# Global Energy Perspectives

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Global Energy Solutions e.V.

**Part 1: Basic elements for avoiding greenhouse gases and generating climate-neutral energy (technical toolbox)**

Chapter 2-14

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# 2.14 Energy transport infrastructure

## 2.14.1 Abstract

Energy can be transported in different forms. Whether via electrons and thus via the electricity grid or in molecular form and thus in pipelines or tanker ships. In any case, infrastructures are needed to bring the energy from the point of generation to the point of consumption. The type of infrastructure used depends heavily on local, national or regional circumstances, such as the structure of the energy consumers, the distance of energy transport, the existence of energy (transport) infrastructure, end-use technologies, etc.

The expansion of the electricity grid infrastructure is a priority task in many developing and emerging countries in order to supply consumers with the safe, clean and versatile energy source electricity. In a climate-neutral energy system, a higher share of final energy consumption will be covered by electricity, as the efficiency of electricity-based consumers is higher than that of consumers based on combustion processes in most applications. However, not all consumers will be electrifiable and molecule-based energy carriers are advantageous for transporting energy over long distances and storing it, especially over longer periods of time. Therefore, even in a climate-neutral energy system, energy will be transported and consumed in the form of molecules.

Energy carriers in the form of molecules become particularly relevant for transregional and intercontinental transport. This allows the connection of regions with low-cost renewable energy production with regions of the world with high energy consumption or less potential for renewable energy. The production and transport of hydrogen and its derivatives is given special priority. The transport options for hydrogen are subject to different technical and economic constraints, especially regarding transport distance, project size/transport volume, existing infrastructure and subsequent use. Up to a distance of about 4,000 km, gaseous transport via pipelines is more economical than via liquefied hydrogen derivatives by sea. For distances over 4,000 km, the transport of hydrogen bound in ammonia or methanol via ships becomes economically viable.

However, there is no clear favourite for transporting energy in molecular form over long distances. Depending on the conditions in the exporting and importing country and the intended use of the energy carrier, different transport modalities are likely to develop.

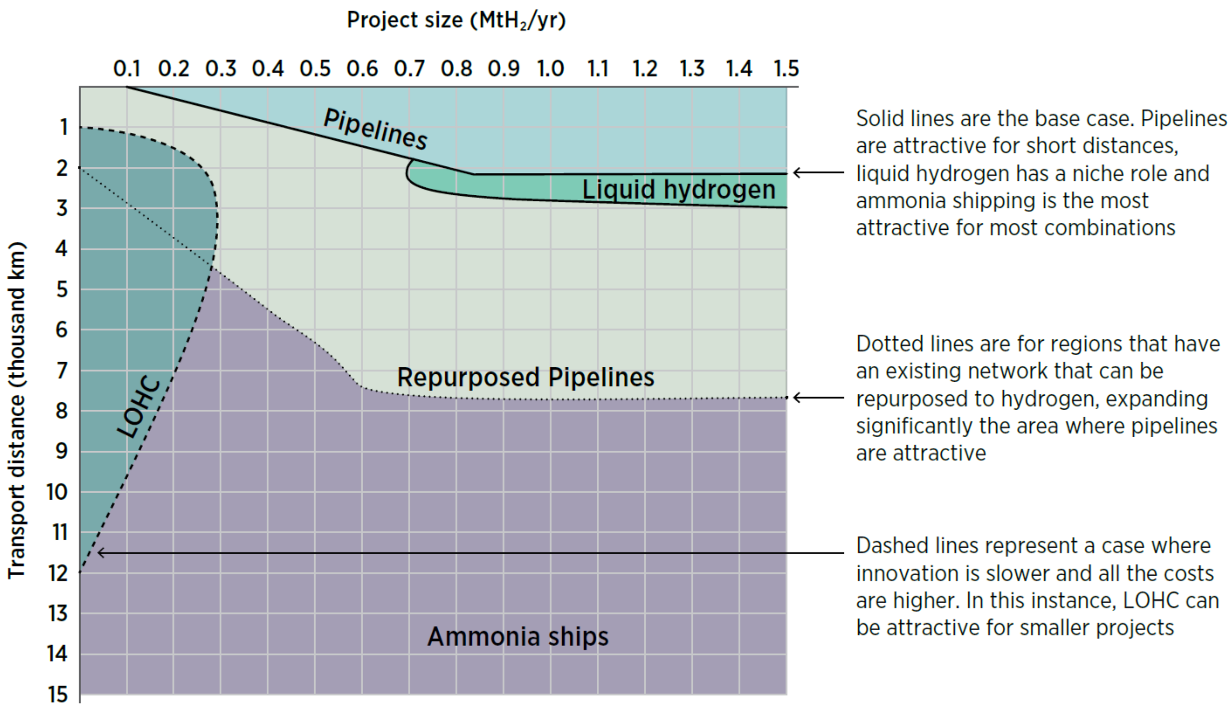


*Figure 277: Cost-effective hydrogen transport routes in 2050 depending on distance and project and transport volume.* [768]

*Source: IRENA, 2022a.*

Energy transport infrastructures need to be scaled up considerably for a climate-neutral energy system. Should the international trade and transport of climate-neutral molecules become established on a large scale and should the injection of $CO_2$ also develop as an important component of a climate-neutral energy system, the existing transport infrastructure will have to be scaled up many times over its current capacities. The transport of $CO_2$ is added to the energy sources in such an energy system. The conversion of existing transport and storage infrastructures for natural gas also plays an important role on the path to a climate-neutral energy system, as it can significantly reduce transformation costs.

[768] This IRENA study excludes methanol and other carbon-based hydrogen carriers, as only sustainably produced $CO_2$ (biogenic or directly from the air) can be considered renewable. According to IRENA, the cost advantages of transporting hydrogen via carbon-containing carriers do not outweigh this disadvantage. If climate-neutral production and use of methanol were possible, however, the intercontinental transport of methanol via existing infrastructures, especially along the lines of the transport of liquid chemicals and oil, would be comparably attractive as via ammonia.

*Table 63: Scaling of energy infrastructures and important boundary conditions*

| Energy transport infrastructure | Necessary scaling | Boundary conditions |
|---|---|---|
| **Power grid** | Factor 2-5 | Construction and expansion generally necessary in emerging and developing countries, depending on the degree of electrification and region |
| **Gas network and storage** | Not clear, especially retrofitting of existing infrastructure | Depending on national conditions and degree of electrification, possible further use for climate-neutral energy sources after conversion |
| **Liquid hydrogen** | Complete structure | Strongly dependent on application and cost development of other hydrogen derivatives |
| **LOHCs** | Complete structure | Strongly dependent on application and cost development of other hydrogen derivatives |
| **Ammonia** | Factor 50 | Experience and applications exist, depending on cost development of other hydrogen derivatives |
| **Methanol** | Factor 50 | Experience and applications exist, depending on cost development of other hydrogen derivatives |
| **$CO_2$ for CCS** | Factor 150 | Strong regional differences in CO production and capture potential, strongly dependent on costs and local acceptance |

To build a climate-neutral energy system, annual investments in the energy sector need to double to triple to between three and six billion USD compared to today. The investment required for energy transport infrastructure for a climate-neutral energy system accounts for about 30 % of total investments in many models and scenarios. The withdrawal and *redirection of* capital that today goes into the extraction of fossil fuels is essential and can cover about 20 % of the total financing needs.

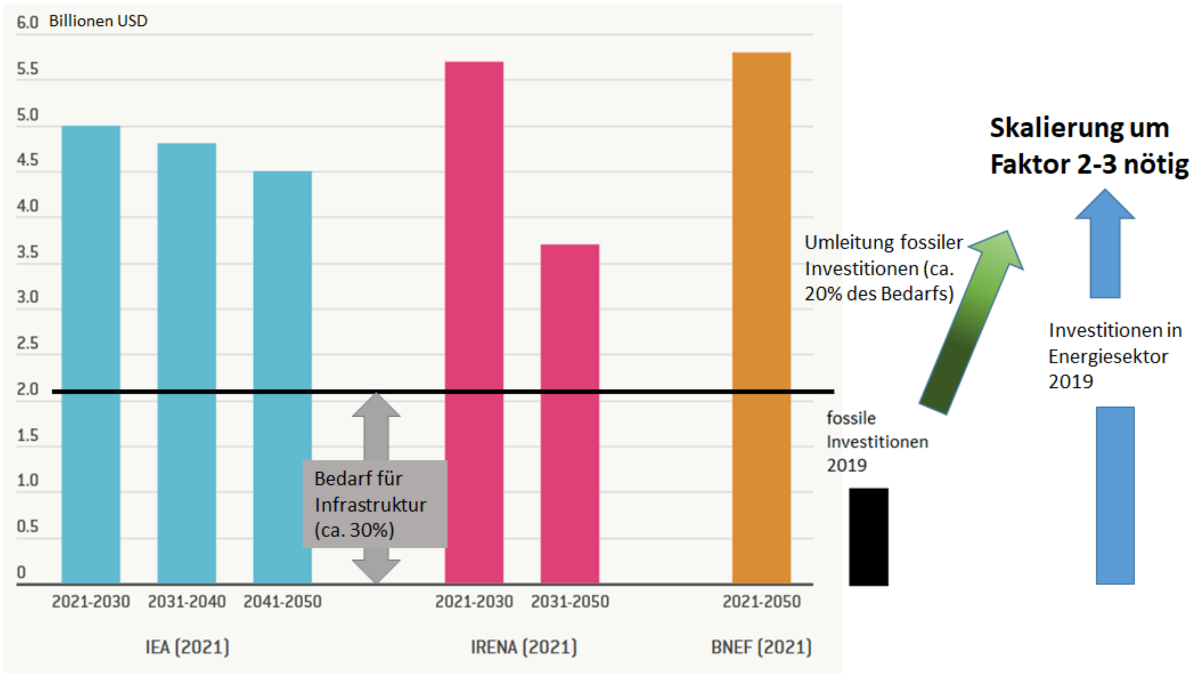


*Figure 278: Annual global investment required for a climate-neutral energy system (adapted by author).*

*Source: Bruegel, (2021).*

The successful implementation of financing requires the increased involvement of private capital from the institutional investor sector as well as the improvement of financing conditions through multilateral development banks and special financing facilities. State-owned enterprises (SOEs) in the energy sector are important actors in the implementation of energy transport infrastructure projects. The activities of SOEs must be given greater attention in the course of the transformation of the global energy system and need to be aligned with the goal of climate neutrality.

### 2.14.2 Introduction and relevance

Energy is not necessarily produced where it is needed. Therefore, infrastructure is an essential element of any energy system to transport energy in a suitable form over sometimes long distances and distribute it to the end users. In our current fossil energy system, the main energy sources are coal, gas and oil. These are extracted from their sources, e.g. the oil and gas fields, and transported to where they are to be used. This is done in their pure form, e.g. in gas heaters, or in the form of intermediate products: Oil is turned into petrol or diesel, which can also be transported to the end user.

In addition, electricity is produced from fossil fuels, which is then transported and distributed. Mostly, however, it is not electricity but coal or gas that is transported over longer distances (inter-continental), as this results in less energy loss and thus lower costs in the current system.

In order to switch to a climate-neutral energy system, large shares of fossil energy sources are gradually being replaced by renewable energies such as solar and wind power. Since these energy sources are not automatically available where the currently predominant energy sources are in the form of oil, gas and coal deposits, transport must be organised via partly different routes. In addition to transport, renewable energy sources are not always available in sufficient quantities when energy is needed. This problem of volatility can be reduced, but not eliminated, by choosing a suitable location (more and more constant wind or sun hours) for the production of renewable energy sources.

These challenges have to be met against the background that a large part of the final energy users will not or cannot relocate to the new renewable energy generation sources. In addition, there are other large energy users. This is particularly the case in the global south, especially on the African continent and the Indian subcontinent, due to the development of greater economic output, the desired increase in living standards and the continuing population growth.

The organisation of energy transport in a climate-neutral energy system is also a challenge because renewable energies have so far been fed in and used primarily in the form of electrical energy and not in the form of molecules. Existing infrastructure must therefore be adapted to these new conditions, especially the greater focus on electricity. New infrastructure to be built must be thought of differently from the outset than the existing infrastructure, which is primarily based on the feed-in of molecules. In this context, the storage of energy has an important role to play, as previous fossil energy sources are in some ways also storage facilities. The storage of electricity in large quantities (which can also mean its conversion into molecule-based energy carriers) in order to be able to react to the variability in energy use is another challenge that must be solved in the context of a climate-neutral energy system.

In this chapter, individual building blocks for a reference scenario for a climate-neutral energy system are discussed, suitably combined with each other and related to the fields of application of individual industrial and economic sectors.

Infrastructure development for the transport and distribution of energy, but also of $CO_2$, which is intercepted via CCUS, faces two challenges in this context: On the one hand, energy demand will increase in the wake of growing prosperity, especially in low- and middle-income countries, which already requires the expansion, and in many cases even the construction, of suitable infrastructure. On the other hand, high-income countries will have to rebuild their infrastructure to meet the requirements of climate neutrality. Construction and reconstruction are of course associated with costs, but they also pose organisational challenges, because a high degree of cooperation between countries is required to ensure cost efficiency and sufficient supply at the same time, such as the European electricity and gas grids). The annual investment costs in the Net Zero scenario of the International Energy Agency (IEA) are shown in Figure 279.

Infrastructure also competes for land that could otherwise be used, for example, for new settlements, primarily in regions of high population density. As new transport routes are needed in addition to the existing infrastructure, but also other forms of transport, conflicts of interest are to be expected with parties who feel adversely affected by the new infrastructure because a new power line or pipeline for hydrogen should ideally run over or in the immediate vicinity of their property.

Since the great global potentials for solar and wind energy lie in countries of the global South, but significant demand for energy will continue to exist in the already very rich countries, the development of suitable global transport routes for energy can be a good starting point for wealth creation in the global South. Similar to countries that have abundant oil and gas reserves, sun- and wind-rich countries can leverage far-reaching wealth potential through the local use of these energy sources, but also through the transport of energy to the currently rich and thus solvent countries.

There is great potential for international cooperation in this field, as the leading technologies continue to lie with the countries of the Global North.

Furthermore, global (energy) infrastructure, as well as the rest of the infrastructure, is vulnerable to the physical impacts of climate change. In this context, the International Energy Agency (IEA) estimates that a quarter of the world's electricity transport and distribution routes will be affected by cyclones, so infrastructure as a whole needs to be built more resiliently to withstand such conditions. [769]

[769] Cf. IEA, 2021e.

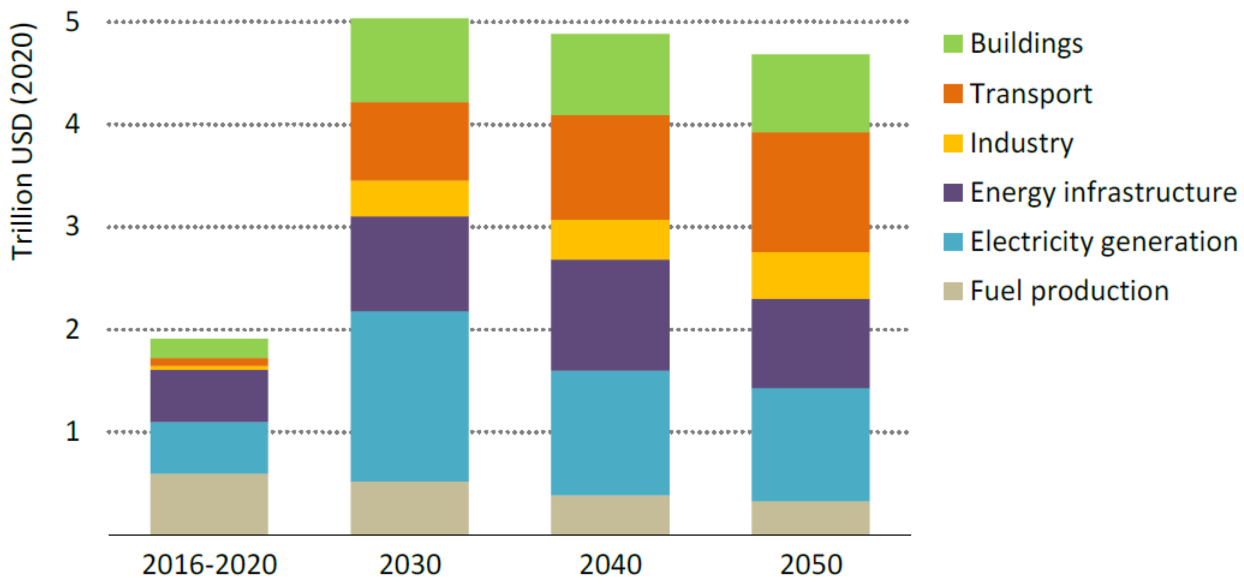




*Figure 279: Average global annual energy investment required by sector and technology for the NZE scenario.*

*Source: IEA, 2021e.*

### 2.14.3 Electricity: stocktaking and perspectives

*"Electricity networks are the foundation of reliable and affordable electricity systems, making them critical infrastructure in all modern economies."*[770]

Electrical energy plays a greater role in a climate-neutral energy system than it does in the currently prevailing fossil energy system. This is because renewable energy is primarily generated as electrical energy from hydropower, sun or wind. Energy from hydropower, sun and wind must primarily be generated where it occurs and cannot be transported as such. Exceptions exist in the case of hydropower, whose place of use can be influenced geographically to some extent by large-scale infrastructure measures. This is different from fossil energy, which can be extracted as coal, gas or oil and then transported as such. An exceptional role is played by energy from biomass, which can certainly be transported before it is used for energy, but which can only be used to a limited extent as a substitute for fossil energy sources, for example in industrial processes. A climate-neutral energy system must therefore be able to deal with energy in the form of electricity to a much greater extent. This applies above all to the transport, distribution and storage of electricity as central tasks of an infrastructure.

In the debate on the transformation of the energy system towards renewable energy sources, energy generation is very often the main focus of discussion. However, it is absolutely

[770] IEA, 2021e, p. 207.

necessary to think about the corresponding infrastructure as well, which becomes clear with an example from India: Although the potential for offshore wind energy is estimated at 10-20 GW, it is currently not being realised. This is due to the high capital costs as well as the fact that the country's lack of electricity infrastructure is the bottleneck.[771] It is therefore important to understand not only the value of the energy itself, but also the value of the overall system to provide this energy when it is needed.[772] Therefore, the storage of energy is of great importance, because in every country there are peaks and troughs in the demand for energy that need to be matched with peaks and troughs in the supply of energy. This is the value of a total system mentioned above, which goes beyond the value of the energy itself. In a system where the share of electrical energy is higher or increasing, the problem must be solved that electricity is not as easy to store as energy in the form of molecules. Currently, gas storage facilities in colder countries such as those in Central and Northern Europe take on the task of meeting the high demand for energy during the colder seasons. Flexible gas-fired power plants serve the peak demand in the electricity sector.

#### 2.14.3.1 Inventory of electricity infrastructure

Worldwide, there are about 4.7 million km of transmission grids and 96 million km of distribution grids for electrical energy. The voltages of the transmission networks range from 100 kV to over 750 kV. Most of the lines consist of overground power lines. While transmission grids are used to transport electrical energy over longer distances, distribution grids are responsible for regional transport to consumers. These have voltages ranging from less than 100 kV to less than 1 kV at the lowest level. Depending on the region, the kilometre lengths of the available voltage levels vary, with the majority of lines transporting electricity at voltages up to 400 kV (Figure 280). Transformers are needed to switch between the individual voltage levels. These have a total capacity of about 40,600 gigavolt-amperes (GVA) worldwide.[773] Currently, about 100 billion US$ are invested in the transmission grids and about 200 billion US$ in the distribution grids worldwide every year. [774]

A higher level of prosperity is generally accompanied by increased material consumption for the electrical infrastructure.[775] Factors influencing the design of electricity grids are the area of the states, the topography, the population density, the distribution of energy resources over the land area, but also the way in which a state is populated: are there more urban centres, is the land area more evenly populated or is parts of it not populated at all?

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[771] Cf. IEA, 2021e, p. 39.
[772] Cf. IEA, 2021e, p. 71.
[773] Cf. Kalt et al., 2021a.
[774] Cf. Figure 279, S.469
[775] Cf. Kalt et al., 2021b.

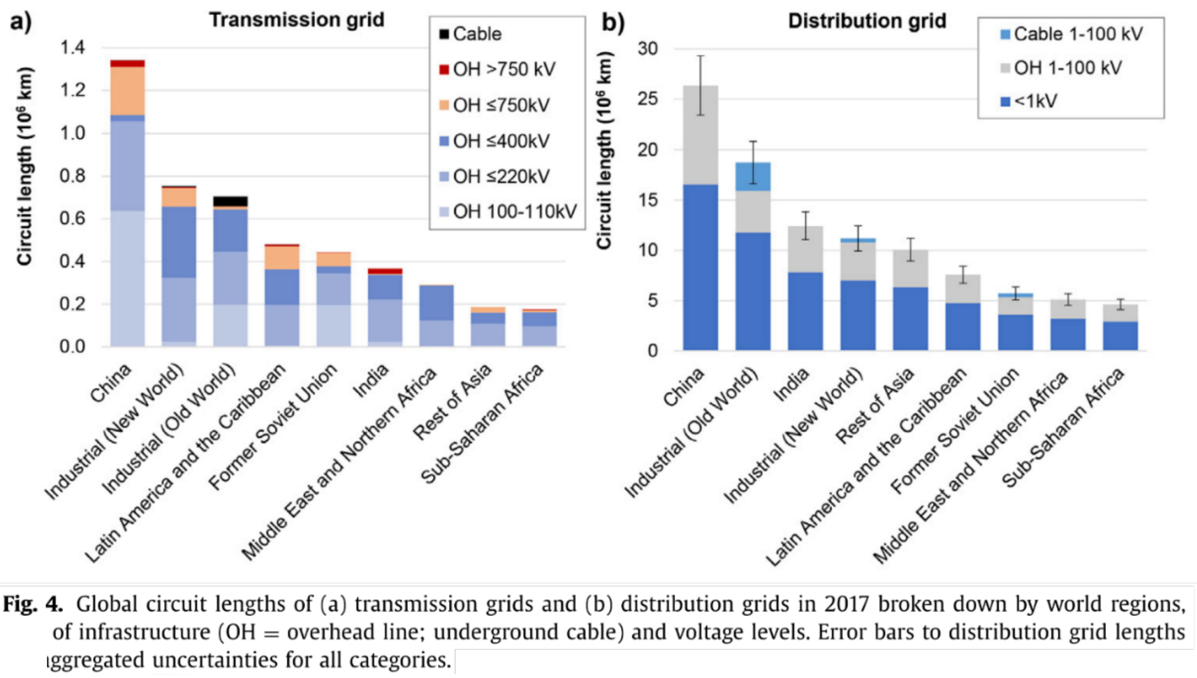



*Figure 280: Lengths of transmission and distribution networks for different regions of the world.*

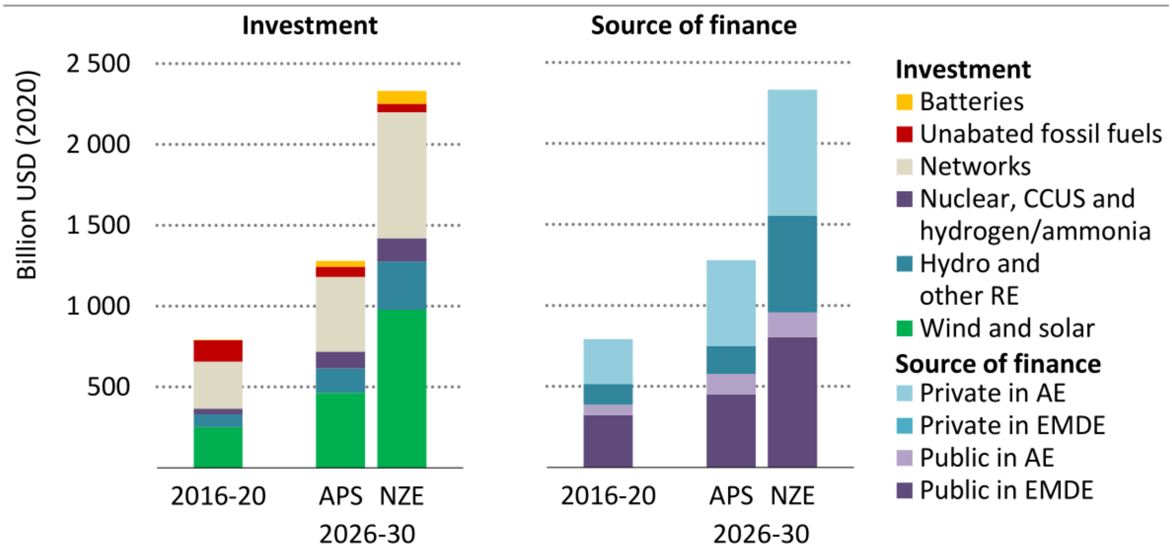
*Source: based on Kalt et al., 2021a.*

### 2.14.3.2 Prospects for the electricity infrastructure

Even though different approaches are being discussed on how the energy system of the future could look like, a significant share of renewable energies will be needed in any case. In general, electricity infrastructure projects are more time-consuming to implement than most renewable energy projects. This is why it is important to think about this area at an early stage in order to prevent electricity infrastructure from becoming the bottleneck of the global energy transition.[776]

Figure 281 shows that, as a rule of thumb, one can assume that about half of the investments that are incurred for electricity production should be budgeted for the necessary electricity infrastructure. Between the years 2016 and 2020, the distribution of investment funds was still roughly equally divided between the private sector and the public sector, both in industrialised countries and in developing/emerging economies. In the IEA's Net Zero scenario, however, the share of private sector investment in developing/threshold countries increases sharply between 2026 and 2030 compared to the industrialised countries. To meet the requirements of the scenario, public investment also increases in developing/threshold countries compared to developed countries (see Figure 280).

[776] Cf. IEA, 2021e, p. 208.






*Investment in renewables and networks increases to fulfil announced pledges, but much more is needed to achieve the net zero emissions pathway, most of it from private capital*

Notes: AE = advanced economies; EMDE = emerging market and developing economies; Other RE = other renewables. Investment values represent annual averages for the indicated time periods.

*Figure 281: Average annual investments by type and source in the energy sector, 2016-2020, and by scenario, 2026-2030.*

*Source: IEA, 2021e, p. 131.*

The IEA's Net-Zero scenario assumes that the length of electricity grids is likely to double by 2040, with a further 25% expansion by 2050. In such a scenario, annual investment would rise from just under US$ 300 billion to US$ 820 billion in 2030, peaking at around US$ 1 trillion in 2040 before falling back to around US$ 800 billion in 2050 (see Figure 282).[777] The IEA assumes that constantly more than 60 % of this investment will be generated by the increasing demand for electricity. A share of about 10-20 % of the investments, which varies over the years, serves the integration of an increasing share of renewable energies into the power grid and the remaining part is accounted for by the renewal of aging components. Increased demand is developing primarily in developing and emerging countries, which is why investments there will be higher than in industrialised countries. Nevertheless, demand is also expected to increase in industrialised countries.

