

Indian Technology Catalogue

Green Fuels

2026

Danish Energy Agency

Green Strategic Partnership
India-Denmark



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अध्यक्ष तथा पदेन सचिव भारत सरकार
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FOREWORD

The world is focusing on environmental issues, especially climate change and therefore, the idea of growing sustainably has taken center stage globally. India being an active participant has already started taking several initiatives towards sustainable development and green energy transition towards achieving net-zero carbon emissions by 2070.

The demand for electricity is increasing with the increase in economic activity. Availability of affordable and reliable electricity is a key factor in sustainable growth of the country. Meeting the increasing electricity demand along with the green energy transition is an opportunity as well as a challenge for the country. The intermittent nature of Renewable energy (mainly Solar and wind) has forced the policy makers to look other green fuels like Hydrogen and biogas to achieve the net-zero goal.

An MoU has been signed between Ministry of Power, Govt. of India and Ministry of Climate, Energy & Utilities, Kingdom of Denmark on 5th June, 2020 which was renewed in 2025 to develop and promote strategic and technical cooperation in the energy sector for mutual benefits. Under this MoU, first Technology Catalogue was published in 2022 which focused mainly on conventional technologies.

I am happy to note that the Indian Technology Catalogue on Green Fuels has been prepared. The catalogues would make the relevant data of green fuel technologies publicly available to all stakeholders. The technology catalogue may therefore be used as a guiding database comprising inputs from across the Indian power sector.

This technology catalogue focuses specifically on green fuels—key emerging and critical technologies essential for enabling deep decarbonization and flexible grid integration in the evolving Indian power system.

This technology catalogue has been reviewed by key stakeholders from the Indian power sector and Government institutions to ensure that the information is up to date and adapted to Indian conditions.

I would like to thank all the stakeholders for their cooperation in timely providing their valuable inputs, making this publication possible. I would also like to thank the team of officers from the IRP Division, CEA, along with the experts from Danish Energy Agency for their excellent work. I trust that this Technology Catalogue will fulfill the expectations and needs of all stakeholders engaged in the sustainable development of the power sector.

(Ghanshyam Prasad)

New Delhi
7 Aug 2026

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Foreword

The global energy system is undergoing a significant shift. To meet the goals of the Paris Agreement and maintain a sustainable trajectory for future generations, countries must continue the transition away from fossil energy and build energy systems centred on renewable, flexible and low-carbon solutions. As electricity from renewable sources scales rapidly, attention is moving toward the sectors where direct electrification alone cannot mitigate emissions. In these sectors, green fuels will be essential to decarbonise industry, long-haul transport and other hard-to-abate areas.

India is set to experience one of the largest growths in energy demand globally, and is already taking major steps to integrate renewable energy, strengthen energy security and build a competitive green industrial base. To support these ambitions, decisions on green hydrogen, Power-to-X fuels, advanced biofuels and related infrastructure should be grounded in transparent, comparable and up-to-date information. The technologies in this field are advancing at different speeds, with declining costs and emerging value chains. Establishing a shared evidence base is therefore helpful for effective long-term planning, policy design and investment. This is particularly relevant in the Indian context, where strategic choices will need to balance near-term deployment with long-term system transformation.

This Technology Catalogue on Green Fuels responds directly to that need. Its objective is to provide a uniform, publicly accessible reference for cost and performance data across a wide range of green fuel technologies relevant to India. It offers a common foundation for analysis and dialogue carried out by government institutions, system planners, researchers, private companies and investors, and supports a coherent approach to developing India's future green fuel landscape.

The catalogue has been jointly developed under the India–Denmark Energy Partnership through close collaboration between the Central Electricity Authority of India and the Danish Energy Agency. It builds on a well-established methodology and is adapted to Indian conditions through an open, structured process. As green fuels will cut across sectors beyond electricity - power, industry, transport and agriculture - this shared approach will be important to ensure consistency, transparency and broad stakeholder anchoring.

Publishing a technology catalogue on green fuels now is timely. Global markets are forming, domestic strategies are being defined, and infrastructure choices taken in the coming years can be expected to shape economic competitiveness and energy security for many years to come. A robust, widely accepted data foundation is crucial for guiding these decisions.

It is therefore a great pleasure, together with our partners at CEA, to present this first edition of the Indian Technology Catalogue on Green Fuels. We trust that it will meaningfully strengthen long-term energy planning and support the development of sound policies and investments that advance India's green transition.

(Adrian Lübbert)

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Disclaimer

This technology catalogue is developed using best available data at the time of publication. The data can be used as desired, but no liability should accrue to the authors of the publication.

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Acronyms

1G	First Generation
2G / 2g	Second Generation
°C	Degree Celsius
AA	Analytical grade (used for methanol purity “grade AA”)
AE	Alkaline Electrolyser / Alkaline Electrolysis
AEM	Anion Exchange Membrane
ASME	American Society of Mechanical Engineers
ASU	Air Separation Unit
BB	Bubbling Bed
BCM	Billion Cubic Meters
BFW	Boiler Feed Water
BPGTP	Biogas-Based Power Generation & Thermal Application Programme
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CBG	Compressed Biogas
CCU	Carbon Capture and Utilization
CFE	Capillary Fed Electrolysis
CFRP	Carbon Fibre Reinforced Polymer
CH_3OH	Methanol
CH_4	Methane
CHP	Combined Heat and Power
CPG	Compressed Purified Gas
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2 eq	Carbon Dioxide Equivalent
CRI	Carbon Recycling International
CSTR	Continuous stirred-tank reactors
DBT	Dibenzyltoluene
DM	Dry Matter
DME	Dimethyl Ether
DOE	U.S. Department of Energy
DO	Direct Oxidation
DSO	Distribution System Operator
EB / EBP	Ethanol Blending Program
EF	Entrained Flow
EPA	Environmental Protection Agency
FA	Formic Acid
FCEV	Fuel Cell Electric Vehicle
FEED	Front-End Engineering Design
FT	Fischer–Tropsch
GDL	Gas Diffusion Layer
GHG	Greenhouse Gas
GoI	Government of India

GW	Gigawatt
H_2	Hydrogen
H_2O	Water
HCl	Hydrogen Chloride
HHV	Higher Heating Value
HRT	Hydraulic Retention Time
IEA	International Energy Agency
ICE	Internal Combustion Engine
IH	Indirect Heating
IMC	Indore Municipal Corporation
INR	Indian Rupee
IOCL	Indian Oil Corporation Limited
ISBL	Inside Battery Limits
kt	Kilotonne (1,000 tonnes)
kt/y	Kilotonne per year
kWh	Kilowatt-hour
LEL	Lower Explosive Limit
LHV	Lower Heating Value
LOI	Letter of Intent
MET	Methanol
MMt	Million Metric Tonnes
MNRE	Ministry of New and Renewable Energy
MSW	Municipal Solid Waste
Mt	Million tonnes
Mt/y	Million tonnes per year
MW	Megawatt
MTH	Methylcyclohexane Toluene Hydrogen
NAP	Naphthalene
NEC	N-Ethylcarbazole
NNBOMP	New National Biogas & Organic Manure Programme
O&M	Operation and Maintenance
OPEX	Operating Expenditure
PEM	Proton Exchange Membrane
PFSA	Perfluorosulfonic Acid
PFD	Process Flow Diagram
PLF	Plant Load Factor
PM	Particulate Matter
ppm	Parts per Million
PSA	Pressure Swing Adsorption
PTL	Porous Transport Layer
PV	Photovoltaic
R&D	Research and Development
RD&D	Research, Development and Deployment
RH_2C	Renewable Hydrogen Canada
RTO	Regenerative Thermal Oxidation

RWGS	Reverse Water Gas Shift
SATAT	Sustainable Alternative Towards Affordable Transportation
SBM-G	Swachh Bharat Mission-Grameen
SCADA	Supervisory Control and Data Acquisition
SECI	Solar Energy Corporation of India Limited
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolyser Cell
TCD	Tonnes of Cane per Day
TOL	Toluene
t/d	Tonnes per Day
tph	Tonnes per Hour
TPD	Tonnes per Day
TRL	Technology Readiness Level
UEL	Upper Explosive Limit
UP	Uttar Pradesh
UO	Unspecified Oxidation
VAT	Value Added Tax
VS	Volatile Solids
VPSA	Vacuum Pressure Swing Adsorption
WBA	World Biogas Association
WBREDA	West Bengal Renewable Energy Development Agency
WRI	World Resource Institute
YSZ	Yttrium Stabilised Zirconia
ΔH°	Standard Enthalpy Change

Preface

Central Electricity Authority (CEA) has prepared the first edition of the catalogue containing data on technologies for green fuels. The catalogue may continuously be updated as technologies evolve, if data change significantly etc. All updates will be listed in the amendment sheet and in connection with the relevant chapters, and it will always be possible to find the most recent version on the Central Electricity Authority's website. In parallel with this publication, a Technology Catalogue for Energy Storage has also been released. Previously, in 2022, the CEA published a Technology Catalogue for the Generation and Storage of Electricity.

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.

1. Technology catalogue guideline

This catalogue presents technologies for generation and conversion of energy carriers.

Most of the processes are characterised by multiple inputs and outputs, which include for example different fuels/feedstocks, electricity and process heat (recoverable or lost).

Upstream and downstream processes are not included; the datasheets do not provide information on prices for fuels, environmental impact from fuel procurement, or the economic consequences of the substitution of fossil fuels with other fuels.

The main purpose of the catalogue is to provide generalized data for analysis of energy systems, including economic scenario models and high-level energy planning.

The following sections (1.2 and 1.3) explain the formats of the technology chapters, how data was obtained, and which assumptions they are based on. Each technology is subsequently described in a separate chapter, making up the main part of this catalogue. The technology chapters contain both a description of the technologies and a quantitative part including a table with the most important technology data.

1.1. Definitions

INR: The Indian rupee is used as the standard currency throughout this document. One Indian rupee corresponds to 0.0121 US dollars (USD) or 0.00893 euros (EUR) for the price level in the year 2023.

LHV: 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 that the latent heat of vaporization of water in the reaction products is not recovered. 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.

HHV: 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% cannot be exceeded.

Electrolysers are assumed to be designed and operated for approximately 4000 full load hours annually by using the advantage of lower power prices by producing e.g. in hours of high renewable energy production. The assumed number of start-ups and consequent shut-downs for electrolysers, unless otherwise stated, is 50 per year.

Any exception to these general assumptions is documented in the relative technology chapter with a specific note.

1.2. Qualitative description

The qualitative part describes the key characteristics of the technology as concisely as possible. The following paragraphs are included where relevant for the technology.

1.2.1. Brief technology description

This section provides a brief description of how the technology works and the purpose it serves, along with an illustration showing its main components and working principles.

1.2.2. Input

The main raw materials and other forms of energy consumed (e.g. electricity, heat) by the technology or facility. Moisture content of the fuel and required temperature of the input heat is specified.

Auxiliary inputs, such as enzymes or chemicals assisting the process are mentioned and their contribution is described, if considered relevant.

1.2.3. Output

The output energy carrier as well as co-product or by-products, for example process heat. Temperature of the output heat is specified as well. Non-energy outputs may be stated as well, if relevant.

1.2.4. Energy balance

The energy balance shows the energy inputs and outputs for the technology. Here an illustrative diagram is shown based on data for the first year included in the data sheets, thus currently available technology.

For process heat losses and the produced energy carrier, it is important to specify information about temperature and pressure.

The first important assumption is that the energy content of all the fuels, both produced and consumed, is always expressed in terms of Lower Heating Value (LHV). Consequently, because of the presence of some latent heat of vaporisation, the energy balance may result in a difference between total energy input and total energy output.

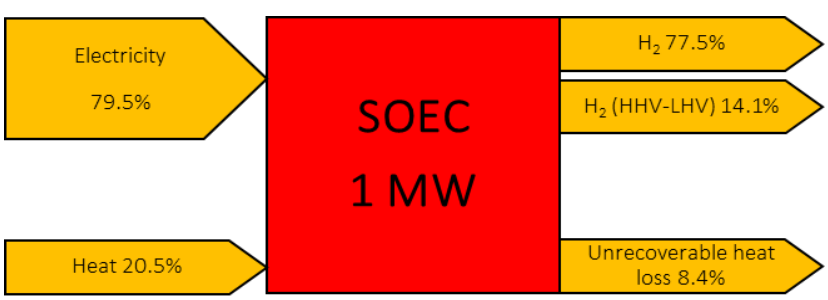


Figure 1-1: Example of Energy balance. All inputs sum up to 100 units.

For comparison, 100 units of total input are used to standardize the diagrams. This choice allows the reader to easily calculate the efficiency for each of the outputs, which will be directly equal to the energy value in the balance.

Each of the inputs and outputs has to be accounted for in the diagram, including auxiliary electricity consumption in input and process heat losses in output.

Auxiliary products, for example chemicals and enzymes, will in general only assist the process and are therefore not relevant for the energy balance. They should just be included as *auxiliary product input data.*

1.2.5. Typical capacities

The capacity, preferably a typical capacity (not maximum capacity), is stated for a single plant or generation facility. In case different sizes of plants are common, multiple technologies can be presented, e.g. Large, Medium and Small.

1.2.6. Regulation ability

Mainly relevant for hydrogen technologies where electricity is used as a main input. Description of the part-load characteristics, how fast can they start up and how fast are they able to respond to supply changes and how part-load or fast regulation leads to increased (or lower) wear and hence increased cost.

1.2.7. Space requirement

Space requirement is specified in 1,000 m^2 per MW output (*Typical plant capacity*). The space requirements may, for example, be used to calculate the rent of land, which is not included in the financial cost, since this cost item depends on the specific location of the plant.

1.2.8. Advantages/disadvantages

A description of specific advantages and disadvantages relative to equivalent technologies. Generic advantages are ignored; e.g. renewable energy technologies mitigating climate risks and enhancing security of supply.

1.2.9. Environment

Environmental and resource depletion impacts are mentioned, for example harmful emissions to air, soil or water; consumption of rare or toxic materials; issues with handling of waste and decommissioning, etc.

The energy payback time or energy self-depreciation time of the technology may also be mentioned. This is the time required to produce an amount of energy equal to the amount of energy that was consumed during the production of the technology.

1.2.10. Research and development perspectives

This section lists the most important challenges to further development of the technology. Also, the potential for technological development in terms of costs and efficiency is mentioned and quantified. Indian research and development perspectives are highlighted, where relevant.

1.2.11. Examples of market-standard technology

Recent full-scale commercial projects in India, which can be considered market-standard, are mentioned, preferably with links. A description of what is meant by “market-standard” is given in the introduction to the quantitative description section (Section 1.3). For technologies where no market standard has been established yet, reference is made to best available technology in R&D projects in India or alternatively in international projects.

1.2.12. Projection of performance and costs

Cost reductions and improvements of performance can be expected for most technologies in the future. This section accounts for the assumptions underlying the cost and performance in 2024 as well as the improvements assumed for the years 2030, 2050 and 2070.

The specific technology is identified and classified in one of four categories of technological maturity, indicating the commercial and technological progress, and the assumptions for the projections are described in detail.

In formulating the section, the following background information is considered:

Data for 2024

In case of technologies where market standards have been established, performance and cost data of recently installed versions of the technology in India or the most similar countries in relation to the specific technology are used for the 2024 estimates.

If consistent data is not available, or if no suitable market standard has yet emerged for new technologies, the 2024 costs may be estimated using an engineering-based approach applying a decomposition of manufacturing and installation costs into raw materials, labor costs, financial costs, etc. International references such as the IEA, NREL etc. are preferred for such estimates.

1.2.13. Learning curves and technological maturity

The future costs of technologies may be projected by applying a cost decomposition strategy, as mentioned above, decomposing the costs of the technology into categories such as labor, materials, etc. for which projections 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).

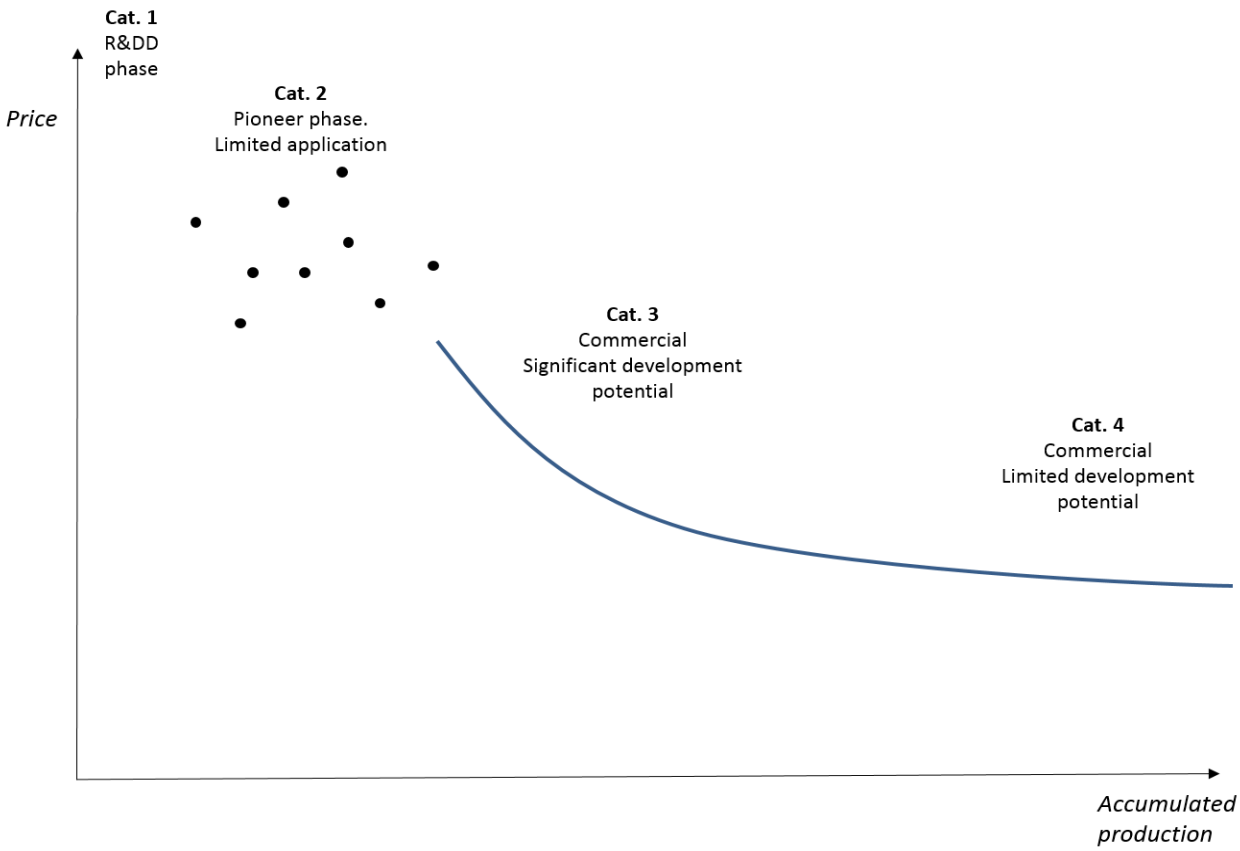


Figure 1-2: Technological development phases, correlation between accumulated production volume and price.

1.2.14. Uncertainty

The catalogue covers both mature technologies and technologies under development. This implies that the price and performance of some technologies may be estimated with a relatively high level of certainty whereas in the case of others, both cost and performance today as well as in the future are associated with high levels of uncertainty.

The uncertainty level could in general be described by referring to the maturity levels shown in Figure 1-2. This section of the technology chapters explains the main uncertainties of the data and identifies the areas where the uncertainty ranges in the quantitative description are based. This includes technological or market related issues of the specific technology as well as the level of experience and knowledge in the sector and possible limitations on raw materials. The issues should also relate to the technological development maturity as discussed above.

In the quantitative section, the level of uncertainty is illustrated by providing a lower and higher bound beside the central estimate. It should be noted, that projecting costs of technologies far into the future is a task associated with very large uncertainties. Thus, depending on the technological maturity expressed and the period considered, the confidence interval may be very large. It is the case, for example, of less developed technologies and long time horizons (2070).

1.2.15. Additional remarks

This section includes other information, for example links to websites that describe the technology further or provide key figures on it.

1.2.16. References

References are numbered in the text in squared brackets and bibliographical details are listed in this section.

1.3. Quantitative description

To enable comparative analyses between different technologies it is imperative that data are actually comparable: All cost data are stated in fixed 2023 prices, excluding taxes and subsidies. The information given in the tables relates to the development status of the technology at the point of final investment decision (FID) in the given year (2024, 2030, 2040, 2050 and 2070). 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 shown below, containing all parameters used to describe the specific technologies. The datasheet 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. The generic part is included to allow for easy comparison of technologies. In the technology-specific part, all parameters relevant to the specific technology's energy modelling, which are not included in the generic part, are added.

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 2024 and 2070.

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 in cost and performance data, the bounds expressing the confidence interval could result in large intervals. The uncertainty only applies to the market-standard technology. The uncertainty interval does not represent the product range (for example a product with lower efficiency at a lower price or vice versa). In case it is relevant to include products of different product range, this should be done by including more data sheets.

The level of uncertainty is, in general, only stated for the most critical figures such as investment cost and specific output shares. Other figures are considered if relevant.

All data in the tables are referenced by a number in the utmost right column (Ref), referring to source specifics below the table.

Notes include additional information on how the data is obtained, as well as assumptions and potential calculations behind the figures presented are included when relevant. Before using the data, please be aware that essential information may be found in the notes below the table.

The generic parts of the datasheets for green fuel technologies are presented below:

Technology		Name/ description									
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)		Note	Ref
Energy/technical data						Lower	Upper	Lower	Upper		
Typical total plant size (MW output) of the main fuel e.g. H_2											
Typical total plant size (1000 tonnes output//year) of the main fuel e.g. H_2											
- Inputs ($MWh_{input,n}$ /($MWh_{input\ total}$)											
A) Energy input share (% total input (MWh/MWh))											
B) Energy input share (% total input (MWh/MWh))											
C) Energy input share (% total input (MWh/MWh))											
X) Auxiliary products inputs (kg/MWh)											
Y) Auxiliary products inputs (kg/MWh)											
- Outputs ($MWh_{output\ ,n}$ /($MWh_{input\ total}$)											
A) Output share of main fuel (% total input (MWh/MWh))											
B) Output share secondary (% total input (MWh/MWh))											
C) Output share (% total input (MWh/MWh))											
D. Heat loss (% total input (MWh / MWh))											
- hereof recoverable heat loss (%-points of heat loss)											
- hereof unrecoverable heat loss (%-points of heat loss)											
X) Non-energy outputs (kg/MWh)											
Y) Non-energy outputs (kg/MWh)											
Forced outage (%)											
Planned outage (weeks per year)											
Technical lifetime (years)											
Construction time (years)											
Financial data											
Specific investment (INR/MW of main output)											
- hereof equipment (%)											
- hereof installation (%)											
Fixed O&M (INR/MW of total input)											
Variable O&M (INR/MWh of total input)											
Technology specific data											

1.4. Energy/technical data

1.4.1. Typical total plant size

The total capacity, preferably a typical capacity, is stated for a single plant or facility. It is expressed as MW of input, based on the energy content (LHV) of the fuel, and as kg of main product output.

1.4.2. Input

All inputs that contribute to the energy balance are included as *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 is specified if relevant (in the technology specific part).

For heat input the temperature is specified in the technology specific part.

Auxiliary inputs, such as enzymes or chemicals that are assisting the process, but do not contribute to the energy balance are included as *auxiliary products* (under *input*) and are expressed in kg/MWh of total energy input.

1.4.3. Output

Similarly, energy outputs are expressed as the percentage value in relation to the total energy input, or equivalently as MWh/MWh of total input.

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.

The process heat (output) is, if possible, separated in recoverable and unrecoverable heat and the temperatures are specified in the notes.

1.4.4. 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 maintenance) is given in days per year.

1.4.5. 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 remain within acceptable limits. For instance, power plant efficiencies often decrease slightly (a 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 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. As explained in the *General Assumptions*, different types of plants are designed for different annual utilization and typical number of start-ups per year. The expected technical lifetime considers these assumptions.

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.

1.4.6. Construction time

Time from final investment decision (FID) until commissioning completed (start of commercial operation), expressed in years.

1.4.7. Financial data

Financial data are all in INR, fixed prices, at the 2023-level and exclude all taxes and subsidies.

Indian data has been prioritized in developing this catalogue.

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 into equipment costs and installation costs. Equipment costs cover the components and machinery including environmental facilities, whereas installation costs cover engineering, civil works, buildings, grid connection, installation and commissioning of equipment.

The rent of land is not included, it is assumed that the differences in demand for land are insignificant for different types of RE fuel producing technologies.

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.

Cost of grid expansion

The costs for the connection of the plant to the system are included in the investment cost (shallow costs), while no cost of grid expansion or reinforcement is considered in the present data (deep costs).

Business cycles

The cost of energy equipment shows fluctuations that can be related to business cycles. This was the case of the period 2007-2008 for example, where costs of many energy generation technologies surged dramatically. The trend was general and global. An example is combined cycle gas turbines (CCGT), where investments increased sharply from $400-600 per kW to peaks of $1,250. When projecting the costs of technologies, it is

attempted, as far as possible, to compensate for the effect of any business cycles, that may influence the current prices.

Economy of scale

A typical size of the plant is stated in the technology description and datasheet. No economy of scale or scaling rule is considered in this catalogue. Instead, the cost component specified for the technologies is intended to be used in a limited range around the typical capacity and not, for example, for doubling the capacity.

In case a technology has a modular nature and could be scaled across different sizes, this will be specified in the specific technology chapter.

Operation and maintenance (O&M) costs

The fixed O&M is calculated as cost per plant size (INR/MW/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. The cost of reinvestments to extend the lifetime of the plants may be mentioned in a note if the data is available.

The variable O&M costs (INR/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. 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.

Start-up costs

The O&M costs stated in this catalogue include start-up costs and takes into account a typical number of start-ups and shut-downs. Therefore, the start-up costs should not be specifically included in more general analyses. They should only be used in detailed dynamic analyses of the hour-by-hour load of the technology.

Start-up costs are stated in costs per MW of typical plant size (INR/MW/startup), if relevant. They reflect the direct and indirect costs during a start-up and the subsequent shut down.

The direct start-up costs include fuel consumption, e.g. fuel which is required for heating up boilers and which does not yield usable energy, electricity consumption, and variable O&M costs corresponding to full load during the start-up period.

The indirect costs include the theoretical value loss corresponding to the lifetime reduction for one start up. For instance, during the heating-up, thermal and pressure variations will cause fatigue damage to components, and corrosion may increase in some areas due to e.g. condensation.

An assumption regarding the typical amount of start-ups is made for each technology in order to calculate the O&M costs and are included in the O&M. As a general assumption, biofuel production and

production/upgrade of biogas features 5 start-ups per year, while for electrolysers 50 start-ups per year are assumed. Any change with respect to this general assumption, e.g. for a specific technology which is characterized by a different utilization, is specified in the notes.

1.4.8. Technology specific data

Additional data is specified in this section, depending on the technology.

For example, operating temperatures are indicated for electrolysis and whenever process heat is available as output, its temperature is specified as well.

For electrolysis technologies, parameters regarding the regulation ability are specified as follow:

- Ramp Up Rate (% of Full Load/minute)
- Ramp Down Rate (% of Full Load/minute)
- Start-up time (minutes)
- Minimum load (%)

Relevant emissions to the environment, including emissions to water and air, are reported in g per MWh of total input of fuel at the lower heating value.

All plants are assumed to be designed to comply with the environmental regulation that is currently in place in India and planned to be implemented within the 2024 time horizon. For the projection for the future years the same assumption is made when estimating parameters related to this issue e.g. efficiency, cost and emissions.

1.5. References

Numerous reference documents are mentioned in each of the technology sheets. Other references used in the Guideline are mentioned below:

[1] Danish Energy Agency: ”Forudsætninger for samfundsøkonomiske analyser på energiområdet” (Generic data to be used for socio-economic analyses in the energy sector), May 2009.

[2] “Economy of Scale in Power Plants”, August 1977 issue of Power Engineering Magazine

[3] “Projected Costs of Generating Electricity”, International Energy Agency, 2015.

[4] “Konvergensprogram Danmark 2015”. Social- og Indenrigsministeriet. March 2015.

[5] “Technology Data for Hydrogen Technologies”.

[6] “Technology data for advanced bioenergy fuels”, Energistyrelsen

[7] “Hydrogen Analysis Resource center website”, US DoE. Url: http://hydrogen.pnl.gov/tools/lower-and-higher-heating-values-fuels

[8] “Energy Technology Perspectives”, International Energy Agency, 2012.

[9] International Energy Agency. Available at: http://www.iea.org/. Accessed: 11/03/2016.

2. Electrolysers

This chapter aims to provide a comprehensive understanding of the technical and economic aspects of small and large-scale electrolysis systems, aiding informed decision-making, though the data presented is not intended for specific investment purposes. Three technologies are discussed in detail: Alkaline Electrolyser (AE), Proton Exchange Membrane (PEM), and Solid Oxide Electrolyser Cell (SOEC).

2.1. Brief technology description

Production of low-carbon hydrogen has many pathways, but in recent years, electrolyser technology has found more attraction worldwide. The basic working of an electrolyser is based on the principle that when two electrodes (anode and cathode) are placed in water separated by a conductive medium (electrolytic solution), a potential difference is induced between them which results in the splitting of water into hydrogen on the cathode side and oxygen on the anode side. The generalised reaction involved in the process is as under:

$$H_2O \longrightarrow H_2 + ½\ O_2$$

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

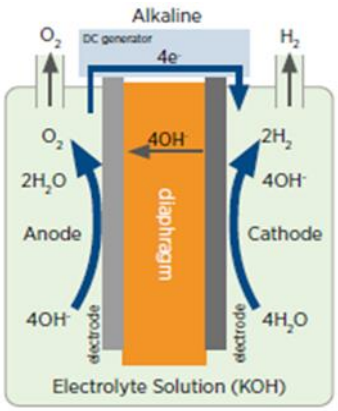
Among all electrolysis technologies, AE, PEM and SOEC technologies are predominant in the market, despite having varying Technology Readiness Levels (TRL) according to IEA [1]:

- AE - Alkaline Electrolyser (TRL 9) / Category 4- Commercial technologies, with large deployment,
- PEM – Proton Exchange Membrane (TRL 9)/ Category 4- Commercial technologies, with large deployment,
- SOEC - Solid Oxide Electrolytic Cell (TRL 7)/ Category 2 Technologies in the pioneer phase.

Alkaline and PEM electrolysers are already on the market. While alkaline electrolysers have a longer track record, particularly in the chlor-alkali industry, both technologies are currently at Technology Readiness Level 9 (TRL9) for dedicated hydrogen production. To remain competitive with conventional hydrogen production methods reliant on unabated fossil fuels, they both require policy backing and technological advancements. SOEC is quickly approaching commercialisation.

2.1.1. Alkaline Electrolyser (AE)

Developed in the late 18th century, this is the first ever electrolyser technology used in industries to produce hydrogen on a large scale and are the most common electrolysers commercially available. The AE cell operates at temperatures between 50-90 °C and can function at atmospheric pressure or under pressurized conditions up to 35 bar. Experimental AE are under investigation, which operates at up to 100 bar. 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) or NaOH. In Figure 2-1, the operation of AE is presented. Water is fed to the cathode wherein during electrolysis operation, OH ions are transported across the membrane to form hydrogen and oxygen. The electrical efficiency of the system is around 63–70%. The following chemical reactions occur during the process [2].



Anode: $4OH^- \rightarrow 2H_2O + O_2 + 4e^-$

Cathode: $4H_2O + 4e^- \rightarrow 2H_2 + 4OH^-$

Figure 2-1: Schematic of Alkaline Electrolyser [3]

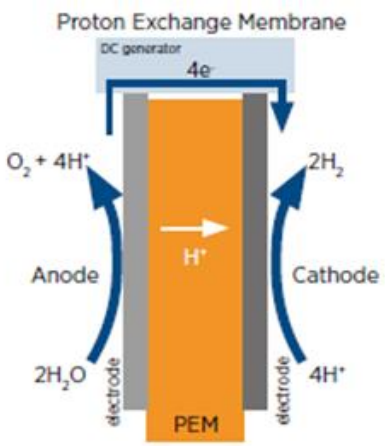
The main materials used in the various parts of AE are listed in Table 2-1.

Table 2-1: Materials used in AE.

Purpose/Use case	Material Used
Anode/Cathode	Nickel
Cathode Catalyst	Carbon-Platinum
Anode Porous Transport Layer (PTL)	Titanium/Zirconium
Cathode Porous Transport Layer (PTL)	Stainless steel mesh
Bi-polar / Separator Plate	Stainless Steel
Diaphragm	Nickel - Oxide

2.1.2. Proton Exchange Membrane (PEM)

The Proton Exchange Membrane (PEM), also known as Polymer Electrolyte Membrane, is a technology overcoming the challenges faced in AE, notably replacing the corrosive electrolytic solution with a polymer electrolyte (Nafion Perfluorinated membrane), thereby reducing the space and requiring a smaller area than AE. However, PEM electrolysers tend to be more expensive than AE systems, primarily due to the cost of the noble materials used as electrolyte and electrodes [4]. The schematic diagram of the PEM is presented in Figure 2-2. The electrical efficiency of the system is said to be 56–60%. The following chemical reactions occur during the process.



Anode: $2H_2O \rightarrow O_2 + 4H^+ + 4e^-$

Cathode: $4H^+ + 4e^- \rightarrow 2H_2$

Figure 2-2: Schematic of PEM electrolyser [3]

The main materials used in various parts of PEM are presented in Table 2-2.

Table 2-2: Materials used in PEM

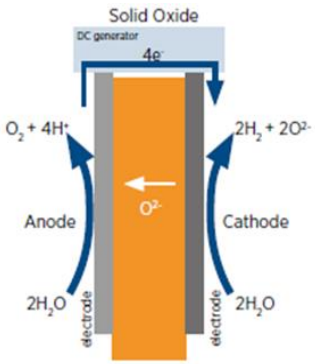
Purpose/Use case	Material Used
Anode	Iridium
Cathode	Platinum
Anode PTL material	Titanium
Cathode PTL material	Carbon fleece
Bi-polar / Separator Plate	Titanium/Gold/ Pt-Ti
Diaphragm	Solid Polymer

2.1.3. Solid Oxide Electrolytic Cell (SOEC)

SOEC is considered to be a special type of electrolyser because it uses two energy sources, heat and electricity, thereby reducing the electrical energy requirement. Further, the ability to utilize inherent heat generated during the process significantly enhances the overall efficiency of SOEC systems. As this technology requires operation at high temperatures of 700 °C and reaching as high as 1000 °C in some specific cases, it becomes challenging to select appropriate materials that could handle such high temperatures. This, in turn, are costly and are difficult to handle. Manufacturers currently are using Yttrium Stabilised Zirconia (YSZ). The research to optimise its overall performance is still in progress.

In the SOEC system, hydrogen is generated at the cathode part, and the oxide anions are passed to the anode, where oxygen forms through the solid electrolyte [4]. Refer to Figure 2-3 for the schematic diagram of SOEC.

The current efficiency of a system is around 74%–81%. The following chemical reactions occurs during the process.



Anode: $2O^{2-} \rightarrow O_2 + 4e^-$

Cathode: $2H_2O + 2e^- \longrightarrow 2H_2 + 2O^{2-}$

Figure 2-3: Schematic of SOEC electrolyser [3]

The main materials used in the various parts of SOEC are listed in the Table 2-3.

Table 2-3: Materials used in SOEC

Purpose/Use case	Material Used
Anode	Lanthanum Strontium Manganite (LSM) - YSZ
Cathode	Nickel - YSZ
Electrolyte	YSZ

2.1.4. System description

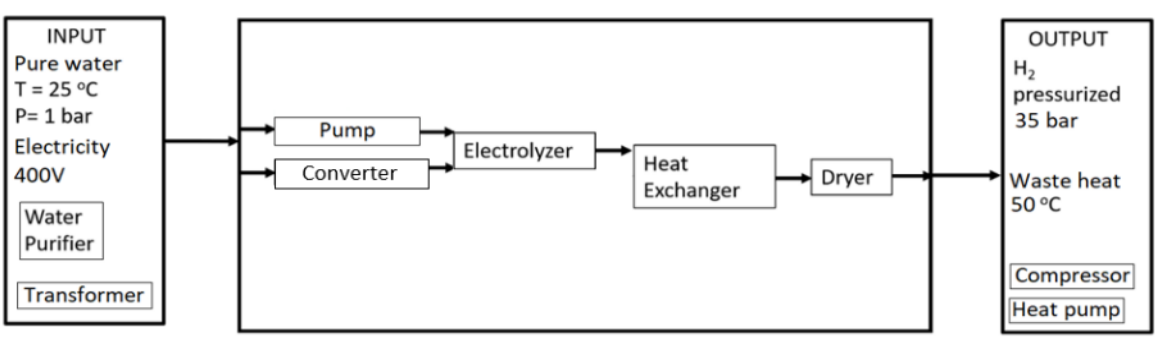


Figure 2-4: A sketch of an electrolysis system for AEC and PEM. [5]

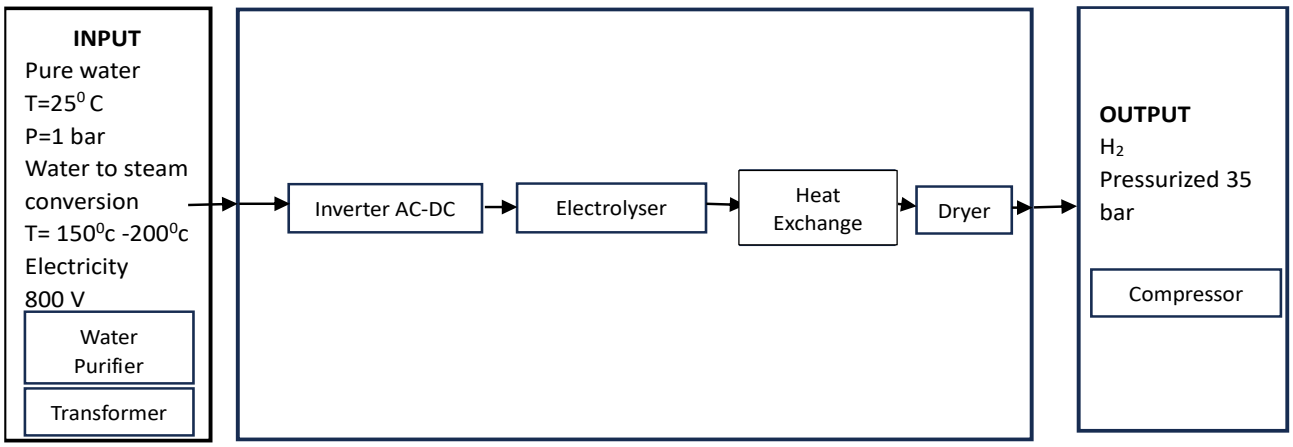


Figure 2-5: A sketch of an electrolysis system for SOEC

The figures above outline the input, system components, and output for an AE or PEM system and an SOEC system, respectively. The box on the left shows the required inputs, along with additional components like a water purifier and transformer. These components are not of the electrolysis system but may be necessary depending on the local water quality and grid level. The box in the middle represents the electrolysis system, with all components here included in the CAPEX. The box on the right displays the output streams and any additional components that may be needed to enhance the output streams.

For AE, water is first fed into the purifier, then sent to the AE module. The water is compressed by a pump before entering the electrolyser stack. After the electrolysis products are formed, they pass through a heat exchanger. Oxygen is then removed using a de-oxy column, and the products are dried before being sent to storage.

The specifications based on commercially available systems are stated in Table 2-4 below.

Table 2-4: Specifications of the electrolysis technologies used for comparative analysis

Technology	AE [6]	PEM [6]	SOEC [7]
Input temperature and pressure (pure water)	25 °C, 1 bar	25 °C, 1 bar	25 °C, 1 bar & 150 °C – 200 °C (conversion of water to steam)
Input electricity	400 VAC and up to 33 kV (using rectiformers)	400 VAC and up to 33 kV (using rectiformers)	800 VAC
Water for electrolysis purity (input)	5 µS/cm	0.2-1 µS/cm	1 µS/cm
H_2 purity (output)	99.99	99.99	99.99

H_2 output pressure (range)	50 bar	50 bar	35 bar
Waste heat temperature (output)	50 °C	50 °C	-

2.2. Input

For all three electrolysis technologies discussed above (AE, PEM, SOEC), the input is electricity and water (high-water purity is desired). The conductivity of the water used serves as an indicator of its quality. The water should meet the ASTM type I/II quality, for which the conductivity would be < 5 μScm^{-1}, 0.2 μScm^{-1}, and 1 μScm^{-1} for AE, PEM and SOEC, respectively. For SOEC the water is fed as steam and hence this technology also requires thermal energy. If the hydrogen produced was to be used for synthetic fuel, then the waste heat of these synthesis processes (e.g. Fischer-Tropsch synthesis, Haber-Bosch process etc.) could be used to produce steam for SOEC electrolysis.

2.3. Output

For all three electrolysis technologies, the output is hydrogen, oxygen and excess heat from the process [4] [8]. For SOEC, the recoverable excess heat will be used to produce steam that can then be used as input for further SOEC electrolysis. Oxygen finds applications in various industries, including paper and pulp, glass manufacturing, water treatment, aquaculture, steel and metal production, healthcare, food processing, and oxyfuel carbon capture and storage. The excess heat may be used for various purposes as well, such as steam generation for industrial processes, or even for power desalination plants or as district heating in the case of PEM and AE. AE and PEM systems are found in the literature to generally have operating temperatures of 50-90 °C and 60-80 °C, respectively. [8] [9]

2.4. Energy balance

An energy balance for each of the three electrolysis technologies, AE, PEM, and SOEC, is investigated in this section and presented in Figure 2-6, Figure 2-7, and Figure 2-8. For AE and PEM, the input is 100% electricity, while for SOEC (in 2020), electricity is 79.5% of the input energy, while the remaining 20.5% is supplied by thermal sources. SOEC operate at high temperatures i.e., over 600 °C so the thermal energy is used to convert water into steam.

In addition, energy flow diagrams with the efficiency of conversion to hydrogen and usable heat have been depicted based on [5]. For AE and PEM, 5% of the energy is estimated to be unrecoverable heat loss [5].

In Figure 2-6, the energy balance for AE is shown, where 66.5% of the output is hydrogen (Lower Heating Value (LHV) basis), and 16.4% is recoverable heat which can potentially be used for district heating in colder regions, industrial processes, greenhouses and other purposes.

Similarly, in Figure 2-7, the energy balance for PEM is shown, where 58% of the output is hydrogen (LHV basis), and 26.4% is recoverable heat which can possibly be utilized for district heating systems, especially in colder regions. Additionally, industries can leverage this recovered heat for processes such as drying, preheating, or steam generation. Greenhouses, residential buildings, and commercial spaces can also benefit from this heat, contributing to energy efficiency. Integrating waste heat recovery into existing systems further enhances overall sustainability.

Further, in Figure 2-8 the energy balance for 1 MW SOEC is shown. The energy balance shows that 79.5% of the input energy comes from electricity and 20.5% from heat. This differentiation is done since SOECs operate at higher temperature wherein, the water needs to be converted to steam and the operation occurs at temperatures over 600°C.



