hydrogen tanks are selected in accordance with application, tank complexity and cost. The cost usually rises in proportion to the nominal working pressure.

Other means of storing hydrogen gas is in caverns (underground storage). Underground storage can include salt caverns, exhausted oil and gas fields. Aquifers have also been investigated in this respect, but the uncertainty and cost of H_2 storage is a major drawback. These underground cavities provide enough space for large scale gaseous hydrogen storage as well as natural thick and low-permeation materials to surround the stored hydrogen. In present day, only a few locations in the USA and Europe are utilizing this type of hydrogen storage [7].

In the case of liquid hydrogen or cryogenic hydrogen storage, the hydrogen is liquefied at a temperature of -253^{o}C in cryogenic refrigeration plants and with high cost. The hydrogen tanks used in this case are heavily insulated special cryogenic tanks and are used mainly in space travel.

From the aforementioned technologies in the physical-based storage methods, compressed hydrogen storage in steel tanks is examined.

Underground hydrogen storage [[40]], [[41]]

Underground Hydrogen Storage (UHS) technology is a key solution for future energy systems, enabling the large-scale storage of hydrogen to balance the seasonal or long-term variability of intermittent renewable energy sources such as solar and wind power.

This is an industrial-scale storage method that makes use of natural or man-made geological structures at significant depths. There are four main methods:

- Storage in Lined rock cavern

Lined rock caverns (LRC) are an excavated subterranean chamber in hard rock formations sealed with a lining system. Lined rock caverns can be accommodated in a wide range of geological formations that are geographically widespread, but may be limited in spatial extent. This versatility allows storage in areas where other storage options are limited by geological factors. The storage capacity that may be held within a lined rock cavern may be 10's of GWh.

- Storage in Salt cavern

Hydrogen storage in salt caverns relies on leached cavities within salt beds or domes, where unique geological conditions provide natural tightness, mechanical stability, and strong resistance to chemical reactions. Owing to the substantial thickness of salt formations, this technology enables the construction of large-capacity storage facilities with frequent injection–withdrawal cycles, making it suitable for peak-shaving applications. Site selection depends on the geometry, depth, and composition of the salt layers, as well as potential leakage caused by interbedded non-salt layers or highly soluble potassium–magnesium salts. Although it requires significant water resources for leaching and brine disposal, construction costs are relatively low since all operations are conducted from the surface through a single, properly equipped well without the need for additional underground infrastructure.

- Storage in Aquifer

Hydrogen storage in deep aquifers is based on injecting gas into porous and permeable rock layers that are sealed by impermeable cap rocks above, similar to the structure of depleted oil and gas reservoirs. Two fundamental geological conditions must be met to establish an underground storage facility: (i) the selected reservoir rocks must have good storage properties, and (ii) they must be overlain by impermeable cap rocks to prevent the upward migration of stored gas. This technology requires detailed and costly geological investigations to evaluate site tightness and potential risks such as leakage, biochemical reactions, and interactions between hydrogen and reservoir minerals. Despite the high exploration cost, it remains a promising option in areas lacking depleted reservoirs or salt caverns, and is generally safe due to the absence of oxygen in the storage environment.

- Storage in depleted oil and gas deposits

Storage of hydrogen in depleted natural gas fields is the most common type of underground storage, taking advantage of geological traps whose integrity has been proven by the presence of natural gas over millions of years. These fields typically already have wells and surface infrastructure, significantly reducing the cost of conversion to hydrogen storage, although comprehensive geological, technical, and safety assessments are still required. Residual gas can serve as cushion gas, and operating at pressures higher than the original reservoir pressure allows greater storage capacity than the amount of natural gas originally present. In contrast, depleted oil fields are less suitable for hydrogen storage due to potential chemical reactions between hydrogen and residual oil, leading to irreversible losses.

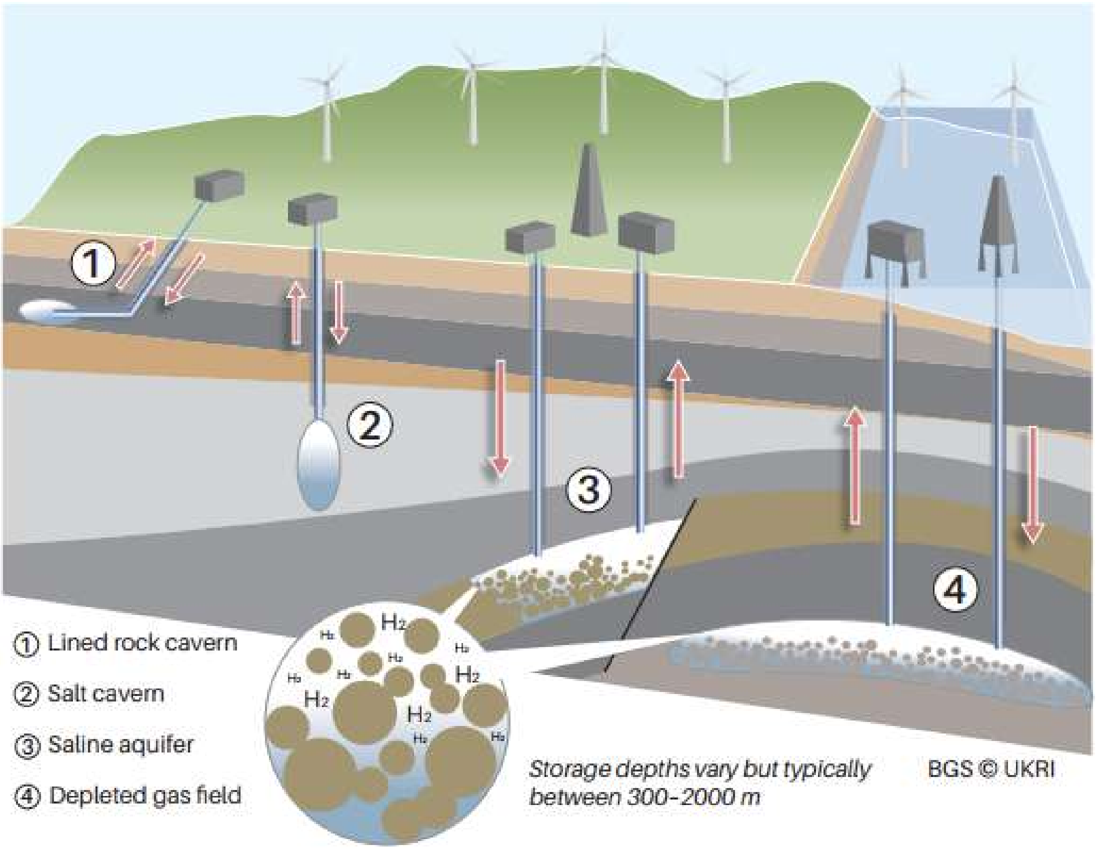

Figure 24: Types of geological structures considered for underground hydrogen storage.

Compressed hydrogen in pressurized storage tanks

Introduction

Pressurized hydrogen storage is the only storage method currently in use on a significant scale world-wide [11]. The technology and the materials of the hydrogen vessels have seen improvements as the demand of hydrogen storage is growing. However, hydrogen storage in pressurized tanks is a means of small and medium scale storage. Due to the limitations regarding material properties and operating costs, large scale storage on volumetric terms in pressurized tanks exceeding 200 bar at ambient temperature is not feasible, as the desired volumetric densities for a large scale storage cannot be achieved [12]. Nonetheless, there are technologies in development [13] that allow for a large scale pressurized hydrogen storage up to 40 g/L, but being the exception and not the rule of the industry, they were not examined in this report. For small and medium-scale pressurized hydrogen storage, there are many different pressurized tank technologies used for different purposes and applications. These tank technologies are described in this chapter. The technology, however, that is described more in detail in this chapter is the more frequently used medium-scale hydrogen storage tanks for short to medium term. This technology fits the purpose of storage of hydrogen in a sustainable energy sector, i.e. production and storage of hydrogen gas from renewable energy production in large-scale electrolysers.

Technology description

The purpose of a low, medium or high-pressure hydrogen tank is to be able to store as much hydrogen inside it as the volume containing the hydrogen as possible. There are three main problems when trying to compress and store hydrogen in a tank.

Firstly, the main concern is the integrity of the materials when subjected to high pressures and temperatures. The pressure tanks need to withstand pressures from 50 bar to 1000 bar for hydrogen storage, over many cycles where they are being filled and emptied. As a result, different materials are used to support the tank and make its mechanical strength higher. Moreover, due to the heat of compression [14], the temperature rises while compressing the hydrogen inside the tank. This causes the material of the tank to heat from inside out and be critically damaged if the temperature exceeds certain levels. For this reason, the hydrogen is pre-cooled in systems that use high-pressure hydrogen storage like in the automotive industry and in hydrogen fueling stations. Hydrogen is cooled prior to compression with two methods: either cooled-compression or cryo-compression. For cryo-compression, a temperature in the order of 50 K has been reported while for cooled compression the temperature of approximately 288 K is utilized. Cooled and cryo-compression are used for performing fast and high volumetric compression for automotive purposes [15]. Therefore, for hydrogen storage at ambient temperature (temperature without pre-cooling of hydrogen), as mentioned earlier, maximum 200 bar of pressure is used.

Secondly, the case of hydrogen embrittlement causes problems. Hydrogen embrittlement is the process in which metals like steel react with hydrogen, making them brittle and susceptible to cracking [16]. This is commonly observed in tanks with metallic liners and less in the ones with polymer liners. Hydrogen embrittlement happens over long periods of time and it is usually one of the main factors that determines the tank's lifetime from the manufacturer.

Thirdly, the phenomenon called hydrogen permeation can cause problems. Hydrogen permeation occurs when hydrogen molecules, due to their small size, tend to go through the walls or interstices of a container to its piping or interface material [14] and, in the case of pressurized tanks, this results in pressure drop inside the tank as well as a decrease of the mass and thereby the state of charge of the stored hydrogen in the tank. This is a more common problem for materials like polymers and less common for metallic materials.

Pressure tanks categories

To overcome the challenges of pressurized hydrogen storage, different materials are chosen for different purposes. Hydrogen pressure tanks are divided into 4 types [17] according to the materials they utilize: Type I, II, III and IV, as it is seen in Figure 25. The four different types of tanks have all undergone durability and safety tests which includes: 5500 cycle tests to 125% of nominal working pressure, drop test, surface damage and chemical exposure tests and a burst test at more than 180 % of nominal working pressure. Permeability test has also been performed to make sure the tanks does not exceed the safety limits for use in vehicles for personal transportation [18].

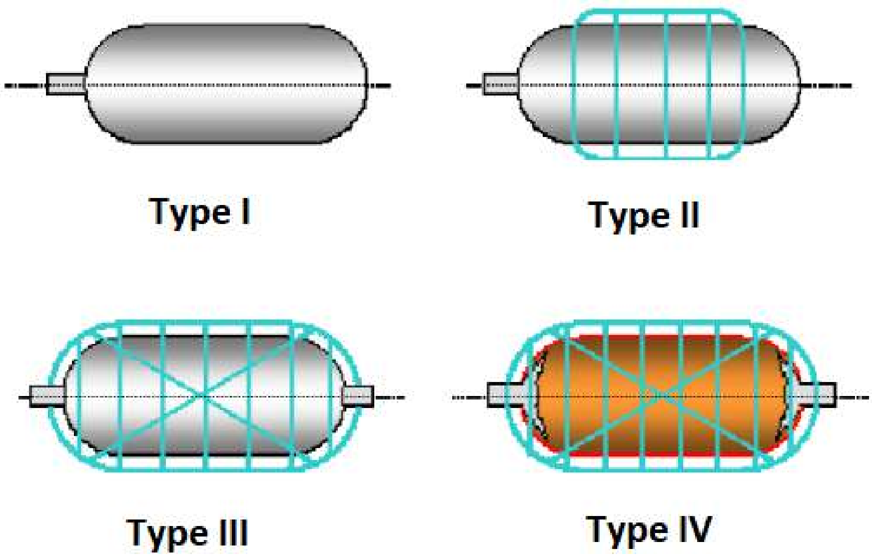

Figure 25: Schematic of different hydrogen pressure tank types [18]. The blue lines represent fibers used for wrapping, made of different materials depending on the tank type. More details in the text below.

Type I: These types of tanks are seamless steel or aluminum tanks. They are bulky and heavy with thick walls. They are designed for pressures up to 250 bar and are resistant to hydrogen permeation but not hydrogen embrittlement. They are commonly used as a cheap solution for stationary applications.

Type II: These types of tanks are seamless metallic (aluminum) tanks with filament windings like glass fiber/aramid or carbon fiber around the metallic cylinder. They are also heavy and are designed for pressures from 450 to 800 bar. They are cost competitive due to the relatively low amount of fibers used for the wrapping.

Type III: These types of tanks are made from seamless or welded aluminum liners fully wrapped with fiber resin composite. They are lighter and have thinner walls compared to Type I and II tanks. Their materials are also less susceptible to hydrogen embrittlement, and they are designed for pressures from 300 to 700 bar. They are more expensive due to the high number of fibers used for the wrapping.

Type IV: These types of tanks are the state of the art when it comes to high-pressure hydrogen tanks and are made completely from carbon fiber with a polymer (thermoplastic) liner. The carbon fiber wrapping provides enough strength to withstand pressures up to 1000 bar while the thermoplastic liner acts as a permeation barrier, however, it is less resistant to permeation than steel or aluminum. They are the lightest and the most expensive tanks today and are used (along with Type III tanks) mainly in the automotive industry for short term storage.

A collective overview table with the technical characteristics of each type of tank can be seen in Table below.

Table 11: Technical characteristics of pressurized hydrogen tanks

Type	Working Pressure (bar)	Materials	Usage	Permeation [mol/s/m/MPa$^{1/2}$]	Typical Storage Period [months]	Average cost [€/kg$_{H2\ stored}$]	Ref.
Type I	< 250	Seamless steel or aluminum	Stationary applications	2.84×10^{-27}	years	500	[19] [18]
Type II	450-800	Seamless steel/aluminum with filament windings like glass fiber/aramid or carbon fiber wrap	Stationary applications or short transportation (tube trucks)	2.84×10^{-27}	years	900	[20] [18]
Type III	300-700	Seamless or welded aluminum liners fully wrapped with fiber resin composite	Stationary and automotive applications. Used also in hydrogen fueling industry	2.84×10^{-27}	days to months	1,100	[21] [18]
Type IV	350-1000	Fully carbon fiber casing with a polymer (thermoplastic) liner	Automotive and other fuel cell applications (cars, trucks, drones etc.) but also short-medium term stationary storage (state of the art)	5.55×10^{-15}	days to months	1,200	[21] [18] [19]

Components in pressurized tanks storage systems

In this section, the components of a pressurized storage system are analyzed and described. In the industry, storage systems vary a lot depending on the application. Given this, it is difficult to select one type of storage system to investigate variables such as the type of the tank used, size of the tank, pressure class, compressor size etc., which are often customized for each application's purpose.

To describe a typical pressurized storage system for a stationary application, the following assumptions have been made:

- The system is a stationary storage system that is receiving hydrogen produced in low pressures (atmospheric or low-pressure output, typically the case for alkaline electrolysers). It should be noted that PEM already delivers H_2 at elevated pressure, typically 30 bars, and that systems at higher pressures are in R&D stage. It is worth mentioning that high pressure AEC is also on its way to the market currently.
- The system should be pressurizing the hydrogen gas for effective but also economic storage based in 2019 already existing and proven systems.
- Storage time is medium term as large-scale pressurized tanks hydrogen storage is not applicable nor feasible today.

Based on the above assumptions, an overview of a simple pressurized tanks storage system can be seen in Figure below.

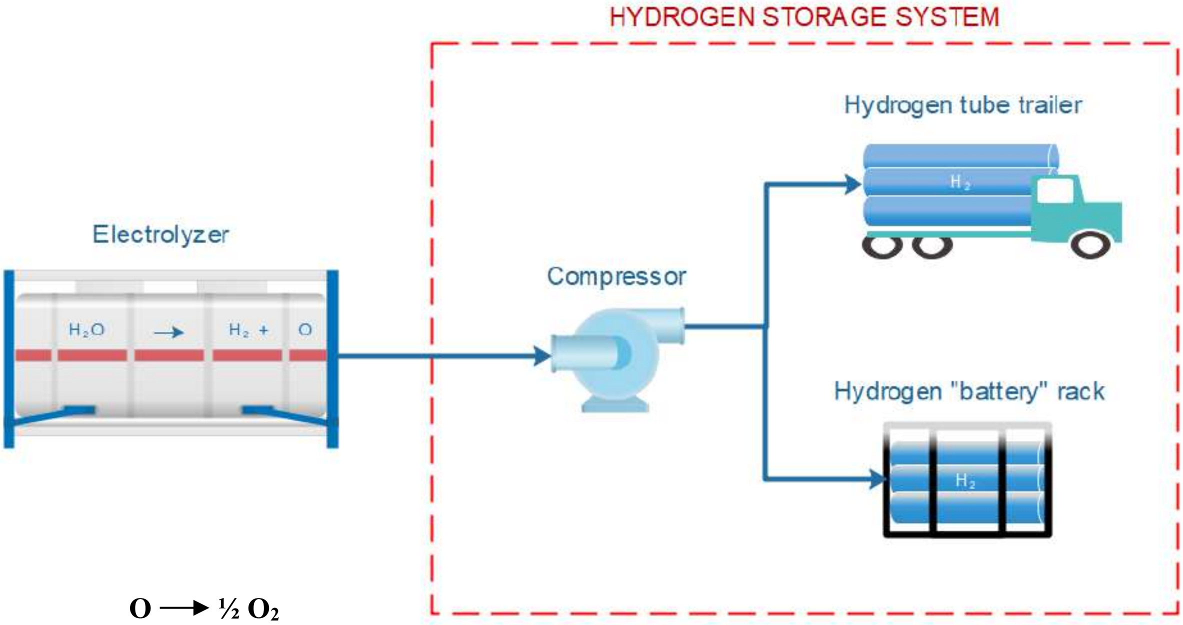

Figure 26: Typical pressurized tank storage system

Compressor. This system component is responsible for raising the pressure from the atmospheric (or low) pressure input to the desired pressure output in the pressurized tanks. It can include one compressor or many compressors in series, depending on the desired pressure output. Compressor sizes and specifications may vary according to the application, however, only a limited variety of compressors can work with hydrogen due to its molecular size and weight. The compressors energy requirement contributes a significant amount to the cost and the efficiency of the system as described in the subsequent "Energy efficiency and losses" section. The compressor that was used in the system that is analyzed in the data sheet is a typical 5-stage, 100 kW compressor that can compress 1 kg_{H2}/min at 200 bar with an energy consumption of 4 kWh/$kg_{H2\ compressed}$ [19], [22].

Type I or II tanks. The type of tanks that can be chosen for such a system are either Type I steel tanks or Type II steel tanks with partial composite wrapping. These tanks are most suitable for low-pressure stationary hydrogen storage due to their durability, low permeation characteristics and low cost. The industry uses both tank technologies for stationary applications, with Type II tanks providing relatively higher-pressure range and more hydrogen capacity than Type I with less steel, albeit at higher costs. An image of Type I & II tanks can be seen in figure below.

Figure 27: (left) Type I steel cylinder, (right) Type II steel cylinder with composite wrap [23]

These tanks are either placed on hydrogen tube trailers for transportation purposes or in racks called hydrogen batteries, for stationary storage and usage. A picture of both the systems can be seen in Figure 24. For the specific system analyzed in the data sheet, 15 Type I tanks in a hydrogen battery rack, operating at 200 bar with a collective storage capacity of 500 kg_{H2} are seen.

Figure 28: (left) Hydrogen storage of Type I steel tanks, (right) Hydrogen tube truck with Type I steels tanks [24], [25]

Input/output

The input and the output of the pressurized hydrogen tanks of all types is hydrogen gas and energy for its compression, respectively. Hydrogen is generated from electrolysis or steam reforming of hydrogen rich hydrocarbons (mainly from methane by 'SMR', Steam Methane Reforming) and then compressed by compressors into the storage tanks. The hydrogen can be retrieved when needed usually, to produce electric power through fuel cells.

Energy balance

The losses for a pressurized hydrogen tank can be divided into operational losses and standby losses. Furthermore, the energy efficiency is described. It should be mentioned that unlike a battery storage system, in which energy storage and energy conversion are within the same system/medium, pressurized hydrogen storage system only stores the energy. The energy conversion is done by electrolysis for producing hydrogen from electricity produced by renewable energy sources such as wind and solar, and a fuel cell system, for instance, can thereafter be utilized to generate electricity after storing the hydrogen. Hence, only the efficiency for storing the hydrogen is considered in this technology catalogue. Comparing different energy storage technologies, one needs to take the complete round-trip-efficiency into account from electricity to electricity or from energy source to energy end use.

Operational losses

The operational losses of pressurized hydrogen tanks are affiliated primarily with the energy losses of the compression and secondarily with energy losses caused by the pressure losses in the valves and tubes during filling and retrieving of gas. Energy losses associated with pressure losses in a complex system as in i.e. a hydrogen fueling station system operating in 900+ bar of pressures are summing up a total of <5% with the majority of them happening in components that connect the station and the car [8]. Based on this, it is safe to assume that in a simple system like the one described in the "Components in pressurized tanks storage systems" section, where operating pressures are up to 200 bar, there are no heat exchangers etc., the pressure losses due to valves, tubing etc. are <1% and therefore negligible.

Standby losses

The standby losses mainly occur due to hydrogen permeation. Type I, II and III tanks have metallic casing or liner, and therefore have almost negligible permeability. Type IV tanks, however, have higher permeability because of their polymer liner. For reference, aluminum permeability is 2.84×10^{-27} mol/s/m/ $MPa^{1/2}$ at ambient temperature and a polymer like Noryl™ has a permeability of 5.55×10^{-15} mol/s/m/$MPa^{1/2}$ at ambient temperature which is 12 orders of magnitude larger [18]. For the system under study, the usage of Type I steel tanks makes these standby losses negligible.

Energy efficiency

Energy efficiency or roundtrip efficiency of the hydrogen storage system described is given by Equation (1).

$$\eta_{roundtrip} = \frac{E_{hydrogen\ out}}{E_{hydrogen\ in}+E_{compression}+E_{permeated\ hydrogen}} \times 100\% \qquad (1)$$

The roundtrip efficiency of the storage system assumes that the electricity for the compression can be translated into a 1:1 loss in the energy content of the hydrogen.

For such a system, the $E_{hydrogen\ out}$ of the system is its capacity of 500 kg multiplied by 33.33 kWh/kg, similar to the amount of $E_{hydrogen\ in}$. The energy consumed by the compressor for the compression of 1 kg to 200 bar is approximately 4 kWh/kg [19], [22]. The energy losses due to permeation and pressure losses are negligible. In the calculations however, a collective 1% will be assigned to them to indicate a margin of error and uncertainty. Given this, the Equation (1) can be calculated as follows:

$$\eta_{roundtrip} = \frac{16.67\text{MWh}}{16.67\text{MWh}+2\text{MWh}+\sim 0+\sim 0} \times 100\% \qquad = 89\% - 1\%_{perm.\&press.} = 88\%$$

Typical capacities

Pressure tanks come in various sizes, depending on the application. A summary with some typical characteristic capacities can be seen in Table below.

Table 12: Characteristics of pressurized hydrogen tanks

Manufacturer	Type	Diameter (cm)	Length (cm)	Tank weight (kg)	Water volume (L)	Nominal working pressure (bar)	Hydrogen capacity (kg)	Purpose
Doosan mobility [26]	IV	22.5	56.5	4.3	10.8	350	0.28	Fuel cell drone
Hexagon [27]	IV	44.0	105.0	59	76	700	3.1	Automotive
Mahytec [28]	IV	49.0	307	260	300	500	9.5	Fueling stations, transportation
Hexagon	IV	65.3	441.9	267	1,170	250	21	Fueling stations
SteelHead [29]	III	43.5	261.6	178	270	350	6.2	Automotive
FIBAtech [30]	II	55.9	290	1,082	213	930	10	Fueling stations
FIBAtech [31]	I	55.9	1,100	2,740	2,254	200	33	Fueling stations, Transportation

Typical storage period

Hydrogen can be stored in compressed hydrogen tanks practically indefinitely [19]. The exact amount of storage time comes down to the materials of the tanks and how susceptible they are to hydrogen permeation and embrittlement. Hydrogen tanks have a lifetime expectancy that is determined from the manufacturer, and when this time expires the tank needs to be replaced as there is no guarantee for storing hydrogen safely without any leakages any longer.

For example, there is no significant pressure drop in steel tanks (that would indicate leaks) in laboratories even after 3 years of dormancy. It is important to note that a long-term hydrogen storage in pressurized tanks is always performed in ambient temperature. If a cooled compression in a tank is followed by an exposure for a long term in ambient temperature, a pressure drop along with the lowering of the volumetric density will be observed. Gaseous hydrogen, if not in use in a laboratory environment, tends to be used relatively fast after its production. Existing hydrogen fueling stations for example replenish their bulk hydrogen stock via on-site hydrogen electrolysis or with hydrogen tube truck delivery. This bulk hydrogen supply can be stored in ambient temperatures and up to 200 bar of pressure for months, even years. Inspection of the low-pressure steel tanks is done once a year to ensure the safe usage of these tanks.

Advantages/disadvantages

Storing hydrogen in pressurized hydrogen tanks can have advantages and disadvantages which are described briefly in this section.

Advantages

1. Long-term energy storage: Depending on the materials of the tank, hydrogen can be stored for relatively long periods of time without losing significant energy content (see section "Typical storage period").
2. Widespread and proven technology: As it was mentioned, it is the only technology that is used in any significant scale for hydrogen storage to date [11].
3. Cost-efficient in comparison with other industrialized storage methods: The materials of the tanks, especially when composite support is not used significantly (i.e., Type I&II tanks), are the most cost-efficient leading to a decrease in storage costs.

Disadvantages

1. Not easily transportable in large quantities. To store and transport large amounts of hydrogen gas today means that trucks carrying pressure tanks must be employed. The cost of this procedure and the relatively small amount of hydrogen transported at a time inhibits the transportation of hydrogen gas in large quantities over large distances.
2. Cost of materials and compression. Even though compressed hydrogen storage is the most cost-effective storage method today, the costs of materials of high-pressure tanks as well as the energy input to compress hydrogen to store it in significant quantities is still an issue.
3. Safety issues. Hydrogen is an explosive gas when in contact with air in significant concentrations i.e., 4% (LEL) and 59% (UEL). Therefore, extreme caution should be exercised when handling high pressure hydrogen storage systems.

Space requirements

A typical low-pressure stationary hydrogen storage system has a footprint that is summarized in table below.

Table 13: Storage system space requirements

System component	Length [m]	Width [m]	Height [m]	H_2 Capacity [kg]	Footprint [m²]	Ref.
Compressor	3.5	2	2.5	-	7	[19], [32]
Hydrogen battery	12.3	2.4	~ 2	500	29.5	[33]
Overall system	15.8	4.4	2.5	500	~ 40 - 50 (including piping, power electronics)	

Water consumption

In contrast to other energy storage technologies, hydrogen storage systems have a relatively straightforward relationship with water consumption. Water is primarily used in the production of hydrogen, particularly in electrolysis processes where water is split into hydrogen and oxygen. However, in the context of hydrogen storage itself, water consumption is minimal.

Similar to vanadium redox flow batteries, water losses in hydrogen storage systems are mainly associated with secondary effects such as humidification of the storage environment, cooling systems, and maintenance activities. These losses are typically small and can be managed through efficient system design and operation.

It's worth noting that the water consumption associated with hydrogen production can vary greatly depending on the production method, with electrolysis being one of the most water-intensive methods. However, once the hydrogen is produced, the storage and utilization of hydrogen have a relatively low water footprint. As a result, hydrogen storage systems can be considered a water-efficient option for energy storage, especially when compared to other technologies such as pumped hydro storage, which requires significant water resources for reservoirs, or thermoelectric power plants, which often rely on water cooling systems. In contrast, hydrogen storage systems offer a more water-conservative approach, making them an attractive option for regions where water scarcity is a concern.

Environment

Hydrogen gas itself does not pose any significant environmental threats as its large-scale use is still in its infancy. When larger amounts of gaseous hydrogen are used then, its potential accumulated leakage towards the atmosphere could speed up the ozone layer destruction faster than conventional pollutants. This is, however, an assumption of scientists that is based on the widespread use of hydrogen as a fuel and the environmental impact would still be very depending on the human factor [34].

Safety

Hydrogen is flammable and explosive when mixed with air within a certain concentration interval, like all the other combustible fuels. The flammability range is from 4% to 75% hydrogen in air. The premise for fire or explosion is that there is air presents with hydrogen, which is not the case during operation as the hydrogen system is closed. Another risk specifically related to handling high pressure hydrogen is the pressure burst which can occur under high pressure if a component malfunctions. When handling hydrogen, a lot of safety equipment must be installed in order to shut down the system if it detects hydrogen leakages. Hydrogen storage vessels has undergone a large test for both lifecycle performance, overpressure and collision/drop tests to secure the use of them in vehicles and for storage, as described in the section "pressure tank categories". Typically, hydrogen storage vessels would be installed in open air and a leak would only become dangerous if an ignition occurs, otherwise the leak would empty the system into the atmosphere. Even if the leak is ignited, it would burn in a straight flame upwards as hydrogens is lighter than air. The worst-case scenario is a pressure burst followed by an explosion or fire. In this context, it is worth mentioning the incident which took place at a hydrogen filling station in Kjørbo, Norway in 2019. An explosion was caused due to an error in assembling a plug in a hydrogen storage tank, which was a part of the high-pressure storage unit. This led to hydrogen leakage which thereafter reacted with air causing ignition. Additionally, the leak was in large quantity which may have resulted in ignition scenarios due to the fact that the failsafe did not respond as it was supposed to [35].

Research and development

Type IV tanks are the cutting edge, impactful technology for medium-high pressure short- and medium-term storage technology for pressurized hydrogen. The materials and technology used in this type of tanks are subject of research and development within the industry as it is the most promising for applications that use portable hydrogen storage (automotive industry). A schematic of the Type IV tank components can be seen in Figure 29.

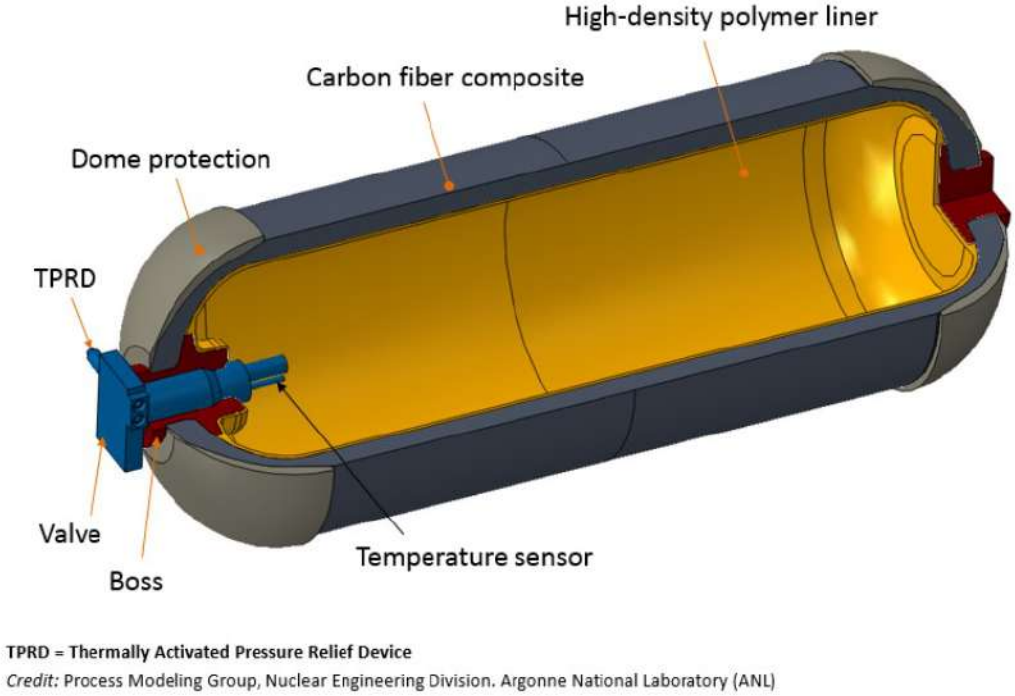

Figure 29: Components of a Type IV hydrogen pressure tank [36]

The components of the Type IV tank contain:

- Carbon fiber composite wrapping, which provides the shell of the tank with the necessary mechanical strength to withstand the high pressures of the compressed hydrogen.
- High-density polymer liner, which serves as a gas diffusion barrier and prevents hydrogen permeation through it.
- Dome protection, usually from foam for resistance from impact, usually used in the automotive industry. Some Type IV tanks do not use this foam dome.
- Temperature sensor, close to the inlet of the hydrogen for monitoring the temperature development during filling and unloading of hydrogen gas.
- Valve and boss (protruding feature on a workpiece) for filling and retrieving hydrogen from the tank.
- Pressure relief device that also can be thermally activated, to control and limit the pressure of the tank.

Other technologies such as multifunctional layered stationary hydrogen storage vessels are being developed in an effort to maximize the hydrogen stored and minimize the cost of the materials [37].

In general, pressurized tanks manufacturing companies are investing in optimizing their products to achieve lightweight and low-cost bulk transportation high pressure gaseous hydrogen vessels. This is done mainly by improving the durability of components in contact with high pressure hydrogen while ensuring operational safety. However, due to the nature of this physical storage method, radical improvements are not foreseen for the short-term future as they are dependent mainly on the materials used which are unchanged for many years.

Considering the pressurized hydrogen storage as a system, there is currently research on manufacturing specialized hydrogen compressors to optimize the compression characteristics and increase the mass flow rate for hydrogen [38]. Special hydrogen compressors are not commonplace yet. However, Linde has recently developed a ionic-liquid compressor aimed at hydrogen fueling stations [39]. Nevertheless, expensive high-power piston-compressors are utilized for compressing hydrogen gas to the desired pressures for storage.

Examples of current projects

The gas industry currently uses a high variety of pressurized tanks for hydrogen storage, depending in the applications that hydrogen is used for. In Table 14, a list of examples of various uses of hydrogen tanks and their purpose is presented.

Table 14: Examples of market standard technology and applications

Image	Location	Usage	Year	Specs.	Technology provider	Ref.
	Elancourt, France	Stationary storage of energy used in tele-communication application.	2016	3x850L@30bar Type IV tanks, 7 kgH_2	MAHYTEC	[40]
	HyBalance Hobro, Denmark	Stationary and transport ready storage of hydrogen from electrolyser output.	2018	18 Type IV tanks @450 bar, 500 kgH_2	Air Liquide	[41]
	Denver, USA	Stationary storage for hydrogen fueling station for research purposes.	2016	Multiple Type I tanks @ 200 bar + Type II tanks @850 bar, 310 kgH_2	Air Products	[42]

Investment cost estimation

For the cost of the tanks themselves, it is highly dependent on the upscaling of the hydrogen storage industry. For Type I tanks where the only variable of their cost is the amount of steel used and its cost development in the next years. Projections from the hydrogen industry state that costs of Type I tanks can fall to half of the current price by 2050 [19]. The rest of the tank types will follow a similar trend according to their area of implementation in the hydrogen storage industry with Type IV to have significant cost reductions due to their increasing demand from the automotive industry. Type IV cost targets from DOE are see in Table 15.

The compressors used in the storage system are projected to have a significant performance in technology, maybe even change the existing technology altogether. Today's compressor technology is projected to increase in performance around 20% over the next 30 years, as an estimate. The costs of the compressors for compressed hydrogen storage however, depending on the industry's growth, can go down to half even one-fourth of today's costs.

Table 15: Technical System Targets: Onboard Hydrogen Storage for Light-Duty Fuel Cell Vehicles by DOE [43]

Storage Parameter	Units	2020	2025	Ultimate
Usable, specific energy from H_2 (net useful energy/max system mass)	kWh/kg (kg H_2/kg system)	1.5 (0.045)	1.8 (0.055)	2.2 (0.065)
Usable energy density from H_2 (net useful energy/max system volume)	kWh/L (kg H_2/L system)	1.0 (0.030)	1.3 (0.040)	1.7 (0.050)
Storage system cost	$/kWh net ($/kg H_2)	10 (333)	9 (300)	8 (266)

The cost data of the hydrogen storage system described in the "Components in pressurized tanks storage systems" section was retrieved either from manufacturers, or from companies running such or similar systems. The average cost of individual components is described in Table below:

Table 16: Cost of individual components for Hydrogen storage system

System component	Average Cost [€/unit]	Average Operational Cost [€/year]	Lifetime [years]	Ref.
Compressor	500,000	6,000	25	[19], [32]
Hydrogen battery	600 €/kg	1.250	25	[33]
Piping, power electronics, man-hours	~150,000/system	~1,000/system	25	[19]
Overall system for 500kg$_{H2}$	950,000	8,250	25	

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The description in this chapter is to a great extent based on the Danish Technology Catalogue *"Technology data catalogue for Energy Storage".*

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Data sheet

The following page contains the data sheet of the technology. All costs are stated in U.S. dollars (USD), price year 2025. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency does not have the lower price or vice versa.

Pressurized hydrogen gas storage system (Compressor & Type I tanks @ 200bar)											
Parameter	**Unit**	**2025**	**2030**	**2040**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
						Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data											
Energy storage capacity for one unit	MWh	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7		1
Output capacity for one unit	MW	-	-	-	-	-	-	-	-	A	
Input capacity for one unit	MW	0	0	0	0	0.1	0.99	0	0	B	1, 2
Round trip efficiency	%	88	89	90	90	88	88	90	90	C	1
- Charge efficiency	%	88	89	90	90	88	88	90	90	D	
- Discharge efficiency	%	~100	~100	~100	~100	~100	~100	~100	~100	E	
Energy losses during storage	% / period	<1	<1	<1	<1	<1	<1	<1	<1	F	
Auxiliary electricity consumption (only for heat and gas storage)	% of output	<1	<1	<1	<1	<1	<1	<1	<1	J	
Forced outage	%	0	0	0	0	0	0	0	0	I	
Planned outage	weeks per year	3	2	1.5	1	3	3	1.5	0.5	G	3
Technical lifetime	years	25	30	30	30	25	25	30	30		
Construction time	years	0.5	0.4	0.4	0.3	0.5	0.5	0.3	0.2		3
Regulation ability (Only for electricity storage)											
Primary regulation	% per 30 sec	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	H	3
Secondary regulation	% per minute	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	H	3
Economic data											
Specific investment	MUSD/MWh	0.085	0.067	0.040	0.031	0.085	0.085	0.053	0.031		1
Compressor component	MUSDMWh	0.045	0.034	0.017	0.011	0.045	0.045	0.022	0.011		1
Type I tanks component	MUSD/MWh	0.027	0.022	0.015	0.013	0.027	0.027	0.020	0.013		1
Installation, equipment, manhours	MUSD/MWh	0.013	0.011	0.009	0.007	0.013	0.013	0.010	0.007		1
Fixed O&M	USD/MW/year	895	746	746	597	895	895	672	448		1
Variable O&M	USD/MWh	-	-	-	-	-	-	-	-		
Technology specific data											
Gravimetric energy density	kWh/kg	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3		
Volumetric energy density @0ºC and 1atm pressure	kWh/m^3	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09		
Permeation characteristics for Type I tanks	$mol/s/m/Mpa^{1/2}$	$2,84\times 10^{-27}$	$2,84\times 10^{-27}$	$2,84\times 10^{-27}$	$2,84\times 10^{-27}$	$2,84\times 10^{-27}$	$2,84\times 10^{-27}$	$2,84\times 10^{-27}$	$2,84\times 10^{-27}$		3
Water consumption	L/MWh	0	0	0	0	-	-	-	-		

Notes:

A Cannot be defined since there is no conversion of hydrogen back to electricity in the form of a fuel cell in the system

B The only power input that is considered is the input for the compressor and does not include power needs for the electrolyser that is making the hydrogen as described in the system definition. Compressor power input decrease of 5% every 10 years

C Calculated in the "Energy Efficiency" section. Compressor efficiency linearly improved by 20% until 2050.

D The charge efficiency is practically the round-trip efficiency itself as there are almost no losses in the discharge process (See note E)

E Almost no losses during discharge as it is a physical discharge for a pressurized gas from a valve.

F Permeation characteristics are negligible for Type I tanks, see also Technology specific data.

G System O&M includes maintenance of the compressor and periodic check of the tanks integrity.

H System complies with the frequency regulation requirements from Energinet

I No hydrogen storage systems are known to have time of forced outage.

J Compressor consumption is not considered auxiliary. Rest of losses that can be translated into energy losses and consequently more electricity consumption are negligible.

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5. COMPRESSED AIR ENERGY STORAGE

Brief technology description

Compression/expansion

Compressed Air Energy Storage (CAES) is a way of storing electrical energy mechanically and thus the input is electricity to drive a compression. In the most basic form of CAES electrical energy is used to compress air, which can subsequently be stored in pressure tanks or in huge amounts in underground formations, where such suitable formations are available. When release of the stored energy is required, the compressed air is used to drive a turbine able to generate electricity. The expansion of air is associated with a temperature drop.

When air is compressed, heat is released and constitutes a loss of energy during the storage operation because it dissipates to the external environment. However, if the heat may be stored intermediately (e.g. sensibly in ceramic material), the heat may be reinjected during the expansion process and thus it is not lost. This has an impact on the overall efficiency (electricity to electricity). This form of CAES is usually called Adiabatic CAES, A-CAES (or sometimes Advanced Adiabatic CAES, AA-CAES) because of the lack of exchange of heat between the storage system and the external environment. Additional forms of CAES have been proposed, such as isothermal CAES. For these additional forms of CAES there are currently no commercial installations, so only CAES and AA-CAES will be considered here.

Presently CAES technology is used in combination with gas turbine combustion, which can be said to compensate for the temperature drop. Therefore, CO_2 is released in traditional CAES.

Although the concept of CAES has been considered favorable for energy storage for many years for storing variable and renewable energy, only two plants have been realized until now, the first in Huntorf, Germany, in 1978 and the second in McIntosh, Alabama, USA, in 1991. Interestingly, the Huntorf storage facility was constructed to balance nuclear power so that the nuclear generation could be run in an optimal way and the CAES facility could handle the differences between production and demand for electricity. None of the realized facilities are based on A-CAES, but only on CAES, meaning that the round-trip efficiencies are relatively low. Both plants have been operated with use of natural gas turbines to compensate for the lost heat (cf. above).

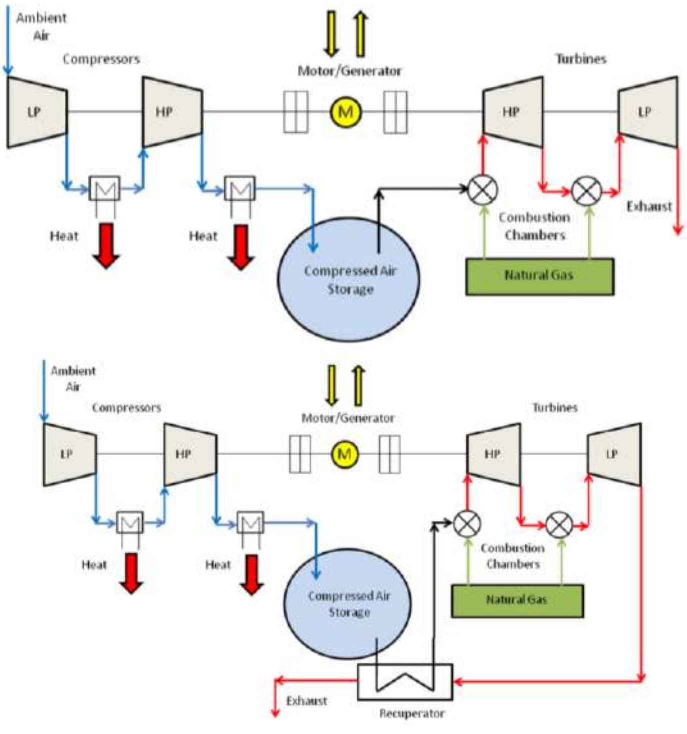

Figure 30: Operating principle of the CAES plant Huntorf (left) and the McIntosh (right) [1]

Several excellent and more exhaustive technical descriptions of Compressed Air Energy Storage (CAES) and Adiabatic Compressed Air Energy Storage (A-CAES) are available in literature. Figure 30 illustrates a plant diagram of two different CAES plants.

Table 17 gives key data for the same two plants. The Huntorf plant uses 0.8 kWh of electricity and 1.6 kWh of gas to produce 1 kWh of electricity. It was the world's first CAES plant when it was commissioned in 1978 [2]. The newer McIntosh plant includes a recuperator which recycles waste heat from the exhaust stream and uses 0.69 kWh of electricity and 1.17 kWh of gas to produce 1 kWh of electricity [2].

For A-CAES (a technology, which has not yet been realized) storage of heat has been proposed in ceramic materials like rocks or bricks at elevated temperatures (say 600 °C). It is questionable how many traditional CAES plants will be built in the future. Many optimistic studies have been performed - particularly in the US - during the past 25 years, however it remains a fact that none have been built.

Table 17: Data for the Huntorf and the McIntosh traditional CAES plants [3].

Type	Simple CAES process, two-stage NG combustors	2nd generation CAES, recuperator, two-stage NG combustors
Location	Huntorf, Niedersachsen	McIntosh, Alabama
Commissioning	1978	1991
Turbine power	320 MW_{el}	110 MW_{el}
Generation capacity	~ 1 GWh	2.6 GWh
Thermal round trip efficiency	~ 42 %	~ 52 %
Specific cost	320 DM/kW_{el}	591 USD/kW_{el}
Turbine start-up time	> 9 in.	14 min.t

Air storage volumes

CAES depends completely on a connection to suitable storage volumes. Small units may utilize high pressure gas cylinders (surface level), but to allow for large amounts of energy (hundreds of MWh) CAES is usually planned and established in connection with large underground formations able to hold significant amounts of compressed air. Such formations could be depleted oil or gas fields, aquifers, salt caverns, lined rock caverns and abandoned mines [4]. An illustration of some of the storage principles is shown in Figure below.

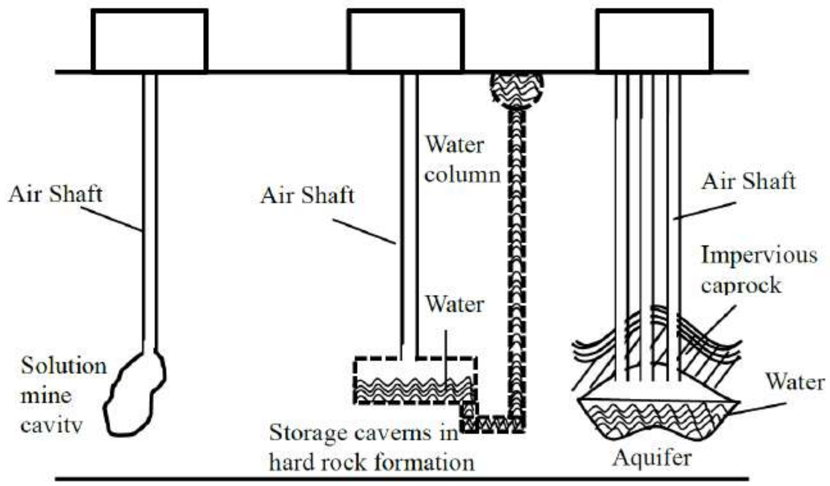

Figure 31: Various Geological Formations for Underground Storage [5]

The two existing CAES plants are connected to solution-mined caverns in salt domes. Such caverns are relatively cheaply, and easily developed and suitable salt deposits are found in many places all over the world. However, the preparation of caverns may be restricted due to potential environmental issues and political opposition. Kieu at al. have developed a study in Cuu Long Basin to assess the potential of underground energy storage in Viet Nam (Figure 32) [24]. The result of the study points to two formations of

Dong Nai and Bien Dong as possible candidates for underground storage in Viet Nam. The two sedimentary units are two porous reservoirs that contains sandstone layers, which make them favorable for reservoir storage [24].

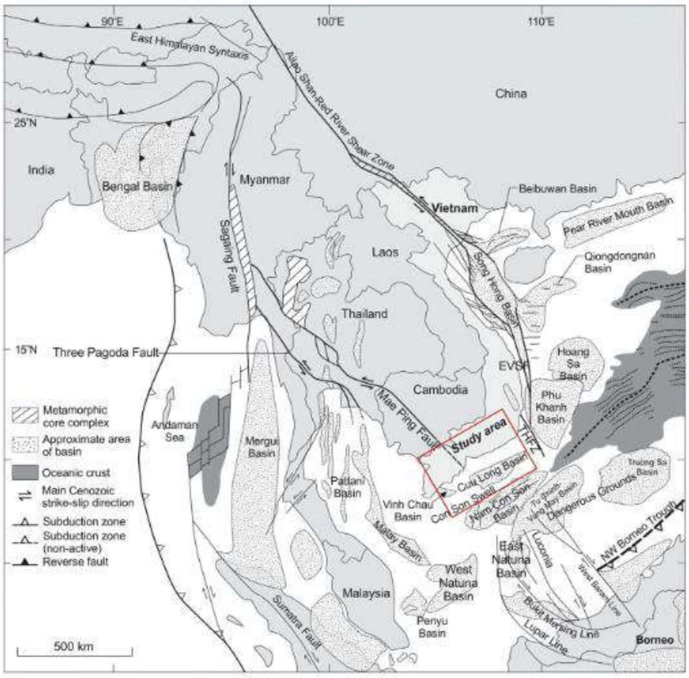

Figure 32: Major structural characteristics for the greater Indo-China area, including the study area [24].

Input/Output

The input for CAES is electricity. For traditional CAES input of some fuel (usually natural gas) is required in the electricity output phase. For Adiabatic Compressed Air Energy Storage fuel is not required (see below). The output for CAES is electricity. Traditional CAES also generates heat in the compression phase, whereas A-CAES stores this heat and thus does not generate heat to the external environment.

Energy balance

Figure 33 illustrates details of the energy lost by using CAES in the compression stage and in the expansion stage. The numbers which can be derived are a charging efficiency of about 80 % and a discharge efficiency of about 70 %, leading to a round cycle efficiency of approx. 55 % (electricity to electricity). However, input of chemical fuel in this calculation complicates the calculation since the electricity that could have been produced from the fuel should be subtracted. Setting the electrical efficiency of chemical fuel to 35 % the output efficiency in Figure 33 would be 44 % leading to a round cycle efficiency of 44 %.

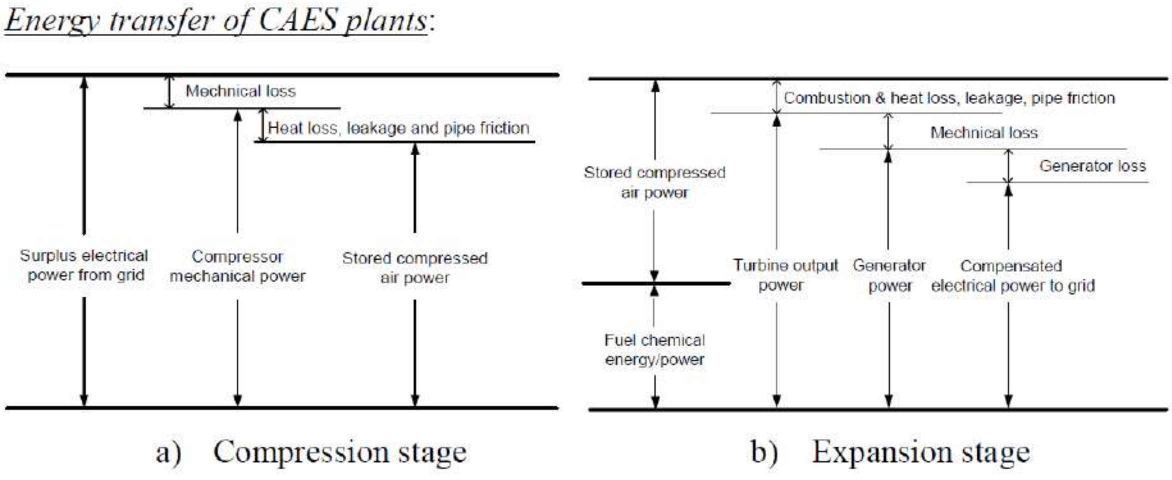

Figure 33: Energy transfer of a conventional CAES plant [7]. The source does not quote numbers but only graphics.

