TECHNOLOGY DATA

Energy transport

Technology descriptions and projections for long-term energy system planning.

Danish Energy Agency

Technology Data - Energy transport

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Amendment sheet

Publication date

Publication date for this catalogue "Technology Data for Energy Transport" is December 2017. Hereby the catalogue can be updated continuously as technologies evolve, if the data changes significantly or if errors are found.

The newest version of the catalogue will always be available from the Danish Energy Agency's web site.

Amendments after publication date

All updates made after the publication date will be listed in the amendment sheet below.

Date	Ref.	Description
July 2025	111	Major update and new description of the chapter, adding quantitative data for transmission level. Data for distribution level remains the same as before
Feb 2025	113	Updated chapter and datasheets. Datasheet for rural and LTDH removed
April 2024	Guideline/cover	Updated guideline in terms of scenario projection reference, price year, and further minor updates / new cover
Nov 2021	121-123 now 421-423	Removal of chapters on CO2 transport including Introduction to the topic and transfer into the new Technology Catalogue for Carbon Capture, Transport and Storage
Mar 2021	131-133	Addition of chapters on transport of gases and liquids including introduction to the topic
Nov 2020	121-123	Addition of chapters on CO2 transport including Introduction to the topic

Preface

The *Danish Energy Agency* publishes catalogues containing data on technologies for energy transport. This is the first edition of the catalogue. This catalogue includes data on of a number of technologies which replace previous chapters published in the catalogue for individual heating and energy transport. The intention is that all energy transport technologies from previous catalogues will be updated and represented in this catalogue. Also the catalogue will continuously be updated as technologies evolve, if data change significantly or if errors are found. All updates will be listed in the amendment sheet on the previous page and in connection with the relevant chapters, and it will always be possible to find the most recently updated version on the Danish Energy Agency's website.

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.

Finally, the catalogue is meant for international as well as Danish audiences in an attempt to support and contribute to similar initiatives aimed at forming a public and concerted knowledge base for international analyses and negotiations.

Danish preface

Energistyrelsen udarbejder teknologibeskrivelser for en række teknologier til brug for transport af energi. Dette er den første udgave af dette katalog. Dette nuværende katalog indeholder data for en stor del af teknologibeskrivelserne, som erstatter de tidligere udgivne kapitler i kataloget for individuel opvarmning go energitransport. Det er hensigten, at alle teknologibeskrivelserne fra det tidligere kataloger som omhandler energitransport, skal opdateres og integreres her. Desuden vil kataloget løbende opdateres i takt med at teknologierne udvikler sig, hvis data ændrer sig væsentligt eller hvis der findes fejl. Alle opdateringer vil registreres i rettelsesbladet først i kataloget, og det vil altid være muligt at finde den seneste opdaterede version på Energistyrelsens hjemmeside.

Hovedformålet med teknologikataloget er at sikre et ensartet, alment accepteret og aktuelt grundlag for planlægningsarbejde og vurderinger af forsyningssikkerhed, beredskab, miljø og markedsudvikling hos bl.a. de systemansvarlige selskaber, universiteterne, rådgivere og Energistyrelsen. Dette omfatter for eksempel fremskrivninger, scenarieanalyser og teknisk-økonomiske analyser.

Desuden er teknologikataloget et nyttigt redskab til at vurdere udviklingsmulighederne for energisektorens mange teknologier til brug for tilrettelæggelsen af støtteprogrammer for energiforskning og -udvikling. Tilsvarende afspejler kataloget resultaterne af den energirelaterede forskning og udvikling. Også behovet for planlægning og vurdering af klima-projekter har aktualiseret nødvendigheden af et opdateret databeredskab.

Endeligt kan teknologikataloget anvendes i såvel nordisk som internationalt perspektiv. Det kan derudover bruges som et led i en systematisk international vidensopbygning og -udveksling, ligesom kataloget kan benyttes som dansk udspil til teknologiske forudsætninger for internationale analyser og forhandlinger. Af disse grunde er kataloget udarbejdet på engelsk.

Index

Guideline/Introduction

This catalogue presents data for energy transport technologies. Focus is on the existing main systems in Denmark where energy is transported in a geographically widespread network infrastructure. The following energy transport systems (corresponding to the energy carriers) are treated in the catalogue:

- Natural gas, including upgraded biogas
- District heating
- Electricity

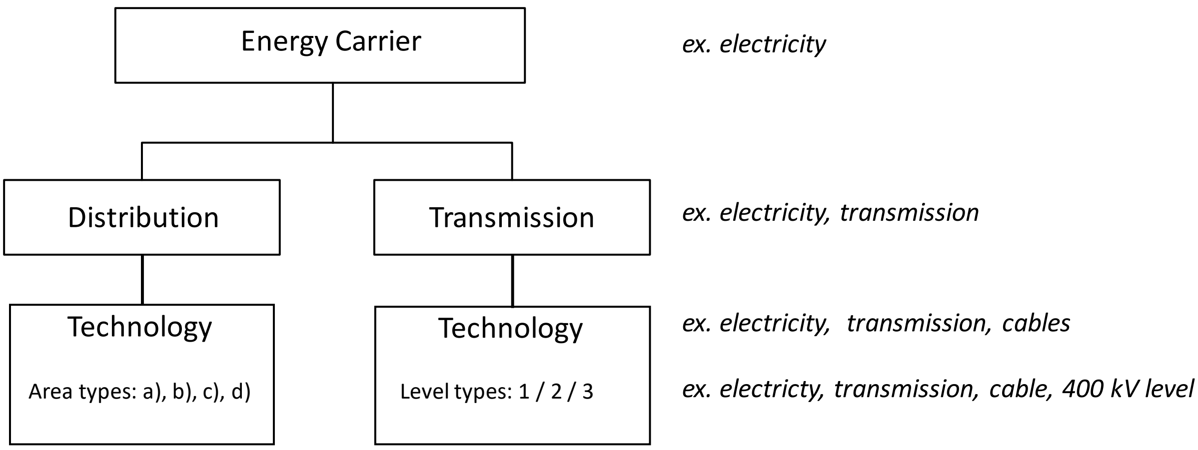
Other energy transport systems such as networks for hydrogen, biogas etc. as well as road and sea transport of liquid and solid fuels are not included. Energy storage installations in the respective systems are treated in a separate catalogue on energy storage. The catalogue does not contain prices for the energy itself.

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.

These guidelines serve as an introduction to the presentations of the different technologies in the catalogue, and as instructions for the authors of the technology chapters. The general assumptions are described in section 1.1. The following sections (1.2 and 1.3) explain the formats of the technology chapters, how data were obtained, and which assumptions they are based on. Each technology is subsequently described in a separate technology 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.

General terminology and definitions

The description of energy transport technologies follows a hierarchic terminology to cover the relevant options and variants. The following diagram summarizes the hierarchy followed in the development of the catalogue and the categorization of technologies.



With a view to cross-technology comparisons, a general separation between transmission and distribution systems is maintained throughout the catalogue, as defined below. Thus, an entire energy transport system for a specific energy carrier may consist of a combination of transmission technologies and distribution ones.

Definitions of different components, stations, distribution and transmission systems, as well as some general assumptions follows:

Components:

Single line is defined as a transmission or distribution cable/pipe etc. connecting two points in the network. It has a certain capacity for energy transport, an energy loss, and certain unit costs. For district heating it comprises both the forward and return pipes.

A service line is the connection from the distribution network to each consumer's point of connection. It is assumed to be buried. It usually includes a switch/valve and a metering device at the connection point.

A distribution network is defined as a complete distribution system covering an area, including distribution lines, service lines, and necessary stations.

Two types of stations and substations are considered in this catalogue:

Station Type 1: this category includes all those stations that perform a transformation of the characteristics of the energy carrier (e.g. voltage, pressure, etc.) in correspondence to a change of level or from transmission to distribution.

Examples of these are power transformers or heat exchangers in district heating networks.

Station Type 2: this category includes those stations and equipment needed to provide a certain supply quality or to maintain the characteristics of the energy carrier.

Examples of this type are pumping stations or capacitor banks for reactive power compensation.

Other main components of an energy carrier system can be included as well, where relevant.

Interfaces:

The interfaces for the transport technologies towards other parts of the energy systems are, in general:

Upstream: The energy as delivered from the producer at the connection point. The infrastructure between the plant (power plant, gas processing plant, district heating plant, etc.) and the connection point, including equipment installed at the connection point is included in the plant cost and dealt with in the *Technology Catalogue for Electricity and District Heating Plants*.

Downstream: The energy as delivered to the consumer. Service line and metering equipment at the point of connection are included in transport system costs.

The necessary equipment for transforming and converting the energy carrier's properties on its way through the transport system, (e.g. pressure, voltage, temperature, etc.) and for powering the transport processes (pumps, compressors, etc.) are included, where relevant.

Transmission system, levels and stations:

A transmission system is defined as the network that connects the main energy producers, storage installations, etc. with the distribution networks, so that a transmission network supplies the energy to one or more distribution networks. Usually there are no consumers connected directly to the transmission network, except for very large users or groups of users.

Substations located at points of interface to the distribution networks are included in the transmission system (transformer stations, heat exchangers, etc.). Similarly, substations connecting different levels of transmission belong to the higher level.

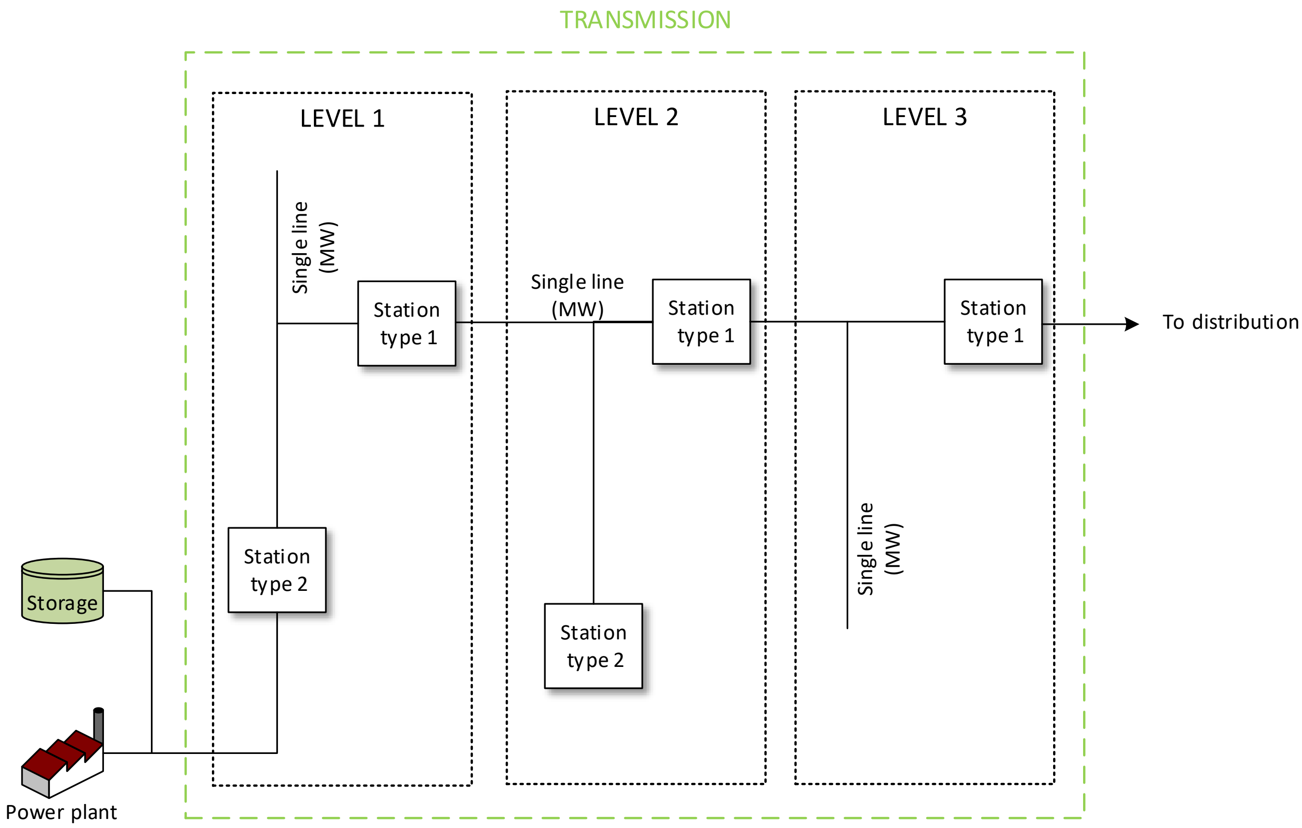
For each of the transmission technologies a number of levels are defined corresponding to the relevant voltage, pressure, or temperature levels. Separate data sheets are provided for each transmission level. For some technologies only one level is relevant.

Transmission, [technology]	**Level**		
	1	**2**	**3**
Natural Gas	80 bar	16 – 40 bar	
Electricity, overhead lines	400 kV	132 / 150 kV	50 / 60 kV
Electricity, cables	400 kV	132 / 150 kV	50 / 60 kV
District heating	< 110 deg. C	<80 deg. C	

Furthermore, a number of different station types may be relevant for a certain technology and level:

Transmission	**Stations [type 1] (level change)**	**Stations [type 2] (auxiliary service)**
Natural Gas	- M/R station (pressure release) - Compressor	
Electricity, overhead lines	Transformer station / substation	Compensation
Electricity, cables	Transformer station / Substation	Compensation
District heating	Heat exchanger transmission/distribution	Pumping station

The following figure displays the transmission system specifying its boundaries, different levels, components and stations.



Distribution system, area types and stations:

A distribution system is defined as the network of lines that supplies energy to the consumers in a delimited area. Energy is fed into the system from either transmission networks and/or directly from one or more energy producers. The substations connecting the distribution system to the transmission system are defined to be part of the transmission systems. Other substations internally in the distribution grid are included, including pump stations, regulator stations, transformer stations, valves, etc. The service lines to consumers are also part of the distribution systems.

In this catalogue, energy distribution sub-systems are characterized by their energy consumption density, describing the yearly energy consumption per unit of area (MWh/ha or km^2). This density will highly influence the investment cost and, for some energy forms, also the operating costs and losses. In a relatively densely populated area the lengths of lines per unit consumption will be shorter, but on the other hand, the unit installation cost per unit length of distribution line is usually also higher due to more difficult burial work, traffic regulation, etc. For a simplification of this approach four different area types have been defined.

It has to be underlined that this categorization refers to commercial and/or residential areas only, while industrial areas are excluded due to the very diverse nature of consumption depending on the type of industry. Instead, the connection of a specific industry to the distribution grid can be modelled by using single components such as service lines.

The four types of areas defined are the following:

a) **New developed areas**
This reflects a situation where a new area is built and the installation of energy distribution systems is coordinated with the overall construction plan, which lowers the investment costs. The specific energy consumption corresponds to requirements in present and future building codes, i.e. a relatively low energy consumption density for heat, but not necessarily for electric power since heat pumps may be a preferred heating option.

b) **New distribution in existing sparsely populated rural areas, villages, etc.**
In this situation a new energy distribution system is rolled out to an existing area with low energy consumption density.

c) **New distribution in existing medium populated areas, suburban, etc.**
In this situation a new energy distribution system is rolled out to an existing area with medium energy consumption density.

d) **New distribution in existing densely populated areas, city centers, etc.**
In this situation a new energy distribution system is rolled out to an existing area with high energy consumption density.

It is assumed that all relevant consumers are connected.

Separate data sheets are provided for each area type.

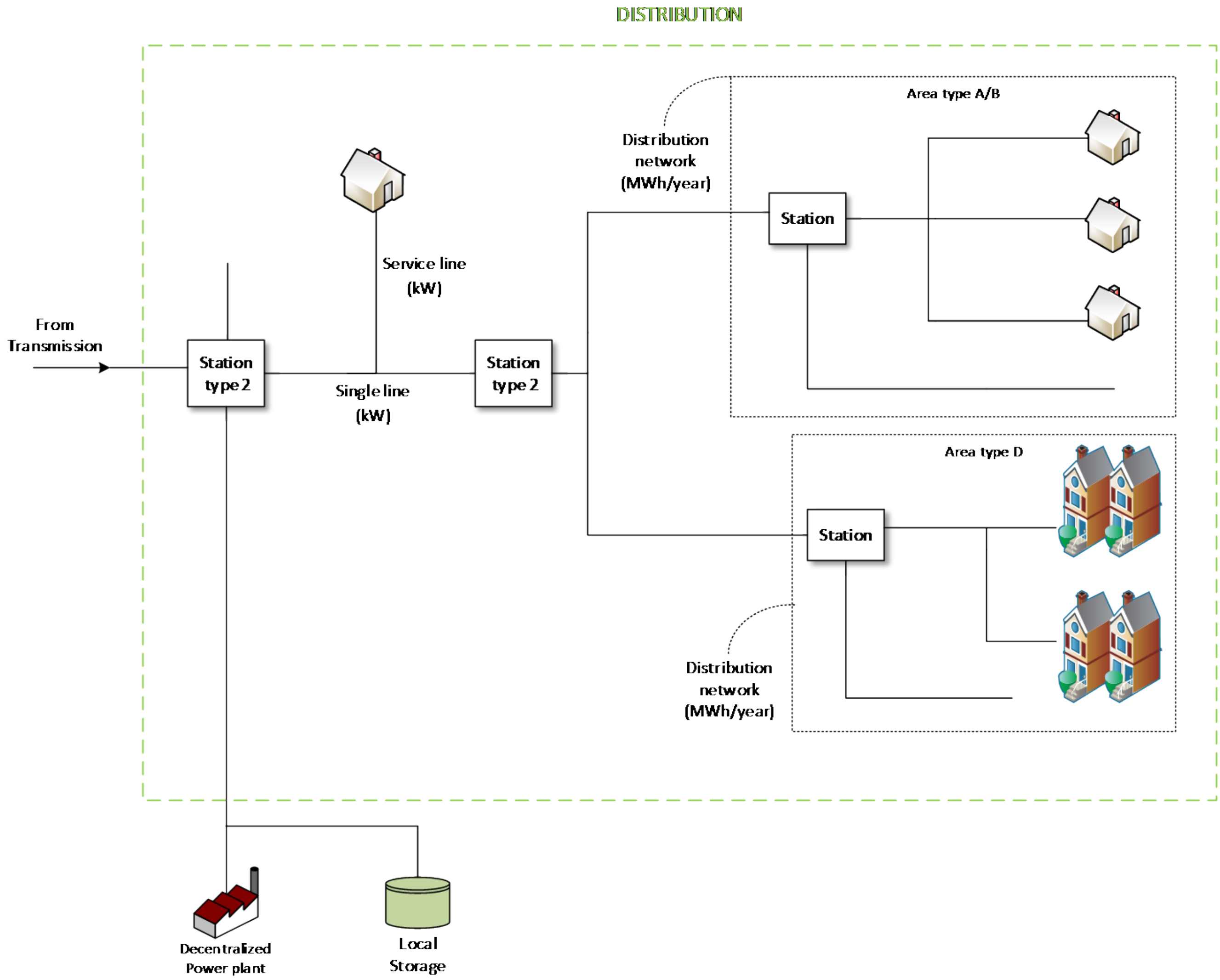
For a certain distribution technology, a number of different station types may be relevant:

Distribution	Stations [type 1] (level change)	Stations [type 2] (auxiliary service)
Natural Gas	D/R station	
Electricity, overhead lines	Transformer / substation	
Electricity, cables	Transformer / substation	
District heating	Heat exchanger station	Pump station
District heating, low temperature	Heat exchanger station	Pump station

The following figure displays the distribution system specifying its boundaries, different area types, components and stations.

As indicated, a distribution system can be composed of several distribution networks of different area types, each containing the necessary distribution lines, stations and service lines. Apart from that, the distribution system can also include individual single lines, service lines and stations outside the defined areas.

For this reason, the quantitative description includes data for both the networks defined by area type and the individual components.



General notes

The unit MW/MWh (or kW and kWh) is used in general for energy and power, though not directly convertible between the energy forms.

For natural gas, a lower calorific value of 39.6 MJ/Nm^3 or 0.011 MWh/Nm^3 is used for conversion.

Overview of the technologies

Different technologies for transmission and distribution networks are considered and each can be applied to a different transmission level (1, 2, 3) or different distribution area types (a, b, c, d).

An overview of the technologies considered is shown below.

Transmission technologies	Distribution technologies
• Natural gas, 80 bar • Natural gas, 40-16 bar • Electricity, overhead lines, 400 kV • Electricity, overhead lines, 132/150 kV • Electricity, overhead lines, 50/60 kV • Electricity, cables, 400 kV • Electricity, cables, 132/150 kV • Electricity, cables, 50/60 kV • Electricity, HVDC, 400 kV • Electricity, HVDC sea cable, 250-400 kV • Electricity, HVAC sea cable, 400 kV • Electricity, HVAC sea cable, 132/150 kV • Electricity, HVAC sea cable, 50/60 kV • District heating, < 110 deg. C / 25 bar • District heating, < 80 deg. C	• Natural gas, area type a) • Natural gas, area type b) • Natural gas, area type c) • Natural gas, area type d) • Electricity, cables, area type a) • Electricity, cables, area type b) • Electricity, cables, area type c) • Electricity, cables, area type d) • District heating, area type a) • District heating low temp., area type a)[1] • District heating, area type b) • District heating, area type c) • District heating, area type d)

Each energy carrier (electricity, gas and district heating) is represented by one qualitative description as explained in Section 1.2, but not all sub-technologies have individual datasheets or qualitative descriptions. Where relevant, specific information is given for each technology for an energy carrier. Several tables with quantitative data are included for each carrier, representing the different levels and areas. These are based on two different templates: one for transmission and one for distribution. The content of the templates is described in Section 1.3.

1.2. Qualitative description

The qualitative description covers the key characteristics of the technology as concise as possible. The following paragraphs are included where relevant for the technology.

[1] Concerning new developed areas, district heating will consist of two separate data sheets. One for conventional district heating and one for low temperature district heating

Contact information

Containing the following information:

- Contact information: Contact details in case the reader has clarifying questions to the technology chapters. This could be the Danish Energy Agency, Energinet.dk or the author of the technology chapters.
- Author: Entity/person responsible for preparing the technology chapters
- Reviewer: Entity/person responsible for reviewing the technology chapters.

Brief technology description

Brief description for non-engineers of how the technology works and for which purpose.

An illustration of the technology is included, showing the main components and working principles.

Input

The main properties and sources of the energy input in the transport system, and description of the typical interface(s) at input points.

Output

The main properties of the energy at the point of connection to the consumer and the characteristic use of the energy.

Energy balance

The energy balance shows the energy inputs and outputs for the technology. This should also show the energy losses (e.g. heat losses) and the input of auxiliary energy (e.g. electricity for pumping) in the transmission and distribution lines and stations.

Description of transmission system

A description of the transmission systems, including lines, relevant stations for conversion, and auxiliary systems is given here. This includes a description of the relevant technical equipment and various properties of the energy carriers at the different transmission levels, e.g. pressure, temperature, or voltage levels. Thus, the total transmission system may consist of sub-system networks at different transmission levels, with each their properties and characteristics. The main properties and characteristics, including dimensioning criteria and limitations for use are mentioned. The most important installation methods are described, as well as the most important operation and maintenance work.

Description of distribution system

The section contains a description of the distribution system, including a description of the relevant technical equipment and various properties of the energy carriers at the distribution level (e.g. pressure, temperature, and voltage levels), the relevant substation types, and the service line connections to the consumers. In addition, the most important installation methods are described, as well as the most important operation and maintenance work.

Space requirement

Space requirement is specified in 1000 m2 per MW per m. 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 installation.

Advantages/disadvantages

A description of specific advantages and disadvantages relative to equivalent technologies. Specific subgroups of technologies can be compared as well (e.g. HVDC vs. HVAC, overhead lines vs. cables, high temperature vs. low temperature DH).

Environment

Particular environmental characteristics are mentioned, for example visual or noise impacts, specific risks in case of leakages and the main ecological footprints.

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 if possible. Danish research and development perspectives are highlighted, where relevant.

Examples of market standard technology

Recent full-scale commercial projects, 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 yet been established, reference is made to best available technology in R&D projects.

Prediction 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 the first technology year (base year) as well as the improvements assumed for future years.

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

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

Data for the base year

In case of technologies where market standards have been established, performance and cost data of recent installed versions of the technology in Denmark or the most similar countries in relation to the specific technology in Northern Europe are used for the base year estimates.

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

Assumptions for projecting costs into future years

According to the IEA:

"*Innovation theory describes technological innovation through two approaches: the technology-push model, in which new technologies evolve and push themselves into the marketplace; and the market-pull model, in which a market opportunity leads to investment in R&D and, eventually, to an innovation*" (ref. 6).

The level of "market-pull" is to a high degree dependent on the global climate and energy policies. Hence, in a future with strong climate policies, demand for e.g. renewable energy technologies will be higher, whereby innovation is expected to take place faster than in a situation with less ambitious policies. This is expected to lead to both more efficient technologies, as well as cost reductions due to economy of scale effects. Therefore, for technologies where large cost reductions are expected, it is important to account for assumptions about global future demand.

The **IEA's Announced Pledges Scenario (APS)** is used as a central estimate for projections in the Technology Catalogue, whenever possible. The IEA describes the Announced Pledges Scenario in their 2022 version as follows:

"The Announced Pledges Scenario introduced in 2021 aims to show to what extent the announced ambitions and targets, including the most recent ones, are on the path to deliver emissions reductions required to achieve net zero emissions by 2050. It includes all recent major national announcements as of September 2022 for 2030 targets and longer term net zero and other pledges, regardless of whether these have been anchored in implementing legislation or in updated NDCs. In the APS, countries fully implement their national targets to 2030 and 2050, and the outlook for exporters of fossil fuels and low emissions fuels like hydrogen is shaped by what full implementation means for global demand. […] Non-policy assumptions, including population and economic growth, are the same as in the STEPS."

According to the IEA, the less ambitious **Stated Policies Scenario (STEPS)** *"provides a more conservative benchmark for the future, because it does not take it for granted that governments will reach all announced goals. Instead, it takes a more granular, sector-by-sector look at what has actually been put in place to reach these and other energy-related objectives, taking account not just of existing policies and measures but also of those that are under development. The STEPS explores where the energy system might go without a major additional steer from policy makers."*

The STEPS Scenario may be used as an upper bound and to assess the expected development of technologies based on a frozen-policy approach. Previous versions of the Technology Catalogue before updating the guideline in april 2024 have used the outdated New Policies Scenario, relatively equivalent to the current STEPS, as a central framework for projections (and supplemented by other outdated scenarios of the IEA). This scenario corresponds to the frozen-policy approach that the Danish Energy Agency uses to project international fuel prices and CO_2-prices and technologies may be assessed in that regard when suitable.

Technologies updated before this cutoff date and which do not contain any explicit methodological description within the chapter regarding alternative supplementary scenarios have been updated based in this previous methodology.

As a more ambitious projection, the **Net Zero Emissions by 2050 Scenario (NZE)** may be used as a lower bound for the technology development. According to the IEA, the NZE *"is a normative IEA scenario that shows a pathway for the global energy sector to achieve net zero CO2 emissions by 2050, with advanced economies reaching net zero emissions in advance of others. This scenario also meets key energy-related United Nations Sustainable Development Goals (SDGs), in particular by achieving universal energy access by 2030 and major improvements in air quality. It is consistent with limiting the global temperature rise to 1.5 °C with no or limited temperature overshoot (with a 50% probability), in line with reductions assessed in the IPCC in its Sixth Assessment Report."*

By using this approach, the quantitative data in the Technology Catalogue provides a sample space that is consistent with the IEA's Global Energy and Climate Model, encompassing relevant outcomes for policy assessments of technologies as well as technology developments in compliance with national targets, and international treaties.

- *Learning curves and technological maturity*

Predicting the future costs of technologies may be done by applying a cost decomposition strategy, as mentioned above, decomposing the costs of the technology into categories such as labor, materials, etc. for which predictions already exist. Alternatively, the development could be predicted using learning curves. Learning curves express the idea that each time a unit of a particular technology is produced, learning accumulates, which leads to cheaper production of the next unit of that technology. The learning rates also take into account benefits from economy of scale and benefits related to using automated production processes at high production volumes.

The potential for improving technologies is linked to the level of technological maturity. The technologies are categorized within one of the following four levels of technological maturity.

Category 1. Technologies that are still in the *research and development phase*. The uncertainty related to price and performance today and in the future is highly significant (e.g. wave energy converters, solid oxide fuel cells).

Category 2. Technologies in the *pioneer phase*. The technology has been proven to work through demonstration facilities or semi-commercial plants. Due to the limited application, the price and performance is still attached with high uncertainty, since development and customization is still needed. The technology still has a significant development potential (e.g. gasification of biomass).

Category 3. *Commercial technologies with moderate deployment*. The price and performance of the technology today is well known. These technologies are deemed to have a certain development potential and therefore there is a considerable level of uncertainty related to future price and performance (e.g. offshore wind turbines)

Category 4. *Commercial technologies, with large deployment*. The price and performance of the technology today is well known and normally only incremental improvements would be expected. Therefore, the future price and performance may also be projected with a relatively high level of certainty. (e.g. coal power, gas turbine)

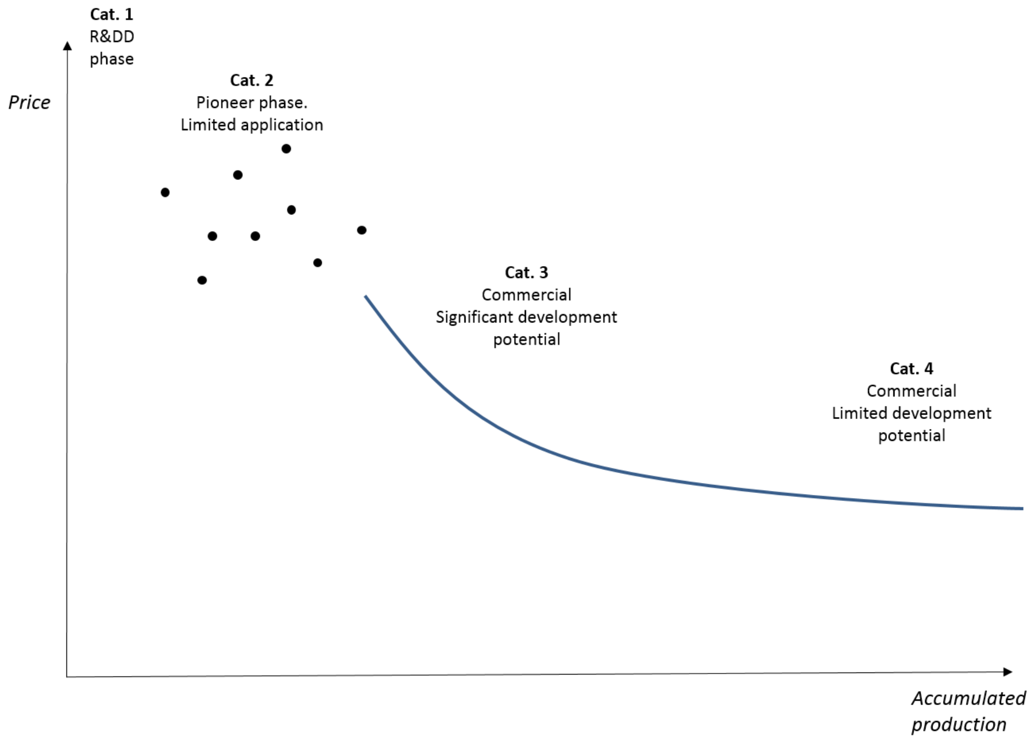


Figure 1: Technological development phases. Correlation between accumulated production volume (MW) and price.

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.

This section of the technology chapters explains the main challenges to precision of the data and identifies the areas on which 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.

The level of uncertainty is illustrated by providing a lower and higher bound beside the central estimate, which shall be interpreted as representing probabilities corresponding to a 90% confidence interval whenever possible. 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 (category 1 and 2) and longtime horizons (2050).

Additional remarks

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

References

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

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 real prices excluding value added taxes (VAT) and other taxes. The information given in the tables relate to the development status of the technology at the point of final investment decision (FID) in the given year (2015, 2020, 2025, 2030, 2023, 2040 and 2050 where applicable). 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 after permits have been received.

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 made to allow for easy comparison of technologies. 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 the base year and final year.

The level of uncertainty is illustrated by providing a lower and higher bound. These are chosen to reflect the uncertainties of the best projections by the authors. The section on uncertainty in the qualitative description for each technology indicates the main issues influencing the uncertainty related to the specific technology. For technologies in the early stages of technological development or technologies especially prone to variations of cost and performance data, the bounds expressing the confidence interval could result in large intervals. The uncertainty only applies to the market standard technology; in other words, the uncertainty interval does not represent the product range (for example a product with lower efficiency at a lower price or vice versa).

The level of uncertainty is stated for the most critical figures such as investment cost and energy losses. Other figures are considered if relevant. If a certain value in the data sheet has the value zero, this is stated as "0". If the value is not relevant the field is left blank. All data in the tables are referenced by a number in the utmost right column (Ref), referring to source specifics below the table. The following separators are used:

; (semicolon)	separation between the time horizons (2015, 2020, etc.)
/ (forward slash)	separation between sources with different data
+ (plus)	agreement between sources on same data

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

The datasheets for energy distribution technologies and energy transmission technologies are presented below:

General data sheet – Distribution technologies

[one data sheet per area type, if relevant; technology years may be updated and extended]

Technology	Energy Transport [Technology] Distribution, [area type sub-division]									
	2020[1]	2025[1]	2030[1]	2050[1]	Uncertainty (2020[1])		Uncertainty (2050[1])		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy losses, lines (%)										
Energy losses, stations (%)										
Auxiliary electricity consumption (% of energy delivered)										
Technical life time (years)										
Typical load factor (unitless ratio)										
- Residential										
- Commercial										
Construction time (years)										
Financial data										
Investment costs										
Distribution network costs (EUR/MWh/year) **[Area type]**									A	
Service line costs, 0 - 20 kW (Eur/unit)										
Service line costs, 20 - 50 kW (Eur/unit)										
Service line costs, 50-100 kW (Eur/unit)										

Service line costs, above 100 kW (Eur/unit)										
Single line costs, 0-50 kW (EUR/m)										
Single line costs, 50-250 kW (EUR/m)										
Single line costs, 100-250 kW (EUR/m)										
Single line costs, 250 kW - 1 MW (EUR/m)										
Single line costs, 1 MW - 5 MW (EUR/m)										
Single line costs, 5 MW - 25 MW (EUR/m)										
Single line costs, 25 MW - 100 MW (EUR/m)										
Reinforcement costs (Eur/MW)										
[type 1] station (EUR/MW)										
[type 2] station (EUR/MW)										
Investments, percentage installation (%)										
Investments, percentage materials (%)										
Operation and maintenance costs										
Fixed O&M (EUR/MW/year)										
Variable O&M (EUR/MWh)										
Technology specific data										

Notes

A: Distribution network costs include the necessary distribution lines, service lines and stations to supply an area.

[1]Technology years may be updated from this shown example and extended

General Data Sheet – Transmission technologies

[one data sheet per level type, if relevant; technology years may be updated and extended]

Technology	Energy Transport [Technology] Transmission, [level type]									
	2020[1]	2025[1]	2030[1]	2050[1]	Uncertainty (2020[1])		Uncertainty (2050[1])		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy losses, lines 1-20 MW (%)										
Energy losses, lines 20-100 MW (%)										
Energy losses, lines above 100 MW (%)										
Energy losses, stations [Type 1] (%)										
Energy losses, stations [Type 2] (%)										
Auxiliary electricity consumption (% energy transmitted)										
Technical life time (years)										
Typical load factor (unitless ratio)										
Construction time (years)										

Financial data										
Investment costs										
Single line costs, 0 - 50 MW (EUR/MW/m)										
Single line costs, 50-100 MW (EUR/MW/m)										
Single line costs, 100 - 250 MW (EUR/MW/m)										
Single line costs, 250-500 MW (EUR/MW/m)										
Single line costs, 500-1000 MW (EUR/MW/m)										
Single line costs, above 1000 MW (EUR/MW/m)										
Reinforcement costs (Eur/MW)										
[type 1] station (EUR/MW)										
[type 2] station (EUR/MW)										
Investments, percentage installation (%)										
Investments, percentage materials (%)										
Operation and maintenance costs										
Fixed O&M (EUR/MW/km/year)										
Variable O&M (EUR/MWh/km)										
Technology specific data										

Notes

[1]***Technology years may be updated from this shown example and extended***

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Energy/technical data

Each transmission technology data sheet includes the technology name and the level type in the header.

Each distribution technology data sheet includes the technology name and the area type in the header.

Energy losses

The losses in energy transport systems are given in percent of the energy delivered to the system, as an average over a normal (or average) year for the relevant area type (e.g. an energy loss of 50% means that half the energy fed into the system during a normal year is lost). These general values are based on experience and express typical values for representative new distribution and transmission systems. The uncertainty values indicate estimated variances from average systems, with a confidence interval of 90%.

For distribution systems, the losses are divided into line losses and single station losses. The former represents an average for the total length of network lines including service lines. Line losses for the distribution side are given as average system values for the respective area types.

The latter, expresses the typical losses in stations, if any.

For transmission systems, line losses are given as typical average system values in percent of the energy flow for three different capacity ranges:

- Small lines, 1-20 MW
- Medium lines, 20 - 100 MW
- Large lines, above 100 MW

Energy losses in stations consist of the typical losses, if any, in various types of stations, e.g. transformer stations. They distinguish between losses in station types 1 and 2.

Furthermore, for district heating and gas systems in particular, there may be auxiliary energy consumption necessary for the operation of the system (pumps and compressors, heating of gas after decompression, etc.).

In case of transmission, the auxiliary consumption is stated as the typical energy use for transmitting each unit of energy in the system (% of energy transmitted).

In distribution systems, typical auxiliary energy consumption necessary for the operation of the system (pumps and compressors, heating of gas after decompression, etc.) is given as average values for the area (% of energy delivered).

Technical lifetime

The technical lifetime is the expected time for which an energy line or pipe can be operated within, or acceptably close to, its original performance specifications, provided that normal operation and maintenance takes place. During this lifetime, some performance parameters may degrade gradually but still stay within acceptable limits. For instance, energy losses often increase slightly 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 line/pipe is decommissioned or undergoes a lifetime extension, which implies a major renovation of components and systems as required to make it suitable for a new period of continued operation.

The technical lifetime stated in this catalogue is a theoretical value inherent to each technology, based on experience.

In real life, specific installations of similar technology may operate for shorter or longer times. The strategy for operation and maintenance, e.g. the number of operation hours and the reinvestments made over the years, will largely influence the actual lifetime.

Typical load factor

The typical load factor expresses the utilization rate of the system.

It is expressed with a value between 0 and 1, where zero means no utilization of the system and 1 corresponds to full utilization.

In a typical transmission or distribution network, the total rated load is rarely or never reached, since the demand is diversified in time and not simultaneous.

Typical load factor is calculated as average load in a year divided by maximum load. Similarly, it could be calculated as energy transported yearly divided by maximum load and 8760 hours.

The following formula applies:

$$Typical\ load\ factor = \frac{Average\ load\ [MW]}{Maximum\ load\ [MW]} = \frac{Energy\ transported\ yearly\ [MWh]}{8760\ [h] * Maximum\ load\ [MW]}$$

For distribution systems different values are given for typical residential and commercial areas.

The data sheet for area ´type a)´ presents the load factor for an area where new building standards (BR 10 or later) apply.

For transmission systems the load factor values vary widely, and the expected mean value is stated. The notes may indicate an expected range for lower and higher values.

Construction time

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

Financial data

Financial data are all in Euro (€), real prices, at the 2020-level and exclude value added taxes (VAT) and other taxes. For updates before 2020, prices were given at the 2015-level Several data originate in Danish references. For those data a fixed exchange rate of 7.45 DKK per € has been used.

European data, with a particular focus on Danish sources, have been emphasized in developing this catalogue. This is done as generalizations of costs of energy technologies have been found to be impossible above the regional or local levels, as per IEA reporting from 2020 [ref. 3]. For renewable energy technologies this effect is even stronger as the costs are widely determined by local conditions.

Investment costs

The investment cost is also called the engineering, procurement and construction (EPC) price or the overnight cost.

The investment cost for transmission systems is reported on a normalized basis both in terms of rated power and length of transmission lines, i.e. cost per MW per m.

Where possible, the investment cost is divided on equipment cost and installation cost. Equipment cost covers the components and machinery including environmental facilities, whereas installation cost covers engineering, civil works, buildings, installation and commissioning of equipment. Cost may be disaggregated in a more detailed cost breakdown if it improves readability or understanding of the given technology, but shall also be denoted by the below categories.

The rent of land is not included but may be assessed based on the space requirements, if specified in the qualitative description.

The owners' predevelopment costs (administration, consultancy, project management, site preparation, approvals by authorities) and interest during construction are not included. The costs to dismantle decommissioned installations are also not included. Decommissioning costs may be offset by the residual value of the assets.

The investment costs for energy distribution systems can be described as:

- A total network cost for an area with a certain yearly consumption (according to area types), or
- Split into service line costs, single line costs, station costs, and possibly reinforcement costs

The investment costs for a total distribution system may thus be composed of a combination of networks of different area types, and/or a combination of single components located outside the defined areas, as considered relevant for the specific model purpose.

For transmission systems the network costs and service line costs are not relevant.

The investment costs for establishing new energy transport systems depend on many local and regional factors. For some installations, e.g. burial of cables and pipes, experience shows that the price levels are higher in the Eastern part of Denmark, especially near Copenhagen, than in the rest of the country. Furthermore, costs increase considerably in city areas where many lines may be buried next to or over each other, and traffic regulation is more complicated. Also, burial of lines in paved areas is usually considerably more expensive that burial in open land.

Also there may be variations of the energy densities within each area type. For instance, a newly developed area (area type a) could consist mainly of multi-apartment building, or mainly of single family houses.

For distribution systems such variations within each area type can be accounted for by correction factors stated in the notes in the bottom of the sheets. The uncertainty values are not intended to cover these variations.

Service line costs

The cost of service lines are stated per consumer connected.

The costs include connection to the main lines and termination inside or outside the building, typically with a metering device and an isolation device (valve, contactor etc.). The data do not show whether the costs are paid by the distribution company or the consumer.

The costs of service lines depend mainly on the installed capacity, the length of the lines, and the area type. In this context average (typical) lengths have been assumed, depending on the size of the customers rated power/heat/flow capacity:

a) 0-20 kW: 20 m (for example, actual values to be stated)
b) 20-100 kW: 50 m (for example, actual values to be stated)
c) Above 100 kW: 100 m (for example, actual values to be stated)

If the lengths of lines differ from these values their costs can be scaled with length.

The service line costs are usually lower in new development areas, where the buildings as well as the distribution grid is new, corresponding to area 'type a)'.

Distribution network costs

The costs to establish distribution networks depend on the installed capacity, which with a typical load profile corresponds to a yearly energy demand. Thus, the costs are counted in EUR/MWh/year. The influence of varying energy consumption densities of different areas is accounted for by selecting the values from the data sheet with the appropriate area type.

Single line costs

The single line investment costs for distribution systems are unit length costs (EUR/m) for lines within certain capacity ranges (MW). These values can supplement the general network costs, e.g. in case of connecting isolated distribution areas with distribution lines, or for connection of single (larger) consumers. Thus, the investment cost for a distribution line is found by multiplying the length with the cost for the appropriate capacity interval.

For transmission systems, the line investment costs are counted in unit length and unit power capacity costs (EUR/MW/m) for different capacity ranges. Thus, the investment cost for a transmission line is found by multiplying the length and capacity with the cost for the appropriate capacity interval.

Reinforcement costs

Reinforcement costs are the average unit cost of reinforcing a distribution or transmission network with one MW capacity at the consumer level. This may be relevant in cases where the consumers in an existing distribution system has a higher capacity demand due to altered energy use, for instance application of heat pumps for domestic heating.

Stations

The investment costs of relevant station types in distribution and transmission systems are given in unit cost per MW capacity. The type of station is stated in the data sheets. If more than one type of station is relevant for a technology, they are mentioned in separate rows in the table.

Percentage installation / materials

For the complete distribution or transmission system it is assessed how large a share of the total investment is installation costs, and how large a share is materials. The two shares together should equal 100 percent.

Contingency

Project owners often add a contingency to a project's capital cost estimate to deal with project overruns due to uncertainties and risks caused by uncertainties in the project definition. The Association for the Advancement of Cost Engineering International (AACE International) has defined contingency as "*An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience*.". AACE International further describes contingency as "*…planning and estimating errors and omissions…..design developments and changes within the scope, and variations in market and environmental conditions**. The Technology Catalogues represent general techno-economic data for different technologies; and are not intended as basis for investment decisions. Therefore the data in the Technology Catalogues aim at not including contingency.

*Source: AACE (2022) Cost engineering terminology (https://library.aacei.org/terminology/welcome.shtml).

Operation and maintenance (O&M) costs.

The fixed share of O&M includes all costs, which are independent of how many hours the components are operated, e.g. administration, operational staff, payments for O&M service agreements, property tax, and insurance. Any necessary reinvestments to keep the infrastructure operating within the technical lifetime are also included, whereas reinvestments to extend the life are excluded. Reinvestments are discounted at 4 % annual discount rate in real terms. The cost of reinvestments to extend the lifetime may be mentioned in a note if data are available.

The variable O&M costs include consumption of auxiliary materials (water, lubricants) and electricity, treatment and disposal of residuals, spare parts and output related repair and maintenance (however not costs covered by guarantees and insurances).