Figure 2-6: Energy balance for a 1 MW AE cell compared on LHV basis. [5]

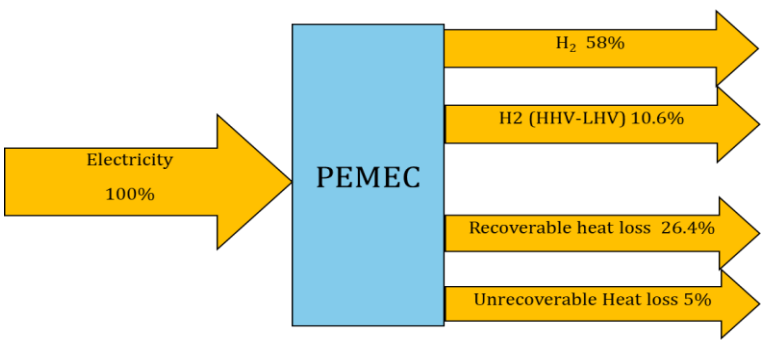


Figure 2-7: Energy balance for a 1 MW PEM electrolysis cell compared on LHV basis. [5]

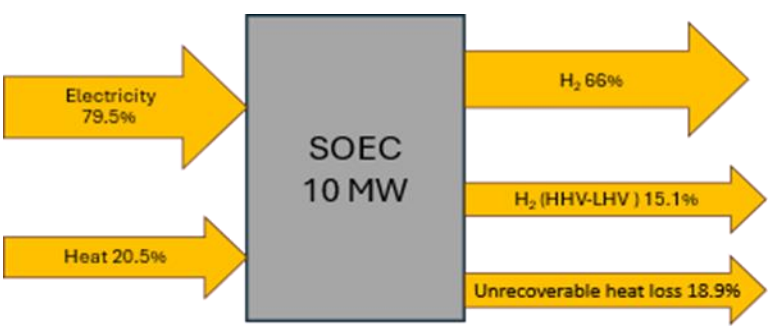


Figure 2-8: Energy balance for a 1 MW SOEC compared on LHV basis. [10]

2.5. Typical capacities

Some examples of recently commissioned plants include:

- Deendayal Port Authority's green-hydrogen plant in Kandla, Gujarat of 1 MW (as phase-1 of a planned 10 MW) was developed by DPA (implementation by L&T) for port buses and on-site operations; it uses an indigenously made alkaline electrolyser (AEC) and was commissioned on 31 July–1 Aug 2025. [11]
- GAIL's 10 MW plant at Vijaipur, Madhya Pradesh was developed by GAIL for its gas-processing complex; it employs PEM electrolysers and was commissioned on 24 May 2024. [12]

- ACME's integrated green-hydrogen-to-ammonia facility at Bikaner, Rajasthan, developed by ACME for green-ammonia production, uses alkaline electrolysis (~2.5 MW) and has operated since 2021. [13]

Since the green hydrogen sector is still in its nascent phase, most plants commissioned so far are of smaller capacity, and it is likely that future plants will be larger. Some other projects are discussed in section 2.11.

Globally, the development of electrolyser systems has accelerated due to their use cases and national commitments. There are 20 leading manufacturers of electrolyser technology, with 95% focusing on AE or PEM technologies [14]. Currently, a large AE system (20 MW) is manufactured by ThyssenKrupp, while a large PEM system (24 MW) is produced by the Linde group. Sunfire, a German company, has demonstrated the first megawatt-scale SOEC project, with a capacity of 2.6 MW consisting of 12 modules of 216 kW each [15]. AE technology, with its favourable size and operating conditions, is expected to grow in the next decade, similar to PEM electrolysers. According to the IEA electrolyser database, several gigawatt-scale AE and PEM projects are in the pipeline, but scaling SOEC systems to gigawatt levels remains difficult due to operational challenges [16].

2.6. Regulation ability

In general, electrolysis systems can operate very dynamically, with limitations mainly due to heat management, the maximum voltage of the rectifier, and the time constants of external components [17]. A cold start refers to start-up from ambient temperature after a long shutdown, while a warm start refers to start-up from heated standby or idle mode, where the system is kept at operating temperature and pressure, if necessary. Minimum load capacity is the lowest input required for the system to operate and generate output. The cold start-up time, warm start-up time, and minimum load capacity for the three systems are shown in the datasheets.

2.7. Space requirements

The lack of commercial electrolyser projects in the Indian market makes it difficult to accurately estimate the required setup area. According to IRENA, a 1 GW alkaline electrolyser facility occupies approximately 100,000-170,000 m^2 (10-17 ha), equivalent to 100-170 m^2/MW, while a 1 GW PEM facility occupies approximately 80,000-130,000 m^2 (8-13 ha), equivalent to 80-130 m^2/MW, with the smaller PEM stack footprint translating into a 20-24% reduction in overall facility footprint compared to alkaline systems of the same capacity [18]. It is important to note that these estimates may vary based on specific project designs and local conditions.

Considering only the electrolyser unit footprint, and therefore excluding balance of plant, the Danish Energy Agency's Technology Catalogue on renewable fuels generation estimates a land requirement of 25 m^2/MW for alkaline electrolysis (AE), around 10 m^2/MW for PEM electrolysis, and approximately 30 m^2/MW for SOEC, in terms of input electric energy [10]. These figures offer a preliminary understanding of space requirements for different electrolyser technologies in India, but more data from commercial projects will be needed to refine these estimates.

2.8. Advantages/disadvantages

PEM technology offers advantages such as a smaller size, flexible operation, and higher-pressure output. However, it also has drawbacks: it is less mature, has a shorter stack lifetime, and is more expensive than AEM. The high upfront costs are mainly due to the use of precious metals like iridium and platinum, which

are also considered critical materials. SOECs have higher efficiencies and low material costs. This technology has significant promise, especially because it can operate in reverse as fuel cells and can be integrated into other high-temperature processes or synthetic fuel production.

Table 2-5 shows the advantages and disadvantages of all the three technologies.

Table 2-5: A summary of advantages and disadvantages of the electrolysis technologies investigated. [10]

	Advantage	Disadvantage
Alkaline Electrolyser	The technology is very mature and scalable AEC has a low operating temperature, with a quick start up (pressurized) for response in grid services making it suitable for use as a flexible technology. Long stack lifetime of more than 70,000h (2020) currently. MW scale electrolyser systems are already being deployed	Less flexibility under atmospheric operation. The use of highly caustic electrolyte in AE. Leakage of KOH. High membrane resistance Low maximum operational current density, nominally operated around 0.6-1 A/cm^2 as average.
Proton Exchange Membrane	PEM has a low operating temperature, low noise, high power density. Quick response time. Pressurized hydrogen can be produced for direct storage without compression; however, it is challenging. Current densities >2.0 A/cm^2 can be used for operational systems leading to compact system sizes. MW scale electrolyser systems are already being deployed Smaller footprint than AE.	Very sensitive to impurities, with a prerequisite of very pure water (Type I) as input. Lifetime of the commercially available systems is still uncertain. Catalyst used in electrode layers are expensive and scarce. PEM constituents 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.

Solid Oxide Electrolytic Cell	SOEC has high efficiency (up to 95 %), high production rates. SOECs can be used to make synthesis gas from co-electrolysis of steam and CO_2. CO_2-electrolysis plants have been commercialized. SOECs can cope with transient variation due to quick response time. SOECs can be used reverse mode as a fuel cell for grid balancing.	SOECs are still in demonstration phase for large scale applications for hydrogen production and are not readily commercially available. SOEC's units are about 10 times smaller in H_2 output than PEM and AE. The stack components are susceptible to corrosion. Commercially available lifetime system is short compared to PEM and even shorter to AE. SOECs can be operated only at current densities up to 0.5 A/cm^2

2.9. Environment

One of the major environmental concerns related to this technology is waste generation throughout the lifetime of the electrolyser. The availability, extraction, and disposal of critical materials[1] used in electrolysers pose environmental risks. Proper waste management and expanding recycling practices can help mitigate this threat [10].

Life Cycle Assessment (LCA) can help to map pollution factors of various processes. There are various studies/analyses on this aspect. One such study is: Susanne Lundberg, "Comparative LCA of Electrolysers for Hydrogen Gas Production", 2021 [19] and another is "Critical Materials Assessment, U.S. Department of Energy, 2023" [20].

Table 2-6, Table 2-7, and Table 2-8 list the materials used in AE, PEM, and SOEC technologies, respectively, along with their material criticality factors (Low, Medium, or High). This criticality reflects supply risk, economic importance, and environmental concerns related to extraction or mining. The material value refers to the cost of the materials used [21].

The Ministry of New and Renewable Energy, through OM No 353/35/2022-NT dated 18 August 2023, defined Green Hydrogen standard, establishing specific criteria for its production. The definition incorporates a threshold for greenhouse gas emissions (non-biogenic) at 2 $kgCO_2eq/kg\ H_2$ for system boundaries. The threshold is measured as an average over the last 12 months [22].

The Green Hydrogen Certification Scheme of India (GHCI) adopts a boundary which encompasses all direct emission sources and includes indirect emissions from the electricity and/or fuel used during the Green Hydrogen production process as defined below. For Green Hydrogen produced through electrolysis, the non-

[1] Critical materials are the resources needed to produce numerous key technologies for the energy transition, including wind turbines, solar panels, batteries for EVs and electrolysers e.g. lithium, nickel, cobalt, copper and rare earth elements (REEs). *Gielen, D. (2021), Critical minerals for the energy transition, International Renewable Energy Agency, Abu Dhabi.*

biogenic greenhouse gas emissions arising from water treatment, electrolysis, gas purification, and drying and compression of hydrogen shall be included.

The emissions from the construction, manufacturing, and decommissioning of the capital goods (including hydrogen production device, etc.), business travel, employee commuting, and upstream leased assets shall not be included in Green Hydrogen production boundary. The emissions owning to generation and transmission of renewable electricity shall also not be included. However, emissions of the processes mentioned in GHCI from upstream leased assets shall be covered.

GHG emissions arising from the conversion/use of input materials onsite shall be included in the emission intensity calculations. Those input materials, which are not providing energy to the process, would include for example, water, oxygen, salts, catalysts, solvents, and acids. Only materials generated offsite and brought across the system boundary into the hydrogen production facility shall be accounted for within this emission category. All other flows that cross the system boundary to generate any materials on site shall be accounted for within their corresponding emission categories.

The system boundary shall include all the production stages till the purification and compression of hydrogen. Producers are required to provide the final composition of the hydrogen produced, as well as the pressure at which it has been produced. The composition and pressure level of the hydrogen shall be documented on the certificate.

2.9.1. Alkaline Electrolyser

Most of the materials used in AE, such as steel and nickel, are considered non-critical. AE is regarded as the most affordable electrolyser technology because it avoids the use of precious metals. The material criticality for different materials used in AE is listed in Table 2-6.

Table 2-6: Criticality analysis for Material of AE Electrolyser [21]

Component	Material	Purpose	Material Value	Material Criticality
Electrolyte	Potassium Hydroxide (KOH)	Electrolyte	Medium	Low
Anode	Platinum (Pt)	Catalyst material	High	High
	Zirconium	Porous Transport Layer (PTL)	Low	Low
Cathode	Nickel	Supporting material	Medium	High
	Titanium	Porous Transport Layer (PTL)	Low	Low
Supporting Material	Steel	Bi-Polar Plates	Medium	Low

The AE electrolysis process utilizes an alkaline electrolytic solution, typically potassium hydroxide (KOH), to facilitate the electrochemical reactions. As per the Material Safety Data Sheet (MSDS), this alkaline solution is found toxic for aquatic organisms as it disables the oxygen dissociation in the water body and leads to an increase in the pH of the water. Since the electrolyser system is mostly situated near to water body due to its requirement of water as input, a stringent plan for the safe disposal of used electrolytic solution should be in place.

2.9.2. Proton Exchange Membrane

This technology is characterized by the use precious metals like iridium and platinum, which are also considered critical materials. The material criticality of these materials and others used in PEM electrolysers is listed in Table 2-7.

Table 2-7: Criticality analysis for Material of PEM Electrolyser [21]

Component	Material	Purpose	Material Value	Material Criticality
Electrolyte	Pefluorosulphonic acid (PFSA)	Electrolyte	Medium	Medium
Anode	Iridium	Catalyst material	High	High
	Titanium / SS mesh	Gas Diffusion Layer (GDL)	Low	Medium
Cathode	Platinum	Catalyst Material	High	High
	Titanium	GDL	Low	Medium
Supporting Material	Stainless Steel	Bi-Polar Plates	Low	Medium

2.9.3. Solid Oxide Electrolytic Cell

The material criticality of different materials used in SOEC is given in Table 2-8.

Table 2-8: Criticality analysis for Material of SOEC Electrolyser [21]

Component	Material	Purpose	Material Value	Material Criticality
Electrolyte	Yttria-stabilized Zirconia (YSZ)	Electrolyte	Medium	High
Anode	Ni based oxide doped with YSZ	Catalyst material	Medium	High
	Nickel	Supporting material	Medium	Moderate
Cathode	Strontium doped lanthanum manganite	GDL	Medium	High
	Lanthanum strontium cobalt ferrite	Catalyst material	Medium	High
Supporting Material	Doped Lanthanum Chromate (or) Inert metals	Bi-Polar Plates	Medium	High

2.10. Research and development perspectives

This section provides a brief discussion of the ongoing R&D objectives, emphasizing the critical need to overcome barriers to commercialization and highlighting the technologies most likely to be deployed in the market. Furthermore, it clarifies the prioritized areas within AE, PEM, and SOEC for R&D efforts and offers enhanced contextualization of the figures to underscore their implications for the commercial viability of hydrogen production technologies. It is expected that for all three technologies, R&D efforts will be put up to upscale the green hydrogen economy across the globe. These efforts are aimed at addressing specific challenges across various aspects of the technology, including cell, stack, system, manufacturing, and supply chain, with a primary focus on reducing capital costs, improving efficiency, and extending system lifetime to enable commercialization. To elucidate the potential impacts of these R&D endeavours, a study conducted by O. Schmidt et al. [23] explores the effects of varying levels of R&D investment (1x, 2x, and 10x) on capital costs and lifetime.

At current funding levels (RD&D (Research, Development and Deployment), 1x), production scale-up leads to cost impacts ranging from 23% to 27% by 2030 across three electrolysis technologies. This impact is higher than increasing R&D funding only (R&D, 2x and 10x), which results in 0% to 24% by 2030. Cost reductions are primarily attributed to economies of scale rather than technological advances.

Production scale-up is most impactful for technologies not yet commercialized. Learning during early-stage production has a larger effect on cost reduction for SOEC compared to already partially exploited AE and PEM systems. The learning curve theory suggests that doubling cumulative production capacity leads to constant relative cost reduction, benefiting early-stage technologies more than mature ones. Furthermore, PEM is expected to have higher cost reduction potential by 2030 than AE, likely due to PEM's lower technological maturity.

Apart from the traditional electrolysers i.e., AE, PEM and SOEC, another technology is getting traction which is Anion Exchange Membrane (AEM). AEM is considered to have huge potential for large scale application.

2.11. Examples of market-standard technology

This section provides a summary of various electrolysis systems implemented in India, both commercially and in demonstration phases. The electrolysers are deployed at different locations for a range of applications and purposes. These are summarized in Table 2-9 along with their specifications.

It is important to note that all the plants listed as "Under Construction" in the table are nearing their commissioning phase. Additionally, several other commercial-scale green hydrogen plants are currently in development across the country.

Table 2-9: Examples of market technology for hydrogen production via electrolysis [2].

Organization	Location	Electrolyser Type	Technology Provider	Plant Status*	Application	Specification	Ref.
Larson and Toubro	Hazira, Gujarat	AE + PEM	McPhy	O + UC	NG blending	380 kW+ 400 kW	[24]
Oil India Limited	Jorhat, Assam.	AEM	H2e Power	O	NG blending - Fuel	100kW (4.7 Nm^3 /h)	[25]
ACME	Bikaner, Rajasthan	AE	Kapsom	UC	Green Ammonia	500 Nm^3 / h	[26]
NTPC Limited	Leh, Ladakh	AE	Gastec	UC	Mobility	2 x 375 kW (2 * 75 Nm^3/h)	[27]
NTPC Limited	Greater Noida, UP	AE	AHES	UC	Mobility	2 x 800 kW (2 * 150 Nm^3/h)	[28]

***UC** – Under Construction; **O** – Operational; **P** - planned

[2] More projects can be found in the Green Hydrogen Project database by MNRE: https://nghm.mnre.gov.in/project.php and in the Manufacturing of electrolysers and fuel cells database by MNRE: https://nghm.mnre.gov.in/project.php?cat=16&language=en

Table 2-10 shows the list of the company with their Bid manufacturing capacity, Awarded manufacturing capacity and maximum incentive (subsidy).

Table 2-10: List of companies with their Bid manufacturing capacity, Awarded manufacturing capacity and Maximum incentive. [29]

Company	Bid manufacturing capacity (MW/year)	Awarded manufacturing capacity (MW/year)	Maximum incentive allocation (million rupees/year)
Reliance Electrolyser Manufacturing Limited	300	300	4,440
Ohmium Operations Private Limited	137	137	2,028
John Cockerill Greenko Hydrogen Solutions Private Limited	300	300	4,440
Advait Infratech Limited (consortium with Rajesh Power Service Private Limited)	100	100	148
Jindal India Limited	300	300	4,440
L&T Electrolysers Limited	300	63	932
Homihydrogen Private Limited	101.1	101.1	1,502
Adani New Industries Limited	300	198.5	2,938

Some concrete examples of projects are presented below.

2.11.1. Alkaline Electrolyser

i) Green Hydrogen Plant, Hazira, Gujarat [30]

Larsen & Toubro (L&T) has commissioned a green hydrogen plant in Hazira, Gujarat. The production of Green Hydrogen is based on an alkaline electrolysis process powered by rooftop solar and battery storage. The plant produces 45 kg of Green Hydrogen daily, which will be used for captive consumption in the company's Hazira manufacturing complex. Additionally, high purity oxygen generated as a by-product is employed in other applications.



Figure 2-9: Green Hydrogen Plant, Hazira, Gujarat. [30]

Table 2-11: Technical Specifications of Hazira Plant.

Component	Capacity
Electrolyser Capacity (Alkaline)	380 kW
Electrolyser Capacity (PEM)	420 kW (Future expansion plan)
Total Electrolyser Capacity	800 kW
Rooftop Solar Plant Capacity	990 kW peak DC
Battery Energy Storage System (BESS)	500 kWh
Total Plant Area	3000 sq. meters
Project Capacity (Tonnes H_2 per Annum)	15

Noteworthy plant information:

- Hydrogen's purity is about 99.99%.
- The manufacturing facility will use a blend of 15% hydrogen with natural gas as a fuel.
- The use of hydrogen as fuel and the high purity oxygen in cutting and welding applications, highlights the versatility and potential applications of Green Hydrogen beyond captive consumption.
- The future expansion plan includes the addition of a 420 kW PEM electrolyser and an augmentation of the solar plant capacity to 1.6 MW peak DC, indicating a proactive approach to meet potential increased demand.

2.11.2. Proton Exchange Membrane (PEM)

Green Hydrogen Project, Guna Madhya Pradesh [31]

GAIL (India) Limited was awarded a contract to set up one of the largest Proton Exchange Membrane (PEM) electrolyser hydrogen plants in India. The project will be installed in Guna District of Madhya Pradesh and will be based on renewable power. It was commissioned in May 2024.

The Project has been designed to produce around 4.3 Metric Tonnes of Hydrogen per day (approx. 10 MW capacity) with a purity of about 99.999 %. Initially, the hydrogen produced from this unit will be used as a fuel along with natural gas for captive purposes for various processes and equipment running in the existing plant at Vijaipur. Further, this hydrogen is planned to be dispensed to retail customers in the nearby geographies, transported through high pressure cascades.

Table 2-12: Technical Specifications of Green Hydrogen Project, Guna, MP.

Item	Specification
Technology	PEM
Hydrogen production	1570 Tonnes H_2/year
Power Capacity	10 MW
Hydrogen Purity	99.999 Volume %

Shell's Rhineland Refinery in Wesseling, Germany [32]



Figure 2-10: 10 MW PEM electrolyser at Shell's Rhineland Refinery in Wesseling.

The unit has a capacity of 10 MW and is located in Wesseling, Germany.

Table 2-13: Technical Specifications of electrolyser plant at Shell's Rhineland Refinery in Wesseling.

Item	Specification
Technology	PEM
Power capacity	10 MW
Hydrogen purity	99.9995%

2.11.3. Solid Oxide Electrolytic Cell (SOEC)

GInHy 2.0 Project, Salzgitter Flachstahl GmbH, Germany [33]



Figure 2-11: GrInHy 2.0 Project, Salzgitter Flachstahl GmbH, Germany.

The GrInHy 2.0 project focuses on harnessing the substantial cost-reduction potential of high-temperature electrolysers. An added dimension of value arises if the electrolyser system can operate reversibly using a reversible Solid Oxide Cell (rSOC). The project is strategically integrated and operational within the iron and steel works at Salzgitter Flachstahl. The prototype system, boasting a nominal electrolyser capacity of 720 kWAC, serves the integrated iron-and-steel-works' requirements. The prototype's adaptability is demonstrated by its operation with natural gas and hydrogen in fuel cell mode, showcasing its versatility in various energy sources. Over approximately 20,000 hours of operation, significant quantities of high-quality hydrogen were produced and utilized for critical industrial processes, showcasing the project's practical applicability.

Table 2-14: Technical Specifications of GrInHy 2.0 Project.

Item	Specification
Technology	SOEC
Hydrogen production	200 Nm^3 H_2/h
Power capacity	720 kWAC

2.12. Projection of performance and costs

The projection of costs is based on the sources referenced in the corresponding datasheets. The key references are BloombergNEF [34], TNO [35], Hydrogen Council [36], Viet Nam Technology Catalogue [37], TERI [38], as well as insights from Indian stakeholders.

The total expense of setting up an electrolyser system can be categorized into three key components: the stack, the balance of plant (BoP), and installation costs. The stack typically makes between 30% and 50% of the system's cost before installation. [35] [34] The remaining portion covers equipment that prepares the inputs (water and power) and processes the output (hydrogen storage and compression), as the power supply unit (such as the rectifier), the oxygen separator tank, circulation pumps, the cooling system, valves, piping, and various instrumentation—all of which are part of the balance of plant. Additionally, installation expenses can contribute up to half of the final overall cost.

Not all components of an electrolysis system are likely to fall in cost at the same rate. Innovative elements, like electrolyser stacks, may experience faster declines compared to conventional parts, such as transformer stations, utilities, and civil works, which connect the electrolyser systems to the high-voltage grid. [35] Further, water availability and the power solution can significantly impact costs, causing variations between projects. Water availability and the power solution will continue to drive cost variations between projects. As this trend is expected to persist, the broad range of electrolysis system Capex is likely to remain through 2050. [34]

According to a study from TNO, economy of scale reduces costs as electrolyser capacity increases from 100 MW to 200 MW, lowering Capex by 13% and O&M costs by 22%. This leads to a lower levelized cost of hydrogen ($LCOH_2$), making larger systems more cost-efficient. [35]

Increasing the voltage in an electrolyser stack reduces unit stack costs by increasing hydrogen yield but comes at the expense of efficiency. This trade-off means that a system with lower Capex may still have a higher $LCOH_2$ if its lower efficiency leads to greater electricity consumption, the primary driver of operational costs. Therefore, to ensure meaningful comparisons, cost analyses must account for efficiency differences. [34]

Investment costs have risen in recent years due to higher energy, raw material, and labour costs, along with increased interest rates. Beyond inflation, limited electrolyser manufacturing capacity, particularly in Europe and the U.S., has also contributed to price increases. [35] India's local labour costs are 55% of those in China, but this advantage is offset by the need to import materials like steel, which are unaffected by local labour costs. For this estimate, India's non-equipment costs are expected to be 70% of those in China. [34]

The specific investment costs for electrolyser technologies, including Alkaline Electrolysis (AE), Proton Exchange Membrane (PEM), and Solid Oxide Electrolysis Cells (SOEC), are projected to decline significantly from 2024 to 2070. This reduction reflects ongoing technological advancements, economies of scale, and improved manufacturing efficiencies. Due to high uncertainty beyond 2050, all values for 2070 are assumed to remain the same as in 2050. Across all technologies, costs are expected to decrease substantially by 2050. These declines are accompanied by corresponding reductions in the percentage variation from 2024, indicating steady improvements in cost-efficiency. By 2030, AE's cost is projected to decrease to 67%, PEM to 69%, and SOEC to 63% of their respective 2024 costs. Further reductions are anticipated by 2040, with AE at 53%, PEM at 50%, and SOEC at 55%, ultimately reaching 46%, 40%, and 42% respectively by 2050.

In addition to cost reductions, efficiency improvements are observed across all technologies. AE's efficiency is expected to increase from 58% in 2024 to 69% by 2050. PEM shows a similar trend, improving from 55% in 2024 to 66% by 2050. SOEC starts with a higher efficiency of 67% in 2024, increasing to 72% by 2050. These efficiency gains contribute to overall cost reductions by enhancing energy utilization, thus supporting the economic viability of electrolysis technologies.

Despite these cost and efficiency improvements, uncertainty remains, particularly for emerging technologies like SOEC, which exhibits broader cost variability due to its evolving maturity. The projected cost uncertainties

highlight the influence of factors such as raw material prices, technological breakthroughs, and regional market conditions. Overall, these trends suggest a positive outlook for the economic viability of electrolysis technologies, supporting their role in the future hydrogen economy.

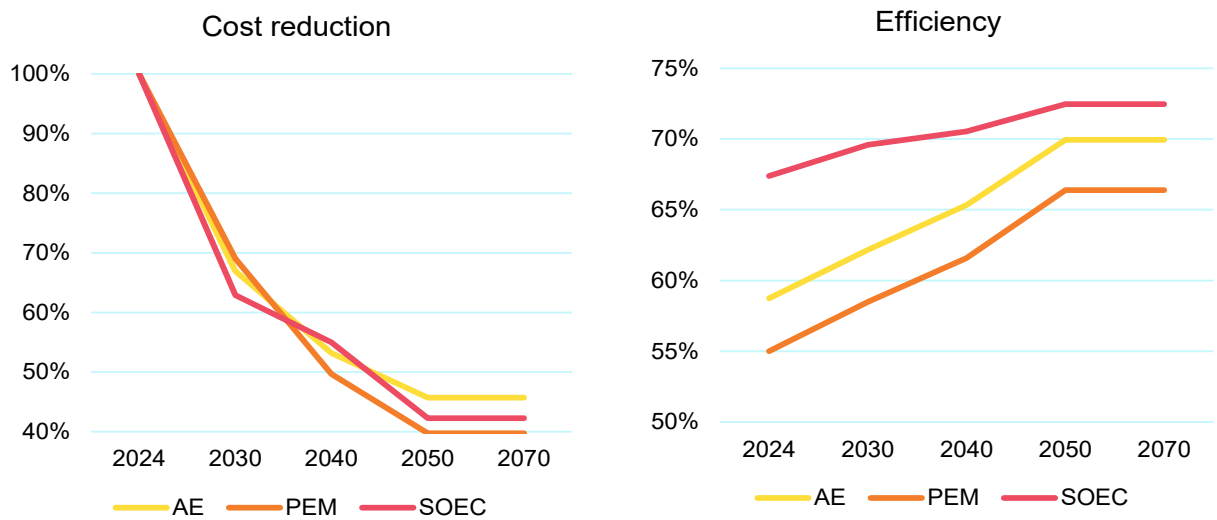


Figure 2-12: Percentage of variation of the electrolysers specific investment (INR/KW of total electric input) and efficiency (%) total electric input (MWh / MWh)) of Alkaline, Proton Exchange Membrane and Solid Oxide electrolysers between 2024 and 2070 according to Indian stakeholders

2.13. Uncertainty

Uncertainty remains a critical factor in projecting cost and efficiency trends for electrolysis technologies. Price estimates are based on literature reports from experts in academia and industry, but significant variability exists due to factors like non-standardized project designs, immature development processes, and differing assumptions about contingency costs, which can range from over 30% to under 10% of tangible costs. Additionally, regional disparities are pronounced, with system Capex in Europe and the US up to four times higher than in China, driven by differences in labour costs and supply chain efficiencies according to BNEF. Trade policies and potential shifts in manufacturing dominance further add to this unpredictability. The industry's early stage also leaves room for disruptive technologies or unforeseen events, making regular updates to forecasts essential. Overall, these uncertainties highlight the need for continuous government support, robust policy frameworks, and adaptive strategies to foster the economic viability of electrolysis technologies in the evolving hydrogen economy.

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2.15. Datasheet

Technology	Hydrogen production via AE electrolysis									Notes	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Typical total plant size (MW input_e)	10	10	10	10	10	0.75	10				1
Typical total plant size (kgH2 / day of max output)	4086	4324	4544	4865	4865	300	4800			A	1
- Inputs											
Electricity (% total input (MWh / MWh))	1	1	1	1	1					B	1, 2
Water for electrolysis (kg / MWh input_e)	187	198	208	223	223	175	200				1, 2
- Outputs											
Hydrogen (% total input_e (MWh / MWh))	58.74	62.17	65.32	69.94	69.94	55.00	62.17	64.04	75.74		1, 2
ΔE from HHV to LHV (% total input_e (MWh / MWh))	11.86	12.55	13.19	14.12	14.12	11.11	12.25	13.81	14.45		2
Heat loss (% total input_e (MWh / MWh))	29.40	25.28	21.49	15.94	15.94	27.08	33.83	13.99	17.80		2
- hereof unrecoverable heat loss (%-points of heat loss)	3	3	3	3	3	3	3	3	3		2
- hereof recoverable for district heating (%-points of heat loss)	26.40	22.28	18.49	12.94	12.94	24.08	30.83	10.99	14.80		2
Hydrogen (kg / MWh input_e)	17.02	18.02	18.93	20.27	20.27	16.67	20.00	19.85	23.81		1, 2
Forced outage (%)	2	2	2	2	2	0	3				1, 2
Planned outage (days per year)	11	11	11	11	11	11	15			C	1, 2
Technical lifetime (years)	25	25	25	25	25	20	30			D	1, 2, 3
Stack electrode lifetime (years)	10	12	12	13	13	5	10				1
Construction time (years)	0.6	0.6	0.6	0.6	0.6	0.2	1			E	1, 2
Regulation ability											
Ramp Up Rate (% of Full Load/minute)	42					10	42				1
Ramp Down Rate (% of Full Load/minute)	42					10	42				1
Start-up time (minutes)	<60					<20	<60				1
Start-up time (minutes) hot	<15					<10	<15				1
Minimum load (% of full load)	30					15	40				1, 5
Financial data (in 2023₹)											
Specific investment (INR / kW of total input_e)	115000	76965	61196	52567	52567	70000	149472	43076	54365	F, H	1, 2,6,7,8,9
Specific investment (INR / kgH2 / day of max output)	246483	155867	117945	94621	94621	150033	320368	92325	116522	H	
- hereof equipment (%)	86	86	86	86	86	80	95				1, 2
- hereof installation (%)	14	14	14	14	14	5	20				1, 2
Fixed O&M (% of specific investment / year)	4.5	3.8	3.5	3.2	3.2	4.0	10.0	3.4	8.5	G	1, 2, 4,6
Variable O&M (INR / kWh of total input)											
Startup cost (INR/ kW of total input per startup)											
Technology specific data											
Current Density (A / cm2)	0.80	1.00	1.20	1.50	1.50	0.35	1.00	1.20	2.00		1, 2,6
Space requirements (m2 / MW input_e)	240.85	141.50	117.41	93.93	93.93	100.00	400.00	75.15	140.90		1, 2

Notes

A This factor changes in real cases depending on the operation hours and should be changed accordingly.

B Electricity input is 100% as no heat is required

C Planned outage is mainly because of changing the electrolyte solution for operation

D Technical lifetime describes the system lifetime; the life of stack will be around 10 years.

E The construction time varies across geography where the developer wants to construct. It took 7 months for commissioning a 380kW AE electrolyser plant by L&T in Hazira India but it should take less than that timeline for a 1MW plant if we consider only the time taken for setting up the gH2 facility and not the time for setting up the input electricity plant.

F The tariffs, capacity payments and network connection fees to DSO / TSO are not contained in CAPEX nor in O&M

G The fixed O&M does not include the costs for stack replacement at the end of its lifetime

H The lower range describes Indian data and the upper range describes international data. However the Indian data was too scarce to be taken as point estimate

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Technology	Hydrogen production via PEM electrolysis									Notes	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Typical total plant size (MW input_e)	10	10	10	10	10	1	17.4				1, 7
Typical total plant size (kgH2 / day of max output)	4528	4816	5071	5466	5466	400	7999			A	1, 2, 7
- Inputs											
Electricity (% total input (MWh / MWh))	100	100	100	100	100					B	1, 2, 7
Water for electrolysis (kg / MWh input_e)	208	221	232	251	251	167	268	202	324		1, 2, 7
- Outputs											
Hydrogen (% total input_e (MWh / MWh))	55	58	62	66	66	52	55	63	66		1, 2, 7
ΔE from HHV to LHV (% total input_e (MWh / MWh))	11	12	13	14	14						2
Heat loss (% total input_e (MWh / MWh))	34	29	26	20	20						2
- hereof unrecoverable heat loss (%-points of heat loss)	3.00	3.00	3.00	3.00	3.00	1.22	5.00				2, 7
- hereof recoverable heat loss (%-points of heat loss)	30.67	26.45	22.72	16.94	16.94	20.00	33.59				2, 7
Hydrogen (kg / MWh input_e)	18.87	20.07	21.13	22.77	22.77	16.67	19.11	20.12	23.06		1, 2, 7
Forced outage (%)	2	2	2	2	2	0	3				1, 2, 7
Planned outage (days per year)	10	10	10	10	10	5	11			C	1, 2, 3, 7
Technical lifetime (years)	25	25	25	25	25	20	25			D	1, 2, 4, 7
Stack electrode lifetime (years)	10	12	14	16	16					E	1, 2
Construction time (years)	0.6	25	25	25	25	0.25	1			F	1, 2, 7
Regulation ability											
Ramp Up Rate (% of Full Load/minute)	100									G	1, 7
Ramp Down Rate (% of Full Load/minute)	100									G	1, 7
Start-up time (minutes)	10										1
Start-up time (minutes) Hot											
Minimum load (% of full load)	10					10	40				1, 7
Financial data (in 2023₹)											
Specific investment (INR / kW of total input_e)	130000	89750	64570	51657	51657	70000	152141	40727	51965	H, L	1, 2, 5, 7,8,9,10,11
Specific investment (INR / kgH2 / day of max output)	291701	189356	129376	96032	96032	130133	282836	75712	96606	H, L	1, 2, 5, 8, 9, 10, 11
- hereof equipment (%)	82	82	82	82	82	80	95				1, 2
- hereof installation (%)	18	18	18	18	18	5	20				1, 2
Fixed O&M (% of specific investment / year)	5	4.1	3.6	3.2	3.2	2	8	1.29	5.15	K	1, 2, 6, 7,8
Variable O&M (INR / kWh of total input)											
Startup cost (INR/ kW of total input per startup)											
Technology specific data											
Current Density (A / cm2)	2.00	3.57	5.36	7.14	7.14	1.60	2.80	5.71	10.00	I	1, 2
Space requirements (m2 / MW input_e)	140.00	82.25	68.25	51.19	51.19	70.00	171.91	25.59	161.60	J	1, 2

Notes

A This factor changes in real cases depending on the operation hours and should be changed accordingly.

B Electricity input is 100% as no heat is required

C Planned outage is mainly because of changing the electrolyte solution.

D Technical lifetime describes the system lifetime; the life of stack will be around 10 years.

E Assuming 75% utilization based on inputs from NTPC

F The construction time varies depending on where the developer wants to construct.

G Based on stakeholder inputs the ramp rates are 10%/sec both up and down

H The AE and PEM CAPEX are assumed to be rather similar based on actual inputs for projects with investment decisions in India. However, the contractors can change the balance between making money on the CAPEX versus the OPEX.

I PEM electrolysers operate at higher current densities compared to alkaline, of about 1.6 - 2.8 A/cm^2.

J This value includes the complete plant, incl. BOP, while the value for the electrolyzer unit alone is smaller.

K The fixed O&M does not include the costs for stack replacement at the end of its lifetime

L The lower range describes Indian data and the upper range describes international data. However, the Indian data was too scarce to be taken as point estimate

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1 Inputs based on various Indian and international stakeholders

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7 Input from large manufacturer operating in India

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Technology	Hydrogen production via SOEC electrolysis									Notes	Reference
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Typical total plant size (MW input)	10	10	10	10	10	1	10	1	10		1
Typical total plant size (kgH2 / day of max output)	6086	6312	6412	6613	6613					A	1
- Inputs											
Electricity (% total input (MWh / MWh))	79.5	80.5	81.4	81.4	81.4					A	1, 2
Heat (% total input (MWh / MWh))	20.5	19.5	18.6	18.6	18.6						1, 2
Water for electrolysis (kg / MWh input)	219	227	230	238	238	209	228	227	248		1, 2
- Outputs											
Hydrogen (% total input (MWh / MWh))	67.39	69.59	70.54	72.46	72.46	63.39	67.39	68.16	72.46		1, 2, 3
ΔE from HHV to LHV (% total input (MWh / MWh))	15.47	16.04	16.30	16.81	16.81						1
Heat loss (% total input (MWh / MWh))	17.14	14.37	13.16	10.73	10.73						1
Hydrogen (kg / MWh input_e)	25.36	26.30	26.72	27.55	27.55	22.85	27.00	25.73	29.65		1
Forced outage (%)	3	3	3	3	3	1.4	3				1
Planned outage (days per year)	11	11	11	11	11	5	11				1
Technical lifetime (years)	25	25	25	25	25						1
Frequency of stack replacement (years)	5	8	10	13	13					B	1
Construction time (months)	1	1	1	1	1	0.75	1				1
Regulation ability											
Ramp Up Rate (% of Full Load/minute)											
Ramp Down Rate (% of Full Load/minute)											
Start-up time (minutes)	> 600										5
Minimum load (% of full load)	> 35										5
Financial data (in 2023₹)											
Specific investment (INR / kW of total input_e)	160769	101080	88389	67949	67949	100000	221538	52659	73294	C	1, 3, 4, 5, 6,7,8,9,10
Specific investment (INR / kgH2 / day of max output)	264181	160130	137858	102754	102754	151223	335016	79632	110837	C	1, 4,7,8,9,10
- hereof equipment (%)	87.5	87.5	87.5	87.5	87.5	80	95				1
- hereof installation (%)	12.5	12.5	12.5	12.5	12.5	5	20				1
Fixed O&M (% of specific investment / year)	12	12	12	12	12	12	12	12	12	E	1
Variable O&M (INR / kWh of total input)											
Startup cost (INR/ kW of total input per startup)											
Technology specific data											
Current Density (A / cm2)	0.825	0.970588	1.455882	1.455882	1.455882	0.8	0.85	1.411765	1.5		1, 4
Space requirements (m2 / MW input_e)	240.8511	141.5	117.4149	117.4149	117.4149					D	1

Notes

A This factor changes in real cases depending on the operation hours and should be changed accordingly.

B The stack replacement time is based on 34500 hours of operation. Assuming a utilization of 75% gives a stack lifetime of around 5 years.

C The CAPEX includes all components required for converting electricity and purified water into H_2 gas. CAPEX does not include transformer, water purifier or compressors. The tariffs, capacity payments and network connection fees to DSO / TSO are not contained in CAPEX nor in O&M. The main vaule is estimated as an average of the cost estimates in the references.

D This value includes the complete plant, incl. BOP, while the value for the electrolyzer unit alone is smaller.

E The fixed O&M does not include the costs for stack replacement at the end of its lifetime

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7 Electrolysis System Cost Forecast 2050: Higher for longer, BloombergNEF, September 12, 2024

8 Hydrogen Insights December 2023, Hydrogen Council, McKinsey & Company

9 EREA & DEA: Viet Nam Technology Catalogue for Energy Storage, Renewable fuels, Power-to-X (2023) https://ens.dk/media/5413/download

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3. Hydrogen Storage

3.1. Brief technology overview

Hydrogen is the most abundant element in the universe, making up 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. Due to its small molecular size and unique properties, storing hydrogen in large quantities presents challenges. Typically, hydrogen is stored as hydrogen gas (H_2) or in liquid form. Hydrogen is also a suitable energy storage medium owing to its high gravimetric energy density of 120 MJ/kg or 33.33 kWh/kg, or 10.8 MJ/Nm^3 [1]. This energy density makes hydrogen a potential candidate as an energy carrier, and unlike batteries, the energy loss is very minuscule. Further, referring to Figure 3-1, hydrogen has a higher energy capacity, making it suitable for long-term storage. It has recently drawn a lot of attention across the globe due to its ability to decarbonize various industries, such as steel, cement, transportation, etc. when its source is green.

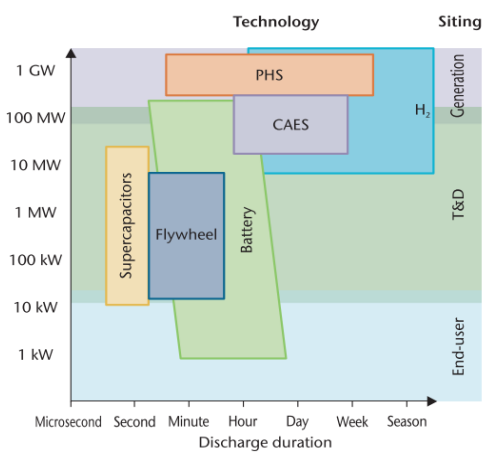

Figure 3-1: Characteristics of different storage technologies. [2]

3.1.1. Hydrogen Storage

Hydrogen storage is classified into physical-based and material-based technologies and geological storage. The different hydrogen storage technologies and their classification are shown in Figure 3-2. Physical storage methods include compressed gas, liquid and the cryo-compressed[3] form. Physical storage relies on altering storage conditions, such as pressure and temperature, particularly in cryo-compressed gas storage. On the other hand, material-based, or chemical storage involves absorption or adsorption techniques [3].

[3] Cryo-compressed: Cryo-compressed refers to a method for storing hydrogen at cryogenic temperatures (-150°C) and in a pressurized state.

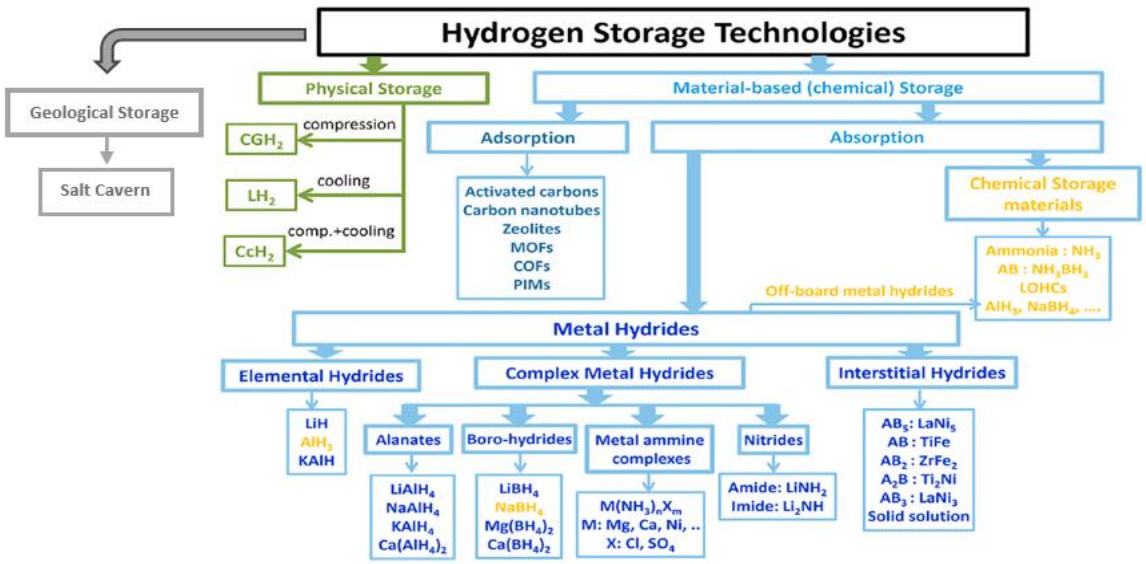

Figure 3-2: Hydrogen storage technologies. [3]

The storage method should be selected based on the application and site requirements. Out of these storage technologies, the most commonly used and commercially matured storage technologies are hydrogen gaseous tank storage, cryogenic liquid storage, and ammonia as an intermediate carrier. Most of the adsorption and absorption technologies are in the research and development stage at least in the Indian scenario.