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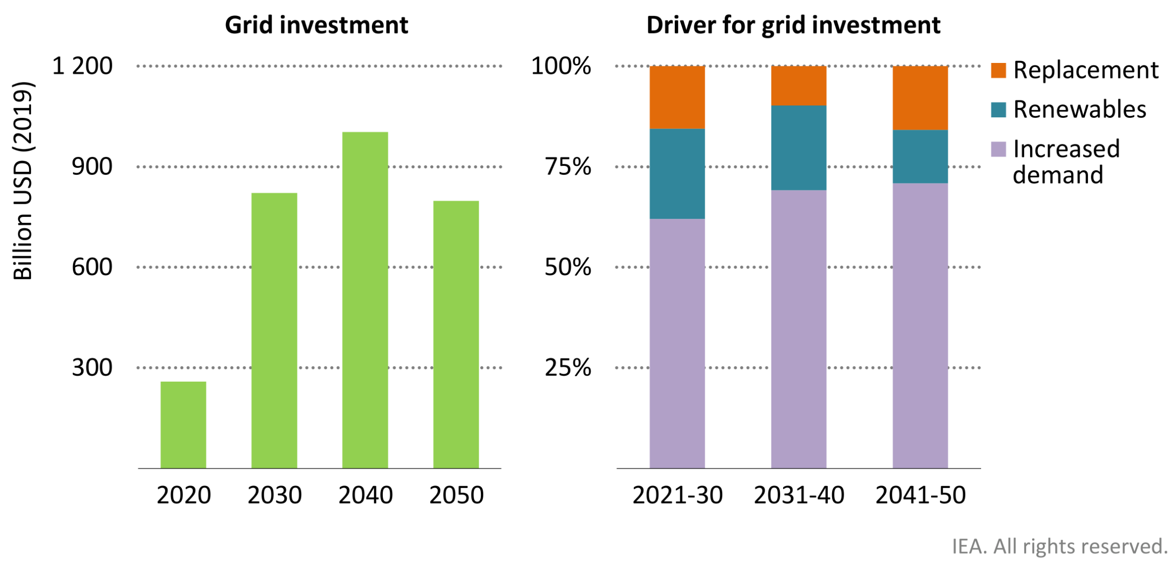
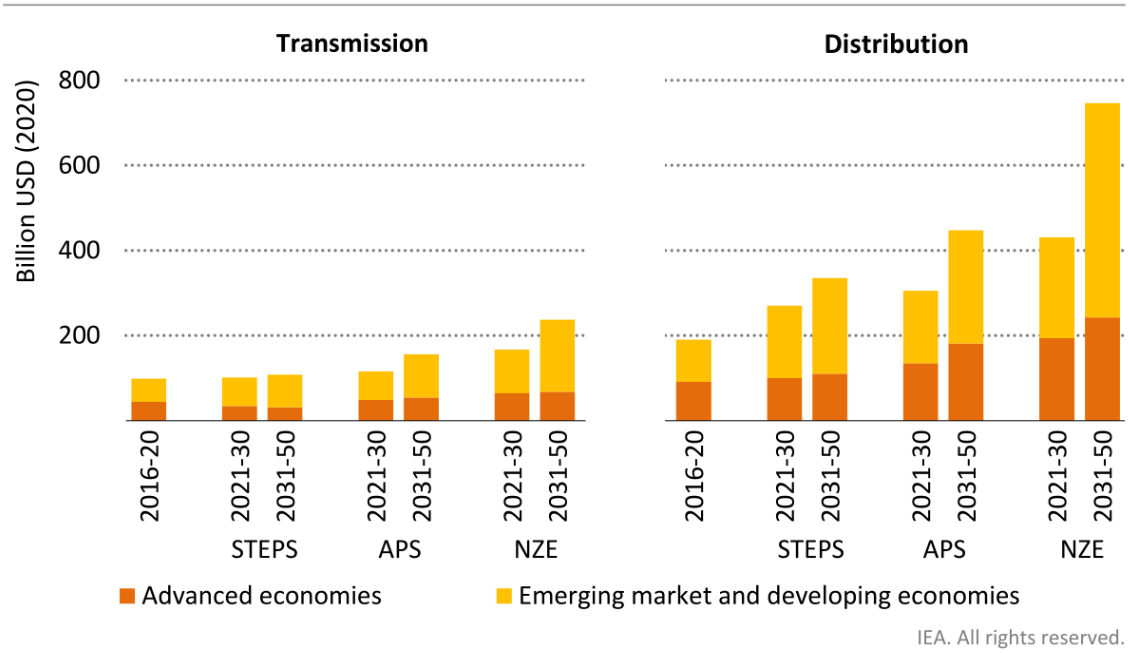



***Electricity network investment triples to 2030 and remains elevated to 2050, meeting new demand, replacing ageing infrastructure and integrating more renewables***

*Figure 282: Global investment in power grids in the Net Zero scenario.*

*Source: Bouckaert et al., 2021, p. 118.*

In the IEA's Net Zero scenario, global investment volumes for the transmission grid are just below US$ 200 billion annually between 2021 - 2030 and increase to just above US$ 200 billion annually between 2031 and 2050 (see Figure 283). One third to one quarter of these volumes are accounted for by industrialised countries, two thirds to three quarters by developing and emerging countries. In the area of distribution grids, the investment volume is significantly higher at around US$ 400 billion (2021 - 2030) and around US$ 750 billion (2031-2050). Here, too, the share is higher in the developing and emerging countries than in the industrialised countries (see Figure 279). Worldwide, about 10 million km of transmission grids and about 200 million km of distribution grids then will be installed in 2050 (about double the current level).




*Grid investment needs to scale up as electricity demand and variable renewables increase, making long-term visions for grids essential for energy transitions*

*Figure 283: Average annual investment in electricity grids by scenario.*

*Source: IEA, 2021e, p. 208.*

A central challenge is the question of how to deal with the fluctuating generation of renewable energies (especially solar and wind). As the share of electricity generation from renewable sources such as wind or solar increases, the demands on the flexibility of the electricity system increase. Traditional electricity systems have a large share of base-load power plants (e.g. nuclear, coal or gas-fired power plants) that run continuously and produce electricity that is constantly purchased. Peaks in demand are covered by connecting more flexible generation sources such as coal-fired (moderately flexible) and gas-fired (very flexible) power plants. Renewable energy sources, on the other hand, feed in electricity when wind or sun is available. This creates peaks and lulls in electricity generation. In addition to the focus on making demand more flexible (not part of this study) and the expansion of storage facilities with different capacities, the electricity system must be organised in such a way that flexibility can also be guaranteed on the generation side. In 2020, the necessary flexibility of the electricity grid in industrialised countries was provided to about 30 % by coal-fired power plants, to about 20 % by gas-fired power plants, to just under 30 % by hydropower and to a small extent by oil, and to an even smaller extent by nuclear energy, other new renewables and demand-side management. In developing and emerging countries, the ratios are identical.[778]

For the year 2050 of the IEA's Net Zero Scenario, the situation is correspondingly different (Figure 284): In industrialised countries, demand-side management and battery storage

[778] Cf. Figure 281

provide the largest shares of flexibility, each with just over 25 %. Another new component in the scenario is hydrogen in combination with ammonia and hydropower, each with around 15 %. Since the aim is to achieve almost complete defossilisation, contributions from coal, gas and oil fall to around 5 % in total, with gas accounting for the majority of this. Nuclear and renewables continue to contribute small but increased shares of around 5 % to total flexibility. The picture is similar for developing and emerging countries, with demand management playing a comparatively smaller role here, which is compensated for by hydrogen and ammonia as well as hydropower.

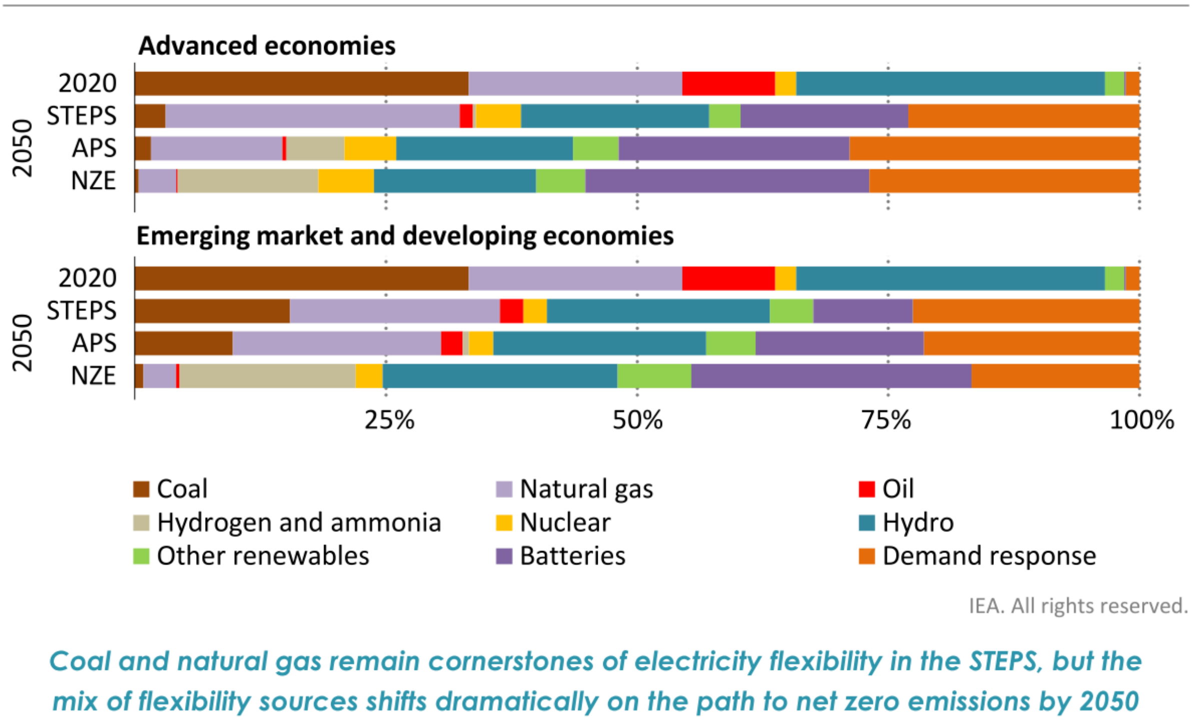



*Figure 284: Flexibility of the electricity system depending on source and by scenario 2020 and 2050.*

*Source: IEA, 2021e, p. 206.*

Since a climate-neutral energy system must increasingly and ultimately operate predominantly on the basis of renewable energy, the picture turns around: Solar and wind energy are available to the energy system in the form of electricity. However, there are also applications that will be difficult or impossible to electrify in the foreseeable future (e.g. air and sea transport, certain industrial applications), so the question of converting electrical energy into molecular forms of energy arises.

Consequently, the electricity system must be thought out beyond different sectors of energy use and connected through coupling with other energy-consuming sectors: Sector coupling. This includes the provision of heating/cooling for industry but also for heating buildings as well as the transport sector when talking about electric mobility. While a relatively constant amount of energy is used throughout the year in the mobility sector, there are strong regional seasonal fluctuations in the heating/cooling sector: In northern latitudes, a lot of heating must be used in winter, while in areas to the south there is a lot of cooling in summer. At the same time, the available storage options for electricity, such as batteries or water-based pumped storage power plants, are only designed for short periods and not for longer periods such as several weeks, as their storage capacity is too low.

For a study, the countries Sweden, Denmark, Germany, the Czech Republic, the Netherlands, Belgium, Switzerland and France were considered together.[779] The volume of electricity storage comprises a total of about 0.06 TWh compared to a storage volume in the form of gas storage of about 550 TWh, which is larger by a factor of almost 1,000.

The authors conclude that gas storage facilities are also needed to supply the heating/cooling sector on an increasingly electrical basis. Electricity must be converted into gaseous energy carriers such as hydrogen or methane in order to be able to store the energy seasonally. Other studies also support this assessment.[780] Subsequently, it will be investigated whether only the gas storage facilities should be coupled with the electricity grid and the energy transport should take place again via the power lines after the gas has been converted back into electricity, or whether energy should also be transported in gaseous form via the existing gas pipelines and grids and used as such, e.g. in existing gas heating systems. In the individual application case, it can be decided whether hydrogen or methane is to be used. Therefore, a consideration of energy carriers in the form of molecules as well as the necessary infrastructures is also essential and takes place below.

### 2.14.4 Energy in the form of molecules

Our current energy system and many of its infrastructures are based on fossil energy, which is stored as chemical energy within molecules. The physical state of such energy carriers can be solid (coal, methane hydrate/methane ice), liquid (oil) or gaseous (natural gas, methane). Electricity is partly produced from these primary energy carriers. For applications where conversion into electricity is not practical, the gas or solid is used directly (e.g. in cement production) or further processed in non-electric form (e.g. from oil to paraffin, petrol or diesel fuel). Depending on the prevailing environmental conditions (temperature and pressure), the same substance can exist in other aggregate states, so that it is also technically possible to switch between them, e.g. to achieve better conditions for transporting the energy carrier. In addition, chemical-technical processes can be used to convert one energy carrier into another. The best-known example is certainly refineries, which "refine" crude oil into petrol, diesel or paraffin, which is then used in the transport sector, for example.

[779] Cf. frontier economics, 2019, p. 23.
[780] Cf. e.g. e.g. Enervis, 2017; Energy Brainpool, (2017).

Molecule-based energy carriers are important for a renewable energy system because there is already a lot of technical and operational experience in dealing with these substances, as well as the corresponding infrastructure. In addition, molecule-based energy carriers allow a lot of energy to be stored per volume, as the energy density is higher. Energy storage is necessary to bridge phases of high energy consumption or to compensate for fluctuations in energy consumption but also in production. Depending on the application, these phases can range from fractions of a second (e.g. in electronics) to months when it comes to seasonal fluctuations in energy demand, e.g. supplying European households with heat in winter. Even though battery technology is constantly improving, it is not foreseeable that such long periods of high demand can be covered by electricity-based storage. Nevertheless, as a large-scale expansion of renewable generation is an essential element of a climate-neutral energy system, it will be important to couple the electricity infrastructure with that for molecule-based energy sources. This will make it possible to transfer electricity to molecule-based energy carriers for storage purposes and to (re)generate electricity. Among the molecule-based energy carriers, natural gas plays a special role because it produces the lowest greenhouse gas emissions per unit of energy among the fossil energy carriers ($CO_2$ -intensity). In addition, hydrogen, but also methane and ammonia are relevant because these substances can be produced from electrical energy by chemical processes.[781]

In addition to the storage issue, molecule-based energy carriers are often advantageous for energy transport over long distances compared to electricity as an energy carrier. This is particularly the case for intercontinental transport or when only rudimentary electricity grid infrastructure is available. Table 64 presents the transport costs of onshore energy over different modes according to a study for the USA. The high differences for the transmission of electricity over long distances are due to different assumptions for capital costs, line losses and the inclusion of transformers.

However, the conversion losses of gaseous or liquid energy sources are not taken into account here and about four to five times the amount of electricity would have to be generated from renewable energies in order to obtain usable energy in the same amount for final consumption. This in turn has a major impact on the overall costs of energy supply due to higher required renewable generation capacities and land consumption.

[781] Hydrogen via the splitting of water into hydrogen and oxygen (electrolysis), methane via the combination of hydrogen and carbon dioxide and ammonia via the combination of hydrogen and nitrogen.

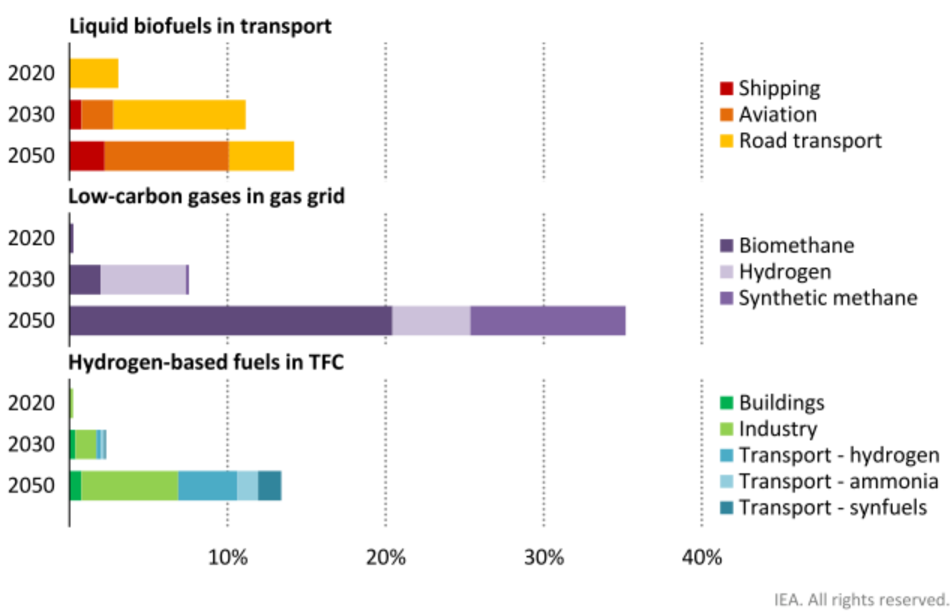
*Table 64: Transport costs for energy by transport mode.*

*Data source: DeSantis, et al., 2021; Saadi et al., (2018).*

| **Transport modes** | **HVDC (high voltage DC)** | | **Liquid (pipeline)** | | | **Gaseous (pipeline)** | |
|---|---|---|---|---|---|---|---|
| **Energy source** | Power | Power | Crude o | Methanol | Ethanol | Natural gas | Hydrogen |
| **Amortised cost in US$/MWh /1000 miles** | 41,5* | 4,4** | 0,8 | 2,2 | 1,7 | 3,7 | 5 |

Furthermore, certain industrial processes require molecule-based energy carriers as raw materials. Steel production, for example, requires a chemical reducing agent to remove the oxygen from the iron ore. Here, the use of natural gas and hydrogen is already being tested and implemented to replace the $CO_2$ -intensive process via coke and coal, which is currently the standard procedure.

Thus, in its Net Zero scenario, the IEA also assumes high quantities and shares of low-$CO_2$ or climate-neutral liquid and gaseous energy sources in 2050 to supply certain applications (see Figure 285).




***Low-emissions fuels in the form of liquid biofuels, biomethane, hydrogen-based fuels help to decarbonise sectors where direct electrification is challenging***

Notes: TFC = total final consumption. Low-carbon gases in the gas grid refers to the blending of biomethane, hydrogen and synthetic methane with natural gas in a gas network for use in buildings, industry, transport and electricity generation. Synfuels refer to synthetic hydrocarbon fuels produced from hydrogen and $CO_2$. Final energy consumption of hydrogen includes, in addition to the final energy consumption of hydrogen, ammonia and synthetic hydrocarbon fuels, the on-site hydrogen production in the industry sector.

*Figure 285: Global supply of low-GHG energy sources per sector in the IEA Net Zero Emissions Scenario*

*Source: IEA, 2021b, p. 106.*

### 2.14.4.1 Hydrogen

**Transport of Natural gas**[782]

Due to its comparatively low $CO_2$ intensity, the increased use of natural gas in many countries represents a bridging technology for the shift towards a climate-neutral energy system. However, for a long time, natural gas was primarily used locally or regionally because its volumetric energy density is about 1,000 times lower than that of crude oil, making transport per unit of energy more complex and expensive. Internationally traded gas accounted for only about one-fifth of the total volume of gas demanded in 2018. In comparison, about half of the oil produced was traded internationally.[783] Regionally, natural gas is mainly transported in gaseous form via pipelines, but in international trade it is also increasingly transported in liquefied form as liquefied natural gas (LNG) by ship (Figure 286). Up to 50 % of the total costs of internationally traded gas (pipeline and LNG) come from the transport chain.[784]

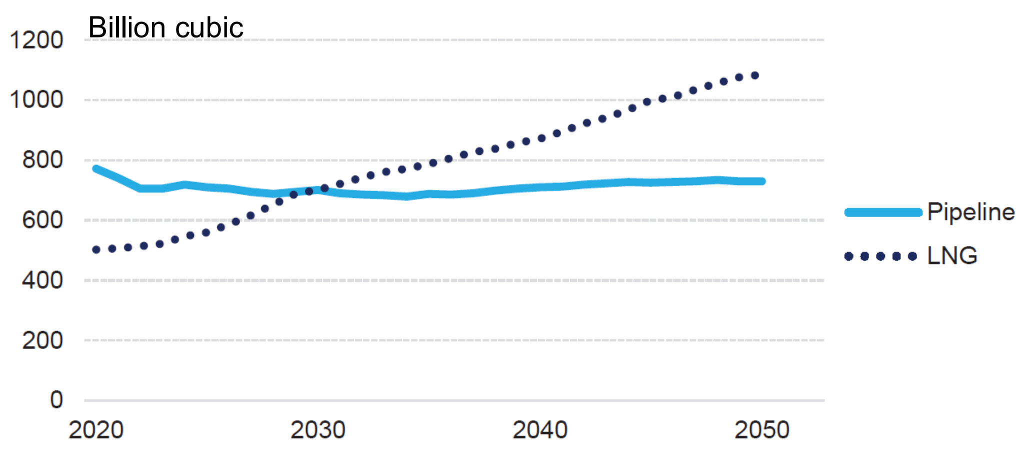



*Figure 286: International natural gas trade by transport route.*

*Source: Gas Exporting Countries Forum, (2022).*

The Global Gas Outlook 2050 of the Gas Exporting Countries Forum predicts a strong increase in international trade in LNG. In terms of internationally traded gas, transport by LNG tanker will overtake transport by pipeline in 2030 and account for as much as 60 % of the volume in 2050. In total, 1,800 Mt or 1,100 bcm of LNG would be shipped in 2050, almost four times the amount shipped in 2021 (see Figure 286). In principle, gas can also be transported as Compressed Natural Gas (CNG) in smaller tanks on trucks or by rail. However, CNG is primarily used to supply local markets where the expansion of corresponding gas networks is not yet far advanced and is not part of this study.

[782] Further information on the transport of methane can be found in chapter 2.12.2, on the transport of hydrogen in chapter 2.5.1 or on the transport of $CO_2$ in chapter 2.8.4.
[783] Cf. Hafner & Luciani, 2022, p. 23.
[784] Cf. Hafner & Luciani, (2022).

**Transport via pipeline**

More than 1,600 major natural gas pipelines with a total length of about 1 million km are in operation worldwide. Another 400 pipeline projects with a length of almost 0.2 million km are currently under construction or in planning (see Figure 287).

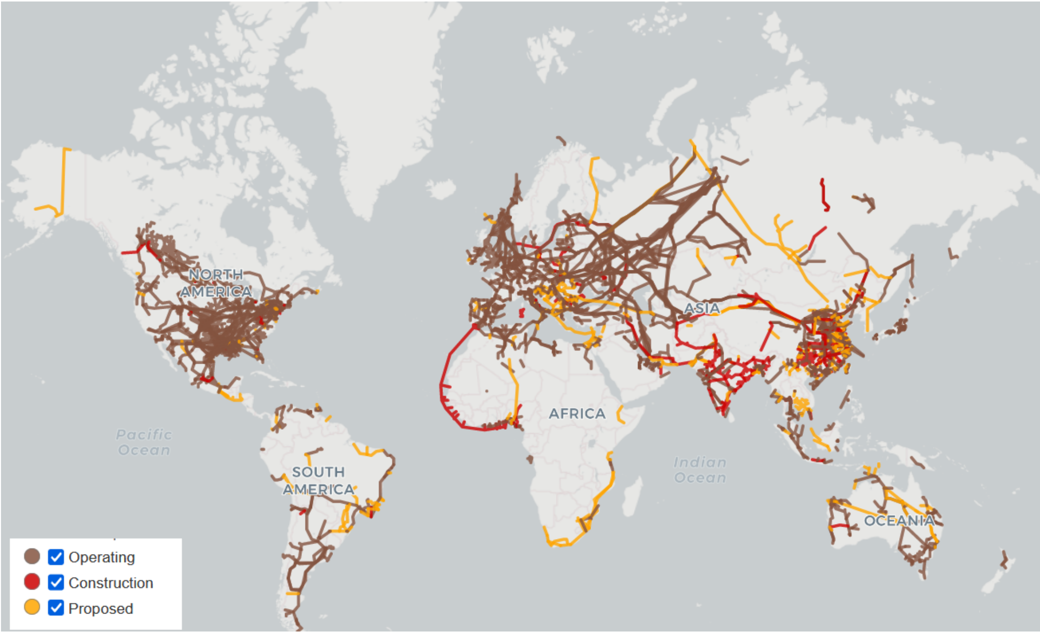



*Figure 287: Global natural gas pipeline infrastructure in 2022.*

*Source: Global Energy Monitor, (2022).*

While the USA has the longest pipeline network, over 60 % of cross-border natural gas pipeline capacity is in Europe, especially for imports from the former states of the Soviet Union and North Africa.[785] A representation of the natural gas pipelines in operation, construction and planning by region is shown in Figure 288.

[785] Cf. snam, (2022).

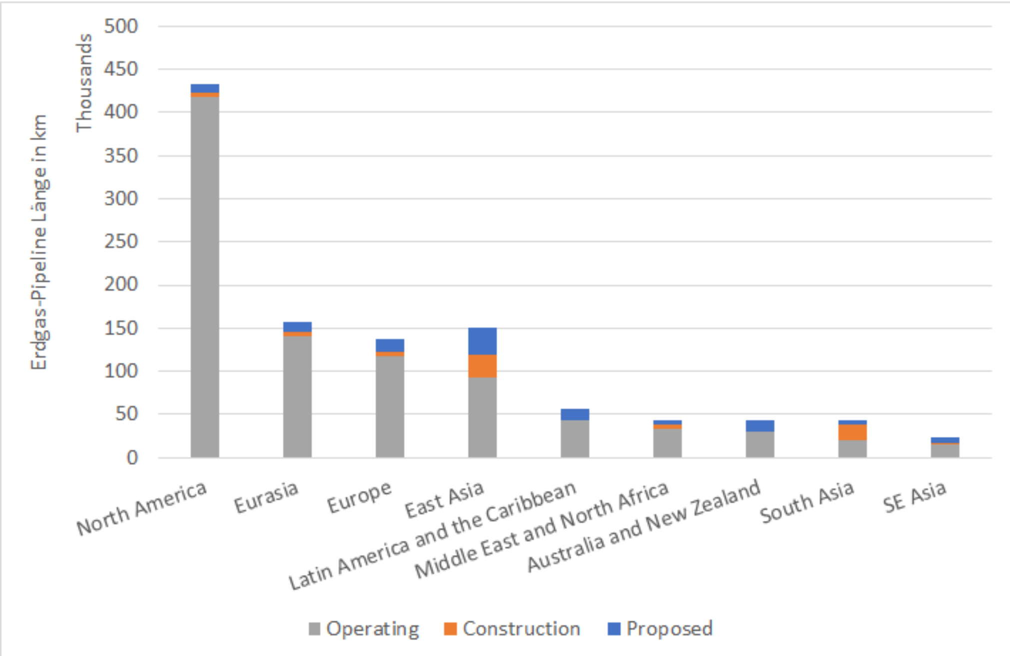



*Figure 288: Length of natural gas pipelines by world region in 2022.*

*Data source: Global Energy Monitor, (2022).*

In the following, some techno-economic key data for the transport of gas via pipelines are summarised. As with the electricity grid, the pipeline network can also be divided into different hierarchical levels. Table 65 gives an overview of the characteristics of the different pipeline types. Together, these form the gas network: from the source of gas to transport over long distances to distribution within cities and provision to the end consumer.

