INVESTMENT NEEDS IN TRANS-EUROPEAN ENERGY INFRASTRUCTURE UP TO 2030 AND BEYOND

Final report

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By: Edwin Haesen, Pieter Vingerhoets, Michèle Koper, Ivo Georgiev, Carsten Glenting, Minke Goes, Charlotte Hussy

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Confidentiality statement and acknowledgments

The European transmission infrastructure expenditure analysis conducted by the project team in order of the European Commission depends strongly on primary data collected from many project promoters active in Europe. The project team engaged with all promoters via collective web meetings, written exchanges and phone calls to collect and review data, and ensure its completeness and robustness with reasonable endeavours.

The project team thanks all project promoters who responded for supporting this study with data provision and further clarifications, as well as both ENTSOs for providing all relevant contact details and further communications in their respective working groups. The team thanks also industry experts who engaged in an open discussion on the prospects of power-to-gas and carbon network infrastructure.

The data collected from all promoters includes also confidential information, and was obtained with a supporting statement of the European Commission on how this data would be used. The full data set and the project team's analysis is available to the European Commission. This public report provides a high-level synthesis to describe the overall expenditure challenge per infrastructure type, as well as per PCI region for gas and electricity grid infrastructure.

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Executive summary

Strengthening the European internal energy market, facilitating the energy transition, and ensuring secure system operation all rely on adequate well-developed and cost-effective transmission grids in Europe.

An analysis of all projected capital expenditures in the domains of electricity transmission, gas transmission, storage, oil supply connections, carbon networks and power-to-gas grid injections highlights an overall expenditure of EUR 229 Bln in the decade 2021-2030 in the EU28 region. This adds to the EUR 67 Bln of infrastructure investments still pending for commissioning up to 2020.

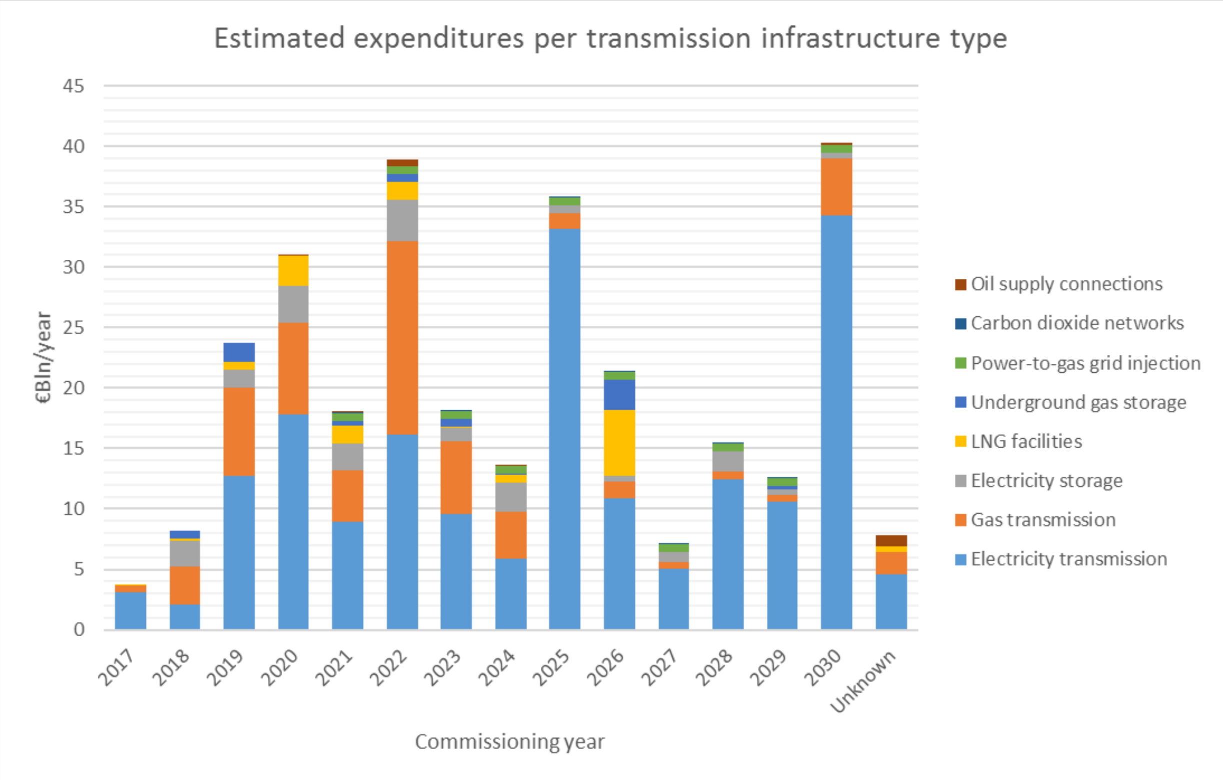

Figure 1. Trend of transmission infrastructure expenditures from the present to 2030 in the EU28 region.

The analysis is based on primary data and further clarifications obtained from project promoters, both TSOs and private investors. The information is cross-checked with data from the latest gas and electricity TYNDP, national plans and reference costs to allow for corrections and filling of data gaps. The analysis endeavoured to capture the full scope of transmission infrastructure expenditures projected by promoters based on the pan-European TYNDPs, national plans, and company investment schemes.

The analysis shows that the highest share (65%) of transmission investments are foreseen in the electricity transmission sector. An outlook to 2050 based on external studies shows that a full decarbonization of the power sector in coming decades will require continuing grid developments to facilitate this energy transition. However, many TSOs claim their investment schemes show limited clarity up to 2030 even, being bound by a time horizon of 10 years or less in grid planning.

Gas transmission investments (incl. gas storage) account for a mere 25% of all transmission investments in the decade 2021-2030. Especially for the second half of the decade the projected investment volumes drop due to high uncertainty on future gas demand. This poses questions on the viability of an investor's or societal business case. Innovations in the sector in line with decarbonization ambitions, such as power-to-gas grid injections, are still in a research stadium. These may become substantial and at some point become economically viable if support and incentive schemes are established.

Table 1. Total capital expenditure per infrastructure category in the EU28 region.

Transmission infrastructure	Capital expenditure [€Bln]	
	up to 2020	*2021-2030*
Electricity transmission	36	152
Gas transmission	19	41
Electricity storage	7	14
LNG facilities	3	10
Underground gas storage	2	5
Power-to-gas grid injection	-	6.5
Carbon dioxide networks	-	0.2
Oil supply connections	<1	1.8
Total	67	229

These figures broadly confirm the trends stated in the pan-European TYNDPs. The analysis also gave insights in the comparison of individual promoter investment portfolios with its own present annual expenditures as well as compared with the sector's reference costs.

Across all transmission infrastructure classes more than half of the projected expenditures in the 2021-2030 decade are for non-mature projects which require further technical and financial analysis. Specifically for gas and electricity transmission infrastructure the debate on priority projects takes place via the TEN-E Regional Groups. Eventually some of the PCI projects may qualify for further financial assistance (grants or other instruments). Without making a statement on the need of specific projects or the financial challenge of individual promoters and regions, the total volume of projected expenditures does differ across the TEN-E priority corridors. For electricity the highest investment expenditure volume is in the NSI West corridor, followed by the North Sea Offshore Grid, the NSI East corridor, and BEMIP. Depending on the region 40 to 75% of all expenditures could qualify for a PCI label based on the criteria in Annex IV of the TEN-E regulation. In the gas domain the highest investment expenditure volume is in the North South interconnector West, followed by the North-South gas interconnections in Central Eastern and South Eastern Europe, then the Southern Gas Corridor and the BEMIP gas region. Depending on the region 50 to 80% of all expenditures could qualify for a PCI label based on the criteria in Annex IV of the TEN-E regulation.

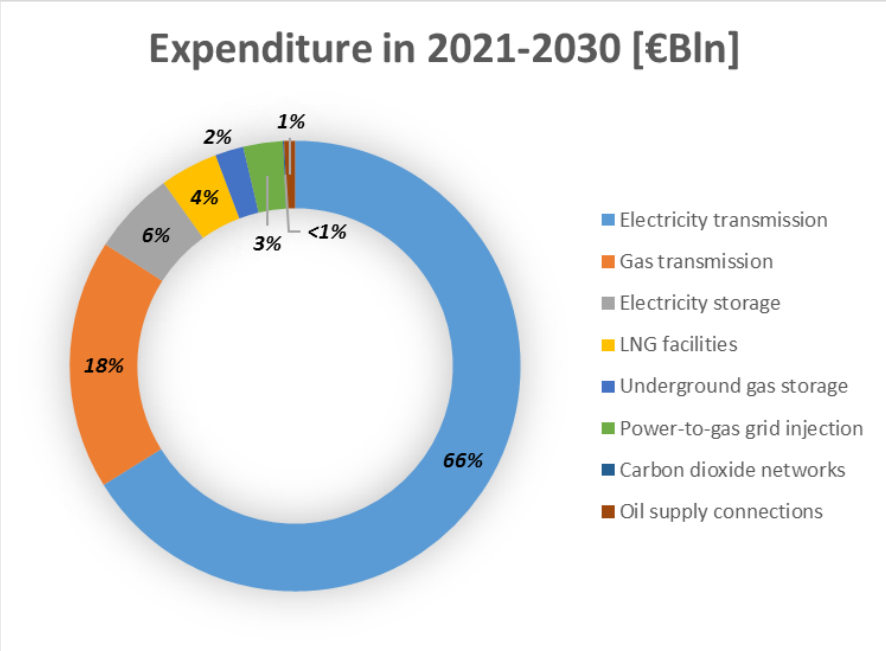

Figure 2. Share of expenditures per transmission infrastructure category in the decade 2021-2030.

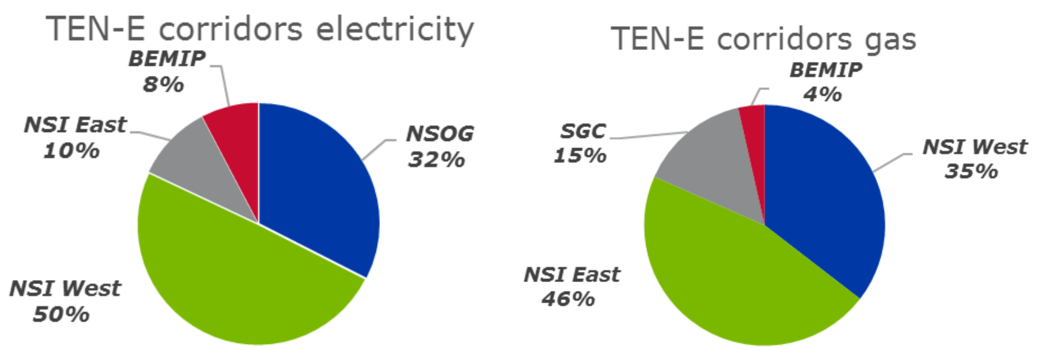

Figure 3 - Share of total transmission investments (excl. storage) per TEN-E corridor in the decade 2021-2030

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1 Background

1.1 National and pan-European grid development plans

The European energy system is in full transition and facing significant changes. There is an increase in the share of renewables and new technologies (including energy storage, digitalization of operations, and carbon storage) are added to the infrastructure. There is progress in the participation of demand and other new actors in energy markets at local and cross-border level. The achievement of climate objectives has been a major driver in these evolutions and will become even more important in the long term. The EU's Energy Union strategy is progressing towards full integration of the internal market which will increase competitiveness, while at the same time maintaining security and affordability of energy supply. The overall volume of transmission investment expenditures will remain substantial, but trends across types of infrastructure, across regions and over time may change and need to be well understood.

There is a high degree of uncertainty as regards to the detailed developments of the energy system and the required supporting and connecting infrastructure. Several reasons drive this uncertainty:

- The cycle of transmission grid infrastructure developments is relatively long, and highly susceptible to delays because of procedural issues, financing issues, and changes in planning assumptions.
- Technological innovations in the energy sector can have a profound impact on transmission investments. Examples are power-to-gas infrastructure, more decentralized market platforms, and more efficient use of grids due to further digitalization of the sector.
- Policy directions may shift infrastructure needs. Examples are gas phase-outs, nuclear phase-outs, push to particular technologies (offshore wind, PV), e-mobility, etc.

Directives 2009/72 and 2009/73 give national level TSOs in electricity and gas the responsibility to provide a national ten-year network development plan to the regulatory authority based on existing and forecasted supply and demand. This plan is required to contain efficient measures in order to guarantee the adequacy of the system and the security of supply. National plans may or may not include the full set of expected (smaller) investments, modernizations and extensions a TSO prepares for in its investment schemes.

Regulations 714/2009, 715/2009 and 347/2013 lay out the requirements for ENTSO-E and ENTSO-G in developing pan-European ten-year network development plans. Regulation 347/2013 furthermore provides the process to identify Projects of Common Interest (PCIs), which need to stem from the latest available TYNDP, and which benefit from a European priority status for permitting and could access financial support measures.

European legislation requires coordination and consistency between both levels of plans which is assessed by ACER.

In this document pan-European ten-year network development plan projects are referred to as TYNDP projects [1] [2]. National ten-year network development plan projects are referred to as NDP projects.

For gas and electricity transmission investments this allows to see investments in a hierarchical set-up as depicted in Figure 4.

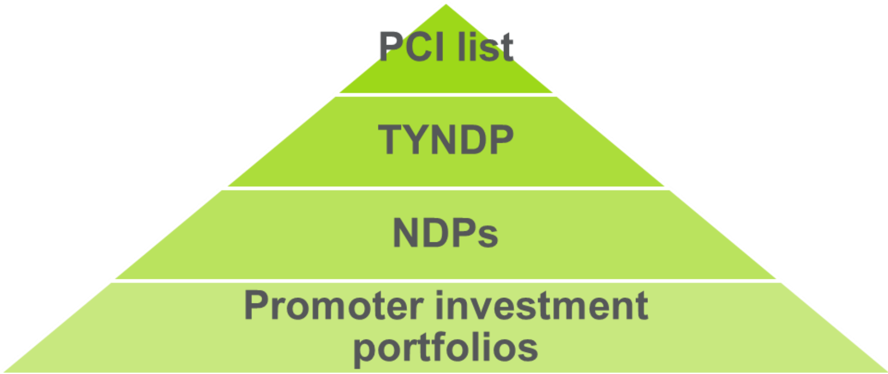


Figure 4 - Relation of investment plans

It has to be noted that the different layers also have a different time focus. PCIs mostly have a higher priority and urgency, and often have an expected commissioning in the coming few years. Both TYNDP and NDPs strictly speaking have a ten-year focus according to EU legislation, but some look further ahead. The notion of a promoter's investment portfolio is not described in legislation, and is to be understood as the total foreseen or best estimate infrastructure investment portfolio of a promoter. It is rather a projection that promoters make for internal use to ensure financial stability and anticipate investment waves.

