SMART SECTOR INTEGRATION

ANALYSIS OF THE MACRO-ECONOMIC AND ENVIRONMENTAL BENEFITS OF POWER-TO-GAS

STUDY FOR OPEN GRID EUROPE GMBH AND AMPRION GMBH
FINAL REPORT

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R E P O R T

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ABBREVIATIONS

€	Euro
a	year
AC	Alternate Current
BEV	Battery Electric Vehicle
BMBF	Bundesministerium für Bildung und Forschung (German Federal Ministry of Education and Research)
BMUB	Bundesministerium für Umwelt, Naturschutz, Bau und Reaktorsicherheit (German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety)
BMVI	Bundesministerium für Verkehr und digitale Infrastruktur (German Federal Ministry of Transport and Digital Infrastructure)
BMWi	Bundesministerium für Wirtschaft und Energie (German Federal Ministry for Economic Affairs and Energy)
BNetzA	Bundesnetzagentur (German Federal Network Agency)
CCGT	Combined Cycle Gas Turbine
CH_4	Methane
CNG	Compressed Natural Gas
CO_2	carbon dioxide
COP	Coefficient Of Performance
DC	Direct Current
DSM	Demand Side Management
REN	Renewable energies
el	electric
EU	European Union
FC	Fuel Cell
FCEV	Fuel Cell Electric Vehicle
GHG	Greenhouse Gas
GT	Gas turbine
GW	Gigawatt
H_2	Hydrogen
HGÜ	Hochspannungs-Gleichstrom-Übertragung (High Voltage Direct Current Transmission)
km	Kilometer
LBST	Ludwig-Bölkow-Systemtechnik GmbH
M€	Million EURO
MW	Megawatt

MWh	Megawatthour
N	Nitrogen
NEP	Netzentwicklungsplan (German grid development plan)
NO	North region
O&M	Operation & Maintenance
OS	East region
p.a.	per anno / per year
$PtCH_4$	Power-to-Methane
PtG	Power-to-Gas
PtH_2	Power-to-Hydrogen
PV	Photovoltaics
SU	South region
TWh	Terrawatthour
WE	West region

1 BACKGROUND AND OBJECTIVES

The steadily increasing use of intermittent renewable electricity from solar and wind energy plants is responsible for a fundamental change of the German power sector with an impact on the overall energy system. Wind and PV electricity production does not follow the demand and generation is not necessarily located in proximity to the end-users. Hence, energy transport grids are required to connect supply and demand in space. And other measures like grid management (including redispatch and curtailment), demand side management (DSM), operating reserve, and energy storage as well as the exchange of energy with the neighbouring countries (import and export) represent the various flexibility options for balancing supply and demand in time.

An important characteristic of the future energy system will be an increasing integration of individual energy sectors. On the one hand, electricity can be directly used in the transport, heating, and industry sectors. On the other hand electricity can be converted into other energy carriers via electrolysis ("Power-to-Gas") to be used for other energy applications across all energy sectors or as a feedstock in the chemical industry. Such smart sector integration provides large flexible loads, offers the option to store large quantities of energy for extended time periods, and allows for synergetic utilisation of the existing gas grid.

The goal of this study is to quantify the macro-economic and environmental benefits emerging from smart sector integration based on Power-to-Gas (PtG) technologies and to provide insights into the corresponding cost/benefit ratio. In this context, the major question is how sector integration via PtG can contribute to reducing the need for power grid expansion. This benefit shall then also be compared with the benefit of other options to advance the energy transition (Energiewende) and with other flexibility measures in the power sector, respectively.

The study focuses on the early introductory phase of the energy transition by 2025 to 2035, specifically with a view to sector integration between electricity and gas infrastructures. The assessment is complemented by a longer term perspective with a view to 2050 as far as supportable by robust assumptions.

In analysing the effect of integrating additional renewable electricity on the existing power dominated energy market ("all electric world") the study focuses on a penetration of renewable generation beyond the assumptions of the national grid development plan for electricity (Netzentwicklungsplan Strom - NEP-Electricity) and focuses on the use of PtG as an innovative concept. Hence, both electricity and gas infrastructures are assessed within one model, however, without simultaneous modelling of all energy end-users. Instead, the scenarios are designed to assess the introduction of PtG in the transport, heating (space heating and hot water), and industry sectors independently from each other. Additionally; long-term storage of renewable electricity are analysed as well as an extended use of the existing gas infrastructure to support the electricity grid.

Assessing the sectors separately helps to manage the complexity of the energy system. It is also the explicit objective of the study to compare the economic and environmental effects of PtG introduced to each sector independently. In this respect, the scenarios for this study can be understood as conservative. Adding up the measures for each individual energy sector will therefore most probably increase the need for an early introduction of PtG technology.

Key parameters for quantifying the macro-economic benefits are specifically the CO_2 avoidance costs as well as the reduction of system costs (e.g. for redispatch and supply side management).

This study is structured as follows. Chapter 2 describes the methodology and boundaries of the analysed system in more detail. Chapter 3 includes a definition of the scenarios as well as a summary of major input parameters and assumptions for further evaluation. The actual results from a comprehensive cost and benefit analysis of the PtG technology are provided in chapter 4. Finally, chapter 5 draws a conclusion by summarizing and interpreting the results.

2 METHODOLOGY

This chapter describes the methodology of the study. First the general approach as well as the boundaries of the analysed system are detailed (chapter 2.1). This is followed by an introduction into the modelling platform used to answer the research questions outlined in the previous chapter.

2.1 General approach and system boundaries

The cost benefit analysis of the smart sector integration by Power-to-Gas technology is based on a cost comparison between a system design with and without PtG technology (see Figure 3). On the one hand, the system benefits from the use of PtG technology are derived from the following cost categories:

- **Cost avoidance from power grid expansion:** For each of the sector integration cases (mobility, heating, and industry) we calculate one system layout with HVDC transmission required to meet the power demand without the PtG technology. This calculation takes into account the existing power network topology as well as, depending on the scenario definition, the expected grid expansion according to the German grid development plan for electricity (NEP-Electricity). The avoided costs for power network expansion represent the benefit of PtG.
- **Cost avoidance from other system elements:** In order to account for good energy storage capability (where applicable also storage potential of the gas grid) as well as the load flexibility of the PtG technology the analysis also considers the costs avoidance from other system elements such as curtailment of renewable feed-in, redispatch, power energy imports, energy generation by fossil flexible power plants, energy storage by conventional storage technologies, secondary infrastructure (e.g. charging infrastructure for BEVs), and end-user applications (e.g. electric heat pumps).

On the other hand, the system benefits are compared with actual costs of the respective PtG technology in order to determine the overall effect of the different sector integration cases.

- **Investment outlays:** Capital expenditures (CAPEX) represent a major cost driver for the PtG technology. It is calculated based on techno-economic assumptions as well as on optimal dimensioning as a modelling result for all PtG components (electrolysis, methanation facility, compressors, gas storage and infrastructure, etc.) required to satisfy a given H_2 or CH_4 demand. The initial investment outlays are annualised.
- **Operating expenses:** Besides CAPEX, the calculation accounts also for the operating expenses for all system elements including variable operating costs (e.g. costs for water consumption of the electrolysis) as well as fixed maintenance costs.

- **Electricity costs:** Typically electricity costs play a major role for the PtG technology. They are included in the model intrinsically through additional renewable capacities or larger energy imports or greater needs for flexible (mainly fossil) power plants. In this context, the model accounts explicitly for operating costs (i.e. fixed maintenance and variable generation costs) of all power plants. However, only the investment outlays for new power plants (renewable and where needed fossil power plants) are included.
- **Gas transport costs:** In addition to single PtG facilities the analysis also accounts for the cost of the gas transport if the PtG facility has a different location in comparison to the consumer (i.e. it is not an onsite facility). In case additional pipelines are needed, the analysis considers corresponding investment outlays similar to the PtG facilities itself. Moreover, it includes also operating expanses of the gas grid.
- **Costs of the secondary infrastructure and end-use applications:** In addition to the above mentioned cost elements the calculation also takes into account the costs of the secondary infrastructure, i.e. H_2 and CH_4 refuelling stations, as well as end-use applications, i.e. ICE vehicles based on synthetic methane and H_2 or CH_4 heating appliances.

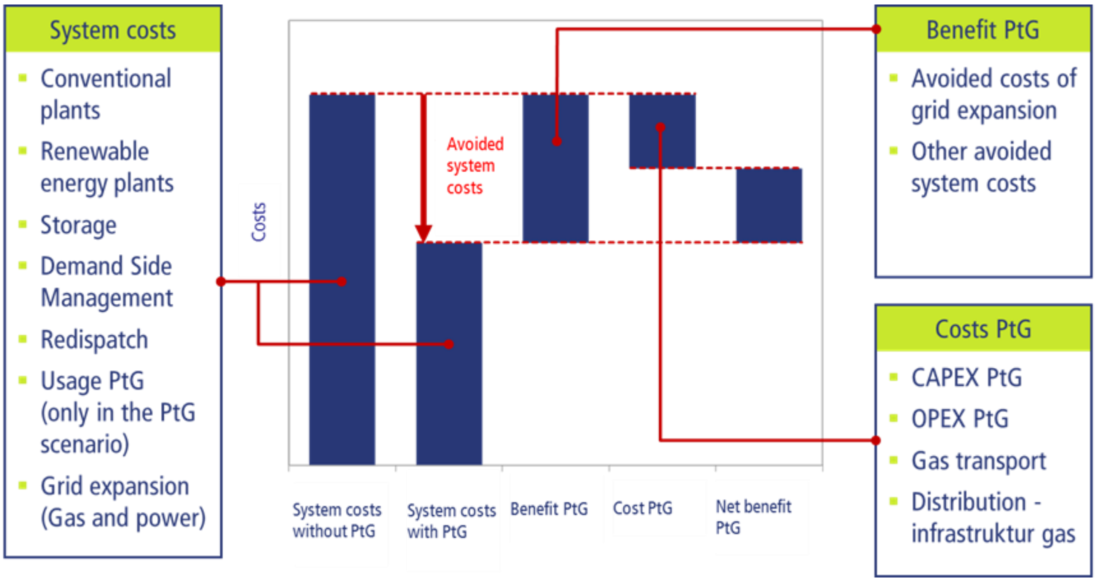


Figure 1: General methodology of the net benefit of PtG

A net benefit from various cases of the smart sector integration (see Figure 1) arises from the difference between the avoided system costs (i.e. gross benefit of PtG) and the actual costs of the PtG technology. In this context, the cost calculation is based on the principle of additionality. This means that the analysis includes only the costs which are relevant for a given year. Hence it accounts on the one hand for the operating expenses for all elements of the energy system (all power plants, storage technologies, and PtG facilities) but on the other hand only for the CAPEX of additional facilities in excess to already existing capacities. In this way the analysis neglects investments which have been already made (so-called "sunk costs") in existing capacities (e.g. existing flexible and renewable power plants, pumped-hydro storage, and the existing power and gas grid). However, these costs are compared only with the additional CO_2 emission reduction beyond today's, this way providing true CO_2 avoidance costs. Nevertheless, at this point it is important to mention that this study considers only a portion of the overall system costs which might be relevant for achieving the overall CO_2 emission reduction goals in Germany.

In general, the actual boundaries of the analysed system result from the fact that the underlying analysis is conducted from a power system perspective. Therefore, the starting point of the analysis is the power demand consisting of "traditional or conventional power demand" (such as e.g. for lightning in households etc.) as well as of direct and indirect energy demand[1] from other sectors. The power demand will be increasingly satisfied by intermittent feed-in from wind and PV power plants being responsible for the mismatch between supply and demand in space and time.

The mismatch in time can be balanced mainly by flexibility measures such as

- curtailment of intermittent supply,
- optimised use of dispatchable (conventional and renewable) power plants (so-called supply side management),
- use of energy storage technologies (pumped-hydro, H_2 and CH_4 storage, stationary batteries, etc.), and
- use of shiftable and deferrable loads on the demand side (so-called demand side management).