The variable O&M is in most cases very low for transmission and distribution systems and it is mainly constituted by auxiliary consumption. Where auxiliary consumption is not relevant, e.g. for electricity, this figure could equal zero.

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, if relevant.

The operation costs do not include energy losses.

Auxiliary electricity consumption is included in the variable O&M for district heating and gas (natural gas, hydrogen, biogas/syngas) technologies. The electricity price applied is specified in the notes for each technology, together with the share of O&M costs due to auxiliary consumption. This enables corrections from the users with own electricity price figures. The electricity price does not include taxes and PSO.

It should be noted that O&M costs often develop over time. The stated O&M costs are therefore average costs during the entire lifetime.

For distribution systems the fixed costs are counted per MW capacity per year (€/MW/year), and the variable costs are counted per MWh delivered to the distribution network (€/MWh).

For transmission systems the fixed costs are counted per MW capacity per km transmission line at the relevant level (€/MW/km/year), and the variable costs are counted per MWh transported per km of line (€/MWh/km).

Business cycles

Historic costs of energy equipment can show fluctuations that are related to business cycles. This was the case of the period 2007-2008 for example or more recently around 2021-2022, where prices costs of many energy generation technologies increased dramatically driven by rapid increases in global raw material costs and supply chain costs. The primary objective of the technology catalogues is to establish general representative techno-economic data for different technologies, which can form a basis for energy planning activities and technical and economic analyses. The catalogues do not attempt to reflect fluctuations in technology costs due to fluctuations in costs of labour and materials driven by e.g. global/regional crises or major events affecting short term supply or demand. The technology cost developments in the catalogues thus intend to reflect an average business cycle situation and macroeconomic environment in a general long-term equilibrium.

Technology specific data

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

This could for instance be the necessary width and depth of the trench for burial of lines, the height and spacing of masts for overhead lines, the typical diameters of pipes of certain capacity ranges, transformer electrical losses depending on loads, heat losses depending on pipe classes, etc.

For technologies related to transmission of electricity, the cost of overload is specified.

It represents the cost in terms of degradation of the line due to overheating caused by an overload of the line and can be used for example to calculate the convenience of overloading an existing line vs. building a new one.

The unit and calculation method is specified in a note to the table.

1.4. Definitions

Definitions of the transmission and distribution systems, as well as different area types and transmission levels, are given in the Introduction.

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. “Projected Costs of Generating Electricity”, International Energy Agency, 2020.
3. “Konvergensprogram Danmark 2015”. Social- og Indenrigsministeriet. March 2015.
4. “Energy Technology Perspectives”, International Energy Agency, 2012.
5. International Energy Agency. Available at: http://www.iea.org/. Accessed: 11/03/2016.

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Revising a previous edition by SWECO (Oskar Fangström, Katarina Yuen)

Publication date

Date	Reference	Description
July 25	Qualitative description and datasheets	Major update and new description of the chapter, adding quantitative data for transmission level. Data for distribution level remains the same as before
December 17	Qualitative description and datasheets	Initial publication with quantitative scope limited to distribution level

Amendments after publication date

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Qualitative description

Brief technology description

Strong transmission and distribution grids are key prerequisites to the transition of the power system from fossil fuel based (synchronous generation) to renewable based (often non-synchronous generation).

The electrical grid is an interconnected network that delivers electricity from suppliers to consumers. It consists of generators that produce electrical power, transmission lines that transport large quantities of power over large distances within a country or between countries, and distribution networks that distribute electricity at lower power levels to end users. Electricity transport is carried out at different voltage levels.

Voltage transformation is carried out by transformers in transformer stations. Higher voltages enable transport of larger amounts of active power at low losses. In Denmark the transmission grid system is defined as lines with voltage ranges from 132 kV and up. Near customers the voltage is reduced in several steps by step-down transformers and transported by distribution lines to users, who are supplied at voltage levels down to 230 and 400V (residential consumers). The major components of an electric power system are illustrated in Figure 1 [1] (fictional system) with generators, transmission grid and distribution system. The electrical grid is a fundamental part of the infrastructure in all developed countries.

The Danish transmission grid (Figure 1A) is owned operated and developed by the Danish TSO Energinet. It consists of an alternating current (AC) network (132 kV, 150 kV, 220 kV and 400 kV) and direct current (DC) connection between East and West Denmark and alternating current and direct current connections to neighboring areas. Larger wind farms and PV installations, including e.g., the large offshore wind farms are connected to the transmission grid. Smaller wind farms and PV installations are normally connected to the distribution grid with lower voltages.

The electrical grid in Europe is interconnected across country borders and constitutes a large and complex network. The typically meshed structure of transmission systems improves their reliability/ security of supply in the case of fault on an important system component. Many systems also possess a high degree of flexibility (up- and down regulation according to fluctuating demand (load)), which is also a precondition for integrating variable renewables as wind and solar.

Input

The input for the transmission system is electrical power, but this power can come from various sources. Historically, electrical power was generated at utility scale by thermal power plants, hydropower plants, and nuclear power plants with power levels in the range of a few hundred kW up to 1000 MW. Thermal power plants and nuclear power plants use fuel (fossil fuel, biofuel, nuclear fuel) as a primary energy source, which is used to heat water into high pressured steam that drives a turbine-generator set producing electricity.

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Thermal plants, especially gas power plants, have a high ability to regulate the power output. Also, hydropower has a high ability to quickly ramp up and down power regulation- with reaction time below a second. The water behind the hydropower dams represents an energy storage that can be used to provide balancing services on short notice. Besides the storage is used to accumulate water from rainy or snow melting periods and provide balancing power on a seasonal level.

The turbine-generator sets of thermal, nuclear, concentrated solar power systems and hydropower plants have, thanks to the large rotating masses, a significant amount of inertia. In comparison wind turbines have smaller rotating masses and inertia.

The inertia provides stability to the power system and is an important factor for the dynamic grid stability and security of supply. Large scale power plants are normally connected to the transmission network by a step-up transformer and may be located far from demand centres where the fuel (coal, natural gas, uranium) is located, processed or stored. Generation based on conventional generators are characterised as synchronous generation.

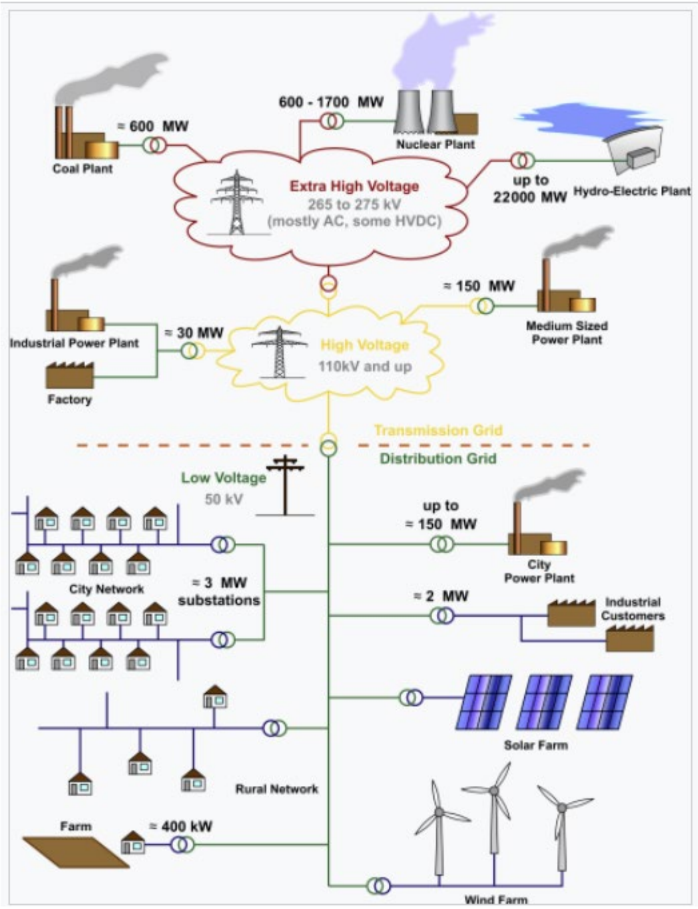

Figure 1: Illustration (example) of major components in an electric power grid, [1]

Over the last 30 years there has been an increased amount of installed capacity of non-synchronous generation (generation fuelled by the wind (kinetic energy) and solar radiation (Photo Voltaic (PV)). The development of renewables is still accelerating on a European and global basis. In 2023 wind and solar contributed with about 18% and 9 % respectively of the total European generation [2].

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Denmark has for decades been a pioneer in developing commercial wind power and integrating wind in the Danish power system. In Denmark the total energy generation from wind and solar in 2023 was record high 63 % of the consumed energy with wind covering 54%, which is record high in the world. Solar (PV) contributed with 9% [3].

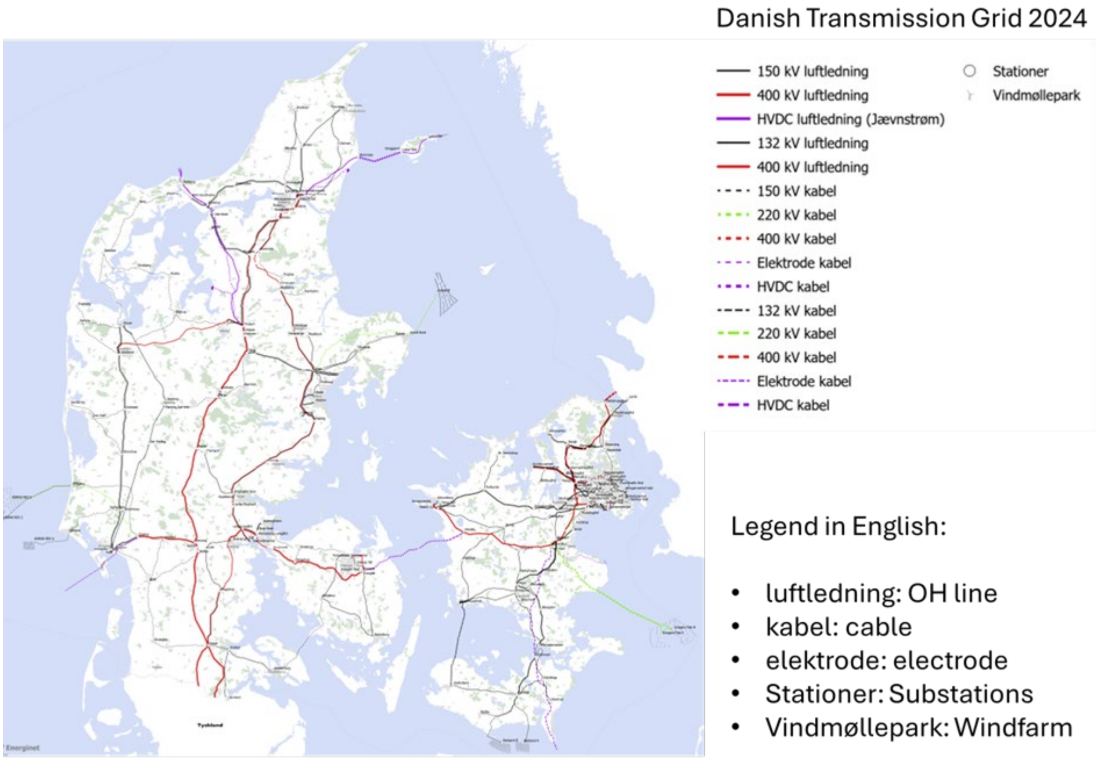

Figure 2.A: The Danish Transmission system, 2024 (Energinet)

Wind power and solar /PV power have installed capacity ranging from a few kW to installations (power plants) of several hundreds of MW, with smaller power plants connected to the distribution grid, and larger power plants connected to the transmission grid.

Today, wind and PV can participate in markets for power regulation. This mostly takes place as downregulating power, as wind and solar power normally operate at their maximum due to their low variable costs.

New wind turbine designs are most often connected to the grid through inverters. Also, PV installations are inverter connected. These sources lack the physical inertia of traditional generators, leading to potential instability and reliability issues as their presence on the grid grows. Smart inverters represent a transformative solution to the inertia challenge. These advanced systems go beyond simple energy conversion, offering capabilities to support grid stability through features like synthetic inertia, frequency and voltage control, and dynamic response to grid disturbances. Thus, the concept of “grid-forming” smart inverters has emerged as a promising solution, enabling renewable energy sources to actively participate in setting grid frequency and voltage, thus contributing to grid stability in a way that mimics traditional generators [45].

A smaller part of PV generation in Denmark comes from domestic PV, where private households and office/industrial buildings have installed PV system on the rooftop. The PV facility is connected to the low voltage system of the building, the active power may be used by the consumer and the surplus is delivered to the electrical grid. This kind of consumer is often called a prosumer.

Output

The output of the transmission system is electric power which has a vast usage in the society: the residential, commercial and industrial sector.

In the residential sector electricity is used for lighting, charging of electrical cars or bicycles, washing, refrigeration, freezing, cooking, heating (e.g. heat pump) [5].

In Denmark, private consumption for one person in an apartment is about 1900 kWh/y. For two persons the consumption in an apartment is about 2200 kWh. A family of 4 persons in a house had on average a consumption of 4,500-5,000 kWh/y in 2023 [4]. The consumption roughly doubles if a heat pump or an electrical car is included in the household consumption.

The commercial sector uses electricity for lighting, ventilation, cooling and heating, refrigerators, computers, etc. The industrial sector uses electricity to drive machinery, processes and boilers. The direct electrification of transportation sector has an increasing size, due to electrical vehicles, buses, trucks, ships/boats etc.

Energy balance

In an electrical system, electricity consumption needs to be continuously balanced with production. The transmission system operator (TSO) is responsible for this balance in real time and maintains a second-by-second balance between electricity production from producers and demand from consumers, import/export and losses.

In Denmark, the total grid losses are about 6-7%, where about approx. 2-3% stem from the transmission grid and approx. 4-5% stem from the distribution grid [39], [40]. The 2-3 % losses in the transmission cover DK1, DK2 and the Great Belt link excluding losses on the foreign Direct Current (DC)connections to Norway, Sweden, Holland, UK and Germany. The losses in a DC interconnection in Denmark is typically 2-3% [38].

The U.S. Energy Information Administration (EIA) estimates that annual electricity transmission and distribution (T&D) losses averaged about 5% of the electricity transmitted and distributed in the United States in 2018 through 2022 [24].

In Statistical factsheet, 2018 [46], ENTSO-E estimates the total transmission loss within ENTSO-E to be about 2 %.

The TSO takes over the balancing of the system one hour before real time. Before that a suite of electricity markets with different are active in providing a pre-balance between generation and demand, se Figure 1B:

- Forward and future financial markets, where future prices are hedged.
- Spot-markets, or day-ahead markets where generation bids and demand bids are delivered before noon (the day before real time) and the clearing of markets determines the operation of generators for the coming day. Europe has one interconnected electricity market setting the prices and

generations and exchanges in all bidding zones/countries in the same optimisation. There are similar markets in US and other parts of the world.

- Intraday markets opening when the spot market has been cleared. The market is open until one hour before real time. The market is mostly used by the market participants for self-balancing closer to real-time, when they have more certain knowledge of future conditions for generation and demand.

- When the intraday market has closed the TSOs take over the balancing in the real time market. The resources in the real-time market are different kind of reserves, that the TSO has bought in advance on the reserve markets, or they can be voluntary regulating power bids (manual reserves) given just before real time. The reserve markets include different products that the TSO needs for safely controlling the power system stability, especially in stressed situations e.g., with unplanned outages of generators, demand centres, substations and transmission and/or distribution lines.

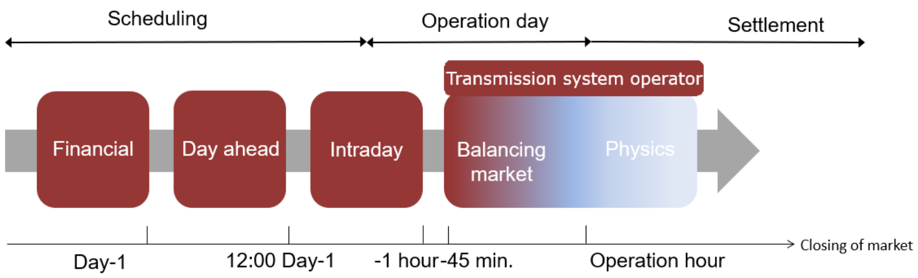

Figure 1B: Suite of power markets (Ref.: Energinet)

Description of a transmission system

General

Three phase Alternating Current (AC) systems are widely used in transmission all over the world. A transmission system is used for bulk transport of power at large distances and to interconnect large areas. The transmission system operates at high voltages, typically 110kV-1000kV, and the power capacity of lines ranges from 100 MW to several GW.

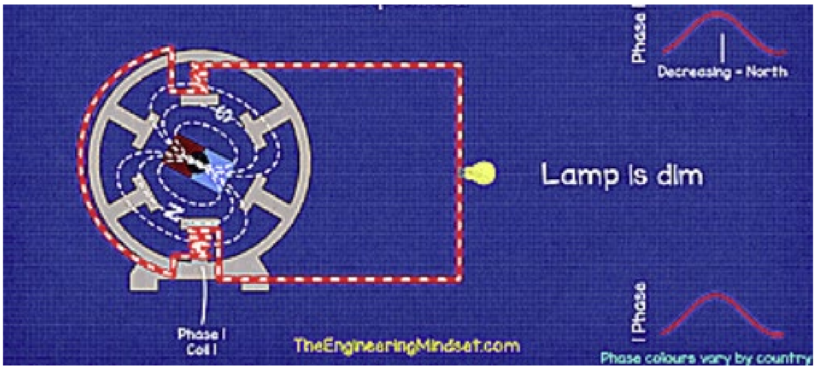

Figure 1C: AC power explained [48]

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Figure 1C is an illustration of how AC electricity works. A magnet, driven by for example a wind turbine or a steam turbine, rotates and creates a varying magnetic field in the two shown coils which are connected by a conductor. The varying magnetic field induces in the line a time varying current which has the form of a sinus curve. This varying current is called a phase. When installing 4 additional coils, 2 and 2 opposite each other, two additional phases can be formed. The end result is a 3 phased AC system, with each phase described by a sinus curve and the curves being shifted 120 degrees apart.

The transmission grid in Denmark operates at 132 kV to 400 kV. The transmission at 400 KV consists mainly of overhead lines. At lower transmission voltage levels underground cables are now dominating, especially in densely populated areas. Today, the transmission grid in Denmark consists of 2,900 km of overhead lines and 3,200 km of cables [12].

Substations and compensation stations

Transmission substations are found where electricity enters the transmission network (often near a major power source), or where it leaves the transmission network for distribution to homes and businesses. Because the output from power generators – such as biomass plants or wind power plants – have different voltage levels than the voltage level of the grid, the output must be converted by a transformer to a level that suits the transmission system.

Transmission substations are the 'junctions' where circuits connect to one another, creating the meshed network around which electricity flows at high voltage.

Substations can be AIS or GIS stations. AIS (Air insulated substations) uses air as the insulating medium (open air stations), while GIS (Gas insulated substations) uses specialized insulating gases, e.g., SF6. AIS tends to have larger physical dimensions and requires more spacing between components, whereas GIS offers compact designs with reduced maintenance requirements. As SF6 is a potent greenhouse gas, ENTSO-E's research programme includes efforts to develop SF6-free solutions. The amended F-Gas Regulation (EU) 2024/573, aims for a complete phase-out of F-gases by 2050. Including a complete phase-out of SF6 for transformers in 2032.Figure 3 illustrates the layout of a substation with its elements.

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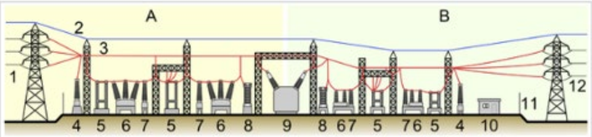

Elements of a substation

A. Primary power lines' side
B. Secondary power lines' side

1. Primary power lines
2. Ground wire
3. Overhead lines
4. Transformer for measurement of electric voltage
5. Disconnect switch
6. Circuit breaker
7. Current transformer
8. Lightning arrester
9. Main transformer
10. Control building
11. Security fence
12. Secondary power lines

Figure 3. Elements of a substation, example [6]

Transformers

An important element is the transformer enabling change in AC voltage and thus allowing operators to interconnect AC networks of different voltage levels to each other. Power transformers must be built to withstand severe electrical stress from fault currents and transients. Their availability and longevity have a major impact on grid reliability and profitability.

Integrating a tap changer with the transformer allows for the regulation of the output voltage by adjusting the number of transformer windings (the transformation ratio). Although the effects on the network depend on the network itself, this nonetheless enables more flexibility to the operator compared to a fixed voltage step up or down ratio.

Key functions of power transformers with tap changers are [7]:

- Voltage step-up and -down: As increasing voltage will reduce the currents required to transmit the same electrical power, step-up transformers are used to minimise transmission line losses. Step-down power transformers are used to bring down transmission voltages to usable voltage level for end-customer connections.

- Slow dynamic regulation to adjust to changing network conditions, supporting the voltage stability of the AC-grid.

Compensation stations

Compensation stations are used to control voltage and transfer capacity of the transmission grid. Compensation is in the form of reactive power provided or consumed by means of capacitor banks or reactors, flexible alternating current transmission systems (FACTS), etc.:

- Reactive power[2] can be provided by generators themselves (any generator or demand facility must be able to control reactive power within certain limits to be granted a grid connection), or alternative provided through capacitors[3]. Hence capacitors are often placed near inductive loads (i.e. if not on-site at the nearest substation) to reduce transport of reactive power on transmission lines. Capacitor banks help to raise the voltage profile and improve the power factor by supplying reactive power and thereby relieving the transmission line of transporting the reactive power to inductive loads (appliances with moving parts as motors, fans, etc.).

- Reactors absorb reactive power and reduce the voltage level on the transmission line and are typical used in connection with high voltage underground cables or light loaded overhead lines. When the voltage level is lower due to higher loads, the reactor is disconnected again.

- Static Var Compensator (SVC). An SVC includes both a capacitor and a reactor. The main advantage of SVCs over simple mechanically switched capacitors/ rectors is their near-instantaneous response to changes in the system voltage by using power electronics. For this reason, they are often operated at close to their zero-point to maximize the reactive power correction they can rapidly provide when required.

- A static synchronous compensator (STATCOM) is a fast-acting device capable of providing or absorbing reactive power and thereby regulating the voltage at the point of connection to a power grid [8]. The technology is based on VSCs, but a STATCOM offers better dynamic performance than an SVC, in particular a faster response time.

Interconnected large systems

High Voltage Direct Current (HVDC) connections are very often used in the transmission grid to transport large amounts of active power/ energy over long distances e.g., power transport from a major power source as an offshore wind substation. HVDC systems are also used to interconnect power systems with different frequencies or different phase angles (and same frequency).

Denmark has two separated transmission systems, of which the eastern system (DK2) is synchronous with the Nordic synchronous system and the western system (DK1) is synchronous with the grid of the Continental European synchronous area.

Large, interconnected transmission systems enable optimal power dispatch between numerous power generators with different characteristics, enhance system reliability, and are key to efficiently hosting an increasing amount of variable energy sources as wind and solar.

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[2] Reactive power is used to generate electromagnetic fields for the operation of inductive loads such as motors, transformers, and transmission lines. Moreover, reactive power also provides the function of regulating voltage levels in transmission lines, ensuring a smooth supply of real power. Real power is that part of the power that can do work.

[3] Capacitors are electronic components that provide energy storage in the form of an electrostatic field. A capacitor provides reactive power and raises the voltage profile.

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Reliability

Industrialised countries seek to obtain a high level of power system reliability because the economic losses from power outages are substantial.

The Danish security of supply of electrical was on average 24 outage minutes for a consumer in 2022. This corresponds to a reliability (or uptime) of 0.999954 or 99.995%. Of the 24 outage minutes 2 minutes could be related to outage in the transmission system. The remaining to the distribution system [10].

Figure 3 shows the statistics for outages in the Danish transmission system since 2007 (the unit on the y-axis is seconds). It follows that the islands of Bornholm, Læsø and Anholt contribute significantly in some years. Outage on Bornholm, Læsø and Anholt are included, as Energinet has a reserve supply obligation to the islands (only in case of interruption, which is not due to local electricity distribution network)

Figure 3: Outage seconds in the Danish transmission grid since 2007 (demand weighted).

The future Danish target for reliability is also high. In "Energinets redegørelse for elforsyningssikkerhed, 2023" [10], the target 10 years ahead (in 2033) for outage minutes is:

- Resource adequacy (adequacy of power): 5 minutes.
- transmission grid adequacy: 1 minute.
- robustness of transmission grid (against disturbances/faults): 1 minute.
- distribution system: 29 minutes

HVAC and HVDC systems

The majority of electric transmission systems today use three phase High Voltage Alternating Current (HVAC). Most of the electricity is produced, transferred, and consumed as AC power. Furthermore, the voltage of AC power can be stepped up and down with relative ease. Technology development has enabled the use of HVDCas a highly efficient alternative for transmission of electric power and for interconnecting power grids with different frequencies.

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A DC grid system is a grid system based on DC instead of AC. The connection to the fundamental AC grid system is made by AC/DC (near end) and DC/AC (remote end) converters. Such DC grids are often mentioned as overlay DC grids [11].

DC grids can be designed as radial multi-terminal systems or in a meshed way, providing the characteristics of a grid. Two-terminal long-distance DC corridors emerged in the 1960s and in the 1970s, with the rapid advancements in power electronics and control systems. The first multi-terminal, non-meshed, HVDC system was commissioned in the 1990s.

Meshed multi-terminal DC grids (MTDC), in which feature more than one power-flow path between two grid terminals are still being examined at the research level to solve the challenges of integration with the AC meshed grid. (Multi-terminals are described later in section "New technology- multi-terminals"). The concept of DC grids may one day also allow the various large electricity networks to be interconnected on a global level. Furthermore, a DC overlay grid system is able to enhance the flexibility of the entire transmission grid, being able to cope with the characteristics of renewable power infeed in a more effective manner [11].

HVDC systems require terminal and costly converter stations, which is not required by HVAC. The cost per distance (excluding converters) for Over Head- transmission Lines (OHL) is however lower for HVDC systems, due to smaller space requirements, reduced number of conductors and reduced losses. With regard to cables, HVDC enables longer cable transmission due to the lack of capacitive[4] losses that are present in AC cables.

Figure 4 illustrates a typical layout of a HVDC converter substation (Greenlink, link between GB and Ireland) with converter hall, converter transformers, AC switchgear and busbars, harmonic filters[5], lightning towers, ancillary plant etc.

Figure 4. Example of layout of HVDC, VSC substation, Greenlink[6] [50].

Above a specific break-even distance, the HVDC technology becomes cheaper than HVAC. The break-even distance for overhead lines is around 600 km and for high voltage cable lines it is around 50 km [37]. Additionally, the HVDC systems can be applied as "embedded" systems to lower the impedance[7] in specific areas of the AC network.

[4] A cable has high capacitance, because the conductors are close together (separated by an insulator). The AC cable is repeatedly charged and discharged (with the frequency). The charging current uses capacity of the cable and leaves less room for active power transmission.
[5]Harmonics are frequencies that are integer multiples of the fundamental frequency. HVDC converters generate both AC and DC harmonic currents and voltages. Filters are used to reduce harmonics and their adverse effects.
[6] Greenlink to be commissioned in 2025
[7] Impedance is the equivalent to resistance in DC. Impedance encompasses the additional physical characteristics of an AC transmission-line/cable, which has capacitive properties and inductive properties.

HVDC systems also enable a number of additional benefits, such as enhanced voltage regulation and controllability, ability to interconnect regions with different frequencies, providing fast power run-back or run-up[8], black start capability[9] etc. The choice between HVDC and HVAC is based on economical, technical, and environmental judgments.

Voltage Source Converters (VSC) are self-commutated[10] converters to connect HVAC and HVDC systems using devices suitable for high power electronic applications, such as IGBT[11]s (electronic switch). VSCs are capable of self-commutation, being able to generate AC voltages without the need to rely on an AC system. This allows for independent rapid control of both active and reactive power and black start capability [11].

VSCs maintain a constant polarity of the DC voltage for their building blocks. The change of power flow direction is achieved by reversing the direction of the current. VSC-based HVDC systems offer a fast active power flow control while also ensuring flexible and extended reactive power controllability at the two ends of the HVDC link.

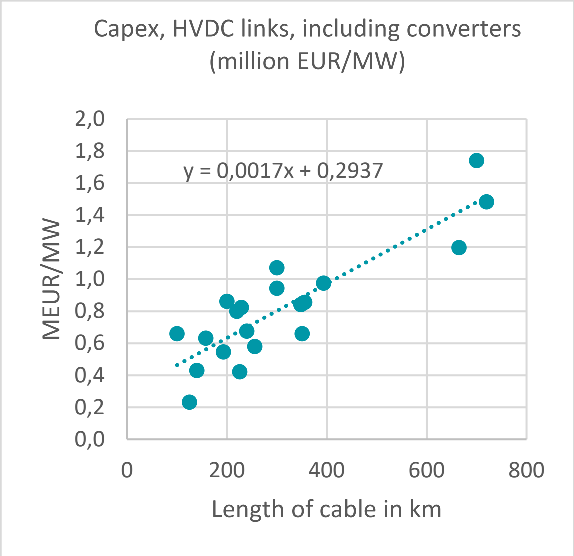
Line-commutated converters (LCCs) are the conventional, mature and well-established technology used to convert electric power from AC to DC or vice versa. The term "line-commutated" indicates that the conversion process relies on a stable line voltage at both terminals of the HVDC system [11].

A LCC requires connection to a grid with sufficient short circuit power level to avoid commutation faults and a synchronous voltage source to operate (AC voltage at both terminals of the HVDC system). In comparison to a VSC, it still allows for higher power conversion capacities but would require converter stations with a larger ground footprint than the equivalent capacity VSC sites.

HVDC- point to point

In the TYNDP-22 (ENTSO-E's Ten-Year Network Development Plan) [30] many HVDC point to point projects have been promoted. The projects are typically interconnectors between countries/ synchronous areas involving long sea cables. For illustration the capital costs of a selection of proposed new projects are shown in figure 5. It follows that the left part of the figure has the best approximation to being linear (Coefficient of determination R^2=0,76). Figure 3 include heterogenous projects with regard to converter types (VSC/LCC) and onshore/offshore cables etc.).

[8] If a severe disturbance threatens system stability, HVDC can help maintain synchronized power-grid operation by fast power run-up (increase power flow on a line) or run-back (decrease power flow on a line) control functions.
[9] Black start is starting a power system from an un-energised state.
[10] Voltage Source Converters (VSC) are self-commutated converters to connect HVAC and HVDC systems using devices suitable for high power electronic applications, such as IGBTs. VSCs are capable of self-commutation: being able to generate AC voltages without the need to rely on an AC system.
[11] Insulated-gate bipolar transistor



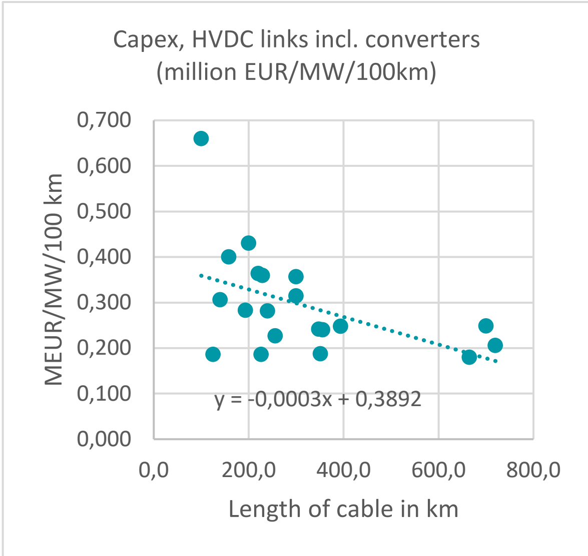


Figure 5 Capex of proposed offshore HVDC links in TYNDP 2022, including converters. In the left-hand figure capex is in MEUR/MW (R^2=0,76) and in figure to the right the capex is in MEUR/MW/100 km (R^2=0,24) (price level 2022), [30]

HVDC circuit breaker

The HVDC circuit breaker is a switching device that interrupts the flow of normal and abnormal direct current. The challenge in breaking direct current is the absence of zero current crossings. An additional component must be used that either generates zero-crossings by application of special oscillating circuit and mechanical circuit breakers or power electronics to break the current. The HVDC circuit breakers are required for meshed DC-grids and multi-terminal DC links [11].

Overhead lines vs cables

Power is usually transmitted through overhead power lines. Underground power transmission has a significantly higher installation cost and greater operational limitations but lower fault frequency. However, cable faults need longer repair times. Underground transmission is more common in urban areas or environmentally sensitive locations. In densely populated areas, cables often provide the only technically viable solution.

The transmission grid in Denmark consists of 2,900 km of overhead lines and 3,200 km of cables: sea cables (often DC) and underground land cables (AC). The numbers include Energinet’s shares of the interconnections abroad [12].

Conductors

Choice of conductors is based on considerations such as cost, transmission losses and other desirable characteristics of the metal like tensile strength. Copper, with lower resistivity than aluminium, was once the conductor of choice for most power systems. However, aluminum has a lower cost for the same current carrying capacity and is now often the conductor of choice. Overhead line conductors may be reinforced with steel or aluminium alloys [13].

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Conductors may be placed overhead or underground. Overhead conductors are usually air insulated and supported on porcelain, glass or polymer insulators. Cables used for underground transmission are insulated with cross-linked polyethylene or other flexible insulation. Conductors are often stranded to make them more flexible and therefore easier to install.

Conductors are typically rated for the maximum current that they can carry at a given temperature rise over ambient conditions. As current flow increases through a conductor it heats up. For insulated conductors, the rating is determined by the insulation, routing of cable phases, configuration of metal shields and installation conditions, including soil conditions and installation depth.

For overhead line conductors, the rating may be determined by the max. allowable sag or the conductor's max. permittable temperature. For long overhead line connections (depending on compensation) there are also other problems that can limit the rating, including restrictions related to voltage drop and phase angle stability.

Superconductors [49]

Superconducting cables are based on special superconducting materials that are cooled down to extremely low temperatures (e. g., – 180 °C) using e.g., liquid nitrogen to activate the superconductivity (very low resistance). They may carry about five times the power of a conventional cable system with the same outer dimensions.

These cables are called HTS, high temperature superconductors. There exist also LTS, low temperature superconductors, where the cooling is even more extreme down to about – 268 °C, using liquid helium as coolant. For practical applications HTS seems most promising and has the focus in the following.

Because of small space requirements super conducting cables may in the future find wider application in (transmission) congested urban areas where they can provide high power transport capacity. Here they can be routed underground through existing gas, oil, water or electric corridors thus avoiding need of obtaining additional and costly right of way.

The losses of the superconducting cables are mostly due to the energy required to keep low nitrogen temperatures and its circulation. The technology requires special cable joints and specific cable terminations for extreme temperature differences and permanent cooling for keeping very low temperatures.

The design of superconducting HVDC power cables is very similar to the design of superconducting HVAC power cables.

Today superconducting cables are mainly prototypes and/or form part of demonstration projects. It is uncertain when and if the cost of the technology will come down to a level making it generally and wider applicable[12].

[12] Together with "Stadtwerke München Infrastructure" and other partners, NKT in October 2024 has inaugurated the test system for the world's longest superconducting cable system, SuperLink, in the German city of Munich (https://www.nkt.dk/om-os/pressemeddelelser-events/nkt-paabegynder-test-af-verdens-laengste-superledende-kabel)

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Three types of superconductors are available for AC or DC power cables:

- $Bi_2Sr_2Ca_2Cu_3O_{10}$ (BSCCO) with a critical temperature of – 160 °C (liquid nitrogen as coolant)
- $YBa_2Cu_3O_7$ (YBCO) with a critical temperature of – 180 °C (liquid nitrogen as coolant)
- MgB_2 with a critical temperature of – 235 °C for MgB_2 (liquid helium as coolant)

The critical temperature is the temperature for obtaining very low resistance.

ENTSO-E evaluates the TRL (Technology readiness level) for superconductor cables (HTS) in DC transmission to be 5-6, while TRL for superconductor cables (HTS) in AC transmission is estimated at 7-8[13].

Description of distribution system

This shorter, overall description is taken from the previous edition of the chapter that solely quantified distribution systems.

An electric power distribution system carries electricity from the transmission system to individual users. Distribution substations connect the distribution grid with the transmission grid and steps down the voltage to medium voltage, typically 10 – 70 kV. In secondary substations, distribution transformers make a final step down in voltage to low voltage (400V), distributed by service lines to end users. Users demanding larger amounts of powers can be directly connected to the medium voltage, or even higher voltage levels. Traditionally, medium voltage distribution was composed of overhead lines, which have a lower degree of technical complexity. A significant cabling of the medium voltage grid has taken place in Denmark and neighbouring countries. Drivers being increased security of supply and reduced visual pollution.

Space requirement

Space requirement for overhead lines varies in agricultural land, forest and habituated areas [43], [44]. In agricultural land the space requirement is limited to the poles and stays. In forest a 400 kV overhead line needs a clearance of 30 m – 40 m (on each side) where no trees are allowed to grow. In populated areas a clearance zone of about 40-meter width is set for non-residential buildings, whereas a clearance of approximately 200 m width is required for buildings where humans reside permanently in order to avoid exposure of magnetic fields. The space requirement reduces with lower voltages. Regarding magnetic field analysis, then this is a function of the phase-phase distances, phase distances for measurement, and the current strength (where the latter may well be independent of the voltage level).

Electric cables have a significantly lower space requirement. In populated areas and cities, cables are normally laid close to or under roads and streets. Ground cables do not affect the use of agricultural land. As far as possible, medium voltage cables follow roads also in rural areas. In forests, a clearance is required to provide easy access to the cable and to avoid tree roots from damaging the cable. For transmission grids this clearance is 10 m – 15 m. The magnetic field from cables is smaller than for overhead lines and does not add to the space requirements.

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[13] TRL 5 – Laboratory testing of integrated system, TRL 6 – Prototype system verified, TRL 7 – Integrated pilot system demonstrated, TRL 8 – System incorporated in commercial design, TRL 9 – System ready for full scale deployment

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Environment

The environmental impacts of the electrical grid systems are mainly

- Visual impacts – Overhead lines are often considered to have a negative aesthetic impact on the surroundings
- Electromagnetic fields – Electricity infrastructure produces both electric and magnetic fields that may be harmful. Exposure to electric and magnetic fields is regulated and appropriate safety distances are assured when establishing electrical transmission infrastructure.
- Noise – Sizzles, crackles and hissing noises occur around high voltage overhead lines during periods of high humidity. Transformers emit humming sounds. These noises are audible only at close vicinity to the equipment. Noise during construction and maintenance can have an impact on the environment.
- Intrusion in sensitive areas – The environmental impact due to intrusion can be minimized by e.g. avoiding placement in sensitive areas, limiting construction to winter when soil and water are more likely to be frozen and vegetation is dormant, etc.
- Electrical hazard – Safety requirements on design and operation are established to assure safe design and operation of electric facilities.
- SF_6 gas is often used in gas insulated substations. SF_6 is a strong climate gas[14].

Research and development perspectives

The path towards a net zero emission system by 2050 in Europe requires new strategies and the upscaling of emerging technologies. The European TSOs are already ramping up investment programs for new infrastructure and implementing smarter system solutions, and various TSOs have set the goal of being able to operate a grid system with 100 % renewable infeed in the coming decades.

In its RDI (Research, Development and Innovation) report from 2021 ENTSO-E described the focus areas for research within the European transmission system in the years 2021-25 [15].

The ENTSO-E strategy for RDI can be illustrated by the six flagship projects shown in Figure 7. It is noticed that some of the sub-projects in the flagships are not focused directly on grid technology and grid operation but on the interplay to other areas impacting the future power grid.

[14] The amended F-Gas Regulation (EU) 2024/573, aims for a complete phase-out of F-gases by 2050. Including a complete phase-out of SF6 for transformers in 2032.

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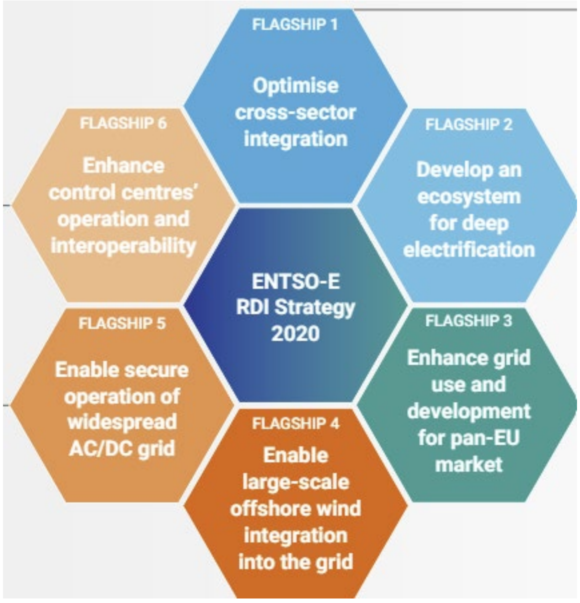

Figure 7: ENTSO-E RDI Roadmap 2020–2030 flagships and the main topics addressed in each.

Flagship 1 aims to optimize energy cross-sector integration (power, PtX, hydrogen, green fuels)

ENTSO-E proposes four project concepts in this area, covering the mass smart charging of EVs (1), the development of innovative models and tools for coordinated multi-sector operation and planning (2), the design of a pan-European cross-sector data model (3) and provision of market architecture for the cross-sector integration (4)

Flagship 2 aims to develop an ecosystem for deep electrification

Focus is on integrating the coordinated flexibility potential to the future energy system by harmonizing flexibility assessments and demonstrating how market viability and energy system security can go hand-in-hand in a coordinated approach for a P2X plant.

Flagship 3 aims to enhance grid use and development for the pan-EU market

It proposes a project concept on eco-design processes to reach SF6-free solutions, as well as a project concept to lower the carbon footprint of TSOs via lifecycle assessments embedded in smarter asset management processes.

Flagship 4 aims to enable large-scale offshore wind integration into the grid

First a project developing an interoperability framework between offshore wind and the onshore AC grid and then a follow-up project demonstrating this in practice with a full-scale multi-vendor multi-terminal high-voltage direct current (HVDC) system.

Flagship 5 aims to enable a secure operation of widespread hybrid AC/DC grids

As the share of power electronic coupled sources increases in the system and as more DC projects are embedded in the system, the main needs are concerned with the capability to properly model such systems in planning and manage them in operations.

A project on the stability management of a power electronics dominated system, and another project on assessment models for interactions, controllability and protection schemes.

Flagship 6 aims to enhance TSOs' control centres' operations and interoperability including TSOs' Energy Management Systems, a further focus on AI-driven solutions and especially on mitigating cyber risks in an efficient manner

New technology – multi-terminals

A few multi-terminal direct current (MTDC) systems are in operation around the world today. However, MTDC grids overlaying their AC counterpart might be a reality in a near future. The main driver for constructing such DC grids is the large-scale integration of remote renewable energy resources into the existing AC grids.

DC overlay systems can be designed as radial multi-terminal systems or in a meshed way, providing the characteristics of a grid with more than one DC power-flow path between two DC grid terminals.

Radial MTDC systems

Two-terminal long-distance DC corridors emerged in the 1960s and, with the rapid advancements in power electronics and control systems, the first multi-terminal, non-meshed, HVDC system was commissioned in the 1990s.

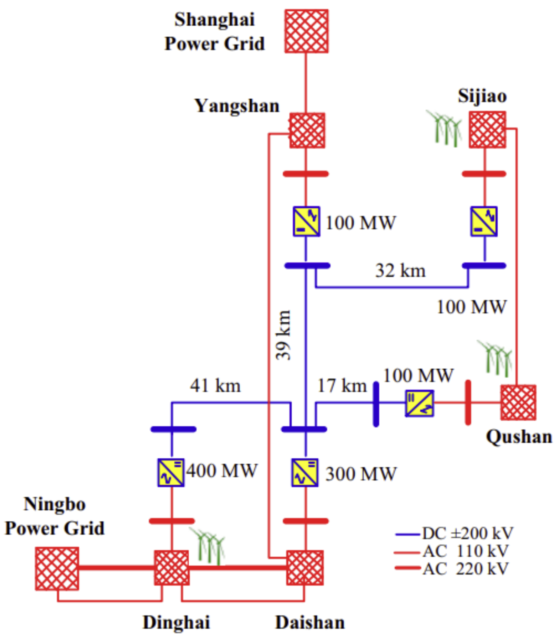

Figure 8: Zhoushan 5-Terminal DC project, China [16]

Figure 8 shows the Zhoushan 5-DC-Terminal project from 2014. It is a five terminal DC project at high voltage level. The five-terminal system connects five islands with the main power grid providing power for stabilizing the weak power grids on the islands. The system is designed as a radial multi-terminal system in a non-fault selective way, which results in a disconnection of the five terminals in case of a DC fault. A refurbishment with DC circuit breakers (DCCB) has later been implemented[15].

Another multiterminal project is the Sardinia-Corsica-Italy radial system [17]. The point-to-point 200 MW, 200 kV DC interconnection between Italy and Sardinia was extended in 1988 with an MTDC station of 50 MW in Corsica. The three MTDC stations form together the SACOI interconnection which operates as an MTDC system.

Authorities, TSOs, wind industry and other stakeholders of countries around the North Sea have reviewed the potential large-scale coordinated infrastructure over the past decade. A recent example is the large-scale North Sea Wind Power Hub proposed by, among others, TenneT NL, TenneT DE and Energinet. The whole system is intended to function as a hub for wind power transport via a multiterminal system transmitting power from the hub to several connected countries.

Meshed MTDC systems

Meshed multi-terminal DC grids, in which feature more than one DC power-flow path between two grid terminals, is still being examined at the research level to solve the challenges of integration with the AC meshed grid [17]. Figure is an illustration of a meshed multiterminal overlaid DC grid.

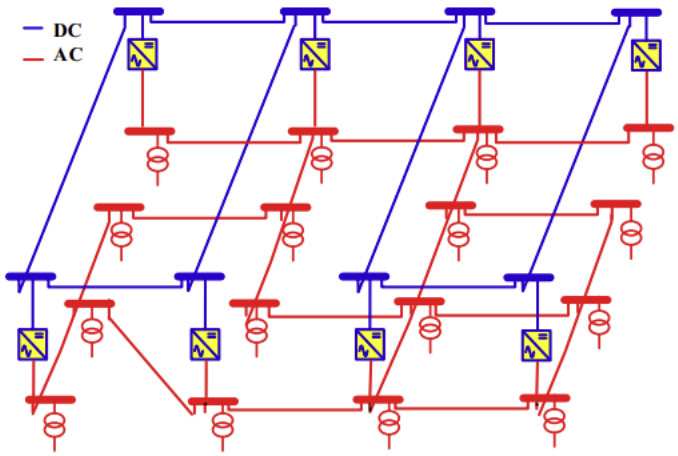

Figure 9: Example of design of a meshed multi-terminal DC [16]

[15] In the later Zhangbei project, 16 DCCBs of different types have been installed. One type is a further development of the type used in the Zhoushan project.

Challenges and characteristics for DC grids and AC/DC hybrid grids [16], [17]

Power flow control

In AC grids, flexible AC transmission system (FACTS) devices can be employed to adjust voltage levels by providing or consuming reactive power. In MTDC grids, the system state is different, since DC bus voltages are only characterized by their amplitude, and not by their phase-angle, and the transmission line impedances do not present any reactive component (inductive and capacitive reactance).

Devices of importance for dynamic behaviour (converter)

In a MTDC grid, the most vital component providing power exchange to and from the AC grid is the power electronics-based power converter. In comparison to synchronous generators, power converters have a time response that can be several orders of magnitude faster. Precise modelling of power converters and their controllers is, therefore, a key aspect for assessment of the MTDC grid's dynamic behaviour.

Stability via VSC controllers

Stability analysis for an MTDC grid, which only relies on the DC bus voltage magnitudes, has to be approached in a different way than in AC power systems. In this sense, detailed models for the MTDC grid, the power converters' controllers and the AC network, should be elaborated and systematic analyses should be carried out to define the ranges of the VSC controllers in order to ensure dynamic voltage stability at the MTDC grid and to know how fast the VSC controllers and protections should react in order to avoid a collapse of the MTDC grid. VSC converter systems are preferred in designing a MTDC grid[16].

Protection devices and HVDC breaker

The development of appropriate protection devices and strategies for MTDC grids is a challenging issue, and the lack of efficient protection strategies is a constraint on the pace of development of MTDC technology. In this regard, several manufacturers and researchers are working on making DC circuit breakers commercially available and standardized.

Components & enablers [17]

The most important components:

- Transmission corridor technologies (LCCs[17]) with capacities of approx. 4 – 8 GW per circuit, and continuing developments towards 2050
- VSCs[18] with ratings in the range of 1 – 3 GW per circuit, and continuing developments towards 2050
- HVDC Circuit breakers
- HVDC Gas insulated switchgears

[16] There are several multi-terminal DC networks (MTDC) in operation with LCC converters, but it is clearly simpler to make MTDC with VSC converters because one does not have to change polarity to change the power direction.
[17] Line commutated converter.
[18] Voltage source converter.

Enablers are:

- Advanced operational coordination between TSOs
- Advanced modelling technique of hybrid systems (AC/DC): dynamics, stability
- Tailored fault clearing strategies to the specific HVDC/HVAC grid characteristics

Advantages & field of application [17]

The choice between an extension of a grid in AC or DC depends on a variety of technical, economic, environmental, and technical factors. The profitability threshold between the two types of current systems has varied over time depending on the use cases. The first building of a DC system was registered in 1954 in Sweden when the island of Gotland was connected to the mainland via a 98 km long sea cable.

With the increasing need to integrate remote large-scale renewables and the growing share of distributed DC connected energy resources, DC transmission will become more relevant, and its integration within the current AC system will contribute in several ways to achieving a cost-efficient energy transition.

Major advantages of the integration of DC systems in AC systems will be [17]:

- An increase of transmission capacity by leveraging existing AC corridors to create new higher capacity DC corridors, boosting transmission capacity with limited additional environmental and social impact.
- An enhancement of active power flow control which enables a better utilisation of the lines closer to thermal limits.
- An increase in ancillary services provision
- Enhancement of flexibility in the overall transmission grid, being able to cope with the characteristics of renewable power infeed. To date, there exist more than 180 HVDC operational projects worldwide. A few non-meshed multi-terminal systems are in operation in Europe, North America and Asia. In the next ten years, over 25,000 km of HVDC transmission lines will be built and operated in parallel with over 300,000 km HVAC transmission lines according to the TYNDP[19] estimates, yet most of these are case-by-case, point-to-point connections.

Research and development are being accelerated in the field to overcome the technical and regulatory barriers to operate and control MTDC system and integrate them in meshed AC systems. Such integration will combine the benefits of AC and DC technologies and open the door to new devices and systems, such as HVDC circuit breakers, HVDC gas insulated switchgears and flexible DC transmission system devices that can bring benefits to the security, reliability, performance, and economics of a DC grid system.

[19] ENTSO-E's Ten-year network Development Plan

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Concepts such as the "North Sea Wind Power Hub" already show advanced DC grid layouts complementing the AC onshore system. The Mediterranean Grid ("Med Grid") idea is already linking European, North African and Middle Eastern areas around the Mediterranean area.

Technology Readiness Level (TRL) (ENTSO-E evaluation)[20]

For the estimation of the TRL of DC grid systems, ENTSO-E evaluates as follows:

• TRL 9 for **radial** multi-terminal systems.

• TRL 4 for **meshed** multi-terminal systems.

Examples of market standard technology

Viking link (DC corridor between two synchronous areas)

Viking Link [18] is a new high voltage direct current (DC) electricity interconnector between the substation Revsing in southern Jutland, Denmark, and Bicker Fen in Lincolnshire, Great Britain. Its capacity is 1400 MW:

- The interconnector went into operation in December 2023.
- Viking Link is developed by Energinet and the British National Grid, via National Grid Viking Link Ltd. and other subsidiaries.

The connection is composed of the following components:

North Sea:

- 625 km high voltage direct current (HVDC) submarine cables between Great Britain and Denmark. The cables are buried in the seabed.

Denmark:

- A pair of onshore underground high voltage DC cables from the west coast of Jutland to the existing 400 kV substation Revsing near Vejen
- Converter station (VSC technology) in Revsing near Vejen to convert electricity between DC and AC
- New equipment within the existing 400 kV substation at Revsing

Great Britain:

- A pair of onshore underground high voltage DC cables (66.5 km) from the coast in Great Britain to a converter station
- A converter station (VSC technology) to convert electricity between direct current (DC) and alternating current (AC)
- High voltage alternating current (AC) underground cables from the converter station to the existing National Grid substation at Bicker Fen in Lincolnshire
- New equipment within the existing substation

[20] ENTSO-E's Technology Readiness Levels (TRLs) are a method for estimating the maturity of technologies. The use of TRLs enables consistent, uniform discussions of technical maturity across different types of technology.

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West Coast Line: New interconnector to Germany (AC corridor in the same synchronous area based on conventional AC technology)

Together with the German TSO TenneT, Energinet expands the trading capacity between Denmark and Germany by connecting the German and the Danish part of the West Coast Line [18]. On the Danish side, Energinet builds a new double circuit 400 kV overhead line from the substation Endrup to the Danish-German border.

The expansion of the interconnection capacity between Denmark and Germany is related to Viking Link – a 1400 MW interconnector between Denmark and Great Britain. With the realisation of Viking Link, it is necessary to have instant back up capacity in the Danish power system in case of failure on Viking Link. The new line to Germany will guarantee that reserve power can be retrieved in central Europe immediately. The new power line will also increase the trading capacity between Denmark and Germany.

The new interconnector between Denmark and Germany is on the EU list of important infrastructure projects contributing to the interconnection of the European electricity networks, the so-called Projects of Common Interest (PCI).

Technical description:

- The interconnector is established as a double circuit 400 kV overhead line. In environmentally sensitive areas, the line is established with cables in the ground.
- The interconnector goes from the substation Endrup east of Esbjerg and to the German border.
- The power line is approx. 75 km long.
- The line is delayed and is expected to be commissioned in 2026.

Prediction of performance and cost

The evaluation of costs and performance is based on the following main sources:

1. Unit Investment Cost Indicators - Project Support to ACER, PWC, final updated report, September 2023, https://www.acer.europa.eu/sites/default/files/documents/Publications/UIC_report_2023.pdf
2. 2024-ENTSOs TYNDP scenarios, downloads: https://2024.entsos-tyndp-scenarios.eu/download/
3. TYNDP 2022 project sheets (from project promoters) https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission/
4. Screening of possible hub concepts to integrate offshore wind capacity in the North Sea, DNV for DEA, 2021, https://ens.dk/sites/ens.dk/files/Vindenergi/final_report_-_screening_of_possible_hub_concepts_to_integrate_offshore_wind_capacity_in_the_north_sea.pdf
5. Netzentwicklungsplan Strom 2035, Version 2021, German TSOs, https://mst.dk/media/xq3jv14h/netzentwicklungsplan-strom-2035-version-2021.pdf
6. Netzentwicklungsplan Strom 2035, Version 2023, German TSOs, https://www.netzentwicklungsplan.de/en/nep-aktuell/netzentwicklungsplan-20372045-2023

7. Transmission Cost Estimation Guide for MTEP22, MISO (Midcontinent Independent System Operator), 2022, https://cdn.misoenergy.org/20220208%20PSC%20Item%2005c%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP22_Draft622733.pdf

8. Ea Energy Analyses' updated data assumptions in the Balmorel model based. Original source is National Grid, FES (Future Energy Scenarios) with successive updates based on Ea's projects in the sector.

9. ENTSO-E Offshore network development plans, Jan. 2024: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/ONDP2024/ONDP2024-methodology.pdf

Source 1. The data were collected from a questionnaire. ACER (European Regulator) requested project promoters of relevant infrastructure projects to submit costs and technical data for their commissioned projects. Project promoters were asked to submit data for relevant infrastructure assets commissioned in the period 2014- 2023. This source includes assessments of OH lines (AC), underground cables (onshore), submarine cables (AC and DC), AC substations, transformers and HVDC converters.

Source 2 is from ENTSO-E. It includes planning/screening prices for use in TYNDP 2024. For electrical transmission the source only gives data for HVDC cables and onshore HVDC stations.
Source 3 is based on TYNDP2022 project sheets for concrete projects. The sheets are the results of individual assessments of project promoters.

Source 4 provides the data assumptions used in DNV's screening of hub-concepts for DEA in the North Sea. Transmission components include DC offshore cables, onshore and offshore HVDC converters and onshore HVAC transformers.

Source 5 and 6 give cost data for the German TSOs planning of transmission in the North Sea and the Baltic. Data include DC and AC cable systems and AC and DC stations.

Source 7 is a transmission cost estimation guide from MISO, US, who is the Midcontinent Independent System Operator in US. From this source we only look at data for capacitor banks, reactors and Statcoms. The reason is that the costs include all taxes and additional expenses, which we could not isolate. Also, the general price level in the US may differ from conditions in Europe.

Source 8 is Ea Energy Analyses' data assumptions in their Balmorel model. The data is routinely updated with the latest knowledge from client projects.

Source 9 is the recent data-basis for ENTSO-E's offshore development plans, 2024

Uncertainty

Performance data of electrical grid, such as energy losses, technical lifetime and load profile typically depends on techno-economic-market considerations such as amount of energy transfer to adjacent countries, value of energy loss, lifetime vs. investment costs, etc. Changes in regulations, economic and political foundations may have impact on the performance data. Furthermore, large changes on the basic design and operation of the grid will have impact on both performance and costs that are difficult to anticipate.

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Quantitative description

To enable comparative analyses between different technologies it is imperative that data are actually comparable: All cost data are stated in fixed prices/real terms (price level 2020) excluding value added taxes (VAT) and other taxes. Investment costs (Capex) include purchase and installation. The information given in the tables relate to the development status of the technology at the point of final investment decision (FID) in the given year (2025, 2030, 2035, 2040 and 2050).

Price level 2020 is determined by using the yearly inflation rates in EU on average as most data has been collected from Europe.

The Inflation rates for EU on average have been [26]:

- European Union inflation rate for 2023 was 3.4%
- European Union inflation rate for 2022 was 8.83%
- European Union inflation rate for 2021 was 2.55%
- European Union inflation rate for 2020 was 0.48 %
- European Union inflation rate for 2019 was 1.63%

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 after permits have been received.

The quantitative data are described in tables in this report and supplementary datasheets. Data contains parameters used to describe the specific transmission components.

One of the data sources, [28], has percentiles (25 and 75 percentiles) of cost figures for the specific samples in each category. These percentiles can be taken as uncertainties. In other tables the uncertainty of numbers is in general assessed as plus/minus 30 %.

Disruption of transmission asset costs

For offshore wind generation, different studies have indicated a capex increase of about 40 % during the last 3-4 years [46]. From informal talks with industry stakeholders (from TSOs and asset suppliers), it can be concluded that also capex of transmission assets has raised from 2019 to 2023, e.g. in nominal prices:

- Costs of 400 kV OHL have increased by about 20%-40%
- Costs of 400 kV substations have increased by about 40-60%
- Cost of underground cables have increased by about 65%(-100) %
- Costs of HVDC assets have increased maybe by 50-80 %

The transmission cost data published in 2023 may typically originate from project references dated 2-3 years back in time or more and have not been fully exposed to the cost disruption. Nor has earlier data.

Therefore, cost data (converted to 2020 level) from reference in this catalogue has been raised accordingly to obtain 2025 cost prices (2020 price level). For all assets, prices were raised by 20% as a rough estimate to arrive at the 2025 prices. That means that part of/most of the price disruption has been reflected in e.g., 2023 prices from relevant references.

According to contacted transmission sector stakeholders, the main reasons for the surging prices over the last years can be summarised as follows:

- After the COVID-19 pandemic, demand for transmission assets surged due to renewed activity in the energy field. This caused an imbalance between demand and supply. The supply chains became challenged and still are.
- Significantly increased interest rates increased the general cost basis of supplier business, which raised supplier bids in tenders.
- Additional demand increase took place because of the general trend of energy systems going from "fossil fueled" to "green", a development that calls for new investments in the transmission network.
- Increased prices of raw materials.
- The war in Ukraine had global macroeconomic effect and also meant that important factories of transmission assets (e.g. transformers) in Ukraine were destroyed.

Stakeholders from the transmission industry expect the prices to level out, but they do not foresee a downward movement of prices in the near future (in real terms). Even with new factories producing transmission assets being built in e.g. India, China, Germany and US they expect the supply capacity to be lower than the demand for years to come.

In this catalogue we have assumed that in the market in the longer term we will again attain an equilibrium between supply and demand when new factories for transmission assets have been built. Consequently, we have assumed continued high prices until 2030 and thereafter a decline in prices towards 2050. In 2050 the prices are assumed to be back (in real terms) to prices before the assumed 20% price rise.

Overview and discussion of collected relevant data for transmission *(For easier reading all the following tables 1-13 are also shown in the excel file of the Technology Data for Energy transport)*

Technical data for AC transmission

Table presents typical and approximate values of technical parameters for transmission: energy losses and transfer capacities for the components described in this catalogue. For cables the short time load-ability (40 hours)[21] has also been indicated. The numbers are indicative and depend on specific designs of the transmission components: electrical current, line length, conductor type, impedance etc.

An illustrative comparison of capacity between Over Head Lines (OHL- and underground cables is shown in Figure 10. For combined OHL/UGC transmission lines, rated capacity of the applied cable system may be lower than rated capacity of the overhead line sections, as the short-term dynamic loadability of the cable system is designed to match the rated capacity of the OHL sections in order to meet required transmission capacity during contingencies for up to 40 hours.

[21] Insulated cables have a large thermal mass compared to overhead lines, and the thermal time constant of a cable installation and the surrounding soils normally allows for significant short-term overloading.

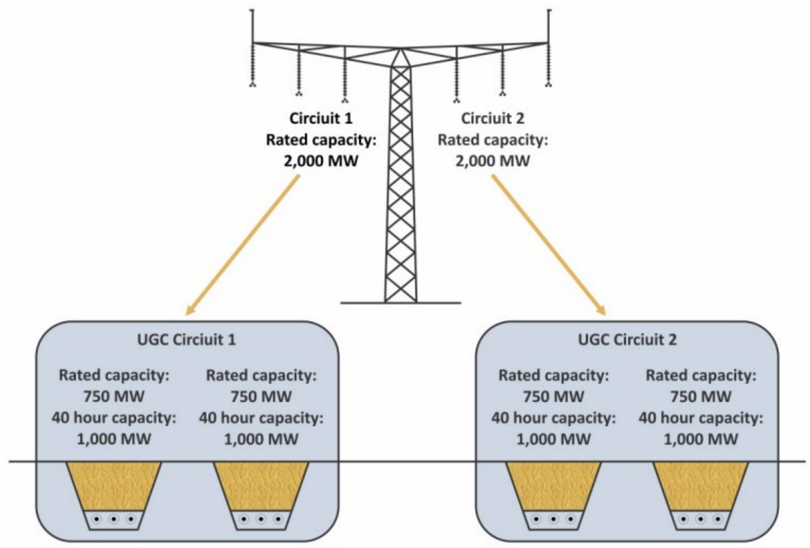

Figure 10: Comparison between AC capacity of an OH-lines and corresponding UGC (underground cable) [27]

Technical data/General			Comment
Energy losses			
(Typical values, depend on length, layout, conductor material, impedance, ampere, compensation etc.)	Energy losses HVAC OH line	5%/100 km (Ref. 1)	At rated power, with compensation
	Energy loss HVDC OH line	1%/100 km (Ref. 1)	At rated power
	HVDC converter loss (per end)	1-2 %	
	Energy loss HVAC cable	5%/100 km	At rated power, with compensation
	Energy loss HVDC cable	1%/100 km	At rated power
	Energy loss Transformer	1-2 %	
Capacity (AC) - typical values (depend on conductor and max. ampere). With compensation.			
OH-lines	110-150 kV 2 circuits	1100 MW	
	220 kV 1 circuit	1100 MW	
	220 kV 2 circuits	2200 MW	
	330 kV 2 circuits	3300 MW	
	380-400 kV 1 circuit	2000 MW	
	400 kV 2 circuits	4000 MW	
Underground cables	110 - 150 kV 1 circuit	210 MW	280 MW (40 hours load)
	110 - 150 kV 2 circuits	420 MW	560 MW (40 hours load)
	220 - 225 kV 1 circuit	420 MW	560 MW (40 hours load)
	220 - 225 kV 2 circuits	840 MW	1120 MW (40 hours load)
	300 - 500 kV 1 circuit	750 MW	1000 MW (40 hours load)
References			
	1. Comparative evaluation of power loss in HVAC and HVDC (2016)		
	https://www.researchgate.net/publication/313587347		

Table 1: Technical data for OH-lines and cables [23], [27]

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OH-lines - AC and DC

Table presents economic data for OH-Lines. Some data are based on [28], which are ACER´s recent (2023) investment cost indicators. The original data from [28] are in the unit MEUR/km (upper part of table). By using the capacities from Table , the costs can be calculated in kEUR/km/MW (as shown). Low and high prices in Table correspond 25 and 75 percentiles of data samples.

(Netz, 2021) provide data for AC and DC and (Balmorel, 2022) has data for DC. Figures for 2025 are estimated by adding 20% to the price from the source (2020 price level). The 20% is an estimate based on informal talks with industry stakeholders in the power transmission sector. The increase is explained by higher material cost, supply chain bottlenecks etc.

OH lines						**2020 price level**		**Size of data sample**	**Reference**	**Comment**
			Original price frc	**Original, from source: Low**	**Original from, source: High**	**Pice from source**	**2025**			
ACER, pwc, UIC, 2023	Overhead line (MEUR/km)- AC	110-150 kV 2 circuits	0,32	0,22	0,39	0,29		3	1	1,2
		220 kV 1 circuit	0,41	0,30	0,54	0,37		7	1	1,2
		220 kV 2 circuits	0,53	0,44	0,67	0,47		21	1	1,2
		330 kV 2 circuits	0,57	0,52	0,57	0,51		5	1	1,2
		380-400 kV 1 circuit	0,47	0,30	0,61	0,42		18	1	1,2
		400 kV 2 circuits	1,26	0,53	1,63	1,13		45	1	1,2
	Overhead line (kEUR/km/MW)- AC									
1100	MW	110-150 kV 2 circuits	0,30	0,20	0,36	0,26		3	1	1,2
1100	MW	220 kV 1 circuit	0,37	0,28	0,49	0,33		7	1	1,2
2200	MW	220 kV 2 circuits	0,24	0,20	0,31	0,22		21	1	1,2
3300	MW	330 kV 2 circuits	0,17	0,16	0,17	0,16		5	1	1,2
2000	MW	380-400 kV 1 circuit	0,23	0,15	0,30	0,21		18	1	1,2
4000	MW	400 kV 2 circuits	0,32	0,13	0,41	0,28		45	1	1,2
Netz, 2021	Overhead line (MEUR/km)- AC	380 kV, 2 circuits-AC	2,50			2,49			3	2
	4000 MW OH line AC (kEUR/km/MW)	381 kV, 2 circuits-AC	0,63			**0,62**	**0,75**		3	2
Netz, 2021	Overhead line (MEUR/km) DC	2 circuits; 2 GW per circuit	2,00			1,99			3	2
	4000 MW (kEUR/km/MW) DC	2 circuits	0,50			**0,50**	**0,60**		3	2
Balmorel model, 2022	Overhead line - DC-kEUR/km/MW		0,76			0,74			2	3
References										
	1. Unit Investment Cost Indicators - Project Support to ACER Final report, pwc, Sept. 2023									
	2. Balmorel Model assumptions									
	3. Netzentwicklungsplan Strom (German TSOs), version 2021									
Comment	1. Low and high prices correspond to the 25 and 75 pencentiles of the data sample									
	2. 2025 prices are calculated by adding 20% to price from source									
	3. Balmorel 2022 data have already been lifted									

Table 2: Economic data for OH-Lines, AC and DC (references in the bottom of the table)

The data from (Netz, 2021) is selected for the price forecast. The argument is that (Netz, 2021) provide figures which must be assumed to be consistent between AC and DC, as prices come from the same source: the German TSOs. In addition, the German TSOs have large experience with transmission costs from their many projects.

OH lines, 2020 price level													
		2025	**2025 low**	**2025 high**	**2030**	**2035**	**2040**	**2045**	**2050**	**2050 low**	**2050 high**	**Reference**	**Comment**
OH lines AC	kEUR/km/MW (4000 MW capacity)	0,75	0,58	0,98	0,75	0,72	0,68	0,65	0,62	0,48	0,80	1	1,2,3,4
OH lines DC	kEUR/km/MW (4000 MW capacity)	0,60	0,46	0,78	0,60	0,58	0,55	0,53	0,50	0,38	0,65	1	1,2,3,4
References													
	1. Netzentwicklungsplan Strom (German TSOs), version 2021												
Comment													
	1. Low and high are minus/plus 30%												
	2. 2025 prices: after adding 20% to price from source												
	3. Prices in 2050 assumed to be as prices before 20% increase in 2025												
	4. Prices assumed to decrease linearly from 2030 to 2050												

Table 3: Cost forecast for OH-Lines, AC and DC

Table presents the cost forecast for OH-Lines, AC and DC. The costs are assumed unchanged until 2030. From 2030 to 2050 the prices are assumed to decrease (until the level before the 2025 uplift). The uncertainty interval (high and low values) is assumed to be plus/minus 30%.

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Economic data for AC and DC cables onshore and offshore

Table 4 presents the collected data for cables from different references, see bottom of table. Data are in the unit MEUR/km or in kEUR/km/MW. The different categories AC/DC and onshore/offshore are indicated by different colours.

Where shown, low and high correspond to the 25 and 75 percentiles of the data samples, respectively.

For AC underground cables the original data from (ACER,pwc) are in unit mEUR/km. By using the capacities from table 1, the costs can be calculated in kEUR/km/MW, as shown in the table.

Cables							2020 price level		Size of data sample	Reference	Comment
				Original price from source	Original from source, low	Original from source, high	Price from source	2025			
ACER, pwc, UIC, 2023	**AC, Onshore underground cable**	110 - 150 kV 1 circuit	mEUR/km	0,83	0,43	0,64	0,74		14	1	1
		110 - 150 kV 2 circuits	mEUR/km	2,23	0,85	3,06	2,00		4	1	1
		220 - 225 kV 1 circuit	mEUR/km	1,78	1,23	2,11	1,59		16	1	1
		220 - 225 kV 2 circuits	mEUR/km	4,40	4,23	4,56	3,93		4	1	1
		300 - 500 kV 1 circuit	mEUR/km	1,31	1,05	1,39	1,17		4	1	1
280	MW	110 - 150 kV 1 circuit	kEUR/km/MW	2,97	1,54	2,29	2,65		14	1	1
560	MW	110 - 150 kV 2 circuits	kEUR/km/MW	3,99	1,52	5,46	3,56		4	1	1
560	MW	220 - 225 kV 1 circuit	kEUR/km/MW	3,18	2,20	3,77	2,84		16	1	1
1120	MW	220 - 225 kV 2 circuits	kEUR/km/MW	3,93	3,78	4,07	3,51		4	1	1
1000	MW	300 - 500 kV 1 circuit	kEUR/km/MW	1,31	1,05	1,39	1,17		4	1	1
Netz, 2023 prices	AC, 220 kV cable system, onshore		mEUR/km	2,10						5	
	AC, 220 kV cable system, onshore	500 MW	kEUR/km/MW	4,20			**3,75**	**4,51**		5	2,3
	AC Offshore cable										
NETZ, 2021 prices	AC cable system 220 kV (offshore) Baltic Sea		mEUR/km	2,90			2,89			2	
NETZ, 2023 prices	AC cable system 220 kV (offshore) Baltic Sea		mEUR/km	2,10			1,88			5	
NETZ, 2023 prices	AC cable system 220 kV (offshore) Baltic Sea	500 MW	kEUR/km/MW	4,20			**3,75**	**4,51**		5	2,3
NETZ, 2021 prices	AC cable system 155 kV (offshore) Nord Sea		mEUR/km	1,50			1,49			2	
ACER, pwc, UIC, 2023	**AC Offshore cable (132-380 kV)**		mEUR/km	2,01			1,79		9	1	
Balmorel, 2022 prices	**AC Offshore cable**		kEUR/km/MW	1,96			1,90			3	
NETZ, 2021 prices	**DC onshore cable, 525 kV Nord Sea**		mEUR/km	6,50			6,47			2	
NETZ, 2023 prices	DC onshore cable, 525 kV Nord Sea and Baltic Sea		mEUR/km	7,60			6,79			5	
NETZ, 2023 prices	DC cable system 525 kV (onshore) (bipole)	2000 MW	kEUR/km/MW)	3,80			**3,40**	**4,07**		5	2,4
Balmorel, 2022 prices	**DC onshore cables**		kEUR/(km* MW)	1,74			1,69			3	
ACER2023 prices	**DC offshore cable (300-500 kV)**		mEUR/km	1,11			0,99		6	1	
	Offshore transmission cable, 150-320 kV (AC?, DC?- unclear)		mEUR/km	3,29			2,94		7	1	
NETZ2021 prices	**DC offshore** cable system, 525 kV Nord Sea		mEUR/km	4,00			3,98			2	
NETZ2023 prices	DC offshore cable system, 525 kV Nord Sea and Baltic Sea		mEUR/km	6,00			5,36			5	
NETZ2023 prices	DC offshore cable system, 525 kV (bipole)	2000 MW	kEUR/km/MW	3,00			**2,68**	**3,22**		5	2,4
NETZ2021 prices	DC offshore cable system, 525 kV Nord Sea and Baltic Sea		mEUR/km	2,00			1,99			2	
2024 ENTSO-Eplanning p	**DC offshore cables**		kEUR/(km* MW)	1,62			1,40			4	
Tyndp 2022-project prom	**DC offshore cables**		kEUR/(km* MW)	1,70			1,65			6	
DNV2021 prices	**DC offshore cables**										
	0,5 GW 525 kV Cable		mEUR/km	1,64			1,63			7	
	1 GW 525 kV Cable		mEUR/km	1,89			1,88			7	
	1,5 GW 525 kV Cable		mEUR/km	2,14			2,13			7	
	2 GW 525 kV cable		mEUR/km	2,47			2,46			7	
DNV2021 prices	**DC offshore cables**										
	0,5 GW 525 kV Cable		kEUR/km/MW	3,28			3,28			7	
	1 GW 525 kV Cable		kEUR/km/MW	1,89			1,89			7	
	1,5 GW 525 kV Cable		kEUR/km/MW	1,43			1,43			7	
	2 GW 525 kV cable		kEUR/km/MW	1,24			1,24			7	
Balmorel 2022 prices	**DC offshore cables**		kEUR/(km* MW)	2,13			2,06			3	
References											
	1. Unit Investment Cost Indicators - Project Support to ACER. Final report, pwc, Sept. 2023, https://www.acer.europa.eu/sites/default/files/documents/Publications/UIC_report_2023.pdf										
	2. Netzentwicklungsplan Strom (German TSOs), version 2021										
	3. Balmorel model data										
	4. ENTSO-E planning prices for TYNDP 2024										
	5. Netzentwicklungsplan Strom (German TSOs), version 2023										
	6. TYNDP 2022 project sheets (from project promoters)										
	7. Screening of possible hub concepts to integrate offshore wind capacity in the North Sea, DNV for DEA, 2021										
Comments	1. Low and High values are 25 and 75 percentiles of the sample										
	2. Shown 2025 prices estimated by adding 20 % to price from source										
	3. 220 kV with capacity of about 500 MW										
	4. 525 kV bipole with capacity 1500-2000 MW										

Table 4: Economic data for AC and DC cables, onshore and offshore (references in the bottom of the table)

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Cables, 2020 price level													
		2025	2025 low	2025 high	2030	2035	2040	2045	2050	2050 low	2050 high	Reference	Comment
AC onshore cables	kEUR/km/MW (500 MW capacity)	4,51	3,47	5,86	4,51	4,32	4,13	3,94	3,75	2,88	4,88	1	1,2,3,4
AC offshore cables	kEUR/km/MW (500 MW capacity)	4,51	3,47	5,86	4,51	4,32	4,13	3,94	3,75	2,88	4,88	1	1,2,3,4
DC onshore cables	kEUR/km/MW (1500-2000 MW capacity)	4,07	3,13	5,29	4,07	3,91	3,74	3,57	3,40	2,62	4,42	1	1,2,3,4
DC offshore cables	kEUR/km/MW (1500-2000 MW capacity)	3,22	2,48	4,19	3,22	3,09	2,95	2,82	2,68	2,06	3,48	1	1,2,3,4
References													
	1. Netzentwicklungsplan Strom (German TSOs), version 2023												
Comment													
	1. Low and high are minus/plus 30%												
	2. 2025 prices: adding 20% to price from source												
	3. Prices in 2050 assumed to be as prices before 20% increase in 2025												
	4. Prices assumed to decrease linearly from 2030 to 2050												

Table 5: Cost forecast, AC and DC, onshore and offshore cables

It follows from Table 4 that in general there is high variation in prices for each category. The prices therefore have a high uncertainty.

As basis for cost forecast the data from (Netz, 2023) is selected for cable systems. The argument is that (Netz, 2023) provide figures which must be assumed to be consistent between AC and DC and onshore/offshore, as prices come from the same source: the German TSOs. In addition, the German TSOs have large experience with transmission costs from their many projects and German prices are assumed to be close to Danish/Nordic prices.

Where shown, figures for 2025 (2020 price level) are estimated by adding 20% to the price from the source (2020 price level). The 20% is an estimate based on informal talks with stakeholders in the power transmission sector primarily in Denmark and the assumption that part/most of the price rise over the last years has been reflected in the 2023 prices in the references. The increase is explained by higher material cost, supply chain bottlenecks etc.

Table 5 summarizes the results. Prices are assumed unchanged from 2025 to 2030. From 2030 to 2050 the prices are assumed to decrease in real terms (2020 price-level) (until the level before the 2025 uplift).Thus, we have assumed that in the market in the longer term we will again attain an equilibrium between supply and demand when new factories for transmission assets have been built. Consequently, we have assumed continued high prices until 2030 and thereafter a decline in prices towards 2050.

Economic data for substations

Table presents the collected relevant data for substations from several references, see bottom of table. Different colours are used to indicate the different categories.

Where shown, low and high correspond to the 25 and 75 percentiles of the data samples, respectively. The range between the two percentiles give a good indication of the uncertainty.

The reference from (ACER, 2023) have many costs data stemming from the same projects but sorted due to different indicators. One indicator is number of bays in the substation. A bay is a set of equipment which connects a circuit into the substation. The more bays the bigger the substation. Other indicators used by (ACER, 2023) are kEUR/kV and kEUR/MVA. It can be confusing with so many different indicators but nevertheless the data is reported here to illustrate the spread and the difficulties encountered when comparing numbers from different references.

(ACER, 2023) data are shown for AIS New, AIS Updated/refurbished and GIS New. AIS means open air stations (air insulated stations), GIS refers to Gas Insulated Stations. In a GIS station the major conducting components are contained within a sealed environment.

It follows that (ACER, 2023) price data for AC substations often are significantly smaller than data from other sources, e.g., (Netz, 2023) data, often a factor of 3 in unit MEUR/MW. The reason for this discrepancy cannot be immediately explained. Therefore, the data from (ACER, 2023) has been discarded from further processing[22].

Balmorel prices for a DC substation plus platform (0.23+0.45 MEUR/MW) is in good agreement with the (Netz, 2023) data which is 0.63 MEUR/MW (price from source).

As basis for cost forecast the data from (Netz, 2023) is selected for substations. The argument is that (Netz, 2023) provide figures which must be assumed to be consistent between AC and DC and onshore/offshore, as prices come from the same source: the German TSOs. In addition, the German TSOs have large experience with substation costs from their many projects and German prices are assumed to be close to Danish/Nordic prices.

Where shown, figures for 2025 are estimated by adding 20% to the price from source (2020 price level). The 20% is an estimate based on informal talks with industry stakeholders in the power transmission sector and the assumption that part of the price rise over the last years has been reflected in the 2023 prices. The increase is explained by higher material cost, supply chain bottlenecks etc.

[22] It can be noted that ENTSO-E (covering all of Europe) in their recent 2024 Offshore Network Development Plans also use (NETZ, 2023)-price data for Substations (AC and DC) for their analyses. ENTSO-E TYNDP 2024 Offshore Network Development Plans – Methodology.

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Substations							2020 price level				
				Original price from source	Original, low	Original, high	Price from source	2025	Size of data sample	Reference	Comment
ACER, 2023 prices	Onshore AC substation	0-5 bays, all	mEUR/asset	5,31	2,20	6,70	4,74		77	1	1
		New/AIS/maximum 5 bays		11,71	3,59	16,91	10,47		24	1	
		New/GIS/maximum 5 bays		13,62	5,40	15,99	12,18		8	1	
		Refurbishment or Upgrade/AIS/maximum 5 bays		3,40	2,12	4,30	3,04		28	1	
		Refurbishment or Upgrade/GIS/maximum 5 bays		4,45	1,00	6,40	3,98		13	1	
		6-9 bays, all		12,59	7,88	16,41	11,25		62	1	
		New/AIS/from 6 to 9 bays		12,14	8,18	16,68	10,85		24	1	
		New/GIS/from 6 to 9 bays		9,82	7,82	11,53	8,78		20	1	
		Refurbishment or Upgrade/AIS/from 6 to 9 bays		15,38	6,81	23,44	13,75		14	1	
		10-60 bays, all		29,85	19,26	40,33	26,68		23	1	
		10-60 bays , New		43,57	22,72	58,86	38,95		13	1	
		10-60 bays Refurbishment/upgrade		29,85	20,88	41,92	26,68		10	1	
ACER, 2023 prices	Onshore AC substation	All	kEUR/kV	31,25	16,68	43,45	27,93		118	1	3
		AIS New		31,72	18,52	43,62	28,36		48	1	4
		AIS updated/Refurbished		27,57	12,33	45,26	24,64		33	1	
		GIS New		35,11	27,68	42,31	31,38		26	1	5
ACER, 2023 prices	Onshore AC substation	All	kEUR/MVA	68,82	37,58	93,13	61,53		44	1	2
		AIS New		65,88	43,41	81,89	58,90		19	1	
		AIS updated/Refurbished		50,03	23,46	70,73	44,72		16	1	
		GIS New		123,68	93,48	133,74	110,56		8	1	
ACER, 2023 prices	Onshore AC substation	220-275 kV	mEUR/bay	1,21	0,84	1,52	1,08		48	1	
		300-330 kV		1,21	1,05	1,37	1,08		4	1	
		380-400 kV		3,38	1,15	5,24	3,02		56	1	
Netz, 2023	**AC onshore substation, 220 kV**		mEUR/MW	0,24			**0,21**	**0,25**		4	7,8
ACER, 2023 prices	AC Offshore substation		mEUR/asset	133,07	104,73	154,83	118,96		6	1	
Netz, 2023	**AC offshore substation, 220 kV (with platform)**		mEUR/MW	0,56			**0,50**	**0,60**		4	7,8
NETZ, 2021 prices	AC (Offshore + Onshore station)/2	Baltic Sea	mEUR/MW	0,35			0,35			2	6
NETZ, 2023 prices	AC (Offshore + Onshore station)/2	220 kV, AC, Baltic SEA	mEUR/MW	0,40			0,36			4	6
NETZ, 2021 prices	DC (offshore + onshore station)/2, 320 kV (with AC/DC converter)	North Sea	mEUR/MW	0,50			0,50			2	6 -
NETZ, 2021 prices	DC (onshore + offshore station)/2, 525 kV (with AC/DC converter)	North Sea	mEUR/MW	0,38			0,38			2	6
NETZ, 2023 prices	**DC onshore 525 kV station with converter (AC/DC)**	North Sea and Baltic Sea	mEUR/MW	0,30			**0,27**	**0,32**		4	7,9
NETZ, 2023 prices	**DC offshore station 525 kV with converter (AC/DC), incl. platform**	North Sea and Baltic Sea	mEUR/MW	0,70			**0,63**	**0,75**		4	7,9
ENTSO-E-planning prices 2024	Onshore DC station with converter (AC/DC)		mEUR/MW	0,25			0,22			5	
Tyndp 2022-project promoters	Onshore DC station with converter (AC/DC)		mEUR/MW	0,15			0,14			6	
DNV 2021 prices	Onshore DC station with converter (AC/DC)	1 GW, 525 kV	mEUR/MW	0,18			0,18			7	
Balmorel 2022 prices	One DC/AC substation		mEUR/MW	0,24			**0,23**			3	
	Offshore platform AC (no substation)		mEUR/MW	0,15			0,15			3	
	Offshore platform DC (no substation)		mEUR/MW	0,47			**0,45**			3	

Comments

1. Substation bay: A set of equipment which connects a circuit into a substation.
2. MVA: Mega Volt Ampere measures the size of transformers/substations
3. kV is busbar rating
4. AIS: Air insulated substation (typical open air station).
5. GIS: In a gas insulated substation (GIS) the major conducting structures are contained within a sealed environment with a dielectric gas (SF6)
6. Half of one offshore + one onshore station
7. Prices for 2025 by adding 20% to price from source
8. 220 kV substation, capacity in the range of 500 MW
9. 525 kV HVDC substation, capacity in the range of 1500-2000 MW

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3. Balmorel model data
4. Netzentwicklungsplan Strom (German TSOs), version 2023
5. ENTSO-E planning prices for TYNDP 2024
6. TYNDP 2022 project sheets (from project promoters)
7. Screening of possible hub concepts to integrate offshore wind capacity in the North Sea, DNV for DEA, 2021

Table 6: Economic data for substations

Table summarizes the cost forecast. Prices are assumed unchanged from 2025 to 2030. From 2030 to 2050 the prices are assumed to decrease (until the level before the 2025 uplift). The uncertainty interval (high and low values) is assumed to be plus/minus 30%.

Substations, 2020 price level														
		Price from source	2025	2025 low	2025 high	2030	2035	2040	2045	2050	2050 low	2050 high	Reference	Comment
AC onshore substation	MEUR/MW (500 MW capacity)	0,21	**0,25**	0,19	0,33	0,25	0,24	0,23	0,22	0,21	0,16	0,27	1	1,2,3,4,5
AC offshore substation, incl. platform	MEUR/MW (500 MW capacity)	0,50	**0,60**	0,46	0,78	0,60	0,58	0,55	0,53	0,50	0,38	0,65	1	1,2,3,4,5
DC onshore substation with converter (AC/DC)	MEUR/MW (1500-2000 MW capacity)	0,27	**0,32**	0,25	0,42	0,32	0,30	0,29	0,28	0,27	0,21	0,35	1	1,2,3,4,6
DC offshore substation with converter (AC/DC), incl. platform	MEUR/MW (1500-2000 MW capacity)	0,63	**0,75**	0,58	0,98	0,75	0,72	0,69	0,66	0,63	0,48	0,82	1	1,2,3,4,6

References

1. Netzentwicklungsplan Strom (German TSOs), version 2023

Comment

1. 2025 prices: adding 20% to "year of source" prices
2. Low and high: minus/plus 30%
3. Prices in 2050 assumed to be as prices before 20% increase in 2025
4. Prices assumed to decrease linearly from 2030 to 2050
5. AC substation includes transformers, switchgear, powerlines, compensation, control equipment etc.
6. DC substation includes converter, converter transforme DC substation includes converter, converter transformers, AC switchgear and busbars, harmonic filters , lightning towers, ancillary plant etc

Table 7: Cost forecast, substations

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Economic data for transformers

Table 8 shows economic data for transformers. Where shown, low and high prices correspond to the 25 and 75 percentiles of the data samples, respectively. The range between the two percentiles give a good indication of the uncertainty.

Transformers will normally be a part of a substation, and their costs will be included in the substation cost (also in this catalogue).

When comparing figures in kEUR/MVA it follows that (DNV, 2021) and (Netz, 2021) prices are significantly lower than (ACER, 2023).

It is also seen that (DNV, 2021) and (Netz, 2021) prices are in fairly good agreement.

As basis for cost performance the data from (Netz, 2021) is selected for transformers. The argument is that (Netz, 2021) provide figures from the German TSOs, who have large experience with transformers from their many projects and German prices are assumed to be close to Danish/Nordic prices. Besides (Netz) prices have been selected for other transmission components.

Where shown, figures for 2025 are estimated by adding 20% to the price from source (2020 price level). The increase is explained by higher material cost, supply chain bottlenecks etc. The 20% is an estimate based on informal talks with industry stakeholders in the power transmission sector (primarily in Denmark) and the assumption that part of the price rise over the last years has been reflected in the 2023 prices.

Table 9 summarizes the cost forecast for transformers. Prices are assumed unchanged from 2025 to 2030. From 2030 to 2050 the prices are assumed to decrease (until the level before the 2025 uplift). Thus, we have assumed that in the market in the longer term we will again attain an equilibrium between supply and demand when new factories for transmission assets have been built. Consequently, we have assumed continued high prices until 2030 and thereafter a decline in prices towards 2050.

The uncertainty interval (high and low values) is assumed to be plus/minus 30%.

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Transformers						2020 price level				
			Original price from source	Original low	Original high	Price from source	2025	Size of data sample	Reference	Comment
ACER, 2023 prices	150/60 kV	mEUR/asset	1,21	1,10	1,27	1,08		3	1	1
	220/66 kV	mEUR/asset	1,54	1,34	1,72	1,37		12	1	1
	400/110 kV	mEUR/asset	4,36	3,63	4,73	3,90		15	1	1
	400/220 kV	mEUR/asset	4,63	2,94	6,18	4,14		7	1	1
	150/60 kV	kEUR/MVA	63,80	51,26	88,79	57,04		3	1	1
	220/66 kV	kEUR/MVA	97,70	82,66	108,70	87,34		12	1	1
	400/110 kV	kEUR/MVA	76,80	57,39	92,83	68,66		15	1	1
	400/220 kV	kEUR/MVA	28,20	22,75	34,46	25,21		7	1	1
DNV, 2021 prices	210/30 kV, 700 MVA	mEUR/asset	7,50			7,46			2	
	210/30 kV, 500 MVA	mEUR/asset	5,10			5,08			2	
	210/30 kV, 700 MVA	kEUR/MVA	10,71			10,7			2	
	210/30 kV, 500 MVA	kEUR/MVA	10,20			10,2			2	
NETZ, 2021 prices										
	380/110 kV, 300 MVA	kEUR/MVA	17,33			**17,3**	**20,8**		3	2
	380/220 kV, 600 MVA	kEUR/MVA	13,33			**13,3**	**16,0**		3	2
	220/110 kV, 200 MVA	kEUR/MVA	17,50			**17,4**	**20,9**		3	2
Comments										
	1. Low and high are the 25 and 75 percentiles of the sample									
	2. 2025 prices obtained by adding 20% to price from source									
References										
	1. Unit Investment Cost Indicators - Project Support to ACER. Final report, pwc, Sept. 2023									
	2. Screening of possible hub concepts to integrate offshore wind capacity in the North Sea, DNV for DEA, 2021									
	3. Netzentwicklungsplan Strom (German TSOs), version 2021									

Table 8: Economic data for transformers

Transformers, 2020 price level													
		2025	2025 low	2025 high	**2030**	**2035**	**2040**	**2045**	**2050**	**2050 low**	**2050 high**	**Reference**	**Comment**
380/110 kV, 300 MVA	kEUR/MVA	**25,9**	19,9	33,7	25,9	23,8	21,6	19,5	17,3	13,3	22,5	1	1,2,3,4
380/220 kV, 600 MVA	kEUR/MVA	**19,9**	15,3	25,9	19,9	18,3	16,6	15,0	13,3	10,2	17,3	1	1,2,3,4
220/110 kV, 200 MVA	kEUR/MVA	**26,1**	20,1	33,9	26,1	23,9	21,8	19,6	17,4	13,4	22,6	1	1,2,3,4
References													
	1. Netzentwicklungsplan Strom (German TSOs), version 2021												
Comment													
	1. 2025 prices: adding 50% to price from source												
	2. Low and high: minus/plus 30%												
	3. Prices assumed to decrease linearly from 2030 to 2050												
	4. Prices in 2050 assumed to be as prices before 50% increase in 2025												

Table 9: Cost forecast, transformers

Economic data for compensation

Compensation is used to control voltage and transfer capacity of the transmission grid. Compensation is in the form of reactive power provided or consumed by means of capacitor banks, reactors, SVCs and Statcoms (see qualitative chapter).

Table 10 and
Table 2 present economic data for compensation via capacitor banks, reactors, SVC and Statcoms. All figures are in kEUR/MVAr. The data in
Table 10 is from US, MISO (system operator) [34]; the data in
Table 2 is from Germany (Netzentwicklungsplan, version 2021) [32].

The cost figures in US can be problematic to use directly for European purposes due to possible differences in market and price structures. Also, the definition of the CAPEX is different in the two cases:

Table 10 (US) figures include taxes and contingency etc., while
Table 2's figures are the raw CAPEX costs (equipment, installation).

2025 prices have been estimated by adding 20% to the price from source. The increase is explained by higher material cost, supply chain bottlenecks etc.

By comparing 2025 figures in
Table 10 with corresponding figures in
Table 2 it is seen that US figures for STATCOM and SVC are about 45% and 90% higher that German figures, respectively. For capacitor banks and reactors, German prices are significantly higher than US prices.

As basis for cost performance the data from (Netz, 2021) is selected. This data is assumed to best represent European conditions. Also, as mentioned the US definition of CAPEX differs from the definition in this study.

Compensation	**2025 prices (price level 2020)**										
	Voltage class	**69 kV**	**115 kV**	**138 kV**	**161 kV**	**230 kV**	**345 kV**	**500 kV**	**765 kV**	**Reference**	**Comment**
	Reactor (kEUR/MVAr)	16	16	16	16	16	16	25	36	1	1,2,3,4
	Capacitor bank (kEUR/MVAr)	12	12	12	12	12	12	12	12	1	1,2,3,4
	SVC, Static VAr compensator (kEUR/MVAr)	115	115	115	115	115	115	115	115	1	1,2,3,4
	STATCOM (kEUR/MVAr)	227	227	227	227	227	227	227	227	1	1,2,3,4
References											
	1. Transmission Cost Estimation Guide For MTEP22, April 2022 (DRAFT)										
Comments											
	1. MVAr: MVA reactive power										
	2. Unit costs include all material, shipping, foundation, and installation costs, taxes (not specified) and contingency										
	3. Original prices in 2022 US$: exchange rate in 2022 is 0,951 EUR/$;										
	4. Prices in 2025: addition of 20% to price from source										

Table 10: Economic data for compensation, US data

Compensation								
					Price level 2020			
			Unit	**Price, original from source**	**Price from source**	**2025**	**Reference**	**Comment**
Netz,2021	380 kV, 100 MVAr	**Capacitor bank**	kEUR/MVAr	20	20	24	1	1
Netz,2021	380 kV, SVC	**SVC**	kEUR/MVAr	50	50	60	1	1
Netz,2021	380 kV, 100 MVAr	**Reactor**	kEUR/MVAr	21	21	25	1	1
Netz,2021	380 kV	**STATCOM**	kEUR/MVAr	130	129	155	1	1
References:								
	1. Netzentwicklungsplan Strom (German TSOs), version 2021							
Comment:								
	1. 2025 prices by adding 20% to price from source							

Table 2: Economic data for compensation, European data (Germany)

Table 3 summarizes the cost forecast for compensation, European data. Prices are assumed unchanged from 2025 to 2030. From 2030 to 2050 the prices are assumed to decrease (until the level before the 2025 uplift). The uncertainty interval (high and low values) is assumed to be plus/minus 30%.

Compensation, 2020 price level													
		2025	2025 low	2025 high	2030	2035	2040	2045	2050	2050 low	2050 high	Reference	Comment
Capacitor bank	kEUR/MVAr	24	18	31	24	23	22	21	20	15	26	1	1,2,3,4
SVC	kEUR/MVAr	60	46	78	60	58	55	53	50	38	65	1	1,2,3,4
Reactor	kEUR/MVAr	25	19	33	25	24	23	22	21	16	27	1	1,2,3,4
STATCOM	kEUR/MVAr	155	119	202	155	148	142	135	129	99	168	1	1,2,3,4
References													
	1. Netzentwicklungsplan Strom (German TSOs), version 2021												
Comment													
	1. Low and high: minus/plus 30%												
	2. 2025 prices: adding 20% to price from source												
	3. Prices assumed to decrease linearly from 2030 to 2050												
	4. Prices in 2050 assumed to be as prices before 20% increase in 2025												

Table 3: Cost forecast, compensation, European data (Germany)

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Economic data, O&M

The annual costs of operating and maintaining the transmission system components vary due to system design, materials, climate, age etc. Often the costs are assumed to be a percentage per year of the investment cost (CAPEX). It can be argued that O&M costs would not increase with the same rate as an abrupt capex increase. However, for the sake of simplicity the percentages are kept unchanged from 2025-2050.

Table 4 lists some guiding values.

O&M in % of CAPEX			
OH lines (AC and DC)			1,5
Onshore HVDC cable			2,5
Offshore HVDC cable			2,5
Offshore HVDC converter station			1,5
Onshore HVDC converter station			0,7-1,5
Offshore AC substation			1,5
Onshore AC substation			1,5
Offshore AC cable			2,5
Onshore AC cable			2,5

Table 4: O&M (percentage per year of CAPEX) in transmission systems [30], [31], [36], [42]

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112 Natural gas distribution grid

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Qualitative description

Brief technology description

General information on the natural gas network

The natural gas system in Denmark is divided into different levels. These are:

- Transmission at 80 bar
- Main distribution at 16-40 bar
- Distribution

An overview of the transmission and distribution lines is shown in Figure 1.

The transmission network will not be covered extensively, as it is beyond the scope of this section. For safety reasons an odorant is added to gas before it enters the main distribution system, see Figure 1. The odorant gives the gas its characteristic smell of gas.

Figure 2 shows that the gas network covers most of Denmark, except for some of the islands and a part around Aarhus and Djursland.

Besides the natural gas network, there are networks for town gas in Copenhagen and Aalborg. However, the town gas networks will not be covered, as they use a different gas pressure, convey town gas (today a mixture of natural gas and air) and are constructed in a different period of time as well as with a different technology.

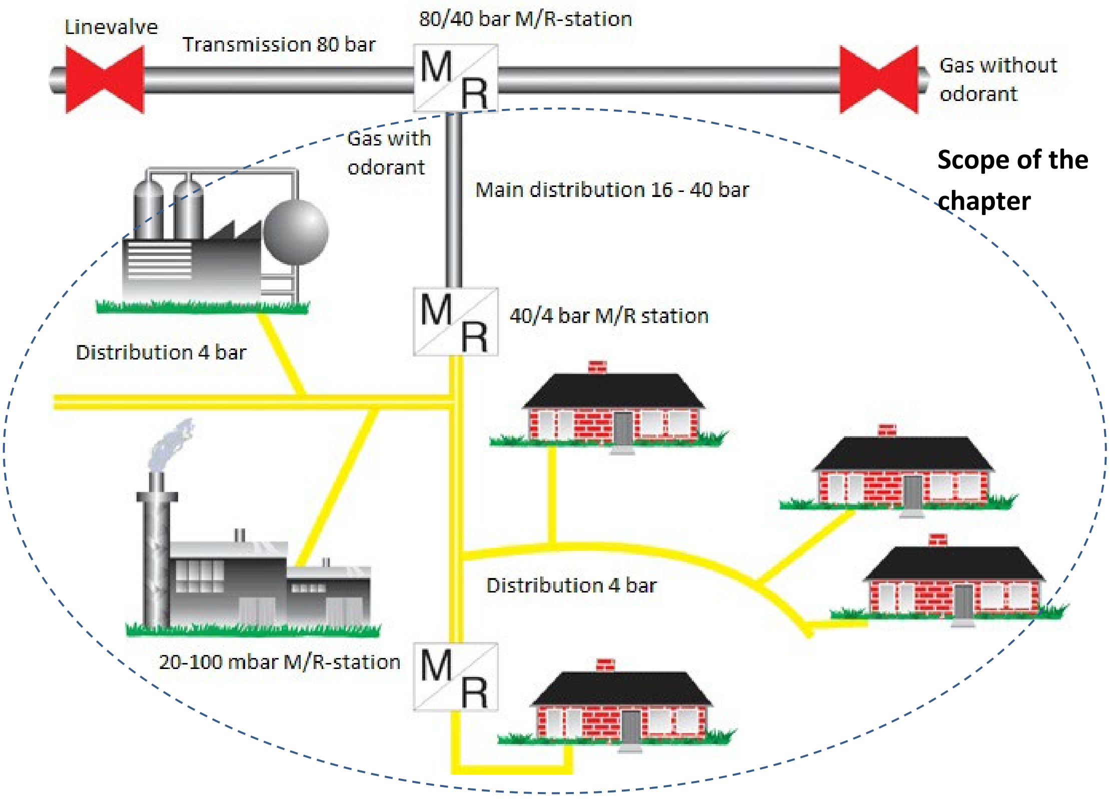

Figure 1 Overview of the gas network. Based on ref. [1].

Ownership of the network

Energinet, the Danish national transmission system operator for the natural gas system, owns and operates the transmission system. The distribution network, including main distribution lines, are owned and operated by the distribution companies.

When the natural gas network was planned, the network was divided into five areas:

- Northern part of Jutland
- Southern part of Jutland
- Funen
- Western part of Zealand
- Northern part of Zealand

However, some gas distribution companies have merged so that today there are currently three natural gas distribution companies:

- Dansk Gas Distribution A/S (Previously DONG Gas Distribution A/S)
- NGF Nature Energy Distribution A/S
- HMN Gasnet P/S

Their coverage can be seen in Figure 2, where the original division in five areas also can be perceived.

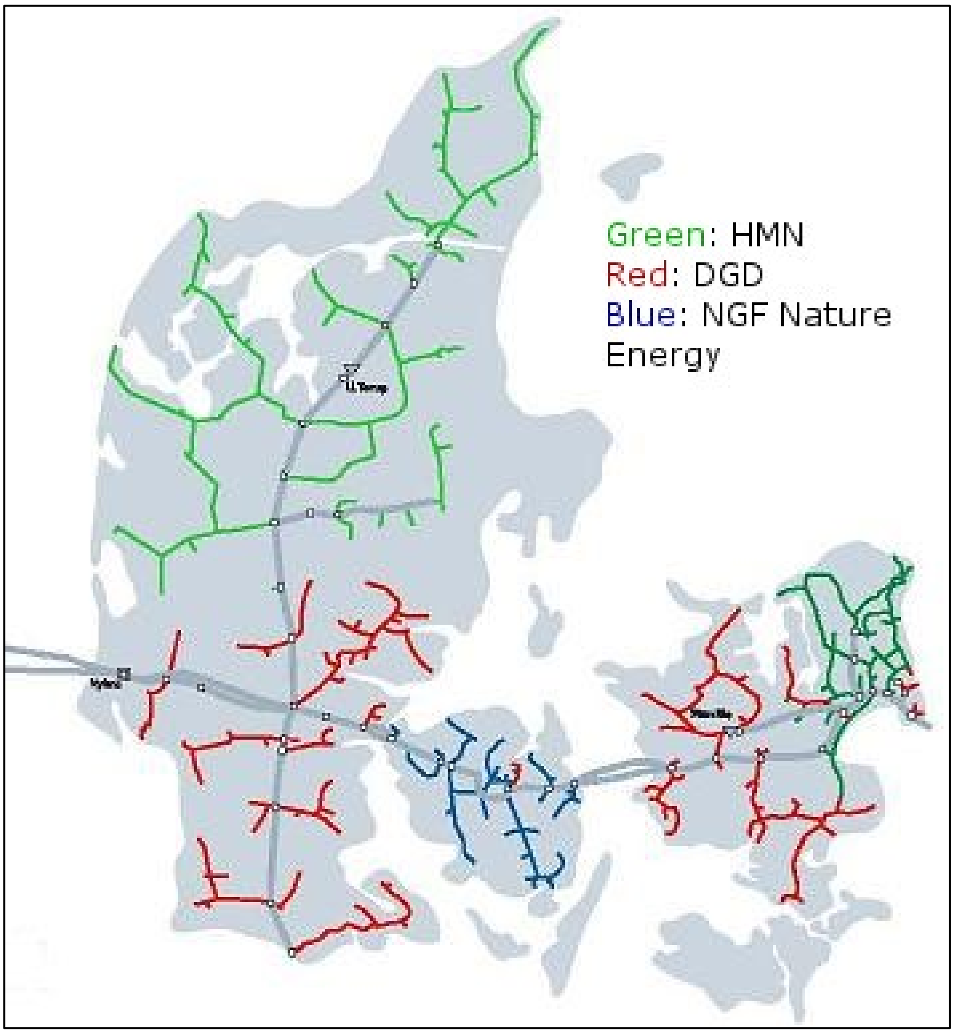

Figure 2 Geographical extent of the Danish transmission network (grey) and the main distribution network (green, red & blue). The colours refer to the companies operating the system.

Due to the described history of ownership, different designs and pressure levels exist in different parts of Denmark. The natural gas system contains pipelines operating at different pressure levels. The highest pressure is found in the gas transmission grid that operates at pressures of up to 80 bars. The maximum pressure in the main distribution grid varies among the gas distribution companies and regions (cf. Figure 2):

- HMN Jutland: 40 bar
- HMN Zealand: 19 or 40 bar
- DGD Jutland: 40 bar
- DGD Zealand: 19 bar
- NGF Nature Energy: 19 bar

Input

As of 2016, the main source of natural gas in Denmark is the North Sea where the natural gas is produced, mainly from the Tyra field. The natural gas is then transported from the North Sea to the onshore transmission network.

Besides the source in the North Sea, natural gas can also be imported from Germany. This part of the transmission line to Germany can be used both for import and for export.

The transmission network has five entry/exit points for natural gas:

- Nybro at the west coast of Jutland is the main entry point for Danish gas from North Sea gas fields.
- Ellund at the border to Germany is both an entry point for gas import and an exit point for gas export.
- Dragør near Copenhagen is the exit point for the gas export to Sweden.
- Stenlille on Zealand is one of the two Danish entry/exit points to a seasonal underground gas storage facility.
- Lille Torup in northern Jutland is another entry/exit point to a seasonal underground gas storage facility.

Since 2011, biogas upgraded to gas network quality has been injected into the gas network. From the start only at gas distribution level, but from 2016, biogas has been injected into the gas transmission network.

Output

The output is the same as the input, namely gas. As losses from the gas system are negligible, the amount of gas delivered from the gas network is basically the same as the amount delivered to it.

Energy balance

The energy consumption related to operation of the gas network is generally low. The network is supplied with natural gas at a sufficiently high pressure, so no further compression is required in the main distribution lines or in the distribution system. Therefore, the electric power consumption related to operation of the main distribution lines and the distribution system is as low as 0.005 % of the transported energy.

Reduction of the pressure in the system necessitates preheating, as the gas is cooled by the expansion. The heat is provided by burning an amount of gas corresponding to around 0.1 % of expanded gas. However, as there are different pressure levels in different parts of the country, preheating is not always required.

Description of the main distribution system

The main distribution system is supplied with gas from the transmission system. As mentioned earlier, the pressure in the transmission system is 80 bar. Before entering the main distribution system of the transmission system, the pressure is reduced to 19 or 40 bar depending on the geographical location. The pressure reduction takes place in MR (meter/regulator) stations.

- HMN Jutland: MR stations regulate pressure from 40 to 4 bar.
- HMN Zealand: MR stations regulate from both 40 and 19 bar down to 4 bar.
- DGD Jutland: MR stations regulate pressure from 40 to 4 bar.
- DGD Zealand: MR stations regulate pressure from 19 to 4 bar.
- NGF Nature Energy: MR stations regulate pressure from 19 to 4 bar.

As mentioned earlier, operation of MR stations with pressure reduction from 40 to 4 bar requires preheating, as the gas is cooled by the expansion. The heat is provided by burning an amount of gas corresponding to around 0.1 % of expanded gas. For MR stations with the more limited pressure reduction from 19 to 4 bar, preheating is not required. Instead, further preheating is required when the gas is expanded from 80 to 19 bar, compared to expanding from 80 to 40 bar.

The main distribution system supplies the 4 bar distribution network as well as a limited number of larger consumers, such as CHP plants and industrial customers. Due to the high pressure, the system is made of steel pipes.

Figure 3 Routing of gasline with distribution pipe. Source: HMN Gasnet.

Description of distribution system

Gas from the transmission system supplies the distribution system with gas at 4 bar. Before the gas enters gas installations, the pressure is reduced from 4 bar to 20 mbar, and the gas consumption is measured.

Figure 4 Cupboard containing pressure regulator and flowmeter mounted outside a private house.

In some areas, mainly the Greater Copenhagen area and the southern part of Jutland, Distribution Regulator stations (DR) reduce the gas pressure from 4 bar to 100 mbar before the gas is delivered to customers. However, all three gas distribution companies have stated that this will not be done for future networks, except for rare special cases [3][4][5]. Therefore, 100 mbar systems will not be treated further in this description.

Space requirement

The space requirement for the described system is limited to the MR stations. The space requirement for a 40/4 bar or 19/4 bar MR station is around 1,000 m^2.

Advantages/disadvantages

The gas system has a number of advantages.

It can be supplied with gases from various sources, including green gases, such as upgraded biogas and gases from power-to-gas processes, as long as the gas meets the natural gas specifications. It provides a large storage capacity corresponding to 2-3 months of consumption [1]. These properties may allow integration of large amounts of renewable energy in the energy system.

Furthermore, the gas system can provide very high power capacity compared to most other energy carriers, which is required by some parts of the industry [7]. The energy loss is very low compared to other energy distribution and transport systems.

The main disadvantage is that today the cost of producing green gases of natural gas quality from e.g. renewable power production is relatively high. Therefore, the only green gas in the Danish gas system is upgraded biogas.

Environment

Natural gas networks have a minimal environmental impact during the construction phase.

The environmental impacts during operation mainly consist of CO_2 emissions due to preheating at MR stations and minor losses of mainly methane during distribution of the gas.

There are no general data available on methane loss from the Danish gas system. If data from a European survey are applicable for the Danish system, the losses will correspond to 0.1 % of the amount of gas transported in gas networks. European gas networks are generally older than the Danish system. Therefore, it is expected that the losses from the Danish system are lower than the 0.1 %.

Research and development perspectives

Transportation and distribution of natural gas is a proven and efficient technology. Only little development is expected. The main development is expected to be in relation to green gas production and utilization of the gas.

Examples of market standard technology

The transmission lines and main distribution lines are made of steel pipes, whereas the 4 bar distribution system is made of PE pipes.

MR stations mostly consist of a redundant string with pressure regulators, meters (volume flow measurements) as well as pressure and temperature measurement and flow computer in order to determine gas flow at reference conditions.

If a distribution line is crossing a stream, a road or a railway directional drilling is often applied, which has made such crossings significantly cheaper than it was earlier.

Prediction of performance and costs

Prediction of cost and energy consumption is mainly based on the experience of HMN Gasnet.

Natural gas networks represent a mature and commercial technology with large deployment, corresponding to technological maturity level category 4. Therefore, prices have more or less stabilized over the last years. No significant changes in performance and costs are expected to happen to the technology in the foreseeable future.

Uncertainty

Data on construction costs for gas networks depend on a number of project specific details and are difficult to generalize.

Furthermore, if developments in e.g. directional drilling occur, they will impact costs in a way that is difficult to anticipate.

Additional remarks

The biogas' path to the Danish gas network

As mentioned earlier, today biogas is injected into the existing natural gas infrastructure. Costs related to biogas are not included in data stated in the data section.

What is biogas?

Biogas is produced by anaerobic digestion of biodegradable material. It consists mainly of 50-80 % methane and 20-50 % CO2. In addition, biogas contains low concentrations of undesirable substances, e.g. impurities, such as H2S, siloxanes, ammonia, oxygen and volatile organic carbons (VOC).

Biogas quality requirements

In order to be injected into the natural gas network or in order to be used in gas vehicles, the upgraded biogas quality must meet the same requirements as natural gas. In Denmark, these requirements are described in the Gas Regulations, section C12. The methane limit is not directly specified in C12, but can be deduced from the lower wobbe limit, which is 50.8 MJ/Nm^3. This equals a minimum methane content of 97.3 % assuming the rest is CO_2.

H_2S is limited to 5 mg/Nm^3. To avoid the risk of condensation, the water dew point up to 70 bar must be below minus 8 °C. Further requirements are given in the Gas Regulations, section C12.

Biogas upgrading

A large number of technologies are available for upgrading, but four technologies stand out as the clearly most common technologies

- Water scrubber
- Chemical scrubber (amine scrubber)
- Membrane scrubber
- PSA (Pressure Swing Absorption) scrubber

The technologies are further described in [8].

Biogas odorisation

Biogas must be odorized before entering a gas distribution network. The level of odorisation is the same as for natural gas, see C12. No odorisation is done, if the upgraded biogas is injected into the transmission system.

Injection points

Possible injection points

- Nearby 4 bar distribution network.
- Nearby 19-40 bar distribution network. Gas compression is needed before injection.
- Nearby 80 bar gas transmission network. Gas compression is needed before injection.

The selection of injection point(s) depends on

- Biogas plant capacity

- Local 4 bar gas distribution network base-load consumption
- Distance to nearby 4 bar gas distribution network
- Distance to nearby 19-40 bar gas distribution network
- Local 4 bar gas distribution network base-load consumption
- Distance to nearby 80 bar gas transmission network
- Cost of compression.

If the local gas consumption shows large variations during the day, a local intermediate storage facility can be used to increase the local consumption of biogas/upgraded biogas.

Selection of entry point(s) will be based on an economic optimization.

References

[1] www.naturgasfakta.dk
[2] www.gasmarked.dk
[3] Dansk Gas Distribution
[4] NGF Nature Energy
[5] HMN Gasnet
[6] Energinet
[7] DGC
[8] "Biogas upgrading - Technology review", published by Energiforsk 2016. ISBN 978-91-7673-275-5.

Data sheets

Table 5: Natural gas main distribution line

Technology	Energy Transport, Natural Gas Main distribution line									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy losses, lines 1-20 MW (%)	0,1	0,1	0,1	0,1	0,01	0,15	0,01	0,15	A	1
Energy losses, lines 20-100 MW (%)	0,1	0,1	0,1	0,1	0,01	0,15	0,01	0,15	A	
Energy losses, lines above 100 MW (%)	0,1	0,1	0,1	0,1	0,01	0,15	0,01	0,15	A	
Energy losses, stations [Type 1] (%)	-	-	-	-	-	-	-	-	B	
Energy losses, stations [Type 2] (%)	0,10	0,10	0,10	0,10	0	0,12	0	0,12	C	2
Auxiliary electricity consumption (% energy transmitted)	0,005	0,005	0,005	0,005	0,004	0,006	0,004	0,006		2
Technical life time (years)	50	50	50	50	50	80	50	80		2
Typical load profile (-)	0,2	0,2	0,2	0,2	0,05	0,4	0,05	0,4		2
Construction time (years)	1	1	1	1	0,7	1,5	0,7	1,5	D	2
Financial data										
Investment costs										
Investment costs; single line, 0 - 50 MW (EUR/MW/m)	11	11	11	11	9	13	9	13	E, F	2
Investment costs; single line, 50-100 MW (EUR/MW/m)	4,2	4	4	4	3,4	5,0	3,4	5,0	E, G	2
Investment costs; single line, 100 - 250 MW (EUR/MW/m)	2,2	2	2	2	1,8	2,7	1,8	2,7	E, G	2
Investment costs; single line, 250-500 MW (EUR/MW/m)	1,2	1	1	1	0,9	1,4	0,9	1,4	E, G	2
Investment costs; single line, 500-1000 MW (EUR/MW/m)	0,7	1	1	1	0,5	0,8	0,5	0,8	E, G	1
Investment costs; single line, above 1000 MW (EUR/MW/m)	-	-	-	-	-	-	-	-	i	
Reinforcement costs (EUR/MW)	-	-	-	-	-	-	-	-	H	
Investment costs; [type 1] station (EUR/MW)	-	-	-	-	-	-	-	-	B, J	
Investment costs; [type 2] station (EUR/MW)	27000	27000	27000	27000	7000	45000	0	0	C, K	2
Investments, percentage installation	75	75	75	75	65	85	65	85		2
Investments, percentage materials	25	25	25	25	15	35	15	35		2
Fixed O&M (EUR/MW/km/year)	0,12	0,12	0,12	0,12	0,10	0,15	0,10	0,15		2
Variable O&M (EUR/MWh/km)	1,1E-05	1,1E-05	1,1E-05	1,1E-05	9,0E-06	1,4E-05	9,0E-06	1,4E-05		2

Notes

A There are no general data available for the Danish gas system. The stated losses are based on a European survey that includes all parts in level 2 of the transmission, including stations. It is assumed that the losses (given as kg/km) are the same for transmission level 1 and 2. European gas networks are generally older than the Danish system. Therefore, it is expected that the losses from the Danish system are significantly lower than stated in the table. The lack of data explains the high uncertainty stated.

B Type 1 MR stations supplying the transmission system level 2 - not part of the scope

C Type 2 MR stations supplying the 4 bar distribution system. The stated number represents the gas consumption for preheating before expansion from 40 to 4 bar. Expansion from 19 or 16 bar to 4 bar doesn't require preheating. Losses are included in the number stated for lines, see note A.

D Includes engineering, tender, and construction.

E Rates include VVM review, landowner compensation and archaeological screening. Based on 20 km, of which 8 % is based on drilling.

F Data given is for a 50 MW capacity

G Two pipes were chosen for each interval (one for the lowest power level and one for the highest). The average of these two are stated in the table.

H Not possible to give general numbers. Depends on kind of reinforcement. Can be calculated based on the other numbers given.

I Capacity not relevant - too high

J Type 1 MR stations supplying the transmission system level 2 - not part of the scope

K Type 1 MR stations supplying the transmission system level 2 .The stated costs are the average cost for a 40/4 bar MR station where reheating after expansion is required and a 19/4 bar MR station where reheating is not necessary. The cost is only modestly size dependent. A 40/4 bar station capacity of 10.000 m3/h is 20 % higher than a similar station with a capacity of 5.000 m3/h.

References

1 Survey methane emissions for gas transmission and distribution in Europe Marcogaz WG-ME-14-26 29/02/2016

2 HMN Naturgas

Table 6: Gas Distribution, rural

Technology	Natural Gas Distribution, rural areas									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy losses, lines (%)	0,26	0,26	0,26	0,26	0,05	0,3	0,05	0,3	A	1
Energy losses, stations (%)	-	-	-	-	-	-	-	-	B	
Auxiliary electricity consumption (% of energy delivered)	0	0	0	0	0	0	0	0	C	
Technical life time (years)	50	50	50	50	50	80	50	80		2
Typical load profile (-)									D	
- Residential	0,2	0,2	0,2	0,2	0,15	0,25	0,15	0,25	D	
- Commercial	N/A	N/A	N/A	N/A					D	
Construction time (years)	0,4	0,4	0,4	0,4	0,3	0,5	0,3	0,5		2
Financial data										
Distribution network costs (EUR/MWh/year) Rural	140	140	140	140	130	150	130	150		2
Investment costs; service line, 0 - 20 kW (EUR/unit)	1600	1600	1600	1600	1400	1800	1400	1800		2
Investment costs; service line, 20 - 50 kW (EUR/unit)	-	-	-	-	-	-	-	-	E	
Investment costs; service line, 50-100 kW (EUR/unit)	-	-	-	-	-	-	-	-	E	
Investment costs; service line, above 100 kW (EUR/unit)	-	-	-	-	-	-	-	-	E	
Investment costs; single line, 0-50 kW (EUR/m)	50	50	50	50	45	55	45	55	F	
Investment costs; single line, 50-250 kW (EUR/m)	**50**	50	50	50	45	55	45	55	F	
Investment costs; single line, 100-250 kW (EUR/m)	50	50	50	50	45	55	45	55	F	
Investment costs; single line, 250 kW - 1 MW (EUR/m)	50	50	50	50	45	55	45	55	F	
Investment costs; single line, 1 MW - 5 MW (EUR/m)	53	53	53	53	48	59	48	59	G	
Investment costs; single line, 5 MW - 25 MW (EUR/m)	68	68	68	68	62	75	62	75	G	
Investment costs; single line, 25 MW - 100 MW (EUR/m)	-	-	-	-	-	-	-	-		
Reinforcement costs (EUR/MW)	-	-	-	-	-	-	-	-	H	
Type 1 station (EUR/MW)	-	-	-	-	-	-	-	-	I	
Type 2 station (EUR/MW)	-	-	-	-	-	-	-	-	I	
Investments, percentage installation	80%	80%	80%	80%	70%	90%	70%	90%		2
Investments, percentage materials	20%	20%	20%	20%	10%	30%	10%	30%		2
Fixed O&M (EUR/MW/year)	750	750	750	750	600	900	600	900		2
Variable O&M (EUR/MWh)	0	0	0	0	0	0	0	0		2

Notes

A There are no general data available for the Danish gas system. The stated losses are based on a European survey. European gas networks are generally older than the Danish system. Therefore, it is expected the losses from the Danish system are significantly lower than stated in the table. The lack of data explains the high uncertainty stated.

B As mentioned in the qualitative description, new gas systems will be constructed without stations in the distribution network

C There is no power consuming parts in the distribution system consumption for preheating before expansion from 40 to 4 bar. Expansion from 19 or 16 bar to 4 bar doesn't require preheating. Losses are included in the number stated for lines, see note A.

D Based on given case

E Capacity range not relevant for given case

F Stated number is for Ø40 pipes - the smallest pipe applied. It is only marginally cheaper to apply smaller pipes.

G Two pipes were chosen for each interval (one for the lowest power level and one for the highest). The average of these two is stated in the table.

H Reinforcement not relevant

I No station will be installed for the distribution network

References

1 Survey methane emissions for gas transmission and distribution in Europe Marcogaz WG-ME-14-26 29/02/2016

2 HMN Naturgas

Table 7: Gas distribution, suburban

Technology	**Natural Gas Distribution, suburban areas**									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy losses, lines (%)	0,26	0,26	0,26	0,26	0,05	0,3	0,05	0,3	A	1
Energy losses, stations (%)	-	-	-	-	-	-	-	-	B	
Auxiliary electricity consumption (% of energy delivered)	0	0	0	0	0	0	0	0	C	
Technical life time (years)	50	50	50	50	50	80	50	80		2
Typical load profile (-)	-	-	-	-	-	-	-	-		
- Residential	0,2	0,2	0,2	0,2	0,15	0,25	0,15	0,25	D	
- Commercial	N/A	N/A	N/A	N/A					D	
Construction time (years)	0,4	0,4	0,4	0,4	0,3	0,5	0,3	0,5		2
Financial data										
Distribution network costs (EUR/MWh/year) Suburban	150	150	150	150	140	170	140	170		2
Investment costs; service line, 0 - 20 kW (EUR/unit)	1600	1600	1600	1600	1400	1800	1400	1800		2
Investment costs; service line, 20 - 50 kW (EUR/unit)	-	-	-	-	-	-	-	-	E	
Investment costs; service line, 50-100 kW (EUR/unit)	-	-	-	-	-	-	-	-	E	
Investment costs; service line, above 100 kW (EUR/unit)	-	-	-	-	-	-	-	-	E	
Investment costs; single line, 0-50 kW (EUR/m)	53	53	53	53	48	59	48	59	F	
Investment costs; single line, 50-250 kW (EUR/m)	53	53	53	53	48	59	48	59	F	
Investment costs; single line, 100-250 kW (EUR/m)	53	53	53	53	48	59	48	59	F	
Investment costs; single line, 250 kW - 1 MW (EUR/m)	53	53	53	53	48	59	48	59	F	
Investment costs; single line, 1 MW - 5 MW (EUR/m)	60	60	60	60	54	66	54	66	G	
Investment costs; single line, 5 MW - 25 MW (EUR/m)	87	87	87	87	78	95	78	95	G	
Investment costs; single line, 25 MW - 100 MW (EUR/m)	-	-	-	-	-	-	-	-		
Reinforcement costs (EUR/MW)	-	-	-	-	-	-	-	-	H	
Type 1 station (EUR/MW)	-	-	-	-	-	-	-	-	I	
Type 2 station (EUR/MW)	-	-	-	-	-	-	-	-	I	
Investments, percentage installation	80%	80%	80%	80%	70%	90%	70%	90%		2
Investments, percentage materials	20%	20%	20%	20%	10%	30%	10%	30%		2
Fixed O&M (EUR/MW/year)	310	310	310	310	250	370	250	370		2
Variable O&M (EUR/MWh)	0	0	0	0	0	0	0	0		2

Notes

A There are no general data available for the Danish gas system. The stated losses are based on a European survey. European gas networks are generally older than the Danish system. Therefore, it is expected the losses from the Danish system are significantly lower than stated in the table. The lack of data explains the high uncertainty stated.

B As mentioned in the qualitative description, new gas systems will be constructed without stations in the distribution network

C There is no power consuming parts in the distribution system

D Based on given case

E Capacity range not relevant for given case

F Stated number is for Ø40 pipes - the smallest pipe applied. It is only marginally cheaper to apply smaller pipes.

G Two pipes were chosen for each interval (one for the lowest power level and one for the highest). The average of these two is stated in the table.

H Reinforcement not relevant

I No station will be installed for the distribution network

References

1 Survey methane emissions for gas transmission and distribution in Europe Marcogaz WG-ME-14-26 29/02/2016

2 HMN Naturgas

Table 8: Gas distribution, city

Technology	Natural Gas Distribution, city areas									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy losses, lines (%)	-	-	-	-	-	-	-	-	A	1
Energy losses, stations (%)	-	-	-	-	-	-	-	-	B	1
Auxiliary electricity consumption (% of energy delivered)	0	0	0	0	0	0	0	0	C	1
Technical life time (years)	50	50	50	50	50	80	50	80		1
Typical load profile (-)									D	
- Residential	0,2	0.2	0.2	0.2	0.15	0.25	0.15	0.25	D	
- Commercial	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	D	
Construction time (years)	0,4	0,4	0,4	0,4	0,3	0,5	0,3	0,5		1
Financial data										
Distribution network costs (EUR/MWh/year) City	10	10	10	10	10	10	10	10		1
Investment costs; service line, 0 - 20 kW (EUR/unit)	-	-	-	-	-	-	-	-		
Investment costs; service line, 20 - 50 kW (EUR/unit)	-	-	-	-	-	-	-	-		
Investment costs; service line, 50-100 kW (EUR/unit)	-	-	-	-	-	-	-	-		
Investment costs; service line, above 100 kW (EUR/unit)	15.000	15.000	15.000	15.000	12.000	18.000	12.000	18.000	E	1
Investment costs; single line, 0-50 kW (EUR/m)	64	64	64	64	58	70	58	70		1
Investment costs; single line, 50-250 kW (EUR/m)	64	64	64	64	58	70	58	70		1
Investment costs; single line, 100-250 kW (EUR/m)	64	64	64	64	58	70	58	70		1
Investment costs; single line, 250 kW - 1 MW (EUR/m)	64	64	64	64	58	70	58	70		1
Investment costs; single line, 1 MW - 5 MW (EUR/m)	72	72	72	72	65	79	65	79		1
Investment costs; single line, 5 MW - 25 MW (EUR/m)	104	104	104	104	94	114	94	114		1
Investment costs; single line, 25 MW - 100 MW (EUR/m)	-	-	-	-	-	-	-	-	F	
Reinforcement costs (EUR/MW)	-	-	-	-	-	-	-	-	F	
Type 1 station (EUR/MW)	-	-	-	-	-	-	-	-	F	
Type 2 station (EUR/MW)	-	-	-	-	-	-	-	-	F	
Investments, percentage installation	80%	80%	80%	80%	70%	90%	70%	90%		1
Investments, percentage materials	20%	20%	20%	20%	10%	30%	10%	30%		1
Fixed O&M (EUR/MW/year)	20	20	20	20	16	24	16	24		1
Variable O&M (EUR/MWh)	0	0	0	0	0	0	0	0		1

Notes

A For the defined case "New distribution in existing densely populated areas, city centres etc." it is assessed the natural gas based heating will be designed with one boiler and heat is distributed to the end users by a local district heating system. This means that the local natural gas system will only consist of a service line with a capacity of 1.5 MW supplying a boiler as well a meter and a pressure regulator. Therefore, losses are neglected

B As mentioned in the qualitative description, new gas systems will be constructed without stations in the distribution network

C There is no power consuming parts in the distribution system

D Based on given case

E Stated number is for a service line supplying 1,5 MW.

F Not relevant, see note A

References

1 HMN Naturgas

Table 9: Gas distribution, new developed area

Technology	Natural Gas Distribution, New developed areas									
	2015	2020	2030	2050	Uncertainty (2020)		Uncertainty (2050)		Note	Ref
Energy/technical data					Lower	Upper	Lower	Upper		
Energy losses, lines (%)	0,26	0,26	0,26	0,26	0,05	0,3	0,05	0,3	A	1
Energy losses, stations (%)	-	-	-	-	-	-	-	-	B	
Auxiliary electricity consumption (% of energy delivered)	0	0	0	0	0	0	0	0	C	
Technical life time (years)	50	50	50	50	50	80	50	80		2
Typical load profile (-)	-	-	-	-	-	-	-	-		
- Residential	0,2	0,2	0,2	0,2	0,15	0,25	0,15	0,25	D	
- Commercial	N/A	N/A	N/A	N/A					D	
Construction time (years)	0,4	0,4	0,4	0,4	0,3	0,5	0,3	0,5		2
Financial data										
Distribution network costs (EUR/MWh/year) City	270	270	270	270	240	300	240	300		2
Investment costs; service line, 0 - 20 kW (EUR/unit)	1600	1600	1600	1600	1400	1800	1400	1800		2
Investment costs; service line, 20 - 50 kW (EUR/unit)	-	-	-	-	-	-	-	-	E	
Investment costs; service line, 50-100 kW (EUR/unit)	-	-	-	-	-	-	-	-	E	
Investment costs; service line, above 100 kW (EUR/unit)	-	-	-	-	-	-	-	-	E	
Investment costs; single line, 0-50 kW (EUR/m)	47	47	47	47	42	51	42	51	F	
Investment costs; single line, 50-250 kW (EUR/m)	**47**	47	47	47	42	51	42	51	F	
Investment costs; single line, 100-250 kW (EUR/m)	47	47	47	47	42	51	42	51	F	
Investment costs; single line, 250 kW - 1 MW (EUR/m)	47	47	47	47	42	51	42	51	F	
Investment costs; single line, 1 MW - 5 MW (EUR/m)	50	50	50	50	45	55	45	55	G	
Investment costs; single line, 5 MW - 25 MW (EUR/m)	63	63	63	63	57	70	57	70	G	
Investment costs; single line, 25 MW - 100 MW (EUR/m)	-	-	-	-	-	-	-	-		
Reinforcement costs (EUR/MW)	-	-	-	-	-	-	-	-	H	
Type 1 station (EUR/MW)	-	-	-	-	-	-	-	-	I	
Type 2 station (EUR/MW)	-	-	-	-	-	-	-	-	I	
Investments, percentage installation	80%	80%	80%	80%	70%	90%	70%	90%		2
Investments, percentage materials	20%	20%	20%	20%	10%	30%	10%	30%		2
Fixed O&M (EUR/MW/year)	920	920	920	920	740	1100	740	1100		2
Variable O&M (EUR/MWh)	0	0	0	0	0	0	0	0		2

Notes

A There are no general data available for the Danish gas system. The stated losses are based on a European survey. European gas networks are generally older than the Danish system. Therefore, it is expected the losses from the Danish system are significantly lower than stated in the table. The lack of data explains the high uncertainty stated.

B As mentioned in the qualitative description, new gas systems will be constructed without stations in the distribution network

C There is no power consuming parts in the distribution system

D Based on given case

E Capacity range not relevant for given case

F Stated number is for Ø40 pipes - the smallest pipe applied. It is only marginally cheaper to apply smaller pipes.

G Two pipes were chosen for each interval (one for the lowest power level and one for the highest). The average of these two is stated in the table.

H Reinforcement not relevant

I No station will be installed for the distribution network

References

1 Survey methane emissions for gas transmission and distribution in Europe Marcogaz WG-ME-14-26 29/02/2016

2 HMN Naturgas

113 District heating distribution and transmission grid

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Publication date
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Amendments after publication date

Date	Ref.	Description
Feb 2025	-	Updated chapter and datasheets. Datasheet for rural and LTDH removed

Qualitative description

Brief technology description

District heating (DH) is a water-based method of transporting heat energy, employing a piping network to deliver heat to both residential and commercial consumers. The technologies for generating this heat are diverse, including options such as combined heat and power plants (CHP), boilers, heat pumps, use of waste heat, and large-scale solar thermal plants, see the catalogue on Generation of Electricity and District heating for this. These systems often incorporate storage solutions to help balance the heat generation with consumption demands see the catalogue for Energy Storage for this.

Danish history of DH in short

District heating has been used for more than 100 years in Denmark (Frederiksberg Forsyning, 2024), and has historically been based on different fuels to supply heat. In the 70's the energy supply was mainly based on oil, but war and crises influenced the oil prices, leading to an economic downturn in Denmark (Rosanna Farbøl, 2018).

These crises acted as a catalyst for change, leading to a transformative overhaul of the energy sectors in Denmark and other Western nations. A diverse energy supply system was introduced, reducing dependence on oil imports, and prompting a new focus on energy consumption practices. As shown in Figure 4, energy sources used to fuel DH changed from being primarily based on heavy fuel oil, to in 1990 being based on: natural gas, coal, waste, and biomass. In addition, more efficient energy utilization was achieved through significant increases in cogeneration in new and expanded DH networks, as the cost-effectiveness of DH networks was significantly improved through the development of pre-insulated pipes in the 1980s.

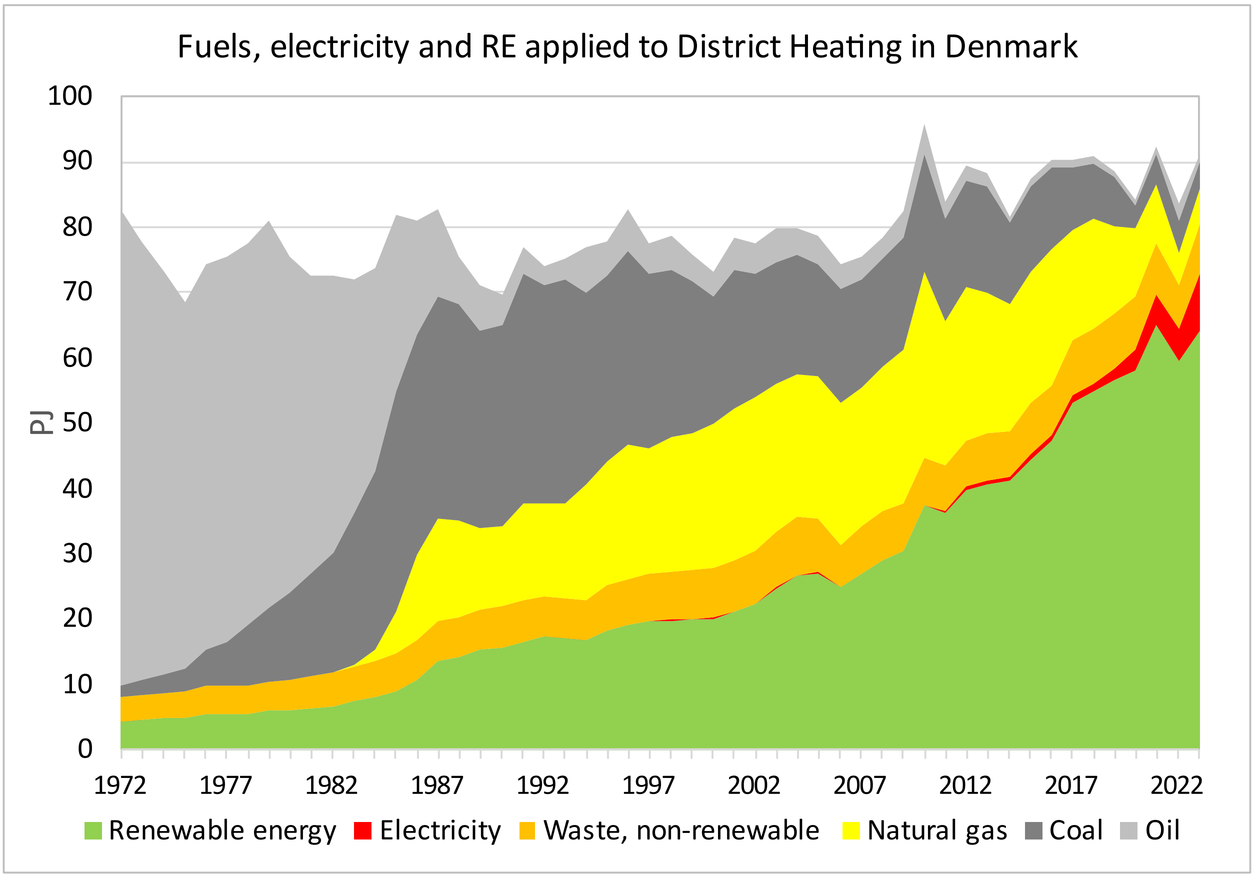

Figure 4 - Fuels applied in District Heating in Denmark. Kilde: Energistyrelsen – energistatistik 2023.