The objective of this study is to collect and analyse the totality of all electricity/gas promoter investment portfolios in the decade 2020 – 2030 as much as possible.

This study extends to electricity storage at transmission level, and underground gas and LNG storage. These infrastructure classes can also (when fulfilling specific criteria) qualify for a PCI label. They can be part of the relevant TYNDP, but are not always included in NDPs. The same accounts for transmission projects promoted by private non-TSO entities (sometimes referred to as 'third parties').

This study also includes power-to-gas infrastructure and carbon networks. Neither have formal development plans subject to regulatory oversight or regulated infrastructure ownership. Carbon dioxide networks could under certain conditions qualify for PCI status subject to having cross-border relevance, though no such PCI projects exist yet.

1.2 Investment challenges of transmission asset developers

ENTSO-G's TYNDP2017 states a combined gas transmission expenditure of EUR 86 Bln in the coming ten years. About half of this expenditure is foreseen for the coming five years. More mature projects with a FID or Advanced FID account for about EUR 45 Bln. Apart from these portfolio figures, the gas TYNDP gives no project-specific cost estimates.

ENTSO-E's TYNDP2016 states a combined electricity transmission expenditure (not including storage) of EUR 150 Bln, with a large part by 2025 but also listing longer-term investments up to 2035. In this portfolio mature projects (i.e. those included in NDPs or having intergovernmental agreements) account for about EUR 80 Bln.

These transmission projects are promoted by either licenced national TSOs or private entities. Promoters rely mainly on the following sources to finance these transmission assets:

- **Regulated revenue** – For licensed TSOs part of the costs can be recovered via transmission tariffs from grid users in accordance with regulatory processes. Private investors depend on the regulatory regime for congestion rents to the extent such regime exists in the hosting country. Many promoters indicated no specific new issues are foreseen in the coming decade and the applicable laws and regulations are stable. Others did highlight the risk of short-term regulatory periods for long-term investments. One particular case is that of gas infrastructure in case gas demand would decrease and less capacity would be booked. More generally some identified a risk that TSO benchmarking or evolutions in other aspects of the end consumer bill may impact long-term stability. Some highlighted the risk that methodologies may change, for example based on EU network codes for harmonised tariff structures (published for gas, in scoping by ACER for electricity).
- **Own equity** – Most promoters indicated to rely for 20 to 50% on own equity for their portfolio, with some exceptions going below or above. No specific issues for the investment wave of the coming decade were raised apart from usual economic/regulatory issues: the weighted average cost of capital set by the NRA, shareholder willingness to invest, ongoing study for non-mature projects, and the need to balance the equity/debt ratio to ensure the total holding reaches a financially healthy status.
- **Debt** – Most promoters indicated they rely for 40 to 60% on external debt. In some cases attracting loans has been difficult due to uncertain utilization rates, especially for gas infrastructure. Many promoters rely on instruments from the European Investment Bank (EIB) or the European Bank for Reconstruction and Development (EBRD) for financial assistance.

- **Public funding** – The Connecting Europe Facility is being indicated by a number of promoters as a financing source, often for up to 50% of the needed investment budget.

The TEN-E Regulation (EU) 347/2013 aims to support Projects of Common Interest in resolving permitting, regulatory and financing barriers. The progress on implementation of PCIs is monitored closely by ACER via annual reporting. The TEN-E regulation addresses financing issues of PCI promoters via grants and financial instruments under the Connecting Europe Facility regulation. Synergies with other structural EC funds are ensured for non-PCI projects.

The aim of this study is to provide an overview of, and insight in the expenditure volume for transmission infrastructure developers in the domains of electricity, gas, oil, carbon networks and power-to-gas in the decade 2021-2030. It does not aim to answer whether this poses a substantial challenge for the promoter as this would require a more detailed review of the financing capabilities and risks. Also this study does not aim to review the benefit provided by the projects or the impact of delays, which is the main role of the TYNDPs, NDPs and their regulatory reviews.

1.3 Approach

In this study information is collected on planned investments (including financial and technical details) for the transmission of electricity, gas, oil and carbon dioxide networks, for the storage of electricity and gas, and finally power-to-gas infrastructure. Project promoters were consulted directly to ensure up-to-date and reliable information is used in this analysis. This information is complemented with expenditure information available from the TYNDPs and NDPs. For electricity and gas infrastructure all European TSOs (as members of both ENTSOs) were contacted, as well as all private promoters with a project in the latest TYNDP. The response rate, especially amongst TSOs, was high which ensured a robust projection of the total investment volume.

Power-to-gas infrastructure and carbon dioxide networks are more in early stage of research and innovation. As there are no reviewed development plans as for electricity and gas, the analysis of potential future expenditures relies more on literature review and engagement with sector experts.

An important note regarding all expenditures is that all costs are expressed as costs at year of expected commissioning. Alternative options exist such as cost a year of financial closure, or cost in present (2017) value. In the data survey to all promoters it was clearly expressed that the year of commissioning is taken as cost reference. Also the electricity TYNDP which publishes cost estimates per project cluster uses this same convention. Evidently this approach is a partial explanation for expenditure increases compared to today’s situation, as well as the higher average costs provided by promoters as those based on ACER’s 2015 reference costs (Section 2.1 and 2.2).

A more detailed description of methodology and approach is provided in Appendix A (for gas, electricity, oil transmission and storage) and Appendix B (for power-to-gas projects).

2 Expenditures in the decade 2021-2030

2.1 Electricity transmission

The reported expenditures for transmission grid infrastructure (excluding storage) add up to EUR 139 Bln in the decade 2021-2030 in the EU28 region. An additional EUR 36 Bln is still reported for investments with expected commissioning year up to 2020. An extrapolation was made to fill in data gaps (see later on in this section) which brings the total expenditure at EUR 152 Bln.

About half of these investments in the decade 2021-2030 are in a very early stage of analysis and labelled 'under consideration'. Only 19% have made clear progress and are in a permitting phase or even partly under construction.

Figure 5 shows the trend of transmission expenditures per year with an indication of the planning stages. Note that to reflect the total EU28 expenditures, cross-border projects to non-EU28 countries are taken for 50% into account.

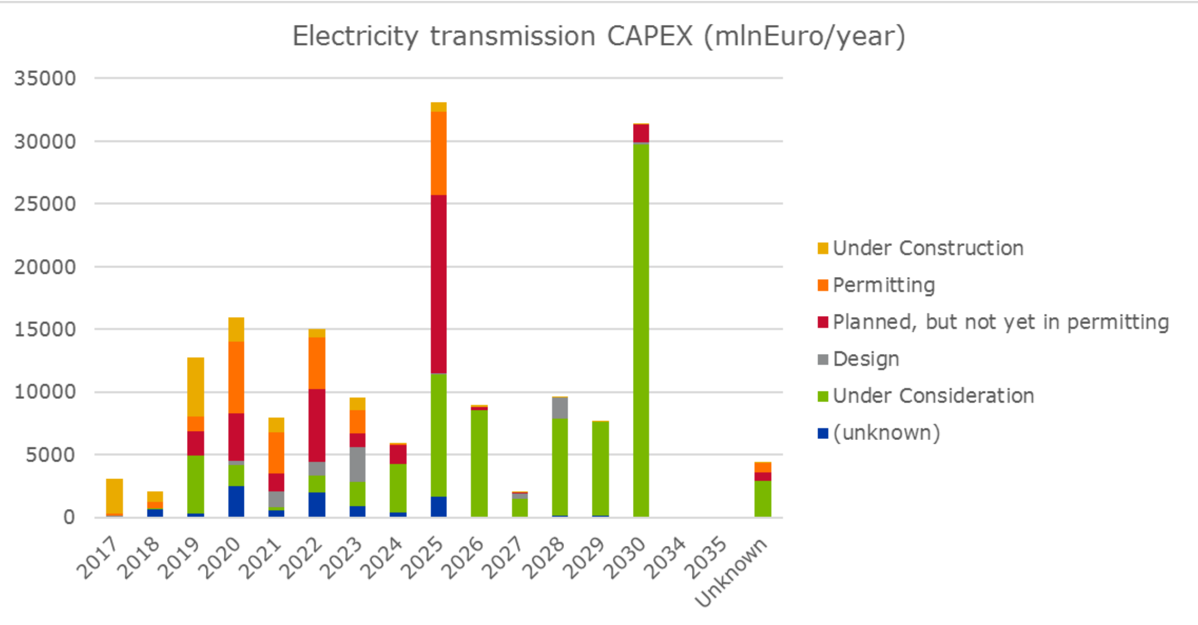


Figure 5. Transmission expenditures per year split per planning stages.

The trend shows substantial peaks for 2025 and 2030 which is due to a higher number of large investments estimated to be commissioned in those years. For 2025 a considerable number of interconnectors around Belgium, between France and Spain, and inside Germany are part of the figure in this single year. Also for 2030 a substantial share of offshore interconnectors and large DC corridor projects inside Germany are included. It is likely that for non-mature projects ‘rounded’ years are given. This points out these dates are based on provisional planning, susceptible to change, and require more detailed study and planning by the promoter and other involved parties.

As noted in Chapter 1, much of the information provided by promoters actually stems from NDPs. Some promoters indicated there may be no reliable information on expenditures beyond the time horizon of the NDP, which may be prior to 2030. When the investment portfolios of TSOs in the EU28 region with a time horizon before 2030 are extrapolated until 2030, an upward correction of EUR 13 Bln is made. This brings the best estimate expenditure projection of electricity transmission infrastructure for the decade 2021-2030 at EUR 152 Bln.

A substantial number of foreseen investments are offshore projects; these often have also relatively higher costs due to size (length) and technology use (DC substations). In the EU28 about 35% of the total investment forecast is for offshore projects, while the remaining 65% is for onshore investments. As DC corridors are also in some cases proposed for onshore projects, the share of DC projects is also over half (57%) of all forecasted investments.

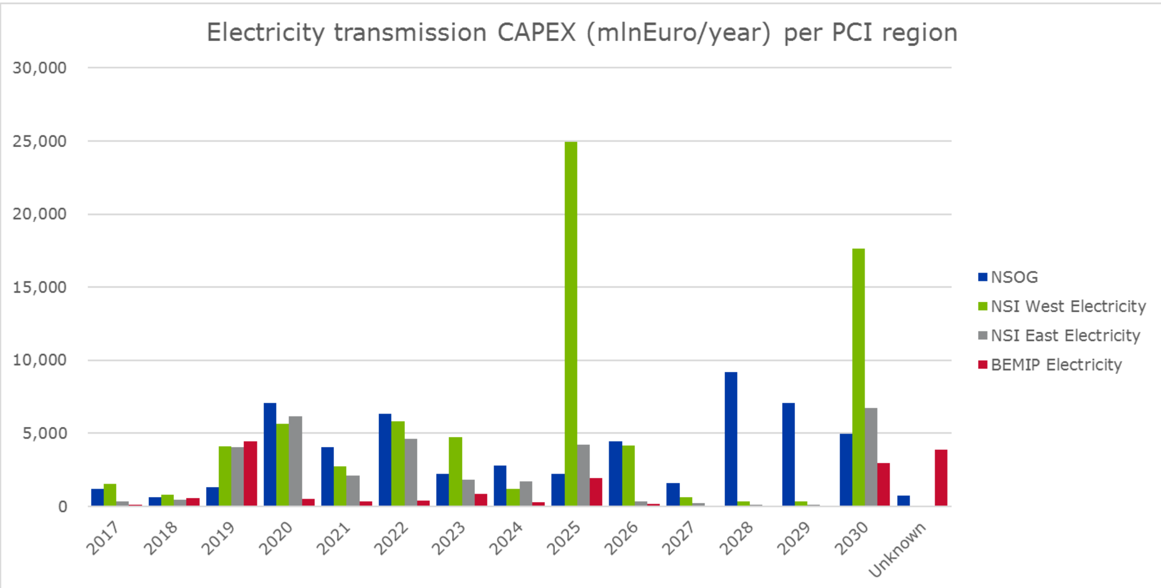


Figure 6 - Transmission investments in the four electricity TEN-E corridors

Identification of system needs and PCIs are handled in the TEN-E process via four priority corridors for electricity. The reported expenditures are split per PCI region in Figure 6. These figures represent the full transmission grid investment portfolio, and is not restricted to those with a PCI label at present nor the ones who could qualify under present TEN-E technical criteria. The allocation per region is done following the same regional approaches as in the present PCI list. The highest investment expenditure challenge in the decade 2021-2030 is in the NSI West corridor, followed by the North Sea Offshore Grid, the NSI East corridor, and BEMIP. It is emphasized that these expenditures are purely based on the totality of investments reported by promoters, and do not reflect PCI selection criteria or priority for financial assistance to facilitate implementation of these projects. The comparison of PCI regional expenditures can be explained by several factors. The NSOG region expenditure depend a lot on high-cost subsea cables. The BEMIP region is relatively smaller than the others. For the difference between the NSI West and East corridor some other factors have to be taken into account. In the data collection from a few TSOs in the NSI East region a relatively low share, or an uncertain, or even no internal expenditure was reported. Also the NDPs in the NSI East countries have a tendency for shorter term time horizons than in the West, as for example also expressed in ACER's Opinion on NDPs (2016). The spread in 2021-2030 expenditures between the NSI West and East may therefore be smaller than appears from the data collection and figures reported in this study.

Robustness of the figures was checked by comparing with TYNDP2016 reported costs, as well as estimates based on ACER's unit investment costs [3]. Based on a subset of all reported investments which allow for such comparison (i.e. if sufficient technical details are given), it is noted that the costs reported in this data collection are on average 9% higher than in the TYNDP2016. Comparing reported costs with estimates based on ACER's unit investment cost, the claimed costs are on average 5% higher though on individual project level variations can be much higher. This shows that reference costs need to be interpreted with sufficient margin (as is also reflected in ACER's report by the use of standard deviations). The difference between reported costs and the estimates based on ACER's unit investment costs is more striking for offshore interconnectors, as reported costs are on average about 50% higher. Across all types of projects, many promoters in any case reported a CAPEX uncertainty range, as is also given in the TYNDP, which is often about +/- 10%.