Ramping configuration

Startup times of about 10 minutes are described in the literature for CAES [8]. This allows several ancillary services and thus both black starts, secondary reserves and reactive power system services are possible. Furthermore, the technology is perfectly suited for load shifting (the original purpose of the Huntorf plant) within the limits of available storage and power capacity.

Typical capacities

As mentioned above only two CAES plants have been realized until now and consequently it does not really make sense to state typical performance characteristics and capacities. The characteristics of the two existing plants can be seen in table below.

Table 18: Supplementary descriptive data for the Huntorf and McIntosh facilities. The indicated heat rates (thermal energy in over electrical energy out) can be recalculated to 1.96 kWh/kWh for Huntorf and 1.20 kWh/kWh for McIntosh [9].

	Huntorf 1978, Germany 	**McIntosh 1991, USA** 
Turbine Power / Discharge time	Old 290 MW / 2h New 320 MW / 3h	110 MW / 24h
Compression Power / Charging time	60 MW / 8h	50 MW / 38h
Power ratio	0.19	0.45
Charge / Discharge time Ration	2.7	1.6
Cavern Pressure	46 – 72 bara	45 – 74 bara
Efficiency Heat Rate	42% 6700 BTU/kWh (without heat recuperator)	54% 4100 BTU/kWh (with heat recuperator)
Availability	> 90%	> 90%
Reliability	> 97%	> 97%
Start-up reliability	> 95%	> 95%
Cavern	2 x 150 000 m^3 (Salt Cavern)	538 000 m^3 (Salt Cavern)

As can be seen the CAES plants have been built for up to 50-60 MW charging power and 100-300 MW discharging power.

Based on the numbers shown in the above table the energy storage capacities of the plants are 480 MWh for Huntorf and 1,900 MWh for McIntosh.

The energy density of compressed air naturally depends on the pressure difference between upper and lower limit of the pressure variation. For the Huntorf facility the energy density is approximately 0.3 kWh/m^3. For the McIntosh the number is about the same since the same pressure range is used. However, the energy densities (kWh/m^3 and kWh/kg) associated with CAES is not considered relevant, one reason being that the technology is stationary.

It is interesting to note that both plants are utilizing salt domes as storage facility for the compressed air. Other proposed storage facilities are abandoned mines and aquifers, but these types have not yet been realized.

Typical storage period

The practical span of storage periods for CAES can be estimated from Figure 34 showing the number of starts per year for the Huntorf plant in the period from 1978 to 2000. In course numbers, the numbers of starts vary in the range 50-200 with outliers up to 400 and down to about 25. This shows that practical storage periods range between hours and days. However, these storage periods reflect the facility's actual use pattern rather than the capability. Since air is stored in underground caverns in salt domes, which are very tight (cf. use of salt caverns for natural gas) the air can be stored for much longer time if desired. The levelized cost of energy storage will increase if longer time periods are applied, but it can easily be done.

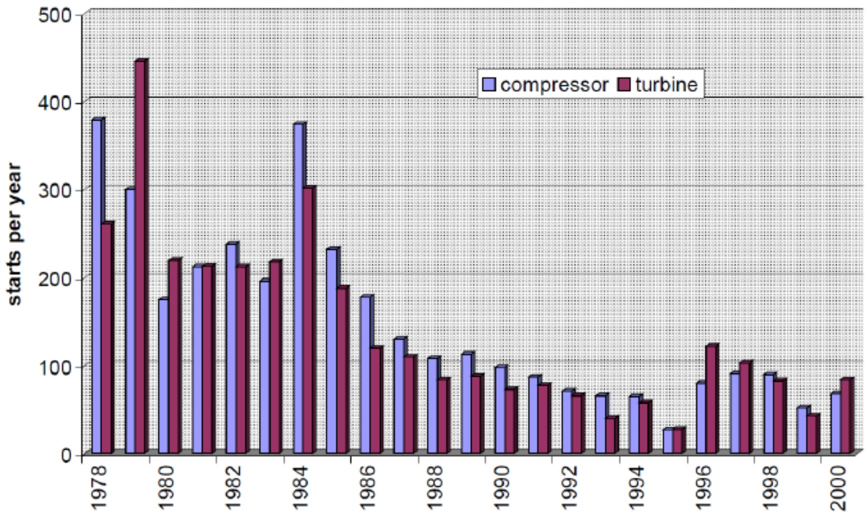

Figure 34: Number of compressor starts (charges) and turbine starts (discharges) for the Huntorf facility for the period between 1978 and 2000 [10].

Advantages/disadvantages

Advantages:

The following advantages are cited from [8]:

- The CAES plant can provide significant energy storage (in the thousands of MWh) at relatively low costs (approximately \$400/kW$_{ac}$ to \$500/kW$_{ac}$ in 2003USD). The plant has practically unlimited flexibility for providing significant load management at the utility or regional levels.
- Expanders have a large size range. Commercial turboexpander units range in size from 10-20 MW$_{ac}$ (Rolls Royce-Allison) to 135 MW$_{ac}$ (Dresser-Rand) to 300-400 MW$_{ac}$ (Alstom).
- The CAES technology can be easily optimized for specific site conditions and economics.
- CAES plants are capable of black start. Both the Huntorf and McIntosh plants have black start capability that is occasionally required.
- CAES plants have fast startup time. If a CAES plant is operated as a hot spinning reserve, it can reach the maximum capacity within a few minutes. The emergency startup times from cold conditions at the Huntorf and McIntosh plants are about 5 minutes. Their normal startup times are about 10 to 12 minutes.
- CAES plants have a ramp rate of about 30 % of maximum load per minute.
- A CAES plant can (and does) operate as a synchronous condenser when both clutches are opened (disconnecting the motor-generator from both the compressor train and the expander train), and the motor-generator is synchronized to the grid. Reactive power can be injected and withdrawn from the grid by modulating the exciter voltages. Both the Huntorf and the McIntosh plant are used in this manner. Since this operation does not require the use of stored air, the plant operator can choose to operate the plant in this mode for as long as necessary.

Disadvantages:

- For traditional CAES the use of natural gas implies CO_2 emissions. However, for A-CAES there is no use of chemicals and no exhausts.

- Geographical placement is limited to places, where high pressure air can be stored in sufficient amount. Several geological underground formations are suitable, but the restriction puts limitations to where CAES can be placed.
- In the basic form (without intermediate heat storage) CAES shows a relatively low electricity to electricity efficiency around 45 % without recuperation.

Space requirement

The space requirement for a CAES facility can be seen from Figure 35 [11], which shows the Huntorf CAES plant from above. Thus, an area of approx. 200x200 m (40,000 m^2) is required for 320 MW_{el} output. However, according to reference [8] 1 acre, which corresponds to approximately 4000 m^2 (63x63 m), is required for a 100 MW output plant.

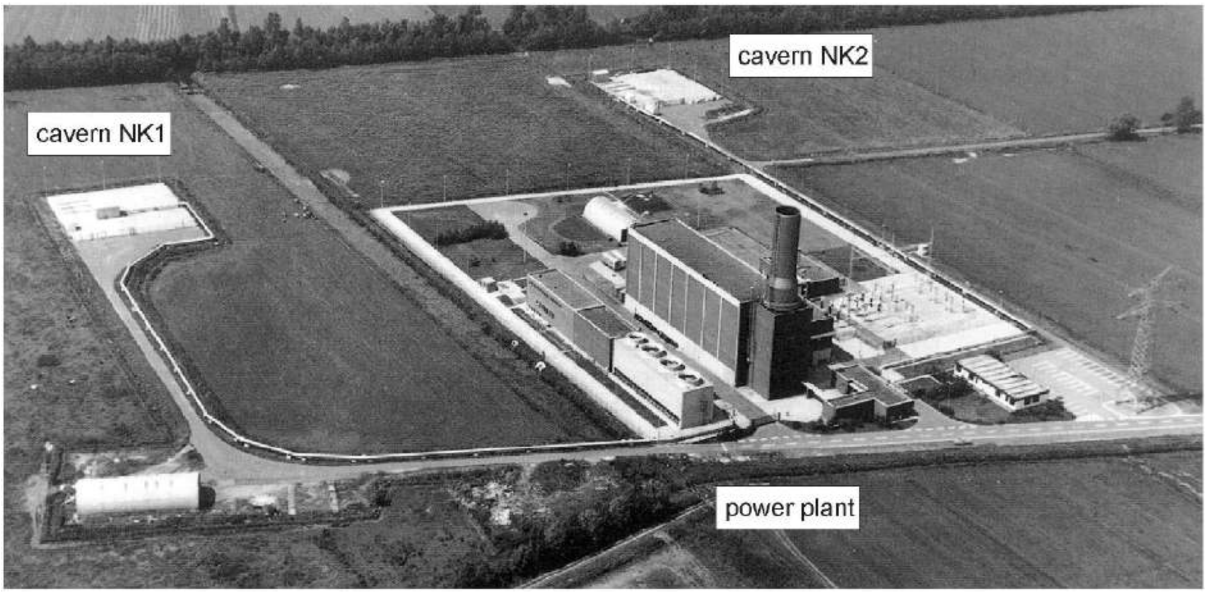

Figure 35: Aerial photo of the Huntorf facility [12].

The placing of a CAES plant depends completely on accessibility to store large amounts of compressed air. Since the energy storage capacity depends on the volume of underground formations, it is not possible to give a number in m^2/MWh. As mentioned, the existing two plants utilize underground caverns in salt domes. Other structures may be used but the entrepreneur is not free to establish a CAES plant wherever needed and thus the 200 by 200 m^2 surface area (for 320 MW) mentioned above does not set the complete requirements.

Water consumption

Compressed Air Energy Storage (CAES) systems have a relatively low water consumption compared to other energy storage technologies. Water is not directly involved in the compression and expansion of air, which are the primary processes in CAES systems. However, water may be used in secondary systems such as cooling and humidification.

The water consumption associated with CAES systems is mainly related to the cooling of the compressed air, which can be achieved through various methods, including air-cooled or water-cooled systems. In the case of water-cooled systems, the water consumption is typically small and can be managed through efficient system design and operation.

Environment

The main environmental impacts from operating a CAES plant - except from surface footprint – relate to the use of fossil energy in the expansion phase [13]. This problem could be overcome by the development of A-CAES (Adiabatic CAES), where heat is stored from the compression phase and redelivered in the expansion phase.

However, it has been found that the environmental impacts correlate strongly with the size and method of construction of the underground storage cavity in the construction phase [14]. Particularly for solution mined salt caverns, the dissolved salt may (depending on location) contain concentrations of heavy metals, which may not readily be disposed in rivers or lakes or even in the sea.

Research and development

Research and development efforts for CAES are directed towards improving the relatively low round cycle efficiency by intermediately storing the heat generated in the compression phase and reuse it during the expansion phase (ACAES) [15]. Figure 36 shows how the German utility company RWE envisages how a heat storage facility can be incorporated in a CAES plant. Heat may be stored at temperatures up to 600 °C or even higher in rock (stone) or other ceramic materials. The technology is being developed for a variety of purposes these years. It thus seems fair to anticipate that A-CAES will be commercially available within a time perspective of 10-15 years. This development is expected to improve the power-to-power efficiency to around 70 % and bring A-CAES into a much more attractive efficiency class.

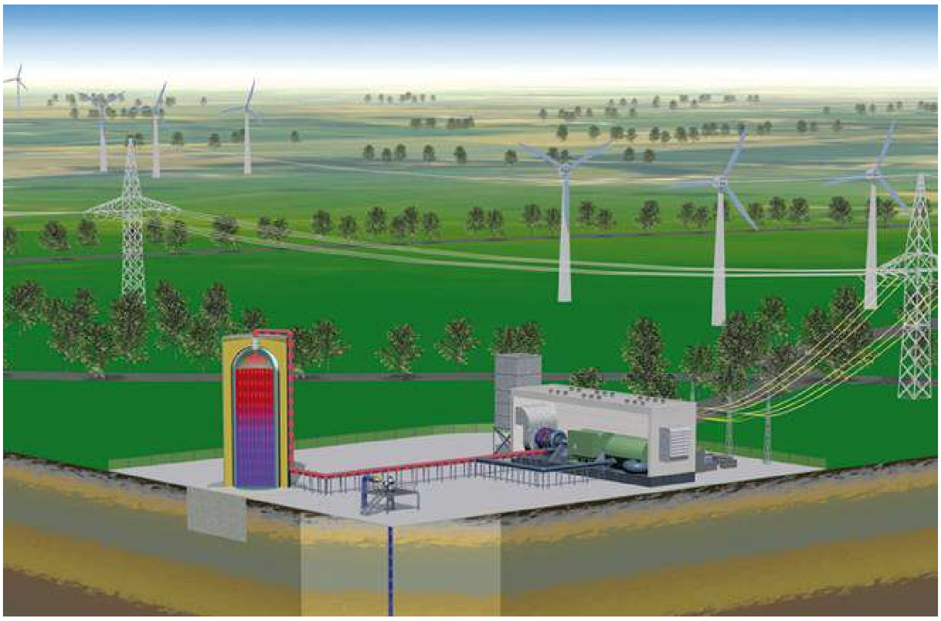

Figure 36: RWE´s vision for an ACAES plant [15].

Examples of current projects

As already mentioned, there are only two commercial CAES plant worldwide, the plant in Germany and the one in the USA.

Demonstration and pilot projects are present around the world, the Hydrostor A-CAES facility in Canada and the LAES demonstration project in Vermont. Hydrostor has commissioned a first 2.2 MW/ 10 MWh A-CAES plant on Ontario, Canada, which is an emission-free, water-compensated A-CAES system. The air pressure is kept constant using water [23].

The demonstration plant in Vermont is planned to provide more than 8 hours of storage capacity and to provide transmission network upgrade deferral services [23].

Investment cost estimation

The U.S. Department of Energy has conducted an analyses of grid energy storage technology cost including an estimate for 2030[16]. The final capital costs of various CAES projects found in the literature were collected and the summary is presented in Table 19 [16]. The average capital cost was estimated based on such literature review, excluding highly specific technologies in the process. All-in costs without substation/switchyard or 5 miles of transmission line costs were considered, reaching an average of 1153 $\$_{2020}$/kW [16]. An estimation of capital cost in relation to power capacity scaling was also provided, assuming that the system cost would drop by 8% every 10x increase of power [16]. The approximation starts from adapting the estimate for scaling PHS (16% drop every 10x increase in power), and considering half that value, since PHS benefits more from scaling due to requirement for expansion of the underground powerhouse and the nature of excavation [16].

Table 19: Summary of CAES capital cost literature review, adapted from [16]

Study year	Site/system	MW	Duration (hours)	Capital cost $/kW (Study year USD)	Reference
1991	McIntosh Plant	110	26	1068	[17]
1991	McIntosh Plant	110	26	1198	[18]
2012		136	26	1042	
2012	Dresser-Rand SMARTCAES	135	8-24	1204	
2012	Dresser-Rand SMARTCAES	405	8-16	983	
2012	Low fuel CAES	369	8-16	1311	
2014	ADELE – Adiabatic CAES for Electricity Supply, Germany	90		712	[19]
2014		300-500	10	1758	
2020	Siemens	400-600		9500	[20]
2020		160	10-30	1381	

Cavern costs have also to be considered when assessing CAES projects. The most cost-effective option are salt-dome caverns because they are wide and deep. Bedded cavers are more expensive, because characterized by shallower depth. The cavern cost of the 110 MW McIntosh Plant was estimated to be 4.3 $/kWh [18], while Siemens provided a cost of 3.4-4 $/kWh [16]. Overall, the cavern costs for salt domes are estimated to be in the 2-4 $/kWh range, while bedded caverns costs are >10 $/kWh [16]. The average cost has been calculated to be 3.66 $/kWh.

Figure 37 gives a cost breakdown for a CAES plant and shows the fraction of costs associated with developing the salt cavern. This fraction is about 40 %. It can be seen that the turbine is another costly component of the system and comprises about 30 % of costs. The figure comes from a report from 2012, in which the capital cost for CAES was estimated to be 900 $/kW, projected to remain at a constant cost until 2050.

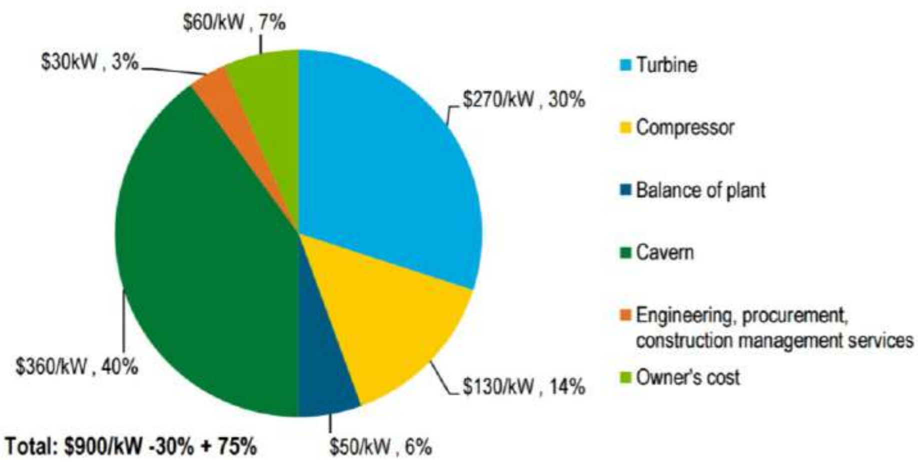

Figure 37: The capital cost breakdown for a CAES plant, approximately 262 MW net with 15 hours of storage and with storage in a solution-mined salt dome is assumed [21].

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The description in this chapter is to a great extent based on the Danish Technology Catalogue *"Technology data catalogue for Energy Storage"*.

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Data sheet

The following pages contain the data sheet of the technology. All costs are stated in U.S. dollars (USD), price year 2025. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Compressed Air Energy Storage										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data										
Energy storage capacity for one unit	MWh	3,000	3,000	3,000	-	-	3,000	10,000	A	
Output capacity for one unit	MW	300	300	300	-	-	300	500	A	
Input capacity for one unit	MW	60	60	60	-	-	60	80	A	
Round trip efficiency	%	60	70	72	55	55	64	72	A, B, C	
- Charge efficiency	%	80	84	85	80	80	80	85	A	
- Discharge efficiency	%	80	84	85	69	69	80	85	A	
Energy losses during storage	% / period	0	0	0	0	0	0	0	A	
Auxiliary electricity consumption	% of output	-	-	-						
Forced outage	%	5	4	4	-	-	2	4	A	
Planned outage	weeks per year	5	4	3	-	-	2	3	A, B	
Technical lifetime	years	40	40	40	35	45	35	45	A, B	
Construction time	years	< 3	< 3	< 3	2	3	2	3	A	
Regulation ability										
Idle to full discharge	sec	700	1,000	1,000	500	1000	800	1,200	A, D, E	
Full charge to full discharge	sec	-	-	-					F	
Economic data										
Specific investment	MUSD/MWh	0.13	0.13	0.11					A	1, 2, 3
- Energy component	%	40	40	40					G	2
- Capacity component	%	50	50	50						2
- Other project costs	%	10	10	10						2
Fixed O&M	USD/kW/year	18.4	18.4	18.4						1, 2, 3
Variable O&M	USD/MWh	1.7	1.7	1.7						1, 2, 3
Technology specific data										
Energy storage expansion cost	MUSD/MWh	0.065	0.065	0.055					H	
Output capacity expansion cost	MUSD/MW	0.065	0.065	0.055					H	

Notes:

A The starting values are from the Danish TC, adjusted using the references (if present in the column).

B For efficiency it is assumed that that new CAES plants can be constructed with at least the same efficiency as the McIntosh plant.

C The use of gas in a CAES plant is assumed at the same efficiency as the average use of chemical fuels in the Danish electricity system, i.e. 35% in 2014.

D The obtainable ramping rate is likely to decrease after application of thermal energy storage. This is because the heat must be delivered to the storage material, which is a process that cannot be controlled independently.

E If a CAES plant is operated as a hot spinning reserve, it can reach the maximum capacity within a few minutes. The emergency startup times from cold conditions at the Huntorf and McIntosh plants are about 5 minutes. Their normal startup times are about 10 to 12 minute.

F Operation not suitable nor relevant for CAES. Data not available.

G Energy component here taken as the cavern excavating.

H Compressed air energy storage is considered a scalar system and therefore the energy and output capacity expansion costs are here estimated to be equal to the energy and output capacity components plus the “other costs”.

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1 IEA, "Energy Storage Technology Roadmap, Technology Annex, p. 5,", March 2014

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6. FLYWHEELS

Brief technology description

Flywheels store energy mechanically as kinetic energy by bringing a mass into rotation around an axis. According to classical, mechanical physics the kinetic energy of a rotating mass m in distance r from the point of rotation can be expressed as:

$$E_{kin} = \frac{1}{2} \cdot I \cdot \omega^2,$$

where I is the moment of inertia – equal to $m \cdot r^2$ – and ω is the angular velocity (radians per second).

It is seen from this expression that the kinetic energy of a rotating flywheel increases proportionally to the mass and to the distance from the rotation point squared. The energy also increases proportionally to the angular velocity squared.

To maximize the stored energy for a given mass and rotation speed, the mass should be separated from the rotation point as much as possible. On the other hand, the centrifugal force acting on the mass is defined as:

$$F_c = m \cdot r \cdot \omega^2$$

and thus the requirements to the materials binding the mass to the rotation center increases proportionally to the separation distance. This fact sets limits to the maximal available distance because of the properties (tensile strengths) of known, available construction materials.

Whereas flywheels were formerly mainly constructed of metallic materials, modern flywheels are usually constructed – at least partially – by polymer/fiber composite materials. Flywheels are appropriate for applications to fast dynamic energy storage like peak shaving. Large flywheels should preferably be designed from composite materials due to the high rotational speeds and the larger strength-to-weight offered by these materials. Metallic rotors are mainly used for simple seconds to minutes energy storage systems like UPS (uninterruptable power supplies). Thus, Amber Kinetics believes in steel as a suitable rotor material as seen on the photo to the right in Figure below.

Figure 38: Photo of WattsUp Power's and Amber Kinetics' flywheels. The latter allowing for a look into the internal steel rotor whereas the first utilizes composite materials for the rotor [1].

Flywheels have been known and used for centuries in steam and combustion engines, whereas development of the independent energy storage potential has only been underway since the 1960s [2]. According to the reference given in [3] the world's largest flywheel has been in operation since 1985. It consists of 6 discs each with a diameter of 6.6 m and thickness 0.4 m, weighing 107 t. The system can supply 160 MW over a 30 sec period and has shown excellent reliability, especially concerning the mechanical construction. Another system developed by Okinawa Electric Company and Toshiba ROTES (ROTary Energy Storage) has been operated since 1996 [4]. The two examples indicate that flywheels represent highly reliable technology. This statement is supported by more recent data from Beacon Power, which states that their system is capable of more than 150,000 charge/discharge cycles at constant full power [5]. Such flywheel systems can be seen in Figure below, with the addition of a separate fiber composite flywheel being carried by a forklift.

Figure 39: Photo of Beacon Power's flywheels [6]. The fiber composite flywheel itself is seen to the right on the fork-lift. Each unit is 100 kW. Photo from manufacturer's store.

A cross section of a flywheel system and the system installed in an operation environment can be seen in

Figure below.

Figure 40: Drawing showing a cross section of the flywheel system and a visualization of how each module of a Beacon flywheel is mounted for operation [6]

Input

The input for flywheels is electricity.

Output

The output from flywheels is electricity.

In principle flywheels can also be charged and discharged mechanically, but in any practical perspective for grid applications electricity would be the input and output.

Energy balance

Modern flywheels are operated in high vacuum to eliminate (or strongly reduce) aerodynamic drag. Likewise, the bearings are contact-less magnetic bearings, which means that the mechanical energy losses during a full storage cycle are negligible from a practical perspective. Flywheel technology does not imply any significant energy loss even over prolonged periods. However, the power electronics taking care of converting primary power to the power format suitable for the flywheel and vice versa (the power electronics include rectifier, bus, inverter, and converter) gives rise to loss of energy during the use of flywheels. These losses are naturally associated with charging and discharging the wheels and depends somewhat on the mode of operation. In 2018 WattsUp Power stated that stand by losses of today's flywheel technology is about 5% per day whereas round trip efficiency is 98 % for the wheel.

In contrast Beacon Power in 2009 stated that the energy loss would be about 15% for a full charge/discharge cycle, measured at the transformer terminals, whereas for typical operation providing frequency control the loss per cycle would be 6-7% [5].

Due to its mechanical design and working principle, flywheels have zero degradation in energy storage capacity over time. This is independent of how the system is operated and in particular independent of depth of charge and discharge, which is in noteworthy contrast to the properties of most electrochemical battery systems.

Ramping configuration

Flywheels can absorb and release electro-mechanical energy extremely fast. The response time is up to 10 times faster than the response times of batteries, meaning that flywheels can react on demand and supply signals almost instantaneously. This property is attractive for providing ancillary services in the power grid and makes flywheels highly suitable for frequency regulation.

Due to the fast response time flywheels can provide ultrafast ancillary services to the grid, with reaction times down to 3 ms. Primary reserves – and even synthetic inertia - can easily be provided and managed by use of flywheels to maintain grid frequency. The reason for flywheels sometimes outshining batteries for certain applications is their high ramping rate. The fast up and down ramping rates and the remarkable storage capacity makes flywheels suitable [2] for

- Ramping (how fast an application can increase or decrease load)
- Peak Shaving
- Time Shifting (storing energy produced at a specific time to use it at a different time)
- Frequency regulation
- Power quality (especially voltage) – Power distribution grids strive to have a power factor as close to 1 as possible. Using flywheels, power utilities may vary active and re-active power to reach a perfect power factor.

An example illustrating the response time of a flywheel system can be seen on Figure below.

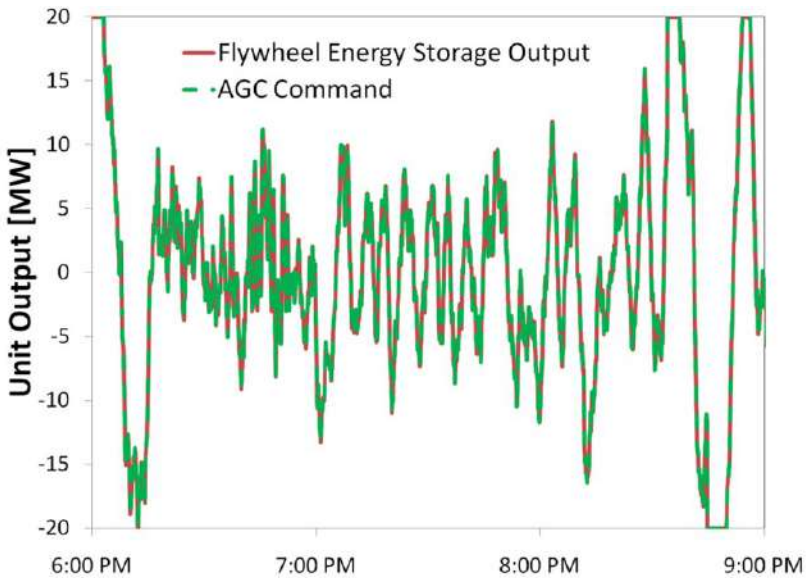

Figure 41: The reaction of a flywheel (MW input/output) in response to signals from the Automatic Generation Control. It can be seen that within the accuracy of the graph (please note the axis scaling) the flywheel follows signals completely. Source: Beacon Power.

Typical capacities

Storage density

The energy storage density – whether on volume or weight basis – for flywheels (about 0.05 kWh/kg) is comparable to advanced batteries and in the range of 1-2 orders of magnitude lower than for chemical methods for storing energy (in ways like the natural energy storage media oil and gas). This is, however, not important for static applications. On the other hand, flywheels have high power densities of about 1 kW/kg [7] also confirmed by WattsUp Power in February 2018.

Sizes of flywheel plants

Flywheels for energy storage can be produced and deployed in numerous sizes ranging from multi-MW utility applications to small systems (few kW and kWh) intended for use in cars and buses. Until recently Beacon Power seemed to be the dominating producer of large-scale flywheels. Their systems are based on a modular flywheel size (a single flywheel) of 100 kW and 25 kWh, with the standard unit size consisting of an assembly of 10 modules which can be combined in any multiple of 10. Such modules sum up to 1 MW and 250 kWh. Figure below shows a photo of an example of their systems that currently provides 20 MW of frequency regulation service.

Figure 42: Photo of Beacon Power flywheel installation in commercial operation in PJM, Hazle, Pensylvania. The plant includes 200 flywheel modules lowered into the ground (5 on each side of a container. The plant currently provides 20 MW of frequency regulation service to PJM and reached full commercial operation in July 2014 [6].

Typical storage period

Flywheels can be constructed to store energy from seconds to years, but usually the storage period is shorter than days. Flywheels have relatively small standby losses, and the user or producer will design a flywheel for each specific application. Now a typical 10 second storage application could be a UPS (uninterruptable power supply) for hospitals or server centers. In other less typical applications like power peak shaving, the flywheel will be designed to store the power for days and in the most extreme conditions in space applications NASA’s flywheel designs store the power for up to 3 years.

Advantages/disadvantages

Flywheels are fast reacting, reliable, efficient, and clean in terms of use of resources and waste disposal.

Some advantages and disadvantages are shown in Table below.

Table 20: Advantages and disadvantages of Flywheel Energy Storage Relative to Other Energy Storage Technologies, 2003 [8]. Please note that the table reflects data from 2003 and may have been improved since then. For instance, WattsUp is now using tip speed of 875 m/sec.

Advantages	Disadvantages
Power and energy are nearly independent	Complexity of durable and low loss bearings
Fast power response	Mechanical stress and fatigue limits
Potentially high specific energy	Material limits at around 700 M/sec tip speed

High cycle and calendar life	Potentially hazardous failure modes
Relatively high round-trip efficiency	Relatively high parasitic and intrinsic losses
Short rechange time	Short discharge time

As an example of hazardous failure modes, the crash of two Beacon Power flywheels in 2011 is prominent. The incident was described by the Beacon Power spokesman:

"flywheels failed due to flawed early production runs of the carbon fiber material used in their manufacture. The faulty flywheels spun out of balance and tilted to touch the chamber sides, which caused the flywheels to "grind down" into a heated "cotton candy-like material" of carbon fiber. Safety features in the chamber detected the rising temperature and released water to cool the units, which created steam that caused pressure to increase, blowing off chamber covers in an explosive manner" [9].

Space requirement

The land area requirement for flywheels naturally depends on the capacity of the installation. Figures 32 gives indications of the area demand, additionally, Beacon Power states that the space required for an installation of 20 MW is 1 acre (approx. 4000 m^2)

Water consumption

Flywheel energy storage systems do not use water as part of the energy storage mechanism. Energy is stored mechanically as rotational kinetic energy, and water does not participate in any electrochemical or thermodynamic process related to charging or discharging.

Operational water use is therefore negligible. Water may be used indirectly in auxiliary systems, such as closed-loop cooling for power electronics, bearings, or vacuum systems, depending on the system design and scale. In most commercial flywheel installations, cooling is air-based or uses sealed liquid cooling circuits, resulting in no meaningful water consumption during normal operation. Overall, flywheel energy storage exhibits very low water consumption, limited to initial installation and maintenance of auxiliary systems rather than ongoing operation.

Environment

There are no environmentally hazardous aspects of flywheels. Materials and production methods imply the same environmental emissions as any manufacturing based on metals and polymers.

Under operation, there is no use of water, harmful chemicals, or hazardous materials.

It can be argued that application of flywheels in the grid will save CO_2 emissions to the extent they improve the ability to utilize variable renewable energy production.

Research and development

In 2013 the European Association for Energy Storage (EASE) stated the following R&D needs for flywheels [10]:

1. Flywheel disc: Study of better materials for fiber flywheels (high density) should be carried out to reduce the total cost.
2. Electrical machines: High performance machines are required to be used in these devices and although permanent magnet machines seemed to be the best option, the high cost of the magnets has redirected the research to search new machine concepts with less magnets.
3. Bearings: Faster control systems are being developed to improve the bearings response and more efficient actuators are used to increase the performance of the complete system.
4. Power electronics: Increase the added value of the power electronics in an energy storage system, ensuring the robustness and reliability.
5. Digital control and communications: Communication improvements permit to control the system with guaranties of robustness, being able to analyse many variables, maintaining a complete analysis of the application from anywhere, being easily integrated with some other subsystems.

6. Security case or frame: A better knowledge and a wider experience in prototypes would reduce the cost in security.
7. Demonstration plants to evaluate whether flywheel technology is convenient for certain applications.

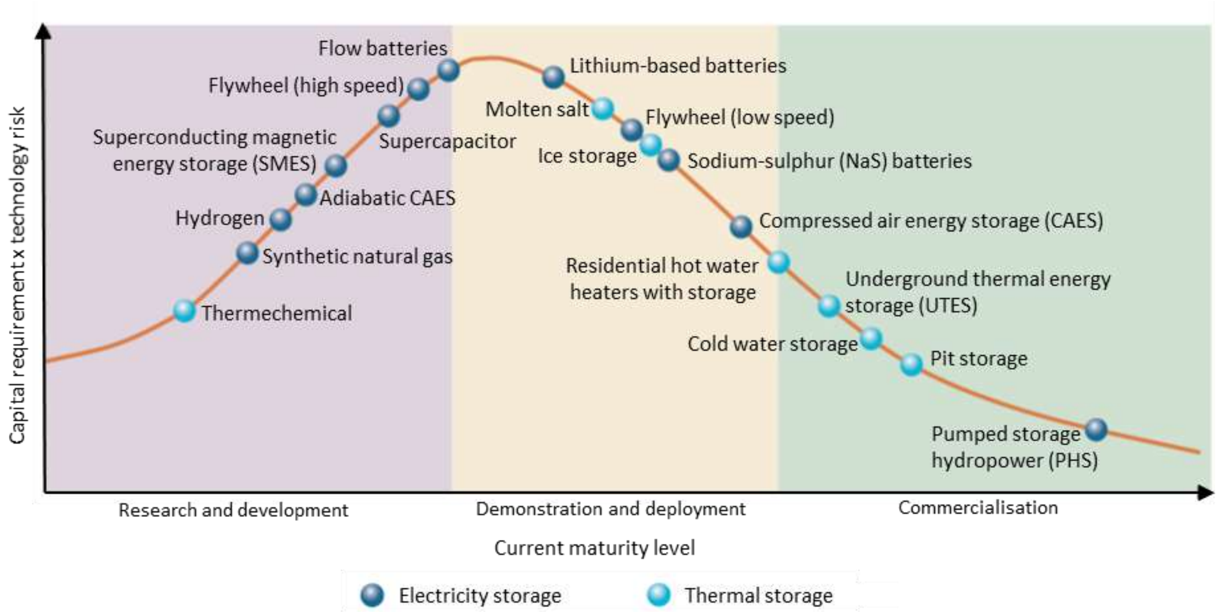

Figure 43: Ranking of energy storage technologies concerning maturity level [11]. Data published in 2013. Flywheels have moved to the next class of the figure since then.

Figure above shows how the International Energy Agency (IEA) considers the maturity of flywheels compared to other storage technologies. The ranking was published in 2013 and since then flywheels have gained maturity so that they are now used in commercial applications. An example comes from Amber Kinetics, which has installed several flywheels around the world with over 1,000,000 hours of run time. In California, Amber Kinetics was selected to install a long-duration flywheel energy storage system to provide peak reduction and help balance the grid. In Taiwan, Amber Kinetics delivered Taiwan's first 4h flywheel energy storage, in operation since February 2019 [24]. In Netherlands, S4 Energy and ABB have installed a storage facility that combines battery and flywheels to help maintain a stable grid in the country. The facility features a 10 MW battery system and a 3 MW flywheel system, both connected to a nearby wind farm [25].

Flywheels are generally considered to be a little less mature technology than many batteries and in addition the cost is perhaps still too high to make them competitive on the commercial market somewhat depending on the specific application, though [12]. However, as described in the present document, flywheels also seem to be catching up rapidly and gaining market shares although batteries are still dominating many energy storage applications. In some applications – like grid stabilization for railways and large battery charging – flywheels are often a preferred solution.

Examples of current projects

Amber Kinetics has designed, built, and tested first a sub-scale 5 kWh prototype flywheel system, and secondly installed and tested a full commercial scale 6.25 kW/25 kWh system in 2015 in California [15]. The goal of the study was to assess the value of the flywheel energy storage system to the grid, considering the ancillary services required and load shifting for grid stabilization. The study concluded that the proposed flywheel system is a cost-effective solution to improve grid stabilization [15,16].

Beacon power has also designed and built a utility-scale 20 MW flywheel battery system in Pennsylvania, beginning operation in 2013 at 4 MW and reaching full commercial operation in 2014. The project explores flywheel applications in the regional electricity market's fast response regulation. The FESS can charge and discharge at full rated power with a 98% availability year-round [16,17].

Figure 44: Beacon Power Hazle Township, PA plant 20 MW - 2013

Investment cost estimation

There are several studies in the literature that have provided information on the techno-economic implication of flywheel energy storage systems, especially in comparison with pumped hydro storage, CAES and electro-chemical batteries [18,19]. The result of the study from Nikolaidis and Poullikkas was that the power capital cost of flywheels is more attractive than PHS and CAES [18]. Rahman et al. have demonstrated that the capital cost of flywheels is highly dependent on the rotor type because the rotor material used have a strong influence on the final investment cost [13]. Therefore, they have developed the cost function for the components of flywheels and the cost estimation for both steel rotor and composite rotor flywheels [13].

Mongird at al. have investigated the capital cost of flywheels in their work for the U.S. Department of Energy collecting data from the literature and the manufacturers [14]. They have developed the relationship between the $/kW and the energy to power ratio, as the duration that the storage can deliver its output, which is shown in Figure 45. Furthermore, the authors declared that flywheels 2025 capital costs are assumed the same as estimated in 2018, because they are mature technologies [14].

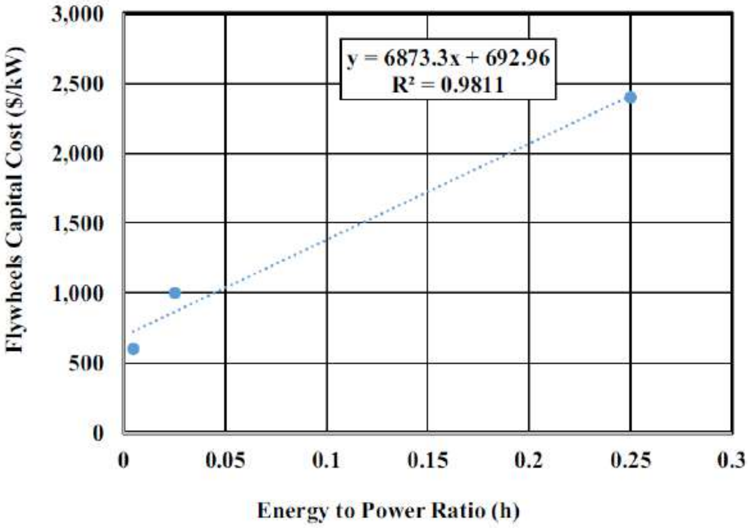

Figure 45: Capital cost by energy to power ration for flywheel energy storage systems [14].

The typical lifetime of flywheels is between 15 to 20 years [13]. According to Mongird et al., there is a limited number of sources that have provided information on O&M costs for flywheels. Fixed O&M may vary between $5.56/kW-yr to $5.8/kW-yr, and a variable O&M around $0.3/MWh [22, 23].

The investment cost estimation for Viet Nam was calculated in 2020 taking into consideration the references from [13, 14, 16]. The Danish technology catalogue number was disregarded as it was derived by rather old reference (older than 2015), and therefore not the most updated. The projection to 2030 and 2050 though was calculated considering the learning curve from the Danish technology catalogue.

The updated 2025 Viet Nam Technology Catalogue has revised all cost projections by converting them to 2025 USD.

Investment costs [MUSD/MW]	Characteristic	2018	2020	2025	2030	2050
Vietnam technology catalogue 2025				21.8	20.4	19.7
Vietnam technology catalogue 2023			17.5		16.4	15.8
Danish technology catalogue	1 MW		17.4		16.3	15.7
Literature [13]	20 MW – composite rotor		11.1			
Literature [13]	20 MW – steel rotor		7.9			
U.S. Department of Energy 2019 [14]	20 MW – 0.25 h	29.3				
NREL 2021 [16]			10.7-28.5			

References

The description in this chapter is to a great extent based on the Danish Technology Catalogue *"Technology data catalogue for Energy Storage"*.

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Data sheet

The following page contains the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2025. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency does not have the lower price or vice versa.

Flywheels

Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy storage capacity for one unit	MWh	0.1	0.1	0.1	0.1	0.1	0.1	0.15	A, B	
Output capacity for one unit	MW	1	1	1	1	1	1	1.5	A, B	
Input capacity for one unit	MW	1	1	1	1	1	1	1.5	A, B	
Round trip efficiency	%	98	98	98	98	99	98	99	A, B	
- Charge efficiency	%	99	99	99	99	99.5	99	99.5	A, B	
- Discharge efficiency	%	99	99	99	99	99.5	99	99.5	A, B	
Energy losses during storage	%/day	3	1	1	2	5	0.5	1.5	A, C	
Auxiliary electricity consumption	% of output									
Forced outage	%									
Planned outage	weeks per year									
Technical lifetime	years	20	25	25	20	25	20	25	A, D	
Construction time	years	0.25	0.25	0.25	0.25	0.25	0.25	0.25	A, B	
Regulation ability										
Response time from idle to full-rated discharge	sec	0.003	0.003	0.003	0.003	0.003	0.003	0.003	A, B	
Response time from full-rated charge to full-rated discharge	sec	0.003	0.003	0.003	0.003	0.003	0.003	0.003	A, B	
Economic data										
Specific investment	MUSD/MWh	21.8	20.4	19.7					A	1, 2, 3
- Energy component	%	98.5	98.5	98.5					A, B	
- Capacity component	%	1.5	1.5	1.5					A, B	
Fixed O&M	USD/MW/year	7.1	7.1	7.1						3
Variable O&M	USD/MWh	0.4	0.4	0.4						3
Technology specific data										
Specific energy	Wh/kg	350	350	350	300	400	350	400	A, B	
Specific energy	Wh/l	1500	1500	1500	1300	2000	1300	2000	A, B	
Cycle life	cycles	350,000	350,000	350,000					B	
Water consumption	L/MWh	0	0	0						

Notes:

A The starting values are from the Danish Technology Catalogue, adjusted using the references (if present in the column).
B Data informed by WattsUp Power February 2018.
C Loss per day measured by WattsUp Power. The projected losses towards 2050 is justified by results already now obtained by NASA.
D +25 years on mechanics. 15 years on electronics. Informed by WattsUp Power March 2017.

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7. FUEL CELLS

Brief technology description

Fuel cells are energy generators that convert chemical energy to electrical energy through an electrochemical process. Hydrogen fuel cells convert hydrogen into electricity, with the only by-product being water vapor and heat. Like batteries, fuel cells have a negative electrode (anode) and a positive electrode (cathode) which are separated by an electrolyte. Unlike batteries, fuel cells need a fuel as a catalyst in order to produce electricity, in this case hydrogen. The fuel is supplied to the anode, while an oxidant (typically oxygen or air) is supplied to the cathode. A chemical reaction at the anode separates the hydrogen molecules into protons and electrons which take separate paths to the cathode. The protons migrate through the electrolyte to the cathode, while the electrons flow through an external circuit, creating an electric current. The protons, electrons, and oxygen unite at the cathode where water and heat is produced [1, 13].

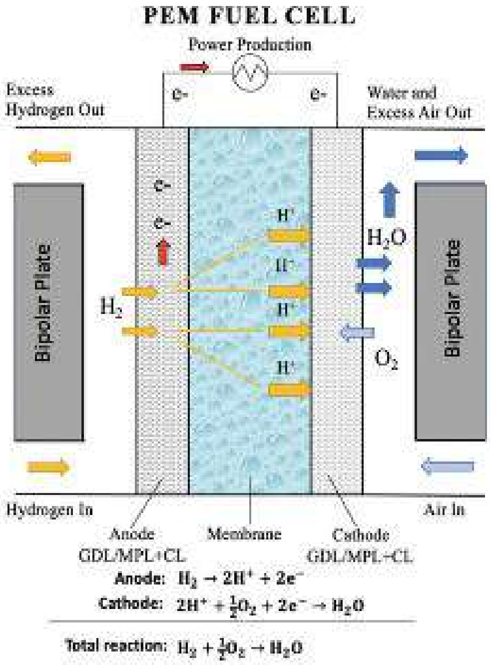

Figure 46: Schematic diagram of proton exchange membrane fuel cell. [2]

Fuel cells are categorized into proton exchange membrane fuel cells (PEMFCs), direct methanol fuel cells (DMFCs), solid oxide fuel cells (SOFCs), phosphoric acid fuel cells (PAFCs), alkaline fuel cells (AFCs), molten carbonate fuel cells (MCFCs), and others. The two most common types of fuel cells are Polymer exchange membrane fuel cells (PEMFC) and solid oxide fuel cells (SOFC).

PEMFCs have been used in hydrogen fuel cell vehicles as they have a high-power density and low operating temperature relative to other fuel cell technologies. Due to their use in transportation applications, PEMFCs have received significantly more research and development attention compared to other fuel cell technologies. SOFCs, on the other hand, operate at higher temperatures and exhibit lower power density but higher electrical efficiency. This high-temperature operation makes them unsuitable for transport applications; however, for stationary electricity production, these characteristics do not represent a limitation.

Components of a PEMFC

Proton exchange membrane fuel cell (PEMFC), consists of several key components that perform complementary functions to convert chemical energy into electrical energy. At the core of the system is the membrane electrode assembly (MEA), which comprises the polymer electrolyte membrane, catalyst layers, and gas diffusion layers, where electrochemical reactions occur and proton transport as well as reactant distribution are facilitated. Bipolar plates are arranged between individual cells to collect electrical current, distribute hydrogen and oxygen to the MEA, and support thermal and water management during operation. Sealing gaskets, insulation plates, and end plates ensure gas tightness, electrical insulation, and structural integrity of the entire stack. In addition, the gas supply system and coolant manifolds regulate reactant flow and remove excess heat generated during the electrochemical process. Finally, current collectors and electrical connectors enable effective and stable power delivery from the fuel cell stack to external loads or energy storage systems.

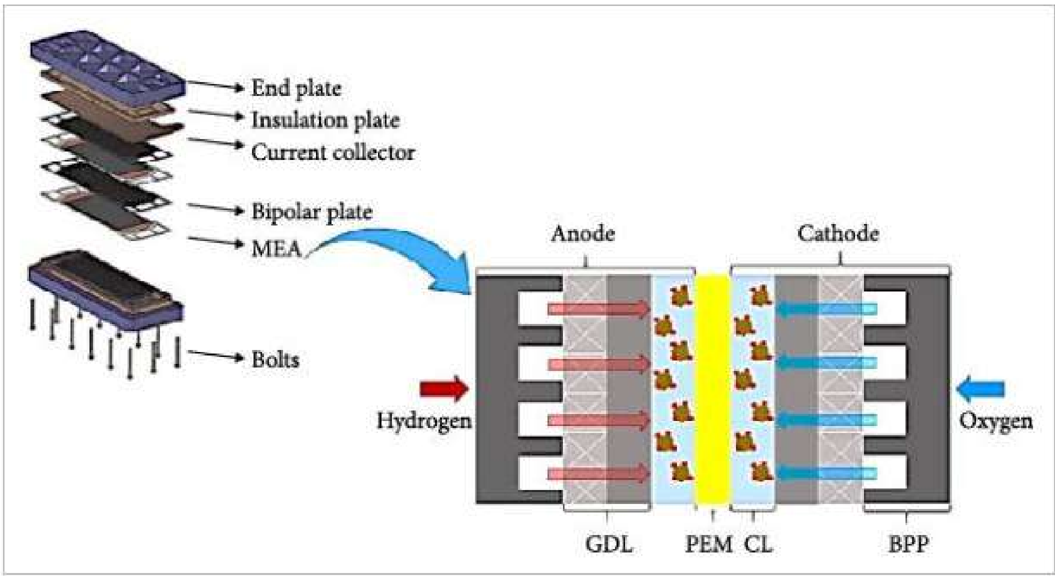

Figure 47: Fuel cell stack components

PEMFCs are an outstanding option among various fuel cell types because of their simplicity, lightweight, high efficiency, high mass power density, no waste production, low typical operating temperature and pressure, high technological maturity, and relatively low cost. For power ranges >100 W, the typical efficiency of a PEMFC ranges from 40% to 60% [16] and is only significantly impacted by size. It uses a PEM as the electrolyte and can operate efficiently at 50–100 °C. This specific type of fuel cell is used extensively in a range of applications, from electric vehicles (EVs) to portable power supplies and backup power systems, because of its high efficiency, compact nature, and quick start-up characteristics. PEMFCs are light in weight and flexible, which makes them particularly ideal for transportation and mobile use [14].

Hydrogen as part of the energy system

A growing number of experts have the expectation that hydrogen will play a large role in decarbonized energy systems. The reason for this is that it can be used to help decarbonize difficult-to-abate sectors of the world's economy, such as the shipping, aviation, and steel industries. However, this is only the case if the hydrogen is produced by renewable energy (green hydrogen) via electrolysis or nuclear energy (pink hydrogen) via electrolysis, as otherwise the hydrogen is not considered emission free. Hydrogen can be converted back into electricity when needed, and this makes hydrogen a potential option for long-term storage as it is possible to store hydrogen for long periods of time without losses (unlike batteries, which lose charge over time).

Fuel cells can be used to convert hydrogen back into electricity (and possibly heat). Another option is to simply burn hydrogen in hydrogen-ready CHP plants, but this process results in NOx emissions and is thereby less environment-friendly. Currently, fuel cells convert hydrogen into electricity much more efficiently than simply burning hydrogen in a converted gas power plant. However, if the hydrogen is burned in a combined cycle CHP plant, the efficiency of burning hydrogen matches that of current fuel cell technology.