*Table 65: Properties of different pipelines in the gas network.*

*Source: Hafner & Luciani, 2022, p. 26.*

| **Pipeline** | **Use/transport** | **Diameter / cm** | **Pressure / bar** |
|---|---|---|---|
| *Collection* | Source to the treatment plant | 10-30 | Low |
| *Transport* | Over long distances | 40-140 | 15-120 |
| *Distribution* | Within cities | 5 - 65 | < 14 |
| *Supply* | To the end user | < 5 | ~ 5 |

Gas transport is realised via pressure differences within the network. Since the pressure decreases due to friction between the molecules and with the pipeline wall during transport, compressors in the transport pipelines ensure that the pressure is maintained every 100 - 200 km. In addition, there are measuring points to collect data such as flow rate, pressure and temperature and forward them to the network operators who control the transport process.

The costs for a transport pipeline are divided into about 90 % for investments (CAPEX) and about 10 % for operation (OPEX). The typical service life is about 40 years. Key factors influencing the costs are the length, the capacity (which is jointly defined by the diameter and the pressure) and project-specific framework conditions. These include above all the geography and climatic conditions of the transport route, but also legal requirements, e.g. regarding the environmental standards to be met, but also the cost of the necessary approval procedures. The cost fluctuations are therefore very broad.

The majority of the investment costs (CAPEX) for gas pipelines (70-85%) are for the pipeline itself, while 15 - 30% of the investments are for compressor and metering stations. The costs of compressor stations range between 2 - 4 million USD/MW. Transport tariffs for gas pipelines also vary depending on the project and range from 1 to 20 USD/mcm/100 km (see Figure 289).

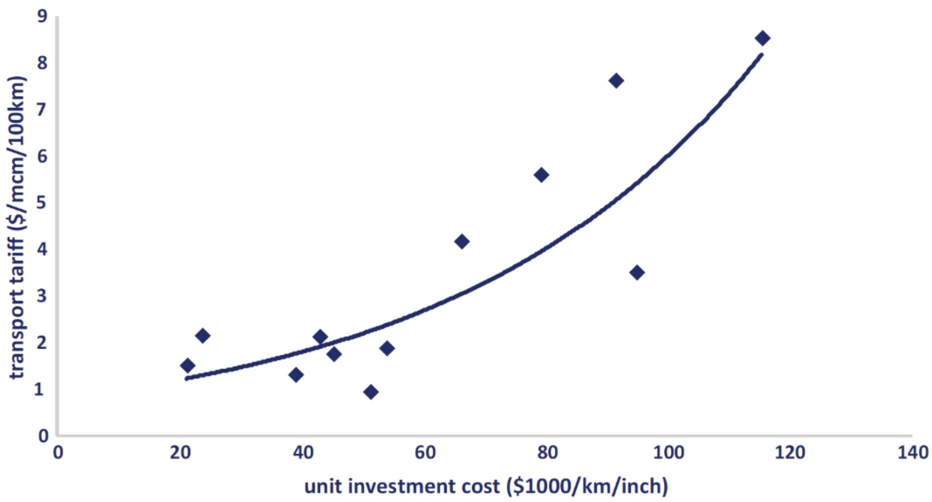



*Figure 289: Investment costs and transport tariffs for major international natural gas pipeline projects (2000-2020).*

*Source: Hafner & Luciani, (2022).*

Figure 290 summarises some factors that increase the difficulty of implementing a pipeline project. An expected cost premium is given as a percentage. Offshore projects in great ocean depths, very hard rock underground, mountainous landscapes as well as routes through urban regions lead to the largest price premiums.

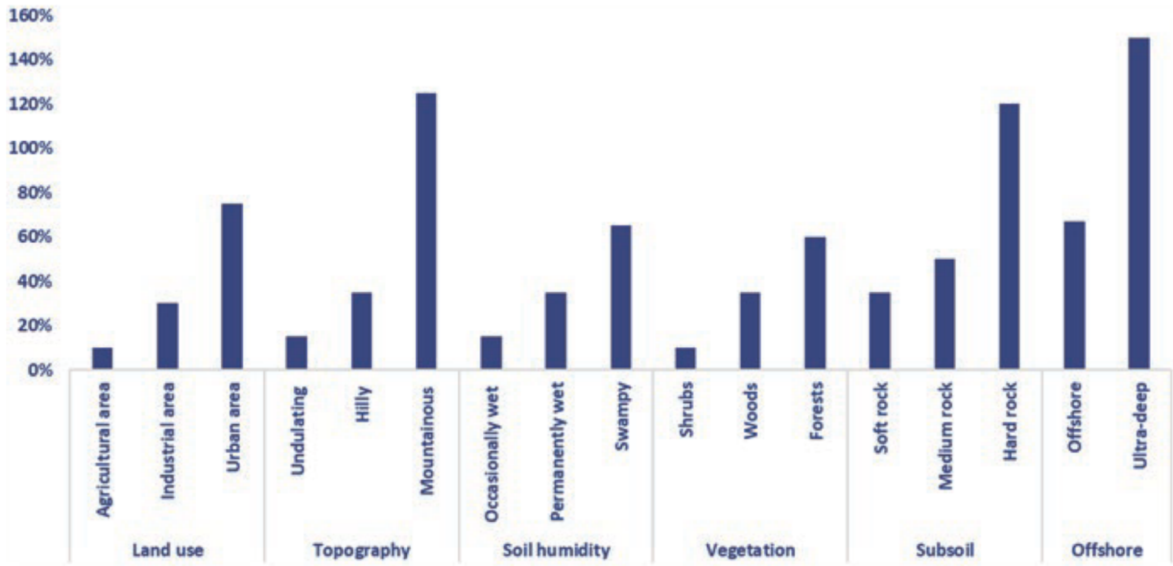



*Figure 290: Factors influencing the cost of a pipeline project and their percentage mark-up.*

*Source: Hafner & Luciani, 2022, p. 29.*

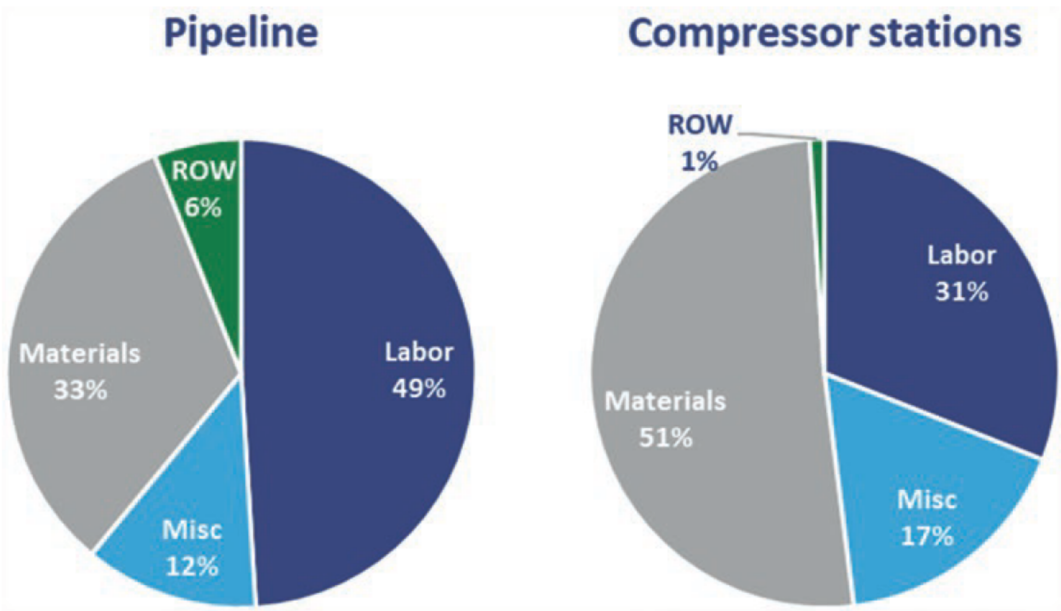



*Figure 291: Proportionate average investment costs for gas transport for the pipeline and compressor stations.*

*Source: Hafner & Luciani, 2022, p. 28.*

Furthermore, it can be stated that the investment costs per transported unit of gas decrease when the pipeline transports larger quantities (economies of scale). Despite large differences in the total costs of individual pipeline projects, individual cost items can be put in relation to each other (see Figure 291).

The most important cost items are personnel (pipeline: 49 %, compressor station: 31 %) and materials (pipeline: 33 %, compressor station: 51 %). Other costs include, for example, project administration, fees incurred, transport of different equipment, etc. ROW means "right-of-way" and refers to costs associated with the use of the necessary area and the occurrence of any damage.

### Transport as Liquified Natural Gas (LNG)

The transport of LNG has already been reported on in chapter 2.12.2.

### Storage for natural gas

Probably the biggest difference between energy infrastructures of electricity and molecules is the better storage capability for gaseous and liquid energy sources. In regions where gas is mainly used to provide heat, considerable storage capacities for natural gas exist. This compensates for the seasonally strongly fluctuating demand, because without gas storage, the transport infrastructures would have to be designed for maximum demand and would only be partially utilised in most hours of a year. In addition, these conditions pose major challenges in terms of grid stability. The use of natural gas storage facilities is more economical than oversized transport capacities for natural gas.

Gas storage facilities are available in above-ground and underground versions. Since above-ground facilities only have a very small volume, they are mainly used for local, short-term balancing of supply and demand. They cannot compensate for fluctuating consumption over a day or even between summer and winter and are therefore not considered further here. In addition to the regasification terminals, LNG storage facilities also exist at the same location to balance landfall, regasification and consumption. Their worldwide capacity amounts to over 70 million cubic metres. This is orders of magnitude below the existing storage capacities of the natural gas infrastructure and is primarily relevant for short-term operations at the import terminals.[786] Underground storage, on the other hand, can be used to compensate for large load peaks and also seasonal fluctuations in consumption. Underground storage of natural gas has been established practice for decades. Basically, a distinction is made between two types of underground storage: cavern storage and pore storage (see Figure 292).

[786] Cf. IGU, 2022b.

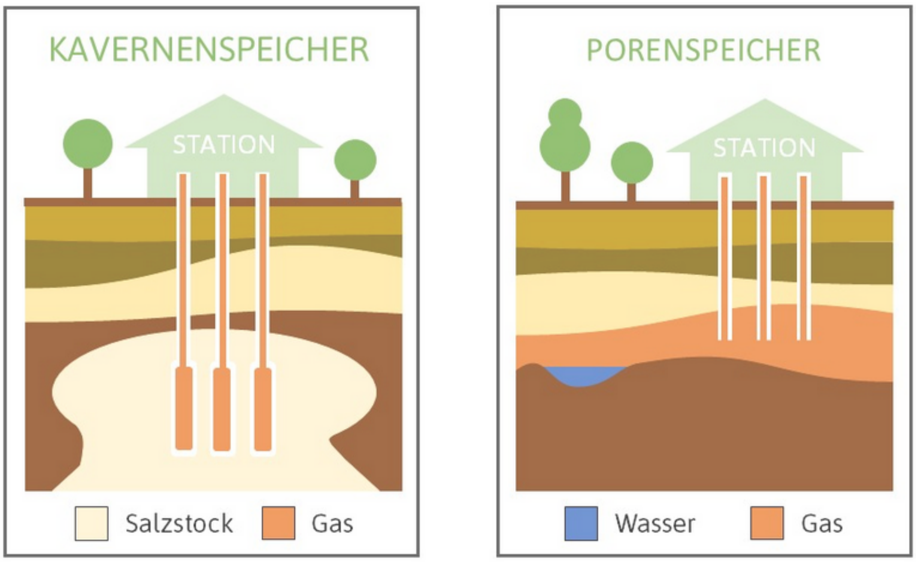



*Figure 292: Schematic comparison of cavern and pore storage.*

*Source: INES, (2022).*

Cavern reservoirs are large (artificially) washed out salt domes with large cavities and can reach volumes of up to 1 million cubic metres. To create an (artificial) salt cavern, boreholes in a layer of salt rock are filled with water and washed out to the required volume. The gas can then be stored underground at pressures of up to 200 bar and, due to the physical-chemical properties of the rock salt caverns, kept underground without additional sealing. In the case of pore storage, on the other hand, the gas is injected into deep water-bearing rock strata (aquifers) or depleted oil and gas deposits. Due to geological conditions, these reservoirs also often have a natural gas-impermeable cover layer that keeps the reservoir sealed.

A significant advantage of salt caverns compared to the use of aquifers or depleted oil and gas fields is the reduced proportion of buffer gas of less than 20 %. This buffer is necessary to maintain the pressure (75 - 200 bar) and thus the stability of the gas storage. Depending on the geological conditions and the design of the gas grid infrastructure, both types of gas storage are used. The storage capacity in Germany, for example, is divided into about 36 % pore storage and 64 % cavern storage. A quarter of Germany's annual natural gas consumption (230 TWh) or about two months of winter consumption can be stored underground.

Worldwide, gas storage capacities are mainly found in countries with large natural gas consumption. About 700 underground storage facilities with a total capacity of more than 470 billion $m^3$ of natural gas (equivalent to about five times the annual consumption of natural gas in Germany) were in operation in 2021. Figure 293 depicts the geographical distribution of underground natural gas storage capacities.

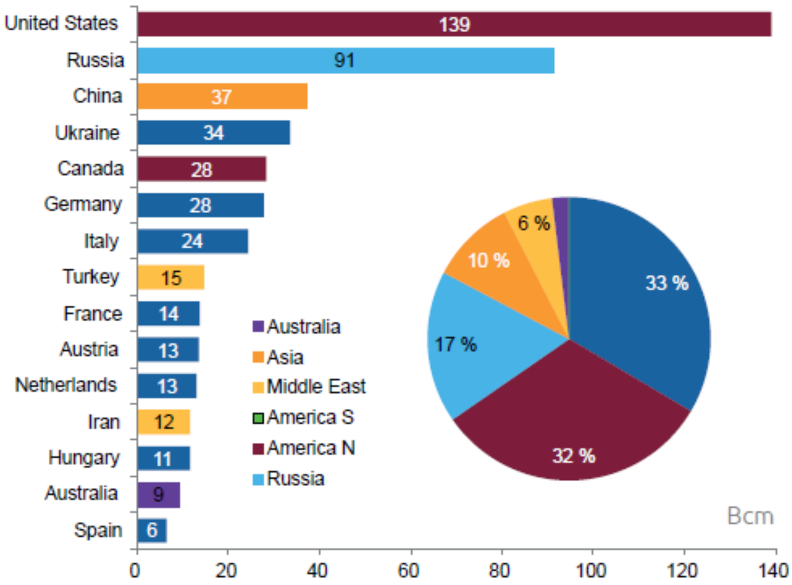



*Figure 293: Underground gas storage capacities of the largest 15 storage nations in billion cubic metres.*

*Source: IGU, 2022a.*

The investment costs for underground gas storage facilities vary greatly depending on type, capacity and geological conditions and ranged from 0.2 to 2.9 EUR/$m^3$ storage capacity in Europe in the years from 2000 to 2014.[787] Extracted storage of oil and gas and aquifers are somewhat less expensive due to geological conditions and partly existing infrastructures.[788]

In summary, there is a large capacity available with the existing gas storage facilities in many industrialised countries. Against the background of progressive electrification of parts of today's natural gas consumption, even less storage capacity may be needed in the future. Today's capacity for underground storage of natural gas can also be used for hydrogen storage (see below). The possibility of building, expanding or even deconstructing underground natural gas storage facilities in individual countries depends heavily on the geological situation, the existing natural gas infrastructure and the evolving energy system as a whole. An overview and classification of the global or country-specific possibilities are beyond the scope of this paper.

### 2.14.4.2 Ammonia

As already described in chapter 2.6.1, one way to transport or store hydrogen is to store it in its chemical compounds such as ammonia. Ammonia is the most important hydrogen derivative and is produced from the synthesis of nitrogen and hydrogen ($NH_3$) and is largely produced using the Haber-Bosch process, which has been known since the early 20th century. Ammonia

[787] Cf. ACER, 2015.
[788] Cf. Osieczko et al., (2019).

is in demand worldwide in industry as a basic material for fertilisers and for the production of plastics and synthetic fibres.

De facto, more hydrogen can be transported on one cubic metre of ammonia as a hydrogen carrier than in pure liquid form. In addition, the Haber-Bosch process, which produces the synthesis gas, requires comparatively little conversion energy (2 - 4 kWh/kg or 10 % of the HHV). On the other hand, the reconversion of ammonia into hydrogen is energy-intensive (so-called cracking process). The energy input here is estimated at 10 - 12 kWh/kg hydrogen (approx. 25 - 30 % of the HHV of hydrogen).[789] Despite several projects in the pilot phase, there is still no mature large-scale process for splitting ammonia back into hydrogen, or this is not yet being operated commercially. The "energy penalty" in the transport of ammonia is therefore not at the beginning but at the end of the value chain, unlike in the transport of pure hydrogen. The high reconversion costs therefore mean that additional ammonia must be produced in order to provide the net amount of energy transported at the beginning.

In the literature, the transport of ammonia as a carrier of hydrogen over long distances is nevertheless rated as superior to liquid hydrogen. This is due to its advantageous properties (relatively low boiling temperature and high proportion of transportable hydrogen) and the well-established production process as well as the infrastructure and necessary technology already available in many places. With a production of 183 Mt (equivalent to 32.4 Mt of hydrogen) in 2020, ammonia is one of the mostly produced chemicals, with about 10% of global production volumes being transported internationally via pipelines or tankers. There are currently 170 tankers worldwide capable of transporting ammonia, 70 of which are in continuous operation. Europe is the largest importer of ammonia with 4.4 Mt per year. There are 38 export ports and 88 import ports worldwide (see Figure 294).[790]

The main customers for ammonia from the chemical industry are located at export and import ports. If ammonia were to be used as an energy carrier on a large scale, storage capacities for ammonia at the export and import ports would have to be greatly expanded, as would the cracking facilities for converting it back into hydrogen. Currently, ammonia is only stored in smaller capacity tanks of up to 90,000 tonnes.[791]

[789] Cf. Andersson & Grönkvist, (2019). The cracking process is the reverse reaction of the ammonia synthesis process. Ammonia starts to decompose at temperatures above 200°C, but temperatures up to 650°C usually have to be applied to achieve complete decomposition of the chemical into its components. Ruthenium, a very expensive precious metal, is also used as a catalyst. To reduce costs and also ensure availability, less rare precious metals are being investigated for use (nickel, cobalt, iron), but this could lead to required temperatures of up to 900°C due to poorer conductivity.
[790] Cf. IRENA, 2022a.
[791] Cf. IRENA, 2022a.

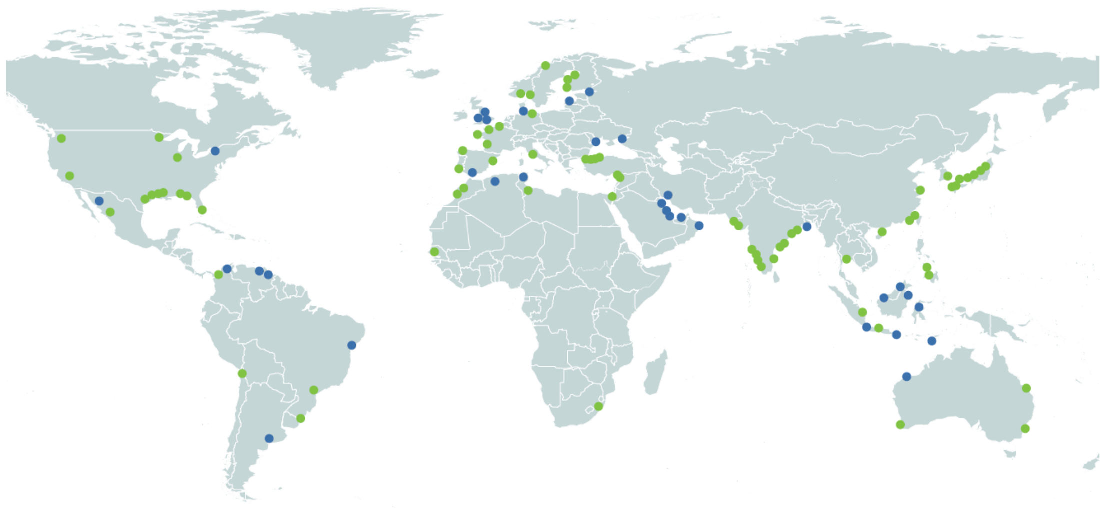



*Figure 294: Existing ports worldwide with export and import possibilities of ammonia.*

*Source: IRENA, 2022a, p. 27.*

The import terminal accounts for the largest share of CAPEX (57 %), due to the high costs for reconversion plants, while the export terminal accounts for only 36 %. This is due to the fact that plants for the Haber-Bosch process have already been able to reduce their CAPEX by scaling up through many years of implementation on the market. KBR assumes hydrogen transport costs via ammonia of 4.5 USD/kg (CAPEX 3 USD and OPEX 1.5 USD),[792] IRENA for 2050 of 0.7-1 USD/kg$H_2$.[793]

In addition to intercontinental transport via ships, there are over 5,500 km of ammonia pipelines in operation (3,000 km in the USA and a 2,400 km pipeline between Russia and Ukraine).[794]

#### 2.14.4.3 Methanol

Another energy-dense hydrogen derivative is methanol ($CH_3OH$), which was already discussed in chapter 2.6.4. The simplest representative of the alcohol group has a gravimetric hydrogen storage capacity of 12.5 % and a volumetric capacity of 99 kg/m3, comparable to ammonia. The most common route for the production of methanol is via the synthesis of hydrogen and $CO_2$. This process is technically mature, although less established than the "traditional" natural gas-based production method. The energy input is about 1.3 - 1.8 kWh/kg $H_2$ for the hydrogenation of $CO_2$, 4.5 % of the HHV of methanol.

An additional aspect of the use of methanol as a hydrogen carrier is the origin of the $CO_2$ used. Methanol can only be climate-neutral if its production (and direct use) does not release any

[792] Cf. KBR Advisory Consulting, (2021).
[793] Cf. IRENA, 2022a.
[794] Cf. KBR Advisory Consulting, (2021).

additional $CO_2$ into the atmosphere. Here, for example, $CO_2$ can be used for synthesis with hydrogen that has been captured in industry, then transported to Europe, for example, and reused after hydrogen has been split off ($CO_2$ cycle). Another possibility is the use of $CO_2$ from Direct Air Capture (DAC), which is, however, currently still very expensive (see chapter 2.8.).[795] An important aspect in this regard is the certification of hydrogen and its derivatives, which is taken up in chapter 2.4.

In summary, methanol has the advantage over liquid hydrogen and ammonia that it can be transported without the need for cooling and that costs can be saved through existing infrastructure. However, especially compared to ammonia, methanol has a lower hydrogen storage capacity, which affects the economic viability of this transport medium if the goal is to recover the hydrogen itself. In addition, there is the problem of ensuring $CO_2$ neutrality. As a hydrogen carrier for transport, ammonia is therefore favoured in many studies on the topic.

### 2.14.5. Construction, conversion and rebuilding of infrastructure

#### 2.14.5.1 New hydrogen pipelines

Pipelines designed to deliver 100 % hydrogen differ from natural gas pipelines mainly in their material and the compressors required. The International Energy Agency (IEA) estimates that the cost of a new hydrogen pipeline (CAPEX) is about 10-50 % higher than that of conventional gas pipelines, due to the increased material costs for the reinforced outer walls and, if necessary, the larger diameter to be able to transport more energy.[796] In Table 66 lists the boundary conditions for a new 1,500 km long hydrogen pipeline.

*Table 66: Example costs of a new hydrogen pipeline.*

*Source: Khan et al., (2021).*

| | |
|---|---|
| **Length** | 1,500 km |
| **Pressure level** | 70 bar |
| **Distance between compressors** | 500 km |
| **Capacity** | 4,280 t / day |
| **Availability** | 90 % |
| **CAPEX (total)** | USD 4.57 billion |

[795] Cf. IRENA, 2021a.
[796] Cf. IEA 2021d.

| | |
|---|---|
| **OPEX (total per year)** | 166.2 million USD (approx. 3.6 %) |
| **Inlet Compression Effort** | 0.63 kWh/kg $H_2$ |
| **Enroute Compression Effort** | 0.45 kWh/kg $H_2$ |

In this example, the total "transport cost" for hydrogen is 0.69 USD/kg $H_2$. This price is mainly driven by the high initial and irreversible investment costs for the pipeline. The sunk costs of pipeline systems represent an investment risk and assume that the demand for hydrogen will remain over the lifetime of the pipeline. To reduce the cost of long-distance transport of large quantities of hydrogen via a pipeline system, there are two other options: The re-functioning of existing natural gas pipelines or the blending of hydrogen into existing natural gas networks.

#### 2.14.5.2 Conversion of existing natural gas pipelines

Natural gas networks with a total length of 1 million km are installed worldwide. Reconversion is intended to adapt underutilised pipelines - or pipelines that will be less utilised in the future due to the potential ramp-up of the hydrogen economy - for hydrogen transport. The investment costs of converted pipelines can be 65 - 94% cheaper than those of a new hydrogen pipeline.[797] Figure 295 shows the cost difference between new and existing converted pipelines. A prerequisite for retrofitting is that the pipeline material can withstand the risk of brittleness and the necessary pressure for hydrogen transport. Therefore, costs for reinforcing the outer walls may have to be calculated. In addition, compressors that are not designed for operation with hydrogen (higher impeller speed and embrittlement problems), but also valves, measuring devices, leakage detectors and gas flow control systems have to be replaced. Projects aimed at pipeline re-functioning have already been successfully carried out. For example, Air Liquide acquired two pipelines in Texas, USA, and converted them to run on hydrogen. Similar projects are planned between Germany and Denmark, for example.

[797] Cf. IRENA 2022a.

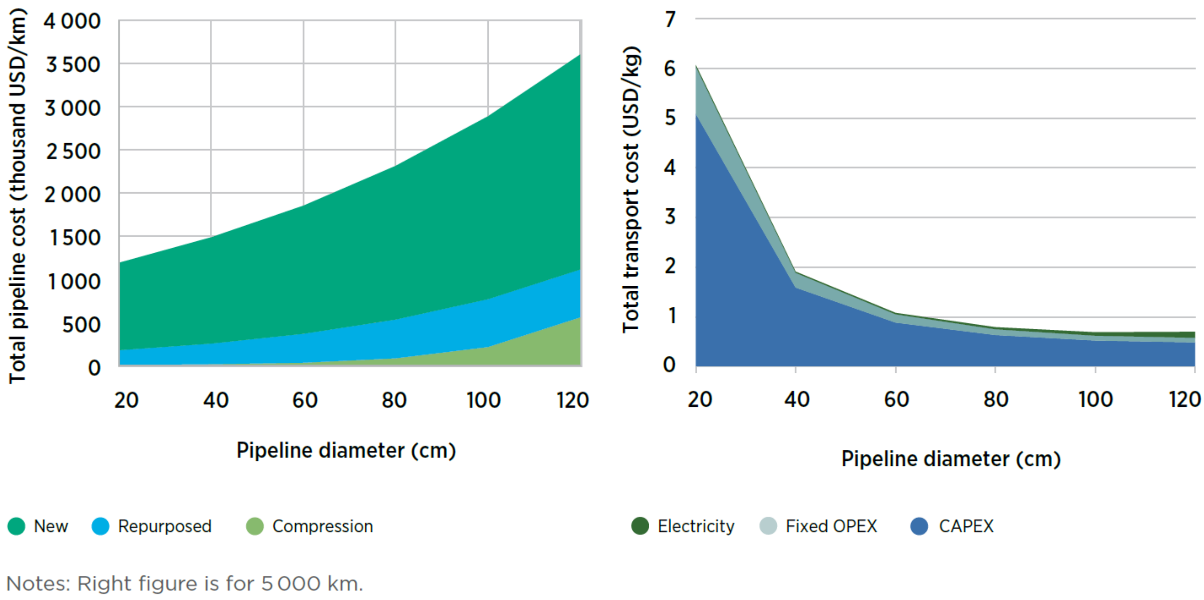



*Figure 295: Investment costs for hydrogen pipelines (left) and total transport costs (right). Source IRENA, 2022a, p. 113.*

### 2.14.5.3 Case Study European Hydrogen Backbone

In Europe in particular, there is a far-reaching vision of some natural gas grid operators for a well-developed European hydrogen transport network by 2040, the European Hydrogen Backbone (see Figure 296). According to the European Hydrogen Backbone Initiative, if hydrogen were to play a greater role in a climate-neutral energy system in Europe, a starting network with a length of 6,800 km could already exist in 2030, connecting hydrogen clusters with each other. By 2040, the total pipeline infrastructure could grow to almost 23,000 km. Of the total investment costs, converted and new hydrogen pipelines would account for 60%, while compression facilities would account for 40%. At the same time, converted natural gas pipelines would account for 75% of the total length of the network. The split of the total costs between retrofitting existing infrastructure and building new hydrogen pipelines would be 50 % each.[798] This shows the high value of the existing infrastructure for a Europe-wide hydrogen transport network.