The overall trends shown in Figure 5 are mostly based on the costs as reported by the promoter. In cases where there were no costs reported by the promoter, TYNDP cost estimates are used. For all other projects (those who are not presented in the TYNDP), ACER's unit investment costs are applied to estimate investments if sufficient technical parameters are known. In case insufficient technical parameters are available, average parameters of e.g. line or pipeline length are applied. In a relatively small number of cases, other corrections were applied.

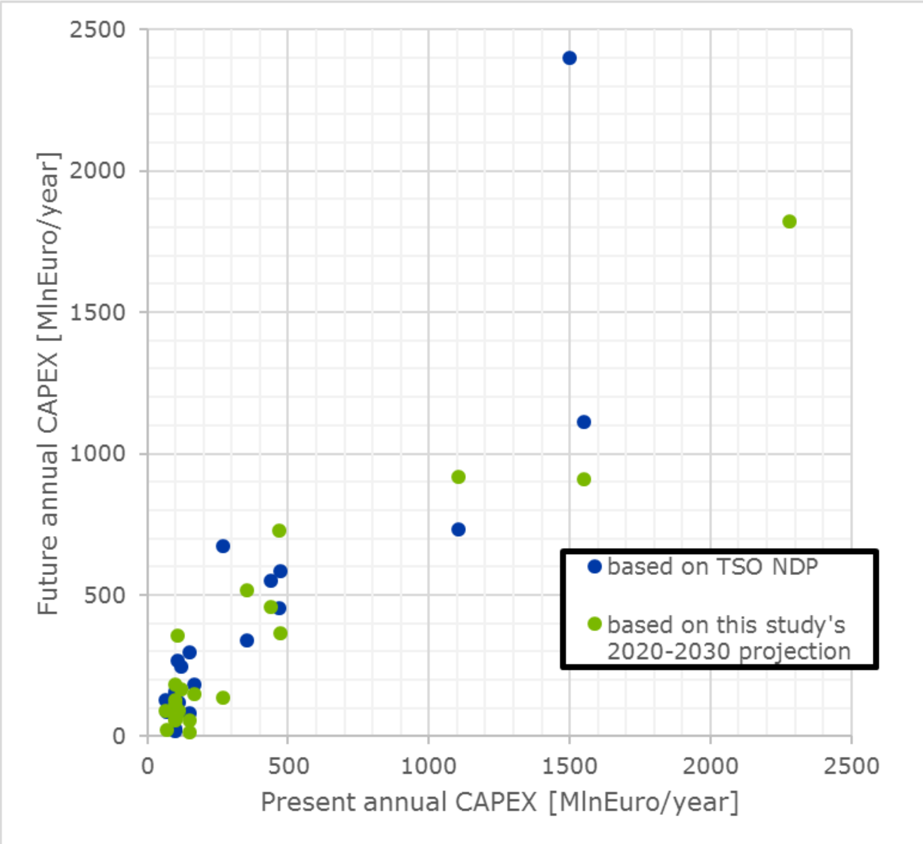


Figure 7. Comparison of TSO annual CAPEX in recent years (X-axis) compared with future average annual CAPEX (Y-axis) based on projections for the coming years in the latest NDP (blue dots) or based on data collected in this study regarding the 2021-2030 decade

For most of the TSOs in the EU28 region also a comparison was made between today's annual CAPEX figures (as given in annual reports), projected annual CAPEX as given in recent NDPs or other TSO statements (including costs as of today, with time horizon often before 2030), and the projected annual CAPEX for the 2021-2030 period as analysed in this study. Figure 7 shows this comparison; each dot represents a TSO's relation between present annual expenditure (X-axis) and future expenditure (Y-axis). Results showed that NDP annual CAPEX forecasts are quite in line with present CAPEX figures, on average being about 3-4% higher. The comparison of the 2021-2030 expenditure projections are on average across TSOs 29% higher than today's annual expenditures, which is a substantial increase.

In the data collection several TSOs provided only details of projects that are included in the latest TYNDP, while some provided more expenditures in line with their NDP or own investment schemes. In some cases the volume of NDP expenditures is substantially higher than that of the promoter's share in the TYNDP. In case limited additional NDP information was given, the promoter explicitly confirmed the TYNDP actually covers the bulk of the projected expenditures. Still there is a possibility that the data collection in this study underestimates the totality of all transmission expenditures. If that is the case even more TSOs would see a stronger substantial expenditure increase compared to today's situation. It is therefore advised to see the expenditures of Figure 7 as minimum trends.

To get the full picture of transmission expenditures in this period it is relevant to take into account also OPEX, for the investments in the 2021-2030 decade but also the earlier commissioned and still operational asset base. This analysis did not study OPEX segments in detail since a) analysing the existing asset base was out of scope of the study, and b) definitions and interpretations of operational costs vary widely across many parties which hampers a uniform data collection. A general survey on OPEX challenges showed that many promoters do not foresee particular new challenges with operational expenditures in their projections for 2021-2030. On a per project basis most feedback indicated an OPEX in the range of 0-5% each year, with the year of expected commissioning as reference, and depending on the project type with average about 1-2%.

2.2 Gas transmission

The collected and checked gas grid transmission expenditures (excluding storage) showed a collective best estimate expenditure projection in the EU28 region of EUR 67 Bln in coming years based on known projects, of which EUR 41 Bln in the decade 2021-2030 and EUR 19 Bln up to 2020.

These numbers are slightly higher compared to the most recent gas TYNDP2017, especially since a longer time frame was covered (up to 2030) than the TYNDP and also transmission investments not part of the TYNDP were collected. The analysis does confirm most gas transmission investments are scheduled for the coming five years. The peak at 2030 in the Figure 8 also represents project costs which were indicated to go beyond the NDP time horizon.

The survey of promoters also confirmed there are diverse views on the evolution of gas demand in some countries, and thus the economic viability of more large infrastructure projects. It must also be noted that only a limited number of gas TSOs provided investments which are not part of the TYNDP. Many of the TSOs who did provide only TYNDP investment details confirmed this covers the bulk of the projected asset expenditures in coming years.

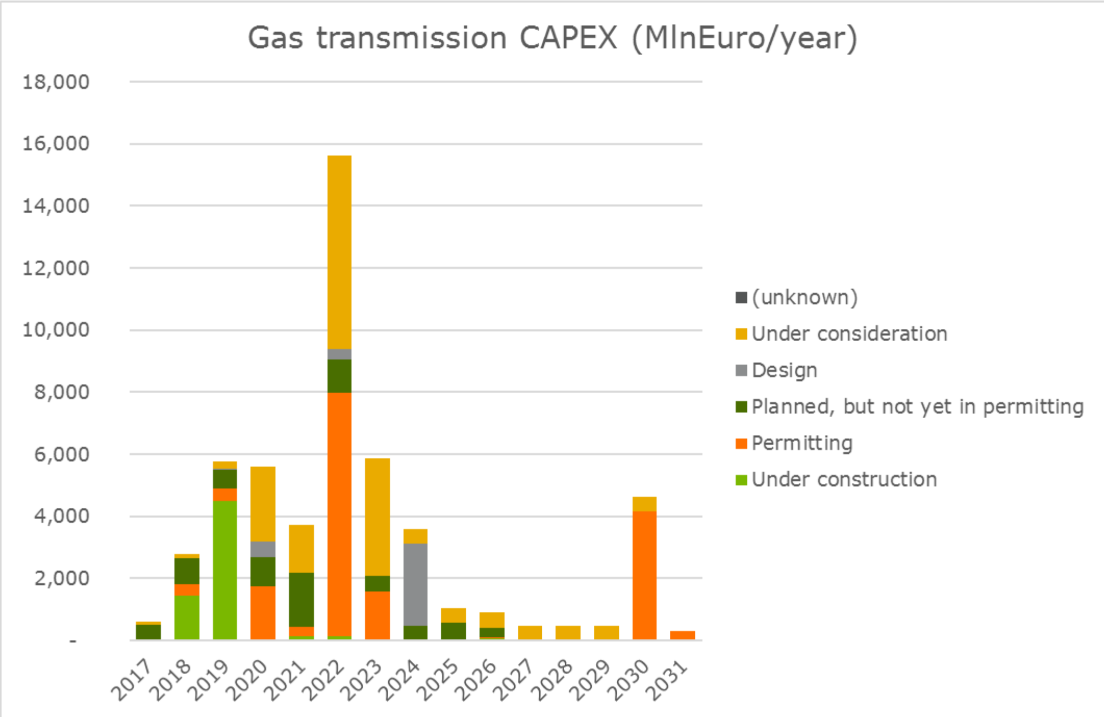


Figure 8. Gas transmission investments split per planning phase.

The reported gas transmission expenditures are also split per PCI region in Figure 9. It is important to note that compared to the electricity PCI regional split, for gas transmission more projects connect an EU28 with a non-EU28 country. These figures represent the full transmission grid investment portfolio, and is not restricted to those with a PCI label at present nor the ones who could qualify under present TEN-E technical criteria. The allocation per region is done following the same regional approaches as in the present PCI list. The highest investment expenditure volume in the decade 2021-2030 is in the North South interconnector West, followed by the North-South gas interconnections in Central Eastern and South Eastern Europe, then the Southern Gas Corridor and the BEMIP gas region. Note that the Southern Gas Corridor has most planned investments indicated for commissioning by 2020. Note also that the large expenditure envelope in the North South Interconnector West region covers also many assets (>33%) which would probably not be eligible for a PCI status under the present TEN-E criteria, and are based on substantial investments in national projects still among others in Germany, France and Italy. It is emphasized that these expenditures are purely based on the totality of investments reported by promoters, and do not reflect PCI selection criteria or priority for financial assistance to facilitate implementation of these projects.

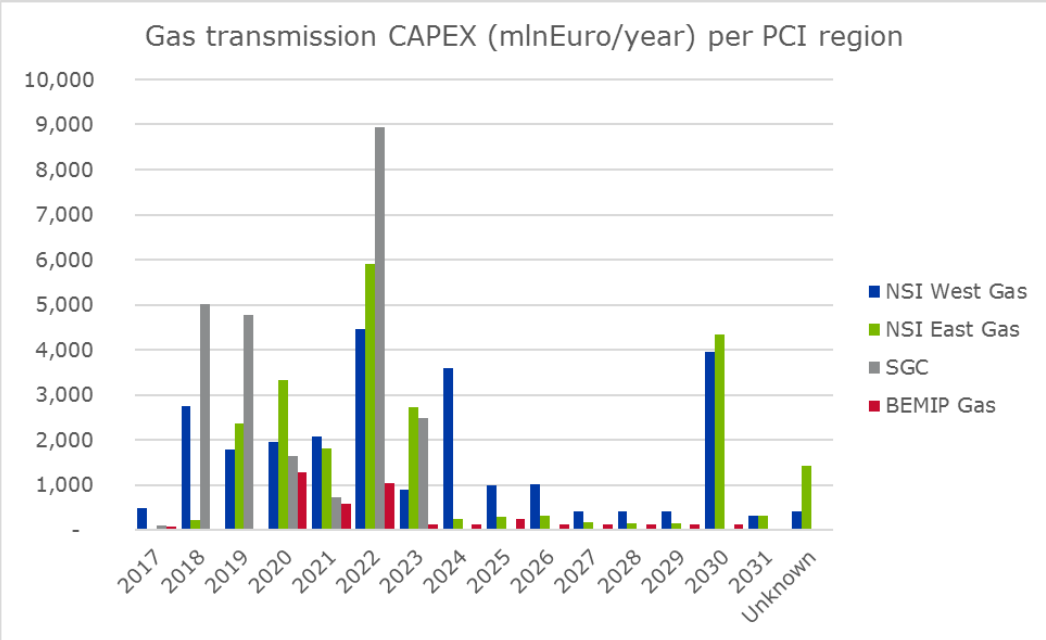


Figure 9 - Transmission investments in the four gas TEN-E corridors

As noted earlier most of the expenditures are for projects with an expected commissioning year before 2025. For the gas transmission development no extrapolation is suggested as was done for electricity transmission in section 2.1. In the electricity domain several TSOs claimed there was not more information available in their most recent NDP which may have a time horizon before 2030. Nevertheless various long-term studies (see Chapter 3) indicate the need for further electricity grid development to facilitate the energy mix and shifts or even increase in electrical energy demand. In gas transmission development the views are more diverse with some TSOs claiming gas is essential in the decarbonization of the energy sector (as transition fuel, or with innovative green gas usage), while others state there is large uncertainty whether future volumes will be sufficiently high to motivate investments. Therefore the expenditure projection in this analysis relies on the provided and checked costs provided by promoters and information from the TYNDP, without further extrapolation of trends towards 2030.

The provided project specific expenditures are also compared to standardized costs based on ACER's unit investment costs [4]. It shows that the claimed expenditures are 9% higher as when applying the reference costs. As in the case of electricity transmission, possible explanations are inflation and margins to cope with delays. Also some of the projects are modernization/expansion projects (partly or fully) which may actually have lower costs as compared to completely new investments. When comparing claimed expenditures and reference expenditures on country level, also deviations can be 50% in either direction. It is worth to note that also ACER's unit investment costs are based on a large set of past projects and reflect a standard deviation for different sizes of pipelines and compressor stations of 20 to 50%.

2.3 Electricity storage

This study identified 29 electricity storage facilities considered for commissioning by 2030 in the EU28 region. This covers a total estimated expenditure of about EUR 19 Bln. Focusing on the decade 2021-2030 the estimated expenditure is EUR 14 Bln. This projected expenditure covers all 23 storage projects included in the latest electricity TYNDP and 6 additional projects in the pipeline. Overall most of these projects (22 out of 29) are expected to be commissioned by 2025 (see Figure 10).