Flexibility measures regarding the spatial mismatch include

- power transport through existing and new power lines,
- conversion of power to and transport of H_2 and synthetic CH_4, e.g. in adequate pipelines up to the end user (if applicable including re-electrification),
- dedicated curtailment of renewable power plants, redispatch of dispatchable power plants, as well as import and export of power along the power lines (to reduce congestion),
- appropriate spatial distribution of renewable power plants

[1] In this context, direct power demand represents direct use of electricity in the transport (e.g. by BEVs) or heating sector (e.g. by electric heat pumps), whereas indirect power demand stands for electricity needs from PtG facilities for hydrogen or synthetic CH_4 production for transport (e.g. FCEVs or CNG vehicles), the heating sector (e.g. H_2 or CH_4 heating systems), or the chemical industry.

Since the underlying analysis focuses on the use of PtG technology for smart sector integration between the mobility, heating, and industry sectors Figure 2 depicts the relationship between single components of the analysed system subdivided in sectors and energy carries (green: power; blue: hydrogen; orange: natural gas or synthetic methane). As mentioned, the power demand (green) in each grid node consist of conventional power demand, electricity exports to neighbouring countries, direct power use by BEVs in the transport sector and by heat pumps in the heating sector (based on end user heating needs), as well as adjustable power consumption by electrolysis and methanation facilities.

The power demand is satisfied on the one hand by intermittent renewable feed-in, dispatchable power plants, must-run capacities (i.e. power plants with a minimal load such as e.g. heat and power cogeneration facilities), power imports, and flexible power generation by H_2 or CH_4 gas turbines. On the other hand, system stability is supported by power supply from pumped-hydro storage, stationary batteries, dedicated curtailment of renewable power plants, and demand side management. The hydrogen demand (blue) from FCEVs in mobility, H_2 appliances in heating sector, the chemical industry, and H_2 gas turbines for re-electrification can be satisfied by electrolysis or steam methane reforming depending on the scenario or end-use case. Moreover, hydrogen can be stored in tube storage facilities or salt caverns or it can be injected directly into the natural gas grid.

Finally, synthetic methane (orange) is produced by methanation facilities from hydrogen within the considered system, both for dedicated vehicles with gas-based combustion engines (so-called CNG vehicles) in the transport sector and for CH_4 appliances in the heating sector. In addition, synthetic methane is used by CH_4 turbines for re-electrification to stabilise the power supply. Natural gas imports and domestic NG production are relevant only for conventional power plants (potentially with minimal load in case of power and heat cogeneration) and for hydrogen production via steam methane reforming (considering the corresponding CO_2 emissions).

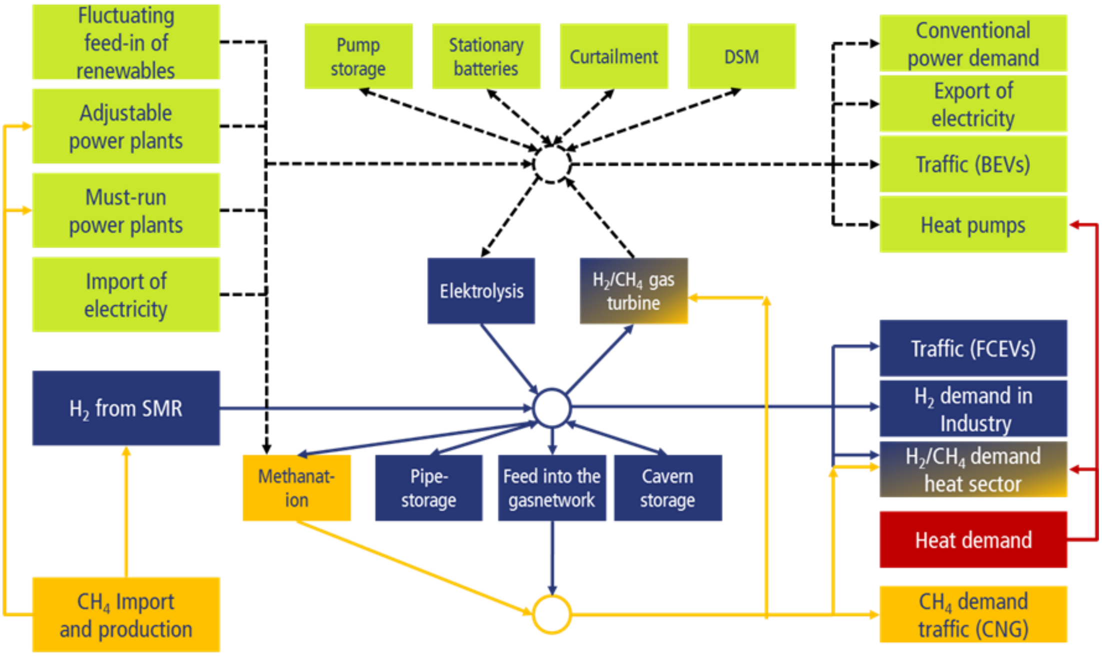


Figure 2: Correlation between the single components of the analysed systems divided into sectors and energy carriers (green: power; blue: hydrogen; orange: natural gas or synthetic methane)

2.2 Modelling platform

The cost benefit evaluation is conducted in specific modelling environment developed and implemented for energy system analyses with a focus on sector integration. The one important strength of this modelling environment is its flexibility and thus the variety of potential analyses. In this way, the costs and benefits of different PtG applications are quantified at an adequate level of detail. Short computing times thanks to appropriate assumptions[2] allow for an exact and quick analysis of the role different assumptions or parameters have on the final results within a select number of scenario variations and sensitivity calculations. Thus the modelling outcomes provide comprehensive insights tailor-made for the underlying research question. Furthermore, automated and easily adaptable interfaces between the various modules of the modelling platform enable calculation of adequate result figures and indicators. This flexible approach and the dedicated integration of both energy carriers, power and gas, within one overarching modelling platform in the sense of a rigorous system thinking provides a quantitative support for strategic decision-making in the best possible way.

[2] e.g. by reducing the network topology to a reasonable number of regions; by considering the erection of single transport lines (e.g. HVDC lines or H_2 pipelines) as an exogenous input parameter and comparing the results between different scenario variants.

As indicated in Figure 3 the modelling platform contains several modules building on each other. The hourly modelling of the energy system is the core element of the quantitative analysis. It accounts for cost-optimal hourly production of different power plants (conventional and dispatchable power plants up to a predefined capacity or renewable power plants according to their availability), use of storage technologies (pumped-hydro, stationary batteries or H_2 and CH_4 storages or gas infrastructure), as well as other flexibility measures (e.g. demand side management, etc.).

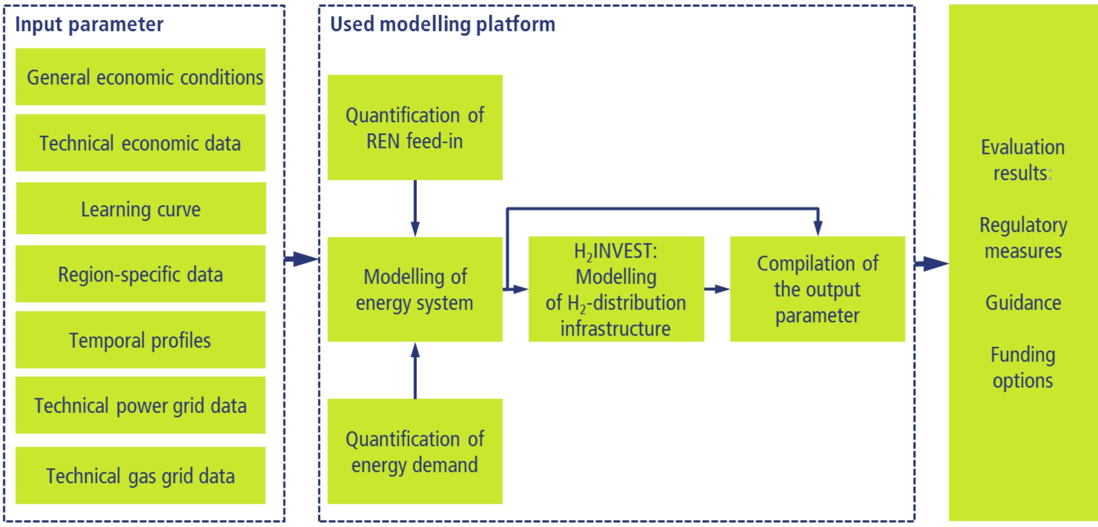


Figure 3: Structure of the modelling platform

In addition the model includes a network simulation for the three energy carriers electricity, hydrogen, and methane providing optimal energy flows in hourly resolution. At this point it is important to mention that the modelling is based on the assumption of time-wise and spatial separation of the underlying mathematical problem. This means that, in the first step, a market simulation based on the merit order is performed without any grid constraints (i.e. under the assumption of a "copper plate" for electricity and a "bathtub" for gas). Here, the regional energy demand, renewable feed-in and power plant capacities are aggregated into one grid node in order to conduct a simultaneous investments and operation optimisation for power plants within a German market model.

In the second step, the optimal power plant capacities and scheduling from the previous step are distributed among single regions (according to the merit-order and regional criteria) within a time-independent network simulation. Based on these results, the actual network simulation optimises the energy flow within the existing power and gas grid as well as the use of other flexibility measures (e.g. redispatch, curtailment, import/export) for each hour a year.

The underlying mathematical problem in both steps is defined as a linear program minimizing the overall system costs. In this context the different technology- and grid-dependent limitations are represented as corresponding modelling constraints. The decision variables in the first step include both investment decisions in new power plant, storage, and PtG capacities and their hourly scheduling within a prototypical year. In the second step, the regions are defined as grid nodes for electricity, hydrogen and synthetic methane. In this context each node for each energy carrier requires a balance for each hour of the year between

- on the one hand the total input into a given grid node, i.e. the sum of production, imports from other nodes or neighbouring countries, conversion of one energy carriers to another (e.g. re-electrification of hydrogen), use of storage and redispatch of flexible power plants
- and on the other hand the total output of a given node, i.e. the sum of demand, exports to other nodes or neighbouring countries, conversion into another energy carrier (e.g. use of power for hydrogen production via electrolysis) as well as, if necessary, curtailment, demand side management, redispatch of flexible power plants and/or use of storage.

The corresponding decision variables comprise curtailment of renewable power plants, redispatch of flexible power plants, active power imports and exports, transport of the three energy carriers between the nodes, and, if necessary, building of new transmission capacities. It is important to mention that due to the separation of the time and spatial dimensions all time-dependent decision variables (such as e.g. storage usage, demand-side management, investments in new generation capacities, etc.) are optimised in the first modelling step (market simulation) and are used as fixed input for the second step (grid simulation).

A pre-determination of renewable feed-in as well as of energy demand in appropriate time (hourly) and spatial (per grid node or region) resolution precedes the modelling of the energy system. It is followed by a detailed modelling of the secondary infrastructure in the transport sector (i.e. refuelling stations or charging points) based on the LBST-tool H2INVEST as well as on simplifying assumptions. Furthermore the output parameters are compiled in an adequate format in order to allow for a final evaluation of the results.

The major input parameters and assumptions are the following:

- **General macroeconomic boundary conditions** such as e.g. the level of the energy demand in the single sectors (power, heating, mobility and industry), import prices for different energy carriers, interest rate, etc. This data is based on acknowledged and publically available sources.
- **Techno-economic data** such as specific investment outlays, maintenance costs, lifetime and efficiencies of the selected PtG technologies (electrolysis, methanation facilities, etc.) as well of the other technologies used in the model (e.g. conventional

and renewable power plants, other storage technologies, etc.). The data is based on an LBST-internal database as well as on acknowledged and publically available sources.