Physical storage of Hydrogen

The physical mode of hydrogen storage technologies includes methods based on compression/cooling for storing the hydrogen in some form of vessels [4]. These vessels can be either man-made pressurized tanks, salt caverns or naturally occurring aquifers.

In most storage modes, hydrogen is stored in gaseous form. The hydrogen can be compressed and be stored at low pressure (up to 45 bar), medium pressure (up to 500 bar) or high pressure (up to 1,000 bar or even more) into hydrogen storage vessels. In view of the heat generated during compression, there is a temperature gradient inside the medium and high-pressure regions of the vessel. In order to keep the vessel's components from failing, the hydrogen may need to be cooled. Hydrogen is stored in tanks after being compressed to high pressure. The purpose of this pressurization is to enable fuelling at lower temperatures while maintaining the required pressure levels [5]. The pressurized vessels or hydrogen tanks are usually made of seamless steel or composite wrapping with steel liner or polymeric liner fully wrapped with a fibre resin composite. 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.

In the case of liquid hydrogen or cryogenic hydrogen storage, the hydrogen is liquefied at a temperature of (-)253°C in cryogenic refrigeration plants which comes at a high cost and heavily insulated special cryogenic tanks are required. This storage form is mainly applied in space travel. [6]

Geological storage of hydrogen

Other means of storing hydrogen gas is in underground storage, including salt caverns or exhausted oil and gas fields. Aquifers have also been investigated in this respect, but the uncertainty and cost[4] is a major drawback. Underground storage has been historically used for natural gas and crude oil, which could be used for large-scale gaseous hydrogen storage as well with natural thick and low-permeation materials to surround the stored hydrogen. Underground hydrogen storage technology has been used by many countries like USA, UK, France and Germany [7]. Currently, India does not have any operational underground hydrogen storage facilities. Most hydrogen storage in India is focused on above-ground solutions. India is actively exploring the feasibility of underground hydrogen storage. India can store up to 22,610 TWh of hydrogen in deep saline aquifers. India has major sedimentary basins, such as the Mumbai offshore, Krishna–Godavari, Rajasthan, Cauvery and Cambay basins. [8]

Material-based hydrogen storage

Material-based hydrogen storage technologies are an alternative to the physical storage technologies. They are based on storing hydrogen either in solids or liquids or on material surfaces. It should be noted that most of these material-based storage technologies are at an experimental level and only a few are commercialized. Material-based storage can be divided into 3 sub-categories, namely, hydride storage systems, liquid hydrogen carriers and surface storage systems (sorbents) [4].

Hydride storage systems using metal hydrides, where the hydrogen is adsorbed on the metal surface (incorporated in elemental form into the metallic lattice) with an output of heat. The hydrogen can be retrieved from the metal hydride with an input of heat. Examples of metals that can store hydrogen are palladium and magnesium, along with light metals such as aluminium or certain alloys [4].

Liquid hydrogen carriers or Liquid Organic Hydrogen Carriers (LOHCs), a chemical hydrogen storage, is an upcoming material-based hydrogen storage technology. The LOHCs are usually organic chemical compounds with hydrogen-adsorbing capabilities. The hydrogen is, for example, covalently bound to the LOHC uploaded in a process called hydrogenation and unloaded via dehydrogenation. LOHCs are compounds with similar properties to oil-based liquids which provide them with all the advantages of easy transportation and handling with the existing infrastructure [9].

Surface based storage systems or sorbents can store hydrogen as a sorbate by adsorption on high specific surface area materials such as microporous organometallic framework compounds and microscopic carbon nanotubes. All of these materials can facilitate high volumetric storage densities, although they are still in the experimental phase [4].

In addition, hydrogen can also be stored and transported as chemicals such as ammonia and formic acid. It is accompanied by the advantage of having a high molar fraction of H_2 storage. This will, however, not be discussed in this catalogue.

3.2. Compressed hydrogen in pressurized storage tanks

In this section, the technology of storing hydrogen in pressurised tanks is described. Pressurised hydrogen storage is one of the storage methods currently in use on a significant scale worldwide, particularly for vehicle

[4] Uncertainty include hydrogen permeability, leakage risk, and also underground reservoirs need to be geologically stable. The costs are driven by site preparation, infrastructure development, maintenance, and ensuring the integrity and purity of stored hydrogen.

tanks and distribution buffers. The technology and the materials of hydrogen vessels have seen improvements as the demand for 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. Nonetheless, there are technologies in development 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. [6]

3.2.1. Technology description

Compressed hydrogen storage in pressurized tanks is a promising technology for storing and transporting hydrogen. Specially designed tanks constructed from high-strength materials like carbon fibre reinforced plastic (CFRP) or steel are used to store hydrogen gas at high pressures.

The specific design of the tank, including its materials, thickness, and shape, is crucial to ensure safe and efficient storage of hydrogen at high pressures. These tanks undergo rigorous testing and certification to meet safety standards.

There are four types of pressure vessels in which hydrogen is stored for industrial to mobility purposes [6]. Figure 3-3 shows the different layers of the storage tank in a simple schematic.

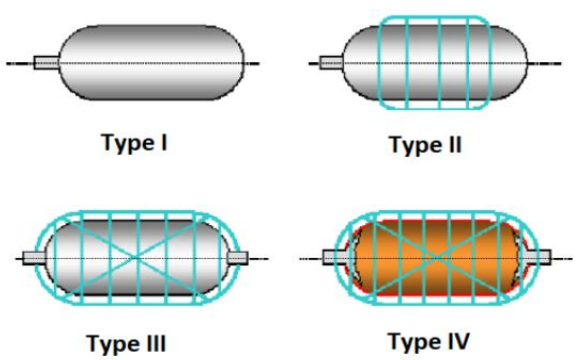

Figure 3-3: Schematic of different components of all types of storage tank. [6]

Type-I Hydrogen storage tank

These types of tanks are seamless steel or aluminium 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 Hydrogen storage tank

These types of tanks are seamless metallic (aluminium) tanks with filament windings like glass fibre/aramid or carbon fibre 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 fibres used for the wrapping.

Type-III Hydrogen storage tank

These types of tanks are made from seamless or welded aluminium liners fully wrapped with fibre 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 fibres used for the wrapping.

Type-IV Hydrogen storage tank

These types of tanks are the state of the art when it comes to high-pressure hydrogen tanks and are made completely from carbon fibre with a polymer (thermoplastic) liner. The carbon fibre 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 aluminium. 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.

The choice of storage is based on the final application which requires a compromise between technical performance and cost competitiveness. H_2 as industrial gas is stored in Type I tanks, the pressure of which is from 150 to 500 bar (usually 200 bar). These are the most commonly used high-pressure vessels and have the lowest costs. When higher pressures are required – mainly for stationary applications – the Type II tanks are preferred. Type III and Type IV vessels are intended for portable applications, for which weight savings and climatic conditions are essential [10]. The pressure limitation for type-I cylinders arises from constraints in the manufacturing process, such as forging and forming. As the wall thickness of the cylinder increases, so does its weight, making handling a significant challenge. As compared to type III and IV, type II cylinders are not used widely. There are several advantages to using type-III and type-IV cylinders over type-II, namely, reduction in weight of the cylinders, no huge difference in cost of the cylinders (all these type-II cylinders need to be imported and the cost is at par with type-III and IV cylinder) and heavy foundation and structural requirements.

Tanks for hydrogen come in a variety of sizes and designs. Although some liquid hydrogen tanks are made of spherical shapes, any shape is suitable for storing hydrogen at pressures close to atmospheric pressure. However, cylindrical containers are the most typical shape for a hydrogen tank. The common parts that may be found on most hydrogen tanks are seen in Figure 3-4.

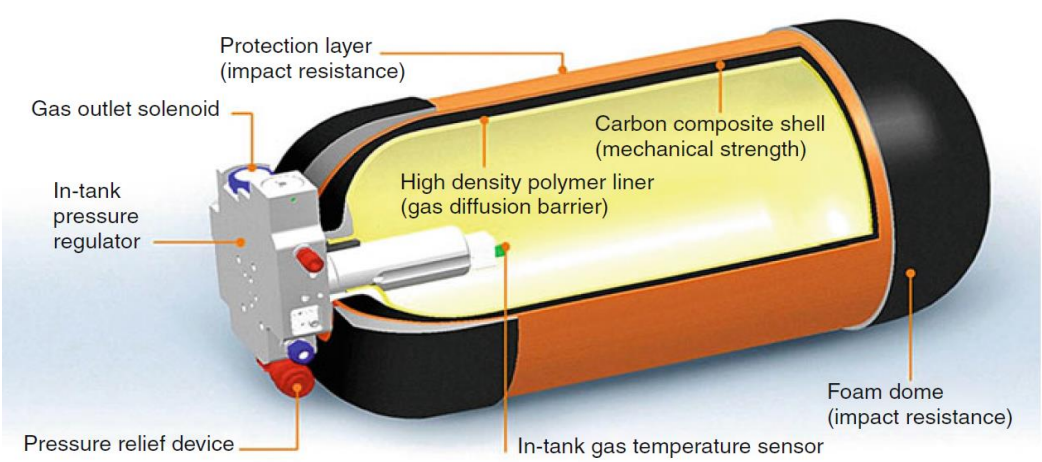

Figure 3-4: Hydrogen gaseous storage tank (Type III and IV). [11]

The different components in the storage tank include:

Liner: As hydrogen molecule size is minuscule, it has the ability to permeate through various materials with ease. A liner is used to prevent hydrogen permeation from the storage tank. In order to minimize weight, high-density polymeric materials are chosen as liners [11].

Shell: The shell of a storage tank serves as the structural component that bears the load. Advanced storage tanks utilize shells made of carbon fibre-reinforced composites to ensure durability under high pressures. The exceptional mechanical properties and low density of carbon fiber allow for achieving higher capacities for storing hydrogen. However, it is important to note that carbon fibre is the most expensive component, accounting for approximately 65% of the overall cost of a compressed gaseous hydrogen storage system. Recognizing its impact on the system cost, research programs have been established to explore methods of reducing the production cost of carbon fibre. [11]

Protection layer: The outermost shell of the storage tank is the protection layer. This component is included for impact resistance. [11]

Balance of plant: The hydrogen tank's neck, which is where the hydrogen is inserted and removed from it, is connected to a hydrogen tank valve or a tube that allows for controlled input and output. The other essential components are pressure regulator, pressure relief device, pressure sensors, temperature sensor, vehicle electrical interface connector, vehicle interface bracket, vent line ports, refuelling port, fill line check valve, and stone shield. An additional tank opening is the optional end plug. [11]

Key Specifications and Critical Performance Parameters

Hydrogen is a non-toxic, colourless, odourless, tasteless and highly flamable energy carrier which is also extremely light and disperses rapidly, and while diffusion/permeation depends strongly on the material, it can pass through many materials considered tight to other gases. These characteristics of the fuel make the storage risky to a certain level. Some of the key requirements while designing hydrogen storage tank are as follows [12]:

Leak Tightness – Any hydrogen tank must meet the essential requirement of safely containing and only releasing hydrogen under controlled conditions [12].

Compact design - The storage vessel should be designed to occupy minimal space, ensuring it is not significantly larger than the volume of hydrogen it holds [12].

High fatigue resistance - Hydrogen tanks are subject to numerous fill, empty, and refill cycles. The more cycles a tank can endure, the longer its expected lifespan. Additionally, hydrogen can embrittle[5] some metallic materials, weakening them over time; this must also be taken into account while designing hydrogen tanks [12].

[5] Embrittlement is the process where a material, typically a metal, loses its ductility and becomes brittle, making it more prone to fracture. This can happen due to various factors such as exposure to certain environment, temperature or the presence of impurities. Hydrogen embrittlement specifically occur when hydrogen atoms diffuse into a meta, leading to the formation of cracks and weakening the material

Adequate weight - While weight may not be a critical concern in every application, it remains an important factor. Tanks constitute a substantial portion of any hydrogen-based application, and as such, their weight can significantly impact the overall system. [12]

Hydrogen Storage tank types

The table below outlines the key differences between the different types of hydrogen storage technologies.

Table 3-1: Technical characteristics of pressurized hydrogen tanks. [6]

Type	Working Pressure (bar)	Materials	Usage	Permeation [mol/(s·m·MPa$^{1/2}$)]	Typical Storage Period [months]
Type I	< 250	Seamless steel or aluminium	Stationary applications	2.84×10^{-27}	years
Type II	450-800	Seamless steel/aluminium with filament windings like glass fibre/aramid or carbon fibre wrap	Stationary applications or short transportation (tube trucks)	2.84×10^{-27}	years
Type III	300-700	Seamless or welded aluminium liners fully wrapped with fibre resin composite	Stationary and automotive applications. Used also in hydrogen fuelling industry	2.84×10^{-27}	days to months
Type IV	350-1000	Fully carbon fibre 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

3.2.2. Input/output

The input for pressurized hydrogen tanks of all types is hydrogen gas and energy for its compression. The output is pressurized hydrogen. Hydrogen is generated from relevant sources and then compressed by compressors into the storage tanks. The hydrogen can be retrieved and used directly from the storage tanks.

3.2.3. Energy efficiency and losses

The losses in a pressurized hydrogen tank can be divided into operational losses and standby losses. Unlike a battery storage system, where energy conversion and storage occur within the same system/medium, a pressurized hydrogen storage system solely stores energy. Energy conversion is carried out for example through electrolysis to produce hydrogen from electricity (or by other methods). The hydrogen can be used directly as fuel or the subsequent fuel cell system, for instance, can be employed to generate electricity. Therefore, only the efficiency of storing the hydrogen is considered in this technology catalogue. When comparing different energy storage technologies, it is important to evaluate the complete round-trip-efficiency, i.e. from electricity to electricity or from the energy source to its final 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 retrieval of gas. Energy losses associated with pressure losses in a complex system as i.e. a hydrogen fuelling station system operating in 900+ bar of pressure sum up a total of <5% with the majority of them happening in components that connect the station and the vehicle [5]. Based on this, it is safe to assume that in a simple system like the one described in the "Technology description" section, where operating pressures are not exceeding 200 bar and no heat exchangers etc. are included, the pressure losses due to valves, tubing etc. are <1% and therefore negligible.

Standby losses

Standby losses primarily occur due to hydrogen permeation. Type I, II and III tanks have a metallic casing or liner resulting in nearly negligible permeability. However, Type IV tanks exhibit higher permeability because of their polymer liner. For reference, aluminium 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 are 12 orders of magnitude higher [5]. In the system being analysed, the use of Type 1 steel tanks effectively minimizes standby losses to a negligible level.

Energy efficiency

The 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, like 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 [5]. 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:

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

3.2.4. 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 3-2.

Table 3-2: Characteristics of pressurized hydrogen tanks. [6]

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

3.2.5. Typical storage period

Hydrogen can be stored in compressed hydrogen tanks practically indefinitely. The exact storage duration depends on the tank materials and their susceptibility to hydrogen permeation and embrittlement. [6]

For instance, steel tanks have shown no significant pressure drop (indicating no leaks) even after 3 years of dormancy in laboratory conditions. It's important to note that long-term hydrogen storage in pressurized tanks is always done at ambient temperature. If a cooled tank is exposed to ambient conditions for an extended period, a pressure drop and a reduction in volumetric density will occur. In practical applications, gaseous hydrogen is generally used quickly after its production. Hydrogen fuelling stations, for example, replenish their bulk hydrogen supplies either through on-site electrolysis or by delivery via hydrogen tube trucks. This bulk hydrogen supply can be stored in ambient temperatures and up to 200 bar for months, or even years. [6]

3.2.6. Capacity and space requirements

The storage capacity of hydrogen in a tank depends on the pressure at which it is stored: higher pressure allows more hydrogen to be stored in the same tank volume. Hydrogen storage can range from a few grams in small cylinders to several kilograms in vehicle or industrial tanks. For example, a 125-liter tank at 700 bar can store up to 5 kg of hydrogen, whereas at 350 bar, storing the same 5 kg would require a tank of roughly 213 litres. Across different tank types, the usable hydrogen volume is generally similar, though Types II–V tanks occupy slightly more space than Type I due to the use of composite materials in their construction, which reduces weight but slightly increases volume [13].

Table 3-3 presents the details of two example hydrogen storage cascades from NTPC projects in India for 192 kg and 528 kg of hydrogen storage.

Table 3-3: NTPC Projects.

Project	Pressure	Hydraulic Capacity	No. of racks	No. of Cylinders per rack	Total storage capacity	Length (m)	Width (m)	Height (m)	Weight (kg)
NTPC Leh Project	450 bar	315 L	3	7	192 kg	3.9	3.16	1.936	5400
NTPC Greater Noida Project	500 bar	780 L	3	1st rack – 9 2nd rack – 6 3rd rack - 1	528 kg	2.458	8.725	2.458	42300



Figure 3-5: NTPC, Leh composite tank arrangement.

3.2.7. Advantages/disadvantages

Storing hydrogen in pressurized hydrogen tanks can have advantages and disadvantages which are described briefly in this section. [6]

Advantages

- Long-term energy storage: Depending on the materials of the tank, hydrogen can be stored for long periods of time without losing significant energy content (see section "Typical storage period").
- Widespread and proven technology: It is the only technology that is used in any significant scale for hydrogen storage to date since 2000
- 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

- Not easy to transport in large quantities: storing and transporting large amounts of hydrogen gas in pressurized tanks is done by employing trucks. The cost of this procedure and the relatively small amount of hydrogen transported at a time inhibit the transportation of hydrogen gas in large quantities over long distances.
- 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.
- Safety issues: Hydrogen is an explosive gas when in contact with air in significant concentrations i.e., 4% (LEL[6]) and 75% (UEL). Therefore, extreme caution should be exercised when handling high pressure hydrogen storage systems.

[6] Lower explosive limit (LEL), upper explosive limit (UEL)

3.2.8. Environment

Hydrogen gas itself does not pose significant environmental risks, as its large-scale use is still in the early stages. However, if larger amounts of gaseous hydrogen are used, the potential for accumulated leakage into the atmosphere could accelerate ozone layer depletion 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 largely depend on the end use [5].

3.2.9. Examples of market-standard technology

Hydrogen as an element is not new to industry; it is being used in sectors such as fertilizer production, pharmaceuticals, and others. Typically, these industries use Type I storage tanks, as their hydrogen needs are mostly static and used on demand. INOXCVA, a leading manufacturer of cryogenic equipment in India, has recently completed the construction of the largest liquid hydrogen storage tank in the country. This tank, with a capacity of 238 m^3, is designed to store hydrogen at cryogenic temperatures of -253°C, making it dense enough for efficient storage and transportation [14].

Another project example is presented below.

Liquid Hydrogen Storage Tank, Sri city, Andhra Pradesh, India



Figure 3-6: Liquid Hydrogen Storage Tank, Sri city, Andhra Pradesh, India.

The project entailed the establishment of a liquid hydrogen storage tank at the VRV Asia Pacific production plant in Sri City, Chittoor district, Andhra Pradesh. The engineering and manufacturing effort produced a 120 m^3 liquid hydrogen storage tank, marking a major milestone in India's cryogenic capabilities. Designed to maintain -253 °C, the deep cryogenic conditions required for liquid hydrogen, the tank ensures optimal storage performance while minimizing evaporation losses. [15]

3.2.10. Projection of performance and cost

From a performance standpoint (in terms of storage capacity), the Type I tanks are not expected to exhibit significant improvements over time. This is because their hydrogen storage capacity is directly proportional to their allowable pressure, which can only be increased by adding more material (steel) to withstand higher pressures. For Type II and Type III tanks, the situation is comparable; however, these tanks offer greater

potential for performance enhancement due to ongoing advancements in the durability and strength of composite materials. [6]

Regarding cost, the price of the tanks is strongly influenced by the overall scale-up of the hydrogen storage industry. For Type I tanks, the main cost driver is the quantity and price of steel, which will determine future cost trends. According to projections from the Danish Technology Catalogue, the costs of Type I tanks could decrease significantly by 2050 [6].

3.2.11. Uncertainty

The largest source of uncertainty in cost projections is the growth of the hydrogen storage industry, where currently pressurized hydrogen gas storage is almost always connected with short-term utilization of hydrogen in either fuelling stations, natural gas enrichment etc. Given this, it is hard to project the growth of the pressurized hydrogen storage industry itself without having to consider the industries that utilize this technology and their growth. Cost reductions can also be lower if another type of pressurized hydrogen gas tank technology is chosen over Type I and increases in market shares. The same is the case for the compressor component of the system which can go down in costs to one-fourth of today's cost price by 2050 if the hydrogen fuelling industry follows the current growth predictions or half if the growth of the industry is more conservative. Additionally, the compressor performance projections carry a high degree of uncertainty, as new technologies are being developed specifically to meet the needs of hydrogen compression. [6]

Where the datasheet does not list uncertainty values, this should not be taken to mean the estimates are certain. Rather, it indicates that the necessary data to quantify the uncertainty is not available.

3.3. Hydrogen storage in Liquid Organic Hydrogen Carrier (LOHC) compounds

3.3.1. Technology description

Liquid Organic Hydrogen Carriers (LOHCs) are organic liquids that can reversibly react with hydrogen. LOHC technology revolves around the reversible hydrogenation and dehydrogenation of specific organic compounds, which serve as carriers for hydrogen molecules.

This material-based hydrogen-storage option has attracted increasing attention in recent years and is assessed to be at a pre-commercial level with first applications available [17].

A LOHC system consists of two compounds: a hydrogen-lean form (H_0-LOHC) and a hydrogen-rich form (H_n-LOHC). Hydrogen is stored by converting H_0-LOHC into H_n-LOHC through a catalytic hydrogenation reaction, and released again by converting H_n-LOHC back into H_0-LOHC via catalytic dehydrogenation [9]. Because these carrier liquids share handling properties with crude-oil derivatives, they can be stored and transported under ambient conditions, without the high-pressure or cryogenic requirements associated with conventional physical hydrogen-storage methods described in the previous chapter. An example of how an LOHC system can be integrated into an existing energy infrastructure is shown in Figure 3-7.

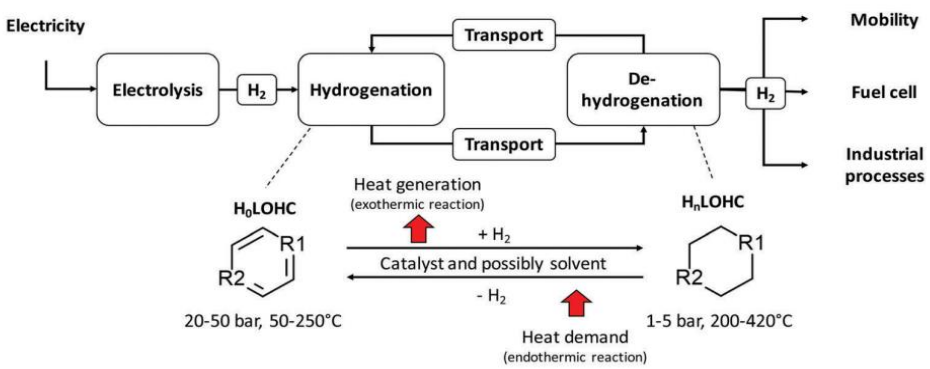

Figure 3-7: LOHC working system. [9]

Conversion Process

During the hydrogenation phase, hydrogen gas is chemically bonded with the carrier compound, forming a stable H_2-LOHC complex (hydrogen richH_n-LOHC). The hydrogenation process is typically exothermic and is often carried out at elevated temperatures and pressures. The resulting hydrogen-loaded LOHC possesses a significantly higher volumetric energy density than molecular hydrogen and can be stored for extended periods under ambient conditions without energy losses. Handling this hydrogenated liquid is much simpler compared to gaseous hydrogen since LOHCs share properties similar to crude oil derivatives. Consequently, LOHCs are exceptionally suitable for intercontinental energy transportation, as the existing infrastructure designed for crude oil can be partially repurposed for this purpose. Transportation of H_n-LOHC can be via trucks, trains, ships, or even by utilizing existing crude oil pipelines. [9]

During the dehydrogenation phase, the stored hydrogen is released from the carrier compound, typically through the application of heat and catalysts.This process is endothermic and typically carried out at or near atmospheric pressure, with temperatures typically ranging between 200 and 450°C [9].

The LOHC is continuously cycled throughout the entire system, including transportation back to the hydrogenation location after dehydrogenation. Consequently, the LOHC can be utilized ideally without a finite lifespan. Nevertheless, some quantities are lost during storage and transport due to side reactions.

Distinctive attributes of LOHC Systems

For safe and effective use of the LOHC system it is recommended to have at least the below mentioned characteristics [18] [19]:

- Low melting point (<−30 °C) of all compounds involved and high boiling point (>300 °C) for simple hydrogen purification by LOHC condensation
- High hydrogen storage capacity (>56 kg/m3 or >6 wt%)
- Low heat of desorption (42−54 kJ/mol-H_2) to enable low dehydrogenation temperature against 1 bar hydrogen pressure (e.g., <200 °C)
- Ability to undergo very selective hydrogenation and dehydrogenation for long life cycles of charging and discharging
- Compatibility with today's infrastructure for fuels
- Low production costs and good technical availability
- Toxicological and eco-toxicological safety during transportation and use (e.g., not classified as "dangerous goods")

Considering the above characteristics, some of the LOHC materials used as of now are listed in [20], which show reason for selection, temperature, pressure, and loading/conversion percentage of the listed LOHC materials.

Table 3-4: LOHC and reason for its selection. [20]

LOHC	Reason for selection
N-Ethyl carbazole (NEC)	Well-studied nitrogenous LOHC
Dibenzyltoluene (DBT)	Already existing application as a LOHC; safe and convenient handling
1,2-Dihydro-1,2-azaborine (AB)	Unique characteristics through integration of boron and nitrogen
Formic acid (FA)	Safe and convenient handling
Methanol (MET)	Very high storage density
Naphthalene (NAP)	Well-studied cycloalkane; high storage density
Toluene (TOL)	Well-studied cycloalkane; planned application as a LOHC

Table 3-5: Hydrogenation and Dehydrogenation Characteristic. [20]

LOHC	Hydrogenation			Dehydrogenation		
	Temp (°C)	Pressure (bar)	Loading[7] (%)	Temp (°C)	Pressure (bar)	Loading[7] (%)
NEC	150	50	100	270	1	90
DBT	150	50	100	310	1	97
AB	80	10	95	80	1	99
FA	50	40	100	60	1	100
MET	250	50	26.4	420	1	100
NAP	200	69	100	280	1	99
TOL	200	20	100	320	1	95

3.3.2. Input/Output

The input and output of LOHC storage systems is hydrogen in gaseous form. A small amount of energy is required for the hydrogenation process, while the dehydrogenation process requires a significantly larger energy input, as explained in the "Technology description" section. During hydrogenation, hydrogen is chemically bound to the LOHC; the loaded LOHC can then be stored at ambient temperature and pressure as a stable liquid fuel. During dehydrogenation, the hydrogen is released from the LOHC for subsequent use. [6]

3.3.3. Energy efficiency and losses

With hydrogen stored via LOHCs, storage losses are minimal, allowing for virtually unlimited storage duration. However, heat losses during hydrogenation and dehydrogenation impact the LOHC system's overall efficiency. Research on DBT-based LOHC systems shows an efficiency range of about 48-54%. This efficiency can increase to 86% when solid oxide cells are incorporated before final use. Reported thermal efficiency is approximately 60%, with electrical efficiency around 40% [16]. The round-trip efficiency of LOHC storage technology can reach up to 43 % [21].

Operational losses

The hydrogenation reaction being exothermic, releasing heat that if not recirculated (as is often the case in practice), contributes to a net energy loss during storage. Additionally, a catalyst loss of approximately 0.1% by weight is assumed for each cycle [9]. Literature also reports significant losses, around 22%, due to conversion and transportation [16]. The dehydrogenation process heat losses can occur through the reactor walls and other components, reducing overall efficiency. Over time, catalysts used in the dehydrogenation process can become deactivated, reducing their effectiveness and increasing operational losses.

[7] Loading (%) refers to the extent to which the LOHC's hydrogen storage capacity is utilized: for hydrogenation, the percentage of the carrier's maximum hydrogen uptake capacity achieved; for dehydrogenation, the percentage of previously stored hydrogen successfully released.

Standby losses

Energy losses during LOHC storage are minimal, with no significant boil-off or other losses observed [20]. Similarly, transporting hydrogen over long distances using LOHCs—whether by pipelines, trucks, or ships—results in negligible energy loss [22].

Energy efficiency

Energy efficiency of hydrogen binding and unbinding on LOHCs can be defined according to Equation (3):

$$\eta_{roundtrip} = \frac{E_{hydrogen\ out}}{E_{hydrogen\ in}+E_{transport\ losses}+E_{heat\ loss}+E_{heatEndothermic}} \times 100\% \quad (3)$$

Considering a system with the $E_{hydrogen\ out}$ is given by its capacity of 210 kg multiplied by 33.33 kWh/kg, which is the same as $E_{hydrogen\ in}$. E_{heat} loss is in the order of 30% due to the endothermic reaction heat not being utilized. Total transport losses are taken as 10% of the total capacity. Given this, the Equation (3) can be calculated as follows:

$$\eta_{roundtrip} = \frac{7MWh}{7MWh + 2MWh + 1MWh} \times 100\% = 70\%$$

An example of the process chain using LOHCs is displayed in Figure 3-8.

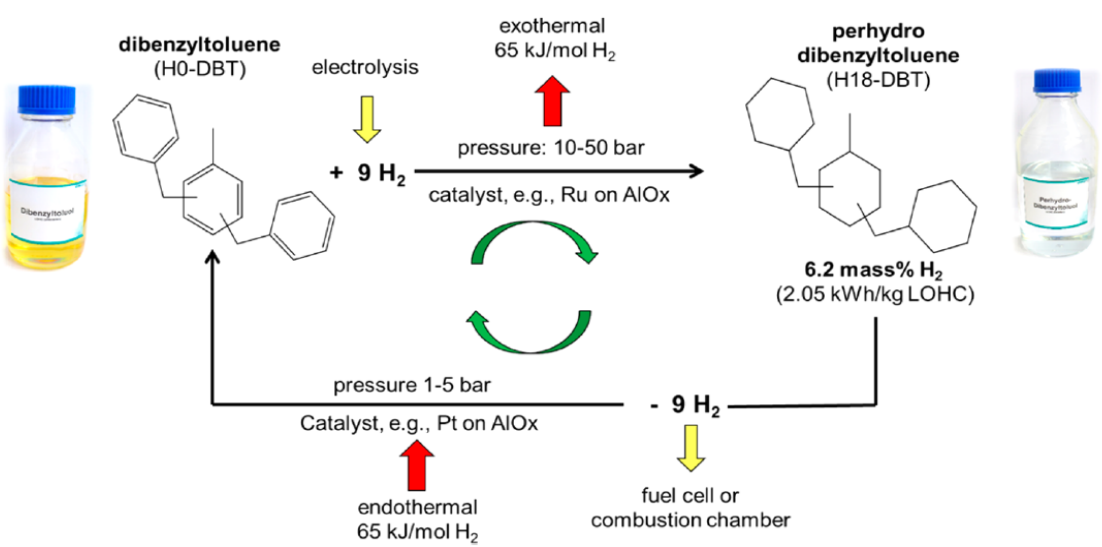

Figure 3-8: Hydrogen storage using DBT-LOHC system. [22]

3.3.4. Typical characteristics and capacities

LOHCs are relatively new in the market. Therefore, the Hydrogenious LOHC Technologies GmbH product brochure[8] is used to illustrate representative sizes and capacities for storage (hydrogenation) and release (dehydrogenation) systems. Table 3-6 and Table 3-7 are derived from the brochure figures.[23]

Table 3-6: LOHC storage system characteristics. [23]

Characteristics	StorageBOX 10	StorageBOX 120	StoragePLANT 5tpd	StoragePLANT 12tpd
Hydrogen capacity	10 Nm^3/h 0.9 kgH_2/h	120 Nm^3/h 11 kgH_2/h	5 t/d 210 kgH_2/h	12 t/d 500 kgH_2/h
LOHC production	20 l/h	240 l/h	4,500 l/h	11,000 l/h
Heat production	9 kW_{th}	100 kW_{th}	1,900 kW_{th}	4,500 kW_{th}
Space requirement	20 foot container	20 foot container	Skid based	Skid based

Table 3-7: LOHC release system characteristics. [23]

Characteristics	ReleaseBOX 10	ReleaseBOX60	ReleaseBOX120	StoragePLANT 1.5tpd
Hydrogen capacity	10 Nm^3/h 0.9 kgH_2/h	60 Nm^3/h 5.5 kgH_2/h	120 Nm^3/h 11 kgH_2/h	1.5 t/d 65 kgH_2/h
LOHC demand	20 l/h	120 l/h	240 l/h	1400 l/h
Heat demand	12 kW_{th}	66 kW_{th}	130 kW_{th}	780 kW_{th}
Space requirement	30-foot container	30-foot container	40-foot container	Skid based[9]

[8] *Please note that The Hydrogenious brochure is a vendor primary source and is used for quoting that vendor's product specifications and operating ranges, but it is not neutral and shouldn't stand alone for system-level conclusions.*

[9] Skid-based, which means the system is pre-assemble on a frame that can be easily transported and installed.

Table 3-8: Comparison of physical properties of different LOHCs. [24]

Parameter		Benzyl-toluene	N-Ethyl Carbazole	Toluene	Diphenylmethane
Storage density	Volumetric/ MWh/m^3	1.8	1.9	1.6	2
	Gravimetric/wt%	6.2	5.8	6.2	6.9
Melting/Boiling point/ °C		- 1/4	69/ 346	- 6/7	24 / 264
Flash point/ °C		137	-	6	127

Table 3-8 shows a comparison of four different LOHCs. The volumetric storage density is given in MWh/m^3 calculated from the lower heating value of hydrogen (33 MWh/t) and the volume of LOHC. The gravimetric storage density is given in weight-% calculated from the mass of hydrogen per mass of loaded LOHC molecule. All four LOHCs show a similar storage density, ranging from 1.6-2 MWh/m^3. As a rule of thumb, one can state a usable value of 50 kg of hydrogen per cubic meter of LOHC [24].

3.3.5. Typical storage period

Effectively, LOHCs can store hydrogen indefinitely, and the loss of hydrogen during storage is negligible. The long-term storage under ambient pressure is one of the advantages of using LOHCs [25].

3.3.6. Space requirement

The space requirement for the LOHC technology depends on the size of the chosen system. Typically, medium to large-scale storage systems are in use. As seen in Table 3-6 and Table 3-7, the smallest size is in the order of a 20-foot container for storage, while in the order of a 30-foot container for release. It is important to note that, skid-based large-scale systems are economically more attractive and can be easily installed. They are significantly larger in size [6].

3.3.7. Advantages/disadvantages

In this section, advantages and disadvantages accompanied with LOHC technology are listed [9].

Advantages:

- Long-term storage: LOHCs allow long-term storage under ambient temperature and with low standby losses; with low maintenance.
- Infrastructure compatibility: LOHC can be stored and transported similarly to crude oil, diesel and gasoline.
- Safety and stability: LOHC are stable and non-explosive, LOHC systems offer generally higher safety compared to compressed or liquefied hydrogen storage and no risk of leakage
- Economic feasibility: particularly for long-distance hydrogen transport, LOHCs offer a cost-effective option due to its infrastructure compatibility

Disadvantages

- Toxic substances may be used, which might require performing toxicity testing
- The overall efficiency is low due to high energy consumption and heat losses during the hydrogen loading and unloading processes, which require high temperatures.

3.3.8. Environment

Many LOHC compounds are uncharged organics like conventional fuels such as gasoline and petrol, thus volatile, flammable and lipophilic. Despite these risks, conventional fuels have been widely used for many years [25]. Not all LOHC have the same characteristics in flammability, toxicity, etc. Toxicity studies have not been performed for all kinds of LOHCs.

One of the most mature LOHC compounds, DBT, has low toxicity along with low flammability. Other LOHCs which are heterocyclic in nature, have similar risks of toxicity as diesel and gasoline. Additionally, nitrogen containing LOHC compounds have shown better biodegradability in case of a spillover, similar to aromatics [26].

3.3.9. Research and development perspectives

LOHC hydrogen can play a significant role in the hydrogen economy. Furthermore, decentralized hydrogenation needs to be optimized. As mentioned earlier, catalyst costs can be a challenge and need to be further investigated. Different combinations of LOHC compounds can lead to cost effective and large-scale solutions. Additionally, heat generated during hydrogenation needs to be recycled and used for system energy optimization [26]. Research in this field can facilitate heat integration to decrease the losses along with blending LOHCs in the existing feedstock.

There are no commercial examples of using LOHC as a hydrogen carrier, but considerable research is being carried out in this space by using different materials for storing hydrogen in Liquid organic compounds. The LOHC can store hydrogen from a very small quantity to a very larger quantity. The definite amount is still undetermined due to the scale at which is used today.

India is currently in the early stages of research and development for LOHC. The focus is on developing technologies for the storage and transportation of hydrogen using LOHCs. Initial research efforts are being conducted to explore the potential of LOHCs for hydrogen storage and transportation. The Council of Scientific and Industrial Research - National Environmental Engineering Research Institute (CSIR-NEERI) has a plan for technology transfer related to hydrogen storage and delivery using a catalytic system known as HyStoCat. Research on LOHCs is still in the early phases in India, with ongoing studies to improve the efficiency and safety of these carriers for hydrogen transport. [27]

3.3.10. Examples of market-standard technology

As previous mentioned, LOHC is considered to be in the pre-commercial phase and only few suppliers/market options are given. Table 3-9 is providing two examples.

Table 3-9: LOHC systems available in the market.

Image	Usage	Year	Specs.	Technology provider	Ref.
	Mid to large-scale transport and stationary applications.	2016	hydrogenation capacity: 792 Nm^3 hydrogen / hour	Hydrogenious	[23], [6]

	Stationary system connected with electrolyzer and fuel cell for smart grid applications	2018	hydrogenation capacity: 94 Nm^3 hydrogen / hour	Covalion	[28], [6]

Hydrogenious LOHC Technologies

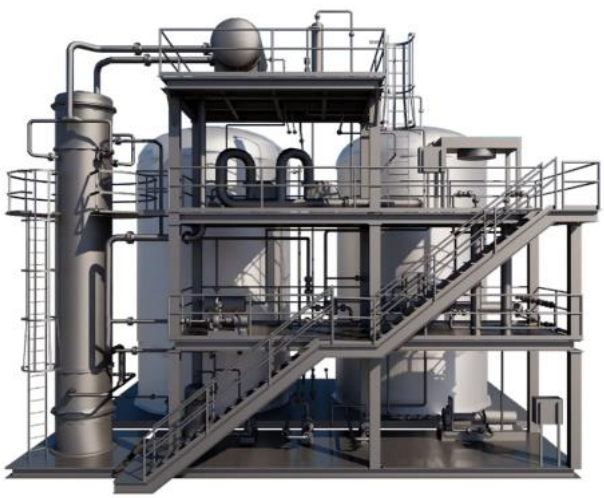

Figure 3-9: Hydrogenation plant. [23]

LOHC technology, developed by Hydrogenious LOHC Technologies GmbH, offers a safe and efficient method for storing and transporting hydrogen by chemically bonding it to organic liquids like dibenzyltoluene (liquid carrier oil). In this system, hydrogen is loaded onto the LOHC through a catalytic hydrogenation process at about 30 bar and temperatures > 200 °C (systems take a hydrogen feed of 30–50 bar). The hydrogen-rich LOHC remains in liquid form at ambient conditions, allowing for easy and safe transport using existing fuel infrastructure without the need for high-pressure tanks or cryogenic systems. To release the hydrogen, the LOHC undergoes dehydrogenation at higher temperatures (approx. 300°C), returning the carrier liquid to its original form for reuse.

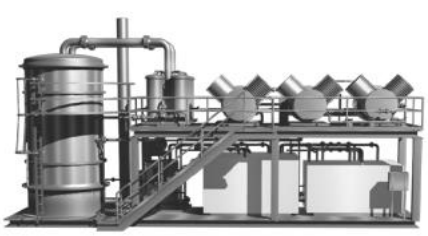

Figure 3-10: LOHC release system

Hydrogenious developed both storage unit (for hydrogenation) and release unit (for dehydrogenation). The storage unit is designed to store hydrogen in the chemically bonding it to organic liquids (hydrogenation process). The process is optimized for continuous operation and high efficiencies. During the exothermic storage reaction high temperature heat is produced. The release unit is designed to release hydrogen from the organic liquids (dehydrogenation). The process is optimized for continuous operation and long-term stability. The endothermic hydrogen release process requires heat, which can be supplied by high-temperature waste-heat, natural gas, electricity or hydrogen.

3.3.11. Projection of performance and cost

LOHC storage is a new technology and due to the few commercial applications, both current cost estimates as well as future cost projections are related to high uncertainty. Consequently, no reliable cost forecasts have been made. Cost reductions will depend on the uptake/commercialization of LOHC and general large-scale hydrogen production and demand.

3.3.12. Uncertainty

The uncertainty in costs primarily stem from the wide range of values reported in the literature. Different studies present varying assumptions and technological maturity levels for LOHC systems, leading to variability in cost estimates. Additional uncertainty arises from the limited number of real-world applications and suppliers.

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3.5. Datasheet

Technology	Pressurized hydrogen gas storage system (Type 1 tanks)									Notes	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Form of energy stored	Chemical										
Application	Local										
Energy storage capacity for one unit (MWh)	16.7	16.7	16.7	16.7	16.7					A	1, 2
Output capacity for one unit (MW)	-	-	-	-	-					C	
Input capacity for one unit (MW)	0.08	0.08	0.07	0.07	0.07					B	3
Round trip efficiency (%)	88.29	88.29	88.96	89.65	89.65						2
- Charge efficiency (%)	88.29	88.29	88.96	89.65	89.65					D	2
- Discharge efficiency (%)	100	100	100	100	100					E	2
Energy losses during storage (% / period)	<1	<1	<1	<1	<1					F	2
Auxiliary electricity consumption (% of output)	<1	<1	<1	<1	<1					I	2
Forced outage (%)	0	0	0	0	0					H	1, 2
Planned outage (weeks per year)	1	0.67	0.50	0.33	0.33	1	3			G	2, 4
Technical lifetime (years)	25	30	30	30	30						1, 2
Construction time (years)	0.3	0.24	0.24	0.18	0.18	0.3	0.5				1, 2, 4
Regulation ability											
Primary regulation (% per 30 sec)											
Secondary regulation (% per minute)											
Financial data (in 2023₹)											
Specific investment (cr. ₹ per MWh)	0.53	0.42	0.25	0.19	0.19	0.52	0.65				1, 2
Compressor component (cr. ₹ per MWh)	0.30	0.24	0.13	0.08	0.08	0.27	0.34				1, 2, 5
Tanks component (cr. ₹ per MWh)	0.18	0.16	0.11	0.10	0.10	0.16	0.20				1, 2, 5
Installation, equipment, manhours (cr. ₹ per MWh)	0.05	0.04	0.03	0.03	0.03	0.05	0.10				1, 2, 5
Fixed O&M (INR/MW/year)	78065	65054	65054	52043	52043	68121	88009				1, 2
Variable O&M (INR/MWh)											
Technology specific data											
Gravimetric energy density (kWh/kg)	33.3	33.3	33.3	33.3	33.3						1, 2
Volumetric energy density @0C and 1atm pressure (kWh/m3)	0.09	0.09	0.09	0.09	0.09						1, 2
Permeation characteristics for Type I tanks (mol/s/m/MPa1/2)	2.84×10-27	2.84×10-27	2.84×10-27	2.84×10-27	2.84×10-27						2

Notes

A Considering 500 kg H_2 storage per unit storage, Energy storage capacity for one unit (MWh) = 500kg multiplied by 33.33 kWh/kg

B The only power input that is considered is the input for the compressor and does not include power needs for the electrolyser that is making the hydrogen as described in the system definition. For the compression of 1 kg to 200 bar is approximately 4 kWh/kg and input capacity for 500 kg for 24 hour is provided.

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

D The charge efficiency is equal to the roundtrip efficiency as there are almost no losses in the discharge process.

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.

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

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

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

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Technology	Hydrogen storage - Liquid organic hydrogen carriers (LOHC)									Note	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
Energy/technical data											
Form of energy stored	Chemical										
Application	System or local										
Energy storage capacity for one unit (MWh)	480	2400	12000	36000	96000	60	2400	480	96000	A	1
Output capacity for one unit (MW)	6	13	34	69	137	1	14	5	143	B	1
Input capacity for one unit (MW)	10	20	50	100	200	2.5	20	10	200	B	1
Round trip efficiency (%)	63	66	69	69	69	48	69	52	72	C	3, 6
- Charge efficiency (%) (hydrogenation)	97	98	98	98	98	80	98	80	98		3, 6
- Discharge efficiency (%) (dehydrogenation)	65	67	70	70	70	60	70	65	73		3, 6
Energy losses during storage (%/day)	0	0	0	0	0	0	0	0	0		5
Auxiliary electricity consumption (% of output)										D	
Forced outage (%)											
Planned outage (weeks per year)											
Technical lifetime (years)	15	15	20	20	20						4
Construction time (years)	1	1	1	1	1	0.8	1.5	0.7	1.5		
Financial data (in 2023₹)											
Specific investment (cr. ₹ per MWh)	0.1496					0.0711	0.2280				4, 5
- energy component (cr. ₹/MWh)	0.0193					0.0159	0.0227			E	5
- capacity component (cr. ₹/MW_H2,LHV)	6.2540					2.6500	9.8580			F	4
Fixed O&M (cr.₹/MW/year)	0.2872					0.1365	0.4379			G	4
Variable O&M (₹/MWh)	157.1077									H	
Technology specific data											
Capital cost (cr. ₹/MW)	7.18					3.41	10.95				4, 5
Specific energy (kWh/kg)	1.90										2
Energy density (kWh/m3)	1799.82										7
Volumetric dencity (kg H2/m3)	54.00										

Notes

A It is assumed the storage in 2024 is for the production for 2 days (48 hours full load) and the storage capacity in days of production is increasing to 5 in 2030 and hereafter by plus 5 day for every 10 years. For the LOHCs the storage is not expensive, it is the reactors that are the expensive part.

B An example of the world's largest LOHC construction started in 2021, with a capacity of 5 tonnes H_2/day, which equals 7 MW. In IEA 2023[ref 8]it is stated that LOHCs are on Technology readiness levels 7. Therefore, it is expected that typical capacity of LOHCs will increase rapidly, as references indicate the ability to deliver multi-ton/day plants (ref7). This capacity is significant because references show that the difference in cost per MW for reactors highly depends on their total size. For example, the specific cost (per MW) for a 2.5 MW reactor is double that of a 10 MW reactor. The capacity is assumed to be 10 MW in 2024

C Without heat recycling from hydrogenation: 30-40% of the released hydrogen need to be burned if the heat for dehydrogenation is provided by hydrogen thereby the efficiency is 60-70% [3],[6]

D It is assumed that the electricity consumption is limited and included in the efficiency, no specific figures for electricity consumption is found

E LOHC carrier material (dibenzyltoluene (DBT)) (2.5 - 4 €/kgLOHC with 15.2 kgLOHC/kgH_2 which corresponds to 6.5 wt%) as well as two tanks (5 €/kgH_2 per tank); LHV H_2=33.3 kWh/kg

F Based on 10 MW size in Table 3 in [4]; includes both hydrogenation and dehydrogenation reactor, average and highest and lowest

G 4% of capacity component investment (see table 3 in [4]

H Cost of replacing the carrier material (assumed to be LOHC carrier material (dibenzyltoluene (DBT)) which is assumed de degrade by 0,1% per cycle

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4. Green Ammonia

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 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 green ammonia production paths is discussed.

Green ammonia has various applications and is primarily thought to be a carbon-neutral solution for shipping as a maritime transport fuel and 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 fossil fuel, among others.

In this catalogue, performance and cost data are given for the ammonia synthesis. Cost and performance data for the electrolysis (for the production of hydrogen) are referred to in a separate chapter within this Technology Catalogue.

4.1. Brief technology description

Currently, commercial ammonia production is predominantly based on the Haber-Bosch process. Around 90% of ammonia across the globe is produced using this process. Figure 4-1 shows the process of making ammonia using the Haber-Bosch process.

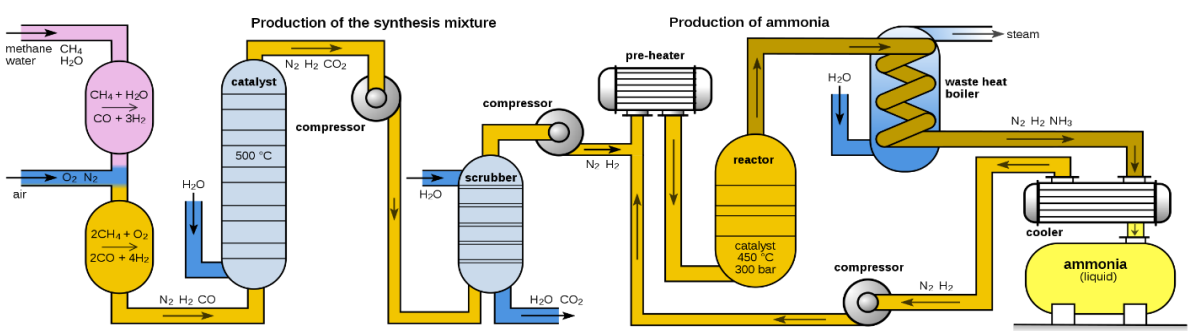

Figure 4-1: Process Flow Diagram of Haber-Bosch Process. [1]

This reaction involves the catalytic reaction of hydrogen and nitrogen at high temperatures and pressures to produce Ammonia. The nitrogen (N_2) is extracted from the air using the Air Separation Unit (ASU) and the hydrogen (H_2) is produced via the Steam Methane Reforming (SMR) process (refer to Figure 4-2).

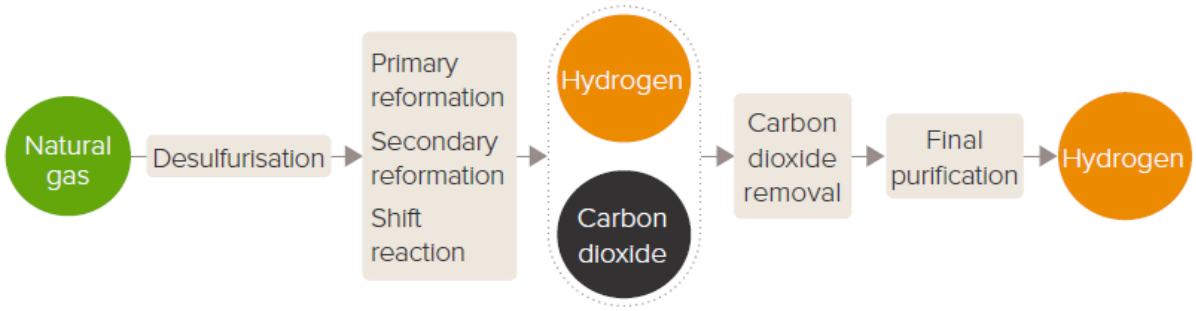

Figure 4-2: Schematic diagram of Steam Methane Reforming. [2]

The H_2 could also be produced using electrolysis, gasification of coal or biomass, or steam reforming of upgraded biogas. All the methods for producing H_2 mentioned above can be based on either fossil or biogenic sources and electricity produced by fossil or renewable energy.

In this chapter, only two types of ammonia are considered i.e. green ammonia and grey ammonia. Furthermore, it is assumed that in both cases N_2 is produced by ASU.

Nitrogen Extraction (ASU): The atmospheric air contains 78.08% of nitrogen. For nitrogen extraction, the nitrogen from the air is separated using a cryogenic ASU with a single column (<9000m^3)/ double column (>9000 m^3) rectifier depending on the capacity of the system, the specific energy consumption of the system ranges from 0.16-0.18 kWh/m3 air processed. [3]

A widely accepted definition of green hydrogen is it is produced using electrolysis of water and renewable energy, and grey hydrogen is that it is produced from natural gas using SMR. [4]

In this chapter, only two types of ammonia are considered: green and grey. Furthermore, it is assumed that in both cases N_2 is produced by ASU.

The definitions for the colour of the ammonia in this chapter are:

- the ammonia is green if the feedstock H_2 is green, and the ASU and the Haber-Bosch process have been driven by renewable energy /electricity,
- the ammonia is grey if the H_2 is grey and the ASU and the Haber-Bosch process have been driven by either fossil or renewable energy /electricity or a mix.

4.1.1. Grey and green ammonia

Grey Ammonia: Generally speaking, if the Ammonia is produced via fossil fuel, it will yield grey ammonia. In this, the system's power consumption is produced using fossil fuel. i.e.: Natural Gas, Coal power plant etc and the H_2 is sourced from a fossil fuel.

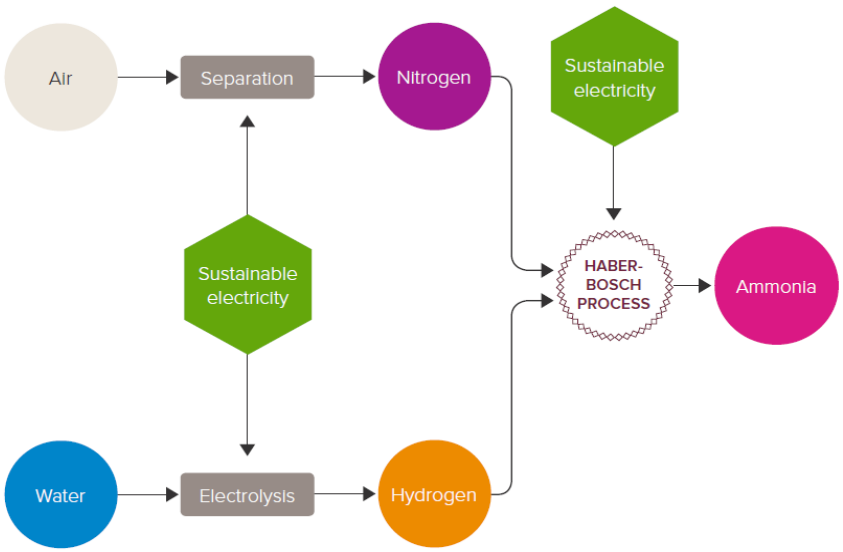

Figure 4-3: Flow diagram for Green Ammonia production. [2]

Green Ammonia: Green ammonia is produced through the Haber-Bosch process like grey ammonia but the energy usage is through renewable energy in addition, green hydrogen (produced using renewable energy rather than fossil fuel) is used for the production of ammonia (refer to Figure 4-3). Green ammonia can also be produced using other methods such as bacterial-based ammonia production and, a chemical looping process which has a TRL of 1-4. Green Ammonia can also be produced using the electrochemical process (electrolysis process to produce ammonia which will be powered by green electricity). TRL of these electrochemical technologies is at 1-2 [2].

4.1.2. Ammonia synthesis using conventional Haber-Bosch process and SMR

Hydrogen Extraction (SMR): Generally, hydrogen is extracted by use of natural gas and biomass sources e.g. upgraded biogas as fuel and using the SMR process as shown in Figure 4-4. The SMR process is endothermic. It requires a process temperature of 700-1000°C under 3-25 bar pressure with Ni as a catalyst [5]. This process is highly energy-intensive. It requires a standard enthalpy of ($\Delta H°$) 206.8 kJ/mol [6], which is said to be the lowest among other ammonia extraction processes. SMR consumes 7.8-9.4 MWh/t NH_3 and contributes around 90% of carbon emissions for the whole process [7].

Ammonia synthesis: Haber Process is used in the manufacturing of ammonia from nitrogen and hydrogen, in which a reaction between nitrogen (N_2) and hydrogen (H_2) takes place with an iron catalyst (Fe^{3+}), Aluminium oxide (Al_2O_3) and potassium oxide (K_2O) as promoters. The reaction is carried out under conditions of 253 bar, 450-500 °C.

$$N_2\,(g) + 3H_2\,(g) \rightarrow 2NH_3\,(g);\ \Delta H^o = -92.4\ kJ/mol$$

(Where ΔH^o is the standard enthalpy of change)

Process Description:

There are 3 main processes for the extraction of hydrogen to produce ammonia - Steam Methane Reforming, Coal Gasification, and Water Electrolysis. Globally 90% of ammonia is currently extracted through the SMR process because of the low enthalpy of reaction and cost. However, considering the high emission factor

from the SMR process, 9kg CO_2 per kg of H_2 [8], industries have now started exploring carbon-neutral approaches to synthesizing ammonia using green sources of energy.

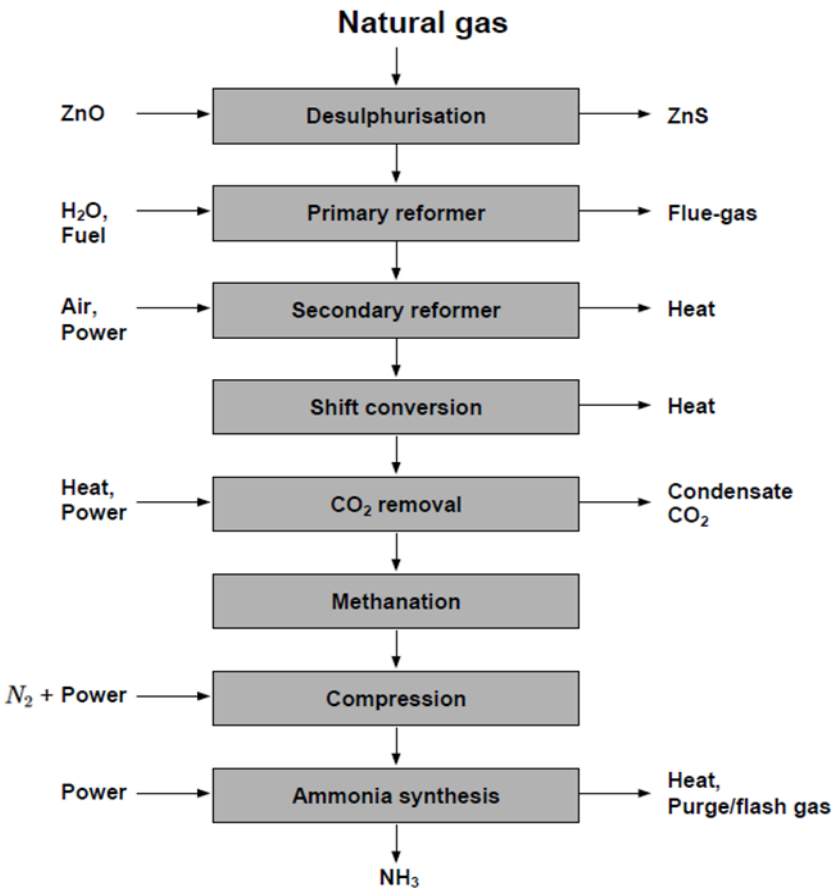

Figure 4-4: Simple Block diagram of SMR process for NH_3 production. [9]

Overall Reaction, based on SMR

The theoretical process conversions, based on methane feedstock, are expected to happen as per the following equation:

$$0.88\ CH_4 + 1.26\ Air + 1.24\ H_2O \rightarrow 0.88\ CO_2 + N_2 + 3H_2$$

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

The synthesis gas production and purification normally take place at 25-35 bar pressure. The ammonia synthesis pressure is usually in the range of 100-250 bar [10].

Feedstock Desulphurization in the SMR process

Most of the catalysts used in the process are sensitive to sulphur and sulphur compounds. The feedstock normally contains sulphur up to 5mg/Nm^3 as sulphur compounds. The feed gas is preheated to 350-400°C, usually in the primary reformer convection section, and then treated in a desulphurization vessel, where the sulphur compounds are hydrogenated to H_2S, typically using a cobalt molybdenum catalyst, and then adsorbed on pelletized zinc oxide:

$$R\text{-}SH + H_2 \rightarrow H_2S + RH$$

$$H_2S + ZnO \rightarrow ZnS + H_2O$$

In this way, the sulphur is removed to less than 0.1 ppm in the gas feed. The zinc sulphide remains in the adsorption bed. The hydrogen for the reaction is usually recycled from the synthesis section.

Primary reforming

The gas from the desulphuriser is mixed with process steam, usually coming from an extraction turbine, and the steam/gas mixture is then heated further to 500-600°C in the convection section before entering the primary reformer. In some new or revamped plants, the preheated steam/gas mixture is passed through an adiabatic pre-reformer and reheated in the convection section, before entering the primary reformer. (Special pre-reformer catalysts are offered by several suppliers). Also, in some plants, part of the process steam is supplied by feed-gas saturation.

The amount of process steam is given by the process steam to carbon molar ratio (S/C ratio), which should be around 3.0 for the efficient reforming processes. The optimum ratio depends on several factors, such as feedstock quality, purge gas recovery, primary reformer capacity, shift operation, and the plant steam balance. In new plants, the optimum S/C ratio may be lower than 3.0.

The primary reformer consists of a large number of high–nickel-chromium alloy tubes filled with nickel-containing reforming catalysts. The overall reaction is highly endothermic and additional heat is required to raise the temperature to 780-830°C at the reformer outlet.

The composition of the gas leaving the primary reformer is given by a close approach to the following chemical equilibria:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \qquad \Delta H^\circ_{298} = 206\ kJ.mol^{-1}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad \Delta H^\circ_{298} = -41\ kJ.mol^{-1}$$

The heat for the primary reforming process is supplied by burning natural gas or other gaseous fuel, in the burners of a radiant box containing the tubes.

The flue gas leaving the radiant box has temperatures above 900°C, after supplying the necessary high-level heat to the reforming process. Thus, only about 50-60% of the fuel's heat value is directly used in the process itself. The heat content (waste heat) of the flue gas is used in the reformer convection section, for various process and steam system duties. The fuel energy requirement in the conventional reforming process is 40-50% of the process feed gas energy [9].

The flue gas leaving the convection section at 100-200°C is one of the main sources of emissions from the plant. These emissions are mainly CO_2, and NOx, with small amounts of SO_2 and CO [9].

Secondary Reforming

Only 30-40% of the hydrocarbon feed is reformed in the primary reformer because of the chemical equilibria at the actual operating conditions. The temperature must be raised to increase the conversion. This is done in the secondary reformer by internal combustion of part of the gas with the process air, which also provides the nitrogen for the final synthesis gas. In the conventional reforming process, the degree of primary reforming is adjusted so that the air supplied to the secondary reformer meets both the heat balance and the stoichiometric synthesis gas requirement.

The process air is compressed to the reforming pressure and heated further in the primary reformer convection section to around 600°C. The process gas is mixed with the air in a burner and then passed over a nickel-containing secondary reformer catalyst. The reformer outlet temperature is around 1,000°C, and up to 99% of the hydrocarbon feed (to the primary reformer) is converted, giving a residual methane content of 0.2-0.3% (dry gas base) in the process gas leaving the secondary reformer. The process gas is cooled to 350-400°C in a waste heat steam boiler or boiler/superheater downstream from the secondary reformer [9].

Shift Conversion

The process gas from the secondary reformer contains 12-15% CO (dry gas base) and most of the CO is converted in the shift section according to the reaction:

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad \Delta H°_{298} = -41 \text{ kJ.mol}^{-1}$$

In the High-Temperature Shift (HTS) conversion, the gas is passed through a bed of iron oxide/chromium oxide catalyst at around 400°C, where the CO content is reduced to about 3% (dry gas base), limited by the shift equilibrium at the actual operating temperature. There is a tendency to use copper-containing catalysts for increased conversion. The gas from the HTS is cooled and passed through the Low-Temperature Shift (LTS) converter.

This LTS converter is filled with a copper oxide/zinc oxide-based catalyst and operates at about 200-220°C. The residual CO content in the converted gas is about 0.2-0.4% (dry gas base). A low residual CO content is important for the efficiency of the process.

CO_2 removal

The process gas from the low-temperature shift converter contains mainly H_2, N_2, CO_2 and the excess process steam. The gas is cooled and most of the excess steam is condensed before it enters the CO_2 removal system. This condensate normally contains 1,500-2,000ppm of ammonia and 800-1,200ppm of methanol. Minor amounts of amines, formic acid and acetic acid could be present in the condensate. All these components should be efficiently removed from the condensate and/or recycled within the process to maximize efficiency. The heat released during cooling/condensation is used for:

- The regeneration of the CO_2 scrubbing solution
- Driving an absorption refrigeration unit
- Boiler feedwater preheat

The amount of heat released depends on the process steam to carbon ratio. If all this low-level heat is used for CO_2 removal or absorption refrigeration, high-level heat has to be used for the feedwater system. An energy-efficient process should therefore have a CO_2 removal system with a low heat demand.

The CO_2 is removed in a chemical or a physical absorption process. The solvents used in chemical absorption processes are mainly aqueous amine solutions (Mono Ethanolamine (MEA), Activated Methyl Diethanolamine (aMDEA) or hot potassium carbonate solutions. Physical solvents are glycol dimethyl ethers (Selexol), propylene carbonate and others. The MEA process has a high regeneration energy consumption and is not regarded as an efficient process.

Methanation

The small amounts of CO and CO_2, remaining in the synthesis gas, are poisonous for the ammonia synthesis catalyst and must be removed by conversion to CH_4 in the methanation reactor:

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

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

The reactions take place at around 300°C in a reactor filled with a nickel-containing catalyst. Methane is an inert gas in the synthesis reaction, but the water must be removed before entering the converter. This is done firstly by cooling and condensation downstream of the methanation reactor and finally by condensation/absorption in the product ammonia in the loop or a make-up gas drying unit.

Synthesis Gas Compression and Ammonia synthesis
Modern ammonia plants use centrifugal compressors for synthesis gas compression, usually driven by steam turbines, with the steam being produced in the ammonia plant. The refrigeration compressor, needed for condensation of product ammonia, is also usually driven by a steam turbine.

The synthesis of ammonia takes place on an iron catalyst at pressures usually in the range 100-250 bar and temperatures in the range 350-550°C [9]:

$$N_2 + 3H_2 \rightarrow 2NH_3 \qquad \Delta H^\circ_{298} = -46 \text{ kJ.mol}^{-1} NH_3$$

Only 20-30% is reacted per pass in the converter due to unfavourable equilibrium conditions [9]. The ammonia that is formed is separated from the recycled gas by cooling/condensation, and the reacted gas is substituted by the fresh make-up synthesis gas, thus maintaining the loop pressure. In addition, extensive heat exchange is required due to the exothermic reaction and the large temperature range in the loop. A newly developed ammonia synthesis catalyst containing ruthenium on graphite support has a much higher activity per unit of volume and has the potential to increase conversion and lower operating pressures.

Synthesis loop arrangements differ with respect to the points in the loop at which the make-up gas is delivered and the ammonia and purge gas are taken out. The best arrangement is to add the make-up gas after ammonia condensation and ahead of the converter. The loop purge should be taken out after ammonia separation and before make-up gas addition. This configuration is dependent on the make-up gas being treated in a drying step before entering the loop. A make-up gas containing traces of water or carbon dioxide must be added before ammonia condensation, with negative effects both to ammonia condensation and energy.

Conventional reforming with methanation as the final purification step, produces a synthesis gas containing inerts (methane and argon) in quantities that do not dissolve in the condensed ammonia. The major part of these inert is removed by taking out a purge stream from the loop. The size of this purge stream controls the level of inerts in the loop to about 10-15%. The purge gas is scrubbed with water to remove ammonia before being used as fuel or before being sent for hydrogen recovery.

Ammonia condensation is far from complete if cooling is with water or air and is usually not satisfactory (dependent on loop pressure and cooling medium temperature). Vaporizing ammonia is used as a refrigerant in most ammonia plants, to achieve sufficiently low ammonia concentrations in the gas recycled to the converter. The ammonia vapours are liquified after recompression in the refrigeration compressor.

4.1.3. Ammonia synthesis using electrolysis + Haber-Bosch process

Hydrogen Extraction via electrolysis: The hydrogen is extracted through the electrolysis process, the previous section of the catalogue will give an in-depth idea about the technology, currently Alkaline Electrolysis (AE) consumes around 51.3 kWh_e and 11litres of water to produce 1kg of hydrogen, with a hydrogen output purity of 99.9 %.

Ammonia synthesis: The Haber Process is used in the manufacturing of ammonia from nitrogen and hydrogen, in which nitrogen (N_2) and hydrogen (H_2) gases are reacted over an iron catalyst (Fe^{3+}) in which Aluminium oxide (Al_2O_3) and potassium oxide (K_2O) are used as promoters. The reaction is carried out under conditions of 253 bar, 450-500 °C.

N_2 (g) + 3H_2 (g) → 2NH_3 (g); ΔH° = -92.4 kJ/mol (Where ΔH° is the standard enthalpy of change)

Almost the whole process of production of ammonia is similar to that of the process described for the conventional Haber-Bosch process using SMR process, but in this process, we will replace steps (desulphurisation, primary reformer, secondary reformer, shift conversion, CO_2 removal, methanation) with an electrolyser for the production of hydrogen and followed by the step i.e. compression and ammonia synthesis apart from the purification step as both hydrogen and Nitrogen in this process will have a higher purity. The simplified block diagram for the process is given in Figure 4-5.

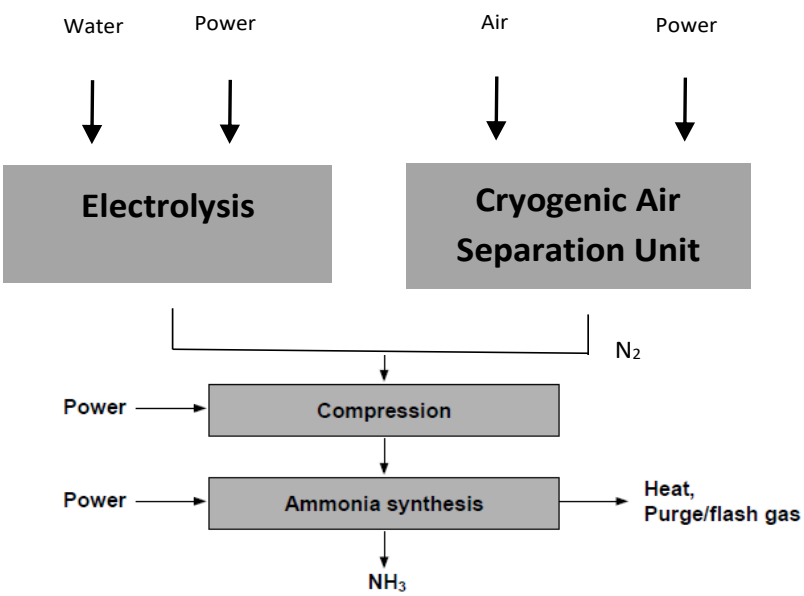

Figure 4-5: Simple Block diagram for Electrolysis based NH_3.

4.1.4. Ammonia production using electrochemical process

Bypassing the Haber-Bosch process entirely, it is possible to synthesize ammonia at substantially lower temperatures and pressures using an electrochemical approach. By forcing the movement of electrons while the reactants come into touch with the surface of catalysts attached to conductive electrodes, the feedstock enters a cell and is electrochemically transformed to ammonia. This state shift may result in significant energy savings from large-scale heating or pressurization as well as more efficient and maybe safer integration into an industrial ammonia process, which can be sourced with the renewable fuel and so the reaction will be identical to the conventional process.

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

Alternatively, some cells have the capacity to carry out this conversion in situ, skipping a step and receiving water right away. Generating ammonia with water as a reaction and so the process will be,

$$3H_2O + N_2 \rightarrow 2NH_3 + 3/2\ O_2$$

However, compared to the hydrogen-fed electrolysis unit, more energy is required for electrochemical ammonia synthesis when water is used as a proton source. Also, to obtain decarbonized hydrogen as a feedstock for the process, it requires preliminary water electrolysis adding substantial energy to the process [11].

There are two ways in which the electrochemical ammonia production can be produced.

Water fed cell using cation/proton or anion exchange membrane

In this setup, water and nitrogen are fed into the electrolytic chamber and use the theory of electrolysis in which depending on the electrode and material behaviour the required ammonia and other products get separated, if the water is fed into an anion membrane, the required ammonia will be extracted from the cathode and vice versa, the usage of anion membrane has been considered recently because of its higher efficiency of recovery because of the alkaline electrolyte. The flow diagram and the simple schematic of the water fed electrochemical method of ammonia extraction is shown in Figure 4-6 and Figure 4-7.

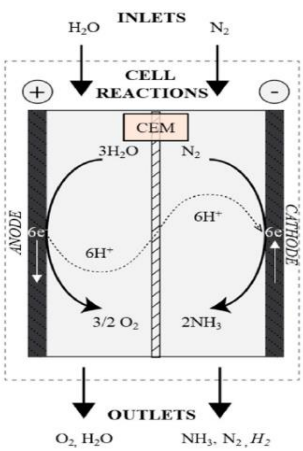

Figure 4-6: Schematic of water fed electrochemical NH_3 production. [11]

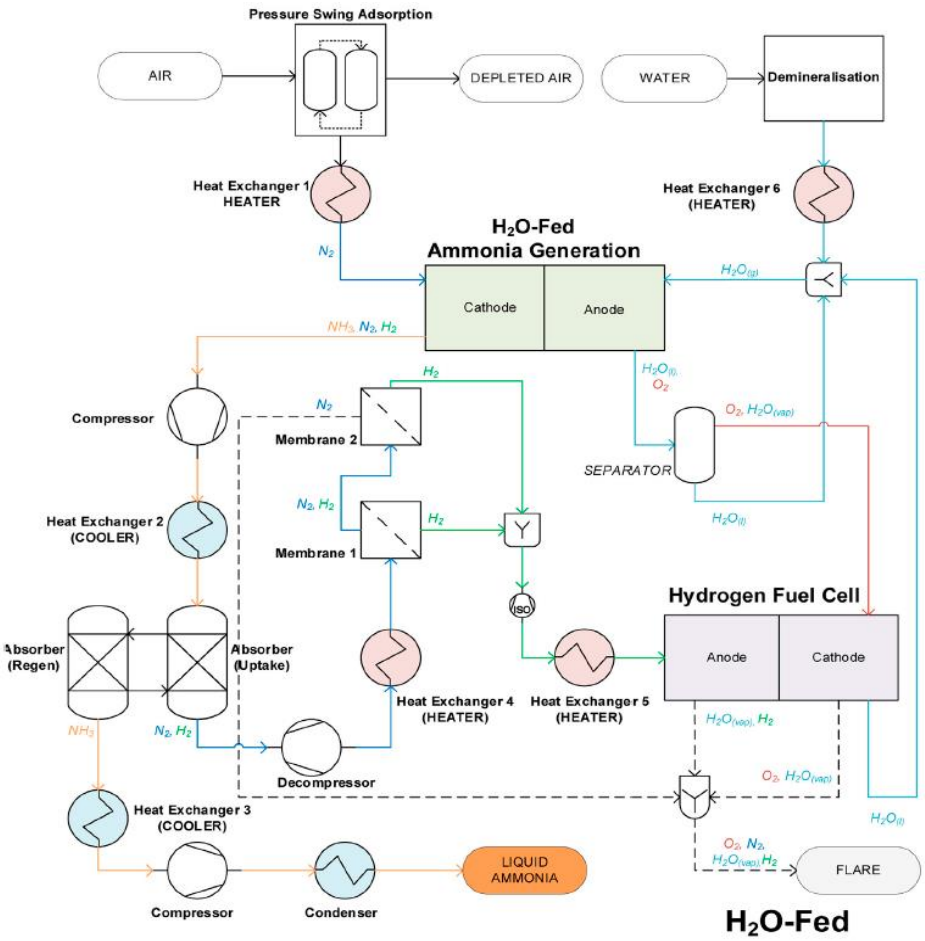

Figure 4-7: Process flow diagram of water fed electrochemical NH_3 production. [11]

Hydrogen fed cell using cation/proton exchange membrane

This process is same as that of Haber Bosch except that the process is done in an electrolytic chamber. This process is highly energy intensive. This process requires power in the water electrolysis system for production of hydrogen in addition to power requirement in the ammonia electrolysis chamber and cryogenic ASU. So comparatively using the green hydrogen with the Haber Bosch process will be cost effective rather than using this process.

A simple schematic of Hydrogen fed electrochemical method of ammonia extraction and respective flow diagram is shown in Figure 4-8 and Figure 4-9.

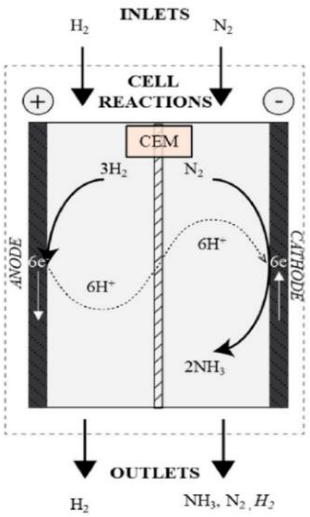

Figure 4-8: Schematic of H_2 fed electrochemical NH_3 production. [11]

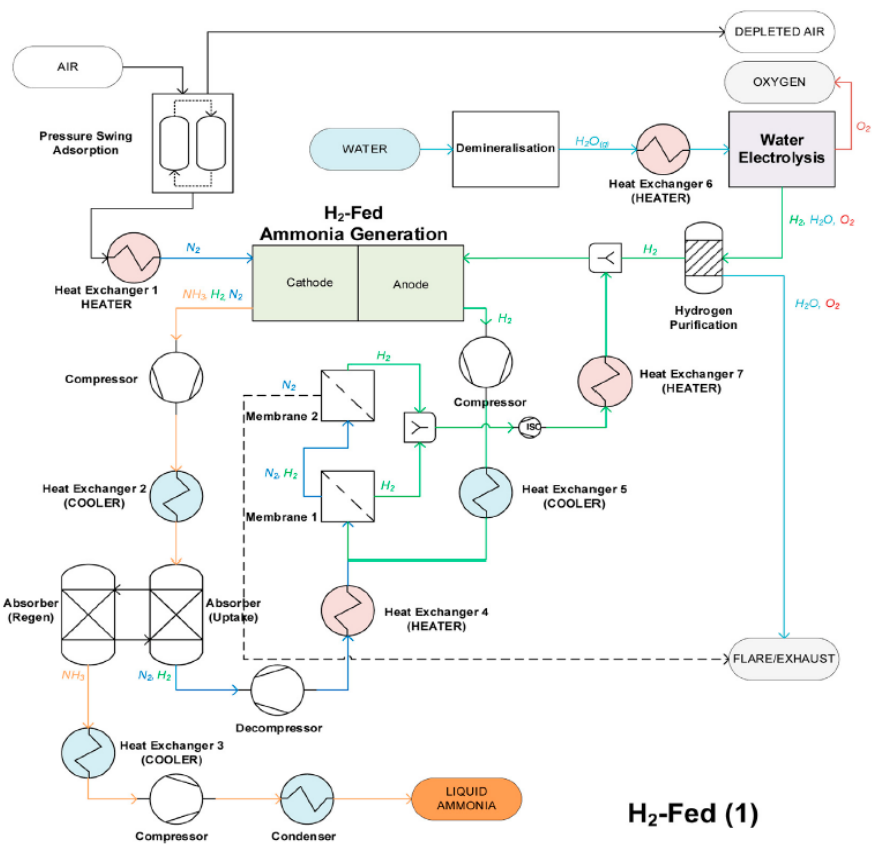

Figure 4-9: Process flow diagram of hydrogen fed electrochemical NH_3 production. [11]

Even though the above electrochemical approach of producing ammonia looks promising the technology is not ready to be commercialized. The TRL of this technology stands at 1-2. Apart from this, another process for which the TRL stands at 1 is Biological Nitrogen fixation in which green ammonia is produced naturally by

bacteria that contains an enzyme catalyst [12]. Thus, the most effective way for producing green ammonia is the Electrolysis + Haber process.

Operation range

The operation ranges of both conventional and green ammonia plants can be divided into [13]:

- Shut down – Cold standby
- Hot standby – no production but the plant is kept warm for fast startup
- 0-20 % operation
- 20-35 % operation
- 35-100 % 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 due to no product demand or missing feed availability. The reason is that frequent cooling and reheating will cause catalyst crunching (due to grinding among catalyst particles caused by expansion upon heating and shrinking upon cooling) and thereby reduce catalyst lifetime. Therefore, an ammonia plant must be kept in hot standby mode (see next section) in periods, in which 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 conditions (i.e., at normal operation temperature and pressure) to enable a fast ramp-up in capacity. Compared to cold standby mode, hot standby mode gives more lifetime to the plant.

   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 takes 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 limited 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 is limited.

   Similarly, for an electrolysis unit, a hot standby mode can enable fast ramp up (within seconds)[10]. Depending on weather forecasts and knowledge about fluctuations in electricity generation and demand, the number of electrolysis cells that are kept in hot standby mode can be optimized.

3. **Operation at 35 – 100% Capacity**
   A conventional ammonia plant usually has an operating range between 70-100% of max.capacity. However, as the general turndown ratio of rotating equipment, many transmitters and control valves are 35%, these plants can normally handle loads down to 35% without major changes.

[10] 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)

4. **Operation at 20 – 35% Capacity**
   If there is a need to reduce operations to 20%, this can usually be achieved by insignificant CAPEX spending for equipment that can handle larger capacity ranges.

5. **Operation at 0 – 20% Capacity**

   For operation at lower capacity than 20% a significant increase in CAPEX is needed, as multiple valves, instruments and rotating equipment would have to be available 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 the requirements for product outflow.

If the feed is hydrogen, i.e., if the plant is connected to a hydrogen storage, the buffer within the hydrogen transmission net will ensure a stable feed flow for which cost is fairly stable. Thus, the demand for operation flexibility will be low.

Alternatively, for the power feed, i.e., if hydrogen is produced by electrolysis of water, and it is not combined with a hydrogen storage, fluctuating power prices and the wish to maximize profit, introduce demands for high flexibility in the operation and capacity of the ammonia plant.

For the case where power is the feed to the plant, the following scenarios must be considered while dealing with fluctuating power prices:

A. Fast ramping: Grid connections that facilitate fast ramping has different costs.
B. Prolonged periods with high power prices

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

Point B: 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 NH3 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 NH3 storage[11] 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 NH3 plant. Combining the green NH3 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

[11] Note: NH3 storage is much cheaper than H2 storage

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.

4.1.5. Properties of ammonia

Thermal and physical properties of gaseous ammonia are shown in Table 4-1. Phase diagram of Ammonia is shown in Figure 4-10.

Table 4-1: Thermal and Physical properties of gaseous ammonia.

Parameter	Value
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

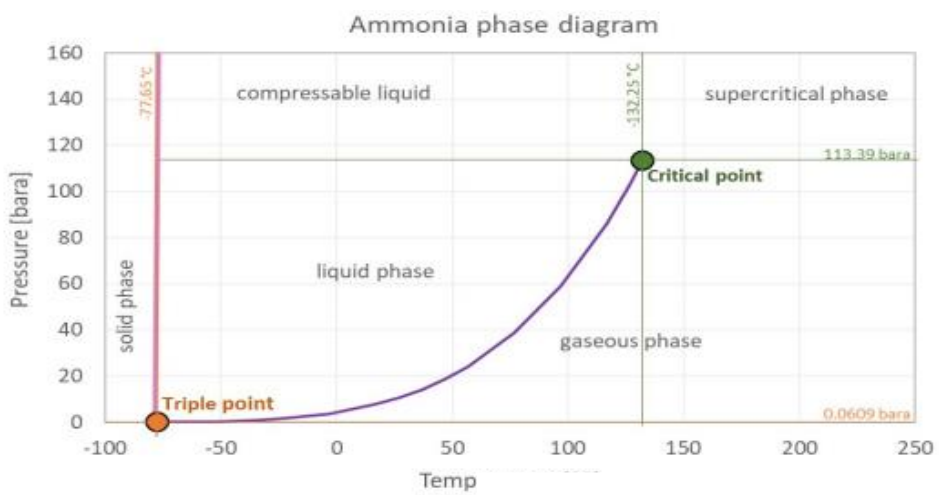

Figure 4-10: Ammonia phase diagram. [13]

4.2. Input

The input to the ammonia synthesis loop is hydrogen, nitrogen and power. 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.

4.3. Output

The output streams from the ammonia synthesis are ammonia, steam, hot water and a tiny purge stream which will be flared as it has impurities of ammonia.

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. Besides the above mentioned, the output from the electrolysis unit and ASU are oxygen from both the electrolysis and ASU unit.

4.4. Energy balance

This section gives an overview of inputs and outputs of ammonia synthesis in energy (e.g., MWh). Figure 4-11 shows the energy balance of the ammonia plant.

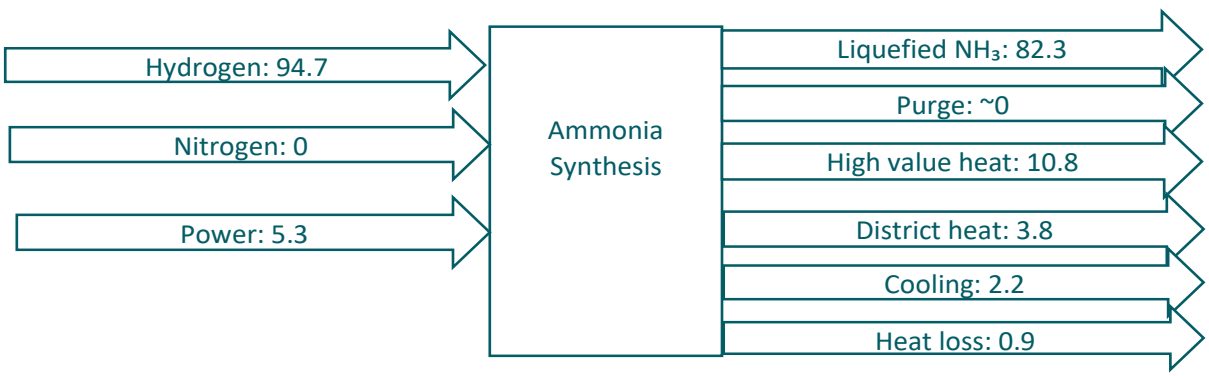

Figure 4-11: Overall energy balance of the ammonia synthesis, numbers given in %. [13]

Considering the energy balance of green ammonia plants including electrolysis unit and ASU, many theoretical papers and studies have looked into the energy requirements of green ammonia plants. These vary greatly compared to a conventional (SMR for H_2 production) ammonia plant, as the power consumption of the electrolysis unit makes up a large majority of the overall plant power requirements. Figure 4-12 shows an example of the energy balance breakdown for a green ammonia plant (operating at 150 bar), where the synthesis loop is the power required to drive compressors and pumps.

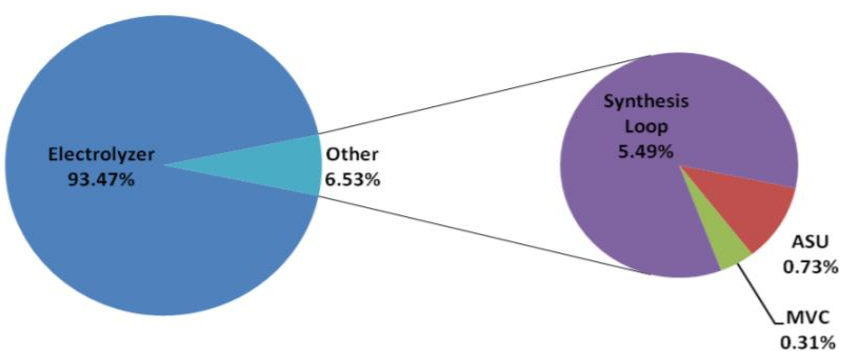

Figure 4-12: Power requirement breakdown for a green ammonia plant. [13]

In the figure the largest portion of power is consumed by the electrolyser (93.47%), which splits water into hydrogen and oxygen. This reflects the high energy demand in green hydrogen production, a critical component of green ammonia. A significant part of the remaining energy is consumed in the synthesis loop (5.49%), where hydrogen and nitrogen are combined to form ammonia via the Haber-Bosch process. A small amount of energy is used by the ASU (0.73%) to extract nitrogen from the air, which is essential for the ammonia synthesis process. Finally, a very minor portion (0.31%) is consumed by Mechanical Vapor Compression (MVC) for processes such as water recycling and distillation.

Based on the authors' estimate the following energy consumption breakdown was found (the MVC above has not been included as it is minor). The table shows Major power consumption units in green ammonia.

Table 4-2: Major power consumption units in green ammonia. [13]

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)	

There is no linear relationship between energy consumption of ASU and NH_3. The energy consumption of ASUs (200-400 kWh/ton N_2) depends on multiple factors such as capacity, extent of integration, and whether a high share of liquid N_2 for backup should be produced [13].

4.4.1. Integration possibilities

Integration possibilities within green NH_3 plants are [13]:

1. Steam produced in the ammonia loop can be used for:
    a. Electrolysis: In the case of SOEC (future option), which operates at 700-900 °C, steam can be used as water for the electrolysis unit
    b. Power production for own consumption e.g., ASU, compressors and pumps in the ammonia plant
    c. Export of steam (for use in nearby industrial processes)
2. Oxygen from the electrolysis unit and the ASU:
    a. Export
3. Excess low-temperature heat
    a. Water/air coolers in electrolysis and ammonia loops can be used for district heating especially if combined with a heat pump

Hybrid NH_3 plant [13]**:**
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 making 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 extra 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 replacing the bottleneck units (or add additional units) and the units that inherit the bottlenecks. The capacity can usually be increased to 110% capacity with no or limited changes. Increasing the capacity by 20-30% can often be done with acceptable investments (as only a few equipment needs to be revamped/replaced), while a 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 the "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:
    a. Steam addition to the steam methane reforming process
    b. Electrolysis: In case of SOEC (future option), which operates at 700-900 °C, steam can be used as water for electrolysis unit
    c. Power production for own consumption e.g., ASU, compressors and pumps in the ammonia plant
    d. Export of steam
2. Oxygen from the electrolysis unit and the ASU:
    a. 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 [12].
    b. Export
3. Hydrogen and off-gas from the NH_3 rec units: Same as under grey NH_3 plant
4. Excess low-temperature heat
    a. Water/air coolers in electrolysis and ammonia loop can be used for district heating especially if combined with a heat-pump.
    b. Heat from electrolysis unit can be used for pre-heating of NH3 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.

4.5. Typical capacities

The conventional ammonia can be produced from few kilograms and can be scaled up to thousands of tonnes per annum. The largest (2016) Haber-Bosch process-based plant have a capacity of 43,35,000 tonnes per annum or 11876.7 tonnes/day by Donaldsonville (Louisiana, USA).

For green ammonia, it depends on the scalability of electrolyser capacity to produce the required hydrogen for the process. The scalability of electrolyser plant has already been discussed in the electrolyser section of the document.

4.6. Regulation ability

For green ammonia production, flexibility challenges are inherent to the process configuration. Electricity is converted to hydrogen via electrolysis, after which hydrogen and nitrogen are fed to the ammonia synthesis loop. While electrolysers can ramp relatively quickly in response to variable electricity supply, the ammonia synthesis loop is a thermally integrated and pressurised system optimised for steady operation. To cope with

the intermittency of renewable power, one or a combination of the following technical options is typically applied [13] :

1. **A turndown ratio of 0% (hot standby mode)**, where the synthesis loop remains pressurised and thermally stable at zero production to enable rapid restart.
2. **Possibility to use grid power**, allowing hydrogen production to continue during periods of insufficient renewable electricity.
3. **Possibility to take feeds (N_2 and H_2) from grid or storage**, decoupling electrolyser operation from the ammonia synthesis loop.
4. **Possibility to increase capacity of a conventional front-end (hybrid solution)**, maintaining stable synthesis operation through oversized or mixed renewable and conventional inputs.

Several technology providers have quoted the following figures for turndown of the ammonia synthesis.

Haldor Topsoe:	10-100% [14]
ThyssenKrupp:	30-100% (based on vendor data)
Casale:	20-110% (based on vendor data)

4.7. Space requirement

A green ammonia plant is a combination of an electrolyser system with conventional ammonia production facility. Depending on the plant capacity, the production plant as well as the electrolyser requirement for area varies.

To understand the space requirement of the whole system, first the area required the ammonia production facility was taken from study of 1500 TPD (Tonnes per day) [15] plant and secondly, in respect to the hydrogen requirement of that 1500TPD plant electrolyser system size will be considered and its corresponding area will be taken. Finally, both the areas will be summed up to find the area occupied by the green ammonia plant.

In case green hydrogen is purchased from 3rd party, the area required for electrolyser system can be neglected and only the area occupied by hydrogen storage facility will be considered.

Area occupied by conventional ammonia production plant:

The pre-feasibility report states that the total plot area is 50 acres (202,343 m²), with 33% reserved for green belt development. The remaining 33.5 acres (135,569.7 m²) will be used for the production facility, requiring approximately 100 m² per 1 TPD plant.

Hydrogen required for ammonia production plant:

According to the WRI report [16], producing one tonne of ammonia requires 178 kg of hydrogen, which is about 2,198 Nm³/day or 91.58 Nm³/hr. A 500kW electrolyser, based on McPhy's MCLYZER data, will be needed, requiring approximately 30 m² of space.

Hence, the Total area required for 1-ton green ammonia plant including electrolyser would be around 130m^2.

4.8. Advantages/disadvantages

The main advantages of green ammonia production relative to conventional ammonia are [13]:

- 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 reduces purging requirement and need for NH_3 recovery section. This increases the overall efficiency of the NH_3 synthesis.
- 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 (load factor) of the renewable power production units

The main disadvantages can be summarized as [13]:

- 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 electrolysis significantly higher than that of natural gas, which gives higher costs of green NH_3.
- High temperatures, pressure, and chemicals can lead to fatal events. Explosion and fire safety assessments, as well as appropriate standards, are also required

4.9. Environment

Haber–Bosch process, while well-established, faces increasing scrutiny due to its environmental footprint. It accounts for over 1.5% of global CO_2 emissions, roughly 350 million tonnes annually, primarily because hydrogen used in ammonia synthesis is derived from fossil fuels. Transitioning to a hydropower-electrolysis-based hydrogen source for "green ammonia" could cut these emissions by around 75% [17]. Moreover, the environmental concerns extend beyond CO_2 emissions, with synthetic nitrogen fixation disrupting the global nitrogen cycle. Ammonia emissions contribute to particulate air pollution, but using ammonia in energy storage would limit its ecological impact since it would largely convert back to nitrogen gas and water, without releasing active nitrogen into the environment. However, burning ammonia directly can lead to NOx gas formation, which remains a concern for air quality [18].

4.10. Research and development perspectives

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 an 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 in the section describing the process step of the Air separation unit, the processes are far away from commercial application today.

4.11. Examples of market-standard technology

The data from the IEA database [19] and from IRENA, 2022 [20] lists over 40 commercial-scale projects which are currently planned or under-construction, covering a planned production capacity of 15 Mt/year globally by 2030 and 71 Mt/year in the long-term. Some examples are listed in Table 4-3:

Table 4-3: Selected global green ammonia plants.

S. No	Location	Electrolyser Type	Capacity (kt/year)	Expected Commission
1.	OCP Group demo project, Morocco	UK	4 t/day	2024
2	Yara, Australia	AE or PEM	<8	2023
		AE or PEM	48-160	2026
		AE or PEM	480	2028
		AE or PEM	800	2030
3	Yara, Norway	AE	5	2022
		AE	500	2025-2026
4	NEOM, Air Products, ACWA Power, Saudi Arabia	AE	1200	2025
5	Intercontinental Energy, Australia	AE and/or PEM or SOE	3000	2030
		AE and/or PEM or SOE	9900	2035
6	Haldor Topsoe, Aquamarine, Germany	SOE	105	2024
7	Hy2Gen, Canada	AE or PEM	183	2025

Some green ammonia projects from India are presented below.

4.11.1. Green Ammonia Plant, Una, Himachal Pradesh, India.

According to [21], Greenko Group and John Cockerill developed 28 units of 5 MW high-pressure alkaline electrolysers for a planned green ammonia plant in Una, Himachal Pradesh, intended to support production of 300 metric tonnes per day of green ammonia. The electrolysers were originally scheduled for delivery in March 2024, with commissioning expected by June 2024. This timeline was not met, and as of mid-2026, no

public source confirms that the Una plant has been commissioned. The project still appears in AM Green's (Greenko's green molecules subsidiary) current site listing, but recent company updates have focused on its larger-scale plants in Kakinada, Andhra Pradesh (under construction, targeting commercial ammonia supply by 2028) and Kandla, Gujarat, with no recent independent confirmation of the Una site's construction progress or revised commissioning date.

Table 4-4: Technical Specifications of UNA Project.

Item	Specification
Technology Used	Alkaline (AE)
Ammonia Capacity	109500 Metric tonnes per year
No. of Electrolyser Units	28
Hydrogen Capacity	140 MW
Hydrogen Purity	99.999 %
Status	Announced

4.11.2. Integrated Green Hydrogen and Green Ammonia plant, Bikaner, Rajasthan

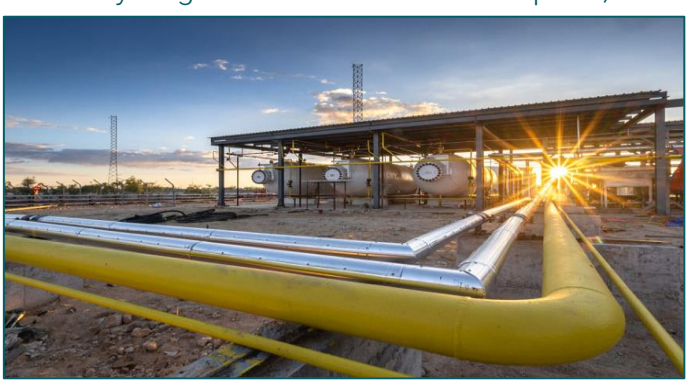

Figure 4-13. Integrated green hydrogen and green ammonia plant, Bikaner, Rajasthan. [22]

ACME Group has set up the world's first integrated pilot project for Green Hydrogen and Green Ammonia at Bikaner in Rajasthan [22]. In this project, green hydrogen is produced using 5 MWp from the solar plant, scalable to 10 MWp. The end use of the hydrogen and ammonia is for fertilizer industries.

Table 4-5: Technical Specifications of Hydrogen and Ammonia Plant, Bikaner, Rajasthan.

Aspect	Details
Location	Bikaner, Rajasthan
Solar capacity	5 MW

Hydrogen production	314 Tonnes H_2/year
Green Hydrogen Production Capacity	Unknown
Status	Commissioned

4.12. Projection of performance and costs

4.12.1. Investment cost

Projections of investment costs for green ammonia plants are based on data from the industry collected in the Danish Technology Catalogue [13] as a whole, as no large-scale plants or projects have been completed or are in operation yet. The input of one Indian stakeholder provides the lower uncertainty range.

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)[12]
- Storage

Based on cost split data for various conventional plants and figures obtained from various vendors, average split factors have been estimated. This approach gives that the average cost of the ammonia synthesis including storage and BOP is around ~54% of that of the cost of conventional NH_3.

[12] Balance of plant (BOP): 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.

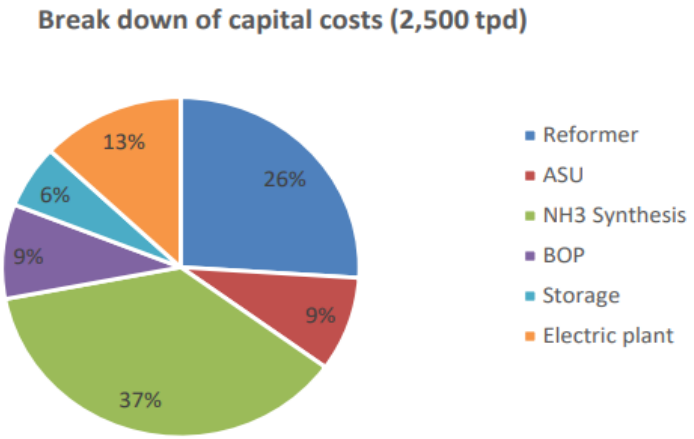

Figure 4-14: Cost split on main systems in a conventional NH_3 plant. from Linde [23]. Reformer, electric plant (power plant) and some balance of plants (BOP) will disappear for a green NH_3 plant. Cost of green NH_3 plant (excl. electrolysis unit and ASU) is therefore taken as 54% of conventional plant, based on all obtained data [13]

In Figure 4-15 a cost-capacity curve for specific CAPEX of green ammonia plant (k€/TPD) 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 4-15 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.

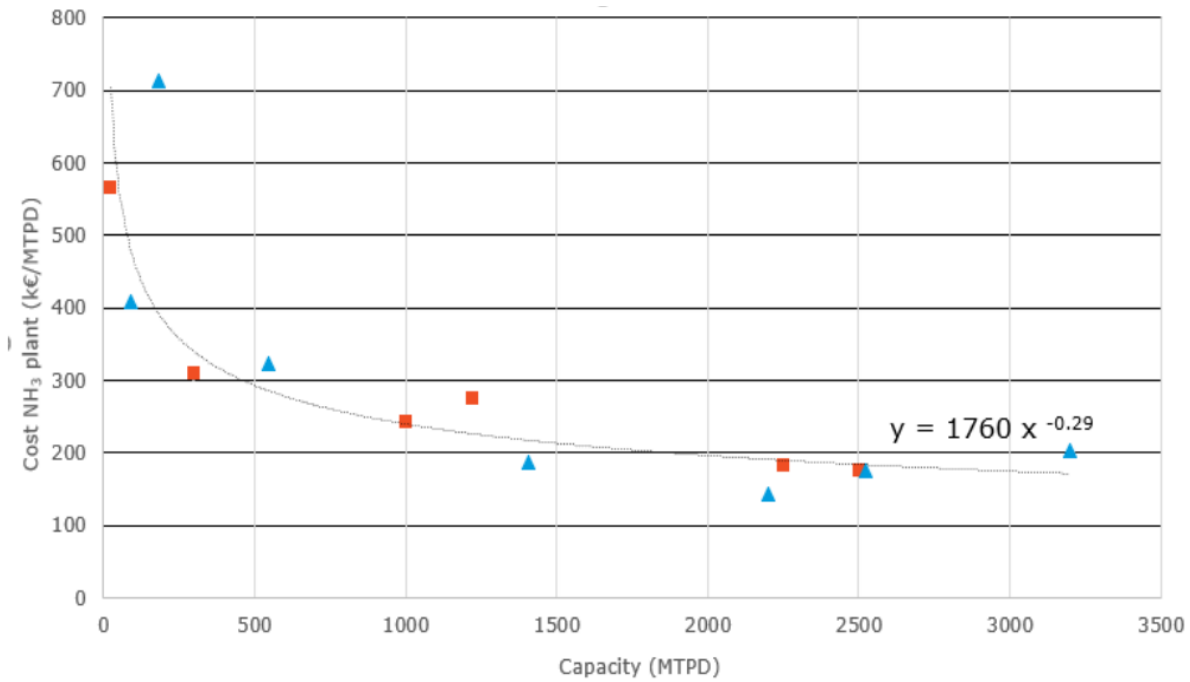

Figure 4-15: Estimated cost of an ammonia plant. Ann.: Ammonia synthesis + BOP + storage (electrolysis unit and ASU are not included in the figure). Blue triangles represent data that is publicly available. All figures adjusted to reflect cost index for 2019. [13]

The financial data given in the Danish Technology Catalogue has been adjusted to the cost year 2023 by inflating the costs and converted to INR.

4.12.2. Variable and Fixed O&M costs

Fixed operating and maintenance costs are taken as 3% of CAPEX [13].

Variable operating and maintenance costs are taken as costs of catalyst replacement and other minor consumables. Catalyst replacement is scaled based on a reference for a 1,500 TPD NH_3 plant with 10 m^3/year [24].

4.13. Uncertainty

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 4-15 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. Location and resource conditions (e.g., quality of the renewable energy source, access to electricity, infrastructure, etc.) have a significant impact on costs. For example, in the review "Green ammonia as a spatial energy vector: a review" [25], it is mentioned that the costs (LCOA) vary from 0.43 lakh INR per ton to nearly 1.82 lakh INR per ton depending on the local renewable energy resource and other site-specific conditions.

Where the datasheet does not list uncertainty values, this should not be taken to mean the estimates are certain. Rather, it indicates that the necessary data to quantify the uncertainty is not available.

4.14. Reference

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4.15. Datasheet

Technology	Green Ammonia plant: Hydrogen to ammonia (excl. electrolyzer and excl. ASU)									Notes	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Typical total plant size, TPD	229	458	916	2290	2290					A	2
Typical total plant size, MW (Ammonia output)	50	100	200	500	500						2
Inputs											
N2 Consumption, t/t Ammonia	0.84	0.84	0.84	0.84	0.84	0.82	0.87	0.82	0.82	B	1, 2, 4
Hydrogen Consumption, t/t Ammonia	0.18	0.18	0.18	0.18	0.18					B	1, 2
Hydrogen Consumption, MWh/MWh Total Inputs	0.95	0.95	0.95	0.95	0.95	0.90	0.97	0.90	0.90	B	1, 2, 4
Electricity Consumption, MWh/MWh Total Inputs	0.05	0.05	0.05	0.05	0.05	0.03	0.10	0.03	0.03	C	1, 2, 4
Outputs											
Ammonia Output, MWh/MWh total input	0.8230	0.8230	0.8230	0.8230	0.8230	0.8065	0.8395	0.8065	0.8395		2
High value heat MWh/MWh total input	0.1080	0.1080	0.1080	0.1080	0.1080					D	2
District Heating Output, MWh/MWh Total input	0.0380	0.0380	0.0380	0.0380	0.0380					E	2
Forced outage (%), unplanned shutdown	5	5	5	5	5						2
Planned outage (weeks per year)	3	3	3	3	3						2
Technical lifetime (years)	25	25	25	25	25	20	30	20	30		1, 2
Construction time (years)	2	2	2	2	2						1
Regulation ability											
Ramp Up Rate (% of Full Load/minute)	20										1, 4
Ramp Down Rate (% of Full Load/minute)	20										1, 4
Start-up time (minutes)	<10										1
Minimum load (% of full load)	10										1
Financial data (in 2023₹)											
Specific investment [cr. ₹/MW Ammonia output]	19.11	15.63	12.79	9.80	9.80	11.00	19.11	6.11	10.62	F, I, J	1, 2
- equipment [%]	50.00	50.00	50.00	50.00	50.00	0.55	0.69				1, 2
- installation [%]	50.00	50.00	50.00	50.00	50.00	0.45	0.31				1, 2
Fixed O&M [cr. ₹/MW Ammonia/year]	0.57	0.47	0.38	0.29	0.29	0.23	0.60			G	1, 2
Variable O&M [INR/MWh Ammonia]	2.41	2.41	2.41	2.41	2.41					H	2
Start up [cr. ₹/1,000 t Ammonia]											
Technology specific data											
Specific investment mark-up factor optional ASU	1.09	1.09	1.09	1.09	1.09					F	2
Specific energy content (GJ/ton Ammonia)	18.90	18.90	18.90	18.90	18.90						2
Specific density (kg/l) or (ton/m3) Ammonia	626.00	626.00	626.00	626.00	626.00						2
Specific investment (cr. ₹/TPD Ammonia output)	4.17	3.41	2.79	2.14	2.14					F	2
Fixed O&M (cr. ₹ /TPD Ammonia)	0.13	0.10	0.08	0.06	0.06						2
Variable O&M (INR /t Ammonia)	12.05	12.05	12.05	12.05	12.05						2

Notes

A Typical NH_3 plant size based on H_2 supply from 100 MWe electrolyzer for 2024.

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 and requires heat pump for use for district heating.

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 The lower uncertainty is based on inputs from Indian stakeholder and the higher one and point estimate are based on the Danish Technology Catalogue

J Cost projection is considering economy of scale only and does not consider further technical development, due to the maturity of ammonia synthesis. In case capacities are expected for other years than shown in the datasheet, one should use the corresponding cost data of the respective capacity instead of the cost data for a given year. See also Figure 16 in the chapter.

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6 India: a future ammonia energy giant, Kevin Rouwenhorston April 13, 2023, https://ammoniaenergy.org/articles/india-a-future-ammonia-energy-giant/

7 Green vs fossil-based energy vectors: A comparative techno-economic analysis of green ammonia and LNG value chains - ScienceDirect, 2023 by Federica Restelli, Marta Gambardella and, Laura Annamaria Pellegrini all Politecnico di Milano

5. Biomass Gasification

5.1. Brief technology description

In biomass gasification solid biomass is converted to a mix of gasses using sub stochiometric thermochemical conversion. The gas is commonly called producer gas and has relatively a low calorific value ranging from 4-6 MJ/Nm3. Biomass gasification is a thermochemical process in which solid biomass is converted to a mix of gasses through partial oxidation under sub-stochiometric thermochemical conversion. The resulting gas is commonly called producer gas and has a relatively low calorific value, typically ranging from 4-6 MJ/Nm^{3}, and mainly consists of CO, H_2, CH_4, and CO_2. The exact composition is dependent on the type of biomass, gasifying process, and gasifying agent used. Common gasifying agents include air, steam, carbon dioxide or oxygen

Gasification is typically carried out at temperatures between 800°C and 900°C. The producer gas can be used directly in gas engines or turbines to generate electricity or further upgraded to produce green fuels or chemicals.

Gasifier are generally classified as fixed-bed, fluidized bed, or entrained-flow gasifiers. Fixed bed gasifiers are typically small scale (kW range), fluidized bed gasifiers are typically medium to large scale (MW range), and entrained-flow gasifiers are typically very large (over 100 MW). This chapter focuses on fixed-bed gasifier, where air is commonly used as a gasifying agent. In fixed-bed gasifier the biomass fuel is fixed or stable on the bed and the gasifier is further classified into downdraft and updraft [1]. The choice of gasifier depends largely on the intended application and the required quality for the producer gas.

5.1.1. Downdraft Gasifier

In a downdraft gasifier, fuel is fed near the top of the reactor. Figure 5-1 shows a schematic diagram of the system. Air can be introduced either at the same level as the fuel or at an intermediate level to it; producer gas, along with char and ash, exit the bottom of the reactor vessel. Usually, a slight vacuum is applied at the gasifier exit to withdraw producer gas. The gasifier has five zones [2]: drying, pyrolysis, combustion, distillation and reduction, which occur sequentially from top to bottom. The top section serves as a surge vessel for fuel drying before entering the pyrolysis zone. Fuel feeding is simple because the top of the downdraft gasifier is at ambient temperature and pressure. The heat required for drying is provided by radiant and combustive heat transfer from the lower pyrolysis and combustion sections. Water vapor from the drying zone moves downward towards the pyrolysis and combustion section, where some of it is reduced to hydrogen but most of it stays in the final producer gas. To remove excess moisture, a small amount of air may be added to the drying section. The dried solid fuel descends by gravity into the pyrolysis zone, where it is heated to the point where volatile matter evolves. The resulting gas then passes through the reduction zone on an ash support grate before leaving the reactor. Pyrolysis products and char are pulled into the gasifier's combustion zone, where they are partially burnt in the presence of oxygen. At this point, an oxidizer gas, such as air or oxygen, is injected. Reactions with oxygen cause temperature rise of up to 1000-1200°C, depending on the moisture content of the fuel. Some downdraft reactor designs use a restriction, known as a throat section, to increase gas velocity and promote heat and mass transfer [1].

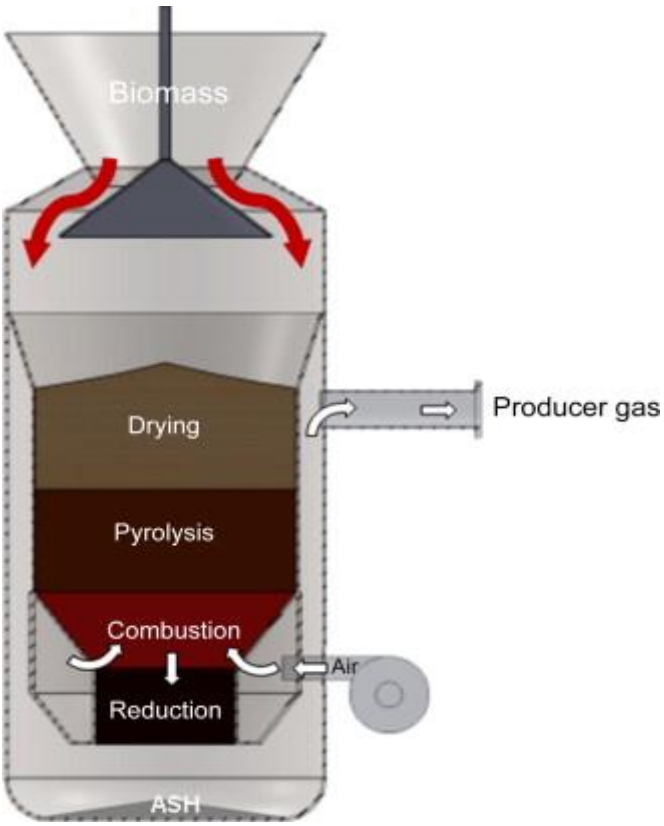

Figure 5-1: Schematic of downdraft gasifier. [3]

5.1.2. Updraft Gasifier

In an updraft gasifier, air is injected toward the bottom of the reactor's combustion zone, causing gas to move upwards via the solid fuel's interstitial spaces. Figure 5-2 shows the schematic diagram of the system The updraft reactor's producer gas departs at a lower temperature (130 - 150°C) than the downdraft reactor due to solid fuel drying. The gasification process of updraft is similar to that of downdraft mode in that the major reaction stages are present, but the gas is heavily contaminated by pyrolysis products (mainly tar, oils, and particulate) from the incoming fuel. Special precautions are taken to prevent air leakage with the incoming biomass because the producer gas exits at the top. The order of these stages is altered about the solids: heated combustion gases enter the reduction zone, providing the necessary energy for the endothermic reaction; the charged solid migrates below to the reduction zone; and the majority of the moisture evaporated from the fuel solids and products of the pyrolysis reactions exit the reactor top with the producer gas. Ultimately, the residual char combines with oxygen or air that is fed into the reactor vessel's bottom, causing the ash to be removed from the reactor's bottom [1].

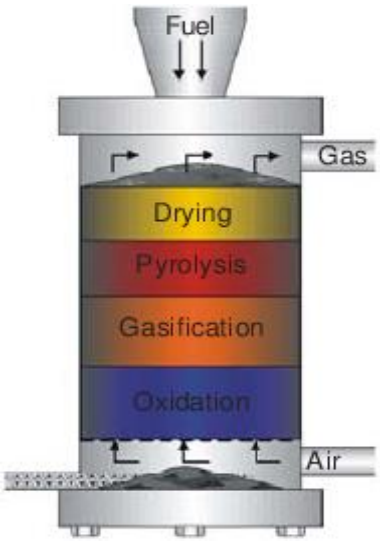

Figure 5-2: Schematic of updraft gasifier. [4]

5.2. Input and output

5.2.1. Input

The main inputs for the gasification are

- Solid biomass such as wood chips, pellets, chunks and briquettes, industrial wood residues, demolition wood, and energy crops can be used.
- Auxiliary electricity for processing machinery.

Requirements for moisture content and size distribution of the fuel depend on the design of the reactor and the process; moisture content in a downdraft gasifier should preferably be around 12% and not exceed 25% on wet weight basis. An updraft gasifier can handle biomass with higher moisture content, but this should not exceed 60% moisture on wet weight basis [1]. A downdraft gasifier normally requires quite uniform fuel with a slightly higher ash melting point than what is needed for an updraft gasifier that also accepts a wider fuel particle size distribution.

5.2.2. Output

- Producer gas suitable for combustion in gas engines, gas turbines, or boilers. Due to nitrogen content in the producer gas, it is not suitable for further upgrading to fuels or chemicals.
- Recoverable heat for domestic heating.
- Ash, slag, and possibly tar and/or effluents from the cleaning step.

The composition of the producer gas is rather broad according to technology, fuel, operational conditions, etc.

Table 5-1: Typical composition of producer gas from fixed bed gasifier. [5]

Component	Typical range (% by volume)
Carbon monoxide	12 - 20
Hydrogen	15 - 35
Methane	1 - 5
Carbon dioxide	10 - 15
Nitrogen	40 - 50

5.3. Energy balance

5.3.1. Updraft gasifier

Based on an energy input of wet biomass (100%), a producer gas energy output of 40-65%, and a heat output of 10-20% can be obtained [6].

5.3.2. Downdraft gasifier

Based on an energy input of wet biomass (100%), a producer gas energy output of 75-85%, and a heat output of 10-20% can be obtained [6].

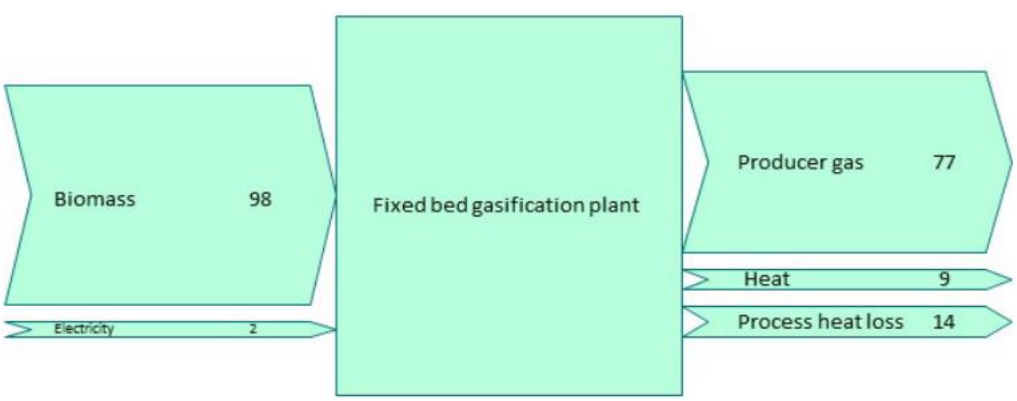

Figure 5-3: Sankey diagram of fixed bed gasifier in 2030. [6]

Fixed bed gasifiers are frequently used together with ICE gensets in CHP systems to supply power for internal consumption as well. In this scenario, an electricity input is required as the gasifier is operating independently, and the system output is product gas and heat. The producer gas condensation and heat circulation that powers the gasification process can often reduce heat loss.

5.4. Typical capacities

Biomass gasifiers have been installed in India since the 1980s. Development has been made to enable gas engines to operate fully on producer gas. Biomass gasifiers have typically been installed adjacent to industries such as rice mills with an electrical output of 10 – 2000 kW_e and thermal output of 25 – 5000 kW_{th} small scale off-grid gasifiers are used for electricity production in rural areas [7]. The Updraft gasifier: 0.08 – 10 MWe (0.2-25 MJ/s fuel) and Downdraft/staged downdraft gasifier: 0.04 – 2 MWe (0.15-5 MJ/s fuel). Capacities above these levels are typically increased by parallel installation of units [6].

5.5. Regulation ability

Operating continuously at peak efficiency is not practical due to seasonal demands, load variations, and fuel property variations; however, operating at a steady load and avoiding cyclic or on-off operation can improve efficiency [8]. Gasifier output can be adjusted in seconds for downdraft gasifiers and in minutes for updraft gasifiers. The start-up period from cold conditions varies based on plant size and design but often takes from hours to days. Minimum loads of 10-20% can be obtained for updraft-, and 25-30% for downdraft gasifiers and are typically kept in continuous operation [6].

5.6. Space requirements

The main space requirements typically relate to the storage, handling, and possibly drying of biomass feedstock, which can be assumed to correspond to what is required for biomass power plants.

5.7. Advantages/disadvantages

Biomass gasification provides an important pathway for addressing India's growing energy demand while reducing dependence on fossil fuels and mitigating environmental impacts. With India generating vast quantities of agricultural residues, forest waste and organic by-products, gasification offers an efficient means of converting these abundant resources into clean fuel for heat and power generation. Biomass gasification systems can support rural electrification, reduce reliance on diesel, and enabled decentralized energy supply for micro, small and medium enterprises. The technology provides several benefits: it enables the utilization of locally available biomass, reduces waste burning and associated air pollution, enhances energy security through diversification of fuel sources, and supports low-carbon development.

Fixed bed gasifiers are relatively simple in their construction and considered robust technology. However, the options for upscaling, particularly downdraft gasifiers, are limited. The advantages and disadvantages of updraft and downdraft gasifiers are listed in Table 5-2.

Table 5-2: Advantages and disadvantages of updraft and downdraft gasifier. [1]

Reactor type	Advantages	Disadvantages
Fixed bed "updraft"	High thermal efficiency	The high content of tar in the producer gas
	Good contact between the solid material and the oxidizing agent	Energy content of tar > 20%
	Can handle materials of different sizes	Low production of CO and H_2, which necessitates a subsequent tar cracking treatment

	Can handle materials with high humidity	Limited flexibility to load and process, as the material being treated needs to have uniform properties
	Reduced entrainment both of dust and of Ashes	Reduced starting difficulties and temperature control
	Simple construction	The catalysts used might not be effective if the energy provided is insufficient, thus requiring an external energy supply. Additionally, catalyst deactivation due to poisoning is possible.
Fixed bed "downdraft"	High carbon conversion	Low specific capacity
	Shorter residence time	Need for uniform sizes in input (pellets no larger than 100 mm)
	Reliable technology	Requires materials with a low moisture content
	Uniform temperature distribution resulting in consistent output and lower tar content in the producer gas	Difficulty starting the process
		Limited possibility of scale-up (the dimensions of the reactor are limited by problems of temperature control)

5.8. Environment

Emission of Pollutants

Biomass gasification can lead to the emission of various pollutants such as particulate matter, tar, and nitrogen oxides (NOx). These pollutants contribute to air quality deterioration and pose health risks, including respiratory issues for nearby populations. Effective gas-cleaning systems are essential to mitigate these emissions [9].

Greenhouse Gas Emissions

While biomass gasification can be considered carbon-neutral under sustainable management, it still produces greenhouse gases like methane (CH_4) and carbon dioxide (CO_2). These emissions contribute to global warming and climate change, necessitating stringent monitoring and control measures [10].

Water Pollution

The gasification process or the subsequent gas cleaning can generate leachates containing harmful chemicals and heavy metals, which pose a risk to water resources. If not properly managed, these contaminants can infiltrate water supplies, affecting both human health and aquatic ecosystems [9].

Soil Degradation and Deforestation

Sourcing biomass feedstock can lead to significant land use changes, deforestation, and soil degradation. These activities can reduce biodiversity, disrupt ecosystems, and deplete soil fertility, emphasizing the need for sustainable biomass-sourcing practices [10].

Ash Disposal Issues

The disposal of ash, a by-product of gasification, poses environmental challenges. Ash can contain toxic substances that, if not properly managed, can contaminate soil and water, leading to further environmental degradation. Safe and effective disposal or utilization of ash is crucial to minimizing these impacts [9].

No emission data is stated in the data sheets below, as the specific utilization of the producer gas is not covered by this technology datasheet.

5.9. Research and development perspectives

Most of the biomass gasification-based systems technology designing and development has happened with the support of the Government of India (GoI). MNRE has remained the main funder of biomass gasifier R&D in the country, and its deployment through a subsidy program [7] [11]. Main features of the gasifier action research projects (GARPs) [7] are:

- Basic and applied research, and design and development of biomass conversion and utilization devices and systems
- Field demonstration of the technology with action research for resolving the problems in field applications and technology improvements
- Quality assurance through testing and performance evaluation of the gasifier systems

Research and development activities focus on incremental operation and design optimization, including better process regulation and automation for unmanned operation, scaling up, and improving gas engine operation with gasification gas.

5.10. Examples of market-standard technology

Major biomass gasifier projects in India are listed in Table 5-3.

Table 5-3: Major Biomass gasifier projects in India

Plant Owner	Location of Plant	**State**	**Plant Capacity (MW)**	**Year**	**Input**	**Reference**
Bannari Amman Sugars Ltd	Tiruvannamalai	Tamil Nadu	28.1	2010	Sugarcane (fibrous reside-baggase)	[12] [13]
S.M. Environmental Technologies Pvt. Ltd. (Formerly Kalptaru Energy Venture Pvt. Ltd.)	Pachhar	Rajasthan	8	2010	Mustard husk	[12] [14]

Shriram Non-Conventional Energy Ltd.	Thanjavur	Tamil Nadu	7.5	2010	Coconut & wood waste	[12] [13]
Global Power Tech Equipment Ltd.	Tiruvannamalai	Tamil Nadu	7.5	2010	Agricultural residue	[12] [13]
Sambhav Energy Ltd.	Rampur	Rajasthan	20	2010	Prosopis Juliflora (mad tree in India)	[12] [15] [14]
E.I.D Parry (India) Limited	Trichy	Tamil Nadu	18	2010	-	[12] [13]
Sukhbir Agro Energy Limited	Ferozepur	Punjab	18	2019	Rice straw and paddy straw	[16]
Green Planet Energy Pvt. Ltd.	Moga	Punjab	6	2012	-	[16]

In addition to these examples, three cases are presented in the next section to provide an overview of the state of the technology in India.

5.10.1. Gosaba Island Rural Electrification Project, West Bengal

Gosaba Island Rural Electrification Project, launched in 1997 by the West Bengal Renewable Energy Development Agency (WBREDA), was an initiative aimed at delivering sustainable electricity to the remote Gosaba Island in the Sundarbans. Located 115 km from Kolkata and 39 km from the nearest grid, the project deployed a 500-kW downdraft closed-top gasifier, sourced from M/s Ankur Scientific, which transformed locally available biomass into electricity. It addressed the island's geographic isolation and absence of grid connectivity. As one of India's earliest examples of decentralized rural electrification through renewable energy, the Gosaba project has since served as a model for similar efforts in other remote regions.



Figure 5-4: 5 x 100 kW biomass gasifier at Gosaba Island, West Bengal, India. [17]

The biomass gasifier plant on Gosaba Island has several remarkable characteristics that highlight its operational efficiency and overall impact on the community. Comprising five 100 kW gasifier units, the plant collectively achieves a total capacity of 500 kW, strategically operating for six hours each day to effectively meet peak energy demand. It predominantly utilizes locally sourced biomass, including wood chips and agricultural residues gathered from approximately 100 hectares of plantations, operating with a consumption rate of around 0.9 kg of biomass per unit of electricity generated. Each gasifier utilizes a downdraft gasification process that converts the biomass into producer gas, which is subsequently purified for combustion in internal combustion engines. The facility distributes electricity through a well-established network, comprising 4 km of high-tension (11 kV) lines and 7 km of low-tension lines, successfully serving 511 consumers across domestic, commercial, and industrial sectors. To enhance reliability, the plant is supported by a small auxiliary diesel supply, operating at a consumption rate of 0.13 liters per unit of electricity at 80% load.

Table 5-4: Summary of Gosaba Island Biomass Electrification. [17]

S. No.	Parameters	Details
1	Plant capacity	5 x 100 kW
2	Location	Gosaba Island, West Bengal
3	Operation hours	6 hours/day
4	Tariff structure	3.50 INR/unit for domestic 3.75 INR/unit for commercial 4.00 INR/unit for industrial
5	Consumption of diesel	0.13 per unit at 80% load
6	Consumption of biomass	900 grams per kWh if dried
7	Operational manpower	10
8	Beneficiaries (Direct & Indirect)	11,000
9	No. of consumers	511 (Commercial: 157, Domestic: 350, Industrial: 4)

5.10.2. 1 MWe Grid-Connected Biomass Gasifier in Mullana, Ambala, Haryana

Chanderpur Renewable Power Company Pvt. Ltd., part of the Chanderpur Group (CPG), has successfully installed a one MW biomass gasifier at its facility in Mullana, located in the Ambala district of Haryana. This plant harnesses wood waste, primarily sourced from the plywood industry including tree branches and other by-products. The energy generated by the gasifier is seamlessly integrated into the grid, supplying power to all three units of the Chanderpur Group.

In the first phase, a 1000 kg/h gasifier system was integrated with four 250 kW Producer Gas Engines in the year 2012. The specific biomass consumption is 1.2 to 1.5 kg/kWh. Tar content in generated gas is less than

15 mg/Nm^3 and water consumption is about 0.6 litres per kWh. This plant was successfully operated for more than 7000 hours annually in field operation [18].



Figure 5-5: 1 MWe biomass gasifier installed in Mullana, Ambala, Haryana. [19]

5.10.3. Sankheda 1.2 MW Biomass Gasifier Project in Gujarat

Ankur Scientific Energy Technologies Pvt. Ltd. has set up a 1.2 MW grid-connected biomass power plant based on its own gasification technology in Sankheda taluka of Vadodara district. The project was commissioned in 2011 in a short duration of 6 months with the help of local villagers and farmers, panchayats, taluk offices, collectorate and relevant departments for land conversion and town planning etc. The system design includes two woody biomass-based gasifiers which are coupled to three units of 400 kWe engine gensets, each running on 100% producer gas. The plant uses biomass fuels such as cotton stalk, tuver stalks, maize cobs, mango seeds, castor husk etc. Bio-char (charcoal generated from biomass), which is a by-product of the gasification process is sold to farmers at a low price as a fertilizer [20].



Figure 5-6: Images of Sankheda 1.2 MW Biomass Gasifier project in Gujarat. [7]

5.11. Projection of performance and costs

The learning curve in biomass gasification technology reflects the improvement in performance and reduction in costs as the cumulative installed capacity increases. In India, the learning curve is shaped by several factors such as R&D and Innovation and Economies of Scale.

Fixed bed biomass gasification technology is proven in operational environments, with TRL level 9 [21]. Small scale gasifier systems are produced industrially, and more than 1,000 units have been sold during the past 10-15 years. Larger plants are usually not produced on an industrial scale. Some larger plants have been in operation since 1996 and are still operating. The price and performance of 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 [22].

Based on international references and the Danish Technology Catalogue the following cost reductions and efficiency improvements are found.

The analysis demonstrates gradual improvements in both cost efficiency and fuel conversion over time. The specific investment required per MW_{th} decreases from 14.76 cr. ₹/MW_{th} in 2024 to 14.07 cr. ₹/MW_{th} by 2030, marking a 5% reduction. This downward trend continues, reaching 13.48 cr. ₹/MW_{th} in 2040 and further declining to 12.90 cr. ₹/MW_{th} by 2050, where it stabilizes through 2070. Overall, this represents a long-term cost reduction of 13% from 2024 levels. Concurrently, the efficiency of producer gas output as a percentage of fuel input shows consistent improvement, increasing from 74.00% in 2024 to 76% by 2030, with further gains to 79% in 2040 and 82% by 2050, maintaining this level through 2070. This indicates enhanced fuel conversion efficiency, contributing to improved gasification performance. However, significant uncertainty in 2024 investment costs, ranging from 9.60 to 31.20 cr. ₹/MW_{th}, underscores potential variability due to factors such as technological maturity and project-specific conditions.

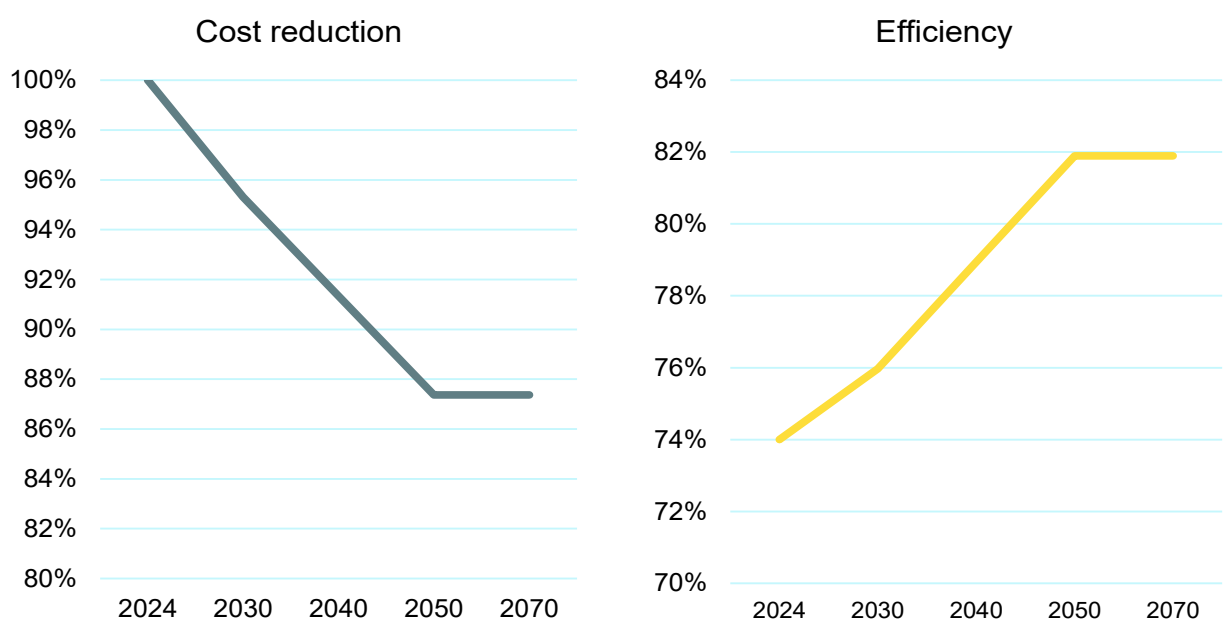

Figure 5-7: Percentage of variation of the biomass gasification specific investment cost (cr. ₹/MWth) and efficiency (Producer gas (% of fuel input)) between 2024 and 2070.

5.12. Uncertainty

Even though several plants have been operating successfully for several years, there is still a great deal of uncertainty about the cost and efficiency of future developments. Considerable learning curve effects are assumed in the data. However, there is a widespread number of different principles and types of fixed-bed gasifiers, such as updraft, and downdraft. Each type operates differently and has unique advantages and disadvantages. Data typically cover feedstock capacity, operating parameters (such as minimum load, electricity, producer gas and heat), and financial data (fixed and variable cost). For instance, updraft gasifiers are known for high tar content, downdraft gasifiers for lower tar content suitable for engine applications, rapid start-up and shut-down capabilities. The extent of future improvements remains uncertain because much of the technology is still being tested at small or pilot scales, where real-world performance data is limited.

5.13. Additional remarks

Today, fixed-bed gasifiers are usually integrated with an internal combustion engine generator. Besides the described fixed bed gasifiers, several suppliers offer CHP technologies [6].

Where the datasheet does not list uncertainty values, this should not be taken to mean the estimates are certain. Rather, it indicates that the necessary data to quantify the uncertainty is not available.

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5.15. Datasheets

Technology	Gasifier, biomass, fixed bed producer gas, small - medium scale									Note	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Typical fuel input capacity, one unit (MWth)	2	2	2	2	2	0.01	10				1, 2
- Input											
Biomass (% of input capacity)	98	98	98	98	98						1
Electricity (% of input capacity)	2	2	2	2	2						1
- Output											
Producer gas (% of fuel input)	74	76	79	82	82						1
Heat (% of input)	10	9	7	5	5						1
Unplanned outage (%)	5	5	5	5	5						1
Planned outage (weeks per year)	3	3	3	3	3						1
Technical lifetime (years)	20	20	20	20	20						1, 3
Construction time (years)	2	2	2	2	2	1.5	2				1, 3
Financial data (in 2023₹)											
Specific investment (cr. ₹/MWth)	14.76	14.07	13.48	12.90	12.90	9.60	31.20			A	1, 3, 5, 6
- of which equipment											
- of which installation											
Fixed O&M (INR/MWth/year)	2270689	2131588	2025009	1918429	1918429	2270689	7379741				1, 6, 7
Variable O&M (INR/MWhth)	284	263	251	239	239	284	304				1, 6
Technology specific data											
Minimum load (% of full load)	25	25	25	25	25	20	30				1, 4

Notes

A Central range from indicated sources

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6. Biogas Production

6.1. Brief technology description

Biogas is a biofuel produced from organic material under anaerobic conditions. The biogas can be used in industrial processes, for producing heat and electricity or for upgrading to biomethane (Upgrading of biogas to biomethane is treated in a separate chapter of this technology catalogue). Biogas mainly consists of primarily methane (CH_4) and carbon dioxide (CO_2). It can be produced from various organic feedstocks and residual materials, like sewage sludge, animal manure, municipal organic waste, biodegradable waste, straw, sugarcane, agricultural and industrial byproducts and energy crops. [1]

The byproduct of the anaerobic digestion process is a nutrient-rich digestate, which can be used as a biofertilizer for agricultural purposes.

6.1.1. Principle of Biogas Production

When organic materials decompose, various gases are naturally emitted. Biogas is produced through anaerobic digestion, a process in which microorganisms break down organic matter in the absence of oxygen. This produces a mixture of gases, primarily CH_4 and CO_2 with a minor content of hydrogen, nitrogen, oxygen, hydrogen sulphide, and ammonia. Biogas production involves controlling this decomposition within a closed system, allowing the capture and utilization of the gases for energy generation. The organic material must remain in the digester for a certain period (Hydraulic Retention Time (HRT)) to allow complete digestion and maximum biogas yield. This time varies based on the system design and feedstock. Biogas is produced through an anaerobic process, which means it occurs in the absence of oxygen. This process involves the breakdown of organic matter by microorganisms, resulting in the production of methane and carbon dioxide.

By using byproducts such as municipal organic waste and animal manure, the production of biogas contributes to waste management, reduces the emissions of methane that would otherwise escape to the atmosphere, and provides a sustainable alternative to fossil fuels.

Methane, carbon dioxide, and small amounts of other gases are produced during anaerobic decomposition, with minimal heat generation. The process occurs in two stages, where bacteria break down specific organic materials. In the first stage, acidic bacteria degrade complex organic substances into peptides, glycerol, alcohols, and simpler sugars. Once enough of these byproducts accumulate, a different group of bacteria converts them into methane. The activity of methane-producing bacteria is highly dependent on environmental conditions, and deviations from their optimal range can disrupt or halt the process. Anaerobic digestion is mainly used to convert organic materials, particularly wet organic waste such as crop residues, animal manure, and human waste, into biogas. The biogas produced will have a methane content ranging from 50% to 75%, which will vary based on the type of waste used. [1]

Table 6-1: The composition and calorific value of biogas varies depending on the feedstock , the table below shows the composition according to [1], [2] and [3]

Composition of biogas	
Methane	50-70%
Carbon Dioxide	20-40%
Hydrogen Sulphide	0.1-3%
Nitrogen (N_2)	0.1-10%
Oxygen (O_2)	0.1-1%
Water vapour (H_2O)	0.1-2%
Calorific Value	20-25 MJ/Nm^3

6.1.2. Typical components of a biogas plant

Biogas plants vary greatly in size, from smaller household-sized plants to large industrial plants. The design of the plants is different depending on the size and technology used in the plants.

Through India's waste-to-energy program, the focus is especially on large-scale biogas production plants with upgrading facilities. Large plants are more advanced, with more components and are often autonomised with continuous stirred-tank reactors (CSTR). [4]

The following is a description of the design of typical larger industrial biogas plants:

The biomass is received and stored in pre-storage tanks and later processed in digesters (reactors). The digesters are normally heated to either 35-40 °C (mesophilic digestion), or 50-55 °C (thermophilic digestion). Typical processing time in the digesters (HRT) is between 60 and 100 days in newer plants, depending on the biomass input and the plants' technical specifications. After being processed in the main digester, the digestate is pumped to post-processing tanks where postdigestion takes place and additional gas is produced and collected. After the 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. Finally, the gas is treated to reduce water and sulphur contents to the desired concentrations.

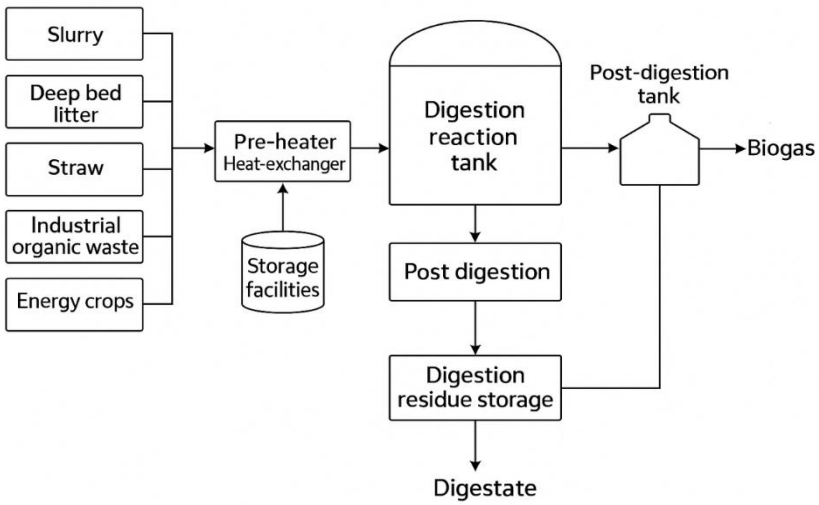

Figure 6-1: Typical components in a biogas plant. Alternative terms for technical description might be used by some actors: e.g., biomass handling might be referred to as pre-treatment, digestion reaction tank as a digester and digestion residue storage as digestate [3]

6.1.3. The process of anaerobic digestion

The chemical process that happens in a biogas plant is the process of anaerobic digestion and takes place in four biological and chemical stages: hydrolysis, acidogenesis, acetogenesis and methanogenesis. The four stages of anaerobic fermentation to accomplish the Biogas-production process are described below.

Hydrolysis

Biomass typically consists of proteins, fats, and carbohydrates, which are large organic polymers. These substances are divided into smaller compounds like amino acids, fatty acids, and basic sugars. It is the crucial initial stage of anaerobic fermentation where fermentative bacteria break down complex organic matter into soluble molecules. During anaerobic digestion, methane-producing microorganisms can utilize some of the substances produced from hydrolysis, such as hydrogen and acetate. Most of the molecules, which are still quite big, need to be further broken down during acidogenesis in order to be utilized for methane production. [1]

Acidogenesis

During acidogenesis in anaerobic digestion, acidogenic microorganisms continue to decompose biomass and organic products after hydrolysis. These fermenting bacteria generate acidity in the gut and produce ammonia, hydrogen gas, carbon dioxide, hydrogen sulphide, shorter volatile fatty acids, organic acids, and small quantities of other substances. The main acids that are generated include e.g., acetic acid, propionic acid, and butyric acid. [1]

Acetogenesis

Acetogenesis involves acetate-producing bacteria (acetogens) converting carbon and energy sources into acetate, a form of acetic acid. These microorganisms break down most of the substances produced during acidogenesis into acetic acid, carbon dioxide, and hydrogen. Acetogens decompose the biomass to a level where methanogens can use most of the remaining material for methane production. [1]

Methanogenesis

Methanogenesis is the last step of anaerobic digestion where methane is produced by methanogens using final products of acetogenesis and some intermediate products from hydrolysis and acidogenesis. Two common methods using acetic acid and carbon dioxide, the primary outputs from the initial three stages of anaerobic digestion, are utilized to produce methane in methanogenesis. [1]

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

$$CH_3COOH \rightarrow CH_4 + CO_2$$

While CO_2 can be converted into methane and water through the reaction, the main mechanism to create methane in methanogenesis is the path involving acetic acid. This stage leads to the generation of methane and CO_2, the two main products of anaerobic digestion.

6.2. Input and output

6.2.1. Input

- Biodegradable organic material (livestock manure/slurry, organic waste from food processing and households, agricultural residues)
- Heat (Process heat for preheating and heating the reactor tanks)
- Electricity for mechanical processing equipment
- Small quantities of water and different chemicals.

6.2.2. Output

- Biogas (for the detailed gas composition see Table 6-1)
- Digestate (can be used as fertilizer)

6.3. 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 tonnes of biomass along with information on the amount of dry matter (DM) 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 feedstock with alternative uses such as straw, energy crops or certain types of industrial waste, which could be used in combustion plants or 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 feedstock. Further, the high-water content and fertilizer value of some of the 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. [3]

To calculate the energy balance of biogas production, it is necessary to calculate both the energy content of the incoming biomass and the energy output in the form of biogas.

Table 6-2 provides an overview of the energy content of some of the most common biomasses. The energy content depends on the DM content, the VS share, and the calorific value of the biomass. Since only the organic (volatile) fraction of the dry matter can be biologically degraded, the energy content is directly related

to both the DM content and the VS share. In this context, the VS share of the DM represents the portion that is biologically degradable and can be converted into energy through anaerobic digestion.

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 easy to convert into biogas, whereas only part of the cellulose is converted, while lignin remains largely unconverted during the digestion process [5]

As an example, the energy content of straw is approx. 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 approx. 45% of the energy content is not converted into gas. As mentioned, some biomasses are more easily converted to biogas than others, thereby giving a higher 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 shown in Table 6-2 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.

Table 6-2: 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 [3]

	DM content	VS Share	The energy content of input in GJ per ton of VS	The energy content of output gas in GJ per ton of VS	Conversion efficiency, biomass to biogas
Straw	85%	95%	17.4	9.5	55%
Slurry	4.5-7%	80%	n.d.	9.2	-
Maize	31%	95%	17.5	11.6	66%
Grass	32%	90%	18	11.5	64%
Beet	18%	95%	17.1	13.2	77%
Beet greens	12%	85%	18.2	12.4	68%

The 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. [6]

Figure 6-2 shows an example of two different plants that produce the same volume of biogas, despite differences in their input and process parameters. The first plant processes 1.8 million tonnes of biomass with an HRT of 35 days, while the second uses 1.0 million tonnes of biomass but operates with a longer HRT of 65 days. The reason why the output is the same is explained by variations in feedstock composition and retention time, which influence the overall conversion efficiency.

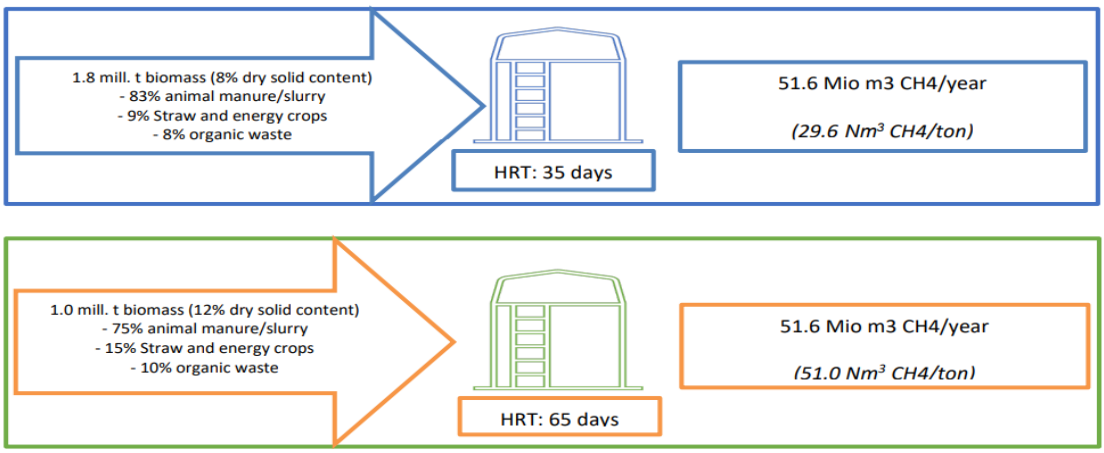

Figure 6-2: Biogas output in two different biogas plants. [3], Note: mill. and mio stand for million.

6.4. Regulation ability

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 output is added. [3] Regulation of the production may require additional feedstock storage capacity. Biogas plants typically have short-term storage in connection with the facility. [3]

6.5. Typical characteristics and capacities

Under the Government of India's GOBARdhan (Galvanizing Organic Bio-Agro Resources Dhan) initiative [7], biogas and compressed biogas (CBG) production has grown across rural and urban regions. The programme promotes waste-to-wealth conversion by utilizing agricultural residues, livestock manure, and organic municipal solid waste to generate renewable energy and organic fertilizers.

Typical characteristics of Indian biogas/CBG plants:

- Plant scale: Biogas and CBG plants in India vary widely in capacity, from small rural units serving households to large-scale commercial plants processing tens to hundreds of tonnes of feedstock per day.
- Production capacity: Typical biogas plants under GOBARdhan generate up to 2,500 m^3/day of biogas. Medium to large CBG plants commonly process between 5–500 tonnes per day (TPD) of feedstock.
- Feedstock types: Agricultural residues, livestock manure, press-mud from sugar mills, and segregated municipal solid waste are the main feedstocks. The specific gas yield depends on feedstock composition, ranging roughly from 8–12% gas yield per unit of feedstock.

Examples of registered plants under GOBARdhan and related programmes [7]:

Location / Plant	Feedstock & Scale	Production Capacity / Notes
Sangrur, Punjab [8]	Paddy straw (100,000 t/year planned)	Currently ~6 TPD CBG; target capacity of ~33 TPD from 300 TPD paddy straw.
Indore, Madhya Pradesh [9]	Segregated municipal wet waste	One of Asia's largest Bio-CNG plants, processing ~550 TPD of waste.

According to the World Biogas Association, India has over 5.1 million biogas plants installed, the vast majority of which are small-scale (1-25 m^3/day) household/community systems. Their combined capacity is approximately 4.43 million m^3 of biogas per day. Meanwhile, large urban waste-to-energy plants in the country contribute about 771,000 m^3/day of biogas. [10]

6.6. Advantages and disadvantages

The following will outline the key benefits and challenges of biogas production.

6.6.1. Advantages

- Biogas is a renewable energy source as opposed to fossil fuels, as it is continuously produced by biomass.
- Utilization of waste. India has high supplies of sustainable feedstock for biogas. Both from agricultural waste and from municipal solid waste, where significant improvements in waste management and collection are expected. Wet and difficult biomasses with few or no alternative uses can be transformed into a high-value energy carrier (biomethane)
- Biogas is produced locally and can reduce dependency on imported fossil fuels
- Digestive can be used as fertilizer. A biogas plant is not only a supplier of energy but the digested substrate, usually named digestive, is a valuable soil fertilizer, rich in nitrogen, phosphorus, potassium and micronutrients, which can be applied on soils with the usual equipment for application of liquid manure
- Flexibility to use different feedstock. Various types of feedstocks can be used to produce biogas
- Reduces emissions from agriculture. When manure is used for biogas production, the emission of greenhouse gasses from handling and storage of manure is reduced
- Low water inputs, compared to other biofuels, biogas needs the lowest amount of process water.
- Flexible and efficient end use of biogas. Biogas is a flexible energy carrier suitable for many different applications. One of the simplest applications of biogas is the direct use for cooking and lighting, but in many countries, biogas is also being used for combined heat and power generation (CHP) or it is upgraded and fed into natural gas grids, used as vehicle fuel or in fuel cells. [11]

6.6.2. Disadvantages

- Methane emissions from biogas plants are unavoidable but can be kept to a minimum if monitored and handled properly (e.g. cooling and coverage)
- Lower energy output compared to combustion. The use of straw and other solid biomasses in biogas production yields a lower energy output than if used for thermal gasification and/or combustion
- High complexity to operate larger biogas plants. The successful operation of biogas plants is relatively complex and requires large experience

- Competition for agricultural land. It is important to prioritise the use of residual biomass and waste-based feedstocks in bioenergy supply chains, as this helps avoid competition with food production and reduces pressure on agricultural land[6]
- Substantial road transport of biomass, the utilisation of large quantities of biomass with low DM content (manure) makes transport and sourcing radius a critical parameter [11]

6.7. Space requirements

The area requirements vary depending on the design and layout of the plant. For smaller or medium-scale biogas units, such as those producing around 1000 m^3 of biogas per day, the total area required, including space for digesters and storage, is approximately 2787 m^2 (0.69 acre). [12], [13] In contrast, large-scale industrial plants occupy substantially more land, typically ranging from 2 to 9 hectares depending on the capacity and type of biomass input. These facilities are usually located on open farmland to reduce the distance required for the transport of feedstock. For example, the SBS Kliplev biogas plant in Denmark, commissioned in 2022, covers about 8.5 hectares and produces 48 million Nm^3 of biomethane annually, while the Solrød biogas plant, commissioned in 2015, occupies 2 hectares and generates 11 million Nm^3 per year [3]. Note, Nm^3 stands for normal cubic meter, a unit used to measure gas volume under standardized reference conditions.

Table 6-3: Details of space required for construction of biogas plant [12]

Capacity of Biogas Plant (m^3/day)	Length (m)	Width (m)
25	19.81	6.1
50	21.34	7.62
75	22.86	9.15
100	24.39	10.66
125	25.9	11.28
150	27.44	12.19
175	28.96	12.81
200	30.49	13.7
225	32	14.33
250	33.53	15.2
275	35	15.85
300	36.58	16.77
325	38.1	17.38
350	39.7	18.29
375	41.2	18.9
400	42.68	19.81
425	44.2	20.43
450	45.7	21.34
475	47.2	21.95
500	48.8	22.86

6.8. Environment

Biogas is a renewable fuel that can substitute fossil fuels in the energy system, thereby avoiding emissions of CO_2. Biogenic greenhouse gases will however, still be emitted from the process. 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.

The emission of greenhouse gases from agriculture can be reduced. Methane is emitted from manure and slurry when stored in stables or slurry tanks, and the higher the temperature in the stables or slurry tanks, the faster the methane emission will happen. This methane is captured and utilised in biogas plants 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% [14].

Odour from biogas plants is often mentioned as a concern, but 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. [3]

The use of digestate as fertilizer also reduces the need for commercial fertilizers, saving significant energy as commercial fertilizer production is energy intensive [15]. When the digestate is used as fertilizer, important nutrients, primarily nitrogen, phosphorus, and potassium, are recycled and can be redistributed between farms [3]. The fertilizer value of the digested biomass is improved compared to that of the untreated slurry, plants absorb soil nutrients, like nitrogen or phosphorus, more easily than raw manure. The fertilizer value is also better known and documented, this allows farmers to use the right volume and ratio of nutrients needed and minimize the additional purchase of synthetic fertilizers [16]

Health-related impacts

Residents of some rural regions in India rely on wood and dried cow dung as fuel sources. The combustion of such biomass releases harmful pollutants, contributing to respiratory illnesses. In contrast, burning biogas offers a cleaner alternative [15].

Furthermore, insufficient waste treatment can contribute to the spread of diseases. This issue can be mitigated or even eliminated by collecting organic waste and utilizing it for biogas production. Biogas technology reduces the attraction of flies and other insects, thereby decreasing the risk of transmitting contagious diseases to both humans and animals [15].

6.9. Research and development perspectives

The Indian government has introduced several policy changes to accelerate growth and investments in the biogas sector.

To support biogas development and deployment, India has implemented various schemes. The first of these is the National Biogas and Manure Management Programme (NBMMP). In May 2018, the government redesigned the scheme by introducing the New National Biogas and Organic Manure Programme (NNBOMP) to help establish small-scale biogas plants with installed capacities ranging from 1 to 25 standard m^3 per day, aimed at fulfilling cooking and organic fertiliser needs in rural areas

The government also modified the existing biogas-based off-grid power scheme to Biogas-based Power Generation (off-grid) and Thermal Application Programme (BPGTP) to create a reliable decentralised

renewable energy source. Large-scale biogas plants (capacity > 2,500 m^3 biogas per day) were included under the Programme on Energy from Urban, Industrial, Agricultural Wastes/Residues and Municipal Solid Waste (Waste-to-Energy Programme). The main objective of this scheme is to promote the recovery of energy from municipal solid waste or biomass gasifiers for feeding power into the grid, supporting captive power, and recovering energy from urban, industrial and agricultural waste in the form of biogas, and CPG (Compressed Purified Gas).

Moreover, the introduction of the GOBAR dhan scheme as an umbrella initiative based on the 'whole of government' approach is expected to further consolidate effort in this area. It covers all schemes, programs and policies promoting the conversion of organic waste into biogas or CBG. A total of 507 plants are currently functional under the scheme across 151 districts in India. Any plant or project that produces CBG/biogas (with daily output exceeding 10 m^3) and biogas slurry as primary outputs is eligible for GOBARdhan. Apart from the Waste-to-Energy Programme for CBG, the government, through the Ministry of Petroleum and Natural Gas (MoPNG), also initiated a CBG scheme called Sustainable Alternative Towards Affordable Transportation (SATAT) in October 2018. The scheme's objective is to encourage the production of 15 million tonnes (MT) of CBG from 5,000 plants [17].

6.10. Examples of market-standard technology

Biogas plants exhibit significant variation in size, ranging from small household units to large industrial-scale facilities. The design of these plants is contingent upon both their scale and the specific technologies implemented. These larger facilities are generally more technologically advanced, integrating additional components and frequently employing automated systems, to optimize efficiency. In India the most commonly used technology for larger plants is the CSTR reactor [4]. The table below lists the capacity of some of the larger industrial plants in India – for more examples see Table 6-4.

Table 6-4: Market Example of biogas plants in India. – all plants upgrade the biogas to bio compressed natural gas. The capacity stated in the table is for the upgraded compressed biogas, , i.e. bio-compressed natural gas [2] (TPD=tonnes per day). Capacity in GJ is calculated with an estimated energy content of 47–52 MJ/kg.

Company	Location	Feedstock	Capacity [TPD]	Capacity [GJ]
Verbio AG	Lehragaga, Punjab	300 TPD Paddy straw and other agricultural waste	33	1,550-1,715
Mittal Enterprises	Garhmukteshwar, Uttar Pradesh	200 TPD Pressmud (sugarcane industry waste)	8	375-415
EverEnviro Resource Management Private Limited	Indore, Madhya Pradesh	500 TPD Biodegradable municipal waste	17-18	825-910
Hingonia Gaushala (IOCL)	Jaipur, Rajasthan	250 TPD Cattle dung	6	280-310

In addition, a short description of one example of a plant is included below.

6.10.1. Community Biogas Plant at Bancharouda, Raipur, Chhattisgarh



Figure 6-3: Community biogas plant at Bancharouda, Raipur, Chhattisgarh. [18]

A community biogas plant with a capacity of 25 m³ has been established in Chhattisgarh under the SBM-G (Swachh Bharat Mission-Grameen) initiative. Situated within the Bancharouda Gothan campus, the plant purchases cow dung from local households through the state's Godhan Nyay Yojana scheme with a daily processing capacity of 500 kg. The biogas produced is supplied to nearby households and institutions. In Bancharouda village, Raipur District, a portion of the biogas is converted to electricity to power lighting on the Gothan campus. The nutrient-rich slurry by-product is either used as manure or sold to farmers, supporting sustainable agriculture in the community. The cost of the plant is approx. 10 lakhs. [19]

Table 6-5: Specifications of plant. [18]

Parameters	Details
Plant capacity	25 cubic meters/day (biogas)
Feedstock	Cow dung from households
Feedstock Capacity	500 kg/day
Cost	10 lakh INR (approx.)
Biogas utilization	Electricity generation for lighting in Gothan compound and cooking
Slurry production	1000 Litre/day
Slurry Utilization	Sold to farmers after drying

6.11. Projection of performance and costs

The potential for improving technologies is linked to the level of technological maturity. It is expected that the investment costs will continue to decrease gradually due to the learning curve effects. Many elements of a biogas plant consist of mature technologies from other industries, e.g., civil construction works and general process equipment, therefore the learning curve effects are expected to be limited. This aligns with IEA's projections that show the biogas production costs are to decrease slightly.

The greatest cost reductions are expected to come from the use of biomasses with a higher methane output per ton input combined with increased professionalization and technical optimization of operations, which are likely to increase efficiency. Further, due to the increasing size of biogas plants, economies of scale are also expected to lead to a reduction in cost. [3]

Learning rates for energy technologies 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%. Studies on learning rates for biogas plants are scarce, and 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 modular technologies. The expectations for cost development applied in the datasheet are therefore further substantiated by the report "Production of upgraded biogas - optimising costs and climate impact" [20]. The report has analysed a variety of specific cost-reduction measures for modern biogas plants of different capacities. It finds that the greatest reduction potential in biogas plants lies within biomass pre-treatment, biogas production, slurry handling and energy integration. Within biomass pre-treatment, re-digestion and selective digestion account for approximately two-thirds of the potential cost reductions, while mechanical shredding technologies contribute the remaining third. Within biogas production, reducing downtime represents about one-third 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 pig 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. [20]

6.11.1. Data for 2024

Until around 2020, biogas production in India was dominated by small-scale household and community plants established under national rural energy programs. The development of larger, industrial-scale biogas and compressed biogas (CBG) plants began accelerating after 2014, supported by new policy initiatives and technical standards that encouraged commercial-scale deployment. By March 2025, India had commissioned 150 CBG projects with a cumulative capacity of 1,211 tonnes per day of feedstock-to-compressed-biogas processing. [21]

Larger biogas plants are still a relatively new technology in India. However, many components of these plants, such as civil construction and general process equipment, are well-established technologies used across various industries. Moreover, other countries have been successfully developing and operating large-scale biogas plants for years. As a result, despite its recent introduction in India, the technology itself can be considered mature and reliable, backed by proven expertise and long-standing global application.

[2] reports that the approximate investment cost of a CBG plant, encompassing both biogas production and upgrading, ranges between 20–25 crores INR for a capacity of 5 TPD of bio-CNG output (equivalent to 4–5 crores INR per TPD output). The report also presents several case examples, summarized in Table 6-6, which pertain to larger facilities with higher specific costs. These cases are considered more representative of actual project costs, and therefore, the cost estimates in this study are derived from those.

The investment costs are divided between the biogas production plant and the upgrading facility, following the CAPEX breakdown provided in [2], and shown below. Miscellaneous costs, adjacent infrastructure, and

land are allocated equally between the two. The machinery and equipment CAPEX assigned to the upgrading facility includes the biogas upgrading and compression unit as well as half of the online monitoring and sensor costs. All remaining machinery and equipment costs are attributed to the biogas production plant.

Based on the data above, specific investment costs of 6.0–8.2 cr INR per MW of output are estimated for the biogas production plant, while the upgrading facility requires 4.9–6.64 cr INR per MW of output. These results are consistent with a quoted offer for a biogas production plant (excluding upgrading) priced at 15 cr INR for a 100 TPD feedstock capacity [22]. Based on an assumed biogas yield of 1.67 GJ per tonne of input (as given in the datasheet), the plant's output is approximately 2 MW. This corresponds to a specific investment cost of about 7.7 cr INR per MW of output.

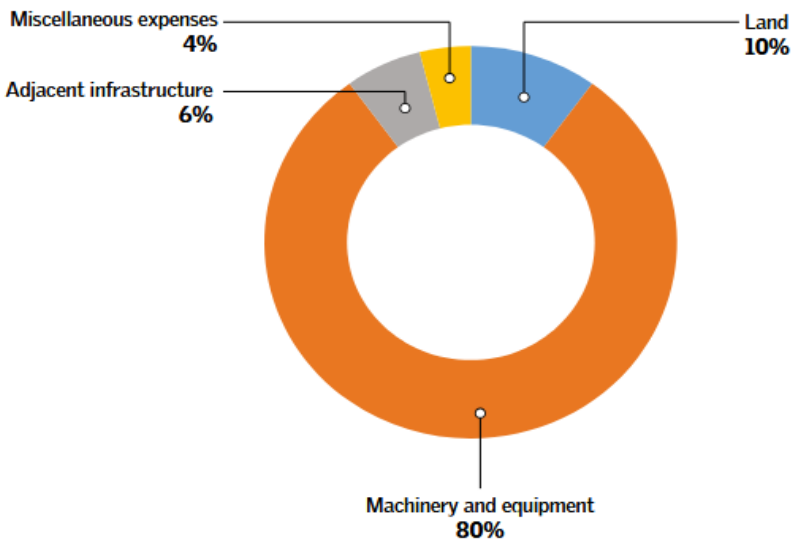

Figure 6-4: CAPEX breakdown of a CBG plant. [2]

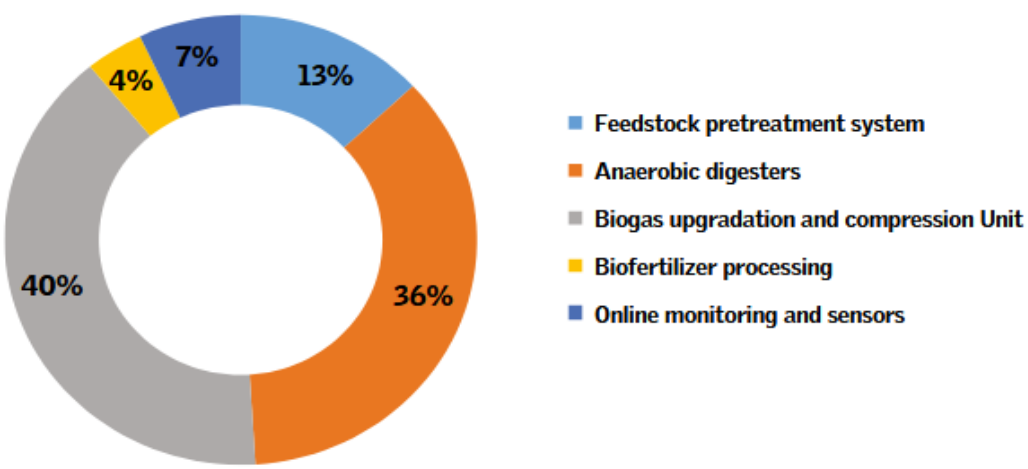

Figure 6-5: CAPEX break-up of equipment and machinery component. [2]

Table 6-6: Overview of several biogas plant manufacturers and their associated CAPEX. [2]

Plant name + location	Plant start date	Bio-CNG Production capacity	CAPEX
Verbio AG (Punjab)	June 2022	33 TPD	230 cr INR (9,550 INR/tonne)
Mittal Enterprises (Uttar Pradesh)	January 2023	8 TPD	26 cr INR (4,450 INR/tonne)
EverEnviro Resource Management Private Limited (Indore)	February 2022	17-18 TPD	150 cr INR (11,400 INR/tonne)
Hingonia Gaushala (Jaipur)	January 2023	6 TPD	38 cr INR (8,700 INR/tonne)

The cost of producing biogas is correlated with the cost of the feedstock, rather than being uniquely dependent on the efficiency improvements in technology. Depending on the availability and value of feedstock, the cost of feedstock can account for a large part of the expenses.

The cost of agricultural waste in India varies by type, location, and demand. According to [2], the price typically ranges from 1,000–2,500 INR per tonne for materials like rice straw, wheat straw, and sugarcane bagasse. Prices fluctuate due to factors such as availability, transportation costs, and usage (e.g., fuel or animal feed)

In the datasheet, the cost of feedstocks and transport are not included in the OPEX as they are highly dependent on local conditions and may vary widely. It is, however, important to include costs for feedstock when calculating the operational cost of biogas plants.

6.11.2. Assumptions for the period 2024 to 2030

For the period 2024 – 2030 the total biogas production in India is expected to increase significantly.

There is currently momentum for biogas development in India, driven by financial support for biogas plants, subsidies for selling the digestate as fertilizer, regulations mandating the blending of compressed biogas (CBG) with natural gas, and policies encouraging the use of crop residues for biogas production instead of burning.

6.11.3. Assumptions for the period 2030 to 2050

Forecasting the development of biogas production for the period 2030-2050 is associated with significant uncertainty. As India is aiming to become carbon neutral by 2070, the deployment of biogas plants is expected to continue to increase at a rapid pace between 2030-2050. The estimated cost reduction applied in the datasheet is 15% between 2024 and 2050. This estimate is based on the analysis presented above in the section Projection of performance and costs which elaborates on cost-reduction measures for biogas plants. Specific cost optimisation potentials of 10–16% are identified. The 15% reduction applied in the datasheet is therefore an estimate within this range.

6.12. Uncertainty

The general uncertainty when calculating energy generation costs for biogas plants is high, but the investment costs seem to contribute less than the operating costs. Key parameters of the energy output are the composition of the input material and the processing time. The data in this technology catalogue consider a fixed composition of the input and a fixed processing time. The HRT is 65 days, which is considered representative of current state of the art plants. Biomass purchase, transportation, auxiliary energy, and labour costs are important to include in an economic assessment but may vary widely. In the datasheet, the biomass purchase and transportation costs are not included. The cost for auxiliary energy and labour costs are included.

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6.14. Datasheet

Technology	Biogas production plant, basic configuration									Note	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Typical capacity (tons/year input)	91250	91250	91250	91250	91250	36500	182500	36500	182500	A	8
Typical total plant size (MW output)	4.83	4.83	4.83	4.83	4.83	1.93	9.66	1.93	9.66	B	2, 8
- Inputs											
Biomass (tons/year)	91250	91250	91250	91250	91250					A	8
Aux. electricity (% of output energy)	2.3%	2.0%	2.0%	1.8%	1.8%						1
Aux. electricity (kWh/ton input)	10.19	8.87	8.56	8.05	8.05						1
Aux. process heat (% of output energy)	6.9%	6.0%	5.8%	5.4%	5.4%						1
Aux. process heat (kWh/ton input))	29.96	26.07	25.17	23.67	23.67						1
- Outputs											
Biogas (%)	100	100	100	100	100						1
Biogas (GJ/ton input)	1.67	1.67	1.67	1.67	1.67					C	1
Biogas production, (MW output)	4.83	4.83	4.83	4.83	4.83					B	1
Forced outage (%)											
Planned outage (weeks per year)											
Technical lifetime (years)	20	20	20	20	20						1, 5, 6
Construction time (years)	2	2	2	2	2						1
Financial data (in 2023₹)											
Specific investment (cr. ₹ per MW output)	7.11	6.75	6.08	5.17	5.17	6.04	8.18	4.65	5.68	F	4, 8
- of which equipment (%)	80	80	80	80	80						1
- of which installation (%)	20	20	20	20	20						1
Total O&M (1000 INR/MW/year)	3554.25	3376.53	3038.88	2583.05	2583.05	710.85	7108.49	516.61	5166.10	D	7
Total O&M (INR/(ton input/year))	188.22	178.81	160.93	136.79	136.79	100.00	449.53	85.00	273.57	E	1
- of which O&M, excl el. and heat (INR/(ton input/year))	121.19	115.13	103.61	88.07	88.07						1
- of which electricity (INR/(ton input/year))	32.41	30.79	27.71	23.55	23.55						1
- of which heat (INR/(ton input/year))	34.62	32.89	29.60	25.16	25.16						1
Technology Specific data											
Methane emission (% of output)	0.009	0.009	0.009	0.009	0.009						1

Notes

A A daily input of 250 ton feedstock, seems to be the most common size for large industrial plants in India, based on literature review.

B Derived from input capacity and Biogas yield; refers to Biogas output

C Highly dependent on the feedstock

D Based on [7] which states that OPEX is between 1-10% of CAPEX; 5% is applied for point estimate

E Derived from Total O&M in 1000 INR/MW/year; upper uncertainty from [1]

F 15% expected reduction towards 2050

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7. Biogas Upgrading

7.1. Brief technology description

Biogas is produced by anaerobic digestion of municipal, agricultural, and industry waste. For some applications where it is important to have a high energy content in the gas, e.g., as vehicle fuel or for grid injection, the gas needs to be upgraded. The upgrading of biogas separates CO_2 from the gas to obtain a higher methane content, improving the heating value. Upgrading can improve heating values to 15–30 MJ/Nm^3. [1] [2] Upgraded biogas is often referred to as biomethane, compressed biogas (CBG), or bio-compressed natural gas.

Biogas is converted into biomethane through a purification process at an upgrading facility. The input for upgrading facilities is raw biogas, which typically contains 50-75% methane (CH_4) and 25-50% carbon dioxide (CO_2), plus a minor content of hydrogen (H), nitrogen (N), oxygen (O), hydrogen sulphide (H_2S) and ammonia (NH_3). The composition of the biogas varies based on the specific mix of the input. [1]

The purification process involves two main steps: first, toxic compounds are removed, and second the CO_2 content is reduced to achieve a sufficiently high calorific value. This purified biomethane has properties similar to natural gas and meets the standards for vehicle fuel or grid injection. [1] [2]

Most upgrading plants are based on one of the three following technologies:

- Pressure Swing Adsorption (PSA)
- Water scrubbing
- Membrane separation
- Amine scrubbing

The following sections give a brief introduction to the different upgrading technologies.

7.1.1. Pressure Swing Adsorption (PSA)

PSA is one of the most common biogas upgrading techniques worldwide, partly due to its lower energy consumption, enhanced methane purity, and immunity to corrosion issues. PSA separates carbon dioxide from biogas by adsorbing it onto a material such as activated carbon or zeolites under high pressure. The adsorbing material is regenerated by lowering the pressure, allowing the process to "swing" between high and low pressures. Before entering the PSA column, hydrogen sulphide and water must be removed. One drawback of this method is the methane loss, which range from 1.8-2%. [3], [4]

7.1.2. Water scrubbing

Carbon dioxide has a higher solubility in water than methane, meaning it dissolves more easily, particularly at lower temperatures. In a scrubber column, CO_2 is absorbed by water, increasing the methane concentration in the gas phase. This process can achieve methane purities of up to 97% with minimal methane loss (less than 5%). Water scrubbing is a physical absorption process where biogas is brought into contact with water, either by spraying or bubbling, to remove CO_2 and hydrogen sulphide, both of which are more soluble in water than methane. The pressure in water scrubber systems, typically around 6 bar, is often high enough for direct injection of biomethane into the gas grid without further compression. Methane loss in this process is generally low, around 1% of the biomethane produced. [3] [1]

7.1.3. Membrane separation

Membrane separation is a process that uses permeable materials to separate specific components from solutions by allowing certain substances to pass through while blocking others. The efficiency of this method is enhanced using membrane cascades with recycling to achieve a higher degree of separation. In single-stage systems, membranes are organized in parallel or series without recycling.

For biogas upgrading, membranes made of materials permeable to carbon dioxide, water, and ammonia are commonly used. Hydrogen sulphide and oxygen also permeate to some extent, while nitrogen and methane pass only minimally. These membranes are typically designed as hollow fibres bundled together.

In the biogas upgrading process, the gas first passes through a filter to remove water and oil droplets that can affect membrane efficiency. Hydrogen sulphide is usually removed with activated carbon. In the membrane stage, carbon dioxide is separated, allowing for the removal of CO_2, water, and other permeable components. Membrane technology is favoured for its low water and chemical requirements and the ability to scale without significant efficiency loss. It tends to have a higher operational cost compared to other methods, especially for larger plants. [1] [3]

7.1.4. Chemical absorption (Amine scrubbing)

An absorption plant consists of an absorption column, a regeneration column, and several heat exchangers. This process utilizes chemical solvents to capture CO_2 from the biogas mixture. The mixture then passes through a heat exchanger to the desorption column, where the solvent is regenerated.

Raw biogas is usually fed into the bottom of the absorption column, while the solvent is introduced from the top, allowing the CO_2 capture process to occur as the gases move through the column. The CO_2-rich gas exits the column and passes through a series of heat exchangers before entering the desorption column at around 90°C.

The main advantages of this absorption technology are its high removal efficiency and its ability to process large volumes of biogas. However, the technology also has drawbacks, including a high energy demand during the regeneration step, corrosion issues, and potential purity problems when other components are present in the biogas mixture. [5]

7.2. Input and output

7.2.1. Input

- 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.

7.2.2. Output

- Upgraded biogas with 95-99 vol. % methane, CO_2, nitrogen, and oxygen.
- Waste gas containing mostly CO_2

7.3. Energy balance

As shown in Figure 7-1, the energy consumption of the upgrading processes varies, but it ranges from approximately 0.5 to 1 kWh/m^3.

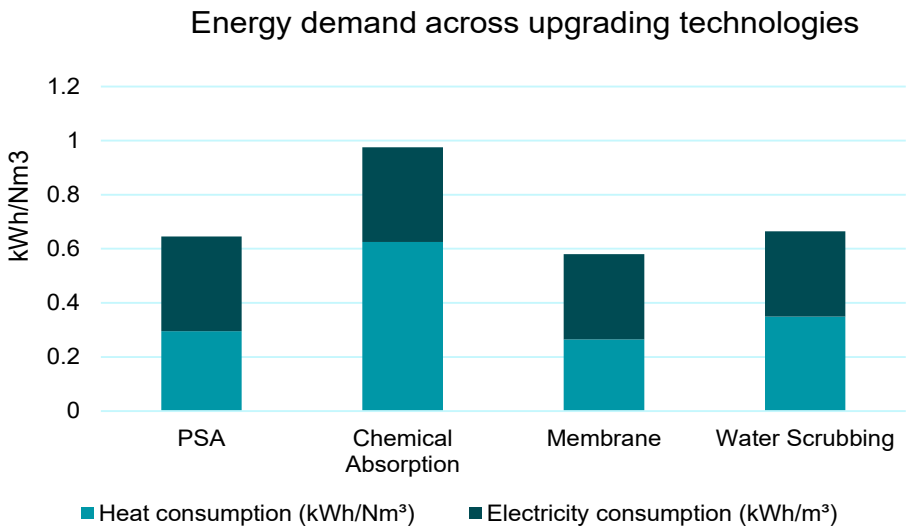

Figure 7-1: Energy consumption of Upgrading. [5]

The data are summarised in Table 7-1 below. Electricity and heat demands are presented per normal cubic metre (Nm^3) of biogas upgraded.[5]

Table 7-1 Energy consumption of selected biogas upgrading technologies (per Nm^3 of biogas).

Technology	Electricity Consumption (kWh/Nm^3)	Heat Demand (kWh/Nm^3)
Pressure Swing Adsorption (PSA)	0.24 – 0.46	0.16 – 0.43
Water Scrubbing	0.20 – 0.43	0.20 – 0.50
Membrane Separation	0.20 – 0.43	0.18 – 0.35
Chemical Absorption	0.05 – 0.65	0.50 – 0.75

7.4. Typical characteristics and capacities

India has approximately 1,108 TWh of biogas potential, according to WBA[13] analysis. India is now focused on waste-to-energy programs especially big-scale biogas production CBG plants with upgrading facilities. The capacity of existing plants varies from small-scale plants (5 to 25 m^3), and medium-scale (25-2,500 m^3) [6].

[13] https://www.worldbiogasassociation.org/biogas-pathways-to-2030-report/

7.5. Advantages/disadvantages

Table 7-2: Advantages and disadvantages of biogas upgrading technique. [7]

Technique	Advantages	Disadvantages
Water scrubbing	High efficiency	Expensive equipment and operation
	Easy to use and cheap	Medium-high CH_4 composition is obtained
	Low electricity consumption	CH_4 losses
	Co-remove of NH_3 and H_2S	Low flexibility regarding biogas composition
	Flexibility of capacity	High water requirement
		Dried stage after scrubbing is needed
PSA	Less affected by impurities	Medium-high CH_4 composition is obtained
	Low energy consumption	Less efficiency than other techniques
	Chemicals are not needed	Pre-treatment is needed for the removal of H_2S Strict control condition
	immunity to corrosion issues	High electricity consumption
Membrane separation	Simple construction and operation	Low selectivity of the membrane
	High reliability	High cost of membranes
	No heat and no chemical products are required	Not suitable for biogas with pollutants not determined, such as landfill gas or wastewater biogas
	Small gas flows can be treated without great cost increase	Medium/high losses of CH_4 (<10%)
	Requires little maintenance	
Chemical scrubbing	High efficiency (>99% CH_4)	High equipment costs
	It presents a greater solubility of CO_2 than water	High heat demand for regeneration
	Low CH_4 losses	Pre-treatment is needed for the removal of H_2S
	Cheap operation, regenerative	Corrosion and salt precipitation.

7.6. Environment

The main objective of the biogas industry is the reduction of fossil fuel consumption, with the final goal of mitigating global warming. Upgraded biogas, in particular, can replace fossil fuels in applications that require higher energy content.

However, biogas upgrading also poses environmental challenges, particularly concerning the use of water and chemicals, as well as methane leaks and emissions. The different technologies are all associated with different challenges.

Water usage is primarily a concern for water scrubbers, which require 0.4 to 4 litres of water per Nm^3 of biogas input. In comparison, chemical scrubbers also have a water demand, but it is significantly lower, at approximately 0.03 litres per Nm^3. [1]

The chemical consumption in water scrubbers and amine scrubbers primarily involves anti-foaming agents. To remove hydrogen sulfide, activated carbon is necessary for various methods, including PSA, membrane separation, and amine scrubbing. The highest reported requirement for activated carbon is 0.08 g/Nm^3 of raw biogas. Additionally, amine scrubbers need to account for amine loss during operation, although only small amounts are typically lost in normal conditions.

It is important to note that high concentrations of amines released into the environment can pose risks to aquatic ecosystems. However, this risk can be mitigated or eliminated by employing appropriate techniques, making it less of a significant environmental concern for upgrading plants. [1]

The highest methane slip among the technologies is reported from PSA (1.8%-2%), followed by the water scrubber (1%), membrane separation (0.5%) and the lowest slip is from amine scrubbing (0.1%). In principle, physical scrubbers have a higher slip than the other technologies, but the methane is utilized internally. 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. Keeping the methane emission from biogas upgrading plants to a minimum is therefore of great importance for the climate impact of biomethane production. The methane slip can be eliminated if the off-gas from the upgrading plant is treated in a regenerative thermal oxidation (RTO) plant. Other solutions for reducing methane leaks and increasing the output of upgraded gas are developed. This is especially relevant for water scrubber plants, as it will increase the competitiveness of the technology. [1]

7.7. Regulation ability

Biogas upgrading plants can down-regulate to 20-30 % of the full load. Cold start-up time is about 2-4 hours, whereas hot standby (maintaining the plant at operating temperature) takes less than 0.5 hours [1].

7.8. Space requirements

The upgrading facilities are located with the biogas plants and therefore have the same requirements. See chapter about biogas production.

7.9. Examples of market-standard technology

Biogas upgrading in India is still in its early stages and is gradually emerging as a promising sector. With the Government of India launching the SATAT initiative for setting up 5,000 plants by 2025 and guaranteed offtake of upgraded biogas, the sector is expected to have many large stakeholders in the near future. The table below present some of the exiting projects in India. It includes plants that do both produce biogas and upgrade it. These are the same examples as in the biogas production chapter.

Table 7-3: Market Example of biogas plants in India. – all plants upgrade the biogas to bio compressed natural gas. The capacity stated in the table is for the upgraded compressed biogas, i.e. bio-compressed natural gas [8]

Company	Location	Feedstock	Capacity
Verbio AG	Lehragaga, Punjab	300 TPD Paddy straw and other agricultural waste	33 TPD
Mittal Enterprises	Garhmukteshwar, Uttar Pradesh	200 TPD Pressmud (sugarcane industry waste)	8 TPD
EverEnviro Resource Management Private Limited	Indore, Madhya Pradesh	500 TPD Biodegradable municipal waste	18-20 TPD
Hingonia Gaushala (IOCL)	Jaipur, Rajasthan	250 TPD Cattle dung	6 TPD

Other examples of projects are presented below in more detail.

7.9.1. EverEnviro Resource Management Private Limited



Figure 7-2: EverEnviro Resource Management Private Limited plant. [8]

EverEnviro set up a plant in Indore, where the Indore Municipal Corporation (IMC) collaborated with EverEnviro. With a capital investment of 150 crore INR, EverEnviro has turned the waste from Devguradiya into a valuable resource. The IMC supplies 90 percent of segregated waste to the plant, and in return, EverEnviro pays them an annual royalty. The contract between the IMC and EverEnviro stipulates that 50 percent of the bio-CNG produced is to be allocated to power Indore's city buses, priced at INR 5 per kilo less than the market rate of CNG. [8]

The plant is currently fuelling 146 buses and has plans to expand to 400 buses. The remaining bio-CNG is sold to Avantika Gas Ltd, the CNG and PNG supplier of the Indore region.

The facility has a reached a CBG production of 20 tonnes. The site effectively handles 550 tonnes of organic waste daily. This systematic treatment of segregated organic materials has led to a notable decrease in

greenhouse gas emissions, mitigating up to 70,000 tonnes/year of carbon emissions equivalent. Besides the CBG production, the facility can produce 40 tonnes of organic fertilizer per day. [9]

Table 7-4: Specification of EverEnviro plant, Indore.[8]

Parameters	Details
Plant Name	EverEnviro Resource Management Private Limited
Plant start date	2022
Biogas purification method	Pressure Swing Adsorption
Bio-CNG production capacity	18-20 TPD
Bio digestate production	100 TPD
Gas offtake method	50% to IMC city buses; 50% for industrial and commercial uses
Number of digesters	4
Feedstock used	Biodegradable municipal waste
Daily Feedstock requirement	500 TPD
Land requirement	15 acres
CAPEX	150 cr INR (11,400 INR/tonnes)

7.9.2. Hingonia Gaushala

IOCL has set up a biogas plant in Hingoniya Gaushala, Jaipur, Rajasthan. The capacity of the biogas plant is 100 tonnes, i.e. to produce biogas, compress it at high pressure, and store it in a cylinder that can be easily transported to fuel stations, where the bottled CBG can be used in vehicles. Additionally, the fuel can be used for cooking in kitchens. [10]



Figure 7-3: Hingonia Gaushala (IOCL) Plant.[10]



Figure 7-4: Biogas Holder Balloon. [10]

The Hingoniya Gaushala is located in the outskirts of Jaipur City. The plant started in January 2023 and has a biogas production capacity of 50 TPD, with a purification capacity of 6 TPD. It employs pressure swing adsorption as the biogas purification method. The feedstock used in the plant is mainly cattle dung and the daily feedstock requirement is 250 TPD. [10]

Table 7-5: Composition of cow dung. [10]

Composition	Percentage by weight
Water	75%
Organic matter	20-25%
Nitrogen (N)	0.5-1.5%
Phosphorus (P)	0.2-0.5%
Potassium (K)	0.5-1.5%
Calcium (Ca)	0.5-1.5%
Magnesium (Mg)	0.2%-0.5%
Sulfur (S)	0.1-0.2%

Biogas fuel can be used in vehicles, for cooking, and to generate electricity and can be compressed and transported by bottling it. [10]

Table 7-6: Specifications of Hingoni Gaushala plant. [10], [8]

Parameters	Details
Plant Name	Hingonia Gaushala (IOCL)
Plant start date	Jan-23
Biogas purification method	Pressure Swing Adsorption
Bio-CNG production capacity	6 TPD
Bio digestate production	50 TPD
Gas offtake method	Gas grid
Number of digesters	2
Feedstock used	Cattle dung
Daily Feedstock requirement	250 TPD
Land requirement	5 acres
CAPEX	38 cr INR (8,700 INR/tonne)

7.10. Research and development perspectives

The Indian government has introduced several policy changes to accelerate growth and investments in the biogas sector. More information is available in the corresponding section of the chapter on Biogas Production.

7.11. Projection of performance and costs

The current costs are estimated based on the cases and CAPEX breakdown given in [8]. A more detailed explanation of how the CAPEX values were derived is provided in the biogas production chapter. Accordingly, the specific investment cost for an upgrading facility is estimated at 4.9–6.64 cr. ₹ per MW of output.

The future development of biogas upgrading technologies presents significant opportunities for enhancement and innovation. As the industry matures, investment costs and operational expenses are expected to decline significantly due to technological advancements and increased experience in the field.

The outlook for biogas upgrading suggests a growing demand for upgraded biogas, necessitating the development of new facilities. It is assumed that technological learning will reduce costs by 15% between 2024 and 2050 following the assumptions made in the corresponding section in the biogas production chapters. However, this projection may vary due to uncertainties and differences among the various upgrading technologies. Examples of areas with a potential future development, includes:

7.11.1. Material Innovations

- Developing advanced materials and adsorbents that can operate efficiently under varying conditions, thereby improving CO_2 capture performance.
- Utilizing advanced technologies to enhance material properties for better separation efficiencies.
- Investigating the effects of various feed compositions on the performance of upgrading technologies.

7.11.2. Process Optimization

- Reducing energy consumption through efficient heat recovery and management during the upgrading process.
- Analysing the impact of trace components in biogas on the performance of different upgrading methods.
- Modifying processes to accommodate larger volumes of biogas and varying pressures while maintaining high purity levels of methane.

7.12. Uncertainty

The general uncertainty when calculating costs for biogas upgrading plants is high due to low data availability about the real costs of large plants and differences among the various upgrading technologies.

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7.14. Datasheet

Technology	Biogas upgrading									Note	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Total plant size [MW output]	4.79	4.79	4.79	4.79	4.79	1.91	9.57	1.91	9.57	A	8
Capacity, Biomethane output [k Nm3 biomethane/h]	0.48	0.48	0.48	0.48	0.48	0.19	0.96	0.19	0.96	B	
Yearly production [k Nm3 biomethane/year]	4216	4216	4216	4216	4216	1686	8432	1686	8432	C	
- Inputs											
Biogas (% of biogas input)	100.00%	100.00%	100.00%	100.00%	100.00%						1
Auxilliary electricity for upgrading (% of biogas input)	1.92%	1.50%	1.33%	1.17%	1.17%	1.44%	2.40%				1
Heat (% of biogas input)	10.48%	8.17%	7.28%	6.39%	6.39%	8.91%	12.05%				1, 2
- Outputs											
Biomethane (% of biogas input)	99.0%	99.0%	99.0%	99.0%	99.0%						1
Waste gas (% of biogas input)	1.0%	1.0%	1.0%	1.0%	1.0%					D	1, 3
Waste heat (% of biogas input)	5.2%	5.2%	5.2%	5.2%	5.2%						1
Forced outage (weeks per year)	0.29	0.29	0.29	0.29	0.29						1
Planned outage (weeks per year)	0.29	0.29	0.29	0.29	0.29						1, 3
Technical lifetime (years)	20	20	20	20	20						1, 4, 5
Construction time (years)	1	1	1	1	1						1
Financial data (in 2023₹)											
Specific investment (cr. ₹ per MW output)	5.77	5.48	5.19	4.90	4.90	4.90	6.64	4.17	5.64		8
Fixed O&M [1000 INR/MW output/year]	2885	2740	2596	2452	2452	2451	3318	2084	2820	F	9
- of which fixed O&M costs upgrading and methane reduction, excl. electricity and heat [k INR/MW output/year]											
- of which fixed O&M costs for heat [k INR/MW output/year]											
- of which fixed O&M costs for electricity [k INR/MW output/year]											
Variable O&M (INR/GJ input)	90	75	63	55	55					E	1
- of which electricity [INR/GJ output]											1
Technology specific data											
Methane slip / emission (%)	0.001	0.001	0.001	0.001	0.001						1
Minimum load (% of full load)	0.5	0.5	0.5	0.5	0.5						1

Notes

A Same size as the biogas production plant; refers to Biomethane output

B LHV of CH_4 = 35.8 MJ/Nm^3

C Operates 8760 h/year

D Consider carbon dioxide + nitrogen + oxygen as waste gas

E Without electricity cost

F Based on [9] which states that OPEX is between 1-10% of CAPEX; 5% is applied for point estimate

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8. First generation (1G) – Ethanol

8.1. Brief technology description

Ethanol is created by yeast (*Saccharomyces cerevisiae*[14]*)* anaerobic fermentation of carbohydrates. In most circumstances, 6-carbon sugars are the most prevalent substrate for fermentation. Other microorganisms can also ferment five-carbon sugars found in plant material (lignocellulosic biomass). Sugar cane, sweet sorghum, and sugar beet are sugar-based feedstocks used in fermentation. Molasses, a byproduct of a sugar mill that contains around 49% sucrose, can be diluted and used in the same way as sugar-based feedstocks. Starch-based feedstocks, such as corn, cassava, and sorghum grain, however, require enzymatic hydrolysis to release sugars before fermentation. Complex feedstocks, such as lignocellulosic biomass, require more complex upstream pretreatment to release fermentable sugars. [1] The present chapter focuses on the use of sugarcane for the production of first-generation (1G) ethanol.

The production of ethanol from sugarcane is through crushing the cane stalks to extract a juice rich in sucrose, a disaccharide that can be easily fermented into ethanol by Saccharomyces cerevisiae. The extracted cane juice is fed into a fermentation tank, where yeast converts the sugars into ethanol. After juice extraction, the fibrous by-product known as bagasse, with a moisture content of 45-50%, is typically burned to produce heat or electricity for internal use. Following fermentation, the resulting mixture, called beer, contains around 5-12% ethanol. This beer is transferred to a distillation column, where ethanol is separated, while a liquid by-product, vinasse, remains at the bottom. The ethanol extracted at this stage is about 92-95% pure, requiring further dehydration to remove residual water. This is commonly achieved using molecular sieves, yielding fuel-grade anhydrous ethanol with over 99.5% purity. [1]

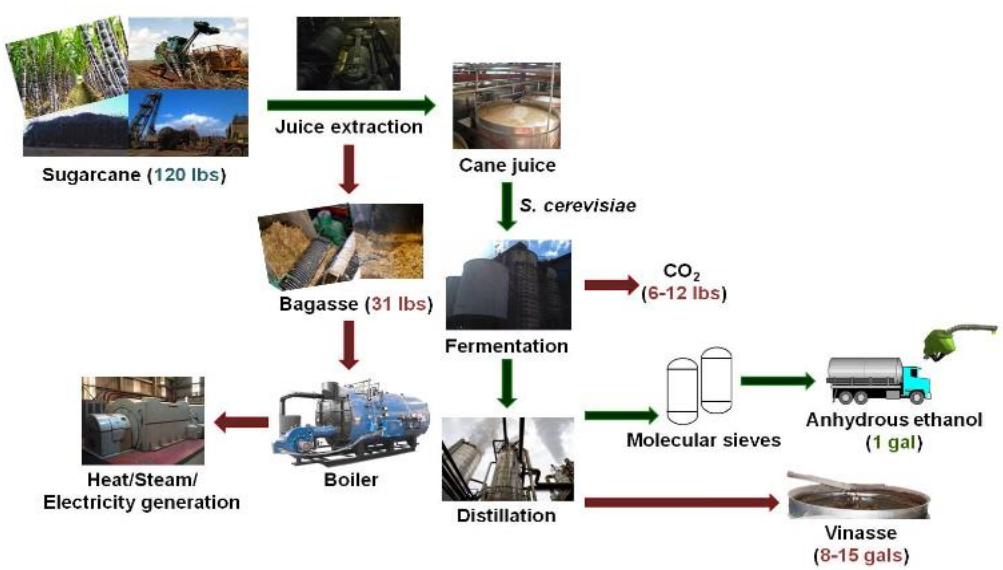

Figure 8-1: The schematic diagram of sugarcane ethanol production. [2]

[14] *Saccharomyces cerevisiae* (*S. cerevisiae*) is a unicellular fungus and is also called baker's yeast.

8.2. Input and Output

8.2.1. Input

The primary inputs in the system are sugarcane (other sugar-based feedstocks), water, and yeast. Some secondary inputs take part in the process such as steam, electricity, nutrients and additives, cooling water, and compressed air.

8.2.2. Output

The primary outputs are ethanol and bagasse (fibrous residue). Ethanol is typically used as a biofuel or for industrial and beverage purposes. The fibrous residue remaining after juice extraction often used as a bioenergy source for generating steam and electricity. And there are some products derived during ethanol production such as Vinasse and CO_2. Vinasse is a liquid waste byproduct left after distillation, which can be used as a fertilizer or for biogas production and Carbon di-oxide is also a byproduct of the fermentation process, which can be captured and utilized in various industries or released into the atmosphere.

8.3. Energy balance

The energy balance diagram illustrates the production of ethanol from sugarcane. It shows that 7,400 MJ of energy from sugarcane along with 45.4 MJ of electricity, is used in the process. The outputs of the process are 1,680 MJ of energy in the form of ethanol and 64.7 MJ of energy from bagasse, a by-product of sugarcane. The diagram highlights the conversion of sugarcane and electricity inputs into ethanol and bagasse, demonstrating the distribution and utilization of energy throughout the ethanol production process. [3]

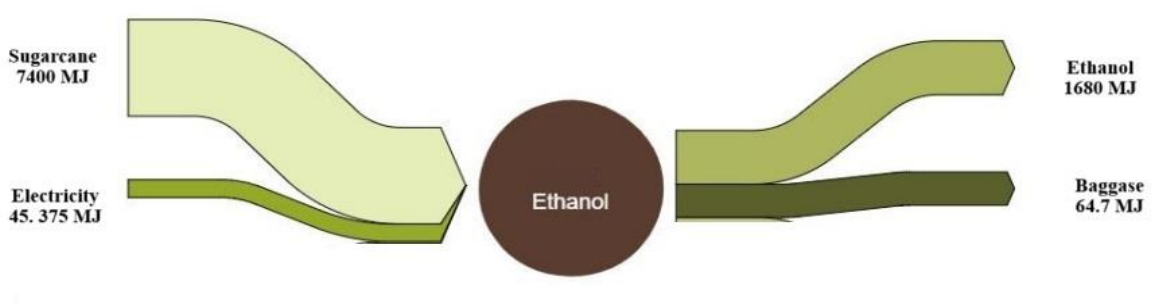

Figure 8-2: 1st generation ethanol energy balance. [4]

8.4. Typical capacities

In India, recent dedicated grain-based ethanol projects have increasingly been developed at capacities of roughly 100–300 KLPD (about 33–100 million litres per year), with some larger facilities exceeding this scale. The largest integrated sugar–ethanol producers operate aggregate distillery capacities of approximately 240–315 million litres per year (about 190,000–250,000 tonnes per year), typically accumulated through multiple co-located distillery units rather than a single production train. A decade ago, individual distilleries were commonly in the range of 60–100 KLPD (roughly 20–33 million litres per year). Since then, government support for ethanol blending and interest-subvention schemes has encouraged construction of larger grain-based ethanol facilities to capture economies of scale and benefit from more consistent year-round feedstock availability compared with seasonal molasses-based production.

8.5. Regulation ability

Plants usually operate continuously with one or two annual maintenance shutdowns. Because the procedure is biological, it's critical to prevent the risk of infections, which can lower yield and impair equipment function. This reduces the possibility of operating below around 80% of capacity. Lower production rates can only be achieved with more frequent start-up and shutdown cycles which increase the operating costs. [7]

8.6. Space requirements

The 250 kilolitre per day (kL/d) ethanol plant[15] at Dhanbad district, Jharkhand covers the total Project Area of 8.80 Ha (21.76 Acres). [8]

The 250 kL/d ethanol plant[16] in Nagpur district, Maharashtra covers the total Project Area of 9.20 Ha (22.73 Acres). [9]

Increase of Distillery[17] from 300 kL/d to 600 kL/d in 4.16 acres of existing land in Belagavi District, Karnataka. [10]

8.7. Advantages & Disadvantages

The key advantages of Ethanol are tabulated in Table 8-1 [11].

Table 8-1: Advantages of ethanol produced from biomass. [11]

Advantage	Description
Renewable	Biofuels are produced from biomass and thus are considered renewable.
Source Material	Whereas oil is a limited resource that comes from specific materials, biofuels can be manufactured from a wide range of materials including crop waste, manure, and other by-products.
Environment Pollution	Biofuels emit less carbon compared to fossil fuels, but the fertilizers used in their cultivation contribute to greenhouse gas emissions. Additionally, biofuels offer a solution for managing municipal solid waste by converting it into usable fuel.
Security	Biofuels can be produced locally, which decreases the nation's dependence on foreign energy. By reducing dependence on foreign fuel sources, countries can protect the integrity of their energy resources and make them safe from outside influences.

[15] K G Spirits LLP
[16] Baidyanath Biofuels Private Limited.
[17] Shree Renuka Sugars Limited

Economic Stimulation	Because biofuels are produced locally, biofuel manufacturing plants can employ hundreds or thousands of workers, creating new jobs in rural areas. Biofuel production will also increase the demand for suitable biofuel crops, providing economic stimulation to the agriculture industry.

First-generation (1G) ethanol, derived from food crops, faces some disadvantages, included in Table 8-2 [11]

Table 8-2: Disadvantages of ethanol from biomass. [11]

Disadvantages	Description
Efficiency	Fossil Fuels produce more energy than some of the biofuels. For, 1 gallon of ethanol produces less energy as compared to 1 gallon of gasoline (a fossil fuel).
Cost	Production of biofuels requires land, this impacts the cost of biofuels as well as that of food crops. Also, though growing engineered biofuel crops can benefit farmers commercially the excess number of such crops can also lead to a loss of biodiversity.
Food Shortages	There is concern that using valuable cropland to grow fuel crops could have an impact on the cost of food and could lead to food shortages
Water Use	Massive quantities of water are required for proper irrigation of biofuel crops as well as to manufacture the fuel, which could strain local and regional water resources

8.8. Environmental concerns

Impacts on the air quality: When the ethanol gets combusted, it emits less hazardous hydrocarbons than gasoline. Because the hydrocarbons have decreased atmospheric reactivity behaviour. The increased aldehyde emissions when compared to petrol or petrol combustion is a disadvantage of pure ethanol combustion. Because, the engines powered by ethanol emit more aldehydes overall than engines powered by petrol. [12]

Water Pollution: The ethanol production process generates wastewater, known as vinasse in the case of sugarcane ethanol, which contains organic matter, nutrients, and potentially harmful chemicals. Improper disposal or treatment of wastewater can lead to water pollution, impacting aquatic ecosystems and human health. [12]

Use of water for sugarcane to ethanol conversion: Conversion of cane to ethanol requires large amounts of water. The total use of water was calculated to be 21 m^3/ton of cane, of which 87% was used in four processes: cane washing, condenser/multijet in evaporation and vacuum, fermentation cooling, and alcohol condenser cooling. However, most water used is recycled. [12]

Land Use Change: The expansion of sugarcane cultivation for ethanol production can lead to deforestation, habitat loss, and conversion of natural ecosystems to agricultural land. This can result in biodiversity loss and contribute to carbon emissions from land-use change. [12]

Pesticide and Fertilizer Use: Intensive agriculture for ethanol feedstock cultivation may involve the use of pesticides and fertilizers, which can lead to soil degradation, water pollution, and negative impacts on biodiversity. [12]

Addressing these environmental concerns requires implementing mitigation measures and adopting sustainable practices throughout the ethanol production supply chain. This includes promoting sustainable land management practices, optimizing water use efficiency, implementing wastewater treatment technologies and the use of renewable energy sources, minimizing air emissions through pollution control measures, and promoting integrated pest management. Additionally, regulatory frameworks and certification schemes can help ensure compliance with environmental standards and promote continuous improvement in environmental performance within the ethanol industry.

8.9. Research and development perspective

Research and development (R&D) in the ethanol sector in India has seen significant progress, driven by the government's commitment to promoting biofuels. The primary focus has been on enhancing the ethanol blending program and developing second-generation (2G) ethanol technologies.

Ethanol Blending Program (EBP): The Indian government aims to achieve 20% ethanol blending in petrol by 2025. The EBP has already increased from 1.6% in 2013-14 to 11.8% in 2022-23. This initiative is part of a broader strategy to reduce reliance on fossil fuels and promote renewable energy sources. The shift from sugarcane-based ethanol to grain-based ethanol, especially maize, is being emphasized to meet future targets. [13]

Second-Generation (2G) Ethanol: 2G ethanol projects focus on using agricultural residues and non-food biomass for ethanol production. These projects are crucial for sustainable biofuel production, as they do not compete with food crops. The Ministry of Petroleum and Natural Gas has been actively promoting 2G ethanol technologies, which can help in managing agricultural waste and reducing greenhouse gas emissions. [14]

Technological Innovations: Various R&D efforts are aimed at improving the efficiency of bioethanol production processes. This includes developing better pre-treatment methods for lignocellulosic biomass, optimizing fermentation processes, and enhancing enzyme efficiency. Research institutions and industry players are collaborating to overcome technical and economic challenges associated with 2G ethanol production. [6]

8.10. Examples of market-standard technology

Some of the projects presented below indicate the role of ethanol production from sugarcane in India.

Table 8-3: Ethanol distillation capacities of Sugar factories in India. [15]

S. No	Company	Location	Year of commissioned	Operating plants for ethanol production	Sugarcane crushing capacity TCD (Tonnes of cane per day)	Ethanol distillation capacity kL/d (kilolitres per day)
1	Bajaj Hindustan Sugar Ltd (BHSL)	Uttar Pradesh	1944	14	136,000	800
2	Balarampur Chini Mills Ltd	Kolkata	1975	3	76,500	520
3	Dalmia Bharat Sugar and Industries Ltd	Uttar Pradesh	1994	4	35,000	305
4	Shree Renuka Sugars Ltd	Karnataka and Maharashtra		7	35,000	930
5	Triveni Engineering and Sugar Industries	Uttar Pradesh	1932	7		320

8.10.1. Bajaj Hindusthan Sugar Ltd

Bajaj Hindusthan Sugar Ltd. (BHSL) is a sugar and ethanol manufacturing company headquartered in Mumbai, Maharashtra, India. The company operates 14 sugar plants exclusively in the northern Indian state of Uttar Pradesh (UP).



Figure 8-3: BHSL in Golagokarnnath, Uttar Pradesh. [16]

Farmers harvest the sugarcane and transport it to the mill, where it is prepared for milling using knives and shredders. The prepared cane is then pressed through mills with three rollers to extract the sugarcane juice. This extracted juice, mixed with water, is sent to the boiling house for further processing. The residual bagasse is redirected to the boilers to be used as fuel for steam generation.

The original syrup undergoes a progressive de-sugarization process until a viscous liquid is produced from which no further sugar can be extracted. This final liquid, known as molasses, is then sent to the distillery for the production of alcohol or ethanol. [17]

Table 8-4: Specifications of plant. [17]

Parameters	Details
Company Name	Bajaj Hindusthan Sugar Ltd (BHSL)
Industry	Sugar and Ethanol Production
First Factory Location	Gola Gokaran Nath, Lakhimpur District, Uttar Pradesh
Initial Crushing Capacity	400 TCD (Tonnes of Cane per Day)
Current Crushing Capacity (Gola Plant)	13,000 MT per day
Total Cane Crushing Capacity	136,000 TCD across all plants
First Ethanol Production	1944 (as a by-product of Gola Gokaran Nath Mill)
Current Ethanol Distillation Capacity	800,000 litres per day

8.10.2. Balarampur Chini Mills Ltd

Balarampur Chini was founded in 1975. The Kolkata-based company is among the largest manufacturers of sugar as well as ethanol. The company's ethanol distillation capacity is 520 KLPD and a cane crushing capacity of 76,500 TCD. The distilleries are located at Balarampur, Manakapur, Gularia (all in Uttar Pradesh). Another distillery in Maizapur, Uttar Pradesh with an installed capacity of 360 KLPD has been commissioned. The

company plans to increase ethanol production from molasses with no residual sugar and sugar cane syrup to increase the contribution of ethanol in blending with petrol. [15]





Figure 8-4: Ethanol distillation plant in Balarampur, Manakapur, Gularia (Uttar Pradesh). [18]

8.10.3. Shree Renuka Sugars Ltd

Shree Renuka Sugars is a global agri-business conglomerate and bio-energy corporation. The company is among the largest sugar and ethanol producers in the country. In the seven integrated sugar mills company, five are in Karnataka: Munoli, Athani, Havalga, Gokak, Ratbag, and two in Maharashtra: Ratnaprabha and Panchaganga. The total sugarcane crushing capacity of the company is 35,000 TCD and Renuka's ethanol capacity has been expanded from 720 KLPD to 1,250 KLPD [19]. The company mainly produces fuel-grade ethanol, sold to oil companies [15].



Figure 8-5: Shree Renuka Sugars Ltd. [19]

8.11. Projection of performance and costs

Due to data scarcity, the given data in the Danish Technology Catalogue [7] for 1st Generation Ethanol was adjusted by inflating it to the cost year 2023 and converting to INR.

8.12. Uncertainty

The uncertainty ranges are based on the given data in the Danish Technology Catalogue [7] for 1st Generation Ethanol and other international data sources that are listed in the datasheet.

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8.14. Datasheet

Technology	1st Generation Ethanol									Note	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Ethanol/year, 1,000 tonnes/year	247	309	347	386	386	360	134				3, 4
Ethanol/year, MW	261	327	373	411	411	315	207			A	3, 4
Inputs											
Feedstock Consumption, MWh/MWh Total Input	0.83	0.84	0.85	0.85	0.85						3, 4
Outputs											
Ethanol Output, MWh/MWh Total Inputs	0.21	0.26	0.29	0.33	0.33					B	1, 4, 5
Bagasse Output, MWh/MWh Total Input											1
Forced outage (%)	0	0	0	0	0						3
Planned outage (weeks per year)	2	2	2	2	2						3
Technical lifetime (years)	22.5	22.5	22.5	22.5	22.5	20	25				2, 3
Construction time (years)	2.5	2.5	2.5	2.5	2.5	2	3				2, 3
Financial data (in 2023₹)											
Specific investment (cr. ₹/MW Ethanol)	8.38	8.21	7.88	7.54	7.54	7.62	10.20	6.86	9.18	C	3, 4, 6, 7
- equipment (%)	75	75	75	75	75						3
- installation (%)	25	25	25	25	25						3
Fixed O&M (cr. ₹/MW/year)	0.67	0.66	0.63	0.60	0.60	0.61	0.82	0.55	0.73	D	3
Variable O&M (INR/MWh)	942.42	942.42	942.42	942.42	942.42						3
Start-up (cr. ₹/1,000 t Ethanol)											
Technology specific data											
Specific energy content (GJ/ton)	15.9	15.9	15.9	15.9	15.9					B	5
Specific density (kg/l) or (ton/m3)	0.14	0.14	0.14	0.14	0.14	0.09	0.20			F	9, 10
Specific investment (MINR/1,000 t Ethanol)	88.63	86.89	84.74	80.19	80.19	66.71	158.19				
- equipment (%)	75	75	75	75	75						3
- installation (%)	25	25	25	25	25						3
Fixed O&M (cr. ₹/1,000 t Ethanol)	0.71	0.71	0.71	0.71	0.71						3
Variable O&M (cr. ₹/1,000 t Ethanol)	0.48	0.48	0.48	0.48	0.48						3

Notes

A The ethanol generation changes according to operation hours of the actual plant

B Sugarcane energy content 15.9 GJ/t (ref. 5)

C Costs across sources have been converted to INR2023 and compared to find the lower and upper band. The central assumption is based in Ref. 3

D Assuming 8% of CAPEX (ref. 3)

E Rough assumption based on difference between OPEX described in ref. 8

F Density of sugarcane bagasse

G Calculated based on other inputs

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9. Methanol from biomass gasification

9.1. Brief technology description

Methanol is a crucial component in the chemical industry, primarily utilized in the production of other chemicals like formaldehyde, acetic acid, and plastics. Further, it is used as fuel for vehicles, ships, industrial boilers and cooking. Globally, approximately 98 Mt are produced annually, with nearly all of it derived from fossil fuels, such as natural gas or coal [1]. India's domestic methanol production was only 0.0693 Mt in the fiscal year 2022–23, while consumption reached 2.84 Mt [2]. This indicates that over 90% of methanol demand was met through imports, as domestic production was minimal. Renewable methanol can be produced either from gasification of biomass, bio-methanol or as e-methanol (described in the chapter: Methanol from power).

Methanol production from biomass gasification involves a series of steps, starting with the feedstock pretreatment and then gasification of biomass to syngas, as described in the chapter about biomass gasification.

The produced syngas, consisting mainly of carbon monoxide, carbon dioxide, and hydrogen, undergo several conditioning or after-treatment steps. The after-treatment depends on the type of gasifier. These include particulate filter, reform of tar and methane decomposition, HCl and removal, etc. Ideally, after conditioning, the syngas should have a H_2 to CO ratio of at least two to one for optimal synthesis of methanol. The cleaned and conditioned syngas are then fed into a methanol synthesis reactor. In the reactor, the syngas is catalytically converted to methanol through the following reaction:

$$CO + 2H_2 \rightarrow CH_3OH.$$

After the initial synthesis, the methanol is separated from unreacted gases through a series of lashing and distillation processes to achieve a final purity of 99.8% methanol in the syngas (by weight) [3].

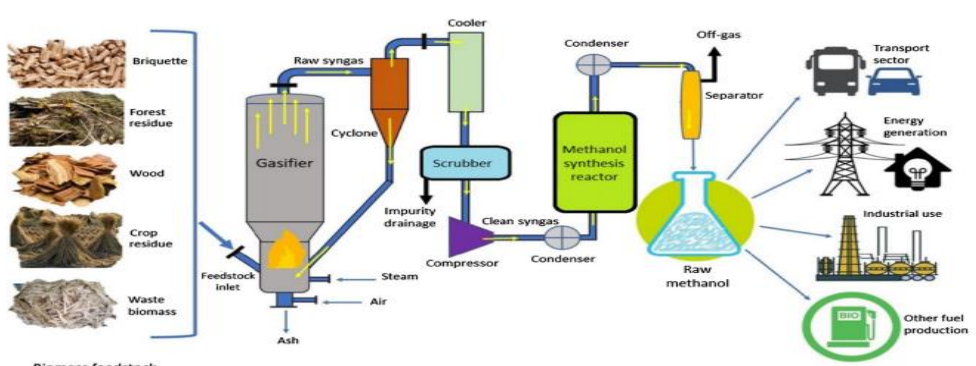

Figure 9-1: Key components in the conversion of biomass to methanol. [4].

9.2. Input and Output

9.2.1. Input

The input to produce methanol from biomass gasification involves biomass feedstock such as wood chips, agricultural residues, forest residues, etc. There are multiple gasification technologies, but a basic segregation can be made between direct and indirect gasification.

In direct gasification, the input includes:

- Biomass feedstock (the material being gasified)
- Air (in some cases) as the gasifying agent, which introduces nitrogen into the gas. Alternatively, pure oxygen mixed with CO_2 or steam can be used to avoid nitrogen contamination in the product gas.

In indirect gasification, the input includes:

- Biomass feedstock
- Heat, which is transferred externally via a medium such as a gas or a movable bed material
- In some cases, steam and/or CO_2 can be added to aid the conversion of the biomass to gas

The key distinction here is that in indirect gasification the heat is produced outside the gasification reactor (often through a parallel combustion process), allowing separation of the flue gas and product gas, making the process more flexible. This process can also generate syngas with a relatively high methane content through pyrolysis, and full conversion can occur if steam or CO_2 are added.

The raw untreated syngas leaving the gasification step need to be cleaned and conditioned to meet the quality level stipulated by the methanol synthesis provider. These process steps vary considerably depending on feedstock and gasifier technology. Some of these processes require an input of chemicals or energy.

9.2.2. Output

The plants produce methanol and, in some cases, excess power or steam for generating electricity.

9.3. Energy balance

The energy balance for a biomass-to-methanol system is shown in the following Figure 9-2.

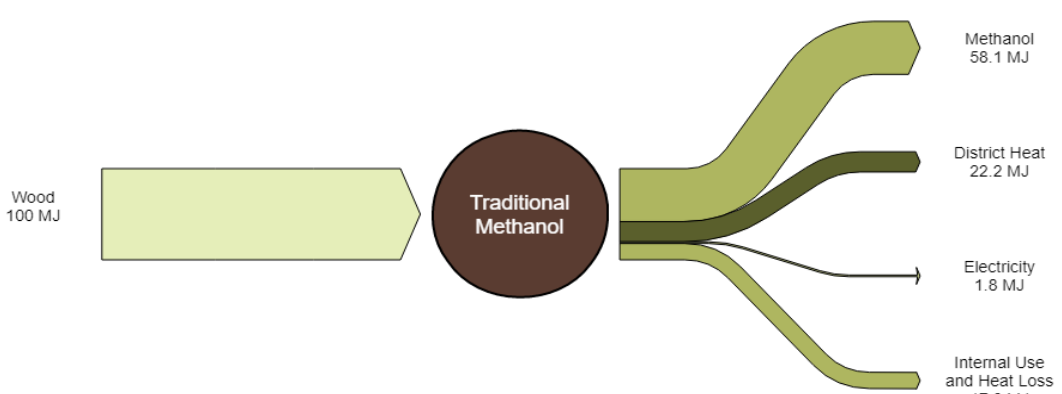

Figure 9-2: Energy balance of Methanol from biomass gasification. [5]

The energy balance diagram illustrates the conversion of 100 MJ of wood into various energy outputs. The primary product is methanol, accounting for 58.1 MJ. In addition, 22.2 MJ is released as heat, which can be used for district heating. 17.9 MJ is consumed from internal use and heat losses during the process, and 1.8 MJ is generated as electricity.

9.4. Typical capacities

There is currently no commercial biomass to methanol plants in operation in India. Methanol is produced through natural gas, coal, biomass, naphtha, etc., however, methanol derived from coal is the most common option in India [6].

Based on the mapping provided by the Methanol Institute, there are only a few biomass-gasification-to-methanol plants currently in operation worldwide. These plants are mainly located in North America, Scandinavia, and China. In Canada, there are two demonstration plants with a production capacity of 1-2 kt of methanol per year. China has one plant in operation with a capacity of 50 kt/y and four additional projects under construction, expected to start up in 2025-2026, with capacities ranging from 120 to 300 kt per year. [7]

Further approx. 40 projects, still in the feasibility or pre-feasibility stage, have been mapped. The majority of these projects are located in Europe and China. These plants vary in size, ranging from 10 kt/y to 500 kt/y, with most expected to have a capacity within the range of 100-300 kt/y. [7]

Based on this it is expected that in the coming years, the typical capacity of these plants will increase from the current maximum of 50 kt/y to between 100 and 300 kt/y.

9.5. Regulation ability

Commercial methanol plants are generally designed to operate continuously at or near their maximum capacity and have limited flexibility for adjusting output, as reaching full production can take two to three days. Smaller scale systems with different catalysts may have better regulation capabilities than large scale plants. In contrast, biomass gasifiers are more adaptable and can operate at reduced capacities, down to about 35% of their rated output. [5].

9.6. Space requirement

The space requirements for a methanol production plant can vary significantly based on the plant's capacity and the technology used. The expected space requirement for a methanol production plant is 293 m^2 /t per hour, however, the space needed is subject to specific project requirements [8].

9.7. Advantages/disadvantages

The advantages of methanol are listed below the Table 9-1.

Table 9-1: Advantages of methanol. [9]

Advantage	Description
Reduced Greenhouse Gas Emissions	Methanol from biomass can be used for the same applications as fossil methanol while reducing GHG emissions. Further it can substitute fossil fuels for some uses and reduce greenhouse gas emissions when produced from renewable sources.
Clean-Burning fuel	When used as a fuel, methanol burns cleaner than traditional fossil fuels, emitting fewer harmful pollutants like sulphur and nitrogen oxides. This makes it an attractive option for improving air quality, particularly in urban areas prone to smog and respiratory issues.
Versatile Industrial Applications	Methanol serves as a feedstock in various industrial processes, such as chemical manufacturing, producing adhesives, plastics, and pharmaceuticals. Its versatility and importance in various industries contribute to its relevance.

Some disadvantages are listed below in Table 9-2.

Table 9-2: Disadvantages of methanol. [9]

Disadvantages	Description
Toxicity	Methanol is highly toxic to humans when ingested, inhaled, or absorbed through the skin. Handling and storage require strict safety measures, making it a challenge in certain applications, especially as a transportation fuel.
Limited Infrastructure	The infrastructure for methanol production, storage, and distribution as a transportation fuel is less developed compared to conventional fuels like gasoline or diesel. Expanding this infrastructure may require additional investment and retrofitting.
Competition for Feedstock	Methanol's use as a fuel competes with its use in the chemical industry. Balancing these applications while ensuring an adequate supply can be challenging.

Energy-Intensive Production	The production of methanol is energy-intensive. The energy required for gasification, and methanol synthesis must be sourced sustainably to maximize environmental benefits.

9.8. Environment

Methanol produced from biomass gasification is considered climate-neutral. When the feedstock consists of (sustainably managed) forestry residues or short-rotation energy crops, the overall carbon footprint is low and the emission reduction is about 70-80% with a carbon footprint assessed to be between 10-40 g CO_2 eq/MJ. [10].

9.9. Research and development perspectives

The production of methanol from biomass and municipal solid waste (MSW) relies on technologies that are generally well-established, as they are comparable to those used in commercial gasification industries, which typically process feedstocks like coal, heavy residual oil, and natural gas. However, biomass gasification for methanol production from wood or straw is still considered a pioneer-phase technology with limited applications to date. Although the technology has been proven through demonstration facilities and semi-commercial plants, many solutions have yet to transition from advanced demonstration stages to full-scale commercial operations, although a few larger plants are already in operation. Due to the limited application, the price and performance remain associated with high uncertainty, and further development and customization are still required. The technology continues to have significant development potential. This technological pathway is the combination of two commercial systems [5] [1].

9.1. Examples of market-standard technology

There are no market-standard technologies in India. Table 9-3 [1] provides information on where, when, and how the various gasification technologies are currently applied or intended for methanol production.

Looking worldwide there are less than 0.5 Mt of renewable methanol production annually, and this output comes from only a few facilities. Key feedstocks include MSW, low-cost biomass, biogas, and waste streams like black liquor from the pulp and paper industry. [7]

The plants currently in operation and those expected to start up in the near future are based on direct oxidation and bubbling bed.

Table 9-3: Gasification technologies intended for methanol production. Table from [1], supplied with [7] (DO = Direct Oxidation, BB = Bubbling Bed, UO = Unspecified Oxidation, MSW = Municipal Solid Waste, EF = Entrained Flow, IH = Indirect Heating, FT = Fischer-Tropsch, FEED = Front-End Engineering Design

Project /owner	Heating Principle /type	Feedstock	Project Phase	Product	Plant capacity
Trans World Energy, Florida (US)	DO, BB	Biomass/MSW	FEED done, start-up expected in Q2 2023	Methanol	875 kt/y

ENI Refinery Livorno, Italian (IT)	DO, UO	MSW	Planned to startup 2028	Methanol	115 kt/y
GIDARA Rotterdam	DO, UO	MSW/waste wood	Start-up expected 2028	Methanol	90 kt/y
Värmlandsmetanol Sweden	DO, BB	Biomass	Planning start-up expected 2029	Methanol	100 kt/y
Enerkem (demonstration plant)	DO, UO	Wood waste and MSW	In operation since 2009	Methanol (and Ethanol)	1kt/y

To illustrate a current project the Enerkem plant is described further below.

9.1.1. Enerkem MSW to Methanol Plant

The Enerkem Municipal Solid Waste (MSW) to Methanol plant, located in Edmonton, Alberta, Canada, was commissioned in 2014. This pioneering facility was constructed by Enerkem. The plant utilizes an innovative two-stage process, starting with the gasification of MSW to produce syngas, which is then converted into methanol using Enerkem's proprietary technology. In the subsequent stage, methanol is further transformed into ethanol, enhancing the value and functionality of the end products [11].



Figure 9-3: Enerkem MSW to Methanol plant. [11]

Enerkem has been gasifying MSW at its Edmonton facility for several years, gradually overcoming operational challenges and improving performance. In 2019, the facility gasified 60,000 tonnes of MSW, approaching its nameplate capacity of 100,000 tonnes per year. Since its start-up in 2015 through to the end of 2019, the plant completed over 10,000 operational hours and produced four million litres of methanol. In 2017, a methanol-to-ethanol conversion unit was installed and became operational in late 2018, enabling the plant to shift to ethanol production.

In the first stage, the MSW is gasified at high temperatures, breaking it down into syngas, which primarily consists of carbon monoxide and hydrogen. This gasification process occurs in a specialized reactor designed to handle diverse waste materials efficiently. In the second stage, the syngas is directed to a catalytic synthesis unit where it is converted into methanol. This methanol can then be further processed into ethanol or other chemicals [1].

Table 9-4: Specifications of plant. [1]

Parameters	Details
Project name	Enerkem Alberta Biofuels
Capacity	38 million litres per year
Feedstock	25-year agreement with City of Edmonton for 100,000 dry tonnes of MSW/ year
Products	Biomethanol, cellulosic ethanol
Green Hydrogen Source	87 MW electrolyser
Bio-Methanol Capacity	Up to 100 kt/y
TRL for Projects	TRL 8 (First of a kind commercial system) TRL 9 (Full commercial operation)

9.2. Projection of Performance and Cost

Currently, due to limited production, data on actual costs of biomass gasification to methanol are scarce, and projections must rely on estimations. The cost of producing bio-methanol will depend heavily on the cost of the bio-feedstock, investment costs, and the efficiency of the conversion processes.

Since feedstock costs are not expected to decrease significantly, reducing CAPEX will be critical to lowering bio-methanol production costs. Key contributors will be achieving economies of scale, process improvements, and more efficient plant configurations. These advancements, alongside increases in plant size, are expected to drive down CAPEX and improve overall cost-effectiveness. [1]

The learning curve for methanol production in India, particularly from biomass and renewable sources, is still in its early stages, with technology maturity remaining low. Conventional methanol production from natural gas and coal is relatively mature, but biomass-to-methanol technologies are nascent, with ongoing R&D and pilot projects aimed at improving efficiency and reducing costs. Challenges include feedstock availability, high capital costs, infrastructure development, and the need for supportive regulatory frameworks. However, government initiatives like the "Methanol Economy" program[18] and increasing public-private partnerships are expected to accelerate progress. Over the next decade, these technologies could move toward commercial maturity with potential cost reductions as operational experience grows [1] [12]. This technology

[18] NITI Aayog's initiative. 'Methanol Economy' programme is aimed at reducing India's oil import bill, greenhouse gas (GHG) emissions, and converting coal reserves and municipal solid waste into methanol.

is categorized 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 are still attached with high uncertainty, since development and customization are still needed, the technology still has a significant development potential

Due to data scarcity, the given data in the Danish Technology Catalogue [5] was adjusted by inflating it to the cost year 2023 and convert it to INR.

9.3. Uncertainty

There is a high level of uncertainty surrounding biomass-to-methanol gasification technology and its future development potential, as the technology is still in an early stage of maturity and has not yet been demonstrated at large commercial scale globally. Examples of market-standard technologies are presented in the section 9.1.

Where the datasheet does not list uncertainty values, this should not be taken to mean the estimates are certain. Rather, it indicates that the necessary data to quantify the uncertainty is not available.

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9.5. Datasheet

Technology	Bio Methanol									Note	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Typical total plant size 1,000 t Methanol/year	300	600	750	900	900	100	300	450	1125	A	1
Typical total plant size, MW	195	390	495	585	585	65	195	292.5	731.25		2
Inputs											
Feedstock Consumption, MWh/MWh Total Input	1	1	1	1	1	0.9	1.5	0.9	1.2		2
Outputs											
Methanol Output, MWh/MWh Total Input	0.59	0.62	0.64	0.66	0.66	0.58	0.6				1, 2
District heat Output, MWh/MWh Total Input	0.22	0.22	0.22	0.22	0.22	0.176	0.275	0.176	0.275		2
Electricity Output, MWh/MWh Total Input	0.02	0.02	0.02	0.02	0.02	0.016	0.025	0.016	0.025		2
Forced outage (%)	4	4	4	4	4						2
Planned outage (weeks per year)	2	2	2	2	2						2
Technical lifetime (years)	20	20	20	20	20						2, 6
Construction time (years)	2.5	2.5	2.5	2.5	2.5						2
Financial data (in 2023₹)											
Specific investment (cr. ₹/MW Methanol)	40.80	28.28	20.80	15.09	15.09	21.89	59.70			B, C	1, 2, 5
- equipment (%)	75	75	75	75	75						2, 3
- installation (%)	25	25	25	25	25						2, 3
Fixed O&M (cr. ₹/MW/year Methanol)	1.83	1.20	0.88	0.64	0.64	0.66	3.00			D	1, 2
Variable O&M (INR/MWh methanol)	21.70	14.47	14.47	14.47	14.47					E	2
Start up (cr. ₹/1,000 t Methanoll)	0	0	0	0	0						2
Technology specific data											
Specific energy content (GJ/ton) methanol)	20.1	20.1	20.1	20.1	20.1						2
Specific density (kg/l) or (ton/m3)	0.79	0.79	0.79	0.79	0.79						2
Specific investment (cr. ₹/1,000 t Methanol)	26.52	18.38	13.52	9.81	9.81	4.12	24.36			F	1, 2
Fixed O&M (cr. ₹/1,000 t Methanol)	0.43	0.29	0.29	0.29	0.29	0.43	1.99			D	1, 6
Variable O&M (cr. ₹/1,000 t Methanol)	1.29	0.86	0.86	0.86	0.86						2
Start up (cr. ₹/1,000 t Methanoll)	0	0	0	0	0						2

Notes

A The average capacity of new plants is expected to grow over time, reflecting advancements in technology and increasing demand for higher efficiency and output.

B Cost data is based on Denmark due to scarcity of Indian data

C Calculated as an average investment cost across different projects in [1] and [2]. [5] suggest a lower investment cost of 166-187 cr. ₹/MW

D Opex range of 5-10% mentioned in [1] so average value of 7.5% is considered here as upper range while lower range is assumed to be 1 % based on [2]

E Biomass and power purchase is highly depended on local conditions

F Point estimate is calculated based on specific investment (cr. ₹/MW Methanol) and plant size, uncertainty based on IRENA [1] and [2]

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10. Methanol from power

10.1. Brief technology description

The conversion of hydrogen to methanol, also called e-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.

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.

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.

The following four conversion pathways are examples, and not an exhaustive list of possible options, of how green hydrogen can be involved in the production of green methanol or e-methanol:

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 International (CRI) [1]. Main reaction in the methanol synthesis:

$$3\,H_2 + CO_2 \leftrightarrow CH_3OH + H_2O$$

Pathway 2, RWGS route: The H_2 and CO_2 are preconditioned in a RWGS reaction in order to reach a syngas composition including CO, similar to fossil-based methanol synthesis. Reverse water gas shift reaction:

$$CO_2 + H_2 \leftrightarrow CO + H_2O$$

Pathway 3, co-electrolysis: In a solid oxide electrolysis cell (SOEC) it is possible to co-produce CO and H_2 based on steam and CO_2. This is currently a technology under development with TRL below 5, but could be part of an e-methanol pathway in the future. Overall reaction in the co-electrolysis:

$$CO_2 + H_2O \leftrightarrow CO + H_2 + O_2$$

Pathway 4, bio e-methanol: The production of green methanol can be achieved by using biogas as a feedstock. Biogas is a mixture of CO_2 and methane, which is often upgraded to biomethane by separating and releasing the CO_2. Instead of separating and releasing the CO_2, it is possible to utilize the CO_2 and methane for methanol production. This can be achieved via steam reforming, which enables the generation of a syngas from biogas. Due to the stoichiometry of the reactions and the composition of biogas, it is necessary to add H_2 in order to achieve a full conversion of the CO_2-content. An example of this pathway has been demonstrated by Lemvig Biogas [2]. In this pathway, the addition of hydrogen can be considered as optional, and thereby the hydrogen production can be operated flexibly depending on the availability of renewable electricity. However, the gas composition in the inlet of the methanol synthesis reactor can then

change significantly resulting in intermittent partial conversion. This would then affect the resulting product and require additional downstream operations. Main reaction in the steam methane reformer:

$$CH_4 + H_2O \leftrightarrow CO + 3H_2$$

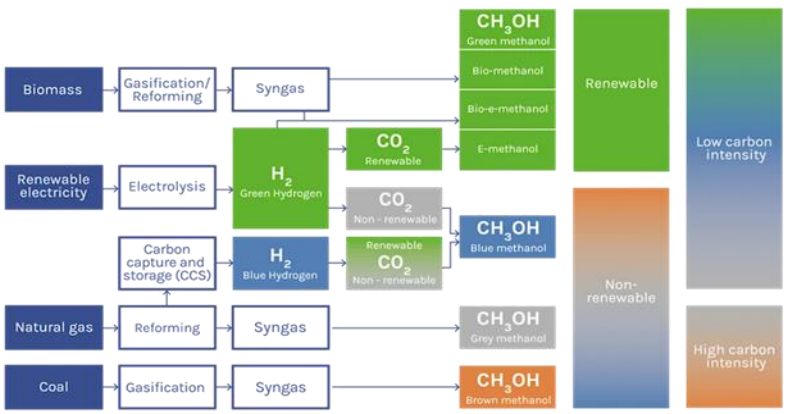

Figure 10-1: Flow diagram for various routes for production of methanol. [3].

10.2. Input and Output

10.2.1. 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 supplied from a central CO_2 and H_2 network and therefore 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. Additional inputs to the process include electricity, cooling, and heating. Electricity is used for auxiliary equipment, and cooling and heating (electrical or steam) is used in the distillation column(s) [4].

10.2.2. Output

The plants produce methanol and, in some cases, could produce some excess power and/or steam for generating electricity [4].

10.3. Energy balance

The energy balance is based on the following information from Haldor Topsøe [5]:

- Steam consumption: 1,600 kg-steam/ton-methanol for example at 10 bar(g)
- H_2 flow rate: 2,130 Nm^3 /ton-methanol
- Steam production: 670 kg-steam/ton-methanol for example at 25 bar(g)

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 10-2 therefore represents the difference between steam consumption and production.

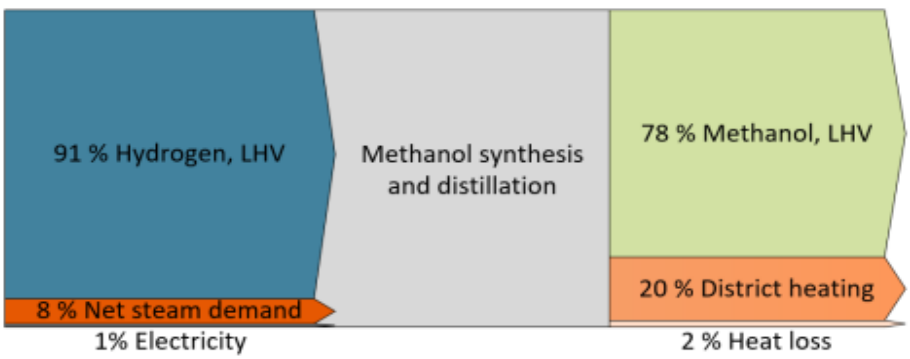

Figure 10-2: Energy balance of methanol from power. [4]

The electricity demand included in Figure 10-2 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. Haldor Topsøe [5] 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, where around 20 percentage points can be recovered as district heating. The potential for recovering excess heat for district heating is primarily relevant in the condensers in the distillation column, where heat is available at a temperature level of around 50-100°C. In order to allow heat utilization for district heating purposes, the cold side of the condenser must operate at higher temperatures compared with conventional cooling water temperatures. Alternatively, a heat pump can be installed which comes with additional CAPEX and power consumption, which is not included in the cost and energy data of this chapter.

10.4. Typical capacities

There are at least seven e-methanol projects announced or under development in India, according to the MNRE Green Hydrogen Project database, ranging in scale from a 0.73 kt/y demonstration unit to projects above 400 kt/y. Most remain at the announced or feasibility stage. But NTPC's CO2-to-methanol demonstration plant at Vindhyachal, built with Jakson Green and Toyo Engineering, has been commissioned, having begun producing methanol in June 2025.[19]

According to the Methanol Institute [6], there were three plants in operation worldwide in 2025: in Denmark, Iceland, and China. The largest one is in Iceland, with a capacity of 4 kt/y of e-methanol production.

To achieve larger production volumes, such as a 1,000 tonnes per day (t/d) e-methanol plant, an electrolyser capacity is required about at least 420 megawatts (MW) — see the detailed assumption in the reference

[19] More up-to-date information can be found in the Green Hydrogen Project database by MNRE, which lists at the time of writing 3 methanol projects: https://nghm.mnre.gov.in/project.php

report [7]. Given the same assumption, for even larger facilities, such as replacing conventional mega-methanol plants with capacities of 2,500 t/d, the necessary electrolyser would need to be in the gigawatt range. This presents a major technological challenge, as the development of electrolysers capable of operating at such scales is still underway [8].

Netherlands: Consortium Nouryon/Gasunie/BioMCN plans a 15,000-ton e-methanol project using CO_2 and H_2 from water electrolysis [7].

Germany: The company Dow plans an e-methanol project of approximately 200,000 tonnes using CO_2 and H_2 from water electrolysis [7]. Consortium plans an e-methanol project using CO_2 from a cement plant and H_2 from water electrolysis [7].

Denmark: Consortium plans an e-methanol project (2023-2030) using CO_2 from MSW and biomass, and H_2 from water electrolysis with up to 1.3 GW capacity [7].

10.5. Regulation ability

In conventional methanol production plants, dynamic operation has not been an important design criterion, since fossil feedstocks generally have constant availability. However, e-methanol production relies on renewable intermittent energy sources. Therefore, the ability to regulate the production capacity is important for such plants unless sufficiently large storage facilities are implemented [4].

The minimum capacity of a methanol plant is to be 40 % in 2020, while reducing to 10 % by 2030 [9]. This assumption reflects that, although regulation ability has not been a concern in the past, there is potential to develop the technology to achieve lower minimum capacities, if required. E-methanol production requires large storage facilities due to its reliance on intermittent renewable energy sources [4].

Cold start-up procedures are time-consuming and pose a catalyst decomposition risk and should be avoided as much as possible. The duration of a cold start-up is in the range of one to two days depending on how fast the system can be heated and pressurized and whether catalyst reduction is needed [4].

10.6. Space requirement

The space requirements for a methanol production plant can vary significantly based on the plant's capacity and the technology used. The expected space requirement for a methanol production plant is 293 m^2 /tph, however, the space needed is subject to specific project requirements [10].

10.7. Advantages/disadvantages

The production of green 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 [4]:

- Enables a methanol production pathway which is not based on fossil feedstock
- No steam reforming is needed
- There is no CO in the incoming feed gas, 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

- 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. This results in less purge.

The following disadvantages are associated with production of e-methanol [4]:

- 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 require dynamic operation design and result in fewer annual production hours compared with fossil feedstocks or need for significant storage of feedstocks or H_2 infrastructure
- CO_2 availability can be variable depending on source
- Increased water content in the raw methanol, resulting in increased energy consumption in the distillation section.

10.8. Environment

Assuming the source carbon dioxide for e-methanol production is renewable or originates from the captured and unavoidable emissions from another process, the end-of-life emissions have no net climate impact. The carbon footprint of methanol produced from solar PV, wind, or hydropower-sourced electricity is low and an emission reduction of >90% is achieved. However, if electricity is sourced from the grid, then the emissions associated with the feedstock production rise steeply depending on the share of fossil generation in the mix. [11]

10.9. Research and development perspectives

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 syngas without CO, but with H_2 and CO_2 of intermittent availability [4].

Examples of relevant research and development areas are the following:

- Optimizing reactor and catalyst design for feedstocks based on H_2 and CO_2
- Plant design enabling dynamic operation or design of storages enabling constant feed streams
- Realizing synergies with processes such as carbon capture, electrolysis System designs enabling sector coupling (notably utilization of waste heat or oxygen)

10.10. Examples of market-standard technology

There is one commissioned green e-methanol plant in India at NTPC's Vindhyachal Super Thermal Power Station in Madhya Pradesh [12] [13]. Table 10-1 [7] provides information on where, when, and how various other projects are currently applied or intended for methanol production.

Table 10-1: Selected methanol from power production projects. [7].

Country	Company	Start-up year	Capacity (t/y)	Product	Feedstock	Source
Iceland	CRI	2011	4,000	e-methanol (Vulcanol)	Geothermal CO_2 and H_2 from water electrolysis	CRI, 2020
China	Dalian Institute of Chemical Physics	2020	1,000	e-methanol	CO_2 and H_2 from water electrolysis (PV)	AAAS, 2020
Sweden	Liquid Wind	2023	45,000	e-methanol	Upcycled industrial CO_2 and H_2 from water electrolysis	Liquid Wind, 2020
Australia (Tasmania)	ABEL	2023	60,000	e-methanol	Biogenic CO_2 and H_2 from water electrolysis	ABEL Energy, 2020
Norway	Swiss Liquid Future/ Thyssenkrupp	NA	80,000	e-methanol	CO_2 from ferrosilicon plant and H_2 from water electrolysis (hydropower)	Swiss Liquid Future, 2020a, Swiss Liquid Future, 2020b
Norway	Consortium of companies/ CRI	2024	100,000	e-methanol	CO_2 and H_2 from water electrolysis	Stefánsson, 2019
Canada	Renewable Hydrogen Canada (RH_2C)	NA	120,000	e-methanol	CO_2 and H_2 from water electrolysis (hydro)	RH_2C, 2020
Belgium	Consortium at the port of Antwerp	NA	8,000	e-methanol	CO_2 and H_2 from water electrolysis	INOVYN, 2020
Belgium	Consortium at the port of Ghent	NA	46 000-180 000	e-methanol	Industrial CO_2 and H_2 from water electrolysis	aet, 2019

One example of an existing project is presented below.

10.10.1. George Olah Renewable Methanol plant

Carbon Recycling International has installed over 200,000 tonnes per year of methanol production capacity. The George Olah Renewable Methanol plant was the first facility constructed in 2010-2012 in Svartsengi, Iceland. Its construction followed years of development which included the construction of a lab-scale pilot, catalyst testing, chemical synthesis condition studies and fund-raising. This facility represents a significant milestone in the field of carbon capture and utilization as it was the first industrial-scale production facility ever built which utilized carbon dioxide waste gas as a resource for methanol production [14].

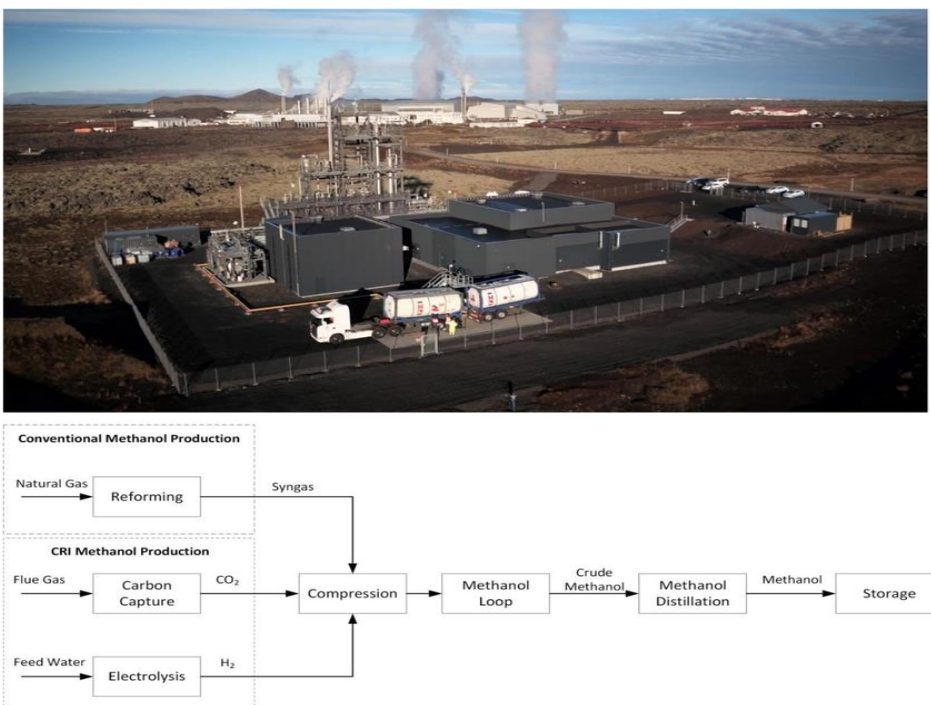

Figure 10-3: George Olah Renewable Methanol plant in Svartsengi, Iceland and block flow diagram [1].

The production unit was developed to capture carbon dioxide from flue gas released by an adjacent geothermal power plant. The carbon dioxide is purified to make it suitable for downstream methanol synthesis. After adequate compression, synthesis gas - composed of hydrogen generated through the electrolysis of water and carbon dioxide - is catalytically reacted to produce methanol. The final purification and water removal processes are achieved through distillation in the last module, utilizing geothermal steam for efficiency.

The production process creates no toxic by-products as the sole chemical released is oxygen following the electrolysis process and treated water from distillation. The company created a standard modular plant design with a larger production capacity of 1300 tonnes per year. Four years after the initial design, due to the modular design and inherent scalability of the technology, the company increased the plant's production capacity to 4000 tonnes per year. This upscaling enables the recycling of 5500 tonnes of carbon dioxide emissions and optimizes the production process to serve the needs of diverse industries [14].

Table 10-2: Specifications of the methanol from power, George Olah Plant. [14].

Parameters	Details
Project Name	George Olah Plant
Project Lead	Carbon Recycling International (CRI)
Geographical Information	Grindavík, Iceland
Commission date	2009-01-10
Investments	6,810,000 € [₹623,115,000 (INR)]
Technological Information	Activities: CCU (Power-to-X) CO_2 Source: Geothermal powerplants H_2 source: electrolyser of H_2O CCU Technology Category: Utilization Info on Utilization: Thermal conversion, Chemical conversion Facility Stage: Operational
CO_2 Capture/Utilization	4500 t/year
Production Volume	5,000,000 litres of methanol/year

10.11. Projection of performance and costs

Due to data scarcity, the given data in the Danish Technology Catalogue [4] was adjusted by inflating it to the cost year 2023 and convert it to INR.

The performance of the hydrogen-to-methanol conversion process is governed by the electricity demand for compression, heat loss in the methanol synthesis, and the heat demand for the distillation process, which are well-known in the field.

The scope of the present chapter and the following datasheet consider system limits as illustrated in figure 4. The H_2 and CO_2 streams are assumed to be supplied at pressure levels above the reactor pressure. The following elements (including installation costs) are included in the CAPEX estimates:

- Methanol reactor including catalyst
- Methanol distillation for achieving grade AA methanol
- Piping between components inside the battery limits (ISBL)
- Electrical cabling on the low voltage side

- SCADA (Supervisory Control and Data Acquisition)
- Methanol tank which is assumed to contain one day's production
- Distillation columns prepared for utilization of district heating (higher temperatures of cooling water)

The following elements are not included:

- H_2 and CO_2 compressors
- Electrical transformers
- High voltage electrical systems
- Fee to DSO for connecting to the electrical grid
- Utility systems: cooling system, steam boiler
- Possible connection to district heating system
- Treatment of purge gases and separated by-products
- Contingencies
- Cost of land
- VAT and taxes
- Owner's costs

The cost estimates provided in the datasheet are based on cost data [9] but adjusted +10 % based on discussions with suppliers of methanol plants. CAPEX is scaled to different plant capacities based on the normal economy scale for chemical process plants. The effects of economy of scale are illustrated in Figure 10-4 where CAPEX is plotted as a function of capacity. The larger the capacity, the smaller the per unit investment costs.

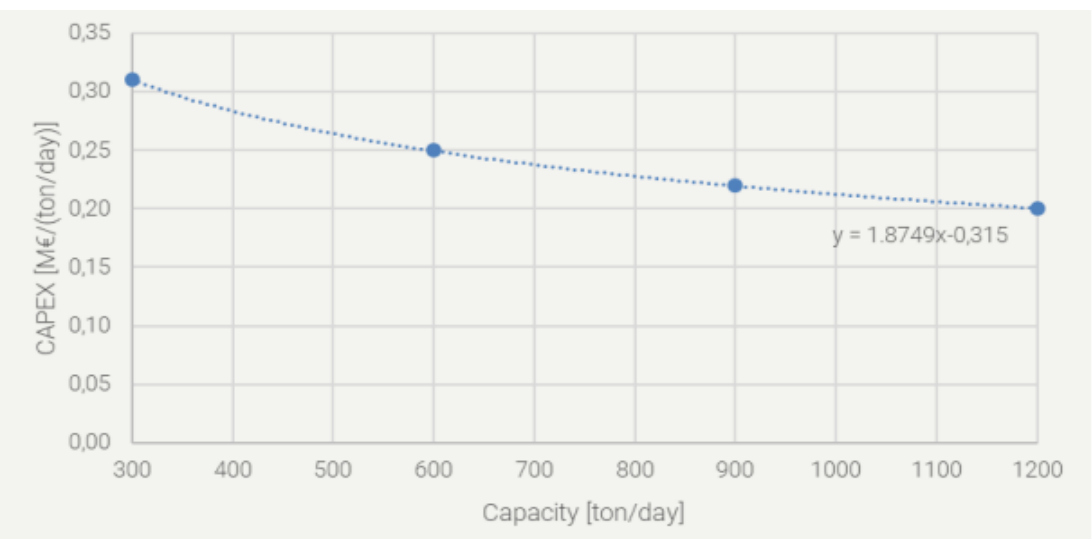

Figure 10-4: CAPEX as a function of capacity. [4]

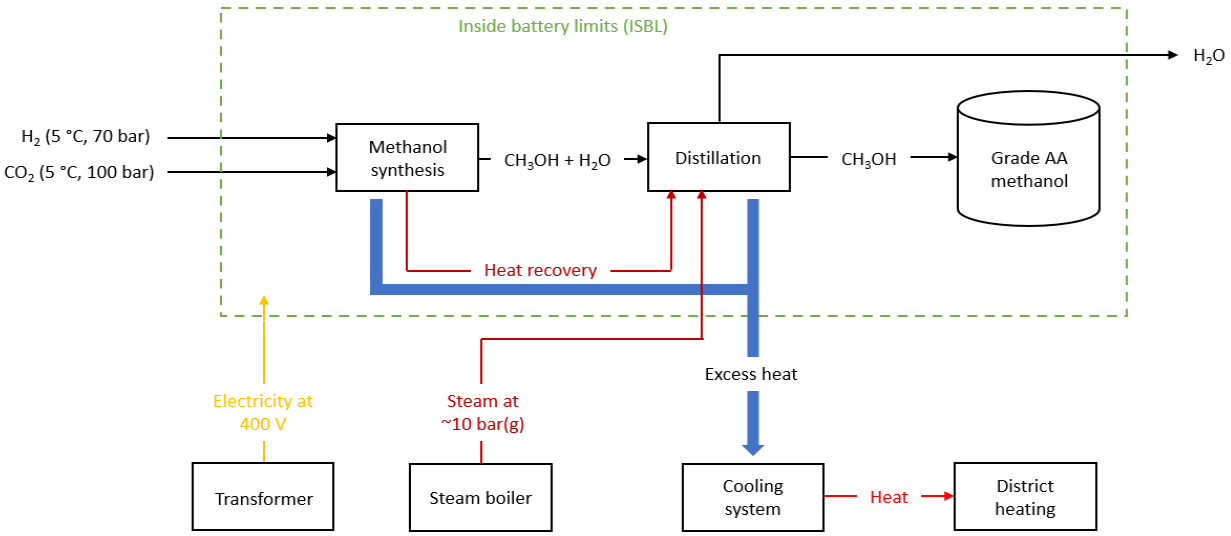

Figure 10-5: Illustration of methanol from power system limits.[4]

The hydrogen to methanol technology has been demonstrated in full commercial scale and is therefore on TRL 9 [4]. The technological maturity is assessed to be in category 4 according to the four levels of technological maturity defined in this Technology Data Catalogue, however the e-methanol process with dynamic operation is still to be demonstrated at scale. 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.

The data for a green methanol plant can be found in the datasheets. 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 1,200 ton/day plant is expected in 2040, it is therefore possible to use cost data for 2050 corresponding to a 1,200 ton/day plant.

10.12. Uncertainty

The uncertainty on the performance estimates is low since methanol reactor and distillation technologies are well-established, but deviations from the stated values are possible, due to different system designs.

The accuracy of the cost figures is expected to be within ±50 % [4].

Where the datasheet does not list uncertainty values, this should not be taken to mean the estimates are certain. Rather, it indicates that the necessary data to quantify the uncertainty is not available.

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10.14. Datasheet

Technology	Power to Methanol									Note	Ref
	2024	2030	2040	2050	2070	Uncertainty (2024)		Uncertainty (2070)			
						Lower	Upper	Lower	Upper		
Energy/technical data											
Typical total plant size 1,000 t Methanol/year	105	210	315	420	420					A, B	1, 2, 3
Typical total plant size, MW	24.15	48.3	72.45	96.6	96.6						2
Inputs											
CO2 Consumption, t/t Methanol	1.51	1.51	1.51	1.51	1.51	1.38	1.51			C	1, 2, 3
Hydrogen Consumption, t/t Methanol	0.19	0.19	0.19	0.19	0.19	0.19	0.19			D	1, 2, 3
Hydrogen [MWh/ton-methanol]	6.4	6.4	6.4	6.4	6.4					E	2
Electricity [MWh/ton-methanol]	0.1	0.1	0.1	0.1	0.1					F	2
Net steam [MWh/ton-methanol]	0.58	0.58	0.58	0.58	0.58					F	2
Outputs											
Methanol Output, MWh/MWh Input	0.665	0.665	0.665	0.665	0.665	0.55	0.78			G	2, 3
District Heating Output, MWh/MWh Total inpu	0.2	0.2	0.2	0.2	0.2					H	2
Forced outage (%)	4	3	3	2	2	1.92	4				1, 2
Planned outage (weeks per year)	3	3	3	3	3	1	3				1, 2
Technical lifetime (years)	25	25	25	25	25	20	30				1, 2, 4
Construction time (years)	2.4	2.4	2.4	2.4	2.4	2	3				1, 2, 4
Financial data (in 2023₹)											
Specific investment (cr. ₹/MW Methanol)	14.37	11.59	10.20	9.27	9.27					I	2
- equipment (%)	77	77	77	77	77	69	85				1, 2
- installation (%)	23	23	23	23	23	15	31				1, 2
Fixed O&M (cr. ₹/MW Methanol/year)	0.42	0.32	0.32	0.28	0.28						2
Variable O&M (INR/MWh)										J	
Start up (cr. ₹/1,000 t Methanol)											
Technology specific data											
Specific energy content (GJ/ton) methanol)	19.9	19.9	19.9	19.9	19.9						2
Specific density (kg/l) or (ton/m3)	0.79	0.79	0.79	0.79	0.79						2
Specific investment (cr. ₹/1,000 t Methanol)	3.31	2.67	2.35	2.13	2.13					K	
- equipment (%)	77	77	77	77	77						1
- installation (%)	23	23	23	23	23						1
Fixed O&M (cr. ₹/1,000 t Methanol)	96.09	74.74	74.74	64.06	64.06						2
Variable O&M (cr. ₹/1,000 t Methanol)										L	
Start up (cr. ₹/1,000 t Methanol)											

Notes

A Announced plants in India have a capacity between 3kt/y and 500 kt/y.

B 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.

C The value is slightly higher than stoichiometric reaction due to the formation of organic by-products

D Calculated based on 2,130 Nm^3-H_2/ton-methanol and 0,09 kg-H_2/Nm^3-H_2

E Converted based on a lower heating value for hydrogen of 33,3 kWh/kg

F 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 Top søe

G Calculated based on a lower heating value for methanol of 19,9 GJ/ton

H The District Heating Output for power-to-methanol (PtM) technology varies based on the system design and efficiency. Typical values range between 0.1 to 0.4 MWh of district heating per MWh of total energy input. For precise metrics, detailed studies and specific project reports should be consulted.

I 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.
J Highly depended on local electricity prices (especially important for hydrogen production)
K Point estimate is calculated based on specific investment (cr. ₹/MW Methanol) and plant size
L Highly depended on local electricity prices (especially important for hydrogen production)

References

1 Indian stakeholder
2 Technology Data for Renewable Fuels, Danish Energy Agency, 2023: https://ens.dk/en/analyses-and-statistics/technology-data-renewable-fuels
3 IRENA: Innovation Outlook - Renewable Methanol, 2021, https://www.irena.org/publications/2021/Jan/Innovation-Outlook-Renewable-Methanol
4 Shi et al.: Methanol production from water electrolysis and tri-reforming: Process design and technical-economic analysis, 2020, https://doi.org/10.1016/j.jcou.2019.12.022

I. Appendix. Cost Projections Methodology

This section replicates the structure used in the Appendix of the Colombian Technology Catalogue [1], adapting its contents to these Technology Catalogues.

Historic data shows that the cost of most technologies have decreased over time. It can be expected that further cost reductions and improvements of performance will also be realized in the future. Such trends are important to consider for future energy planning and therefore need to be considered in the technology catalogue.

To estimate the trend of each technology, four different approaches to projecting costs are often applied:

1. Engineering bottom-up assessment:
    a. Detailed bottom-up assessment of how technology costs may be reduced through concrete measures, such as new materials, larger-scale fabrication, smarter manufacturing, module production etc. Costs are also influenced by the asset size, i.e. by the development of design parameters over time; for instance, how the design of a wind turbine is expected to evolve over time.
2. Delphi-survey:
    a. Survey among a very large group of international experts, exploring how they see costs developing and the major drivers for cost-reduction.
3. Learning curves:
    a. Projections based on historic trends in cost reductions combined with estimates of future deployment of the technology. Learning curves express the idea that each time a unit of a particular technology is produced, some learning accumulates which leads to cheaper production of the next unit of that technology.
4. Literature review:
    a. Aggregating previously published projections to create a metaprojection, based on the premise that combining individual predictions can enhance overall accuracy. The variety of literature values allows to derive low, median and high estimates.

Each of the four approaches comes with advantages and disadvantages, which are summarized in Table I-1.

Table I-1: Advantages and Disadvantages of possible approaches to cost projections.

	Advantages	Disadvantages
Engineering bottom-up	• Gives a good understanding of underlying cost-drivers. • Provides insight into how costs may be reduced.	• Requires information at a very detailed level. • Difficult to obtain objective (non-biased) information from the experts, who possess the best knowledge of a technology. • Potentially very time consuming.

Delphi-survey	• Input from a large number of experts improves robustness of forecast.	• Costly and time-consuming to carry out surveys. • Challenge to identify relevant and unbiased experts.
Learning curves	• Large number of studies have examined learning rates and documented that learning rates correlations are real. • The overarching logic of learning rates has proved correct for many technologies and sectors. • Data available to perform learning curves for most important renewable technologies, e.g. wind and solar.	• Does not explain why cost reductions take place. • One-factor learning rates are usually adopted, but in practice cost drivers included in the learning curves follow different developments. Multi-factor learning rates potentially make up for this issue, but they are difficult and time-consuming to obtain. • The theory assumes that each technology makes up an independent technology complex, but in practice there may be a significant overlap between different technologies, which makes the interpretation and use of learning curves more complicated. • Forecasting based on learning curves depend on the deployment level of the single technology, which is uncertain in the future.
Literature review	• Uses a wide range of data from multiple sources which can be used as low, median, high estimates. • Captures recent trends by focusing on up-to-date publications • Enables comparison of projections across different studies. • Supports transparent methodology by referencing specific publications. • Leverages peer-reviewed and industry-recognized sources.	• Definitions of key parameters (e.g., dollar year, lifetime) are often unclear or inconsistent across sources. • Requires interpretation of ambiguous or undefined values. • Some projections are based on or influenced by others, leading to potential bias or circular reasoning. • Difficult to determine appropriate weighting of projections, especially in rapidly evolving markets like batteries. • Limited real-world data may reduce the accuracy or reliability of projections.

For the purpose of the present catalogue, the literature review [2] is the most suitable way forward in combination with consultation of relevant companies within the sector where possible and public hearings.

While Delphi surveys are too costly and time-consuming, bottom-up engineering requires information at a very detailed level, which is outside the scope of this study.

Literature review

The literature review includes both international and Indian studies relevant to the technology, with the objective of compiling a comprehensive dataset of cost projections. All cost figures extracted from the literature were converted to Indian Rupee and adjusted to a uniform cost year—2023—enabling consistent comparison across studies.

While international studies were included to provide broader context and comparative insights, the projections prioritized Indian data to ensure relevance to the local context. International data were integrated to supplement domestic sources, particularly in cases where Indian data were limited or unavailable. For certain technologies with scarce Indian data, only estimates from international sources such as the Danish Technology Catalogue on Energy Renewable Fuels [3] are utilized.

Uncertainty ranges were established based on the minimum and maximum values reported in the included studies. Outliers were excluded to maintain robustness. The point estimate for each cost item was either calculated as the mean of the defined uncertainty range or with a greater weight assigned to Indian data when possible to reflect the local cost environment more accurately.

Global and regional learning

The learning effects found in this review express a global view on technology learning. Considering that the majority of technology providers today are global players this seems to be a reasonable assumption. Therefore, cost reductions generated in one part of the world will easily spread to the other regions.

The literature review based projections are combining both international and Indian data sources.

References

[1] MME, UPME, DEA & Emergente, “Colombian Technology Catalogue for Power Generation and Storage Technologies 2025,” 2025. [Online]. Available: https://ens.dk/en/global-coorporation/energy-partnerships/colombia

[2] W. Cole and A. Karmakar, “Cost Projections for Utility-Scale Battery Storage: 2023 Update,” 2023. [Online]. Available: https://docs.nrel.gov/docs/fy23osti/85332.pdf

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