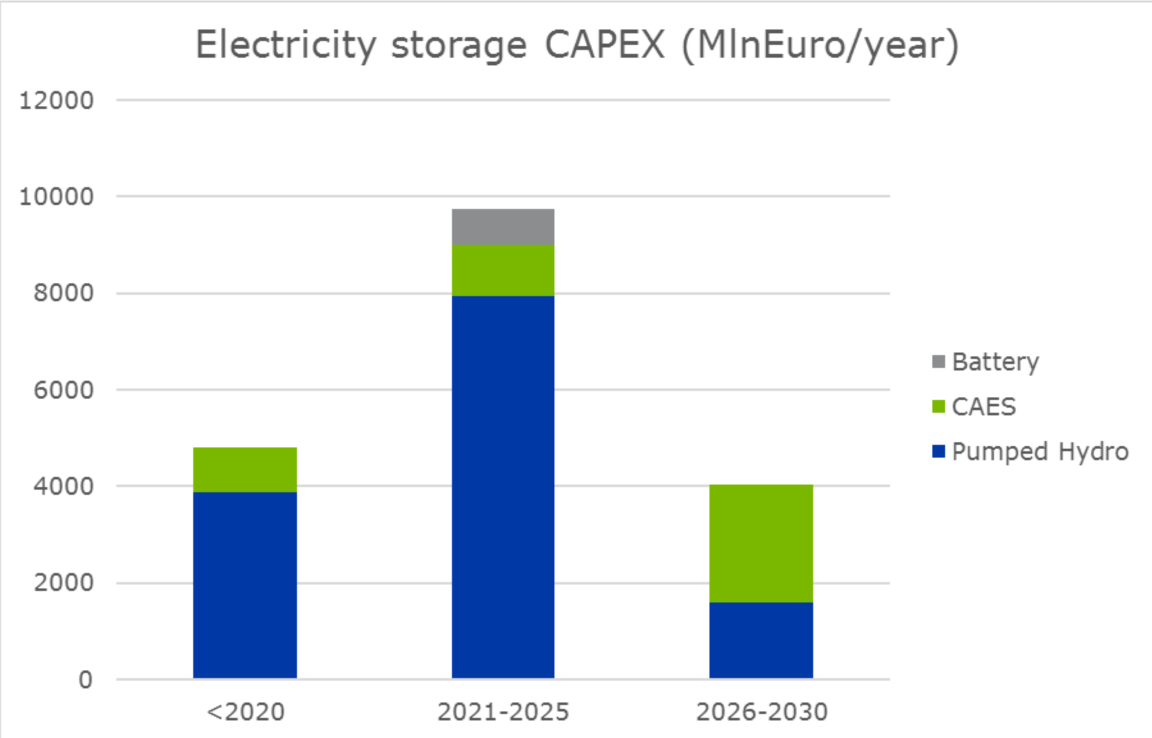


Figure 10. Investments in electricity storage split per technology and timeframe.

Most of the planned projects at transmission level are still pumped hydro based. Cost indicators for these pumped hydro storage facilities are about EUR 0.55 to 1.7 Mln/MW of maximum generating power for respectively the 25 and 75 percentiles of the analysed set. This is a wide variety but in line with the limited available literature. These facilities also show a cost indicator of EUR 8 to 80 Mln/GWh of total storage capacity. Reference costs of such projects in terms of energy content are difficult to set as case-specific environmental and geological conditions have a large impact on the costs. Note that also ACER’s set of electricity transmission unit investment costs does not provide indicators for hydro storage projects.

A smaller share of the investments are CAES based. In the latest TYNDP only one battery project is included. Note that projections of stationary battery investments in the coming decade are mostly showing strong growth, though these are also mostly distribution connected.

2.4 LNG facilities

Up to 2030 an expenditure of EUR 13 Bln in LNG infrastructure is foreseen of which EUR 10 Bln in the decade 2021-2030. This covers 34 projects, most of which are also part of the latest gas TYNDP.

As can be expected, even though more projects focus on expansion rather than completely new facilities, the cost impact of new facilities is substantially higher than that of expansions. It is also worth to note that 75% of the expenditures are for projects with a Less-Advanced FID status as stated in the gas TYNDP.

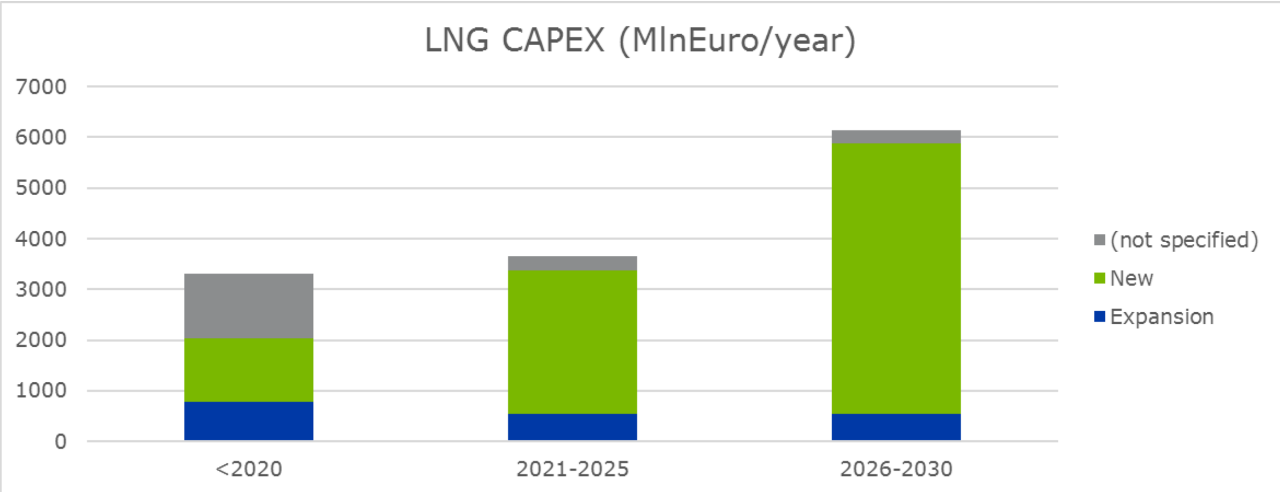


Figure 11. Investments in LNG infrastructure split per timeframe.

The provided expenditures were cross-checked with ACER’s unit investment costs, and also missing data was filled in based on these unit costs or other projects of similar size. The costs on a per project basis, taking into account specific technical characteristics, are diverse. Also ACER’s report provides statistics based on historical projects but emphasizes these are not robust enough to be used as indicators for future projects due to limited data. The limited project information in this study showed that using indicators based on ship size capacity and terminal storage capacity, and taking the average of these, comes closest to the claimed costs by promoters. This was used to fill in the data gaps for projects for which no cost was available. This adds to the uncertainty range for the LNG infrastructure costs projected for the decade 2021-2030.

2.5 Underground gas storage

In the domain of underground gas storage 19 projects are expected to be developed by 2030, of which 11 in the decade 2021-2030. As with LNG infrastructure also for underground storage facilities the majority has the status of a Less-Advanced FID in the latest TYNDP.

The costs of these projects depend strongly on the geological conditions of the chosen aquifer, salt caverne or depleted gas field. For less than half of the projects a cost estimate was available. Also in literature nor in ACER's unit investment cost set are there robust cost indicators for this type of infrastructure. When extrapolating the available cost information to the entire set of projects based on a cost indicator of EUR 0.67Mln/mcm working volume, the total portfolio cost adds up to EUR 7.2 Bln until 2030, of which EUR 4.7 Bln in the decade 2021-2030. Both the limited availability of cost data, and the non-mature status of most projects add significant uncertainty to this total expenditure estimate.

2.6 Oil supply connections

Based on information from oil pipeline developers and authorities in countries where such projects have been under consideration, a total expenditure in this infrastructure of EUR 1.9 Bln is estimated. This corresponds largely with the infrastructure projects presently in the Union's 2nd PCI list. All these projects are expected to be commissioned in the decade 2021-2030.

2.7 Carbon dioxide networks

According to some larger project plans, such as ROAD [5], Teesside collective [6], Caledonia clean Energy [7], the investments in carbon dioxide networks could amount to about EUR 200 Mln in total for the period 2020 to 2030. These roadmaps cover project concepts which are all in a very early phase of development with no financial closure yet. Therefore the number is best seen as a high-end estimate under favourable conditions.

Carbon Capture and Storage (CCS) could be an important component in the transition to a decarbonized energy system. A good overview of CCS techniques and policies is found in [8]. This study assesses the need in Europe for investments in carbon transport pipeline infrastructure. Currently, the infrastructure for large-scale CO_2 transportation is not in place, and it is unclear whether private investors will be interested in an international CO_2 pipeline network. The costs of CO_2 pipeline transportation is discussed in several studies, and compared to ships and trucks. At intercontinental distances (>1000km), a ship is usually preferred, as it can be used to transport other goods such as LPG and therefore bears lower risk of becoming a stranded asset if the project discontinues.

A very limited amount of projects using CO_2 pipeline infrastructure are currently in place in Europe. In US however, CO_2 transportation is frequently used for enhanced oil enrichment (EOR), where the pressure is used to enhance the efficiency of oil extraction(see for instance [9]). The costs of CO_2 transport networks are roughly proportional to the distance covered and comparable to equivalent natural gas networks [10]. In US, the costs are estimated between 330 k$/mile and 560 k$/mile

[11]. In Europe, EOR and carbon pipelines could be installed in the North Sea, which is suggested in a report of the JRC in 2005 [12]. However, as investments in carbon pipelines are today not yet planned, combined with an expected decrease in oil investments towards 2030, suggests that this potential will not be leveraged.

In Europe, very few projects make use of CO_2 capture and transportation. In Norway, a project is operational and a pipeline is constructed from the CO_2 source to the cavity where it is stored, via a 153km pipeline [13]. The investment costs of these projects are known and rely on public funding sources [14]. Other planned CCS demonstration projects, such as in the UK, are seeking public support. Given current conditions and CO_2 prices, as well as forecasts of carbon prices towards 2030, the business case is not yet economically viable. For instance the cost of carbon capture in power generation is estimated to be between 57$/tonne and 78$/tonne in a study by the global CCS institute, while the current ETS CO_2 market prices in Europe are around EUR 5 per tonne, and up to 15EUR/tonne in the year 2010-2011 [15]. A few more projects are underway to perform CCS for energy storage, if we assume those projects are realized, the amount of CCS investments could quadruple by 2020 and beyond, however still being relatively limited in comparison with equivalent investments in the electricity and gas sector.

In the industrial sector, a CO_2 pipeline exists in the Netherlands, which connects a CO_2 source to the nearby greenhouse agriculture industry, which has a high CO_2 demand [16]. Evidently, this requires geographically favourable conditions between production and consumption of CO_2. Currently, the total global CO_2 demand is estimated to be around 80Mtonnes/year, of which more than 60% are used for enhanced oil recovery [14]. This is only a small percentage of the CO_2 emissions, which amounts to 4.4Gtonnes in Europe alone [17]. Due to this small fraction, CO_2 transportation for industrial applications can play only a limited role in the energy transition. In addition, it is not expected that the CO_2 price for industrial sales will rise significantly by 2030.

2.8 Power-to-gas infrastructure

Power-to-gas projects are presently mostly research and demonstration focused. Various studies have reviewed the potential in applications such as mobility, usage of existing gas grids for injection, and industrial applications. Especially the mobility and industrial applications are seen as having large potential, and could thus trigger cost reductions to come to a viable business case. At present limited to no uptake of this infrastructure is expected to happen in absence of regulatory and financial incentives.

Relevant in context of the TEN-E regulation is the estimation of power-to-gas conversion for injection into the existing gas grids. This is a potentially valuable flexibility option to handle situations of RES oversupply (avoid curtailment) and make use of existing gas grid and storage assets in line with decarbonization ambitions. This is an option, though one that requires further analysis. As mentioned in section 3.2 it is one of the potential ways to innovate in the gas transmission and distribution sector when gas demand would otherwise decrease and leave stranded gas grid assets.

Further insights in potential uptake of power-to-gas infrastructure is given in Appendix B. This analysis based on expert surveys showed a potential infrastructure investment for gas grid injection in the decade 2021-2030 up to EUR 6.5 Bln if appropriate incentives are in place. In case no temporary support is created for this technology to create viable business cases and trigger further cost reductions, investments will remain focused on the research and demonstration domain as presently is the case.

Table 2 - Power-to-gas applications and their potential investments in the decade 2021-2030.

Application	Business as usual scenario (Bln€)	Additional policy support scenario (Bln€)
R&D public funded demonstration	3	3
Mobility application	-	6,8 - 68
Injection in gas grid	**-**	**6,5**
Industrial applications	-	54

3 Post 2030 outlook

The main focus of this study is the complete view on transmission investments up to 2030. The outlook in this chapter tracks possible trends for longer term developments between 2030 and 2050. This outlook is mainly based on available studies and statements from associations and infrastructure promoters. This outlook does not include projects or detailed calculations, but rather focuses on qualitative views. In practice there is very limited detailed information from national TSOs on this long-term outlook. Financing capabilities and needs are often limited to a certain time period (15 to 20 years). Also a detailed long-term grid planning requires anticipation of likely developments in the energy system in more than 15 years from now.

In this outlook to 2050 a storyline approach is applied. These storylines indicate main changes as expected from recent published studies, TSOs, sector organizations, the Paris agreement, and ongoing discussions on the use and needs of infrastructure. One storyline depicts a business-as-usual pattern, and another a more ambitious projection. The 2030-2050 outlooks allow for a useful reflection on the detailed investment projections made for 2021-2030. The following sections present the storylines per type of technology.

3.1 Electricity transmission

Further substantial changes in the electricity transmission system are expected in the coming decades to keep up with the rapid and profound developments in the production, consumption and market interaction of electricity flows. Furthermore, electrification of the energy system is increasingly seen as an important enabler for the longer term decarbonisation of the transport and buildings sectors, as for example also highlighted in the EC's 2050 Roadmap. Increased shares of renewables, reduction in supply of fossil electricity sources, use of storage and demand side management will require changes in the current set up of infrastructure.

Analysing the European 2050 electricity system is a complex undertaking. Few studies have endeavoured taking up such task. Notable studies are the 2014 Fraunhofer ISI report on 'Optimized pathways towards ambitious climate protection in the European electricity system' [18], the EC funded "Electricity Highways 2050" study [19], Imperial College's Energy Futures Lab projection [20] and McKinsey's "Transformation of Europe's Power System until 2050" [21]. The Fraunhofer and Electricity Highway study are the only robust studies that optimized grid capacity in 2050 scenarios that meet decarbonization ambitions. Still, they look only at bulk transmission corridors or cross-border market capacities. This highlights the value of transmission corridors, but does not give a views on the complete transmission expenditure.