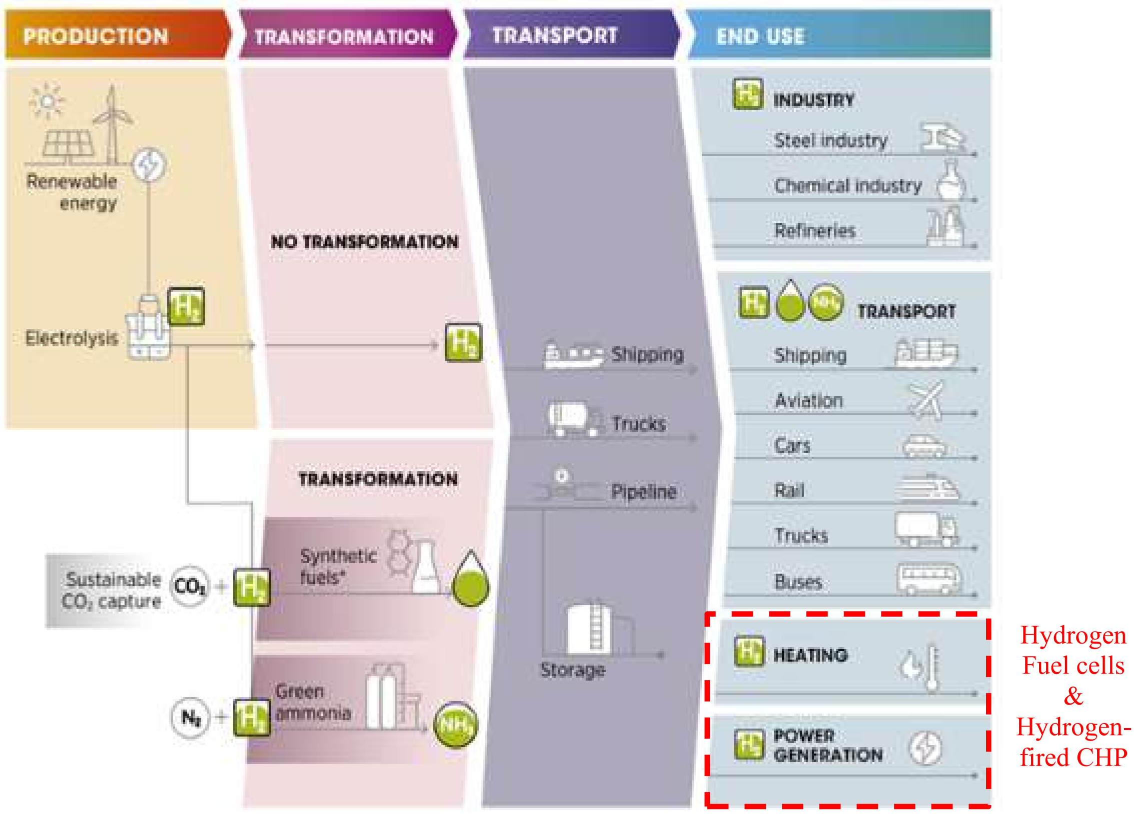

Figure 48: Overview of hydrogen's potential role in the energy system. The red box and text have been added here to show which part of the hydrogen system is being discussed in this section. Source of original figure: IRENA

Applications

Several studies and practical experiences indicate that fuel cells are increasingly being researched and developed as a potential green and sustainable energy supply, capable of replacing various types of fossil fuels [13], [14]. Some of the most notable applications of fuel cells include the following:

- *Road transportation:* Fuel cells are primarily applied in fuel cell electric vehicles (FCEVs) and hybrid battery–fuel cell configurations, improving operational efficiency and energy management. Well-to-wheel analyses indicate a potential emissions reduction of 55.5–62.5% in the 2030–2040 period compare to 2030 level, particularly when combined with low-emission hydrogen sources [17].
- *Aviation and unmanned aerial vehicles (UAVs)*: In aviation, fuel cells are being investigated for small aircrafts, UAVs, and auxiliary power systems due to their ability to maintain performance at small scales and their higher energy density compared to batteries. Experimental results show that PEMFC-powered UAVs can achieve flight durations ranging from several hours to over 48 hours, significantly outperforming battery-only configurations.
- *Stationary power generation and CHP systems*: Fuel cells are deployed for stationary power generation and combined heat and power (CHP) applications at scales from several hundred kilowatts to megawatts. A typical example is a 500-kW system replacing diesel generators for hospitals, with a payback period of approximately 10 years. These applications are particularly suitable for backup power, microgrids, and areas with high reliability requirements.
- *Backup power for critical infrastructure*: In data centers and distributed power systems, fuel cells are considered an alternative to diesel generators, with payback periods of 13.1–13.4 years under standard cost scenarios. The economic viability of these applications strongly depends on hydrogen costs and the capital investment required for fuel cell systems.
- *Mobile applications and small-scale devices*: Small-scale fuel cells are being studied as power

sources for automation equipment and portable devices, particularly in regions with unstable electricity grids. Owing to their high energy density and continuous power supply capability, fuel cells show potential to replace conventional batteries in control systems and emergency power applications.

Input

Hydrogen.

Output

Electricity, Heat, Water.

Energy balance

Fuel cells convert the chemical energy of hydrogen directly into electricity, resulting in relatively high electrical efficiencies compared with combustion-based technologies. Electrical efficiencies of stationary fuel cells are typically in the range of about 45–60%, and can exceed 80% when waste heat is recovered in combined heat and power (CHP) applications [2][3]. This high conversion efficiency at the point of use is one of the key advantages of fuel cell technology.

However, when fuel cells are considered as part of an electricity–hydrogen–electricity pathway, the overall round-trip efficiency is significantly lower. Losses occur during electricity conversion to hydrogen (e.g. via electrolysis), hydrogen compression or storage, and reconversion to electricity in the fuel cell. System-level assessments indicate that round-trip efficiencies for such pathways are typically well below 40%, and often closer to 25–35%, which reduces their attractiveness for large-scale electricity storage compared with some alternative technologies [3][9]. This relatively low round-trip efficiency is widely cited as a key factor limiting the deployment of hydrogen fuel cells for grid-scale energy storage, despite their advantages in flexibility and long-duration storage capability.

Advantages/disadvantages

Fuel cells offer several advantages over conventional power generation methods, including high thermodynamic efficiency, high power density, compact size, low emissions at point of use, low noise, and high-quality electricity output. Fuel cells are modular and maintain good efficiency even at small scales, making them well-suited for aerospace applications, backup power, and distributed power generation, which reduces transmission and distribution losses. Hydrogen fuel cells also benefit from fast refuelling times compared with battery electric systems in vehicle applications and can provide a long operating range where hydrogen infrastructure is available.

However, there are important disadvantages and challenges that currently limit wider adoption [11], [12]:

- **High cost:** Fuel cell systems remain expensive due to the use of precious metal catalysts (e.g., platinum), specialized materials, and relatively low manufacturing volumes, which increases both stack and system costs compared to many conventional technologies.
- **Hydrogen storage and infrastructure:** Hydrogen has a low volumetric energy density and requires high-pressure or cryogenic storage, increasing complexity and cost. In addition, large-scale hydrogen production, storage, and refuelling infrastructure is limited in most regions, which constrains market growth, especially for transport applications.
- **Hydrogen production emissions:** Although fuel cells emit no pollutants at the point of use, the majority of hydrogen is currently produced from fossil fuels without carbon capture, reducing the lifecycle environmental benefit of the technology unless low-carbon hydrogen pathways are developed more broadly.
- **Durability and reliability concerns:** Fuel cell components can degrade over time, especially when exposed to impurities in hydrogen or under variable operating conditions, which can reduce lifetime and increase maintenance needs compared with some alternate technologies.
- **Complexity and safety considerations:** Handling, storage, and transportation of hydrogen require stringent safety measures because hydrogen is highly flammable and diffuses easily, which introduces additional design and regulatory requirements.

Space requirements

Fuel cell systems can achieve relatively compact footprints due to their high-power density and modular design, particularly for proton exchange membrane (PEM) fuel cells used in stationary and transport applications [1], [2]. However, the overall space requirement of a fuel cell installation is strongly influenced by balance-of-plant components such as hydrogen storage, compression equipment, power electronics, and safety systems, which can significantly increase the total footprint, especially for stationary applications using compressed hydrogen [2].

Water Consumption

Water is produced as a by-product of the electrochemical reaction within the fuel cell. No water is consumed during electricity generation within the system boundary. Water consumption may occur upstream during hydrogen production via electrolysis.

Environment

Hydrogen fuel cells produce no direct greenhouse gases or air pollutants during operation, which can reduce local environmental impacts compared with combustion engines. Life-cycle assessment studies show that the total environmental impact of fuel cells varies substantially with how the hydrogen is produced and with the manufacturing process, especially the production and processing of materials. Hydrogen from low-carbon, renewable sources generally results in much lower lifecycle emissions than hydrogen from fossil fuels. Assessments also identify that components such as platinum catalysts and hydrogen storage materials can contribute significantly to overall environmental burdens due to the energy and resource intensity of their extraction and processing. These factors highlight that realizing environmental benefits from fuel cell systems depends on clean hydrogen supply and careful management of material lifecycles [19].

Research and development

Worldwide installed hydrogen fuel cell capacity continues to grow but remains modest compared with conventional power generation. Stationary fuel cell systems had an installed base of roughly 345 MW in 2023, with forecasts of about 418 MW in 2024, and cumulative deployments exceeding 2 GW when aggregated across many regions and technologies [21][22]. South Korea, the United States, and Japan are the largest markets for stationary fuel cells.

For transport applications, the global fleet of fuel cell electric vehicles (FCEVs) reached approximately 88000 units by the end of 2023, supported by more than 1200 hydrogen refuelling stations worldwide [23]. While individual vehicle fuel cell capacities are smaller than stationary systems, these numbers demonstrate growing adoption in mobility applications. Taken together, these data indicate that by 2026, global installed hydrogen fuel cell capacity is in the low gigawatt range for stationary systems, with rapidly expanding deployment in transport.

Fuel cell research and development focuses on reducing costs, improving durability, and increasing efficiency across different applications. Current development status varies by application, with transport and stationary power fuel cells reaching higher technology readiness levels, while other uses remain at demonstration or pilot scale [20]. Key R&D priorities include reducing reliance on scarce and expensive materials such as platinum catalysts, improving lifetime under real operating conditions, and enhancing system integration with hydrogen supply infrastructure. Continued research is expected to support further cost reductions and broader commercial deployment as hydrogen production and distribution mature [20].

Examples of current projects

Figure 49: 50 MW byproduct-hydrogen-fuel-cell power plant located in Seosan, South Korea. [10]

One of the most prominent examples of large-scale stationary hydrogen fuel cell deployment is the Daesan Hydrogen Fuel Cell Power Plant in Seosan, South Korea, completed in 2020. The facility, developed by a consortium including Hanwha Energy and Doosan Fuel Cell, has an electrical capacity of 50 MW and is among the largest hydrogen fuel cell power plants in the world. It operates using by-product hydrogen supplied from nearby petrochemical facilities within the Dsaesan industrial complex, with hydrogen delivered directly via pipeline. The plant generates electricity through fuel cell conversion, producing water as the primary by-product [10].

Investment cost estimation

In order for fuel cells to become competitive, they will need to drastically fall in price. Governments around the world will have to step in and create incentives for companies to make the necessary investments to build stationary fuel cells at scale. According to Hydrogen Council [4], 33 billion USD of government incentives will be needed for fuel cells to fall enough in price to become competitive.

Investment cost estimates indicate that hydrogen fuel cell systems remain capital-intensive, although significant cost reductions are expected over time. According to the Pacific Northwest National Laboratory's 2020 Grid Energy Storage Technology Cost and Performance Assessment, the upfront installed cost of stationary fuel cell systems was estimated at approximately USD 1188-1452 per kW in 2020, reflecting high stack and balance-of-plant costs at limited deployment scale [9].

Long-term techno-economic modelling suggests that substantial cost declines are possible under favourable market conditions. A recent study focusing on China projects that hydrogen fuel cell system costs could fall from above roughly USD 300 per kW in the early 2020s to below around USD 140 per kW after 2031, with further reductions towards about USD 100 per kW by 2038–2040, driven by technological learning, manufacturing scale-up, and strong policy support [18]. However, these projections reflect the Chinese market context, where fuel cell deployment is highly dynamic and strongly guided by government policies and decarbonization demand in industrial sectors, thereby enabling sustained R&D investment and cost reductions. The International Energy Agency's Global Hydrogen Review highlights that high capital costs remain a key barrier to wider deployment globally, and that such cost reductions are highly context-dependent, progressing fastest in regions with strong industrial policy, domestic supply chains, and sustained investment, while early-stage markets are likely to face higher costs in the near term [8]. In the case of Viet Nam, as a country at an early stage of fuel cell adoption, system costs in the near future are likely to remain relatively high due to a strong reliance on imported equipment and external technology supply chains.

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Data sheet

No data sheet is developed for fuel cells due to limited global deployment and high uncertainty.

INTRODUCTION TO RENEWABLE FUELS INCLUDING POWER TO-X

The following chapters of the catalogue will present a selection of technologies for producing renewable fuels, specifically tailored to suit the context of Viet Nam, based on consultations with relevant stakeholders.

The technologies in the catalogue include the green fuel producing unit. This means that the boundary for both cost and performance data are the generation assets plus the required local infrastructure to deliver the renewable fuel for further use.

The text and data have been elaborated based on Vietnamese cases to represent local conditions. For the mid- and long-term future (2030 and 2050) international references have been relied upon for most technologies since Vietnamese data is expected to converge to these international values. In the short run differences may exist, especially for the emerging technologies. Differences in the short run can be caused by e.g., current rules and regulations and the level of market maturity of the technology. Differences in both the short and long run can be caused by local physical conditions.

8. ELECTROLYSERS

Introduction

The upcoming decades are anticipated to witness a surge in the demand for renewable hydrogen, driven by our commitment to transitioning our energy system as close as possible to a 100% renewable framework. Among the various forms of low carbon hydrogen available, water electrolysis has become the most prevalent technique due to its lower emissions throughout the entire process. When combined with 100% renewable energy sources, this method gives rise to green hydrogen, a sustainable, CO_2 emission-free hydrogen variant.

Off-taker importance and type of hydrogen production projects/plants

In recent years, there has been considerable focus on green hydrogen production, with significant emphasis placed on the core machinery involved in water electrolysis, namely the electrolysers. However, the process of generating green hydrogen extends beyond mere possession of electrolysers.

The ultimate application of the hydrogen will dictate its specific requirements, such as purity and pressure, which in turn influence the production and demand of this valuable resource. This chapter will present a comprehensive overview of green hydrogen production, supplemented with case studies of various hydrogen projects to illustrate the different factors that affect hydrogen production.

Hydrogen plants

A hydrogen plant can be defined as a comprehensive assembly of necessary components tailored to produce a predetermined volume of hydrogen, designed for a specific project with distinct attributes. These characteristics include parameters such as volume (tons per hour), purity in terms of water and oxygen content in the hydrogen, as well as pressure and temperature.

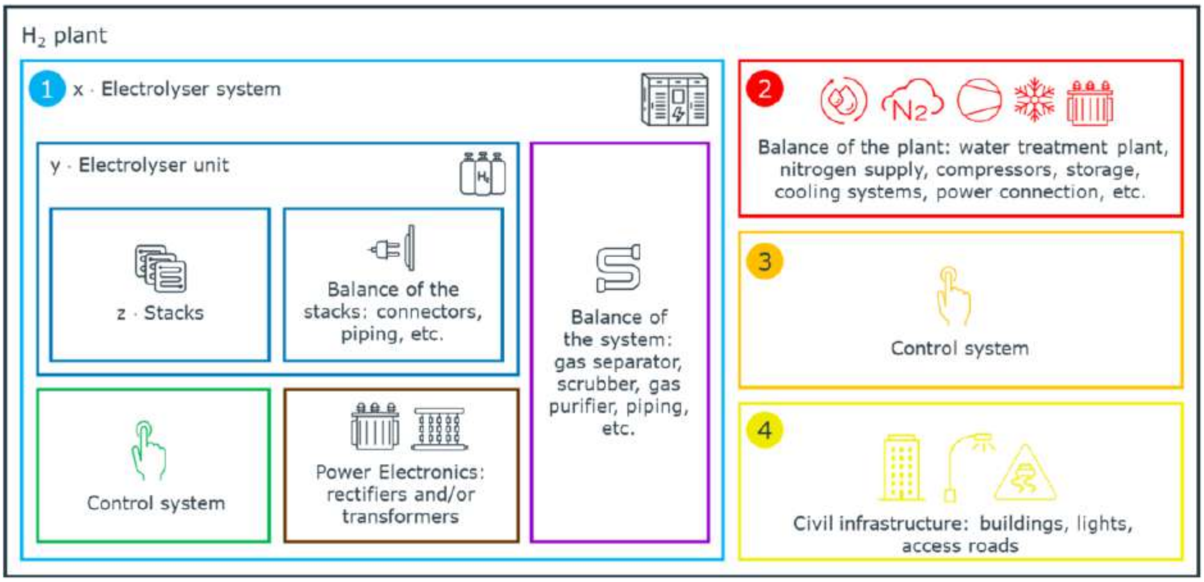

Figure 50: Hydrogen plant general components categorized into four main component groups: electrolyser system(s), balance of the plant, control system, and civil infrastructure.

Figure 50 illustrates the various components that typically make up a hydrogen plant, and these can be classified into four main categories: 1) Electrolyser System, 2) Balance of the Plant, 3) Control System, and 4) Civil Infrastructure.

1) **Electrolyser System**: This represents the core of the Hydrogen Plant, where the electrolysis reaction occurs. It consists of several different components, where the number of each component can also vary, with ‘x’, ‘y’ and ‘z’ describing the variable number. The electrolyser system includes x · electrolyser units, which contain y · stacks of electrolyser cells and a balance of the stacks. The electrolyser system also includes a control system, a balance of the system, and in some cases power electronics, which can include rectifiers and/or transformers. For 10 MW and smaller projects, an

electrolyser vendor can cover stacks and the electrolyser units scope with proprietary technology and most likely working with partners for the rest of the components.

2) **Balance of the Plant**: This refers to all the additional components necessary for hydrogen production that falls outside the scope of the electrolyser vendor. It includes the water supply, nitrogen supply, possible compressors, possible storage, cooling systems, switchgear, grid connection and so on.
3) **Control System**: With the goal of highly automated production that requires minimal human interaction and safe operation, the control system becomes essential. It governs the various components, ensuring smooth and efficient operation of the entire hydrogen plant.
4) **Civil Infrastructure**: This category encompasses all components related to the physical foundation of the hydrogen plant, such as construction of buildings or access roads.

Table 21 lists each component within the four specified categories. The table shows how some components are vendor specific, some are off-taker specific, and some are dependent on the technology or design.

Table 21: Inclusion basis for each component in a hydrogen plant.

Component	Comments
1. Electrolyser system	
Electrolyser Unit	Vendor and off-taker specific
Balance of the system	Vendor and off-taker specific
Power Electronics	Dependent of electrolyser unit design and kV connection at the plant
Control system	Vendor and off-taker specific
2. Balance of the Plant	
Water Treatment Plant	Water source as well as electrolysis technology dependent
Cooling systems	Electrolysis technology dependant and off-taker specifics (excess heat)
Compressors	Off-taker specific
Power connection	Power dependent
Nitrogen	Electrolysis technology specific
3. Control system	
	Off-taker specific
4. Civil infrastructure	
Buildings	Off-taker specific and component choice
Foundations	Off-taker specific
Plumbing	Off-taker specific
Lights	Off-taker specific
Roads	Off-taker specific
Access	Off-taker specific

Brief technology description

Hydrogen plant flow diagram

Figure 47 shows a flow diagram illustrating the primary streams within the various components of a hydrogen plant, which is split into the four distinct categories.

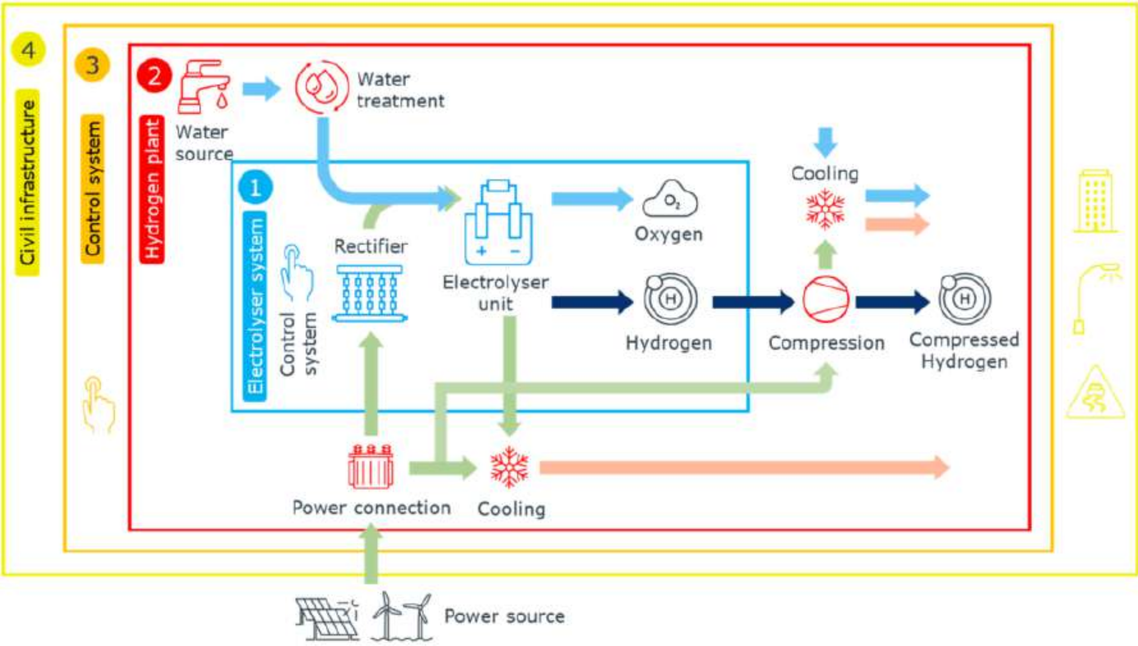

Figure 51: Flow diagram of major streams and components in a hydrogen plant.

Electrolyser system

Description of electrolyser system

Figure 52 provides a comprehensive overview of the electrolyser system, delineating its key components: the electrolyser unit, the balance of the system, the power electronics, and the control system.

Electrolyser Unit: This element includes the stacks (ensemble of cells where the electrochemical reaction takes place) and all necessary components consolidated into a single unit, such as connectors and piping, collectively referred to as the balance of the stacks. Despite stacks varying in size from a few kilowatts to multiple megawatts, electrolyser unit sizes remain in a comparable order of magnitude, measured in megawatts.

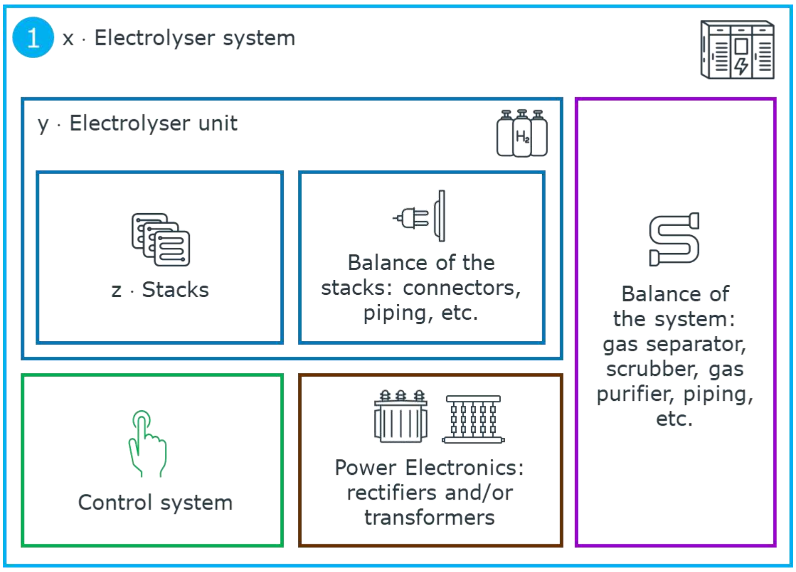

Figure 52: Schematic of the different components included in an electrolyser system: electrolyser units, balance of the system, power electronics and control system.

Types of electrolysers

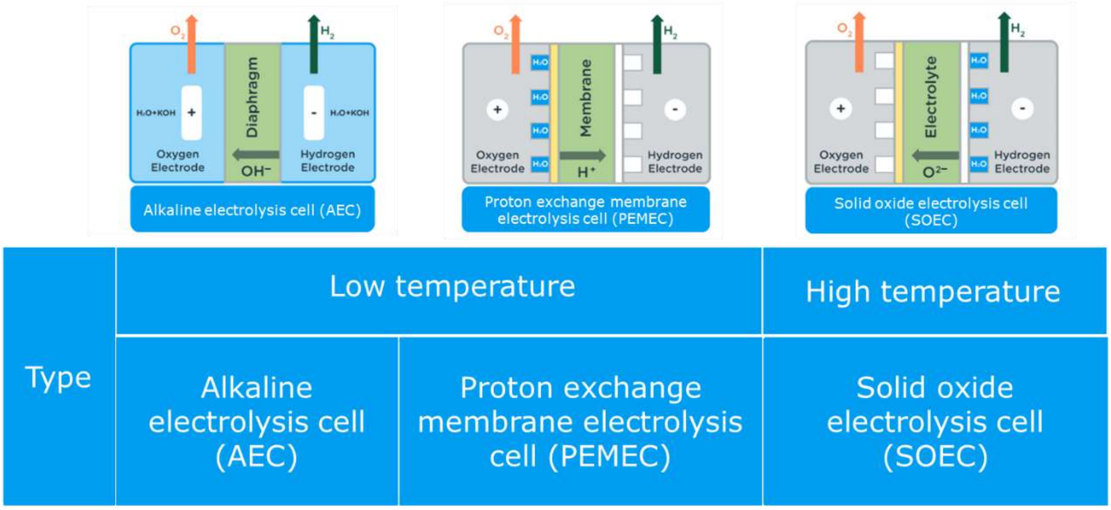

Figure 53: The three primary electrolyser technologies: AEC, PEMEC, and SOEC.

There are three primary types of electrolyser cells: alkaline electrolysis cells (AEC), proton exchange membrane electrolysis cells (PEMEC), and solid oxide electrolysis cells (SOEC). Regardless of the specific technology, the fundamental reaction remains consistent across all types. The operational principle for these three technologies lies in the process of breaking the water molecule using electricity, also known as electrolysis. As result, hydrogen and oxygen are produced, as exemplified in the following reaction.

$$2\,H_2O \rightarrow 2\,H_2 + O_2$$

The reaction at the hydrogen and oxygen electrodes for each technology varies slightly, as shown in table below.

Table 22: The reactions at the hydrogen electrode and oxygen electrode for each of the three electrolysis technologies.

	Hydrogen electrode/Cathode	**Oxygen electrode/Anode**
AEC	$2H_2O + 2e^- \rightarrow H_2 + 2OH^-$	$2OH^- \rightarrow \frac{1}{2}O_2 + H_2O + 2e^-$
PEMEC	$2H^+ + 2e^- \rightarrow H_2$	$H_2O \rightarrow \frac{1}{2}O_2 + 2e^- + 2H^+$
SOEC	$2H_2O + 4e^- \rightarrow 2H_2 + 2O^{2-}$	$2O^{2-} \rightarrow O_2 + 4e^-$

Note: In water electrolysis, common terminology includes referring to the electrodes as the anode and cathode. The cathode is associated with the reduction side, where the reduction reactions take place, while the anode is associated with the oxidation side, where oxidation reactions occur. Alternatively, different terminology may use the terms 'hydrogen electrode' and 'oxygen electrode'. This terminology allows to understand better each side when fuel cells or reversible systems are also considered. Table below shows the partial reaction taking place for every technology in each electrode.

Table 23: State-of-the-art characteristics of different electrolysis technologies (representing status as of 2020). Electrolyser system is defined as components including stacks, power electronics and balance of the system components (gas separators, electrolyte tanks, etc.), and excluding balance of the plant.

Status 2020					
Parameter	**Units**	**AEC**	**PEMEC**	**SOEC**	**Ref.**
Critical raw materials	Chemical elements	Ni, Ru, Ir	Pt, Ti, Ir	Co, Ni	[1]
Max stack size | H_2 output	MWe | $kg_{H2}h^{-1}$	5 | 95	1 | 17	0.05 | 1	[2], [3]

Average stack efficiency	kWhe/kgH_2	52.3	56.3	40.4*	[4], [5], (IRENA, 2021), [7]
Average stack lifetime	h	70,000	55,000	21,250	[2], [3]
Electrolyser Unit Footprint	m²/MW	25	10	30	RE**

*Steam input at 150 °C. Efficiency value excludes the energy consumption related to steam input.
**RE = Ramboll estimate

Alkaline electrolysis cells

Alkaline electrolysis cells (AEC) are the most mature electrolysis technology, and they use a liquid electrolyte (potassium hydroxide, KOH). The main characteristics of AEC are presented in Table 3. Both large stacks and electrolyser systems can be achieved with the use of pressurized AEC technology, with stacks as large as 5 MW with an output hydrogen flow rate of 100 kg/h and systems larger than 500 MW, with a stack lifetime of 70,000 h (2020) [2], [3]. These stacks allow the design of electrolysis units between 10 MW and 25 MW with the possibility to have their own balance of the system and power electronics.

Regarding the materials used in AEC, both pure nickel (Ni) and Ni-plated carbon steel are the more common materials, with the use of some expensive and rare-earth metals such as ruthenium (Ru) or iridium (Ir) being significant in some of the solutions offered in the market, although not in every solution. Recent calculations made by the International Energy Agency estimate that AEC uses around 800 kg/MW of Ni [1]. Pure Ni and Ni-plated carbon steel are used as constituents of different parts in the electrolyser stack, such as bipolar plates and electrode supports, or even as catalysts in the case of Ni. Ni-plated carbon steel is proposed to replace pure Ni in all components due to the relative cost and projected scarcity of Ni in the coming decades. This alternative becomes a viable option under less stringent operating conditions, assuming continuous improvement of the carbon steel coatings. Balance of the system components, such as electrolyte tanks or gas separators, are mainly made of Ni-plated carbon steel, but due to the corrosion characteristics of the electrolyte, some stainless-steel components may also be needed. In addition, stainless steel is also used for electrolyser system tubing. Finally, non-expensive catalysts such as Raney Ni, but also Ni-, Iron (Fe)- and/or Copper (Cu)-containing alloys, are the more common materials used as catalysts. In some cases, the use of Ru and Ir can also be found, allowing the operation of the stack at higher current densities, leading to smaller footprints, although without much improvement in electrical efficiencies [2].

Proton exchange membrane electrolysis cells

Proton exchange membrane electrolysis cells (PEMEC) are characterised by having a solid electrolyte and by operating at much higher current densities, resulting in a significantly smaller electrolyser system footprint. With a relatively high output pressure of ca. 30 bar, it produces high-purity hydrogen (99.999%). Table 22 shows the main characteristics of this technology. Rather large stacks can also be achieved, with current sizes averaging 1 MW and 17 kg/h of produced hydrogen (H_2). Lower footprints compared to AEC can be achieved. These large stacks in hydrogen output and small footprints enable PEMEC manufacturers to currently reach system sizes above 100 MW with slightly higher electricity consumption on average than AEC (56 kWh/kg) as well as a shorter stack lifetime on average (55,000 h as per 2020) [2], [3].

Regarding the materials, PEMEC is the more demanding technology in terms of raw materials, as it uses large quantities of titanium (Ti), platinum (Pt), and iridium (Ir). These metals are very scarce in nature leading to a possible hurdle in long-term operation of commercially available PEMECs and for large scale projects (>100 MW). Ti is used in some of the stack constituents, such as bipolar plates and porous transport layers (PTLs), due to its good performance and stability in the service conditions (high potentials in acidic media). Pt and Ir are used as catalysts to carry out the high-demanding electrocatalytic reaction in acidic media, with loads of Ir and Pt about 0.3 kg/MW and 0.7 kg/MW respectively [1]. In addition, Pt is also used as a coating for some of the Ti constituents described above (mainly PTLs). One of the main advantages of PEMEC technology is the use of fewer balance of the system components, as no electrolyte tanks or gas separators are needed. However, the use of stainless steel for electrolyser system tubing is still necessary, as is the case with AEC technologies.

Solid oxide electrolysis cells

Solid oxide electrolysers (SOECs) are characterised by their ability to operate at high temperatures (i.e., 550–850°C), making them the most efficient technology of the three electrolysis technologies. Additionally, they are made of cheap and abundant materials (i.e., ceramic oxides). Table 3 shows the main characteristics of this technology. Compared to PEMEC and AEC, SOECs use much smaller stacks due to the current difficulties with scaling up high-quality and reliable ceramic technology. However, this electrolyser systems can already achieve the MW scale, allowing for their commercial deployment and paving the way for continuous development. The main advantage of SOECs over other electrolysis technologies is their much higher efficiency. They operate at the thermoneutral point (1.29 V), resulting in stack efficiency very close to 100%. An average electricity consumption for SOECs, while feeding steam water at 150°C, is 40 kWh/kg. This value increase to 45 kWh/kg when accounting for the heating of water [2], [3]. The stack lifetime is the shortest of all the technologies: 21,250 h as per 2020.

SOECs are made of cheap and abundant materials, namely ceramic oxides containing inexpensive and readily available materials such as Zirconium (Zr), iron (Fe), Manganese (Mn) and stainless steels. There are also other materials, such as Cerium (Ce), Lanthanum (La) or Yttrium (Y) that are less abundant but still cost-effective and readily available [2]. Special mention must be made of both Ni and Co as both materials are used quite extensively in SOEC constituents, which could be an issue. However, the current use of Ni and Cobalt (Co) is only 200 kg/MW and 25 kg/MW, respectively, which is four times less than in AEC technologies in the case of Ni [1]. The use of high temperatures is another material concern as more advanced stainless steels need to be used when the operating temperature is higher (i.e., >550°C) in both stack constituents and hot boxes, as stacks will be connected in series and operated at the desired temperature. However, recent developments show a trend in decreasing the operating temperature below this critical level (<700°C), where cheaper stainless steels can be used.

Balance of the System

The specific components required to connect different electrolyser units vary depending on the technology used. Such components can encompass gas separators, gas scrubbers, gas purifiers, connectors, piping, and more. For instance, in alkaline electrolyser system, due to the liquid electrolyte, gas separators, scrubbers and purifiers are needed. These components have considerably large footprints and are normally shared for few stacks. The electrolyser system is composed of both the piping and its corresponding electrical connections. On the other hand, SOEC and PEMEC do not have the need of some of these components (i.e., gas separators, scrubbers and purifiers) as the output of their stacks is of higher purity (both hydrogen and oxygen).

Power Electronics

Typically, each electrolyser unit is paired with a set of power electronics, varying in size and units, inclusive of rectifiers and/or transformers. These components will transform the AC current to DC current and rectifiers, will deliver the appropriate DC current required for the different stacks. Very different options can be found, and specific designs could be done in function of the different characteristics of the technology and the size of the hydrogen plant. For instance, containerized solutions for smaller hydrogen plants (i.e., 10 MW) will include both transformers and rectifiers, while in a larger hydrogen plant transformers, rectifiers and other power electronic components will fall in the balance of the plant components (see Section 0). Often, these components are supplied by specific power electronic companies and as the project becomes larger will not fall within the scope of the electrolyser vendor.

Control System

The electrolyser system is a highly automated assembly governed by a control system that manages the entire operation, ensuring seamless functioning and efficiency. This could include gas sensors, safety shutdowns, Programmable Logic Controllers (PLC) panels, and Supervisory Control And Data Acquisition (SCADA).

Balance of the Plant

Beyond the electrolyser system, a hydrogen plant needs several components to deliver the desired hydrogen to the final off-taker. The most relevant are shown in figure and described in the subsections below.

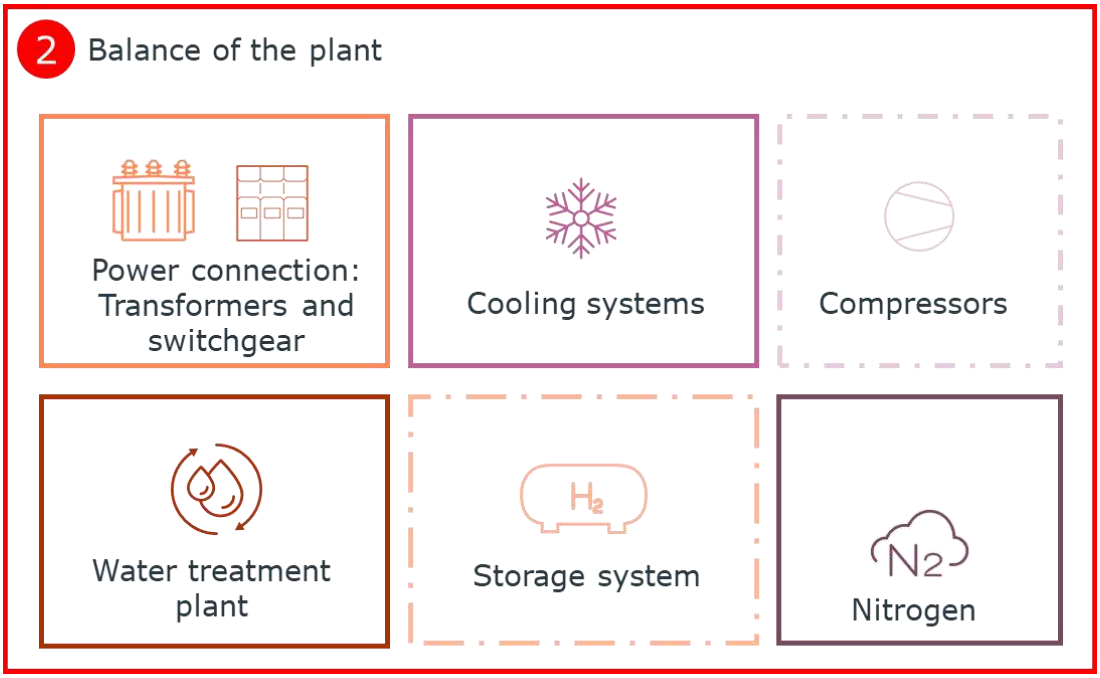

Figure 54: General components of the balance of the plant in a H_2 plant. Compressors and storage system are shown with dotted lines as they are not required in every hydrogen plant.

Water Treatment Plant

High quality water is required during the water electrolysis process, as impurities of water will lead to undesired products in the electrolysis cells and can also irreversibly contaminate the cell. Generally, large volumes of water will be needed for hydrogen production and therefore, water treatment plants will be coupled to hydrogen production.

In general, water sources can be split into several types such as surface water, groundwater, city or drinking water, seawater or effluent or treated wastewater. Each type will need a slightly different approach as they have varying contents of minerals, sediments, and other contaminants. Furthermore, depending on the amount of treatment necessary, different amounts of water extracted will be necessary. For 1 m^3 of ultrapure water, it will be required to source 1.4 m^3 of groundwater, 1.5 m^3 of wastewater or surface water, and 3.3 m^3 of seawater. 1 kg of H_2 requires approximately 9 kg of ultrapure water for the electrolysis process (Eurowater).

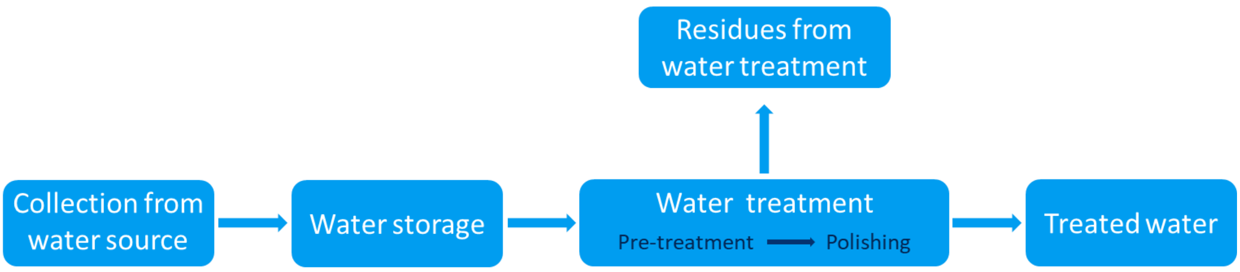

Figure 55: General flow diagram of water.

Depending on the type of electrolysis and the source of water, there will be different requirements for water treatments. However, in each case there will be a pre-treatment step followed by polishing within the water treatment. The source of water determines the pre-treatment, and the polishing step is determined by the electrolyser technology. The steps may include filtration, aeration, UV, desalination, followed by softening, demineralization, degassing and polishing EDI.

Compressors

Compressors play a critical role in green hydrogen plant, especially during the distribution and storage phases, but also by ensuring a pressure level required for offtake delivery. Once green hydrogen is produced via electrolysis, it is in its gaseous state and occupies a large volume. Compressors are used to increase the pressure of this hydrogen gas, significantly reducing its volume, and making it more practical for storage and transport. However, it is important to notice that both AEC and PEMEC technology can deliver hydrogen at pressures as high as 30 bar, which can be sufficient for many Power-to-X (PtX) applications (e.g., ammonia or steel production or pipeline transportation given inlet pressure demand in pipeline system is met).

The compression process begins by collecting low-pressure hydrogen gas from the suction side, then reducing its volume. This results in a pressure increase at the outlet, making the gas ready for storage in high-pressure tanks. The types of compressors used can vary, with options including diaphragm, piston, and ionic liquid piston compressors. Each has its advantages and challenges in terms of efficiency, reliability, and cost.

Reciprocating compressors have great compatibility with high-grade hydrogen, effectively avoiding oil contamination. Within the category of reciprocating compressors, there are various types, such as metal piston, diaphragm piston, and ionic liquid piston. Additionally, there are other alternatives, like hydride compressors and electrochemical hydrogen compressors (EHC). Hydride compressors utilize an absorbent material that adsorbs hydrogen at ambient conditions, later heated to increase pressure. Electrochemical hydrogen compressors (EHC) employ a proton exchange membrane to force hydrogen from low to high pressure through electricity, offering noiseless and scalable operation with high energy efficiency.

One critical aspect of compressor efficiency lies in understanding the energy loss that occurs during the compression process. The prevalent design for hydrogen compressors involves multiple stages with inter-stage cooling, which allows the calculation of power loss, considering both shaft power and the energy consumed by the cooling system. By delving into these factors, valuable insights into the operational costs associated with compressors can be gained [9].

With advancements in technology, hydrogen-specific compressors are being developed to increase efficiency and reduce costs associated with green hydrogen production. Ensuring the effective and safe operation of these compressors is vital, as the high pressure involved can pose safety risks. Hence, they are integral not just to the production but also to the advancement of the green hydrogen industry.

For a more extensive overview of hydrogen compression, see the Danish Energy Agency's (DEA) technology catalogue "Technology data for energy transport" section "Introduction to transport of gases and liquids" [9].

Nitrogen supply

Nitrogen is crucial in green hydrogen production for safety and component preservation. It is used to purge and pressurize systems, reducing the risks associated with hydrogen's flammability. Nitrogen purging before electrolysis removes residual gases, minimizes electrolyser degradation, and ensures system safety. It also creates an inert atmosphere during maintenance and repair, while blanketing stored hydrogen for added safety.

Storage and transport

Before the usage of hydrogen, it may need to be stored or transported. This needs to be done in a manner that is both safe and efficient to ensure its viability as a fuel source. Some methods include utilizing gas compression, cryogenic liquefaction, or chemical carrier methods. Chemical carriers may include liquid organic hydrogen carriers (LOHC), ammonia (NH_3), or methanol (CH_3OH).

Physical methods like high-pressure gas cylinders and cryogenic liquid tanks are commonly used in industrial applications. High-pressure gas cylinders compress hydrogen to minimize its volume, but the compressing process requires significant energy, in the case where hydrogen is not already compressed from the electrolysis process. Cryogenic tanks store hydrogen in liquid form at extremely low temperatures, a process that also consumes energy for cooling, even higher that process in gas form. Furthermore, hydrogen transportation encompasses diverse methods, including high-pressure pipelines, cryogenic ships for long-distance transport in liquid form, and tube trailers or trucks for versatile, high-pressure gas delivery, all tailored to specific needs and pressure requirements.

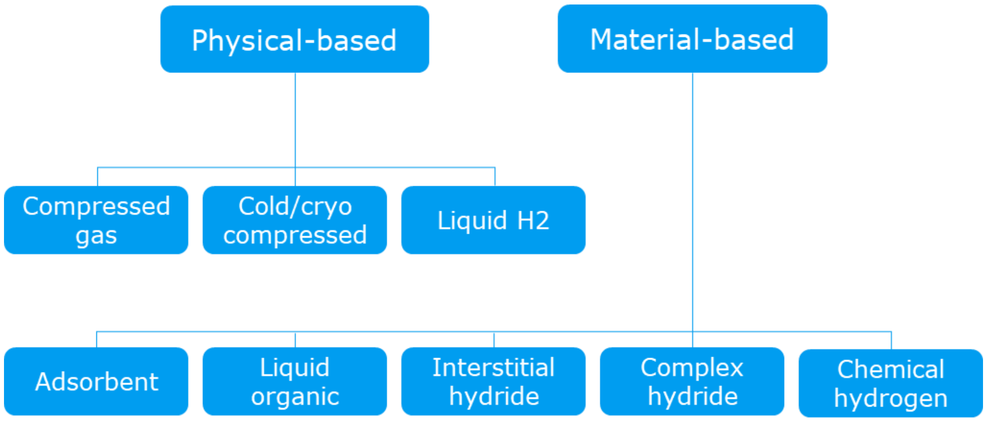

Figure 56: Different options to store hydrogen. Developed from [10].

Alternatively, material-based storage methods are being explored. These include metal hydrides, chemical hydrides, and sorbent materials, which can store hydrogen at near-ambient conditions. This approach can offer greater energy density but faces challenges regarding weight, cost, and the rate of hydrogen release and uptake. In addition to these methods, large storage methods such as salt caverns will be used to store large quantities of hydrogen and for a relatively long period of time.

Storage systems are dependent on the project, location, and off-taker specifics, therefore is omitted from the cost estimation.

For a more extensive overview of hydrogen storage, see the DEA's technology catalogues "Technology data for energy transport" section "Introduction to transport of gases and liquids" [9] and "Technology Data – Energy storage" section "Hydrogen Storage" [10].

Cooling system

Cooling systems are essential in green hydrogen production, particularly during AEC and PEMEC electrolysis and compression stages. They prevent damage and decreased efficiency by managing excessive heat generated by electrolysis. Efficient cooling is crucial for optimal operation and longevity of the electrolyser system, and will involve coolants, heat exchangers, and advanced techniques like liquid cooling. These cooling systems maintain components at optimal temperatures, contributing to stability, durability, and overall process efficiency.

Power Connection

In hydrogen plants, the required electrical power connection, often referred to as the voltage level, depends on the hydrogen plant's size and specific operational requirements. In addition, the available power will be very country dependent as every system operator will have different power options. For example, in Denmark, a 10 MW hydrogen plant would typically have a 10 kV power connection, while a 1 GW plant would have a 400 kV power connection.

While small projects (<10 MW) would have most of the power electronic components within the scope of the electrolysis system design as the projects become larger (i.e., >10 MW) specific electrical designs will be performed to reduce costs and due to the need of more components as further transformers and components such as switchgear will be required.

Switchgear in a hydrogen electrolysis plant is essential for safe and efficient operations. It controls and protects the power distribution system, ensuring reliable electricity flow. It includes power supply switchgear, main switchgear for distribution, and control switchgear for electrolysis cell operation. Protection switchgear safeguards against faults and abnormalities. Communication and monitoring capabilities enable real-time data acquisition and remote control. Safety measures are crucial due to hydrogen's flammability. Overall, switchgear ensures reliable power distribution, protection, and efficient plant operation.

Power requirements such as large step-down transformers and further switchgears may be required depending on the project specific or location specific infrastructure. Potential cost related to this is not included in the CAPEX estimate presented in Section 0 and in the data sheets. However, initial rectifier and transformer for the electrolysers at site are included.

Plant Control system

Control systems in green hydrogen production are essential for monitoring and managing the operational processes, ensuring efficiency, safety, and reliability. These systems govern and oversee all stages of production, from water treatment/use to electrolysis and hydrogen storage and transport.

In the electrolysis process, control systems manage parameters such as current density, temperature, and pressure to optimize hydrogen production. For compressors, control systems ensure optimal operation, controlling the compression rate and heat management to prevent overheating and mechanical failure.

Control systems also regulate hydrogen storage, monitoring pressure and temperature levels within storage vessels and ensuring safety thresholds are not breached. In case of deviations, these systems trigger alarms or automated responses to prevent accidents.

Moreover, they handle safety systems like hydrogen leak detectors and fire suppression systems, triggering them when necessary. Data acquisition is another crucial function, collecting data from various sensors and meters to enable system optimization, preventative maintenance, and troubleshooting.

Given the high level of automation in modern green hydrogen facilities, control systems often utilize advanced technologies such as artificial intelligence and machine learning for predictive maintenance and process optimization. Thus, control systems are the nerve centre of a green hydrogen plant, ensuring smooth, safe, and efficient operations.

Civil infrastructure

Civil infrastructure components relate to the physical foundation of the plant, such as construction of buildings or access roads, and potentially added infrastructure like train tracks, among others. These foundations can vary by size depending on soil characteristics of the location, including soil improvements such piling. Average foundation sizes, rough grading, roads, site paving and a water treatment building are included in the estimate, but no other buildings.

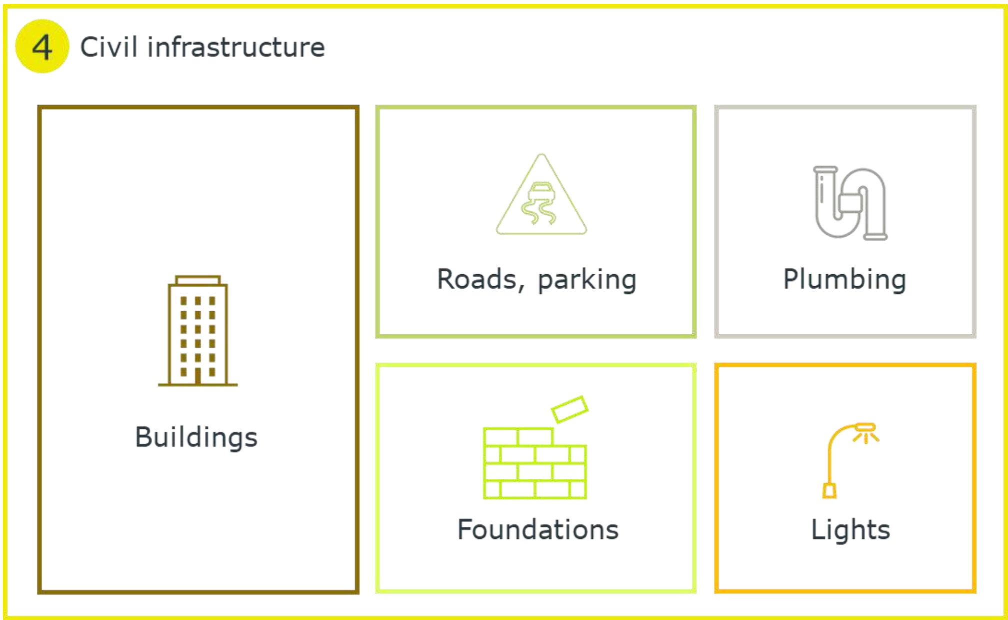

Figure 57: General components of the civil infrastructure category of a hydrogen project.

Buildings

Buildings for green hydrogen production must meet operational, safety, and environmental requirements per international code restrictions such as International Building Code, National Fire Protection Agency 2 – Hydrogen Technologies, and International Fuel Gas Code. They should provide sufficient space for electrolyser systems, compressors, storage, and cooling systems, including room for maintenance and future expansion. Safety measures, such as ventilation systems and gas detection units, should prevent hydrogen build-up, while fire prevention and suppression systems are essential. The hydrogen plant could be outdoors with weather protection for the stacks, and outdoor rated equipment for the electrical equipment. Due to the cost implications for indoor operation, the cost estimate does not include a building for the electrolyser system or balance of the plant. In most cases, components like compressors will usually be indoors.

Power management areas, water supply options, and environmental considerations, such as noise and visual impact, contribute to efficient, safe, and environmentally friendly green hydrogen production.

Roads, access, parking

Roads must enable reliable access for staff, raw material delivery, and hydrogen transportation, accommodating heavy-duty vehicles and considering load capacity. Access infrastructure should include evacuation routes, emergency services access, clear signage, and adequate parking. Consideration for maintenance and replacement access, as smooth plant operation is essential for efficient green hydrogen production.

Foundations

Foundation requirements are crucial for ensuring stability and safety of the installed components, supporting the weight of electrolyser systems, compressors, storage, and cooling systems. Considerations such as load-bearing capacity, local ground conditions, and potential machinery vibrations must be considered. Adequate drainage systems should also be incorporated to prevent water accumulation and potential structural instability.

Plumbing

Pipes should be designed to handle various fluids and high pressures, while efficient drainage and leak prevention are essential. Safety measures, such as quick isolation of plumbing sections, should be in place for hydrogen-related risks, and corrosion-resistant materials should be used, especially when saline or wastewater is involved.

Lights

Lighting requirements in green hydrogen production facilities must prioritize operational, safety, and energy efficiency, providing good visibility for machinery operation and maintenance. This involves implementing emergency lighting systems for safe evacuation, minimizing glare and shadows. Energy-efficient fixtures should be chosen to reduce power consumption, and explosion-proof options are necessary for hydrogen safety.