- **Learning curves** to indicate the change in time of the above mentioned techno-economic data e.g. due to economies of scale or learning effects.
- **Regional data** for electricity, heat, H_2, and CH_4 demand in the single sectors (mobility, heating, industry, etc.) as well as the share of power plant technologies and availability of renewable power generation. This data has been gathered from acknowledged analyses such as national German grid development plan for electricity (NEP-Electricity), offshore wind grid development plan (O-NEP), German grid development plan for gas (NEP-Gas), and statistical data (e.g. population and motor vehicle density on the county level).
- **Time-dependent profiles** in hourly resolution for the energy demand (electricity, heat, mobility, industry) and region-specific time-dependent availability of renewable power generation are taken from acknowledged and publically available data sets (e.g. power demand according to ENTSO-E, etc.).
- **Data on power grid** determining the topology of the power network and the corresponding costs are derived from German grid development plan for electricity.
- **Data on gas grid** determining the topology of the gas network and the corresponding costs are provided by OGE and compared with the internal expertise.

3 SCENARIO DEFINITION AND INPUT PARAMETERS

The focus of this study is on the energy demand sectors electricity, heat (space and hot water), light duty vehicle mobility, and hydrogen for industry. The sectors air and maritime transport, heavy-duty trucks, and rail transport have been deliberately left out. Other applications which have not been considered are base chemicals and other energy demand by industry (e.g. coke, fossil natural gas, and process heat). The analyses, focused on Germany have been carried out for the years 2025, 2030, 2040, and 2050. When assessing the effects of the Power-to-Gas technology each sector is looked at independently, meaning that no case has been assessed for all end-use sectors combined.

The study focus is on the power supply system (production, storage, and power transport and distribution) and the impact on the electricity system caused by the progress of the 'energy transition' in each of the sectors. A specific emphasis has been put on the macro-economic effects of the Power-to-Gas technologies for both methane and hydrogen gas as compared to an 'all electric' world. In this study, the term 'all electric' has been applied to the implementation of 'Energiewende' (energy transition) in the individual end-use sectors without PtG. As such, an 'all electric' world has a different impact on the electricity and energy system as compared to applying PtG at large scale. The potential benefits of utilising the gas grid, which is otherwise being utilised less and less, have become a key ingredient of a PtG based energy system.

With the ambition of determining the different impact of PtG on the individual energy sectors, each of the relevant sectors has been assessed independently from the other ones while the respective other sectors continue to be purely supplied by electricity. For the individual sector in focus, the electricity supply is replaced by either PtH_2 or $PtCH_4$ technology with a share of e.g. 50%. Both PtG technologies are then applied to each of the relevant end-use sectors without mixing them within a single scenario. It has been assumed that by simulating an either-or use of both PtG technologies the bandwidth of results can be identified.

For each of the individual sectors only that share of the energy demand is considered which is relevant for the 'all electric' or the 'PtG' case[3]. In the framework of this study all energy demand having no impact on the electricity system is understood as not being relevant (see right column of Table 1). With the 'energy transition' progressing, the relevant share of the energy demand with a potential impact on the electricity system steadily increases until 2050. The relevant share of the sectoral energy demand and out of this the share contributed by PtG also depends on the individual scenario assumptions. The non-relevant share of the sectoral energy demand is then only considered for calculating the GHG emission reduction.

[3] All fossil or other renewable energy supply (e.g. biomass, geothermal energy) is 'non-relevant' accordingly

Table 1: Acceptable technologies/Energy sources in case of „all electric“, „PtH_2“ and „$PtCH_4$“

	Share of the sectorial power demand relevant for the grid			Share of the sectorial power demand not relevant for the grid
Case:	**„all electric“**	**„PtH_2“**	**„$PtCH_4$“**	
Heat	Electric heat pump	Electric heat pump H_2-gas heating (H_2 from electricity)	Electric heat pump CH_4-gas heating (CH_4 from electricity)	Natural gas, crude oil, biomass, solar thermal energy, etc.
Transport	Battery vehicle	Battery vehicle Fuel cell vehicle with H_2 from electricity	Battery vehicle CNG-vehicle with CH_4 from electricity	Diesel, petrol, fossil CNG, LPG, imported PtL-fuels, etc.
Industry	Decentralised electrolysis*	Centralised electrolysis**	n/a	Steam reforming, etc.

* The „all electric“-case for the industry from the power system viewpoint is the H_2 production through electrolysis at an industrial company site (electricity is transported to the industry site)

** The „PtH_2“- case for the industry is the central H_2 production through electrolysis (H_2 is transported to the industry site)

3.1 Scenario definition

For this study the following three scenarios have been assessed: **„Slow energy transition“**, **„Fast energy transition“**, and **„Focus PtG“**, where the scenario „Slow energy transition“ is serving as base scenario. In this scenario, the ambition towards a GHG emission reduction in the power, heating and transport sector until 2050 are comparably low. Yet, the ambitions still surpass those of the German grid development plan for electricity 2017B (NEP-Electricity 2017B).

THE GRID DEVELOPMENT PLAN NEP 2017 (SCENARIO B) IN VIEW OF THE GHG EMISSION REDUCTION TARGETS 2050

Concerning the consequences for the German electricity grid, scenario B of the national grid development plan (NEP-Electricity 2017B), makes certain assumptions for the impact of the transport sector (number of battery electric vehicles) and heating sector (power for electric heat pumps) for both 2035 and 2050. Extrapolating these assumptions to 2050 suggests that the climate protection targets will be missed for all end-use sectors transport, heating, and industry, specifically in view of the -95% GHG emission reduction target. The additional electricity demand to fulfil the 2050 climate obligations in all other end-use sectors has not even been considered in this NEP assumption.

The NEP-Electricity 2017 therefore does not offer any definitive or quantitative sectoral targets for reaching the climate policy goals by 2050. The major reasons are:

- The NEP does not provide any indication on alternative climate protection measures in the transport and heating sector. As a result, the use of biomass and imported energies (PtX) with a reduced or zero GHG emission can all be opted for as well as reducing the final energy demand. However, the mix of options can be crucial for reaching the climate protection targets.
- Furthermore, neither the industry nor the transport or heating sectors are covered exhaustively. In the transport sector, e.g. air, maritime, and long-distance truck transport are not taken into consideration, in the heating sector, process heat has been excluded. Also, industrial processes which may be substituted by electric ones in the future have not been included. The installed PtG capacity in 2035 is forecasted to be as little as 2 GW and will, according to the NEP, therefore only contribute a very small share to the GHG emission reduction ambitions.
- The extrapolation of 2030/2035 assumptions towards 2050 is based on a small set of data and covers an extended period of time. It is assumed that certain key technologies contributing to GHG reduction (BEVs, electric heat pumps, etc.) will successfully emerge in the market within this timeframe. Yet, timing and development dynamics may have a pivotal effect for reaching the climate protection goals.

More ambitious climate protection goals have however been incorporated in the NEP 2017 Scenario C.

In the scenario "Fast energy transition", much more ambitious GHG emission reduction targets are reached. The scenario "Focus PtG" follows the identical GHG emission reduction targets as the "Fast energy transition" scenario, the major difference being the intensified use of PtG-type energy carriers (H_2 or CH_4) applied in the heating and transport sectors and hence limited use of electric heat pumps or BEVs. Other differences between the scenarios are the potentials of other flexibility options in the electricity system and the costs for PtG technologies. Table 2 compares the GHG emission reduction in the electricity sector, the costs for PtG, and the flexibility potentials for all scenarios. Assumptions and data for each scenario and by sector are documented in chapter 3.1. All scenarios include more ambitious GHG emission reduction targets in 2050 for the sectors transport, heating, and industry than Scenario B in NEP-Electricity 2017.

Table 2: GHG emission reduction targets, PtG-costs, and flexibility potentials in the three scenarios

Criterion	Base-Scenario	Scenario „Fast Energy Transition“	Scenario „Fokus PtG“
GHG emission reduction in the electricity sector	2025: -45% 2030: -50% 2035: -55% 2050: -80%	2025: -50% 2030: -60% 2035: -70% 2050: -95%	2025: -50% 2030: -60% 2035: -70% 2050: -95%
Costs PtG	Medium Electrolysis: 730-400 €/kW_{el} Methanation: ~500 €/kW_{CH4}	Low (-20%) Electrolysis: 580-320 €/kW_{el} Methanation: ~400 €/kW_{CH4}	Low (-20%) Electrolysis: 580-320 €/kW_{el} Methanation: ~400 €/kW_{CH4}
Potential of options for system flexibility	Medium DSM (deferrable loads): 2,5 GW for 3 h at 25 €/MWh DSM (interruptible loads): 2,5 GW at 206 €/MWh Curtailment/Redispatch: +/- 5% Import/Export: +/- 10%	High DSM (deferrable loads): 2,5 GW for 6 h at 13 €/MWh DSM (interruptible loads): 2,5 GW at 100 €/MWh Curtailment/Redispatch: +/- 10% Import/Export: +/- 15%	Low DSM (deferrable loads): 1 GW for 1 h at 50 €/MWh DSM (interruptible loads): 2,5 GW at 206 €/MWh Curtailment/Redispatch: +/- 5% Import/Export: +/- 5%

The demand side management (DSM) assumptions have been based on an evaluation of relevant data from the NEP-Electricity 2017B. According to the base scenario, the deferrable loads can reach a maximum of 2.5 GW and must be balanced within 3 hours before or after the request for DSM at an associated price of 25 €/MWh. Load deactivation (i.e. DSM using interruptible loads that can just be switched off) is valued at 206 €/MWh (as compensation for not using the electricity), also with a maximum of 2.5 GW.

In the scenario "Fast energy transition" characterised by high flexibility of the electricity system, the maximum power limit of 2.5 GW remains identical for both types of DSM, however assuming that loads can be shifted within 6 hours. In addition, the costs incurred are assumed to be lower (only 50% of those in the base scenario): 13 €/MWh for deferrable loads and 100 €/MWh for interruptible loads. In the scenario "Focus PtG", less DSM is available (as compared to the base scenario) with a maximum power of only 1 GW each and the load compensation for deferrable loads has to be enacted within one hour. In this case the price for deferrable loads at 50 €/MWh is double the one of the base scenario whereas the price for interruptible loads remains unchanged.

Providing flexibility by electricity imports and exports is limited to buying electricity from neighbouring countries to avoid grid congestion and in addition to a pre-determined level of electricity transit through Germany. This study assumes that electricity imports and exports are part of the European electricity exchange and, therefore, will also significantly depend on European electricity flows. As a consequence, the pre-defined flows (positive for inflow/import or negative for outflow/export) between the concerned regions in Germany and the neighbouring countries can be enhanced or reduced by a specific percentage and for each hour of the year. For the base scenario this percentage is 10%, 15% for the "Fast energy transition" scenario, and 5% for the "Focus PtG" scenario.

Consequently, electricity flows from or to Germany cannot be inverted but can be increased or reduced in their effect within pre-defined limits. For example in certain cases during strong wind periods German wind electricity may not be exported to e.g. Denmark when Danish electricity is transmitted to other European countries through Germany at the same time. The maximum electricity flows from or to Germany are further limited by the maximum interconnection capacities.

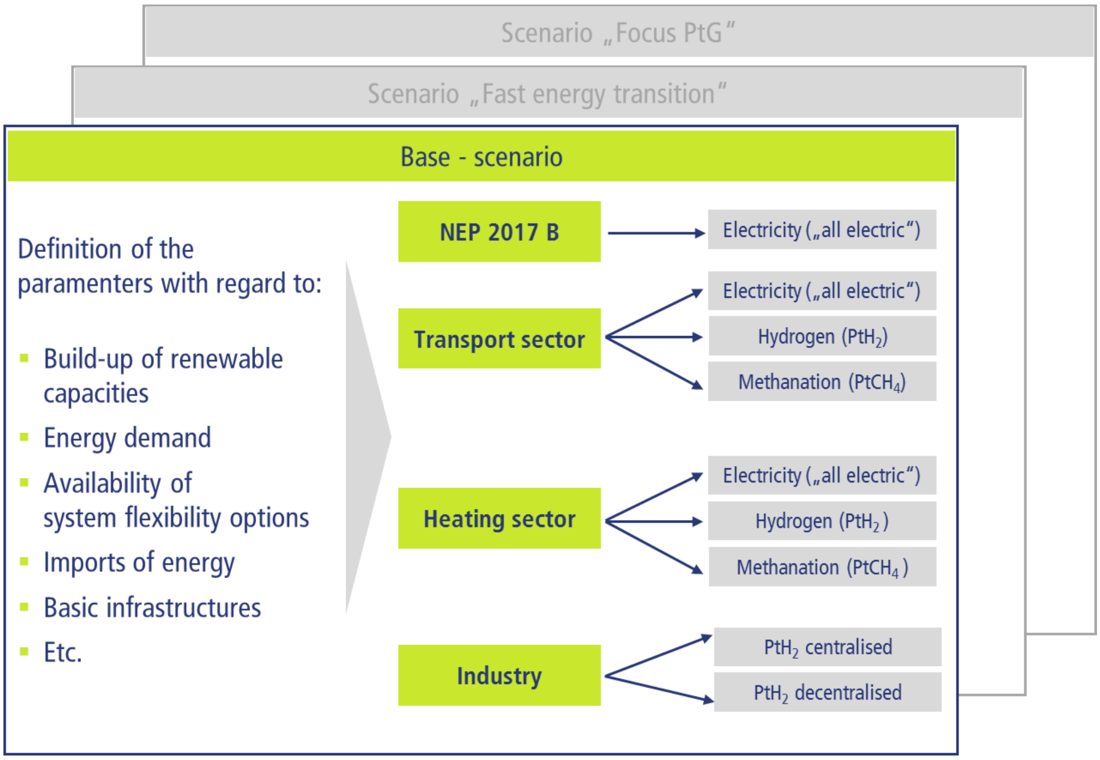
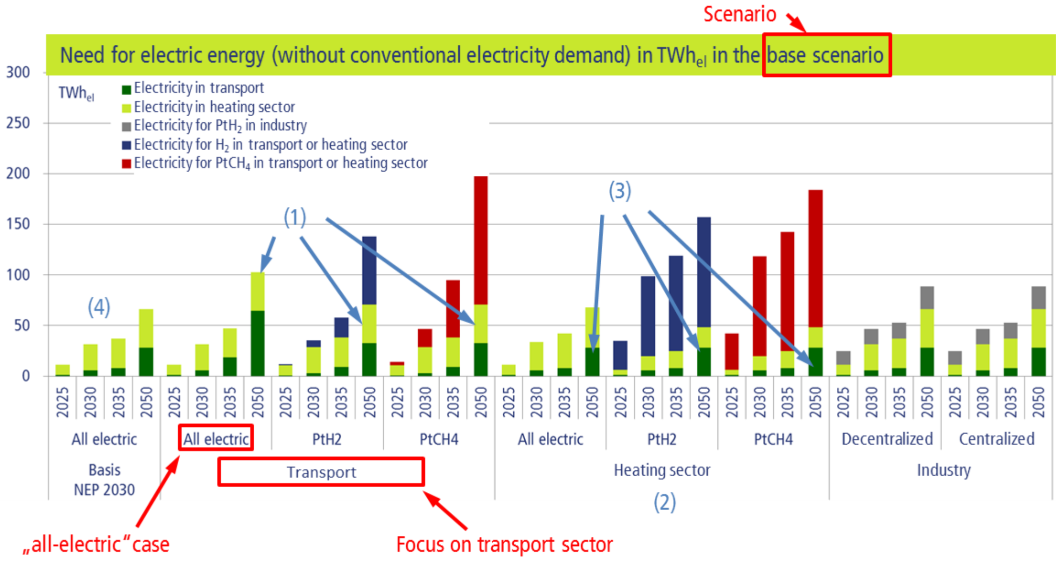


Figure 4: Overview of scenarios and different cases

In addition to the three scenarios with the corresponding analyses for the transport, heating, and industry sectors an "all electric" world based on data from the NEP-Electricity 2017B is used as a benchmark.

Figure 5 explains the general approach for the allocation of energy demand in the various cases and scenarios.



(1) When **focusing on the transport sector**, electricity demand in the heating sector always corresponds to the "all electric" case. A conversion to PtG-technology will not be used for the heating sector. The use of PtG-technology in the heating sector is only reflected in cases with the **focus on the heating sector**.

(2). Here, the electricity demand from the transport sector will be considered according to the „all electric" case (3).

The figures from NEP (4) serve as a reference for the electricity demand from the sectors not in focus. Thus, for example when **focusing on the heating sector** (2), the electricity demand from the transport sector is assumed according to the NEP.

Since in the PtH$_2$/PtCH$_4$ cases the relevant energy demand is satisfied up to 50% by synthetic gases, direct demand for electricity (heat pumps, BEVs) can here also be below the NEP reference value. All in all the demand for electricity when using PtG technology is significantly increased because of the associated efficiency losses.

Figure 5: Comparison of electricity demand for selected cases in the base scenario („Slow energy transition")

3.2 Definition of regions for spatial simulation

For the regional part of the simulations Germany is structured into the 4 regions North, West, South, and East. The allocation of individual federal states to these regions as well as a short description is summarised in Figure 6.

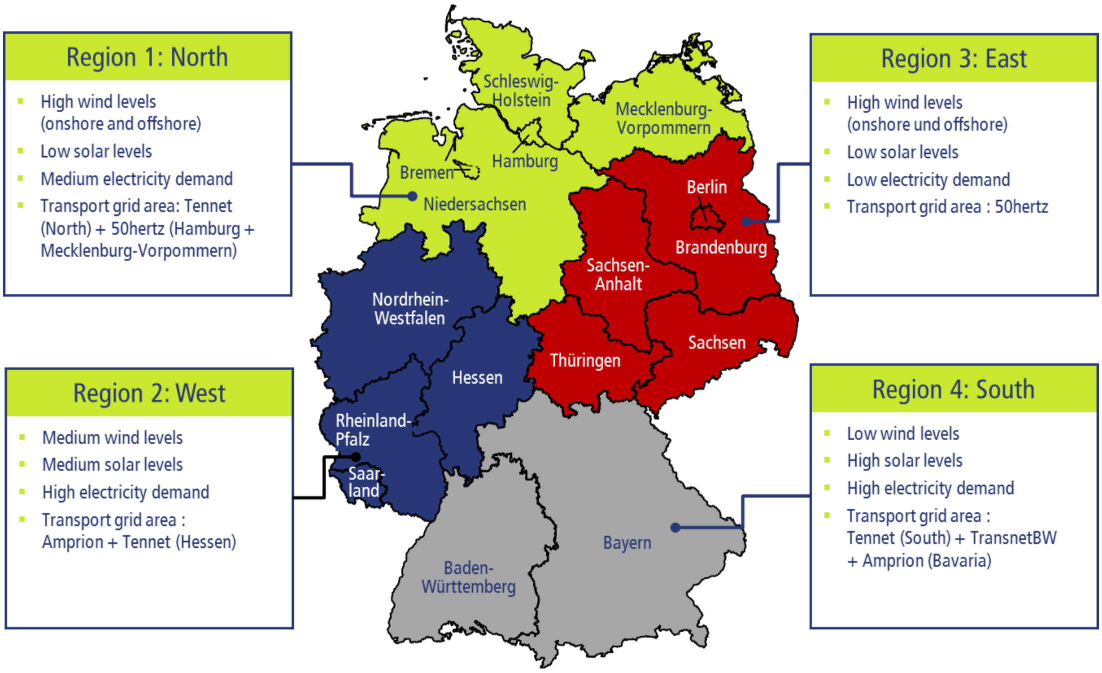


Figure 6: Germany divided in four regions

As part of the modelling exercise each region is assigned an individual profile (e.g. energy supply and demand, ambient temperature), own end-use data (electricity, heat, and fuel), maximum transport capacities for electricity trading, conventional electricity production capacities, as well as inter-regional energy transport capacities. The individual parameter split and allocation (regionalisation) applies real parameters such as power plant or power line locations or real specific performance data of federal states such as electricity demand and number of cars. Details for the regionalisation of individual parameters are provided in the relevant subsections below.

3.3 Input parameters

The most important input parameters for this study are explained in the following subchapters.

3.3.1 General macro-economic boundary conditions

The imputed interest rate is assumed to be 3%. Prices for electricity import and export from neighbouring countries have been set to a constant 50 €/MWh for all time increments. Table 3 summarises the prices for all solid/liquid/gaseous fuels for each time increment and all scenarios. Furthermore, CO_2-certificate prices have been assumed to be zero, as GHG emissions are given a general ceiling, the purpose of which is to avoid a duplication of GHG avoidance costs.

Table 3: Development of raw material prices in all scenarios

	Unit	2025	2030	2035	2050
Crude Oil	€/barrel	95	111	118	139
Petrol	€/l	1.54	1.64	1.68	1.81
Diesel	€/l	1.41	1.52	1.57	1.72
Natural gas	€/MWh	28	29	30	36
Biogas	€/MWh	60	61	62	62
Hard coal	€/t	75	77	79	82
Lignite	€/MWh	3	3	3	3

3.3.2 Techno-economic data

For the calculation of macro-economic costs by 2050 only the incremental investments (CAPEX) for new plants are taken into account. The CAPEX of existing plants (plant inventory) are not considered. In contrast, operating and maintenance costs (OPEX) are included for all plants, old and new.

As an example, the plant inventory for the supply of renewable electricity is shown in Table 4.

Table 4: Assumed power production of existing renewable energies plants

Technology	Unit	Assumed power production of existing plants
Onshore-wind	MWh_{el}/year	66,300,000
Offshore-wind	MWh_{el}year	12,300,000
PV	MWh_{el}/year	38,100,000
Others	MWh_{el}/year	15,100,000

The same approach is used for all other technologies such as fossil power plants, energy transport grids etc.

3.3.2.1 Energy production, conversion and storage

This chapter introduces the most relevant techno-economic data for energy supply, transmission, transformation, and storage. The extent of data along the energy supply chains in this subchapter is shown in Figure 7. Data for secondary infrastructure and technologies close to the end-user are presented in the following chapter.

☐ – not relevant X – not considered here ✓ - considered here

	Transport			Heating sector			Industry	
	BEV	FCEV	CNG	Heat pump	H_2	CH_4	SMR	Electrolysis
Energy generation + transport	✓	✓	✓	✓	✓	✓	✓	✓
Distribution of electricity	X	X	X	X	X	X		X
H_2- distribution		X			X			X
CH_4 distribution			X			X		
Secondary infrastructure (e.g. HRS, Wallboxes)	✓	✓	✓	✓	✓	✓		
End user (e.g. vehicles, heating)	✓	✓	✓					

Figure 7: Energy generation, transport, conversion, and storage in the context of the overall economic perspective

Table 5: Technological and economic data lignite power station

Parameter	Unit	2025	2030	2035	2050
Investment costs	€/kW_{el}	1600			
Lifetime	Years	45			
Maintenance cost	%Invest/Year	1.6			
Average efficiency	%	35	35	35	37
Specific emissions	t_{CO2}/MWh	0.364			

Table 6: Technological and economic data hard coal-fired power station

Parameter	Unit	2025	2030	2035	2050
Investment costs	€/kW_{el}	1.500			
Lifetime	Years	45			
Maintenance cost	%Invest/Year	1.6			
Average efficiency	%	42			
Specific emissions	t_{CO2}/MWh	0.341			

Table 7: Technological and economic data combined-cycle power plant

Parameter	Unit	2025	2030	2035	2050
Investment costs	€/kW_{el}	700			
Lifetime	Years	40			
Maintenance cost	%Invest/Year	3			
Average efficiency (existing plant)	%	51	52	53	54
Average efficiency (new building)	%	57	59	60	63
Specific emissions	t_{CO2}/MWh	0.202			

Table 8: Technological and economic data gas turbine power plant (CH_4)

Parameter	Unit	2025	2030	2035	2050
Investment costs	€/kWel		385		
Lifetime	Years		40		
Maintenance cost	%Invest/Year		2		
Average efficiency	%		35		
Specific emissions	t_{CO2}/MWh		0.202		

Table 9: Technological and economic data for gas turbine power plant (H_2)

Parameter	Unit	2025	2030	2035	2050
Investment costs	€/kW_{el}	451	419	399	385
Lifetime	Years		40		
Maintenance cost	%Invest/year		2		
Average efficiency	%		40		
Specific emissions	t_{CO2}/MWh		0		

Table 10: Technological and economic data for oil-fired power plant

Parameter	Einheit	2025	2030	2035	2050
Investment costs	€/kW_{el}		450		
Lifetime	Years		40		
Maintenance cost	%Invest/Year		2		
Average efficiency	%		34		
Specific emissions	t_{CO2}/MWh		0.264		

Table 11: Technological and economic data for renewable energy generation capacities

Parameter	Unit	Offshore-wind 2025; 2030; 2035; 2050	Onshore-wind 2025; 2030; 2035; 2050	Photovoltaics 2025; 2030; 2035; 2050
Investment costs	€/kW_{el}	3,210; 2,937; 2,697; 2,251	1,111; 1,066, 1,045; 1,035	828; 718 643; 571
Lifetime	Years	20	20	20
Maintenance cost	% Inv. p.a.	2	2	2
Full-load hours	Hours p.a.	4,307	2,136	918
Electricity costs	€/MWh	65; 60; 55; 46	45; 44; 43; 42	79; 68; 61; 54

Table 12: Technological and economic data for power transmission

Parameter	Unit	DC-Power transmission	Pipeline CH_4 for H_2 conversion
Investment costs	€/(km * MW)	4,000	1,050
HVDC-terminal	€ each pipeline (2 head ends)	800,000 (2 x 400,000)	n/a
O&M		0	0
Lifetime	Years	30	30

Table 13: Technological and economic data for gas generation (PtG)

Parameter	Einheit	Electrolysis P_{out} = 3 MPa 2025; 2030; 2035; 2050	Methanation incl. CO_2 from air 2025; 2030; 2035; 2050	Steam reforming
Investment costs	€/kW_{input}	731, 636, 552, 396	517, 507, 507, 507	310
Lifetime	Years	25	25	25
Maintenance cost	% Inv. p.a.	4	4	
	€/MW_{H2} p.a.			560
Efficiency	%	64, 66, 67, 68	83	76
Variable costs	€/MWh_{H2}	0.4		
Electricity purchase	kWh_{el}/kWh_{CH4}		0.041	

Table 14: Technological and economic data for energy storage

Parameter	Unit	Stationary batteries 2025, 2030, 2035, 2050	H_2 salt-cavern incl. compressor	H_2 pipe storage incl. compressor	CH_4 storage	Pump storage
Investment costs	€/kWh	600, 400, 350, 300	0,86	11	No new investment permissible	
Maintenance cost	% Inv. p.a.	1	1,5	0	0	0
Lifetime	Years	15	30	30	n/a	n/a
Capacity/performance	MWh/MW	2	500	24	533	6
Efficiency input	%	92	98	94	98	89
Efficiency output	%	92	95	100	100	90

3.3.2.2 Secondary infrastructure and end-use applications

The costs for providing and operating the secondary energy infrastructures (refuelling stations, wall-box chargers) and some end use technologies (vehicles, heating appliances) cannot be neglected in a full macro-economic comparison of the "all electric" and "PtG" worlds. The relevant costs depend on the modelling approach and have thus been assessed separately to then be added to the other model costs. The costs which are included in the following chapters are summarised in Figure 8.

☐ – not relevant X – not considered here ✓ - considered here

	Transport			Heating sector			Industry	
	BEV	FCEV	CNG	Heat pump	H_2	CH_4	SMR	Electrolysis
Energy generation + transport	✓	✓	✓	✓	✓	✓	✓	✓
Distribution of electricity	X	X	X	X	X	X		X
H_2- distribution		X			X			X
CH_4 distribution			X			X		
Secondary infrastructure (e.g. HRS, Wallboxes)	✓	✓	✓	✓	✓	✓		
End user (e.g. vehicles, heating)	✓	✓	✓					

Figure 8: Secondary infrastructure and end users in the context of an overall economic perspective

Transport sector

For the transport sector, secondary infrastructures comprise home and public charging stations for BEVs. The costs for vehicles and complete system are based on [DLR/KIT 2016], [ABB 2017], [NPE 2015] and [Renault 2016]. The costs and the total number of chargers per vehicle have assumed to be constant until 2050. Charging infrastructure lifetime is 15 years.

Table 15: Assumption for BEV charging infrastructure cost

	Charging capacity [kW]	Investment per system	O&M cost per system	Number of systems needed per BEV	CAPEX per BEV	OPEX per BEV	Number of systems (base scenario, all electric 2050 / 36.6 million BEV)
Charging at home	11.1	2.139 €	150 €/a	0.850	1.818 €	127.50 €/a	31.140.000
Public charging	11.1	7.500 €	750 €/a	0.026	191 €	19.13 €/a	934.300
Fast charging everyday transport	50	37.000 €	3.400 €/a	0.004	148 €	13.60 €/a	146.600
Fast charging BAB /A-Roads	150	111.000 €	4.000 €/a	0.003	284 €	10.24 €/a	93.800
Total					**2.441 €**	**170.47 €/a**	

In contrast to the charging infrastructure needs for BEVs which is based on a fixed vehicle-specific factor from literature, the costs for the fuel cell electric and CNG-vehicle refuelling infrastructure have been calculated by using the LBST-proprietary tool H_2INVEST. This tool includes modules for the calculation of vehicle fleet ramp-up, number of refuelling stations required, refuelling capacities, as well as total costs applying geo-referenced and population specific base data (e.g. average income, car fleets).

Table 16 lists the cost data for each refuelling station and each reference year. O&M costs were set to an average value of 2.5% p.a. of required investments. Fuelling station lifetime has been assumed at 20 years.

Table 16: Investment costs for H_2- and CH_4-refuelling stations 2025 to 2050

H_2 fuelling station	Capacity (kg H_2/d)	Cost 2025 (M€)	Cost 2030 (M€)	Cost 2035 (M€)	Cost 2050 (M€)
very small	56	0.6	0.6	0.6	0.6
small	168	1.0	0.9	0.9	0.9
medium	336	1.6	1.2	1.2	1.2
big	700	2.8	2.0	2.0	2.0
very big	2200	6.9	5.1	5.1	5.1

CNG fuelling station	Capacity (MWh_{CH4}/d)	Cost 2025 (M€)	Cost 2030 (M€)	Cost 2035 (M€)	Cost 2050 (M€)
very small	3.7	0.1	0.1	0.1	0.1
small	11.2	0.3	0.3	0.3	0.3
medium	33.3	0.4	0.4	0.4	0.4
big	60.0	0.5	0.5	0.5	0.5
very big	173.3	0.8	0.8	0.8	0.8

Vehicle purchase and maintenance costs for the different drive-systems have been taken from [McKinsey 2010] as shown in Figure 9.

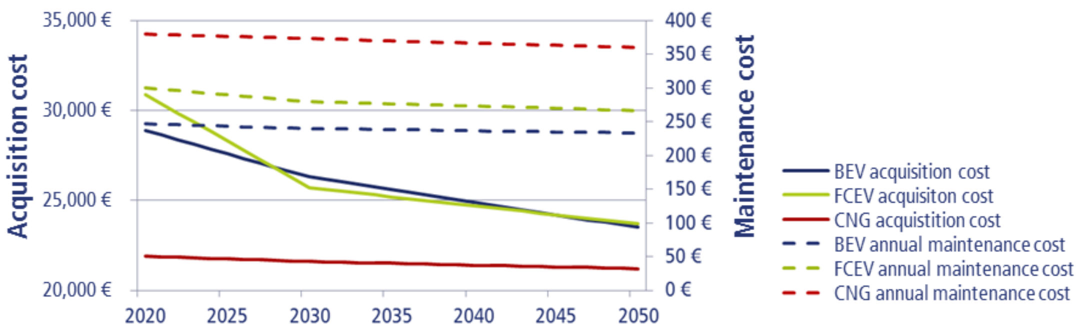


Figure 9: Passenger car acquisition and maintenance costs until 2050

Heating sector

The cost calculation for providing warm water and space heating to end-users (private households, small enterprises, and industry) has been simplified based on existing studies. Relevant investments and operating costs (w/o fuels) are both based on the specific annual heating demand (€/MWh_{th} p.a.). Costs for natural gas (methane) based appliances and heat pumps have been assumed to remain constant as both technologies are treated as mature. Costs for producing heat from burning hydrogen have been estimated by applying a degressive cost increment on methane appliances over time. Until 2020 this cost increment is +300%, in 2025 +150% and in 2050 +10%. For the years in between the increment was interpolated. In addition, a one-time conversion charge from methane to hydrogen gas of 4,000 €/appliance was assumed for the building stock, all data based on [DECC 2016]. A mixture of 50% new buildings and 50% general reconstruction (incl. the installation of floor heating in connection with heat pumps) is expected to be realistic.

Table 17: Specific costs in €/MWh$_{th}$ for heat supply with regards to the end user (without energy carrier)

year	Heat pump	Methane	Hydrogen
2020	114	58	122
2025	114	58	93
2030	114	58	73
2050	114	58	65
Sources: [BMVBS 2012], [BWP 2015], [Uni Linz 2009], [DECC 2016]			

3.3.3 Conventional power demand

The demand for conventional electricity, i.e. w/o electricity for electric heat pumps, and BEVs, is based on the assumptions of the NEP-Electricity 2015 B for 2025 and of the NEP-Electricity 2017 B for 2030 and 2035. The electricity demand development until 2050 was extrapolated from the development between 2025 and 2035.

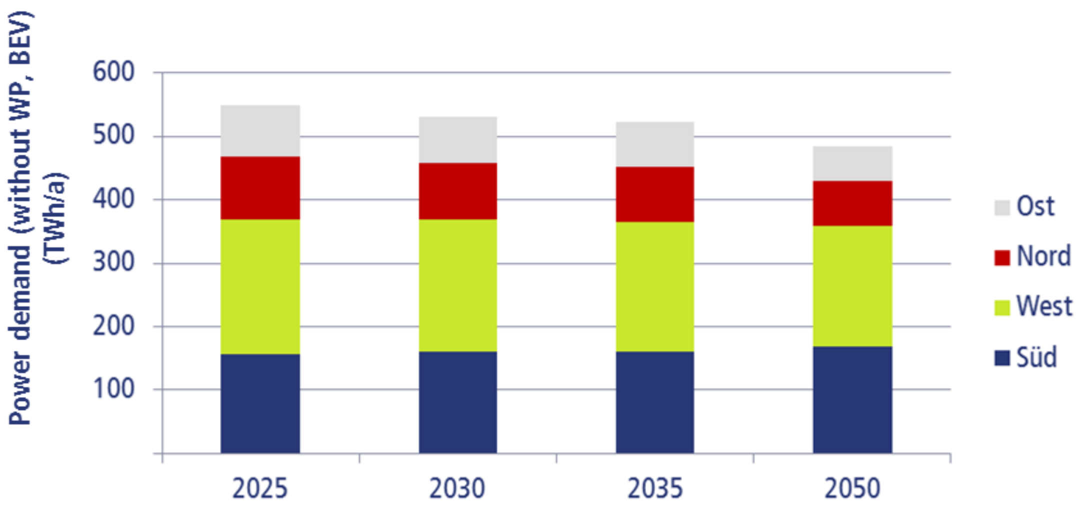


Figure 10: Development of the conventional power demand in Germany for the four regions

According to these assumptions the demand for conventional electricity will decrease from ca. 550 TWh in 2025 to about 485 TWh in 2050. This electricity demand will be applied to all cases and scenarios.

The regionalisation will respect the breakdown specific to the federal states as suggested by the NEPs. While in the region South the conventional electricity demand will rise until 2050, it is expected to decrease in the other regions.

The time profile for the conventional electricity demand, i.e. w/o electricity for heat pumps, BEVs, or PtG plants, follows the profiles of the year 2015 and has been scaled accordingly. The demand profiles are aligned with the transport grid operator assumptions for the four regions:

50Hertz[4] data has been used for the regions North and East, Amprion for region West, and TransnetBW for region South. Historical datasets have been taken from the ENTSO-E Transparency database.

3.3.4 Fuel demand

The fuel demand for each scenario has been assessed using the vehicle ramp-up rates (BEV, FCEV, and CNG) and their specific fuel consumptions and annual driving distances.

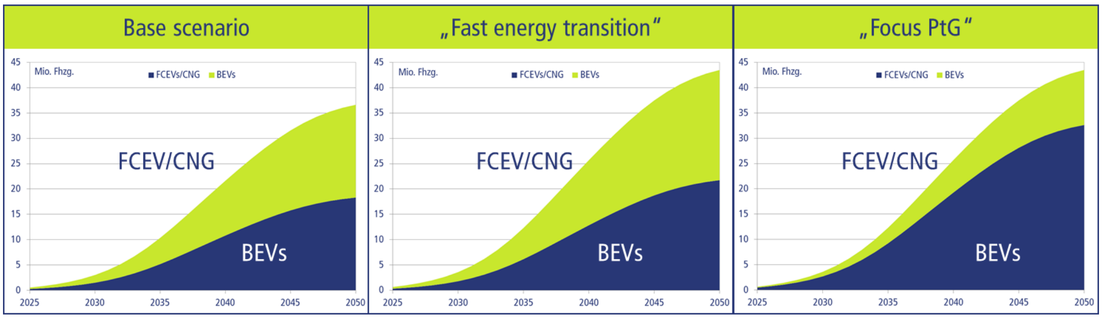


Figure 11: Acceleration curve of battery-, fuel cell- and natural gas vehicles

For the base scenario, the relevant alternative fuel vehicle rolling stock reaches 36.6 Mio cars until 2050 or 80% of the total fleet. In the other two more ambitious scenarios, 43.5 million cars will be substituted by BEV, FCEV, or CNG cars representing 95% of the car fleet. The specific fuel consumption and annual driving distances are summarised in Table 18

Table 18: Assumptions for the fuel consumption of the vehicles until 2050

	FCEV				BEV				CNG-vehicle			
Vehicle type					C. Segment e.g. VW Golf							
Annual driving performance					12.000 km							
Tank-/battery size	4 kg H_2				24 kWh				33 kg CH_4			
Tank-/battery size [kWh]	133				24				450			
Year	2052	2030	2035	2050	2025	2030	2035	2050	2025	2030	2035	2050
Consumption	26.4	23.6	20.8	20.8	16.1	15.6	14.7	14.7	55.1	51.9	48.9	48.9
Reach [km]	504	563	638	638	149	154	163	163	816	866	920	92.0

The relevant vehicle numbers for the years in focus as well as the BEV/FCEV or BEV/CNG shares have been taken from Table 19.

4 TenneT data were not used for the North region due to the large geographic extent.

Table 19: Assumptions for the transport sector

Mobility (Mio. ZEV PKW)	NEP Strom (Reference)	Base scenario	„Fast energy transition“	„Focus PtG“
2025	(0.5)*	0,6	1	1
2030	3	3	3.6	3.6
2035	4.5	10.4	12.3	12.3
2050	(15.9)*	36.6	43.5	43.5
All electric	100% BEV	100% BEV	100% BEV	100% BEV
PtH_2 – case	n/a	50% H2, 50% BEV	50% H2, 50% BEV	75% H2, 25% BEV
$PtCH_4$ - case	n/a	50% CNG, 50% BEV	50% CNG, 50% BEV	75% CNG, 25% BEV

*Own assumptions based on relation of NEP to base scenario

The regionalisation of the car fleet and its demand for electricity, methane or hydrogen is based on the vehicle registration statistics by the German Federal Motor Transport Authority (Kraftfahrtbundesamt) and foresees a split of 18% in region North, 36% in region West, 31% in region South, and 15% in region East.

The temporal refuelling profiles for hydrogen and synthetic methane have been taken from [DLR et al. 2015], representing typical average driver behaviour at a conventional gas station. The temporal charging profiles for BEVs have been assessed by [Mallig et al. 2015] as a result from modelling an expected future charging behaviour of BEVs.

The expected GHG-emission reduction by electricity and methane or hydrogen in the transport sector is calculated using an annual average driving distance of 12,000 km. The conventional vehicle substitution comprises a 50% gasoline and 50% diesel car mix.

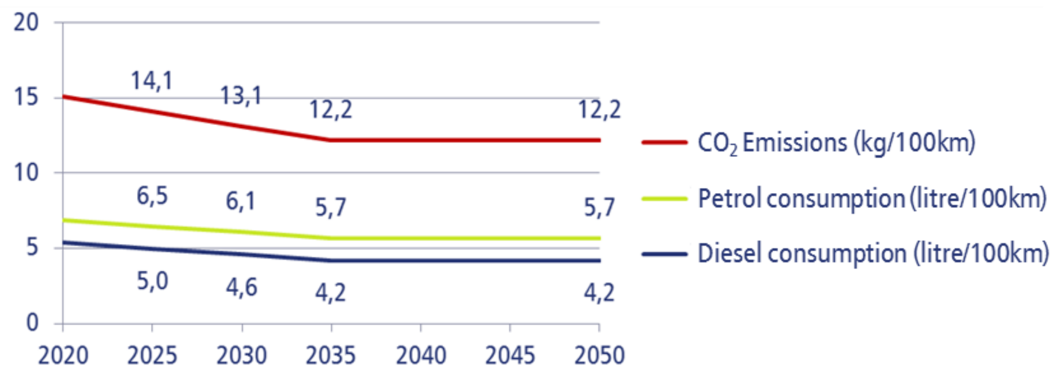


Figure 12: Specific fuel consumption and emissions savings with CO_2-free fuels

Figure 12 depicts the specific conventional fuel vehicle consumption as well as the GHG emission savings for the cars operated with CO_2-free fuels per 100 km driven.

3.3.5 Heating demand

The total electricity demand by electric heat pumps to produce the required total heating demand is based on the 2015 energy statistics of the German Federal Ministry for Economic Affairs and Energy (BMWi), an average heating demand reduced by 2.0% p.a. (Fast energy transition) or 0.2% p.a. (base scenario), as well as a technology mix of heating appliances as published by BMWi in 2015 ("Energy efficiency strategy for housing"). In this scenario, the bandwidths applied are "efficiency" and "renewables", both reaching the climate policy targets (energy savings vs. increased use of GHG-lean or GHG-free fuels), always assuming an end-use-specific heat pump share of 25% for 2050.

Based on these assumptions an electricity demand of ca. 50 and 105 TWh_{el}, respectively, is estimated for 2050. Both results have been used for orientation in selecting the electricity demand for the "Fast energy transition" scenario and the base scenario. The electricity demand by electric heat pumps for 2025, 2030, and 2035 has been adopted in line with the expectations of the Federal German Heat Pump Association (Bundesverband Wärmepumpe), assuming to surpass the goals set by the NEP 2017 B.

No explicit assumptions have been made in this study for the absolute number of individual heat pumps, refurbishment rates or other alternative heating technologies. These are embedded in the original literature data, which were used for this study. The electricity demand figures have been validated with the study "Climate neutral Housing Inventory 2050" by the German Environment Agency (Umweltbundesamt UBA), which, depending on the scenarios, anticipates a heat pump specific electricity demand of about 41 to 117 TWh_{el} by 2050.

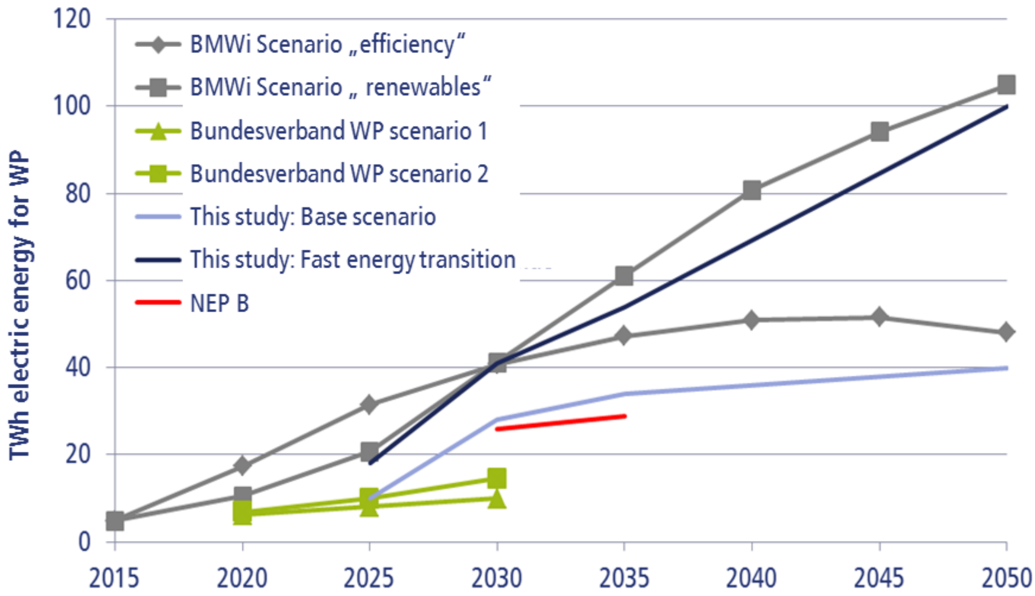


Figure 13: Development of the power demand for heat generation according to different sources and assumptions for this study

Table 20: Assumptions for the heating sector

Application case		NEP Strom (Reference)	Base scenario	„Fast energy transition“	„Focus PtG“
Heating sector (TWh_{el})	2025	(10)*	10	18	18
	2030	26	28	41	41
	2035	29	34	54	54
	2050*	(38)**	40	100	100
When converting electricity to H_2/CH_4, a factor of 3.7 has to be considered (JAZ)***	All electric		100% heat pumps	100% heat pumps	100% heat pumps
	PtH_2-case		50% H_2	50% H_2	75% H_2
	$PtCH_4$-case		50% CH_4	50% CH_4	75% CH_4

*Study Bundesverband WP
* * NEP extrapolated

The future regional allocation of the residential heating demand follows the data published by the Federal States’ Working Group on Energy Balances (Länderarbeitskreis Energiebilanzen) for 2012: 18% share of the total heating demand (space heating and warm water) in Germany for region North, 39% for region West, 26% for region South and 17% for region East.

For each of the four regions, individual ambient temperature profiles have been calculated. Data of several meteorological stations per region have been retrieved.

The space heating demand profiles are based on ambient temperature recordings for 2015. The space heating demand profiles are distributed by degree day figures to each day of a year. The heating capacity of the buildings is taken into account by applying 30% of the degree day figure from the previous day. The duration of the heating period is set to last from October 1 to April 30, outside of which no space heating occurs. The distribution of the daily energy demand for space heating to single hours follows the outside (= ambient) temperature and a night setback between 11 p.m. and 6 a.m. In this period the ambient temperature only contributes by 50%. The final result is a generic space heating demand profile with the ambient temperature having a major impact. Comparing this with typical heating profiles shows a good fit of both. Still, it should be noted that we have applied a rather pragmatic and simplified approach which, however, should still provide sufficient detail for this type of study.

The energy demand profile for supplying hot water is limited to a daily timeframe of 6.00 a.m. and 11.00 p.m. and assumed constant within this period.

The hourly ambient temperature profile in Germany is a composite from several meteorological stations of the German Meteorological Institute (Deutscher Wetterdienst). In total, the data of 16 stations have been used.

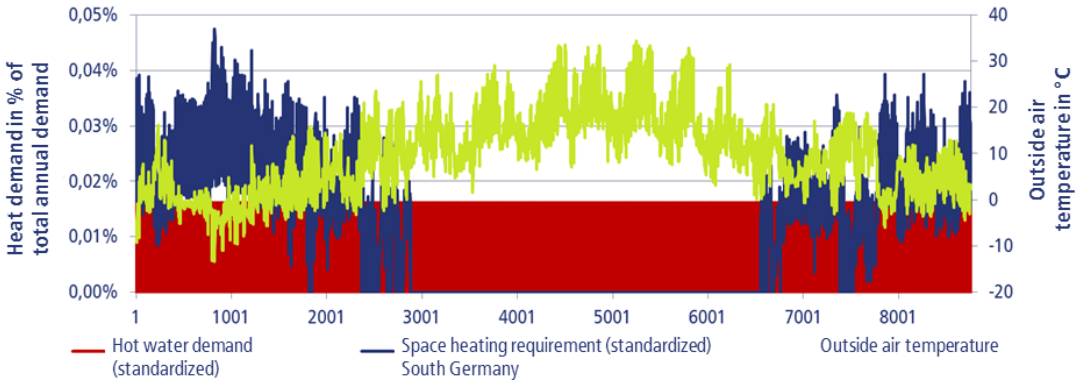


Figure 14: Annual space heating and hot water demand

The conversion of heating to electricity demand is temperature dependant. The average efficiency of the cumulated heat pump installations has been averaged for each year, using a coefficient of performance (COP) of 2 at -16°C and a COP of 5 at +20°C. The COP is linearly interpolated for temperatures between -16°C and +20°C.

Identical space heating and hot water profiles are applied for both methane and hydrogen as fuel.

For the calculation of GHG emissions from the heating sector it has been assumed that 33% mineral oil (264 g_{CO2}/kWh) and 67% natural gas (202 g_{CO2}/kWh) as conventional fuels are being substituted. For the replaced heating appliances a 100% efficiency has been assumed.

3.3.6 Hydrogen demand in industry

The key assumption for the industry sector is that today's annual hydrogen consumption (from steam reforming of methane today) will remain constant until 2050 at ca. 20 TWh_{H2} which is equivalent to ca. 18 million Nm^3_{H2} or ~580 kt_{H2}. The hydrogen consumption for refineries and hydrogen from other sources are not included in this figure. To contribute significantly to GHG emission reduction by 2050, it has been assumed that a growing hydrogen demand share will then be provided by electrolysis (Table 21).

Table 21: Share of hydrogen produced through electrolysis for each scenario

Scenario/ Year	Base scenario („Slow energy transition“)	„Fast energy transition	„Focus PtG“
2025	45%	50%	50%
2030	50%	60%	60%
2035	55%	70%	70%
2050	80%	95%	95%

Table 22 summarises the average annual hydrogen production through electrolysis for each scenario.

Table 22: Assumptions for the industry sector

<table>
<tr><th colspan="2">Application case</th><th>NEP-2017 (Reference)</th><th>Base scenario</th><th>„Fast energy transition“</th><th>„Focus PtG“</th></tr>
<tr><td rowspan="6">Industry (substitution of fossil-based hydrogen in kt_{H2}/a)</td><td>2025</td><td>---</td><td>260</td><td>289</td><td>289</td></tr>
<tr><td>2030</td><td>---</td><td>289</td><td>347</td><td>347</td></tr>
<tr><td>2035</td><td>---</td><td>318</td><td>405</td><td>405</td></tr>
<tr><td>2050</td><td>---</td><td>463</td><td>550</td><td>550</td></tr>
<tr><td>Reference</td><td>---</td><td colspan="3">100% SMR</td></tr>
<tr><td>PtG case</td><td>---</td><td colspan="3">100% Electrolysis (regional)</td></tr>
<tr><td></td><td>„all electric“</td><td></td><td colspan="3">100% Electrolysis (onsite)</td></tr>
</table>

The relevant hydrogen supply regionalisation is based on LBST's proprietary database, according to which 24% of the hydrogen production is located in the North region, 29% in the West region, 4% in the South region, and 43% in the East region.

The industrial hydrogen consumption has been assumed constant within each year.

The SMR plant efficiency has been set to 76% for calculating the GHG emission savings. Specific GHG emission savings through replacing natural gas by hydrogen from electrolysis are typically at 202 g_{CO2}/kWh.

3.3.7 Renewable power generation

A fundamental assumption for all simulations has been that all electricity surpassing the electricity demand predicted by the NEP is provided from renewable sources.

The regionalisation of renewable electricity production is based on the data provided by the NEP (NEP 2015 B und NEP 2017 B). For additional renewable electricity supply a technology and regional allocation formula has been developed. Only wind (on- and offshore) and PV have been allowed to provide this electricity, excluding biomass or hydropower as other renewable electricity sources beyond the NEP.

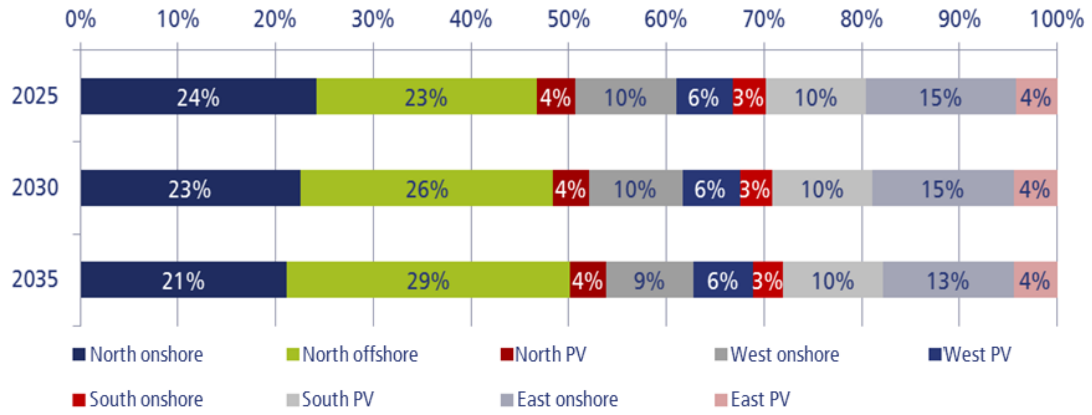


Figure 15: Distribution key of additional renewable-amounts of electricity[5]

For 2050, the renewable electricity allocation formula resembles the one for 2035.

The temporal renewable electricity production profiles have been shaped by the respective profiles of the four regions, as reported by the regional grid operators and according to Table 23 for the year 2015. The historical datasets have been taken from ENTSOE's Transparency database.

Table 23: Allocation of the applied renewable energy generation profiles[6]

Region	Onshore-wind	Offshore-wind	PV	Run-of-river
North	Tennet	Tennet	50Hertz	Amprion
West	Amprion	-	Amprion	Amprion
South	TransnetBW	-	TransnetBW	TransnetBW
East	50Hertz	-	50Hertz	Amprion

Caused by the strong ramp-up of offshore plants in 2015 (in absolute and relative figures) the original profile shows a significant upward gradient from year beginning to year end. In order to compensate for this gradient, the original profile was adapted such that the general trend line for the profile becomes horizontal (see Figure 16).

5 Example: By 2030, out of any 100 MWh of additional renewable electricity 23% or 23 MWh are provided by onshore wind energy in the region North and 4% or 4 MWh from PV in the region East.

6 German PV generation profiles manly display a difference between North and South. Consequently, the profile of Northern grid operator 50hertz has been used for the North region.

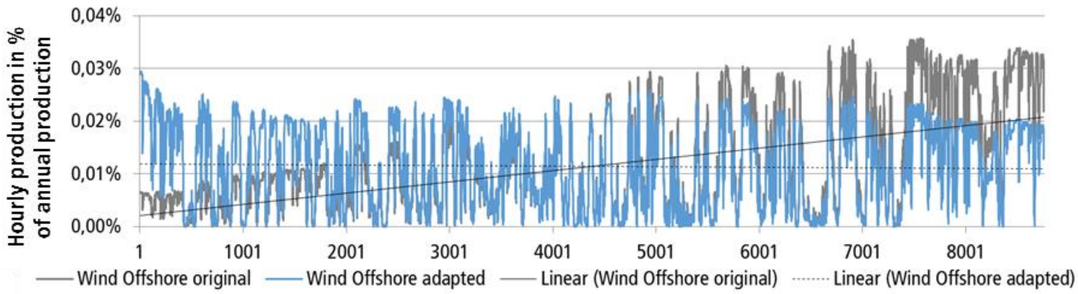


Figure 16: Adjustment of offshore-wind energy production profile

Figure 17 depicts the renewable electricity capacity added in 2050 for each use case. Depending on the application case, renewable electricity capacities of 250 to 500 GW_{el} (equivalent to 500 to almost 1,000 TWh_{el}) need to be developed.

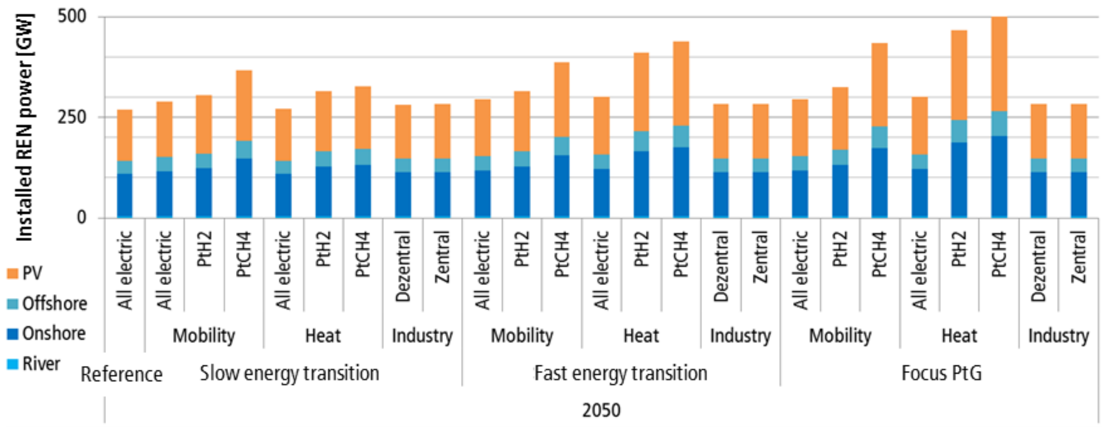


Figure 17: Installed renewable electricity in Germany by 2050 per case (without biomass, without other renewables)

The additionally required renewable electricity capacity beyond an „all electric“ world for the PtH_2 and $PtCH_4$ cases becomes obvious. It is caused by the efficiency losses when providing the PtG energy carriers for the transport and heating sectors as well as from storing electricity via PtG.

3.3.8 Conventional power generation

Based on the NEPs, the conventional electricity capacities used throughout our simulations have been harmonised. All production technologies have been assigned to the categories "lignite", "hard coal", "CCGT/NG", "GT CH_4", "biomass", or "oil". Small CHP plants and blast furnace gas have e.g. been assigned to the category "GT CH_4" whereas waste is filed under the "biomass" category.

The power plant resource planning is a result from the modelling exercise. The regionalised power plant park based on NEP is shown in Figure 18. Only the biomass capacities (incl. waste incineration) have been pre-determined for the year 2050. The remaining power plant park then results from the modelling in this time step.

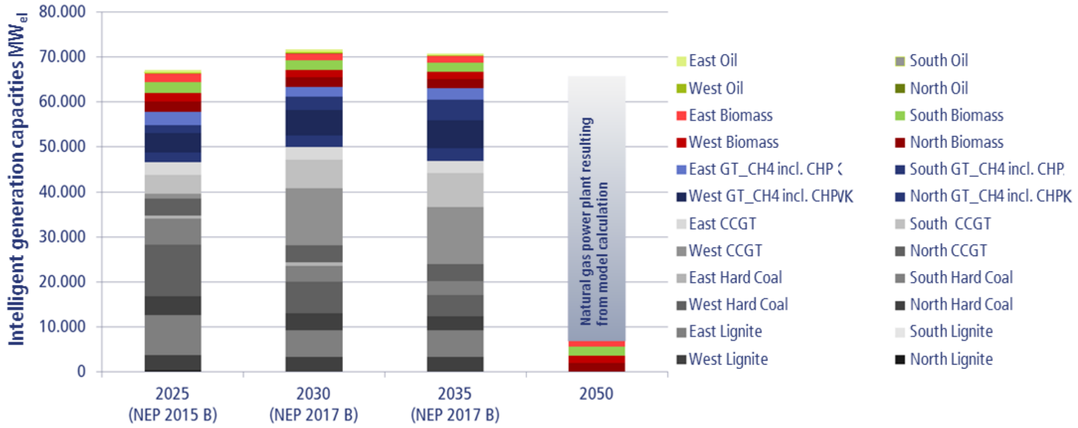


Figure 18: Conventional power plant according to grid development plans

Conventional power plants have been assigned simplified "must-run" load profiles to characterise them with technical capacity restrictions (e.g. minimum part loads, heat extraction). Lignite power plants are earmarked with a minimum part load of 25% for all single units, waste incineration plants need to be operated continuously during 8,760 hours p.a. The electricity production of hard coal, gas turbine, and CCGT plants has partly been coupled to the heating demand (ambient temperature driven) in order to address the heat extraction as suggested by the NEP.

3.3.9 Power trading with neighbouring countries

For incorporating electricity transit through Germany in our model, fixed import and export time series have been defined for each relevant region and neighbouring country. They are based on historic import/export profiles (2015) and have been adjusted by the import, export, and residual quantities provided by the NEP by adapting the temporal profile as well as their amplitudes for each target year.

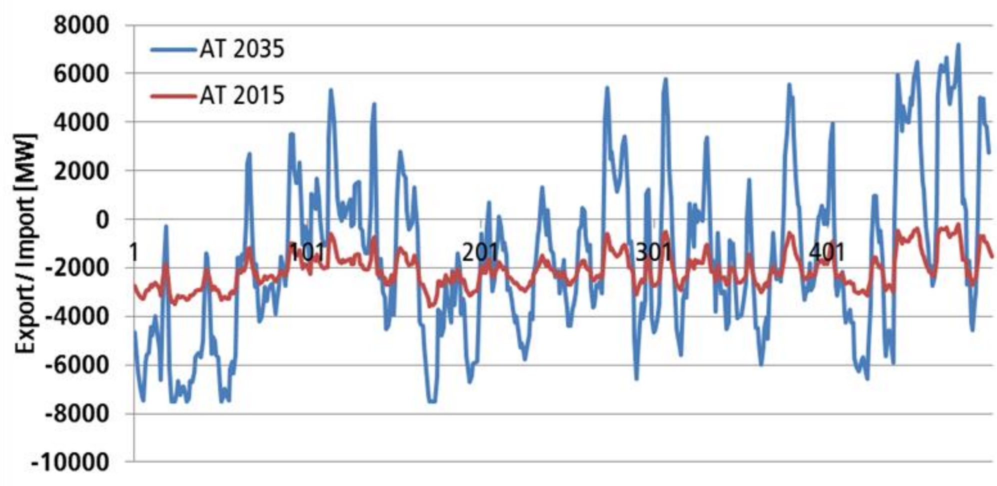


Figure 19: Original (2015) and adapted (2035) import/export-profile between Germany and Austria (negative values: DE → AT)

The following (Table 24) cross borders capacities have been taken into account.

Table 24: Cross-border transmission capacities as used in the model

Cross-border capacities	2025 (Import/Export)	2030 (Import/Export)	2035 (Import/Export)	2050 (Import/Export)
Austria	+7,500 / -7,500	+7,500 / -7,500	+7,500 / -7,500	+11,800 / -11,800
Switzerland	+5,700 / -4,300	+5,700 / -4,300	+6,400 / -6,000	+6,400 / -6,000
Czech Republic	+2,100 / -1,500	+2,600 /-2,000	+2,600 /-2,000	+4,200 / -4,200
Denmark	+4,000 / -4,000	+4,000 / -4,000	+4,600 / -4,600	+12,100 / -12,100
France	+3,300 / -3,300	+4,800 / -4,800	+4,800 / -4,800	+4,800 / -4,800
Luxembourg	+2,300 / -2,300	+2,300 / -2,300	+2,300 / -2,300	+2,900 / -2,900
The Netherlands	+4,700 / -4,700	+5,000 /-5,000	+6,000 / -6,000	+9,000 / -9,000
Poland	+3,000 / -2,000	+3,000 / -2,000	+3,000 / -2,000	+6,600 / -6,600
Sweden	+1,315 / -1,315	+1,315 / -1,315	+2,000 / -2,015	+8,200 / -8,200
Norway	+1,400 / -1,400	+1,400 / -1,400	+1,400 / -1,400	+9,900 / -9,900
Belgium	+1,000 / -1,000	+2,000 / -2,000	+2,000 / -2,000	+2,000 / -2,000

3.3.10 Power and gas grid

3.3.10.1 Power transmission grid

The transmission capacities between the four regions available in today's grid have been summarised in Table 25. The data for today's electricity transport grid have been assessed according to [Egerer 2016], incorporated in the model and harmonised in view of the grid extension and reinforcement measures implied by NEP-Electricity 2017B by 2030 (incl. DC transmission). The transmission capacity is supposed to be symmetric, i.e. bi-directional. In agreement with the client, specific incremental costs for buried DC transmission cables have been defined at 4 million €/(MW km) at increments of 2 $GW_{el.}$ The lifetime has been set at 30 years. Terminals (two stations per cable) at investments of 0.2 million €/(MW) need to be added, also with a lifetime of 30 years. To be on the safe side, an n-1 safety criterion was considered by assuming a capacity reduction of 20% for each cable. Energy losses through cables were neglected.

Table 25: Existing transmission capacities of the power supply lines between the single regions in today's grid (first time step)

From/to (MW)	North	West	South	East
North	0	31,552	4,000	12,448
West	31,552	0	26,320	5,440
South	4,000	26,320	0	18,320
East	12448	5,440	18,320	0

3.3.10.2 Gas transmission grid

In the framework of this model the gas transmission grid will not face any capacity bottlenecks for the transport of hydrogen or synthetic methane. This also implies that a further development of the gas transport grid can be avoided. However, the gas transport capacities will be assessed in an ex-post analysis against the existing pipeline capacities. The first order analysis by the client revealed that the existing capacities are: N → W: 37 GW; W → N: 14 GW; W → S: 76 GW; and S → W: 57 GW. For the conversion from methane to hydrogen, operation-specific investments of 1.05 million €/(GW_{H2} km) are foreseen with an asset lifetime of 30 years and a capacity increment of 4 GW_{H2}. Also, continuous operating costs of the gas grid are calculated for both gases. Transport losses along the pipelines are neglected.

3.3.10.3 Further power and gas network data

The electricity and gas transport distances between the four grid regions averaged transport lengths for electricity (AC, DC), methane, and hydrogen gas have been defined. This exercise was performed by considering the geographic centres of gravity of each region and then assesses the shortest distance between them, the result of which is shown in Figure 20.

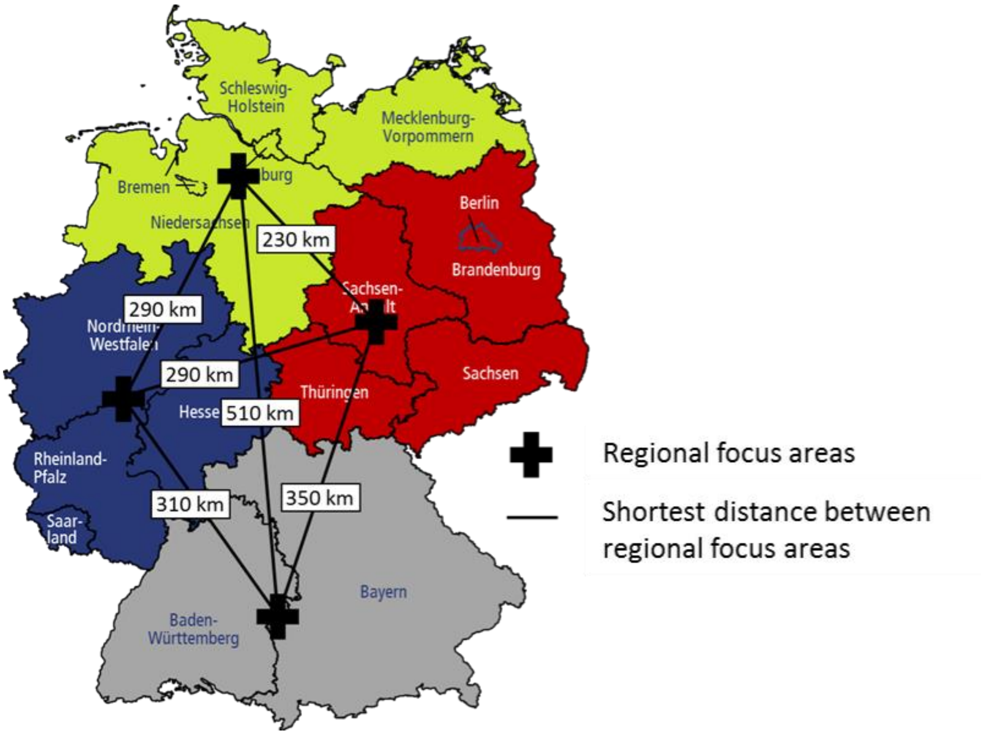


Figure 20: **Averaged transport vectors for electricity and gas (uni-directional for DC-power and methane gas today; bi-directional for AC-power, hydrogen gas, and methane gas in the future)**

Transport grid costs have been incorporated into the model in different ways and for different energy carriers. The combination of average grid lengths between the four regions for electricity and hydrogen gas transport and assumptions for their specific costs results in the following parameters for DC electricity in Table 26 and for H_2 in Table 27.

Power transport cost

Table 26: **Grid lengths and specific cost assumptions for the incremental construction of new DC-powerlines between regions**

Regions		N ↔ W	W ↔ S	S ↔ E	E ↔ N	W ↔ E	N ↔ S
Cable length		290 km	310 km	350 km	230 km	290 km	510 km
HVDC power cable	Spec. investments [M€/km]			4			
Inverter stations	[billion €]			0.8			
	Increment [GW]			2			
	Investments [M€]	1.96	2.04	2.2	1.7	1.96	2.84

Gas transport costs (CH_4 and H_2)

The lengths and hence investments for new or refurbished hydrogen pipelines have been aligned with data available from the gas client OGE. The approach explained in Table 27 has been chosen for their estimation:

- Agreement on real pipeline lengths between regions on the basis of data from OGE (N → W, W → S, N → S) and between regional geographical centres of gravity (other regions).
- Agreement on the energy capacity increment to be added (= transport capacity of a hydrogen pipeline at diameter DN 1200, maximum operating pressure 6.75 MPa and maximum gas velocity of 10 m/sec), where the gas velocity of existing pipelines can be increased temporarily to e.g. 20 m/sec if the capacity increase is only little above 8 GW, roughly doubling the transport capacity of the pipeline.
- Agreement on today's existing dual (= parallel) transport pipelines such that one of two parallel pipelines can be refurbished to hydrogen operation.
- Agreement on specific investments for the adaptation (= refurbishment) of an existing methane gas pipeline to hydrogen operation or building a new dedicated hydrogen pipeline (1.0 or 3.6 million €/km). