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

EMBASSY
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Agency

EREA
Electricity & Renewable Energy Authority

Input for energy
system modelling

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FOREWORD

Today, innovations and technology improvements within energy generation, storage and renewable fuels are taking place at a very rapid pace, making long-term energy planning central to unlocking the potential of new, renewable-based technologies. Long-term planning of energy systems is very dependent on cost, technical performance and environmental impacts of future energy technologies. Thus, the objective of this technology catalogue is to provide a robust review-based technical foundation for a range of energy storage and renewable fuel technologies, thereby constituting a key input to solid long-term energy planning in Viet Nam.

Through to the multi-stakeholder involvement in the data collection process, as well as the technology identification and prioritization, this Technology Catalogue contains data that have been scrutinised and discussed by a broad range of relevant stakeholders including Electricity and Renewable Energy Authority (EREA) and agencies under the Ministry of Industry and Trade (MOIT), Viet Nam Electricity (EVN), independent power producers, local and international experts, other development partners organizations, energy branch associations and universities, among others. The stakeholder engagement is essential to ensure that the Technology Catalogue is well anchored and remains relevant among all stakeholders.

The aim for this Technology Catalogue is therefore to assist 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 technologies in Viet Nam.

The Vietnamese Technology Catalogue builds on the approach of the Danish Technology Catalogue, which has been developed by the Danish Energy Agency and Energinet in an open process with stakeholders for many years.

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. This present publication is a new catalogue including selected energy storage and renewable fuel technologies, which have been identified as relevant in the Vietnamese context through stakeholder consultations. This present Technology Catalogue for energy storage technologies and renewable fuels, published along with the updated Technology Catalogue for power generation technologies, constitutes substantial quantitative input to the Viet Nam Energy Outlook Report 2023.

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Credits

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AMENDMENT SHEET

Version	Date	Reference	Description
-	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 separations 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	MethanizationN_2-EU Electrochemical synthesis NH_3
MOF	Metal organic framework
MTPD	Metric ton per day
NH3syn	NH_3 synthesis
NH3rec	NH_3 recovery unit
NH3reg	NH_3 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	Ton per day
TRL	Technology readiness level
WGS	Water gas shift

INTRODUCTION

The catalogue consists of 12 chapters describing different technologies for energy storage and renewable fuels. The first six chapters are storage technologies and the last 8 are technologies for the production of renewable fuels, including Power-to-X.

The technologies described in this catalogue cover both very mature technologies and 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 estimated with a rather high level of certainty whereas, in the case of other technologies, both cost and performance today and 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 the section on research and development indicating their technological progress, their future development perspectives and the uncertainty related to the projection of cost and performance data.

The primary objective of publishing technology catalogues is to establish a uniform, commonly accepted and up-to-date basis for energy planning activities, such as future outlooks, evaluations of security of supply and environmental impacts, climate change evaluations, as well as technical and economic analyses, e.g., on the framework conditions for the development and deployment of certain classes of technologies.

With this scope in mind, it is not the target of the technology data catalogues, to provide an exhaustive collection of specifications on all available incarnations of energy technologies. Only selected, representative, technologies are included, to enable generic comparisons of technologies with similar functions in the energy system.

The text and data have been prepared 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 level of market maturity of the technology. Differences in both the short and long run can be caused by local physical conditions.

INTRODUCTION TO ENERGY STORAGE

The first part of the catalogue will present a selection of storage technologies, specifically tailored to suit the context of Viet Nam, based on consultations with relevant stakeholders. The technologies are compared based on storage capacities and timescales. The graph in Figure 1 shows how the different technologies perform. It gives an idea of how they differ from one another in terms of storage capacity and discharge time, and therefore how they can be useful for different applications.

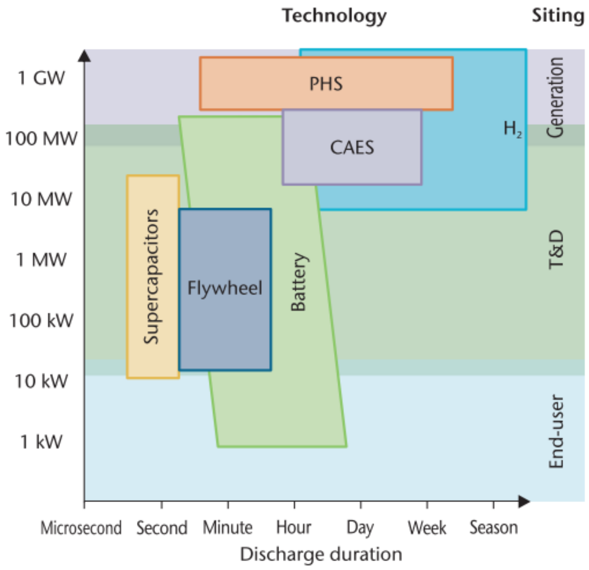


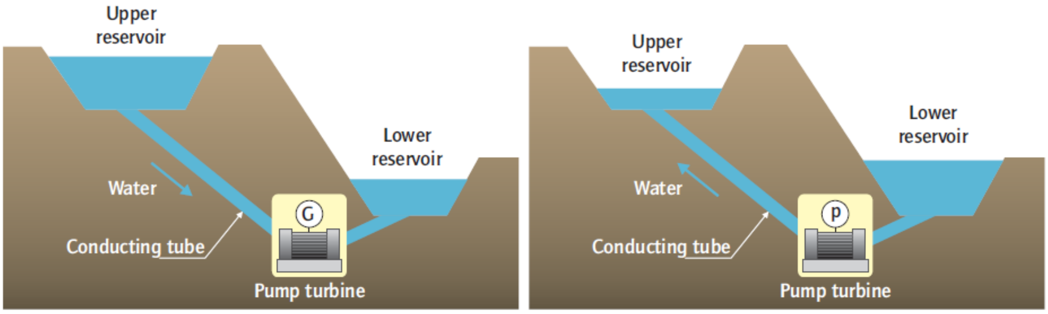
Figure 1: Electricity storage technologies [1]

[1] M. van der Hoeven, Technology Roadmap Hydrogen and Fuel Cells. International Energy Agency, 2015.

1. HYDRO PUMPED STORAGE

Brief technology description

Pumped storage plants (PSPs) use water that is pumped from a lower reservoir into an upper reservoir to charge the storage. To discharge the storage, water is released to flow back from the upper reservoir through turbines to generate electricity. Pumped storage plants take energy from the grid to lift the water up, then return most of it later (round-trip efficiency being 70% to 85%). Hence, PSP is a net consumer of electricity but provides for effective electricity storage. Pumped storage currently represents 99% of the world's on-grid electricity storage [1].



Source: Inage, 2009.

Figure 2: Pumped storage hydropower plants [2]

A pumped storage project would typically be designed to have 6 to 20 hours of hydraulic reservoir storage for operation. By increasing plant capacity in terms of size and number of units, hydroelectric pumped storage generation can be concentrated and shaped to match periods of highest demand, when it has the greatest value. Both reservoir and pumped storage hydropower are flexible sources of electricity that can help system operators handle the variability of other renewable energy sources such as wind power and photovoltaic electricity.

There are three types of pumped storage hydropower [3]:

- Open loop: systems that developed from an existing hydropower plant by addition of either an upper or a lower reservoir. They are usually off stream.
- Pump back: systems that are using two reservoirs in series. Pumping from the downstream reservoir during low-load periods making additional water available to use for generation at high demand periods.
- Closed loop: systems are completely independent from existing water streams – both reservoirs are off-stream.

Pumped storage and conventional hydropower with reservoir storage are the only large-scale, low-cost electricity storage options available today. Pumped storage power plants are often a cheap way of storing large amounts of electricity. However, pumped storage plants are generally more expensive than conventional large hydropower schemes with storage, and it is often very difficult to find good sites to develop pumped hydro storage schemes.

Interest in pumped storage is increasing, particularly in regions and countries where solar PV and wind are reaching relatively high levels of penetration and/or are growing rapidly [4]. The vast majority of current pumped storage capacity is located in Europe, Japan and the United States [4].

Currently, pumped storage capacity worldwide amounts to about 140 GW. In the European Union, there are 45 GWe of pumped storage capacity. In Asia, the leading pumped hydropower countries are Japan (30 GW) and China (24 GW). The United States also has a significant volume of the pumped storage capacity (20 GW) [5].

According to *Development strategies for hydro pumped storage in Viet Nam* developed by Lahmeyer International and Institute of Energy in 2016, Viet Nam has nearly 10 GW potential of hydro pumped storage concentrating in the North and South-Central regions as shown in the following map:

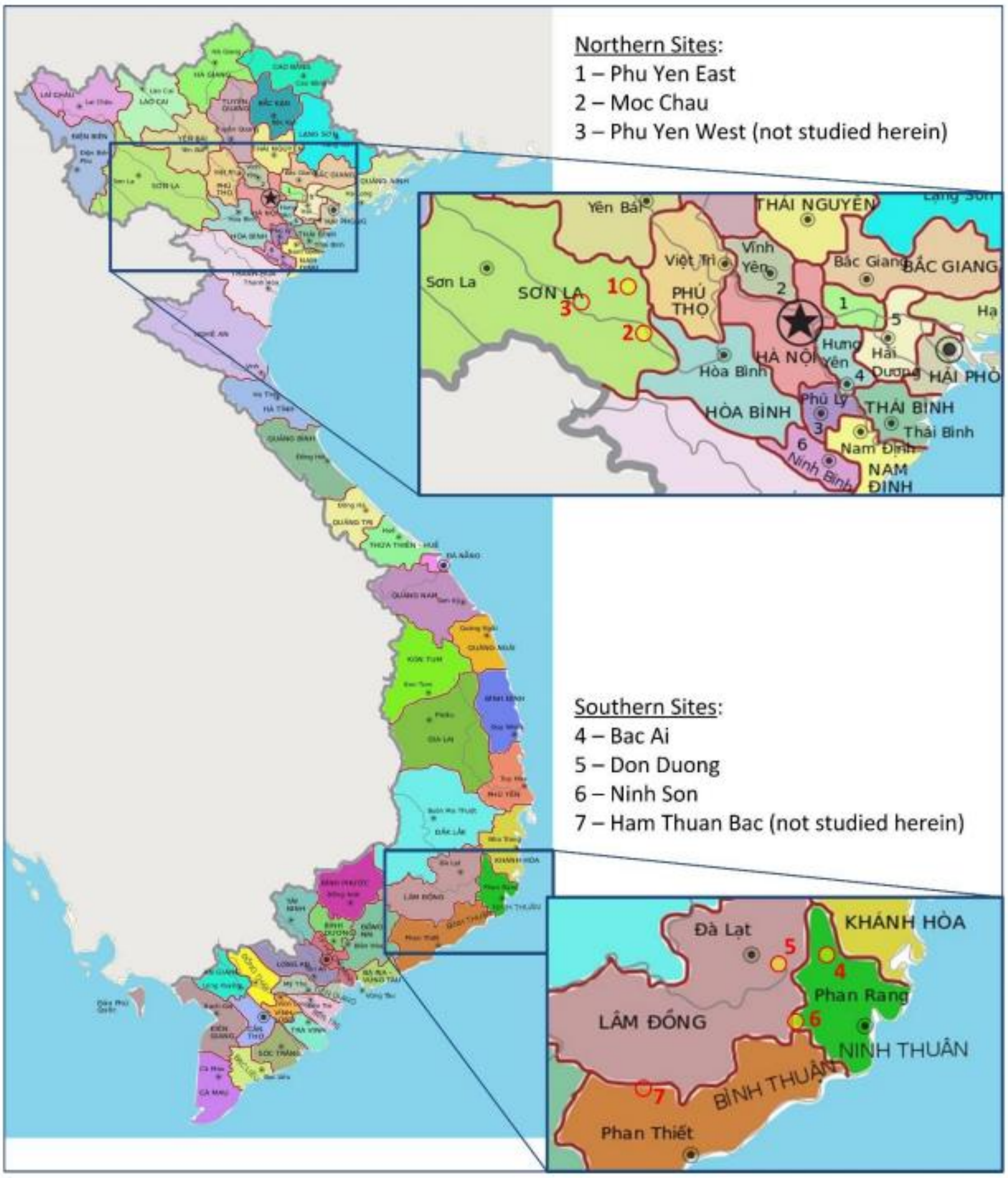


Figure 3: Map of potential locations of hydro pumped storage in Viet Nam [6].

According to PDP VIII, Vietnam will develop about 3.6 GW of hydro pumped storage power plants with projects: Bac Ai PSPP (1200 MW – period 2021-2030), Phuoc Hoa PSPP (1200 MW – period 2021-2030), Dong Phu Yen PSPP (900 MW – period 2031-2035), Don Duong PSPP (300 MW – period 2031-2035). In addition, some localities propose additional pumped storage hydropower projects: Dien Bien, Lai Chau, Quang Tri, Kon Tum, Khanh Hoa, Dak Nong. However, the number of projects, capacity and location must be further evaluated based on power system needs.

Typical capacities

50 to 500 MW per unit [12]

Ramping configurations

Pumped storage hydropower plants have a fast load gradient (i.e. the rate of change of nominal output in a given timeframe) as they can ramp up and down by more than 40% of the nominal output per minute. Pumped storage and storage hydro with peak generation are able to cope with high generation-driven fluctuations and can provide active power within a short period of time.

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.
- The reservoirs can be used for additional purposes like water supply, fishing and recreation [15].

Disadvantages:

- Very limited locations.
- 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.
- High investment cost.

Environment

The possible environmental impacts of pumped storage plants have not been systematically assessed but are expected to be small. 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 [8]. PSP projects require small land areas, as their reservoirs will in most cases be designed to provide only hours or days of generating capacities.

Research and development

Hydro pumped storage is, like hydro reservoir power, a well-known and mature technology and can be classified as a category 4 technology.

Under normal operating conditions, hydropower turbines are optimized for an operating point defined by speed, head and discharge. Head is the change in water levels between the hydro intake and the hydro discharge point. It is a vertical height measured in metres. At fixed-speed operation, any head or discharge deviation involves some decrease in efficiency. Variable-speed pump-turbine units operate over a wide range of head and flow, improving their economics for pumped storage. Furthermore, variable-speed units accommodate load variations and provide frequency regulation in pumping mode (which fixed-speed reversible pump-turbines provide only in generation mode). The variable unit continues to function even at lower energy levels, ensuring a steady refilling of the reservoir while helping to stabilize the network.

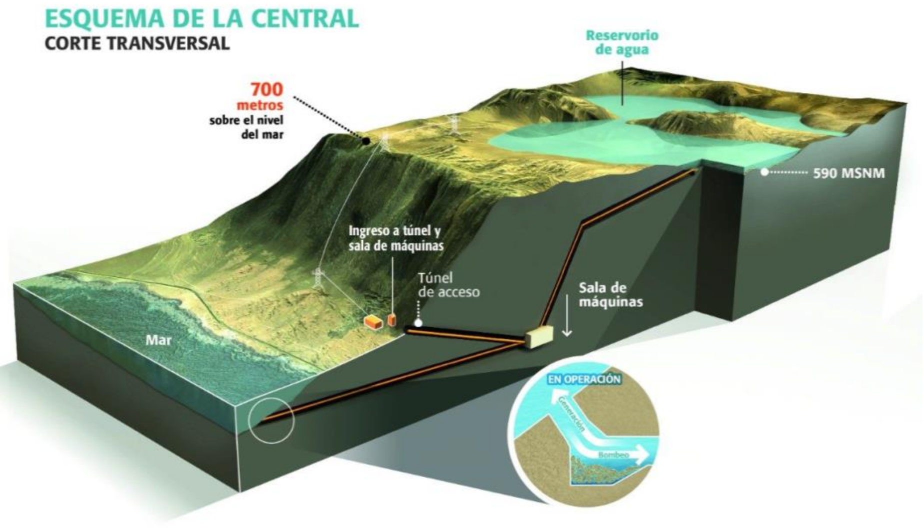


Figure 4: A 300 MW sea water pumped storage hydropower plant in Chile [13]

Pumped storage plants can operate on seawater, although there are additional challenges involved compared to operation with fresh water. The 30 MW Yanbaru project in Okinawa was the first demonstration of seawater pumped storage. It was built in 1999 but finally dismantled in 2016 since it was not economically competitive. A 300 MW seawater-based project has recently been proposed on Lanai, Hawaii, and several seawater-based projects have been proposed in Ireland and Chile.

In Germany, RAG, a company that exploited coal mines, is considering creating artificial lakes on top of slag heaps or pouring water into vertical mine shafts, as two different new concepts for PSP [10].

Examples of current projects

Bac Ai pump storage plant

Bac Ai is the first Vietnamese pumped storage power plant and is in the progress of technical design. The total capacity of the plant is 1,200 MW, with 4 units of 300 MW. According to Revised Power Master Plan 7, Bac Ai PSP plant will be put into operation in 2028-2030. The upper reservoir will be built on top of Da Den Mountain, with dam height of 72 m, the normal rising water level is 603 m, and the effective volume is 9 million m^3. The lower reservoir will use water from Song Cai reservoir belonging to Tan My irrigation system with a dam height of 38.4 m, the normal water level is 193 m and effective volume is 200 million m^3, available for Bac Ai PSPP is 10 million m^3. The designing water head is 403 m, and the maximum discharge flow is 248 m^3/s. The plant is going to use Francis turbines and the round cycle efficiency is 70%. The total investment of Bac Ai is expected to be 918 M$ ($2019, the administration, consultancy, project management, site preparation cost, the taxes and interest during construction are not included), equal to the investment rate of 0.77 M$/ MW_e. The total capital (including these components) was 1,019 million $, corresponding to 0.848 M$/$MW_e$ [17].

Pumped storage plants, such as the Grand Maison power station in France, can ramp up to 1,800 MW in only three minutes. This equals 600 MW/min [11].

The Fengning Pumped Storage Power Station is a pumped-storage hydroelectric power station about 145 km (90 miles) northwest of Chengde in Fengning Manchu Autonomous County of Hebei Province, China. Construction of the power station began in June 2013 and the first generator has been commissioned in 2019, the last in 2021. Project costs are US$1.87 billion. In 2014, Gezhouba Group was awarded the main contract to build the power station. It is the largest pumped-storage power station in the world with an installed capacity of 3,600 MW, which consists of 12 x 300 MW Francis pump turbines [14].

Indonesia has presented plans for building the country's first pumped storage hydropower plant. The power plant is planned to operate by shifting water between two reservoirs; the lower reservoir on the Upper Cisokan River and the upper reservoir on the Cirumamis River, which is a right-bank tributary of the Upper Cisokan. When energy demand is high, water from the upper reservoir is sent to the power plant to produce electricity. When energy demand is low, water is pumped from the lower reservoir to the upper by the same pump-generators. This process repeats as needed and allows the plant to serve as a peaking power plant. The power plant will contain four Francis pump-turbines which are rated at 260 MW each for power generation and 275 MW for pumping. The upper reservoir will lie at maximum elevation of 796 m and the lower at 499 m. This difference in elevation will afford the power plant a rated hydraulic head of 276 m. It is expected that the plant will be commercially operational in 2024.

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Data sheets

The following page contains the data sheet of the technology. All costs are stated in U.S. dollars ($), price year 2019.

Technology	**Hydro pumped storage**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Generating capacity for one unit (MWe)	250	250	250	100	500	100	500	A	1;6
Generating capacity for total power plant (MWe)	1,000	1,000	1,000	100	4,000	100	4,000		1;6
Electricity efficiency, net (%), name plate	80	80	80	70	82	70	82		1;3;5
Electricity efficiency, net (%), annual average	80	80	80	70	82	70	82		1;3;5
Forced outage (%)	4	4	4	2	7	2	7		5
Planned outage (weeks per year)	3	3	3	2	6	2	6		5
Technical lifetime (years)	50	50	50	40	90	40	90		1
Construction time (years)	5	5	5	2.2	7	2.2	7	B	1,8
Space requirement (1000 m^2/MWe)	30	30	30	15	45	15	45		1
Additional data for non-thermal plants									
Capacity factor (%), theoretical	-	-	-	-	-	-	-		
Capacity factor (%), incl. outages	-	-	-	-	-	-	-		
Ramping configurations									
Ramping (% per minute)	50	50	50	10	100	10	100		2;5
Minimum load (% of full load)	0	0	0	0	0	0	0		2
Warm start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		2
Cold start-up time (hours)	0.1	0.1	0.1	0.0	0.3	0.0	0.3		2
Environment									
PM 2.5 (gram per Nm^3)	0	0	0	0	0	0	0		
SO_2 (degree of desulphuring, %)	0	0	0	0	0	0	0		
NO_X (g per GJ fuel)	0	0	0	0	0	0	0		
Financial data									
Nominal investment (M$19/MWe)	0.89	0.89	0.89	0.60	6.0	0.60	6.0	C;E	1;3;4
- of which equipment (%)	30	30	30	20	50	20	50		7
- of which installation (%)	70	70	70	50	80	50	80		7
Fixed O&M ($19/MWe/year)	8,320	8,320	8,320	4,000	30,000	4,000	30,000		3;4;6;7
Variable O&M ($19/MWh)	1.4	1.4	1.4	0.5	3.0	0.5	3.0		1;7
Start-up costs ($/Mwe/start-up)	-	-	-	-	-	-	-		
Technology specific data									
Size of reservoir (MWh)	10,000	10,000	10,000	3,000	20,000	3,000	20,000	D	1;6
Load/unload time (hours)	10	10	10	4	12	4	12	D	1;6

References:

1. Ea Energy Analyses and Danish Energy Agency, “Technology Data for the Indonesian Power Sector – Catalogue for Generation and Storage of Electricity”, 2017.
2. Eurelectric, “Hydropower – Supporting a power system in transition”, 2015.
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8. PECC1, F/S report of Bac Ai PSPP, 2015.

Notes:

A. Size per turbine.
B. Uncertainty (Lower) is estimated as - 50%.
C. Numbers are very site sensitive. There will be an improvement by learning curve development, but this improvement will be equalized because the best locations will be utilized first. The investment largely depends on civil work.
D. The size of the total power plant and not per unit (turbine).
E. Investment cost include the engineering, procurement and construction (EPC) cost. See description under Methodology.

2. LITHIUM-ION BATTERIES

Brief technology description

With increasing shares of renewable energy in power systems, the grid faces variability and uncertainty in supply. Due to this, the power sector has seen a lot of growth in the role of electricity storage technologies. Some of the main technologies being looked at include storing excess electricity using electrochemical storage batteries like lithium-ion, redox flow, lead-acid, high temperature sodium sulphur (NaS) and sodium nickel chloride. Other technologies also include fuel cells, supercapacitors, flywheels, and conversion to hydrogen. The potential applications of batteries in electricity systems are very broad, ranging from supporting weak distribution grids, to the provision of bulk energy services or off-grid solutions (Figure 5).

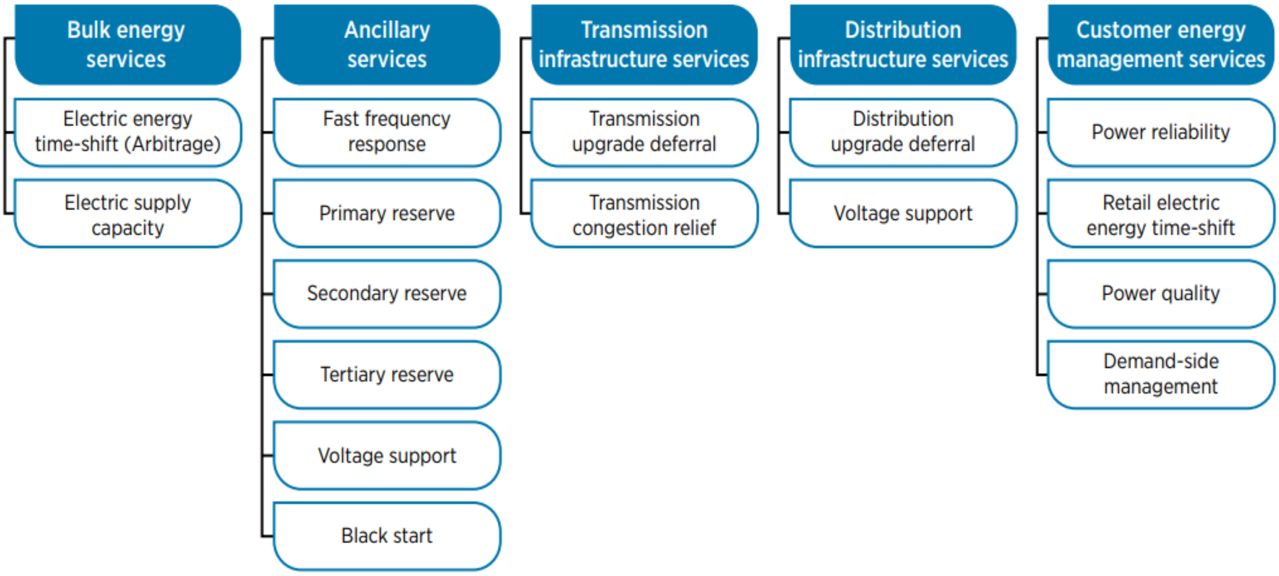

Figure 5: Range of services electricity storage can provide (ref. 41).

Electrochemical storage (batteries) has experienced the most notable cost declines in the past years. This is especially true for li-ion batteries, which have been used in different grid applications around the world. As per data from IEA, in 2018, li-ion batteries made up 93% of energy storage technology mix (excluding pumped hydropower storage). Furthermore, lithium-ion batteries (LIB) have completely dominated the market for grid scale energy storage solutions in the last years and appear to be the dominating battery solution (Figure 6). Due to the current importance of LIB storage in the power system, a special focus is being directed to it through this chapter.

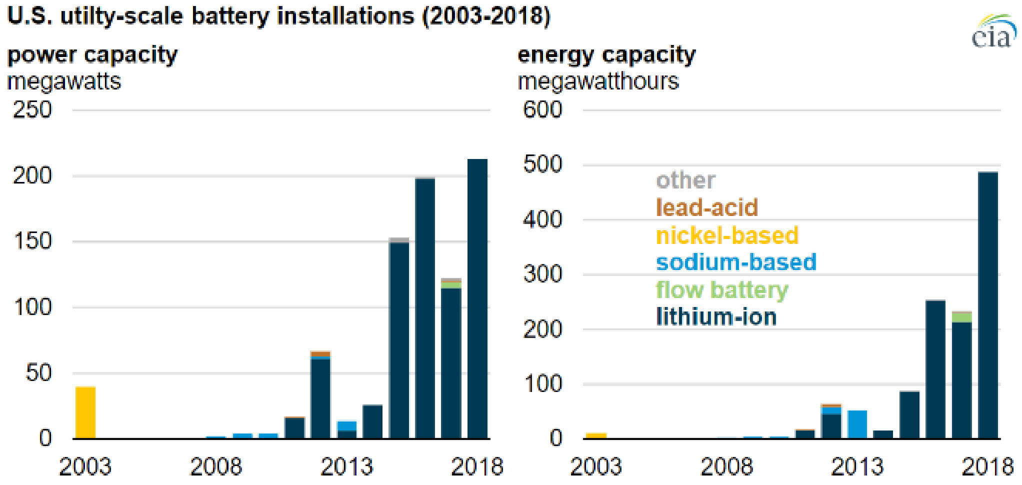

Figure 6: Utility-scale battery installations by type in the US (2003-18). Source: EIA.

This technology description here focuses on batteries for provision of bulk energy services and customer energy management services, i.e. time-shift over several hours (arbitrage) – for example moving PV generation from day to night hours –, the delivery of peak power capacity, demand-side management, power reliability and quality.

A typical LIB installed nowadays has a graphitic anode, a lithium metal oxide cathode and an electrolyte that can be either liquid or in (semi-)solid-state. When liquid, it is composed of lithium salts dissolved in organic carbonates; when solid, lithium salts are embedded into a polymeric matrix. Three major types of Li-Ion batteries installed nowadays for utility-scale storage are reported in Table 1. Li-Ion batteries commonly come in packs of cylindrical cells and can reach energy densities of up to 300 Wh/kg. The unit's footprint can be assumed to be around 5 m2/MWh.

Table 1: Major LIB types in use for utility-scale storage (Ref. 47)

Short name	Name	Anode	Cathode	Energy densitiy Wh/kg	Cycles	Calendar life	Major manufactures
NMC	Lithium Nickel Manganese Cobalt Oxide	Graphite	Li $Ni_{0.6}Co_{0.2}$ $Mn_{0.2}O_2$	120-300	3000-10000	10-20 years	Samsung SDI LG Chem SK Innovation Leclanche Kokam
LFP	Lithium Iron Phosphate	Graphite	$LiFePO_4$	50-130	6000-8000	10-20 years	BYD/Fenecon Fronius/Sony*
LTO	Lithium Titanate	$LiTO_2$	$LiFePO_4$ Or Li $Ni_{0.6}Co_{0.2}$ $Mn_{0.2}O_2$	70-80	15000-20000	25 years	Leclanche Kokam Altairnano

Electrons flow in the external circuit and Li ions pass through the electrolyte. The charging and discharging of the battery depend on the shuttling mechanism of Li ions between anode and cathode. This process is controlled by an electronic battery management system to optimize cell utilization and degradation, while delivering the desired loading/unloading current. The fast Li-ion transport and the small diffusion distance due to the lamellar architecture of components inside the cell ensure that the response time for LIB is very low (ref. 1). It also has a low self-discharge rate of only 0.1–0.3% per day and good cycle efficiency of up to 97% (ref. 8).