Input

For all three electrolysis technologies, the input is electricity and water. For SOEC, PEMEC and AEC, high- purity water is needed. The water quality is normally determined by the conductivity of the water but also by the content of other impurities. Water categories are normally described as Type I (ultrapure water), Type II and Type III (drinking water). While SOEC and AEC can accept Type II water with conductivities around 1 μS/cm, PEMEC technology needs Type I and conductivities below 0.1 μS/cm. In addition, SOEC use steam rather than water and as it operates at the thermoneutral point is thus a consumer of heat. If the hydrogen produced was to be used for synthetic fuel, then the waste heat of these synthesis processes (e.g., Fischer-Tropsch synthesis, Haber-Bosch process) could be used to produce steam for further SOEC electrolysis and increase SOEC electrolysis efficiency further [11].

Output

For all three electrolysis technologies, hydrogen and oxygen are an output, and in the case of PEMEC and AEC, excess heat is also an output [12]. As mentioned in Section 0, SOEC operates at the thermoneutral point or slightly below and therefore, it absorbs heat from the surroundings. Oxygen is a by-product, which can be used in various industries, such as paper and pulp production, glass manufacturing, water oxygenation, fish farming, steel and metal industry, medical care industry, food, manufacturing, oxy fuel Carbon Capture and Storage (CCS), thermal gasification, and more. The excess heat may be used for district heating in case of PEMEC and AEC. AEC and PEMEC systems are found in the literature to generally have operating temperatures of 50-80°C and 60-80°C [13]. In 2020 systems can deliver heat at 50°C possibly for district heating, according to manufacturers, this is expected to increase to 70°C by 2024.

Energy balance (representing 2020 data)

An energy balance for each of the three electrolysis technologies, AEC, PEMEC and SOEC is shown/displayed in this section and presented as Figure 58, Figure 59, and Figure 60. The data represent 2020 and is based on Ramboll projects.

The energy balances are on a plant level, i.e., including the Balance of Plant (BOP).

For AEC and PEMEC, the input is 100% electricity while for SOEC (in 2020) electricity is 79.5% of the input energy, while the remaining 20.5% is supplied by heating requirements. This differentiation is done since SOECs operate at higher temperature wherein, the water needs to be converted to steam and the operation occurs at temperatures over 600°C.

Figure 58: The energy inputs and outputs of an AEC (2020, 10 MW hydrogen plants). Data is derived from Ramboll references.

Figure 59: *The energy inputs and outputs of a PEMEC (2020, 10 MW hydrogen plants). Data is derived from Ramboll references.*

Once water or steam is supplied to the electrolysis cells, formation of H_2 and O_2 takes place along with heat dissipation. Since the heat needs to be at a certain temperature to be fed into the district heating grid, only a percentage of the heat generated can be directly utilized. An important aspect related to the analysis performed herewith does not consider the latent heat of vaporization of steam in the product and normally referred as the Low Heating Value (LHV) and High Heating Value (HHV) of hydrogen. This is performed in order to get an accurate analysis of the usable energy produced by electrolysis.

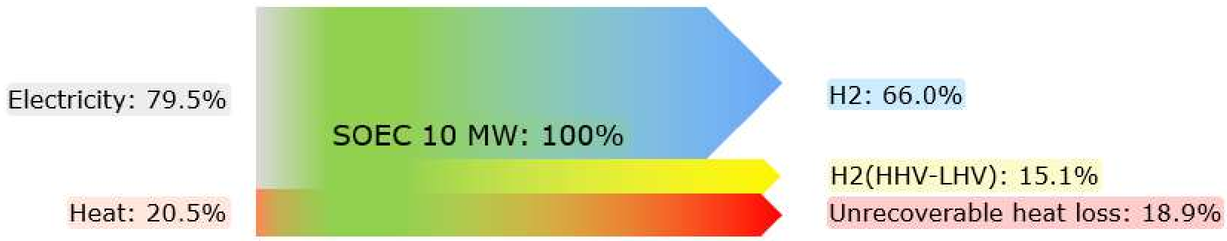

Figure 60: The energy inputs and outputs of an SOEC (2020, 10 MW hydrogen plants). Data is derived from Ramboll references.

Typical capacities

Table below shows the maximum electrolyser system size for each technology. AEC and PEMEC can deliver projects >500 MW while SOEC projects are in the 50 MW range.

Table 24: Cold and warm start-up time, power response signal and load range for AEC, PEMEC and SOEC technologies. Status 2020.

	AEC	PEMEC	SOEC
Cold start-up time (from 0 to 100%) [minutes]*	< 80	0.5	600
Warm start-up time (from 0 to 100%) [seconds] *	240 (60-300)	< 10	600
Power response signal [seconds] *	< 1-5	< 1-5	< 1-5
Load range per electrolyser system (%)*	15-100	5-130	30-125

Ramping configuration

In general, electrolysis systems can be operated very dynamically, limited mainly by the heat management, the maximum voltage of the rectifier, and the time coefficients of external components [14]. The cold start-up time, warm start-up time, and the power signal response for the three systems are displayed in Table 4.

A cold start is defined as start-up from ambient temperature after a long shutdown. A warm start is defined as start-up from heated stand-by or idle mode, which means that the electrolyser system is held at operating temperature and pressure if necessary. The power response signal is the time it takes for the electrolyser system to adjust to a change in the power input and is measured in seconds. This rapid reaction may allow the system to stabilise power grids when the system is running at operating temperatures.

Advantages/disadvantages

In this section, a summary of advantages and disadvantages of AEC, PEMEC and SOEC are displayed in table below. The data is collected from literature [15], (Hansen, n.d.).

Table 25: A summary of advantages and disadvantages of the electrolysis technologies investigated.

Technology	Advantages	Disadvantages
AEC	1. The technology is very mature and scalable. 2. AEC has a low operating temperature, with a quick start up (pressurized) for response in grid services making it suitable for use as a flexible technology. 3. Long stack lifetime of more than 70,000h (2020) currently. 4. MW scale electrolyser systems are already being deployed.	1. Less flexibility under atmospheric operation. 2. The use of highly caustic electrolyte in AEC. 3. Leakage of KOH. 4. High membrane resistance. 5. Low maximum operational current density, nominally operated around 0.6-1 A/cm^2 as average [17].
PEMEC	1. PEMEC has a low operating temperature, low noise, high power density. 2. Quick response time. 3. Pressurized hydrogen can be produced for direct storage without compression; however, it is challenging. 4. Current densities >2.0 A/cm^2 can be used for operational systems leading to compact system sizes. 5. MW scale electrolyser systems are already being deployed. 6. Smaller footprint than AEC.	1. Very sensitive to impurities, with a prerequisite of very pure water (Type I) as input. 2. Lifetime of the commercially available systems is still uncertain. 3. Catalyst used in electrode layers are expensive and scarce. 4. PEMEC constituents are expensive due to catalysts and bipolar plates (oxide resistant stack elements). 5. Cost efficient water treatment and drying the hydrogen at high pressure is still challenges to be addressed.
SOEC	1. SOEC has high efficiency (up to 95 %), high production rates. 2. SOECs can be used to make synthesis gas from co-electrolysis of steam and CO_2.	1. SOECs are still in demonstration phase for large scale applications for hydrogen production and are not readily commercially available.

3. CO-electrolysis plants have been commercialized. 4. SOECs can cope with transient variation due to quick response time. 5. SOECs can be used reverse mode as a fuel cell for grid balancing.	2. SOEC's units are about 10 times smaller in H_2 output than PEMEC and AEC. 3. The stack components are susceptible to corrosion. 4. Commercially available lifetime system is short compared to PEMEC and even shorter to AEC. 5. SOECs can be operated only at current densities up to 0.5 A/cm^2.

Space requirement

Evident differences can be seen with smaller footprints for PEMEC technologies (10 m^2/MW) compared to Alkaline (25 m^2/MW) and SOEC (30 m^2/MW) much more similar between them. Significant increases in the system sizes are expected if a compressor for delivering high pressure hydrogen (>30 bar) is required, on top of the base system or in function of the final solution used as power electronics (i.e., rectifiers, transformer, switchgear, etc.). This may lead to much more similar sizes on the overall of the project footprint.

Water consumption

As mentioned earlier, the hydrogen production via water electrolysis requires approximately 9 kg of water per 1 kg of hydrogen (Eurowater). The water consumption levels for the electrolysis process vary depending on what technology and what water sources are being used.

Table 26: Water consumption per MWh for the electrolysis process for the different technologies and water sources

Kilogram water/ MWh Electricity input	**Ultrapure water**	**Groundwater**	**Wastewater / Surface water**	**Seawater**
AEC	175 kg	245 kg	262.5 kg	577.5 kg
PEMEC	167 kg	233.8	250.5	551.1 kg
SOEC	228 kg	319.2 kg	342 kg	752.4 kg

Environment

For all the electrolysis technologies producing hydrogen, the only products are hydrogen, oxygen, and excess heat. Electrolysis can be used to balance fluctuations in the power supply and hence increase the value of electrolysis (clean energy carrier) by further conversion into chemicals.

For AEC, the oxygen electrode, the hydrogen electrode, as well as the catalyst layer are usually nickel-based which is becoming a scarce resource due to the high use in other renewable technologies (i.e., batteries).

For PEMEC, the membranes consisting of fluoropolymer need to be disposed or recycled after use. In addition, the catalyst layer consisting of platinum and its alloys for the hydrogen electrode, and iridium, ruthenium and their alloys for oxygen electrodes are very scarce in nature leading to a possible hurdle in long-term operation of commercially available PEMECs [18].

For SOEC, Ce, La and Y are less abundant but still cost-effective and readily available as they are made of oxides which are much more abundant. These might obstruct the commercialization of large scale SOEC electrolyser systems although alternatives to this material can be found.

Research and development

For AECs, the main challenge is improving the efficiency of the stacks while continuing to use low-cost materials. Development regarding the catalyst but also the stack design is undergoing to improve this efficiency. Some examples of these developments in AEC technologies are given by different electrolyser companies such as Hysata or Hydrogen Pro. On one hand, Hysata has recently presented a capillary stack design where efficiencies could be improved significantly (up to 95%) [19]. On the other hand, Hydrogen Pro works in obtaining better catalyst without using any expensive metal [20].

For PEMEC, stack cost is the major hurdle to commercialization of large-scale electrolyser systems. The cost of catalysts and bipolar plates are under investigation in terms of research on lab scale. Furthermore, scarcity of elements is considered while finding alternative materials for substitution. In this sense, recent achievement by TNO in the Netherlands has shown that it is possible to reduce Ir loading considerably (200 times) and therefore obtaining cheaper stacks [21].

Finally, SOECs are working in scalability and durability. Recent studies from ISPT in the Netherlands has shown that larger stacks (~50 kW) with higher surface cell area and higher current density (800 cm^2 and 1 A/cm^2) could lead to obtain larger hot modules (~1 MW) and therefore GW-size electrolyser systems [22]. In addition, lowing the temperature of operation of SOECs will allow the use of even cheaper materials to make SOECs stacks more cost-effective.

Finally, it is worth it to mention the efforts that different Danish companies are doing in developing electrolysis technologies. Green Hydrogen Systems develops pressurized alkaline technology with manufacturing capacities by the end of 2023 close to 400 MW [23]. Equally, Topsøe has announced the construction of a new manufacturing factory to reach 500 MW capacity by the end of 2025 [24].

Examples of current projects

Hard-to-abate industries

Fertilizer, steel and chemical industries are the most typical examples of hard-to-abate industries. These industries require large quantities of hydrogen continuously (> 10 000 tons per year) which requires the construction of a hydrogen plant with an electrolyser system as large as 100 MW. In addition, pressure and purity will depend on the final use. Most of these industrial demands would require relatively low pressures (< 50 bar) and not very demanding hydrogen purities (99.5 %), which opens to the use of all three technologies quite freely with AEC and SOEC to be preferential. In addition, SOEC could profit of the excess heat released in these industrial processes, which would make the hydrogen production very efficient. .

Offshore production

Offshore hydrogen production is gaining a lot of attention due to the recent studies pointing that the transport of electrons from offshore wind production through HVDC connection would be much more expensive than the transportation of hydrogen molecules for large-scale projects [25], [26]. These studies indicate that for offshore projects at distances larger than 100-150 km from the coast, offshore transportation of hydrogen through a pipeline would be cheaper than transportation of power through cables with onshore hydrogen production. Dolphin [27] in the United Kingdom, PosHYdon [28] and H2opZee [29] in the Netherlands, Aquaventus [30] in Germany, and Brintø ENERGY ISLANDS [31] are ongoing initiatives that are actively assessing the viability of offshore hydrogen projects in Northern Europe.

Currently, there are two main concepts discussed and compared for offshore hydrogen production, as follows:

- The centralized concept that consists of an offshore windfarm connected and feeding power to offshore platforms equipped with the several electrolyser units, with auxiliary balance of plant equipment. The produced hydrogen is exported via pipelines to shore. This concept can be categorized into a mid-scale, ranging from 100 MW, and a large-scale, exceeding 500 MW.

- The decentralized concept that consists of having each wind turbine equipped with an integrated electrolysis system. In terms of electrolysis capacity, the power supply is limited by the output of each wind turbine (10-16 MW). Similarly, hydrogen is exported to shore via pipelines.

The two concepts are illustrated in Figure 61, emphasizing a significant distinction between them. In the decentralized approach, there is no need for electrical exportation, in contrast to the centralized option, where such infrastructure is required.

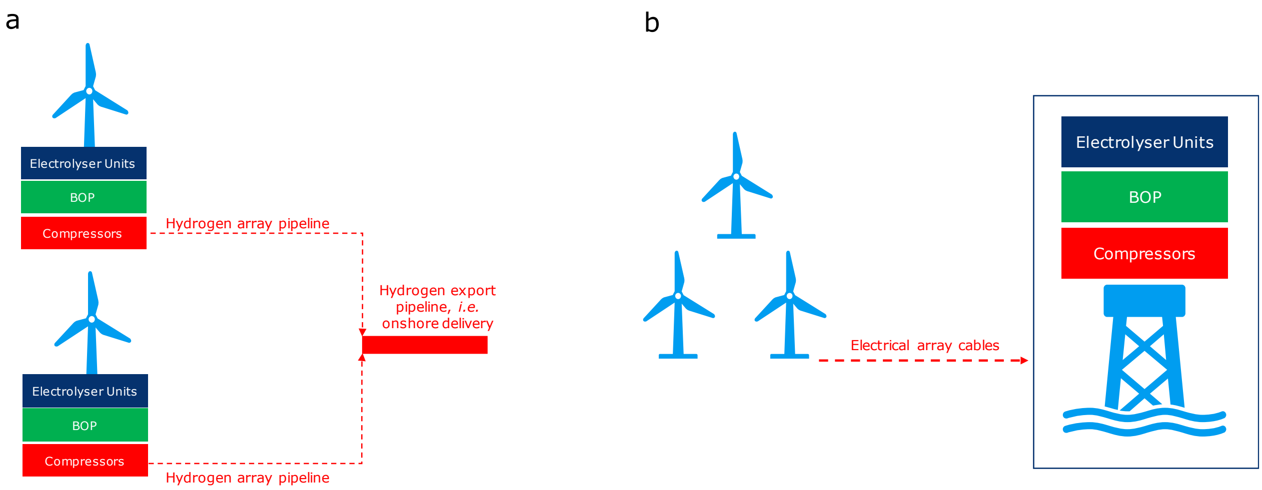

Figure 61: a) schematics of decentralized and b) centralized concepts for offshore hydrogen production.

Beyond the turbine selection and the foundations of offshore structures, both Centralized and Decentralized concepts encompass considerations that hold significant importance from a design perspective. These crucial aspects include:

Electrical Infrastructure (EI): Primarily essential for the centralized concept, an electrical infrastructure is imperative to facilitate the efficient transmission of electrical power to the electrolysers situated on the platforms.

Transport and Installation (T&I): The transportation and predominantly offshore installation processes are of paramount significance. These activities involve the mobilization of valuable assets and are sensitive to adverse weather conditions.

CAPEX: Since cost factors vary significantly between the two concepts, a comprehensive evaluation becomes imperative to guide decision-making.

By focusing on these key considerations, a more holistic approach to design can be achieved, enhancing the overall effectiveness and viability of offshore energy projects.

Table 27: Comparison between decentralized and centralized concepts, concerning EI, T&I and CAPEX.

Parameter	Centralized	Decentralized
EI	Requirement of electrical infrastructure; expecting additional costs and energy losses relative to the Decentralized Concept	No need for electrical infrastructure due to how turbine and hydrogen production plant are set-up, expecting lower energy losses relative to the Centralized Concept – however need of array H_2 pipeline from each unit to a large H_2 pipeline exporting production onshore.
T&I	Less interdependent compared to decentralized, and with lower cost associated	Challenging from a technical perspective, more demanding in terms of vessel days, interfaces between the various equipment packages and with higher cost associated
CAPEX	CAPEX includes electrical infrastructure, and higher voltage cables.	CAPEX is free of additional costs with electrical infrastructure.
	No additional expected CAPEX requirements for ancillary systems (*i.e.,* power storage) similar to onshore of equivalent size; expected economy of scale savings.	CAPEX has higher ancillary systems costs per MW due to smaller but redundant pieces of equipment. Beside supplying power to wind turbines, it accounts also with hydrogen production.
	CAPEX for traditional windfarm elements expected to be in alignment with values	

for a conventional windfarm development of similar characteristics.

Additionally, each wind turbine has higher costs associated with turbine foundation; Requirement of ancillary systems to ensure turbine power supply, expecting (higher) additional costs relative to the Centralized Concept.

Table 27 shows the cost estimates for both centralized and decentralized offshore project as well as an onshore hydrogen plant using PEMEC technology at 100 MW, and 1 GW. This cost encompasses the expenses associated with electrolyser equipment, as well as the necessary balance of plant (BOP), some electrical infrastructure, and the ship used for construction and residence. Compressor may not be needed in the future as electrolysis technology could deliver hydrogen at the desired pressure. This does not include the cost of the platform(s) for the electrolysers, the foundation(s), the jacket(s), or the wind turbine(s).

Table 28: Cost estimates for both centralized and decentralized offshore production in comparison to onshore production for PEMEC.

	100 MW	1 GW
Centralized offshore production*		
Specific investment [€/kW of total input_e]	1.450	1.350
- hereof material %	78%	83%
- hereof labour %	8%	11%
- hereof EPC %	14%	6%
Decentralized offshore production*		
Specific investment [€/kW of total input_e]	1.500	1.350
- hereof material %	77%	83%
- hereof labour %	7%	10%
- hereof EPC %	16%	7%
Onshore production*		
Specific investment [€/kW of total input_e]	1.300	1.200

* Ramboll internal data

Installation is a main cost driver of distinction between offshore and onshore plants. Transporting the necessary equipment and components to the offshore site and installing them can be more expensive than setting up a similar onshore facility. Offshore installation often involves specialized vessels, cranes, and personnel, all of which come at a premium. Besides, not accounted in Table 27, offshore electrolyser plant requires the construction of additional marine infrastructure, such as, foundations, platforms, and subsea pipelines. These elements are essential for the safe and reliable operation of the plant but add to the overall cost in comparison to onshore plants. Finally, offshore maintenance is more challenging than onshore, and more advanced remote monitoring and control system can also increase cost.

Water treatment for offshore plants

When it comes to water treatment and supply for both onshore and offshore electrolysis processes, a crucial element is the inclusion of an ultrapure water storage tank. This tank serves the purpose of stabilizing and initiating the system. What's particularly noteworthy for offshore is the added advantage of harnessing the available heat generated by the electrolysis process through a thermal desalination strategy. This approach transforms what would otherwise be wasted heat into a practical application.

At the core of this heat integration lies as critical component a heat exchanger. This unit facilitates efficient heat transfer between the warm stream from the electrolyser and the incoming cold seawater.

Notably, thermal desalination stands out as a robust solution in this context. Unlike alternative water treatment methods like reverse osmosis, it demands considerably less maintenance, making it an attractive and sustainable choice for offshore applications.

Transportation (shipping, planes, long-haul trucks)

Finally, another option to develop hydrogen plants is for transportation application in form of hydrogen stations with in-situ production. In here, sizes can be much more viable with projects as small as few MWs in electrolyser system size, but with much heavier requirement in terms of compressor and storage as transportation applications requires at least 350 bar or even 750 bar. Storage solutions normally include larger pressures as filling is done by the so-called cascade technique in which a higher pressure is used to fill a gas at lower pressures. In here, space requirements as well as flexibility are quite likely to be constraints, as production is done as much as demand on possible and, therefore, PEMEC electrolyser systems could be a good solution for this type of applications. As in the previous example, if enough space is available, pressurized AEC can however be an option.

Projects in recent years

In this section, different electrolyser systems deployed either commercially or in demonstration phase are summarized. The electrolyser systems at different locations are deployed for various applications and their specifications are also summarized in table below.

Table 29: Examples of operational hydrogen plant projects in recent years across locations, sizes and technologies. (IEA, 2023)

Project	Location	Type	Size (MW)	H_2 prod. (t/y)	COD year	Off-taker Sector
Sinopec - Kuqa	China	AEC	260	44.1k	2023	Refining
Iberdrola – Puertollano I	Spain	PEMEC	20	3500	2022	Ammonia
Hofors rolling project	Sweden	AEC	17	2900	2023	Iron & Steel
NTPC-Technip-L&T MeOH project, Vindhyachal	India	PEMEC	5	700	2023	Methanol
Multiphly	Netherlands	SOEC	2.5	500	2023	Refining, synfuels
H2RES Orsted offshore wind	Denmark	AEC	2	300	2022	Mobility
Hydrogen Lab Leina (phase 1)	Germany	SOEC	1	200	2021	Methanol

Projects in Vietnam

At present, many domestic and foreign investors have been studying, proposing, and implementing hydrogen development projects in Vietnam. Although most projects are still in the stages of investment preparation and research and have not yet entered commercial operation, they have already shown many positive signs for the development of a hydrogen production economy in Vietnam.

Currently, several green hydrogen production projects have been implemented by investors (including the Trà Vinh Green Hydrogen Plant, Bến Tre Green Hydrogen Plant, Bạc Liêu Green Hydrogen Plant, and Tiền Giang Green Hydrogen Plant) with a total capacity of approximately 120,000 tons of hydrogen per year. In March 2023, the Trà Vinh Green Hydrogen Plant project commenced construction in Vinh Long Province (formerly Tra Vinh Province). Once completed and operational, the plant will have a designed capacity of 24,000 tons of hydrogen and 195,000 tons of oxygen per year. The plant will produce green hydrogen through seawater electrolysis, using electricity to split water into hydrogen and oxygen. The project primarily uses renewable electricity and will export hydrogen to international markets in the initial phase, as the domestic hydrogen market in Vietnam is still underdeveloped.

In addition, many domestic and foreign investors are collaborating with local authorities to study, survey, and propose hydrogen production projects in provinces such as Binh Dinh (20,000 tons/year), Long An (249 tons/year), Ninh Thuan, Quang Binh, Quang Tri, Soc Trang, and Ho Chi Minh City, among others.

Investment cost estimation

The data from the different sources in the tables below is adjusted for inflation from their original price years to USD2025, but have not been applied technology learning/learning rate.

Investment costs [MUSD2025//kW of total input_e] - AEC	2020	2025	2030	2040	2050
This Technology Catalogue		1175	750	575	400
Technology Catalogue – Vietnam 2023	734		508		282
Fraunhofer ISE, 2021	892	597			
IEAGHG, 2024			1580		339
Electric Hydrogen, 2024*	2300				
***Includes development, engineering, equipment, site works and construction. Broader scope than this catalogue because development costs are included and therefore higher CAPEX.**					

Investment costs [MUSD2025//kW of total input_e] - PEMEC	2020	2025	2030	2040	2050
This Technology Catalogue		1325	875	675	475
Technology Catalogue – Vietnam 2023	1044		733		452
Fraunhofer ISE, 2021	969	673			
IEAGHG, 2024		2032		339	339
Electric Hydrogen, 2024*	2550				
***Includes development, engineering, equipment, site works and construction. Broader scope than this catalogue because development costs are included and therefore higher CAPEX.**					

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Data sheet

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2025. The *uncertainty* it related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Hydrogen production with Alkaline Electrolysis (AEC)											
Parameter	**Unit**	**2025**	**2030**	**2040**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
						Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data											
Form of energy stored	None										
Application	None										
Input capacity for one unit	MW input_e										
Output capacity for one unit (hydrogen)	kgH_2/day max										
Input capacity for total plant	MW input_e	100	100	100	100	100	100	100	100		
Output capacity for total plant (hydrogen)	kgH_2/day max	46,656	49,379	51,885	55,556	49,037	44,496	56,845	54,323	A, B	
Input											
Electricity	% total input (MWh/MWh)	100	100	100	100	100	100	100	100		
Electricity consumption (stack level)	kWh/kgH_2	51.4	48.6	46.3	43.2	48.9	53.9	42.2	44.2	C, D	1, 2, 3, 4
Electricity consumption (stack+BOP level)	kWh/kgH_2	56.7	53.6	51.0	47.6	53.9	59.4	46.5	48.7	E	1, 2, 3, 4
Water for electrolysis	kg/MWh input_e	175	185	195	208	166.9	183.9	213	204		
Output											
Hydrogen (% total input_e)	% total input_e (MWh/MWh)	58.7	62.2	65.3	69.9	61.7	56.0	71.6	68.4	F	
Delta E from HHV to LHV (% total input_e)	% total input_e (MWh/MWh)	11.9	12.6	13.2	14.1	12.5	11.3	14.4	13.8	G, H	
Heat loss (% total input_e)	% total input_e (MWh/MWh)	29.4	25.3	21.5	15.9	26.0	32.5	14.0	17.8		
- hereof unrecoverable heat loss	%-points of heat loss	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	I	
- recoverable for district heating	% points of heat loss	26.4	22.3	18.5	12.9	23.0	29.5	11.0	14.8		
Hydrogen	kg/MWh input_e	19.4	20.6	21.6	23.1	20.4	18.5	23.7	22.6		
Forced outage	%	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	J	
Planned outage	days per year	11	11	11	11	11	11	11	11	J	
Technical lifetime	years	25	25	25	25	20	30	20	30	J	
Frequency of stack replacement [h]		80,000	92,500	94,500	101,500	70,500	89,500	83,000	120,000	C, D, K	1, 2, 3, 4, 5
Construction time	years	2	2	2	2	1.5	2	1.5	2	L	
Economic data											

Hydrogen production with Alkaline Electrolysis (AEC)											
Parameter	**Unit**	**2025**	**2030**	**2040**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
						Lower	**Upper**	**Lower**	**Upper**		
Specific investment	USD/kW of total input_e	1,175	750	575	400	950	1,400	350	475	D, M, N, X	2, 4, 5, 6, 7, 8, 9, 10
Specific investment	USD/kgH_2/day max output	2,518	1,519	1,108	720	1,937	3,146	616	874	A, B, O	
- hereof equipment	%	90	90	90	90	90	90	90	90	J, P	
- hereof installation	%	10	10	10	10	10	10	10	10	J, P	
Fixed O&M	% of specific investment/y	4	4	4	4	4	4	4	4	J, Q	8
Variable O&M	USD/MWh	-	-	-	-	-	-	-	-	R	
Technology specific data											
Current density	A/cm^2	0.8	1.0	1.2	1.5	0.5	0.8	1.2	1.5	J, S	8
Cold start up time	min from 0 to 100%	60	30	<30	<30	38	79	<30	<30	T	3, 8, 11
Stack size	MW	5.0	5	10	10	3.8	6.3	10	10	J	3, 10, 12
Degradation rate	%/1000h	0.13	0.12	0.11	0.10	0.11	0.15	0.09	0.11	J, S, U	5, 8
Plant footprint	m^2/MW input_e	184	108	90	72	147	276	57	108	V, W	
Water consumption	L/MWh	670	670	670	670	-	-	-	-		13

Notes:

A For the unit regarding "day" a 100% load factor is assumed here (Where the system is operated at nominal capacity all 24 hours of the day). In operation the daily full load hours may vary and should therefore be adjusted for.

B Maximum hydrogen output per day, assuming 24 hours of full load operation in a day.

C The values were derived from multiple sources. 2040 were calculated using linear regression based on the data provided in the mentioned references, encompassing the years 2030 and 2050.

D Upper and lower values are based on the average of the standard deviations found in the relevant data as shown in note C. Standard deviations for specific investments follow expected values from typical pre-FEED projects (20%).

E Based on reference [3], the energy consumption of the entire system (including both stack and balance of plant components) is estimated.

F Efficiency for AEC and PEMEC is calculated based on the electricity consumption of the stack and BOP level, and assuming the LHV of hydrogen.

G The HHV electrolyser efficiency can be calculated as the sum of the rows: "ΔE from HHV to LHV" and "Hydrogen".

H The calculation is based on the HHV and LHV of hydrogen.

I 3% of the energy is estimated to be unrecoverable for AEC and PEMEC hydrogen plants.

J Based on internal projects and references performed at Ramboll including FEED projects and estimations from clients and from suppliers.

K Values have been rounded to nearest 500.

L It is estimated internally at Ramboll that construction for 1 MW and 10 MW H2 plants will take 0.75-1 years, 100 MW H2 plants will take 1.5-2 years, and 1 GW H2 plants will take >3 years. This estimate includes large electrical components and the plant itself.

M Investment costs for 100 MW of all technologies are based on public CAPEX estimates for 2030 and 2050. 2020 projects at Ramboll have then been used to find the progression by size.

N Values have been rounded to nearest 25.

O To analyse the cost breakdown of a hydrogen plant, the electrolyser unit and the Balance of the Plant (BOP) are considered. Additionally, various other cost factors that are essential for the plant commissioning are taken into account, such as civil work, installation, and Engineering, Procurement, and Construction (EPC) expenses.

P For H2 plants sized 1 MW and 10 MW, estimated cost ratio of equipment to installation is 95:5, and for H2 plants sized 100 MW and 1 GW, the estimated cost ratio of equipment to installation is 90:10.

Q Stack replacement costs are not included.

R The price of the input streams (water and electric energy), has not been estimated.

S The values are based on public sources. Approaching 2050 yields is a higher margin of uncertainty.

T The operational flexibility of a system is often determined by its cold start-up time, which represents the most time-consuming step and serves as a crucial distinguishing factor between different technologies.

U The provided degradation rate of the electrolyser stack is an average value. However, it is important to note that this rate is also influenced by the operation profile, such as the frequency of start/stop operations.

V The size of the electrolyser unit is determined based on a multistack configuration, using benchmarking data sourced from Ramboll. For example, the assumptions for 10 MW electrolysis for PEMEC, AEC and SOEC were 2 x 5 MW stacks inside one container, 2 x 2.5 MW stacks inside one container, needing two containers, and 72 x 0.14 MW containers, respectively.

W The plant footprint includes the installation of electrolyser units, each with their respective rectifiers. A safety distance of 5 m is maintained between each unit, and a designated laydown area is provided for maintenance operations. BOP is also included in the total footprint value.

X The data presented here includes the electrolyser unit, electrolyser system (excl. electrolyser unit cost), balance of the plant (BOP), control system, civil infrastructure and indirect costs such as EPC expenses. The data does not include compressors, hydrogen storage nor power connection in the form of step-down transformers and further switchgears. However, initial rectifiers and transformers for the electrolysers at site are included.

References

1 DNV, "Hydrogen Forecast to 2050", 2022.

2 Monitor Deloitte, "Fueling the Future of Mobility: Hydrogen Electrolysers", 2021.

3 IRENA, Making the breakthrough: Green hydrogen policies and technology costs, Abu Dhabi, 2021.

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5 DoE Hydrogen and Fuel Cell Technologies Office, "Technical Targets for Liquid Alkaline Electrolysis," DoE, [Accessed July 2023].

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7 IEA, "Global Hydrogen Review 2023," 2023.

8 Clean Hydrogen Partnership, Strategic Research and Innovation Agenda 2021-2027, 2022.

9 ISPT, "Gigawatt green hydrogen plant; State-of-the-art design and total installed capital costs," 2020.

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12 Böhm et.al., "Projecting cost development for future large-scale power-to-gas implementations by scaling effects," Applied Energy, vol. 264, 15 April 2020.

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Hydrogen production with PEMEC											
Parameter	**Unit**	**2025**	**2030**	**2040**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
						Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data											
Form of energy stored	None										
Application	None										
Input capacity for one unit	MW input_e										
Output capacity for one unit (hydrogen)	kgH_2/day max										
Input capacity for total plant	MW input_e	100	100	100	100	100	100	100	100		
Output capacity for total plant (hydrogen)	kgH_2/day max	44,566	47,398	49,909	53,791	46,013	43,207	57,143	50,811	A, B	
Input											
Electricity	% total input (MWh/MWh)	100	100	100	100	100	100	100	100		
Electricity consumption (stack level)	kWh/kgH_2	53.9	50.6	48.1	44.6	52.2	55.5	42.0	47.2	C, D	1, 2, 3, 4
Electricity consumption (stack+BOP level)	kWh/kgH_2	60.5	56.9	54.1	50.2	58.6	62.4	47.2	53.1	E	1, 2, 3, 4
Water for electrolysis	kg/MWh input_e	167	178	187	202	162.0	172.5	214	191		
Output		0									
Hydrogen (% total input_e)	% total input_e (MWh/MWh)	55.0	58.5	61.6	66.4	57.9	52.3	70.5	62.7	F	
Delta E from HHV to LHV (% total input_e)	% total input_e (MWh/MWh)	11.3	12.0	12.7	13.7	11.7	11.0	14.5	12.9	G, H	
Heat loss (% total input_e)	% total input_e (MWh/MWh)	33.7	29.5	25.7	19.9	31.8	35.4	15.0	24.4		
- hereof unrecoverable heat loss	%-points of heat loss	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	I	
- recoverable for district heating	% points of heat loss	30.7	26.5	22.7	16.9	28.8	32.4	12.0	21.4		
Hydrogen	kg/MWh input_e	18.6	19.7	20.8	22.4	19.2	18.0	23.8	21.2		
Forced outage	%	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	J	
Planned outage	days per year	11	11	11	11	11	11	11	11	J	
Technical lifetime	years	25	25	25	25	20	30	20	30	J	
Frequency of stack replacement [h]		65,500	77,500	90,000	105,000	55,000	76,000	86,500	123,500	C, D, K	1, 2, 3, 4, 5
Construction time	years	2	2	2	2	1.5	2	1.5	2	L	
Economic data (in USD2025)											
Specific investment	USD/kW of total input_e	1,325	875	675	475	1,050	1,600	375	575	D, M, N, X	2, 4, 5, 6, 7, 8, 9, 10
Specific investment	USD/kgH_2/day max output	2,973	1,846	1,352	883	2,282	3,703	656	1,132	A, B, O	
- hereof equipment	%	90	90	90	90	90	90	90	90	J, P	
- hereof installation	%	10	10	10	10	10	10	10	10	J, P	

Hydrogen production with PEMEC											
Parameter	Unit	2025	2030	2040	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
						Lower	Upper	Lower	Upper		
Fixed O&M	% of specific investment/y	2	2	2	2	2	2	2	2	J, Q	8
Variable O&M	USD/MWh	-	-	-	-	-	-	-	-	R	
Technology specific data											
Current density	A/cm^2	2.8	5.0	7.5	10	1.5	3.0	7.5	12.5	J, S	8
Cold start up time	min from 0 to 100%	0.3	0.2	0.2	0.2	0.3	1.0	0.1	0.3	T	3, 8, 11
Stack size	MW	1.5	2	5	10	1	1.3	10	10	J	3, 10, 12
Degradation rate	%/1000h	0.17	0.13	0.10	0.10	0.19	0.25	0.10	0.11	J, S, U	5, 8
Plant footprint	m^2/MW input_e	77	45	37	28	61	115	22	42	V, W	
Water consumption	L/MWh	526	526	526	526	-	-	-	-		13

Notes:

A For the unit regarding "day" a 100% load factor is assumed here (Where the system is operated at nominal capacity all 24 hours of the day). In operation the daily full load hours may vary and should therefore be adjusted for.

B Maximum hydrogen output per day, assuming 24 hours of full load operation in a day.

C The values were derived from multiple sources. 2040 were calculated using linear regression based on the data provided in the mentioned references, encompassing the years 2030 and 2050.

D Upper and lower values are based on the average of the standard deviations found in the relevant data as shown in note C. Standard deviations for specific investments follow expected values from typical pre-FEED projects (20%).

E Based on reference [3], the energy consumption of the entire system (including both stack and balance of plant components) is estimated.

F Efficiency for AEC and PEMEC is calculated based on the electricity consumption of the stack and BOP level, and assuming the LHV of hydrogen.

G The HHV electrolyser efficiency can be calculated as the sum of the rows: "ΔE from HHV to LHV" and "Hydrogen".

H The calculation is based on the HHV and LHV of hydrogen.

I 3% of the energy is estimated to be unrecoverable for AEC and PEMEC hydrogen plants.

J Based on internal projects and references performed at Ramboll including FEED projects and estimations from clients and from suppliers.

K Values have been rounded to nearest 500.

L It is estimated internally at Ramboll that construction for 1 MW and 10 MW H_2 plants will take 0.75-1 years, 100 MW H_2 plants will take 1.5-2 years, and 1 GW H_2 plants will take >3 years. This estimate includes large electrical components and the plant itself.

M Investment costs for 100 MW of all technologies are based on public CAPEX estimates for 2030 and 2050. 2020 projects at Ramboll have then been used to find the progression by size.

N Values have been rounded to nearest 25.

O To analyse the cost breakdown of a hydrogen plant, the electrolyser unit and the Balance of the Plant (BOP) are considered. Additionally, various other cost factors that are essential for the plant commissioning are taken into account, such as civil work, installation, and Engineering, Procurement, and Construction (EPC) expenses.

P For H_2 plants sized 1 MW and 10 MW, estimated cost ratio of equipment to installation is 95:5, and for H_2 plants sized 100 MW and 1 GW, the estimated cost ratio of equipment to installation is 90:10.

Q Stack replacement costs are not included.

R The price of the input streams (water and electric energy), has not been estimated.

S The values are based on public sources. Approaching 2050 yields is a higher margin of uncertainty.

T The operational flexibility of a system is often determined by its cold start-up time, which represents the most time-consuming step and serves as a crucial distinguishing factor between different technologies.

U The provided degradation rate of the electrolyser stack is an average value. However, it is important to note that this rate is also influenced by the operation profile, such as the frequency of start/stop operations.

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13 IRENA and Bluerisk, 2023 - Water for Hydrogen Production

9. GREEN AMMONIA SYNTHESIS

Brief technology description

In a future green energy system, fuels for energy production, industries and transportation will need to be replaced by green alternatives. One possible alternative is the use of green ammonia for large engines in the shipping industry or even in power production.

Today nearly all industrial production of ammonia is based on the Haber-Bosch process, where elemental nitrogen and hydrogen are combined under high pressure and temperature using a catalyst. Whereas nitrogen can be recovered from ambient air, the hydrogen is predominantly produced by steam reforming of natural gas (methane), a process that results in large emissions of fossil CO_2. Thus, reducing the CO_2 emissions from ammonia production is heavily linked to reducing emissions from hydrogen production. This can be achieved by capturing and storing CO_2 from conventional (further defined below) hydrogen production or alternatively substituting the conventional production of hydrogen with green hydrogen from electrolysis based on renewable energy.

In this chapter of the Technology Catalogue, a brief description of the different NH_3 production paths is given. Thereafter, the catalogue focusses on the production of green ammonia. Green ammonia has various applications and is primarily thought to become a carbon-neutral solution for shipping as a maritime transport fuel as well as to be used as feedstock for green fertilizers. It can potentially also be considered for applications in fuel cells, long-term energy storage, fuel for industry and peak power plants, or as an addition/mixture to conventional fuel, among others.

The production pathway of green ammonia incorporates

- electrolysis for H_2 production,
- air separation unit (ASU) for nitrogen production, and
- the ammonia synthesis (see light green box in Figure 62).

Within this catalogue, performance and cost data are given for the ammonia synthesis, only. An indication of the cost and energy requirements of the ASU is given in this chapter as well but held separate from the synthesis. Cost and performance data for the electrolysis are given in a separate chapter within this Technology Catalogue and are meant to be combined, when evaluating the whole production pathway.

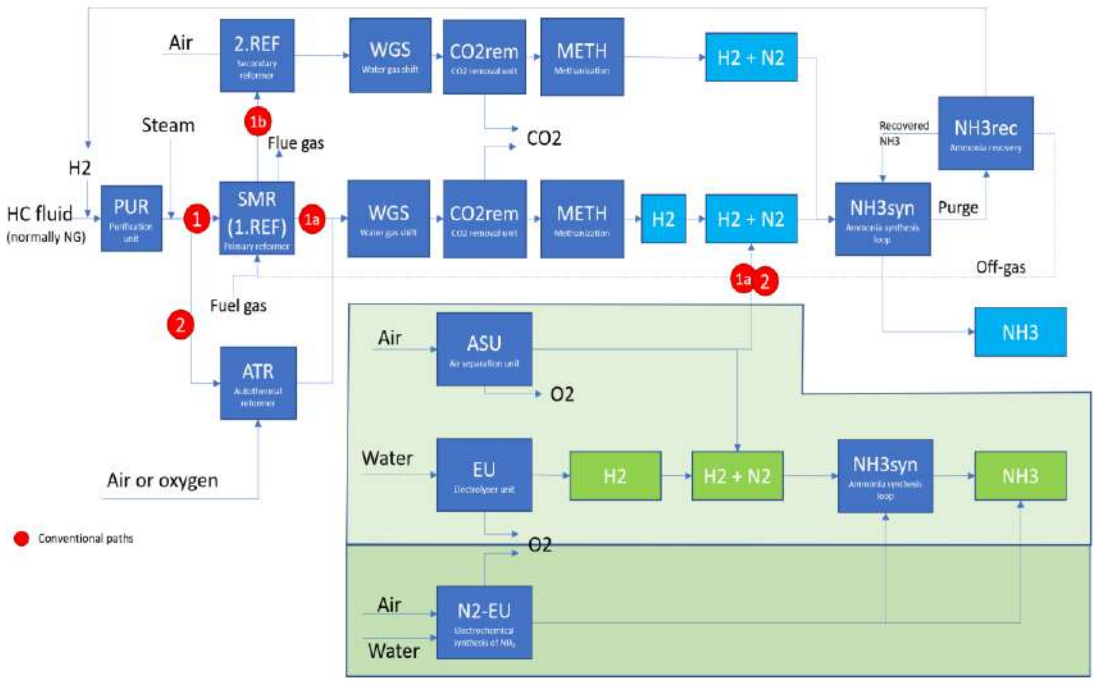


Figure 62: Different pathways for production of NH_3. The light green area is the green NH_3 production part that is covered within this Technology Catalogue. The darker green area marks a potential future route (electrochemical). The white background shows the three conventional parts, i.e. 1a) SMR+ASU, 1b) SMR+2.REF and 2) ATR+ASU

Different production routes to ammonia, i.e., both conventional and green paths, are given in Figure 62.

While the overall routes are described in subsection "*Different Configuration*", each process step (i.e., dark blue boxes) is described in subsection "*process steps*".

Different Configurations

Conventional – grey NH_3

A conventional ammonia plant uses fossil fuels (in most cases natural gas) as its raw material.

Figure 63 shows a conventional NH_3 plant based on primary and secondary reformer technology, where nitrogen is admitted via air to the secondary reformer. Alternative reformer configuration is autothermal reformer (ATR) or single steam methane reformer (SMR) combined with ASU unit to provide the nitrogen.

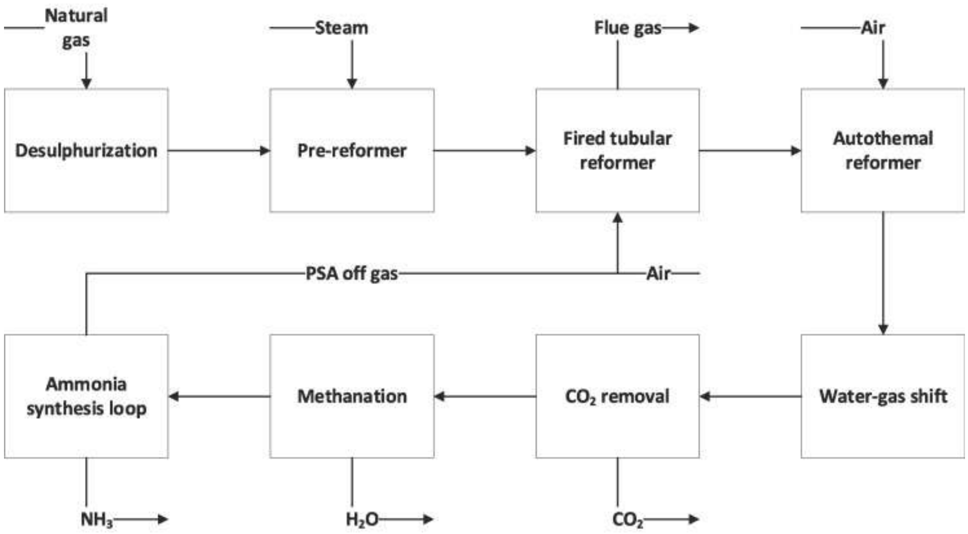


Figure 63: Conventional ammonia plant [20]

Conventional – blue NH_3

A blue ammonia plant is a conventional NH_3 plant with carbon capture (CC) to capture the CO_2 emissions from the reformer. This will significantly reduce the carbon footprint compared to that of grey ammonia. The raw material is however still natural gas, and the plant layout is similar to that of a conventional plant.

Electrolysis – green NH_3

A green ammonia plant uses green hydrogen produced via electrolysis to feed the ammonia synthesis loop (see Figure 60). The electrolysis shall be powered with renewable energy such as solar or wind power.

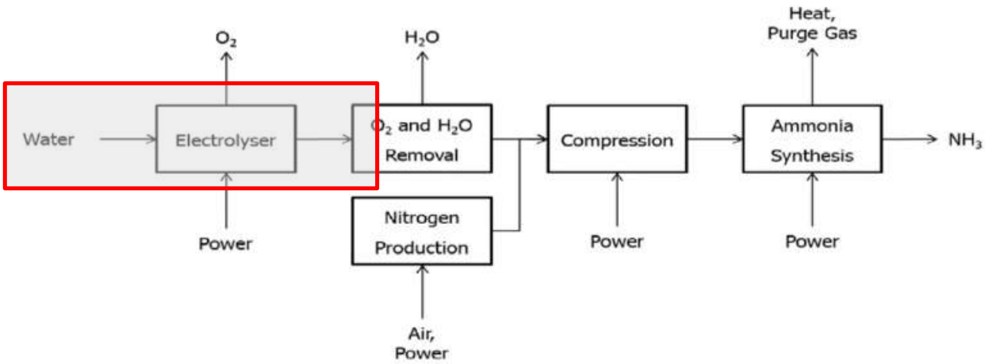


Figure 64: Green ammonia plant. Any impurities of O_2 in the H_2 product is removed by reacting it with H_2 over a DeOX (de-oxygenation unit).

Electrochemical synthesis of ammonia – green NH_3

Direct production of NH_3 by electrocatalytic reaction of water and air, i.e., eliminating the Haber-Bosch process, may become an alternative process for green NH_3 with use of renewable electricity. This technology is still only at research level (see further description below under *4) Autothermal reforming (ATR)*).

Process steps

This section provides description of each of the process steps showed in Figure 40.

Feed purification (PUR)

The feed purification section removes impurities (sulphur, chlorine and heavy metals) that are poison to downstream catalyst. The purification section typically consists of two reactors; The first one is a hydrogenator that converts organic sulphur (and Chlorine) into H_2S (HCl) via the following reaction:

$$R\text{-}S + 1.5\,H_2 \xrightarrow[300-450\,°C]{\text{Catalyst}} R\text{-}H + H_2S$$

The second one is a downstream absorber that removes H_2S (and HCl) from the feed via absorption.

Steam methane reforming (SMR)

Steam methane reforming is a method for producing hydrogen from hydrocarbons and steam via the following reactions:

$$C_nH_m + nH_2O \Rightarrow nCO + (n+1/2m)\,H_2 - Q$$

$$CH_4 + H_2O \Rightarrow CO + 3H_2 - Q$$

$$CO + H_2O \Rightarrow CO_2 + H_2 + Q$$

The reforming reactions are highly endothermic, meaning that heat must be added. The SMR typically consists of several catalyst-filled tubes to which heat is added either via a fired radiation box or via convection with a >1000 °C hot flue gas. In both cases, fuel must be added to provide the heat. The temperature of the flue gas leaving the reformer depends on the technology applied but is in the 900-1150 °C range.

Typical outlet conditions	
Temp.	800-920 °C [13]
Pres.	20-50 barg
CH_4	5-10 dry %
CO	15-20 dry %
CO_2	5 dry %
H_2	70 dry %
N_2, Ar	< 1 dry %

Secondary reformer (2. REF)

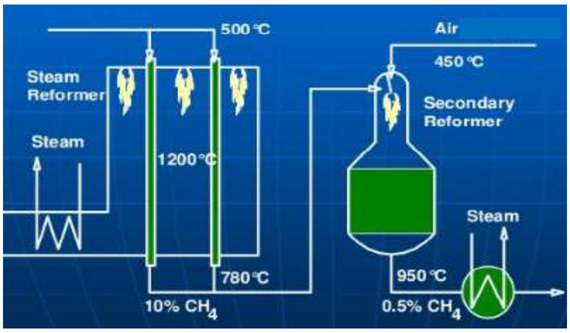


Figure 65: Primary and secondary reformer arrangement

Typical outlet conditions	
Temp.	900-1000 °C
Pres.	20-50 barg
CH_4	<0.5 dry %
CO	10-15 dry %
CO_2	5-10 dry %
H_2	50-60 dry %
N_2	20-25 dry %
Ar	<0.5 dry %

Nitrogen for the NH_3 production can either be added via an ASU or via an air-fired secondary reformer.

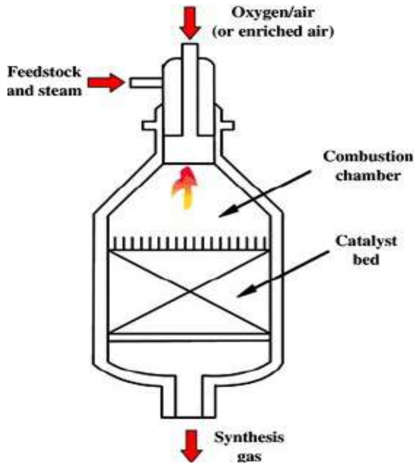
Within the secondary reformer, heat for the reforming process is provided by burning some of the syngas inside the reactor with admitted air. By adding air, N_2 is added, meaning that an ASU is not needed. The reaction scheme is:

$$CH_4 + \tfrac{1}{2} O_2 \Rightarrow CO + 2H_2$$

The addition of air is controlled such that the hydrogen to nitrogen ratio at the inlet to the ammonia loop is approximately 3:1, which is the required stoichiometric ratio for the ammonia reaction.

[13] If followed by secondary reformer, the outlet temperature (T_{out}) is ~800°C, while it is ~900°C if there is no downstream reformer

Autothermal reforming (ATR)



Typical outlet conditions	
Temp.	1000-1100 °C
Pres	20-50 barg
CH_4	< 0.5 dry %
CO	15 dry %
CO_2	5-10 dry %
H_2	50 dry %
N_2	25 dry %
Ar	< 0.5 dry %

Figure 66: Autothermal reformer (ATR)

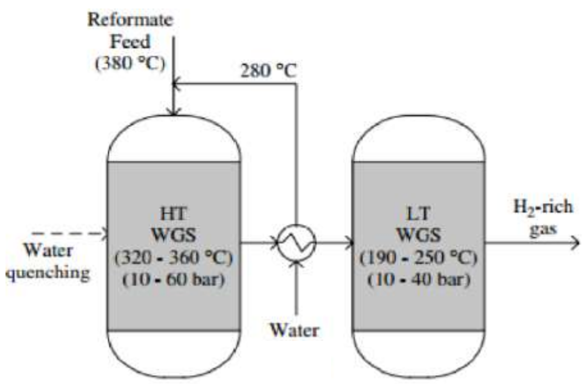
Like SMR, ATR can be used to convert hydrocarbon feed into a hydrogen rich syngas. Within ATR, heat for the reforming reaction is provided by burning part of the syngas inside the reactor commonly with pure oxygen. This gives the following reaction scheme:

$$2\ CH_4 + O_2 + CO_2 => 3\ H_2 + 3\ CO + H_2O$$

$$4\ CH_4 + O_2 + 2\ H_2O => 10\ H_2 + 4CO$$

The advantage of ATR is that the product H:CO ratio can be varied, depending on the amount of steam and oxygen (O_2) added.