A business-as-usual scenario for 2050 could be the EC's PRIMES based modelling (EU Reference Scenario 2016 [22]), which has the following assumptions and outcomes for 2050:

- 55% RES share in production;
- 35% VRES share in production;
- Macro-economic assumptions (GDP growth) made based on the GEM-E3 model at 1.5% per year average;
- Annual increase of 0.7% electricity demand due to electrification of heat (25%) and transport (75%);
- Reflection of energy efficiency policies adopted in recent years;
- Considers country specific potentials for RES penetration and CCS transport and storage.

The Reference Scenario highlights that power grid investments will be continuously higher towards 2050 than historical trends, at about EUR 40 Bln/year. This includes both transmission and distribution costs. Assuming a transmission / distribution investment ratio of 1 / 2 [1], this stays close to the annual transmission grid expenditure found for the decade 2021-2030 in Section 2.1. However it must be emphasized, this Reference Scenario does not meet the ambition of a full power sector decarbonization by 2050.

In the ambitious scenario we assume a stronger investment shift from transmission to distribution level to cope with distributed resources, nearly 100% renewable energy sources to meet electricity demand, success in promoting flexibility, a stronger electrification of demand, and a well-integrated European transmission system e.g. to cope with substantial offshore wind developments, and facilitate European North-South flows.

A detailed study which reflects this storyline is the Electricity-Highways study of a 100% RES scenario. This is one out of five scenarios studied, and is described by the following parameters and outcomes:

- 100% RES share in production;
- 70% VRES share in production;
- 1.5% Annual increase of electricity demand influenced by GDP and population;
- Annual improvement of energy efficiency by 1.5%;
- Still an annual increase of 1.6% electricity demand due to electrification of heat (60%) and transport (40%);
- Final electricity demand 4200 TWh (compared to 3200 TWh in 2014);
- Limited exchanges with North Africa grid (3% of total available RES production).

[1] Ratio applied by Eurelectric for this decade's investments, though it also states by 2050 the ratio is rather 1 / 4.

Key changes from today and even 2030 operation of the grid will include a large number of hours when the grid will be entirely supplied by variable renewable energy sources. Various flexibility sources (demand response, storage) and limited dispatchable generation (bio-fuel based, and likely other reserves) will become essential. This will in turn involve significantly increased power flows across the EU's transmission grid which may increase the need for more transmission 'corridors' as shown in the Electricity Highway study, as a cost-effective solution to pool resources over large regions and ensure system adequacy. These changes include large connections from the North (from the British and Irish islands, and from the Nordic countries) down through France and Central Europe, as well as between Italy and neighbouring countries. Some regions as Germany may require relatively less investment as such corridor needs should already be addressed by 2030. The figure below presents the Electricity Highways view of investment needs under a '2040 least regret grid' scenario.

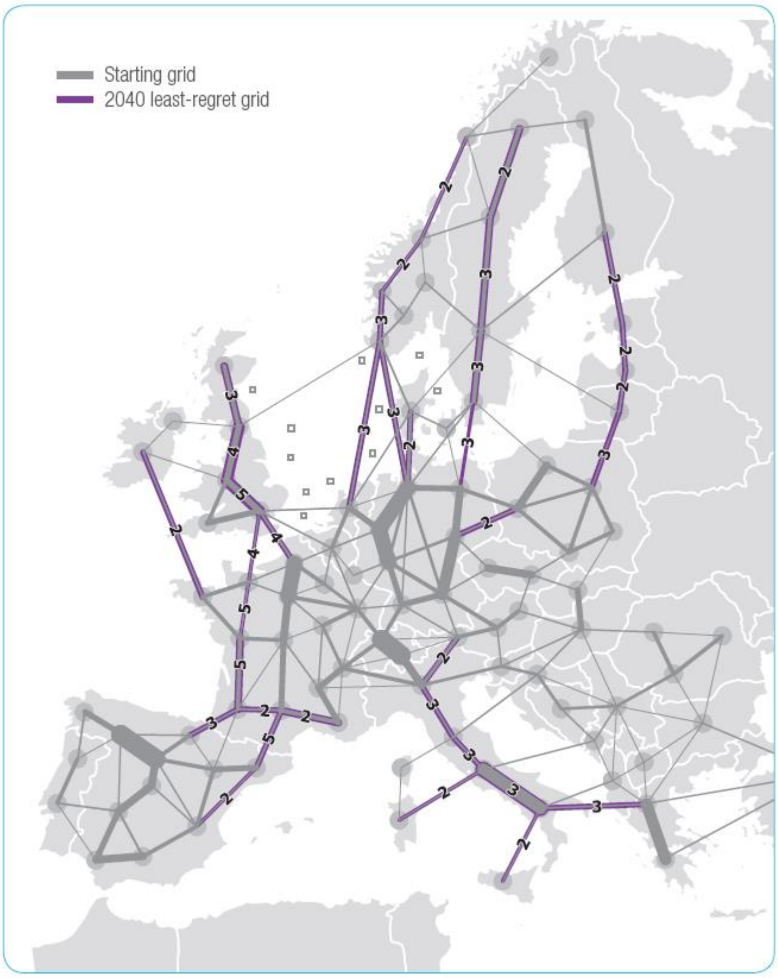


Figure 12. Grid architecture for 2040 covering all scenarios examined (grey: starting grid; purple: reinforcements) as suggested in the 'Electricity Highways 2050' study

The reinforcement needs relate primarily to supporting high levels of RES and will cost EUR 12 to 20 Bln/year (depending on asset technology chosen) in the 100% RES scenario. This will allow for more electrification and for demand to increase from the approximate current 3200TWh to up to 4200 TWh. Maximum load could increase to above 900GW from 500GW at present. Again it is emphasized this infrastructure expenditure covers only the bulk transmission corridors, nor the total transmission investment. Furthermore, in a post 2030 perspective the Institute of Energy Economics at the University of Cologne [23] concluded that large grid extensions, allowing the full exploitation of the most favourable RES-E sites throughout Europe, are beneficial from a least-cost perspective. In particular, if the electricity network were to be cost-optimally extended, 228,000 km would be built before 2050 (+76% compared to today). Exceptions may only be sites located furthest from large consumption areas in Central Europe, where the value of grid extensions may not always outweigh its costs.

As a summary, the majority of individual studies foresee that the ambitious emission targets, combined with the increasing share of renewables connected to the electricity grid, would lead to an increase in the investment projections post 2030.

3.2 Gas transmission

In the business-as-usual scenario for gas, investment in the gas sector are expected to fade out. This is due to the high degree of uncertainty in the European gas demand, and political declarations in some countries to prepare phasing out fossil gas use. Investors will not risk setting up large new infrastructure projects due to the uncertainty over long-term developments in the gas market and the possibility of lower booking volumes. Countries with existing gas infrastructure and a potential lifetime beyond 2030 will assess the pros and cons of renovating this infrastructure in a period of gradually declining volumes of gas consumption.

The absolute maximum in the business-as-usual scenario will be to maintain the investments at the same level as in the period up until 2020 for some time. However more likely is that investments in the gas sector will further drop, continuing the trends already observed in 2021-2030 projections.

This trend is also stated in various other sources. For example the EC's Energy Roadmap 2050 states: '*Gas will be critical for the transformation of the energy system. Substitution of coal (and oil) with gas in the short to medium term could help to reduce emissions with existing technologies until at least 2030 or 2035.*' The same roadmap indicates the longer term viability of the gas sector: *'If carbon capture and storage (CCS) is available and applied on a large scale, gas may become a low-carbon technology, but without CCS, the long-term role of gas may be limited to a flexible backup and balancing capacity where renewable energy supplies are variable.'*

The European Low Carbon Roadmap of the European Climate Foundation indicates: *'..These include energy efficiency measures; decarbonization of the power sector; a fuel shift from oil and gas to power and biomass; afforestation; and many others..'* [24]

For the ambitious scenario the gas sector will need to innovate and 'reinvent' itself. The ambitious scenario is not a high decarbonizing scenario as such, but more specifically focused on the gas sector being an enabler in a greening economy. For example biogas may be one of the options for a 'reinvention' of the gas sector, since it can use the existing gas infrastructure for transport of a green biogas fuel. If the production and use of biogas really takes off, additional investments in the period 2030-2050 could become necessary. Assuming that the demand will mainly be as the most suitable long-term fuel for heavy transport (busses, trucks and ships), the larger part of the investment need will be in the distribution grids. Another possible role of gas grids in greening the economy could be the use of gas infrastructure as energy storage using power-to-gas technology to absorb oversupply from variable RES (wind and PV). This technology is at the moment not commercially viable yet (see also Appendix B). Also a connection to CCS could be an option, to be regarded as a 'low carbon technology'. This ambitious scenario covers several options which all do deserve further discussion and analysis to ensure decarbonization objectives are met in a cost-effective way. Also other options exist to allow for 2050 goals to be met, including the earlier mentioned options of more flexibility (storage, demand response), electrification of energy demand, and more intelligent interaction between operators and all system actors.

Furthermore, a paper from the University of Basel [25] finds that although the European natural gas market is expected to remain dependent on imports by 2050, the supply situation faces less bottlenecks and infrastructure congestions would play only a minor role. Therefore no substantial new corridor investments in gas transmission infrastructure are projected. It is important to note, that such long-term simulations could have an underestimation of the gas demand. In this context, ambitions decarbonization policies may free up gas infrastructure capacities for increased gas demand in other sectors, such as transportation. However, given stringent emissions restrictions, such options may not be attractive even in a scenario of excess capacity in the gas sector. Therefore, the investment levels for new transmission infrastructure post 2030 are for gas transmission infrastructure are more uncertain, in comparison with the electricity.

3.3 CCS and carbon dioxide networks

Section 2.7 already described the limited expected uptake of carbon dioxide networks in the 2021-2030 decade. The International Energy Agency formulated goals of 2000MtCO_2/year captured and stored by 2030, and 7000 MtCO_2/year captured and stored by 2050 [26]. According to the current price of 50€/tonne this would amount to EUR 100 Bln and EUR 350 Bln by 2030 and 2050, respectively. However, the cost evolution of CCS technologies towards 2050 is hard to predict. In addition, the numbers quoted by literature are extremely dependent on the scenario considered and the generation mix in 2050.

Towards 2050 some visionary scenarios include a large-scale rollout of CO_2 pipelines in Europe, and an extended contribution of CCS to the energy system. In North Western and Central Europe, sufficient storage capacity would theoretically be available in aquifers and gas/oil fields [27]. In contrast with the current gas infrastructure, CO_2 transportation would only be needed from source to storage cavity. A report of the Joint Research Centre suggests that 20 374km of pipelines and a cumulative investment of EUR 29 Bln is required by 2050 to satisfy Europe's climate objectives [28]. This is similar to [27], where a pipeline infrastructure between 22000km and 33000 km is suggested. Investment estimates towards 2050 are highly uncertain, and dependent on the scenario considered.

In conclusion, towards 2030 some carbon network developments will be ongoing but play a minor role in the overall energy system due to the lack of business case. The exception may be for a few favourable industrial cases and some large-scale demonstrations. To reach the commercial viability point for carbon networks, a very strong CO_2 price or tax would be needed, based on a deep decarbonization scenario. An alternative could be that CCS will become obligatory for fossil fuel power plants though this deviates from most 2050 energy mix projections. Without these strong regulatory incentives, no major evolution is expected beyond large-scale demonstration projects in Europe by 2030. Towards 2050 however, more CO_2 capture could be possible, up to 33000km of pipeline infrastructure and EUR 29 Bln investments. These figures have a high level of uncertainty as the amount of carbon capture is dependent on the generation mix strategies opted by Europe and its Member States.

3.4 Power-to-gas infrastructure

With increasing levels of variable renewable energy, the need for flexibility resources increase as well. The International Energy Agency expects a storage need by 2050 between 70 and 90 GW. The outlook of power-to-gas infrastructure towards 2050 depends on the application and the scenario [29].

For **industrial applications**, the potential will be lower than the most optimistic 2030 scenario presented in Chapter 2. This is simply because the business case for delivering hydrogen to oil refineries, one of the largest sources of hydrogen demand, is expected to disappear completely. Other business cases, such as power-to-chemicals (e.g. methanol and ammonia), can still have a permanent future and provide the basis for an investment potential of EUR 245 Bln in the sector between 2020 and 2050.

For **injection of hydrogen or methane in the gas grid**, large uncertainties exist. In a fully decarbonized energy system, admixture of hydrogen in a natural gas grid would no longer be the issue, as all gas should be synthetic. In that case power-to-methane will be more important to obtain a net zero-emission application. Power-to-gas would essentially be a form of long-term storage to store excess electrical energy. The potential of power-to-gas would greatly increase when the methanation step (transforming CO_x and H_2 into methane and H_2O) is included, removing the barriers for hydrogen transportation due to its relative incompressibility. However, in a fully decarbonized system strong CO_2 sources from power plants will no longer be present, which reduces the efficiency and speed of the capturing process. With a CO_2 content of only 390 parts per million, it takes

2300000m^3 of air from the atmosphere to produce 1 ton of CO_2 [30]. The American Physical Society estimates that carbon capture from the air is inherently more costly than carbon capture from large CO_2 sources. Different literature sources quote costs for CO_2 capture from the air between 0.2€/Nm^3 CO_2 and 0.9€/Nm^3 CO_2 compared to 0.05-0.13€/Nm^3 CO_2 from conventional power plants [31] [30]. This impacts the business case for methanation, which is reliant on a sufficiently large CO_2 supply.

For **hydrogen (or methane) based mobility**, an enormous potential exists, up to a full rollout of hydrogen (or SNG) public charging infrastructure, including heavy vehicles, ships and airplanes. However, for road and in particular railway transportation, the competition with electric mobility will be a key determining factor for the deployment of power to gas based mobility in 2050. Currently, electric mobility is becoming increasingly popular, with increasing driving range and decreasing battery costs.

In conclusion, power-to-gas is currently a sector with a lot of projects starting up in demonstration phase. It is uncertain to what extent and when these projects can develop in a full commercial manner. A key determining factor will be the future generation mix and the scenario considered. Only in a deep decarbonisation scenario (>70-80% GHG reduction), power-to-gas as a form of energy storage will be cost effective [32]. For some applications, such as mobility, the competition with batteries will be an important factor, while for energy storage applications, to a certain extent electrical storage and power-to-gas can be complementary. Finally, power-to-hydrogen for industry has the largest potential on a short term, with the power-to-refinery a transitional business case that can be leveraged to bring down the costs of electrolysis and enable other future sustainable business cases.