[798] Cf. European Hydrogen Backbone Initiative, (2020).

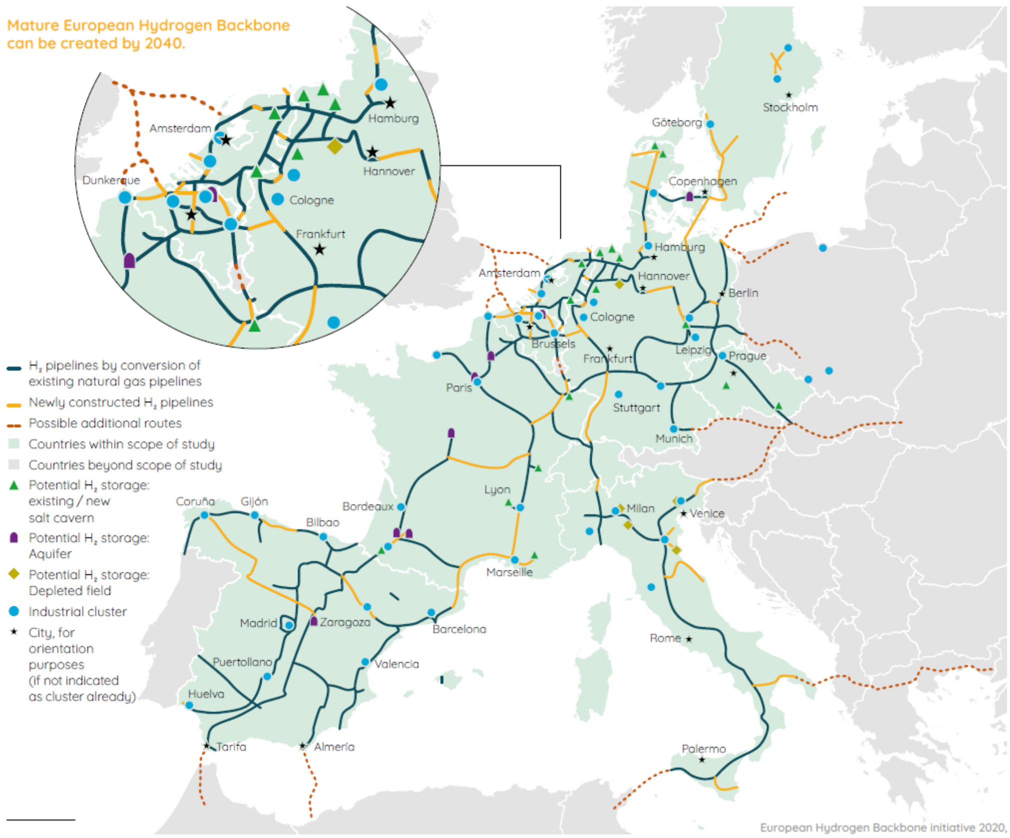



*Figure 296: The European Hydrogen Backbone in 2040.*

*Source: European Hydrogen Backbone Initiative, (2020).*

### 2.14.5.4 Construction, conversion and rebuilding

The transformation towards a climate-neutral energy system requires infrastructures to transport energy in the form of electrons and molecules as well as $CO_2$. However, the development of energy infrastructures is not only driven by climate transformation. Especially the development of electricity infrastructures in developing and emerging countries is essential to enable higher prosperity for the people living there.[799] A direct distinction between the infrastructure needed to increase prosperity on the one hand and to create a climate-neutral energy system on the other can only be determined through detailed analyses in the respective countries. However, in this chapter, a possible categorisation and classification of countries with different prerequisites will be made in order to better assess infrastructure requirements.

As explained above, the development of electricity infrastructure will account for about half of the total investment in many countries and will increase by many millions of km. Furthermore, it became apparent that gas pipelines and networks as well as underground gas storage facilities are available in many industrialised but also emerging countries in large transport capacity and geographical distribution. This infrastructure can also be used for land transport and local

[799] Cf. IEA, 2021e.

storage of climate-neutral molecules. For the development of a global transport infrastructure for climate-neutral energy carriers, on the other hand, the expansion of infrastructure for maritime transport will be necessary. Depending on the form of hydrogen transport, the infrastructure (export terminals-tanker ship-import terminals) must either be completely new (liquid hydrogen and LOHCs) or expanded by a factor of at least 50 based on the existing infrastructure (ammonia and methanol). The large-scale deployment of CCS can only succeed if the corresponding transport and storage infrastructure is scaled up by a factor of 150 (see Table 67).

*Table 67: Scaling of energy infrastructures and important boundary conditions*

| Energy transport infrastructure | Necessary scaling | Boundary conditions |
| --- | --- | --- |
| **Power grid** | Factor 2 - 5 | Upgrading and expansion necessary anyway in emerging and developing countries, depending on the degree of electrification and region |
| **Gas network and storage** | Not clear, especially retrofitting of existing infrastructure | Depending on national conditions and degree of electrification, possible further use for climate-neutral energy sources after conversion |
| **Liquid hydrogen** | Complete structure | Strongly dependent on application and cost development of other hydrogen derivatives |
| **LOHCs** | Complete structure | Strongly dependent on application and cost development of other hydrogen derivatives |
| **Ammonia** | Factor 50 | Experience and applications exist, depending on cost development of other hydrogen derivatives |
| **Methanol** | Factor 50 | Experience and applications exist, depending on cost development of other hydrogen derivatives |
| **$CO_2$ for CCS** | Factor 150 | Strong regional differences in CO production and capture potential, strongly dependent on costs and local acceptance |

#### 2.14.5.5 The role of existing infrastructure - Case Study EU

In addition to the necessary construction of energy transport infrastructure, existing infrastructure can play an important role. For Europe in particular, the data situation is sufficient to make statements about the further use of existing infrastructure. For many other regions of the world, there is not enough information and analysis available. A global analysis of the relevance of existing infrastructure is beyond the scope of this paper. Therefore, the relevance and the role of the existing gas infrastructure in Europe is elaborated in a case study below.

An important boundary condition when considering the relevance of the existing gas infrastructure (grids and storage) is the degree of electrification of final consumption. Depending on assumptions and modelling, the share of electricity in final energy consumption can vary greatly. A complete electrification of final consumption is considered unrealistic both at the political level and in science. However, when looking across many studies, it can be determined that for a climate-neutral energy system in the EU, a higher degree of electrification is economically sensible and technically feasible, i.e. it is a no-regret measure. Today, the share of electricity in final energy consumption is just under 25 %. According to various studies, this share will rise to over 50 % by 2050. However, only a few scenarios have a degree of electrification of over 60 %. An increase in the share of electricity in final energy consumption in the EU to 40 - 50 % is generally considered realistic (see Figure 297). [800]

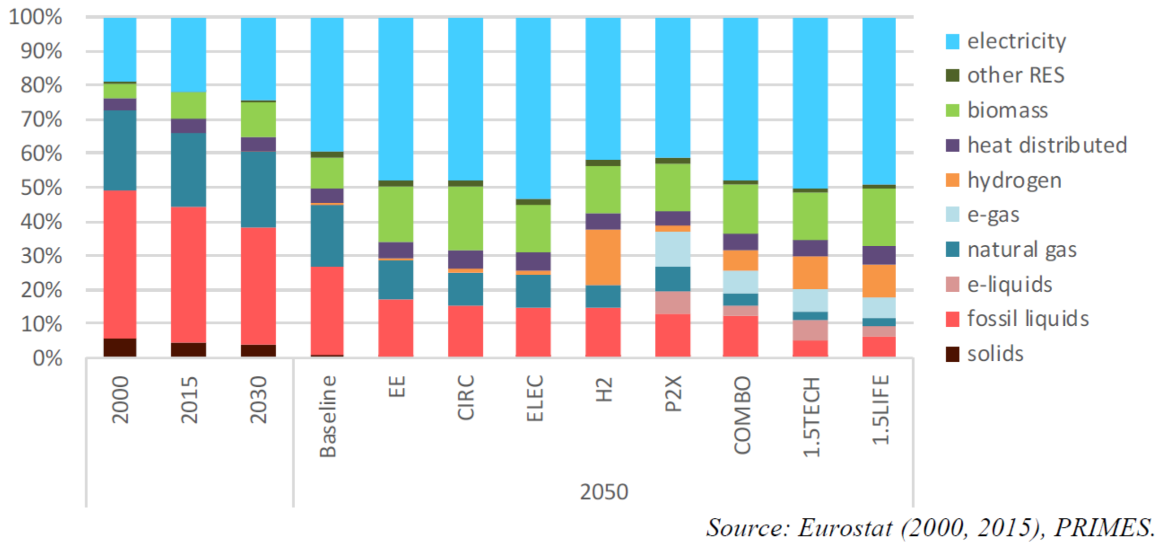



*Figure 297: Share of energy carriers in final energy consumption.*

*Source: European Commission, (2018).*

The use of electricity for the production of climate-neutral molecule-based energy sources within the EU is already covered here and, depending on the model and scenario, accounts for 10 - 40 % of electricity consumption. This means that, in addition to the use of electricity, gaseous energy carriers will still play an important role (see Figure 298).

[800] Cf. Lebelhuber & Steinmüller, 2019; Capros et al., 2019; Arduin et al., 2022; European Commission, (2018).

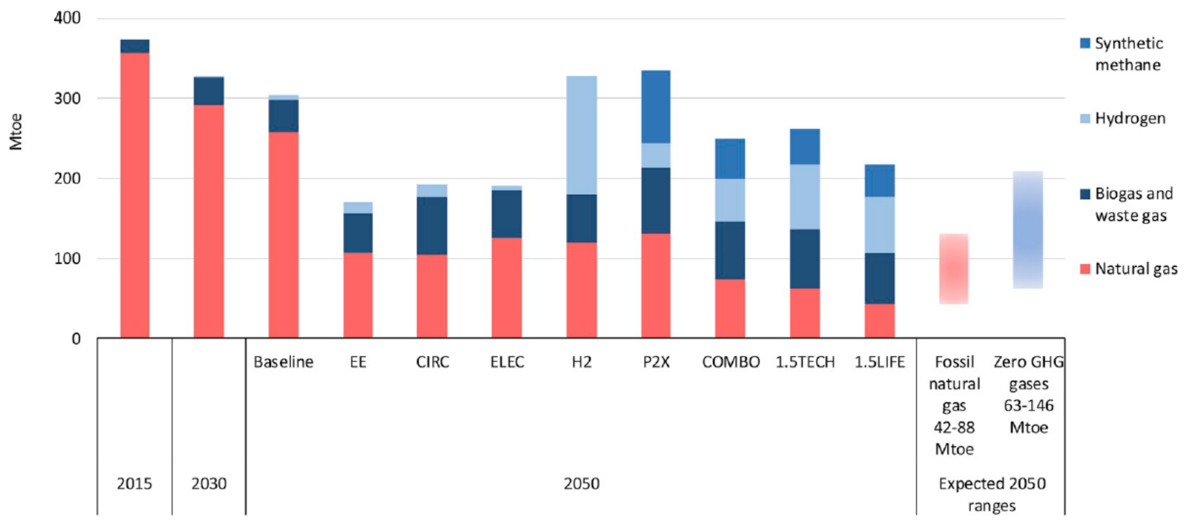



*Figure 298: Consumption of gaseous energy sources by type and scenario.*

*Source: Capros et al., (2019).*

Table 68: Uses and relevance of existing gas infrastructure for a future climate-neutral energy system in the EU

| | |
|---|---|
| **Seasonal storage of renewable energy** | Gas storage facilities and grids play a role especially for long-term energy storage and are easier to keep in balance than electricity grids. |
| **Use of gas infrastructure can reduce required electricity grid expansion** | The expansion of electricity grids is complex and can be cost-optimised by using the existing and converted gas infrastructure. |
| **Allows the use of climate-neutral gases** | Carbon neutral gas has the potential to decarbonise various end-use sectors using existing and converted gas infrastructure. |
| **Gas infrastructure is available and cost-effective** | Comparatively low investment needed to convert existing gas transport infrastructure in the EU to renewable gases. |
| **Possible acceleration of energy and climate transformation** | Certain sectors are behind transformation targets (building renovation) or can hardly or only with difficulty become electrified or climate neutral. |
| **Solving the problem of acceptance Infrastructure development** | Existing gas infrastructure is largely underground and already exists. Acceptance problems with regard to further use are therefore likely to be low. |
| **Energy security can be increased** | The use of gas infrastructure as well as renewable gases from different origins enables diversification of energy sources and can thus support security of supply. |

Depending on the scenario, the use of gaseous energy sources is thus assumed to be between just under 50 % and around the level of 2015. This also means that the existing infrastructure for the transport and storage of methane can continue to play an important role in the future.[801]

The cost savings from using and converting the existing gas infrastructure on the way to a climate-neutral EU could amount to between EUR 30 - 49 billion annually.[802] However, depending on the production location of climate-neutral gases within the EU, the import share of climate-neutral molecules, their geographical landing and injection into the EU gas grid, and the place of use, the existing gas infrastructure would have to be expanded and upgraded. The maintenance and possible expansion of gas interconnectors between the EU countries is seen as particularly important in this context. The studies reject the construction of new gas infrastructure that only serves to transport methane but has no technical capability to transport hydrogen. [803]

Existing gas infrastructure can therefore play a major role in a climate-neutral energy system in an industrialised region like the EU. However, this does not mean that the construction of new gas supply networks in countries without a high share of gas in final energy consumption is a sensible path to a climate-neutral energy system in every case. The different conditions in different countries and possible approaches to infrastructure development are taken into account in the following chapter.

### 2.14.6 Realisation and operation of energy infrastructure

#### 2.14.6.1 Admixture of hydrogen in existing natural gas networks

The blending of hydrogen into natural gas networks is seen as having a transitional role for transport as long as a dedicated hydrogen infrastructure designed for the pure transport of the element has not yet been developed. Nevertheless, before hydrogen can be mixed into the existing gas grid, it must first be ensured that the infrastructures used can withstand the intended mixing ratio. Given the heterogeneity of the network, this could lead to problems. Figure 299 shows the technical limits of blending for different components of the existing natural gas infrastructure.

---

[801] Cf. Lebelhuber & Steinmüller, 2019; frontier economics, 2019; Gas Infrastructure Europe, (2021).
[802] Cf. frontier economics, (2019).
[803] Cf. Arduin et al., 2022; Capros et al., (2019).

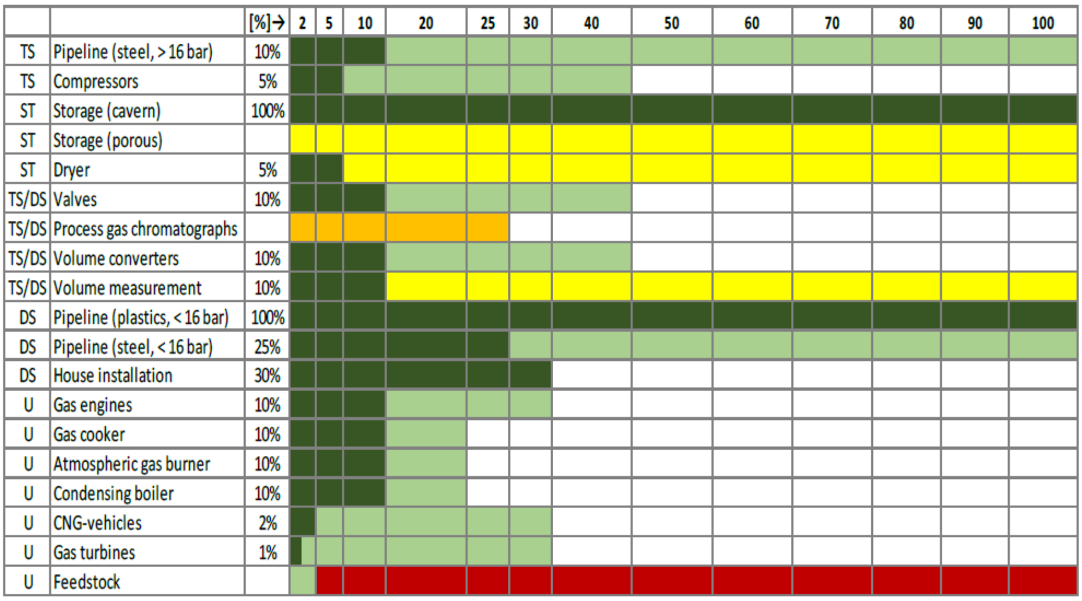



*Figure 299: Limitations for the admixture of hydrogen in selected components of the natural gas infrastructure (dark green: possible without retrofitting according to the current status, light green: retrofitting necessary, yellow: unclear data situation or further investigations necessary, red: technically not possible).*

*Source: Fraunhofer IEE, (2022).*

Hydrogen can therefore be fed into natural gas grids in proportions of 2 - 10 % before major adjustments must be made to the pipelines and does not pose a major challenge from a technical point of view. Some example projects are also already in operation worldwide (see Table 69).

*Table 69: Example projects for the admixture of hydrogen in gas grids.*

*Source: IEA, 2021d.*

| Project name | Status |
|---|---|
| Avacon + DVGW (Germany) | Pilot project (20 % admixture) |
| GRHYD (Capelle la Grand, France) | Pilot project (20 % admixture) |
| Snam (Italy) | Pilot project (10 % admixture) |
| HyDeploy (UK) | Pilot project (20 % admixture) |
| Hyp SA (Australia) | Pilot project (5-10 % admixture) |

### 2.14.6.2 Transport of liquid hydrogen

Another way to transport pure hydrogen is to transport the liquid form ($LH_2$). See also chapter 2.5.3. The advantage of liquid hydrogen over gaseous hydrogen is the increased density. However, condensation of hydrogen occurs at atmospheric pressure of the gas only at very low temperatures (-246.0°C). With methane, condensation occurs at the same pressure already at -161.5°C, which is why less energy is needed for the liquefaction of methane. The energy required for liquefaction is estimated to be 25-35 % of the calorific value of hydrogen, which is significant.[804] The more tonnes of liquid hydrogen a plant can produce per day, the less energy needs to be used per kilogram. In addition, the utilisation factor of the plant determines the energy input, whereby 100 % utilisation means less electricity consumption per kilogram of hydrogen than about 25 %, since, for example, the additional consumption for the start-up and shut-down is saved. Large plants with a high utilisation factor are therefore preferable for the liquefaction process. Especially the process step of cryo-cooling is very energy-intensive and requires about three quarters of the total process energy. The infrastructure for liquid hydrogen is currently not developed for mass transport: worldwide, there is a liquefaction capacity of only 0.22 Mt/year (0.4 Promilla of the LNG liquefaction capacity).[805]

When the transport of $LH_2$ can be economically and energetically worthwhile is considered in the next section. Due to the higher volumetric energy density of liquid hydrogen, two forms of transporting $LH_2$ are conceivable: Transport by lorry and transport by ship.

### 2.14.6.3 Liquid hydrogen transport via truck

A lorry can carry about 4,000 kg of liquid hydrogen, whereas with the same volume (approx. 56 $m^3$) only about 1,100 kg of gaseous hydrogen could be transported (at 350 bar = 21 kg/$m^3$). Despite external insulation of the liquid hydrogen tanks, however, heat cannot be prevented from entering the tanks. This leads to a slight evaporation of the hydrogen and the so-called "boil-off" gas is produced in the tank. If this is not removed, the pressure increases. Therefore, the excess gas is usually discharged from the tank unused. These energy losses, known as "vent-off", account for approx. 0.3 - 0.6 % of the quantity contained in the tank per day during hydrogen transport by truck.[806] Of 4,000 kg, 3,760 - 3,880 kg of hydrogen remained after one day. This corresponds to a significant amount of energy lost. Transporting $LH_2$ over distances that can only be covered in several days by lorry does not make sense from an economic and energetic point of view because of these losses. The transport of $LH_2$ is therefore only relevant for the supply of end consumers on the "last mile".

### 2.14.6.4 Liquid hydrogen transport via ship

At the beginning of 2022, the first tanker for transporting $LH_2$ was put into operation and has so far completed one journey between Australia and Japan.[807] However, in order to transport the quantities of liquid hydrogen relevant for a climate-neutral energy system over long

[804] Cf. IRENA, 2022a; Zemo Partnership, (2021).
[805] Cf. IRENA, 2022a.
[806] Cf. Zemo Partnership, (2021).
[807] Cf. IGU, 2022b.

distances on the world's oceans between producer and consumer, a fleet would have to be built that is at least equivalent to today's LNG fleet with more than 640 tankers. However, the required (port) infrastructure is significantly more complex and the energy losses higher than for the transport of LNG.

A study by KBR Advisory Consulting has calculated the levelized costs of hydrogen (LCOH) for the transport of liquid hydrogen by ship at different export volumes in 2020 (without production costs of hydrogen but with conversion and reconversion costs).[808] With increasing export volumes, the share of transport in the LCOH decreases (positive scale effect). Larger export volumes allow, for example, the standardisation and optimisation of the size of the cargo tanks. At an export volume of 200,000 t/year, the share is 7 USD/kg $LH_2$, while at 500,000 t/year it falls to 5 USD/ kg $LH_2$.

Of the 7 USD, 4 USD are for the CAPEX of the infrastructure and 3 USD for the operating costs. 50 % of the CAPEX must be spent on the export terminal, 39 % on the import terminal and 11 % on the tankers. The high share of the export terminal follows from the high costs for the liquefaction plant. Transport by ship is also affected by boil-off losses. The longer the distance to be covered, the higher the amount of hydrogen lost. This means that additional hydrogen has to be produced to transport the same amount. This has a negative impact on the LCOH. Figure 300 shows how the LCOH increase with increasing distance.

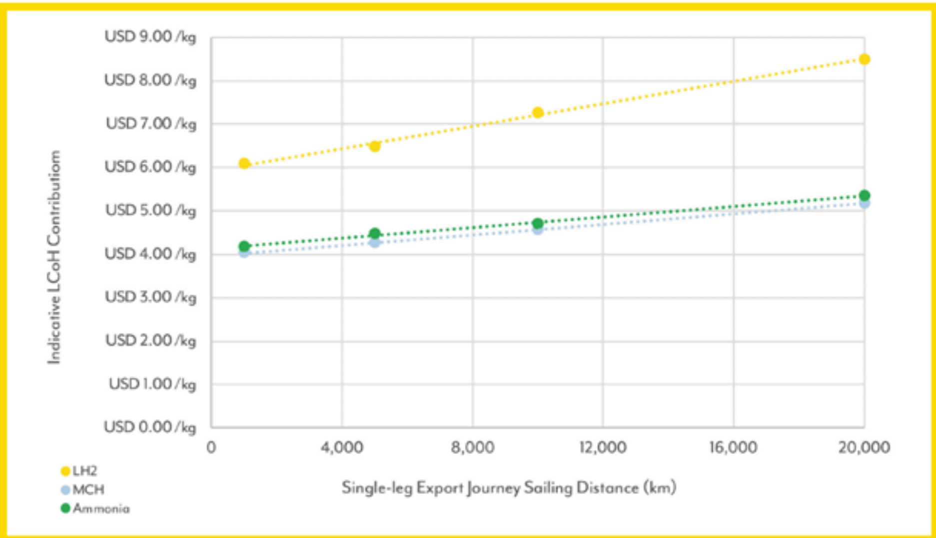



*Figure 300: Increasing LCOH with increasing distance due to "boil-off" losses (250 kt/year).*

*Source: KBR Advisory Consulting, (2021).*

Overall, the transport of liquid hydrogen is mainly affected by the high energy input for its liquefaction, the additional energy costs for cooling and the costs for the specific infrastructure. In the storage of liquid hydrogen, "boil-off" losses must also be taken into account, which can

[808] Cf. KBR Advisory Consulting, (2021).

influence long-term storage. Due to their material properties, chemical hydrogen storage systems (hydrogen derivatives) offer advantages that can make the manageability, transport and storage of hydrogen more efficient (Chapter 2.7.5 ff).

#### 2.14.6.5 Hydrogen storage

Thanks to its high density, $LH_2$ could be temporarily stored in cryo-cooled tanks before final shipment or consumption with energy losses. Tanks already exist for special applications (NASA: 227 and 334 tonnes). However, boil-off losses of 0.1 % per day must be expected even with progressive development. The storage of significant quantities assuming a probable seasonality of consumption (at least in northern latitudes) makes the storage of $LH_2$ in necessary quantities for a country's energy supply seem unlikely.[809]

For this reason, and in view of the cost advantages of using hydrogen pipelines for regional and national transport, the question of large-scale storage of gaseous hydrogen arises. Due to its volatility and low density, even at high compression (40 kg/m$^3$ at 700 bar), large quantities, such as might be needed for the envisaged German energy transition, cannot be stored in tanks. Too many pressurised tanks would simply be needed. However, the low density of hydrogen must be considered if existing natural gas storage facilities are to be used for hydrogen storage. When an underground natural gas storage facility is converted into a hydrogen storage facility, **only a quarter of the previous amount of energy** can be stored.[810]

Not all geological natural gas reservoirs are equally suitable for the storage of gaseous hydrogen. The use of aquifer storage and depleted oil and gas reservoirs raises questions regarding the volatility and possible reaction of hydrogen underground. Salt cavern storage facilities are considered the most promising, as there are no storage losses and hardly any contamination. Nevertheless, the use of other materials is required, especially for steel components such as the cavern heads and required pipelines, due to the mentioned embrittlement problem.[811]

Research and demonstration projects on the storage of hydrogen in underground storage facilities are taking place in many countries (see Table 70). However, there are currently only four commercial hydrogen storage facilities worldwide with a total storage capacity of 512 GWh in salt caverns, three of which are in the USA and one in the UK.

By comparison, the global natural gas storage capacity is about 4,500 TWh, which is almost 10,000 times larger. Potential exists to convert natural gas storage to hydrogen in the existing cavern storage facilities for natural gas. The advantage of converting these facilities would be

[809] Cf. IRENA, 2022a.
[810] Cf. IRENA, 2022a.
[811] Cf. Caglayan et al., (2020).

that seasonal storage would be possible at a relatively low cost of 0.2-0.3 USD/kg$H_2$. At the same time, depending on the annual and seasonal hydrogen demand, new underground storage facilities would also have to be developed. The theoretical availability of as yet unused storage potential is very high in Europe, for example, at almost 85 PWh (see Figure 301), but also requires extensive investment.