A schematic overview of a battery system and its grid connection can be seen in Figure 7. A Thermal Management System (TMS) controls the temperature in the battery packs to prevent overheating and thermal runaway (the phenomenon is explained in the following). The Energy Management System regulates the energy exchange with the grid. Power electronics convert DC into AC before power is injected into the grid. In some cases (high-voltage grids), a transformer might be required to feed electricity into the grid. Some manufacturers offer container-type storage battery modules which can be connected in series to increase the storage capacity.

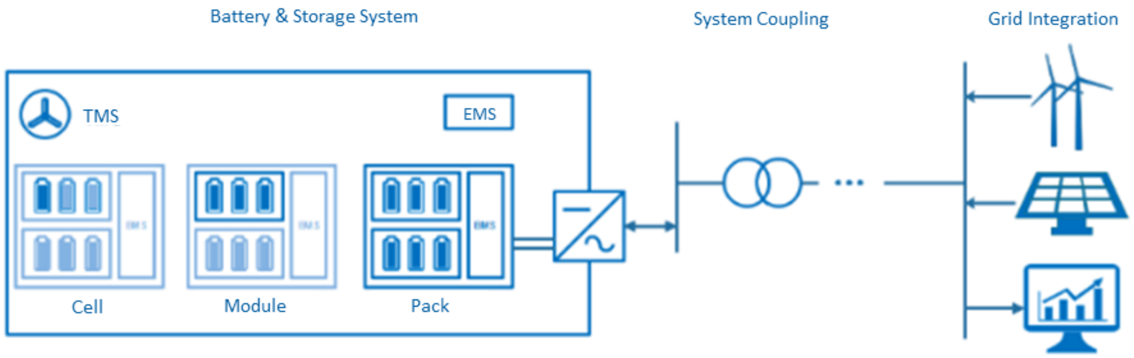

Figure 7: Schematic illustration of a battery storage system and its grid connection (Ref. 43).

Charging and discharging rates of LIB are often measured with the C-rate, which is the maximum current the battery can deliver with respect to its volume. For example, if a battery is discharged in 20 minutes, 1 hour or

2 hours then it has C-rates of 3C, C or C/2 respectively. Operations at higher C-rates than specified in the battery pack are possible but would lead to faster degradation of the cell materials (ref. 9). Generally, for the same chemistry/construction, a battery going through a 15-minute full discharge will have a lower cycle life (and thereby lifetime) than a similar battery used for a 1-hour full discharge cycle.

LIB do not suffer from the memory effect issue (the effect of batteries gradually losing their maximum energy capacity if they are repeatedly recharged after being only partially discharged) and can be used for variable depths of discharge at short cycles without losing capacity (ref. 11). The relationship between battery volume (in MWh) and loading/unloading capacity (in MW) can be customized based on the system needs and in order to obtain a better business case.

The lifetime of battery energy technologies is measured by the total number of cycles undergone over the lifetime. Nowadays, a Li-Ion battery typically endures around 10000 full charge/discharge cycles [ref missing]. Batteries generate DC current, which then needs to be converted into AC to be fed into the most interconnected grids. This is achieved through power electronics (inverters).

As mentioned at the beginning of this section, battery energy storage systems (BESS) can have manifold applications and thus can be installed at different voltage levels (Figure 8). BESS architecture is ultimately shared across use types, with minor differences depending on the single applications. In off- and micro-grid contexts (not represented in Figure 8), grid connection costs are reduced totally or partially.

Batteries can be installed in households and industrial buildings behind the meter to reshape the load curve and to integrate distributed generation such as rooftop or industrial PV. The major benefits are related to retail tariff savings, peak tariff reduction, reliability, and quality of supply (ref. 43). Batteries can boost the self-consumption of electricity and back up the local grid by avoiding overload and by deferring new investments and reinforcements. In case of bi-directional flows to/from the grid (presumption), BESS can increase the power quality of distributed generation and contribute to voltage stability. In developed market settings, these functions might not only reflect requirements enforced by the regulation, but also materialize in remunerated system services.

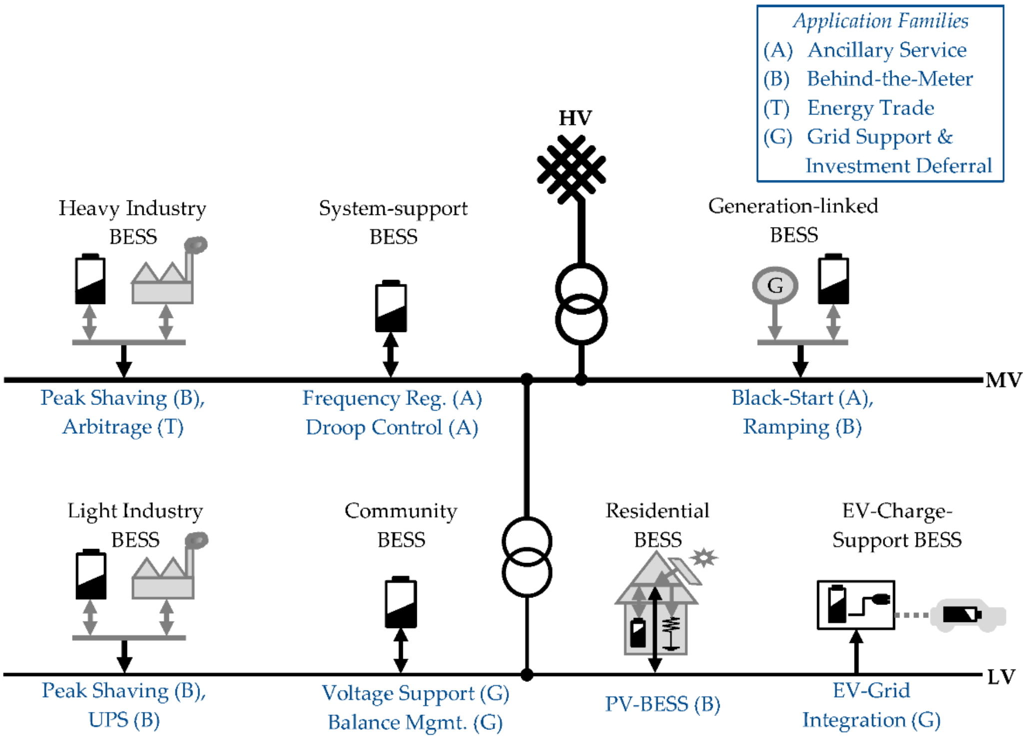

Figure 8: Different uses of battery systems depending on voltage level and application families (Ref. 43).

Input

Electricity.

Output

Electricity.

The efficiency of Li-ion battery cells is close to 100%. However, there are several sources for losses, which can be grouped into operational and stand-by losses. Operational losses are related to the power electronics and to the circuit resistance in the LIB. They increase with the second power of the current flowing in the battery's external circuit. Stand-by losses are the result of unwanted chemical reactions in the battery (*self-discharge rate*). Self-discharge rates increase with temperature but can be assumed to be in the order of 0.1% of the energy content per day.

Auxiliaries (thermal management system, energy management system) require energy to run as well, and losses therein must be accounted for as well.

AC-DC conversion and energy demand from the control electronics lead to a grid-to-grid efficiency (AC-AC) of about 90% nowadays. Frequency regulation requires fast short-cycle charge-discharge and reduces round-trip efficiency. Extensive cycling reduces the lifetime of batteries. Overall, the round-trip efficiency can be expressed as a decreasing function of the C-rate, that is how much current is released by the battery.

Typical capacities

For bulk energy services, Li-Ion batteries come in large sizes. Small batteries are in the order of MW/MWh, but can reach several hundreds of MW/MWh. For example, the Hornsdale facility in Australia has 100MW/129MWh capacity/energy components and a further expansion of 50MW/64.5MWh is in the pipeline. For distributed applications, battery size can range from a few kW to hundreds of kW.

For bulk energy services applications (for instance time shifting, i.e. storing energy produced at a specific time to use it at a different time), several hours of storage might be needed, depending on the system needs. For example, an AES installed LIB facility in San Diego can feed the grid 37.5 MW of power continuously for 4 hours. This tendency will increase in the future with the necessity of moving variable renewable energy generation over long time frames.

Ramping configurations

Li-ion batteries (LIB) installations are very flexible in terms of power/energy capacity and time of discharge. This type of battery has a response time in the order of milliseconds (determined by the inverter), which makes it suitable for the wide range of applications mentioned before, including power quality.

Advantages/disadvantages

Advantages/disadvantages are considered in relation to other battery technologies.

Advantages:

- Li-ion batteries (LIB) modules do not need maintenance and can work in harsh environments, thus operational costs are contained.
- LIB have a relatively high energy and power density.
- In general, battery energy storage systems have the stack-ability to follow closely with demand. Furthermore, they are easy-to-place and easy-to-move.
- Round-trip energy efficiency is remarkably high for LIB among commercially scalable batteries. Other batteries have an efficiency of 10% lower or more. Some batteries like NiCd/Ni-MH lose energy capacity if not fully discharged. This is called memory effect. LIB do not suffer from memory effect and have low self-discharge.
- The combination of high power and energy density and the very short response time (few milliseconds) enables the usage of LIB in both power intensive applications such as frequency regulation and energy intensive applications like time shifting of dispatch. Li-Ion batteries can therefore benefit from different revenue streams, associated with a set of system services. The lack of memory effect allows short and deep discharging.
- LIB have a relatively long lifetime (i.e. many cycles) compared to many other battery types. This strengthens the business case and the financial viability of battery storage systems, since it lowers the levelized cost of storage.

Disadvantages:
Li-ion batteries (LIB) have a relatively small number of technical disadvantages, mainly related to electrochemical reactions within the cells.

- Electrode materials are prone to degradation if overcharged and deeply discharged repeatedly. A proper management system can effectively mitigate this problem.
- Continuous cycling lowers the overall lifetime of the battery.
- Li-Ion battery systems need cooling to remove the heat released by the battery modules. The auxiliary consumption needed for cooling can be sizeable depending on the type of application and battery use. Safety issues from thermal runaway are of concern. Thermal runaway arises as a consequence of high temperatures in the battery cells; within milliseconds, the energy content in the battery is emptied out and unacceptably high temperatures are reached. Li-Ion batteries can charge in the 0-45°C temperature range, discharge even at slightly higher temperatures; thermal runaway can start already at 60°C. Overcharging is a cause of thermal runaway.
- The electrolyte has a limited electrochemical stability window. Beyond this limit, a redox reaction takes place between the oxygen released from the cathode and the electrolyte; the battery might catch fire (ref. 21). During a thermal runaway, the high thermal power released from one cell can spread to the adjacent cells, making entire modules unstable.
- Stability of cathode materials in contact with electrolyte is better for phosphate cathodes than oxide cathodes but phosphate-based batteries deliver lower potential. Thermal runaway can be suppressed using inhibitors (ref. 22).
- With LIB demand increasing exponentially every year, the supply of raw materials and incremental costs are the main concerns. Lithium extraction has the potential for geopolitical risks because the world’s known resources of easily extractable lithium are largely concentrated in three South American countries: Chile, Bolivia, and Argentina (ref. 23), but the limited availability of cobalt resources remain the biggest concern.
- The self-discharge rate and all the parasitic losses in the system become a significant source of losses at residence times beyond a few days, hence Li-Ion batteries are not advisable for long-term storage.

Environment

Some LIB contains toxic cobalt and nickel oxides as cathode materials and thus need to be meticulously recycled. At present, the market price of component materials like lithium/cobalt is still not high enough for making it economically beneficial. Unlike portable electronics, large installations help enforce recycling regulations.

Lithium resource depletion from fast adoption of LIB in electric vehicles and utility scale storage is a concern (ref. 24). US-EPA reported that across the battery chemistries, the global warming potential impacts attributable to the LIB production is substantial (including energy used during mining): the literature points at a climate impact ranging from 39 kg CO_{2eq}/kWh to 196 kg CO_{2eq}/kWh (ref. 46).

Research and development

LIB have been well-known for decades, but their use as utility-scale storage has gained momentum only in recent years. LIB moved from the pioneer phase (category 2) to the commercial phase with a significant development potential (category 3). Therefore, there is still significant potential for R&D.

Due to the economic and technological impact, a wide range of government and industry-sponsored research is taking place across the world towards the improvement of LIB at material and system level.

Higher energy density is achievable by discovering new cathode with higher electrochemical potential and anode/cathode materials, which can build in more lithium per unit volume/weight.

Higher electrochemical potential for cathode materials needs to be matched with the electrochemical stability of the electrolyte used. Thus, research in new electrolyte systems is also needed. Electrolytes with better chemical stability also lead to lower chances of thermal runaway. Improved power capacity is obtained if lithium-ion movement is faster inside the electrode and the electrolyte materials. In short, cathodes with high electrochemical potential, anodes with low electrochemical potential, cathode/anodes with high lithium capacity, electron/lithium transport, electrolytes with large electrochemical stability window and fast lithium transport are the desirable directions in LIB research.

A nickel-phosphate-based cathode can operate at 5.5 V (compared to 3.7 V of cobalt oxide cathodes), but a complementary electrolyte is not available yet (ref. 25). On the anode side, silicon-based anodes can improve upon carbon-based anodes. Stability for long-term operations has however remained an issue (ref. 26). On the electrolyte side, ionic liquids are being researched for safer high-potential operations (ref. 27).

In the future, Lithium-Air and Lithium-Sulphur batteries could reach commercialization, but challenges related to humidity, unwanted chemical reactions (production and leaking of polysulphide ions into the electrolyte in the case of Li-S batteries).

Another promising branch of research is linked to Lithium Solid-State batteries (SSBs). SSBs use a solid electrolyte instead of a liquid/gel electrolyte as in today's Li-ion batteries: this would strongly reduce flammability risks and increase the energy density of a battery pack, besides being very stable (ref. 44). The main disadvantages connected to SSBs are the high cost, poor ionic conductivity of the electrolyte, incompatibility between electrolyte and electrodes and the fast growth of lithium dendrites. This eventually leads to a poor cycle performance and a rapid capacity degradation (ref. 45).

Investment cost estimation

In the IEA's 2019 World Energy Outlook, battery installations are forecast to provide 330 GW and 550 GW of system flexibility in 2040 in the Stated Policies and the Sustainable Development Scenarios respectively. India will be one of the leading markets. Given a 2018 cumulative capacity of 8 GW, this returns ~8 capacity doublings in 22 years.

LIB installations for utility operation from major companies like Samsung SDI/TESLA are modular and scalable: Costs can be assumed to increase linearly with the storage size. Modular systems that have been used by TESLA to create 80 MWh storage system within 3 months (ref. 29).

Data for the Samsung SDI model is here the main reference for technical parameters; other manufacturers are considered to tune and compare the data.

Due to lack of specific daily discharge loss data, generally accepted information obtained from published journal articles and review papers is used as a standard (ref. 8). Unforeseen outages are very rare and can be considered not to occur, provided that good management is performed.

Samsung SDI also suggests operation between C/2 to 3C rate. A 10C-rate, long-lifetime battery (ref. 30) is under development and 20C-60C-rate batteries are being experimented (ref. 31).

Commercial units have nowadays a lifetime of about 10000 cycles (ref. 42). More stable electrode materials (e.g. polyanion cathode and titanate anode) and a better system management are set to boost the asset's lifetime, which is projected to reach 30 years in 2050.

Modular manufacturing and automated installation capabilities can drastically cut down on system setup time to few weeks from current ~3 months, as demonstrated by TESLA.

Round-trip efficiency is already rather high and the improvement in system performance will therefore be minimal in the future. Internal losses depend on advancements in battery chemistry and R&D in cell materials; materials will also affect the performance of power electronics, whose efficiency could improve by some % in the next years due to better-engineered solid-state converters.

The historical and projected prices for Li-Ion batteries are shown in the figure below, as forecast by Bloomberg. A battery pack is expected to cost 62 USD/kWh in 2030 with the assumption of an 18% learning rate. The IEA's 2019 World Energy Outlook foresees that the total battery system costs will drop to well-below 200 USD/kWh by 2040. Cost reductions are much more significant for the battery pack than for the entire BESS, as power electronics' development is expected to be more moderate. Price drops for the single components of a BESS (battery pack, DC-AC conversion, management systems) are heavily influenced by the potential market applications, which drive R&D efforts and advancements in the manufacturing process.

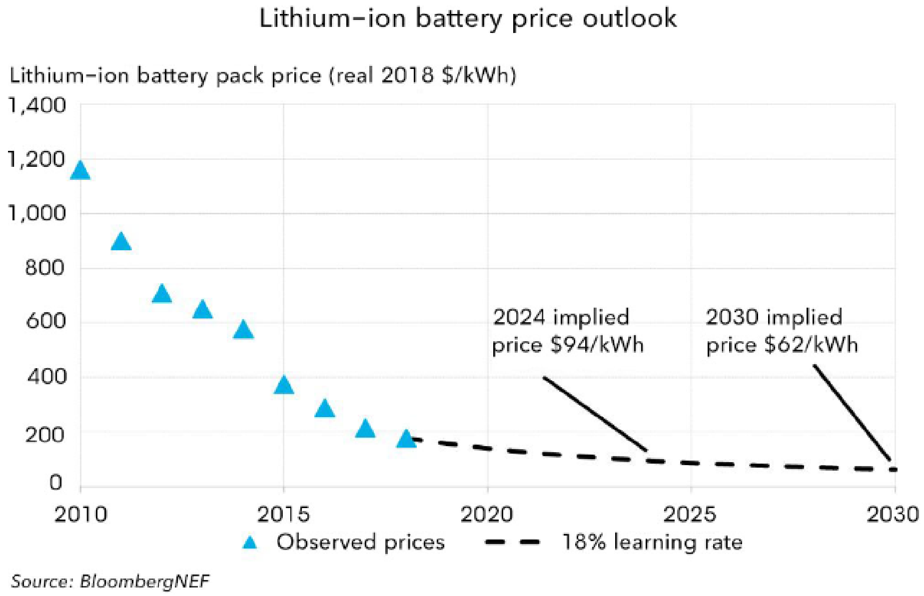

Figure 9: Li-Ion battery pack price projections. Source: Bloomberg NEF.

The price of a small-size battery storage such as TESLA's *Powerwall* (13.5kWh/7kW unit, 0.5 C-rate) can be assumed to be around 500 USD/kWh in 2020, which excludes hardware and installation costs. Figures are lower for bigger storage units.

Lazard's Levelised Cost of Storage report estimates O&M costs to lie in a wide range (0.3-5 USD/kWh). These include both fixed and variable O&M. When costs are calculated for the asset's lifetime, O&M can account for between ¼ and 1/3 of the Levelised Cost of Storage (ref. 34). Although module costs will decrease, counterbalancing effects from more expensive engineering and further automation would keep installation costs and O&M costs at a similar level or even slightly higher.

Similar to the semiconductor industry, improvements in LIB have been exponential (ref. 35), with price reductions of ~15%/year. Demand from EV and electronic industry have contributed to the accelerated development of the manufacturing industry and of the supply chain. Further improvements came from the R&D knowledge in high-performance materials reaching commercial status. It is assumed that energy density will improve in 2030 by ~30-50% due to R&D efforts put into the battery materials.

Data presented in the data sheet are from specific cases and publicly available sources. Better-negotiated prices are most possibly accessible to project managers. Uncertainty in future development of technology and commercialization affect the accuracy of the suggested numbers for LIB energy storage systems.

Investment costs [MUSD2019/MW]	**2018**	**2020**	**2030**	**2050**
This Technology Catalogue		0.76	0.43	0.20
Danish technology catalogue		0.76	0.43	0.20
NREL ATB		0.86	0.48	0.36
Lazard	0.63			

Note: values for 2-hour storage.

Uncertainty in future data

Development in LIB has been rapid in the last few years and upgrades in manufacturing capacity and technologies have been astounding. This is aided by the explosion of the requirements in the area of EV and portable electronics. Large R&D efforts are accelerating the progress, unlike any other storage technologies. For example, development in 6V capable electrolytes, vanadate cathodes and silicon-based anodes can increase the electrochemical potential by 70% and Li-capacity by 3 times – leading to 5-fold increases in the energy density, but these technologies are many years from commercialization. In addition, a polymer gel electrolyte-based battery has been developed that has a cycle life of 200,000 at 96% efficiency (ref. 36). Commercialization of such technology can make LIB systems last for centuries.

Examples of current projects

According to the IEA, at the end of 2018 8 GW of battery capacity were installed worldwide, with 3 GW added only in 2018 (the figure includes all types of batteries)[1]. Many energy storage systems provide system support by participating in frequency regulation services. An example of a large such installation is the Hornsdale battery in Australia. Technology providers include TESLA, A123 systems, LG Chem, BYD, Toshiba, Samsung SDI, Fluence.

- Hornsdale TESLA battery in Australia. 129 MWh/100MW, with an expansion in the pipeline of additional 64.5 MWh/50MW. The facility provides mainly system support in the frequency regulation market, but also bulk energy services.
- AES/Samsung SDI/Parker Hannifin. 30 MW and 120 MWh (bulk energy service). SDG&E Escondido, San Diego, USA. From 2017.
- Samsung SDI/GE. 30 MW and 20 MWh (black start and frequency regulation). Imperial Irrigation District, El Centro, California, USA. From 2016.
- Toshiba. 40 MW and 40 MWh (bulk energy service for RE). Minamisoma, Fukushima Prefecture, Japan. From 2016.
- AES Alamitos BESS. 100 MW and 400 MWh using Fluence Advancion 5 technology. Long Beach, California, USA. From 2020.
- CATL. 50 MW/100 MWh (Lithium iron phospate), grid-connected energy storage of the Luneng National Energy Storage Power Station Demonstration Project. From 2018, it is the largest electrochemical energy storage project in China (ref. 49).

Figure 10: Picture of the 40 MW and 40 MWh energy storage system in Fukushima, Japan (Ref. 48).

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[1] A world map with storage installations by storage type can be found at the following link: https://public.tableau.com/shared/YFTR6XFTD?:showVizHome=no&:embed=true. Last accessed: September 2020.

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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 2019. 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.

Technology	**Batteries – Lithium-ion (utility-scale)**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Energy storage capacity for one unit (MWh)	6.0	7.0	8.0					A,B	1,2
Energy/Power ratio (hours)	1.04	2.08	4.16					E	1,2
Discharge time (hours)	1.00	2.00	4.00					E	1,2
Round-trip efficiency (%) AC	91	92	92					C	3,12
Round-trip efficiency (%) DC	95	96	96					C	3,12
Self-discharge rate (%/day)	0.10	0.10	0.10						4
Forced outage (%)	0.38	0.35	0.25					M	
Planned outage (weeks per year)	0.20	0.10	0.10					L	
Technical lifetime (cycles)	10000	15000	20000					M	5
Technical lifetime (years)	20	25	30					D	
Construction time (years)	0.20	0.20	0.20						
Energy density (Wh/kg)	150	200	300						
Ramping configurations									
Response time from idle to full-rated discharge (ms)	50	50	50						6
Financial data									
Nominal investment (MUSD/MWh)	0.578	0.264	0.157	0.455	0.920	0.075	0.398	G	13
- energy component (MUSD/MWh)	0.152	0.062	0.035	0.080	0.215	0.030	0.131		7,8
- power component (MUSD/MW)	0.311	0.184	0.069	0.273	0.580	0.045	0.284	H	9,10,11
- other project costs (MUSD/MWh)	0.115	0.110	0.105	0.102	0.125	0.023	0.125	N	9,12
Fixed O&M (USD/MWh/year)	621	311	155	500	650	250	350		12
Variable O&M (USD/MWh)	2.30	2.07	1.84	0.45	6.36	0.34	2.84	I	10
Technology specific data									
Energy storage expansion cost (MUSD/MWh)	0.267	0.172	0.14	0.182	0.294	0.052	0.200	B,F	7,8
Output capacity expansion cost (MUSD/MW)	0.311	0.184	0.069	0.273	0.580	0.045	0.284	B,F	9,10,11

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Notes:

A. One unit defined as a 40 feet container including LIB system and excluding power conversion system. Values are taken from Samsung SDI brochures for grid-connected LIBs from 2016 and 2018 [2,14]. Units with C-rates below/above 1 are possible, depending on the system needs and cost of the energy and power rating components. A C-rate of 1 is here assumed for 2020, as it is close to several new installations.

B. Power and energy output can be scaled linearly by utilizing many modules (up to 100MW has been demonstrated). Output capacity expansion can be done reprogramming the management unit without any new battery module.

C. 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 RT eff. Vs. C-rate is exemplified in Figure 7 [3,51]. 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% [21,22].

D. 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.

E. The discharge time is the amount of hours the battery can discharge at rated output capacity. It equals the Energy/Power ratio corrected for the discharge efficiency.

F. Since multi-MWh LIB systems are scalar, the energy and output capacity expansion costs are here estimated to be equal to the energy and output capacity components plus the "other costs".

G. Power conversion cost is strongly dependent on scalability and application.

H. 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 RT eff. Vs. C-rate is exemplified in Figure 7 [3,51]. 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% [21,22].

I. Cost per MWh of energy discharged from the battery

L. It is expected not to have any outage during lifetime of the grid-connected LIB. Only a few days during the e.g. 15 years life time is needed for service and exchanging fans and blowers for thermal management system and power conversion system. Forced outage is expected to drop with increasing robustness following the learning rate and cumulated production. Planned outage is expected to decrease after 2020 due to increased automation.

M Cycle life specified as the number of cycles at 1C/1C to 80% state-of-health. Samsung SDI 2016 whitepaper on ESS solutions provide 15 year lifetime for current modules operating at C/2 to 3C [14]. Steady improvement in battery lifetime due to better materials and battery management is expected. Kokam ESS solutions are also rated at more than 8000-20000 cycles (80-90% DOD) based on chemistry [3]. Thus, for daily full charge-discharge cycles, the batteries are designed to last for 15-50 years if supporting units are well functioning. Lifetimes are given for both graphite and LTO anode based commercial batteries from Kokam. Cycle lives are steadily increasing over last few years as reflected in 2020/2030 numbers [4,5,14].

N. Other costs include construction costs and entrepreneur work. These costs 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.

Examples for calculation of CAPEX using datasheet:

Frequency regulation in 2020: 4C-rate, 2 MWh BESS system. 20 years operation time.
Cost items:
2 MWh "energy component", year 2020
2 MWh "other project costs", year 2020
4C = 0.25-hour discharge time Þ 8 MW "power component", year 2020

CAPEX: 2 * (0.152 M$ + 0.115 M$) + 8 * 0.311 M$ = 3.022 M$

Energy integration in 2030: ¼C-rate, 16 MWh BESS system. 25 years operation time.
Cost items:
16 MWh "energy component", year 2030
16 MWh "other project costs", year 2030
¼C= 4-hour discharge time Þ 4 MW "power component", year 2030

CAPEX: 16 * (0.062 M$ + 0.11 M$) + 4 * 0.184 M$ = 3.488 M$

3. VANADIUM REDOX FLOW BATTERIES

Brief technology description

Vanadium redox flow batteries also known simply as Vanadium Redox Batteries (VRB) are secondary (i.e. rechargeable) batteries. VRB are applicable at grid scale and local user level. Focus is here on grid scale applications.

VRB are the most common flow batteries. A flow battery consists of a reaction cell stack, where the electrochemical reactions occur, at least one storage tank filled with electrolyte (anolyte) consisting of reactants in solution for the negative battery electrode, i.e., the anode; at least one storage tank filled with electrolyte (catholyte) consisting of reactants in solution for the positive battery electrode, i.e., the cathode; piping connecting the storage tanks with the reaction cell stack, and mechanical pumps to circulate the electrolytes in the system. A schematic of a traditional flow battery can be seen in Figure 11. The region bordered by the grey electrodes is the reaction cell stack.

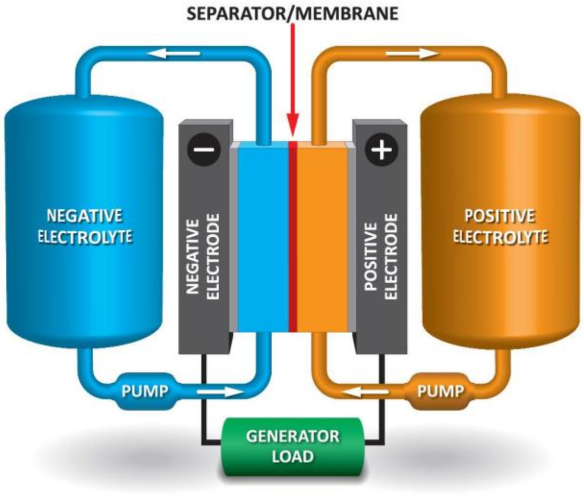

Figure 11: Schematic of flow battery [1].

The anolyte reactive species are V^{2+} and V^{3+} ions. The catholyte reactive species are VO_2^+ and VO^{2+} ions with the V atom in oxidation state +5 and +4, respectively. Traditionally, the reactive species have been dissolved with concentrations of 1.5-2 M in aqueous sulfuric acid solutions with an acid concentration of 2-5 M [2].

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 12.