3.5 Outlook overview

The following table puts the qualitative 2030-2050 outlook in perspective of the detailed 2021-2030 expenditure trends, based on data collected in this study as well as review of external studies.

Infrastructure type	2021-2030 expenditures		2030-2050 expenditures	
Electricity transmission	➚	The data illustrates an increasing expenditure trend in the investment levels up to 2030, which goes beyond the levels of today. A substantial number of the expenditures are from foreseen investments in offshore projects (35%), which have relatively higher costs.	➚	A continuous annual increase is projected in investment levels towards 2050 in a decarbonisation scenario where the emission targets are reached. The need for transporting renewable energy and the avoidance of bottlenecks will mean an increase in the investment levels. In a business-as-usual

				scenario (not meeting COP21 ambitions) the trend from 2021-2030 investments will stagnate as the power grid investments will continue to be higher than historical trends. This confirms that beyond 2030 transmission investment levels are most likely to increase even further.
Gas transmission	➘	The data illustrates a drop in investment levels after 2025, as most of the expenditures stems from projects with an expected commission date before year 2025. The views on further gas transmission development are diverse. Some TSOs are considering gas as being essential in the decarbonisation of the energy sector, and others doubt that future volumes will be sufficiently high to motivate investments.	➘	It is considered that gas could facilitate an energy transition with reduced emissions until at least 2035. Opportunities are under review for gas sources / gas infrastructure becoming an enabler in a green energy system. For example biogas is an option for rethinking the gas sector as is the use of more sustainable gas in transport or hearting, which could necessitate some investments. However, in a post 2035 business as usual, a lower gas demand is likely to lead to a reduction in the investment levels.
Carbon dioxide networks	➔/➚	Some pilot carbon network developments will be ongoing towards 2030, but overall would have a minor role in the energy system, making the investment levels limited.	?	The cost evolution of CSS technologies are hard to predict, as they are dependent on the scenario considered and the generation mix, making the future investment levels uncertain. CCS could be an emissions reduction enabler if supported by strong regulatory incentives.
Power-to-gas infrastructure	➔/➚	As power-to-gas is currently a sector in the demonstration phase, the investment levels are limited. Adding, power-to-hydrogen for industry and mobility applications has the largest potential.	?	Future investment levels will depend heavily on the generation mix in the scenario considered. Power-to-gas is foreseen to have the most potential for mobility applications.

Appendix A Methodology for gas, electricity, oil transmission and storage

A 1 Process

The flowchart in Figure 13 provides an overview of the data collection methodology as applied in this project. A brief description of each step is provided below the figure.

Figure 13. Data collection and review process

Data template

A data collection template was set up at the start of the project and agreed upon with the European Commission. This format has been used throughout the entire project. This data collection template not just allowed for the consistent and uniform collection of data, but also served as a harmonised assessment tool. In the setup of the template a trade-off was done between completeness of information requested and ease in submission. The template covered a limited number of open questions. The data structure of transmission asset info was based as much as possible on terminology of the TYNDPs, was kept as limited as possible (key planning, technical and financial parameters), and was pre-filled to the extent possible based on info in the latest TYNDP.

Contact promoters

Contact details of the relevant project promoters were provided by the ENTSOs. All promoters have been contacted individually with the data collection template prefilled with their information. Reminder emails and phone calls were used to follow up on the submission of the templates.

Webinar

Several webinars were held (two on gas/electricity projects of TSOs, and one on power-to-gas and carbon dioxide networks). These webinars addressed the aim of the project, clarification of the data template and process, and common questions.

1st data analysis

Once the data was submitted, a first review was done on completeness. If necessary questions on details were raised to the project promoter. This iteration improved the submitted data both on completeness as well as overall consistency.

Follow-up

Further follow-up interviews were held with a selection of project promoters (as agreed with the Commission) to discuss their submitted data and clarify country-specific aspects.

2nd data analysis

The final stage of the methodology was the 2nd data analysis, in which all collected data was compared to reference cost indicators, cross-checked with other promoters, and cross-checked with present annual expenditures and NDPs. This allowed to make corrections and fill data gaps.

A 2 Robustness

Robustness of the data set and its conclusions was improved by the following actions. This focuses mostly on the electricity and gas transmission grid data.

To reach a data set that is as much as possible complete, a **high response rate** from promoters was essential. This was prepared by selecting a clear data structure and pre-filling with public TYNDP info. Engagement with all promoters was driven via an EC supporting letter, a webinar to openly discuss the approach and possible issues, interactions with the ENTSOs, and multiple reminders and contacts with all promoters.

Also in case of positive response, in various cases more iterations were needed to ensure **completeness of the data provided**. This was in particular needed when only TYNDP info was provided and no further expenditures of smaller assets, modernizations, etc. As highlighted in Chapter 2, for some TSOs the non-TYNDP part of their portfolio is quite extensive, while for others the TYNDP investments simply cover the majority of future expenditures. In a limited number of cases where there was no positive response, information from the NDP was taken as best available information.

Even with a complete set of data, several aspects create a significant uncertainty for the full expenditure view. All combined they create an uncertainty in either direction of the projections given in section 2.

- Many promoters highlighted an uncertainty for project expenditures. Typically for electricity transmission projects this is about 10%, a similar confidence interval also applied in the TYNDP2016.
- Comparisons were made with estimates based on ACER's unit investment costs. Not surprisingly as the unit costs have a high standard deviation, also the claimed costs can deviate strongly from the estimated based on unit costs. However, both for gas and electricity the claimed costs are on average higher, in particular for some types of infrastructure. Also some promoters have a systematic deviation for all their projects from the estimates based on unit costs which could not be explained in this study.
- Operational expenditures cover an important cost component for infrastructure owners. As this is a complex topic in many financial and regulatory topics, only a brief analysis of this component was made.
- Many projects put forward for commissioning in the decade 2021-2030 are non-mature at this stage and may still be cancelled or further postponed. Also their cost estimates have higher uncertainty.
- Some promoters may have limited views on expenditures in the later years of the 2021-2030 decade. As explained in section 2.1 an upward correction was made for electricity transmission projects to cover this.
- The future of gas transmission investments are uncertain and subject to gas demand evolutions and possible innovations in the sector.
- The future of carbon dioxide networks and power-to-gas infrastructure is in a very early phase which complicates giving robust estimates.

Appendix B Methodology for power-to-gas infrastructure

B 1 Sources

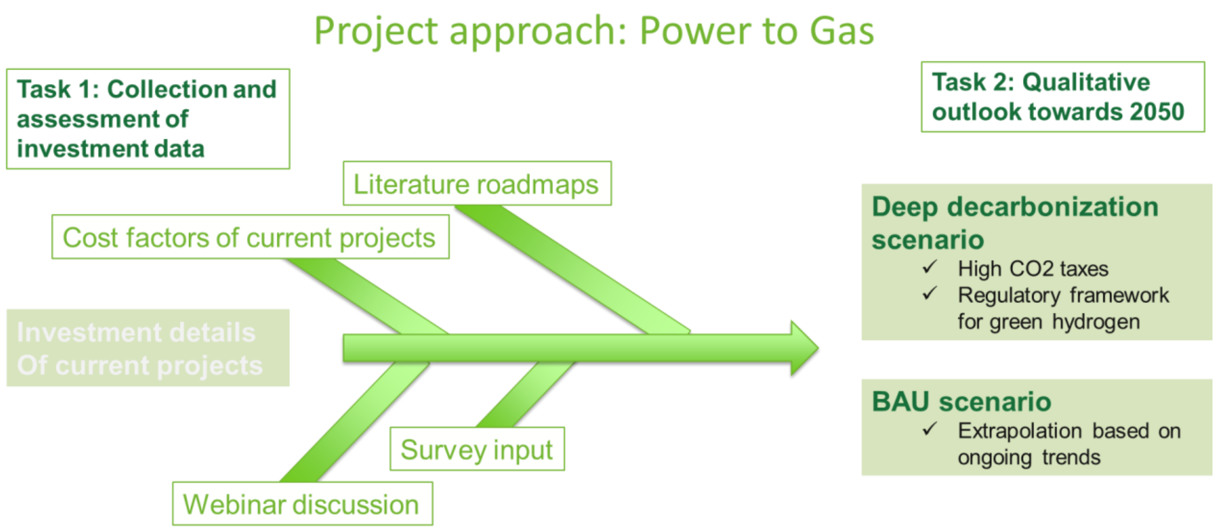
Only a limited number of power to gas demonstration projects are currently operational in Europe. Providing an outlook for commercial evolution of the sector, based only on the cost structure of the current demonstration projects, would yield a severely distorted result, probably underestimating the potential of the technology. Indeed, once the technological evolutions and external factors such as regulation have evolved and power to gas reaches full commercial maturity, an exponential uptake of power to gas projects could occur. This is substantially different from the already mature technologies involved in gas and electricity networks.

Currently, almost all projects are reliant on EU or other sources of public funding. Some projects have a strongly funded R&D component intermixed with them, especially projects which use any type of methanization (which has intrinsically a higher cost, as it involves an additional conversion of hydrogen to methane.) Due to the pre-commercial nature of power to gas technology, the current investments in demonstration projects cannot be considered as representative for an outlook towards 2030.

Taking into account these preconditions, the consortium provides in this study an estimate for the investments in power to gas 2021-2030, by performing a scenario analysis based on the following methodology:

Step 1: Estimation of the current investment size of the sector

For this step, information was collected from various platforms, such as the European power to gas platform [33], Hydrogen Europe [34] and the Fuel Cell and Hydrogen Joint Undertaking of the European Commission [35]. Power to gas projects currently rely heavily on public funding. Detailed investment data on project level is often not public, however a general number for the total sector investment was estimated, based on the aggregated analyses of the platforms themselves.



Step 2: Estimation of the cost factors of the projects

As mentioned above, the investment details of demonstration projects are not representative for the evolution of the investments in the sector as a whole, due to the reliance on public funding and the intermixed R&D component. Cost factors of commercial hydrogen activities which perform electrolysis are a much better indicator. Therefore, the consortium contacted Hydrogenics, a world-leading company which performs electrolysis for various applications. An insight in their cost structure and evolution in the past years provides complements the literature sources used elsewhere in the project.

Step 3: Expert survey addressing key questions

In this phase, experts were confronted with a survey on key issues towards the future of power to gas. The questions addressed the possible dominant technologies in 2030, the expected business cases and the evolution of the sector as a whole. Finally, comments were left open for regulatory recommendations if 30 power to gas experts from various sources and platforms answered the questionnaire.

Step 4: Webinar organization

The consortium organized a webinar on the topic of power to gas, where high-level speakers provided input, followed by a discussion moderated by the consortium. The results of this discussion contributed to the vision put forward in this report.

B 2 Technology overview

Power-to-gas is a very promising yet pre-commercial technology that allows the conversion of electricity to hydrogen gas, and subsequently to methane. The strength of power to gas technology lies in its variety of possible business cases. Hydrogen as well as methane can be used for various applications; direct injection in the gas grid as a long-term storage option, hydrogen or SNG mobility applications, and as industrial feedstock. The first step, power to hydrogen, separates water into H_2 and O_2 using a process called electrolysis. After this step, the hydrogen gas can be converted to methane using a CO_2 source, either from industry and conventional power plants, by using carbon capture technologies, or by extracting CO_2 directly from the atmosphere.

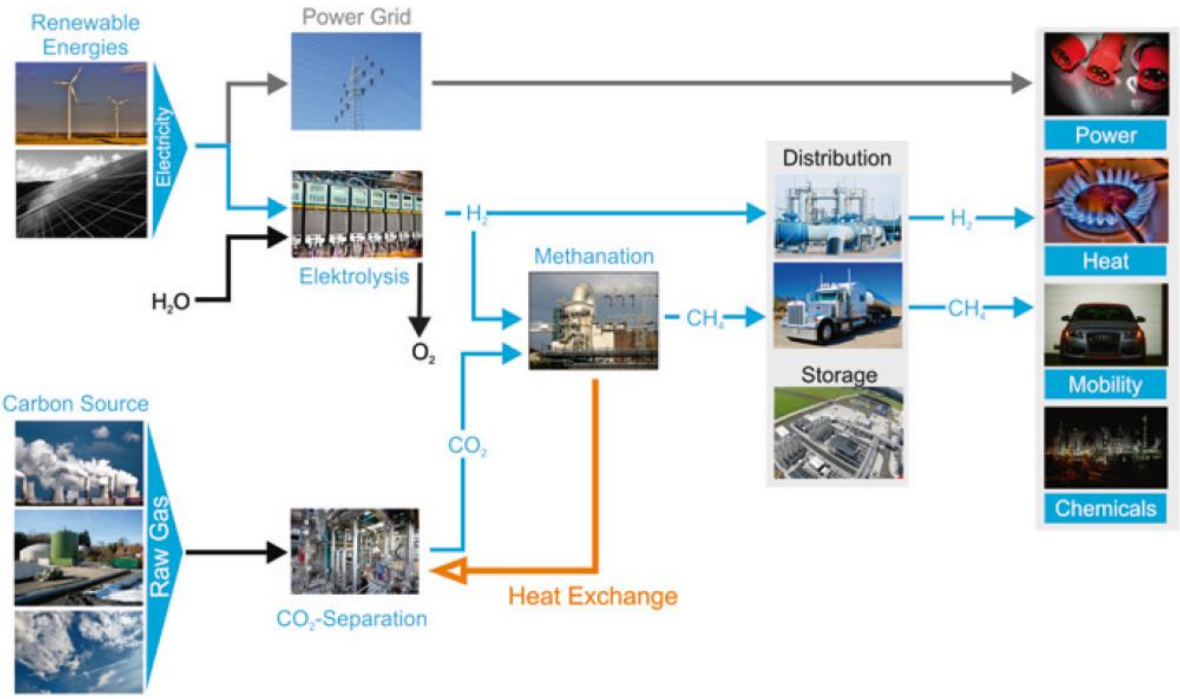


Figure 14. Overview power to gas system applications.