*Table 70: Operational salt cavern projects for hydrogen storage.*

*Source: IEA, 2021d.*

| Project name | Country | Capacity |
|---|---|---|
| Teeside | United Kingdom | 27 GWh |
| Clemens Dome | United States | 82 GWh |
| Moss Bluff | United States | 125 GWh |
| Spindletop | United States | 278 GWh |

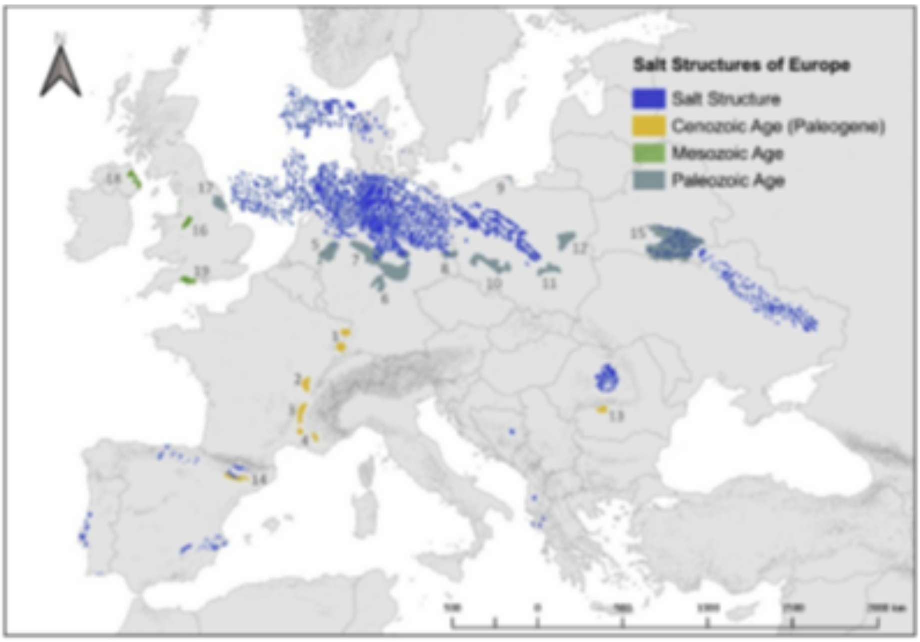



*Figure 301: Distribution of salt caverns across Europe.*

*Source: Caglayan et al., (2020).*

The expansion of infrastructure, especially hydrogen pipelines aligned with the occurrence of salt caverns, will be necessary in order to be able to ensure an inter-European hydrogen supply on a large scale (compare European Hydrogen Backbone in Figure 296). In countries without an existing or only rudimentarily developed infrastructure, the main question is how hydrogen infrastructures can be integrated or built in an overall plan in the most economically sensible way. This requires more detailed analyses of the expected expansion of the electricity grid and the degree of electrification, the potential hydrogen consumption and consumers, and geological conditions.

### 2.14.6.6 Liquid Organic Hydrogen Carriers

Liquid Organic Hydrogen Carriers (LOHC) serve as carriers for hydrogen and are produced by hydrogenating (or loading) a LOHC molecule ($H_0$ LOHC) and then dehydrogenating (discharging) it to use the hydrogen.[812] In its dehydrogenated form, the LOHC as a hydrogen storage medium is in a liquid aggregate state (unlike, for example, nitrogen in the case of ammonia or $CO_2$ in the case of methanol). This has the advantage that the LOHC can be pumped to the hydrogenation reactor instead of requiring an additional compression effort as in the synthesis of $N_2$ and $H_2$ .[813] Like the Haber-Bosch process, the hydrogenation process is exothermic. Thus, significant energy savings can be achieved during hydrogenation and LOHCs have the lowest conversion effort among chemical hydrides (0.7 $kWh_{el}$ /kg H ).$_2$[814] For the hydrogenation process, compressed hydrogen is used in a pressure range between 10 and 50 bar at a temperature between 130 and 200°C. [815]

Among the best studied and most economically viable LOHCs are toluene-methylcyclohexane (T-MCH) and dibenzyltoluene (DBT). The gravimetric hydrogen storage capacity for the former is 6.1 % and the volumetric is 47 kg/m$^3$ (see Table 71).

For dibenzyltoluene, these values are 6.2 % and 64 kg/m$^3$ (Table 72). For comparison, 122 kg of hydrogen can be transported per cubic metre with ammonia as the carrier medium, i.e. about 2.6 and 1.9 times as much. While the hydrogenation process of LOHCs consumes little energy relative to ammonia, the dehydrogenation process (endothermic) is more energy-intensive. For T-MCH, temperatures up to 350°C and an energy input of approx. 11.2 kWh/kg $H_2$ are required, for DBT 270-290°C and 9 kWh/kg $H_2$ (in the form of heat)..[816]

*Table 71: Important properties for the transport of hydrogen via T-MCH*

| | |
|---|---|
| **Density** | 770 kg/m$^3$ |
| **Hydrogen storage capacity** | 6.1 % (gravimetric); 47 kg/m$^3$ (volumetric) |
| **Conversion effort** | 0.7 kWh/kg $H_2$ (electricity) |
| **Reconversion expenditure** | 11.2 kWh/kg $H_2$ (heat) |
| **Energy Panelty** | 12 kWh/kg $H_2$ (30 % HHV) |

LOHCs such as T-MCH and DBT offer several advantages for the transport of hydrogen. Firstly, they are liquid at room temperature and have similar properties to the crude oil-based energy carriers petrol or diesel. Theoretically, it is therefore possible to use existing infrastructures such as pipelines, ship transport or rail transport for the transport of hydrogen via LOHCs

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[812] Cf. Niermann et al., (2019).
[813] Cf. , (2019).
[814] Cf. AAndersson & Grönkvist, (2019).
[815] Cf. AAndersson & Grönkvist, (2019).
[816] Cf. Niermann et al., (2019).

and thus save costs.[817] In addition, there is no need for the energy-intensive production, collection and storage of other gases besides hydrogen, as is the case with ammonia and methanol.[818] Finally, the reversibility of the substances means that after dehydrogenation, the LOHCs can be shipped back to the site of hydrogen production, hydrogenated and thus reused. Theoretically, a circular economic model can thus be created. In practice, however, it turns out that LOHCs must deteriorate and be exchanged during storage and transport due to side reactions.[819] This creates additional waste.

*Table 72: Important properties for the transport of hydrogen via DBT*

| | |
|---|---|
| **Density** | 1.032 kg/m$^3$ |
| **Hydrogen storage capacity** | 6.2 % (gravimetric); 64 kg/m$^3$ (volumetric) |
| **Conversion effort** | 0.7 kWh/kg $H_2$ (electricity) |
| **Reconversion expenditure** | 9.0 kWh/kg $H_2$ (heat) |
| **Energy Penalty** | 10 kWh/kg $H_2$ (24.6 % HHV) |

The storage of hydrogen in LOHCs is currently only taking place in isolated plants. For example, the largest plant currently under construction (Chempark Dormagen) is said to have a capacity of 5 t/day (a normal ammonia plant has a capacity of 3,000 t/day). The transport of hydrogen in LOHCs is also only taking place in pilot projects and is to be scaled up by 2030.[820]

#### 2.14.6.7 Comparison of $H_2$ transport options

Especially in the ramp-up phase of the hydrogen economy, in which the use of low-$CO_2$ hydrogen in industry is becoming established, the so-called "blending" of 2 - 20 % hydrogen content into existing natural gas grids can play a role in transporting smaller quantities to the end consumer. However, the question here is whether such unspecific distribution of hydrogen to all grid users makes economic sense compared to specific use for decarbonising industrial processes. As soon as demand grows, dedicated pipeline networks for hydrogen become inevitable, requiring the adaptation of existing natural gas networks (if hydrogen displaces part of the natural gas from the market) or the more costly construction of new hydrogen pipelines. Due to the high CAPEX of these pipelines, a constant demand must be ensured to stimulate investments. At the same time, however, demand will only increase if hydrogen can be transported cheaply by sea and thus purchased on the market. This "chicken and egg" dilemma (Chapter 2.4.) can only be compensated for by suitable policy measures. A summary of

817 Cf. Niermann et al., (2019).
818 Cf. Andersson & Grönkvist, 2019
819 Cf. Niermann et al., (2019).
820 Cf. IRENA, 20222022a.

hydrogen transport options and their advantages and disadvantages are shown in Table 73 can be seen.

Table 73: Advantages and disadvantages of different hydrogen transport options

| | $H_2$ (gaseous) | $H_2$ (liquid) | Ammonia $(NH_3)$ | Methanol $(CH_3OH)$ | LOHC |
|---|---|---|---|---|---|
| **Per** | Low energy loss and existing infrastructure can be used | Relatively high energy density | High energy density, gaseous from -33°C, Existing infrastructure | Liquid up to 65°C, Existing infrastructure can be used | Liquid at room temperature, existing oil infrastructure usable |
| **Contra** | High costs, infrastructure not yet developed,<br>low density | Very low boiling point, Infrastructure not developed, energy losses | High energy losses Reconversion not yet fully developed | High energy losses, $CO_2$ occurs during reconversion | High energy losses and lower storage density |

### Transport over medium distances (1,000 - 4,000 km)

In summary, the transport of hydrogen via pipeline networks will play a role when large quantities are to be transported over distances of up to 4,000 kilometres. Figure 302 ranks cost-effective hydrogen transport modes according to distance and project and transport volume (1 Mt $H_2$ /year corresponds to a hydrogen volume of about 33 TWh, i.e. a production of hydrogen with an electrolysis capacity of 10 GW with 60 % utilisation per year).

Converted natural gas pipelines for hydrogen can significantly increase the potential transport distance for gaseous hydrogen because investment costs can be reduced. The gaseous transport of hydrogen, even with newly built pipelines, is more economical than other forms of transport, given a corresponding transport volume per year. The relatively low energy costs of transport and the high transport volume can compensate for the investment costs up to this distance. For distances of 4000 km and more, the construction of new pipelines is uneconomical compared to other forms of transport (the longer the pipeline, the higher the investment and operating costs). Transport by LOHC can be an option, especially for small-scale projects.

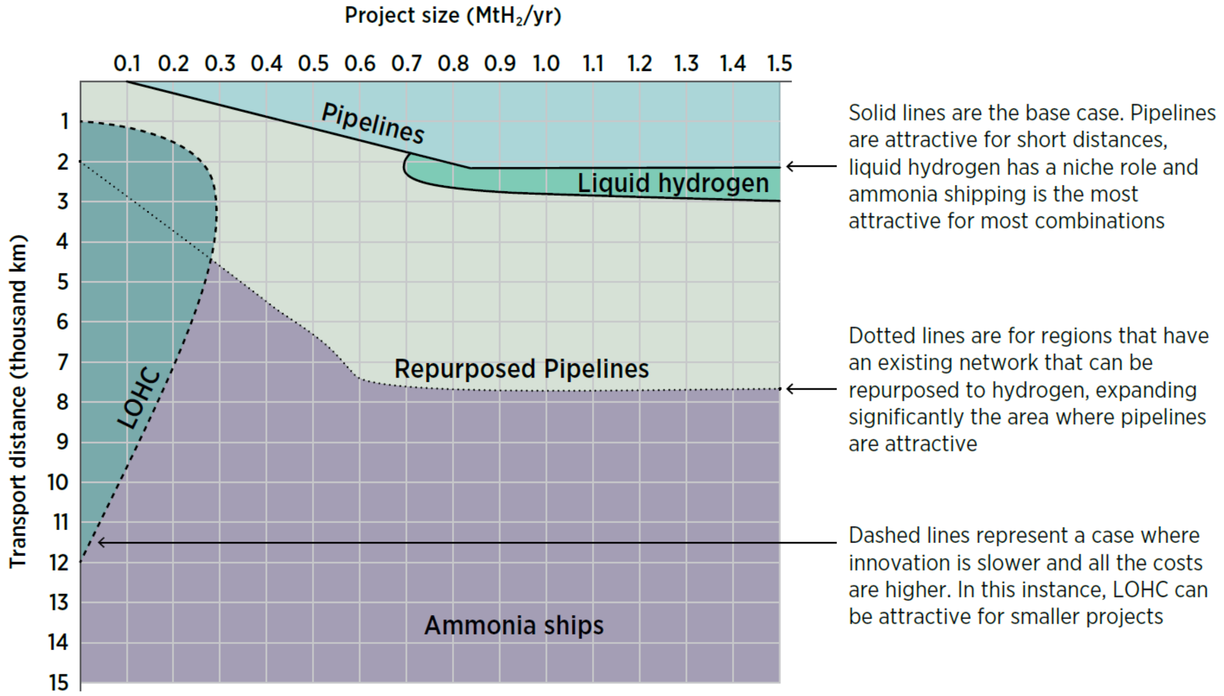


*Figure 302: Cost-effective hydrogen transport routes in 2050 depending on distance and project and transport volume. and project and transport volume.*

*Source: IRENA, 2022a.* [821]

### Transport over long distances (>4,000 km)

If no pipeline network is available, or the distance cannot be bridged by pipelines, transport by ship is an option (see Figure 302). For transport by ship, hydrogen should be available in liquid (pure) form or as a liquid hydrogen derivative due to its higher density, so that larger quantities of hydrogen can be transported given the limited ship capacity.

[821] This IRENA study excludes methanol and other carbon-based hydrogen carriers, as only sustainably produced $CO_2$ (biogenic or directly from the air) can be considered renewable. According to IRENA, the cost advantages for transporting hydrogen via carbon-containing carriers do not outweigh this disadvantage. However, if climate-neutral production and use of methanol is possible, the intercontinental transport of methanol via existing infrastructures, especially along the lines of the transport of liquid chemicals and oil, is comparably attractive as via ammonia.

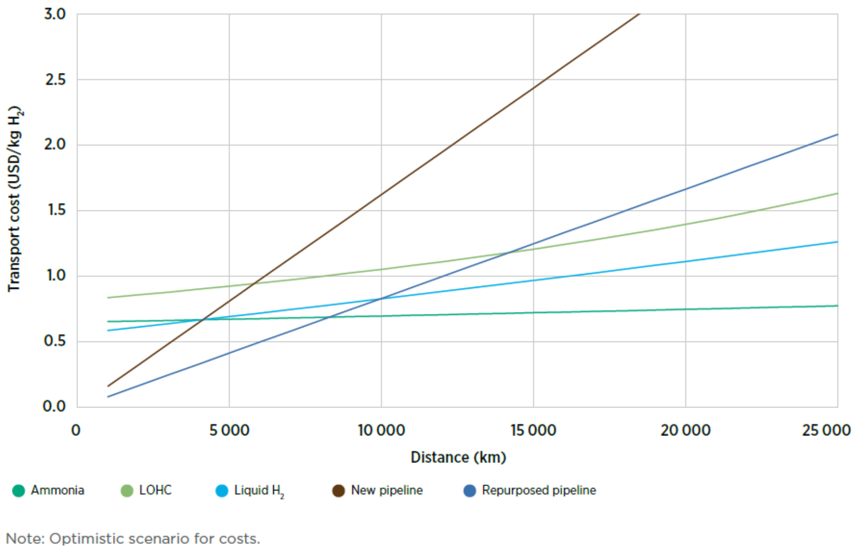


*Figure 303: Transport costs of hydrogen (1.5 $MtH_2$ /year) as a function of distance under optimistic cost assumptions in 2050.*

*Source: IRENA, 2022a, p. 126.*

Other studies calculate somewhat higher transport costs for the sea route of 2 - 3 USD/kg $H_2$.[822] If hydrogen is to be consumed as an end product, the transport of liquid hydrogen can be economically optimal due to the omission of reconversion costs. However, the off-gassing losses to be taken into account (which increase over longer distances) and the high initial conversion costs limit the possible applications and it must be shown on the basis of concrete case studies to what extent liquid hydrogen transport can compete economically with hydrogen derivatives, especially ammonia. The latter, in turn, is particularly suitable for long distances. This can be explained by the already well-developed infrastructure (low investment costs) and the higher hydrogen storage density per cubic metre also compared to methanol (71 kg/m$^3$ vs. 122 kg/m$^3$). If ammonia is used directly (depending on the requirements and equipment of the buyer), the costs are further reduced by the omitted reconversion costs. However, the application of ammonia to date is mainly limited to use in the chemical industry for the production of urea.

### 2.14.6.8 Scaling the hydrogen demand and infrastructure

Various studies assume a global hydrogen demand of about 500 - 680 Mt/year in 2050 for a 1.5 degree pathway, whereby about 25 % of the demand could be covered by international trade.[823] The rest would be produced and transported regionally. For regional transport, the converted natural gas grid or new hydrogen pipelines could play a major role.

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[823] Cf. IRENA, 2022b; IEA, 2021d; IEA, 2021e; BCG, 2022; Worldbank, (2022).

With the above assumptions, the international transport of hydrogen would be between 100 and 170 Mt/year. Other studies also assume an increasing demand for ammonia and methanol per se (ammonia demand in 2050: 250 Mt and methanol demand in 2050: 500 Mt).[824] In the following, however, only the international transport of hydrogen through the various derivatives will be discussed. The infrastructure for transporting liquid hydrogen and LOHCs does not yet exist and would have to be completely expanded. Today, about 20 Mt of ammonia (hydrogen content of 3.5 Mt)[825] and 25 Mt of methanol (hydrogen content of 3.1 Mt)[826] are transported internationally per year. Even if ammonia or methanol were used as a hydrogen carrier, the existing port infrastructure would have to be expanded by a factor of about 50. However, the large-scale transport of methanol would be easier to implement due to the existing oil tanker fleet.

Depending on the use of the imported hydrogen (chemical industry vs. fuel for transport vs. natural gas substitute in power generation), the advantages of certain hydrogen derivatives and thus also the different transport modes predominate. From a global perspective, not only one solution for the intercontinental transport of hydrogen is likely to become established. Rather, depending on the existing customer structure in the importing countries, the extent of the existing natural gas networks and the industrial development in the exporting countries, certain infrastructures and utilisation paths will prevail. In particular, the possibility of direct use of climate-neutral ammonia and methanol in certain industrial applications or as fuel can lead to the development of a multi-layered transport infrastructure for hydrogen and its derivatives. [827]

#### 2.14.6.9 Transport of $CO_2$

The complete transformation of industrial processes to $CO_2$ -free methods is a long-term process. Furthermore, for some $CO_2$ or greenhouse gas sources, it will not be possible to avoid emissions in the long term, if at all. Therefore, it is essential to have processes and techniques for the removal of $CO_2$ from waste gas streams and also directly from the air, and to know their areas of application and the expected costs. Chapter 2.8 contains detailed information on this. Therefore, the necessary infrastructures for the transport or long-term geological storage of $CO_2$ are discussed below, even though $CO_2$ as such is not an energy carrier.

Today, trucks, trains, ships or pipelines are used for the transport of smaller quantities of $CO_2$ . In view of the global nature of this analysis, only the regional transport of $CO_2$ by pipelines

[824] Cf. IEA, 2021a; IRENA, 2021a.
[825] Cf. IRENA, 20222022a.
[826] Calculated from the global import volume of USD 8 billion in 2020 (cf. OEC, n.d.) and the price of USD 300 per tonne (cf. Methanol Institute, n.d.). The volumes transported globally by sea are inevitably lower.
[827] Cf. Hydrogen Import Coalition, 2021; Hydrogen Council/McKinsey & Company, (2021). .

and tankers will be discussed here. Intercontinental transport of $CO_2$ for subsequent injection in distant regions is not foreseeable as of today.

Unlike natural gas, $CO_2$ is only present as a solid or gas at atmospheric pressure and must therefore be pressurised in order to be converted into a liquid state (see phase diagram in Figure 161, p. 269). In principle, $CO_2$ can be transported as a gas, liquid or solid. The phase diagram of pure $CO_2$ shows the area in the P-T diagram above the vapour pressure curve in the supercritical range that is suitable for liquefying the $CO_2$.

Usually, liquid $CO_2$ is transported at pressures >75 bar. Experiences from the transport of liquefied hydrocarbons (e.g. LNG, LPG) can also be transferred to the transport of liquefied $CO_2$. The conversion of $CO_2$ into the solid state for transport is considered disadvantageous due to the high energy requirement.

In order to be able to transport the large quantities of $CO_2$ that are expected to be captured in the future, an expanded infrastructure and functioning logistics are needed.

### Transport of $CO_2$ via pipelines

Experience with the continuous transport of large quantities of $CO_2$ in pipelines has existed since the 1970s and $CO_2$ is transported in pipelines of about 10,000 km in length worldwide. In the USA, there are about 50 $CO_2$ pipelines with a length of more than 8,000 km and a throughput of 68 Mt $CO_2$ /year, mainly for the use of $CO_2$ for the increased exploitation of fossil deposits through enhanced oil recovery.[828] In Europe (mainly in the UK), about ten pipelines with a length of 1,300 km are in operation, so these pipelines can be considered state of the art.[829]

The investment costs for the construction of a pipeline have already been discussed in chapter 2.8. Depending on the diameter of a pipeline and whether it is laid on land or in the water, the costs range between 0.2 and 1.2 M€/km (see also figures in chapter 2.8.).

For the operation of a pipeline, the costs of the Figure 304 can be seen. The annual transport capacity has a high influence on the transport costs and the capacities of today's pipelines range between 0.5 and 20 Mt $CO_2$ /year.

[828] Cf. IEA, 2021c; Righetti, (2017).
[829] Cf. Markewitz, (2017).

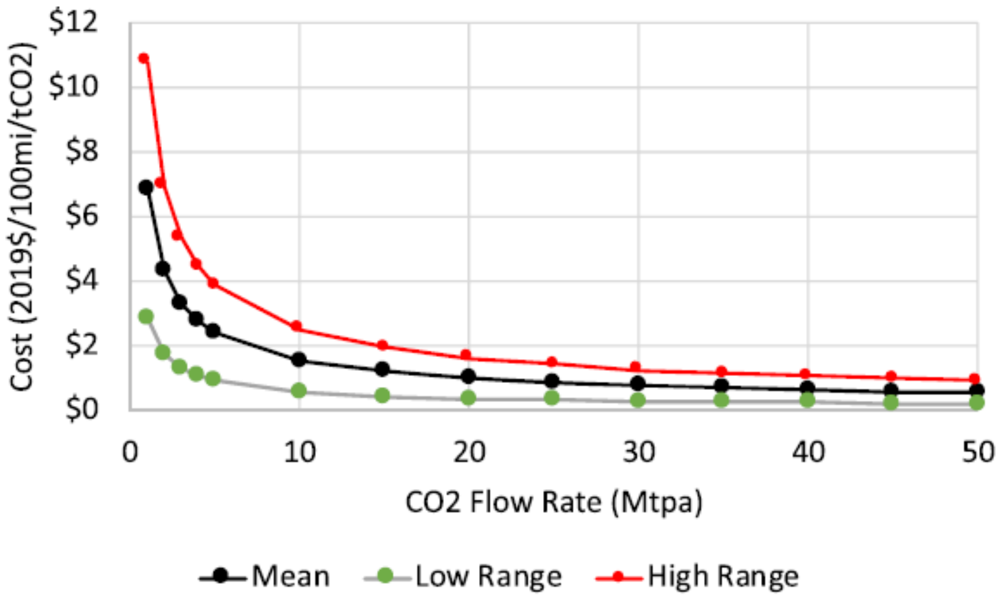



*Figure 304: Range of transport costs for pipelines as a function of $CO_2$ transport rate per year.*

*Source: Smith et al., (2021).*

The operating costs of a pipeline are mainly determined by the capital expenditure (CAPEX), which is proportional to the length of the pipeline. Changes in costs occur if the pipeline runs on land through difficult terrain, e.g. mountains or settlement.

### Transport of $CO_2$ via ship

Experience with the transport of liquefied $CO_2$ is currently not as extensive as with the transport of LNG or LPG (2,000 $tCO_2$ /year worldwide).[830] The infrastructure of $CO_2$ transport by ship consists of:

**Liquefaction**: $CO_2$ is brought to the liquid state through a series of cooling and compression steps

**Intermediate storage**: Buffer storage serves to close the gap between continuous $CO_2$ capture and discrete (batchwise) transport by ship

**Loading/unloading equipment:** The loading/unloading equipment consists of either conventional articulated loading arms or flexible cryogenic hoses and auxiliary equipment such as cryogenic pumps and piping for transfer from the storage tank to the loading arm and a return line for the evaporating gas

**Vessel**: Either a purpose-built $CO_2$ tanker or a converted vessel can be used; however, vessel conversion is challenging if the vessel is not originally designed to transport CO .2

**Conditioning:** $CO_2$ must be brought from a liquid state to a state in which it can be further transported or injected after shipment, usually by heating and pumping,

[830] Cf. Orchard et al., (2021).

When transporting by ship, conditions are set that keep $CO_2$ near the triple point in a semi-frozen state.[831] When transporting $CO_2$ , a loss of 3 -4 %/1,000 km is to be expected, which can be reduced by intercepting and reliquefying the $CO_2$ . [832]

The transport costs given by the IPCC (IPCC, 2005) show that transport by ship is more cost-effective than a pipeline from a transport distance of more than 1,800 km. The costs of transport by ship depend strongly on the size of the ships with the corresponding equipment and the existence of stations for loading and unloading the ships.

**Storage/finite storage of $CO_2$**

In principle, a distinction is made in the storage of $CO_2$ between storage in caverns, solution in underground, water-bearing strata (aquifers) and carbonisation of silicate-containing rock. Details on this have already been provided in chapter 2.8.5 and can be found there.

### 2.14.6.10 Costs of capture, transport and injection of $CO_2$

Figure 305 compares in detail the different transport modes of $CO_2$. It becomes clear that the transport of $CO_2$ via pipelines can play a role especially for large and long-term transport volumes. However, intercontinental transport via ships is comparatively expensive and will only be necessary to a limited extent in most cases, as the $CO_2$ is more likely to be reused regionally (Carbon Capture and Utilisation, CCU, see Chapter 2.9.) or injected (Carbon Capture and Storage, CCS, see Chapter 2.8.).

| Transport method | Costs (USD/t) | Capacity (Mtpa) | Advantages | Disadvantages | Ideal application |
|---|---|---|---|---|---|
| Offshore pipeline (new) | 3-25 | 1 - 20 | Long lifetime, high capacity | High capex, long permitting times | Large-scale offshore storage projects |
| Offshore pipeline (refurbished) | 3-25 | 1 - 10 | Reduced permitting time and environmental impact | High opex, shorter lifetime, reduced capacity | Large-scale offshore storage projects |
| Onshore pipeline (new) | 5-20 | 0.5 - 20 | Long lifetime, high capacity | Long permitting times, potential planning issues | Connecting clusters to onshore storage projects and coastal terminals |
| Onshore pipeline (refurbished) | 5-20 | 0.5 – 10 | Reduced permitting time, environmental impact and planning issues | Shorter lifetime, reduced capacity | Connecting clusters to onshore storage projects and coastal terminals |
| New build ship | 10-20 | 0.1 - 1 | Flexible source and storage locations,cheap over long distances | Lack of experience, not all ports can accommodate CO2 vessels | Connecting coastal point sources to terminals and offshore storage/EOR projects |
| Truck | 15-20 | 0.01-0.1 | Established technology from food and drink industry | Expensive for high capacity | Connecting small emitters outside of clusters to onshore storage projects and coastal terminals |
| Rail | ~10 | 0.1-1 | Existing infrastructure reduces capex | Limited routes | Connecting small-to –medium-size emitters to storage sites and coastal terminals |

*Figure 305: Comparison of $CO_2$ transport options.*

*Source: IGU, 2022a.*

[831] Cf. Kuckshinrich et al., 2010.
[832] Cf. IPCC, 2005.

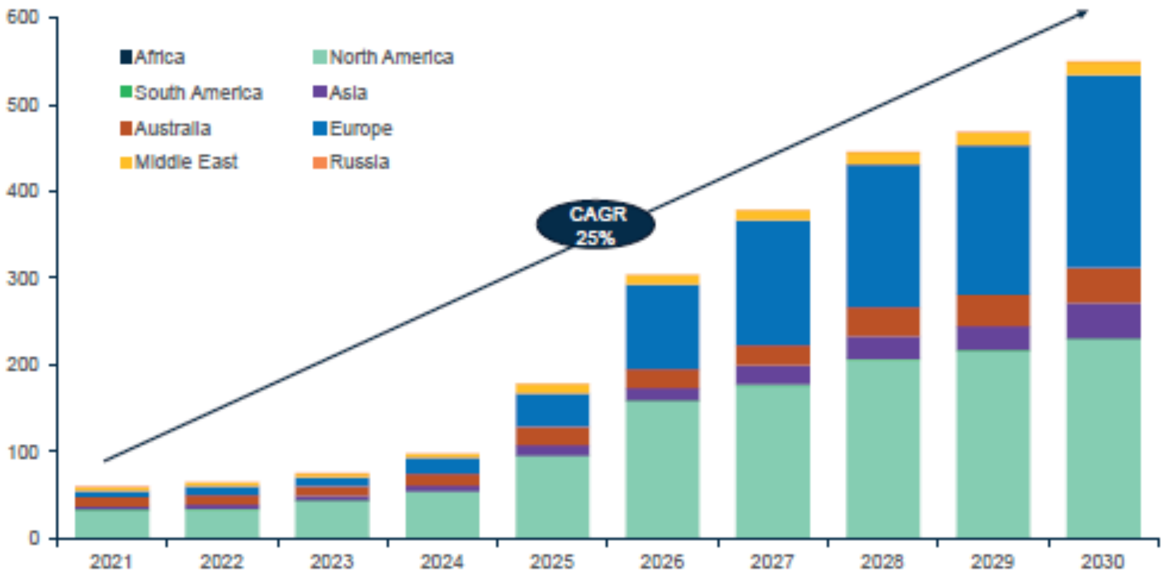
#### 2.14.6.11 Scaling the $CO_2$ infrastructure

The capture and injection of $CO_2$ is estimated to pick up significantly by 2030, reaching volumes of over 500 Mt $CO_2$ /year (Figure 306). Compared to today, this means a tenfold increase in the infrastructure needed to transport and store $CO_2$.

Scaling up to the quantities of 7.6 Gt $CO_2$ /year in 2050 estimated by the IEA would require an infrastructure more than 150 times larger than available today.[833] Almost all transport infrastructures and logistics chains for this would therefore still have to be built. This applies in particular to the transport of $CO_2$ from industrial emitters to the storage sites.

[833] Cf. IEA, 2021c; IEA, 2021b.

**Figure 44: CO2 capture demand outlook by region (million tpa of CO2 capture)**




Source: Rystad Energy

**Figure 45: CO2 capture demand outlook by sector (million tpa of CO2 capture)**

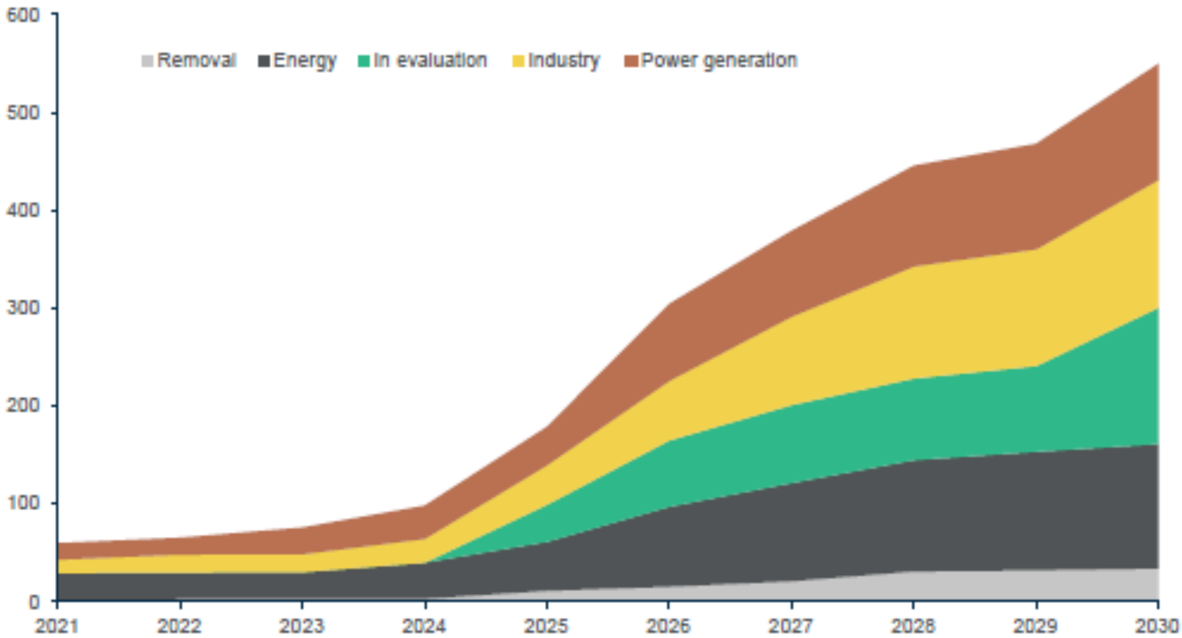



*Figure 306: Estimated scaling of $CO_2$ capture by 2030.*

*Source: IGU, 2022a.*

Assuming 100 USD/t$CO_2$ for capture at point sources until injection into the ground, the annual cost of CCS deployment in 2050 would be 760 billion USD. This is comparable to the annual investment required in wind and solar according to the IPCC. Accordingly, scaling up the large-scale use of CCS also requires significant capital.

#### 2.14.6.12 Framework for infrastructure development in different countries

Different countries and regions are very different in terms of their level of economic development, political systems, technological capacities, existing and planned energy infrastructures and fossil and renewable energy sources. General suggestions on which energy infrastructures point the "best" way to climate neutrality for which countries and regions can therefore hardly be given and detailed national or regional analyses are necessary. However, countries can be classified according to certain conditions. This enables an initial assessment for a sensible and realistic development of local energy infrastructures. For this purpose, countries or regions can be divided into three characteristic groups.[834]

- High degree of industrialisation, well-developed energy infrastructure
- Low level of industrialisation and little energy infrastructure
- Exporters of (fossil) liquid and gaseous energy sources

These groups are neither exclusive nor homogeneous. For example, some countries or regions fall into several categories to some extent. The expansion of electricity infrastructure is a priority in many countries even without the driver of climate neutrality. However, other infrastructure measures diverge depending on the group and the degree of renewable energy potential. The synopsis in Table 74 shows basic priorities for building new and rebuilding existing infrastructure and can serve as a guide for framework conditions in the field of energy infrastructure. It can only do limited justice to the complexity of a specific case, country or region.

*Table 74: Infrastructure development by group and renewable energy potential*

| | High potential for renewables | Low potential for renewables |
|---|---|---|
| **Group 1 (Industrial and Industrial Emerging Countries)** | Expansion of electricity infrastructure | Development and conversion of existing import capacities<br>Expansion of electricity infrastructure |

[834] This is done following the classification of different countries in terms of the development of their coal economies in Jakob & Steckel, (2022).

| | | |
|---|---|---|
| | Conversion and conversion of existing infrastructure to climate-neutral molecules<br>Low import capacities necessary | Conversion and expansion of existing infrastructure for molecules |
| **Group 2 (developing country)** | Expansion of electricity infrastructure<br>Building export capacities for climate-neutral molecules<br>according to internal consumption and storage requirements | Expansion of electricity infrastructure<br>Building import capacities for climate-neutral molecules<br>according to internal consumption and storage requirements |
| **Group 3 (Fossil exporters)** | Conversion of existing infrastructures for export of climate-neutral molecules and for consumption<br>Expansion of electricity infrastructure | Conversion of existing infrastructures for import of climate-neutral molecules and consumption<br>Expansion of electricity infrastructure |

### Role of sector coupling

In the past, the different sectors that provide energy (energy generation, transport and distribution) or consume energy (transport, buildings, industry) were often considered independently of each other. The concept of sector coupling is designed to better connect infrastructures and optimise them as an overall system. The goal is a higher permeability of energy flows between generation and consumption, greater flexibility, and also a consumption-side switch to electricity from renewable energies or other climate-neutral energy sources. The diversity of energy sources and consumption structures are very complex, especially in diversified industrialised countries. The coupling of sectors then leads to lower final energy consumption when consumers switch to electrified processes. However, electrification is not possible extensively or quickly in every sector. Therefore, energy in the form of molecules will also be needed in a future energy system.

Some of the existing fossil infrastructures can also be used for the transport and use of energy carriers such as hydrogen, ammonia or methanol.[835] The production of chemical energy carriers from renewable electricity (power-to-X), sustainable biomass or fossil energy carriers with CCS functionally links the different production and consumption sectors.

[835] These energy sources must be climate-neutral in their production and use.

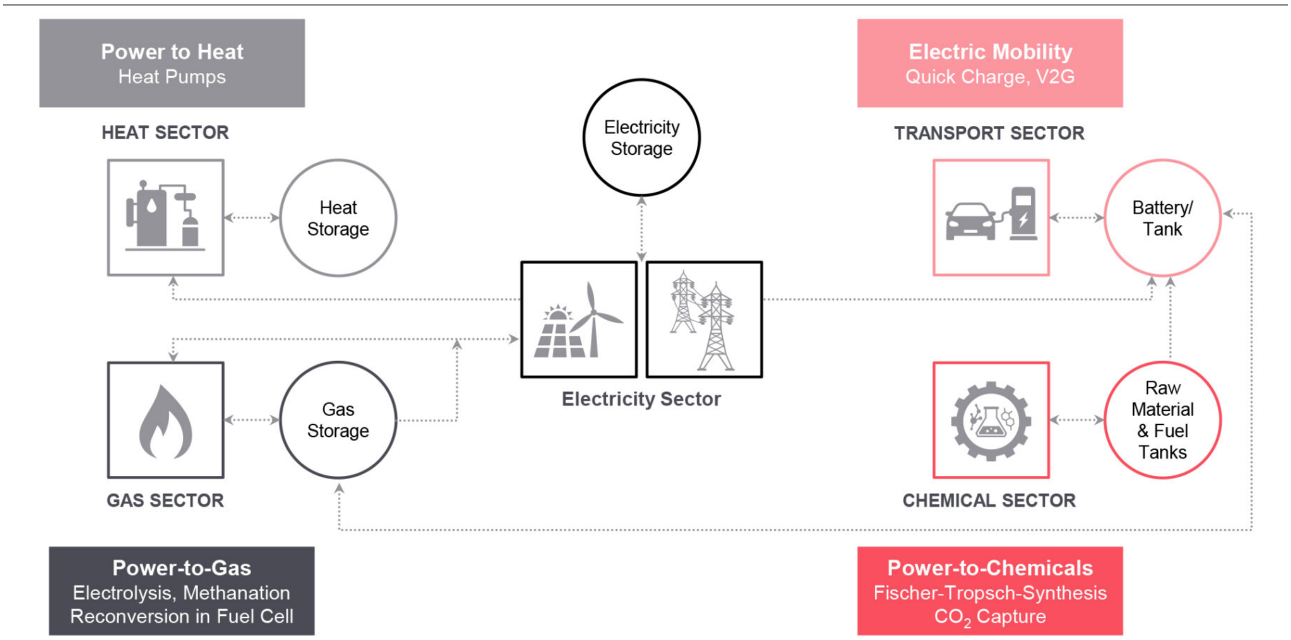



*Figure 307: Figure of sector coupling.*

*Source: Future Bridge, (2022).*

Economies of scale can make various sector coupling technologies economical. Therefore, optimal utilisation of infrastructure, especially transport infrastructure, is an important factor. If not only one consumption sector, but several consumption sectors (e.g. chemical industry and heavy-duty transport) can use climate-neutral hydrogen, ammonia or methanol, considerable synergy effects can arise in procurement and transport, both from a technical but also from an economic perspective. In order to leverage these synergies, cross-industry and cross-sectoral cooperation is needed.

### 2.14.6.13 Realisation / operation of energy and $CO_2$ infrastructure

Energy infrastructures of the technological-globalised world are among the most complex and largest man-made structures of modern times. This concerns the planning, construction and operational, i.e. the technical side, as well as the financial, administrative and regulatory side. As is often the case in a world of states with different political, social and technical conditions, there is no patent recipe for how governance for energy infrastructure should be regulated and implemented. A variety of political and economic structures, ideas and elements influence the realisation and operation of grid-connected and non-grid-connected infrastructure for the realisation of a climate-neutral energy system. This means that a uniform and generally valid representation of actors, financing and operating mechanisms of these infrastructures is only possible to a limited extent globally.

In general, however, a distinction can be made between systems that are strongly state-owned and those that are strongly private. Nevertheless, even between different energy infrastructures within a country, major differences can occur in terms of governance, ownership and decision-making power. In detail, energy infrastructures can be differentiated according to four models with varying degrees of state or private sector influence:[836]

- Full state ownership, financing and management
- Public-private cooperation (public-private partnership PPP) in various forms
- Private ownership, financing and management under state supervision and regulation (regulatory asset base) in various forms
- Private ownership, financing and management

Since large-scale energy infrastructure in most cases requires large amounts of capital and has a long service life, fulfils an important economic function and serves to supply many large and small customers, state influence is also very strong in liberalised and free markets. In many countries of the industrialised North, the influence of the state on energy infrastructure is nevertheless less than in less liberalised emerging countries (Figure 308).[837]

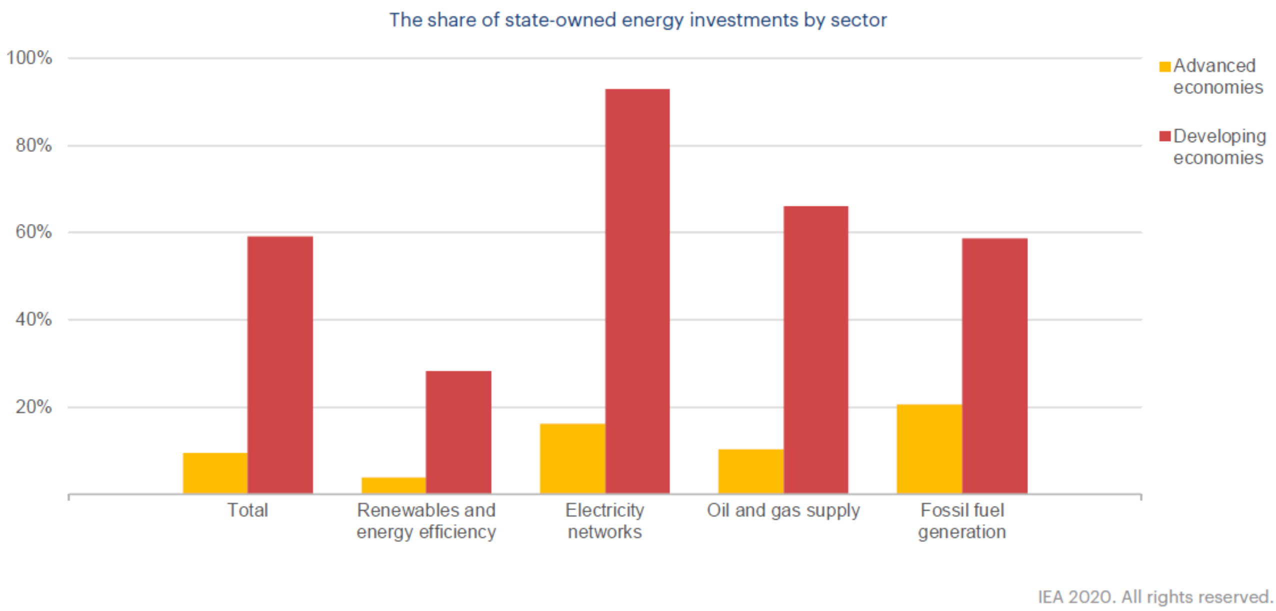



*Figure 308: Share of state investment in the energy sector.*

*Source: IEA, 2020b.*

Figure 309 shows different governance modes for energy infrastructure in detail, which allows an important aid for the classification of energy infrastructure projects with regard to planning, financing, involved actors and operation.

[836] Cf. Lowes & Woodman, (2020).
[837] Cf. Prague et al., 2018; IEA, 20202020b.

| | Statism (public) | | | Co-ordinated marketism (mixed) | | | Liberal marketism (private) | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Model | Public build and public own | Public commission, private build, public ownership | Public commission, private build, joint ownership | Public commission, private build and private ownership | PPP/PFI | Regulated asset base | Direct financial incentives | Competitive incentive systems | Market creation through regulation | Active de-regulation/free markets |
| Who decides? | State | State | State | State | State | State | Private sector | Private sector | Private sector | Private sector |
| Who builds? | State | Private sector | Private sector | Private sector | Private sector | Private sector | Private sector | Private sector | Private sector | Private sector |
| Who owns asset? | State | State | State/private | Private | Private? Special purpose vehicle? | Private | Private | Private | Private | Private |
| Who manages? | State | State | Joint | Private | Private/state | Private | Private | Private | Private | Private |

*Figure 309: Governance modes for energy infrastructure.*

*Source: Lowes & Woodman, (2020).*

Particularly in the case of pipeline infrastructure (oil and gas pipelines; electricity and heat grids), state decision-making power is often greater than in the case of non-pipeline infrastructure (extraction, conversion, generation and consumption facilities for fossil fuels or renewable energies; tankers and export/import facilities for LNG, coal or other chemical energy sources). The following chapters examine the actors and operation as well as financing of different energy infrastructures on the way to a global climate-neutral energy system.

It should be noted that only large-scale energy infrastructures are discussed in the following. However, the provision of energy to people, especially in countries with little or no existing energy infrastructure, is often much more decentralised and sometimes without a connection to a central supply infrastructure. In Africa and South Asia, for example, many decentralised energy infrastructures based on renewable energies have emerged in recent years, e.g. solar home systems or rural biogas facilities that are not connected to the official (electricity) infrastructure grid. These decentralised and comparatively simple energy infrastructures can also improve the economic and social situation of the rural population in developing and emerging countries.[838]

### Actors and operation

Actors who play a significant role in energy infrastructure can be classified according to their functional-technical importance in addition to the distinction of whether influence and

[838] Cf. Worldbank, 2021; IRENA, 2021b.

ownership is predominantly state-owned, private or a mixture. Here, a distinction can be made between line-bound and not line-bound infrastructure.

Thus, pipeline-based energy infrastructures represent a natural monopoly and the power of disposal over the pipeline or the grid determines which other actors have access to the infrastructure and the respective transported energy carriers at what prices (see Figure 310). Transport pipelines (especially oil and gas) across national borders are often planned, realised and operated in cooperation between the countries involved and their energy organisations or companies (whether state-owned or private).

The further transport and distribution of gas and electricity within a country is carried out by grid operators, while liquid energy sources are often distributed via rail or road networks after conversion into usable fuels in refineries. The transport of gas or electricity, which can be used directly by consumers, is the task of transmission system operators (TSOs) over longer distances and at a higher infrastructure level. Further distribution in the lower network levels is sometimes carried out by smaller regional or local Distribution System Operators (DSOs).

International non-pipeline energy infrastructures (oil and natural gas) often consist of a transport chain from the export terminal via tankers to the import terminal (compare chapter on LNG). The export and import terminals are operated by state-owned or private energy companies or consortia. The ship transport is organised by large energy companies or specialised charter companies. As non-pipeline infrastructure is less prone to monopolistic action, private companies are more likely to be found in this sector. Generally, however, this depends on the governance structure of the energy system of the country concerned.

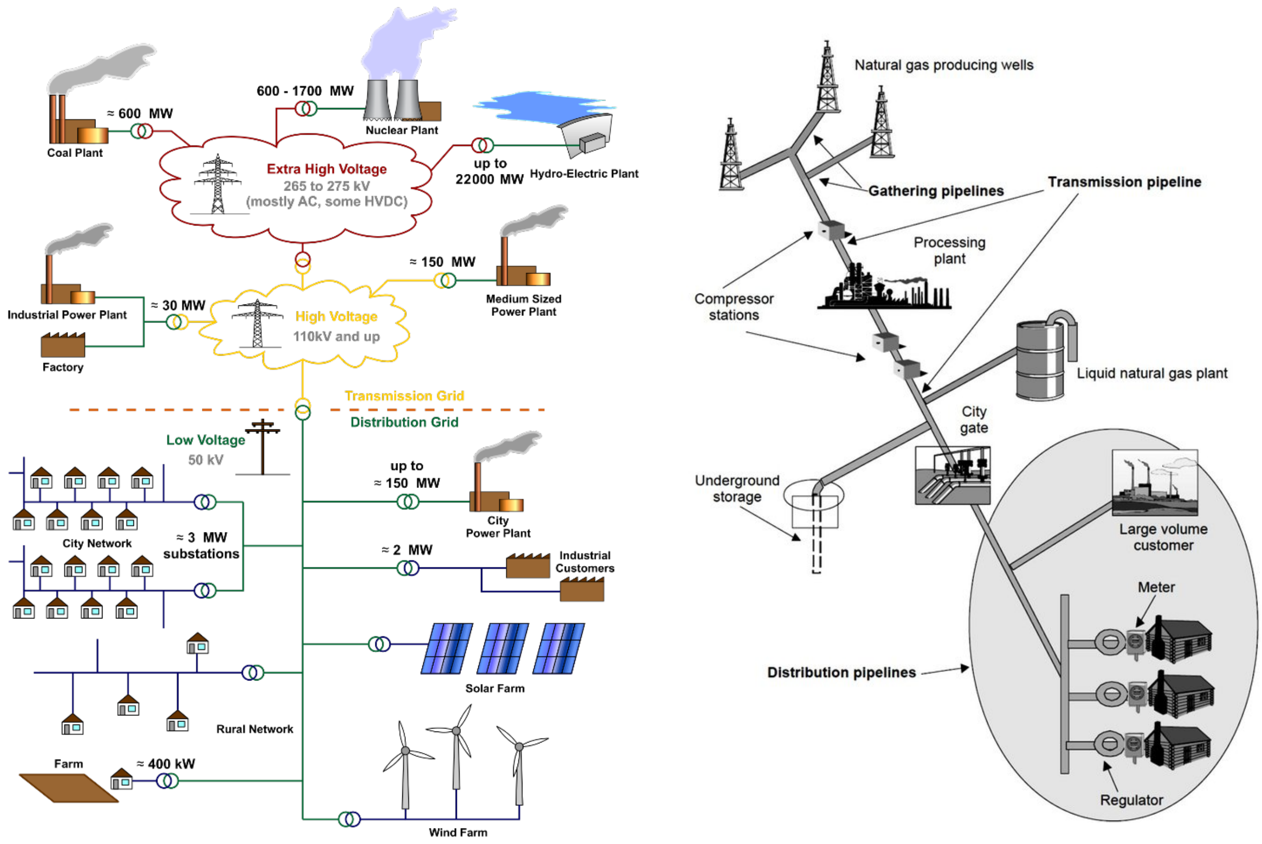



*Figure 310: Structure of the grid-based infrastructures for electricity (left) and gas (right)*

*Source (left): Wikipedia, 2022; Source (right): Parvizsedghy, 2015.*

To illustrate different governance modes and actors in the field of energy infrastructures worldwide, three countries are compared below: Morocco as an example of a smaller emerging country with a high share of energy imports, India as a large emerging country with industry and existing energy infrastructures, and Germany as an example of a liberalised industrialised country (see Table 75).

Table 75: Key governance indicators, actors and energy infrastructures in Morocco, India and Germany[839]

| | **Morocco** | **India** | **Germany** |
|---|---|---|---|
| **Governance (electricity transmission infrastructure)** | State | State | Private with regulation and state |
| **Governance (gas transport infrastructure)** | State | State | Private with regulation and state |
| **Key players** | ONEE (Electricity Networks), | Power Grid Corporation of India (power | Tennet TSO, 50Hertz, Amprion, TransnetBW |

[839] The presentation is limited to the most important and largest infrastructures and actors.

| | | | |
|---|---|---|---|
| | SNPP (gas pipelines) | transmission)<br>Gas Authority of India and India Oil (gas and oil pipelines) | (electricity transmission grid)<br>GTG Nord, gasunie, GRTgaz, nowega, Thyssengas, Ontras, fluxys, OGE, Gascade, terranets BW, bayernets, ferngas (gas pipelines) |
| **Important infrastructures[840]** | Mainly coastal transmission network,<br>Maghreb-Europe pipeline (gas),<br>Oil and gas production structures and ports | Expanded transmission network,<br>Expanded transport pipelines for oil and gas,<br>Oil and gas production structures and ports | EU-wide integrated electricity grid,<br>EU-wide integrated gas grid,<br>Import ports for oil and, in the future, LNG |

As can be seen from the comparison above, the density of actors is generally higher in liberalised states, as different private sector actors build, own and operate energy (transport) infrastructure (Figure 308). In addition to the diversity of actors, the regulatory framework is often more complex, as both the interests of the general public with regard to the supply of energy and the interests of private actors must be taken into account. A high degree of transparency with regard to infrastructure costs is provided by reporting obligations in liberalised energy markets such as in Germany, while in the case of state-owned infrastructure (and possibly without strong control) there is often less information on costs, planning and operation.

### The role of state-owned enterprises

State-owned enterprises (SOEs)[841] own large parts of the energy infrastructure in many countries around the world and as a group emit over 6.2 Gt $CO_2$ /year. There is ample evidence of a strong link between fossil fuel production, energy infrastructure and SOEs. For example, SOEs hold over 60% of the world's power generation capacity in operation and in planning. [842]

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[840] A map view for the individual countries can be found in the appendix.
[841] OECD definition: "any legal entity that is recognised as an enterprise under national law and in which the state exercises ownership should be considered a SOE." (Prague et al., 2018, p. 13)
[842] Cf. Prague et al., (2018).