Input

Input to a DH network is heat in the form of hot water from various sources and based on various technologies, e.g. CHP plants, boilers, waste heat, large-scale solar heating plants, large electric heat pumps or electric boilers.

Output

The output is the same as the input, heat transferred through circulating hot water. However, due to heat distribution network losses the amount of heat delivered from the DH network is lower than the amount supplied to it.

Energy balance

Transportation of heat in DH pipes results in heat losses to the surroundings. The heat losses are dependent on the pipe lengths, the pipe insulation, and temperature difference between the pipes and their surroundings and varies a lot from one system to another. Average network losses are in the range of 15-20 %. In very large and dense systems, the loss can be as low as approximately 5 % while it can be more than 35 % in small systems with low heat density. These heat losses er inclusive losses in pump stations and heat exchanger stations. In large heat exchanger stations, efficiency is 98-99%. Heat losses in pumping stations are negligible. Heat exchanger stations are normally only found in connection with transmission networks. Most of the electricity for running the pumps is transformed to heat losses to the surroundings. A portion of this heat loss contributes to heating the DH water.

Transmission and distribution networks

Large DH systems are often set up with two different levels: transmission lines and distribution networks. The distribution network is distributing the energy at a lower pressure and temperature than the transmission line. A typical large DH setup is illustrated in Figure 5 below. In small scale DH networks, the transmission pipe would be replaced by a large distribution pipe.

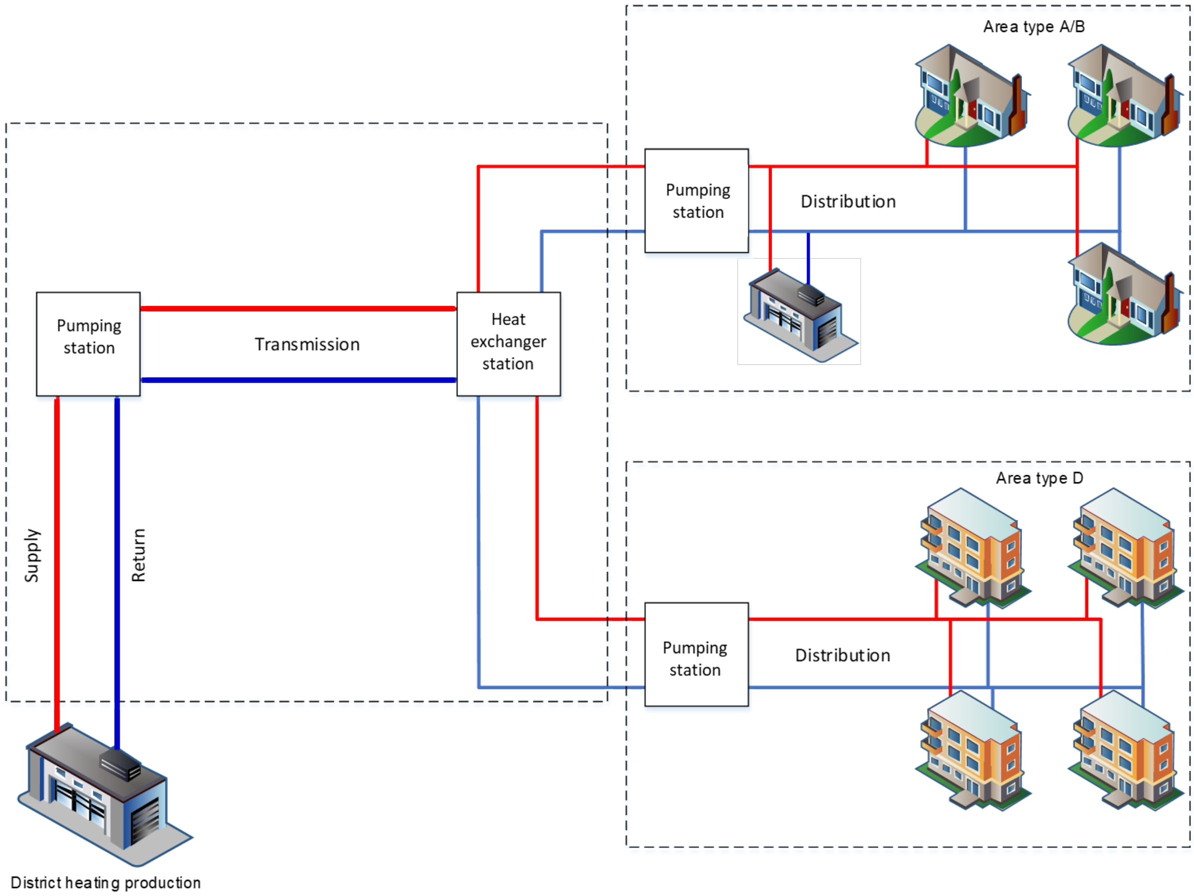

Figure 5 - District Heating Network

Description of the transmission system

DH transmission systems are used to transfer large quantities of heat between different distribution areas using water as a heat transfer fluid. Transmission systems operate at higher temperature and pressure levels (<110 °C and 25 bar) compared to distribution systems. However, when the heat is transferred to the distribution system, the pipes have a lower capacity to carry heat because the temperature is reduced. This lower temperature is beneficial, as it aligns better with the requirements of the customers' internal piping systems. Heat is typically transferred from transmission systems to distribution systems through heat exchanger stations to reduce the pressure and temperature levels.

A DH distribution system distributes heat to consumers in a distribution area using water as a heat transfer fluid. Distribution systems often operate with supply temperatures between 70-95 °C, and pressure levels between 6.5 and 16 bars.

However, due to an increasing attention to reducing temperature levels, to increase heat production efficiency and reduce heat loss, some areas operate at temperatures as low as 55-60 °C, mostly during the summer months. Development for lowering the supply temperature even further is ongoing but will require decoupling of space heating and domestic hot water production due to different temperature requirements for space heating and production of domestic hot water, e.g. floor heating only requires 30-35 °C whereas production of domestic hot water will require at least 50 °C to prevent the growth of legionella bacteria. This is typically solved either by a three-pipe system that allows a lower flow temperature for space heating while meeting the domestic hot water temperature requirement, or by installing a micro booster (small individual heat pump) to raise the domestic hot water temperature to the required level.

Operating at lower temperatures is more feasible in buildings erected after the 21th century, as new building codes supports this, e.g. by requiring higher insulation standards, and by the use of floor heating.

Space requirement for district heating pipes

The space required for the construction of the trenches for DH pipes varies depending on the ground conditions and whether it is a paved or unpaved area, but also on the size and type of pipes. To secure the trench walls from collapsing in unpaved areas, the trench walls are sloped thus increasing the trench width. Vertical trench walls, possibly with sheet piles, are typically used in paved areas. The space requirements are presented in **Error! Reference source not found.**. An explanation of the pipe types is given in the section: *Examples of market standard technology*.

Trench width requirements	Paved areas	Unpaved areas
Single Pipes	0.6 – 1.2 meter	1.75 - 2.4 meter
Twin Pipes	0.4 – 0.7 meter	1.5 - 1.8 meter

Table 10 - Space requirements, span from the smallest (DN50) to largest distribution pipes (DN250).

Advantages and disadvantages for district heating

District heating has a range of advantages and disadvantages that are critical to understand when planning and designing sustainable and efficient communities. This section explores the various benefits, such as energy efficiency and the possible ability to reduced environmental impact, alongside the potential drawbacks, like initial infrastructure costs and complexity of installation, that come with implementing district energy solutions. By evaluating these factors, stakeholders can make informed decisions that align with both economic and ecological objectives.

Advantages

1. **Energy production optimization**: urban settings benefits from centralized heating systems, which can switch between various production methods based on demand. Biomass and biogas can be advantageous during high electricity prices, especially with CHP systems that also generate power for sale. Equally, heat pumps and electric boilers become more advantageous when electricity costs drop.
2. **Compatible with fluctuating energy sources:** District energy systems can leverage renewable energy sources and waste heat, which can significantly reduce greenhouse gas emissions compared to individual heating and cooling solutions. If a DH system is connected to a heat storage and heat is produced at CHP plants, large heat pumps or large electric boilers, the DH system can offer flexibility services to the electricity network helping to integrate a higher share of intermittent power producing technologies e.g. wind and solar power. This is already happening today and will be even more important in the future as part of several other Smart Energy solutions.
3. **Reliability**: District energy systems can offer higher reliability and stability in energy supply due to redundancy measures. By different production units in the same network making it possible to prioritize the preferred heat production, e.g. the most efficient, economic, environmentally friendly etc.
4. **Space Benefits**: The heat interface unit, which connects the district heating to the internal heating system in buildings, normally requires less space than heating alternatives such as gas boilers and heat pumps.
5. **Future-proof Infrastructure**: District energy systems can adapt more easily to future energy sources and technologies compared to decentralized systems.
6. **Peak Demand Management:** Centralized systems can be more effective at managing and reducing peak energy demands, by means of storage facilities. The use of seasonal heat storage allows for the integration in the DH system of large-scale solar heating plants and hence takes advantage outside the summer season of the economically advantageous and CO_2-neutral solar heat.
7. **Reduction in Infrastructure Complexity:** Fewer individual systems mean reduced requirements for fuels, fuel storage, and maintenance infrastructure in each building.
8. **Maintenance:** It is a well-proven and reliable technology that offers easy operation for the heat consumers. Heating from district heating is as convenient for the consumer as any other utility (water, electricity) by moving the responsibility of operation and maintenance away from the consumer to professional service providers.
9. **Sector-coupling**: Heat pumps and electric boilers in DH systems can be used to absorb surplus electricity from wind and solar power, and can utilize heat from waste incineration (WtE) and industrial waste heat from emerging PtX industries and datacenters.

Disadvantages

1. **High Initial Investment:** The capital costs for establishing district energy infrastructure can be high, and the payback period of the investment is often very long.
2. **Inflexibility**: Once established, district energy systems can tie consumers to a particular energy source or provider, limiting their flexibility to switch.
3. **Heat Losses**: Energy can be lost during transmission from central plants to end-users, especially over long distances.
4. **Geographical Limitations:** District energy systems are most efficient in densely populated areas and may not be as practical or cost-effective in rural or sparsely populated areas.

Environment

The development of district heating in Denmark has taken place through the Heat Supply Act, which mandates to choose the cheapest socio-economic heat supply solution. This assessment includes the costs of air emissions that impact the climate and the local environment, supporting the development of environmentally sound solutions.

As with other construction works, environmental legislation and municipal regulations ensure that the establishment of DH networks has a minimal environmental impact during construction. This includes protection of sensitive nature and habitats, handling of noise and dust, handling of possibly contaminated soil, etc.

By centralizing heat production and through sector coupling with, e.g., the electricity system, DH systems can contribute to a more efficient use of energy resources. Examples of this include cogeneration at combined heat and power (CHP) plants, and heat production from large electric heat pumps and electric boilers.

The flexibility of DH systems includes the possibility of integrating various renewable and low-carbon heat sources, such as large-scale solar heating, geothermal energy, or waste heat from industrial processes. The flexibility is achieved by means of relatively cheap thermal storage solutions that allow temporal separation of heat production from consumption, enhancing the system's ability to balance and optimize the use of intermittent renewable energy sources.

Research and development perspectives

Research and development in district heating focus on making systems more efficient and integrated as part of a smart energy system.

Low-temperature district heating (LTDH), with a supply temperature of 50-55°C and a return of 25-30°C, is now a proven 4th-generation district heating technology. Recently, ultra-low-temperature district heating (ULTDH) has been introduced, with a supply temperature below 45°C and a return of 20-25°C. ULTDH separates district heating supply from domestic hot water (DHW) supply, using small individual heat pumps (micro boosters) to produce DHW, thus minimizing legionella risk. ULTDH is still developing but is promising for both new low-energy and some existing buildings.

Both LTDH and ULTDH provide advantages as lower heat losses, higher energy efficiency, e.g., for heat pumps, and compatibility with various heat sources, including renewable and industrial waste heat. LTDH and ULTDH are considered cost-effective, particularly in low-density, low-energy urban areas.

The trend toward low-temperature DH systems, as studied by the 4DH Research Centre (2024), highlights a shift towards more efficient, low-temperature networks that align with sustainable energy goals, as shown in Figure 6.

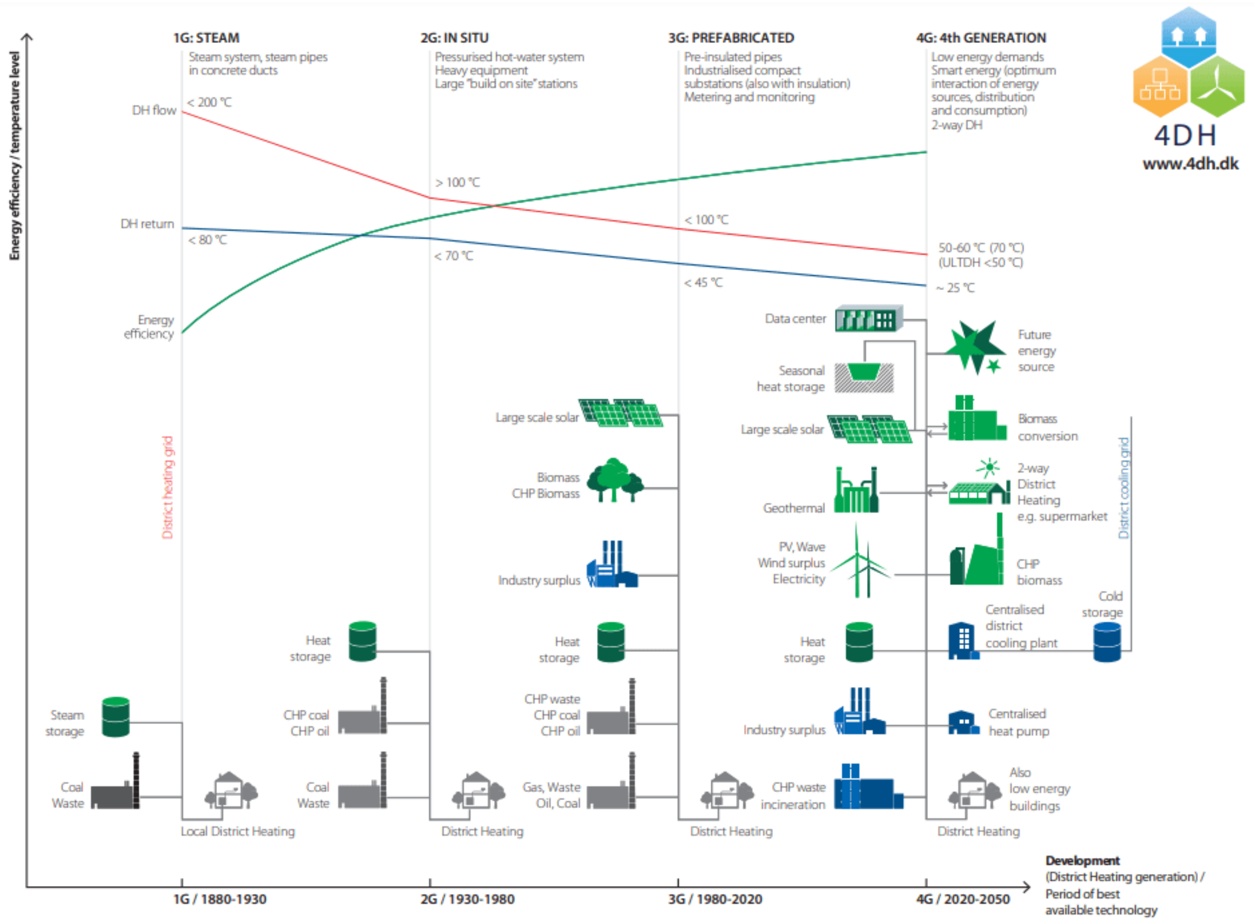

Figure 6 - Evolution in temperature reduction (4DH Research Centre, 2024) . Note: DH flow is the same as DH supply.

Research and development efforts are also investigating how to best retrofit existing buildings to work with these new low-temperature heating systems since a large part of the building stock, with its long lifespan, will continue to be a significant driver for heat energy for decades to come.

Focus areas within R&D include improving material technology to reduce losses, enhancing the pipe installation processes by e.g. smarter sleeve joints, developing advanced control systems for better network management, and exploring how to use digital technologies like IoT and AI to optimize the operation of district heating across different sectors.

Examples of market standard technology

A central element of DH is the pipes used. They can be twin or single (number of pipes within same insulation) and both single and twin pipes are manufactured in a variety of different materials, such as steel, different plastic materials, copper, and aluminium.

Where possible, twin pipes should be used instead of single pipes as this ensures reduced heat losses as well as construction costs. However, in areas with a high altitude changes single pipe systems are preferred. The twin pipe systems are available in dimensions up to DN250 (nominal diameter) but are normally not used for dimensions above DN150, as larger sizes become inflexible and difficult to handle.

While steel pipes are normally used for larger dimensions, more flexible pipes are preferred for smaller dimensions (DN15-DN50). These flexible pipes are easier to install, e.g., at consumer sites, as they can be bent where it requires complex routing and require fewer joint and less welding.

There are various solutions from different manufacturers aimed at making piping systems more flexible. Many of these use plastic materials, such as PE (polyethylene) with a diffusion barrier of aluminium.

Figure 7 shows twin pipes made from different materials. The picture on the left is conventional steal pipe, that is non-flexible, while the picture at the right shows a flexible PE pipe.

Regardless of the choice of materials and functionality, DH systems must be designed for a service life of at least 30 years according to DS/EN 13941-1:2019.

Figure 7 - Twinpipes – Steel and flexible PE pipe

Prediction of performance and costs

As shown in Figure 8, price indices show that there has been an increase of 30% in current prices and 15% in real prices from 2020 to 2024 for establishing and expanding district heating networks. This increase reflects a turbulent economic period with high inflation, driven by factors such as the 2021-2023 energy crisis and supply chain disruptions following the Russian invasion of Ukraine (U.S. Bureau of Labor Statistics, 2024).

In addition, the limited growth in the number of available contractors for district heating projects has since 2022 contributed to the construction cost increase, as demand for new DH projects continues to outpace workforce expansion in the sector.

A future stabilization of construction costs is expected in line with recent price index trends, but the rising costs has raised concerns that this have made district heating less competitive compared to individual heat pumps. But the competitiveness will also depend on the general longer technical lifetime of district heating systems as well as the development of heat production costs, where other parameters come into play: Economies of scale in energy pricing for DH plants compared to small, individual heat users; utilization of fluctuating electricity prices through flexible operation of CHP plants and electrically driven heat pumps and electric boilers; the possibility of utilizing cheap waste heat from industrial processes, etc.

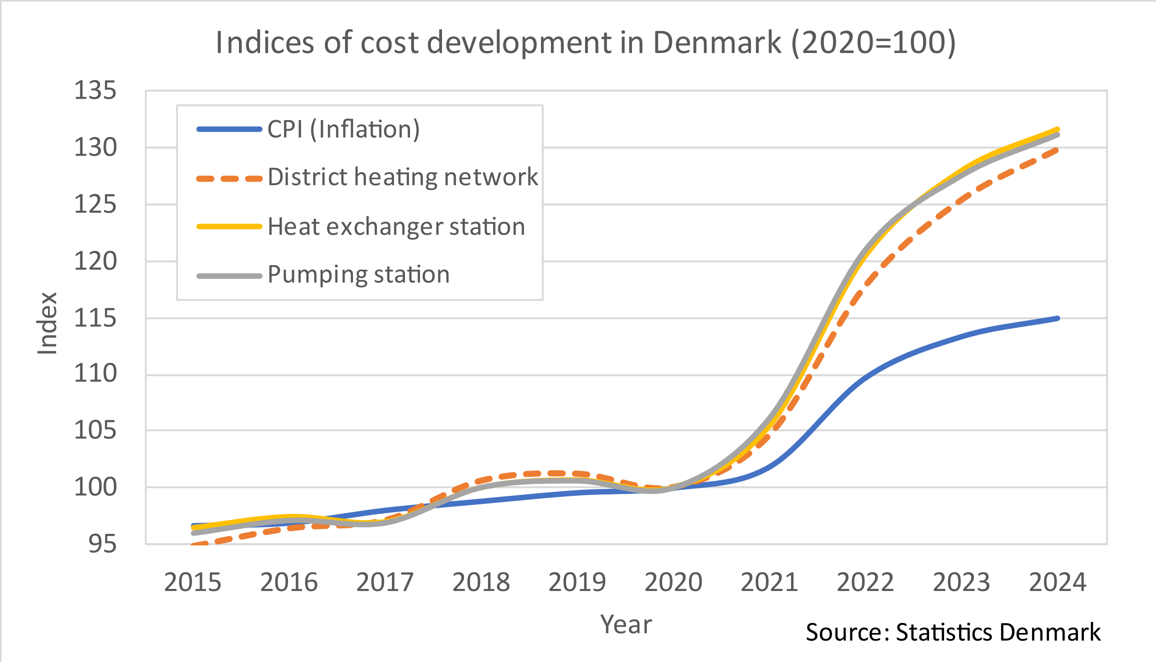

Figure 8 - Cost development 2015-2024 for district heating networks, large heat exchanger stations and pumping stations based on cost indexes from Statistics Denmark

Technology data sheets

The technology in the data sheets below refers to pre-insulated pipe systems that meet the requirements of DS/EN standards for design and installation. Twin pipes are assumed for sizes up to DN150, while pipe pairs are chosen for larger dimensions. The data sheets are organized into four tables, each providing key figures for the following types and conditions:

1. DH transmission systems at high temperature and pressure levels (design 110 °C and 25 bar).
2. DH distribution networks in suburban areas: Medium populated areas with predominantly detached, single-family homes of 1-2 floors. Heat density around 10 GWh/year/km^2.
3. DH distribution networks in city areas: More densely populated areas, including traditional Danish provincial towns with mixed, closely packed buildings of 2-3 stories or newer apartment complexes up to 4-5 stories with open spaces around. City represents urban areas with a relatively low heat density (around 15 GWh/year/km^2) with potential for new district heating, as urban areas with higher heat density are assumed to already have district heating.

4. DH distribution networks in new areas: Newly developed clusters of 1-2 story homes with shared green areas. Key data for LTDH is also included due to a considerable potential in new areas. Heat density around 6,5 GWh/year/km^2.

As a mature technology, district heating costs are generally expected to remain stable in real terms, with future expenses for new pipelines, heat exchangers, and pumping stations anticipated to follow inflation trends, like the period before 2020. However, there is still potential to improve system efficiency and reduce heat loss by adopting still lower operating temperatures.

Uncertainties

Key cost figures and efficiency indicators for DH networks, including investment cost per meter or per MW, heat loss ratios, and expected technical lifespan, can vary significantly based on the unique characteristics of each project, making standardization complex. Moreover, significant modifications to the core design and operational processes of these systems can result in unforeseen impacts on both the resulting investment costs and overall performance.

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Data sheets

Table 11: District heating Transmission

Technology	Energy Transport District Heating Transmission											
Year 2020 (fixed prices)	2020	2025	2030	2035	2040	2050	2025	2025	2050	2050	Note	Ref
Energy/technical data							Lower	Upper	Lower	Upper		
Energy losses, lines 1-20 MW [% per km]	1	1	1	1	1	1	0,8	1,5	0,8	1,2	A	[1, 2]
Energy losses, lines 20-100 MW [% per km]	0,25	0,25	0,25	0,25	0,25	0,25	0,2	0,375	0,2	0,3	A	[1, 2]
Energy losses, lines above 100 MW [% per km]	0,1	0,1	0,1	0,1	0,1	0,1	0,08	0,15	0,08	0,12	A	[1, 2]
Energy losses, Heat exchanger stations [%]	1	1	1	1	1	1	0,8	1,5	0,8	1,2		1
Energy losses, Pumping stations [%]	0	0	0	0	0	0	0	0	0	0	G	1
Auxiliary electricity consumption [%] energy transmitted	1	1	1	1	1	1	0.5	2	0.5	2		[1, 4]
Technical life time [years]	45	45	45	45	45	45	30	60	30	60	B	[1, 2]
Typical load profile (-)	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.6	0.4	0.6		1
Construction time [years]	2,5	2,5	2,5	2,5	2,5	2,5	1,5	4	1,5	4		1
Financial data												
Investment costs; single line, 0 - 50 MW [EUR/MW/m]	56	63	63	63	63	63	51	75	51	75	[C, D]	[1, 3]
Investment costs; single line, 50-100 MW [EUR/MW/m]	28	32	32	32	32	32	25	37	25	37	[C, D]	[1, 3]
Investment costs; single line, 100 - 250 MW [EUR/MW/m]	17	20	20	20	20	20	16	23	16	23	[C, D]	[1, 3]
Investment costs; single line, 250-500 MW [EUR/MW/m]	11	12	12	12	12	12	10	14	10	14	[C, D]	[1, 3]
Investment costs; single line, 500-1000 MW [EUR/MW/m]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Investment costs; single line, above 1000 MW [EUR/MW/m]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Fixed O&M [EUR/MW/km/year]	100	100	100	100	100	100	50	200	50	200		
Variable O&M [EUR/MWh/km]	0,1	0,1	0,1	0,1	0,1	0,1	0	2	0	2		[1, 4]
Investments, percentage installation	60%	60%	60%	60%	60%	60%	50%	70%	50%	70%	C	2
Investments, percentage materials	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%		2
Investment, percentage soft cost	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	F	2
Technology-specific data												
Reinforcement costs [EUR/MW]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	E	
Investment costs; Heat exchanger station [EUR/MW]	122.288	140.162	140.162	140.162	140.162	140.162	77.089	168.194	77.089	168.194		1
Investment costs; Pump station [EUR/MW]	111.654	127.473	127.473	127.473	127.473	127.473	70.110	152.968	70.110	152.968		1

References:

1. Based on Ramboll experience figures

2. LOGSTOR A/S

3. Consolidated with data from Danish District Heating Association

4. Consolidated with statistics from Danish District Heating Association 2020

Notes:

A. The loss is per trench km of transmission pipeline pair.

B. The technical life time of a district heating pipe is minimum 30 years. However the life time can be substantially longer depending on operation conditions e.g. temperaturevariation, soil conditions etc.

C. The cost is per trench meter transmission pipeline pair in unpaved areas.

D. Two district heating pipes were chosen for each interval (one for the lowest effect level and one for the highest). The average of these two are stated in the table. For cost interpolation: P = a * C^b, where P = cost in EUR/MW/m, C = capacity in MW, a = 330 and b =-0,571.

E. Depends on the scale of the transmission grid and supply strategy of reserve capacity. Therefore, it is not possible to generalize these costs.

F. Soft costs include design, planning, tender, permits, supervision, etc.

Table 12: Energy Transport District Heating Distribution, Suburban

Technology	Energy Transport District Heating Distribution, Suburban											
Year 2020 (fixed prices)	2020	2025	2030	2035	2040	2050	2025	2025	2050	2050	Note	Ref
Energy/technical data							Lower	Upper	Lower	Upper		
Energy losses, network [%]	12	12	12	12	12	12	10	16	9	14	[A, B]	2
Auxiliary electricity consumption [%] of energy delivered	2	2	2	2	2	2	0,5	3	0,5	3		4
Technical life time [years]	45	45	45	45	45	45	30	60	30	60	C	2
Typical load factor (-)												
- Residential	0,2	0,2	0,2	0,2	0,2	0,2	0.18	0.22	0.18	0.22		
- Commercial	0,2	0,2	0,2	0,2	0,2	0,2	0.15	0.25	0.15	0.25		
Construction time [years]	2	2	2	2	2	2	1	3	1	3		
Financial data												
Investments cost, distribution network [MEUR/km2]	6,5	7,3	7,3	7,3	7,3	7,3	5,5	9,1	5,5	9,1	[D, E]	[1, 3]
Investments, percentage installation	60%	60%	60%	60%	60%	60%	50%	70%	50%	70%	E	2
Investments, percentage materials	25%	25%	25%	25%	25%	25%	20%	30%	20%	30%	E	2
Investment, percentage soft costs percentage	15%	15%	15%	15%	15%	15%	10%	20%	10%	20%	H	2
Fixed O&M [EUR/MW/year]	1.000	1.000	1.000	1.000	1.000	1.000	750	2.000	750	2.000	M	1
Variable O&M [EUR/MWh]	2,0	2,0	2,0	2,0	2,0	2,0	1,5	3,0	1,5	3,0	M	[1, 4]
Technology-specific data												
Investment costs; service line, 0 - 20 kW [EUR/unit]	4.165	4.706	4.706	4.706	4.706	4.706	3.243	6.192	3.243	6.192	[B, E, F, J]	[1, 3]
Investment costs; service line, 20 - 50 kW [EUR/unit]	4.519	5.107	5.107	5.107	5.107	5.107	3.548	6.679	3.548	6.679	[B, E, F, J]	[1, 3]
Investment costs; service line, 50-100 kW [EUR/unit]	4.987	5.636	5.636	5.636	5.636	5.636	3.953	7.310	3.953	7.310	[B, E, F, J]	[1, 3]
Investment costs; service line, above 100 kW [EUR/unit]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	K	
Investment costs; single line, 0-50 kW [EUR/m]	308	349	349	349	349	349	241	456	241	456	[B, E, G]	[1, 3]
Investment costs; single line, 50-250 kW [EUR/m]	390	441	441	441	441	441	327	554	327	554	[B, E, G]	[1, 3]
Investment costs; single line, 100-250 kW [EUR/m]	407	459	459	459	459	459	342	577	342	577	[B, E, G]	[1, 3]
Investment costs; single line, 250 kW - 1 MW [EUR/m]	516	583	583	583	583	583	457	700	457	700	[B, E, G]	[1, 3]
Investment costs; single line, 1 MW - 5 MW [EUR/m]	725	819	819	819	819	819	646	971	646	971	[B, E, G]	[1, 3]
Investment costs; single line, 5 MW - 25 MW [EUR/m]	1.309	1.479	1.479	1.479	1.479	1.479	1.184	1.753	1.184	1.753	[B, E, G]	[1, 3]
Investment costs; single line, 25 MW - 100 MW [EUR/m]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	L	
Reinforcement costs [EUR/MW]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Pumping station above 1 MW [EUR/MW]	98.736	112.725	112.725	112.725	112.725	112.725	61.999	135.270	61.999	135.270	I	1
Pumping station below 1 MW [EUR/MW]	255.209	291.367	263.880	263.880	263.880	263.880	160.252	349.641	160.252	349.641	I	1

References:

1. Based on Ramboll experience figures. Costs have been deflated by a factor of 0.870 to 2020-EURO from project data in 2024.

2. Ramboll experience and technical data from LOGSTOR A/S

3. Consolidated with data from Danish District Heating Association

4. Consolidated with statistics from Danish District Heating Association 2020

Notes:

A. For entire distribution network inclusive pump stations and service lines. For pump stations the heat loss is negligible.

B. Twin pipes assumed up to 5 MW and pipe pairs for larger pipe capacities

C. The technical life time of a district heating pipe is minimum 30 years. However the life time can be substantially longer depending on operation conditions e.g. temperaturevariation, soil conditions etc.

D. The distribution network costs are inclusive pumping stations but exclusive service pipelines and based on an area of scattered single-family houses of 1-2 floors with a heat density of 10 GWh/year/km2.

E. A paved area is assumed for the distribution network. For service lines 50 % unpaved and 50 % paved area is asumed.

F. Cost of service lines are based on an average service line lenght of 15 meters. Two service lines were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table.

G. Two district heating pipes were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table. The cost is per trench meter.

H. Soft costs include costs for design, planning, tender, permits, supervision, etc. after the final investment decision.

I. Investment costs per MW for pumping stations below 1 MW are very different from costs for stations above 1 MW.

J It is assumed that the service line is constructed at the same time as the street line. For a subsequent customer connection (saddle connection), the investment costs for service lines are increased by 33%

K. Service lines above 100 kW are not relevant in the specific area type.

L. Single lines above 25 MW are not relevant in the specific area type.

M. The amount of thermal energy in MWh can be calculated from the heat density mentioned in note D. The effect in MW equals: amount of energy [MWh]/(8760 load factor). For a district heating system, the load factor is around 0.34.

Table 13: Energy Transport District Heating Distribution, City

Technology	Energy Transport District Heating Distribution, City											
Year 2020 (fixed prices)	2020	2025	2030	2035	2040	2050	2025	2025	2050	2050	Note	Ref
Energy/technical data							Lower	Upper	Lower	Upper		
Energy losses, network [%]	7	7	7	7	7	7	5	9	4	8	[A, B]	2
Auxiliary electricity consumption [%] of energy delivered	2	2	2	2	2	2	0,5	3	0,5	3		4
Technical life time [years]	45	45	45	45	45	45	30	60	30	60	C	2
Typical load factor (-)												
- Residential	0,2	0,2	0,2	0,2	0,2	0,2	0.18	0.25	0.18	0.25		
- Commercial	0,2	0,2	0,2	0,2	0,2	0,2	0.15	0.25	0.15	0.25		
Construction time [years]	2	2	2	2	2	2	1	3	1	3		
Financial data												
Investments cost, distribution network [MEUR/km2]	6,0	6,7	6,7	6,7	6,7	6,7	5,0	8,4	5,0	8,4	[D, E]	[1, 3]
Investments, percentage installation	60%	60%	60%	60%	60%	60%	50%	70%	50%	70%	E	2
Investments, percentage materials	25%	25%	25%	25%	25%	25%	20%	30%	20%	30%	E	2
Investment, percentage soft costs	15%	15%	15%	15%	15%	15%	10%	20%	10%	20%	H	2
Fixed O&M [EUR/MW/year]	1.000	1.000	1.000	1.000	1.000	1.000	750	2.000	750	2.000	M	1
Variable O&M [EUR/MWh]	2,0	2,0	2,0	2,0	2,0	2,0	1,5	3,0	1,5	3,0	M	[1, 4]
Technology-specific data												
Investment costs; service line, 0 - 20 kW [EUR/unit]	4.961	5.607	5.607	5.607	5.607	5.607	3.805	7.432	3.805	7.432	[B, E, F, J]	[1, 3]
Investment costs; service line, 20 - 50 kW [EUR/unit]	5.334	6.028	6.028	6.028	6.028	6.028	4.135	7.883	4.135	7.883	[B, E, F, J]	[1, 3]
Investment costs; service line, 50-100 kW [EUR/unit]	5.827	6.585	6.585	6.585	6.585	6.585	4.627	8.482	4.627	8.482	[B, E, F, J]	[1, 3]
Investment costs; service line, above 100 kW [EUR/unit]	7.160	8.091	8.091	8.091	8.091	8.091	6.264	9.918	6.264	9.918	[B, E, F, J, K]	[1, 3]
Investment costs; single line, 0-50 kW [EUR/m]	339	383	383	383	383	383	262	507	262	507	[B, E, G]	[1, 3]
Investment costs; single line, 50-100 kW [EUR/m]	380	430	430	430	430	430	303	560	303	560	[B, E, G]	[1, 3]
Investment costs; single line, 100-250 kW [EUR/m]	441	499	499	499	499	499	372	625	372	625	[B, E, G]	[1, 3]
Investment costs; single line, 250 kW - 1 MW [EUR/m]	551	623	623	623	623	623	488	749	488	749	[B, E, G]	[1, 3]
Investment costs; single line, 1 MW - 5 MW [EUR/m]	773	874	874	874	874	874	692	1.035	692	1.035	[B, E, G]	[1, 3]
Investment costs; single line, 5 MW - 25 MW [EUR/m]	1.390	1.571	1.571	1.571	1.571	1.571	1.259	1.863	1.259	1.863	[B, E, G]	[1, 3]
Investment costs; single line, 25 MW - 100 MW [EUR/m]	2.533	2.862	2.862	2.862	2.862	2.862	2.306	3.393	2.306	3.393	[B, E, G, L]	[1, 3]
Reinforcement costs [EUR/MW]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Pumping station above 1 MW [EUR/MW]	98.736	112.725	112.725	112.725	112.725	112.725	61.999	135.270	61.999	143.842	I	1
Pumping station below 1 MW [EUR/MW]	255.209	291.367	291.367	291.367	291.367	291.367	160.252	349.641	160.252	349.641	I	1

References:

1. Based on Ramboll experience figures. Costs have been deflated by a factor of 0.870 to 2020-EURO from project data in 2024.
2. Ramboll experience and technical data from LOGSTOR A/S
3. Consolidated with data from Danish District Heating Association
4. Consolidated with statistics from Danish District Heating Association 2020

Notes:

A. For entire distribution network inclusive pump stations and service lines. For pump stations the heat loss is negligible.

B. Twin pipes assumed up to 5 MW and pipe pairs for larger pipe capacities.

C. The technical life time of a district heating pipe is minimum 30 years. However the life time can be substantially longer depending on operation conditions e.g. temperaturevariation, soil conditions etc.

D. The distribution network costs are inclusive pumping stations but exclusive service pipelines and based on mixed densely packed buildings in 2-3 storeys and with a heat density of 15 GWh/year/km2.

E. A paved area is assumed for the distribution network as well as for service lines.

F. Cost of service lines are based on an average service line lenght of 15 meters. Two service lines were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table.

G. Two district heating pipes were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table. The cost is per trench meter.

H. Soft costs include costs for design, planning, tender, permits, supervision, etc. after the final investment decision.

I. Investment costs per MW for pumping stations below 1 MW are very different from costs for stations above 1 MW.

J It is assumed that the service line is constructed at the same time as the street line. For a subsequent customer connection (saddle connection), the investment costs for service lines are increased by 33%

K. The value stated is for a DN50 twin pipe. This pipe size is able to deliver up to around 250 kW. If a higher capacity is needed the price will increase.

L. The value stated is for a DN400 pipe pair. This pipe size is able to deliver up to around 45 MW. If a higher capacity is needed the price will increase.

M. The amount of thermal energy in MWh can be calculated from the heat density mentioned in note D. The effect in MW equals: amount of energy [MWh]/(8760 load factor). For a district heating system, the load factor is around 0.34.

Table 14: Energy Transport District Heating Distribution, New Area

Technology	Energy Transport District Heating Distribution, New Area											
Year 2020 (fixed prices)	2020	2025	2030	2035	2040	2050	2025	2025	2050	2050	Note	Ref
Energy/technical data							Lower	Upper	Lower	Upper		
Energy losses, network [%]	18	18	18	18	18	18	12	24	10	20	[A, B]	2
Auxiliary electricity consumption [%] of energy delivered	2	2	2	2	2	2	0,5	3	0,5	3		4
Technical life time [years]	45	45	45	45	45	45	30	60	30	60	C	2
Typical load factor (-)												
- Residential	0,17	0,17	0,17	0,17	0,17	0,17	0.1	0.2	0.1	0.2		
- Commercial	0,17	0,17	0,17	0,17	0,17	0,17	0.1	0.2	0.1	0.2		
Construction time [years]	1	1	1	1	1	1	0.5	2	0.5	2		
Financial data												
Investments cost, distribution network [MEUR/km2]	4,7	5,3	5,3	5,3	5,3	5,3	4,0	6,6	4,0	6,6	[D, E]	[1, 3]
Investments, percentage installation	60%	60%	60%	60%	60%	60%	50%	70%	50%	70%	E	2
Investments, percentage materials	25%	25%	25%	25%	25%	25%	20%	30%	20%	30%	E	2
Investment, percentage soft costs	15%	15%	15%	15%	15%	15%	10%	20%	10%	20%	H	2
Fixed O&M [EUR/MW/year]	1.000	1.000	1.000	1.000	1.000	1.000	750	2.000	750	2.000	M	1
Variable O&M [EUR/MWh]	1,60	1,7	1,7	1,7	1,7	1,7	1,3	2,6	1,3	2,6	M	[1, 4]
Technology-specific data												
Investment costs; service line, 0 - 20 kW [EUR/unit]	3.504	3.960	3.960	3.960	3.960	3.960	2.707	5.231	2.707	5.231	[B, E, F, J]	[1, 3]
Investment costs; service line, 20 - 50 kW [EUR/unit]	3.784	4.276	4.276	4.276	4.276	4.276	2.951	5.593	2.951	5.593	[B, E, F, J]	[1, 3]
Investment costs; service line, 50-100 kW [EUR/unit]	4.154	4.694	4.694	4.694	4.694	4.694	3.296	6.066	3.296	6.066	[B, E, F, J]	[1, 3]
Investment costs; service line, above 100 kW [EUR/unit]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	K	
Investment costs; single line, 0-50 kW [EUR/m]	243	274	274	274	274	274	189	361	189	361	[B, E, G]	[1, 3]
Investment costs; single line, 50-250 kW [EUR/m]	302	342	342	342	342	342	253	431	253	431	[B, E, G]	[1, 3]
Investment costs; single line, 100-250 kW [EUR/m]	318	359	359	359	359	359	268	451	268	451	[B, E, G]	[1, 3]
Investment costs; single line, 250 kW - 1 MW [EUR/m]	400	452	452	452	452	452	354	543	354	543	[B, E, G]	[1, 3]
Investment costs; single line, 1 MW - 5 MW [EUR/m]	562	635	635	635	635	635	502	752	502	752	[B, E, G]	[1, 3]
Investment costs; single line, 5 MW - 25 MW [EUR/m]	1.012	1.144	1.144	1.144	1.144	1.144	916	1.356	916	1.356	[B, E, G]	[1, 3]
Investment costs; single line, 25 MW - 100 MW [EUR/m]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	L	
Reinforcement costs [EUR/MW]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		
Pumping station above 1 MW [EUR/MW]	92.764	105.907	105.907	105.907	105.907	105.907	59.308	127.088	59.308	127.088	I	1
Pumping station below 1 MW [EUR/MW]	247.371	282.419	282.419	282.419	282.419	282.419	158.154	338.902	158.154	338.902	I	1

References:

1. Based on Ramboll experience figures. Costs have been deflated by a factor of 0.870 to 2020-EURO from project data in 2024.

2. Ramboll experience and technical data from LOGSTOR A/S

3. Consolidated with data from Danish District Heating Association

4. Consolidated with statistics from Danish District Heating Association 2020

Notes:

A. For entire distribution network inclusive pump stations and service lines. For pump stations the heat loss is negligible.

B. Twin pipes assumed up to 5 MW and pipe pairs for larger pipe capacities.

C. The technical life time of a district heating pipe is minimum 30 years. However the life time can be substantially longer depending on operation conditions e.g. temperaturevariation, soil conditions etc.

D. The distribution network costs are inclusive pumping stations but exclusive service pipelines and based on close cluster housing in 1-2 floors in shared green areas and with a heat density of 6.5 GWh/year/km2.

E. An unpaved area is assumed for the distribution network as well as for service lines. Coordination with the establishment of other infrastructure (electricity, water, sewerage) may entail construction cost benefits.

F. Cost of service lines are based on an average service line lenght of 15 meters. Two service lines were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table.

G. Two district heating pipes were chosen for each interval (one for the lowest capacity level and one for the highest). The average of these two are stated in the table. The cost is per trench meter.

H. Soft costs include costs for design, planning, tender, permits, supervision, etc. after the final investment decision.

I. Investment costs per MW for pumping stations below 1 MW are very different from costs for stations above 1 MW.

J It is assumed that the service line is constructed at the same time as the street line. For a subsequent customer connection (saddle connection), the investment costs for service lines are increased by 50%

K. Service lines above 100 kW are not relevant in the specific area type.

L. Single lines above 25 MW are not relevant in the specific area type.

M. The amount of thermal energy in MWh can be calculated from the heat density mentioned in note D. The effect in MW equals: amount of energy [MWh]/(8760 load factor). For a district heating system, the load factor is around 0.34.

For the entire table: With low-temperature district heating (LTDH), the stated heat loss of the district heating network is reduced by 20-25% and the district heating network investment is reduced by up to 5%.

Introduction to transport of gases and liquids

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Date	Ref.	Description

Abbreviations

Amb.	Ambient condition (P=1.025 bar, T€[-50:50] °C	LPG	Liquefied petroleum gas
CC	Carbon Capture	M	Mass
CH2	Compressed hydrogen	M/R	Metering and regulation station
CNG	Compressed natural gas	MTPD	Metric ton per day
CNO	Numb of carbon atoms in a chemical molecule	NG	Natural gas
CP	Cathodic protection	NH_3	Ammonia
DME	Dimethyl-Ether	P	Pressure
DN	Nominal diameter	Pd	Design pressure
dP/dL	Pressure drop per length (bar/km)	PG	Petroleum gas
E	Energy	Pin	Inlet/suction pressure
EIGA	European industrial gases association AISBL	Pmax	Max operation pressure
ESD	Emergency shutdown	Pmin	Min operating pressure
GT	Gross Tonnage	Pout	Outlet/discharge pressure
H_2	Hydrogen	PSA	Pressure swing adsorption unit (separate components by selective absorption at high pressure and desorption/regeneration at low pressure)
H2NG	Fuel group: include H2 and NG	PSV	Pressure safety valve (protect against overpressure)

HB	Material hardness measured by "Hardness Brinell" method
HC	Hydrocarbons, i.e. molecules that consist of only C and H (C_nH_m)
HHV	Higher heating value
HRC	Material hardness measured by "Hardness Rockwell C" method
L20	Fuel group: include DME, NH_3 and LPG (and ethane)
LDME	Liquefied dimethyl-ether
LH2	Liquefied hydrogen
LHC	Fuel group: All fuels that are liquid at P=1.025 bar and T=50°C
LNG	Liquefied natural gas
LNH3	Liquefied ammonia
Q	Energy flow, MW
RE	Renewable power
SCC	Stress corrosion cracking
SMR	Steam Methane Reforming
T	Temperature
Td	Design temperature
US	United States
VLGC	Very large gas carriers/ships
W	World

Purpose and scope

This technology catalogue provides an overview of the different technologies for transporting fuels with specific focus on Hydrogen (H_2), Ammonia (NH_3), Dimethyl Ether (DME) and Liquid organic hydrogen carrier (LOHC). The catalogue provides cost and performance data for transportation via pipeline, truck and ship.

The document include catalog on transport via:

1. Pipeline
2. Trucks
3. Ships

These Subsections are preceded with this introduction section that include:

1. Description of the different types of fuels and their key properties (See section *Properties* & *Short fluid description and Grade*)

2. Grouping fuels into (Section *Transport form – chemical phase*):
   - Liquid fuels (**LHC**)
   - Fuels that are liquefied @ 20 bar (**L20**)
   - Fuels that require extreme cooling to liquify (**H2NG**)

   There exist many different fuels (see Table 11). To avoid having to treat each fuel separately, the above three fuel groups have been defined. These groups are used to identify which transport form/phase is possible/optimal and thereby which elements that are needed in the transport chain.

3. Advantages and disadvantages of different transport forms (i.e. pipeline, truck, train and ships) (Section *Transport unit – pipeline, truck, train or ship*)

4. Material of construction, i.e. steel grade needed for handling the different types of fuels (Section *Material of construction*)

5. Safety issues (Section *Safety*)

6. Overall transport chain (Section *Transport chain - logistic and infrastructure*) giving an overview of the elements that must be included in the entire transport chain

7. Energy loss - overview of different type of energy losses and how they can be predicted (Section *Energy losses*)

8. Possible elements of the transport chain:
    - Conversion to/from hydrogen carrier (Section *Conversion to/from carrier (LOHC)*) (only for H_2)
    - Conversion to liquid phase by cooling (Section *Convert to liquid phase by cooling*)
    - Compressor (Section *Compressor*)
    - Pumps (Section *Pumps*)
    - Fiscal metering (Section *Fiscal metering stations*)
    - Storage tanks (Section *Storage tanks*)

    These sections include losses and costs for the different elements.

9. Examples (Section *Examples - full transportation chain*) of calculating loss and cost for the entire transport chain

Properties

Key properties

This chapter list key chemical properties for fuels and some LOHC. The purpose is for later reference.

This catalogue aims to lump components into fuel groups that are treated together. Therefore, properties for other fluids than the H_2, NH_3, DME and LOHC have been included.

In Table 11, the following properties are given:

1. **Energy density:** The energy density listed is per mass. This can be converted to energy density per volume by multiplying with the density which is given too. The mass- and volume-based energy density is plotted in Figure 9.

2. **Freezing point and boiling point/distillation curve:** The freezing point give the solidification point while the boiling point/distillation curve give the point/range where it vaporizes. For single components (i.e. H_2, NH_3, MeOH, etc.), freezing and boiling points are single point, while for mixtures (LPG, gasoline, jet fuel, etc.) it's ranges. These properties give the chemical phase (solid, liquid, gas) that a given fuel will take at ambient pressure (1.025 bar).

3. **Flash point, autoignition point and flammability/explosion limit:** These properties are ignition and safety related properties. Flash and autoignition point give the lowest temperature at which it ignites <u>with</u> and <u>without</u> an ignition source. The explosion limit gives the fuel concentration range in air where it will burn/explode in the presence of an ignition source.

Fuel types	Fuels	Energy density - LHV (MJ/kg)	Heat of condensation (@ boiling point) (MJ/kg) (% of LHV)	Temperature, C				Flammability/Explosion limit, % (LFL/LEL) / (UFL/UEL), %	Molecylar weight, kg/kmole	Density, g/l, kg/m3 (at Amb.) (Liquid dens. @ Pboil)	Chemical/CNO
				Freezing point	Boiling point/ Distillation curve	Flash point	Autoignition				
H_2,NH_3	Hydrogen	120		-259.2	-253	NA	560	4/75	2	0.0899 (70.9)	H2
	Ammonia	19	1.37 (7.4%)	-77.73	-33.4	132	651	15/28	17	0.73 (620/7 bar)	NH_3
Hydrocarbon mixture	NG	47		-182	-163	-188	600	~5/16	16-18	0.76 (657)	C1
	LPG	46.6	0.43 (0.9%)	-188	-43	(-60)-(-100)	410-580	1.8/9.6	42-56	~ 2.4 (540)	C3-C4
	Petrol/benzin/ gasoline	43		<-40	30-210	-43	280	1.4/7.6	~72	~ 780	C4-C12 (typical C7-C11)
	Diesel	43		<-6	150-360	52-96	210-230	0.6/5.5	198-202	800-850	C12-C20
	Vegetable oil (HVO)	44		<-10/-40	180-320	> 55	424	4/33	~ 250	~ 780	C15-C18
	Heavy fuel oil (HFO)	39		NA	150-750	> 50, 65-80	>400	NA	mean=240, 50-1800	~ 980, >900	tyical C20-C50
	Marine gasoil (MGO)	44-45		>-40	150-500	60-85	>250	1/6	200-300	850-870	<C35
	Jet-fuel (Jet A-1)	>42.8		<-47	205-300	38-66	>229	0.6/4.7	~185	775-840	C10-C13, mostly kerosene
	Kerosene	43		-47	150-275	37-72	220	0.6/4.7	~170	780-810	C6-C20 (typically C10-C16)
Oxy fuels	Methanol	20		-97.6	65	11-12	385	6/36	31	790	CH3OH
	Ethanol	27		-114	78.4	16.6	363	3.3-19.0	46	789	C2H5OH
	Propanol (Bio-LPG)	34		-126	82	26	371	2.1/13.5	60	803	C3H7OH
	n-Butanol	33		-89.8	118	35	343	1.4/11.2	74	810	C4H9OH
	DME	29	0.47 (1.6%)	-141	-24	-41	350	3.4/27	46	2.11 (668)	C2H6O
	Bio-Diesel (FAME)	38		(-16)-16	340-360	173	261	NA	~296	~ 880	C16-C81, Ester
LOHC	DBT: Dibenzyltoluene			<-31.8	>250	190-210	500	NA	272	1029	C21H20
	HDBT: Perhydro-Dibenzyltoluene			-34	~390	~200		NA	291		C21H38
	FA: Formic acid	6		8.4	100.8	69	601	14/34	46	1220	CHOOH
	MET: Methanol	20		-98	65	11-12	385	6/36	31	790	CH3OH
	TOP: Toluene	40.6		-95	110.6	6	480	1.1/7.1	92	867	C7H8
	Methylcyclohexane	43.3		-126.3	101	79-87	540	0.9/5.9	98	770	C7H14

Table 11: Key fuel properties.

Energy density

The energy density for various fuels are shown in Figure 9.

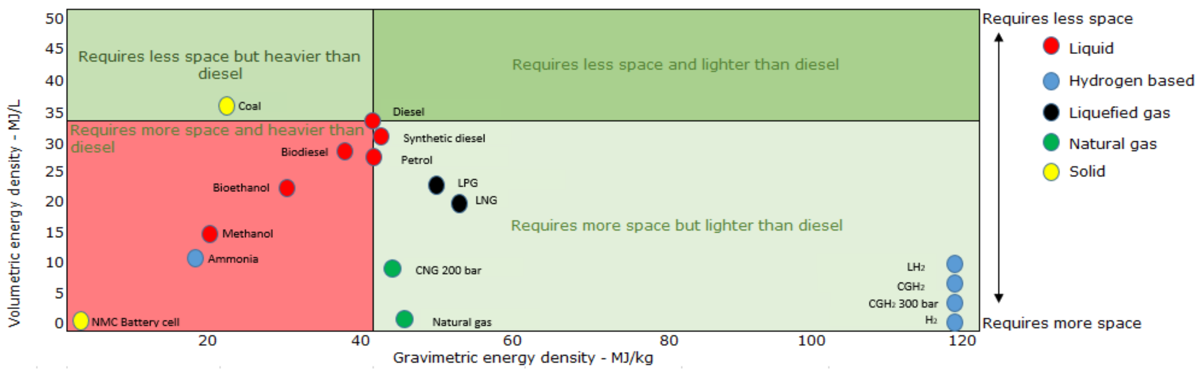


Figure 9: Energy density for various fuels

Phase curve

In Figure 10 the gas-liquid phase curve is represented for various fuels. Thus, the fuel is liquid on the left-hand side of the curve and gas on the right-hand side. The red line represents ambient condition (pressure is 1.025 bar and temperature is between -50 °C and +50 °C). This red line express which phase the fluid is if not exposed to any cooling or pressurization. At 20 bar (the purple line) the majority of fuels (all except for hydrogen, methane and ethane) are liquids.

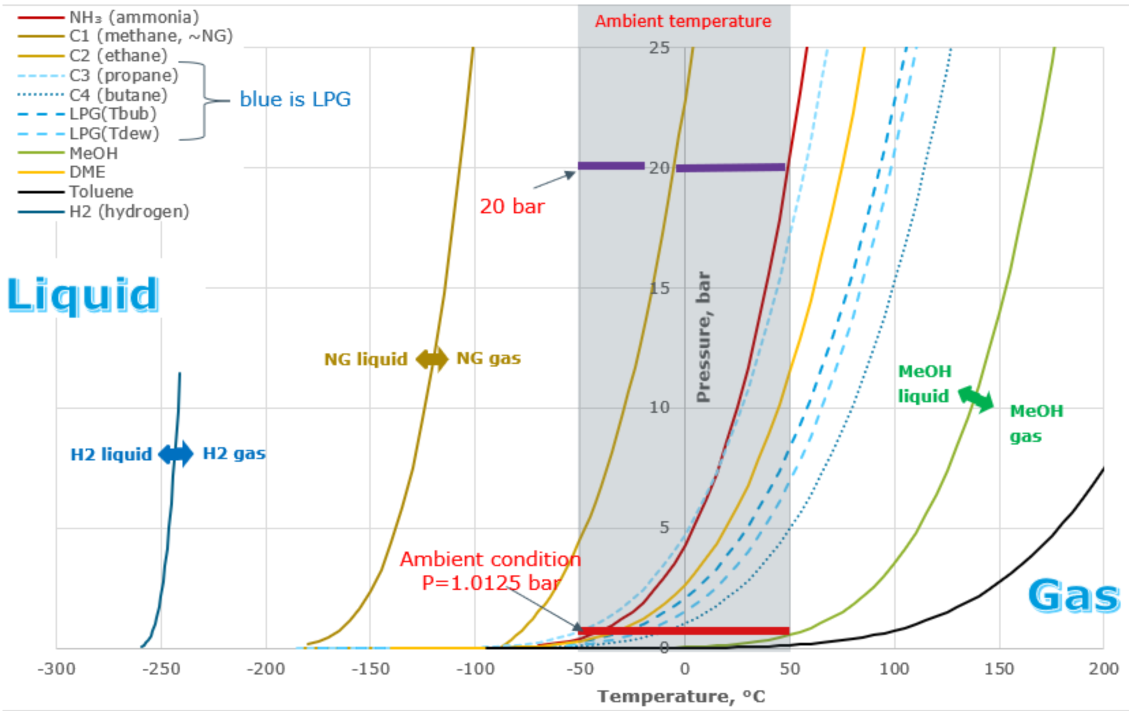


Figure 10: Phase curve for various fuels. Toluene is representative for LOHC which all are liquid at ambient condition. All hydrocarbon mixtures above C5 and all alcohols are below the MeOH curve

Short fluid description and Grade

Hydrogen (H_2)

Hydrogen is lighter than air, highly flammable, very easily ignited, does not cool when expanded, and has so small molecular size that leakage and even penetration into the surrounding material is a key design issue.

Hydrogen fuel grades – key requirements to hydrogen when used as fuel for PEM fuel cells for road vehicles (ISO 14687, SAE J2719):

1. >99.97 %
2. < 5 ppm H_20, < 5 ppm O_2
3. Max requirements to several other impurities

Ammonia (NH_3)

Ammonia is a toxic, corrosive, less flammable gas with a strong characteristic odor. Ammonia is lighter than air but because of its tremendous affinity for water, it reacts immediately with the humidity limiting the dispersion in the environment. Is not a greenhouse gas.

Typical product specification ref. 25:

1. >99.5 wt % NH_3

2. 0.2-0.5 wt % Water
3. max 5 ppm oil

Refrigerant grade ammonia ref. 28
1. >99.95 wt % NH_3
2. < 33 ppm H_2O
3. < 2 ppm oil

Ammonia is still not approved as fuel, thus no fuel grade requirement exists yet.

Dimethyl ether (DME)

Dimethyl ether (DME, CH3OCH3) is colorless, non-toxic and highly flammable.

Typical product specification

- 99.7 DME
- Rest is MeOH

Transport form – chemical phase

Within this catalogue, fuels are divided into three groups (see Table 12).

Group	Description	Include	Transport form	Transport options		
				Pipeline	Truck/ train	Ship
1 LHC	Liquid @ ambient condition (see ***Liquid fuels (LHC)***)	• HC where CNO≥5 • All alcohols • All LOHC	Liquid P=few bars, T=Amb.	yes	yes	yes
2 L20	Liquid @ P=20 bar (see ***Liquid at ≥ 20 bar (L20) - NH3, DME and LPG***)	• NH_3 • LPG • DME • (Ethane)	Pressurized Liquid P=10-30 bar, T=Amb.	yes	yes	yes
			Cooled liquid P=few bars, T~ (-25)-(-45) °C	no	yes	yes
3 H2NG	Require extreme cooling to liquify (see ***H2 and NG***)	• H_2 • Methane/NG	Pressurized gas NG: P=60-80 bar, T=Amb H_2: P=60-140 bar, T=Amb	yes	yes	no
			Cooled liquid[23] NG: P=few bars, T~-163°C H_2: P=few bars, T~-253°C	no	yes	yes
			Carrier (only H_2) P=few bars, T=Amb.	yes	yes	yes

Table 12: Transport groups, which fuel belong to each group, possible transport form/phase and possible transport options

Group 1 (LHC) is liquid at ambient condition. Group 2 and 3 fuels are converted into the more energy dense transport form either via pressurization, cooling or reaction with a carrier[24] (latter only relevant for H_2). The advantages and disadvantages for each of these packing methods are listed in Table 13 below.

[23] Might be a combination of cooling and pressurization
[24] See definition/description in 0 and
Table 14

	Pressurized	Cooled	Carrier[24] (only H_2)
Advantages	1. Low compression loss 2. Low transportation loss	1. High volumetric energy density compared with compressed gas	1. Higher volumetric energy density compared with both CH2 and LH2 2. Stored at ambient condition 3. Existing infrastructure can be used 4. Neglectable transport and standby loss 5. Long term storage without loss 6. Safety – less flammable fluid
Disadvantages	1. Low volumetric energy density requiring many tours if transported with trucks/ships. 2. Cost intensive as high amount of steel is required due to the high pressure (thick tank walls)	1. Capital cost of installing refrigeration/cryogenic unit 2. High conversion loss 3. Normally high loss when transferring fluid from one vessel to another (all surfaces must be kept cold) 4. Boil off (or cooling or highly isolated) under transportation/standby	1. Capital cost of installing conversion unit 2. High conversion loss 3. Extra transport fuel as weight of carrier must be transported too (both forth and back)

Table 13: Advantages and disadvantages for different methods of converting group 2+3 into more energy dense transport form.

Liquid fuels (LHC)

All fuels and LOHC that are liquids at P=1.025 bar and T=50°C will be treated as one group called liquid fuels (LHC). This group includes:

1. All hydrocarbons with carbon number (CNO) larger and equal to 5 (gasoline, diesel, HFO, MGO, Jet fuels, etc.)
2. All alcohols (Methanol, Ethanol, Propanol, etc.)
3. All liquid organic hydrogen carriers (LOHC) (see examples in Table 11)

All these fuels are stored and transported in the same manner as conventional liquid-hydrocarbons.

Liquid at ≥ 20 bar (L20) - NH_3, DME and LPG

This fuel group (L20) include fuels that are liquid at (P=20 bar, T=50°C) and vapor at (P=1.025 bar, T=50°C). All fuels within this group will all be transported and stored as liquids.

This group include NH_3, DME an LPG. Pure ethane is also part of this group but will require a little higher pressure to liquify than the others.

The liquefaction will always be via pressure when transported in pipeline while either pressurization, cooling or both can be applied when transported via truck, rail and ships.

H_2 and NG

Fuels that are gaseous at 20 bar can either be transported as compressed gas (will always be the case for pipe-transport), cryogenic liquid or via a carrier (the latter is only for H_2). Hydrogen and natural gas require cryogenic cooling for liquefaction.

Pipe transport: As cooling is impractical, H_2 and NG will always be transferred as compressed gas in transmission pipes.

Mobile transport: NG will normally be transported as a liquid. Hydrogen is today mostly transported as compressed gas but liquid transportation exist too. As hydrogen require extreme cooling, its optimal transportation (and storage) form is still under development. Figure 11 gives an overview of different ways hydrogen can be transported/storage.

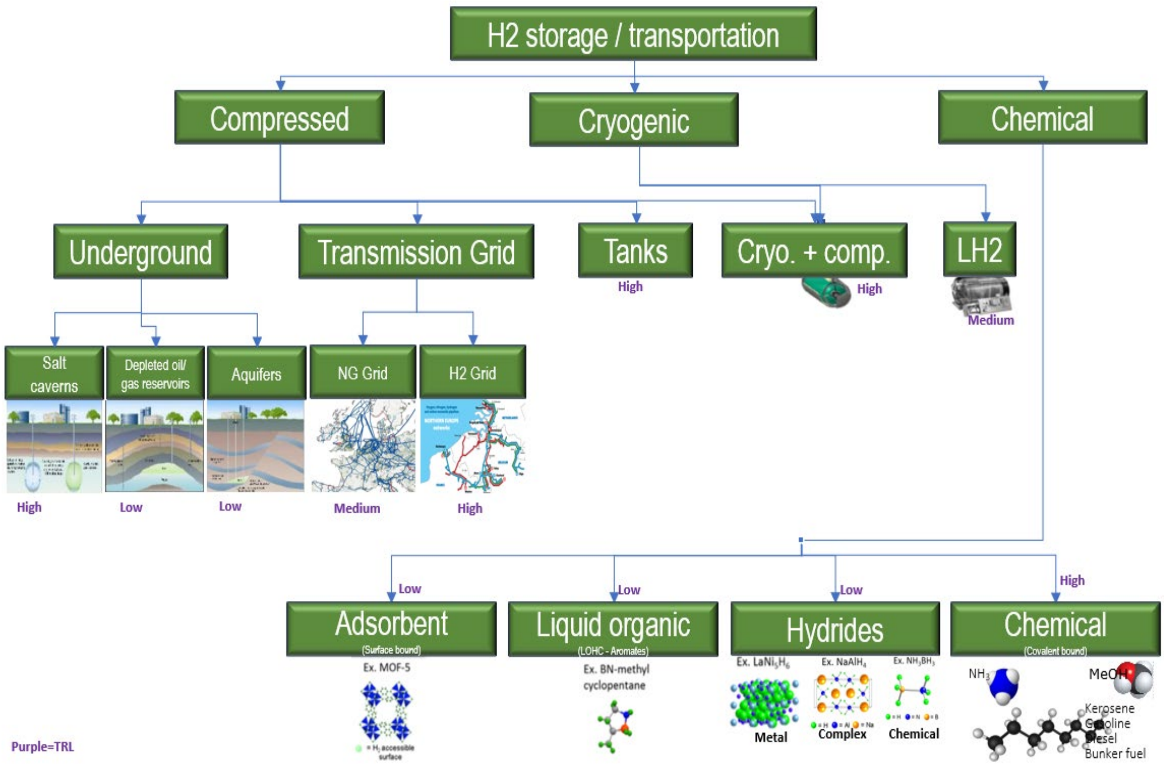
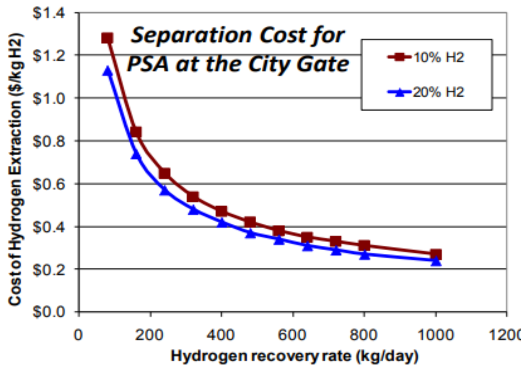


Figure 11: Different H_2 storage and transport technologies

For compressed underground and tank storage see ref. 7.

Transport of hydrogen via existing NG-grid: Today no H_2 is allowed in the Danish NG-grid. Investigation have been made [ref. 16] and it is expected that 10% hydrogen can be added with minor modifications and more (but still moderate) investment is required to allow up to 20% H_2.

The disadvantages of admitting H_2 to the existing net is that any users that need pure H_2 (or pure CH_4[25]) need to separate H_2 from CH_4 which is expensive. Normally a PSA will be applied for such separation and here the natural gas will come out at low pressure and need to be re-pressurized.



Re-pressurization can incur an

Figure 12: Separating H_2 from NG using PSA ref. 19

Liquid hydrogen require liquefaction. The energy loss under liquefication process is very high (see *Cryogenic Liquefaction of H2*) meaning that LH2 only is optimal for very long-distance transport.

Hydrogen carriers are substances that are able to bind several hydrogen atoms. As hydrogen is more expensive to store/transport than other fuels, extensive research has lately been carried out to investigate whether hydrogen carriers are optimal for storage and transportation of hydrogen.

Different types of hydrogen carriers are listed in Table *14* together with their advantages/disadvantages.

	Description	Component (examples)	TRL	Advantages	Disadvantages
Adsorbent	Solid that adsorb hydrogen on the surface or in the pores of complex materials via intermolecular forces.	Metal–organic frameworks (MOFs), graphene, carbon nanotubes	1	Materials can be reused many times Stable materials	Immature technology
Ion hydrides	Compounds consisting of hydride ions (H^+) and electropositive metals, typically an alkali or alkaline earth metal	LiH, NaH, KH, MgH	2	Flexible source of hydrogen Can be stored infinite under dry conditions	Must not be exposed to any moist before the dehydration, pyrophoric Dehydrogenation is strongly exothermic => waste heat
Covalent metal hydrides	The hydride is part of complex ions, where hydride is covalent bound to a metal atom	LiBH4, NaBH4, LiAlH4, NH4BH4	2	More stable than ion hydrides	Highly alkaline waste after hydrogen release
Metallic hydrides	Hydride is nonstoichiometric bound/adsorbed/absorbed to precious metals and its alloys. Hydrogen is released by heating	Precious metals (Pd, Pt)	2	Knowledge available from the Ni-Hydrogen battery technology	High cost as currently made in small quantities and as require >95% purity
Liquid Organic hydrocarbons (LOHC)	Liquid organic hydrogen carriers are organic chemical components that relatively easy can be hydrogenated/dehydrogenated.	See Table 11 and ref. 7.	7	Transported and handled as liquid fuel are handled today	Many different technologies for releasing hydrogen
H_2 righ chemical	Non carbon-based compounds that relatively easy can be hydrogenated/dehydrogenated.	NH_3, hydrazine	4-8	Except for the cracking into H_2, mature technology ready for large scale exploration	Toxic Untested as hydrogen supply Very high cracking temperature required NH_3 is poison to PEM fuel cell, i.e. no NH_3 traces after cracking

Table 14: Different type of hydrogen carriers

[25] Most of todays gas-turbines cannot take larger amount of hydrogen.

Liquid organic hydrocarbons (LOHC) and hydrogen rich chemicals are all transported as liquids (thus covered by LHC in this catalogue). Adsorbent, ion hydrides and covalent metal hydrides are solids and need special transportation which is not included in this catalogue.

Transport unit – pipeline, truck, train or ship

Ways to transport fluid are listed in Table 15 together with key advantages/disadvantages.

	Advantages	Disadvantages
Pipeline	• Limit number of intermediate storage/compression stages (Table 18). • Combine transport and storage • Very low OPEX • Very low risk • Can transport large amount of energy much cheaper than electric cables	• High CAPEX • Less flexible than mobile transportation
Trucks	• Provide point to point solutions, i.e. limit number of intermediate storage/compression stages	• Risk is higher than pipeline, train and ships • Size limited to max weight, width and length of a truck
Trains	• Risk are lower than trucks but higher than pipelines	• No point to point solution – needs other transportation form in both ends • Size limited to max weight, with and length of train carriage
Ships	• Less fuel consumption per distance: ship ~0,3 MJ/ton/km, train ~0,6 MJ/ton/km, road ~1.2 MJ/ton/km. Reason is less friction loss due to buoyancy forces. [26] • Size limitation: much larger amount can be transported per trip than on trucks and trains • Social risk (the amount of people that can die if an accident occurs) is much less offshore than onshore (see ***Safety***) • Cheapest option for very long distances	• No point to point solution – needs other transportation form in both ends

Table 15: Ways to transport major amount of fluids and associated advantages/disadvantages

Overall:

1 Truck: optimal for low capacity, short distance, onshore transport

2 Train: optimal for long distance, through desert areas without intermediate consumers, and where onshore route is much shorter than offshore (i.e. across US, Russia and Australia)

3 Ship: optimal for long distance where a valid offshore route exists

4 Pipeline: optimal when larger quantities and/or many consumers

Below a catalogue for pipeline (chapter 0), truck (chapter 0) and ships (chapter 0) are given. Train have been excluded as other transportation forms are normally more optimal in Europe due to either short distance, many intermediate consumers and lot of coastline. An exception is ammonia which is transported via rail from Russia to Europe [ref. 25].

Figure 13: Train transporting NH3 from Russia to Europe.

[26] Energy Efficiency of different modes of transportation, James Strickland, 2006

Material of construction

Hydrogen (H_2)

Hydrogen embrittlement is cracking associated with hydrogen penetration into the metal grid. At low pressure (<150 bar), hydrogen is only able to enter materials in the form of atoms or hydrogen ions. Thus, pure gaseous hydrogen is not absorbed by materials at ambient temperatures, as it is in molecular form. However, dissociation of hydrogen into H-atoms can occur due to (point 2-4 can occur at temperature below 150°C):

1. High temperature[27] (>150°C, very little <200°C) [ref. 27]
2. Surface irregularities (impurities in the hydrogen and at the surface)
3. Corrosion
4. Electrochemical or chemical surface treatment
5. Cathodic protection

Any penetration of H-atoms into the metal grid may lead to hydrogen embrittlement when temperature is below ~150°C.

Hydrogen embrittlement can only occur in combination of the following three factors:

1. A susceptible material
2. Hydrogen environment (H^+-ion formation – see points above)
3. High tensile stresses

Thus, if stresses are sufficiently low, the environment not sufficiently aggressive, or the material not susceptible, the hydrogen will diffuse through the material without causing damage.

Susceptible material: ASME B31.12 specify material requirements to hydrogen pipes[28] and material grades that are approved for hydrogen pipes. For design pressures (Pd) <200 barg and design temperatures (Td) <175°C Carbon steel (A 105/A 106) and Micro alloy steel (X42 and X52) is applicable.

[27] Material is normally exposed to hydrogen at high temperature under manufactures (casting, carbonization, coating, plating, cleaning, pickling, electroplating, electrochemical machining, welding, roll forming and heat treatment).
[28] The key material requirements are also listed in ref. 6 and 1.

For Pd>200, high alloy steel (SS-316L) should be used [ref. 6]. X70 may be used subject to evaluation of the hardnability in weld heat affected zones. Within this catalogue, X52 have been used.

High tensile stresses: The stress levels can be lowered by:

1. Closer pipe support
2. Thicker pipe walls
3. Thermal relieving residual welding stresses
4. Hydrotesting (autofrettage)

Ammonia (NH_3)

Ammonia is corrosive to:

1. Copper
2. Copper alloys
3. Zinc
4. Nickel (must be kept below 5 wt%)
5. Most plastic

Oxygen levels of more than a few ppm in liquid ammonia can promote stress corrosion cracking especially at high temperatures. Ammonia and oxygen induced SCC are not expected at ambient temperatures, but stresses caused by welding can initiate SCC if oxygen is present. Ammonia as produced contains no oxygen. However, when filled into a tank, it must be ensured that the tank is purged until <0.5% oxygen before NH_3 is admitted.

Water content in ammonia should be > 0.1 wt %. Research have shown [ref. 8] that presence of water inhibit the formation and growth of SCC (see grade specification under *Ammonia (NH_3)*).

Non-ferrous alloys are resistant to ammonia. Minimum requirement for stress yield strength and post-welding treatment are given in IGC Code chapter 17.12. The code also describe how ammonia stress corrosion cracking is avoided.

Steel piping are suitable for ammonia gas and liquid. Within this catalogue X52 have been applied.

Dimethyl ether (DME)

Steel piping are suitable for dimethyl ether. Within this catalogue X52 have been applied.

Liquid fuels (LHC)

Steel piping are suitable for most LHC. Within this catalogue X52 have been applied.

Safety

Key safety parameters are listed in Table 16. All fuels are flammable with H_2 being the most flammable/explosive. NH_3 do also have toxicity impact (see section *Ammonia (NH_3)*).

Table 16: Key safety parameters

		H_2	NH_3	DME	LHC/Toluene
Toxicity		None	See ***Ammonia (NH_3)***	None	Depend on chemical. Liquid, i.e. leakage do not lead to inhalation.
Flammability/ Explosion limit[29], %	Lower (LFL/LEL), Upper (UFL/UEL)	4 75	15 28	3.4 27	1.1 7.1
Flame		Very difficult to see	Yellow	Blue	Most white + yellow
Flash point, C		NA	11	-24	≥6
Auto ignition point, C		560	651	235	200-500
Ignition energy, mJ		0.017	680	0.29	>0.2, most ~0.25
Detection limit air		25 ppm	5-50 ppm (smell), ~1 ppm	-	-

For every system the risk (= probability × severity of consequence) must be quantified. If risk violate acceptance criteria, measures to eliminate, reduce the probability and/or consequence must be taken.

Collision

The probability for collision between mobile transport depend strongly on where the transport is carried out. Generally, the likelihood for collision is much higher in populated areas, i.e. in cities, on train stations or in harbours. Additionally, the likelihood for collision on road is much more likely than collision with train or ships. Contradictory, if a collision occurs, then probability of tank rupture, and leak of large amount, is much higher from thin walled tank that carry cooled liquid (which is the most common liquefaction method on ships) than for thick walled tank that carry pressurized liquid [ref. 13].

Loading/unloading

Due to the nature of fuels, loading (and unloading) are very critical process that must be executed with utmost safety precautions. Any leakage is critical.

It must be ensured that all loading systems/tanks are emptied for oxygen before exposed to fuels. Any purge with inert gas to remove oxygen must subsequently be vented to prevent contamination of fuel with inert gas. Tank-purge can be avoided if tank is only used for one fluid type and the tank is kept at slightly overpressure to prevent ingress of air. This is common for CH2 tube trailer tanks.

If loaded with refrigerated/cryogenic liquid, the loading system/tanks must either be pre-cooled or loading must be slow to prevent uncontrolled pressure rises and unsafe temperature gradients. Due to the sub-zero boiling points at atmospheric pressure of LPG, NH_3, DME and H_2, the refrigerated liquids that are entering tanks and piping which are at ambient temperature and pressure immediately begin to boil. Boiling and evaporation will continue until the materials reaches the liquid temperature. This initial boiling will cause a rapid pressure increase in the loading system. The pressure attained will depend on the quantity of liquid and the heat available for evaporation. Care should therefore be taken

[29] Gas to air ratio

to introduce liquid into non-cooled tanks sufficiently slowly to avoid an uncontrolled pressure rise. The initial boiling will also cause local cooling of the tank structure, with the risk of thermal stresses of the materials. Spray cooling[30] is essential for very cold cargoes.

Leakage

Pipeline is the safest mode of transporting of fluid fuels. Long-distance pipelines must fulfill high demands of safety, reliability and efficiency. If properly maintained, pipelines can last indefinitely without leaks. Significant leaks that occur are normally caused by damage from nearby excavation or by corrosion caused by incorrect operation.

Pipeline is normally equipped with some leakage detection system. Leakage detection system can include:

1. **Internally leakage detection systems**:
    1.1. Sensors and computer system that via a series of pressure and flow rate sensors and mathematical models estimate whether leakage occur
    1.2. Acoustic pressure waves measures
2. **External leakage detection systems:** Infrared radiometers, thermal cameras (above ground only), gas detectors, acoustic sensors, and digital oil leak detection cable
3. **Odor addition**: see section *Odorization*

In case a leakage is detected, insulation valves and associated vents are installed frequently (for every 10-20 km) so the leakage can be isolated, vented and repaired without having to empty the entire pipeline.

Sectionalization

Pipelines and larger transportation tanks are sectionalized (pipes with ESD valves that are closed in case of an emergency) to mitigate the risk of very large leakages, fires and explosion.

Hydrogen (H_2)

Due to the low flash point, low ignition energy and wide flammability range, the probability that hydrogen ignites immediately is very high. For cryogenic liquefied H_2, burning is also a risk.

Monday June 10, 2019, a hydrogen gas filling station at Kjørbo (near Oslo) in Norway caught fire and exploded. Three people were treated for minor injuries due to airbags deploying in their car nearby. The fire caused severe damage on the filling station. A root cause analysis by the authorities, Nel and Gexcon has identified the cause to be an assembly error of a specific plug in a hydrogen tank in the high-pressure storage unit. Due to human error, the inner bolts of the plug had not been adequately torqued. This led to a hydrogen leak, which created a mixture of hydrogen and air that self-ignited, which created an explosion (pressure wave) and the fire.

[30] Cargo tanks are cooled down by spraying the initial loaded fuel (LNG) through spray nozzles

Ammonia (NH_3)

The major safety concern related to ammonia is its toxicity issues are:

Conc. ppm	Exposure period	General effect
5-50	Max 8 h	Odor, detectable by most persons, Mild discomfort
50-80	2 hours Exposure for longer periods not permitted	Perceptible eye and throat,
100		Nuisance eye and throat irritation
140	2 hours	Serve irritation, need to leave exposure area
134	5 min	Tearing of eyes, eye-, nasal-, throat- and chest irritation
500	30 min	Upper respiratory tract irritation
700	<1 h	No serious injuries and repeated exposure produce no chronic effect
700-1700	Can be fatal after 30 min	Convulsive coughing, Severe eye, nose and throat irritation,
5000-2000	Can be fatal after 15 min	Incapacitation from tearing of eyes
5000-10000	Rapidly fatal (within min)	Respiratory spasm, Rapid asphyxia
>10000	Promptly lethal	

Table 17: Ammonia toxicity exposure levels ref. 14, 25 and 8.

As ammonia is a toxic gas, it must be transported according to local legislation which normally means requirements to general safety procedures concerning:

1. Leakages
2. Minimum allowable cargo tank steel temperature
3. Firefighting and emergency procedures
4. Training of personal - driver/crew must complete specific training

Safety measures for handling ammonia include:

1. Protective full body chemical protective clothes, googles/face shield, gloves and safety footwear
2. 5 gallons of water (first aid if skin or eyes are exposed) and breathing apparatus

Figure 14: NH3 leakage - Panaji

Ammonia pose some challenges to ensure safety of the crew on ships as personal cannot escape. Thus, any leakage can be fatal why piping and vessels normally are double walled with leakage detectors between the double wall.

Odorization

Odorant (normally tetrahydrothiophene (THT) or mercaptan) is added to the NG distribution net and partly to the NG transmission net, allowing leaking gases to be detected before it reaches combustible levels. The disadvantages with odorants are:

1. Human must be present in the vicinity of the leak and not all are able to detect the odors at the mandatory level
2. Commercial odorants are poisons for catalyst used in most synthesis and in hydrogen-based fuel cells. Thus, cost of removing odors will be high

Due to these disadvantages and as it is assumed that the hydrogen net mainly will be a transmission net (and not a distribution net in densely populated areas), odorization is not recommended as a safety solution and will not be included in the performance and cost evaluation of hydrogen transmission piping.

Transport chain - logistic and infrastructure

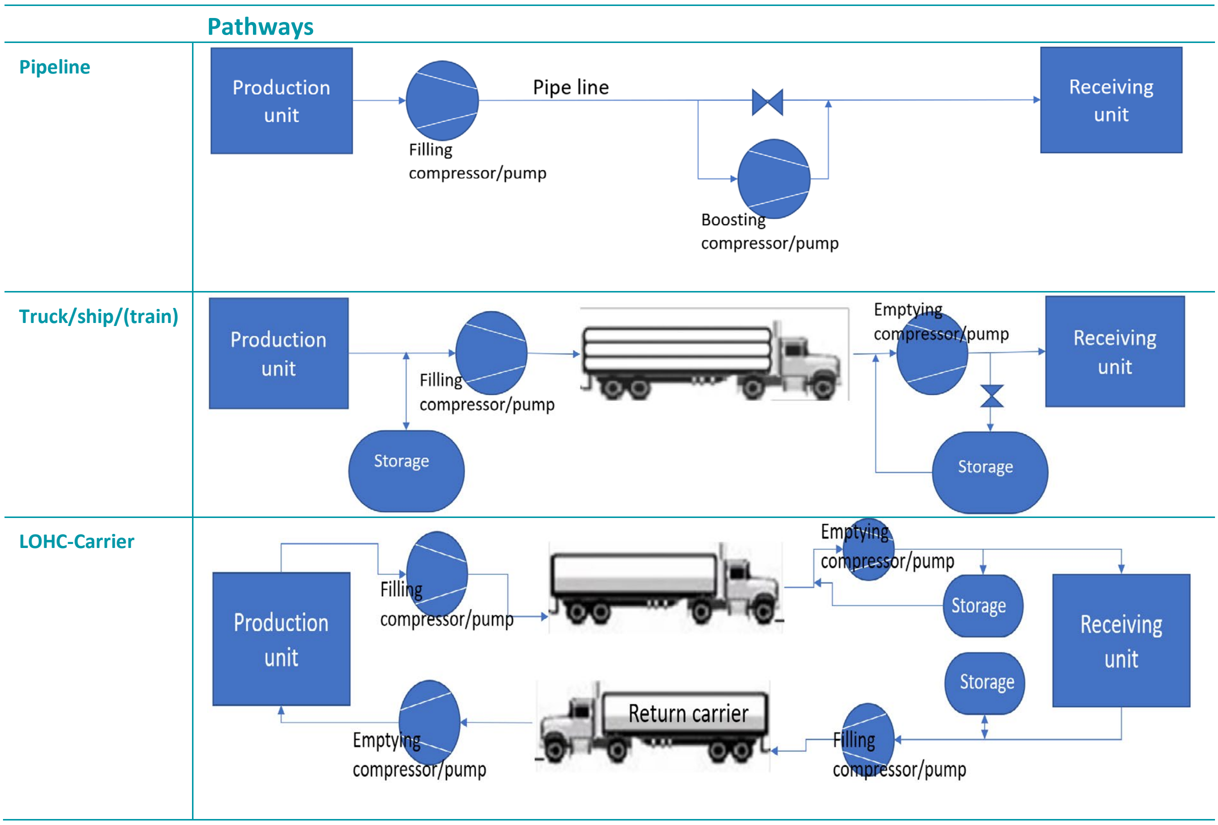


Table 18: Infrastructure for the different transportation solutions

Table 18 give overall units need for the different transport method.

While filling compressor/pumps are used to transfer the fuel from the production unit to the transportation unit, emptying compressor/pump is used to transfer the fuel from the transport unit to the receiving unit. Emptying compressors/pumps may for liquid fuels be replaced with gravity (see Figure 28).

Pipeline: Key elements are the pipeline, filling and boosting pressurization units (see detail description in *Elements in pipe transmission net*). Boosting compressor is compressor/pump substations along the pipeline that boost the pressure to compensate for pressure drop along the pipeline.

Truck, ship, train: Key elements are the transportation unit (truck, train or ship), filling and emptying compressor/pump and storage tank in each end.

LOCH-carrier: Same key elements as above except that the carrier must be transported back again if not used at the receiving unit. The production unit include the conversion to carrier and liquefaction by cooling.

Whether additionally storage and compression/pumping facilities are needed will depend on the actual design. However, when design an infrastructure, it is important to notify that transfer of gas or liquefied fuel from one vessel to another inherit the following losses:

1. **Compression/pumping losses:** Especially compression is complex and can inherit larger losses as the pressure drops on the suction side, and increase on the discharge side, while emptying and filling the vessels.
2. **Cooling losses:** need to cool down the material of the new storage vessel

To limit these losses, it is optimal to limit the number of vessels in the infrastructure. Thus, it should be considered whether the storage and transportation tank could be the same vessel.

Hydrogen battery

Figure 15: Hydrogen storage, transportation and fuel tank.

Section *Energy losses* gives and overview of the various sources of energy losses. Sections *Conversion to/from carrier (LOHC)* to *Storage tanks* describe the units within the transport chain and section *Examples - full transportation chain* gives some overall loss and cost calculation examples.

Energy losses

Depending on transport phase (gas or liquid) and transport unit (pipeline, truck, train or ships), the energy losses may include:

1. **Conversion to/from a carrier** (only for hydrogen) (see *Conversion to/from carrier (LOHC)*)

2. **Cooling losses** – losses in conversion to liquid phase via cooling
   2.1. Refrigeration of NH_3, LPG and DME (see *Refrigeration of NH_3, LPG and DME*)
   2.2. Cryogenic liquefaction of NG and H_2 (see *Cryogenic Liquefaction of NG* and *Cryogenic Liquefaction of H2*)

3. **Pressurization losses** – shaft power and interstage cooling losses within filling, boosting and emptying compressors/pumps
   3.1. Compression losses (for CNG and CH2) (see *Energy loss – reciprocating H2 compressor*)
   3.2. Pumping losses (for LH3, LPG, LDME, LNG, LH2) (see *Pumps*)

4. **Fuel for propulsion** (for truck, train and ships): Fuel consumption depend on weight due to increased resistance and increased force needed when accelerating.

Trucks:

Vehicles EU 2018	$LoadFactor_{weight}$	Traffic data*	
	%	$Energy_{wtw}$ [MJ/km]	CO_2e_{wtw} [g/km]
Truck with trailer 50-60 t	0%	11,0	763
Default	50%	18,7	1279
	100%	25,0	1706

Table 19: Fuel consumption - ref. 21

As a truck is full one way and empty the other way, 19 MJ/km is used as average (19 MJ/km is ~50% load). For CH2, the fuel is carried in thick walled tubes, and for LH2, the fuel is carried in a double walled tank. Thus, for CH2 and LH2, 24 MJ/km have been used as an average as the fuel-tanks have a higher weight why the transported fuel per truck is lower.

Ships: The fuel consumption per day of a ship can be described the Barras formula[31]:

$$Fuel\ consumption/day = \frac{W^{2/3} \times v^3}{Fc}$$

[31] Barras (2004): Ship Design and Performance for Masters and Mates

Where

W=ship´s displacement (total weight) in tons
v= ship´s speed in knots (typically between 12-14 knots)
Fc= Fuel coefficient (Fc=120.000 for diesel engine)

As ships displacement is not always given, the following approximation has been made based on average from various sources (valid if velocity ~13 knots):

Equation 1

$$\text{Fuel [MJ/km]} = 0.023 \times M_{cargo} + 1400$$

Where M_{cargo} is the weight of the transported fuel in tons. Normally a tanker is empty on the return route, meaning that the fuel consumption for propulsion is approximately half of the delivery trip.

5. **Heat interaction with the surroundings** - Boil-off (for cooled liquids)
If the temperature of the transported fuel is different from ambient, there will be some minor loses due to heat-interaction with the surrounding. Thus, if the fuel transported is colder than ambient, energy need to be added to keep it cold. If not, some vaporization/boil-off will occur. Typically, boil-off rate (BOR) from double walled vessels with vacuum between are:

- LH2: 2-3 %/day for small portable H_2 containers and down to 0.06%/day for large. Typical boil-off is ~0.1/day [ref. 18]
- LNG: Typical 0.15-0.6 %/day on ships

This boil-off loss can be minimized if the mobile unit is using the boil-off for fuel. Thus, under the transportation the boiloff can be eliminated but not when the transportation stops.

6. **Leakage:** Leakage is assumed negligible

7. **Heating before depressurization** (only for CNG): On NG transmission pipes, there is additional losses associated with depressurization as NG must be heated before depressurized. For hydrogen, heating before depressurization is not needed as hydrogen do not cool upon depressurization when >-150 °C.

8. **Odor removal** (only for CNG): Odor is often added to NG net. Thus, losses are associated with removing the odor. As per discussion in section *Odorization*, odor is not considered for hydrogen transmission pipes

Conversion to/from carrier (LOHC)

LOHC (liquid organic hydrogen carrier) are organic hydrocarbon liquids with hydrogen "adsorbing" capabilities (see description in
Table 14).