Water gas shift (WGS)



Typical outlet conditions	
Temp.	~ 160 °C
Pres.	20-40 barg
CH_4	<0.5 dry %
CO	<0.5 dry %
CO_2	20 dry %
H_2	60 dry %
N_2	20 dry %
Ar	<0.5 dry %

Figure 67: Typically shift configuration in an ammonia plant

The purpose of the shift reactor(s) is to produce additionally hydrogen (H_2) by converting CO via the following reaction:

$$CO + H_2O <=> CO_2 + H_2 + Q$$

As the shift reaction is exothermic, low temperature favours a low equilibrium content of CO. However, a low temperature also decreases the reaction rate. To ensure fast conversion and at the same time low CO slip, the shift section can be a series of shift reactors with interstage cooling. A conventional ammonia plant typically includes a high temperature shift (HTS) and a low temperature shift (LTS).

CO_2 removal unit (CO_2rem)

Typical outlet conditions	
Temp.	~30 °C
Pres.	20-50 barg
CH_4	<0.5 dry %
CO	<0.5 dry %
CO_2	0.05 dry %
H_2	75 dry %
N_2	25 dry %
Ar	<0.5 dry %

The CO_2 in the syngas from the WGS must be removed before the syngas is admitted to the NH_3 synthesis. The reason is that CO_2 is poisonous to the NH_3 catalyst. Alternatively, all CO_2 could be converted to methane in downstream methanization reactor (see methanization step in next subsection), but this will create a huge amount of inert (CH_4 and Ar are inert in the ammonia loop) in the NH_3 loop that must be compressed and purged out. The CO_2 removal unit is typically based on amine absorption technology. Other applied technologies are Selexol, Benefield and Vetrocoke.

Methanization (METH)

The methanization process aims to remove any residual CO and CO_2 (as they are poisonous to the ammonia catalyst) from the feed stream before it enters the ammonia synthesis reactor.

$$CO + 3H_2 \rightarrow CH_4 + H_2O + Q$$

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O + Q$$

Typical outlet/syngas conditions	
Temp.	~30 °C
Pres.	20 – 50 barg
CH_4	< 1 dry %
CO	< 5 ppm
CO_2	< 5 dry ppm
H_2	75 dry %
N_2	25 dry %
Ar	< 0.5 dry %

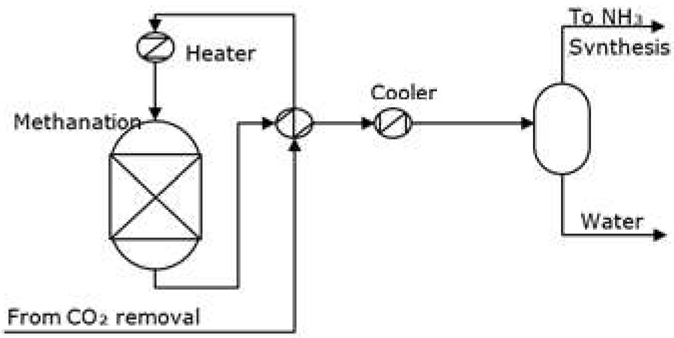


Figure 68: Methanization, cooling and water separation

Ammonia Synthesis (NH_3syn)

The hydrogen and nitrogen feed stream are compressed and admitted to the ammonia loop (referred to as the Haber-Bosch process).

$$3H_2 + N_2 \rightarrow 2NH_3 + Q$$

This ammonia reaction is highly exothermic, and the heat produced is used to generate steam. The steam generated is an export from the ammonia synthesis loop. In a conventional plant, some of the steam is used for hydrogen production in the steam methane reformer (SMR) and some for power generation in steam turbines. The conversion rate is typically only ~25 % per single pass, so a large internal recycle is required to ensure high overall conversion.

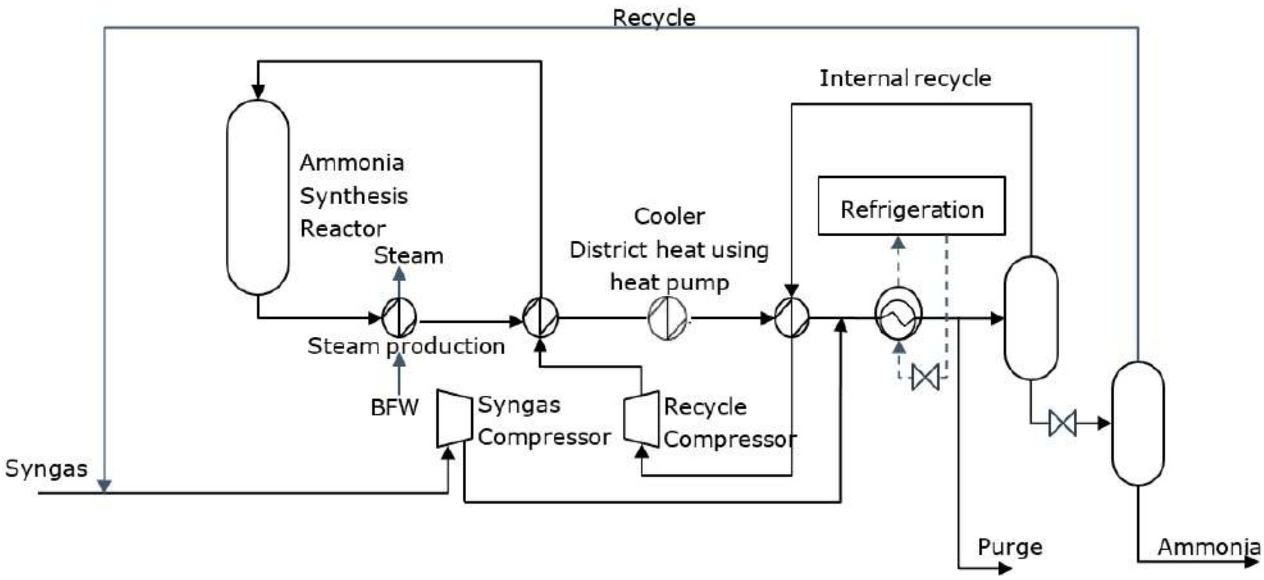


Figure 69: Ammonia synthesis loop and downstream purification

The ammonia synthesis benefits from a high operating pressure. Depending on the technology provider the loop usually runs at anything between 150 to 250 barg. A common overall loop pressure drop is approximately 10 bar. Temperatures in the loop range from 350˚C to 550˚C. The steam from the ammonia reactor is cooled, chilled and condensed. The condensed ammonia is separated from unreacted reactant first in a high-pressure vessel and then in a 20-25 barg vessel. The unreacted reactants are recycled back to the process.

Typical ammonia product outlet conditions	
Temp.	-10 – 0 ˚C
Pres.	20-25 barg
NH_3	> 99 %

Electrolysis

For electrolysis reference is made to the dedicated catalogue chapter “Electrolysers”

Air separation unit (ASU)

Pure nitrogen is required as feedstock for the Haber-Bosch synthesis of ammonia, as shown in Figure 40. Pure nitrogen is produced by an ASU, which uses a cryogenic distillation process to separate ambient air into nitrogen, oxygen, and argon. Figure 70 shows a flow-diagram for a typical ASU configured for nitrogen production. Ambient air is compressed and dehydrated before it is chilled by heat exchange with the cold liquid N_2/O_2 products from distillation. Final chilling is obtained by expansion of the air. The distillation column will separate liquid nitrogen from liquid oxygen and argon. The ASU does not produce any usable heat.

The ASU will deliver highly pure nitrogen (>99.9%), but can also be configured to coproduce pure oxygen, which may be used in the production of grey/blue hydrogen if the ammonia plant employs autothermal reforming (ATR).

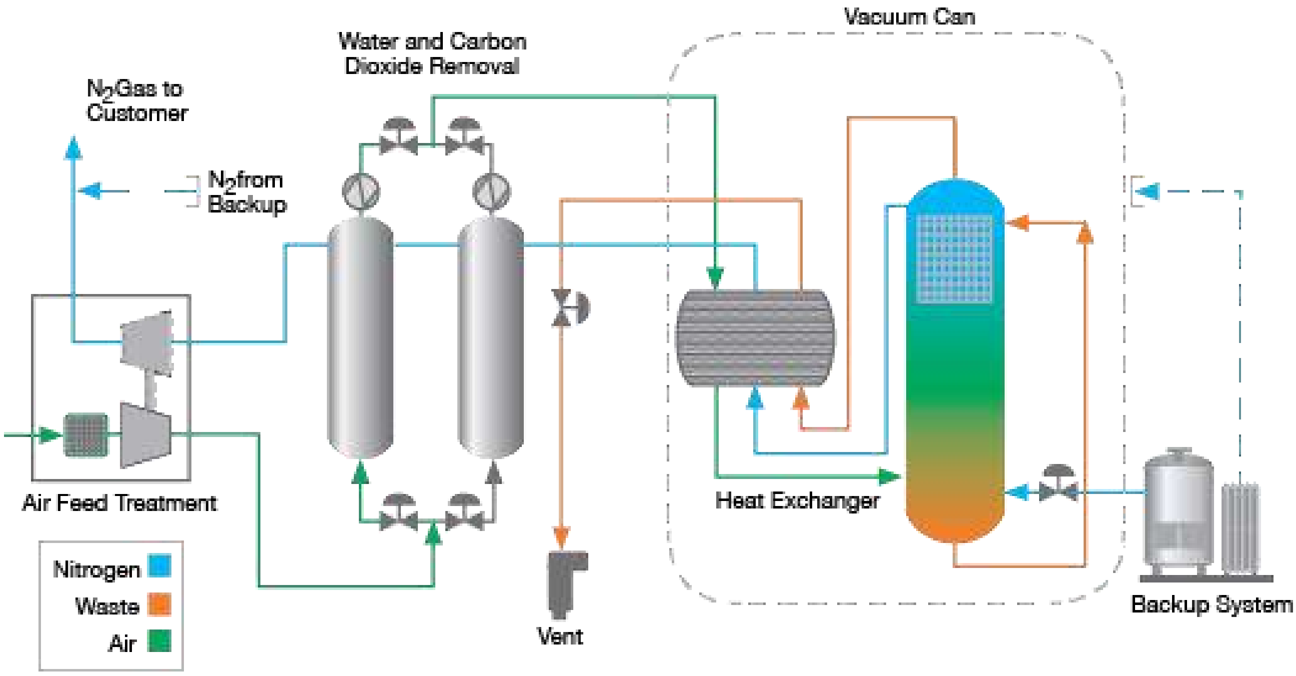


Figure 70: Schematic flow diagram of nitrogen plant. Source: AIChE

Electrochemical synthesis of ammonia (N2-EU)

Direct electrochemical synthesis of ammonia from N_2/air and water by use of renewable electricity is an interesting alternative, as it avoids the Haber-Bosch process and potentially also the air separation. The electrochemical synthesis of ammonia is a process path that has been under development for the past 20 years and many different configurations are being examined. Several studied paths exist. The different approaches to electrochemical ammonia production that have been studied can be divided into a low and high temperature path:

Low temperature path (<100°C): This is typically conducted in an aqueous cell, where the aqueous solution is both the hydrogen source and acts as the electrolyte. Different aqueous electrolyte solvent and different catalytic materials have been investigated (Fe_2O_3, MOF (Au, Fe, Cu), Ni, etc.) to maximize efficiency and reaction rate. However, at low temperature only very low reaction rates have been achieved.

High temperature path (>100°C, typically 200-650°C): The high temperature path typically applies a solid-state electrolyte or a molten salt. The hydrogen source can be hydrogen itself, steam or methane-steam mixture. The main advantage of the high temperature path is that significantly higher reaction rates are achieved. However, the efficiency is lower. A major disadvantage with higher temperature is the competing hydrogen formation reaction and decomposition of the NH_3 product which start above 250°C and is dominating at 500°C [1].

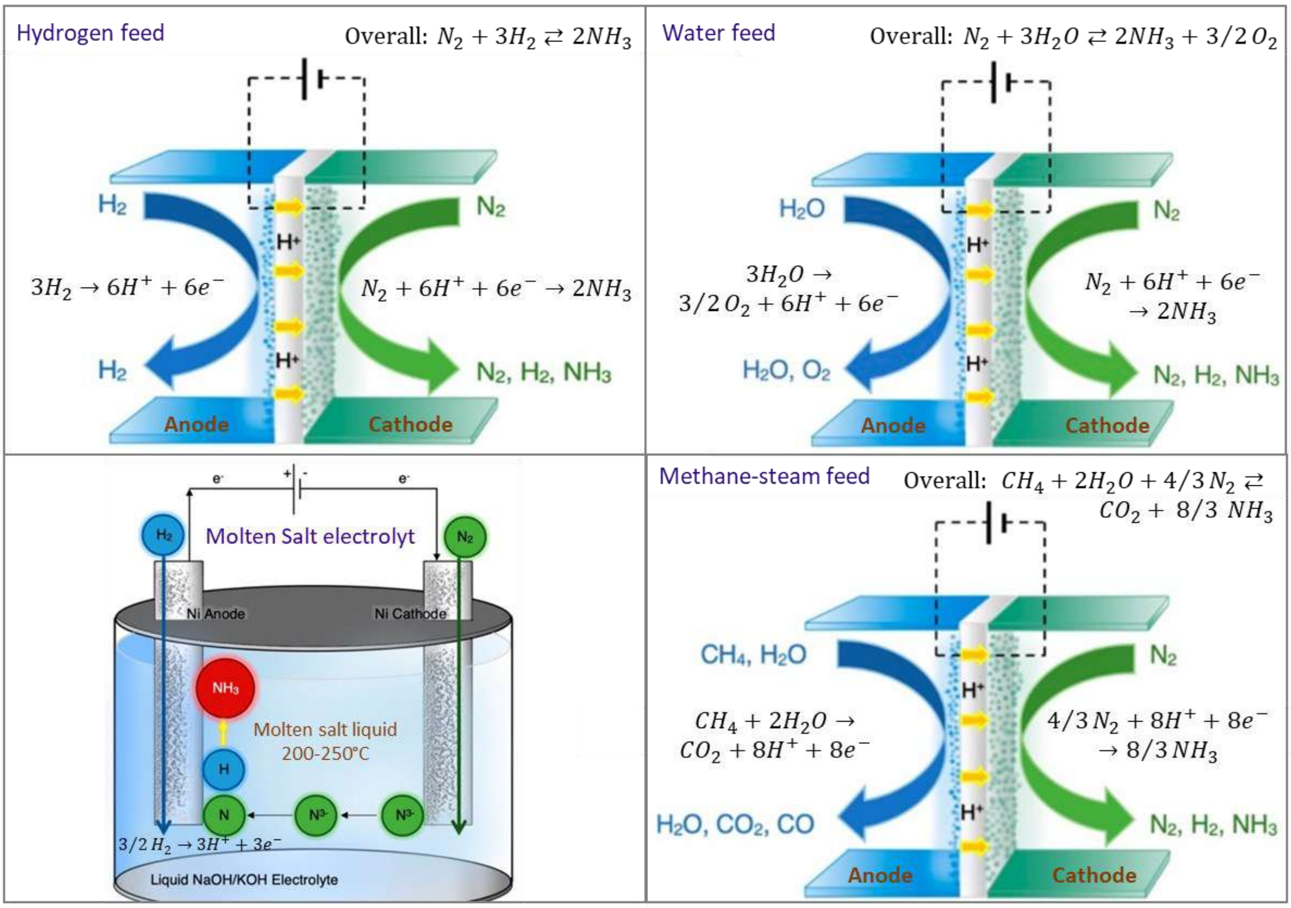


Figure 71: Illustration of the anode and cathode reactions during electrochemical NH_3 production. [1]

Results indicate an inverse relationship between efficiency and reaction rate. Hence high temperature and the catalysts that provide the higher reaction rate tend to provide the lowest efficiency. The achieved reaction rates and efficiencies today are still far too low for practical application [1, 2], hence this process will be decades away from commercialization. The TRL is judged to be 1-2.

Operation range

The operation ranges of both conventional and green ammonia plants can be divided into:

1. Shut down – cold standby
2. Hot standby – no production but plant is kept warm for fast startup
3. 0-20 % operation
4. 20-35 % operation
5. 30-100 % operation

Shut down – cold standby

Shut down/cold standby is when the plant is shut down and cooled to ambient temperature. Cold shut down should generally only be used for maintenance. It should not be used for a short stop of the plant in case of no product demand or missing feed availability. The reason is that frequent cooling and reheat will cause catalyst crunching (due to grinding among catalyst particles caused by expansion upon heating and shrinking upon cooling) and thereby reduced catalyst lifetime. Therefore, an ammonia plant is preferred to be kept in hot standby mode (see next section) even if it is not in operation.

Hot standby mode

Hot standby mode is an operation mode where there is no production but almost all units are kept at normal operation condition (i.e., at normal operation temperature and pressure) to enable a fast ramp up in capacity.

For an ammonia plant, the hot standby mode depends on the duration, i.e., it may be still-standing for a couple of days, while circulating hot gas may be used to keep the reactor warm for prolonged periods (weeks).

Starting an ammonia loop from cold conditions can take up to one day, while ramping up from hot conditions is usually ~2 hours. Hot standby mode requires no feedstock. The energy that needs to be added during prolonged hot standby will be equal to heat loss to the surroundings, which will be very little if the plant is properly insulated. For start-up, a start-up heating system is needed anyhow, so the additional capital investment for facilitating a hot stand-by mode will be very minor.

Similar, for an electrolysis unit, a hot standby mode can enable fast ramp up (within seconds)[14]. Depending on weather forecast and knowledge about fluctuations in electricity generation and demand, the number of electrolysis cells that is kept in hot standby mode can be optimized.

Operation at 30 – 100% Capacity

A conventional ammonia plant usually has an operating capacity of 70-100%. However, as general turndown ratio of rotating equipment, many transmitters and control valves are 30%, these plants can normally handle loads down to 30% without major changes.

Operation at 20 – 35% Capacity

If there is a need to reduce operations to 20%, this can usually be achieved by additional CAPEX spending to buy equipment that can handle lower capacity ranges.

Operation at 0 – 20% Capacity

For operation at lower capacity than 20% a significant increase in CAPEX can be expected, as multiple valves, instruments and rotating equipment would have to be purchased to manage the wide range of operating loads.

Demand for operation flexibility

The requirements for operation flexibility depend strongly on the feed availability (power or hydrogen) and on requirements for product flow. If the feed is hydrogen, i.e., the plant is connected to a hydrogen transmission net, the buffer within the hydrogen transmission net will ensure a stable feed flow, which cost is fairly stable. Thus, the demand for the operation flexibility will be low.

Alternatively, if the feed is power, i.e., hydrogen is produced by electrolysis of water, fluctuating power prices and the wish to maximize earning naturally imposes some desire for high flexibility in the capacity of the ammonia plant. Regarding fluctuating power prices, the following scenarios must be considered:

A. Fast ramping: Grid connections that facilitate fast ramping cost less.
B. Prolonged periods with high power prices

Point A: The ammonia synthesis cannot ramp as fast as the electrolysis unit. However, minor "hydrogen plus nitrogen" storage can ensure that a green ammonia plant can fulfil point A.

Point B: As discussed earlier, it is crucial that the temperature within the ammonia reactor is kept constant as frequent cooling and reheat will cause crunching, whereby the catalyst lifetime is reduced. To maximize earnings under prolonged periods with high power prices and at the same time ensure a constant temperature in the ammonia reactor, the following design options (or a combination of them) can be applied:

1. Design NH_3 plant with large operation range + additional NH_3 storage: Periods with high price of power can be optimized by ramping down the capacity of the NH_3 plant and even put it into a hot standby mode. This can be combined with additional NH_3 storage (NH_3 storage is much cheaper than H_2 storage) to fulfil any contractual requirement on a minimum ammonia production rate.
2. Locate next to a hydrogen transmission net: As stated above this will minimize fluctuating feed cost.
3. Hybrid NH_3 plant: Combining the green NH_3 production with existing conventional NH_3 production will make it possible to ramp up the load of the reforming section when the power prices are high.

[14] Typical power connection requirement is: 50% ramp in power supply within <5s and 100% ramp in power supply within 30s (if a connection can guarantee this connection requirement, a higher price is given)

The most optimal option depends on the circumstances. The location next to a hydrogen transmission net or next to an existing conventional ammonia plant are likely to be the most cost-efficient solutions. The disadvantage of point 1 (and to some extent also to point 3) is that the huge capital cost of an ammonia plant normally requires >90% load to pay back the capital expenses.

The below figure shows the thermal and physical properties of gaseous ammonia:

Molecular weight: 17 kg/kmol

Normal density: 0.77 kg/m³

Lower heating value, LHV: 19 MJ/kg

Higher heating value, HHV: 23 MJ/kg

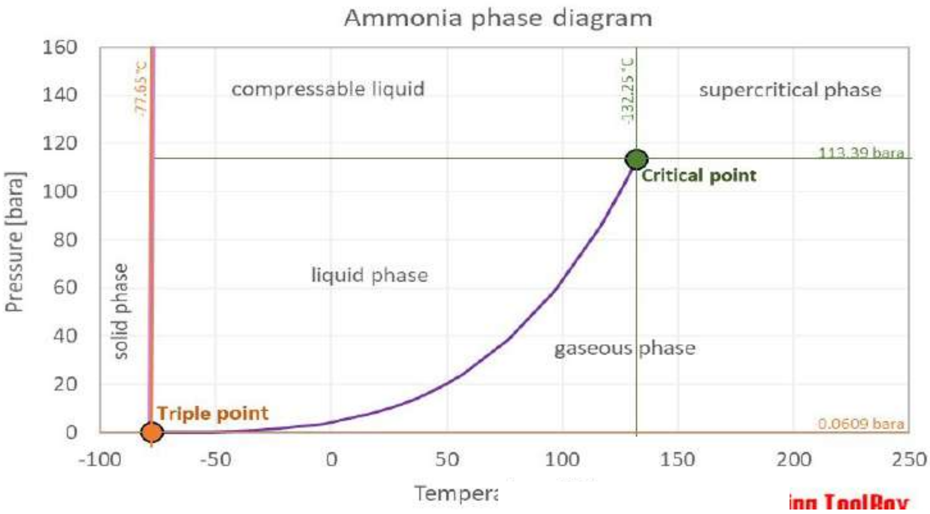


Figure 72: Ammonia phase diagram

Input

The input and output subsections give an overview of inputs and outputs of an ammonia synthesis in energy (e.g. MWh).

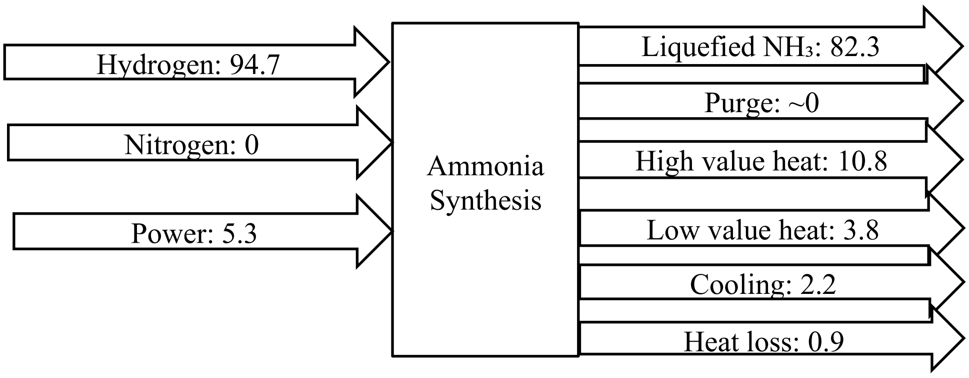


Figure 73: Overall energy balance of the ammonia synthesis.

The input to the ammonia synthesis loop is hydrogen, nitrogen and power as shown in Figure 69. Including the electrolysis unit and the air separation unit (ASU), the input streams are water, air and power. Boiler feed water (BFW) is normally used to extract the high value residual heat from the ammonia synthesis reaction, while cooling water is used to remove the low-calorie residual heat.

Output

The output streams from the ammonia synthesis are ammonia, steam, hot water (usable for low temp. heating applications) and a tiny purge stream.

The high value heat can be used to make steam at different levels. The steam can be converted to high pressure steam and used within the plant to drive the compressors. The steam that is not used to power the process can be exported.

The purge is needed to remove any accumulated impurities, but as the feed stream is almost 100% pure H_2 and N_2, the purge will be insignificant. As the purge contain impurities of NH_3, it must be burned off as a fuel or sent to a flare.

Including electrolysis unit and ASU, the overall output streams are, besides the above mentioned, oxygen from the electrolysis unit and oxygen from the ASU.

Energy balance

The energy balance of the ammonia synthesis is given in *Figure 73*. Energy balance of green ammonia plants including electrolysis unit and ASU. Many theoretical papers and studies have investigated the energy requirements of green ammonia plants. These vary greatly compared to a conventional ammonia plant, as the power consumption of the electrolysis unit makes up a large majority of the overall plant power requirements. Figure below shows an example of the energy balance breakdown of a green ammonia plant (operating at 150 bar), where the synthesis loop is the power required to drive compressors and pumps.

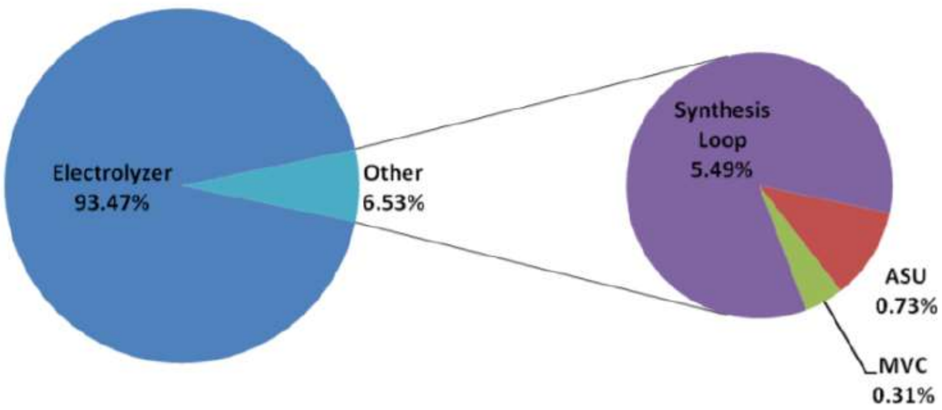


Figure 74: Power requirement breakdown for a green ammonia plant (MVC=Mechanical Vapor Compression, includes pumping and desalination of feed water to electrolysis unit) [5].

Based on the estimate of the Danish technology catalogue, the following energy consumption breakdown was found (the MVC above has not been included as it is minor):

Table 30: Major power consumption units in green ammonia plant

Plant area	Power consumption	%
ASU	250 kWh/t N_2	2.1%
Electrolysis unit (65% eff.)	9350 kWh/t NH_3	94.4%
Syngas & make up compressor	290 kWh/t NH_3	2.9%
Ammonia refrigeration	50 kWh/t NH_3	0.5%
TOTAL	**9900 kWh/t NH_3 (36 GJ/t NH_3)**	

The energy consumption of ASU's (200-400 kWh/ton N_2) depends on capacity, extent of integration, and whether a high share of liquid N_2 for back-up should be produced.

Integrations within conventional NH_3 plants are:

1. Steam produced in ammonia loop is normally used for:
    1.1. Steam addition to the steam methane reforming process
    1.2. Power production for the compressors and the pumps in the ammonia plant
    1.3. Export of steam
2. Recovered hydrogen in ammonia recovery unit (NH_{3rec}):

2.1. Is used as hydrogen required for hydrogenation within the feed purification section

3. Recovered fuel gas (i.e., off-gas) from ammonia recovery unit (NH_{3rec}):

   3.1. Use as fuel for the steam methane reformer (SMR)

   3.2. If no steam methane reformer (SMR), normally exported

Integration possibilities within green NH_3 plants are:

1. Steam produced in ammonia loop can be used for:

   1.1. Power production for own consumption e.g., ASU, compressors and pumps in the ammonia plant

   1.2. Export of steam (for use in nearby industrial processes)

2. Oxygen from the electrolysis unit and the ASU:

   2.1. Export

3. Excess low-temperature heat

   3.1. Water/air coolers in electrolysis and ammonia loop can be used for low-temp. heating applications.

If ammonia is becoming a transportation fuel, then the ammonia market will increase substantially. Thus, there will be an interest in increasing the capacity of existing ammonia plants and/or make them greener, which both can be accomplished by adding an electrolysis unit to the existing plant. Whether the secondary reformer can cope with the increased N_2 demand or an ASU needs to be added, will depend on the demand for increased capacity.

If the purpose of adding an electrolysis unit is to increase the capacity, it will normally be done by identifying the bottlenecks of the existing ammonia plant and replace the units (or add additional units) that inherit the bottlenecks. The capacity can usually be increased to 110% capacity with no or very minor changes. Increasing the capacity with 20-30 % can often be done with acceptable investments (as only few equipment needs to be revamped/replaced), while larger capacity increase will require major investments as almost all items need to be replaced.

If the conventionally grey reforming section and the new green "ASU and electrolysis unit" section should be able to operate independently, i.e., without the other in operation, major integrations are not possible. Independent operation will be used if "ASU and electrolysis unit" is shut down when the power prices are high.

Integration possibilities within hybrid NH_3 plants:

1. Steam produced in ammonia loop can be used for:

   1.1. Steam addition to the steam methane reforming process

   1.2. Power production for own consumption e.g. ASU, compressors and pumps in the ammonia plant

   1.3. Export of steam

2. Oxygen from the electrolysis unit and the ASU:

   2.1. Feeding the secondary reformer with enriched air: The capacity of the secondary reformer can be increased by feeding it with enriched air, as extra feeding duty (via partial combustion of feed gas with oxygen) can be obtained without having to add excess nitrogen [6]

   2.2. Export

3. Hydrogen and off-gas from the NH_{3rec} units: Same as under conventional NH_3 plant

4. Excess low-temperature heat

   4.1. Water/air coolers in electrolysis and ammonia loop can be used for low-temp. heating applications

   4.2. Heat from electrolysis unit can be used for pre-heating of NH_3 recycle

A key feature of the electrolysis unit is that it can provide hydrogen for start-up. The feed purification section needs hydrogen, which is recycled from the downstream system, but as the downstream system is not in operation when starting the plant, imported H_2 is needed for conventional plants. This will not be the case for green or hybrid plants.

Typical capacities

The typical capacity of conventional ammonia plants built today is in the range of 1000 to 3500 ton per day (TPD) of ammonia for a single line.

For green ammonia production, the size of the electrolysis unit or the available renewable electricity will set the limit for how large the units can be.

Ramping configuration

For plants based on intermittent renewable energy, one (or a combination) of the following options must be selected

1. A turndown ratio of 0% (hot standby mode)
2. Possibility to use grid power
3. Possibility to take feeds (N_2 and H_2) from grid or storage
4. Possibility to increase capacity of a conventional front-end (hybrid solution)

Several technology providers have quoted the following figures for turndown.

Haldor Topsøe:	10-100% [7]
ThyssenKrupp:	30-100% (vendor info)
Casale:	20-110% (vendor info)
KBR:	30-100% (vendor info)

Advantages/disadvantages

Advantages:

The main advantages of green ammonia production relative to conventional ammonia are:

- No fossil fuel (natural gas) is required, hence production can be made CO_2 emission free
- Location is not bound to areas/regions where inexpensive natural gas is available
- N_2 and H_2 feedstocks are pure, which reduce purging requirement and need for NH_3 recovery section. This increases the overall efficiency of the NH_3-synthesis (Figure 40)
- Capacity variation can contribute to an increased flexibility in power consumption, i.e. if power production is high, power utilization can be increased. This will increase the average utilization factor (capacity factor) of the renewable power generators

Disadvantages:

The main disadvantages can be summarized as:

- Fluctuations in renewable power generation leading to fluctuations in the operating profile will reduce the average utilization factor (load factor).
- Today the cost of hydrogen produced via electric power is significantly higher than that of natural gas, which gives higher costs of green NH_3.

Space requirement

Looking at conventional ammonia plants the plot space required for a production capacity of 1390 TPD is around 150 x 100 m. This includes all operation buildings but not storage facilities. The actual placement of processing areas within the plant is not critical, as long as industry safety rules are followed. A typical ammonia plant (with secondary reformer and no ASU) may have the following layout:

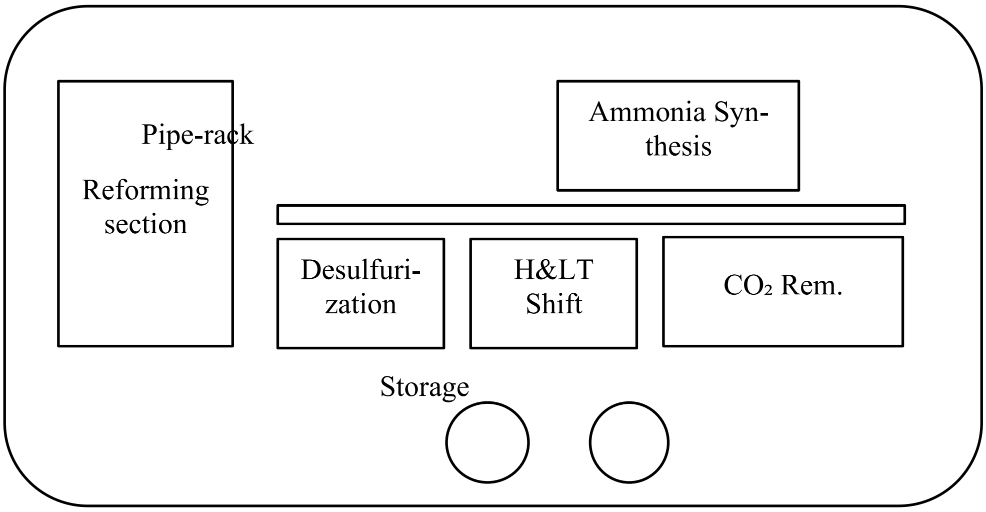


Figure 75: Typical ammonia plant layout

For a green ammonia plant, only the ammonia synthesis section of the plant is relevant, with the other areas removed to make space for electrolysis unit and ASU. The electrolysis unit and the ASU require less plot space than the reformer, desulphurization, shift reactors and CO_2 removal unit. Qualitatively speaking a green ammonia plant would require a smaller plot area than a conventional one for the same capacity.

Water consumption

For green ammonia production, water consumption is primarily driven by the upstream production of green hydrogen via electrolysis, as described in the hydrogen electrolysis section. Beyond hydrogen generation, additional water use occurs in downstream process steps, but at a significantly lower magnitude.

In the ammonia synthesis loop (e.g. Haber–Bosch), water does not participate in the core chemical reaction and is not consumed. Water use is instead associated with auxiliary processes such as cooling, gas purification, and, where applicable, nitrogen separation (e.g. air separation units with wet cooling). These water requirements are typically non-consumptive or result in limited evaporative losses, depending on the cooling system design.

Overall, incremental water consumption beyond that required for electrolysis is modest. Consequently, the total water footprint of green ammonia is largely determined by the electrolyser configuration and cooling strategy, with ammonia synthesis itself adding only a minor additional water demand.

Environment

Key HSE (Health, Safety and Environment) concerns to consider in an ammonia plant are:

1. Ammonia is a toxic component – see description in [8]
2. Hydrogen is a highly flammable and explosive component – see description in [8]
3. Leakage
4. High pressure equipment
5. Chilling unit
6. Hot surfaces

Research and development

The Haber-Bosch process for ammonia synthesis is a mature process that has been in use in the industry for 100 years. The process has undergone significant improvements over the years, hence it is believed that future improvements and cost reductions will be marginal.

It is expected that the electrolysis technology for H_2 production will improve substantially towards 2050. In a ten-year timeframe it is expected that H_2 can be delivered at high pressure directly from the electrolysis unit. This will lead to reduction of CAPEX and electricity consumption for feedstock compression to green ammonia synthesis.

Successful combining electrolysis unit and ASU in a solid oxide electrolyser cell (SOEC) or successful development of the electrochemical process for low temperature production of ammonia from air and water may be potential game changers. However, as mentioned earlier, the processes are far away from commercial application today.

Examples of current projects

Only few NH_3 plants with electrolysis units are operational today. One plant is the pilot plant in Minnesota (operational since 2013) which output is 25 ton of green ammonia per year. The electrolysis unit is powered by wind [15]. Yara is developing a hybrid solution at their Pilbara ammonia plant in Western Australia. The plan is to erect a 100 MW solar farm to drive a 50-60 MW electrolysis unit, which will increase the production of ammonia from the existing Haber-Bosch unit with ~80 Ton Per Day (TPD) [16]. The engineering for the tie-in of green hydrogen was completed in 2018. It is planned that the plant will expand its green ammonia production in stages up until 2030 when an expected 90% of its production will come from green sources. Yara are also partnering with Ørsted to develop a 100 MW electrolysis plant to produce green hydrogen for ammonia production in Holland. This is expected to be operational in 2024/2025 and will produce approximately 200 TPD of green ammonia [17].

Air Products have recently announced investment in a new green ammonia facility to be operational by 2025 at the industrial hub of NEOM in Saudi Arabia. Using Haldor Topsøe technology, the 4 GW plant will produce 650 TPD of green hydrogen, an equivalent of 3250 TPD of green ammonia [18]. In Denmark, near Lemvig, a new green ammonia plant is planned to produce 5000 ton/year green ammonia. The project is a collaboration between Skovgaard Invest, Haldor Topsøe and Vestas [19].

Table 31: Examples of ammonia projects [10]; TPD estimated as (t/y) / 360

Location	Companies	Ammonia capacity (kt/y)	Ammonia capacity (estimated tpd)	CAPEX (mUSD)	CAPEX (mUSD / (kt/y))
Pilbara, Australia	Yara	24	67	200	8.33
Puertollano,	Iberdrola, Fertiberia	200	556	2,124	10.62
Abu Dhabi, United Arab Emirates	KIZAD, Helios Industry	200	556	1,000	5.00
Duqm, Oman	ACME, Tatweer	770	2,139	2,500	3.25
Neom, Saudi Arabia	Air Products, ACWA Power, ThyssenKrupp, Haldor Topsøe	1,200	3,333	5,000	4.17
Pilbara, Australia	InterContinental Energy	5,710	15,861	17,080	2.99
Pilbara, Australia	InterContinental Energy	9,900	27,500	27,790	2.81
Al Wusta, Oman	OQ, InterContinental Energy, EnerTech	10,450	29,028	25,000	2.39
Mauritania	CWP	11,425	31,736	40,000	3.50

The above table shows some of the renewable ammonia plants around the world and indicates the estimated capital cost for those renewable ammonia plants, including renewable energy generation cost.

Investment cost estimation

Predictions of investment costs for green ammonia plants are based on data from the industry as a whole, as no large-scale plants or projects have been completed or are in operation yet. Overall plant cost data has been broken down into major plant section to get a distribution of cost. Several different sources have been compared and values for each section of the plant have been determined from this. For the investment cost analysis, the following sections of the ammonia plant are included:

- Ammonia synthesis
- Balance of plant (BOP), typically is surrounding utility, storage, startup and shut down facility. There is often variation in what BOP includes. Here storage and electric plant is listed separately, meaning they are not included in the BOP
- Storage

Based on cost split data for various conventional plants and figures obtained from various vendors, average split factors have been estimated. This approach gives that the average cost of the ammonia synthesis including storage and BOP is around ~54% of that of the cost of conventional NH_3.

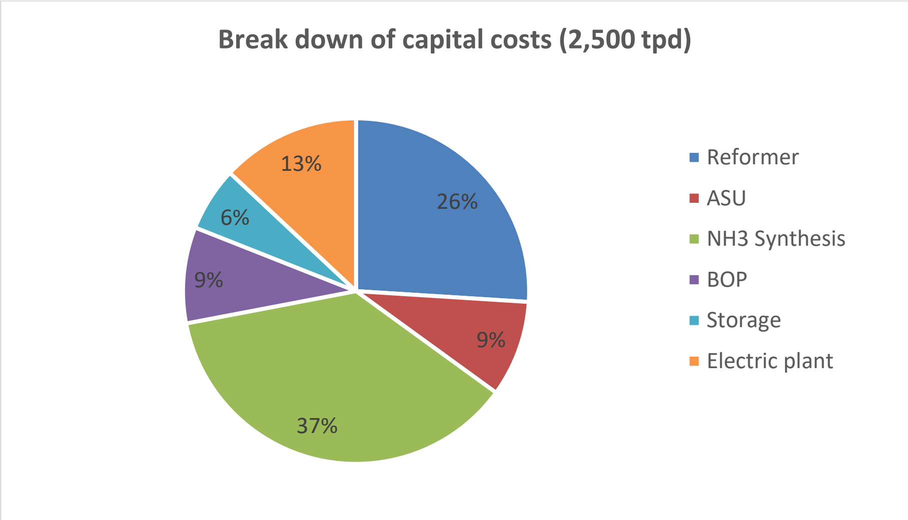


Figure 76: Cost split on main systems in a conventional NH_3 plant from Linde [9]. Reformer, electric plant (power plant) and some balance of plants (BOP) will disappear for a green NH_3 plant. Cost of green NH_3 plant (excl. electrolysis unit and ASU) is therefore taken as 54% of conventional plant, based on all obtained data.

In Figure above, a cost-capacity curve for specific CAPEX of green ammonia plant has been derived using cost data of conventional ammonia plants at different capacities. The 0.54 factor explained above has been used to remove ASU and scope not relevant for green ammonia. All costs in the figure have been scaled using the Chemical Engineering Plant Cost Index (CEPCI) to reflect 2019 costs. It is observed that at low capacities (<300 TPD) there is a steep increase in the specific CAPEX. As the design hours, construction time and the amount of metal used per unit capacity is much larger for small plants than for large plants, customized small plants will always be much more expensive than large plants.

However, skit-mounting and mass production can change this picture substantially, i.e., the steep increase for small capacities shown in Figure 77 may decrease substantially if a market for small ammonia plant comes forward. But it is questionable whether a larger market for small ammonia plants will develop, as the advantages of having distributed ammonia plants is limited.

In order to add the cost of the ASU, a multiplication factor of 1.06-1.09 must be added to the total cost of the ammonia plant sections as listed above.

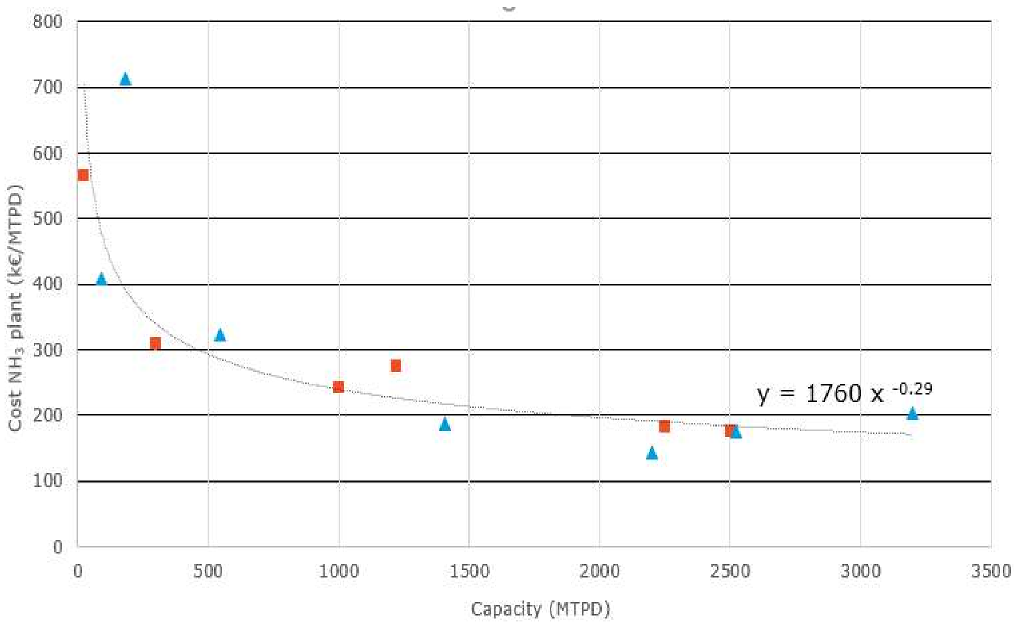


Figure 77: Estimated cost of ammonia synthesis + BOP + Storage (electrolysis unit and ASU is not included in the figure). Blue triangles represent data that is publicly available. All figures adjusted to reflect cost index for 2019. A conversion factor of 0.8931 is used to convert to USD_{2019}

The investment cost estimates shown in the below table is directly linked to the capacity steps rather than the years. With respect to small NH_3 plants (< 500 TPD) there is high uncertainty as few plants are built in this size range today (the data from the small plants in Figure 72 is vendor-estimated values and not values from actual constructed plants). For larger NH_3 plants, there are many references, hence the uncertainty is somewhat lower. In addition, CAPEX will depend a lot on location and local conditions. Although the few existing small NH_3 plants (< 500 TPD) shown in the below table can be considered as early-stage pilot projects, we can still expect a bit higher investment cost than the estimate cost below for small plants (i.e., in 2020 and 2030). The exact investment cost for such small NH_3 plants in Viet Nam will be highly dependent on location, local conditions, and the global development of the technology (and its impact on cost reduction) by the time it will be introduced in Viet Nam.

The updated 2025 Viet Nam Technology Catalogue has revised all cost projections by converting them to 2025 USD.

Investment costs [MUSD/MW]	**2020**	**2025**	**2030**	**2040**	**2050**	**Note**
	below 100 kt/y		100 – 300 kt/y	300 – 700 kt/y	700 – 1000 kt/y	
	below 278 tpd		278 – 833 tpd	833 – 1944 tpd	1944 – 2777 tpd	
Vietnam technology catalogue 2025		2.33	1.9		1.2	
Vietnam technology catalogue 2023	1.87 (84 kt/y)		1.53 (168 kt/y)	1.25 (335 kt/y)	0.96 (839 kt/y)	A
Port Lincoln, Australia [10, 11]	8.50 (19 kt/y)					B
Port Bonython, Australia [10, 11]	8.03 (40 kt/y)					B
South Australia [10, 12]			5.18 (200 kt/y)			B, C
Esbjerg, Denmark [10, 13]				2.97 (650 kt/y)		B
Morgan (2013) [5]				0.96 (400 kt/y)		D
Fasihi et al (2021) [14]				0.69 (from 400 kt/y)	0.69 (from 400 kt/y)	A

Morgan (2013) [5]					0.91 (1,000 kt/y)	D
Danish Technology Catalogue (updated 2021)	1.87 (84 kt/y)		1.53 (168 kt/y)	1.25 (335 kt/y)	0.96 (839 kt/y)	A

Notes
Assuming t/y = 360 tpd
A: Only NH_3 synthesis loop, excl. electrolysis, excl. ASU, NH_3 storage and utilities
B: Capital cost for renewable ammonia plants, excluding renewable energy generation cost
C: Including electrolysers
D: Large scale plant, including air separation unit, N_2 & H_2 compressor, N_2 buffer and 30 days NH_3 storage

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The description in this chapter is to a great extent based on the Danish Technology Catalogue "Technology Data – Renewable fuels; 103 Green Ammonia".

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Data sheet

This section contains the data sheets of the technology. The uncertainty it related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

The datasheet has been produced for a 229 TPD green ammonia plant, which is equivalent of a plant using electrolysis units of a total of ~90 MW. Figures for capacities increasing up to 2,290 TPD (requiring a~900 MW electrolysis unit) are included to give a reference of potential future giga-plants.

The cost development exclusively reflects effects from economy of scale and no further technological development is expected. Cost estimation of future giga-plants will also apply for earlier years. In case a giga-plant of e.g., 2,290 TPD is expected for 2040 already instead of 2050, one should use the expected cost values for this plant size of 0.8 M$/MW, instead of the cost data for the given year.

Fixed operating and maintenance costs are taken as 3% of CAPEX. Variable operating and maintenance costs are taken as costs of catalyst replacement and other minor consumables. According to Morgan, E. R. (2013), Catalyst replacement is scaled based on a reference for a 1,500 TPD NH_3 plant with 10 m^3/year. Iron catalyst price is assumed to be 2,825 USD/m^3.

Green Ammonia plant: Hydrogen to ammonia (excl. electrolyser and excl. ASU)										
Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Typical total plant size	TPD	229	458	2290					A	
Typical total plant size (Ammonia output)	MW	50	100	500						
Inputs										
N2 Consumption	t/t ammonia	0.84	0.84	0.84	0.82	0.86	0.82	0.86	B, L	
Hydrogen Consumption	t/t ammonia	0.18	0.18	0.18	0.18	0.18	0.18	0.18	B, L	
Hydrogen Consumption	MWh/MWh total inputs	0.95	0.95	0.95	0.93	0.97	0.93	0.97	B, L	
Electricity Consumption	MWh/MWh total inputs	0.05	0.05	0.05	0.05	0.06	0.04	0.08	C, L	
Outputs										
Ammonia Output	MWh/MWh total inputs	0.82	0.82	0.82	0.81	0.84	0.81	0.84		
High value heat	MWh/MWh total inputs	0.11	0.11	0.11	0.11	0.11	0.11	0.11	D, L	
Heat loss	MWh/MWh total inputs	0.04	0.04	0.04	0.00	0.04	0.03	0.04	E, L	
Forced outage, unplanned shutdown	%	5	3	2	2	8	2	4	M	
Planned outage	Weeks per year	3	3	3					M	
Operation capacity	%	20-100	20-100	20-100					N	
Technical lifetime	years	30	30	30						
Construction time	years	2	2	2						
Economic data										
Specific investment	MUSD/MW ammonia output	2.33	1.90	1.20	1.82	3.07	0.84	1.4	F, I, J, M	
- equipment	%	50	50	50					M	
- installation	%	50	50	50					M	
Fixed O&M	kUSD/MW ammonia/year	56	46	29	44	73	20	34	G, M	
Variable O&M	USD/MWh ammonia	0.03	0.03	0.03	0.01	0.06	0.01	0.06	H, M	
Start up	MUSD/1,000t ammonia	-	-	-						
Technology specific data										
Specific investment mark-up factor optional ASU		1.09	1.09	1.09	97%	100%	97%	100%	F, M	

Specific energy content	GJ/ton ammonia	18.9	18.9	18.9						
Specific density	kg/l or ton/m^3 ammonia	626	626	626						
Specific investment	MUSD/TPD ammonia output	0.51	0.42	0.26	0.40	0.67	0.18	0.30	F, I	
Fixed O&M	MUSD/TPD ammonia	15.3	12.5	7.8	11.9	20.1	5.5	9.1		
Variable O&M	USD/t ammonia	0.15	0.15	0.15	0.07	0.29	0.07	0.29		
Start up	MUSD/TPD ammonia	-	-	-						
Water consumption	L/MWh	0	0	0	-	-	-	-	K	

Notes:

Performance and cost data are given for the ammonia synthesis only. An indication of the cost and energy requirements of the ASU is given in the chapter as well, but it is held separate from the synthesis. Cost and performance data for the electrolysis are given in a separate chapter and datasheet within this Technology Catalogue and are meant to be combined, when evaluating the whole production path-way.

A Typical NH_3 plant size based on H_2 supply from 100 MWe electrolyser for 2020.

B Assuming 98% efficiency with respect to mass of the ammonia synthesis

C Assumption of higher-pressure electrolysis available in the future, requiring lower compression power. A green ammonia plant that contains a dedicated ASU for nitrogen production will have additional power requirements

D Steam at up to 350 °C may be produced by NH_3 synthesis

E Heat available at 30-60°C

F Specific investment of green NH_3 plant (excl. electrolysis, excl. ASU, NH_3 storage and utilities) is estimated as 54% of conventional NH_3 plant based on NG. Cost is decreasing with time mainly because of scale effect (increasing plant size). To add the cost of an ASU a multiplication factor of 1.06-1.09 should be applied to the total Specific Investment (both entries in Economic data and Technology-specific data) as a rule of thumb.

G G: Fixed O&M is taken as 3% of CAPEX

H Variable O&M estimated as cost for catalyst replacement and misc. consumables

I Economic data is given in 2025-$

J Cost projection is considering economy of scale only and does not consider further technical development, due to the maturity of ammonia synthesis. In case capacities are expected for other years than shown in the datasheet, one should use the corresponding cost data of the respective capacity instead of the cost data for a given year. See also Figure 16 in the chapter.

K When the electrolysis process is excluded, the water consumption is negligible.

L Based on calculated mass and energy balance

M Based on collected data, i.e. based on several sources, as specified in the qualitative section

N Based on normal operation ranges for instrumentations and rotating equipment. Lower capacity range is possible but it is normally expensive as spare instrumentation and rotating equipment is required

10. METHANOL SYNTHESIS (E-METHANOL)

The conversion of hydrogen to methanol is one of the key conversion pathways, which is often considered in Power-to-X concepts and projects. Methanol is of special interest, since it is an important chemical building block and can be used as a green fuel, when produced based on green feedstocks and green energy.

Brief technology description

The conventional method of producing methanol is based on the reaction of a syngas composed of H_2, CO and CO_2 in a methanol synthesis reactor with the following main reactions:

$$2H_2 + CO \leftrightarrow CH_3OH$$

$$3H_2 + CO_2 \leftrightarrow CH_3OH + H_2O$$

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

Here, the two first reactions are producing methanol, while the third reaction is the water-gas-shift (WGS) reaction, which occurs in the reactor.

In the conventional fossil methanol production pathway, the syngas is often generated based on coal gasification or from natural gas through steam methane reforming. The composition of the syngas is adjusted by utilizing the water gas shift reaction (the last of the three reactions listed above) in order to maximize methanol production. This is achieved when the syngas composition results in a module *M* around 2 [1]. The module is defined according to the following equation:

$$M = \frac{x_{H_2} - x_{CO_2}}{x_{CO} + x_{CO_2}}$$

where *x* denotes mole fraction.

Syngas (or synthesis gas):

A syngas is a gas mixture, which can include H_2, CO, CO_2, CH_4 and H_2O. A syngas is a typical intermediate product stream involved in chemical conversion of fuels.

The production of methanol from hydrogen requires an additional feedstock delivering the required carbon atom. Within the scope of green methanol production, the feedstock to the methanol synthesis can be green hydrogen produced by electrolysis with green electricity, and a green CO_2 resource, for example captured from a biogenic point source or by direct air capture (DAC). Another possibility is the use of biogas (CH_4 and CO_2) where a full conversion of the carbon content to methanol can be achieved if H_2 is added as feedstock.

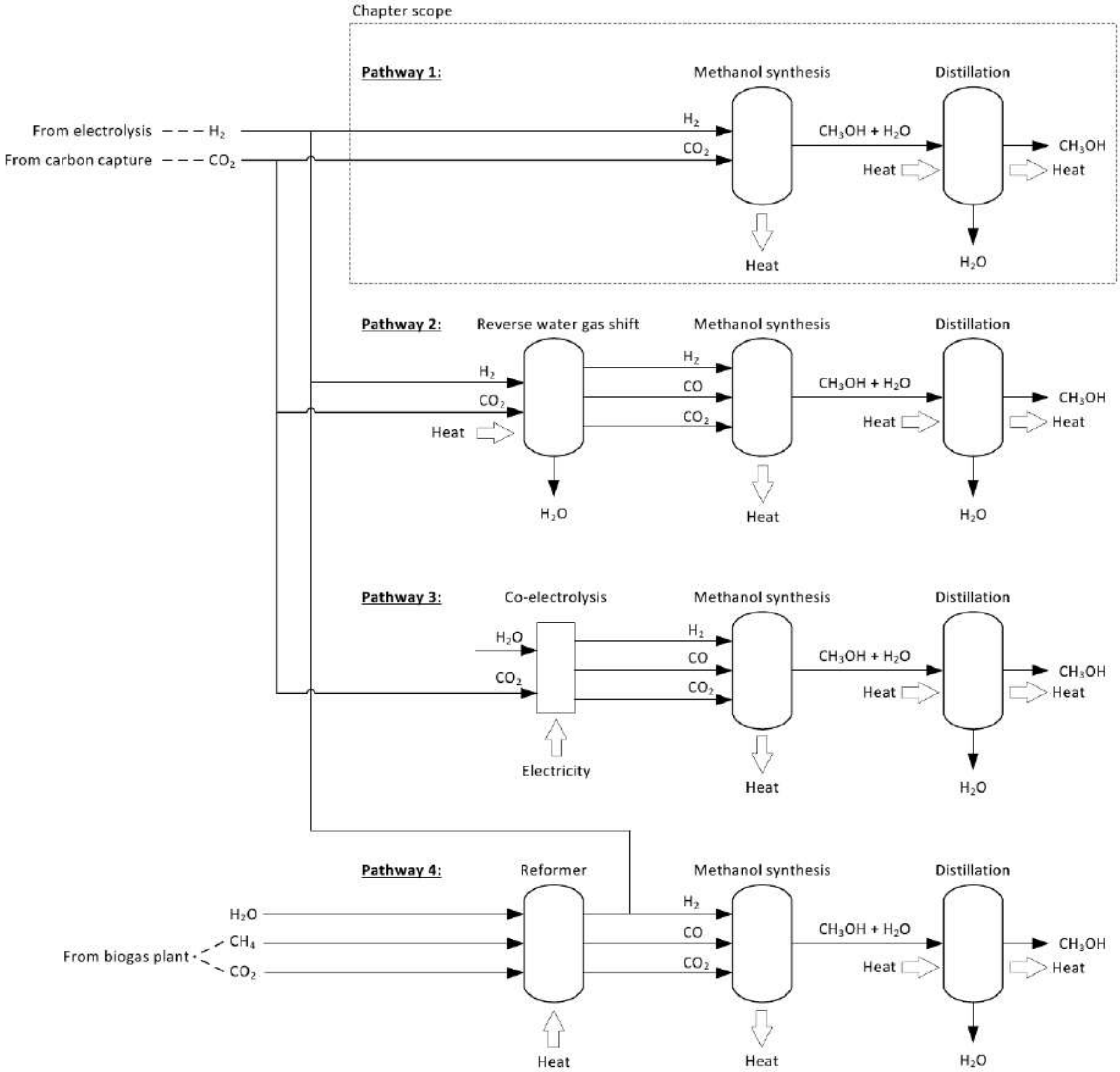

Figure 78: Overview of four pathways enabling the production of green methanol. The methanol synthesis generates high temperature heat which can be used in the distillation. The distillation generates lower temperature heat at 50-100 °C, which can be utilized for low-temp. heating applications

The following four conversion pathways are examples of how green hydrogen can be involved in the production of green methanol or e-methanol (see Figure 79)

- **Pathway 1, direct conversion of H_2 and CO_2 to methanol:** The methanol production is based on H_2 and CO_2 as feedstocks. The feed stream does therefore not include CO, which is a difference compared with the other pathways. This pathway is used at George Olah Renewable Methanol Plant in Iceland operated by Carbon Recycling Internation (CRI) [2]. Main reaction in the methanol synthesis:

$$3H_2+CO_2 \leftrightarrow CH_3OH+H_2O$$

- **Pathway 2, reverse water gas shift (RWGS) route:** The H_2 and CO_2 are preconditioned in a RWGS reaction in order to reach a module around 2, similar to conventional methanol synthesis reaction. Depending on the design of the RWGS reactor and the resulting equilibrium there could be a need for bypassing/recycling CO_2 and H_2 in order to achieve an optimum syngas module. Reverse water gas shift reaction:

  $CO + H_2O \leftrightarrow CO_2 + H_2$Main reactions in the methanol synthesis:

$$2H_2+CO \leftrightarrow CH_3OH$$

$$3H_2+CO_2 \leftrightarrow CH_3OH+H_2O$$

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

- **Pathway 3, co-electrolysis:** In a solid oxide electrolysis cell (SOEC) it is possible to co-produce CO and H_2 based on steam and CO_2. This is currently a technology under development with TRL below 5, but could be part of an e-methanol pathway in the future. Overall reaction in the co-electrolysis:

$$CO_2+H_2O \leftrightarrow CO+H_2+½O_2$$

Main reactions in the methanol synthesis:

$$2H_2+CO \leftrightarrow CH_3OH$$

$$3H_2+CO_2 \leftrightarrow CH_3OH+H_2O$$

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

- **Pathway 4, bio e-methanol:** The production of green methanol can be achieved by using biogas as a feedstock. Biogas is a mixture of CO_2 and methane, which is often upgraded to biomethane by separating and releasing the CO_2. Instead of separating and releasing the CO_2, it is possible to utilize the CO_2 and methane for methanol production. This can be achieved via steam reforming, which enables the generation of a syngas from biogas. Due to the stoichiometry of the reactions and the composition of biogas, it is necessary to add H_2 in order to achieve a full conversion of the CO_2-content. Main reaction in the steam methane reformer:

$$CH_4+H_2O \leftrightarrow CO+3H_2$$

Main reactions in the methanol synthesis:

$$2H_2+CO \leftrightarrow CH_3OH$$

$$3H_2+CO_2 \leftrightarrow CH_3OH+H_2O$$

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

The scope of the current chapter and the following description is pathway 1 as indicated in Figure 56. The core of the hydrogen to methanol technology via pathway 1 is the catalytic conversion of H_2 and CO_2 to methanol, which follows the following overall reaction, as named previously:

$$3H_2+CO_2 \leftrightarrow CH_3OH+H_2O$$

The reaction occurs at around 200-300 °C and 50-100 bar , and is exothermal with ΔH = -49.16 kJ/mol of methanol [2].

In addition to the reaction above, the water-gas-shift reaction is also present in the methanol reactor, which results in the formation of CO [2]:

$$CO_2+H_2 \leftrightarrow CO+H_2O$$

The reaction is endothermic with ΔH = 41.22 kJ/mol of CO. The heat for this reaction will be supplied via the exothermal reaction above, and the overall energy balance results in a net heat output from the reactor.

It should be noted that due to the presence of CO, methanol will also be formed due to the reaction of H_2 and CO, however to a minor degree compared with a syngas with module around 2 as mentioned previously. The methanol reactor can be constructed as a boiling water reactor or a tube-cooled reactor [2], where the heat released from the reaction is carried away as steam or heated water. Boiling water reactors are typically more expensive than tube-cooled reactors [2], however, in terms of heat recovery, steam is a more valuable output stream compared with heated water.

In a methanol plant, there is a range of process steps around the methanol reactor, which are depicted in a simplified sketch in Figure 75. The sketch does not include any pressurization or conditioning of the feed streams, since it is assumed that the CO_2 and H_2 streams are supplied from a central pipeline at the right conditions and purity. Only one distillation column is included, although typical plants include multiple distillation steps.

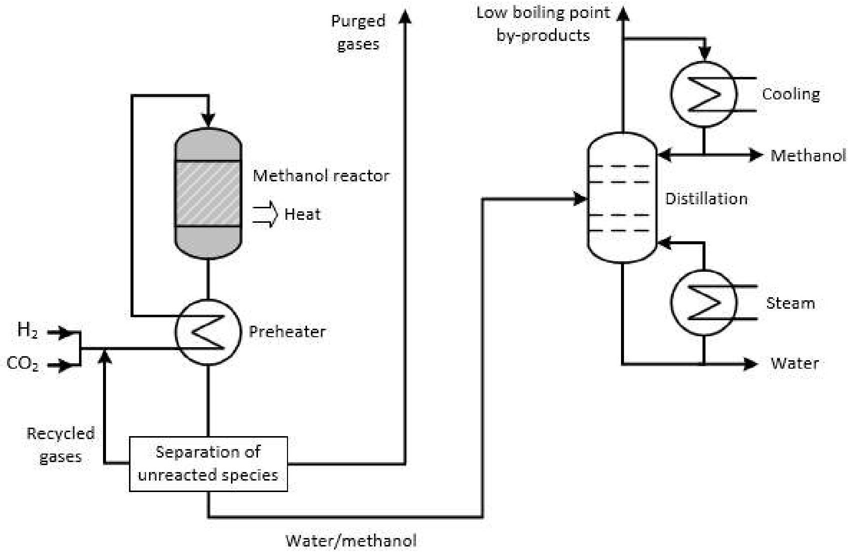

Figure 79: Simplified sketch of a hydrogen to methanol production plant.

After the methanol reactor, the effluents are used for preheating the incoming feed, and unreacted gases are separated and recycled or purged. The methanol produced in the methanol synthesis is mixed with water, and therefore a distillation is needed in order to separate water and methanol and other byproducts from the reaction, for example higher alcohols, esters, ethers and ketones [2]. The byproducts are small in volume compared with the methanol output and exits the plant as off-gases or as wastewater. Off-gases can be handled via oxidation, and the wastewater can be treated using conventional wastewater facilities.

Input

The inputs are feed streams of CO_2 and H_2. In the following it is assumed that the CO_2 and H_2 are entering the considered methanol plant at 5 °C for both streams and at 100 bar for CO_2 and 70 bar for H_2. Based on these conditions the feed streams are already at appropriate pressure levels, and therefore further compression of H_2 and CO_2 is not considered.

In case of on-site generation of CO_2 and H_2 via carbon capture and electrolysis, the feed streams will enter at different conditions and lower pressure levels. If this is the case, compression of the feed streams is required thus compressor costs should be added to the CAPEX.

Additional inputs to the process include electricity, cooling and heating. Electricity is used for auxiliary equipment, cooling is used primarily in the distillation column(s), and heating (electrical or steam) is used in the distillation column(s). Electricity for auxiliary equipment is required at 400 V-AC level and a steam pressure level at around 10 bar(g) and 184 °C is required.

Output

The primary output from the process is methanol at a given grade for example US Federal specification grade AA or IMPCA reference specifications, both specifying a methanol content above 99.85 %wt. Additional output streams are purge gases, in case inert gases are present, and separated by-products.

Energy Balance

The energy balance of a methanol plant producing grade AA methanol is shown in Figure 80. The energy balance is based on the following information from Haldor Topsøe [3]:

- Low pressure steam consumption: 1,600 kg-steam/ton-methanol
- H_2 flow rate: 2,130 Nm^3/kg-methanol
- Medium pressure steam production: 670 kg-steam/ton-methanol

The medium pressure steam is generated in the methanol synthesis reactor based on the heat released during the reaction. This steam is at a higher pressure and temperature than the heating demand of the distillation process. In the energy balance it is therefore assumed (included in CAPEX estimate) that the heat (steam) generated in the methanol reactor can be used in the distillation section. The net steam demand in Figure 80 therefore represents the difference between steam consumption and production.

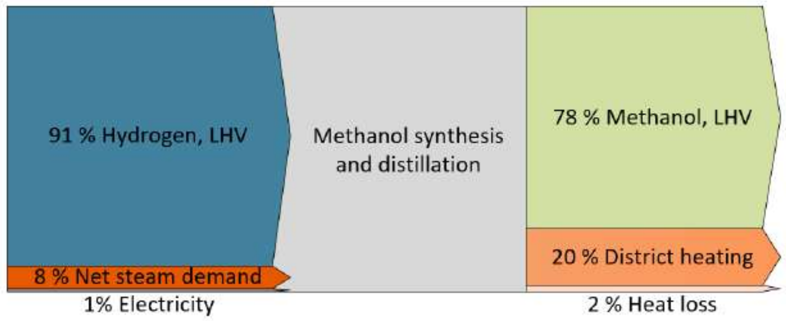

Figure 80: Energy balance of a methanol plant. "District heating" is low temperature heat that can be used for heating or low temperature industrial purposes.

The electricity demand included in Figure 80 corresponds to 100 kWh/ton-methanol and includes pumping power and power for cooling systems, but excludes compression of H_2 and CO_2, since these feedstocks are assumed to enter the battery limits at sufficient pressure (otherwise compression of the feed streams would be required). Haldor Topsøe [3] also provides a figure for the electricity consumption of the methanol plant of 500 kWh/ton-methanol, which is based on partly pressurized H_2 from electrolysis and atmospheric CO_2. When a value of 500 kWh/ton-methanol is used, the inputs to the energy balance are 86 % hydrogen, 7 % net steam demand and 7 % electricity demand.

The energy content in the hydrogen is converted to energy content in methanol, but with losses due to the exothermal reaction. Additionally, heat is needed for separating methanol and water in the distillation section. Due to this, 22 % of the input energy is lost as heat, a portion of the heat loss can be recovered and utilized for low-temperature heating application.

Typical capacities

Typical capacity of methanol plant is around 100,000 ton/year or 300 ton/day.

Ramping configuration

In conventional methanol production plants, the ability to regulate has not been an important design criterion, since fossil feedstocks generally have constant availability. However, e-methanol production relies on renewable intermittent energy sources, and therefore the ability to regulate the production capacity is important for such plants unless sufficiently large storage facilities are implemented.

Cold start-up procedures are time consuming and pose a catalyst decomposition risk, hence it should be avoided as much as possible. Instead of shutting down the plant, measures such as hot standby mode of operation should be implemented.

Advantages/disadvantages

Advantages:

The production of e-methanol relies on the supply of a green CO_2 source and a green H_2 source. Compared with conventional methanol production, based on syngas from fossil feedstock (example natural gas or coal), the e-methanol production pathway provides the following advantages:

- Enables a carbon-neutral way of producing methanol
- No steam reforming is needed
- There is no CO in the incoming syngas, which results in lower heat of reaction of the methanol synthesis, and it is therefore possible to select among multiple reactor types, when designing the plant. One example is tube-cooled reactors, which are not an option in conventional methanol plants due to the presence of CO in the syngas and the resulting high heat of reaction [2].

- Purity of H_2 stream from electrolysis is high, and the same can be the case for CO_2 depending on CO_2 source and capture design. Results in less purge.

Disadvantages:

The following disadvantages are associated with production of e-methanol:

- No CO in the syngas results in a less reactive gas and non-conventional syngas composition
- H_2 availability relies on renewable energy sources, which can result in fewer annual production hours compared with fossil feedstocks or need for significant storage of feedstocks
- CO_2 availability can be variable depending on source

Space requirement

Expected space requirement for a 300 ton/day methanol production plant is around 4,000 m^2, however, the space needed is subject to specific project requirements.

Water consumption

For e-methanol production, water consumption is dominated by upstream hydrogen production via electrolysis, as described in the hydrogen electrolysis section. The methanol synthesis step itself does not consume water as a reactant.

In the synthesis process, carbon dioxide reacts with hydrogen to form methanol and water. Water is therefore produced as a by-product rather than consumed, and is typically separated from the product stream. Additional water use is associated with auxiliary systems such as cooling, gas conditioning, and CO_2 capture and purification, depending on the chosen capture technology and cooling configuration.

As a result, net water consumption beyond that required for electrolysis is limited and, in some cases, partially offset by process water generated during methanol synthesis. The overall water footprint of e-methanol is therefore largely governed by hydrogen production and system design rather than the synthesis reaction itself.

Environment

The main output streams are methanol, water, reaction by-products and inert gases. Depending on the degree of purification reached in the distillation, the water phase will contain small amounts of methanol and byproducts from the reaction. These organic compounds can be removed on site or in central wastewater facilities.

Depending on the purity of the feed streams, gases are purged in order not to build up inert gases in the system. The purge stream contains inert gases and unreacted gases and can be combusted or recovered. In conventional methanol plants, purge gases are often burned as part of the combustion process providing heat to the steam reformer. In an e-methanol plant, such a combustion process would not by default be part of the plant, for example if process steam is generated in an electric boiler. However, the purity of the feed stream for an e-methanol plant can also be expected to be higher compared to conventional fossil-based plants, since the purity of hydrogen from electrolysis is higher compared with hydrogen from steam reforming. A higher purity of feed streams would reduce the need for purging.

Similar to purging, low boiling point byproducts, which are separated in the distillation section, would also need to be handled safely – for example combusted or recovered.

Research and development

Large-scale methanol production has existed for decades, and many of the unit operations required for converting H_2 and CO_2 to e-methanol would be based on existing technology. The research and development perspectives are therefore primarily aimed at adapting and optimizing plant designs for a syngas without CO, but with H_2 and CO_2 of intermittent availability.

The hydrogen to methanol technology has been demonstrated in full commercial scale and is therefore on TRL 9. The methanol reactor is already a mature technology and therefore the development potential is limited. The performance and cost figures are therefore not expected to change in the future. However, there is significant potential in developing business cases for e-methanol plants considering the full supply chain and integrating methanol plants in national energy and carbon infrastructure.

Examples of relevant research and development areas are the following:

- Optimizing reactor and catalyst design for feedstocks based on H_2 and CO_2
- Reactor design enabling dynamic operation or design of storages enabling constant feed streams
- Realizing synergies with processes such as carbon capture, electrolysis and other PtX-processes
- System designs enabling sector coupling (notably utilization of waste heat or oxygen)

Examples of current projects

The first e-methanol plant entering into commercial operation is the small-scale CRI plant in Iceland with a capacity of 4,000 ton/year. As indicated in the list of typical capacities section above and in IRENAs Innovation Outlook [4], many plants are planned to enter into commercial operation in the coming years. Recently, the first utility scale plant (see Shunli project in Table 31) of 110,000 ton/year has entered into operation.

Based on the list of planned projects and the recently commissioned Shunli project, the current market standard is assessed to be a production capacity of around 100,000 ton/year. However, plant designs must be tailored to the feedstock available at the relevant location – most often to the CO_2 capacity of an available point source. The below Table shows an overview of completed and planned projects.

Table 32: Overview of completed and planned methanol projects.

Project	Capacity	Status	Country
European Energy, Kassø [11]	32,000 ton/year	Planned for 2023	Denmark
Green Fuels for Denmark [12]	50,000 ton/year	Uncertain, as no final investment decision was made during the publication of the report	Denmark
LiquidWind [13]	50,000 ton/year	Start of operation for first plant planned for 2024	Sweden
Vordingborg Biofuels [14]	100,000 ton/year	Ready for production in 2025	Denmark
Ørsted and Maersk [15]	300,000 ton/year	Ready for production in 2025	United States
Shunli Project [16]	110,000 ton/year	Commissioned in Q3 2022	China
Sailboat Project [16]	100,000 ton/year	Commissioning planned in 2023	China
Finnfjord e-methanol [16]	100,000 ton/year	Investment decision expected in 2023	Norway
George Olah Renewable Methanol Plant [16]	4,000 ton/year	Operational since 2012	Iceland

Investment cost estimation

The cost estimates are based on cost data presented by Nami et al. , but adjusted +10 % based on discussions with suppliers of methanol plants. CAPEX is scaled to different plant capacities based on normal economy scale for chemical process plants. The effect of economy of scale is illustrated in figure below, where

CAPEX is plotted as a function of capacity.

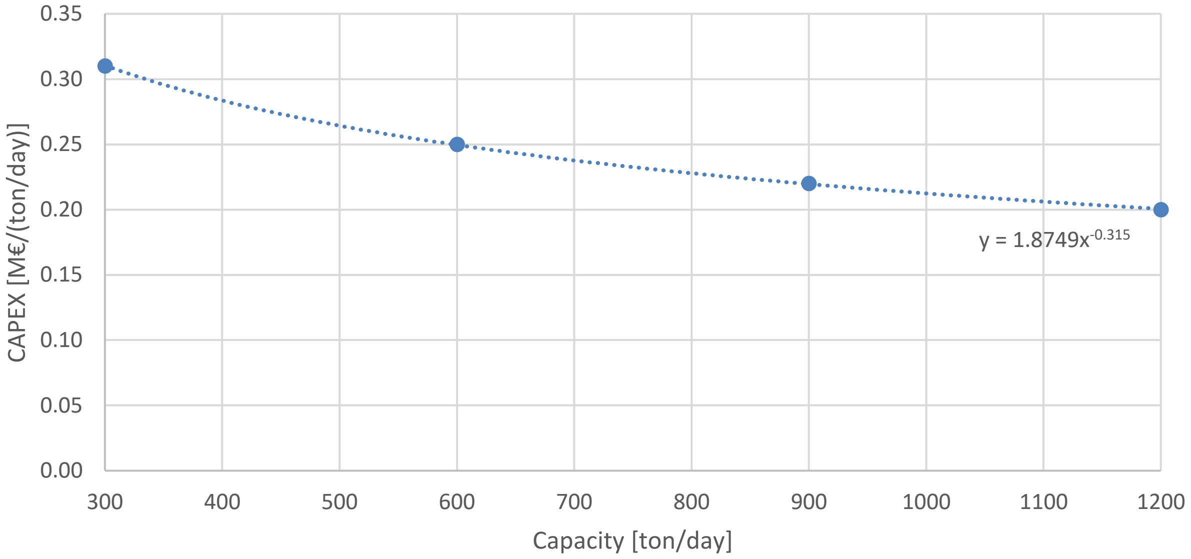

Figure 81: CAPEX as a function of capacity. A conversion factor of 0.7857 is used to convert to USD2019

The updated 2026 Viet Nam Technology Catalogue has revised all cost projections by converting them to 2025 USD.

Investment costs [MUSD/MW]	**2020**	**2025**	**2030**	**2040**	**2050**	**Notes**
	Below 150 kt/y		150 - 250 kt/y	250 – 350 kt/y	350 – 450 kt/y	
	Below 417 tpd		417 – 694 tpd	694 - 972 tpd	972 - 1250 tpd	
Vietnam technology catalogue 2026		1.65	1.33		1.06	
Vietnam technology catalogue 2023	1.33 (108 kt/y)		1.07 (216 kt/y)	0.94 (324 kt/y)	0.86 (432 kt/y)	A
Hank et al. [4, 5]	3.02 (4 kt/y)					
Hank et al. [4, 5]	1.08 (10 kt/y)					
Bos et al. [4, 6]	2.08 (65 kt/y)					B
Zhang et al. [4, 7]	0.85 (100 kt/y)					
Swiss Liquid Future [4, 8]	2.25 (100 kt/y)					C
Clausen et al. [4, 9]				0.85 (300 kt/y)		
Pérez-Fortes et al. [4, 10]					0.85 (440 kt/y)	D
Danish Technology Catalogue	1.33 (108 kt/y)		1.07 (216 kt/y)	0.94 (324 kt/y)	0.86 (432 kt/y)	A

Notes
Assuming t/y = 360 tpd
A. *excluding electrolyser, datasheet section elaborates in details on included and excluded components*
B. *Includes capital cost for a 100 MW wind farm.*
C. *Estimated cost for methanol produced in the wind and solar belts of the world.*
D. *Cost of methanol plant does not include hydrogen production.*

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The description in this chapter is to a great extent based on the Danish Technology Catalogue *"98 Methanol from hydrogen (2023)"*.

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[16] Carbon Recycling International, [Online]. Available: https://www.carbonrecycling.is/projects.

Data sheet

The scope of the following datasheet considers technology limits, as illustrated in figure below.

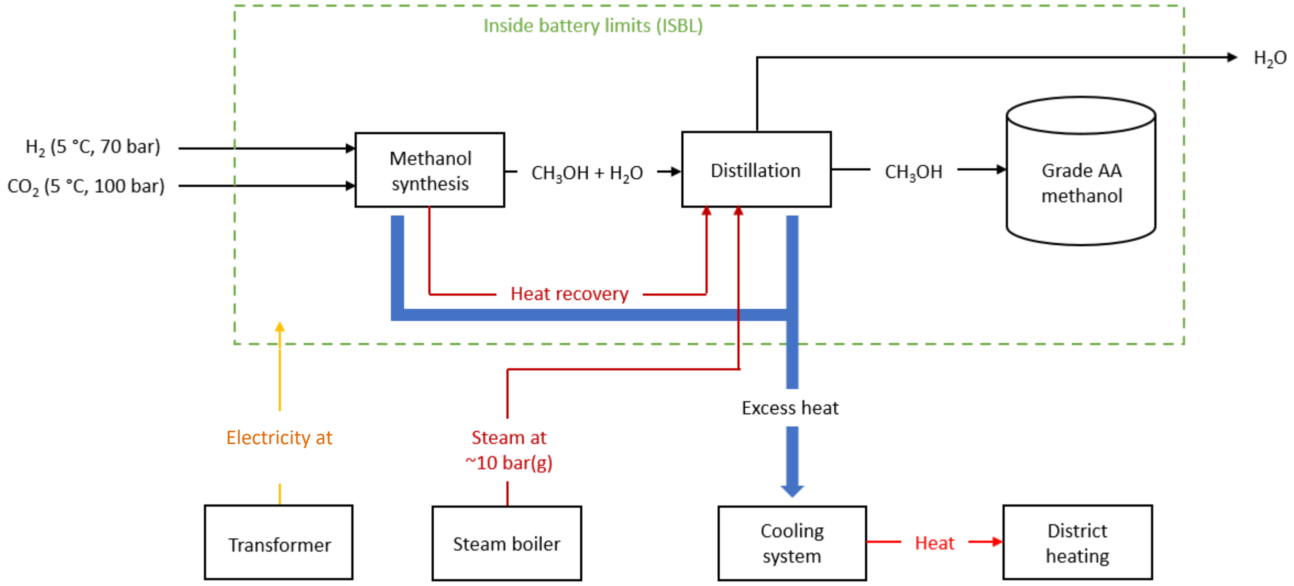

Figure 82: Illustration of technology ("battery") limits.

The H_2 and CO_2 streams are assumed to be supplied from central national or regional pipelines at pressure levels above the reactor pressure. The following elements (including installation costs) are considered to be included in the CAPEX estimates:

- Methanol reactor incl. catalyst
- Methanol distillation for achieving grade AA methanol
- Piping between components inside the battery limits (ISBL)
- Electrical cabling on low voltage side
- SCADA
- Methanol tank which is assumed to contain one day's production
- Distillation columns prepared for utilization of low-temp. heating applications (higher temperatures of cooling water)

The following elements are not included:

- H_2 and CO_2 compressors
- Electrical transformers
- High voltage electrical systems
- Fee to DSO for connecting to electrical grid
- Utility systems: cooling system, steam boiler
- Possible connection to low-temp. heating systems
- Contingencies
- Cost of land
- VAT and taxes
- Owner's costs

The cost estimates provided in the datasheet are based on cost data presented by Nami et al. , but adjusted +10 % based on discussions with suppliers of methanol plants.

The datasheet of a green methanol plant is shown below. The accuracy of the cost figures is expected to be within ±50 %. It should be noted that the evolution of CAPEX with time is assumed to be due to increase of plant size and associated benefits of economy of scale, and not due to technological development. If, for example, a 1200 ton/day plant is expected in 2040, it is therefore possible to use cost data for 2050 corresponding to a 1200 ton/day plant.

E-methanol (excl. electrolyser)										
Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Typical plant size	ton-methanol/day	300	600	1200					A	1
Typical total plant size	MW methanol output	69	138	276						
Inputs										
CO_2	ton/ton-methanol	1.4	1.4	1.4	1.4	1.5	1.4	1.5	B	2
Hydrogen	ton/ton-methanol	0.19	0.19	0.19	0.2	0.2	0.2	0.2	C	2
Hydrogen	MWh/ton-methanol	6.4	6.4	6.4	6.4	7.0	6.4	7.0	D	
Electricity	MWh/ton-methanol	0.1	0.1	0.1	0.08	0.12	0.08	0.12	E	2
Net steam	MWh/ton-methanol	0.58	0.58	0.58	0.46	0.70	0.46	0.70	F	2
Outputs										
Methanol	MWh/MWh total input	0.78	0.78	0.78	0.780	0.858	0.780	0.858	G	
Heat loss; usable as low-temp. heat	MWh/MWh total input	0.2	0.2	0.2	0	0.22	0	0.22	H	
Additional heat loss	MWh/MWh total input	0.02	0.02	0.02	0.018	0.022	0.018	0.022	I	
Water	ton/ton-methanol	0.55	0.55	0.55	0.550	0.605	0.550	0.605	J	
Forced outage	%	5	3	2						
Planned outage	weeks per year	3	3	3						
Technical lifetime	years	30	30	30						
Construction time	years	2	2	2					K	
Economic data										
Specific investment	MUSD/ton-methanol/day	0.38	0.31	0.25	0.19	0.57	0.12	0.37	L, O, P	3
Specific investment	MUSD/MW methanol output	1.65	1.33	1.06	0.83	2.48	0.53	1.60	O, P	
- equipment	%	75	75	75						
- installation	%	25	25	25						
Fixed O&M	kUSD/ton-methanol/day/year	11.0	8.6	7.4					M	
Fixed O&M	kUSD/MW methanol/year	48	37	32						
Variable O&M	USD/ton-methanol	33	33	33					N	3
Variable O&M	USD/MWh methanol	6.0	6.0	6.0						
Start-up	MUSD/ton/day-methanol	-	-	-						
Technology specific data										
Water consumption (L/MWh)		0	0	0	-	-	-	-	Q	

Notes:

A In the period 2020-2030 the plant size is governed by the available carbon resource. Towards 2050, direct air capture is expected to play a role resulting in increased plant sizes.

B The value is slightly higher than stoichiometric reaction due to the formation of organic by-products.

C Calculated based on 2,130 Nm^3-H_2/ton-methanol and 0,09 kg-H_2/Nm^3-H_2.

D Converted based on a lower heating value for hydrogen of 33,3 kWh/kg.

E Haldor Topsøe [5] states a value of 500 kWh/ton-methanol, which includes compression of H_2 and CO_2. The figure provided in the table covers electricity demand for auxiliary equipment excl. compressors and is assumed to be 20 % of the value provided by Haldor Topsøe.

F Steam produced in the methanol reactor is reused for heating purposes in the distillation section. The value provided states the net import steam.

G Calculated based on a lower heating value for methanol of 19,9 GJ/ton.

H Based on assumption that warm streams can be cooled to 50 °C.

I Includes heat loss to ambient and cooling at temperatures below 50 °C.

J Based on stoichiometry of the chemical reaction. The waste water includes traces of organic byproducts from the methanol synthesis, and can be handled in conventional central waste water facilities or treated on site.

K Construction time from order placement to start of commercial operation. Methanol reactor is a long lead item which is a governing factor for the construction time.

L According to battery limits as described in the text. Reduction in specific investment over time is due to economy of scale and not due to technological development.

M Estimated to be 3 % of CAPEX.

N Excludes costs related to process inputs such as steam, electricity, hydrogen and carbon dioxide.

O Included in the CAPEX data are the: Methanol reactor incl. catalyst, Methanol distillation for achieving grade AA methanol, Piping between components inside the battery limits (ISBL), Electrical cabling on low voltage side, SCADA (Supervisory Control And Data Acquisition), Methanol tank which is assumed to contain one day's production, Distillation columns prepared for utilization of district heating (higher temperatures of cooling water).

P Excluded from the CAPEX data are the: H2 and CO2 compressors, Electrical transformers, High voltage electrical systems, Fee to DSO for connecting to electrical grid, Utility systems: cooling system, steam boiler, Possible connection to district heating system, Treatment of purge gases and separated by-products, Contingencies, Cost of land, VAT and taxes and Owners costs.

Q When the electrolysis process is excluded, the water consumption is negligible.

References

1 Lemvig Biogas, "Erfaringer med totrins udrådning i fuldskala hos Lemvig Biogasanlæg," [Online]. Available: https://www.biogas.dk/wp-content/uploads/2021/12/Lars-A-Kristensen_Lemvig-Biogas_21-12-08.pdf

2 Haldor Topsøe, [Online]. Available: https://info.Topsøe.com/hubfs/DOWNLOADS/DOWNLOADS%20-%20Brochures/eMethanol.pdf?hsCtaTracking=6ca24cee-0aed-45df-8aa4-846ecd19151c%7C5d9f6bef-ebfc-483e-8a06-cdfed4aee34a

3 H. Nami, G. Butera, N. J. B. Campion, H. L. Frandsen and P. V. Hendriksen, "MarE-fuel: Energy efficiencies in synthesising green fuels and their expected cost," 2021

11. BIOMETHANOL FROM BIOMASS GASIFICATION

Brief technology description

The production of methanol from biomass is a two-step process. In the first step the solid biomass is converted into a bio-syngas and in the second step this syngas is further converted into methanol.

Gasification is a process that converts organic or fossil-based carbonaceous materials at high temperatures (>700°C), without combustion, with a controlled amount of oxygen and/or steam into carbon monoxide, hydrogen, and carbon dioxide (syngas). Stoichiometry for methanol production of syngas requires the ratio of H_2/CO to equal 2. The H_2/CO ratio can be lowered to some extent by the reverse water-gas shift reaction. Depending on the catalyst supplier, the methanol synthesis reaction is normally carried out at about 40 to 120 bar and 200 to 300°C.

Methanol is not the only product that could be produced by this route. Dimethyl Ether (DME) could also be produced instead of methanol or in an additional process step. The methanol could also be further processed into gasoline.

The biomass could be agricultural or forestry residues. There is a wide range in the design of gasifiers used for biomass. Different technological solutions can be implemented in order to obtain different plant configurations; in particular, the mode of contact of the biomass with the gasification agent may be in counter-current, or co-current, or crossflow, and the heat can be transferred from the outside or directly in the reactor using a combustion agent; the residence time can be in the order of hours (static gasifiers, rotary kiln) or minutes (fluidized bed gasifiers).

Different gasifier designs are better suited to different feedstocks and gas needs. The syngas to methanol reactions are practised commercially mostly using natural gas to produce the syngas but there are a few plants that gasify coal to produce the syngas. While the scale of commercial plants is large there have been some small-scale methanol plants built where large natural gas reserves are not available. The overall process is shown in the following simplified process flow diagram.

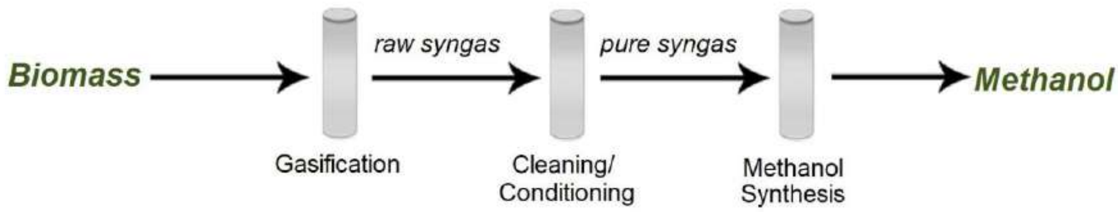

Figure 83: Biomass to Methanol Process

Technology Specific Data

Some the properties of methanol are shown in the following table.

Table 33: Methanol Properties

Property	Value
Density, kg/m^3	791
LHV, MJ/kg	19.9
LHV, MJ/litre	15.7
Oxygen content	50 wt%
Blending Octane number	~115
Flash point, C	12

Input

The primary input for most process is just the biomass. The reactions are exothermic and generate enough heat for the process and in some cases also enough heat to produce the power required for the system. In other examples, power is purchased for the process.

Output

The plants produce methanol and -in some cases- could produce some excess power and/or steam for sale.

The input and output of a typical system are shown in the following table [1]. These will be n^{th} plant values. Pioneering plants typically have a lower efficiency.

Table 34: Inputs and Outputs

Parameter	Input	Output
Wood, dry	100 MJ	
Power		1.8 MJ
Methanol		58.2 MJ

Energy Balance

The energy balance for a biomass to methanol system is shown in the following figure [2].

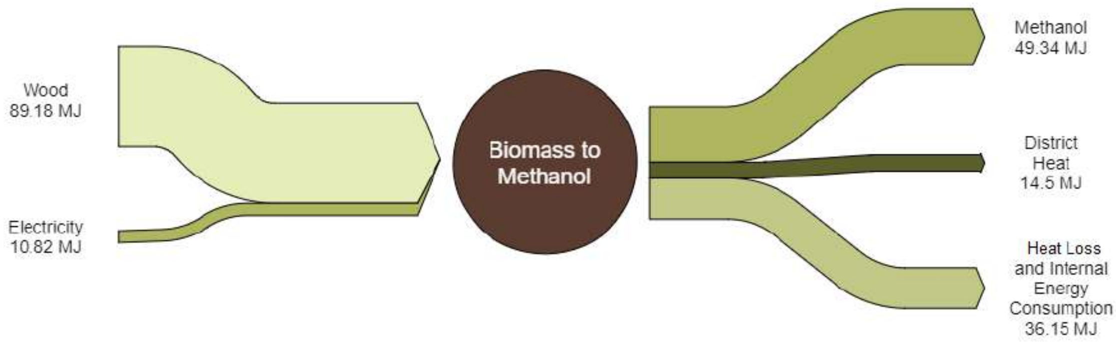

Figure 84: Biomethanol Energy Balance

There are two potential means to recover some of the waste heat. The plants use some of the process heat to produce electricity for the plant use and potentially a small amount to be exported. Steam from the exit of the final steam turbine would be available for other uses. This could have a temperature between 150 and 185°C depending on the design. There may also be some opportunity to recover some lower grade heat as the syngas is conditioned prior to synthesis. Details of the potential for energy recovery are not reported in most of the recent techno-economic studies published.

Other biomass to methanol systems have been proposed that offer higher efficiencies [1, 3]. The Green-SynFuels project provided the energy balance for both a traditional biomass to methanol plant and one integrated with a solid oxide electrolyser to produce hydrogen to provide a better CO to H_2 ratio for the methanol synthesis stage. Clausen [3] provided information for a highly optimized biomass to methanol process. The energy balances for these systems are shown in the following figures.

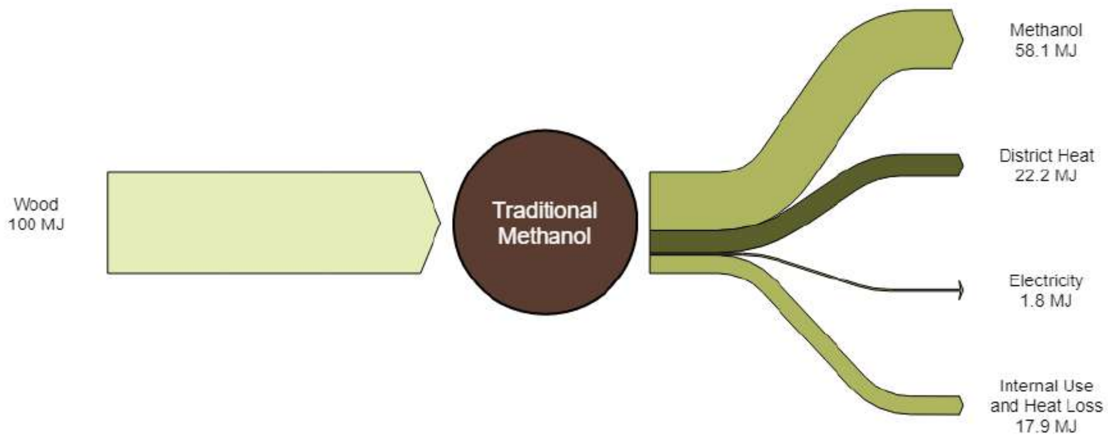

Figure 85: GreenSynFuels Traditional Methanol Plant

This plant produces electricity instead of consuming it and the methanol production rate is slightly higher per unit of wood consumed. The following figure shows the highly optimized system described by Clausen [3]. The methanol production rate is 8% higher per unit of feedstock.

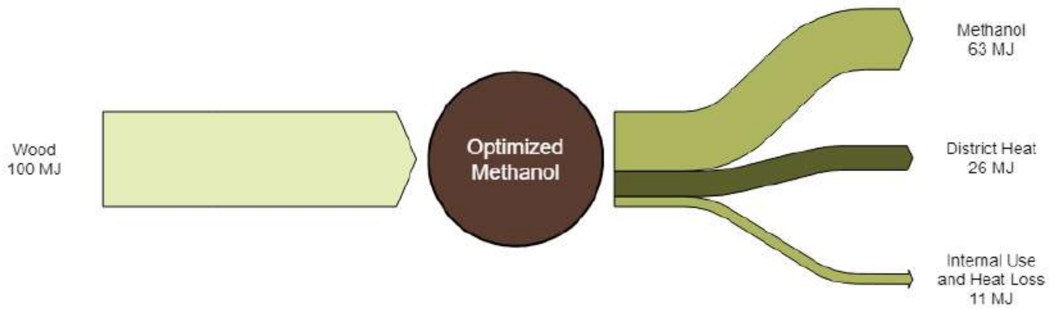

Figure 86: Optimized Biomass to Methanol Plant

This final energy balance considers the supplementation of hydrogen to alter the carbon to hydrogen ration of the syngas to better match the methanol synthesis requirements. It produces more methanol per unit of energy input and has a much better carbon efficiency.

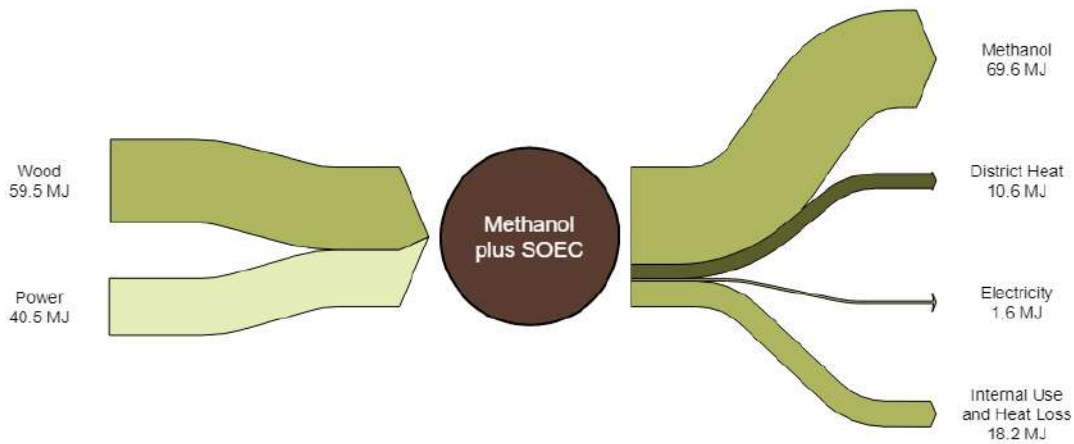

Figure 87: Hybrid Biomass to Methanol Plant

The available quantitative data that is available on the technology is mostly from third parties and not from the technology providers or plant operators. No actual plant data is available. There are three basic reactions that occur in the process. The first reaction breaks the biomass down, at high temperature and low oxygen, to a combination of hydrogen, carbon monoxide and carbon dioxide. A simplified reaction is shown below. Actual biomass has highly variable composition and complexity with cellulose as one major component.

$$C_6H_{12}O_6 + O_2 + H_2O \rightarrow CO + CO_2 + H_2 + CH_4 + \text{other species}$$

Note: The above reaction uses glucose as a surrogate for cellulose.

Stoichiometry for methanol production of syngas requires the ratio of H_2/CO to equal 2. The product gases are then subjected to the water-gas shift reaction to increase the quantity of hydrogen. The equilibrium for this reaction is temperature dependent which controls the CO to CO_2 ratio.

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

Carbon monoxide and hydrogen react over a catalyst to produce methanol. Today, the most widely used catalyst is a mixture of copper and zinc oxides, supported on alumina. At 50–100 bar and 250 °C, the reaction is characterized by high selectivity (>99.8%):

$$CO + 2\ H_2 \rightarrow CH_3OH$$

Compared to the production of diesel and jet fuel from the gasification of biomass, this pathway requires a lower H_2/CO ratio and operates at lower temperatures but higher pressures.

Typical Capacities

There is currently no commercial biomass to methanol plants in operation. In the past OCI operated a former natural gas to methanol plant on crude glycerine from biodiesel plants as the feedstock in the Netherlands but that operation is now processing natural gas again. There was also a bioDME pilot plant operated in Sweden for a number of years where methanol production was an intermediate product (Chemrec) [4]. It gasified black liquor from a pulp mill rather than biomass.

Commercial plants would likely be similar in size to the biomass to diesel and jet technology, with estimates of early commercial plant consuming 500 to 1000 tpd of biomass and producing 125 to 250 million litres of methanol per year. Eventually plants could be built larger with feedstock availability being the limiting factor.

As with the biomass to diesel and jet process, the plant size will be determined by the feedstock availability. The proposed plant in Sweden would produce 130 million litres of methanol per year (65 MW) from 1,100 tpd of wood [5]. It is not stated but this is likely on a wet basis (660 dry tpd). NREL undertook a techno-economic analysis of a wood to methanol plant [6]. They based the plant on 2000 tpd of feedstock producing 380 million litres per year (200 MW).

Ramping configuration

While biomass gasifiers can operate down to about 35% of rated capacity, commercial methanol plants usually operate at steady state conditions close to the design capacity. Commercial methanol plants can take 2-3 days to reach full production so starting and stopping the plants is generally not an option for regulating capacity. Smaller scale systems with different catalysts may have better regulation capabilities than the large-scale plants.

Advantages/disadvantages

Advantages:

- Methanol is not widely used as a transportation fuel today but there are several potential emerging applications that are generating some interest. One is the use of methanol as a hydrogen carrier for fuel cell vehicles such as those developed by Serenergy in Denmark.
- There is also some interest in methanol as a marine fuel to meet the new IMO sulphur limitations.
- In China there is some methanol gasoline blending with 10 and 15% methanol. Low level methanol blends (3%) with a co-solvent have been used in the UK in recent years. Methanol has also been used in blends with ethanol and gasoline in performance vehicles.
- Methanol from biomass can be used for the same applications as fossil methanol, while reducing GHG

emissions.

Disadvantages:

- Much of the world's methanol is produced from stranded natural gas and is very low cost. It will be difficult for biomass to methanol to complete against these projects on only an economic basis.

Space requirement

Space requirements will be similar to the space for the biomass to diesel and jet pathway, on an area per feedstock basis. The area per volume of fuel produced will be lower due to the lower energy density of methanol compared to diesel and jet fuel. Based on the Velocys commercial FT liquids plant, the area requirements for biomass to methanol are about 0.16 ha/million litres of methanol.

Water consumption

For biomethanol produced via biomass gasification, water consumption is linked to feedstock preparation, the gasification process, and downstream synthesis, rather than hydrogen electrolysis. Water or steam is typically used in the gasifier as a reactant and as a heat transfer medium, influencing syngas composition through steam reforming and water-gas shift reactions. Part of this water is chemically converted, while the remainder is recovered and recycled within the process.

Additional water use occurs in gas cooling and cleaning (e.g. quenching, scrubbing), methanol synthesis cooling, and auxiliary systems. These steps can lead to both consumptive and non-consumptive water use, depending on process integration and the extent of internal water recycling. In contrast to e-methanol, water is also generated as a by-product during methanol synthesis, which can partially offset upstream water demand if recovered.

Overall, water consumption for biomethanol is moderate and highly plant-specific. It is strongly influenced by gasifier type, feedstock moisture content, and the degree of water and heat integration, with modern designs aiming to minimise net water intake through closed-loop operation and reuse of process water.

Environment

Biomass to methanol should have a very low GHG emission profile, especially when they are designed to be self-sufficient in electric power. Methanol as a fuel is a biodegradable product.

Research and development

Biomass gasification for methanol production from wood or straw is a category 2 technology, a pioneer phase technology with limited applications to date. The technology has been proven to work through demonstration facilities or semi-commercial plants. However, due to the limited application, the price and performance is still attached with high uncertainty, since development and customization is still needed. The technology still has a significant development potential. This technology pathway is the combination of two commercial systems. There has been considerable development work on biomass gasification in Europe over the past several decades but there has not been a commercial break through yet.

The production of a synfuel from a biomass gasification system is a more demanding application than the use of the gas in an engine or in an external combustion system. It is reported that the Chemrec BioDME plant operated for more than 11,000 hours between 2011 and 2016 [7]. Production during that time was reported to be 1000 tons of DME. The capacity of the plant was 165 kg/hour which works out to 6,000 hours of operation. More work is required on the integration of the two main systems.

Examples of current projects

The below table shows an overview of existing and planned projects.

Table 35: Existing and planned bio-methanol projects [8].

Project/ study	Capacity (t/y)	Status	Country
Trans World Energy (TWE)	875,000	FEED done, start-up Q2 2023	Florida (US)
ENI Refinery	115,000	Basic engineering ready Q3 2020	Italy
LowLand Methanol	120,000	Start-up early 2023	Netherlands
Södra	5,000	Operational	Sweden
Enerkem, Rotterdam	215,000	Engineering	Netherlands
Enerkem, Tarragona	215,000	Engineering	Spain
VTT	265,000	Detailed study	Finland
Chemrec	147,000	Preliminary engineering	Sweden
Chemrec, n^{th} plant	290,000	Concept	Sweden
New Hope Energy	715,000	Investment decision Q4 2020	Texas (US)

There is a biomass gasification to methanol proposal for a plant in Sweden, Värmland Methanol [9]. The plant is cost estimated at approximately 323 million USD and will produce 375,000 liters of methanol per day (130 million litres/year). As a "byproduct" 15 MW of district heating is obtained. An EPC contract with ThyssenKrupp Industrial Solutions of Germany has been signed. The project was proposed in 2009 but has been unable to raise financing for the project. ThyssenKrupp Industrial Solutions do have experience and expertise in gasification and methanol production technologies.

Enerkem, a Canadian company has operated a municipal solid waste (MSW) gasification to methanol production system in Edmonton Alberta for the past two years. The company is focused on MSW as a feedstock due to the favourable economics. The Edmonton plant is in the process of being converted to produce ethanol rather than methanol from the syngas.

Investment cost estimation

Since production is currently low, limited data are available on actual costs, meaning that potential costs need to be estimated. The bio-methanol production cost will depend on the bio-feedstock cost, investment cost and the efficiency of the conversion processes. [8].

The updated 2026 Viet Nam Technology Catalogue has revised all cost projections by converting them to 2025 USD.

Investment costs [MUSD/MW]	2020	2025	2030	2040	2050
	Below 150 kt/y		150 - 225 kt/y	225 - 300 kt/y	300 – 900 kt/y
	Below 450 tpd		450 - 676 tpd	676 – 901 tpd	901 – 2703 tpd
Vietnam technology catalogue 2026		4.83	2.69		1.34
Vietnam technology catalogue 2023	3.88		2.16		1.08
Södra, Sweden [8]	3.19 (5 kt/y)				
ENI Refinery, Italy [8]	4.23 (115 kt/y)				
LowLand Methanol, The Netherlands [8]	1.60 (120 kt/y)				
Chemrec, Domsjö, Sweden [8]	3.36 (147 kt/y)				
Enerkem, Rotterdam, The Netherlands [8]			3.79 (215 kt/y)		
Enerkem, Tarragona, Spain [8]			3.79 (215 kt/y)		
VTT, Finland [8]				2.04 (265 kt/y)	

Chemrec, nth plant [8]				2.71 (290 kt/y)	
New Hope Energy, Texas, USA [8]					1.01 (715 kt/y)
Trans World Energy, Florida, USA [8]					0.70 (875 kt/y)
Danish Technology Catalogue	5.97 (100 kt/y)		3.32 (200 kt/y)	2.41 (250 kt/y)	1.66 (300 kt/y)

Notes:
Assuming t/y = 333 tpd

References

The description in this chapter is to a great extent based on the Danish Technology Catalogue *"97 Methanol from Biomass Gasification"*.

[1] Lebaek, J., Boegild Hansen, J., & Mogensen, M., GreenSynFuels. Economic and technological statement regarding integration and storage of renewable energy in the energy sector by production of green synthetic fuels for utilization in fuel cells. Final project report, 2011. https://www.osti.gov/etdeweb/servlets/purl/1015395

[2] Andersson, J., Lundgren, J., & Marklund, M., Methanol production via pressurized entrained flow biomass gasification–Techno-economic comparison of integrated vs. stand-alone production. Biomass and Bioenergy, 64, 256-268, 2014.

[3] Clausen, L. R., Integrated torrefaction vs. external torrefaction–A thermodynamic analysis for the case of a thermochemical biorefinery. *Energy*, *77*, 597-607, 2014.

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[8] IRENA and Methanol Institute, Innovation Outlook: Renewable Methanol, International Renewable Energy Agency, Abu Dhabi 2021.

[9] Värmlands Metanol AB. http://www.varmlandsmetanol.se/Om%20Projektet.htm

Data sheet

The following page contains the data sheet of the technology. The uncertainty it related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Techno-economic analyses of standalone biomass gasification to methanol systems have been published [1, 2]. These are used as the basis for the Economic analysis and where possible compared to the published data for the proposed Swedish plant. The start-up costs are included in the reported costs. The prediction of performance and cost is based on published techno-economic papers rather than on actual plant performance.

There is a high level of uncertainty for the technology given the state of development. The quantitative data for the biomass to methanol process are summarized in the following table.

Bio-methanol										
Parameter	Unit	2025	2030	2050	Uncertainty (2025)		Uncertainty (2050)		Note	Ref
					Lower	Upper	Lower	Upper		
Energy/technical data										
Typical total plant size	1000t methanol/year	100	200	300	50	200	150	375	A, B	3, 4, 5
Typical total plant size	MW	65	130	195	33	130	98	244	A, A1, B	3, 4, 5
Inputs										
Feedstock Consumption	MWh/MWh total input	1	1	1	0.90	1.50	0.90	1.20		1
Outputs										
Methanol Output	MWh/MWh total input	0.58	0.61	0.65	0.58	0.77	0.65	0.86	D	1
Heat loss; usable as low-temp. heat	MWh/MWh total input	0.22	0.22	0.22	0.18	0.28	0.18	0.28	D	1
Additional heat loss	MWh/MWh total input	0.22	0.22	0.22	0.18	0.28	0.18	0.28	D	1
Electricity Output	MWh/MWh total input	0.02	0.02	0.02	0.02	0.03	0.02	0.03	D	1
Forced outage	%	4	0	0						
Planned outage	weeks per year	2	2	2						
Technical lifetime	years	20	20	20						
Construction time	years	2.5	2.5	2.5						
Economic data (in USD2025)										
Specific investment	MUSD/MW methanol	7.44	4.13	2.07	3.72	7.44	1.65	2.48	F	1, 3, 4, 5
- equipment	%	75	75	75						
- installation	%	25	25	25						
Fixed O&M	MUSD/MW/year methanol	0.083	0.055	0.055	0.07	0.09	0.05	0.06	E, F	1
Variable O&M	USD/MWh methanol	28.9	19.2	19.2	25.98	31.75	17.32	21.17	E, F	1
Start-up	MUSD/1000t methanol	-	-	-						
Technology specific data										
Specific energy content	GJ/ton-methanol	20.1	20.1	20.1						
Specific density	kg/l or ton/m3	0.79	0.79	0.79						
Specific investment	MUSD/1000t methanol	4.83	2.69	1.34	50%	100%	80%	120%	F	3, 4, 5
Fixed O&M	MUSD/1000t methanol	0.054	0.036	0.036	90%	110%	90%	110%	E, F	1
Variable O&M	MUSD/1000t methanol	0.161	0.107	0.107	90%	110%	90%	110%	E, F	1
Start-up	MUSD/1000t methanol	-	-	-						
Water consumption	L/MWh	-	-	-	-	-	-	-		

Notes:

A The plant size range is assumed based on the proposed Värmlands plant and the NREL n^{th} plant.

A1 This value is the hourly rating and has been calculated as if the unit produces at capacity and was in operations 8,000 h/year.

B Feedstock availability is likely to determine the maximum plant size.

C Some plants may produce their own power and have no power imports.

D Plants that produce their own power will have much lower heat loss.

E Assumed a 25/75 split on fixed to variable operating costs.

F MUSD/kton is million USD per 1,000 tons.

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12. BIOGAS PRODUCTION AND UPGRADING

Brief technology description

In biogas plants, organic matter is biologically converted under anaerobic conditions into a methane (CH_4) and carbon dioxide-(CO_2) rich gas and digestate. The biogas can be used in industrial processes, for producing heat and electricity, or for upgrading to biomethane. Biogas can also be produced on small scale, e.g., biogas produced in small household biogas digester systems primarily used for lighting and cooking. Currently most biogas production in Viet Nam is produced in household biogas digesters. This catalogue, and the datasheet, will focus on industrial plants for biogas production (with a capacity of above 10,000 tons/year).

The input of biomass is usually transported to the plant by road, but there are also plants where the low dry matter (DM) feedstock is pumped in pipes, thereby reducing local nuisance from truck transport [1,2]. The biomass is received and stored in pre-storage tanks and later processed in digestors (reactors). In biogas plants the digestors are normally heated to either 35-40 °C (mesophilic digestion), or 50-55 °C (thermophilic digestion). For new biogas plants with gas upgrading, the heat in the digesters will typically be supplied with excess heat from the upgrading facility. For plants that are not in connection with an upgrading plant, the heat demand can be supplied by either boilers (gas or biomass-fired) or, heat pumps.

After being processed in the main digestor, the digestate is pumped to post-processing tanks where post-digestion takes place and additional gas is produced and collected. Typical processing time in the digesters (Hydraulic Retention Time, HRT), depends on the biomass input and the plant's technical specifications [3].

Most industrial biogas plants are built as continuous stirred-tank reactors (CSTR). This implies continuous removal of a small quantity of digested biomass from the digesters and replacement with a corresponding quantity of fresh biomass, typically several times a day.

Finally, the gas is treated to reduce water and sulphur contents to the desired concentrations. After the biogas production process, the volume of the digestate is roughly the same, or slightly reduced, as that of the initial feedstock. The digestate can be recycled as a fertilizer in agriculture, either directly or after being separated into solids and fluids. The figure shows the typical components and flows in a biogas plant.

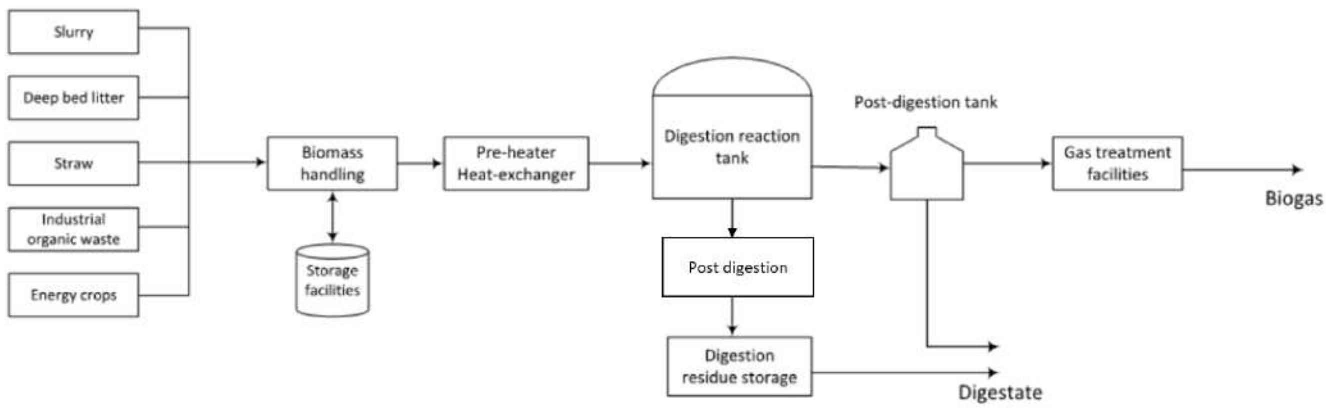

Figure 88: Typical components in a biogas plant. Note: alternative terms for technical descriptions might be used by some actors, e.g., biomass handling might be referred to as pre-treatment; digestion reaction tank as a digester and digestion residue storage as digestate storage or post-storage of digestate. [4]

The composition of the biomass input (feedstock) is important for the economy, dimensioning, and operation of the biogas plants. As the existing plants use CSTR, they are built to handle pumpable biomass, i.e., slurry and wet industrial waste [5].

There is an upper limit to how much high DM feedstock, e.g., straw can be handled in a CSTR. This is due to the risk of floating layers and the longer decomposition time of straw and similar biomasses. In the last couple of years, there has been a technical development toward biogas plants being able to handle a larger share of biomass with a high DM content, such as deep litter and straw. For instance, floating layers are prevented with an increased stirring frequency. Biogas plants, based on the current market standard, should be operated with a DM content of a max of 13-14% in the reactor [3,6]. Recirculation of liquid fraction after separation of the digestate makes the biogas plants able to use a higher share of feedstocks with a high DM%, as it will be mixed with the liquid digestate and thereby decrease the average DM content in the reactor [3,7].

Input

- Biodegradable organic material such as livestock manure/slurry, organic waste from food processing and households, agricultural residues (e.g., straw), energy crops, etc.
- Electricity for mechanical processing equipment
- Process heat for preheating and heating the reactor tanks

Input for biogas upgrading plant

- Raw biogas from a biogas plant.
- Heat (or electricity depending on the technology) for the upgrading process.
- Electricity for compression.
- Smaller amounts of water and various chemicals.

Output

- Biogas
- Digestate, for use as fertilizer

Output from biogas upgrading plant

- Upgraded biogas with 95-99 vol. % methane, carbon dioxide, nitrogen, and oxygen [7].
- Waste gas containing mostly CO_2

Energy balance

In the biogas industry, it is not common practice to measure the energy content of the input material as a calorific value, as is often done for other energy conversion technologies in this catalogue. Instead, the input is measured as tons of biomass along with information on the amount of dry matter in the input, expressed by the DM factor, and the share of organic materials, expressed by the share of volatile solid (VS). Using the energy balance as a yardstick for comparing different technologies is mainly interesting for biomasses (or other energy sources) with alternative uses such as straw, energy crops or certain types of industrial waste, which e.g., could be used in combustion plants or in thermal gasification processes. The lack of focus on the energy balance for biogas plants is partly due to difficulties in measuring the energy content of the input biomasses. Further, the high water content and fertilizer value of some of the biogas feedstocks, particularly slurry and manure, make them unsuitable for combustion in traditional energy plants both seen from an energy production perspective and a nutrient recycling perspective.

To estimate the energy balance of biogas production, the energy content of the biomass going into the plant and the output of biogas needs to be calculated. Table 27 provides an overview of the energy content of some of the most used biomasses. The energy content depends on the DM content, the VS share, and the calorific value of the biomass. The energy content is directly proportional to the DM content and the VS share. Further, the VS share of the DM represents the fraction of the DM that may be transformed into energy.

Dry matter and volatile solids

The Dry Matter (DM) content is the mass of solid remaining after a sample has been dried in an oven at 103°C for 24 hours, divided by the original mass of the sample.

The Volatile Solid (VS) measures the organic matter of a liquid or slurry. From a chemical perspective, the organic matter is the part that burns, and this is also the portion that may potentially be converted to biogas. Important to mention, most plants and other material that a non-professional would term as organic, contain a portion of inorganic matter.

To determine the share of VS, the DM sample is heated at 550°C for 1 hour. The lost mass is the Volatile Solid (VS). The remaining part, the ash, is also called the fixed solids (FS).

The portion of TS that remains after heating at 550° C for 1 hour is called Total Fixed Solids (TFS); the portion lost during heating is Total Volatile Solids (TVS).

Table 36: Data and energy balances for selected biomasses. Output data is given under the assumption of a retention time of 65 days. The conversion efficiencies will vary from plant to plant depending on the specific operations characteristics and specific properties of the biomass – and thus the values are only guiding. Longer retention time would increase the output from the plant and hence the conversion efficiency, and vice versa with respect to shorter retention time. Based on [22]

	DM content	VS Share	The energy content of input in GJ per ton of VS	The energy content of output gas in GJ per ton of VS	Conversion efficiency, biomass to biogas
Straw	85%	95%	17.4	9.5	55%
Slurry	4.5-7%	80%	n.d.	9.2	-
Maize	31%	95%	17.5	11.6	66%
Grass	32%	90%	18	11.5	64%
Beet	18%	95%	17.1	13.2	77%
Beet greens	12%	85%	18.2	12.4	68%

The conversion efficiency (biomass to methane) depends on several factors, including the composition of the feedstock, the processing time, the organic loading rate, and the effectiveness of process control. Fatty biomasses, proteins, and certain carbohydrates (sugars and starches) are relatively easily converted to biogas, whereas only part of the cellulose is converted, and almost none of the lignin.

As an example, the energy content of straw is 17.4 GJ per ton of VS. When straw is used as feedstock in a biogas plant with an HRT of 65 days, 260 Nm^3 methane/ton biomass will be produced, with an energy content of 9.5 GJ. When comparing this to the energy content of straw it implies that 45% of the energy content is not converted into gas. As mentioned, some biomasses are more easily converted to biogas than others giving a high biogas yield per ton of biomass being digested. The "energy loss" therefore depends on the type of biomass input as well as the HRT in the plant. When using a large share of straw, the energy loss will decrease if the HRT is increased, e.g., to 80 days instead of 65. Thus, conversion efficiency and methane production per ton varies depending on HRT, and the difference in methane output for straw and industrial waste would accordingly be different than the one displayed in Table 35 if the HRT had been different. It is noted, that the energy loss should not be perceived as a loss *per se*; thus, the carbon not converted to energy is not lost but returned to the fields, where it is stored and contributes to plant growth.

The heating value of biogas depends on the share of methane, which depends on the type of feedstock and the production pathway. Therefore, measuring the output in Nm^3 methane rather than Nm^3 biogas is practical to allow comparisons across plants. Methane has a lower heating value (LHV) of 35.9 MJ/Nm^3, whereas biogas with a 65% methane content has a LHV of 23.3 MJ/Nm^3.

Figure 89 shows an example of two different plants that produce the same volume of biogas. The first plant uses 1,770,000 t of biomass with an HRT of 35 days, while the second uses 1,030,000 t of biomass and has an HRT of 65 days. The reason why the output is the same is due to differences in feedstocks and HRT across the two plants.

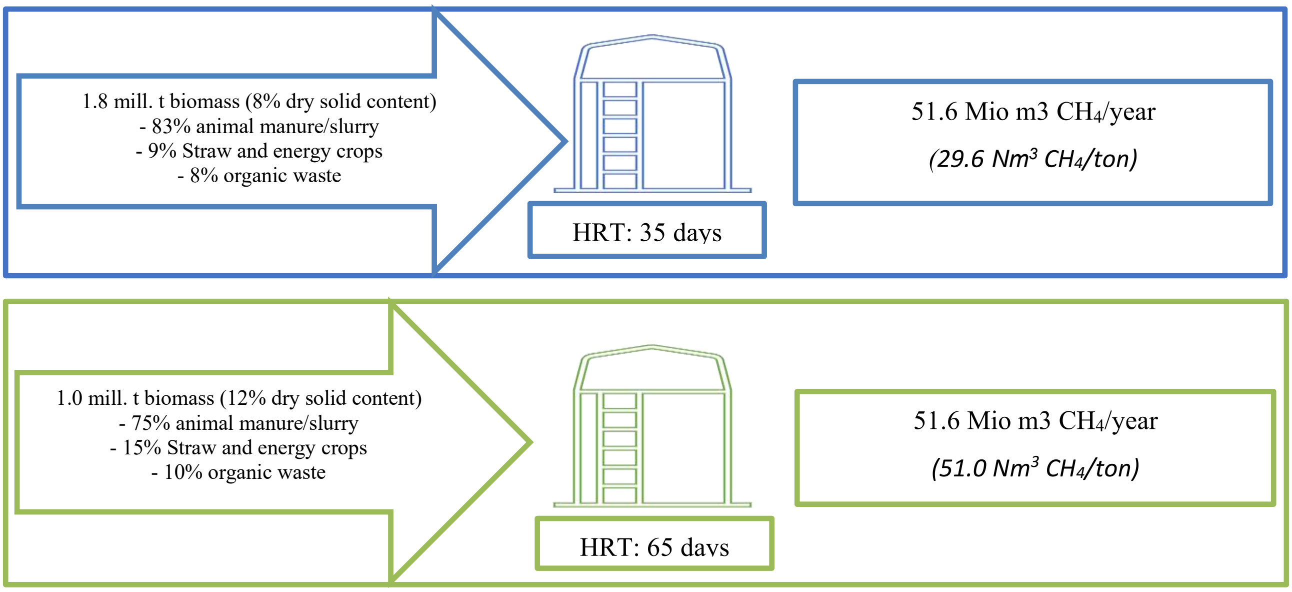

Figure 89: Biogas output in two different biogas plants – own illustration based on [19]

Upgrading of biogas

For some applications where it is important to have a high energy content in the gas, e.g., as vehicle fuel, the gas needs to be upgraded. Upgrading biogas refers to the process of removing carbon dioxide to obtain a gas with a high methane content, known as biomethane. The figure below shows how biogas can either be directly used as an energy source or be upgraded through an upgrading plant to be fed into a gas grid or be directly applied for consumptions needing gas with high energy content. In Viet Nam there is currently no gas grid.

Biogas becomes biomethane through a purification process at an upgrade facility. Biomethane has the same quality properties as conventional natural gas [8]. The input for upgrading facilities is raw biogas from an anaerobic digester, which typically contains 50-75% methane (CH_4) and 25-45% carbon dioxide (CO_2), plus a minor content of hydrogen (H), nitrogen (N), oxygen (O), hydrogen sulphide (H_2S) and ammonia (NH_3). The composition of the biogas varies based on the specific mix of the input.

Before injecting the gas into the gas grid, it is necessary to remove the content of CO_2, thereby increasing ("upgrading") the heating value of the gas. Depending on the composition of the raw biogas, it may also be necessary to remove water moisture, particles, H_2S, NH_3 and N_2. As it is rather expensive to remove N_2, this is rarely done. H_2S needs to be removed before further use as it is a corrosive gas.

During upgrading, a stream of CO_2 will be produced. Today, this CO_2 is usually vented into the air but is increasingly being sold for the purpose of storage or utilization as an additional source of income. This should be considered when the economy of the plant is assessed.

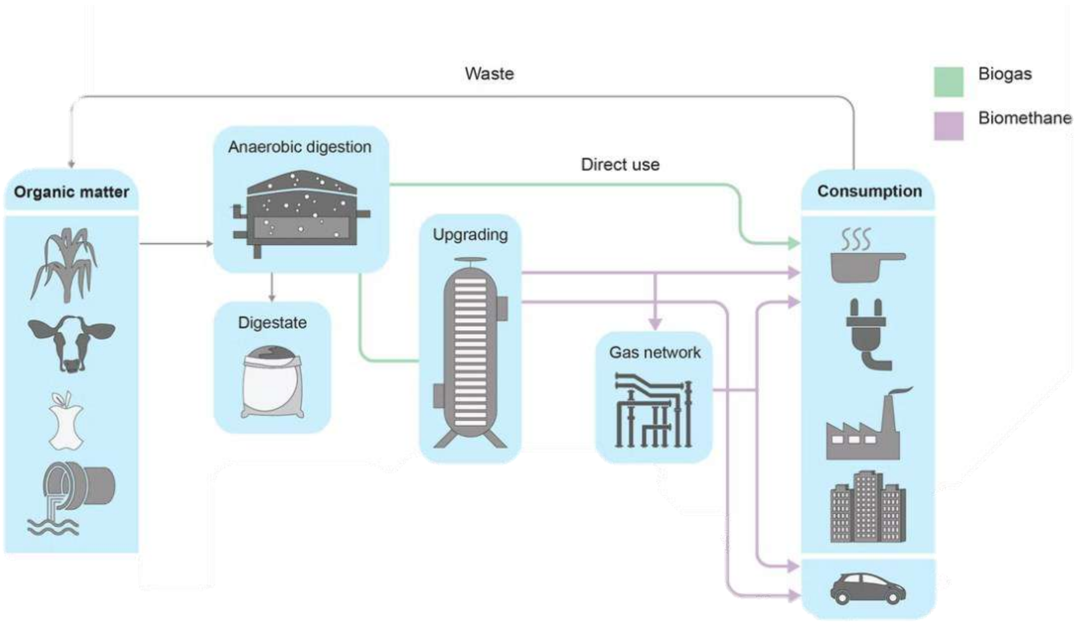

Figure 90: Biogas may either be used directly as an energy source or be upgraded through an upgrading plant to be fed into the gas network or be directly applied for consumptions needing gas with high energy content. Illustration from IEA [8]

In Asia only 2% of the produced biogas is upgraded, in Europe approx.10% is upgraded, while the percentage is much higher in Sweden and Denmark. However, IEA expects that half of the world's demand for biomethane will be in Asia [20].

Typical capacities

For an industrial scale biogas plant the typical capacities are:

Small: 10 tons biomass input /year

Large: 1 million tons biomass input/year

Ramping configurations

Biogas production at existing facilities can be increased by adding organic materials with high methane potential or by prolonging the HRT. However, there is a biological limit to how fast production can be regulated. For example, a biogas plant digesting only animal slurry during summer may increase the gas yield from 14 Nm^3 methane per ton to about 45-50 Nm^3 methane per ton during a period of three to four weeks if feedstock with a higher methane production potential is added. Regulation of the production may require additional feedstock storage capacity.

Biogas plants typically have short-term storage in connection with the facility. For new biogas plants with an upgrading facility, the storage will most likely be in connection to the upgrading facility and with a capacity equivalent to half an hour's production on a large biogas plant.

Advantages/disadvantages

Advantages:

- When manure is used for biogas production, the emission of greenhouse gasses from handling and storage of manure is reduced.
- Wet biomass sources, as well as those with few or no alternative uses can be transformed into a high-value energy carrier (biomethane)
- In Viet Nam poor manure management is a fastest-growing source of GHG emissions from the agriculture [9]; utilising manure for biogas production will decrease these emissions.
- The output gas contains a high level of CO_2, which makes it attractive for subsequent carbon capture and storage (CCS) or carbon capture and utilization (CCU).

- Saved expenses for handling and storage of slurry.
- Environmentally critical nutrients, primarily nitrogen, phosphorus, and potassium, can be redistributed to farms; in that way slurry from livestock farming with excess slurry, can be distributed to farms with crop production. The risk of leaching nitrates is also reduced.
- The fertilizer value of the digested biomass is higher than the value of the raw materials. The fertilizer value is also better known and documented, and it is, therefore, easier to apply the right dose to the crops.
- For waste fractions with high water content, co-digestion of manure and waste can often provide a low-cost and more environmentally friendly option compared to other forms of waste handling, such as landfill or incineration.
- Application of digestate reduces smell compared to the application of raw slurry.
- When straw is used as feedstock and the digestate from the biogas production is used as fertilizer, the content of carbon in the topsoil is not depleted, as it would be if the straw were incinerated in boilers or power plants.

Disadvantages:

- Methane leaks from digestate are unavoidable but can be kept to a minimum (below 1%) if monitored and handled properly.
- Use of straw and other solid biomass resources in biogas production yields a lower energy output than if the same feedstock was used for thermal gasification and/or combustion.
- The successful operation of biogas plants is relatively complex and requires large experience although it is an established and well-known technology worldwide.
- The utilisation of large quantities of biomass with low DM content (manure) makes transport and sourcing radius a critical parameter.
- Substantial road transport of biomass.

Water consumption

Water consumption in biogas production is relatively low, as the anaerobic digestion process itself does not require significant amounts of water. However, water may be used in auxiliary systems such as cooling, cleaning, and maintenance of the digesters.

In the biogas upgrading process, water is used to remove impurities such as carbon dioxide, hydrogen sulphiide, and other contaminants from the biogas. The amount of water used in upgrading depends on the specific technology and process design employed.

Overall, the water footprint of biogas production and upgrading is relatively small, with the majority of water use occurring in the upgrading process.

Environment

Biogas can substitute fossil fuels in the energy system and thereby avoid emissions of CO_2. Furthermore, the emission of greenhouse gasses from agriculture can be reduced. Methane is emitted from manure and slurry when it is stored in stables or slurry tanks, the higher the temperature in the stables or slurry tanks, the faster the emission of methane will happen. In biogas plants, this methane is captured and utilised instead of being released into the atmosphere during manure storage. When the manure is treated at a biogas plant, the emission of methane during storage may be reduced by up to 70%. In Viet Nam, concentrated livestock farms are required to have a waste treatment system, e.g. this could be a biogas plant. This solution requires a local demand or transportation of the produced biogas. [9]

Methane leakage is an environmental issue related to biogas production. Methane is the second most important GHG contributor to climate change following CO_2. On a 100-year timescale, methane has 28 times greater global warming potential than CO_2 per kg [10]. An investigation from 2021 covering 69 Danish biogas plants showed a weighted average leak of methane of 2.5%. [11] It is important to keep the leakages to a minimum (below 1%) to ensure a sustainable biogas production.

Odour from biogas plants is often mentioned as a problem, but it can be avoided with proper filtering of the off-gases, treatment of the air from all parts of the biogas plant and good management during operation. The odour nuisances from field application are reduced when slurry is anaerobically digested compared to the direct application of untreated livestock manure.

Hydrogen sulphide makes up a small part of the produced biogas. H_2S is highly toxic and represents an environmental issue. It is, however, easy to detect as the chemical has a strong odour, a reduction in odour will therefore also solve the toxicity issue. The content of sulphur (H_2S) in the biogas varies depending on the feedstock. When livestock slurry is the main biomass input, the raw gas typically contains 2,000-8,000 ppm, whereas biogas produced from household waste typically exhibits hydrogen sulphide levels of 600-800 ppm. [6]

Multiple methods can be used to remove the sulphur. Common techniques involve using either iron chloride, biological filters, or activated carbon. Iron chloride is dosed into the digester or into the substrate pre-storage tanks when needed. Depending on the substrate, the iron chloride needed for the reduction of the hydrogen sulphide levels varies. In biofilters, the off-gases are led through a chamber filled with products with a large surface on which microorganisms that degrade the unwanted substances live. When activated carbon is used, the gas is led through a filter where activated carbon absorbs the hydrogen sulphide. Over time, the activated carbon will be saturated and has to be re-activated or renewed. The CAPEX of the activated carbon technology is very low; however, it has a high OPEX meaning that it is mostly applied in smaller plants or used as a final polishing of the off-gases from biological filters or in the ramping up of new biogas plants, where the biological filters are not fully matured. The cost of sulphur removal using activated carbon is approx. 0.012 Euro per Nm^3 methane.

Biogas engines tolerate only small amounts of sulphur in the biogas. Therefore, the H_2S content must be reduced below the acceptable level to meet the specification from the engine suppliers and the environmental legislation. When the biogas is upgraded to biomethane and injected into the gas grid, complete sulphur removal may be necessary, and this is normally an integrated part of the upgrading process. As most biogas is upgraded, the cost of sulphur removal is not included in the costs for the biogas plant in the datasheet, but instead in the cost of the upgrading plants.

Research and development

The biogas R&D activities focus on several areas to increase energy production, improve the economy of the plants, reduce the climate impact and optimize the value of the digestate as fertilizer.

To increase energy production the focus is especially on developing technologies enabling increased use of "difficult" biomasses with higher methane potential per ton, such as straw, which is readily available. A development towards increased use of straw has occurred during the recent years, and this development is expected to continue although it is recognized that there might become increased competition for straw in the future, as straw has many alternative uses.

Biotechnological advances within microbial enzymatic hydrolysis may improve biogas production, in particular from lignocellulolytic material. However, today, the high cost of commercial enzyme production limits its application.

To reduce the climate impact and ensure sustainable production of biogas, a significant focus is on developing the operation and technologies of the plants to reduce methane leakages. Gas collection from several tanks in the process is under development, including collecting gas from the pre- and post-storage tanks. This is seen as an important development to reduce methane emissions from leakages.

Further development activities are related to the optimisation of control systems and logistics, for instance, transport systems integrated with larger stable systems, and possibilities for higher DM content in the livestock slurry.

The potential for improving technologies is linked to the level of technological maturity. The technologies are categorized within one of the following four levels of technological maturity further elaborated upon in the methodology (see Appendix). Biogas plants are commercial technologies with large deployment and can therefore be categorized as category 4, meaning that price and performance of the technology today is well known. For the upgrading plants the water scrubber and amine scrubbers are considered to be *Commercial technologies with moderate deployment* so far (Category 3). Price and performance of the technology today is well known. These technologies are deemed to have a significant development potential.

Examples of current projects

Since Viet Nam does not have a mechanism for grid-connected biogas power projects [12], the current biogas projects in Viet Nam are mainly self-sufficient for livestock farms with a small scale of less than 1

MW.

[13,14] Survey a livestock farm in Tien Giang province with a scale of 200 sows and 3000 pigs equipped with a biogas generator with a capacity of 40 kW. This biogas generator supplies nearly 50 light bulbs, 3 motors, and 10 fans running around the farm and connects to household appliances and electrical appliances such as air conditioners, fans, washing machines, lights, and refrigerators. In addition, the generator also helped the family's pig breeding environment improve, the biogas cellar did not have excess gas that had to be burned or discharged into the polluting environment. Investment cost of biogas generator is about 574 million VND (supported by low carbon agriculture program of Tien Giang province), equivalent to 24,590 USD and to 0.61 MUSD/MW (generator only). Efficiency economic results help reduce over 4 million Dong electricity bills per month.

Below four examples of biogas plants with upgrading facility are shown. China is the country with most biogas plants with more than 100,000 biogas plants and additionally a large number of household biogas units. China has a total biogas production of around 72,000 TWh/year.

Anping, Hebei, China (2014)

Capacity: approx. 900.000 t/year (2500 t/d)

Production: 11,5 mill. Nm3 gas/year

Capex ($2014): USD 29 mill.

Capex ($2019): USD 31.32

2,7 MUSD/mill. Nm3 gas

Sifang biogas plant, China

Capacity: 266.000 t/year (69% manure and 31% corn straw)

Production: 7,3 mill. Nm3 CH4/year

Capex ($2017): USD 29 mill.

Capex ($2019): USD 30,25 mill.

3,9 MUSD/mill. Nm3 gas/year

Solrød biogas, Denmark (2015):

Capacity 200.000 t/year

Production: 6 mill. Nm3 CH4/year

14 permanent jobs created,

Capex: USD 14 mio. Excl. CHP.

2,3 MUSD/mill. Nm3 gas

O&M Cost/year: USD 3.7 mill. /year

San Jerónimo WWTP, Mexico (2013)

Capacity: 30.000 t/year

Production: 0,2 mill Nm3 CH4/year

Capex: USD 2,2 mill.

11 MUSD/mill. Nm3 gas

OPEX: USD 0,1 mill. /year

Estimating job creation for a current commercial large-scale biogas plant can be complex and highly variable based on several factors, including the plant's size, technology, location, and operational requirements. Jobs associated with a biogas plant can include those related to construction, operation, maintenance, administration, and more. Here's a general breakdown of potential job categories and considerations:

- Construction: During the construction phase, a biogas plant may require a significant workforce, including labourers, engineers, project managers, and various contractors. The number of construction jobs can vary based on the scale and complexity of the project.
- Operation: Once operational, a biogas plant typically requires skilled operators, technicians, and supervisors to ensure smooth day-to-day functioning. The number of operational jobs depends on the plant's size and complexity.
- Maintenance: Biogas plants need regular maintenance to prevent downtime and ensure efficiency. Maintenance jobs can include technicians, mechanics, electricians, and other skilled workers.
- Administrative and Support: Administrative roles, such as office staff, accountants, and managers, are essential for managing the business side of the biogas plant. Support staff may include security personnel, cleaners, and others.
- Supply Chain: The supply chain for biogas plants involves the procurement of feedstock (e.g., organic waste) and the distribution of biogas or biogas-derived products. Jobs related to logistics, transportation, and procurement may be created.
- Research and Development: Some biogas plants invest in research and development activities to improve efficiency and sustainability. These activities can create jobs for researchers, scientists, and engineers.
- Environmental and Regulatory Compliance: Compliance with environmental regulations is crucial for biogas plants. Jobs related to environmental monitoring and compliance may be necessary.
- Community Engagement: Large-scale biogas plants often interact with local communities. Public relations, community outreach, and education efforts may create additional job opportunities.

The exact number of jobs in each category will depend on the specific characteristics of the biogas plant and its operations.

Investment cost estimation

Investment cost estimation for biogas plants

Globally, the costs of producing biogas today lie in a relatively wide range between 2 USD/MBtu to 20 USD/MBtu. In Europe, the average cost is around 43% higher than in Southeast Asia (Europe at 16/MBtu / Southeast Asia at USD 9/MBtu). 70-95% of the total costs are for installing biodigesters, whereas the rest is cost of feedstock and operation [20].

To estimate the investment cost of biogas plants in Viet Nam different sources have been assessed.

No large industrial biogas plants have been built in Viet Nam, and therefore only local data is available for small household-scale plants. In the technology catalogue for Viet Nam from 2021, biogas production for electricity is included, for a plant with a capacity of 1 MW. The price, however, includes the gas engine to produce electricity and not only the biogas reactor. When the investment cost of a gas engine (based on the Danish technology catalogue[15]) is subtracted, the cost of the biogas reactor is approx. 1.88 MUSD to produce gas for 1 MWe. The efficiency in a gas engine 35%, meaning that to produce 1 MWe the engine needs 2,86 MW gas input. The price for the biogas reactor is therefore 0.66 MUSD/MW gas in 2020.

One example of a biogas plant in Viet Nam is found, this is presented in the section below.

In the Danish technology catalogue the cost and technical data of two sizes of biogas plants are included, where both biogas plants are large industrial plants.

The potential for improving technologies is linked to their level of technological maturity. Biogas plants are assessed to be a category 4 technology, meaning that it is a commercial technology with large deployment.

It is expected that the investment costs will continue to decrease gradually due to learning curve effects, but at a slower pace than previously. The reason for this is that many elements of a biogas plant consist of

[15] According to the Danish technology catalogue a gas engine costs approx. 1,02 MUSD/MW in 2020 and 0,91 MUSD/MW in 2050.

mature technologies from other industries, e.g., civil construction works and general process equipment, where learning curve effects are expected to be limited.

The greatest cost reductions are expected to arise from the use of biomasses with a higher methane output per ton of input, combined with increased professionalization and technical optimization of operations, which are likely to increase the overall efficiency.

Learning rates for energy technologies, describes the cost decrease as the installed capacity is doubled, and typically vary between 5% and 25%. In 2015, Rubin Et. al. published "A review of learning rates for electricity supply technologies", which provides a comprehensive and up-to-date overview of learning rates for a range of relevant technologies. 10-15% seems to be the typical level for many technologies, with solar PV being an exception demonstrating learning rates well above 20% [17]. Studies on learning rates for biogas plants are scarce, however, a 2006 study [18] finds a learning rate of 12% for the investment cost of Danish biogas plants based on data from 1988 to 1998. This improvement is however related to higher yield from the plants (i.e., lower investment cost per methane output) due to feedstock changes.

It should be noted that using a learning curve as a method for forecasting price developments is less applicable for biogas plants, than for solar panels and other module technologies.

The expectations for cost development applied in the datasheet are therefore further substantiated by the report "Production of upgraded bio–as - optimising costs and climate impact [19]. The report has analysed a variety of specific cost-reduction measures for modern biogas plants of different capacities. The report finds that the greatest reduction potential lies within biomass pre-treatment, biogas production, upgrading and sulphur purification. Within biomass pre-treatment, re-digestion/selective digestion contributes with approx. 2/3 of the reduction potential and technologies for mechanical shredding account for the remainder. Within biogas production, reduction of downtime contributes by approx. 1/3 of the potential, whereas the remaining improvement potentials concern optimization of electricity and heat consumption, and reduction of methane loss. For slurry handling, reduction of washing water, rapid discharge of slurry and mixing of deep litter in the slurry contribute about half of the potential, and filter box for separation with the other half. For energy integration, important measures concern the use of heat pumps, heat exchange and regular cleaning of pipes and heat exchangers. Overall, the report identifies cost optimization potentials between 10% and 16%, depending on plant size and configuration.

The updated 2026 Viet Nam Technology Catalogue has revised all cost projections by converting them to 2025 USD.

Investment costs [MUSD/MW]	2020	2025	2030	2050
Vietnam technology catalogue 2026 - 30 MW		1.33	1.16	1.05
Vietnam technology catalogue 2023 - 30 MW	1.04		0.90	0.82
Danish technology catalogue (large plant with a capacity of 60 MW)	1.13		0.98	0.95
Danish technology catalogue (large plant with a capacity of 30 MW)	1.04		0.90	0.83
Previous Viet Nam Technology catalogue (2021) incl. gas engine (Biogas for power plant - 1 MW-e)	2.9-1.02 = 1.88 1.88*35%=0.66		2.7-0.97 = 1.73 1.73*35%=0.61	2.3-0.91 = 1.39 1.39*35%=0.49
Small scale biogas plant / livestock farm in Tien Giang province (40 kW)	0.61			

Investment cost estimation for biogas upgrading (Excluding cost for biogas plant)

In Viet Nam there are no upgrading plants, and it has not been possible to find Southeast Asian projects that provide separate cost estimates for the biogas plant and upgrading plant. The investment cost is therefore estimated using the Danish technology catalogue.

Based on [20] the cost of producing biomethane in Asia is approx. 1/3 cheaper than in Europe. This does however also include the cost of feedstock.

Investment costs [MUSD/MW]	2020	2025	2030	2050
Vietnam technology Catalogue 2026 – 30 MW		0.25	0.19	0.15
Vietnam technology Catalogue 2023 – 30 MW	0.19		0.16	0.12
Danish technology catalogue (large plant with a capacity of 30 MW/year)	0.19		0.15	0.13
Danish technology catalogue (large plant with a capacity of 60 MW/year)	0.13		0.10	0.08

References

The description in this chapter is to a great extent based on the Danish Technology Catalogue *"Technology Data for Renewable Fuels".*

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Data sheet

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2025. The *uncertainty* is related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

The expense of running a biogas facility is contingent on the type of feedstock used since the ideal hydraulic retention time (HRT), requirement for pre-treatment, gas production, and other factors are all dependent on the input. The information presented in the datasheet pertains to a standard plant that utilizes slurry and by-products from agriculture and industry.

Biogas plant Basic plant - 3000 Nm^3 CH_4/h.										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data										
Typical capacity	mill. tons biomass input/year	0.60	0.60	0.60	0.54	0.65	0.54	0.65	A, B	1
Typical total plant size	MW output	29.63	29.63	29.63					R	1, 2
Inputs										
Biomass	mill. tons/year	0.60	0.60	0.60					B	1
Aux. Electricity	% of output energy	2.34	2.03	1.84	1.75	2.92	1.38	2.31	C	1
Aux. Electricity	kWh/ton input	10.19	8.87	8.05	7.64	12.74	6.04	10.06	C	1
Aux. process heat	% of output energy	6.87	5.97	5.42	5.84	7.90	4.61	6.24	D	1
Aux. process heat	kWh/ton input	29.96	26.07	23.67	25.47	34.46	20.12	27.22	D	1
Outputs										
Biogas	%	100	100	100						1
Biogas	GJ/ton input	1.59	1.59	1.59					R	1
Biogas production	MJ/s	29.63	29.63	29.63						1, 2
Forced outage	%	-	-	-						1
Planned outage	days per year	-	-	-						1
Technical lifetime	years	20.00	20.00	20.00	15.00	25.00	15.00	25.00	E	1
Construction time	years	2.00	2.00	2.00	1.00	3.00	1.00	3.00	F, Q	
Economic data										
Specific investment	mill. USD/MW output	1.33	1.16	1.05	1.41	1.90	0.93	1.18	G, H, I, J, N, O, P	1
- of which equipment	mill. USD/MW output	1.06	0.93	0.84	1.13	1.52	0.74	0.95	G, H, I, J	
- of which installation	mill. USD/MW output	0.27	0.23	0.21	0.28	0.38	0.19	0.24	G, H, I, J	
Total O&M	kUSD/MW/year	98.67	85.84	77.95	83.87	113.47	72.38	92.03	G, H, I, L	1
Total O&M	USD/ton-input/year	4.91	4.27	3.88	4.17	5.65	3.57	4.54	G, H, I, K, P, N	1
- of which O&M, excl el. and heat	USD/ton-input/year	3.28	2.86	2.59					G, H, I, K	1
- of which electricity	USD/ton-input/year	0.88	0.76	0.69					G, H, I, P	1
- of which heat	USD/ton-input/year	0.75	0.65	0.59					G, H, I, N	1
Technology Specific data										
Hourly gas output	k Nm^3 CH_4/h	2.97	2.97	2.97						1, 3
Yearly gas output	mill. Nm^3 CH_4/year	26.05	26.05	26.05						1, 3
HRT	days	65.00	65.00	65.00						1, 2
DS	%	16	16	16					M	1, 2
Methane emission	% of output	0.90	0.90	0.90					N	4, 1

CO2 ressource	mill. Nm^3 CO_2/year	19.23	19.23	19.23						1
CO2 ressource	kton/year	37.96	37.96	37.96						
Water consumption	L/MWh	-	-	-	-	-	-	-		

Notes:

A In the uncertainty calculations, the capacity varies with +/- 10%. This is the biogas plant size for which it is assessed the data can be representative with a similar feedstock input.

B The biogas input is based on table 5 in the qualitative description, also inserted in datasheet.

C The uncertainty calculations varies the demand with +/- 25%.

D The uncertainty calculations varies the demand with +/- 15%.

E The uncertainty calculation varies the lifetime of the plant by 5 years.

F The uncertainty calculation varies the construction time of the plant by 1 year.

G The forecasted prices are based on a learning curve of 10%, this is further elaborated upon in the qualitative description.

H Due to current supply bottlenecks it is assumed that the price will not develop towards 2025.

I For uncertainty calculations for 2020 the prices varies by 15%.

J For uncertainty calculations for 2050 the learning curve for the forecast of prices in 2050 is tested with a 5% learning curve and a 15% learning curve.

K Equipment is estimated to constitute 80% of the total investment while installation constitute 20%. All costs are without costs for biomass and transport.

L HRT=Hydraulic Retention Time. The HRT is between 60 and 100 days in newer Danish plants, depending on the biomass input and the plant's technical specifications.

M DS%=dry solid content. The biogas plants should be operated with a DS content of a max of 13-14% in the reactor.

N Due to the warmer climate in Viet Nam, it is assumed that the heat demand required to heat up the digester in a biogas plant is 20% lower than in Denmark, thus lowering the operation and maintenance costs compared to [19]".

O Production costs are calculated to be planned in 2020 and put into operation in 2022. In bare-field plants, everything is established simultaneously.

P The cost of feedstocks and transport are not included in the OPEX as they are highly dependent on local conditions and may vary widely. It is, however, important to include costs for feedstock when calculating the operational cost of biogas plants. Pre-treatment of the biomass is included in the costs. It is assumed that the plant uses grinding and milling as mechanical pre-treatment methods for e.g., straw.

Q Estimated based construction time for similar plants.

R The gas output per feedstock is estimated in table 35 in the chapter.

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Biogas upgrading - Amine scrubber (3,000 Nm3/h)											
		2025	**2030**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data										
Typical total size	MW output	29.34	29.34	29.34						1
Typical total size	k Nm^3 biogas/h	2.97	2.97	2.97						1
Capacity	k Nm^3 biomethane/h	2.94	2.94	2.94						1
Capacity - yearly biomethane production	mill. Nm^3 biomethane/h	25.80	25.80	25.80						1
Inputs										
Biogas	% of biogas input	100	100	100						1
Auxilliary electricity for upgrading	% of biogas input	1.92	1.50	1.17	1.44	2.40	1.46	1.46	A	1
Heat	% of biogas input	10.48	8.17	6.39	8.91	12.05	7.35	7.35	B	1
Outputs										
Biomethane	% of methane input	99.05	99.05	99.05						1
Waste gas	% of methane input	0.95	0.95	0.95						1
Waste heat	% of methane input	5.24	5.24	5.24						1
Forced outage	weeks per year	0.29	0.29	0.29						1
Planned outage	weeks per year	0.29	0.29	0.29						1
Technical lifetime	years	20.00	20.00	20.00	15.00	25.00	15.00	25.00	C	1
Construction time	years	1.00	1.00	1.00	1.00	2.00	1.00	2.00	D	1
Economic data (in USD2025)										
Specific investment, upgrading and methane reduction	kUSD/MW output	248.51	193.84	151.59	211.24	285.79	183.90	119.29	E, F, G	1, 2
Fixed O&M	kUSD/MW output/year	42.35	33.03	25.83	35.99	48.70	31.34	20.33	E, F, G	1, 2
- of which fixed O&M costs upgrading and methane reduction, excl. el. and heat	kUSD/MW output/year	11.85	9.25	7.23					E, F, G	1
- of which fixed O&M costs for heat	kUSD/MW output/year	15.84	12.35	9.67					E, F, G	1
- of which fixed O&M costs for el.	kUSD/MW output/year	14.65	11.42	8.93					E, F, G	1
Variable O&M	USD/GJ input	1.49	1.16	0.91	1.27	1.71	1.10	0.71	E, F, G	1
- of which electricity	USD/GJ input	0.46	0.36	0.28	0.39	0.53	0.34	0.22	E, F, G	1
Technology specific data										
Methane slip / emission	%	0.10	0,10	0.10						1, 3
Minimum load	% of full load	50	50	50						1
CO2 ressource	mill. Nm^3/year	19.23	19.23	19.23						1
CO2 ressource	kton/year	37.96	37.96	37.96						1
Water consumption	L/MWh	-	-	-	-	-	-	-		

Notes:

A The uncertainty calculations varies the demand with +/- 25%.
B The uncertainty calculations varies the demand with +/- 15%.
C The uncertainty calculation varies the lifetime of the plant by 5 years.
D The uncertainty calculation varies the construction time of the plant by 1 year.
E The forecasted prices are based on a learning curve of 15%, this is further elaborated upon in the qualitative description.
F For uncertainty calculations for 2020 the prices varies by 15%.
G For uncertainty calculations for 2050 the learning curve for the forecast of prices in 2050 is tested with a 10% learning curve and a 20% learning curve.

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13. GREEN LIQUID FUELS THROUGH FISCHER-TROPSCH SYNTHESIS

Brief technology description

The Fischer-Tropsch (FT) is a catalytic reaction which can be used to make liquid fuels using a catalytic chemical reaction between hydrogen and carbon monoxide (syngas).

The cleaned syngas is led through a catalyst typically at temperatures of 150–300 °C and pressures of one to several tens of atmospheres, which converts the gas into a range of hydrocarbons (fuels and chemicals). Fossil fuels, especially coal, has traditionally been used in the process. However, in order to produce a renewable fuel, the source needs to come from a renewable source, e.g., biomass or green hydrogen (hydrogen produced from renewable electricity).

There are a number of catalysts that can be used for the Fischer-Tropsch synthesis (FTS) but iron and cobalt based catalyst are the most common. The iron catalysts typically operate in a temperature range of 300 to 350 °C and the cobalt catalysts operate at lower temperatures (200 to 240 °C), and both operate at pressures of 20 to 25 bar [1]. Cobalt catalysts required in situ regeneration every 9 to 12 months and replacement every five years [6]. Cobalt catalyst consumption rate of 0.0009 kg per kg of FT liquids produced was modelled in a lifecycle analysis of an FT system [2]. Iron catalysts have limited lifetimes of 40 to 100 days but are 1/1000th the cost of Cobalt catalysts. Large scale natural gas to FT plants employs multiple parallel reactors that can facilitate catalyst changes.

The following section outlines two pathways for producing green fuels through FTS: one from biomass through biogasification and the other from power using green hydrogen and carbon monoxide. However, the remainder of the chapter and the accompanying datasheet will solely focus on FTS.

Biomass to liquid fuel through FT:

The production of liquid fuel from biomass is a two-step process; in the first step the solid biomass is converted to the gas phase and in the second step the gas is converted to liquid fuels through FTS.

Gasification is a process that converts organic or fossil-based carbonaceous materials at high temperatures (>700°C), without combustion, with a controlled amount of oxygen and/or steam into carbon monoxide, hydrogen, and carbon dioxide (syngas). There is a wide range in the design of gasifiers used for biomass.

The carbon monoxide then reacts with water to form carbon dioxide and more hydrogen via a water-gas shift reaction.

The steps in the process from biomass to liquid fuel are illustrated in the figure below:

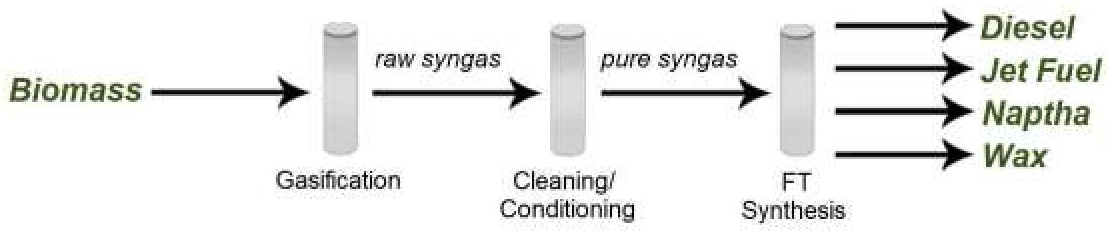

Figure 91: The steps in the process from biomass to liquid fuel

Power to liquid fuel through FT:

The production of liquid fuel from green hydrogen using FTS utilizes electricity to produce hydrogen, which can react with carbon dioxide (CO_2) to produce syngas (hydrogen (H_2) and carbon monoxide (CO)), which is then used in a FT process.

The production pathway can take several forms. There are several different electrolysis technologies, the carbon dioxide could come from many different sources, and there are several different technologies being developed for the conversion of carbon dioxide to carbon monoxide, which along with hydrogen is the reactant for the FTS. There is also some research underway on the direct utilization of carbon dioxide rather than first producing carbon monoxide. There are other production methods to produce emission free hydrogen, for example methane pyrolysis [3]; these are not described in this chapter.

Electricity is used to form hydrogen from water via electrolysis and carbon dioxide is reduced to carbon monoxide and water. The two streams are combined to produce a syngas, which is then synthesized through the FT reactions to produce liquid hydrocarbons and heat. The basic process flow is shown in Figure 88.

The carbon dioxide can be from concentrated sources such as ethanol fermentation facilities and biogas plants. The carbon dioxide can be obtained through medium concentration sources such as thermal power plants, or potentially in the future low concentration sources such as direct air capture facilities. Direct air capture technology is at a very low technology readiness level and there are only few demonstration plants in operation worldwide. The energy requirements for the concept will increase as the concentration of the CO_2 sources decrease. The FT synthesis actually needs carbon monoxide, not carbon dioxide, as one of the reactants. The traditional process to convert CO_2 to carbon monoxide is through the use of the reverse water gas (RWGS) shift reaction. The reaction is undertaken at temperatures between 350 to 600°C, depending on the catalysts used and at relatively low pressures. The reaction is reversible so that there will always be some CO_2 in the gaseous stream leaving the reactor.

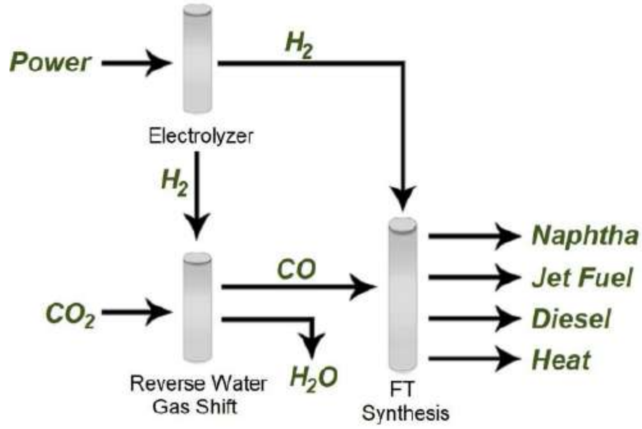

Figure 92: The steps in the process from power to liquid fuel

Input

The primary input is the syngas containing H_2 and CO going through the catalytic reaction. The process does not need any input of power or heat as the FT process is highly exothermic [15].

Output

The FT synthesis leads to a range of products which depend on the reaction conditions and catalysts employed. The most abundant compound classes are paraffins, olefins, and alcohols (oxygenates) as shown below [1]. The alcohols can be removed in the post reaction processing or used for energy to drive the process.

$$nCO + (2n+1)H_2 \rightarrow C_nH_{2n+2} + nH_2O$$

$$nCO + 2nH_2 \rightarrow C_nH_{2n} + nH_2O$$

$$nCO + 2nH_2 \rightarrow CnH_{2n+1}OH + (n-)H_2O$$

The FT reactions are not particularly selective, and they typically make a range of alcohols, olefins and paraffinic hydrocarbons that range from light naphtha that could be used for gasoline production, through to jet fuel, diesel fuel and traditionally heavy waxes, which can be further processed into high quality lubricants. There can be trade-offs between liquid product yield and product selectivity. DeKlerk [1] reported the typical product range for different catalysts and operating conditions. The results are shown in the following table.

Table 37: FT Synthesis Product Distribution

	Low temp Iron	Low temp Cobalt	High temp Iron
	Wt%		
C1 to C2 gas	6	7	23
$C_2 – C_4$	8	5	24
Oxygenates	4	2	10
Naphtha (C_5 to C_{11})	12	20	33
Diesel ($C_{12} – C_{20}$)	20	22	7
Wax (C18 – C100)	50	44	-
Total	100	100	97

Typical capacities

The technology has not yet been commercialized producing green fuels. There are however commercial FT plants using fossil energy as the input. The size of those varies; the largest fossil plant is Shells plant in Qatar which produces 260,000 bbls/day (500 million GJ/year). Shell's original GTL plant in Malaysia has a capacity of less than 15,000 bbls/day (30 million GJ/year). There is work ongoing on small FT distillate reactors using gasified biomass. Velocys claims that the commercially optimal size for their biomass to FT liquids system is 1,900 bbl/day (72 million litres/year) [4]. Their reference plant processes landfill gas and produces 200 bbls/day of finished products (375,000 GJ/year). Feedstock availability is likely to determine the maximum plant size.

The existing pilot plants, using green hydrogen to fuel through FTS, have the capacity to produce 160 litres of fuel per day (~1 barrel). Commercial plants will be much larger.

Ramping configurations

There is little published on the performance of continuously operated plants. Given the high pressure and temperatures required in the reactors and the required reactor residence time, it is likely that the performance will be altered when the process is operated at rates below the design capacity. Goldmann et el [5] reported that the FT process (including the RWGS) has a low tolerance for variations in the supply of reactants.

The regulation ability will therefore have a linkage to the capital cost of the system. Overtoom [6] reported that the Shell FT plant in Malaysia requires two to three days to start the complex and to bring it to full production. During start-up the process is consuming energy without producing products and frequent start-up and shut down can have a significant negative impact on overall system efficiency and economic performance

Advantages/disadvantages

The primary attractiveness of the technology is that the liquid fuel can have a very low GHG emission profile and can be used in heavy duty transport applications, which cannot be easily electrified, for decarbonizing the transport sector.

Further liquid fuels, such as the FT fuels made by this technology can be used in the existing fuel infrastructure and are attractive to the existing fuel providers.

The low tolerance for variation in supply for the FTS is a challenge. The challenge is especially present when using green hydrogen as input as the availability of the low carbon electricity will likely be intermittent, to assure continuous operation when the power is not available to produce the hydrogen, this will require a hydrogen storage. Hydrogen storage, especially in larger scale, will however increase the capital costs considerably. Carbon dioxide storage might also be required depending on the stability of the supply source.

Furthermore, a major challenge is the input of sustainable syngas. FTS are commercialized at large scale, e.g., biomass gasification is however only operated at small scale. Determining the combined size that will work, technically and economically, for both technologies is therefore a challenge.

Water consumption

Water consumption in the production of green liquid fuels through Fischer-Tropsch synthesis is primarily associated with the upstream production of syngas, as well as the synthesis process itself. Water is used as a coolant and for gas purification in the synthesis loop.

In the Fischer-Tropsch reaction, water is produced as a by-product, along with the desired liquid fuels. The amount of water produced is significant, and it is typically separated from the product stream and treated or reused.

Additional water use is associated with auxiliary systems such as cooling, gas conditioning, and product purification. However, the overall water footprint of green liquid fuel production through Fischer-Tropsch synthesis is largely governed by the specific process design and syngas production route employed.

Environment

The sustainability of the product will depend on the biomass input or carbon intensity of the power used to produce the fuel.

The fuels produced have no sulphur, are low in aromatics and are considered clean burning. Their volumetric energy content is about 10% lower than diesel fuel due to the lower density.

Research and development

The FTS is a mature technology, but has not been demonstrated in combination with technologies producing green syngas. The process of producing green fuels through FTS at the scale envisioned for and described in this chapter is therefore a technology in the research and development stage. There is significant uncertainty with respect to the performance and costs of the technology. There is potential to improve yields and reduce costs as more experience with the technology is gained from demonstration facilities and when the technology is scaled to commercial plants.

Examples of current projects

In Europe, Repotec, an Austrian company, have been involved with the Gussing gasifier, the GoBiGas SNG project in Sweden, and the Senden wood gasifier to power facility in Germany.

In Denmark, B&W Vølund built the wood gasifier at Harboøre but no other references for the technology were identified.

The UK-American company, Velocys is working on producing fuels for heavy duty transport and jetfuels from waste and wood using FT plants. They are developing smaller scale microchannel FT technology that was originally developed by the Pacific Northwest National Laboratory in Washington State, USA. Their first project is using landfill gas, but they are working with ThermoChem Recovery International of gasification systems for woody biomass that would be coupled with the Velocys FT technology [11]. The system would produce 1,400 bbl/day of FT products. This would require 1,000 tons of wood per day.

Currently the company works on developing a plant with a production of approx. 95.000 m3 jet fuels/year and an additional production of naphtha in the US and one in the UK with a yearly production of approx. 75.000 m3 of jet fuel and naphtha.

There are only two operating power-to-FT synthesis pilot plants [12, 13] and neither have publicly released any performance data and production rates are on the order of 100's of litres per day. Sunfire first produced FT distillates at their research facilities in Dresden Germany in 2015. They used CO_2 from direct air capture and a solid oxide electrolyser to produce the hydrogen. They claimed up to 70% efficiency for the power to liquids technology, but no detail of that calculation is publicly available. Carbon Engineering [12], the operator of the second plant, also employs its own direct air capture technology for the CO_2 that relies on burning gas, but uses an alkaline electrolyser for hydrogen. They have also not provided any technical performance data.

Further examples of development projects can be found under "examples of current projects".

Investment cost estimation

Previous studies have investigated the cost of producing green fuels using the FTS. However, most studies include the cost of the production of syngas.

For example, [10] conducted an analysis of investment costs that included the gasification plant required for producing liquid fuel through FT synthesis. However, this estimate is limited in scope to the specific gasification plant being considered. The following overview of investment costs is based on these findings.

Reference	Investment cost (M$2019)	Fuel production MW fuel	Cost/MW fuel production (M$2019)
Holmgren et al (2015) incl. upgrading	591	191	3.09
Johansson et al (2013)	652	223	2.92
Haarlemmer et al. (2012)	1,112	197	5.64
Liu et al. (2011)	921	286	3.22
Hamelinck et al. (2004), Hamelinck et al. (2003)	446	172.7	2.58
Hannula and Kurkela (2013)	447	157	2.85
Tijmensen et al. (2002)	574	169	3.40
Swanson et al. (2010)	634	150	4.23
Van Vliet et al (2009)	518	190	2.72
Tunå and Hulteberg (2014)	894	182	4.91
Average price pr MW	**3.27**		

The chapter called Liquid fuels from biomass gasification and Fischer Tropsch in the Danish technology catalogue is likewise including the cost of the gasification plant.

Investment costs [MUSD2019/MW]	2018 (old)	2020	2030	2050
Average price [10] incl. gasification plant	3.27 (2.58-5.64)			
Danish technology catalogue Liquid fuels from biomass gasification and Fischer Tropsch (2018) – incl. gasifier	4.74 (2015)	4.74	4.27	3.79

The cost of the Fischer-Tropsch (FT) process from hydrogen to liquid fuel, as detailed in the Danish Technology Catalogue's chapter on hydrogen to jet fuel, is a valuable resource for assessing the estimated cost of FT using renewable inputs. Another source (14) has estimated the cost of FT with various reactor designs using coal or biomass inputs. [14] finds that the FT process, incur higher costs when using syngas generated from biomass gasification, as opposed to the traditional input syngas derived from fossil carbon-based resources, in this case, coal. While [14] source suggests a significantly lower investment cost than the Danish Technology Catalogue's estimate, it is an older publication, and thus, the more recent Danish Technology Catalogue published in May 2020 provides the best available estimate of the investment cost.

The updated 2026 Viet Nam Technology Catalogue has revised all cost projections by converting them to 2025 USD.

Investment costs [MUSD/MW]	2018 (old)	2020	2025	2030	2050
Vietnam technology catalogue 2026			2.88	2.19	1.23
Vietnam technology catalogue 2023		2.31		1.76	0.99
Danish technology catalogue: hydrogen to jet fuel (2020)		2.31		1.76	0.99
FT island + naphtha upgrade (biomass input) 2010 [14]	1.25				

The capital cost estimates that have been reported in the literature could be categorized as Class 5 or Class 4 estimates [9]. The Cost Estimate Classification System maps the phases and stages of project cost estimating together with a generic maturity and quality matrix, which can be applied across a wide variety of industries. The classes range from 1 (Check Estimate or Bid/Tender with Detailed Unit Cost and Detailed TakeOff) to class 5 (Concept screening using factored parametric models or judgement). Class 5 estimates have uncertainty on the low end of -20 to -50% and on the high end of +30 to +100%. Class 4 capital cost estimates are feasibility type estimates with slightly narrower ranges of -15 to -30% on the low end and +20 to +50% on the high end of the range.

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The description in this chapter is to a great extent based on the Danish Technology Catalogue *"Technology data for renewable fuels"*.

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Data sheet

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2025. The *uncertainty* it related to the specific parameters and cannot be read vertically – meaning a product with lower efficiency do not have the lower price or vice versa.

Hydrogen to Jet Fuel										
Parameter	**Unit**	**2025**	**2030**	**2050**	**Uncertainty (2025)**		**Uncertainty (2050)**		**Note**	**Ref**
					Lower	**Upper**	**Lower**	**Upper**		
Typical total plant size	1,000 kt FT liquids/year	2.00	13.00	165.00	3.0	82.5	247.5	3.0	A, B,	1, 2, 3
Typical total plant size, Output	MW	3.10	20.50	259.60	4.7	129.8	389.4	4.7	A, B, C	1, 2
Input										
CO_2 Consumption	t/t FT Liquids	4.30	3,90	3,30	4.7	3.3	3.6	4.7	C, D, E	
Hydrogen Consumption	MWh/MWh total input	100%	100%	100%	1.2	0.7	1.2	1.2	E	
Power Consumption	MWh/MWh total input	0.50 %	0.50 %	0.50%	0.0	0.0	0.0	0.0	E	
Output										
FT Liquids Output	MWh/MWh total input	0.65	0.70	0.75	0.8	0.6	0.9	0.8	F, G, O	1, 2
Forced outage	%	0	0	0					I	
Planned outage	weeks per year	3								1
Technical lifetime	years	25								
Construction time	years	2								
Economic data										
Specific investment	MUSD/MW liquids/year	2.88	2.19	1.23	4.3	0.9	1.5	4.3	G, J	1, 2, 4, 5
- equipment	%	75%	75%	75%					K	
- installation	%	25%	25%	25%						
Fixed O&M	USD/MWh liquids	23.14	17.39	10.13	25.5	9.1	11.1	25.5	L	1
Variable O&M	USD/MWh liquids	7.26	5.75	2.88	8.0	2.6	3.2	8.0	M	4
Technology specific data										
Specific investment	USD/L FT liquids/year	4.52	3.42	1.92	6.8	1.4	2.4	6.8	G, J	1, 2, 4, 5
- equipment	%	75%	75%	75%					K	
-installation	%	25%	25%	25%						
Fixed O&M	USD/L FT liquids	0.22	0.16	0.10	0.2	0.1	0.1	0.2	L	1
Variable O&M	USD/L FT liquids	0.07	0.05	0.03	0.1	0.0	0.0	0.1	M	4
Water consumption	L/MWh	-	-	-	-	-	-	-		

Notes:

A The plant size range is based on the Schmidt and Mortensen reports and other analysis in the literature. Scale up is our assumption.

B CO_2 availability is likely to determine the maximum plant size.

C Conversion to MW is based on 8,000 operating hours per year and the energy output in all liquid fuels. The conversion is rounded. Some reports are based on only 4,000 hours of operation.

D Carbon efficiency in the literature ranges from 75 to 95%. Assuming that the early plants have low carbon efficiency and increase over time.

E Denominator of FT liquids is the total liquid fuel output.

F Hydrogen and power are the only energy input. Power will be required for pumping, compression, and utilities in addition to hydrogen production. Power estimated based on typical electric demand in petroleum refineries.

G FT Liquids efficiency increases as hydrogen production efficiency increases with adoption of more efficient technologies. 2020 and 2030 assume alkaline electrolysis, 2040 is based on PEM systems, and 2050 assumes SOEC. Limited improvement in FT synthesis assumed, although jet fuel selectivity may improve over time.

H Own calculations.

I This will depend on the level of hydrogen storage and the frequency of low surplus electricity periods that are outside of the range used for the calculation of the required hydrogen storage.

J The capital costs drop as plant size increases and through technological learning. Hydrogen storage costs are included (10% of capital costs) but not sized in the reference. No CO_2 storage is assumed.

K Own assumption.

L Based on 5% of capital cost.

M Based on 1.5% of capital cost. Excludes cost of power and carbon dioxide.

N A reasonable distribution of the FT fuels might be 60% jet fuel, 20% gasoline, and 20% lighter products (LPG and fuel gas), but the distribution of outputs could be very different depending on the plant design, catalyst and the operating conditions.

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APPENDIX 1: METHODOLOGY – QUALITATIVE DESCRIPTION

The technologies described in this catalogue cover both very mature technologies and technologies, which are expected to improve significantly over the coming decades, both with respect to performance and cost. This implies that the price and performance of some technologies may be estimated with a rather high level of certainty whereas in the case of other technologies, both cost and performance today as well as in the future is associated with a high level of uncertainty. All technologies have been grouped within one of four categories of technological development (described in section about research and development) indicating their technological progress, their future development perspectives and the uncertainty related to the projection of cost and performance data.

The boundary for both cost and performance data are the generation assets plus the infrastructure required to deliver the energy to the main grid. For electricity, this is the nearest substation of the transmission grid. This implies that a MW of electricity represents the net electricity delivered, i.e. the gross generation minus the auxiliary electricity consumed at the plant. Hence, efficiencies are also net efficiencies.

Each technology is described by a separate technology sheet, following the format explained below.

Qualitative description

The qualitative description presents the key characteristics of the technology as concisely as possible. The following paragraphs are included where relevant for the technology.

Brief technology description

Brief description for non-engineers of how the technology works and for which purpose.

Input

The main raw materials and forms of energy consumed by the technology or facility, such as electricity, heat, or fuels. For renewable fuels and Power-to-X technologies, this includes the primary feedstocks and energy inputs required in the conversion process. Relevant characteristics of the inputs, such as moisture content of fuels or required temperature of input heat, are specified where relevant. Auxiliary inputs, such as enzymes or chemicals assisting the process, are mentioned and their contribution described if considered relevant.

For energy storage technologies, the input is the form of energy to be stored, such as electricity, hot water, or gaseous fuels. As storage technologies typically store and later release the same type of energy carrier, the input and output descriptions are in some technology chapters combined into a single Input/Output section.

Output

The main energy carrier produced by the technology, as well as any co-products or by-products, such as process heat. For renewable fuels and Power-to-X technologies, this includes the produced fuel or energy carrier and any associated co-products. Characteristics of the outputs, such as the temperature of output heat, are specified where applicable. Non-energy outputs may also be described where appropriate.

For energy storage technologies, the output is the energy released from storage, which is generally the same form of energy as the input. For this reason, the input and output descriptions are in some technology chapters combined into a single Input/Output section.

Energy balance

The energy balance shows the main energy inputs and outputs of the technology, including any auxiliary energy consumption and energy losses. For green fuel and Power-to-X technologies, the energy balance illustrates the conversion of energy and feedstocks into the produced energy carrier and possible co-products, often presented in the form of an illustrative diagram showing the distribution of energy inputs, outputs, and losses. For energy storage technologies, the energy balance focuses on the energy flows associated with charging and discharging the storage system, including the main sources of energy losses and the overall efficiency. The energy content of fuels is expressed in terms of Lower Heating Value (LHV).

Typical capacities

The typical capacity of the technology is stated for a single plant, facility, or storage unit, representing the size most commonly used in practice rather than the maximum capacity. In cases where multiple sizes are common, several typical capacities can be presented, for example Large, Medium, and Small.

For storage technologies, the typical characteristics are also described alongside the capacity. These include:

- Energy storage capacity (in MWh): Amount of energy that can be stored
- Input and output capacities (in MW): Rate at which the energy can either charge or discharge
- Energy density and specific energy (in Wh/m³ and Wh/kg)

For some storage technologies, a minimum amount of energy must be maintained in the unit (e.g., battery SOC or cushion gas in gas storage). In such cases, only the active storage capacity - the energy available between maximum and minimum levels - is specified.

Ranges for the parameters can also be indicated when multiple typical sizes exist.

Typical storage period

This section is only included for the energy storage technologies.

It presents a qualitative expression of how long the energy is typically stored in the unit, which is closely related to the application and the services provided. The storage period is typically in the range from hours or days to longer periods such as months or years.

Ramping configurations

This section describes the technology's ability to respond to changes in supply or demand, mainly relevant for hydrogen technologies using electricity as input and for electricity storage technologies. The description includes part-load characteristics, start-up speed, and response time. Where applicable, the effect of part-load operation or fast regulation on wear and operational costs is noted.

For electricity storage technologies, the qualitative description may also include the capability to provide additional power system services, such as inertia, short circuit power, black start, voltage control, and damping of system oscillations (PSS), when the technology is suitable for power-intensive applications.

Advantages/disadvantages

This section provides a description of specific advantages and disadvantages relative to equivalent technologies. Generic advantages are ignored; for example, benefits such as mitigating climate risks or enhancing security of supply are not included.

Space requirement

The space requirement indicates the area needed for the installation of the technology, expressed per unit of capacity. For renewable fuel plants, it is typically expressed in 1,000 m² per MW of thermal capacity, while for storage technologies it is expressed in m² per MWh. The space requirement may be used, for example, to estimate land rent, which is not included in the financial cost as this depends on the specific location of the plant.

Water consumption

Water consumption is expressed in l/MWh and includes the water used directly in the operation of the plant/facility, such as that required for cooling or for the energy conversion process. This value does not account for the water used in the manufacturing or construction of the technology's equipment and infrastructure, which is typically addressed in life cycle analyses.

However, where relevant, the qualitative description may also include a life-cycle water consumption to allow for a comparison between technologies.

Environment

Particular environmental characteristics and resource impacts of the technology are described, for example emissions to air, soil, or water, and the use of critical, rare, or toxic materials. Where relevant, technology-specific impacts may also be mentioned, such as methane leakage for gas storage or hydro reservoirs, or energy payback time for renewable fuel production.

Research and development

The section lists the most important challenges from a research and development perspective. Particularly Vietnamese research and development perspectives are highlighted if relevant.

The potential for improving technologies is linked to the level of technological maturity. Therefore, this section also includes a description of the commercial and technological progress of the technology. The technologies are categorized within one of the following four levels of technological maturity.

Category 1. Technologies that are still in the *research and development phase*. The uncertainty related to price and performance today and in the future, is very significant.

Category 2. Technologies in the *pioneer phase*. Through demonstration facilities or semi-commercial plants, it has been proven that the technology works. Due to the limited application, the price and performance is still attached with high uncertainty, since development and customization is still needed. (e.g. gasification of biomass).

Category 3. *Commercial technologies with moderate deployment* so far. Price and performance of the technology today is well known. These technologies are deemed to have a significant development potential and therefore there is a considerable level of uncertainty related to future price and performance (e.g. offshore wind turbines)

Category 4. *Commercial technologies, with large deployment* so far. Price and performance of the technology today is well known, and normally only incremental improvements would be expected. Therefore, the future price and performance may also be projected with a fairly high level of certainty (e.g. coal power, gas turbine).

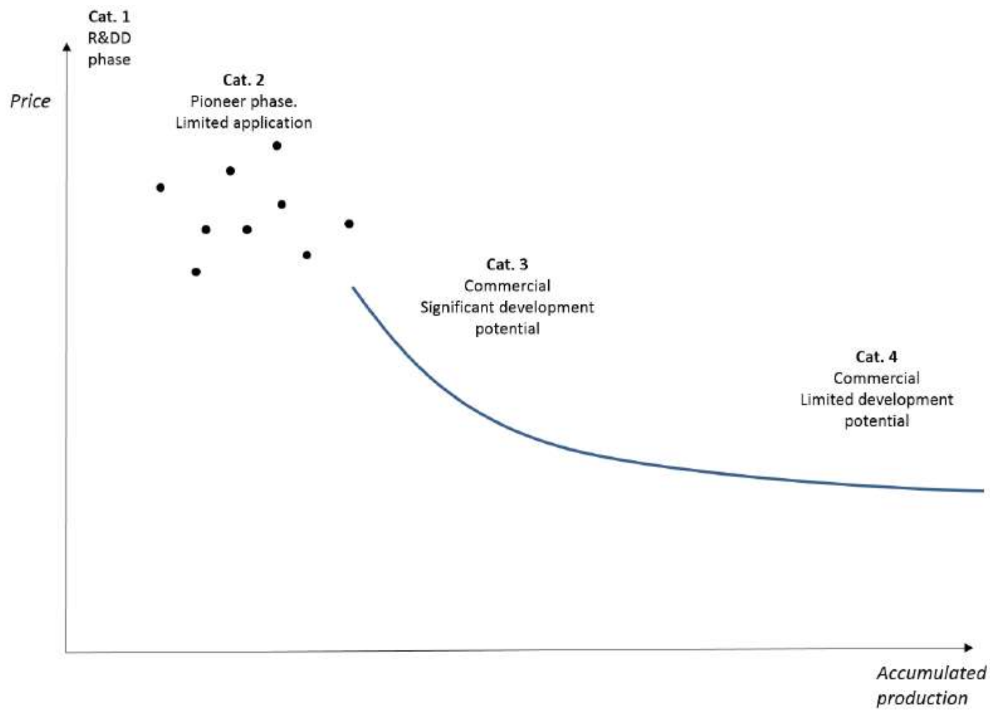

Figure 93: Technological development phases. Correlation between accumulated production volume (MW) and price.

Examples of current projects

Recent technological innovations in full-scale commercial operation should be mentioned, preferably with references and links to further information. This is not necessarily a Best Available Technology (BAT), but rather a representative indication of the typical projects that are currently being commissioned.

Information on general parameters, specifications, fuel or investment capital is obtained from sources such as basic design/ engineering design reports, provided by the power plants, and referenced from project websites.

For technologies where no market standard has yet been established, reference is made to the best available technology among R&D projects.

Investment cost estimation

In this section investment cost estimates from different sources are compared, when relevant. If available, local projects are included along with international projections from accredited sources (e.g. IRENA). On top of the table, the recommended cost figures are highlighted. Local investment cost figures are reported directly when available; otherwise, they are derived from the result of PPAs, auctions and/or support mechanisms.

Cost reductions and improvements of performance can be expected for most technologies in the future.

Cost projections based on the learning curve approach are performed to estimate the costs for the years 2030 (2040) and 2050. Technological learning is based on a certain learning rate and on a capacity deployment defined from the IEA's Stated Policies Scenario (STEPS). The single technology is given a normalized cost of 100% in 2025 (base year); values smaller than 100% for 2030 and 2050 represent the technological learning, thus the relative cost reduction against the base year. For a comprehensive explanation of the methods used, please refer to Appendix 4.

As for the uncertainty of investment cost data, the following approach was followed: for 2025 the lower and upper bound of uncertainty are derived from the cost span in the various sources analysed (usually it is set at +/- 25% but vary depending on the technology). For 2050, the central estimate is based on a learning rate as defined in Appendix 4 and an average capacity deployment from the CPS, STEPS and NZE scenarios of the World Energy Outlook 2025 (see Appendix 4: Prediction of performance and costs). The 2050 uncertainty range combines cost spans of 2025 with the uncertainty related to the technology deployment and learning.

Additional remarks

This section includes other information, for example links to websites that describe the technology further or give key figures on it.

References

References are numbered in the text in squared brackets and bibliographical details are listed in this section.

APPENDIX 2: METHODOLOGY – QUANTITATIVE DESCRIPTION FOR STORAGE TECHNOLOGIES

Quantitative description

To enable comparative analyses between different technologies it is imperative that data are actually comparable: All cost data are stated in fixed 2025 prices excluding value added taxes (VAT) and other taxes. The information given in the tables relate to the development status of the technology at the point of final investment decision (FID) in the given year (2025, 2030, 2040 and 2050). FID is assumed to be taken when financing of a project is secured and all permits are at hand. The year of commissioning will depend on the construction time of the individual technologies.

A typical table of quantitative data is present in each chapter, containing all parameters used to describe the specific technologies. The table consists of a generic part, which is identical for all storage technologies and a technology specific part, containing information which is only relevant for the specific technology or the group of technologies. The generic part is made to allow for an easy comparison.

Each cell in the table contains only one number, which is the central estimate for the market standard technology, i.e. no range indications. Uncertainties related to the figures are stated in the columns named *uncertainty*. To keep the table simple, the level of uncertainty is only specified for years 2025/2030 and 2050.

The level of uncertainty is illustrated by providing a lower and higher bound. These are chosen to reflect the uncertainties of the best projections by the authors. The section on uncertainty in the qualitative description for each technology indicates the main issues influencing the uncertainty related to the specific technology. For technologies in the early stages of technological development or technologies especially prone to variations of cost and performance data, the bounds expressing the confidence interval could result in large intervals. The uncertainty is related to the market standard technology; in other words, the uncertainty interval does not represent the product range (for example a product with lower efficiency at a lower price or vice versa).

The level of uncertainty is stated for the most critical figures such as investment cost and efficiencies. Other figures are considered, if relevant.

Energy/technical data

Energy storage capacity for one unit

The storage capacity, preferably a typical capacity (not maximum capacity), represents the size of a standard unit in terms of energy stored. It refers to a single unit capable of providing the storage service needed, e.g. a hydro plant, a heat tank or a battery installation.

In the case of a modular technology such batteries, a typical size based on historical installations, or the market standard is chosen as a unit. Different sizes may be specified in separate tables, e.g. small, medium, large battery installation.

As explained under "Typical characteristics", the energy storage capacity refers only to the active part of the storage unit, i.e. the energy that can be used, and not to the rated storage capacity of the storage. Additional information on the minimum level of energy required is found in the notes.

The unit MWh is used for electricity, heat and gas energy storage capacity.

Input and output capacity for one unit

The nominal output capacity is stated for a full unit and refers to the active part of the storage. Any other information regarding the minimum level is specified in the notes. It is given as net output capacity in continuous operation, i.e. gross output capacity minus own consumption.

The nominal input capacity is stated for a full unit as well. In case it is equal to the output capacity, the value specified will be the same.

The unit MW is used for all output and input capacities.

Charge and discharge efficiencies (round trip efficiency)

The efficiencies of the charging and discharging processes are stated separately in percent where possible.

The round-trip efficiency is the product of charging and discharging efficiencies and expresses the fraction of the input energy, which can be recovered at the output, assuming no losses during the storage period. It represents the ratio between the energy provided to the user and the energy needed to charge the storage system.

For electricity storage, it is intended as AC-AC value, therefore including losses in the converters and other auxiliaries.

The round-trip efficiency enables comparisons of different storage technologies with respect to efficiency of the storage process. However, not including the losses during the storage period, it does not give a complete picture. Losses are treated below.

Energy losses during storage

The energy lost from the storage unit due to losses in a specific time horizon is specified here.

Technologies with different storage periods will show very different behaviour with respect to energy losses. Therefore, the period is chosen based on the characteristics of the technology (e.g. % losses/hour, % losses/day or % losses/year).

Losses are expressed as a percentage of the energy storage capacity (as defined above) lost over the timeframe chosen.

Auxiliary electricity consumption (self-consumption)

Storage systems for heat and gas usually need auxiliary systems to operate, such as pumps and/or compressor. The auxiliary consumption expresses the consumption of electricity from such equipment as a percentage of output, which has gone through the full storage cycle.

For electricity storage, this component is already included in the overall round trip efficiency (AC-AC).

Forced and planned outage

Forced outage is defined as the number of weighted forced outage hours divided by the sum of forced outage hours and operation hours. The weighted forced outage hours are the sum of hours of reduced production caused by unplanned outages, weighted according to how much capacity was out.

Forced outage is given in percent, while planned outage (for example due to renovations) is given in days per year.

Technical lifetime

The technical lifetime is the expected time for which the storage facility can be operated within, or acceptably close to, its original performance specifications, provided that normal operation and maintenance takes place. During this lifetime, some performance parameters may degrade gradually but still stay within acceptable limits. For instance, efficiencies often decrease slightly (few percent) over the years, and O&M costs increase due to wear and degradation of components and systems. At the end of the technical lifetime, the frequency of unforeseen operational problems and risk of breakdowns is expected to lead to unacceptably low availability and/or high O&M costs. At this time, the plant is decommissioned or undergoes a lifetime extension, which implies a major renovation of components and systems as required making the storage unit suitable for a new period of operation.

The technical lifetime stated in this catalogue is a theoretical value inherent to each technology, based on experience. The expected technical lifetime takes into account a typical number of start-ups and shutdowns.

In real life, specific storage facilities of similar technology may operate for shorter or longer times. The strategy for operation and maintenance, e.g. the number of operation hours, start-ups, and the reinvestments made over the years, will largely influence the actual lifetime.

The lifetime is expressed in years for all the storage technologies. For electrical batteries it is expressed both in years and in number of cycles, since different utilization of the battery in terms of frequency of charge/discharge depth has an impact on its lifetime. This second figure is specified in the Technology Specific Data.

To calculate the technical lifetime in years for batteries based on the total number of cycles, a certain number of cycles per year has been assumed and is expressed in the notes.

Construction time

Time from final investment decision (FID) until commissioning completed (start of commercial operation), expressed in years.

Ramping configuration

The regulation ability parameters are expressed for electricity storage application, while for heat and gas storage these parameters are not relevant.

The electricity regulation capabilities of the technologies are described by two parameters:

- Response time from idle to full-rated discharge (sec)
- Response time from full-rated charge to full-rated discharge (sec)

The response time from idle to full-rated discharge is defined as the time, in seconds, the electricity storage takes to reach 100% of the discharge capacity from idle condition. It is assumed to be equal for the charging process.

The response time from full-rated charge to full-rated discharge is defined as the time, in seconds, the electricity storage takes to go from charging at full capacity to discharging at full capacity. It is assumed to be equal in the other direction.

Economic data

Economic data are all in US dollar at fixed prices, at the 2025-level and exclude value added taxes (VAT) and other taxes.

Investment cost

The investment cost is also called the engineering, procurement and construction (EPC) price or the overnight cost. Infrastructure and connection costs, i.e. electricity, fuel and water connections inside the premises of a plant, are also included.

The rent of land is not included but may be assessed based on the space requirements, if specified in the qualitative description.

The owners' predevelopment costs (administration, consultancy, project management, site preparation, approvals by authorities) and interest during construction are not included. The costs to dismantle decommissioned plants are also not included. Decommissioning costs may be offset by the residual value of the assets.

The total investment cost is reported on a normalized basis, i.e. cost per MW of storage capacity.

For most of the storage technologies it is possible to identify three main cost components: an *energy* component, a *capacity* component and other fixed costs. Where possible, total investment costs are divided into these components.

The cost of energy component includes all the cost related to the equipment to store the energy, which you would incur in case you want to expand the MWh rating of the system, for example battery modules, reservoirs in a pumped-hydro plant or heat tank. The cost of capacity component refers to the part of equipment which condition or convert the energy carrier and make it available to the user or the grid, for example converter and grid connection for a battery system, turbine/pump and grid connection for pumped-hydro plant and heat exchanger and piping for a heat storage. This is the cost you would incur if you would increase the MW capability of the system.

Finally, another cost component reflects the fixed costs related to the project, such as data management and control system, project engineering, other civil works, commissioning.

Summarizing, the components considered are the following:

- *Cost of Energy component* (C_E) [M$/MWh]: cost related to the equipment to store the energy (incl. their installation);
- *Cost of Capacity component* (C_P) [M$/MW]): cost related to the equipment to condition or convert the energy carrier and make it available to the user or the grid (incl. their installation);

- *Other project costs (C_{other})* [M$]: includes fixed costs which do not scale with capacity or energy, such as those for data management and control system, project engineering, civil works, buildings, site preparation, commissioning.

Operation and maintenance (O&M) costs

The fixed share of O&M can be expressed in two different ways.

1. The fixed share of O&M can be expressed in terms of percentage (%) of the total investment cost, as defined in the previous paragraph and stated in the tables.

2. The fixed share of O&M is calculated as cost per energy storage capacity for one unit per year ($/MWh/year), where the energy storage capacity is the one defined at the beginning of this chapter and stated in the tables.

It includes all costs which are independent of how the storage system is operated, e.g. administration, operational staff, payments for O&M service agreements, network or system charges, property tax, and insurance. Any necessary reinvestments to keep the unit operating within the technical lifetime are also included, whereas reinvestments to extend the life are excluded. Reinvestments are discounted at 4 % annual discount rate in real terms. The cost of reinvestments to extend the lifetime of the storage unit may be mentioned in a note if the data are available.

The variable O&M costs ($/MWh) are calculated as costs per MWh of energy effectively released by the storage. They include consumption of auxiliary materials (water, lubricants, fuel additives), treatment and disposal of residuals, output related repair and maintenance, and spare parts (however not costs covered by guarantees and insurances).

Auxiliary electricity consumption (self-consumption) is included for heat and gas storage technologies. The electricity price applied is specified in the notes for each technology, together with the share of O&M costs due to electricity consumption. This enables corrections from the users with own electricity price figures. The electricity price does not include taxes and PSO.

For electricity storage technologies, auxiliary electricity consumption is included in the round-trip efficiency instead.

Planned and unplanned maintenance costs may fall under fixed costs (e.g. scheduled yearly maintenance works) or variable costs (e.g. works depending on actual operating time), and are split accordingly.

It should be noticed that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Definitions

Based on the service provided, electricity storage technologies can be divided into two main categories: power-intensive and energy-intensive.

Power-intensive applications are required to provide ancillary services to the electricity system in maintaining the balance of frequency and voltage or providing power quality. Power intensive applications do this by delivering large amounts of power for time periods on the scale of seconds or minutes, and thus, they are characterized by a high ratio of power to energy (short discharge times) and fast response.

Energy-intensive applications are used for storing large amounts of energy in order to match demand and supply, perform load levelling or reducing congestion in the network. These technologies are characterized by a lower ratio of power to energy (long discharge times) and used on an hourly to seasonal scale.

The distinction between technologies providing power or energy intensive services is not always clear and neat. Some technologies, such as pumped-hydro or Li-ion batteries, can provide both services.

APPENDIX 3: METHODOLOGY - QUANTITATIVE DESCRIPTION FOR RENEWABLE FUELS

Quantitative description

To enable comparative analyses between different technologies it is imperative that data are actually comparable: All cost data are stated in fixed 2025 prices excluding value added taxes (VAT) and other taxes. The information given in the tables relate to the development status of the technology at the point of final investment decision (FID) in the given year (2025, 2030, 2040 and 2050). FID is assumed to be taken when financing of a project is secured and all permits are at hand. The year of commissioning will depend on the construction time of the individual technologies.

A typical table of quantitative data is present in each chapter, containing all parameters used to describe the specific technologies. The table consists of a generic part, which is identical for all technologies and a technology specific part, containing information which is only relevant for the specific technology or the group of technologies. The generic part is made to allow for an easy comparison.

Each cell in the table contains only one number, which is the central estimate for the market standard technology, i.e. no range indications. Uncertainties related to the figures are stated in the columns named *uncertainty*. To keep the table simple, the level of uncertainty is only specified for years 2025/2030 and 2050.

The level of uncertainty is illustrated by providing a lower and higher bound. These are chosen to reflect the uncertainties of the best projections by the authors. The section on uncertainty in the qualitative description for each technology indicates the main issues influencing the uncertainty related to the specific technology. For technologies in the early stages of technological development or technologies especially prone to variations of cost and performance data, the bounds expressing the confidence interval could result in large intervals. The uncertainty is related to the market standard technology; in other words, the uncertainty interval does not represent the product range (for example a product with lower efficiency at a lower price or vice versa).

The level of uncertainty is stated for the most critical figures such as investment cost and efficiencies. Other figures are considered, if relevant.

Energy/technical data

Typical total plant size

The total capacity, preferably a typical capacity, is stated for a single plant or facility. It represents the sum of all input and is expressed in MW.

Input and output

All inputs that contribute to the energy balance are included as main energy input and are expressed as percentage in relation to the total energy input, or equivalently as MWh/MWh of total input. The energy inputs and outputs are always expressed in lower heating value (LHV) and moisture content considered is specified if relevant.

Any energy co-product or by-product of the reaction has to be specified within the outputs, including process heat loss.

Since fuel inputs are measured at lower heating value, in some cases the total efficiency may exceed or be lower than 100%. The output shares represent the partial efficiencies in producing the different outputs.

Forced and planned outage

Forced outage is defined as the number of weighted forced outage hours divided by the sum of forced outage hours and operation hours. The weighted forced outage hours are the sum of hours of reduced production caused by unplanned outages, weighted according to how much capacity was out. Forced outage is given in percent, while planned outage (for example due to renovations) is given in days per year.

Technical lifetime

The technical lifetime is the expected time for which an energy plant can be operated within, or acceptably close to, its original performance specifications, provided that normal operation and maintenance takes place. During this lifetime, some performance parameters may degrade gradually but still stay within acceptable limits.

At the end of the technical lifetime, the frequency of unforeseen operational problems and risk of breakdowns is expected to lead to unacceptably low availability and/or high O&M costs. At this time, the plant is decommissioned or undergoes a lifetime extension, which implies a major renovation of components and systems as required making the plant suitable for a new period of continued operation.

The technical lifetime stated in this catalogue is a theoretical value inherent to each technology, based on experience. In real life, specific plants of similar technology may operate for shorter or longer times. The strategy for operation and maintenance, e.g. the number of operation hours, start-ups, and the reinvestments made over the years, will largely influence the actual lifetime.

Construction time

Time from final investment decision (FID) until commissioning completed (start of commercial operation), expressed in years.

Economic data

Economic data are all in US Dollar ($), fixed prices, at the 2025-level and exclude value added taxes (VAT) and other taxes.

Investment costs

The investment cost is also called the engineering, procurement and construction (EPC) price or the overnight cost. Infrastructure and connection costs, i.e. electricity, fuel and water connections inside the premises of a plant, are also included. The investment cost is reported on a normalized basis, i.e. cost per MW.

The specific investment cost is the total investment cost divided by the Typical total plant size described in the quantitative section. Where possible, the investment cost is divided on equipment cost and installation cost. Equipment cost covers the components and machinery including environmental facilities, whereas installation cost covers engineering, civil works, buildings, grid connection, installation and commissioning of equipment.

Operation and maintenance (O&M) costs

The fixed share of O&M is calculated as cost per plant size ($ per MW per year), where the typical total plant size is the one defined at the beginning of this chapter and stated in the tables. It includes all costs, which are independent of how the plant is operated, e.g. administration, operational staff, payments for O&M service agreements, network use of system charges, property tax, and insurance.

Any necessary reinvestments to keep the plant operating within the scheduled lifetime are also included, whereas reinvestments to extend the life beyond the lifetime are excluded.

Reinvestments are discounted at 4 % annual discount rate in real terms. The cost of reinvestments to extend the lifetime of the plants may be mentioned in a note if the data has been readily available.

The variable O&M costs ($/MWh) include consumption of auxiliary materials (water, lubricants, fuel additives), treatment and disposal of residuals, spare parts and output related repair and maintenance (however not costs covered by guarantees and insurances).

Planned and unplanned maintenance costs may fall under fixed costs (e.g., scheduled yearly maintenance works) or variable costs (e.g.,360 works depending on actual operating time), and are split accordingly. All costs related to the process inputs (electricity, heat, fuel) are not included. It should be noticed that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

Definitions

The latent heat of vaporization is the heat absorbed when a substance changes phase from liquid to gas.

The lower heating value (also known as net calorific value) of a fuel is defined as the amount of heat released by combusting a specified quantity (initially at 25°C) and returning the temperature of the combustion products to 150°C, which assumes the latent heat of vaporization of water in the reaction products is not recovered. The LHV are the useful calorific values in boiler combustion plants and are frequently used in Europe. Using the LHV for efficiency definition, a condensing boiler can achieve a thermal efficiency of more than 100%, because the process recovers part of the heat of vaporization.

The higher heating value (also known as gross calorific value or gross energy) of a fuel is defined as the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to a temperature of 25°C, which takes into account the latent heat of vaporization of water in the combustion products. When using HHV for thermal efficiency definition, the thermodynamic limit of 100%.

APPENDIX 4: PREDICTION OF PERFORMANCE AND COST

Cost reductions and improvements of performance can be expected for most technologies in the future. This section accounts for the assumptions underlying the cost and performance in the first technology year (base year) as well as the improvements assumed for future years.,.

The specific technology is identified and classified in one of four categories of technological maturity, indicating the commercial and technological progress, and the assumptions for the projections are described in detail.

In formulating the section, the following background information is considered:

Data for the base year

In case of technologies where market standards have been established, performance and cost data of recent installed versions of the technology in Vietnam or the most similar countries in relation to the specific technology in Asia are used for the base year estimates. In addition, the Danish Technology Catalogues on Renewable Fuels and Energy Storage technologies are also a useful supplementary reference, providing data on technology types that are not yet available in Vietnam.

If consistent data are not available, or if no suitable market standard has yet emerged for new technologies, the base year costs may be estimated using an engineering-based approach applying a decomposition of manufacturing and installation costs into raw materials, labour costs, financial costs, etc. International references such as the IEA, NREL etc. are preferred for such estimates.

Assumptions for projecting costs into future years

According to the IEA:

“Innovation theory describes technological innovation through two approaches: the technology-push model, in which new technologies evolve and push themselves into the marketplace; and the market-pull model, in which a market opportunity leads to investment in R&D and, eventually, to an innovation” [5].

The level of “market-pull” is to a high degree dependent on the global climate and energy policies. Hence, in a future with strong climate policies, demand for e.g. renewable energy technologies will be higher, whereby innovation is expected to take place faster than in a situation with less ambitious policies. This is expected to lead to both more efficient technologies, as well as cost reductions due to economy of scale effects. Therefore, for technologies where large cost reductions are expected, it is important to account for assumptions about global future demand.

The **IEA’s Announced Pledges Scenario (APS)** is used as a central estimate for projections in the Technology Catalogue, whenever possible. The IEA describes the Announced Pledges Scenario in their 2022 version as follows:

”The Announced Pledges Scenario introduced in 2021 aims to show to what extent the announced ambitions and targets, including the most recent ones, are on the path to deliver emissions reductions required to achieve net zero emissions by 2050. It includes all recent major national announcements as of September 2022 for 2030 targets and longer-term net zero and other pledges, regardless of whether these have been anchored in implementing legislation or in updated NDCs. In the APS, countries fully implement their national targets to 2030 and 2050, and the outlook for exporters of fossil fuels and low emissions fuels like hydrogen is shaped by what full implementation means for global demand. […] Non-policy assumptions, including population and economic growth, are the same as in the STEPS.”

According to the IEA, the less ambitious **Stated Policies Scenario (STEPS)** “provides a more conservative benchmark for the future, because it does not take it for granted that governments will reach all announced goals. Instead, it takes a more granular, sector-by-sector look at what has actually been put in place to reach these and other energy-related objectives, taking account not just of existing policies and measures but also of those that are under development. The STEPS explores where the energy system might go without a major additional steer from policy makers.”

The STEPS Scenario may be used as an upper bound and to assess the expected development of technologies based on a frozen-policy approach. Previous versions of the Technology Catalogue (Technology catalogue for power generation) have used the outdated New Policies Scenario, relatively equivalent to the current STEPS, as a central framework for projections (and supplemented by other outdated scenarios of the IEA). This scenario corresponds to the frozen-policy approach that the Danish Energy Agency uses to project international fuel prices and CO_2-prices and technologies may be assessed in that regard when suitable.

Technologies updated before this cutoff date and which do not contain any explicit methodological description within the chapter regarding alternative supplementary scenarios have been updated based in this previous methodology.

As a more ambitious projection, the **Net Zero Emissions by 2050 Scenario (NZE)** may be used as a lower bound for the technology development. According to the IEA, the NZE "is a normative IEA scenario that shows a pathway for the global energy sector to achieve net zero CO2 emissions by 2050, with advanced economies reaching net zero emissions in advance of others. This scenario also meets key energy-related United Nations Sustainable Development Goals (SDGs), in particular by achieving universal energy access by 2030 and major improvements in air quality. It is consistent with limiting the global temperature rise to 1.5 °C with no or limited temperature overshoot (with a 50% probability), in line with reductions assessed in the IPCC in its Sixth Assessment Report."

By using this approach, the quantitative data in the Technology Catalogue provides a sample space that is consistent with the IEA's Global Energy and Climate Model, encompassing relevant outcomes for policy assessments of technologies as well as technology developments in compliance with national targets, and international treaties.

Learning curves and technological maturity

Predicting the future costs of technologies may be done by applying a cost decomposition strategy, as mentioned above, decomposing the costs of the technology into categories such as labour, materials, etc. for which predictions already exist. Alternatively, the development could be predicted using learning curves. Learning curves express the idea that each time a unit of a particular technology is produced, learning accumulates, which leads to cheaper production of the next unit of that technology. The learning rates also take into account benefits from economy of scale and benefits related to using automated production processes at high production volumes.

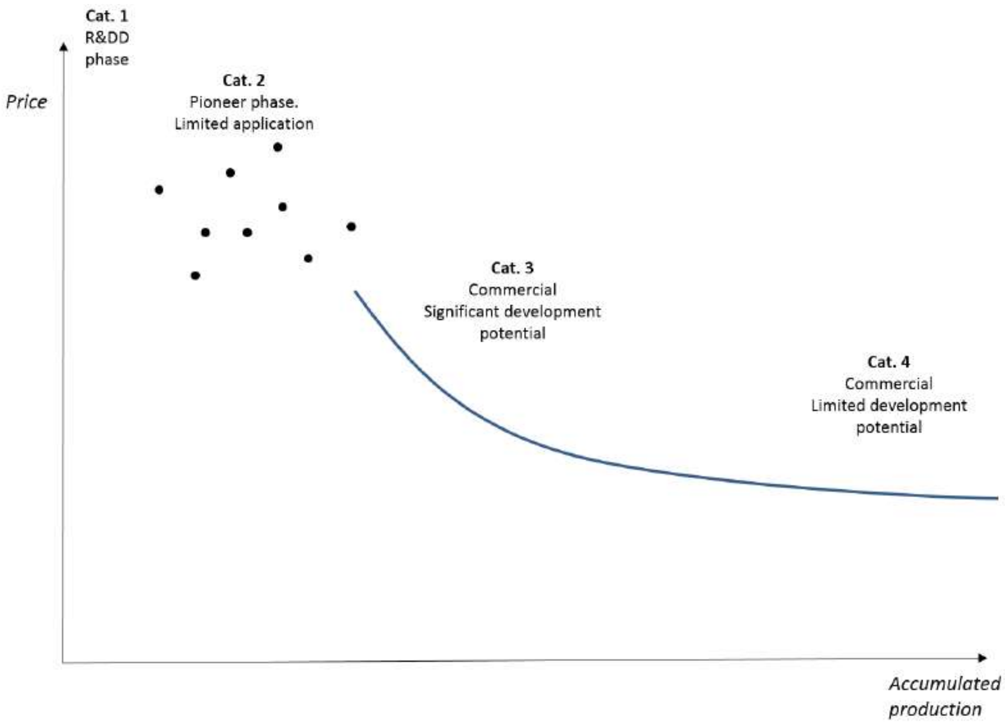

Figure 94: Technological development phases. Correlation between accumulated production volume (MW) and price

The potential for improving technologies is linked to the level of technological maturity. The technologies are categorized within one of the following four levels of technological maturity.

Category 1. Technologies that are still in the *research and development phase*. The uncertainty related to price and performance today and in the future is highly significant.

Category 2. Technologies in the *pioneer phase*. The technology has been proven to work through demonstration facilities or semi-commercial plants. Due to the limited application, the price and performance is still attached with high uncertainty, since development and customization is still needed. The technology still has a significant development potential.

Category 3. *Commercial technologies with moderate deployment*. The price and performance of the technology today is well known. These technologies are deemed to have a certain development potential and therefore there is a considerable level of uncertainty related to future price and performance.

Category 4. *Commercial technologies, with large deployment*. The price and performance of the technology today is well known and normally only incremental improvements would be expected. Therefore, the future price and performance may also be projected with a relatively high level of certainty.