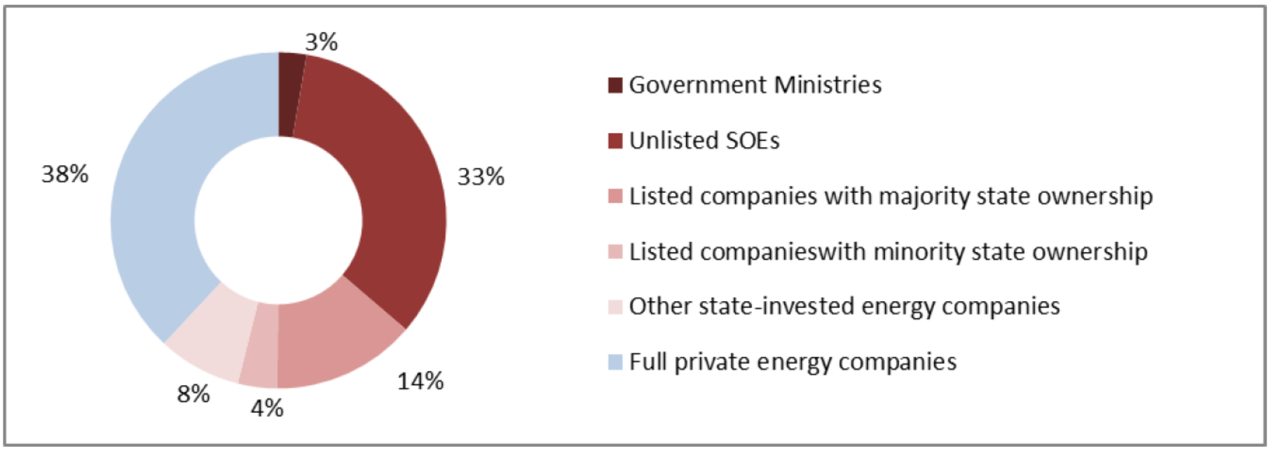


*Figure 311: Ownership of global electricity generation (operating and planned) in 2016.*

*Source: Prague et al., (2018).*

SOEs are unusual market participants. First, they may be strongly influenced by government mandates that go beyond general policy levers such as regulation and pricing. Second, SOEs may have objectives beyond maximising financial returns, such as social or environmental goals. SOEs may also benefit from preferential treatment by their state owners, such as advantages in financing or regulatory exemptions. However, these differences with private companies also raise concerns: potential preferential treatment may distort the market and crowd out private investment. The ability of SOEs to invest may also be adversely affected if political pressure requires SOEs to provide consumers with artificially low energy prices.[843]

The extent to which SOEs can shape and influence the development towards climate-neutral energy infrastructures often depends on the individual case and country. Government mandates and political goals for a managed transition to low-carbon technologies play a major role. In addition to the political factor, other issues play a role when considering SEOs for a carbon-neutral energy system. Many of the SOEs are very large corporations that control an enormous amount of assets and financial resources; some are among the largest companies in the world. They also often have a high level of technical and commercial expertise and are active in business areas that are of outstanding importance for a climate-neutral energy system. This powerful combination of resources in SOEs can support the transformation to a low-carbon energy system through political pressure or appropriate government support.[844]

#### 2.14.6.14 Financing of energy infrastructure

In the course of the climate-neutral transformation of global energy production and consumption, the need for investment in energy infrastructure will increase. Driven by a high increase

[843] Cf. Prague et al., 2018; OECD, (2018).
[844] Cf. Benoit, (2019).

in renewable energies and a strong electrification of the energy system, the electricity grids in the industrialised countries in particular must be upgraded and expanded. At the same time, it is not yet foreseeable to what extent existing infrastructure for the transport of oil and natural gas will continue to be operated with climate-neutral energy sources and what specific investment requirements will be necessary for infrastructure for climate-neutral molecule-based energy sources. This will vary from region to region and depending on the speed of socio-economic and industrial development, the expansion of renewable energies, integration into international supply chains for energy and resource availability. In any case, existing infrastructures are an important asset, which will probably still be needed on a large scale in the transition period to a more electrified energy system, but also for the transport and distribution of climate-neutral molecules.

**Financing requirements**

Thus, the questions of what costs different energy infrastructures have and how energy infrastructure is financed are highly relevant for the implementation of a system transformation towards renewable energies and climate-neutral energy sources. In 2019, global investment in the energy system was over USD 1,900 billion. [845]Figure 312 shows the breakdown by sector. More than half of today's investments in the energy sector still fall on fossil energy sources and infrastructure.

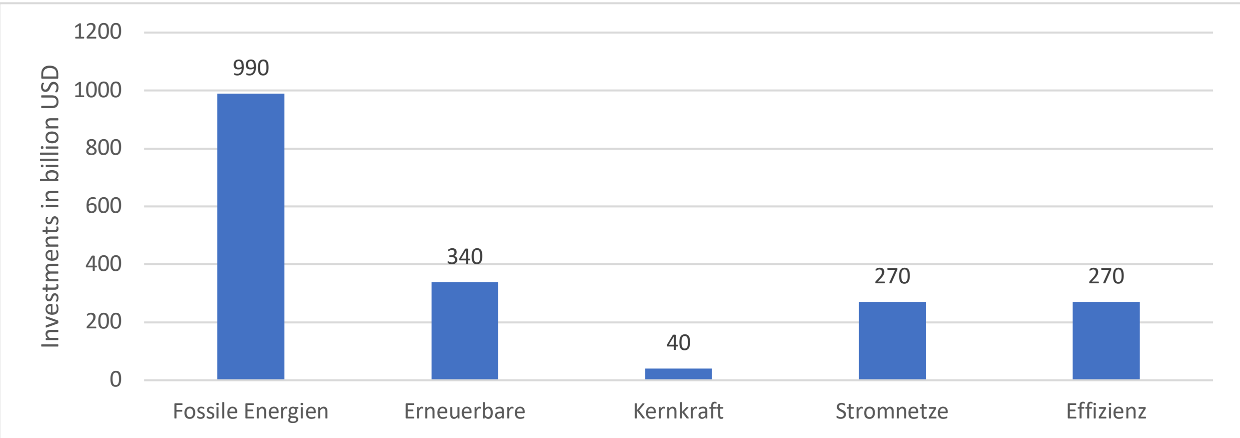


*Figure 312: Global investment in the energy sector in 2019.*

*Source: IPCC, 2022*

According to the IPCC, the investments for achieving a 2°C climate path amount to 2,100-4,100 billion USD/year in the period 2016-2050 (depending on the model). For achieving a 1.5°C pathway, the investments are not significantly higher at USD 2,400-4,700 billion/year.[846]

[845] Cf. IPCC, (2022).
[846] Cf. IPCC, (2022).

Further estimates for the total investment required for a climate-neutral energy system in 2050 are given in Figure 313 and are at a similar level to those of the IPCC.

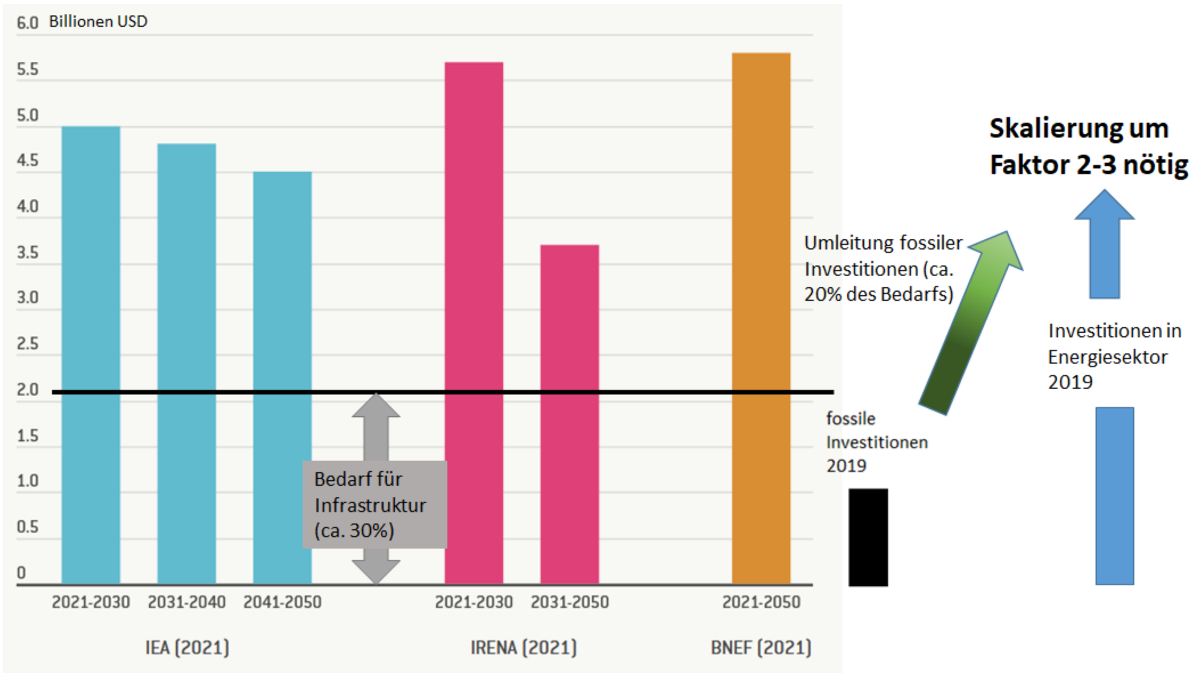


*Figure 313: Annual global investment required for a climate-neutral energy system (adapted by author). Source: Bruegel, (2021).*

The annual investments required for a climate-neutral energy system are "only" a factor of 2 - 3 higher than today's investments. According to the IEA, investments of around 1,000-1,500 billion USD/year will have to be made in the period from 2026 to 2030 in the construction and reconstruction of energy infrastructures. A large part of this will be needed to build electricity infrastructure in emerging economies (Chapter 2.7.4).[847] According to the IPCC, investments in the area of electrification and the expansion of electricity infrastructure are also crucial (see Figure 314).

[847] Cf. IEA, 2021b; Bruegel, (2021).

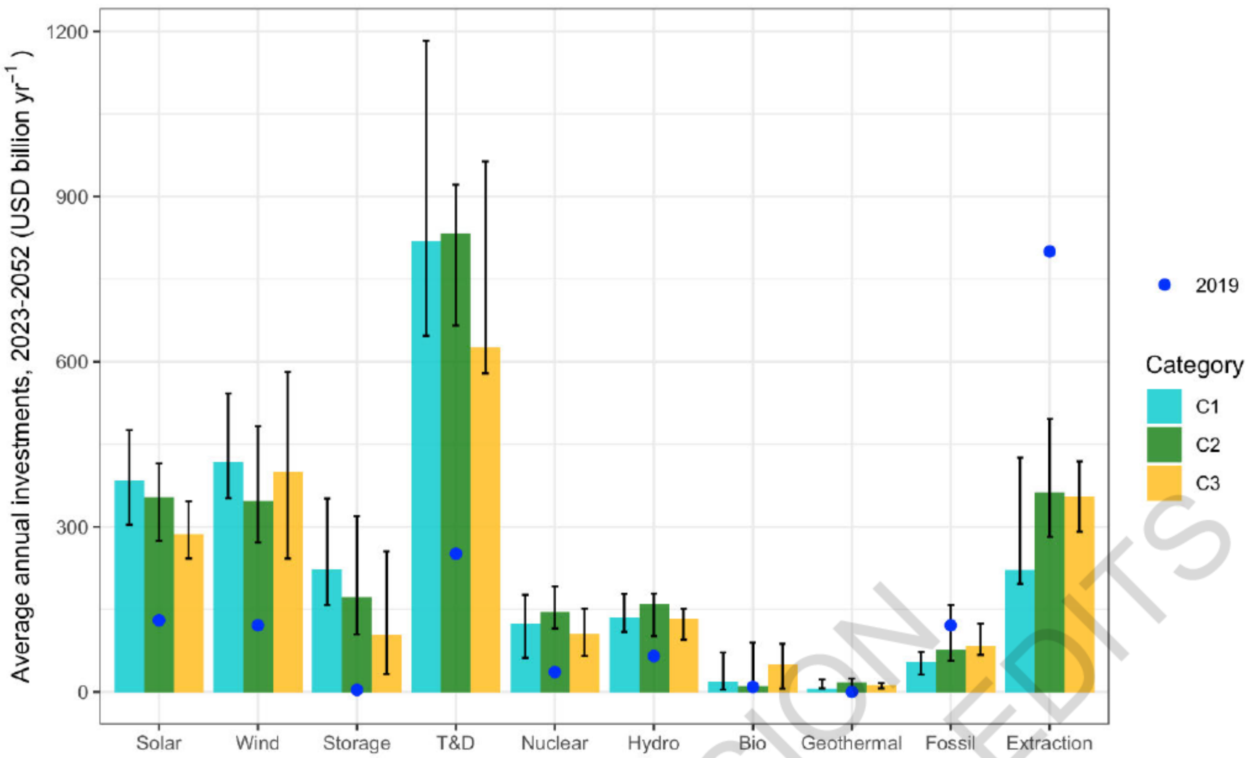


**Figure 6.32 Global average annual investments from 2023 to 2052 (undiscounted, in USD billion yr$^{-1}$) for electricity supply sub-sectors and for extraction of fossil fuels in C1-C3 pathways (Source: AR6 Scenario Database and Chapter 3). Historical investments are also shown for comparison (Source: IEA, 2021; approximations are made for hydro and geothermal based on available data; solar and wind values are for 2020). 'T&D': transmission and distribution of electricity. Bars show median values across models-scenarios, and whiskers the inter-quartile ranges. See Chapters 3 and 15 for additional information on investments and finance.**

*Figure 314: Average annual investments in the power sector in billion USD/year (C1: Below 1.5 degrees and no or hardly any overshoot, C2: Below 1.5 degrees with high overshoot, C3: min. 66 % probability below 2 degrees).*

*Source: IPCC, (2022).*

Interestingly, the expansion of the electricity grid infrastructure by 2050 will require about the same amount of investment per year as is flowing into the fossil part of the energy system today. Since exploration and use of fossil energy sources decreases by 90% for coal, 75% for oil and 55% for natural gas by 2050 in the IEA's Net Zero scenario, for example, the main question is how these financial flows can be diverted into the sectors to be expanded for a climate-neutral energy system.[848]

However, in addition to diverting financial flows from fossil infrastructure, additional capital is also needed for the restructuring of the energy system.

[848] Cf. IRENA, (2020).

### Financing and investment models

The financing of infrastructure projects is complex and subject to a variety of regulatory, technical, social and economic constraints. Infrastructure projects are usually very capital-intensive and must be refinanced over long terms. A schematic representation of the cash flow for infrastructure projects is shown in Figure 315 can be seen. The long-term character and the high investment costs in the construction phase become clear here.

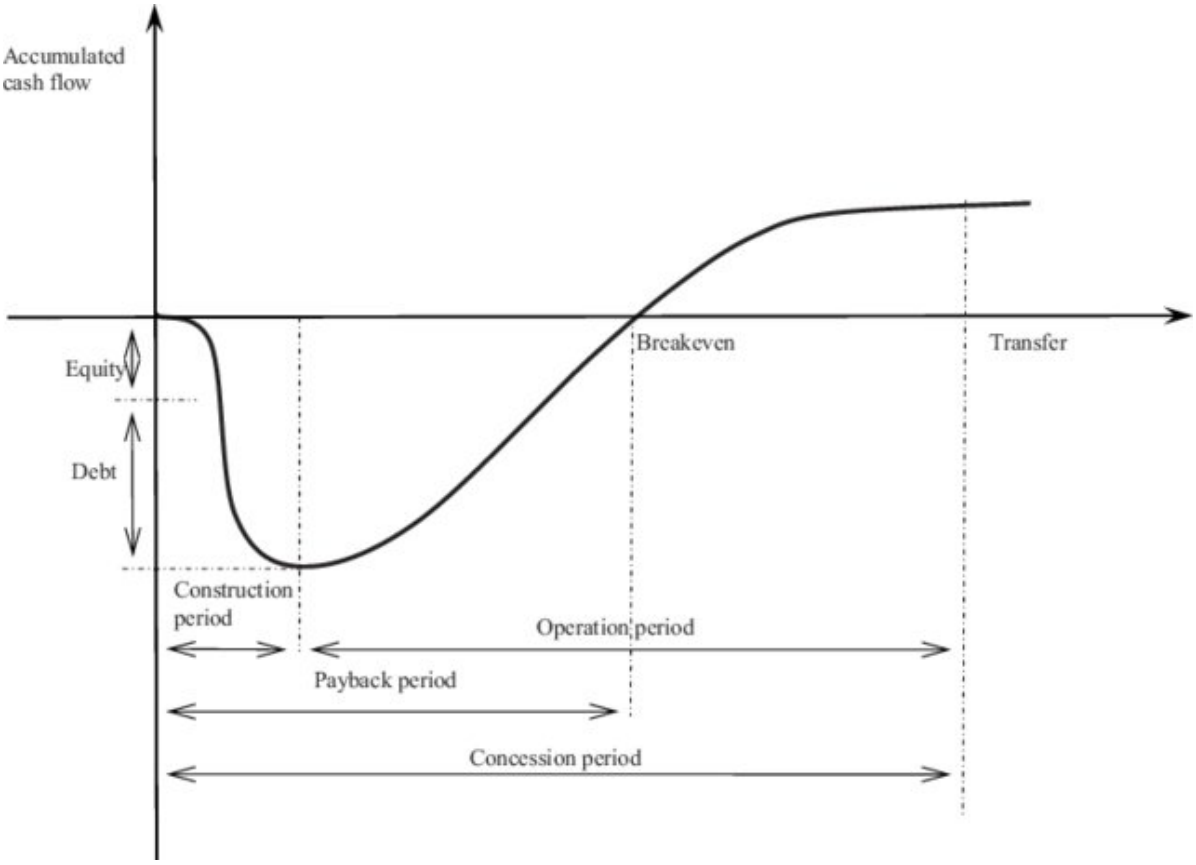


*Figure 315: Schematic representation of cash flow in infrastructure projects.*

*Source: Zhang, (2009).*

This is also reflected in the organisational structure of project finance. In many cases, a project company, also called a special purpose vehicle, is set up for the construction of a large-scale infrastructure (see Figure 316). This company implements the construction and sometimes also the subsequent operation of the infrastructure. In large infrastructure projects, the shareholders in the project company often also act as equity providers or investors with 10 - 30 % of the project costs. The further financing of 70 - 90 % is then secured through lenders, especially banks. [849]

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[849] Cf. Gundes, (2022).

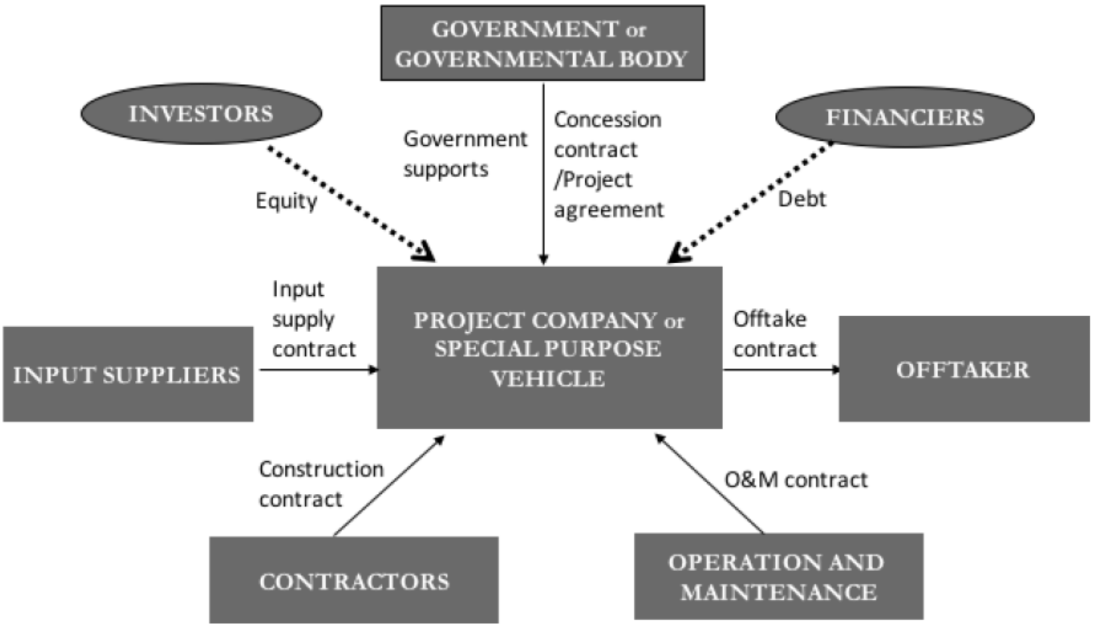


*Figure 316: Typical organisational structure for project financing.*

*Source: Gundes, (2022).*

Depending on the infrastructure, the companies involved and the financing conditions, such as interest rates, state guarantees or risk assumption, the financing model can also be structured differently. Table 76 compares traditional financing methods with newer and innovative approaches.

*Table 76: Financing methods for energy infrastructure*

| Traditional financing methods | Innovative financing approaches |
|---|---|
| National public funding | Private Public Partnerships |
| Multilateral development banks | Foreign sovereign wealth funds |
| Capital markets | International bond market |
| | Foreign direct investment |
| | Pension funds |

### Funding mechanisms and key players

In general, the operators or project companies of infrastructures (whether public or private) act as demanders on capital markets. Providers of debt capital are the public sector, risk and equity capital providers, institutional investors such as sovereign wealth funds, pension funds, insurance companies or investment companies, foundations, family offices (management of large private assets) as well as production companies and smaller private investors. Banks and development banks as lenders have the function of intermediaries on the capital markets. The different capital providers also have different endowments of capital, willingness to take risks or expectations of returns.[850] An interaction of different actors in the financial sector is shown in Figure 317 illustrates. In addition to intermediaries such as banks or institutional investors, international development finance institutions may also be involved in financing projects. These can support private banks or national and regional development banks in financing. The participation of development banks through capital according to market conditions as well as technical and operational support for financing promotes trust and can thus facilitate or even enable financing by other actors in the national or international financial ecosystem.

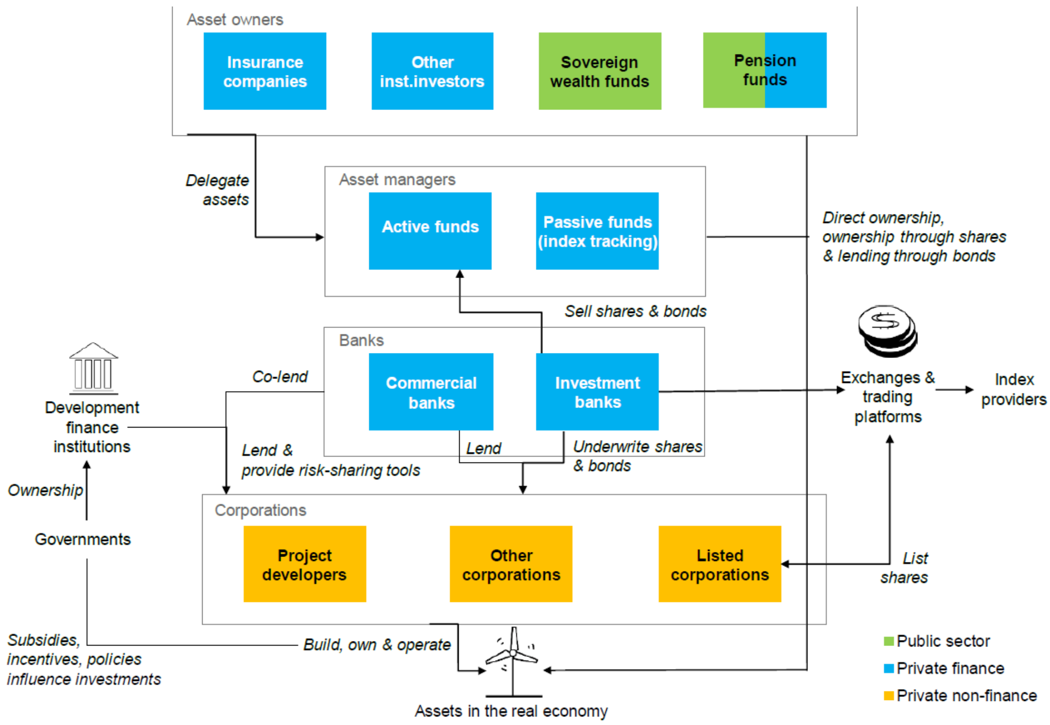


*Figure 317: Investment chain: interaction of the private and public sectors and project developers.*

*Source: BNEF/CIF, (2021).*

In countries with an established domestic financial sector, additional, more sophisticated financing models are available, especially if a country has a well-developed domestic capital market or access to international capital markets. Institutional investors such as pension funds or sovereign wealth funds can also be involved as intermediaries in the financing of energy projects. For example, institutions such as insurance companies can invest in energy infrastructure projects as part of their portfolio diversification. This could be done through an equity investment in an energy infrastructure project or developer. the purchase of publicly or privately traded securities is also a possibility. Important actors for financing energy infrastructure are therefore governments and SOEs, private energy (infrastructure) companies, development banks (international to local), special financing facilities, but also institutional investors and investors. The different actors and their functions are briefly explained below.

[850] Cf. WBGU, (2012).

The important role of SOEs for energy infrastructure, especially in emerging markets, has already been mentioned. Despite a decline, the share of SOEs in power grid infrastructures, and thus in the investments made, still accounts for over 50% of global investments in this sector in 2019 (see Figure 318).

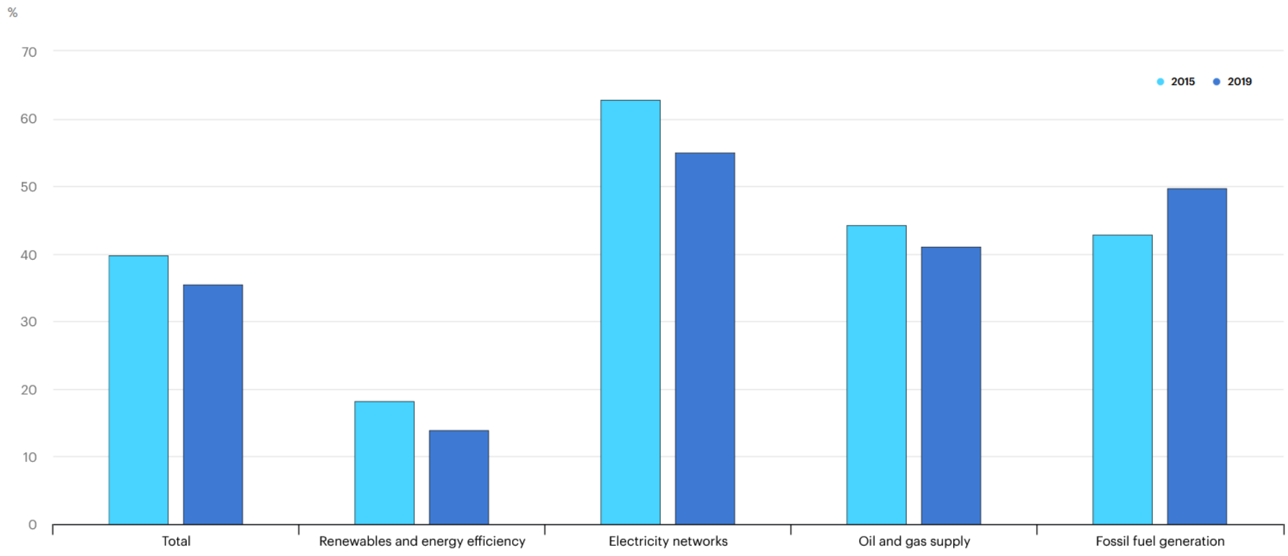


*Figure 318: Share of government/SOE participation in global energy investment by sector, 2015 compared to 2019.*

*Source: IEA, 2020a.*

Private energy (infrastructure) companies also play an important role as project developers and operators.

Multilateral development banks (often also known as multilateral development banks or finance institutions) have a special role in enabling financing as already shown in Figure 317 explained. Often, international and multilateral development banks have a geographical focus (Asian Development Bank, African Development Bank Group, European Bank for Reconstruction and Development).[851]

In addition to the international development banks, many regions and countries have national or regional development or investment banks that act as financiers for energy infrastructure projects. One such bank is the European Investment Bank (EIB), which together with the European Investment Fund (EIF) invested more than EUR 72 billion worldwide in 2019. Over 30% of the financing went to climate-related projects. Since 2022, no fossil fuel projects have been financed by the EIB, unless the infrastructure in question is suitable and planned for the integration of climate-neutral energy sources. By 2025, EUR 30 billion per year is to flow into sustainable investments. [852]

[851] Cf. Bundesbank, (2022).
[852] Cf. European Investment Bank Group, (2020).

Specialised financing facilities in the field of climate finance also exist. In some cases, these institutions have a mandate to support specific sectors, regions or groups of people in financing energy projects. Examples are:

- Green Climate Fund (14 billion USD/year, planned 100 billion USD/year)[853]
- Climate Investment Funds of various multilateral development banks and countries (10 billion USD/year)[854]
- DBSA Climate Finance Facility with focus on South Africa, Eswatini, Namibia and Lesotho[855]
- Global Infrastructure Facility (G20 initiative with the overarching goal of increasing private investment in infrastructure in emerging and developing countries)[856]

With over $100 trillion in assets under management, institutional investors - including infrastructure funds, insurance companies, pension funds, private equity and sovereign wealth funds - are a major potential source of financing for the energy sector. Much of the financing of energy infrastructure is based on traditional balance sheet financing or project financing via loans from banks. Institutional investors can provide further funding through: Equity participation or the purchase of bonds of a company, through equity participation in projects or through special funds or investment vehicles. Currently, institutional investors still play a minor role, but the trend is upwards as Figure 319 shows. The role of institutional investors in SOEs is generally very limited. [857]

[853] Cf. Frankfurt School, (2022).
[854] Cf. CIF, (2022).
[855] Cf. GCF, (2022).
[856] Cf. GIF, (2021).
[857] Cf. IEA, (2020b).

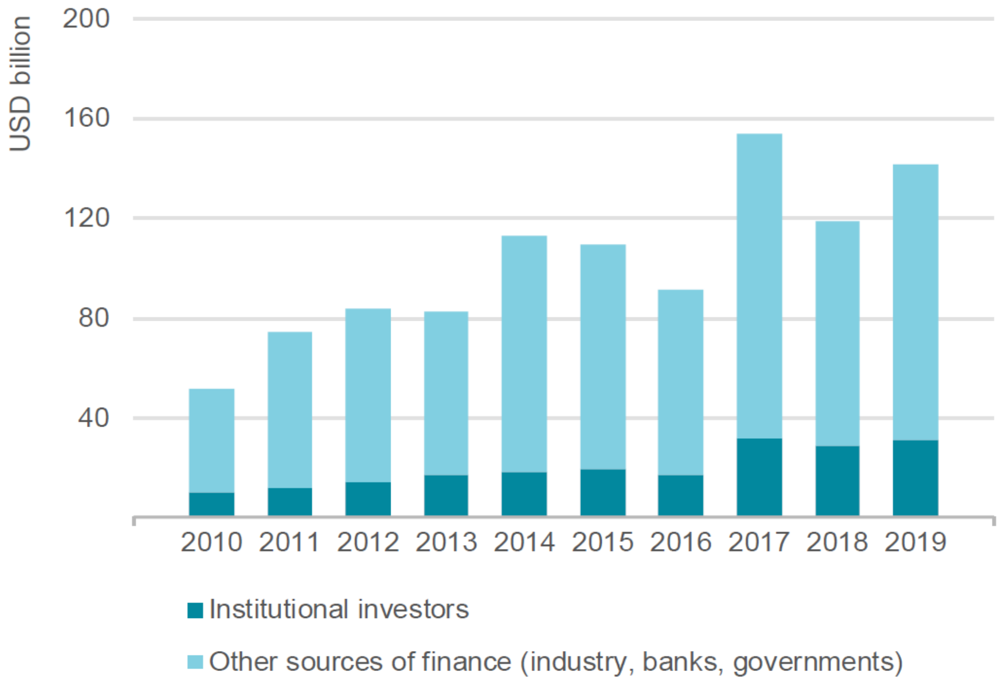


*Figure 319: Financing and acquisition of energy projects by source of finance.*

*Source: IEA, 2020b.*

**Challenges and solutions**

Both government funding and private capital are needed to meet the investment requirements of a climate-neutral energy system. However, there are barriers and challenges to financing energy infrastructure projects. Especially the high initial investments and the high demand for debt capital as well as long payback periods of up to 50 years make financing difficult. The long commitment of a lot of capital and the associated sunk costs and difficulties in easily liquidating the investment inhibit access to many classic capital providers. High transaction and information costs due to the complexity of transregional or international projects have a negative impact. Uncertainties regarding price regulation of the infrastructure and thus refinancing options, as well as the possibility of technological lock-in and the associated risks of a stranded asset are further challenges (an overview of the challenges can be found in the appendix).[858] In addition to these general financing barriers, there are sometimes further barriers in developing and emerging countries to the preconditions for at least foreign direct investment:[859]

- Low political or economic stability
- Limited legal certainty
- Currency risks and the risk of inflation

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[858] Cf. BNEF/CIF, 2021; WBGU, 2012; OECD, 2015.
[859] Cf. WBGU, 2012.

- Small-scale projects and lack of economies of scale
- Low market access of energy consumers and low willingness to pay
- Lack of technical know-how for project implementation

However, there are ways to meet the challenges and at the same time leverage the large financing potential of institutional investors (see Figure 320). It is important to build a pipeline of high quality and creditworthy infrastructure programmes by governments in the respective countries. The development and application of standard contracts and documents for transactions helps to simplify the investment process. Aggregation platforms that collect energy infrastructure projects as a viable asset class need to be created. Development and investment banks, as well as dedicated financing facilities, have a special role to play: they need to act as intermediaries between governments and the private sector to implement risk mitigation instruments and improve the overall market infrastructure. [860]

| | Current Challenges | Action Areas to Facilitate Investment |
|---|---|---|
| **Demand Side** | 1) Lack of bankable projects<br>2) Elevated transaction costs<br>3) Fear over investment quality stemming from macroeconomic and political uncertainty<br>4) Small ticket sizes relative to transaction costs<br>5) Limited transparency regarding ESG compliance | 1) **Expand** infrastructure pipeline development through high-quality project preparation<br>2) **Promote** standardisation of new/greenfield projects<br>3) **Increase** use of credit enhancement products<br>4) **Create** aggregation platforms<br>5) **Enhance** integration and disclosure around ESG alignment |
| **Supply Side** | 1) Low capacity to prepare infrastructure projects that are attractive to private investment<br>2) Constrained public funds and capacity<br>3) Sub-investment-grade sovereign ratings<br>4) Constrained capacity to bundle infrastructure assets to increase overall ticket size<br>5) Lack of resilient, sustainable infrastructure projects capable of withstanding future climate-related events | |

*Figure 320: Challenges and solutions for mobilising institutional capital for infrastructure investment.*

*Source: Swiss Re Institute, (2021).*

### 2.14.7 Relevance for development cooperation

The availability of energy is a central prerequisite for the realisation of a high standard of living, as it already exists for some countries and is to be realised for many countries in the future. In the course of the transformation to a climate-neutral energy system worldwide, energy (transport) infrastructures have an important function, especially because this period first means the large-scale construction of energy infrastructure for many low-income countries. Renewable or climate-neutral electricity can be distributed to local and regional consumers, but also worldwide, via the power grid or after being converted into molecular form. Energy transport infrastructures thus connect regions with high potential and thus favourable generation possibilities for renewable energies with regions of high consumption and lower generation

[860] Cf. Swiss Re Institute, (2021).

potential at higher costs. From a global perspective, emerging and developing countries that were previously not integrated into the global and fossil energy value chains, or only to a limited extent, can benefit from this.

The potential for the generation of renewable energies thus becomes a resource. In a climate-neutral energy system, large areas without large settlements with high solar radiation and / or wind availability will have the same importance as oil, gas and coal deposits in a fossil energy system today. Countries with such resources can develop economically relevant sectors for their own consumption and the export of climate-neutral energy by tapping these resources.

However, the construction of energy (transport) infrastructures is complex and expensive. Therefore, many developing and emerging countries find it difficult to build the infrastructure on their own. Long-term bilateral or multilateral partnerships can play an important role here, which will probably lead to local use and the development of economic capacities in the producer countries going hand in hand with the export of renewably generated energy in order to realise "win-win" situations. In this context, capital and technical know-how from an industrialised country can be used for the development of energy production and transport infrastructure.

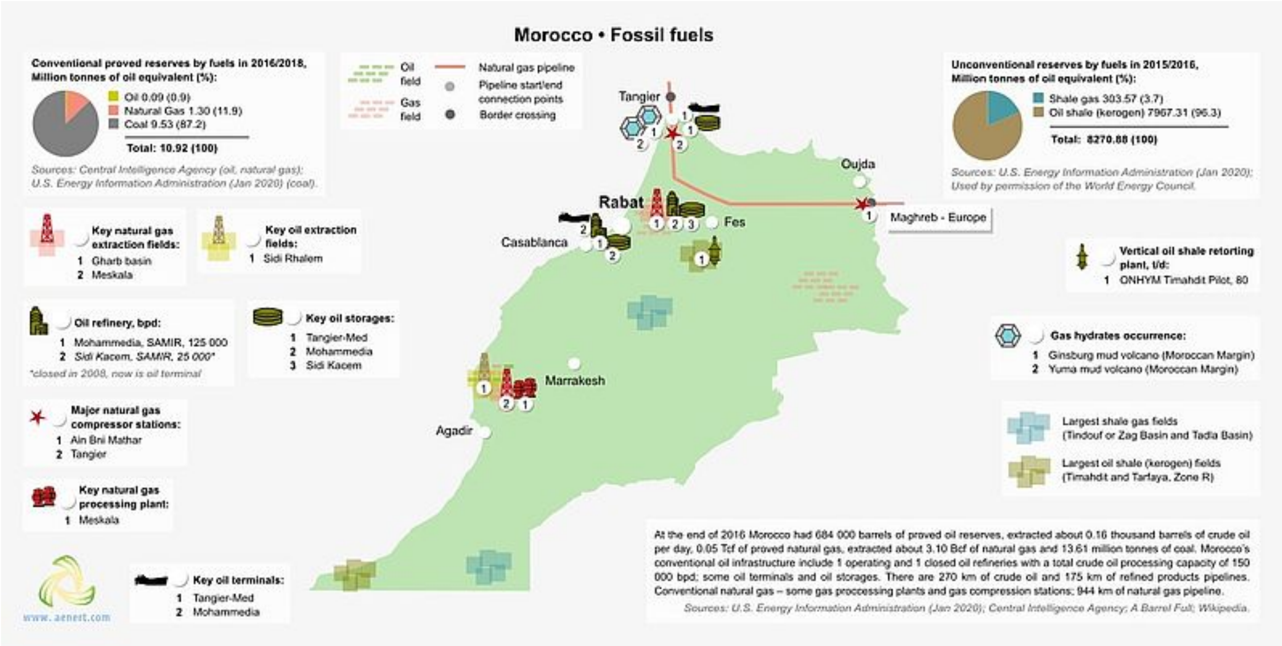
In addition to considering the technical potential for the generation of climate-neutral energy, analyses of the local political, economic and social context are necessary in order to finally be able to weigh up the implementation of different solutions for the design of the respective energy system, including its infrastructure. Special attention must be paid to the advantages and disadvantages of different ways of transporting energy over long distances and integrating it into the existing energy system of the exporting country.

At the same time, it must be ensured that all countries involved benefit and that the relevant energy infrastructures are also available to the local population and are not only built and operated for export to industrialised countries. A corresponding balance between local supply and export should be flanked by political agreements at state level or even within the framework of supranational institutions such as the European Union and the African Union. This may have an impact on the aspirations of some newly industrialising and developing countries to become hydrogen exporters in the future due to their geographical location conditions. However, planned certifications for "green" hydrogen such as the RED III directive and the EU's Carbon Border Adjustment Mechanism (CBAM) could make hydrogen from outside Europe more expensive. In this case, the transport of hydrogen from outside Europe could only compete with hydrogen from within Europe if its production costs continue to fall and transport and logistics become cheaper at the same time. This requires further technology transfer to economically weaker potential export countries as well as the massive promotion of infrastructure projects, the training of local workers and access to sources of financing. If the large sales markets in the industrialised countries are able to cover their own demand with (then relatively expensive) hydrogen through appropriate regulation, it will be difficult for potential export countries in the global South to earn money, which would ultimately slow down development prospects and progress towards the Sustainable Development Goals.

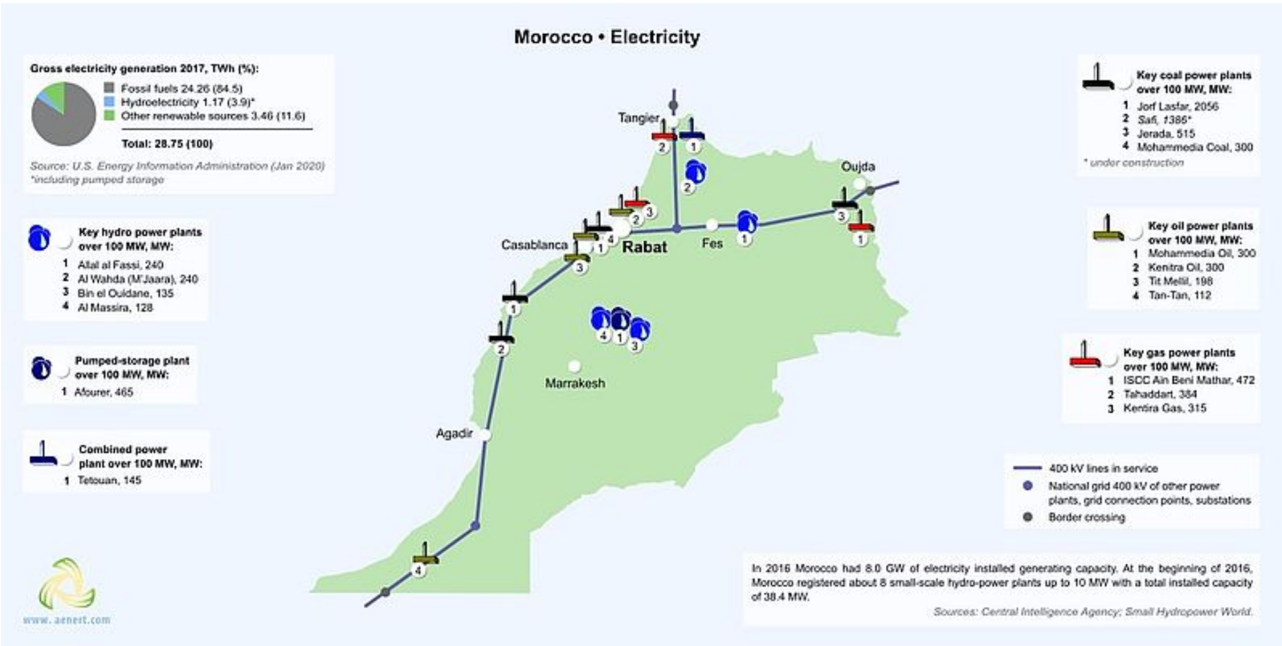
## Appendix to 2.14

### Energy infrastructure in Morocco[861]

### Existing fossil energy infrastructure



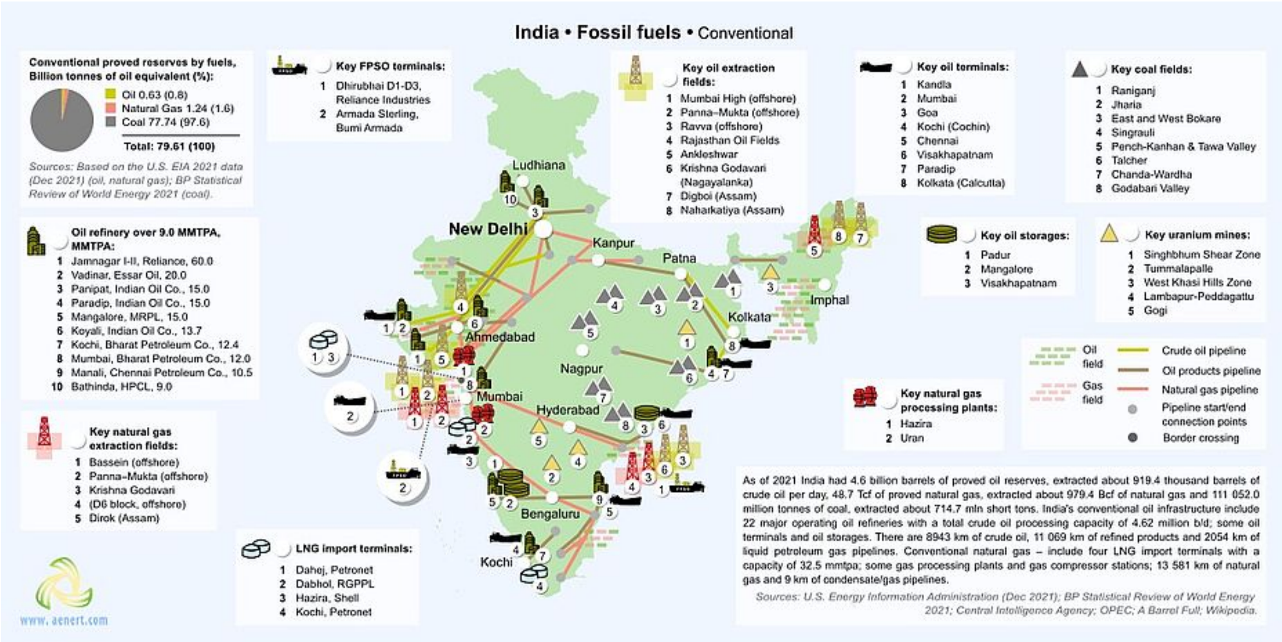

### Existing electricity transmission infrastructure



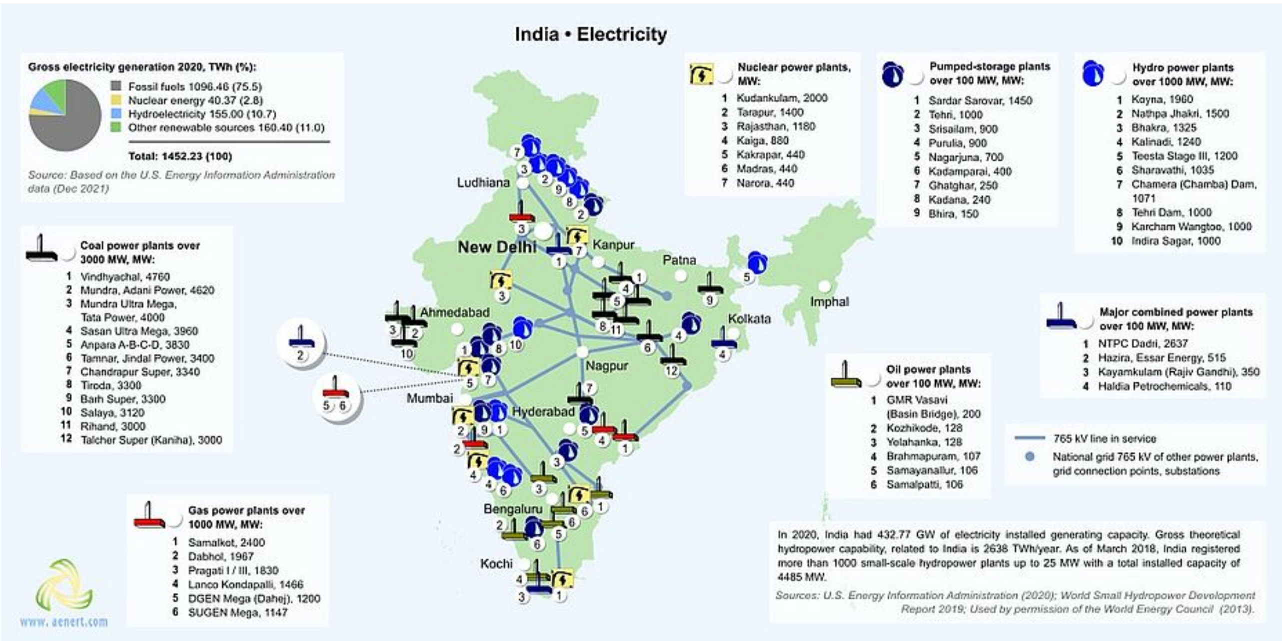

[861] Cf. aenert, 2022a.

## Energy infrastructure in India[862]

### Existing fossil energy infrastructure (gas network of 17,000 km in operation)




### Existing electricity transmission infrastructure

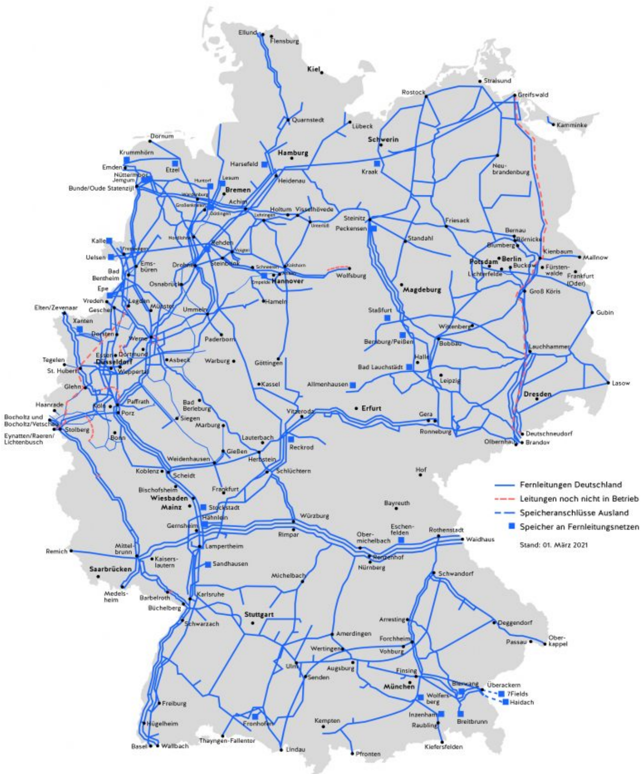



862 Cf. aenert, 2022b.

## Energy infrastructures in Germany[863]

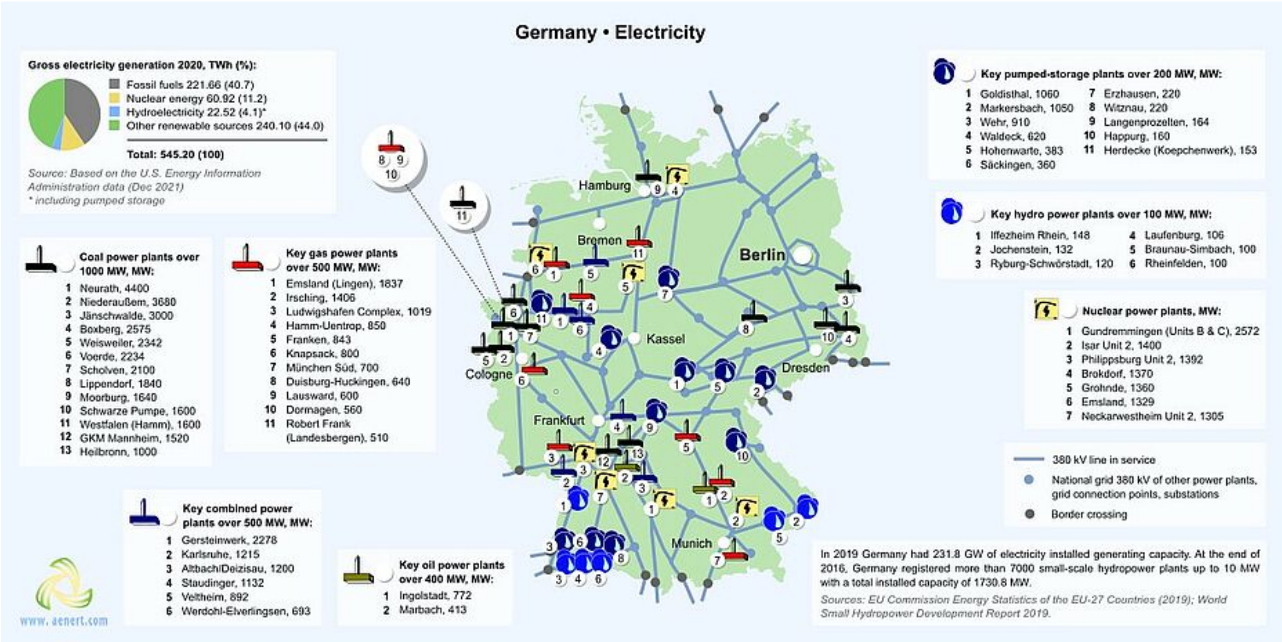
### Existing fossil energy infrastructure


### Transmission gas network (40,000 km in length)[864]




[863] Cf. aenert, 2022c.
[864] Cf. FNB, (2022).

### Existing electricity transmission infrastructure



**Risks for investments in climate-neutral energy infrastructures**[865]

| | | Traditional risks linked to infrastructure projects | Additional risks linked to clean energy infrastructure projects |
|---|---|---|---|
| *Political, policy and regulatory risks* | *Policy and regulatory risk* | Lack of long-term political commitment or policy certainty on infrastructure planning<br>Tariffs regulations to increase fees with inflation fall behind schedule;<br>High bidding costs involved in the procurement process (administrative cost)<br>Fragmentation of the market among different levels of government. | Lack of long-term low-carbon development strategies;<br>Trade barriers (tariff and non-tariff barriers) to- clean energy technologies or their inputs;<br>Lack of political commitment or policy certainty over the stability of specific forms of support to clean energy investment, such as feed-in tariffs.<br>Existence of fossil fuels subsidies that make other investments more attractive to investors.<br>Unstable carbon price. |
| | *Legal and ownership rights* | Unknown future litigation, planning consents not granted, lease running out | Uncertainty about the legal status and property rights of carbon emissions permits |
| | *Political and social risk* | Opposition from pressure groups; corruption<br>Short-term perspective of politicians, limiting infrastructure planning and investment | Additional forms of opposition to specific clean energy technologies or infrastructure, such as wind farms (on-shore and off-shore), geothermal plants or hydroelectric dams, or grid extension |
| | *Currency risk* | Lengthy investment horizon for infrastructure | Lengthy investment horizon for mitigation and adaptation projects that address the threat of climate change |
| *Commercial, and technical risks* | *Technological risk* | Risk of technology failure or under-performance relative to expectations. | Particularly high in the context of low levels of investment in clean energy as they generally involve new technologies. The level of risk will depend on the maturity of the technology and the track record of the technology provider. |

[865] Cf. OECD, 2015.

| | | | |
|---|---|---|---|
| ***Commercial, and technical risks*** | *Construction risk* | Delays in the completion of the project, the interface between the different contracts of subcontractors or stakeholders | Lack of expertise in the construction of clean energy projects. |
| | *Operational risk* | Ability of the management to operate the facility once completed; uncertainty regarding the costs of decommissioning at the end of the facility's life. | Lack of expertise in the operation of clean energy technologies. |
| | *Environmental risk* | Unforeseen environmental hazards linked to an infrastructure project;<br>Weather risks affecting the availability of renewable-energy resources;<br>Risk that a changing climate can adversely affect the proper functioning of the facility. | |
| ***Market risks*** | *Business risk* | More competitors entering;<br>Change in consumer preferences and demand | Technological advances,<br>Lack of familiarity with new clean energy technologies |
| | *Reputation risk* | Damage to a firm's reputation can result in lost revenue or destruction of shareholder value. Such damage may stem from local sensitivities and needs. | The climate context could mitigate the reputational risk though some clean energy technologies, such as wind, tide or carbon capture and storage (CCS) projects could face local stakeholder resistance. |