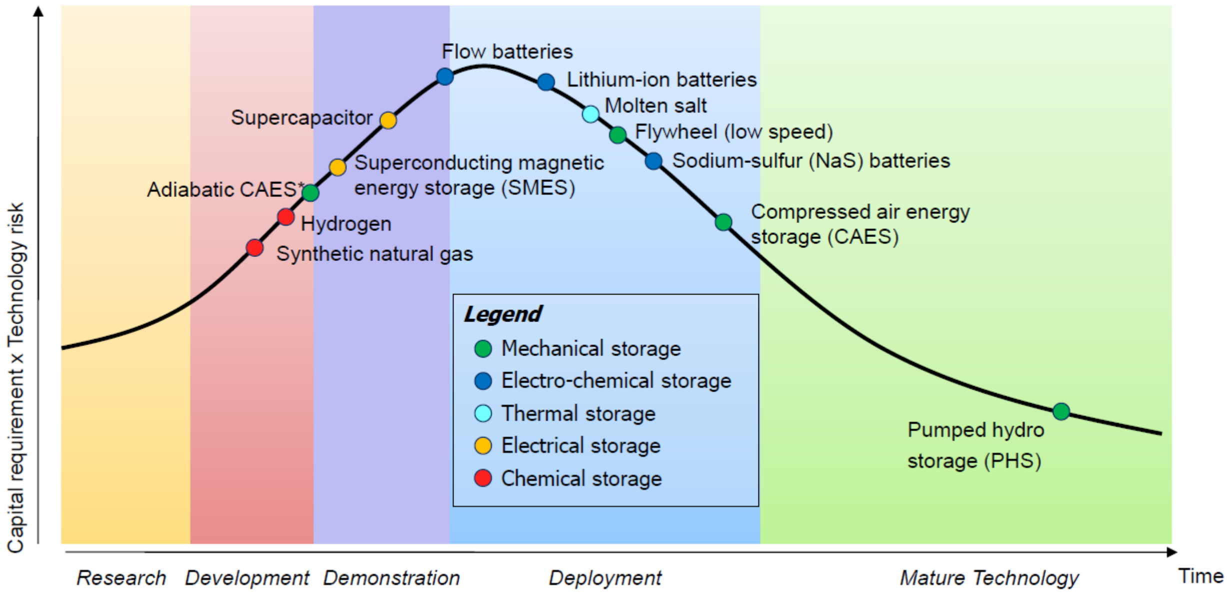


Figure 15**. Maturity level of different storage technologies (source: SBC energy institute analysis, 2013).**

Different technologies for conversion of electric power to hydrogen exist. The traditional technology is alkaline electrolysis. Polymer Electrolyte Membrane (PEM) electrolysis is a more recent technology using a solid polymer to conduct protons, which has a very high potential, especially in terms of flexibility. Solid Oxide electrolysis is a technology at high-temperature, which to date has a lower TRL than alkaline or PEM.

During the webinar, the technology with the highest potential towards 2030 was discussed. The answers from the experts are given below.

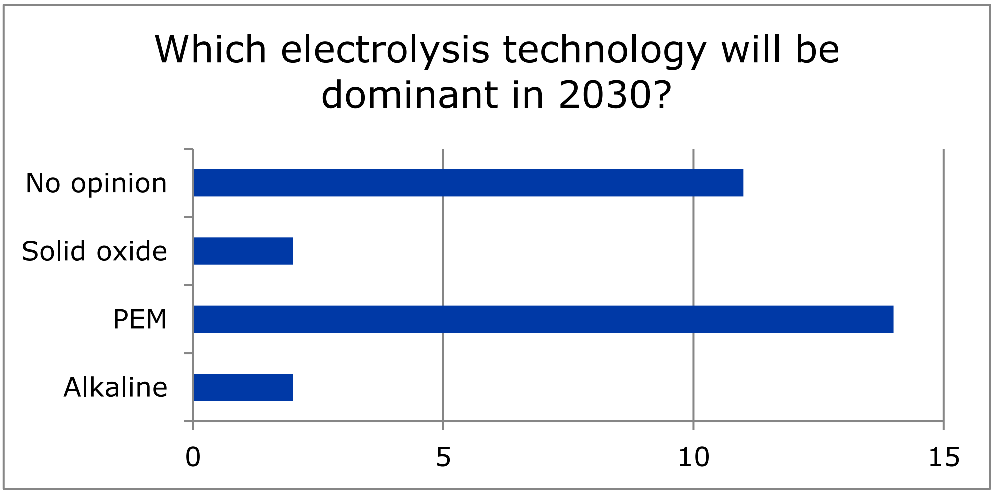


Figure 16. Dominant technology in 2030 according to hydrogen experts.

Most experts consider PEM to have the highest potential. The main reason for this is the balancing flexible capacity of PEM electrolysis, which allows revenue from balancing of the electricity system with large loads of renewable intermittent production. This is not or to a much lesser extent possible with alkaline or solid oxide technologies. It is remarkable that very few of the experts see alkaline as the dominant technology in 2030, while this technology is still used in a lot of demonstration projects these days.

B 3 Investment potential in various power-to-gas applications

A large part of the sector is funded by public entities. A very important share of public investments is covered by the Fuel Cell Hydrogen (FCH) Joint Undertaking by the European Commission.

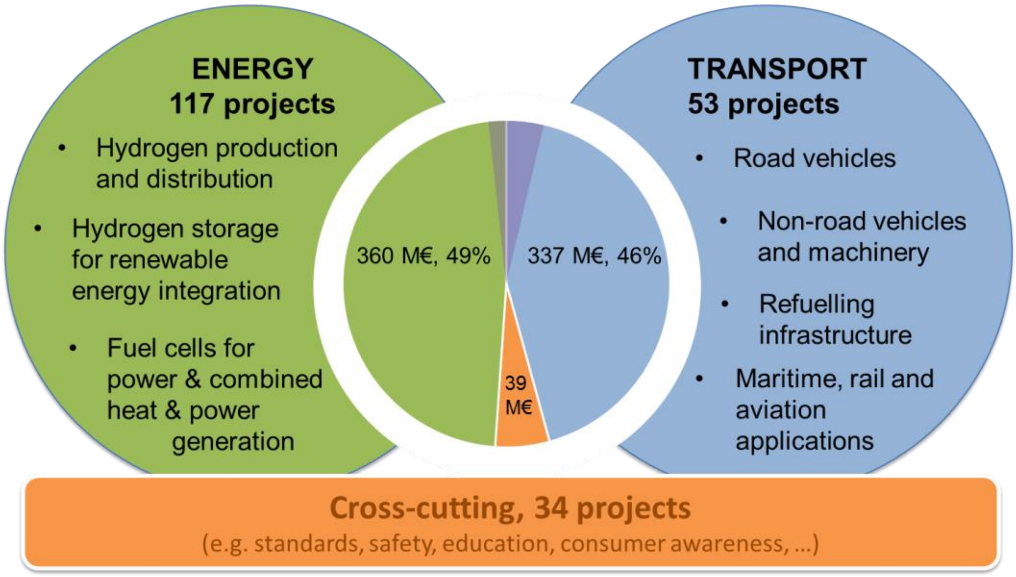


Figure 17. (source: [5] Power to gas projects: funding per topic of the FCH joint undertaking.

The FCH invests around EUR 100 Mln/year, for a total of EUR 750 Mln public investment, together with a similar amount of private investment, which equals to EUR 1.5 Bln in total [36]. In 2015, EUR 110 Mln was allocated over 15 different projects. These projects rely for around half of the total investment on public funding sources and half on private funding, which makes a total yearly investment of around EUR 220 Mln for projects related to the FCH association.

Other than the power to gas projects connected to the FCH JU, the European power to gas platform unites around 50 power-to-gas demonstration projects. An internet search was performed in combination with an e-mail campaign to obtain funding details of the mentioned projects. The members of the European power to gas platform received an e-mail with a template to provide financial details on their projects, similar to the electricity and gas projects. For the FCH projects, the total budgets and beneficiaries per partner were known. For the projects connected to the power to gas platform, a few responses were given but the total budget of these projects was not always publicly available. However, the technical details were usually available on the project websites. In total, around 30MW installed operational power was found for power to gas projects. Assuming a similar cost structure for the European power to gas platform projects than in the FCH JU projects, this would amount to more or less EUR 500 Mln total funding invested in the currently operational projects, or around EUR 80 Mln yearly.

In conclusion, the total investments in current operational power to gas projects, supported by the FCH JU or the EU Power to Gas platform, amount to EUR 2 Bln aggregated, with a **yearly investment in research and demonstration of around EUR 300Mln/year**.

It is stressed that these investment numbers cannot be used as a basis for estimation of the future investments. Recent evolutions show a rapid trend towards larger-scale installations, together with a cost reduction per installed kW. In 2011, the Colruyt group project installed a 150kW PEM electrolyzer for forklifts, which was for that time a large installation [37]. In 2016 the large projects included a demonstration electrolyzer of 6MW in Etzel, Germany [38] and the largest methane production plant of 6,3MW using alkaline electrolysis, delivered to Audi by ETOgas [39]. Clearly, the sector is in full evolution towards larger systems with reduced costs per installed kW. Therefore, for estimation of the cost of electrolysis it is essential that the most recent data are used, as most of the literature values are outdated.

The Hydrogenics company indicated that the cost of their system decreased from 2000-3000€/kW in 2008 to 700-800€/kW for larger systems nowadays [40], (which is similar to other leading companies e.g. [39]). In addition, they predict that given a viable business case, the costs of electrolysis could decrease to around 300€/kW for larger systems. This is in line with other literature sources like e.g. Sgobbi et.al., where 377€/kW for large systems in 2030 is suggested [41].

According to a recent study by ENEA, the cost of hydrogen production is in the range 8-10€/kg [42]. A large part of these costs are related to electricity costs, grid fees and taxes. The non-energy cost of hydrogen is currently below 5€/kg, where the EASE-EERA roadmap predicts an evolution of the non-energy cost towards 2030 to 2€/kg [43]. The PRIMES EUCO27 predicts that the average electricity prices will be more or less constant between 2020 and 2030, however electrolycis installations are expected to be operational during periods of excess electricity. By 2030, we assume that the costs of hydrogen production, including electricity cost, will be 5€/kgH_2[2].

In the following section, we will focus on the cost of power to hydrogen towards 2030. The extra costs of the methanation step will most probably mean that the business case of power to hydrogen will precede the one for power to methane [44]. However, power to methane has large potential for energy storage in a deep decarbonisation scenario. Therefore, power to methane will be discussed in chapter 2, along with the scenarios for 2050.

In the subsequent chapters, we analyse application by application the investment potential for the period 2020 to 2030 and provide a scenario based on a few key assumptions.

3.5.1 Uptake of hydrogen mobility by 2030

To estimate the potential uptake of hydrogen mobility by 2030, a survey was launched among hydrogen experts. A large percentage of the participants of the survey (30 in total) estimate that hydrogen mobility will not take up a major role as a transport fuel by 2030. More than 60% indicates

[2] Electrolysis installations produce around 0,015kgH_2/kWh (see for instance [68]. An electricity price of 45€/MWh yields 3€/kgH_2 electricity cost.

2040, 2050 or even 'never' as the moment in which only 5% of the vehicle fleet is hydrogen powered.

The reason behind this overall pessimistic insight on the uptake of hydrogen mobility is twofold:

- Hydrogen charging infrastructure needs to be rolled out across Europe, which is an important cost factor.
- Electric powered vehicles clearly have an advantage and increased market share compared to hydrogen fuelled vehicles. This can be explained by the increasing range of electric vehicles and the higher efficiency of batteries vs fuel cells.

During the webinar, the suggestion of hybrid hydrogen-electric vehicles came up, where hydrogen could enhance the range of the plug-in electric vehicles. In that way, the charging infrastructure could only be rolled out along the highways, and significant costs could be saved. However, this could be mainly relevant in a scenario in which full decarbonisation is required, which is more relevant in scenarios towards 2040 and 2050. For 2030 time horizon, the experts foresee only a minor role in hydrogen transportation, limited to niche applications (such as forklifts) and demonstration projects.

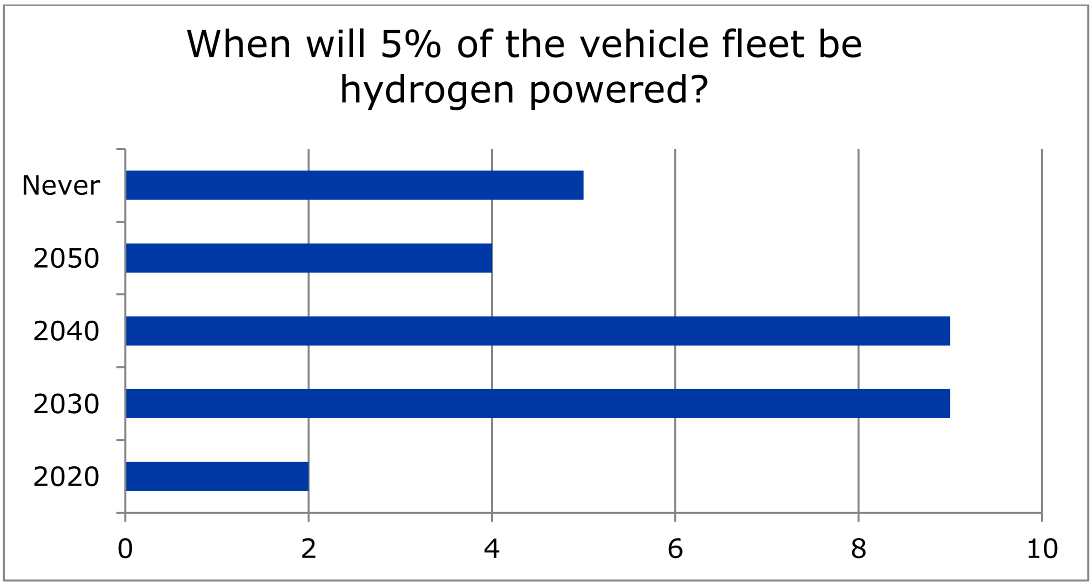


Figure 18. Survey results on hydrogen powered transportation in Europe by 2030.

When assessing the investment needs in hydrogen powered mobility, clear definitions are needed. In this analysis, the manufacturing of hydrogen powered vehicles is not considered. Instead focus is put on the hydrogen production for transport fuel. At the moment only a few demonstration projects using electrolysis exist.

In the PRIMES EUCO27 scenario, the yearly energy demand of public road transport and private cars slightly decreases in Europe from 180647ktoe in 2020 to 170122ktoe in 2030 [45]. As argued before, a major breakthrough of hydrogen mobility cannot be expected, due to the high cost of refuelling infrastructure and the competition of electric mobility. As an illustration the case is presented in which 1% of the European private and public transport would be hydrogen powered.

In the PRIMES EUCO27 scenario, public and private passenger transport and freight transport adds up to 281023ktoe in 2020, decreasing to 253726ktoe in 2030. If 1% of this transport is hydrogen powered in 2030, this amounts to 2537,26ktoe or 29,51TWh yearly in Europe.

The energy content of hydrogen is 33,3kWh/kg, however we also need to take the efficiency of fuel cells into account, which is around 50% [46] and arrive at the following equation:

$$Hydrogen\, needed\; for\; 29{,}51TWh\; mobility = \frac{29{,}51TWh}{33{,}3kWh/kg \times 50\%} = 1{,}77Mtonnes\; H2$$

Clearly this is an application with a high potential. However, the commercial viability and effective implementation of hydrogen powered mobility is highly uncertain.

To estimate the total number of investments in hydrogen mobility between 2020 and 2030, 1% of hydrogen mobility is assumed, or 1,77Mtonnes of H_2 produced (see the equation above). At a price of 5€/kg, the total yearly revenue from hydrogen sales would be 8.85bn€ by 2030. If a payback period of 10 year is taken for the investor and a discount rate of 5%, **the total available investment in hydrogen based mobility over the 10-year period between 2020 and 2030 amount to EUR 68 Bln**. However, the expert survey in this project and other literature studies suggest that even 1% of mobility demand is very uncertain. See for instance the IEA Energy Technology Perspectives 2016 report [47]:

'*Notwithstanding the potential for substantial cost reductions for hydrogen fuel cells in vehicles, long-term prospects for hydrogen fuel-cell electric vehicles (FCEVs) are limited, even in the final decade of the 2 degree scenario, by the availability of low-cost excess electricity from variable renewables. This reflects the investment risks of shifting to centralised hydrogen production and building up an adequate hydrogen distribution infrastructure.'*

Therefore, the consortium estimates that hydrogen mobility of 0,1% of the mobility demand, related to niche applications (such as forklifts) would be more realistic than 1%.

In conclusion, the mobility application is one with an extremely high potential, however, a full rollout of hydrogen distribution infrastructure and charging stations is very uncertain, and not expected to be commercially viable by 2030.

3.5.2 Injection in the gas grid by 2030

One of the main applications of power to gas is direct injection into the gas grid. In general, the round trip efficiency of power-to-gas is rather low compared to other storage technologies like batteries, around 25-50% depending on the application [48]. However, power-to-gas can be used for long-term (seasonal) storage, complementing the more short-term storage capacity of batteries.

Table 3. (source: [4]) Efficiencies of typical storage technologies. A power-to-gas efficiency of 75% does not include reconversion to electricity.

Technology	Efficiency	Capacity rating MW	Time scale
Pumped hydro storage	70–85 %	1–5,000	Hours—months
Li-Ion battery pack	80–90 %	0.1–50	Minutes—days
Lead acid battery	70–80 %	0.05–40	Minutes—days
Power-to-Gas[a]	30–75 %	0.01–1,000	Minutes—months
Compressed air	70–75 %	50–300	Hours—months
Vanadium redox battery	65–85 %	0.2–10	Hours—months
Sodium sulfur (NaS) battery	75–85 %	0.05–34	Seconds—hours
Nickel cadmium (NiCd) battery	65–75 %	45	Minutes—days
Flywheel	85–95 %	0.1–20	Seconds—minutes

Power-to-hydrogen is the main application considered in grid injection for the 2030 horizon. Subsequent conversion of the hydrogen to methane implies the additional methanation step, which increases the total project cost and decreases the efficiency even further. The CAPEX cost of the methanation step is estimated to be 700-3000€/k [49]. According to a recent study, in Germany a fixed feed-in tariff of 100 €/MWh for hydrogen and 130 €/MWh for methane would be required to make a positive net present value for the investment under the current circumstances [50].

Due to the incompressibility of hydrogen gas, the injection in the gas grid is only possible to a limited extent. In several studies, it is estimated that up to 10-15% of the gas mix could consist of hydrogen without major issues [51] [52]. In practice however, admixture of hydrogen in the gas grid is usually limited to a few percent or lower. Examples are 0,02% in The Netherlands and 0.1% in UK [53] [54].

In the survey conducted roughly half of the experts indicated that injection of hydrogen in the gas grid could be commercially viable by 2030, whereas half of the expert predicted that the viability point would be beyond 2030. The viability point is extremely dependent on regulatory incentives, as synthetic gas (hydrogen or methane) is currently not competitive with typical prices of natural gas [55].

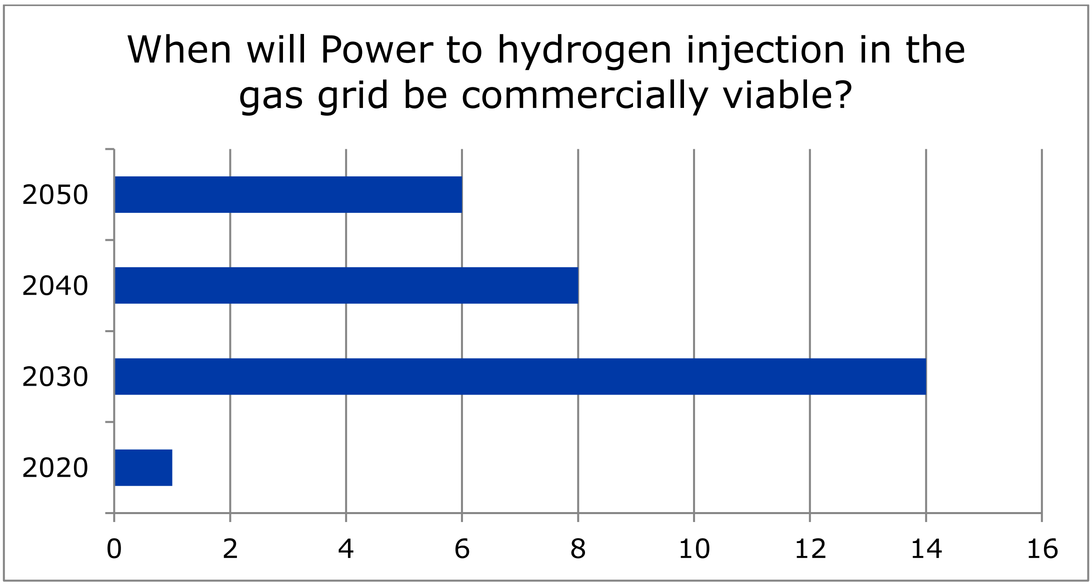


Figure 19. Survey results on commercial viability of POWER-TO-GAS injection in the gas grid [25].

Towards 2030, a scenario of a few percent admixture of hydrogen in the natural gas grid is a realistic projection. Strong financial incentives are required to make green hydrogen injection into the gas grid commercially viable, as concluded in various studies, for instance [44]. A study of ENEA estimates that the levelized cost of gas-from-power is between 100 and 170 €/MWh$_{HHV}$, the latter cost involving a methanation step [42]. Another roadmap study with a calculated business case estimates a cost of 125€/MWh for power to hydrogen and 150-200€/MWh for power to methane [56]. When compared to a natural gas price of around 20-30€/MWh$_{HHV}$ [57], power-to-gas for direct injection in the gas grid is not expected to be commercially viable in the coming years without very strong incentives. However, an increased integration of variable renewable sources in the energy system increases the need for long-term storage solutions where power-to-gas could be an option. Therefore, an uptake of this business case can be expected though probably not before 2030.

For the scenario definition, a business-as-usual scenario is used where injection of green hydrogen into the gas grid remains limited to pre-commercial demonstration projects. Alternatively, assuming strong financial incentives, a mix of a few percent in the gas mix could be achieved by 2030.

According to the 2030 PRIMES EUCO27 scenario, a reduction in gas consumption of around 9% is to be expected by 2030 [45]. This means that no overloading of the current gas grid infrastructure is expected, and there is still a large enough demand to enable a business case for power-to-gas with injection in the gas grid.

The CertifHy project estimated that 1% admixture of hydrogen in the EU gas grid corresponds to yearly 170ktonnes of H_2 being injected in the grid, assuming yearly gas demand of 1721 TWh [58]. The energy content of hydrogen is around 33,3kWh/kg [59]. In recent years, the average wholesale natural gas price in Europe varied between 10€/MWh and 35€/MWh, with very low gas prices in 2016 of less than 15€/MWh [60]. To give an idea of the order of magnitude, the possible revenue is calculated assuming a hydrogen price of 5€/kg.

For the realistic case, 1% admixture of hydrogen would yield a revenue of:

$$Yearly\ Revenue(P2G\ injection\ gas\ grid) = 170ktonnes \times 5€/kgH2 \approx 850M€$$

An admixture of 1% hydrogen would yield revenues by 2030 of 850M€. Assuming a payback time of 10 years and a discount rate of 5%, the **total investment for gas grid injection could be around EUR 6.6 Bln between 2020 and 2030**.

Strong policy support is essential to provide a viable business case. Given the cost of 5€/kgH_2 and an energy content of 33,3kWh/kgH_2 [59], the cost of hydrogen in the gas grid would be more than 150€/MWh, while presently natural gas prices are well below 35€/MWh in Europe [60].

3.5.3 Power to hydrogen for industrial applications

The industrial consumption of hydrogen in Europe is estimated to be around 7Mtonnes per year [61], which represents a major application for the power-to-gas sector. The chemical demand is estimated at approximately 63% (for instance, production of ammonia or methanol), 30% for refineries, 6% for metal processing and 1% for other applications [62]. By far the most common way to create hydrogen for industrial applications (such as oil refinery) at the moment is steam reforming, where methane interacts with steam to create hydrogen gas and CO_2. Electrolysis currently accounts for only a small part of hydrogen production [63].

For 2030, we could assume that the entire hydrogen demand of the sector will be covered by power-to-gas applications, which would be the optimistic scenario. Experts also look at oil refineries. This could be a very well-suited transitional business case, as it could be easily incentivized by regulation and the impact on the fuel price would be limited [63]. According to the PRIMES scenario, a yearly decrease of 3.8% of oil production can be expected between 2020 and 2030 [45]. However, this transitional business case could greatly decrease the costs of the electrolysis manufacturing process, which would enable or enhance other business cases such as power to chemicals or injection in the gas grid.

The current hydrogen demand of the oil refinery sector in Europe can be estimated at 2.1Mtonnes (30% of 7Mtonnes). In 2030, only 1,4Mtonnes would remain, taking into account the decrease in the sector according to the PRIMES EUCO27 scenario [45]. Assuming a hydrogen price of 5€/kg, one would obtain:

$$Yearly\ Revenue(P2G, oil\ refineries) = 1{,}4Mtonnes \times 5€/kgH2 \approx 7bn€$$

Assuming a payback time of 10 years for the investor, and a discount rate of 5%, this would amount to **EUR 54 Bln investments for industrial applications in the period 2021-2030** in the realistic case.

In a more optimistic case, the full industrial hydrogen demand would be covered by power-to-gas, which is currently 7Mtonnes, decreasing to 6.3Mtonnes according to the PRIMES scenario.

3.5.4 Overview of power-to-gas application potential

The table below presents an overview of the applications. The power-to-gas in industrial applications is the most promising business case, especially for refineries.

Table 4. Projected investments in power-to-gas infrastructure between 2020 and 2030 in business-as-usual and policy-support scenarios.

Application	Business as usual scenario (billion €)	Additional policy support scenario (billion €)
R&D public funded demonstration	3	3
Mobility application	-	6.8 - 68
Injection in gas grid	-	6.5
Industrial applications	-	54

The business-as-usual scenario assumes no additional regulatory incentives, in which the power-to-gas sector will probably be limited to large-scale demonstration projects. The results of the calculations in this chapter are summarized in the figure below. Any investments beyond the R&D and demonstration project domain would require regulatory and/or financial incentives.

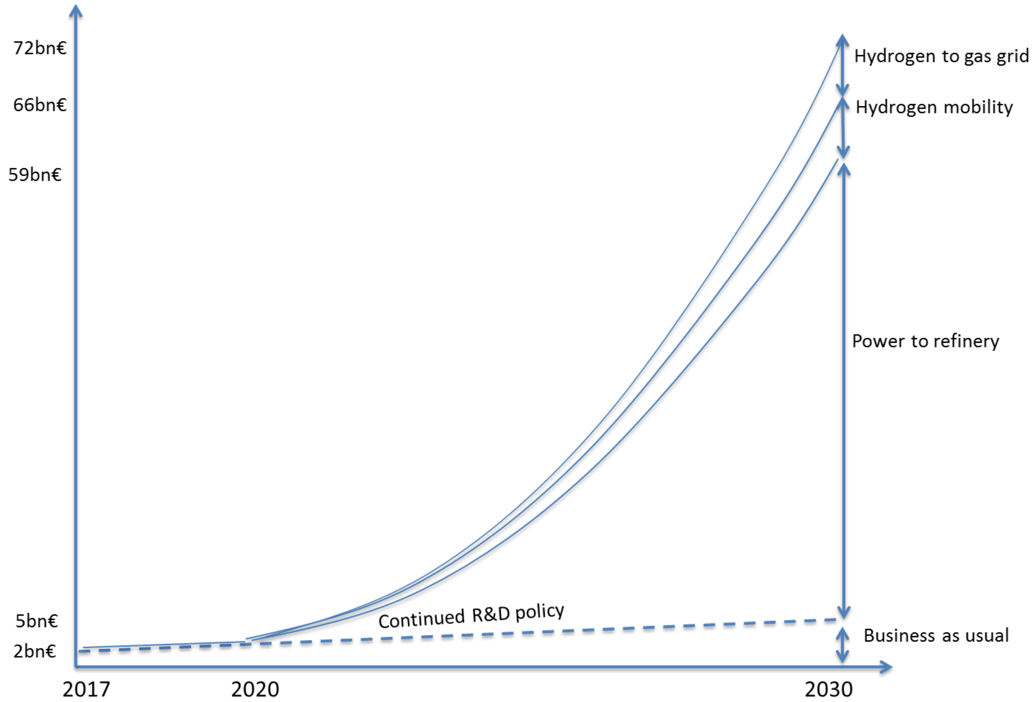


Figure 20. Cumulative investments in the power-to-gas sector between 2020 and 2030 in the business as usual (dotted line) and the 'Additional policy support scenario' (full lines).

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