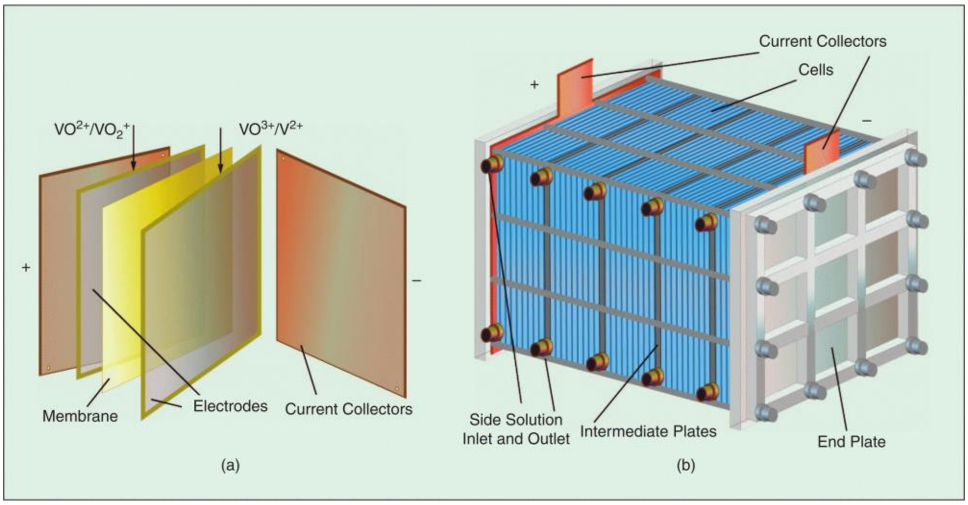

Figure 12: a) Reaction cell. B) Typical stack [2].

During discharge the following reaction occurs in the cell as two protons pass through the membrane and an electron pass through an external circuit.

$V^{2+} \rightarrow V^{3+} + e^-$	(Anode side reaction)
$VO_2^+ + 2H^+ + e^- \rightarrow VO^{2+} + H_2O$	(Cathode side reaction)
$V^{2+} + 2H^+ + VO_2^+ \rightarrow V^{3+} + VO^{2+} + H_2O$	(Full cell reaction)

During charge the reverse reaction occurs. The full reaction provides a cell voltage of 1.26 V. The battery operates at ambient temperatures.

Flow batteries are different from other batteries by having physically separated storage and power units. The volume of liquid electrolyte in storage tanks dictates the total battery energy storage capacity while the size and number of the reaction cell stacks dictate the battery power capacity. The energy storage capacity and power capacity can thus be varied independently according to desired application and customer demand [2].

A VRB installation consists, as a minimum, of a VRB unit as described above, a battery management system, and a power conversion system connecting the battery unit to the grid. For a more detailed technology description the reader is referred to "Encyclopedia of Electrochemical Power Sources" [3].

Input/Output

Primary input and output are both electricity. Electricity is converted to electrochemical energy during charge and converted back to electricity during discharge in the reaction process described above.

Energy efficiency and losses

Electrolyte left in the cell stack during idle periods will self-discharge over time resulting in an energy loss. As the electrolyte volume in the cell stack is generally small compared to the total electrolyte volume, the total energy loss from self-discharge will be at most 2 % of stored energy during any idle period [4]. The mechanical pumps require energy. The energy used by the mechanical pumps is included in the determination of battery efficiency and should thus not be treated as a separate loss.

For individual VRB reaction cells the energy conversion efficiency can be as large as 90 % at low current densities [3]. The grid-to-grid efficiency is reported by multiple sources to be approximately 70 % at constant rated discharge power [1], [4], [5]. UniEnergy Technologies reports 75 % energy efficiency for frequency regulation application and 70 % energy efficiency for peak shaving application [6]. Vionx Energy reports a DC efficiency of 78 % and an AC efficiency of 68 % for their units operating at rated capacity [5].

Regulation ability and other system services

The response time (i.e. the time it takes for the battery to supply a requested charge or discharge power) is according to manufactures < 100 ms if electrolyte is already present in the reaction cell [4], < 1 s if electrolyte must first be pumped into the cell [5], and < 1 min if the pumps are turned off [5]. Large scale VRB installations have been demonstrated to be routinely capable of operating for 30 s at 150 % rated power capacity [7].

Grid scale battery operation depends on the application. Batteries used for time shifting will generally complete a single charge/discharge cycle over 24 hours. Batteries used for various other grid services including stabilization of input from renewables as exemplified below will often not undergo traditional battery cycling but frequently switch between being charged and discharged according to demand.

Due to its short response time combined with the ability to independently vary installation size of energy storage capacity and power capacity, VRB installations can provide a range of system services. The manufacturer UniEnergy Technologies lists the following applications for grid and utility installations: T&D deferral (avoid need to upgrade transmission and distribution equipment), flex capacity/ramping, load shifting, and ancillary services [6].

Typical characteristics and capacities

Examples of commissioned grid-scale VRB installations are listed Table 2.

Table 2: Selected grid-scale VRB installations [6], [8], [9].

Location	Yokohama, Japan	Hokkaido, Japan	Braderup, Germany	Pullman, Washington, USA
Commissioning year	2012	2016	2014	2015
Energy Storage Capacity	5 MWh	60 MWh	1 MWh	4 MWh
Power Capacity	1 MW	15 MW	325 kW	1 MW
Technology provider	Sumitomo Electric Industries	Sumitomo Electric Industries	UniEnergy Technologies	UniEnergy Technologies

The non-exhaustive DOE Global Energy Storage Database lists 21 different installations of at least 100 kW commissioned since 2011[1], [9]. The 21 installations have been supplied by at least 8 different manufacturers. A 200 MW/800 MWh installation is currently under construction in Dalian in China [9].

The energy density and specific energy for two selected commercial units are shown in Table 3.

Table 3: Energy density and Specific energy for commercial VRB units [4], [10].

Manufacturer	Energy Density (Wh/m³)	Specific energy (Wh/kg)
UniEnergy Technologies	9040	11.8
Sumitomo Electric Industries	5880	7.1

Typical storage period

The typical storage period depends on operation. It ranges from minutes to hours for grid scale installations [11]. The storage time is not technologically limited. Energy can be stored for extended periods of time as is the case in small local user level VRB units used for emergency power.

Space Requirement

The installation in Hokkaido, Japan (Table 2) commissioned in 2016 occupy a total land area of 5000 m^2 [12]. This corresponds to a land use of 83.3 m^2/MWh.

UniEnergy Technologies have in promotional material suggested that an installation with 240 MWh storage capacity would occupy a land area of 4000 m^2 [6]. This corresponds to a land use of 16.7 m^2/MWh. This is the lowest value found.

The largest land usage found for current commercially available grid scale VRB units is 140.2 m^2/MWh [10].

Advantages/disadvantages

General advantages and disadvantages of batteries in comparison to other technologies for energy storage are listed in Table 4.

Table 4: Advantages and disadvantages of VRB in comparison with other energy storage technologies.

Advantages	Disadvantages
Short response time	Relatively short lifetime[2]
Flexible installation size	Large investment cost
High energy efficiency	
Versatile application	
Relatively compact	
Low maintenance	

---

[2] Although some batteries have lifetimes as long as 20 years (VRB), battery lifetimes in general are shorter than that of PHS (60 years) and CAES (50 years) [28].

In comparison to other grid-scale batteries, VRB and other flow batteries have the significant advantage that the energy storage capacity and power capacity can be varied independently and optimized for a specific application. In contrast to molten sodium batteries (Na-S and Na-$NiCl_2$) also applicable for grid scale applications, VRB operate at ambient temperatures. The reactants in a VRB are in a solution. This allows the full energy storage capacity of the battery to be utilized without battery degradation in contrast to batteries where charge/discharge products are solid state [1]. VRB have long technical lifetime in comparison to other batteries. Current batteries are reported by multiple manufactures to have unlimited cycle lifetime within the technical lifetime (up to 20 years). Due to the large technical and cycle lifetime compared to other batteries, VRB have the lowest levelized cost of storage (€/kWh per cycle) among grid scale batteries [2]. VRB also have the advantage that the electrolytes can easily be recycled and reused [1]. As vanadium is the active specie in both anolyte and catholyte, leakage of reactants from one electrolyte into the storage container of the other electrolyte will, in contrast to other flow batteries, not result in electrolyte contamination but only loss of energy storage capacity. The energy storage capacity can be regained by re-balancing the volume and vanadium content of the two electrolyte solutions [1]. VRB are by manufactures promoted as being very safe [6].

VRB and other flow batteries have relatively low grid-to-grid energy efficiencies in comparison to other batteries. This is a consequence of losses related to mechanical pumping of electrolyte, undesired electrical currents known as shunt currents, which allows electrons to bypass the external circuit, and leakage of reactant vanadium ions through the reaction cell membrane. Even though the energy density and specific energy for VRB have recently increased, they remain relatively low in comparison to other batteries [1], [13]. The cost of vanadium has historically been high and have recently increased by approximately 50 % [14], [15]. The raw material cost of vanadium has previously been estimated to contribute $140/kWh to the battery cost, which corresponds to approximately 20 % of the total investment costs for a VRB installation [16]. The absolute minimum energy storage capacity cost of VRB with the currently used reaction chemistry is approximately 70 $/kWh, assuming a cost of V_2O_5 at 6 $/lb [17] is used as source of vanadium [18]. The future cost of vanadium might be higher. Currently, demand exceeds supply and prices have increased to approximately 9 $/lb for V_2O_5 [14], [15].

R&D can and has previously allowed lower-cost sources of vanadium to be used as raw material [1]. The vanadium reactants have the potential to corrode the membrane. High quality and large cost membranes must thus be used in VRB reaction cells [1], [13]. Alternatively, the membrane must be replaced within the technical lifetime of the battery.

Environment

The active reactants in VRB are vanadium ions. Besides being relatively expensive, vanadium might also pose environmental risk factors, which are yet to be fully determined [19]. Most VRB components can be recycled [1]. The vanadium electrolyte is, if possible, directly reused. Otherwise, the vanadium is extracted before further disposal or recycling [1]. Some of the initial investment into raw material vanadium might be regained in this process. The cell membranes might be highly acidic or alkaline after end of battery life and should thus be treated as corrosive material during recycling or disposal [19].

Research and development

The VRB technology is under rapid development. There is significant potential for R&D to reduce cost of all battery components [20], [21]. An example is research in use of non-aqueous electrolytes [2]. The minimum cost will, however, likely be limited by the vanadium cost. The vanadium cost is not fixed in the sense that there is a potential for use of lower cost vanadium sources in production than those traditionally used [1].

There is a significant potential for cost reduction of flow batteries by using alternative reaction chemistries, i.e., other redox couples than vanadium [21]. Grid scale redox flow batteries could potentially be based on, e.g., zinc-bromide, bromide-polysulphide, iron-chromium, and zinc-chloride [21].

Investment cost estimation

The investment cost of the vanadium redox flow batteries depends on several components as the membrane, the hydraulic pumps that push the solution through the two tanks, and the electrolyte solution [22]. In the report from 2019, Mongird et al. collected capital costs data from several sources to evaluate the average cost in 2018 and the projected one for 2025 [22]. The capital cost data availability for vanadium redox flow is although limited [24]. Mongird et al. have gathered information from energy storage expert and VRB manufacturers in

2020, in order to estimate the cost for 1 MW, 10 MW and 100 MW VRB systems with different energy to power ratios in 2020 and 2030 [24]. The data used to estimate the investment cost for the Vietnamese Technology Catalogue comes from different sources, such as the Danish technology catalogue, and few different reports from the U.S. department of energy and NREL [22,23,24]. It is interesting to notice how the costs collected are rather consistent, in terms of values by year and cost trend in the future. Furthermore, a learning curve for battery storage was calculated using the projection data from the IEA World Energy Outlook 2021, and again the cost trend does not deviate significantly from the other data collected. The final values for the Vietnamese TC were estimated weighing the reference data and considering a battery of max 1 MW with a discharge time of 4 h.

Investment costs [MUSD$_{2019}$/MW]	Characteristics	2018	2020	2025	2030	2050
This Technology Catalogue			2.63		1.84	1.45
Danish technology catalogue			2.88		1.68	1.56
U.S. Department of Energy 2019 [22]	4 h	3.5		2.65		
NREL 2021 [23]	10 MW– 4h		1.97-2.41			
U.S. Department of Energy 2020 [24]	1 MW – 4h		2.38		1.9	
	1 MW – 10h		4.52		3.61	
	10 MW – 4h		2.19		1.76	
	10 MW – 10h		4.22		3.37	
	100 MW – 4h		2.05		1.64	
	100 MW – 10h		3.95		3.16	
Learning curve – cost trend (IEAWEO 2021)			100%		74%	56%

Examples of current projects

Grid scale VRB installations are commercially available from several currently operating manufactures as shown in the non-exhaustive list in Table 5. The market appears volatile with VRB manufactures frequently entering the market or ceasing to operate.

Table 5: Some currently operating VRB manufacturers.

Manufacturer	Website
CellCube (Enerox GmbH)	https://cellcube.com/
UniEnergy Technologies	http://uetechnologies.com/
VRB Energy	https://vrbenergy.com
Sumitomo Electric Industries	https://sumitomoelectric.com
Invinity Energy System	https://invinity.com/

Sumitomo Electric has installed several projects worldwide. One example is the Hokkaido Electric Power Network Project, in Japan, where 17 MW of redox batteries have been installed to enhance the grid control for new 162 MW of wind turbines. The project has been in operation since April 2022 and has an estimated lifetime of 21 years [27]. Furthermore, VRB Energy has recently announced a framework agreement for a 100 MW of PV and 100 MW/500 MWh of vanadium flow batteries integrated power station in Xiangyang, China, which will be the largest solar battery of the country [28].

A pilot project was carried out in California by the utility San Diego Gas & Electric, consisting of a 2 MW/8 MWh vanadium redox flow battery used to evaluate the most profitable value stream of such battery type in the commercial wholesale market, including its possible role in grid integration [23, 25]. Researcher from NREL in collaboration with Sumitomo Electric have investigated the value stream of utility-scale VRB for local grid support use cases, assessing the voltage regulation, the capacity firming, peak shaving and valley filling and energy arbitrage [26].

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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".* The following sources are used:

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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 2019. 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.

Technology	**Vanadium Redox Battery (VRB)**								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Energy storage capacity for one unit (MWh)	2	2	2	0.4	800	0.4	800	A	
Output capacity for one unit (MW)	0.5	0.5	0.5	0.1	200	0.1	200	A	
Input capacity for one unit (MW)	0.5	0.5	0.5	0.1	200	0.1	200	A	
Round trip efficiency – DC (%)	78	78	78	62	88	67	95	A, B	
- Charge efficiency (%)	-	-	-	-	-	-	-	A	
- Discharge efficiency (%)	-	-	-	-	-	-	-	A	
Energy losses during storage (%/day)	0	0	0	0	0.2	0	0.2	A, C	
Forced outage (%)	0.5	0.5	0.5	0	5	0	5	A, D	
Planned outage (weeks per year)	0	0	0	0	0	0	0	A, D	
Technical lifetime (years)	20	20	20	6	23	8	32	A	
Construction time (years)	1	1	1	0.2	2	0.2	2	A, E	
Regulation ability									
Response time from idle to full-rated discharge (sec)	0.1	0.1	0.1	0.005	2	0.005	2	A, F, G	
Response time from full-rated charge to full-rated discharge (sec)	0.07	0.07	0.07	0.004	1.4	0.004	1.4	A, F, G	
Financial data									
Specific investment (M$2019/MWh)	0.657	0.46	0.36					A, H	[24]
- energy component (%)	65	60	60						
- capacity component (%)	13	12	12						
- other project costs (%)	22	28	28						
Fixed O&M (% total investment)	1.15	0.9	0.9					A	[24]
Variable O&M ($2019/MWh)	0.507	0.507	0.507						[24]
Technology specific data									
Energy storage expansion cost (MUSD/MWh)	0.572	0.405	0.405					I	
Output capacity expansion cost (MUSD/MW)	0.085	0.055	0.055					I	

Notes:

A. The starting values are from the Danish TC, adjusted using the references (if present in the column).
B. Efficiency varies depending on use.
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. Self-discharge only occurs for electrolyte inside the reaction stack. This is a relatively small volume and the self-discharge will be at most 2 % over time for typical installations. 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. Less the 1 s if electrolyte must first be pumped. Less than 1 min if pumps are not on. PCS might be limiting the response time.
G. Might in practice be limited by PCS.
H. Valid for installations with rated discharge times of 4 hours.
I. Vanadium Redox Batteries are considered 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"

4. HYDROGEN STORAGE

Brief technology description

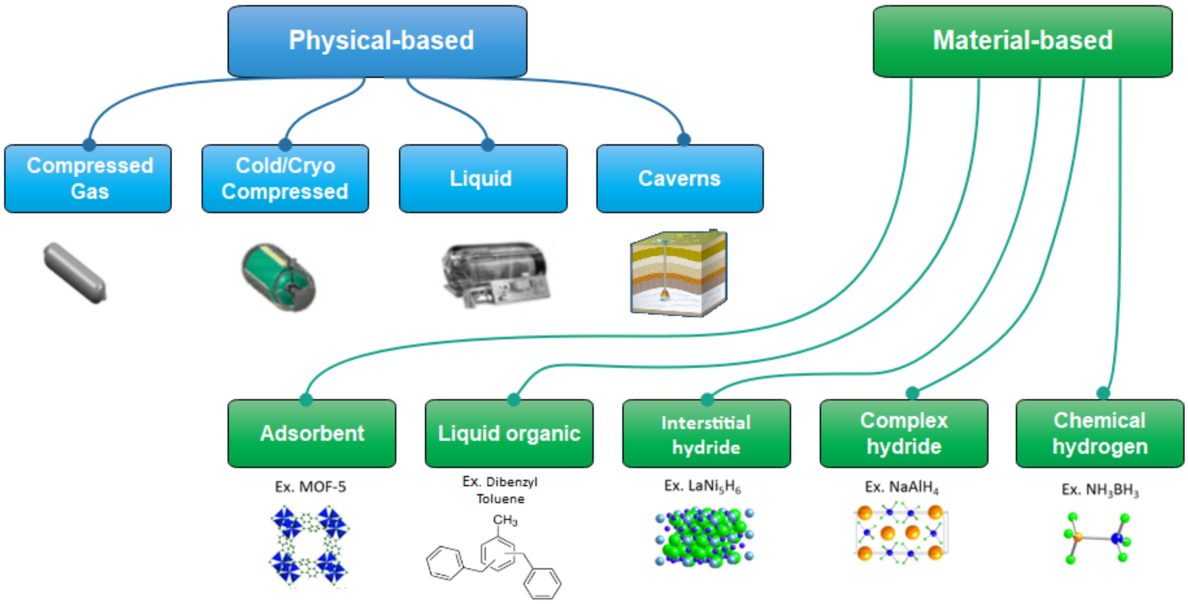


Figure 13: Hydrogen storage categories (icons from [6])

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°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.

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 electrolyzers.

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 14. 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].

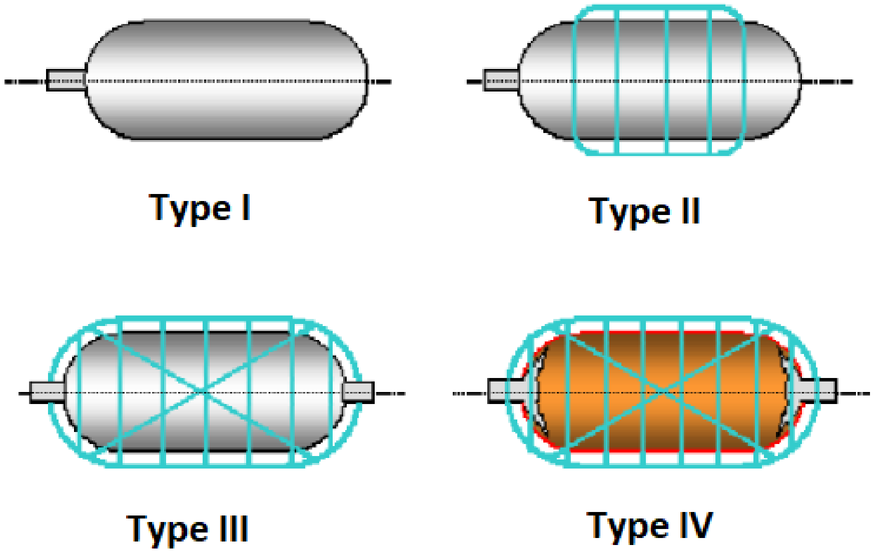


Figure 14: Schematic of different hydrogen pressure tank types [18]. The blue lines represent fibers used for wrapping, made of different materials depending on the tank type. More details in the text below.

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 6.

Table 6: 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]

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.

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 electrolyzers). 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 15.

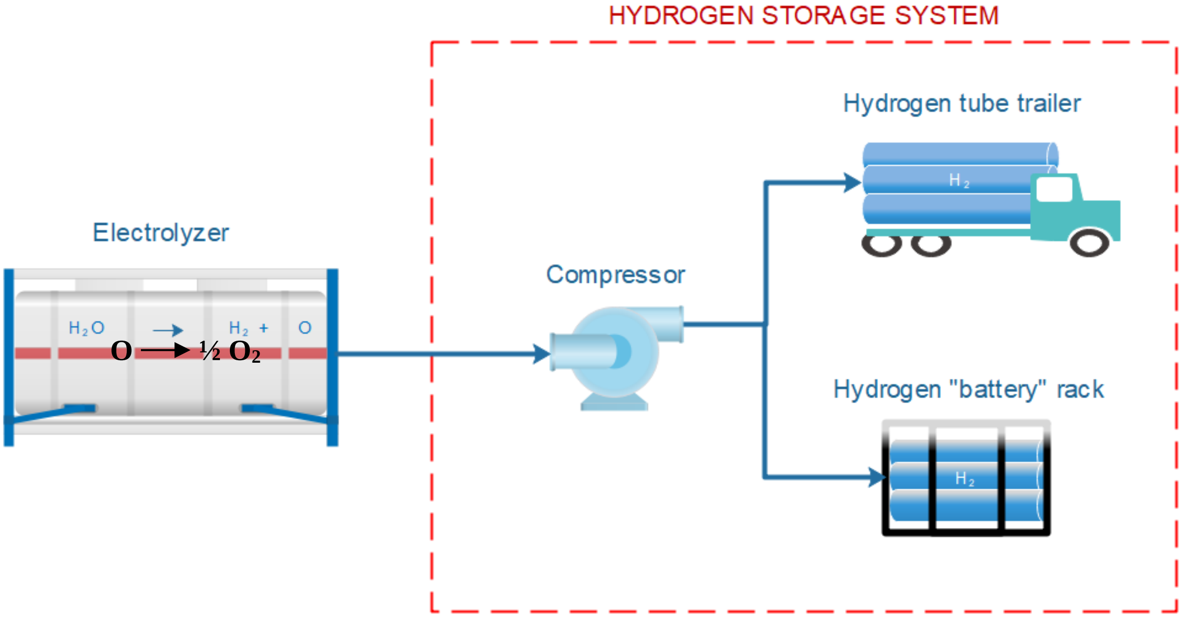


Figure 15: Typical pressurized tank storage system

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 16.

Figure 16: (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 17. 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 17: (left) Hydrogen storage of Type I steel tanks, (right) Hydrogen tube truck with Type I steels tanks [24], [25]

Energy efficiency and losses

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:

$$\eta_{roundtrip} = \frac{16.67MWh}{16.67MWh + 2MWh + {\sim}0 + {\sim}0} \times 100\%$$

$$= 89\% - 1\%_{perm.\&press.} \qquad = 88\%$$

Typical characteristics and capacities

Pressure tanks come in various sizes, depending on the application. A summary with some typical characteristic capacities can be seen in Table 7.

Table 7: 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.

Space requirements

A typical low-pressure stationary hydrogen storage system as shown in Figure 15 has a footprint that is summarized in Table 8.

Table 8: Storage system space requirements

System component	Length [m]	Width [m]	Height [m]	H_2 Capacity [kg]	Footprint [m^2]	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)	

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.

Environment

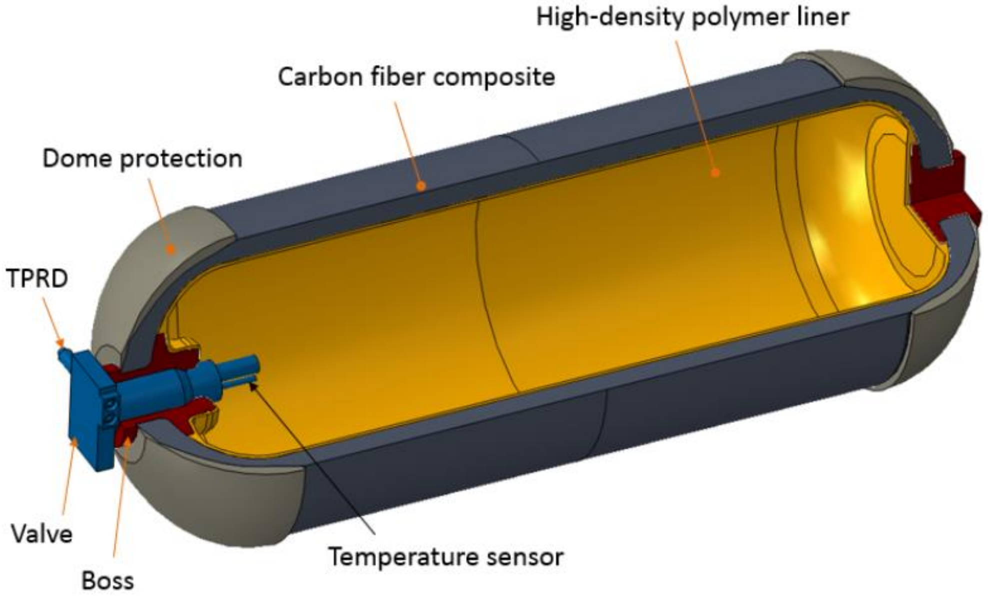
Hydrogen gas itself does not pose any significant environmental threats as its large-scale use is still in its infancy. When larger amounts of gaseous hydrogen are used then, its potential accumulated leakage towards the atmosphere could speed up the ozone layer destruction faster than conventional pollutants. 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 perspectives

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 18.



TPRD = Thermally Activated Pressure Relief Device
Credit: Process Modeling Group, Nuclear Engineering Division. Argonne National Laboratory (ANL)

Figure 18: 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.

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 in Table 9.

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 9: 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 10:

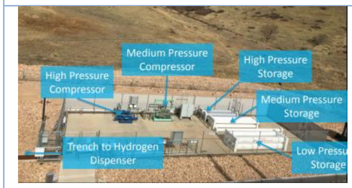
Table 10: Cost of individual components for Hydrogen storage system

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	

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 11, a list of examples of various uses of hydrogen tanks and their purpose is presented.

Table 11: Examples of market standard technology and applications

Image	Location	Usage	Year	Specs.	Technology provider	Ref.
	Elancourt, France	Stationary storage of energy used in telecommunication application.	2016	3x850L@30 bar Type IV tanks, 7 kgH$_2$	MAHYTEC	[40]
	HyBalance Hobro, Denmark	Stationary and transport ready storage of hydrogen from electrolyzer 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]

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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 2019. 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.

Technology	**Pressurized hydrogen gas storage system (Compressor & Type I tanks @ 200bar)**										
	2019	**2020**	**2030**	**2040**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data						**Lower**	**Upper**	**Lower**	**Upper**		
Energy storage capacity for one unit (MWh)	16.7	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)	0.1	0.095	0.09	0.08	0.08	0.1	0.99	0.085	0.08	B	[1,2]
Round trip efficiency (%)	88%	88%	89%	90%	90%	88%	88%	90%	90%	C	[1]
- Charge efficiency (%)	88%	88%	89%	90%	90%	88%	88%	90%	90%	D	
- Discharge efficiency (%)	~100	~100	~100	~100	~100	~100	~100	~100	~100	E	
Energy losses during storage (% / period)	<1	<1	<1	<1	<1	<1	<1	<1	<1	F	
Auxiliary electricity consumption (% of output – only for heat and gas storage)	<1	<1	<1	<1	<1	<1	<1	<1	<1	J	
Forced outage (%)	0	0	0	0	0	0	0	0	0	I	
Planned outage (weeks per year)	3	3	2	1.5	1	3	3	1.5	0.5	G	[3]
Technical lifetime (years)	25	25	30	30	30	25	25	30	30		
Construction time (years)	0.5	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	3.3	H	[3]
Secondary regulation (% per minute)	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	H	[3]
Financial data											
Specific investment ($\text{M\$}_{2019}$/MWh)	0.068	0.068	0.054	0.032	0.025	0.068	0.068	0.042	0.025		[1]
Compressor component ($\text{M\$}_{2019}$/MWh)	0.036	0.036	0.027	0.013	0.009	0.036	0.036	0.018	0.009		[1]
Type I tanks component ($\text{M\$}_{2019}$/MWh)	0.022	0.022	0.018	0.012	0.011	0.022	0.022	0.016	0.011		[1]
Installation, equipment, manhours ($\text{M\$}_{2019}$/MWh)	0.011	0.011	0.009	0.007	0.005	0.011	0.011	0.008	0.005		[1]
Fixed O&M ($\text{\$}_{2019}$/MW/year)	719	719	599	599	480	719	719	539	360		[1]
Variable O&M ($\text{\$}_{2019}$/MWh)	-	-	-	-	-	-	-	-	-		
Technology specific data (See table in the specific section)											
Gravimetric energy density (kWh/kg)	33.3	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	0.09		
Permeation characteristics for Type I tanks (mol/s/m/MPa$^{1/2}$)	2.84×10^{-27}	2.84×10^{-27}	2.84×10^{-27}	2.84×10^{-27}	2.84×10^{-27}	2.84×10^{-27}	2.84×10^{-27}	2.84×10^{-27}	2.84×10^{-27}		[4]

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 electrolyzer 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. Primary regulation: participation in the frequency regulation, ensuring the balance between production and consumption is restored in the event of frequency deviations. The response time for the primary regulation is 15-30 sec. It is also referred to as Frequency Containment Reserve (FCR).
Secondary regulation: participation in the secondary frequency regulation, ensuring the frequency is brought back to its nominal value after a major system disturbance. It is also referred to as Automatic Frequency Restoration Reserve (aFRR). aFRR is automatically activated after 30 seconds and if the grid imbalance persists after 12.5 minutes, mFRR (Manual Frequency Restoration Reserve) supports or gradually replaces aFRR.
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 is negligible.

Hydrogen pipelines

In an energy system where the production and storage of hydrogen play a meaningful role, it is required to also consider hydrogen transportation. This is because usually hydrogen is not only used only where produced, but it must be moved to connect supply to demand. Hydrogen can be transported using trucks, ships or through pipelines, either developing new infrastructure or using existing natural gas pipeline network. The choice between the different options depends on the distance that must be covered, the scale and the end use [1]. In this chapter, only hydrogen pipelines are considered and some information about this technology is provided.

Whether considering long-distance transmission or local distribution, hydrogen transportation is difficult because of its low energy density. To overcome this issue, it is possible to use compression, liquefaction or mix hydrogen into larger molecules [1]. Nevertheless, building and installing new pipeline infrastructures, including transmission and distribution network, implicate high initial capital costs. The entire hydrogen delivery system consists of conversion components (e.g., liquefaction, compression), transmission and distribution components (e.g., local low-pressure distribution pipelines, long-distance high-pressure transport network) and storage facilities.

The large investment costs constitute the major barrier to such projects, which although are necessary where there is not an existing developed gas network, like in Viet Nam [2].

Gas pipeline system

The overall design of a H_2 pipeline system is the same as a natural gas pipeline network. However, various aspects related to construction, installation and operation are different [7].

A gas pipeline network is divided into four categories, based on their use, as shown in Table 12. Even though the categories are the same as for a natural gas network, the pipeline materials might differ depending on their susceptibility to H_2 embrittlement. Thick, low-strength steel is typically recommended for H_2 pipelines, instead of high-strength steels, which are often used for natural gas transmission pipelines but are more vulnerable to H_2 embrittlement. Main distribution and service pipelines are usually made of low-strength steel of high-strength polyethylene [7].

Table 12. Pipelines categories [7]

Name	Diameter (cm)	Pressure (bar)	Use
Service lines	1-5	1	Deliver gas to residential costumer at low pressure
Distribution pipelines	5-25	2-10	Deliver gas to small industrial plants and costumers
Transmission pipelines	15-120	10-120	Move gas long distances at high pressures
Gathering pipelines	10-30	-	Collect has from production fields and connect to transmission grid

A schematic representation of the future H_2 pipeline transportation system is presented [7].

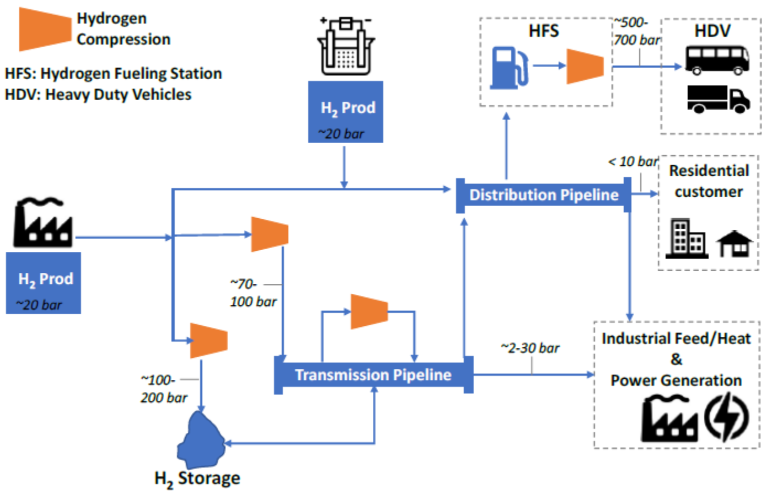

Figure 19. Possible future H_2 pipeline system [7].

Challenges

One of the challenges of operation of H_2 pipelines concerns safety, especially in comparison to natural gas pipelines. Leak management is come complicated, due to H_2 being the smallest molecule known and the related difficulty in containing it. Furthermore, H_2 is highly inflammable especially in dry air. H_2-air mixture are easy to ignite they require 0.017 mJ ignition energy compared to the 0.28 of methane. When H_2 burns in air, it does it in a pale blue, invisible flame which makes it even riskier in case it catches on fire [7].

Overall design, construction and operation of hydrogen pipelines are more challenging than the natural gas pipelines because of the safety issues described above, the embrittlement challenges and hydrogen's low density [7].

Hydrogen pipelines corrosion constitute another challenge. Researchers are still working on developing materials for internal coating to minimize H_2 embrittlement. Another method that is currently being studied is the use of inhibitors (like additive gases) to protect steel from H_2 [7].

Costs

A study from IEA has concluded that the use of pipeline is recommended as cheapest option for distances less than 1.500 km or for distributing large volumes of hydrogen over longer distances [1].

In Table 13, the cost of hydrogen transmission with new infrastructure are listed.

Table 13. Hydrogen transmission costs [6].

	Value	Unit	Comments
New hydrogen pipelines	**1.04 – 3.67**	**M$2019/km**	
New compression	**0.73 – 1.20**	**M$2019/MW**	**MW of installed compression power**
Levelized costs of transportation (LCOT)	**4.6 – 49.8**	**$2019/MWh$_{H2}$ /600 km**	**Discounted costs per MWhH$_2$ transported by the pipeline**

Standards

Few standards have been developed in relation to hydrogen piping and pipeline system. The ASME B31.12 is the American standard that provides the requirement for piping and pipelines to deliver gaseous and liquid hydrogen. It is divided in four parts; the first part is general requirements, followed by the second part which provides information about industrial hydrogen piping system. The relevant part is the third, which provides guidelines on hydrogen pipelines, including details on components, design, installation, and testing. The last part covers the appendices [3].

The Asia Industrial Gases Association (AIGA) has also developed a standard, "Hydrogen pipeline systems", as part of the International Harmonization Council, IHC, which includes members of the Compressed Gas Association, CGA, European Industrial Gases Association, EIGA, and the Japanese Industrial and Medial Gases Association, JIMGA, with the intention to provide information for worldwide use and application [4].

Similarly, the European Industrial Gases Association (EIGA) has developed a publication that contains guidance and practices in relation to the safe design, operation and maintenance of transmission and distribution systems of hydrogen [5].

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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).

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 20 illustrates a plant diagram of two different CAES plants.

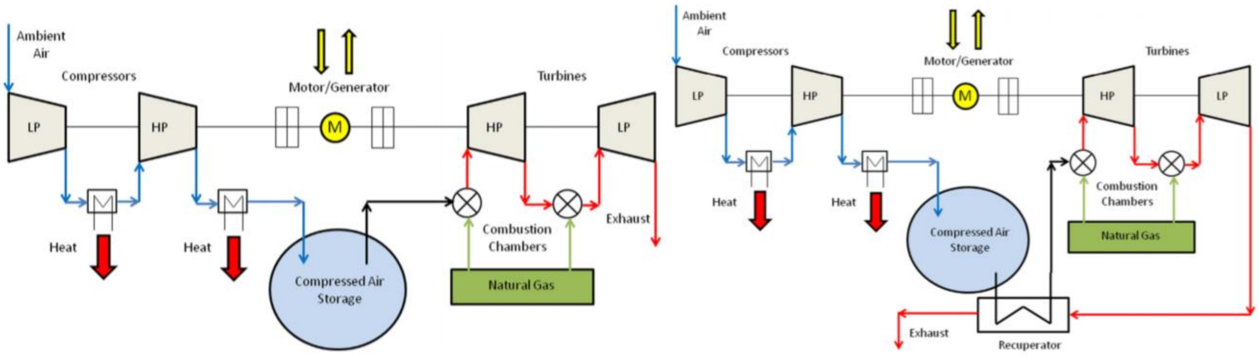

Figure 20: Operating principle of the CAES plant Huntorf (left) and the McIntosh (right) [1]

Table 14 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 14: 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 21.

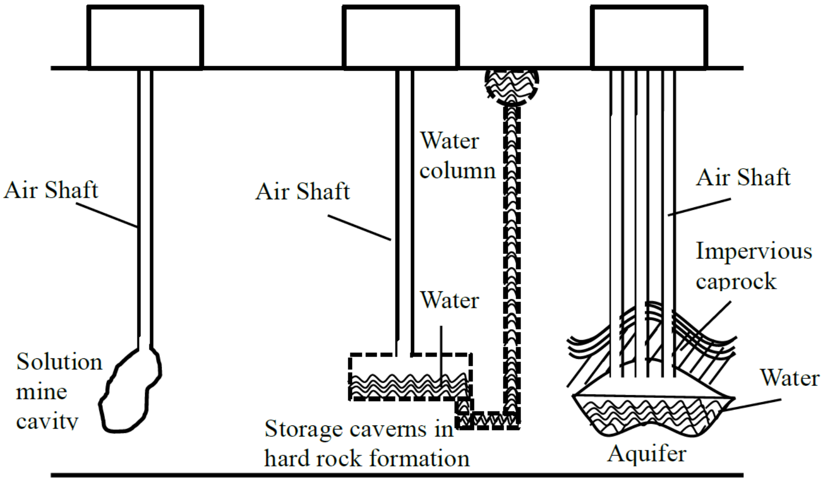

Figure 21: Various Geological Formations for Underground Storage [5]

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 22) [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].

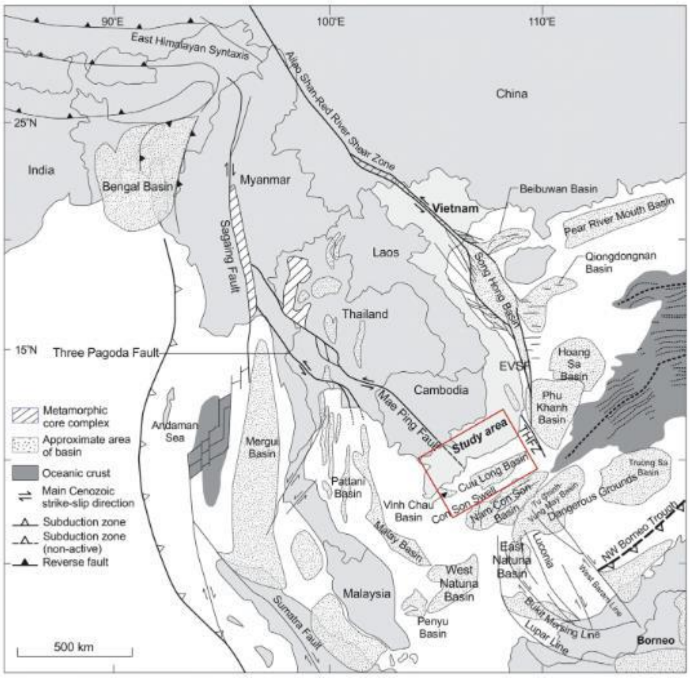

Figure 22. Major structural characteristics for the greater Indo-China area, including the study area [24].

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 efficiency and losses

Figure 23 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 23 would be 44 % leading to a round cycle efficiency of 44 %.

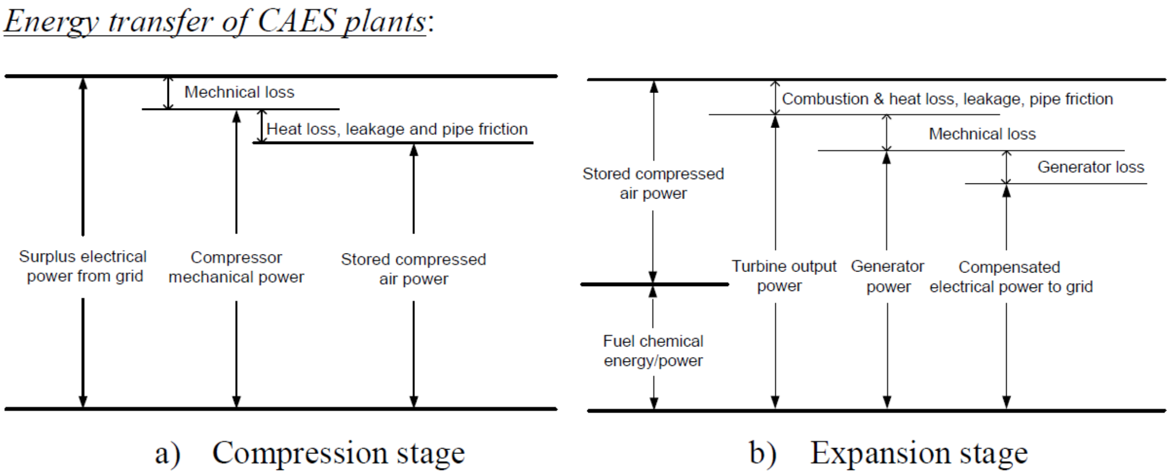

Figure 23: Energy transfer of a conventional CAES plant [7]. The source does not quote numbers but only graphics.

Regulation ability and other system services

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 characteristics and 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 15.

Table 15: 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 24 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.

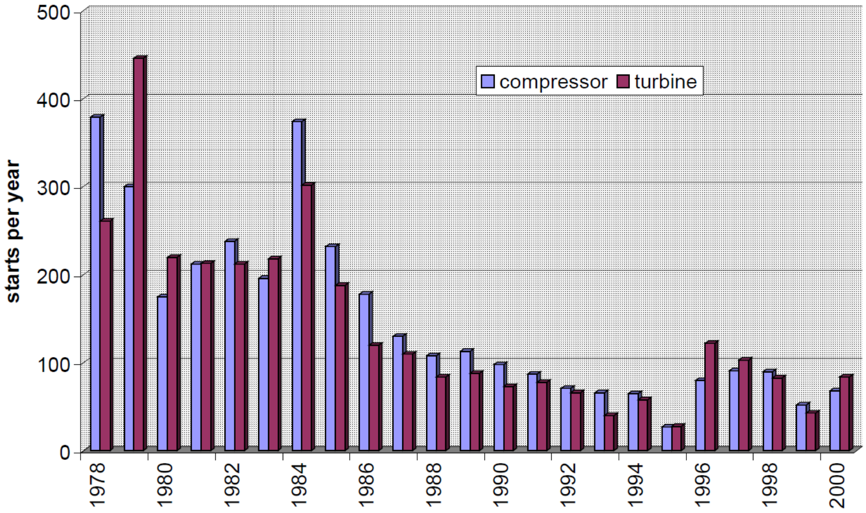

Figure 24: Number of compressor starts (charges) and turbine starts (discharges) for the Huntorf facility for the period between 1978 and 2000 [10].

Space requirement

The space requirement for a CAES facility can be seen from Figure 25 [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.

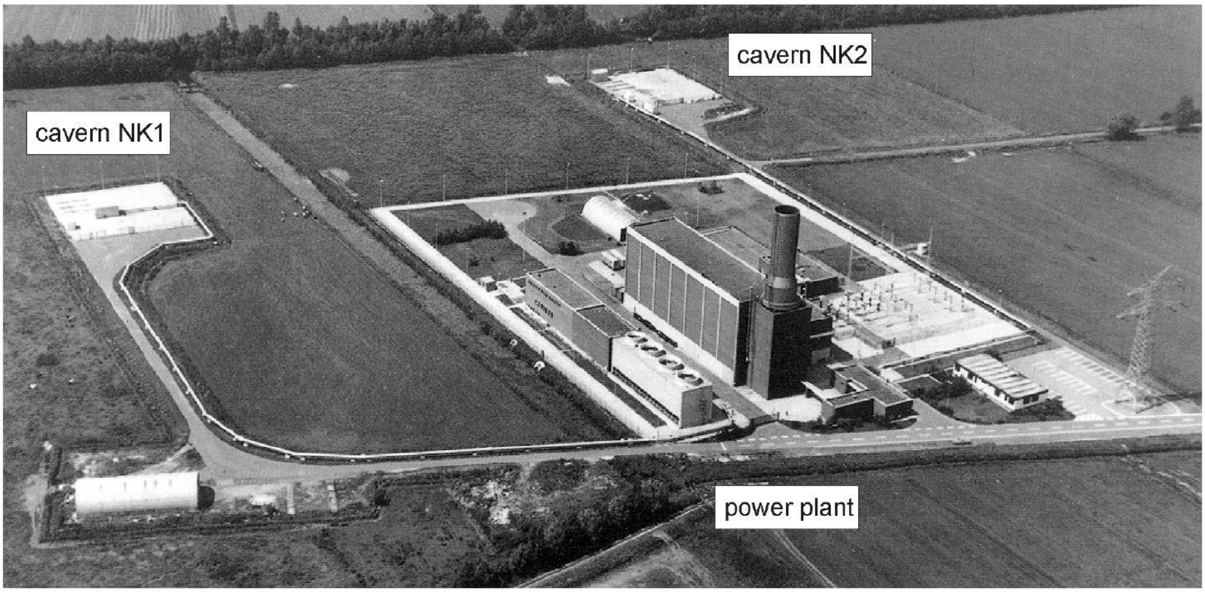

Figure 25: Aerial photo of the Huntorf facility [12].

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.

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.

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 26 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.

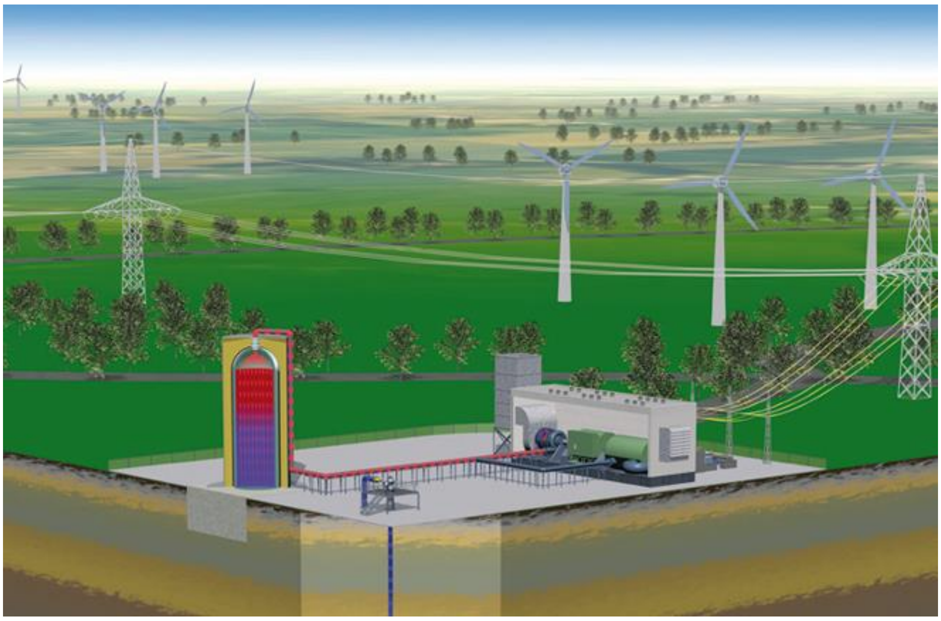

Figure 26: RWE´s vision for an ACAES plant [15].

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 16 [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 16. 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 27 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.

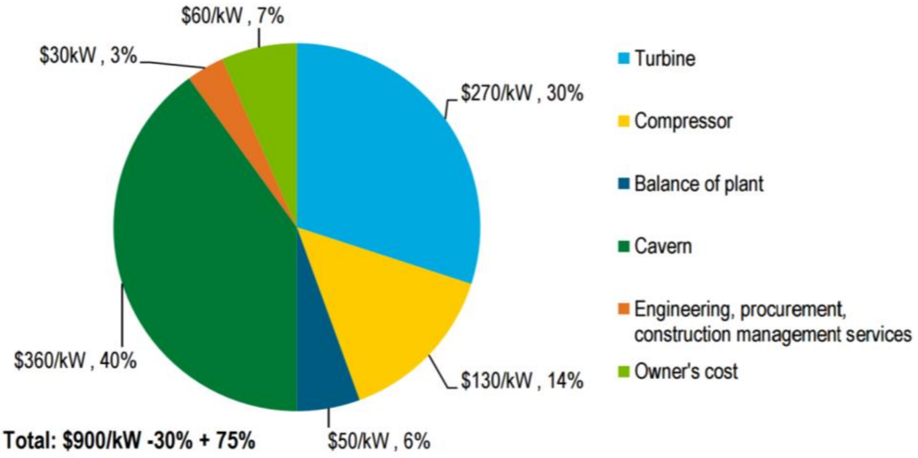

Figure 27: The capital cost breakdown for a CAES plant, approximately 262 MW net with 15 hours of storage and with storage in a solution-mined salt dome is assumed [21].

Investment costs [MUSD$_{2019}$/MW]	Characteristic	2018	2020	2030	2050
This Technology Catalogue			1.04	1.037	0.88
Danish technology catalogue			0.76	0.76	0.76
U.S. Department of Energy 2020 [16]	100 MW – 4h		1.156	1.153	
	100 MW – 10h		1.178	1.172	
	1000 MW – 4h		1.063	1.061	
	1000 MW – 10h		1.083	1.078	
	10000 MW – 4h		0.978	0.976	
	10000 MW – 10h		0.997	0.992	
NREL 2012 [21]	262 MW – 15h		1	1	1
U.S. Department of Energy 2019 [22]	16h	1.70			
NREL 2021 [23]			0.96-1.25		

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].

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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"*. The following sources are used:

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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 2019. 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								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Energy storage capacity for one unit (MWh)	3000	3000	3000	-	-	3000	10000	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	1000	1000	500	1000	800	1200	A, D, E	
Full charge to full discharge (sec)	-	-	-					F	
Financial data									
Specific investment (M$2019/MWh)	0.104	0.104	0.088					A	[16,21,22]
-Energy component (%)	40	40	40					G	[21]
-Capacity component (%)	50	50	50						[21]
-Other project costs (%)	10	10	10						[21]
Fixed O&M ($2019/kW/year)	14.8	14.8	14.8						[16,21,22]
Variable O&M ($2019/MWh)	1.4	1.4	1.4						[16,21,22]
Technology specific data									
Energy storage expansion cost (MUSD/MWh)	0.052	0.052	0.044					H	
Output capacity expansion cost (MUSD/MW)	0.052	0.052	0.044					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”

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:

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

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 28.

Figure 28: 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 29, with the addition of a separate fiber composite flywheel being carried by a forklift.

Figure 29: 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 30.

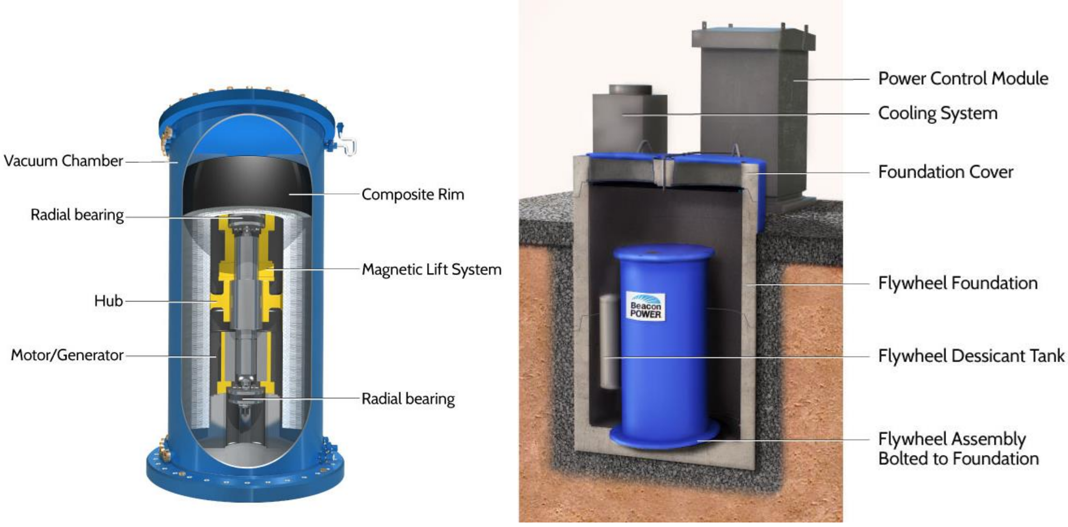

Figure 30: Drawing showing a cross section of the flywheel system and a visualization of how each module of a Beacon flywheel is mounted for operation [6]

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 efficiency and losses

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.

Regulation ability and other system services

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 31.

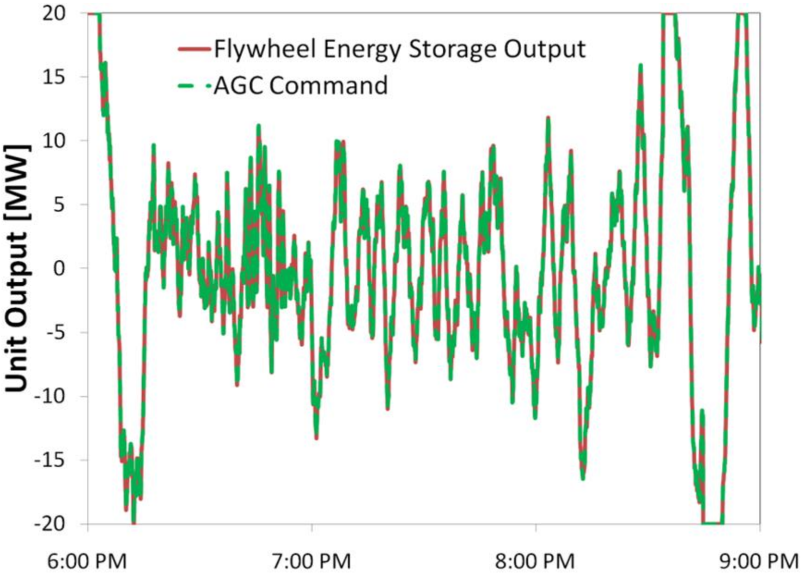

Figure 31: The reaction of a flywheel (MW input/output) in response to signals from the Automatic Generation Control. It can be seen that within the accuracy of the graph (please note the axis scaling) the flywheel follows signals completely. Source: Beacon Power.

Typical characteristics and 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 32 shows a photo of an example of their systems that currently provides 20 MW of frequency regulation service.

Figure 32: 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.

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)

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 17.

Table 17: 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].

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 fibre 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.

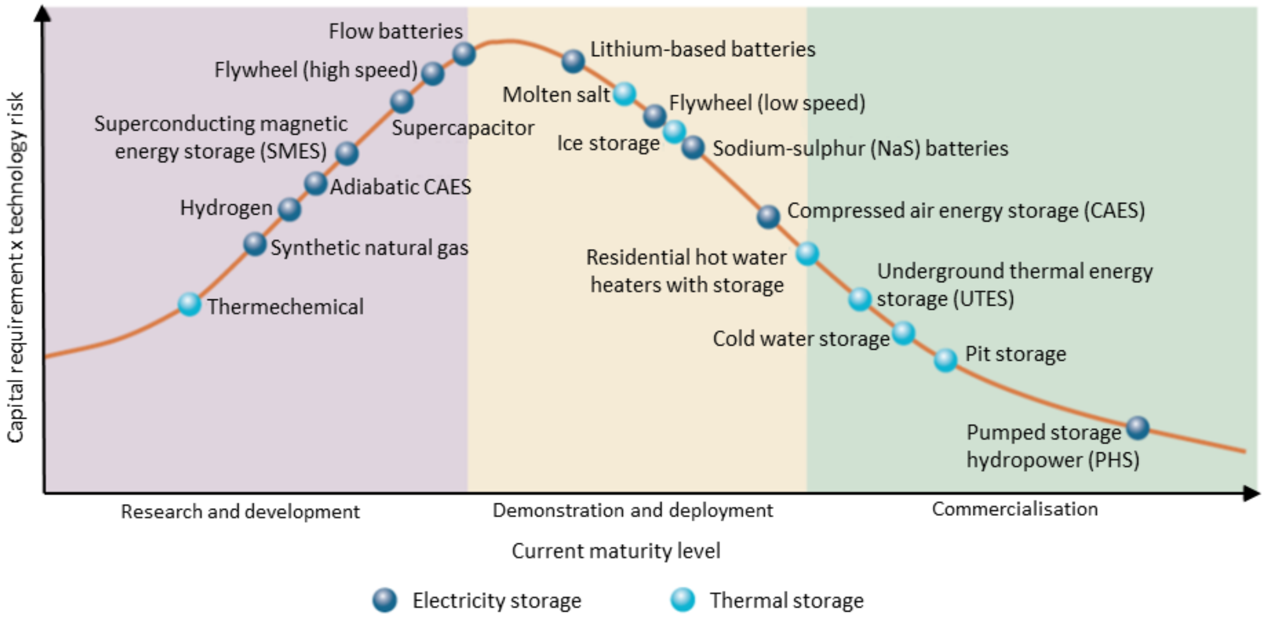

Figure 33: Ranking of energy storage technologies concerning maturity level [11]. Data published in 2013. Flywheels have moved to the next class of the figure since then.

Figure 33 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.

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 34. Furthermore, the authors declared that flywheels 2025 capital costs are assumed the same as estimated in 2018, because they are mature technologies [14].

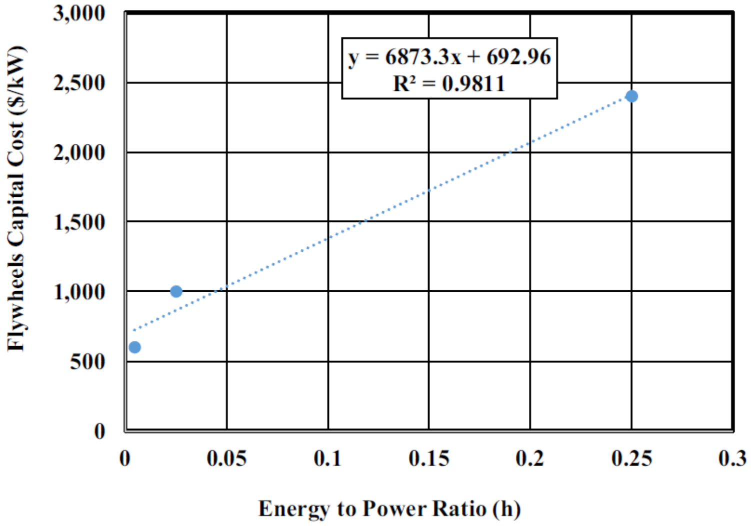

Figure 34. Capital cost by energy to power ration for flywheel energy storage systems [14].

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.

Investment costs [$MUSD_{2019}$/MW]	Characteristic	2018	2020	2030	2050
This Technology Catalogue			1.75	1.64	1.58
Danish technology catalogue	1 MW		0.174	0.163	0.157
Literature [13]	20 MW – composite rotor		1.11		
Literature [13]	20 MW – steel rotor		0.79		
U.S. Department of Energy 2019 [14]	20 MW – 0.25 h	2.93			
NREL 2021 [16]			1.07-2.85		

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 (Figure 35), 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 35. Beacon Power Hazle Township, PA plant 20 MW - 2013

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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".* The following sources are used:

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Data sheets

The following page contains the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. 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.

Technology	**Flywheels**								
US$2019	**2020**	**2030**	**2050**	**Uncertainty (2020)**		**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)	0								
Forced outage (%)	0								
Planned outage (weeks per year)	0								
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	
Specific energy (Wh/kg)	350	350	350	300	400	350	400	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	
Financial data									
Specific investment (M$2019/MWh)	17.5	16.4	15.8					A	[13,14,16]
- Energy component (%)	98.5	98.5	98.5					A, B	
- Capacity component (%)	1.5	1.5	1.5					A, B	
Fixed O&M ($2019/MW/year)	5.7	5.7	5.7						[16]
Variable O&M ($2019/MWh)	0.3	0.3	0.3						[16]

Notes:

A	The starting values are from the Danish TC, 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

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.

7. ELECTROLYSERS

Brief technology description

Electrolysers are used to produce hydrogen gas through the process of water electrolysis. In this process, an electric current is passed through water, splitting the H_2O molecules into hydrogen (H_2) and oxygen (O_2). The reaction is carried out in an electrolysis cell, which contains two electrodes, an anode and a cathode, that are separated by an electrolyte solution. Two of the most mature types are alkaline electrolysis cells (AECs) and polymer electrolyte membrane electrolysis cells (PEMECs), or simply polymer electrolyte membrane (PEM) for short. These two electrolysers will be described and compared in this chapter.

The operating principle for the electrolysis technologies relies on water splitting by electricity (electrolysis) according to the following reaction:

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

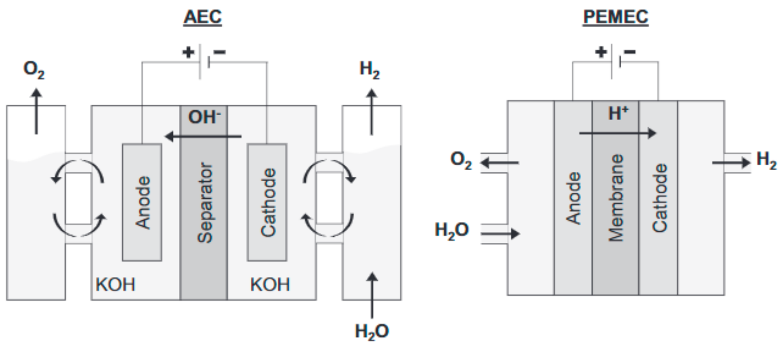

Figure 36: Operating principle of AEC and PEMEC [1].

AECs are the most common electrolysers available commercially. The cell operates at 65-90 °C and can work at either atmospheric pressure or pressurized at up to 35 bars. Experimental AECs are under investigation, which operate at up to 100 bars. The electrodes are typically made up of steel, nickel, or nickel-plated steel.

Furthermore, a separation of the electrode compartments by a micro-porous diaphragm (a porous plate or cylinder responding to pressure difference) is performed to avoid blending of gases. The electrolyte is an aqueous solution of potassium hydroxide (KOH). In Figure 36, operation of AEC is presented. Water is fed to the cathode wherein during electrolysis operation, OH^- ions are transported across the membrane to form hydrogen and oxygen [2].

Reaction at cathode:

$$2H_2O + 2e^- \rightarrow H_2 + 2OH^-$$

Reaction at anode:

$$2OH^- \rightarrow \frac{1}{2}O_2 + H_2O + 2e^-$$

For PEM electrolysis, two electrodes are in contact with a proton exchange polymer electrolyte membrane, typically perfluorosulfonic acid (PFSA), forming a membrane electrode assembly (MEA). Typically, the membranes are catalyst coated and contacted by either expanded metal meshes or carbon or metallic felts. State-of-the-art (SoA) catalysts used commercially have a platinum cathode and an iridium oxide (IrO_2) anode. The reaction takes place by the transport of H^+ ions across the membrane as presented in Figure 36. Water is fed at the anode and hydrogen is formed at the cathode [2].

Reaction at anode:

$$H_2O \rightarrow \frac{1}{2}O_2 + 2e^- + 2H^+$$

Reaction at cathode:

$$2H^+ + 2e^- \rightarrow H_2$$

Input

For both electrolysis technologies, the input is electricity and water. For PEMEC and AEC a high-water purity is desired. The water quality can be determined by the conductivity of the water used, the conductivity should be in the order of 0.2 µS/cm and 5 µS/cm, respectively.

Output

For both electrolysis technologies, the output is hydrogen, oxygen and excess heat from the process [3]. 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 many more. AEC and PEMEC systems are found in the literature to generally have operating temperatures of 50-80 °C and 60-80 °C [4].

Energy balance

An energy balance for both electrolysis technologies, AEC and PEMEC is investigated in this section and presented as Figure 37, 38 and 39.

The energy input in an AEC or PEMEC electrolyser is electricity, which is utilized to power the process of electrolysis, thereby enabling the splitting of water into hydrogen and oxygen. Once water or steam is supplied to the electrolysis cells, formation of H_2 and O_2 takes place along with heat dissipation. An important aspect related to the analysis performed herewith does not consider the latent heat of vaporization of steam in the product. This is performed in order to get an accurate analysis of the usable energy producing by electrolysis. The characteristics of input and output streams are presented in Figure 39 and Table 18.

An important aspect which has not been investigated in this chapter relates to the conversion of hydrogen to chemicals such as ammonia and methanol. These could be the two main energy carriers for Power-to-X transition. Further information about conversion to ammonia and methanol can be found in chapters 2 and 3 of this report.

In this section, energy flow diagrams with the efficiency of conversion to hydrogen and usable heat has been displayed. The hydrogen conversion efficiencies are based on IEA [5], see Table 5. For both AEC and PEMEC, 5% of the energy is estimated to be unrecoverable heat loss [6].

In Figure 2, the energy balance for AEC (2020) is shown, where 66.5% of the output is hydrogen (calculated on LHV basis), and 16.4% is recoverable heat which can potentially be used for applications with a heating demand. Similarly, in Figure 38, the energy balance for PEMEC (2020) is shown, where 58% of the output is hydrogen (calculated on LHV basis), and 26.4% is recoverable heat which can potentially be used for applications with a heating demand.

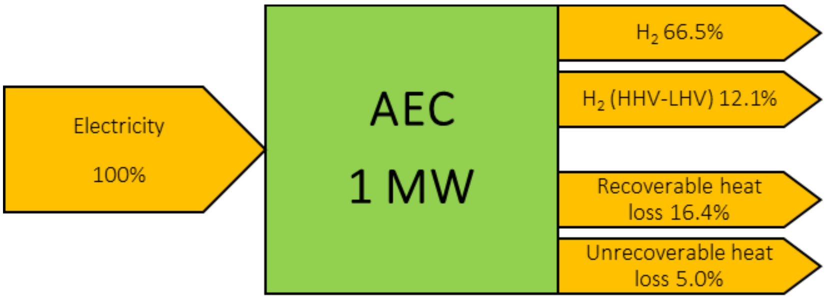

Figure 37: Energy balance (2020) for a 1 MW alkaline electrolysis cell compared on LHV basis.

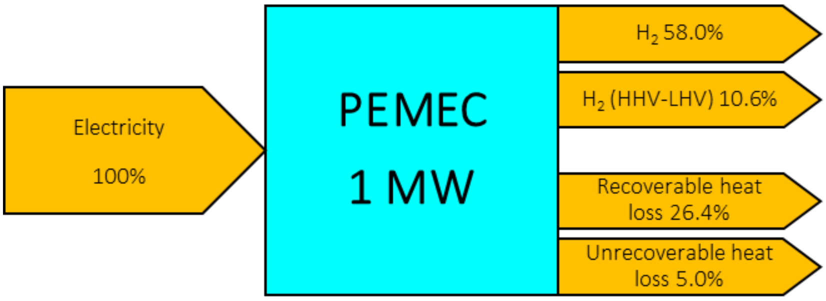

Figure 38: Energy balance (2020) for a 1 MW polymer electrolyte membrane electrolysis cell compared on LHV basis.

System description

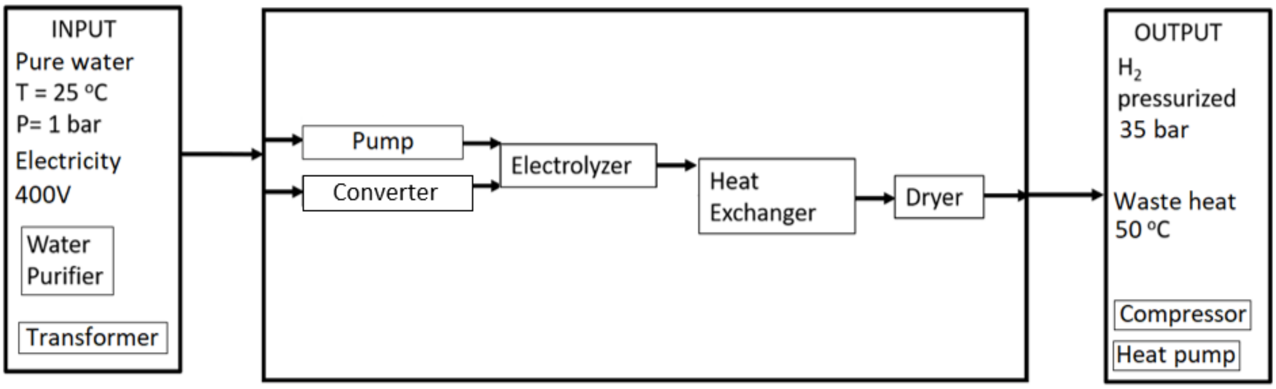

Figure 39: A sketch of an electrolysis system for AEC and PEMEC.

Figure 39 describes the input required, the components in the system, and the output produced for an AEC or PEMEC system. The box on the left shows the required input and two components that are not included in the CAPEX, but which may be required depending on the local water quality and grid level. The box in the middle describes the system that have been analysed. All components in the central box are included in the CAPEX. The box on the right gives the output streams and components that are not included in CAPEX, but which may be required to upgrade the output streams.

In case of AEC, water is fed to the purifier from where it is sent to the AEC module. Herein, the water is compressed using a pump prior to entering the electrolyser stack. Once the electrolysis products are formed, they pass through a heat exchanger, followed by drying of the products prior to being sent for storage. The specifications based on commercially available systems are stated in Table 18 below.

Table 18: Specifications of the standard system (2020) used for analysis.

Technology	AEC	PEMEC
Input temperature and pressure	25 °C, 1 bar	25 °C, 1 bar
Input electricity	400 V_{AC}	400 V_{AC}
Water for electrolysis purity (input)	5 µS/cm	0.2 µS/cm
H_2 purity (output)	99.99	99.99
H_2 output pressure (range)	35 bar (1-35 bar)	35 bar (1-50 bar)
Waste heat temperature (output)	50 °C	50 °C

Typical capacities

By the end of 2022, the global installed water electrolyser capacity for hydrogen production reached almost 700 MW, a 20% increase compared to the previous year [7]. Global installed electrolyser capacity could reach more than 2 GW by the end of 2023 [7]. Based on announced projects, 175 GW could be reached by the end of the decade, and even 420 GW including early-stage projects [7]. NEL Hydrogen ASA, a Norwegian but global company with offices in Europe, North America and Asia, has projects in place for up to 20 MW [8]. In the context of PEMEC systems, Hydrogenics system has a 1.5 MW operational system in Germany [9] and NEL is expected to operate multiple fuelling stations with Nikola with upwards of 1000 MW installed capacity [8]. Siemens has the largest operational PEMEC installation of 3.75 MW consisting of three 1.25 MW electrolysers in Energiepark Mainz [10]. The German electrolyzer manufacturer Sunfire has their largest installation worth 750 kW in Salzgitter, Germany, and plans to establish a 2.5 MW installation at Neste's refinery in Rotterdam, Netherlands. According to the commercially available systems, for AEC and PEMEC, analysis for cost potential is performed on both small- and large-scale systems.

Regulation ability

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

Table 19: Regulation ability [14].

	AEC	PEMEC
Cold start-up time (from 0 to 100%)[minutes]	<120	10 (5-10)
Warm start-up time (from 0 to 100%) [seconds]	240 (60-300)	<10
Power response signal[seconds]	<1 (<1-5)	<1 (<1-5)

Space requirements

Space requirements have been determined based on the commercially available modules. Included in the estimation of space required are the components in the central boxes of Figure 4, excluded are the components in the input boxes on the left and output boxes on the right. Significant increases in the system sizes, compared to the present estimations, are expected if a transformer station or a compressor for delivering high pressure hydrogen (>50 bar) are required, on top of the base system. For alkaline electrolysis, the Danish electrolyzer manufacturer Green Hydrogen Systems was used as a reference which led to an estimation of 10-15 m^2/MW in terms of input electric energy or 0.02-0.03 $m^2/(kgH_2/day)$ in terms of maximal daily hydrogen output (2020). For PEM electrolysis, NEL hydrogen systems were investigated leading to approximately 20 m^2/MW in terms of input electric energy or 0.05 $m^2/(kgH_2/day)$ in terms of maximal daily hydrogen output (2020).

Advantages/disadvantages

In this section, a summary of advantages and disadvantages of AEC and PEMEC are displayed in Table 20. This table highlights the suitability of an electrolysis technology with respect to an application. The data is collected from literature [13].

Table 20: A summary of advantages and disadvantages of the electrolysis technologies investigated.

Technology	Advantages	Disadvantages
AEC	• The technology is very mature and can be adapted to both centralized and decentralized plants. • AEC has a low operating temperature, with a quick start up for response in grid services making it suitable for use as a flexible technology. • Long stack lifetime of more than 100000h currently. • MW scale systems are already being deployed.	• Less flexibility under atmospheric operation. • The use of highly caustic electrolyte in AEC. • Leakage of KOH. • High membrane resistance. • Low maximum operational current density, nominally operated around 0.6 A/cm^2 [16].
PEMEC	• PEMEC has a low operating temperature, low noise, high power density. • Quick response times • Pressurized hydrogen can be produced for direct storage without compression; however, it is challenging. • Current densities >1.0 A/cm^2 can be used for operational systems leading to compact system sizes. • MW scale systems are already being deployed in a global context.	• The process requires high purity water • Lifetime of the SoA system is still uncertain. • Catalyst used in electrode layers are expensive and scarce. • PEMEC modules are expensive due to catalysts and bipolar plates (oxide resistant stack elements). • Cost efficient water treatment and drying the hydrogen at high pressure is still challenges to be addressed.

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 anode, the cathode, as well as the catalyst layer are usually nickel-based which is not a scarce resource. 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 cathode, and iridium, ruthenium and their alloys for anode are scarce in nature leading to a possible hurdle in long-term operation of SoA PEMECs [17].

Research and development

For AECs, the main challenge is related to the resistance and temperature stability of the diaphragm. Currently the diaphragm is also limiting the operation temperature of the alkaline electrolysers, therefore, research is being carried out to improve the temperature stability of the diaphragm by experimenting with various polymer substitutes. Additionally, extensive research is being conducted into improving the AEC catalyst as there is a significant room for improvement with respect to catalyst performance. Solid membranes have also been researched. Solid membranes are called AEMECs, as described earlier [18].

For PEMEC, stack cost is the major hurdle to commercialization of large-scale system. 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. Both PEMECs and AECs are expected to aid with the H_2 fuelling market as envisioned in Europe.

One of the key aspects to enable commercialization of electrolyser stacks deals with the durability of cells. According to Green Hydrogen Systems AEC stacks have a very long lifetime of over 100,000 hours (2020), PEMECs stacks can be operational for a reasonable operational lifetime of over 25,000 hours (2020) and the lifetime of PEMEC cells are expected to increase to 50,000 hours within a few years.

Combination of electrolysis technologies has also been suggested for research. However, given the difference in lifetime of technologies as well as sensitivity to impurities in water input, AEC tends to be a superior choice when combined with pressurized setup and when the excess heating can be utilized in other processes. However, this is solely dependent on application and each technology has its advantages when operated under certain set of conditions.

The market for electrolysers has for years been dominated by a few legacy providers of – primarily – large (footprint and capacity) atmospheric electrolysers delivered to a relatively limited and stable market for industrial hydrogen applications.

All of abovementioned efforts are aimed at making the technologies scalable both as decentralised and centralised systems to have sufficient hydrogen available for various applications. Electrolyser plants are now being subjected to MW scale for AECs and PEMECs. Reduction in price, availability of material, regulation ability as well as efficiency enhancement are being addressed to facilitate large-scale implementation of electrolysers for hydrogen production [21].

Investment cost estimation

To estimate the investment cost of electrolysers in Viet Nam different sources has been assessed. The Danish technology catalogue is based on international data, built on reports from IEA [24], HyEurope [21], IRENA [25] and input from the industry (AEC: Everfuel, Green Hydrogen Systems and NEL. PEMEC: Green Hydrogen Systems and Siemens) and is therefore expected to be applicable for the expected cost in Viet Nam. The data is compared with additional cost data from IRENA.

13 studies estimating learning curves was visited in [19] showing that most studies estimate the learning curve for electrolysers to be between 16-21%, with a mid-estimate at 18%. For AEC studies have found the learning curve to be 18% [1], 18% [26] and 9% [27]. While the learning rate of PEMEC fuel cells is found to be 19.1-21.4% [28], 18% [1], 16% [29] and 13% [27].

Assuming a 16% learning rate would imply that the total amount of units produced would have to double four times (16-fold increase) for the price per unit to drop by 50%. Due to the expected deployment, a 50% decrease of the 2020 unit price is expected to occur by 2040 for both AEC and PEMEC, indicating that the total amount of units produced 2040 will have doubled four times compared to the total amount of units produced by 2020. The total amount of AEC ever produced by 2014 was found to be 20 GW, much of it being deployed in the period from 1956 to 2005 [30] (See Supplementary Figure 2 in [30]). According to Wood Mackenzie the cumulative installed electrolyser capacity in the period from 2000 to 2019 is 253 MW [31]. Assuming 20 GW is produced until 2020, then doubling the cumulated capacity four times would lead to 320 GW having been produced by 2040. Under the Sustainable Development Scenario IEA predicts that the active global electrolyser capacity will be about 500 GW by 2040, a huge increase from about 170 MW active in 2019 [32]. A 50% decrease in price thus seems likely, if governments take the major actions required to fulfil the Sustainable Development Scenario.

As small and large electrolyser systems are built from the same building blocks the difference in CAPEX is expected to be small. Decreases in CAPEX are therefore expected to come from an increase in the number of units produced, rather than an increase in the size of the systems deployed.

AEC

It's worth noting that AEC electrolysers are generally considered to be less expensive than PEMEC electrolysers due to their simpler design and use of lower-cost materials. However, PEMEC electrolysers are often preferred for their greater flexibility in terms of operating conditions.

Investment costs [USD$_{2019}$/kW input_e]	**2020**	**2030**	**2050**
This Technology Catalogue – 100 MW	**734**	**508**	**282**
Danish technology catalogue 2021 (1 MW)	846	643	395
Danish technology catalogue 2021 (100 MW)	734	508	282
IRENA 2020 (1 MW) [19]	1050		
IRENA 2020 (10 MW) [19]	600		
IRENA 2020 (100 MW) [19]	450		
IRENA 2019 (no Capacity defined) [24]	500-1400	400-850	200-700 (long term – not specified as 2050)

PEMEC

Investment costs [USD_{2019}/kW]	2020	2030	2050
This Technology Catalogue – 100 MW	**1044**	**733**	**452**
Danish technology catalogue 2021 (1 MW input_e)	1044	733	452
Danish technology catalogue 2021 (100 MW input_e)	1044	733	452
IRENA 2020 (1 MW) [19]	1150		
IRENA 2020 (10 MW) [19]	750		
IRENA 2020 (100 MW) [19]	500		
IRENA 2019 (no Capacity defined) [24]	1100-1800	650-1500	200-900 (long-term – not specified as 2050)

Examples of current projects

This section provides an overview of current green hydrogen projects. The focus is on identifying projects of particular relevance to Viet Nam, with a particular emphasis on Vietnamese and other Asian initiatives. Given the relatively limited number of projects globally and the scarcity of available data, selected European projects have also been included, as they are believed to be useful for gaining insights into the current state of the technology.

In Viet Nam

The Tra Vinh Green Hydrogen Manufacturing plant [22, 23] proposed by The Green Solutions Corporation will be located in Dong Hai commune, Duyen Hai district, Tra Vinh province with total capacity of 240 MW (12 modules x 20 MW) and estimated land use of 21 ha, expect to operate from 2025. The project is under development and has not yet been approved. The plants produce H_2 by electrolysis of water. The input of plant will be electricity from solar power plant and wind power plant in Mekong delta region and the output will be about 28,000 tons of H_2 per annum and 195,000 tons of O_2 per annum. The number of employees during construction and operation is estimated from 600 – 1500 employees.

Indonesia

Pertamina, an Indonesian oil and gas company, has recently initiated a new project aimed at producing green hydrogen using geothermal energy. The project is located in Ulubelu on Sumatra. The company intends to conduct a trial production of green hydrogen, with an estimated output of approximately 100 kilograms per day. If the pilot project proves to be successful, Pertamina aims to expand the capacity of the project to approximately 1 ton per day of hydrogen production over the next five years. [36]

The French HDF Energy is developing a green hydrogen project in Sumba, Indonesia. The project aims to store electricity from solar power by producing hydrogen in electrolysers (the type of electrolyser is not specified) and store it in hydrogen storages. The hydrogen is then supposed to be used to follow the peak demands using fuel cells. [37]

China

Ningxia Baofeng Energy Group has commissioned a new large green hydrogen project in central China’s Autonomous Region Ningxia. The project combines 200 MW PV with 150 MW of electrolysis, expected to have an hourly hydrogen production on 30,000 Nm^3/h [38].

As per Chinese sources, construction of the largest green hydrogen production facility in the world, with a capacity of 20,000 tons of hydrogen per annum, is underway in Kuqa County (Kucha) located in the southern part of the Xinjiang Uygur Autonomous Region. This facility will be supported by a 300 MW PV and has a capacity of 52,000 Nm^3/h of electrolysers.

It is projected that the enterprise will decrease greenhouse gas emissions in China by approximately 500,000 tons per year. [39]

It is estimated that the cost of producing one kilogram of hydrogen at the facility will be approximately 18 yuan or $2.67 USD. [39]

Europe

Iberdrola has recently inaugurated the most extensive industrial-scale green hydrogen production plant in Europe, located in Puertollano, Spain. This plant is composed of three major elements: a 100 MW photovoltaic solar facility, a lithium-ion battery energy storage system with a capacity of 20 MWh, and one of the most extensive electrolytic hydrogen production systems worldwide, with a 20 MW capacity. Estimated investment cost 160 mill. $ (incl. cost for renewable energy production) [35].

In Wesseling, Germany there is a 10 MW PEMEC plant producing 1,300 tons H_2/year.

Most other electrolyser plants are small scale on test level, e.g., in Avedøre, Denmark there is a small (2 MW) AEC plant from 2016 producing approx. 100 Nm^3/hour.

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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"*. The following sources are used:

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Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. 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.

Technology	**Hydrogen production via alkaline electrolysis (AEC) for 100MW plant**								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Typical total plant size (MW input_e)	100	100	100	100	100	100	100		
Typical total plant size (kgH_2 / day of max output)	47880	48960	54000	45360	50400	50400	57600	L, E	
- Inputs									
Electricity (% total input (MWh / MWh))	100	100	100	100	100	100	100		
Water for electrolysis (kg / MWh input_e)	180	184	203	170	189	189	216		
- Outputs									
Hydrogen (% total input_e (MWh / MWh))	66.5	68.0	75.0	63.0	70.0	70.0	80.0	B	[24]
ΔE from HHV to LHV (% total input_e (MWh / MWh))	12.1	12.4	13.7	11.5	12.7	12.7	14.6	M	
Heat loss (% total input_e (MWh / MWh))	21.4	19.6	11.3	25.5	17.3	17.3	5.4		
- hereof heat loss (%-points of heat loss)	21.4	19.6	11.3	25.5	17.3	17.3	5.4	A, K	
Hydrogen (kg / MWh input_e)	20.0	20.4	22.5	18.9	21.0	21.0	24.0	B	[24]
Forced outage (%)	2	2	2	2	2	2	2	C	
Planned outage (days per year)	2	2	2	2	2	2	2	C	
Technical lifetime (years)	25	30	35	25	25	30	35	C, J	[33]
Construction time (years)	0.33	0.33	0.33	0.33	0.33	0.33	0.33	C, N	
Financial data (2020 price level)									
Specific investment ($ / kW of total input_e)	734	508	282	425	850	160	425	D, I	
Specific investment ($ / kgH_2 / day of max output)	1533	1038	522	937	1687	317	738	E, I, L	
- hereof equipment (%)	90	90	90	90	90	90	90	F	
- hereof installation (%)	10	10	10	10	10	10	10	F	
Fixed O&M (% of specific investment / year)	2	2	2	2	2	2	2	G, I, J	[28]
Technology specific data									
Current Density (A / cm^2)	0.6	1.0	1.5	0.4	0.6	1.2	1.5	H	[21]
Footprint (m^2 / MW input_e)	12.5	10.0	7.5	10.0	15.0	5.0	10.0	H	[21]

Notes:

A. 3% of the energy is estimated to be unrecoverable for large plants.

B. Values are from Table 5 in IEA [24], Today is understood as 2020, Long-term is understood as 2050 and the value selected is the mid of the range given.

C. According to the Green Hydrogen Systems.

D. CAPEX values from interviews with GHS, Everfuel and NEL and reports from IEA [24], HyEurope [21] and IRENA [24]. The values in the datasheet correspond to a fitted curve see figure 6 in the catalogue. For IEA today is taken to be 2020, Long term is taken to be 2050 and values is the middle of the range given.

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

F. These are rough estimates based on operational AEC systems as provided by the Green Hydrogen Systems.

G. O&M is estimated as 2% of CAPEX for large systems. According to the 2-5% given for large to small scale systems from [26].

H. The values are predicted until 2050 with a high margin of uncertainty.
I. The CAPEX includes all components required for converting 400VAC electricity and purified water into H_2 gas at 35 bar and a waste heat stream at 50 °C. CAPEX does not include transformer, water purifier, heat pumps for increasing the temperature of waste heat stream or compressors for increasing the pressure of H_2 further than 35 bar. The tariffs, capacity payments and network connection fees to DSO / TSO are not contained in CAPEX nor in O&M
J. The lifetime of current AEC stacks is more than 100 000 hours according to Green Hydrogen Systems. Assuming that the facility is run for 4000h pr year, the stacks do not need replacement in the technical lifetime. If the full load hours exceed the 100,000h lifetime, then the stack replacement cost will be 30% of the CAPEX cost of a new system in the year of replacement. Everfuel gives a stack replacement of 30% of CAPEX and GHS informs that 30% of current CAPEX is stack cost. The cost of replacing the stack is not included in fixed O&M.
K. 50°C (expected to increase to 70°C, by 2024).
L. Maximum hydrogen output per day, assuming 24 hours of full load operation in a day.
M. The price of the input streams (water and electric energy), has not been estimated.
N. The HHV electolyser efficiency can be calculated as the sum of the rows: "ΔE from HHV to LHV" and "Hydrogen".
O. From the time of purchase to finished construction.

Technology	**Hydrogen production via PEMEC electrolysis for 100MW plant**								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Typical total plant size (MW input_e)	100	100	100	100	100	100	100		
Typical total plant size (kgH$_2$ / day of max output)	41760	47160	50760	43200	46080	48960	50400	L, E	
- Inputs									
Electricity (% total input (MWh / MWh))	100	100	100	100	100	100	100		
Water for electrolysis (kg / MWh input_e)	157	177	190	162	173	184	189		
- Outputs									
Hydrogen (% total input_e (MWh / MWh))	58.0	65.5	70.5	60.0	64.0	68.0	70.0	B	[24]
ΔE from HHV to LHV (% total input_e (MWh / MWh))	10.6	11.9	12.8	10.9	11.7	12.4	12.7	N	
Heat loss (% total input_e (MWh / MWh))	31.4	22.6	16.7	29.1	24.3	19.6	17.3		
- hereof unrecoverable heat loss (%-points of heat loss)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	A	
- hereof recoverable for district heating (%-points of heat loss)	28.4	19.6	13.7	26.1	21.3	16.6	14.3	K	
Hydrogen (kg / MWh input_e)	17.4	19.7	21.2	18.0	19.2	20.4	21.0		[24]
Forced outage (%)	2	2	2	2	2	2	2	C	
Planned outage (days per year)	2	2	2	2	2	2	2	C	
Technical lifetime (years)	20	25	30	20	20	25	30	C, J	[33]
Construction time (years)	0.33	0.33	0.33	0.33	0.33	0.33	0.33	C, O	
Financial data (2020 price level)									
Specific investment ($/ kW of total input_e)	1044	733	452	745	1330	320	530	D, I	
Specific investment ($ / kgH$_2$ / day of max output)	2500	1554	890	1724	2886	654	1051	E, I, L	
- hereof equipment (%)	90	90	90	90	90	90	90	F	
- hereof installation (%)	10	10	10	10	10	10	10	F	
Fixed O&M (% of specific investment / year)	4	4	4	4	4	4	4	G, I, J	
Technology specific data									
Current Density (A / cm^2)	2.2	3.5	4.0	2.2	2.2	3.2	4.0		[21]
Footprint (m^2 / MW input_e)	20.0	20.0	20.0	20.0	20.0	20.0	20.0	H	

Notes:

A. 3% of the energy is estimated to be unrecoverable for large plants.

B. Values are from Table 5 in IEA [24], Today is understood as 2020, Long-term is understood as 2050 and the value selected is the mid of the range given.

C. According to the Green Hydrogen Systems (GHS).

D. CAPEX values from interviews with GHS and Siemens and reports from IEA [24], HyEurope [21] and IRENA [25]. The values in the datasheet correspond to a fitted curve see figure 6 in the catalogue. For IEA today is taken to be 2020, Long term is taken to be 2050 and values is the middle of the range given.

E. 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.

F. These are rough estimates based on existing systems according to GHS.

G. O&M is estimated as 4% of CAPEX. 2%-point is for small systems, according to the 2-5% given for large to small scale systems from [26]. 2%-points is the estimated stack replacement cost. Everfuel and GHS report that the 30% of CAPEX is stack cost. At about 4000 full load hours per year, stacks are likely to be replaced twice during the technical lifetime.

H. This value is fixed due to no increase in research in increasing the pressure of PEMEC systems.

I. The CAPEX includes all components required for converting 400VAC electricity and purified water into H_2 gas at 35 bar and a waste heat stream at 50 °C. CAPEX does not include transformer, water purifier, heat pumps for increasing the temperature of waste heat stream or compressors for increasing the pressure of H_2 further than 35 bar. The tariffs, capacity payments and network connection fees to DSO / TSO are not contained in CAPEX nor in O&M

J. The lifetime of current PEMEC stacks is more than 25000 hours and in the future, it could be more than 50000 hours according to Green Hydrogen Systems.

K. 50 °C (expected to increase to 70°C, by 2024).

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

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

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

O. From the time of purchase to finished construction.

8. 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 40).

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.

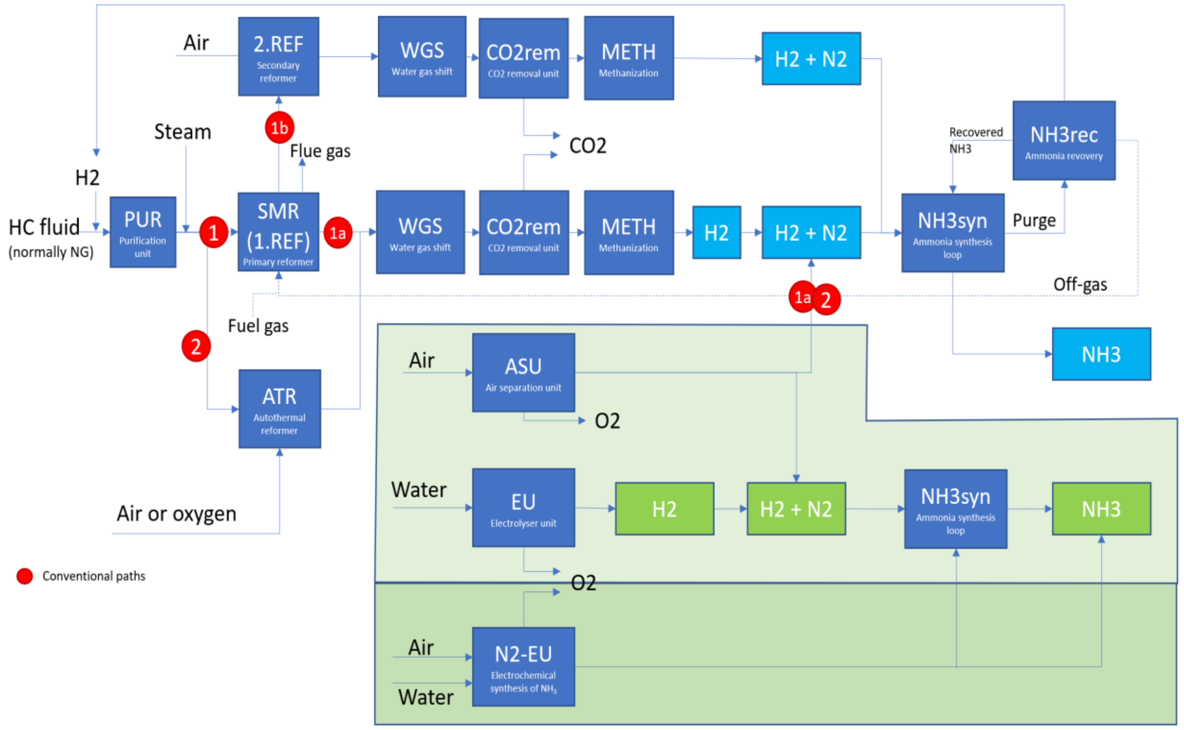


Figure 40: Different pathways for production of NH_3. The light green area is the green NH_3 production part that is covered within this Technology Catalogue. The darker green area marks a potential future route (electrochemical). The white background shows the three conventional parts, i.e. 1a) SMR+ASU, 1b) SMR+2.REF and 2) ATR+ASU

Different production routes to ammonia, i.e., both conventional and green paths, are given in Figure 40.

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

1) Conventional – grey NH_3

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

Figure 41 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 (see Figure 40).

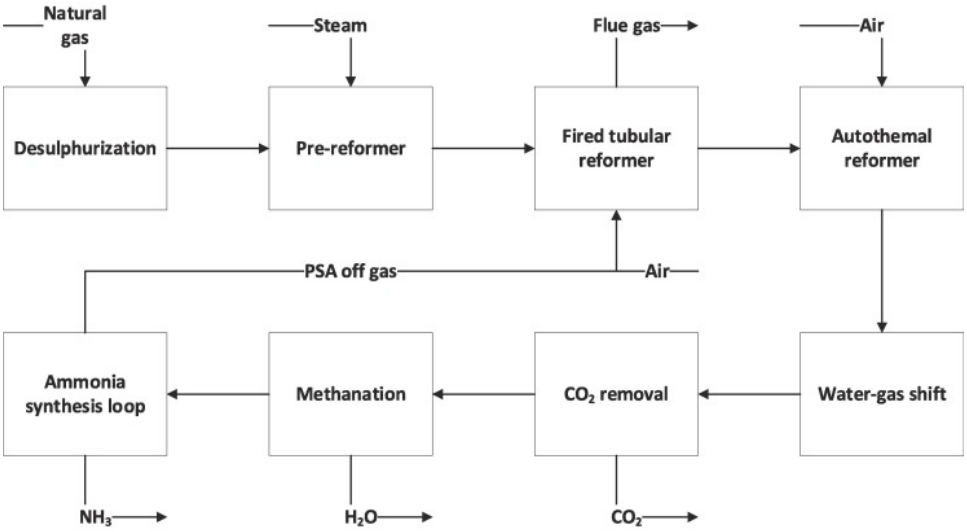


Figure 41: Conventional ammonia plant (Ref. 20)

2) 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.

3) Electrolysis – green NH_3

A green ammonia plant uses green hydrogen produced via electrolysis to feed the ammonia synthesis loop (see Figure 42). The electrolysis shall be powered with renewable energy such as solar or wind power.

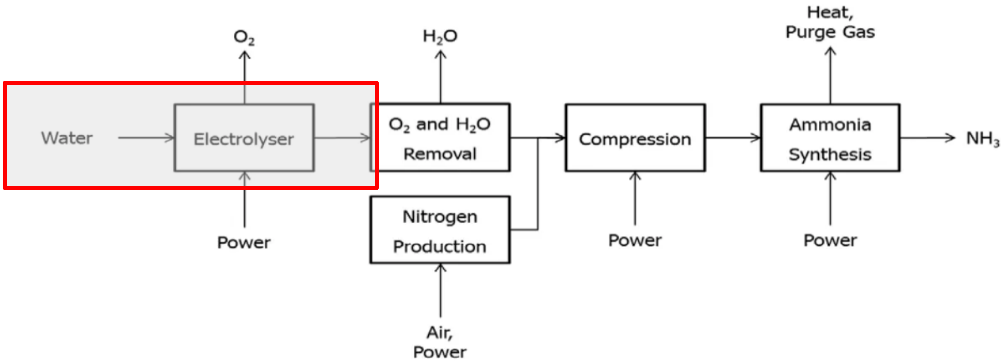


Figure 42: Green ammonia plant. Any impurities of O_2 in the H_2 product is removed by reacting it with H_2 over a DeOX (de-oxygenation unit).

4) 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)).

Typical outlet conditions	
Temp.	1000-1100 °C
Pres	20-50 barg
CH4	< 0.5 dry %
CO	15 dry %
CO2	5-10 dry %
H2	50 dry %
N2	25 dry %
Ar	< 0.5 dry %

Process steps

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

1) 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:

$$\text{R-S} + 1.5\ \text{H}_2 \xrightarrow[300-450\ ^\circ\text{C}]{\text{Catalyst}} \text{R-H} + \text{H}_2\text{S}$$

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

2) Steam methane reforming (SMR)

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

$$C_nH_m + nH_2O \Rightarrow nCO + (n+1/2m)\ H_2 - Q$$
$$CH_4 + H_2O \Rightarrow CO + 3H_2 - Q$$
$$CO + H_2O \Rightarrow CO_2 + H_2 + Q$$

Typical outlet conditions	
Temp.	800-920 °C [3]
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 %

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.

3) Secondary reformer (2. REF)

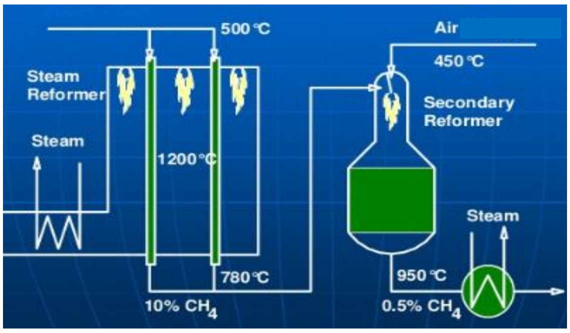


Figure 43: Primary and secondary reformer arrangement

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:

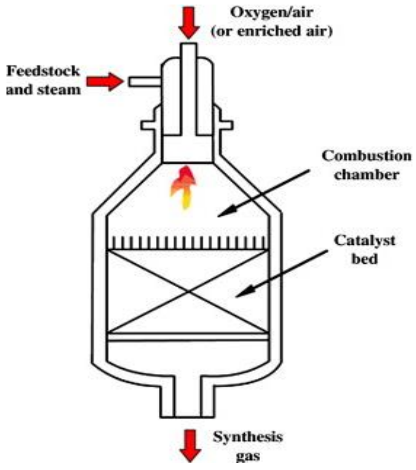
---

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

$$CH_4 + ½ O2 => CO + 2H_2$$

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.

4) 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 44: Autothermal reformer (ATR)

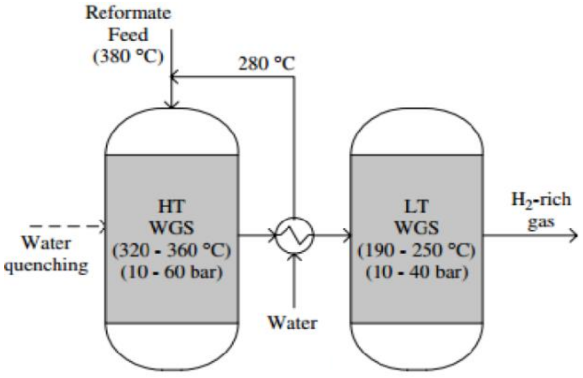
Like SMR, ATR can be used to convert hydrocarbon feed into a hydrogen rich syngas. Within ATR, heat for the reforming reaction is provided by burning part of the syngas inside the reactor commonly with pure oxygen. This gives the following reaction scheme:

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

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

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.

5) 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 45: 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 (see Figure 45). A conventional ammonia plant typically includes a high temperature shift (HTS) and a low temperature shift (LTS).

6) CO_2 removal unit (CO_2rem)

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.

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 %

7) 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 %

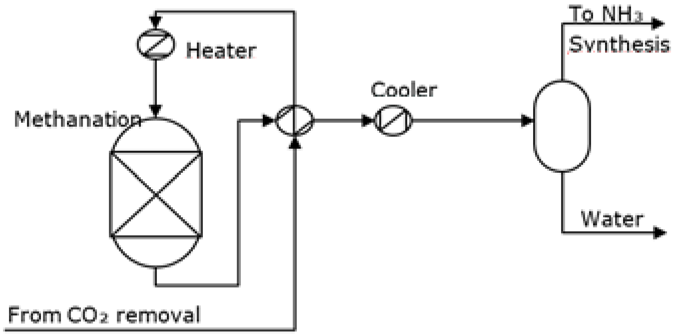


Figure 46: Methanization, cooling and water separation

8) Ammonia Synthesis (NH3syn)

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.

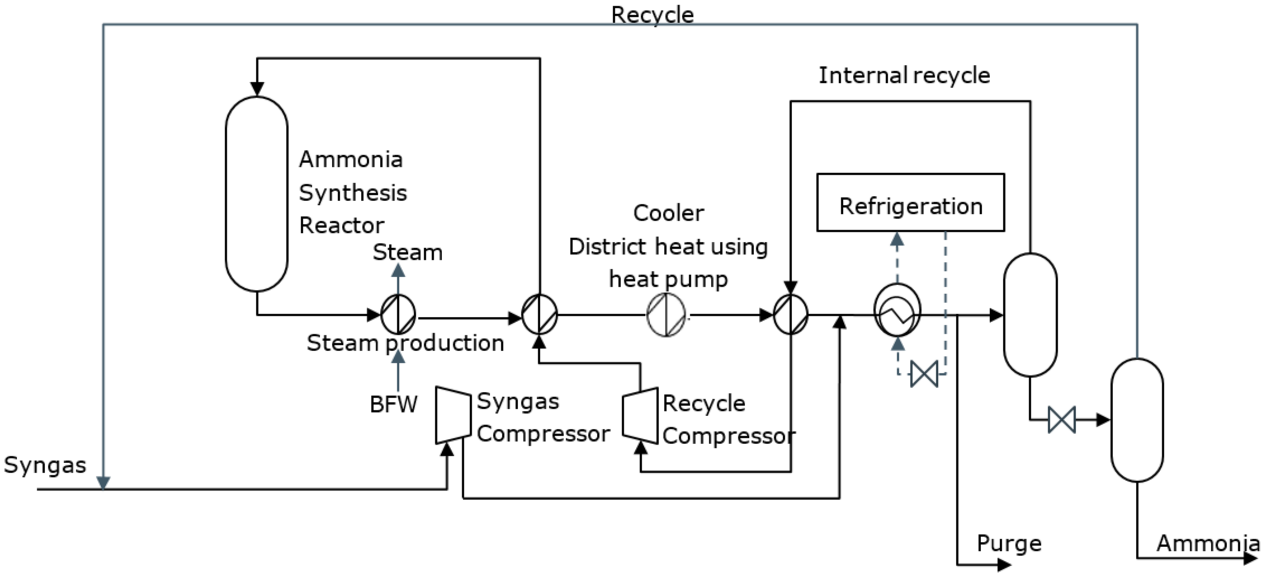


Figure 47: Ammonia synthesis loop and downstream purification

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

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.

9) Electrolysis

For electrolysis reference is made to the dedicated catalogue chapter "Electrolysers"

10) 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 48 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).

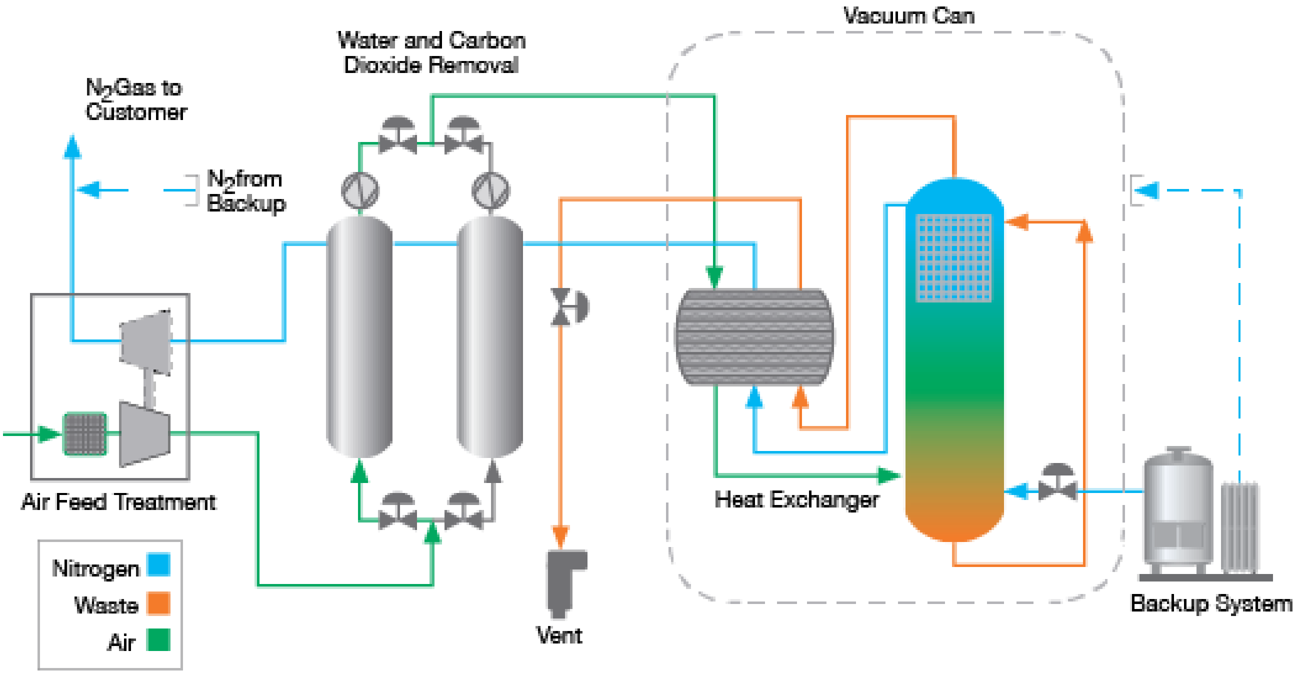


Figure 48: Schematic flow diagram of nitrogen plant. Source: AIChE

11) 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. Some key paths are summarized in Figure 49. 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].

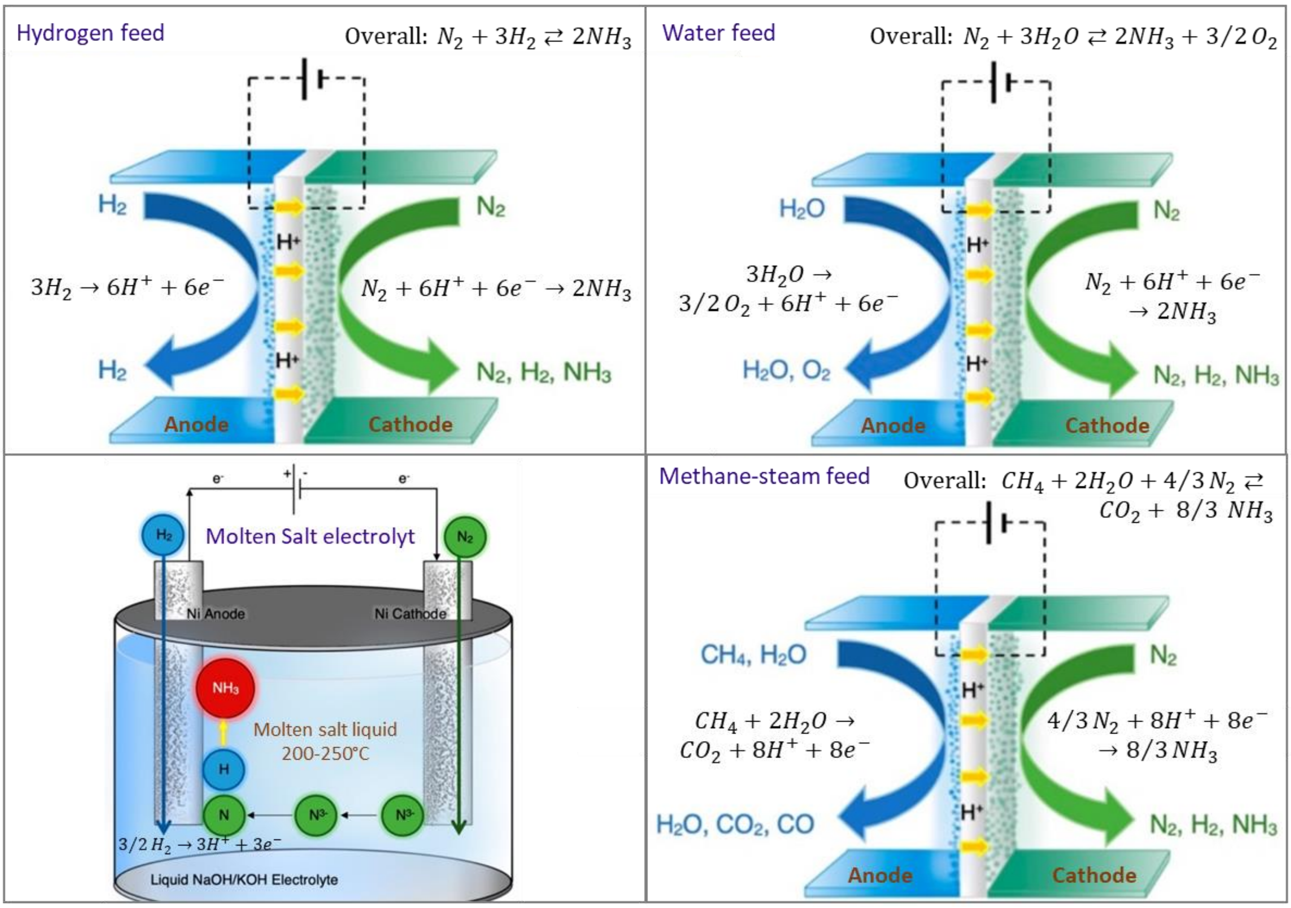


Figure 49: Illustration of the anode and cathode reactions during electrochemical NH_3 production. [1]

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

1) 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.

2) 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)[4]. 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.

3) 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.

4) 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.

5) 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 fulfill 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 fulfill 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.

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 show the thermal and physical properties of gaseous ammonia:

---

[4] 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)

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

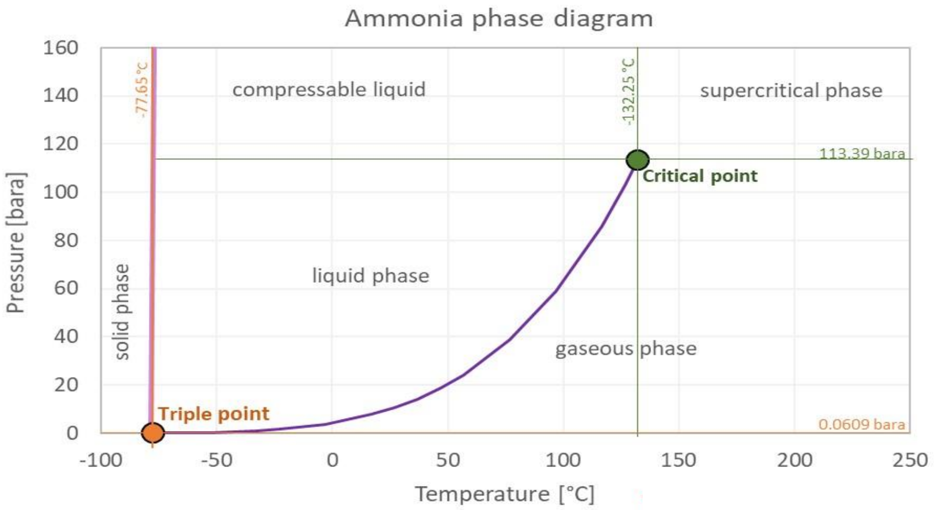


Figure 50: Ammonia phase diagram

Input

The input and output subsections give an overview of inputs and outputs of an ammonia synthesis in energy (e.g. MWh).

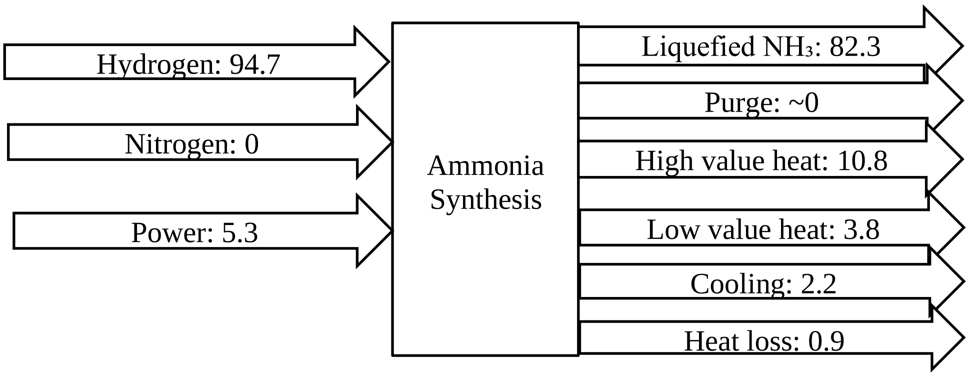


Figure 51: Overall energy balance of the ammonia synthesis. The electrolysis unit is covered in [4] and power required for the ASU is listed in Table 21.

The input to the ammonia synthesis loop is hydrogen, nitrogen and power as shown in Figure 51. 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 (see Figure 47).

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 51. 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 52 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.

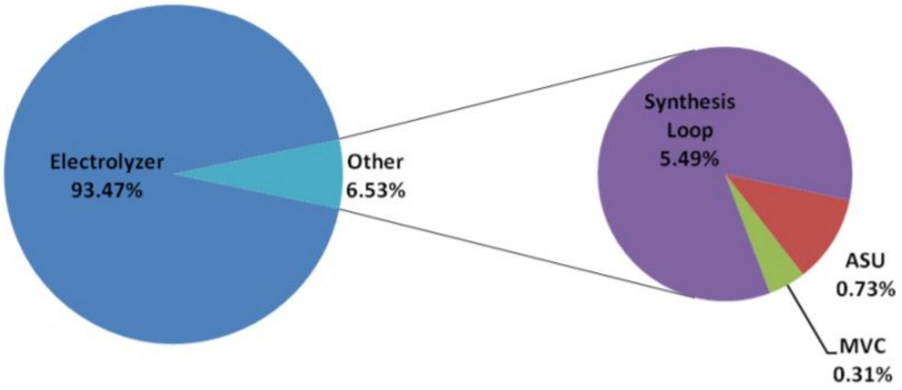


Figure 52: Power requirement breakdown for a green ammonia plant (MVC=Mechanical Vapor Compression, includes pumping and desalination of feed water to electrolysis unit) [5].

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 21: 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 (NH3rec):
    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 (NH3rec):
    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 NH3rec 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.

Regulation ability

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 Topsoe: 10-100% [7]
ThyssenKrupp: 30-100% (vendor info)
Casale: 20-110% (vendor info)
KBR: 30-100% (vendor info)

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:

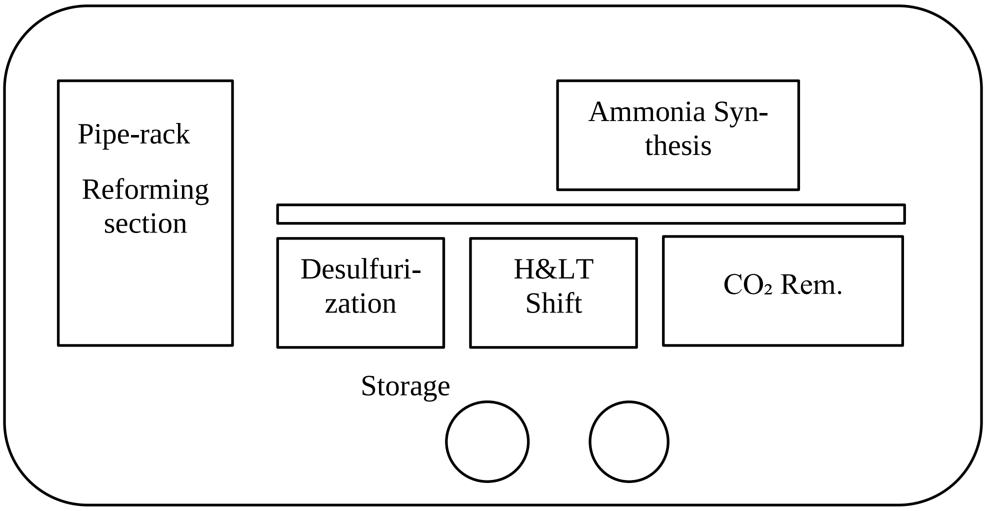


Figure 53: Typical ammonia plant layout

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.

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.

Safety and 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.

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 (one example from Linde is seen in Figure) 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.

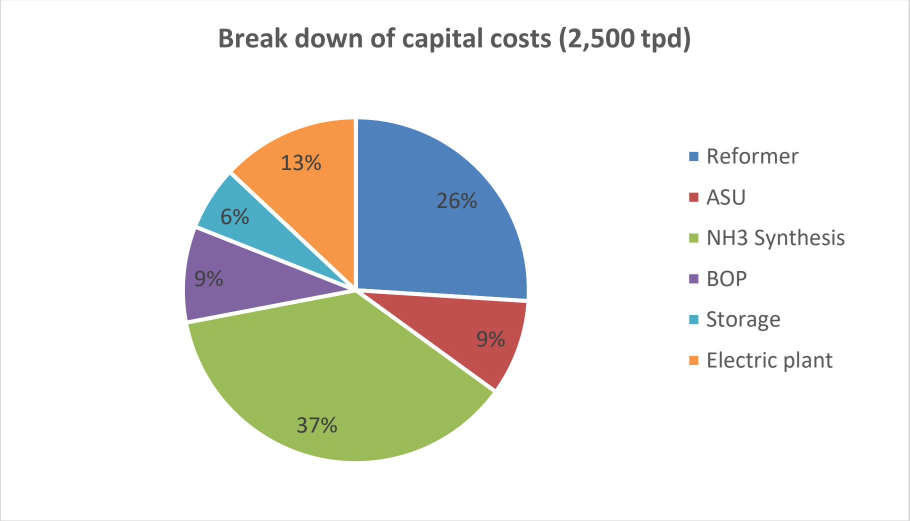


Figure 54. Cost split on main systems in a conventional NH_3 plant from Linde [9]. Reformer, electric plant (power plant) and some balance of plants (BOP) will disappear for a green NH_3 plant. Cost of green NH_3 plant (excl. electrolysis unit and ASU) is therefore taken as 54% of conventional plant, based on all obtained data.

In Figure 55, 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 55 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.

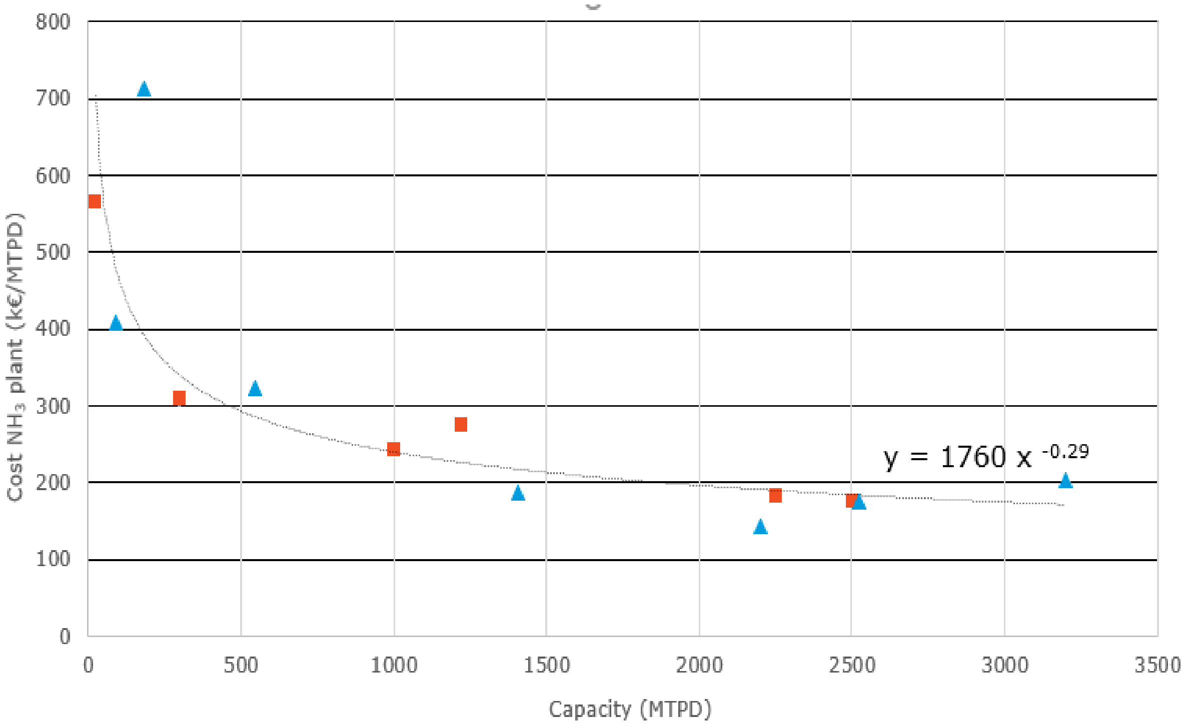


Figure 55: Estimated cost of ammonia synthesis + BOP + Storage (electrolysis unit and ASU is not included in the figure). Blue triangles represent data that is publicly available. All figures adjusted to reflect cost index for 2019. A conversion factor of 0.8931 is used to convert to USD_{2019}

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 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.

Investment costs [MUSD$_{2019}$/MW]	**2020**	**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	
This Technology Catalogue	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 electrolyzers
D: Large scale plant, including air separation unit, N_2 & H_2 compressor, N_2 buffer and 30 days NH_3 storage

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 Orsted 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 Topsoe 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 22: 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, Spain	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.

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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”. The following sources are used:

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Data sheets

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.

Technology	**Green Ammonia plant: Hydrogen to ammonia (excl. electrolyzer and excl. ASU)**								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Typical total plant size, TPD	229	458	2290	100%	100%	100%	100%	A	
Typical total plant size, MW (Ammonia output)	50	100	500	100%	100%	100%	100%		
Inputs									
N_2 Consumption, t/t Ammonia	0.84	0.84	0.84	98%	102%	98%	102%	B	[1]
Hydrogen Consumption, t/t Ammonia	0.18	0.18	0.18	98%	102%	98%	102%	B	[1]
Hydrogen Consumption, MWh/MWh Total Inputs	0.95	0.95	0.95	98%	102%	98%	102%	B	[1]
Electricity Consumption, MWh/MWh Total Inputs	0.05	0.05	0.05	95%	110%	75%	150%	C	[1]
Outputs									
Ammonia Output, MWh/MWh total Input	0.82	0.82	0.82	98%	102%	98%	102%		[1]
High value heat MWh/MWh total input	0.11	0.11	0.11	98%	102%	98%	102%	D	[1]
Heat loss, MWh/MWh Total input	0.04	0.04	0.04	0%	100%	0%	100%	E	[1]
Forced outage (%), unplanned shutdown	5%	3%	2%	2%	8%	2%	4%		[2]
Planned outage (weeks per year)	3%	3%	3%						[2]
Operation capacity	20-100%	20-100%	20-100%						[3]
Technical lifetime (years)	30	30	30						
Construction time (years)	2	2	2						
Financial data									
Specific investment (M$ /MW Ammonia output)	1.87	1.53	0.96	1.46	2.47	0.67	1.1	F, I, J	[2]
- equipment (%)	50	50	50						[2]
-installation (%)	50	50	50						[2]
Fixed O&M (k$/MW Ammonia/year)	45	37	23	35	59	16	27	G	[2]
Variable O&M ($/MWh Ammonia)	0.02	0.02	0.02	0.01	0.05	0.01	0.05	H	[2]
Start up (M$ /1,000 t Ammonia)	N.A.	N.A.	N.A.						
Technology specific data									
Specific investment mark-up factor optional ASU	1.09	1.09	1.09	97%	100%	97%	100%	F	[2]
Specific energy content (GJ/ton Ammonia)	18.9	18.9	18.9						
Specific density (kg/l) or (ton/m3) Ammonia	626	626	626						

Technology	**Green Ammonia plant: Hydrogen to ammonia (excl. electrolyzer and excl. ASU)**								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Specific investment (M$ /TPD Ammonia output)	0.41	0.33	0.21	0.32	0.54	0.15	0.24	F, I	
Fixed O&M (M$ /TPD Ammonia)	12.3	10.0	6.3	9.6	16.2	4.4	7.3		
Variable O&M ($ /t Ammonia)	0.12	0.12	0.12	0.06	0.24	0.06	0.24		
Start up (M$ /TPD Ammonia)	N.A.	N.A.	N.A.						

Notes:

A. Typical NH_3 plant size based on H_2 supply from 100 MWe electrolyzer for 2020.
B. Assume 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 Financial Data and Technology-specific data) as a rule of thumb.
G. Fixed O&M is taken as 3% of CAPEX
H. Variable O&M estimated as cost for catalyst replacement and misc. consumables
I. Financial data is given in 2019-$
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 55 n the chapter.

References

1. Based on calculated mass and energy balance
2. Based on collected data, i.e., based on several sources, as specified in the qualitative section
3. 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

9. 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.

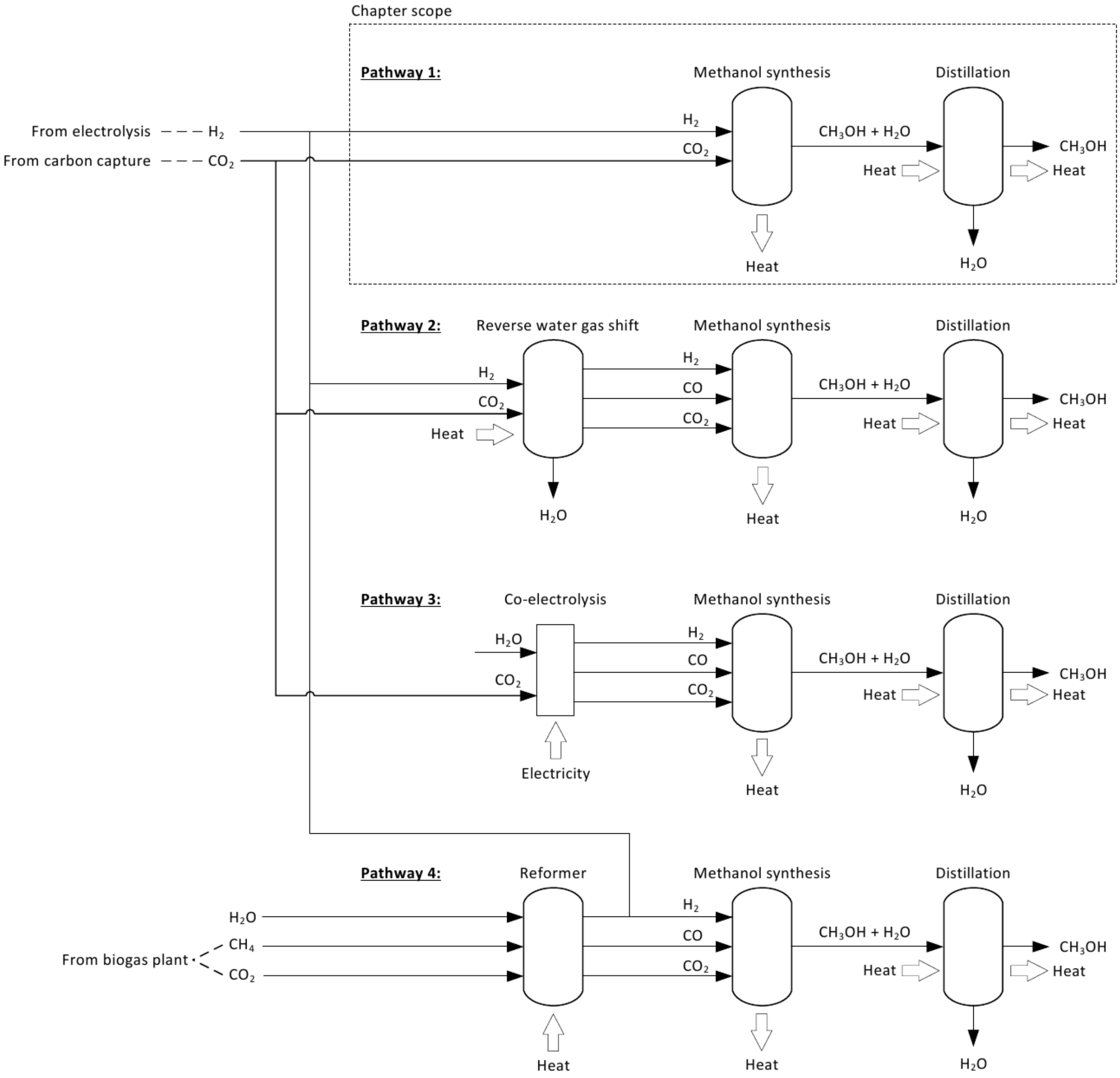

Figure 56: Overview of four pathways enabling the production of green methanol. The methanol synthesis generates high temperature heat which can be used in the distillation. The distillation generates lower temperature heat at 50-100 °C, which can be utilized for low-temp. heating applications

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 56)

- **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:

  $$\mathrm{CO_2} + H_2O \leftrightarrow CO + H_2 + ½O_2$$

  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 feed-stock. 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 $\Delta H = -49.16$ 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 $\Delta H = 41.22$ 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 57. 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.

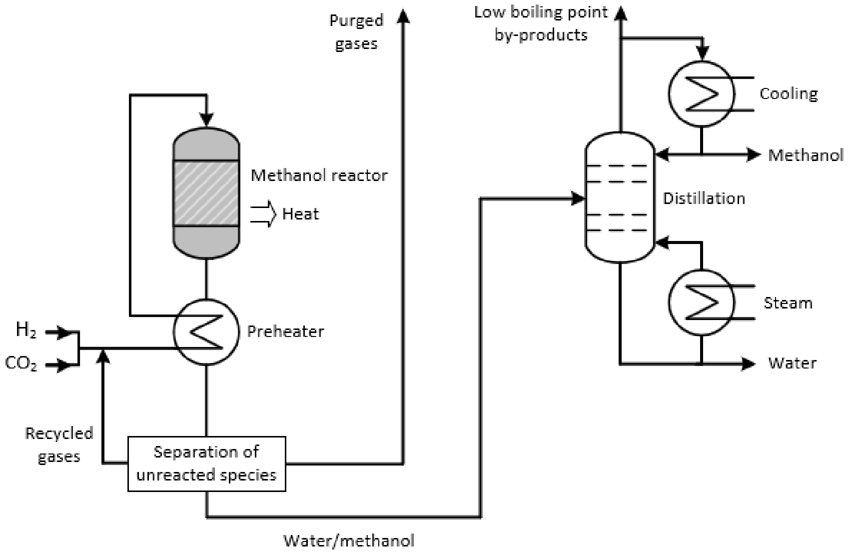

Figure 57: Simplified sketch of a hydrogen to methanol production plant.

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 58. 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 58 therefore represents the difference between steam consumption and production.

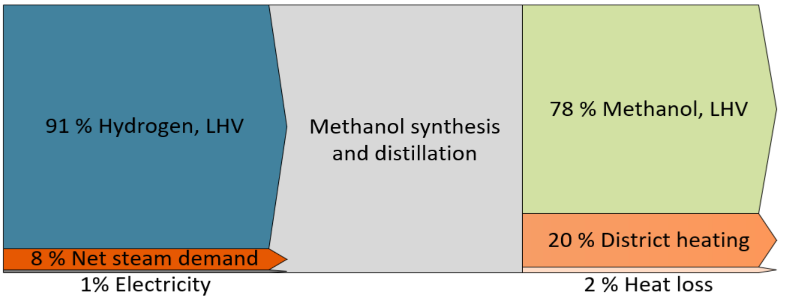

Figure 58: Energy balance of a methanol plant. "District heating" is low temperature heat that can be used for heating or low temperature industrial purposes.

The electricity demand included in Figure 58 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.

Regulation ability

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.

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.

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

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)

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 59, where CAPEX is plotted as a function of capacity.

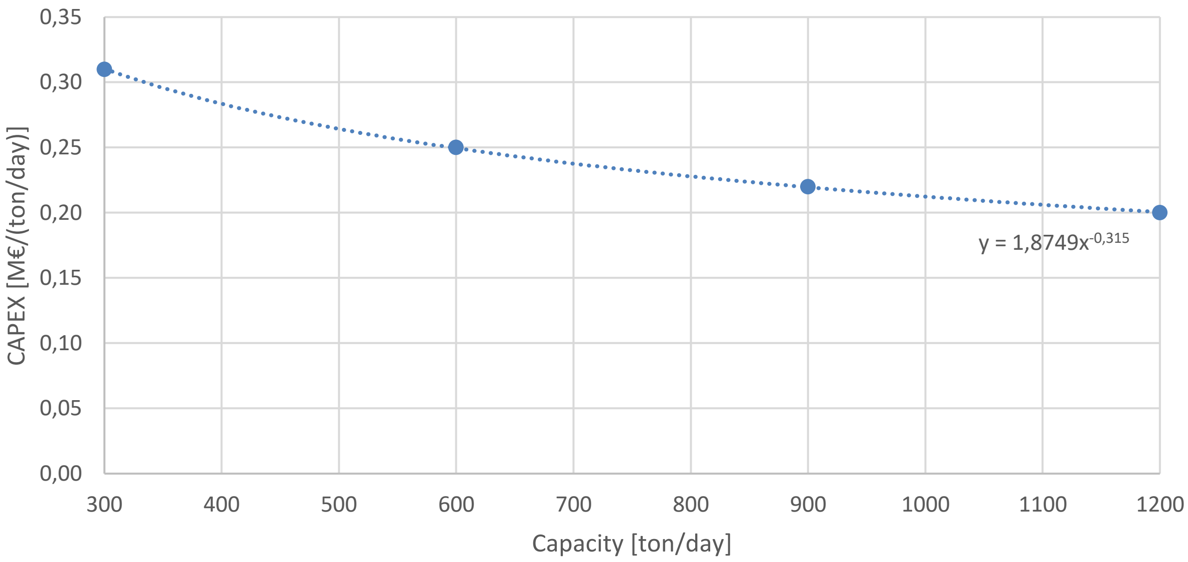

Figure 59: CAPEX as a function of capacity. A conversion factor of 0.7857 is used to convert to USD$_{2019}$

Investment costs [MUSD$_{2019}$/MW]	**2020**	**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	
This Technology Catalogue	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.*

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 23) 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 23: 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

References

The description in this chapter is to a great extent based on the Danish Technology Catalogue *"98 Methanol from hydrogen (2023)".* The following sources are used:

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16. Carbon Recycling International, [Online]. Available: https://www.carbonrecycling.is/projects.

Datasheet

The scope of the following datasheet considers technology limits, as illustrated in Figure 60.

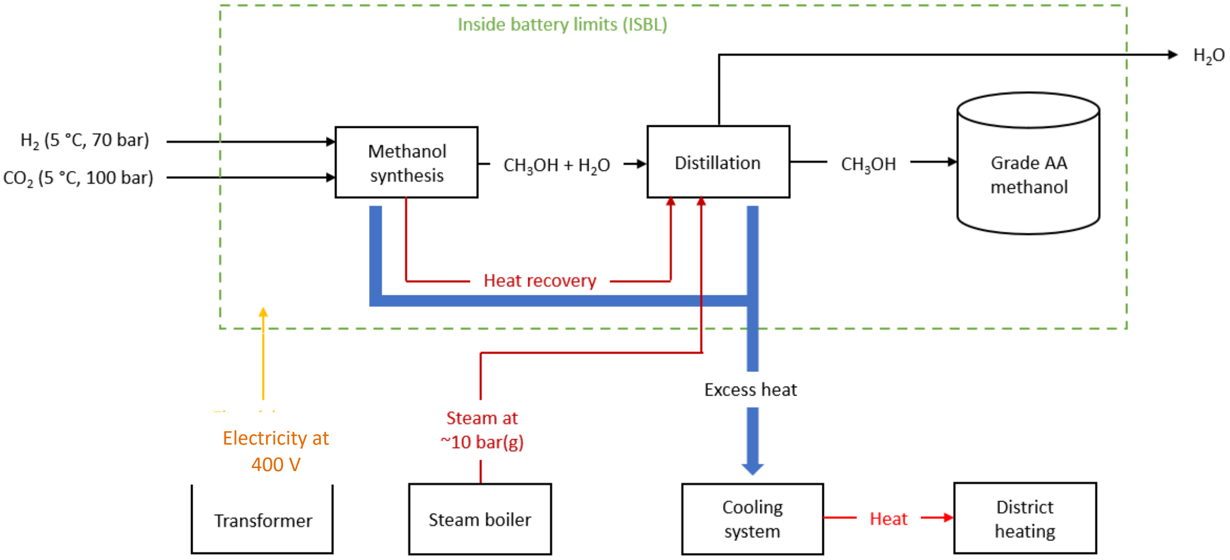

Figure 60: Illustration of technology ("battery") limits.

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.

Technology	E-methanol (excl. electrolyser)								
	2020	2030	2050	Uncertainty (2020)		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 [MWh/MWh total input]; usable as low-temp. heat	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	
Financial data									
Specific investment (M$/(ton-methanol/day))	0.31	0.25	0.20	0.15	0.46	0.10	0.30	L	[3]
Specific investment (M$ /MW Methanol output)	1.33	1.07	0.86	0.66	1.99	0.43	1.28		
- equipment (%)	75	75	75						
-installation (%)	25	25	25						
Fixed O&M [k$/[ton-methanol/day] /year]	9	7	6					M	
Fixed O&M (k$/MW Methanol/year)	38	30	26						
Variable O&M ($/ton-methanol)	27	27	27					N	[3]
Variable O&M ($/MWh Methanol)	5	5	5						
Startup (M$/(ton/day-methanol))	N.A.	N.A.	N.A.						

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.

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10. 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.

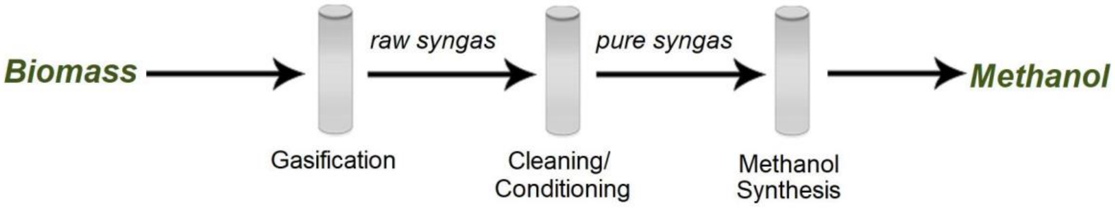

Figure 61: Biomass to Methanol Process

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 nth plant values. Pioneering plants typically have a lower efficiency.

Table 24: Inputs and Outputs

Parameter	Input	Output
Wood, dry	100 MJ	
Power		1.8 MJ
Methanol		58.2 MJ

Technology Specific Data

Some the properties of methanol are shown in the following table.

Table 25: 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

Energy Balance

The energy balance for a biomass to methanol system is shown in the following figure [2].

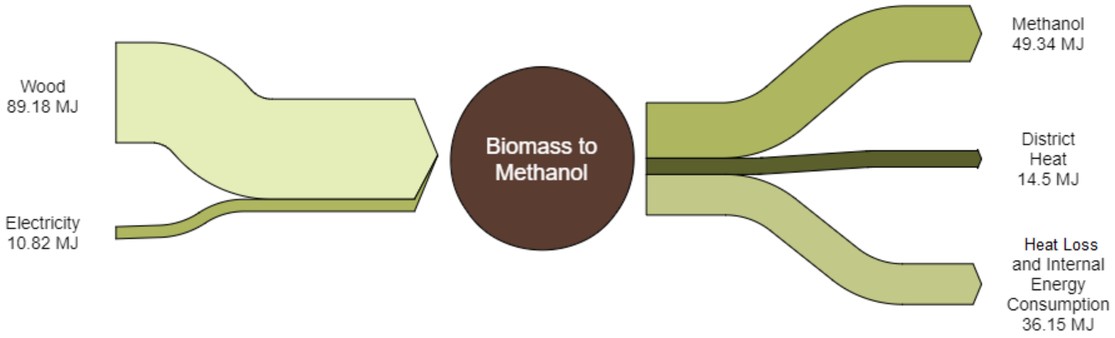

Figure 62: Biomethanol Energy Balance

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 GreenSynFuels project provided the energy balance for both a traditional biomass to methanol plant and one integrated with a solid oxide electrolyzer 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.

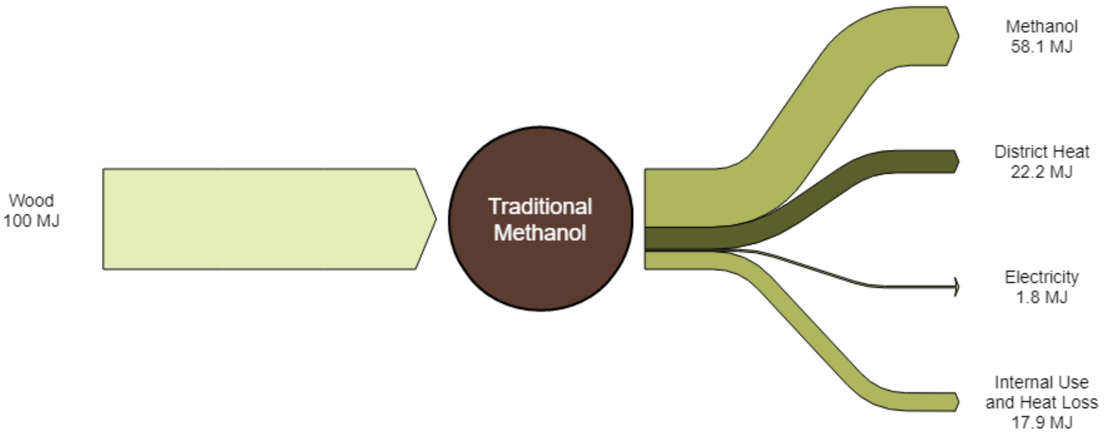

Figure 63: GreenSynFuels Traditional Methanol Plant

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.

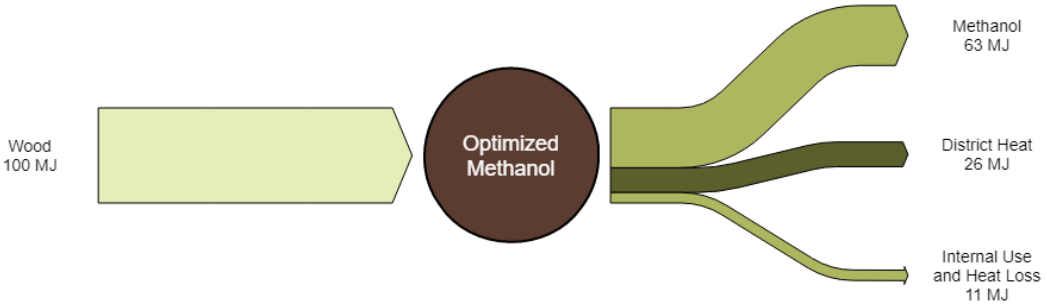

Figure 64: Optimized Biomass to Methanol Plant

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.

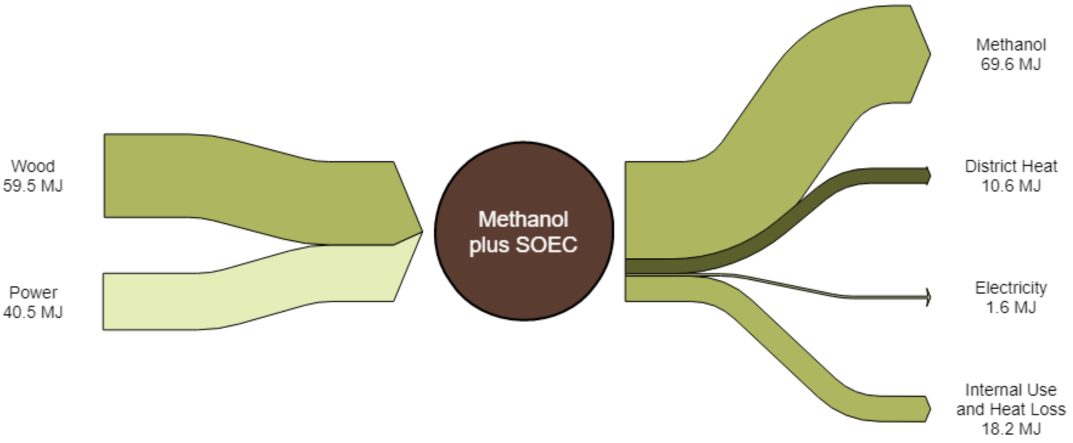

Figure 65: Hybrid Biomass to Methanol Plant

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).

Regulation Ability

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.

Space Requirements

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.

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.

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 tonnes 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.

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].

Investment costs [MUSD$_{2019}$/MW]	2020	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
This Technology Catalogue	5.97 (100 kt/y)	3.32 (200 kt/y)	2.41 (250 kt/y)	1.66 (300 kt/y)
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

Examples of current projects

The below table shows an overview of existing and planned projects.

Table 26: 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, nth 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.

References

The description in this chapter is to a great extent based on the Danish Technology Catalogue *"97 Methanol from Biomass Gasification".* The following sources are used:

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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 financial 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.

Technology	**Bio-methanol**								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**		
Energy/technical data									
Typical total plant size, 1,000 t Methanol/year	100	200	300	50%	200%	50%	125%	A, B	[3, 4, 5]
Typical total plant size, MW	65	130	195	50%	200%	50%	125%	A, A1, B	[3, 4, 5]
Inputs									
Feedstock Consumption, MWh/MWh Total Input	1	1	1	90%	150%	90%	120%		[1]
Outputs									
Methanol Output, MWh/MWh Total Input	0.58	0.61	0.65	100%	133%	100%	133%	D	[1]
Heat loss (MWh/MWh total input); usable as low-temp. heat	0.22	0.22	0.22	80%	125%	80%	125%	D	[1]
Additional heat loss, MWh/MWh Total Input	0.22	0.22	0.22	80%	125%	80%	125%	D	[1]
Electricity Output, MWh/MWh Total Input	0.02	0.02	0.02	80%	125%	80%	125%	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						
Financial data									
Specific investment (M$ /MW Methanol)	5.97	3.32	1.66	50%	100%	80%	120%	F	[1, 3, 4, 5]
- equipment (%)	75	75	75						
-installation (%)	25	25	25						
Fixed O&M (M$ /MW/year Methanol)	0.07	0.04	0.04	90%	110%	90%	110%	E, F	[1]
Variable O&M ($ /MWh methanol)	23	15	15	90%	110%	90%	110%	E, F	[1]
Start up (M$ /1,000 t Methanol)	N.A.	N.A.	N.A.						
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 (M$ /1,000 t Methanol)	3.88	2.16	1.08	50%	100%	80%	120%	F	[3, 4, 5]
Fixed O&M (M$ /1,000 t Methanol)	0.04	0.03	0.03	90%	110%	90%	110%	E, F	[1]
Variable O&M (M$ /1,000 t Methanol)	0.13	0.09	0.09	90%	110%	90%	110%	E, F	[1]
Start up (M$ /1,000 t Methanol)	N.A.	N.A.	N.A.						

Notes:

A. The plant size range is assumed based on the proposed Värmlands plant and the NREL nth 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. M $/k tonne is million USD per 1,000 tonnes

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11. 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.

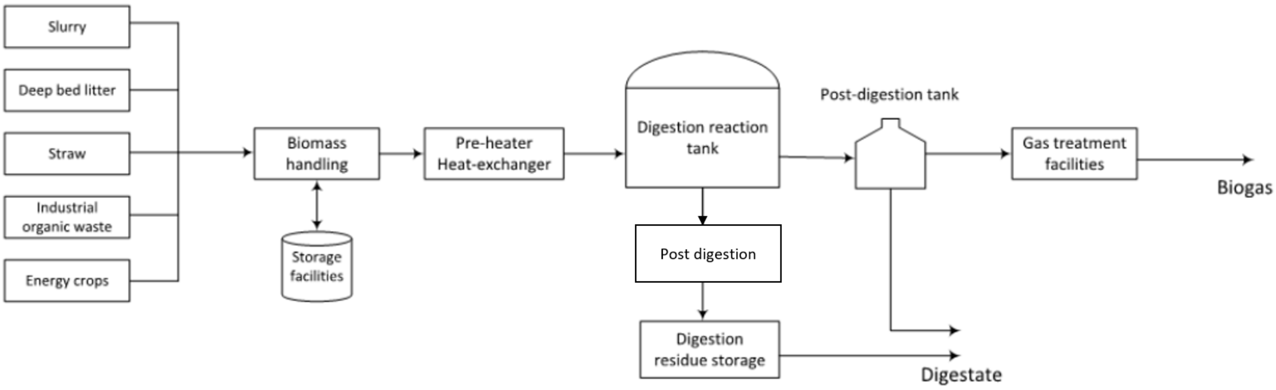

Figure 66: Typical components in a biogas plant. Note: alternative terms for technical descriptions might be used by some actors, e.g., biomass handling might be referred to as pre-treatment; digestion reaction tank as a digester and digestion residue storage as digestate storage or post-storage of digestate. [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 to biogas plant

- 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

Output from biogas plant

- Biogas
- Digestate, for use as fertilizer

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).

	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%

Table 27: 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]

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 27 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 67: Biogas output in two different biogas plants – own illustration based on [19]Figure 67 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.

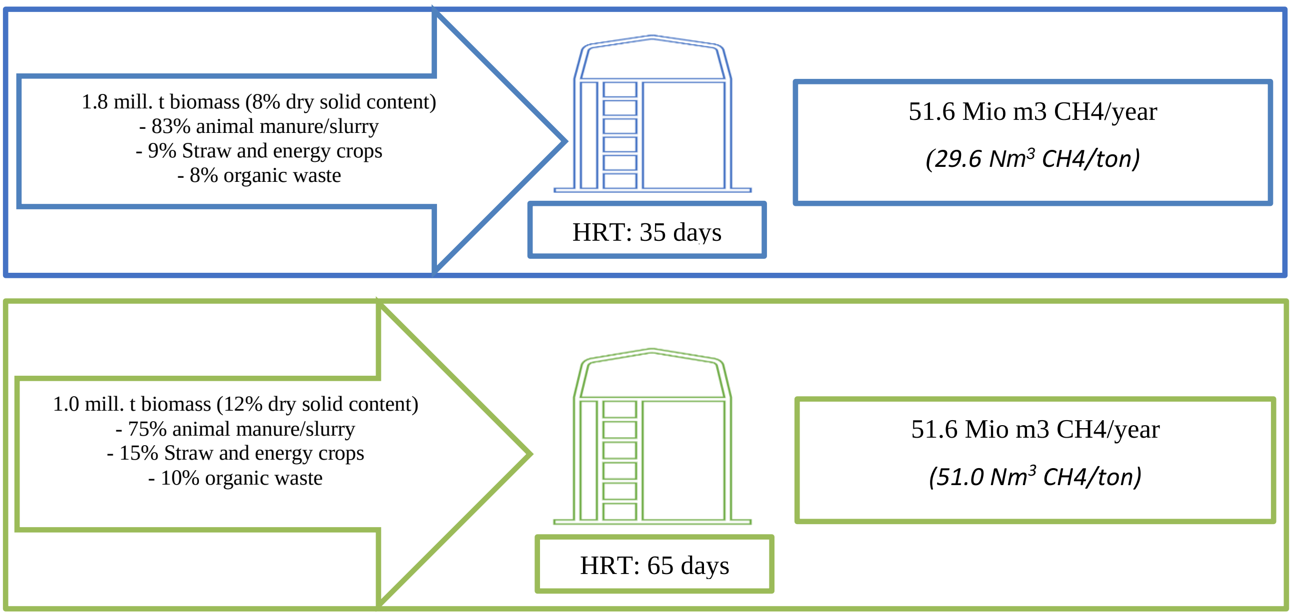

Figure 67: Biogas output in two different biogas plants – own illustration based on [19]

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.

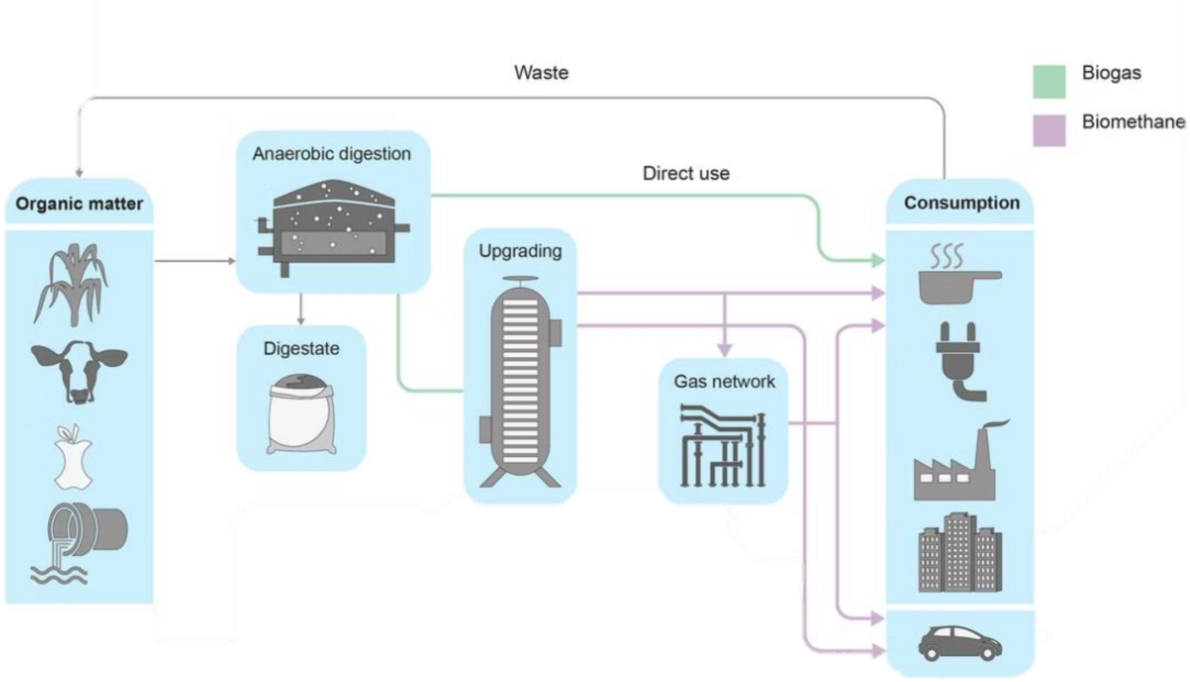

Figure 68: Biogas may either be used directly as an energy source or be upgraded through an upgrading plant to be fed into the gas network or be directly applied for consumptions needing gas with high energy content. Illustration from IEA [8]

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 sulfide (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.

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].

The upgrading plants

The main purpose of the upgrading plant is the removal of CO_2, to end up with a gas with a higher methane content (biomethane). The capacity of the upgrading plant is usually stated in Nm^3 upgraded biogas/year.

Biogas upgrading plants are based on one of the four following technologies:

- Amine scrubbing
- Water scrubbing
- Membrane separation
- Pressure swing adsorption (PSA)

Upgrading can also take place by catalytic conversion of CO_2 to CH_4 by adding hydrogen or through biomethanation. Biomethanation for upgrading can be done by two methods, in-situ or ex-situ processes. The in-situ process involves adding H_2 to the processes in the biogas reactor to obtain an output gas from the biogas process with higher CH_4 content. However, this method produces a too small concentration of methane in the off gas for addition to the gas grid combined with a slip of hydrogen. In the ex-situ process, the off gas from the biogas reactor is further processed in a subsequent (trickle bed) reactor, in which very high methane concentration (> 95%) can be achieved with low hydrogen slip. These technologies, which are less mature than traditional upgrading through CO_2-removal, are not addressed in this technology chapter.

Amine scrubbing uses amines[5] that chemically bind to the CO_2 and H_2S molecules, removing them from the gas. The amine is regenerated in a stripper where the CO_2 is removed from the amine solution by adding heat. This process has the highest efficiency in terms of methane conservation.

To regenerate the amines, the process uses temperatures between 120-150 °C, which typically is produced by the combustion of natural gas[6] or biomass. Cheap heat sources and reuse of the heat are therefore key parameters for amine scrubbing to be economically competitive. Today amine scrubbing plants reuse at least 40% and up to more than 80% of the heat. Further, as the process happens under a pressure between 1-3 bar, there is a demand for electricity to run a compressor ensuring sufficient pressure for the gas to be injected into the distribution gas grid (4/7 bar).

Water scrubbing technology makes use of the absorption, which is a purely physical process. The biogas is put in contact with water by spraying or bubbling through to wash out the CO_2 but also H_2S since these gases are more soluble in water than methane. When injecting biomethane into the gas grid, the gas needs to be under the same pressure as the grid gas. The pressure in water scrubber plants is high enough (around 6 bar) for the gas to be directly injected into the distribution grid meaning that no further compression is necessary for grid injection of the biomethane. The major reason why water scrubbing is opted out is the methane loss, Ih is approx. 1% of the biomethane production.

Membrane separation is a process where membranes, which consist of hollow fibres, separate the carbon from the biogas. Components such as water and H_2S are likewise separated through the process. The membranes are permeable to ammonia, water, and CO_2. Nitrogen and methane only pass through the

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[5] An amine is a compound that contains a nitrogen atom with a lone pair of electrons

[6] Natural gas is often preferred over biogas in Denmark due to tax regulation.

membrane to a very low extent while oxygen and hydrogen sulphide pass through the membrane to some extent. Typically, the process is carried out in two stages. In the first step, before reaching the membranes the gas passes through a filter that catches water and oil droplets that would otherwise affect the efficiency of the membranes. Besides that, H_2S is typically removed using activated carbon. The CO_2 is removed from the gas in the membrane in the second step. The advantages usually presented for membrane technology are the lack of demand for water or chemicals and the ability to scale down the process without large efficiency losses. Based on number of plants, membrane separation is the most widely applied technology in Europe . However, the technology has, relative to the scrubbing technologies, a high OPEX, making it expensive especially for larger plants.

PSA is among the most widely practised upgrading methods worldwide however with relatively high methane losses. It separates some gas components from a mixture of gases under high pressure according to the molecular characteristics of the components and the affinity for an adsorbent material (often active carbon). The process then swings to low pressure to desorb the adsorbent material.

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 from biogas upgrading plant

- Upgraded biogas with 95-99 vol. % methane, carbon dioxide, nitrogen, and oxygen [7].
- Waste gas containing mostly CO_2

Typical capacities (industrial scale biogas plant)

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.

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.

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[7]) 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 mature

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[7] According to the Danish technology catalogue a gas engine costs approx. 1,02 MUSD/MW in 2020 and 0,91 MUSD/MW in 2050.

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.

Investment costs [MUSD$_{2019}$/MW]	**2020**	**2030**	**2050**
ThisTechnology Catalogue - 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 pl–nt - 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 catalog.

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$_{2019}$/MW]	**2020**	**2030**	**2050**
This Technology Catalogue – 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

Examples of current projects

Viet Nam

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 laborers, 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.

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Data sheets

The following pages contain the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. 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.

Technology	**Biogas plant Basic plant - 3000 Nm^3 CH$_4$/h.**								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Typical capacity (mill. tons biomass input/year)	0.60	0.60	0.60	0.54	0.65	0.54	0.65	A, B	[19]
Typical total plant size (MW output)	29.63	29.63	29.63					R	[19, 3]
- Inputs									
Biomass (mill. tons/year)	0.60	0.60	0.60					B	[19]
Aux. electricity (% of output energy)	2.34%	2.03%	1.84%	1.75%	2.92%	1.38%	2.31%	C	[19]
Aux. electricity (kWh/ton input)	10.19	8.87	8.05	7.64	12.74	6.04	10.06	C	[19]
Aux. process heat (% of output energy)	6.87%	5.97%	5.42%	5.84%	7.90%	4.61%	6.24%	D	[19]
Aux. process heat (kWh/ton input))	29.96	26.07	23.67	25.47	34.46	20.12	27.22	D	[19]
- Outputs									
Biogas (%)	100%	100%	100%						[19]
Biogas (GJ/ton input)	1.59	1.59	1.59					R	[19]
Biogas production, (MJ/s)	29.63	29.63	29.63						[19,3]
									[19]
Forced outage (%)	-	-	-						[19]
Planned outage (days per year)	-	-	-						[19]
Technical lifetime (years)	20.00	20.00	20.00	15.00	25.00	15.00	25.00	E	[19]
Construction time (years)	2.00	2.00	2.00	1.00	3.00	1.00	3.00	F, Q	
Financial data									
Specific investment (mill. $/MW output)	1.07	0.93	0.84	0.91	1.23	0.75	0.95	G, H, I, J, N, O	[19]
- of which equipment (mill. $/MW output)	0.85	0.74	0.67	0.73	0.98	0.60	0.76	G, H , I, J	
- of which installation (mill. $/MW output)	0.21	0.19	0.17	0.18	0.25	0.15	0.19	G, H, I, J	
Total O&M (k$/MW/year)	79.26	68.95	62.61	67.37	91.14	58.14	73.92	G, H, I, L	[19]
Total O&M ($/(ton input/year))	3.95	3.43	3.12	3.35	4.54	2.87	3.65	G ,H, I, K, P, N	[19]
- of which O&M, excl el. and heat ($/(ton input/year))	2.64	2.29	2.08					G, H, I, K	[19]
- of which electricity ($/(ton input/year))	0.71	0.61	0.56					G, H, I, P	[19]
- of which heat ($/(ton input/year))	0.60	0.52	0.48					G, H, I, N	[19]
Technology Specific data									

Hourly gas output (k Nm3 CH4/h)	2.97	2.97	2.97						[19,21]
Yearly gas output (mill. Nm3 CH4/year)	26.05	26.05	26.05						[19,21]
HRT (days)	65.00	65.00	65.00					M	[19,3]
DS%	16.00%	16.00%	16.00%					N	[19,3]
Methane emission (% of output)	0.90%	0.90%	0.90%						[19,11]
CO$_2$ resource (mill. Nm^3 CO$_2$/year)	19.23	19.23	19.23						[19]
CO$_2$ resource (kton/year)	37.96	37.96	37.96						

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
B. The biogas input is based on the table in the 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 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. For reference, 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. Production costs are calculated in 2019 prices.

Technology	**Biogas upgrading - Amine scrubber (3,000 Nm3/h)**								
	2020	**2030**	**2050**	**Uncertainty (2020)**		**Uncertainty (2050)**		**Note**	**Ref**
Energy/technical data				**Lower**	**Upper**	**Lower**	**Upper**		
Typical total size (MW output)	29.34	29.34	29.34						[19]
Typical total size (k Nm3 biogas/h)	2.97	2.97	2.97						[19]
Capacity (k Nm3 biomethane/h)	2.94	2.94	2.94						[19]
Capacity - yearly biomethane production (mil Nm3 biomethane/h)	25.80	25.80	25.80						[19]
- Inputs									
Biogas (% of biogas input)	100%	100%	100%						[19]
Auxilliary electricity for upgrading (% of biogas input)	1.92%	1.50%	1.17%	1.44%	2.40%	1.46%	1.46%	A	[19]
Heat (% of biogas input)	10.48%	8.17%	6.39%	8.91%	12.05%	7.35%	7.35%	B	[19]
- Outputs									
Biomethane (% of methane input)	99.05%	99.05%	99.05%						[19]
Waste gas (% of methane input)	0.95%	0.95%	0.95%						[19]
Waste heat (% of methane input)	5.24%	5.24%	5.24%						[19]
Forced outage (weeks per year)	0.29	0.29	0.29						[19]
Planned outage (weeks per year)	0.29	0.29	0.29						[19]
Technical lifetime (years)	20.00	20.00	20.00	15.00	25.00	15.00	25.00	C	[19]
Construction time (years)	1.00	1.00	1.00	1.00	2.00	1.00	2.00	D	[19]
Financial data									
Specific investment, upgrading and methane reduction (k $/MW output)	199.61	155.70	121.76	169.67	229.55	147.71	95.81	E, F, G	[19,3]
Fixed O&M (k$/MW output/year)	34.01	26.53	20.75	28.91	39.12	25.17	16.33	E, F, G	[19,3]
- of which fixed O&M costs upgrading and methane reduction, excl. el. and heat (k$/MW output/year)	9.52	7.43	5.81					E, F, G	[19]
- of which fixed O&M costs for heat (k$/MW output/year)	12.73	9.92	7.77					E, F, G	[19]
- of which fixed O&M costs for el. (k$/MW output/year)	11.77	9.17	7.17					E, F, G	[19]
Variable O&M (($/GJ input)	1.20	0.93	0.73	1.02	1.38	0.88	0.57	E, F, G	[19]
- of which electricity ($/GJ input)	0.37	0.29	0.23	0.32	0.43	0.28	0.18	E, F, G	[19]
Technology specific data									
Methane slip / emission (%)	0.10%	0.10%	0.10%						[19,11]
Minimum load (% of full load)	50.00%	50.00%	50.00%						[19]
CO_2 resource (mill. Nm3/year)'	19.23	19.23	19.23						[19]
CO_2 resource (kton/year)	37.96	37.96	37.96						[19]

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 2025 the prices vary by 15%.
G. For uncertainty calculations the learning curve for the forecast of prices in 2050 is tested with a 10% learning curve and a 20% learning curve.

12. 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:

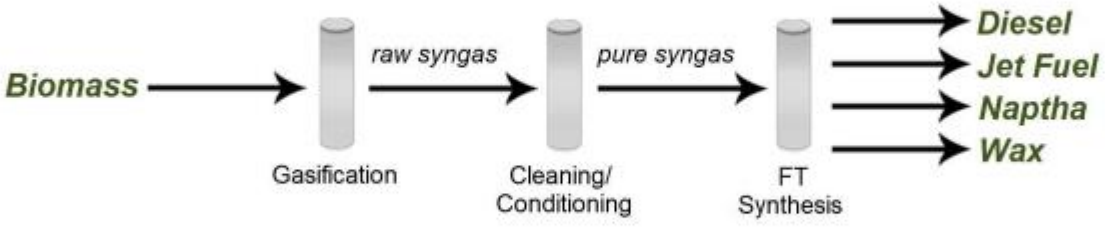

Figure 69: The steps in the process from biomass to liquid fuel

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 70.

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.

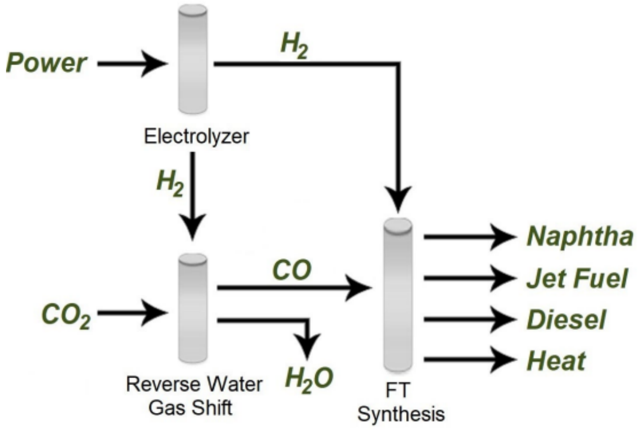

Figure 70: The steps in the process from power to liquid fuel

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.

	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

Figure 71: FT Synthesis Product Distribution

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 gassified 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.

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.

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.

Investment costs [MUSD$_{2019}$/MW]	2018 (old)	2020	2030	2050
This Technology Catalogue		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.

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 tonnes of wood per day.

Currently the company works on developing a plant with a production of approx. 95.000 m3 jetfuels/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 jetfuel 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 electrolyzer 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 electrolyzer for hydrogen. They have also not provided any technical performance data.

Further examples of development projects can be found under "examples of current projects".

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Data sheets

The following pages content the data sheets of the technology. All costs are stated in U.S. dollars (USD), price year 2019. 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								
	2020	**2030**	**2050**	**2020**		**2050**		**Note**	**Ref**
				Lower	**Upper**	**Lower**	**Upper**	-	-
Typical total plant size [1,000 kt FT Liquids/year]	2.00	13.00	165.00	50%	150%	50%	150%	A, B	[16, 17, 18]
Typical total plant size, [MW] Output	3.10	20.50	259.60	50%	150%	50%	150%	A, B, C	[16, 17]
Input									
CO_2 Consumption, [t/t FT Liquids]	4.30	3.90	3.30	100%	110%	100%	110%	C, D, E	
Hydrogen Consumption, [MWh/MWh Total Input]	100%	100%	100%	75%	125%	75%	125%	E	
Power Consumption, [MWh/MWh Total Input]	0.50%	0.50%	0.50%	75%	125%	75%	125%	E	
Output									
FT Liquids Output, [MWh/MWh Total Input]	0.65	0.70	0.75	80%	120%	80%	120%	F, G, O	[17, 16]
Forced outage [%]	0.00%	0.00%	0.00%					I	
Planned outage [weeks per year]	300.00%								[16]
Technical lifetime [years]	2500.00%								
Construction time [years]	2.00								
Financial data									
Specific investment [M$ /MW Liquids/year]	2.31	1.76	0.99	75%	150%	75%	125%	G, J	[16, 17, 19, 20]
- equipment [%]	75%	75%	75%					K	
-installation [%]	25%	25%	25%						
Fixed O&M [$/MWH Liquids]	18.59	13.97	8.14	90%	110%	90%	110%	L	[16]
Variable O&M [$ /MWH Liquids]	5.83	4.62	2.31	90%	110%	90%	110%	M	[19]
Technology specific data									
Specific investment [$ /l FT Liquids/year]	3.63	2.75	1.54	75%	150%	75%	125%	G, J	[16, 17, 19, 20]
- equipment [%]	75%	75%	75%					K	
-installation [%]	25%	25%	25%						
Fixed O&M [$ /l FT Liquids]	0.18	0.13	0.08	90%	110%	90%	110%	L	[16]
Variable O&M [$ /l FT Liquids]	0.06	0.04	0.02	90%	110%	90%	110%	M	[19]

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. Power is the only energy input. Power will be required for pumping, compression, and utilities in addition to hydrogen production.
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. Calculations by Don O'Connor, president of S&T squared consultants inc
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.

APPENDIX 1: DEFINITIONS 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 2019 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 (2020, 2030 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 2020 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.

Output and input 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

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 shut-downs.

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.

Regulation ability

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.

Financial data

Financial data are all in US dollar at fixed prices, at the 2019-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 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 leveling 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 2: DEFINITIONS 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 2019 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 (2020, 2030 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 2020 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.

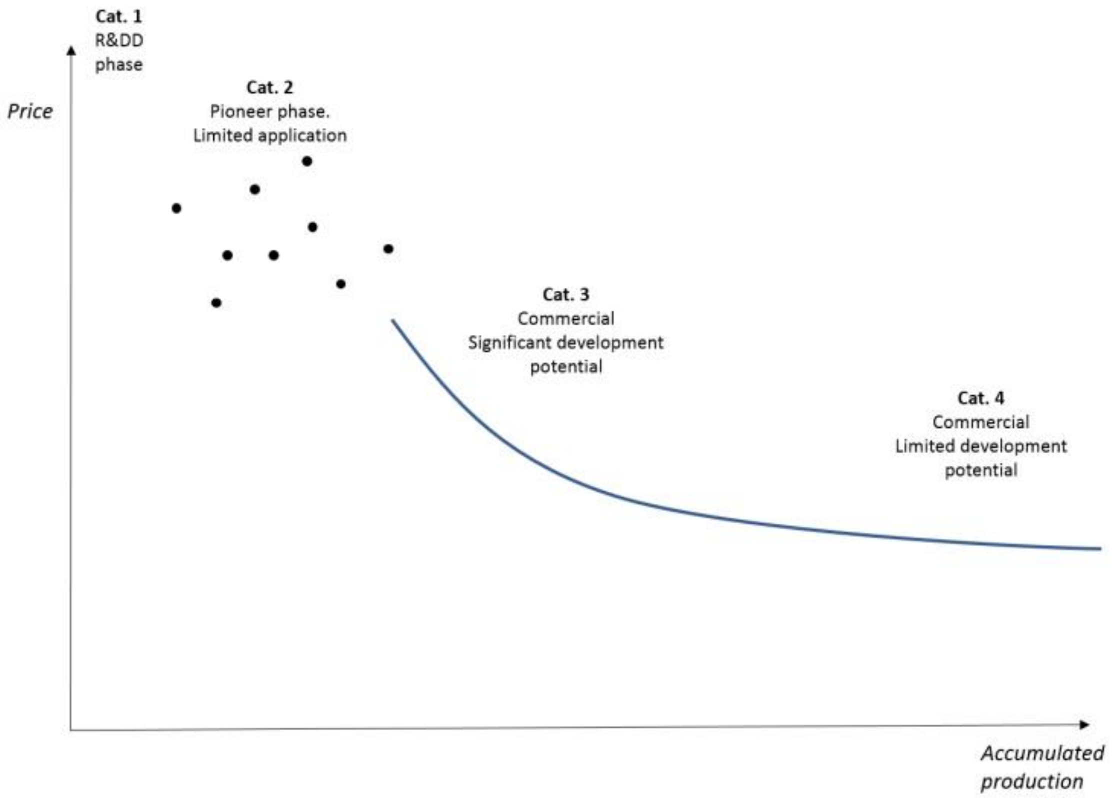
Learning curves and technological maturity

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 labor, 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. 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 (e.g. wave energy converters, solid oxide fuel cells). *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 (e.g. gasification of biomass).

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 (e.g. offshore wind turbines)

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 (e.g. coal power, gas turbine)



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.

Financial data

Financial data are all in US Dollar ($), fixed prices, at the 2019-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% can not be exceeded.