Conversion and reconversion losses today are 30-40 %. Theoretical possible is 18% and potential obtainable minimum loss is 25% [ref. 7].

Convert to liquid phase by cooling

Figure 16 gives an illustration of the steps and losses involved in conversion and transportation as liquefied fuel. The losses in liquefaction can in principle be recovered. However, as the liquefaction and regasification will be at two different locations, the calories extracted from the liquefaction will normally be loss.

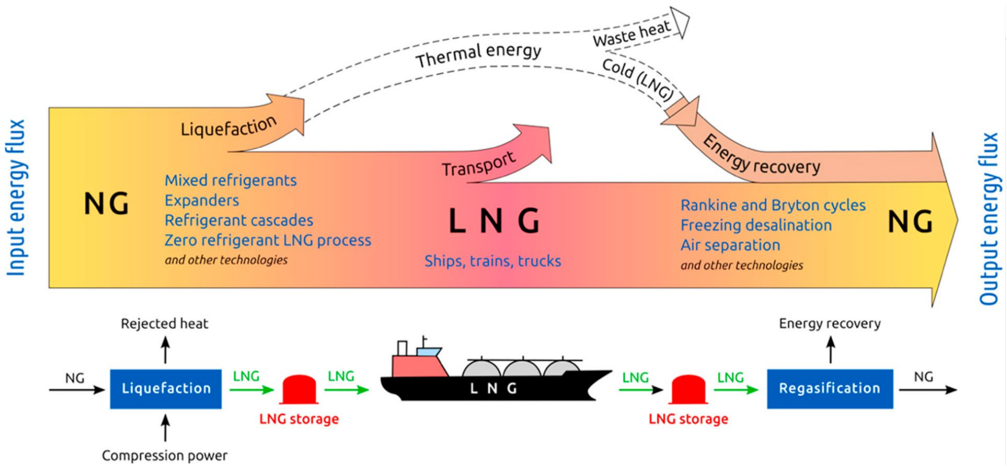


Figure 16: Illustration of steps and losses in transport of LNG. The other liquefied fuels include the same steps [ref. 11]

Refrigeration of NH_3, LPG and DME

The energy removed by the liquefaction is the energy required to cool to boiling point plus the energy required for condensation. For NH_3, LPG and DME, the energy removed by the condensation is the dominating term. Thus, an estimate for the energy removed by the refrigeration (i.e. the % energy loss associated with refrigeration) is given in Table 11. I.e. for ammonia it is ~7.4 **%** of the LHV, while for LPG it is ~0.9% and for DME is ~0.47 % of the LHV.

NH_3 and DME are normally produced as cooled liquids why this step is not needed.

Cryogenic Liquefaction of NG

According to ref. 10, the energy loss associated with liquefaction of NG is between 4-7%.

Cryogenic Liquefaction of H_2

The loss in the liquefaction process is between 25-45%, strongly depend on the capacity of the plant (see Figure 17). The theoretical possible minimum loss is 18% [ref. 22]

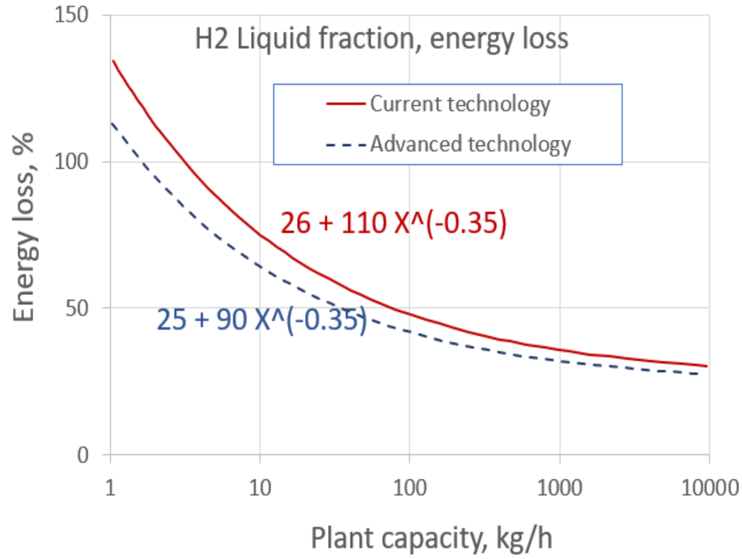


Figure 17: Energy loss associated with liquefaction of H2 [ref.22]

Hydrogen exist in two forms. At very low temperature it is para- H_2 while at ambient ~75% is ortho- H_2. The transition from ortho to para is very slow and releases significant amount of heat (527 kJ/kg) [ref. 18]. Thus, liquefaction of hydrogen, i.e. transferring H_2 (mainly ortho- H_2) to LH2 (para- H_2) must be done over a catalyst ensuring all is para- H_2 before transportation/storage of LH2. If not, 30% of the hydrogen will boil off within two days if stored in full cryogenic tank.

Compressor

Only H_2 compressors are covered within this catalogue.

Types - hydrogen compressors

High grade hydrogen is normally a requirement. Thus, non-lubricated compressor is required to avoid oil contamination in the hydrogen.

Reciprocating/piston compressors are optimal when requiring high compression ratio (and/or having low flow and large flow variations). Thus, reciprocation compressor is optimal in most hydrogen services and will therefore be the only one considered in the performance and cost estimate.

Of reciprocating compressors, the following types exist:

1. Metal piston (free or crankshaft piston)
2. Diaphragm piston
3. Ionic liquid piston (do not require lubrication)

Future alternatives to reciprocating compressors may be the ones listed in Table 20.

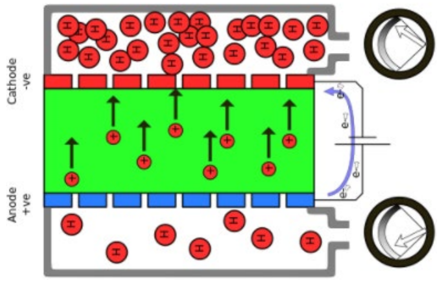
Compressor type	Description
Hydride Compressor	Compressors where H_2 is adsorbed by a hydride at ambient conditions. The absorbent is then blocked in and heated whereby the pressure will increase. Compression ratio >20 and final pressure > 1000 bar is possible. However, the product will be a hydrogen flow at high temperature which is impropriate for transportation. It has a low TRL but may be optimal in the following cases: • H_2 need to be extracted from an impure H_2 rich stream • H_2 is needed at high temperature
Electrochemical hydrogen Compressor (EHC)	EHC is a compressor where the hydrogen is supplied at low pressure at the anode and via electricity is forced through a proton exchange membrane (PEM) to the high-pressure cathode side. EHC are noiseless, scalable and with energy efficiency of >80%. TRL=3-5. 

Table 20: Hydrogen compressors under development

Energy loss – reciprocating H_2 compressor

Energy loss associated with compression include shaft power and power used to operate the cooling system of the interstage coolers.

Shaft power required for compression are given in Figure 18:

1. Adiabatic compression (blue curve): Have no interstage cooling – represent maximum losses
2. Isothermal compression (green curve[32]): Have infinity number of interstage cooling – represent minimum losses, i.e. the ideal compressor

[32] The two green curves calculate the same but with different thermodynamic model (ideal gas law and Viral equation of state) where the stipulate is more accurate

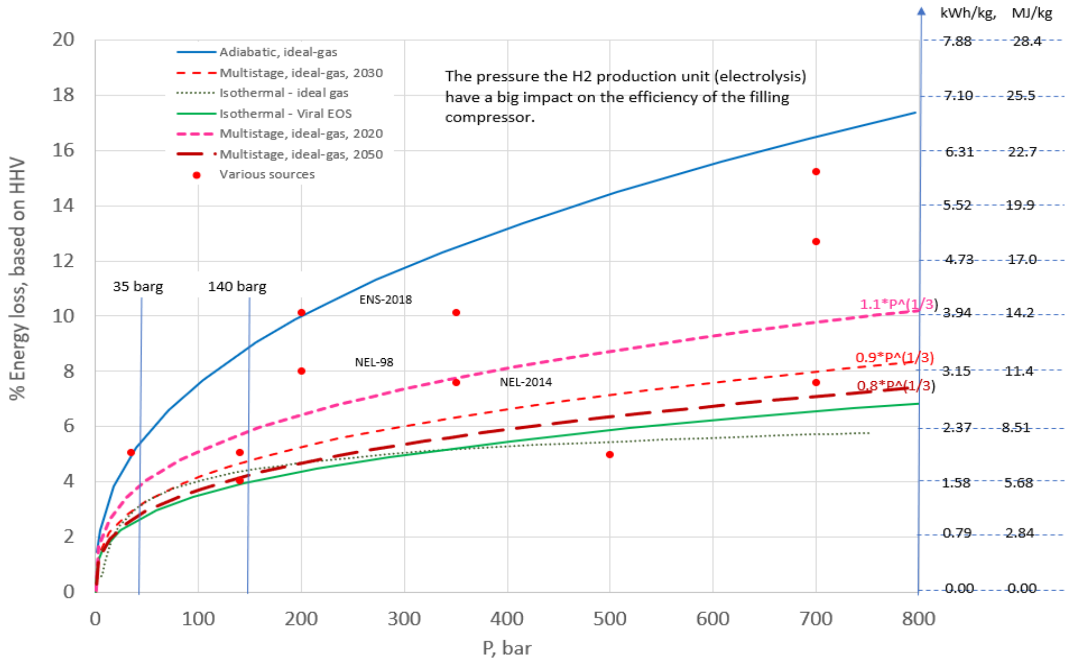


Figure 18: Energy loss for adiabatic, multistage with interstage cooling and isothermal compression (reciprocating H2 compressors). Points from various sources have been added. Numbers along the secondary y-axis are absolute loss.

Most hydrogen compressors are multistage compressors with interstage cooling. Thus, the red curves are used in the performance calculation within this catalogue (the pink is assumed today status, the red is 2030 and the dark red is 2050).

In addition to the shaft power, power used to operate the cooling system must be added too. This usually include pump loss which is very minor compared with the shaft power.

The following formula is used in this catalogue to calculate compression power loss (Pin=suction pressure [bar], Pout=discharge pressure [bar], A=1.1 in 2020, 0.9 in 2030 and 0.8 in 2050 as per Figure 18):

$$Loss\ (\%) = A \times \left(Pout^{\frac{1}{3}} - Pin^{\frac{1}{3}}\right),\quad see\ figure\ above\ for\ value\ of\ A$$

$$Loss\ (kWh/kgH2) = \frac{Loss\ (\%)}{100} \times 39.42 \frac{kWh}{kgH2}$$

Calculation example		
Pin, bar	35	Suction/inlet pressure
Pout, bar	140	Discharge/outlet pressure
A-factor	1.1	A=1.1 (2020), 0.9 (2030), 0.8 (2050)
Loss %	2.1	=A*(Pout$^{1/3}$-Pin$^{1/3}$)
Loss, kWh/kg	0.8	=Loss%/100%*39.42 kWh/kgH2
Loss, MJ/kg	3.0	=LosskWh/kg*3.6

Table 21: Calculate compression loss compressing H_2 gas from 35 bar to 140 bar

As per Figure 18, the compressor operation cost can be lowered substantially by:

1. **Increasing the suction pressure:** Increasing the pressure in the H_2 production unit (electrolysis) will have a huge impact on lowering the operation cost of the compressor as the first steep part of the curve will be cut of
2. **Increasing the number of stages:** Increasing the number of compression stages, and thereby approach the isothermal operation (green line in in Figure 18) will increase the compressor-efficiency. Additionally, multistage pressure level will also enable optimization with respect to the discharge pressure such that gas is only compressed to the current discharge pressure (the discharge pressure will be increasing when filling a tank on a truck/ship and will vary if using pipe-net as buffer/storage)

Cost – hydrogen compressors

Internal tool has been used for cost estimation of compressors. Estimated cost of filling (35-140 bar) and booster (40-140 bar) compressor is given in Figure 22.

Pumps

Internal tool has been used for cost and efficiency estimation of pumps.

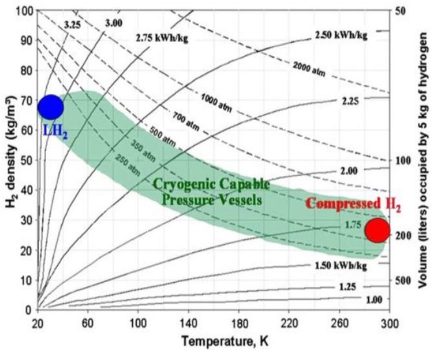
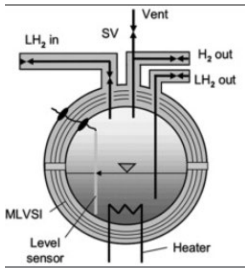
Fiscal metering stations

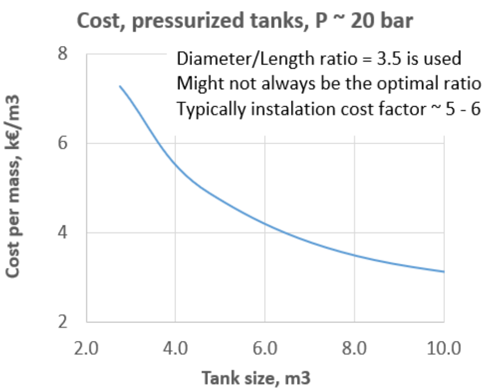
For transmission piping, normally two fiscal metering stations (one redundant ensuring correct measure) with associating lab/sample station will be installed at all filling stations. The cost of fiscal metering station and associated lab depends strongly on how the fluid is produced, i.e. which impurities should be detected, and have been judged outside the scope of this catalog.

Storage tanks

Storage will be in steel or fiberglass (later for hydrogen) tanks. Optimally the shape is spherical (gives largest wall strength per thickness and less heat exchange with surrounding per volume stored). However, as spherical shape takes up more space, cylinder shape is often applied, especially for hydrogen storage.

In Table 22, typically storage form is given for H_2, NH_3, DME and LPG. CAPEX for storage pressurized (up to 20 bar) and refrigerated tanks (down to -33 °C) is given too.

	Pressurized storage	Pressurized and cooled storage	Cooled storage
H_2	P=165–550 bar, T=Amb. Thick walled metallic (Type I) or composite reinforced tank (Type II, II, IV)  See cost and further description in ref. 7	 Red is CH2, Blue is LH2 and green is a combination of the two.	T=-253°C, P≤3.5 bar 
NH_3, DME, LPG	<100 ton, T=Amb., P≥20 bar 	100-1000 ton, T=0°C, few bars 	>10000 ton, up to 40000 t T=-33 °C, P=atm. 



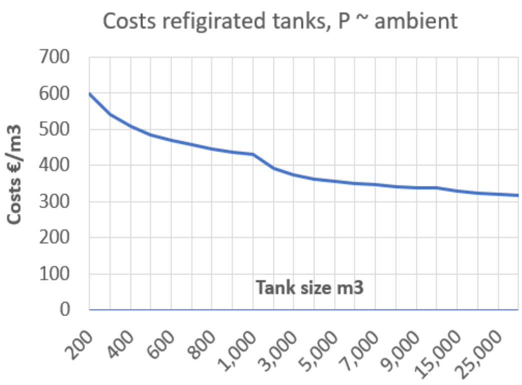


Table 22: Typical storage form vs fuel and transport phase

Examples - full transportation chain

This chapter provide examples where the transport loss and the cost is calculated.

Color codes for all the calculation examples are:

1. blue=input
2. red=numbers obtained from this document either from datasheet or given formulas
3. green= numbers obtained from internal cost estimation program
4. black = calculated values

Pipeline – CH2 calculation example

Pipeline - CH2 Fixed O&M - % of CAPEX: 4 WACC, % 5																	
Fuel: CH2 HHV= 142 MJ/kg	Power/fuel input						CAPEX			life-	CAPEX +	O&M			Tot. Cost	Transort velocity, m/s	7.0
Transport distance: 100 km		%					k€	€	M€	time	Fixed O&M	€	€	k€/y	k€/y	Transport time, h	52
Transport capacity: 100 MW HHV	%	1000km	MW	GJ/t	€/t	k€/y	MW	km*MW		y	k€/y	t	km*t				
Filling compression, Pin=35 -> Pout=140 bar, A=1.1	2.1		2.1	3.0	33	733	48		4.8	20	402				1135	Mass flow, TPD	61
Metering + Scraper trap									5.2	20	434				434	Energy flow, MW HHV	100
Pipeline (Pipe + Booster comp. + Isolation stations)		7.5	0.8	1.1	11.8	261		2559	26	50	1458				1719	Transported per y, TPA	22224
Total				**4**					**36**		**2294**				**3288**	Power cost, €/GJ	11
														€/t	**148**		

Table 23: Calculation example - Pipeline CH2 - small pipe

This example shows the cost and losses associated with a small 100 km pipeline for transporting 100 MW H_2 (could be a branch off pipe to a fueling station). The example is comparable with the example in section *Truck – CH2 calculation example*, where truck transport of the same capacity is calculated.

The red numbers are obtained as follows:

1. Filling compression loss (=2.1% of MW H_2): See calculation in Table 21.
2. Booster compressor loss (=7.5 % of MW H_2), CAPEX for filling compressor (=48 k€/MW), CAPEX of metering an scraper trap (=5.2 M€) and CAPEX for pipeline (=2559 €/(km*MW)) are all from appropriate formulas in Figure 22.
3. Velocity (=7.0 m/s) is obtained from formula given in Table 29

The transport chain does not incorporate any storage. Optimally, storage can be avoided but, in most cases, it might be added. In such case, the capacity will depend on the various demands why it is omitted.

Pipeline – CH2 calculation example

Pipeline - CH2 Fixed O&M - % of CAPEX: 4 WACC, % 5																	
Fuel: CH2 HHV= 142 MJ/kg	Power/fuel input						CAPEX			life-	CAPEX +	O&M			Tot. Cost	Transort velocity, m/s	10.1
Transport distance: 500 km							k€	€	M€	time	Fixed O&M	€	€	k€/y	k€/y	Transport time, h	178
Transport capacity: 4000 MW HHV	%		MW	GJ/t	€/t	k€/y	MW	km*MW		y	k€/y	t	km*t				
Filling compression, Pin=35 -> Pout=140 bar, A=1.1	2.1		2.1	3.0	33	29328	8.8		35	20	2947				32275	Mass flow, TPD	2436
Metering + Scraper trap									5.2	20	434				434	Energy flow, MW HHV	4000
Pipeline (Pipe + Booster comp. + Isolation stations)		2.5	2.5	3.5	39	34575		351	701	50	39945				74520	Transported per y, TPA	888964
Total				**6.5**					**742**		**43327**				**107229**	Power cost, €/GJ	11
														€/t	**121**		

Table 24: Calculation example - Pipeline CH2 - big pipe.

This calculation example is identical to the above but just for a larger capacity and a longer distance.

Additionally, the example is similar to the calculation in the first table of Table 31. The major difference are

- CAPEX €/(km*MW): is "351" in Table 24 and "333" in Table 31. Reason for the difference is that in Table 31, cost functions of the individual component (pipe, isolation & vent station and booster compressors – i.e. the red, purple and gray curve in Figure 22) is used while the overall cost function (i.e the blue curve in Figure 22) is applied in Table 24.

- A utilization factor of 100% is used here while it is 75 % in Table 31

Truck – CH2 calculation example

Truck - CH2	Fixed O&M - % of CAPEX: 5	WACC, % 5				Operation hours per year, h/y 8000										
Fuel: CH2	LHV 120 MJ/kg	Power/fuel input					CAPEX			life-time	CAPEX + Fixed O&M	OPEX (1)			Tot. Cost	Driving speed, km/h 60
Transport distance: 100 km	Density 33 kg/m³						k€	€	M€			€	€	k€/y	k€/y	Loading/unloading time 4.3
Transport capacity: 1.5 t/truck	No. Trucks 14.0	%	MW	GJ/t	€/t	k€/y	MW	km*MW		y	k€/y	m³	km*m³			Roundtrip duration, h 7.6
Filling compression, Pin=35 -> Pout=350 bar, A=1.1		4.2	3.8	5.0	55	1219	50		4.7	20	392				1611	Trips per year 1055
Loading/unloading (wage + deprecitation)												4.1		2761	2761	Mass flow, TPD 67
Driving (wage + fuel + deprecitation)		fuel consumption is part of OPEX											0.08	5388	5388	Energy flow, MW LHV 93
Total														8149	**9759**	Transported per y, TPA 22224
Note 1: Assume 29 €/GJ diesel, 24 MJ/km											DKK/kg	3.3		€/t	**439**	Power cost, €/GJ 11

Table 25: Calculation example - CH2 truck

This example calculated the cost associated with truck transport of CH2. It is calculated with the same transported capacity as pipeline in section *Pipeline – CH2 calculation example*.

The red OPEX parameters for the loading/unloading and driving is found in the datasheet for the truck.

Storage have not been included; If filling compressor do not fill directly into truck-trailer tubes, storage and additionally filling compressor is needed. Alternatively, if produced hydrogen is filling directly into the trailer tubes, additionally trailers is required.

Additionally, loading arm (see Figure 27) is missing too, but this is assumed to be neglectable compared with the other costs.

Ship – LNH3

Ship - LNH3	Fixed O&M - % of CAPEX:	5	WACC, %	5										
Fuel:	LNH3	LHV= 18.9 MJ/kg	Power/fuel input			CAPEX			life-time	CAPEX + Fixed O&M	Port cost			Tot. Cost
Transport distance:	10000 km	Dens.= 626 kg/m³				€ / m³	€ / t	M€			€ / t		k€/y	k€/y
Transport capacity:	45000 t/tank		MJ/km	GJ/trip	k€/y				y	k€/y				
Storage tanks	Tank vol (10% excess)	2x 79000 m³				300		47	30	3238				3238
Filling/emptying pumps	Vol.flow (duration 24 h)	3300 m³/h	SP=0.4 MW, 2*24 h	69.1	7.0			1.3	20	106				113
Loading arms								2.5	20	211				211
Piping and foundation (not included here - depend strongly on location)														
Ship			2435	36525	2582		1750	79	20	6635	1.7		682	9899
Total													682	**10223**
													€/t	**25**

Transport velocity, km/c	580
Loading/unloading time	3.3
Roundtrip duration, d	37.7
Trips per year	9.19
Mass flow, TPD	1193
Energy flow, MW LHV	261
Transported per y, TPA	413533
Power cost, €/GJ	11
HFO cost, €/GJ	8

Table 26: Calculation example – Ship – LNH3

This example gives an overview of the cost associated with LNH3. LNH3 is produced as a liquid why liquefaction of NH_3 is not included.

For ships, storage tanks in both departure and destination harbor is requires as well as filling/emptying pumps and loading/unloading pipes.

Cost of refrigerated storage tanks are found in Table 22. The value for ship are (all value come from the technology datasheet for ships):

1. Fuel consumption of 2435 MJ/km
2. CAPEX for ship of 1750 €/t
3. Port cost of 1.7 €/t

131 Transport by pipeline

Brief technology description

Elements in pipe transmission net

Major elements in a transmission net are (see Figure 20):

1. **Filling pump/compressor:** A filling station is needed to raise the pressure from the outlet pressure of the production unit to the pressure within the transmission net.

2. **Boosting pump/compressor:** Boosting the pressure along the route to overcome friction loss is needed when the pressure drops below the minimum operating pressure.

3. **Isolation valve/vent station:** To seal off segments in case of leakage. The allowable distance between isolation valves will depend on a risk assessment of each section. In populated areas isolation valves are expected more frequently than in rural areas. Typical distance between isolation valves onshore are 10-20 km. Within this catalogue, isolation/vent station for every 20 km have been assumed.

4. **Fiscal metering stations (M/R):** As described in *Fiscal metering stations*, two independent fiscal metering station will most likely be installed after the filling station.

5. **Cathodic protection:** Cathodic protection included as per shown in Figure 20 (green box with CP), i.e. one for filling station, two for each isolation valve/vent station and two for each boosting station.

6. **Scraper traps:** To maintenance/clean the pipeline, a scraper lancer and a scraper receiver is needed (or a valve arrangement will allow for connection of mobile lancer and receivers) in either ends of the pipe.

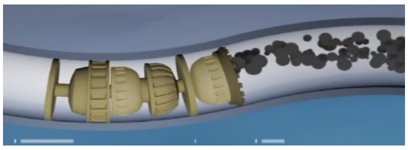


Figure 19: Scraper (also called pig) used to clean/inspect a pipeline

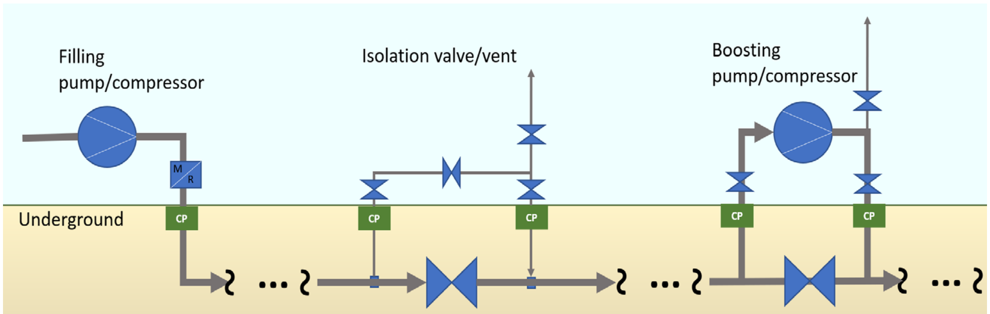


Figure 20: Major elements in a transmission pipe net

Filling compressor, fiscal metering station and scraper traps are installations required at the inlet (and/or outlet) or the pipe. Therefore, these costs have not been included in the "cost per km" estimate. The cost of the filling compressor, the fiscal metering station and the scraper trap are listed in Figure 22.

Existing pipelines

Some key existing pipelines are listed in the following table.

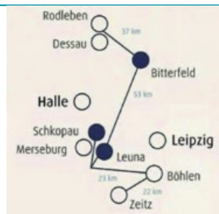
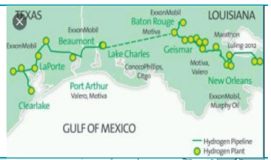
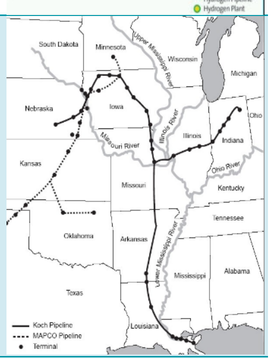
Fluid	Country/ company	Pd, barg	Mat.	Pipe type	Welding	Dn	km	Year	Ref.	
NG	DK, transmission	80				Up to 48"	900		ISO 13623:2017	
	DK, distribution	40, 19, 4					17000		REDEGØRELSE FOR GASFORSYNINGSSIKKERHED 2019 Energinet	
H_2	US,	<68					450-800 miles	1930	Ref. 2	
	GE (Rhine and Ruhr), AL	17 20-210	≤X42	ERW	SMAW	10-12	240	1938 -	10000 kg/h ref. 2, 1 and 30]	 Red are H_2 pipes
	France, AL	97	≤X52	ERW	SMAW		1000	1973-1997		
	NL, Gasunie	100				~10"	237		Convert existing NG to H_2 2018 ref. 5, 15	
	GE, FNB Gas						5900 (1)		Partly converting existing NG pipelines	
	GE, Central, Linde									
	US, Texas, AL Corpus Christi	48 (first) 24 (now)	Gr.B (0)	ERW	SMAW	8	100	1997	Originally crude oil pipelines (1940-50). Ruptured because of corrosion in 1998.	
	US, Texas, AL Freeport to Texas city	51	X60 (0)	ERW	SMAW		54	1997	Originally crude oil pipelines until 1979. Compressor: Lubricating reciprocal + multi-stage filtration for lube oil removal	
	US, Plaquemine-Chalmette ref. 4, 31, AP					14	240 (965)	209	New pipeline connected the two above give a total of 965 km H_2 piping.	
NH_3	US	17	CS				~5000		ASTM A333 ref. 15, ref 28	

Table 27: Key existing pipes (not all are included)

Table notes:
Not constructed yet but is planed

See detailed material properties in ref. 1.

Operation pressure

As mentioned in section *Transport form – chemical phase*, pipeline-fluid-phase will be in the following forms:

Fluid	Phase	Pmin/Pmax/Pdesign, barg
H_2	Compressed gas	40/140/156 40/70/80
NH_3 DME	Compressed liquefied gas	20/20 /23 13/20 /23
Liquid HC	Liquid	3 /8 /10

Table 28: Pipe pressures to be considered in this catalogue.

A max operating pressure of 140 barg have been used in this catalogue. When building new network, 140 barg is believed to be the optimal pressure as this will give the largest buffer/storage capacity. Pressure above have not been selected as this will impose higher risk of hydrogen embrittlement. As major part of the existing natural gas net is designed to 80 barg, 70 barg has also been used in calculations as part of the natural gas transmission net can be converted to hydrogen transmission net.

Converting NG pipes to H_2 pipes

It is possible to use existing NG grid, though with some modifications [ref. 16 and 24].

Gasunie have realized a hydrogen backbone pipeline infrastructure in NL by converting NG pipes to H_2 pipelines.

Within ref. 8, the cost of converting existing NG-transmission pipes to H_2-transmission has been assumed to be equal to 1/3 of cost of new installation.

As the biogas production is relatively extensive in DK and as DK have committed to transport of NG from Norway to Poland (EPII) it is expected that only minor part of the natural gas grid that will be converted to hydrogen transmission grid in the near/medium term.

The existing natural gas transmission net in DK have a design pressure of 80 barg and a min operating pressure of 60 barg.

Underground pipeline

Pipelines should to the extent possible be underground as:

1 Mitigation of risk: Underground installation reduces the likelihood of damage/vandalism and the risk of explosion in in case of leakage
2 Temperature is less variable: This reduces the expansion and shrinkage of the construction material. Additionally, winterization is not needed if freezing point is below 0°C
3 Do not disfigure the nature and is less prone to protest

Key requirements to underground piping:

1 Connections: To minimize the possibility of leaks, all underground connections should be welded
2 Cathodic protection: To eliminate damage caused by lighting, underground pipes must be electric isolated from above ground installations via isolating flanges
3 Corrosion: Galvanic corrosion is caused by difference in electric potential between the pipe and the soil. External coating, electrical measures (i.e. sacrificial anode or impressed current) that mitigate galvanic corrosion if there are coating-defects, and monitoring of the corrosion protection system is a must
4 Pipe casings/load shields where above ground loading can occur (i.e. railroad, etc.)
5 Underground pipeline should be clearly marked - Ref 3 consider accidents caused by excavation of existing pipes

Aboveground pipeline

Most equipment (fiscal metering, compressor/pumping stations, etc.) will normally be above ground installations.

Key requirements to aboveground piping:

1 Connections: Generally, flanged (bolted and non-welded) connection is used above ground. However, as hydrogen is more prone to leakage, welded connections should be considered whenever practical.
2 Cathodic protection: All above ground piping shall have electrical continuity across all connections, except insulated flanges, and shall be earthed at suitable intervals to protect against lighting and static electricity
3 Corrosion: Coating is normally applied to minimize environment corrosion. The type and amount depend on location.

Input

Input is fluid at operation pressure given in Table 28. The flow is given by the optimal pressure drop and velocities listed in Table 29

Output

The output is the same as the input. Exception is pressure, which can be somewhere between the min and the max pressure allowed in the transmission net.

Efficiency and losses

Energy loss occurs as a result of fluid frictional loss (pressure drop) in the pipelines. The friction loss is a strong function of fluid velocity. Thus, the optimal design velocity is a trade-off between capital cost (pipeline diameter) and operating cost (pumping/compression energy).

For the technology catalogue, a cost optimization has been performed. The dP/dL (dP/dL=pressure drop per km) listed in Table 29 give a good trade-off between CAPEX and OPEX (both for operation pressures at 70 bar as well as for operating pressures at 140 bar). The optimum depends on the length of the pipe, cost of the booster vs cost of the piping material.

	dP/dL, bar/km	Velocity, m/s
H_2	dP/dL(max) $\approx 1.28 x Q^{-0.75}$	P=140 bar $V \approx 4.4 \times Q^{0.1}$ P=70 bar $V \approx 6.7 \times Q^{0.1}$
Liquid fluids (NH_3, DME, LHC)	dP/dL(max)=0.04 bar/km	

Table 29: Optimal/max pressure drop per km (dP/dL, bar/km), Q=duty transported in MW

Application potential

H_2: Hydrogen is a key component that is required for optimal production of any synthetic fuels. This include any CCU process, NH_3 production, fuel production from residue biomass/waste (the efficiency converting residue biomass/waste to synthetic fuel can be almost doubled by adding hydrogen) and H_2 fueling stations.

NH_3, DME and LHC: As they are not the "base" element, i.e. the element that is needed for production of all other fuels, and as they are much easier to transport in larger quantities via mobile transportation, pipelines will most likely just be point to point solutions where larger capacities need to be transported.

Typical capacities

The capacities considered in this catalogue are listed in the following table:

<table>
<tr><th>Fluid</th><th>Mass flow
TPD</th><th>Energy flow
MW (HHV)</th><th>DN
inch</th><th>Pmax
barg</th><th>T
°C</th></tr>
<tr><td rowspan="2">H_2</td><td>40-13000</td><td>80-20000</td><td>4-48</td><td>140</td><td rowspan="5">Amb.</td></tr>
<tr><td>40-9000</td><td>80-15000</td><td>4-48</td><td>70</td></tr>
<tr><td>NH_3</td><td rowspan="3">50-10000</td><td>10-2600</td><td>4-24</td><td>20</td></tr>
<tr><td>DME</td><td>20-3700</td><td>4-24</td><td>20</td></tr>
<tr><td>Toluene</td><td>20-5000</td><td>4-24</td><td>10</td></tr>
</table>

Table 30: Capacities considered in this catalogue. To convert the energyflow into LHV based flow, multiply with 120/142=0.85.

It is assumed that the transmission piping is underground piping and for underground piping 4" is selected as a minimum pipe-size. Therefore, for very low capacity, the pipes become quite expensive per unit capacity.

Environmental

The construction phase of a pipeline may have environmental impact depending on the chosen route. An environmental impact assessment (VVM) will be required.

Once the pipeline is constructed it will only have marginal environmental impact.

Blow down of pipeline sections for maintenance or repair work will be rare and done in a slow and controlled manner that will have insignificant environmental impact.

Research and development perspectives

Transmission and distribution pipes for both H_2, NH_3, DME and non-corrosive liquid hydrocarbons is a well-known technology (TRL=8-9).

Improvements and associated cost reduction:

1. Hydrogen compression:
   1.1. Increase the suction pressure
   1.2. Several interstage compressors that is optimized so only compressing to the actual discharge pressure

2. Material of construction:
   2.1. Challenge existing assumptions such as reviewing the limitation on hardness or the belief that higher grades of pipeline steel will be more susceptible to hydrogen embrittlement
   2.2. Approval of newer low alloy steels for H_2 services: It is judged that there is room for larger cost reduction due to improved materials ref. 6.
   2.3. Plastic pipes, may especially be optimal for smaller distribution pipes

3. Max operating pressure:
   3.1. Cost calculation within this report shows that the cost advantages of increasing the pressure is limited. However, this will most likely change if stronger alloys are approved for hydrogen service.

4. Design code:
   4.1. Standardisation and development of Eurocodes for hydrogen pipes (i.e. CEN 234 working group or EIGA)

5. Installation cost:

5.1. Position drilling might reduce installation cost substantially: Directional drilling makes pipelines that crosses streams, existing constructions, etc. much cheaper especially in industrial/urban areas.
5.2. Converting NG pipes to H_2 pipes will make a major reduction in CAPEX.
5.3. Put a smaller H_2 pipeline into an existing NG pipeline

Prediction of performance and costs

Investment cost (CAPEX)

The investment cost will include

1. Cost of equipment, piping, piping elements[33] and instrumentations[34]
2. Installation costs
3. Approvals, expropriation, etc.

Figure 21: Equipment, installation and difficulties associated with installation in larger cities

For onshore pipelines COWI has made an own estimate of the investment cost based on inhouse experience obtained from engineering and installation of natural gas transmission lines in Denmark. The own estimate is benchmarked against references from the literature.

The following assumptions are used for estimate of pipeline investment cost:

1. A class location safety factor[35] of 0.4 for small pipes and 0.5 for large pipes is used. Pipeline construction material is carbon steel (X52) with polymer coating.
2. The design dP/dL is based on values given in Table 29
3. Cathodic protection is included as per Figure 20.

[33] Insulation valves, vent valves, cathodic protections, etc.
[34] Transmitters for measuring pressure, flow, etc.
[35] Lower class location safety factor means thicker pipes. 0.4 is selected for small pipes (assumed installed in populated areas, i.e. pipe to refueling stations) while 0.5 is selected for large pipes which are assumed to be installed in less populated areas

4. Booster station is added to ensure that the pressure do not drop below the minimum allowable pressure
5. Sectionalisation vales (ESD) with ancillaries every 20 km is assumed. This is uncertain as regulative requirements for H_2 pipelines in DK is unclear.
6. Installation cost includes trenching and 8 % for controlled drilling, permitting and environmental investigations
7. Cost factor for engineering and follow-up added (6 to 10% depending on size).
8. Unit cost based on pipeline distance of 200 km. For very short pipelines the unit cost will increase.

Figure 22 shows a system with 35 bar inlet filling compressor and a respectively a 140 bar (lefthand side) and 70 bar (righthand side) operating pressure. In each of the two figures cost and energy loss curves and associated formulas are given depending on the pipeline capacity. These cost and energy loss curves are used to calculate the examples in Table 31 andTable ***32*** and represent estimated values for 2020.

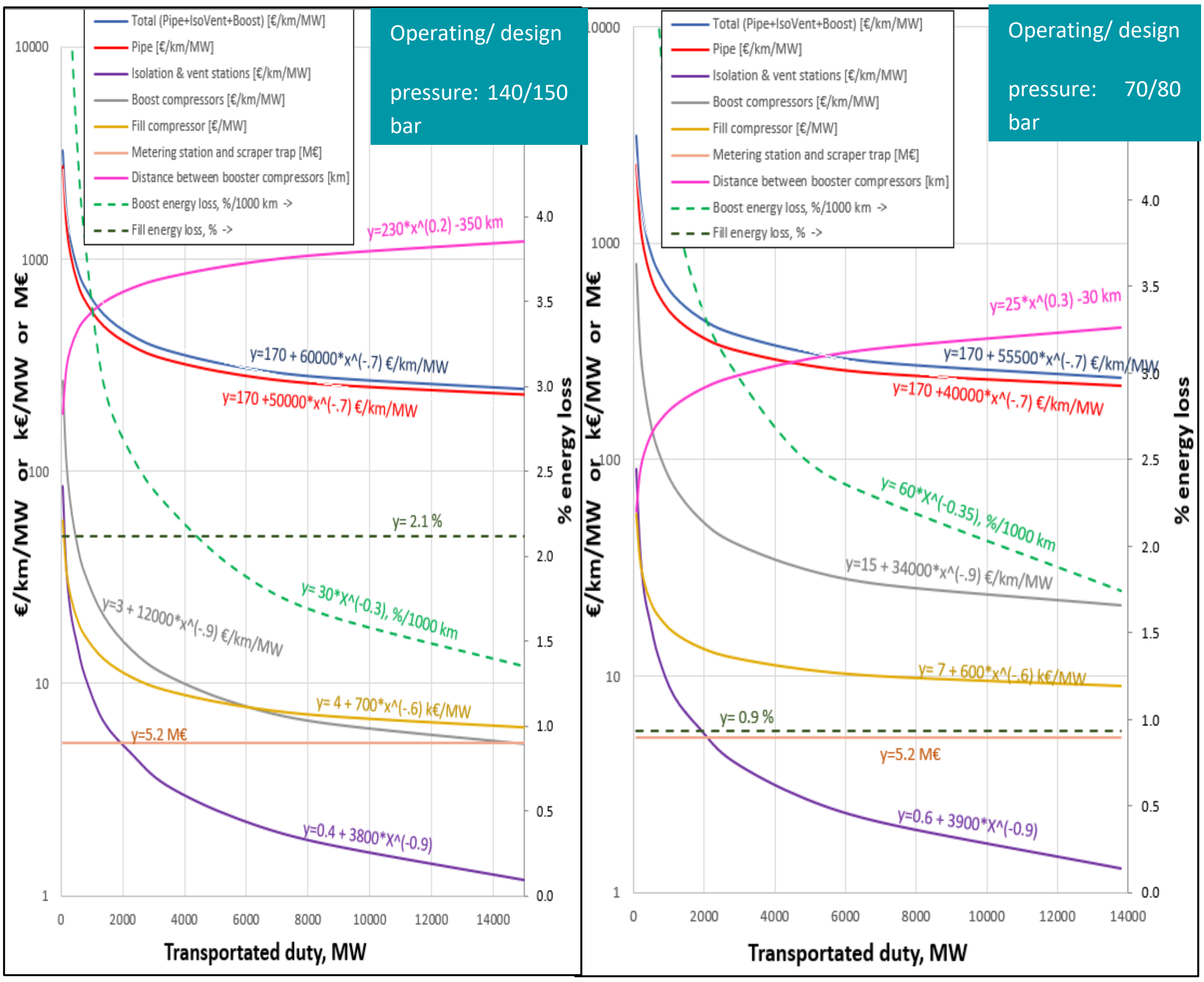


Figure 22: Estimated CAPEX, compression losses and distance between booster compressor vs. transported duty (HHV) for hydrogen transmission pipes. Examples of how to use the figures are given in tables below.

The above curves are based on 100% utilization. Cost for reduced utilization is obtained by multiplying the cost per capacity with (100/X) where X is the average utilization percentage (the examples below is calculated assuming 75 % utilization).

Figure 22 also include a formula for calculating the distance between the booster compressors.

The cost formulas given in Figure 22 are only valid provided the design pressure drop is approximately as per formula in Table 29. As the design pressure drop has been optimized with respect to cost, both lower and higher design pressure drops will tend to increase the cost. Lower design pressure will increase the pipe-diameter/pipe-cost while higher design pressure drop will increase the booster compressor expenses.

		Capacity - Energy		Capacity - Mass flow		Pressures		Note 1: = 170+60000* MW^(-0.7))/1000, [€/m/MW], MW=2500 MJ/s
length, km	500	4000	MW HHV	888,964	TPY	Inlet filling compressor, bar	35	Note 2: = 30* MW^(-0.3), [%/(MW*1000km)], MW=3250 MJ/s
WACC, %	5	126,144,000	GJ/y	2436	TPD	Max grid, bar (note 3)	140	Note 3: = discharge pressure for filling and boosting compressor
Power cost, €/MWh	60	345,600	GJ/day	1128	kNm3/h	Min grid, bar (note 4)	40	Note 4 = inlet pressure for boosting compressor
Utilization	75	**3383**	MW LHV	1011	MMSCF/d			

	Item	Source	Lifetime y	Formular calc. orange cell	% loss MW*1000kr	%loss MW	MW	€ MW*km	k€ MW	M€	M€ y	€ ton H2	€ GJ	Datasheet
CAPEX	Pipe (material and installation)	Figure 2.4	50	170 + 50000 *MW^(-0.7), [€/km/MW]				320	160	641	35	53	0.371	Not in datasheet
	Isolation & vent stations	Figure 2.4	50	0.4 + 3800 *MW^(-0.9), [€/km/MW]				2.6	1.3	5	0.3	0.4	0.003	Not in datasheet
	Booster compressors	Figure 2.4	20	3+12000* MW^(-0.9), [€/km/MW]				9.9	4.9	20	1.6	2.4	0.017	Not in datasheet
	=> Total per length	Sum		Sum				**333**	**166**	**666**	**37**	**55**	**0.391**	0.4 (note 1)
	Filling compresor	Figure 2.4	20	4+ 700* MW^(-0.6) , [€/MW]					8.8	35	2.83	4.3	0.030	Not in datasheet
	Metering station + scraper trap	Figure 2-4	50	5.2 [€]						5.2	0.3	0.4	0.003	Not in datasheet
	=> TOTAL	Sum		Sum						**706**	**40**	**60**	**0.424**	
OPEX	Filling compressor - power @ 100% cap.	Figure 2-4		1.1 *(Pin^(1/3)-Pout^(1/3)), [%/MW]		**2.1**	63				33	50	0.352	2.1 = 2.1 % in datasheet
	Booster compressors - power @100% cap.	Figure 2-4		30* MW^(-0.3), [%/(MW*1000km)]	**2.5**	1.2	37				20	29	0.208	2.7 (note 2)
	Fixed O&M										1	1.5	0.011	0.5 €/km/y/MW
	=> TOTAL										**54**	**81**	**0.570**	
	TOTAL										**94**	**141**	**0.99**	

		Capacity - Energy		Capacity - Mass flow		Pressures		Note 1: = 170+60000* MW^(-0.7))/1000, [€/m/MW], MW=20000 MJ/s
length, km	1000	13000	MW HHV	2,889,133	TPY	Inlet filling compressor, bar	35	Note 2: = 30* MW^(-0.3), [%/(MW*1000km)], MW=7500 MJ/s
WACC, %	5	409,968,000	GJ/y	7915	TPD	Max grid, bar (note 3)	140	Note 3: = discharge pressure for filling and boosting compressor
Power cost, €/MWh	60	1,123,200	GJ/day	3667	kNm3/h	Min grid, bar (note 4)	40	Note 4 = inlet pressure for boosting compressor
Utilization	75	**10994**	MW LHV	3285	MMSCF/d			

	Item	Source	Lifetime y	Formular calc. orange cell	% loss MW*1000kr	%loss MW	MW	€ MW*km	k€ MW	M€	M€ y	€ ton H2	€ GJ	Datasheet
CAPEX	Pipe (material and installation)	Figure 2.4	50	170 + 50000 *MW^(-0.7), [€/km/MW]				236	236	3067	168	78	0.546	Not in datasheet
	Isolation & vent stations	Figure 2.4	50	0.4 + 3800 *MW^(-0.9), [€/km/MW]				1.2	1.2	15	0.8	0.4	0.003	Not in datasheet
	Booster compressors	Figure 2.4	20	3+12000* MW^(-0.9), [€/km/MW]				5.4	5.4	70	5.6	2.6	0.018	Not in datasheet
	=> Total per length	Sum		Sum				**242**	**242**	**3152**	**174**	**81**	**0.567**	0.2 (note 1)
	Filling compresor	Figure 2.4	20	4+ 700* MW^(-0.6) , [€/MW]					6.4	83	6.66	3.1	0.022	Not in datasheet
	Metering station + scraper trap	Figure 2-4	50	5.2 [€]						5.2	0.3	0.1	0.001	Not in datasheet
	=> TOTAL	Sum		Sum						**3240**	**181**	**84**	**0.590**	
OPEX	Filling compressor - power @ 100% cap.	Figure 2-4		1.1 *(Pin^(1/3)-Pout^(1/3)), [%/MW]		**2.1**	206				108	50	0.352	2.1 = 2.1 % in datasheet
	Booster compressors - power @100% cap.	Figure 2-4		30* MW^(-0.3), [%/(MW*1000km)]	**1.7**	1.7	171				90	41	0.292	2.1 (note 2)
	Fixed O&M										7	3.0	0.021	0.5 €/km/y/MW
	=> TOTAL										**204**	**94**	**0.665**	
	TOTAL										**386**	**178**	**1.25**	

		Capacity - Energy		Capacity - Mass flow		Pressures		Note 1: = 170+60000* MW^(-0.7))/1000, [€/m/MW], MW=20000 MJ/s
length, km	1000	30000	MW HHV	6,667,230	TPY	Inlet filling compressor, bar	35	Note 2: = 30* MW^(-0.3), [%/(MW*1000km)], MW=20000 MJ/s
WACC, %	5	946,080,000	GJ/y	18266	TPD	Max grid, bar (note 3)	140	Note 3: = discharge pressure for filling and boosting compressor
Power cost, €/MWh	60	2,592,000	GJ/day	8463	kNm3/h	Min grid, bar (note 4)	40	Note 4 = inlet pressure for boosting compressor
Utilization	75	**25370**	MW LHV	7582	MMSCF/d			

	Item	Source	Lifetime y	Formular calc. orange cell	% loss MW*1000kr	%loss MW	MW	€ MW*km	k€ MW	M€	M€ y	€ ton H2	€ GJ	Datasheet
CAPEX	Pipe (material and installation)	Figure 2.4	50	170 + 50000 *MW^(-0.7), [€/km/MW]				207	207	6202	340	68	0.479	Not in datasheet
	Isolation & vent stations	Figure 2.4	50	0.4 + 3800 *MW^(-0.9), [€/km/MW]				0.8	0.8	23	1.2	0.2	0.002	Not in datasheet
	Booster compressors	Figure 2.4	20	3+12000* MW^(-0.9), [€/km/MW]				4.1	4.1	124	9.9	2.0	0.014	Not in datasheet
	=> Total per length	Sum		Sum				**212**	**212**	**6348**	**351**	**70**	**0.494**	0.2 (note 1)
	Filling compresor	Figure 2.4	20	4+ 700* MW^(-0.6) , [€/MW]					5.4	163	13.10	2.6	0.018	Not in datasheet
	Metering station + scraper trap	Figure 2-4	50	5.2 [€]						5.2	0.3	0.1	0.000	Not in datasheet
	=> TOTAL	Sum		Sum						**6517**	**364**	**73**	**0.513**	
OPEX	Filling compressor - power @ 100% cap.	Figure 2-4		1.1 *(Pin^(1/3)-Pout^(1/3)), [%/MW]		**2.1**	476				250	50	0.352	2.1 = 2.1 % in datasheet
	Booster compressors - power @100% cap.	Figure 2-4		30* MW^(-0.3), [%/(MW*1000km)]	**1.4**	1.4	306				161	32	0.227	1.5 (note 2)
	Fixed O&M										15	3.0	0.021	0.5 €/km/y/MW
	=> TOTAL										**426**	**85**	**0.600**	
	TOTAL										**790**	**158**	**1.11**	

Table 31: Calculation example – H_2 pipe cost using *Error! Reference source not found.*a – P=140 bar and average utilization of 75% is used.

In Table 31 and Table 32, detailed cost estimates for various hydrogen transmission pipe capacity and length are given.

The first table calculate the cost for a 500 km pipe transporting 4000 MW (based on HHV). The pressure operating range is 40-140 bar and the filling pressure is 35 bar. An average utilization/load percentage of 75% is applied.

In Figure 22 the blue curve is the sum of:

- The red curve (pipe cost)
- The purple curve (insulation and vent station cost) and
- The gray curve (booster compressor cost).

Colors in Table 31 and Table 32 follow the color code in Figure 22.

In Table 31 the sum of the first, second and third row (row with red, purple and gray numbers) adds to the fourth row (i.e. the row with the blue numbers).

The "0.4 €/m/MW" listed in the "datasheet" column (the first example) is the value taken from the "Investment costs" data in the data sheet. This value is based on the formula for the blue curve (sum of pipe cost, insulation and vent station cost and booster compressor cost):

$$Investment\ Cost\ \left(\frac{€}{meter * \ MW}\right) = 170 + 60{,}000 * \frac{MW^{(-0.7)}}{1000}$$

Where 2500 MW (HHV) is used for the interval 1000-4000 MW line.

The power used for booster compression in Figure 22 and in the examples above are included in the "Energy losses" in the data sheet. This cost item in the data sheet is based on the formula:

$$Energy\ losses\ (\frac{\%}{MW \ * 1000\ km}) = 30 * MW\text{^}(-0.3)$$

Where 3250 MW (HHV) is used for the interval 1500-5000 MW line. This results in (rounded to) 2.7% loss pr. MW pr. 1000 km for pipeline capacity in the given interval.

The total cost for the 4,000 MW 500 km pipeline is 131 €/ton transported H_2 (or 0.92 €/GJ transported H_2 – note the energy is based on HHV).

The same calculation is performed for 1,000 km pipe with both 13,000 and 30,000 MW capacity. All calculations performed in Table 31 are repeated in the following table with P=70 bar instead of 140 bar.

		Capacity - Energy		Capacity - Mass flow		Pressures		
length, km	500	4000	MW HHV	888,964	TPY	Inlet filling compressor, bar	35	Note 1: = 170+55500* MW^(-0.7))/1000, [€/m/MW], MW=2500 MJ/s
WACC, %	5	126,144,000	GJ/y	2436	TPD	Max grid, bar (note 3)	70	Note 2: = 60* MW^(-0.35), [%/(MW*1000km)], MW=3250 MJ/s
Power cost, €/MWh	60	345,600	GJ/day	1128	kNm3/h	Min grid, bar (note 4)	40	Note 3: = discharge pressure for filling and boosting compressor
Utilization	75	**3383**	MW LHV	1011	MMSCF/d			Note 4 = inlet pressure for boosting compressor

	Item	Source	Lifetime y	Formular calc. orange cell	% loss MW*1000km	%loss MW	MW	€ MW*km	k€ MW	M€	M€ y	€ ton H2	€ GJ	Datasheet
CAPEX	Pipe (material and installation)	Figure 2.4	50	170 + 40000 *MW^(-0.7), [€/km/MW]				290	145	581	32	48	0.336	Not in datasheet
	Isolation & vent stations	Figure 2.4	50	0.6 + 3900 *MW^(-0.9), [€/km/MW]				2.8	1.4	6	0.31	0.5	0.003	Not in datasheet
	Booster compressors	Figure 2.4	20	15+34000* MW^(-0.9), [€/km/MW]				34.5	17.2	69	5.5	8.3	0.058	Not in datasheet
	=> Total per length	Sum		Sum				**328**	**164**	**655**	**38**	**56**	**0.398**	0.4 (note 1)
	Filling compresor	Figure 2.4	20	7+ 600* MW^(-0.6) , [€/MW]					11.1	45	3.58	5.4	0.038	Not in datasheet
	Metering station + scraper trap	Figure 2-4	50	5.2 [€]						5.2	0.3	0.4	0.003	Not in datasheet
	=> TOTAL	Sum		Sum						**705**	**42**	**62**	**0.439**	
OPEX	Filling compressor - power @ 100% cap.	Figure 2-4		1.1 *(Pin^(1/3)-Pout^(1/3)), [%/MW]		**0.9**	28				15	22	0.156	0.9 = 2.1 % in datasheet
	Booster compressors - power @100% cap.	Figure 2-4		60* MW^(-0.35), [%/(MW*1000km)]	3.3	1.6	49				26	39	0.274	3.5 (note 2)
	Fixed O&M										1	1.5	0.011	0.5 €/km/y/MW
	=> TOTAL										**42**	**63**	**0.441**	
	TOTAL										**83**	**125**	**0.88**	

		Capacity - Energy		Capacity - Mass flow		Pressures		
length, km	1000	13000	MW HHV	2,889,133	TPY	Inlet filling compressor, bar	35	Note 1: = 170+55500* MW^(-0.7))/1000, [€/m/MW], MW=20000 MJ/s
WACC, %	5	409,968,000	GJ/y	7915	TPD	Max grid, bar (note 3)	70	Note 2: = 60* MW^(-0.35), [%/(MW*1000km)], MW=7500 MJ/s
Power cost, €/MWh	60	1,123,200	GJ/day	3667	kNm3/h	Min grid, bar (note 4)	40	Note 3: = discharge pressure for filling and boosting compressor
Utilization	75	**10994**	MW LHV	3285	MMSCF/d			Note 4 = inlet pressure for boosting compressor

	Item	Source	Lifetime y	Formular calc. orange cell	% loss MW*1000km	%loss MW	MW	€ MW*km	k€ MW	M€	M€ y	€ ton H2	€ GJ	Datasheet
CAPEX	Pipe (material and installation)	Figure 2.4	50	170 + 40000 *MW^(-0.7), [€/km/MW]				223	223	2896	159	73	0.516	Not in datasheet
	Isolation & vent stations	Figure 2.4	50	0.6 + 3900 *MW^(-0.9), [€/km/MW]				1.4	1.4	18	1.0	0.5	0.003	Not in datasheet
	Booster compressors	Figure 2.4	20	15+34000* MW^(-0.9), [€/km/MW]				21.7	21.7	283	22.7	10.5	0.074	Not in datasheet
	=> Total per length	Sum		Sum				**246**	**246**	**3196**	**182**	**84**	**0.593**	0.2 (note 1)
	Filling compresor	Figure 2.4	20	7+ 600* MW^(-0.6) , [€/MW]					9.0	118	9.43	4.4	0.031	Not in datasheet
	Metering station + scraper trap	Figure 2-4	50	5.2 [€]						5.2	0.3	0.1	0.001	Not in datasheet
	=> TOTAL	Sum		Sum						**3319**	**192**	**89**	**0.624**	
OPEX	Filling compressor - power @ 100% cap.	Figure 2-4		1.1 *(Pin^(1/3)-Pout^(1/3)), [%/MW]		**0.9**	91				48	22	0.156	0.9 = 2.1 % in datasheet
	Booster compressors - power @100% cap.	Figure 2-4		60* MW^(-0.35), [%/(MW*1000km)]	2.2	2.2	212				112	52	0.363	2.6 (note 2)
	Fixed O&M										7	3.0	0.021	0.5 €/km/y/MW
	=> TOTAL										**166**	**77**	**0.540**	
	TOTAL										**358**	**165**	**1.16**	

		Capacity - Energy		Capacity - Mass flow		Pressures		
length, km	1000	300000	MW HHV	66,672,304	TPY	Inlet filling compressor, bar	35	Note 1: = 170+55500* MW^(-0.7))/1000, [€/m/MW], MW=20000 MJ/s
WACC, %	5	9,460,800,000	GJ/y	182664	TPD	Max grid, bar (note 3)	70	Note 2: = 60* MW^(-0.35), [%/(MW*1000km)], MW=20000 MJ/s
Power cost, €/MWh	60	25,920,000	GJ/day	84633	kNm3/h	Min grid, bar (note 4)	40	Note 3: = discharge pressure for filling and boosting compressor
Utilization	75	**253700**	MW LHV	75816	MMSCF/d			Note 4 = inlet pressure for boosting compressor

	Item	Source	Lifetime y	Formular calc. orange cell	% loss MW*1000km	%loss MW	MW	€ MW*km	k€ MW	M€	M€ y	€ ton H2	€ GJ	Datasheet
CAPEX	Pipe (material and installation)	Figure 2.4	50	170 + 40000 *MW^(-0.7), [€/km/MW]				176	176	52759	2890	58	0.407	Not in datasheet
	Isolation & vent stations	Figure 2.4	50	0.6 + 3900 *MW^(-0.9), [€/km/MW]				0.6	0.6	194	10.6	0.2	0.001	Not in datasheet
	Booster compressors	Figure 2.4	20	15+34000* MW^(-0.9), [€/km/MW]				15.4	15.4	4620	371	7.4	0.052	Not in datasheet
	=> Total per length	Sum		Sum				**192**	**192**	**57572**	**3271**	**65**	**0.461**	0.2 (note 1)
	Filling compresor	Figure 2.4	20	7+ 600* MW^(-0.6) , [€/MW]					7.3	2193	176	3.5	0.025	Not in datasheet
	Metering station + scraper trap	Figure 2-4	50	5.2 [€]						5.2	0.3	0.0	0.000	Not in datasheet
	=> TOTAL	Sum		Sum						**59771**	**3448**	**69**	**0.486**	
OPEX	Filling compressor - power @ 100% cap.	Figure 2-4		1.1 *(Pin^(1/3)-Pout^(1/3)), [%/MW]		**0.9**	2,104				1106	22	0.156	0.9 = 2.1 % in datasheet
	Booster compressors - power @100% cap.	Figure 2-4		60* MW^(-0.35), [%/(MW*1000km)]	0.7	0.7	1,634				859	17	0.121	1.9 (note 2)
	Fixed O&M										150	3.0	0.021	0.5 €/km/y/MW
	=> TOTAL										**2115**	**42**	**0.298**	
	TOTAL										**5563**	**111**	**0.78**	

Table 32: Calculation example – H_2 pipe cost using Figure 14 b – P=70 bar and average utilization of 75% is used.

Within Table 33 cost vs pipe diameter and duty is listed for both 140 bar and 70 bar pipes. Surprisingly, at very large pipes the cost of P=70 bar pipe is less than for the pipe with P=140 bar. A major reason is that the optimal dP/dL formula (see Table 29) for the two cases were so similar that the optimal dP/dL for P=70 have been applied for both. Thus, high pressure is from a cost point beneficial at low capacities while at larger capacities the cost become very identical.

As seen in the tables (and Figure 22), it is the "pipe material & installation" and the compressor power-consumption as well as power consumption for filling that contributes to the major part of the cost. Electrolysis Units that operate at higher pressure can in the future eliminate a major part of the filling power consumption.

An additional advantage of the high pressure is the additionally storage capability. The amount of hydrogen gas that can be contained within a given volume of pipe is 1.9 times larger at 140 bar than at 70 bar. Thus, the extra pressure give a huge additionally storage/line packing capability.

100% utilization

Pressure bar	DN inch	CAPEX P+I+B €/m	HHV low MW	 high MW	LHV low MW	 high MW	Cost All €/kg*1000km
70	4	210		65		55	1.22
	6	265	65	165	55	140	0.70
	8	340	165	285	140	240	0.52
	10	420	285	465	240	395	0.41
	12	470	465	690	395	580	0.34
	16	615	690	1130	580	960	0.27
	20	855	1130	1865	960	1575	0.23
	24	1160	1865	2795	1575	2365	0.20
	30	1390	2795	4845	2365	4095	0.17
	36	1845	4845	7280	4095	6155	0.15
	48	3025	7280	13800	6155	11670	0.13
140	4	230		70		60	1.08
	6	325	70	180	60	150	0.64
	8	430	180	320	150	270	0.48
	10	540	320	540	270	455	0.38
	12	635	540	785	455	665	0.33
	16	800	785	1385	665	1170	0.27
	20	1165	1385	2275	1170	1925	0.23
	24	1595	2275	3420	1925	2890	0.21
	30	2220	3420	5740	2890	4855	0.18
	36	3050	5740	8670	4855	7330	0.17
	48	5060	8670	16440	7330	13905	0.15

P=Pipe, I=Isolation and vent station, B=booster compressors

Table 33: Duty ranges vs nominal diameter (DN) and cost. The cost in the last column is based on the high flow (i.e. the high MW).

Table 34 list cost evaluations from other studies. Applied WACC and assumed life time of investment is unfortunately often not cited. Where sufficient information is given, the calculations have been performed with the cost optimized formulas developed here (i.e. the formulas in Figure 22 have been applied). The values match fine with the Hychain and the European hydrogen backbone studies while the IEA and IES studies seems more conservative than the results using the values in this catalogue.

Other benchmark studies of hydrogen transmission lines	Year	Description of the study	Parameters used within this study LHV GW	L km	Pmax bar	Pmin bar	Pfill bar	Retofit %	Utiliz %	Cost € / kg*1000km Other	This
European-hydrogen backbone	2020	13 GW (LHV), 48", 100-600 km, 67-80 bar, P=67-80 bar, Pfill=30-40 bar, SP(boost)=190-330 MW/1000 km, 57 % utilization, 75% retofit of existing piping	13	1000	78	40	35	75	57	0.09-0.17	0.11
								0	100	0.16-0.23	0.13
								0	57		0.17
Hychain - CAPEX low	2020	1000 km, huge pipes, 50 years, 5% wacc, 100 % capacity use	30	1000	78	40	35	0	100	0.10	0.12
Hychain - CAPEX high										0.18	
IEA										0.59	
Hydrogen generation in Europe (EC)											
- Guidehouse	2019	48" pipe including compressor cost. Assume: P=70 bar, 75% utilization	12	1000	70	40	35	0	75	0.23	0.15
- BNEF	2019	34", 75% utilization, 50 km distance. Assume P=70 bar	6	1000	70	40	35	0	75	0.48	0.17
- IES	2019	1500 km								0.57	
Hydrogen europe (2*40 MW)		2500 km, 2 times 48 inch. 50 year, 5% wacc, capacity use 50%. 40 GW require 66" pipe at 140 bar. Else it will be very costly do to high dP Assume 140 bar and 66"	40	1000	140	40	35	0	50	0.08	0.17
									100		0.13

Table 34: Studies found in literature. L=Length, Retofit is percent retrofit of NG net, and utilize is utilization percentage. The column study list the values given in the listed studies, while the white backgrounded cells list the values calculated with the cost-formulas listed within this document. For all calculation here: WACC=5% and 50 year lifetime on "pipe + isolation station + metering and scraber traps and 20 years on compressors.

Capital cost of liquid fuel pipes (L20 (LPG, NH_3, DME) and LHC):

The capital cost (CAPEX) of pipe transport of liquid fuels can be approximated by the following formula:

$$CM = 56 * MTPD^{-0.77}, \qquad [CM] = \left(\frac{€/m}{MTPD}\right)$$

$$CE = CM * \frac{24 * 3.6}{HHV_{liquid}}, \qquad [CE] = \left(\frac{€/m}{MW}\right), \qquad [HHV_{liquid}] = \frac{MJ}{kg}$$

This formula also gives a good approximation of liquefied NH_3, DME and LPG. Thus, the cost per mass unit is approximately the same. The major difference between the different liquids is the specific energy density (HHV) where especially ammonia and alcohol have a lower energy density and is therefore more costly to transfer per energy unit.

Variable operational cost

The variable operation cost will mainly be given by the energy used to boost the pressure as a result of friction losses in the transmission pipe.

Hydrogen (H_2): The booster and filling losses as function of capacity is plotted in Figure 22.

Liquid fuels (NH_3, DME, Toluene): With a dP/dL(max) or 0.04 bar/km, the operation cost is negligible.

Fixed operation cost

The fixed operation cost include maintenance, salaries/wages, etc. While the compressor maintenance cost depends on the capacity of the compressor the fixed O&M have for hydrogen pipes been given as €/km/MW. For liquid carring pipe, the maintenance cost depends very little on the actual capacity. I.e. a value based on €/km have been judged more appropriate for describing a large capacity range.

Hydrogen (H_2): 4% of average CAPEX have been used for 2020. 2% is used for 2030 and 1.5% is used for 2050. The decrease is judged based on IoT-maintenance of compressor is under strong development. Additionally, for the first pipes, additionally surveillance for hydrogen embrittlement is suspected.

Liquid (NH_3, DME, Toluene): 1% of average CAPEX is assumed. No major reduction in maintenance cost is foreseen.

Uncertainty

As the major cost is pipe material and installation the uncertainty is minor as this is mature technology.

Higher uncertainty is added to the upper end as there is a considerable higher risk of unforeseen elements making it more expensive than less expensive.

Improvements on directional drilling as well as approvement of stronger materials can have a larger cost impact on the installation cost.

The uncertainty on specific safety requirements will add some uncertainty to the cost estimates. Especially approvals, expropriation, cost due to resistance (especially in larger cities) is very difficult to estimate.

Quantitative description

See separate Excel file for Data sheet

132 Transport by road

This catalogue includes transport of H_2, NH_3, DME and LHC by truck. Typical operation conditions for the transport is given in Table 36.

Brief technology description

The advantage of road transportation is the flexibility and ability to collect and deliver at almost any location as well as low CAPEX. Road truck is more suitable for relatively short distances and for smaller volumes.

Trucks and trailers

Different designs of trucks and trailers are available depending if they are intended for bulk transport (large quantities from point A to point B) or distribution transport (small quantities to many costumers e.g. tank stations).

Figure 23: a) Tank, b) trailer, and c) tank trailer (semi-trailer)

The maximum permissible weight of lorries in Denmark is given in Table 35.

Weight per non-drive axle	Weight per drive axle	Truck 2 axles	Truck 3 axles	Truck 4 axles	Road train 4 axles	Road train 5 axles	Road train 6 axles	Road train 7 axles
10 t	11.5 t	18 t	24 t	32 t	38 t	44 t	50 t	56 t

Table 35: Permissible maximum weight of lorries in Denmark[36] (in ton).

[36] Bekendtgørelse om køretøjers største bredde, længde, højde, vægt og akseltryk, BEK nr 1497 af 01/12/2016

Tank types

Table 36 gives an overview of different types of truck-tanks and their associated cost (both CAPEX and variable operation cost).

Figure Below	Fluid	Tank types	T, °C	P, barg	Capacity (typical)	Further info	CAPEX Truck & trailer, M€
A, B	LHC	Non pressured Liquid tank	Amb.	0.2-3.5	20-35 m^3 15-35 t	Single wall, Aluminum, CS	0.46 (LHC)
C						Double wall, poison or corrosive fluid, Corrosive: SS, lined with rubber or plastic	
D	LPG, DME,	Compressed liquid tank	Amb.	5-35	13-45 m^3 7-30 t	Single wall, Carbon steel	0.70 (LPG & NH_3 & DME)
E	NH_3	Refrigerated liquid tanks	-50-(-90)	1.5-35	Up to 50 m^3 (<31 t)	Double walled with vacuum between, Boil-off loss	
F	H_2, NG	Compressed gas tanks (CH2, CNG)	Amb.	275-500	Up to 50 m^3 (<13 t LNG) (<1.5 t LH2)	Multiple tubes, each with a PSV. See Figure 25	0.98 (CH2)
E		Cryogenic tank (LH2, LNG)	Down to -253 (H_2) -165 (NG)	6-350	Up to 50 m^3 (<33 t LNG) (<3.5 t LH2)	Double walled with vacuum between, Boil-off loss	0.61 (LH2)

Table 36: Different types of tankers for fuel transport ref. 22.

Tank trailers can be divided into the following categories:

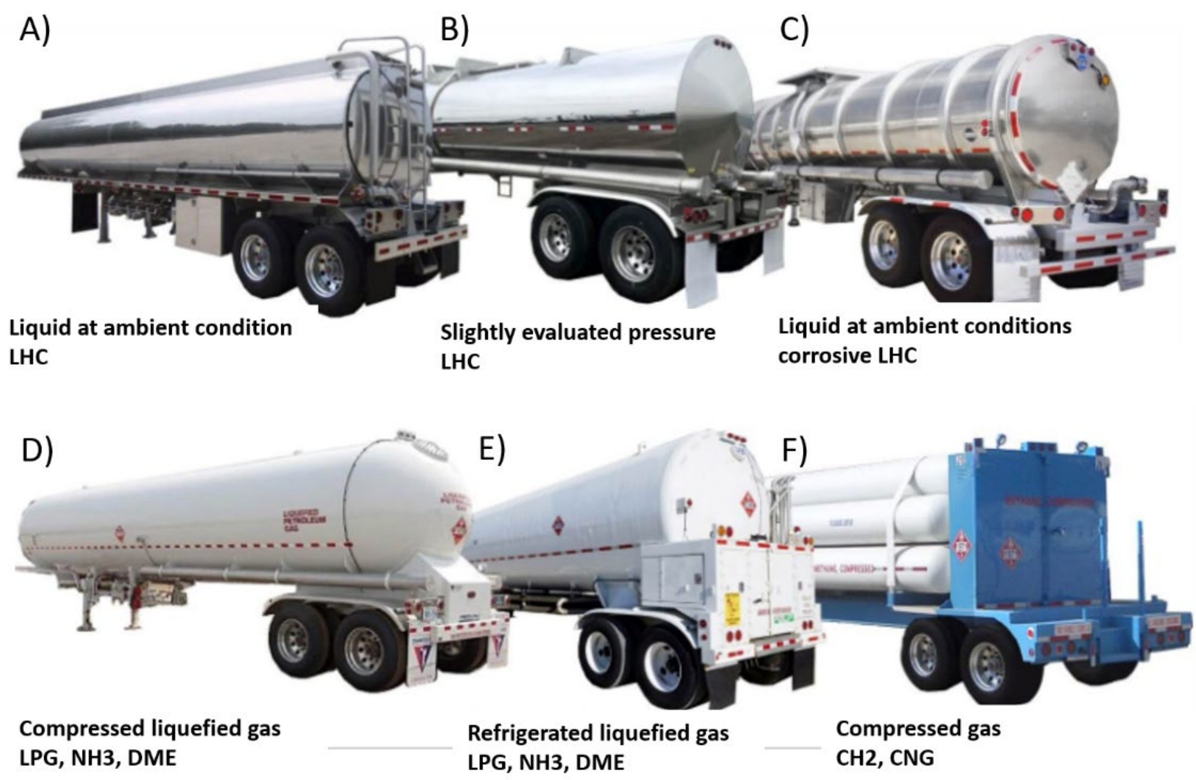


Figure 24: Different tank trailer design [ref. 22].

Hydrogen tanks can be categorized in type I-IV (see chapter about hydrogen storage in ref. 7). The type IV tanks seem to be more favorable for transportation due to the lower cylinder weight and no risk of corrosion.

Figure 25: Hydrogen tube trailer types

Tank design includes various safety functions (see figure below). Among these is division into several compartments to reduce the fluctuations/sloshing of the liquid in the tank. Additionally, a safety system that prevents overfilling of the tank is mandatory as well as it is important to inspect valves and tank for leaks before and after loading.

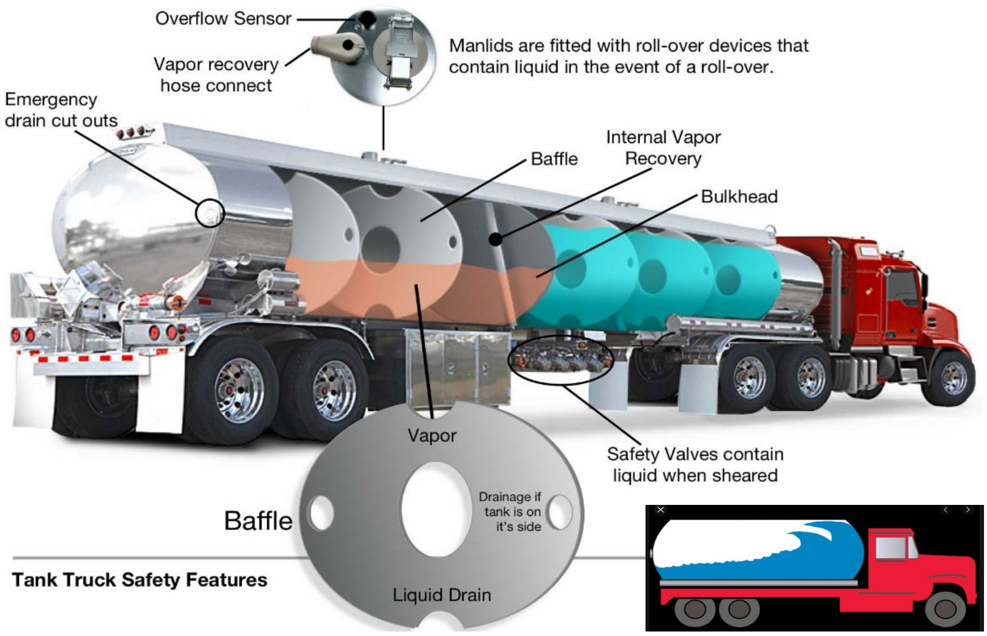


Figure 26: Tank safety features and internal baffles to prevent liquid splashing when driving.

Input

Input is:

1. fuel to be transported
2. fuel for propulsion (see consumption in section *Energy losses*)
3. fuel for keeping transported fuel cold (only for L20, H2NG)

Point 3 is normally not used. Instead, some boil-off is accepted. This boil-off can be minimized by using the boil-off as fuel for propulsion.

Typically transport pressure and temperature is given in Table 12, Table 36 and Table 37.

Loading system:

Fuel to be transported is loaded into the truck via filling compressor/pump and some loading system (typically via a loading arm). Thus, a loading station normally compromise:

1. Storage tanks (see cost in section *Storage tanks*) and associated moat
2. Filling compressor/pump (see cost in *Conversion to/from carrier (LOHC)*, *Compressor* and *Pumps*)
3. Loading arms (cost is ~25-35 k€)
4. Fundament, piping, drip trays, various safety equipment

Figure 27: Loading arm

Loading system is not included in the datasheet as this cost depend strongly on location and how many that share the same loading equipment.

The time used for loading is included in the cost calculations.

Output

The output is the fluid that has been transported. Normally it will be the same input. Exception is boil-off (see *Energy losses*).

Unloading system:

The unloading system normally compromise:

1. Storage tanks (see cost in *Storage tanks*)
2. Unloading via gravity (only possible for liquids) or via compressor/pumps (see cost in *Conversion to/from carrier (LOHC)*, *Compressor* and *Pumps*)
3. Fundament, piping, drip trays, various safety equipment

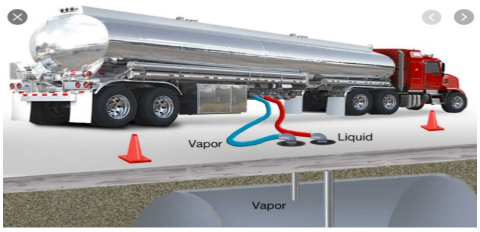


Figure 28: Unloading into storage tank via gravity

For liquid fuels, the fuel is normally unloaded via gravity (see Figure 28) or via a pump.

For compressed gas (CH2 and CNG), gravity cannot be used. To limit the compression loss, it is optimal if the trailer tubes is used as final storage vessels (see Figure 29).


Figure 29: Trailer and storage is same vessel.

For the same reason given for the loading system, the unloading system has not been included in the cost estimate in the datasheet.

Efficiency and losses

Energy losses during transportation with truck include fuel for propulsion, both to the actual transport as well as the transport back of an empty truck, and boil off (see section *Energy losses*).

Application potential

Road truck transport of compressed gas (H_2 and NG) is generally only optimal for small volumes over limited distances.

For liquids, the volumetric energy density is much higher meaning much more energy can be transported per tour. Additionally, the filling and unloading system is much simpler and therefore inherit less losses. Thus, truck is generally optimal also for larger quantities.

Typical capacities

Typical capacities of trucks are given in Table 37. Datasheets for the following have been included in this catalogue:

Fluid	Net Truck		P	T
	Mass, tons	Energy, GJ	bar	°C
CH2	1.5	180	350 - 500	Ambient
LH2	3.1	383	6 - 350	Down to -253
NH_3	28	532	20 - 35	Ambient
DME	31	887		
Toluene	44	1766	1.2 - 4.5	Ambient

Table 37: Typical capacities and condition of tankers for liquid/gas transport

Environmental

As with all other trucks, environmental challenges are:

1. GHG and particle emissions
2. Noise pollution
3. Impact on landscape and habitats from infrastructure

Research and development perspectives

Truck transportation is a well-proven mature technology (TRL=8-9).

Cost reduction improvements may include
1. Reduce the boil off – possible to improve the insulation
2. Improvement of the hydrogen trailer tubes: Lowering the weight of pressured tanks by developing stronger, lighter and cheaper composite materials will reduce transportation costs dramatically
3. Mass production of the hydrogen trailer tubes
4. Standardize the hydrogen trailer tubes so they are incorporated as storage vessels at the production and at the destination units

5. Reduce the loading/unloading time (for CH2, possible use the same vessels for storage and transportation)

Prediction of performance and costs

An estimate for transportation by truck as function of capacity and distance has been derived:

Cost = VariableCost * Distance + FixedCost

The variable cost (VariableCost) include fuel consumption, driver wage and degradation due to usage (the latter is estimated by multiplying "CAPEX + O&M" with time fraction it is driving).

The fixed cost (FixedCost) include wage for supervision and the remaining "CAPEX + O&M".

In the calculation of a cost factors the following is assumed:

1. CAPEX of trailer truck used is given in Table 36
2. Annual Fixed O&M is set to 5% of CAPEX
3. Loading/unloading time used is given in Table 38
4. Availability is set to 8000 h per year
5. Driver cost is 45 EUR/h (operation 24/7).
6. Fuel consumption (MJ/km) used is listed in *Energy losses* and fuel cost is 29 EUR/kJ.
7. Average speed is 60 km/h.
8. Truck CAPEX is annualized with 5% interest over 6 years (assumed lifetime).

With the above assumptions the cost of NH_3 transport is modelled by:

$$Cost = 4.5\frac{€}{t\,NH_3} + Distance \cdot 0.13\frac{€}{t\,NH_3 \cdot km}$$

Example of cost of transport
Based on the above, cost for 30 and 100 km drive are estimated:

Fluid	Loading/ unloading hours, 2020/2030/2050	Reference	FixedCost €/t	Variable Cost €/(t*km)	Total 30 km €/t	Total 100 km €/t
LH2	5/4/3	*	37	1.1	71	149
CH2	4.25/4/3	**	132	2.6	211	396
NH3	3/2.5/2	***	4.5	0.13	8	17
DME	/2.5/2/2	****	3.7	0.12	7	16
Toluene	/2.5/1.5/1.5	****	2.1	0.08	5	10

Table 38: Typical values obtained from *Air liquid A/S, **Everfuel A/S, ***Give Svaergods A/S & ****Fjellerad Transport Aps (values for LPG and Diesel is used). Values are for 2020.

Uncertainty

Transport of LHC are a mature technology, i.e. little uncertainty is assumed.

Transport of L20 (i.e. NH3, DME and LPG) is also mature, especially LPG. NH3 is very toxic and a little higher uncertainty to the high end have been added.

For LH2 and CH2 high uncertainty is added, especially to future values as major improvements are expected (see section *Research and development perspectives*) but unsure.

Quantitative description

See separate Excel file for Data sheet

133 Transport by ship

Brief technology description

		
NH_3	LNG	LH2 (future)

Ship and tank types

For ship transport, only liquid transport exist, most likely because they are not economically favourable due to low volumetric energy density and requirement to very high vessel vall thickness. Thus, only moderate pressure levels (<20 bar) exist, i.e. it is not possible to transport H_2 and NG as compressed gases. However, there exist development projects that look at marine transport of CNG [ref. 11] and marine transport of LH2 [ref. 25].

Liquid/gas transporting ships can be divided into the following types:

Fluid	Tank types (fluid phase)	T, °C	P, barg	Tank Class	Capacity (typical), m3	Ships today	CAPEX M€
LHC	Oil tankers (LHC)	Amb.	Atm.	Integral	3,000-120,000	800	31[37] (50,000 m^3)
LPG DME NH_3[38]	Full refrigerated (refrigerated liquefied gas)	-48	Atm.	A	15,000-200,000	Almost 300	79[39] (80,000 m^3)
	Semi-refrigerated (refrigerated + comp. liquefied gas)	-10	4-17	C	6,000-12,000		
	Pressurized (compressed liquefied gas)	Amb	≥17[40]	C	1,000-3,000	300	
LNG	Cryogenic cooling	-165	Atm.	A, B, M	40,000 – 135,000	500	155[41] (145,000 m^3)
LH2[42]	Cryogenic cooling	-253	Atm.	?	1,250	1 (expected in end of 2020)	

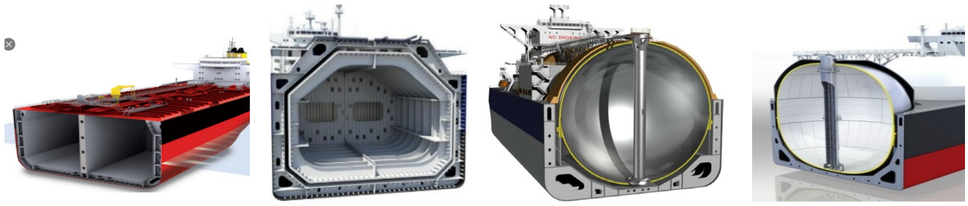
Table 39: Different types of tankers for liquid/gas transport

The tanks can be either integral part of the ship structure or an independent self-supported tank. The independent tanks can be divided into:

1. Class A tanks – prismatic free-standing tanks: Pd< 700 mbar g.
2. Class B tanks – spherical shape: Pd< 700 mbar g.
3. Class C tanks – cylindrical or bilobe shape: Pd> 2 bar g

[37] BRS group annual review 2019
[38] Other fluids that can be transported via LPG tankers: Ethylene (full and semi refrigerated), Propane, Butane and Propylene.
[39] https://www.seatrade-maritime.com/tankers/euronav-buys-another-scrubber-fitted-resale-vlcc-newbuild
[40] Correspond to vapor pressure of LPG at ~45°C.
[41] Danish Ship Finance, Shipping market review 2019
[42] https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487

4. Membrane tanks (M)



Integral tank Class A: prismatic Class B: spherical Class C: cylindrical

Figure 30: Different tank classes. The most cost-efficient onboard storage of ammonia seems to be class C (pressurized tanks) (Topsoe, 2020).

Max size of ships are given by the following classes:

Max size class	Max Length m	Max Beam m	Max Draft m	Max dead weight ton (DWT)	Application/info
Coastal Tanker	205 m	29 m	16 m	50,000	mainly used for transportation of refined products
Aframax	245 m	34 m	20 m	80,000	AFRA (Average Freight Rate Assessment
Suezmax	285 m	45 m	23 m	125,000-180,000	Originally the max. capacity of the Suez Canal.
Very large crude carrier (VLCC)	330 m	55 m	28 m	320,000	Oil tankers
Ultra large crude carrier (ULCC)	415 m	63 m	35 m	550,000	Oil tankers

Table 40: Tanker size classes

Reliquification onboard

The semi-pressurized and fully refrigerated carriers can be provided with reliquification which re-liquify any boil-off produced during loading and operation and return it to the tanks.

Input

Input is the fluid to be transported and the fuel used to sail the ship.

Fuel to be transported:
The terminal will consist of storage tanks with capacity typically 120-150% of the ship's capacity. Loading system will normally be designed for ~10h loading. Fuel is typically loaded with loading arms or flexible hoses.

If refrigerated/cryogenic liquefied fluid, the loading system/tanks must either be precooled or loaded slow (see section *Loading/unloading*). Any generated vapor must be re-liquefied (require specific re-liquefied system) or vented (boil-off).

Fuel used to drive the ship:
Fuel consumption for propulsion is described in *Energy losses*.

Output

The output is the fluid that have been transported. Normally it will be the same input. Exception is boil-off (see section *Energy losses*).

As all ship transport is transporting liquid fuels, unloading will be via pump. The tank pressure will fall as liquid is removed. If the unloading rate is high there may be insufficient boil-off to maintain positive pressure in the tank, and blanketing gas must be added to prevent a vacuum.

Efficiency and losses

Energy losses during the transportation with ship include fuel consumption, both to the actual transport as well as the transport back of an empty truck, and boil off (see *Energy losses*).

Application potential

Ships will be applicable for point to point transportation.

Ship transportation requires a certain minimum volume and distance to be economically favorable compared to the alternatives (pipeline and road transport).

Typical capacities

Typical capacities of ships are given in Table 41.

Fluid	Net Ship		Pd	Td
	Mass, tons	Energy, GW	barg	°C
LH2	10.000*	345	Ambient	-253
NH_3	45.000	240	Ambient	-48
DME	45.000	366	Ambient	-48
Toluene	45.000	508	Ambient	Ambient

Table 41: Typical capacities of tankers for liquid/gas transport. * No liquid H_2 carriers are developed, so the numbers are based on an LNG carrier.

Environmental

The environmental impact of ship transport is mainly due to the emissions from the ship doing propulsion.

Maritime transport account to 2-3 % of the total global CO2 emission.

The IMO's (International Maritime Organization) Marine Environment Protection Committee (MEPC) have introduced the following to measures to reduce and control the GHG emission from ships:

1. The Energy Efficiency Design Index (EEDI) which set minimum energy efficiency performance levels for new ships
2. The Ship Energy Efficiency Plan (SEEMP) which set rules for improvement of energy efficiency of both new and existing ships

Additionally, MEOC have adopted GHG emission goals of 50% reduction by 2050 compared to 2008. Finally, several initiatives are under way for environmental classifications of ships.[43]

Other environmental challenges

1. Ship recycling
2. Ballast water management
3. Hull fouling
4. Waste management

Research and development perspectives

Liquid carriers are a proven commercial technology except for LH2. For LH2 TRL=5 while for the other it is 9.

Reduce GHG emission: Completely carbon-free NH_3 fueling engines are under development and is expected to be ready in 2023-24. Today, it is prohibited to use toxic products, i.e. ammonia, as fuels for ships, thus, amendment to the International code for safety for ships is required.

Much research is conducted in reducing fuel consumption by for example reducing the hull resistance by air lubrication, new designs of the bulbous bow, new hull coatings and improving propulsion.

Developing LH2 technology for transport of liquid hydrogen by ship.

Prediction of performance and costs

Investment cost (CAPEX)

Based on the cost examples given in Figure 31 the red approximation seems valid for L20 fuels (LPG, DME, NH3 (and CO2)).

$$CAPEX = 4000 - 0.05 * M_{cargo}$$

Where M_{cargo} is the weight of the fuel transported. CAPEX for LHC is based value are listed in Table 39 (equal to the green point in Figure 31). For LH2, an obtained cost for LNG is used Table 39 as no LH2 ships are constructed yet. LH2 ship is expected to be slightly more expensive than LNG ships as more extreme cooling is needed, i.e. more insulation is expected to minimize heat interaction with surrounding. Alternatively, more boil off loss will exist.

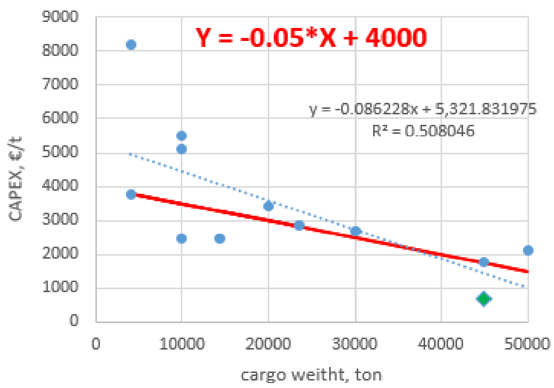


Figure 31: CAPEX of L20 ships (including CO2 carrying ships) vs cargo weight from various obtained examples (green point is price for diesel tanker which is cheaper as no pressure or refrigerated vessels)

[43] Environmental Classifications of Ships, Miljøstyrelsen 2014.

Fixed O&M

Crew wages, maintenance, administration, tax and insurance, canal dues, tugs, pilotage (normal initial value is ~5% of CAPEX[44]).

Port cost

Port cost have been estimated based on 2 days duration in port in both end and tariff for Port of Rotterdam (expensive end) have been applied.

Energy demand

Fuel consumption is estimated using Equation 1 (see *Energy losses*). The following three cases are listed in the datasheet:

1. LHC: 50000 m3 MR2 tanker with a cargo fuel weight of ~45,000 t.
2. L20: 80000 m3 VLGC tanker with a cargo fuel weight of ~45,000 t.
3. LH2: 145000 m2 LNG tanker with a cargo LH2 fuel weight of ~10,000 t.

Uncertainty

The uncertainty related to the costs for transporting hydrogen are substantial, since hydrogen carriers has not yet been built and the cost therefore is based on cost for LNG.

Quantitative description

See separate Excel file for Data sheet

[44] Shipping CO2 – UK Cost Estimation Study, November 2018

References

1 AL. (2005). *Questions and Issues on Hydrogen PipeLine*. Retrieved from https://www.energy.gov/sites/prod/files/2014/03/f10/hpwgw_questissues_campbell.pdf

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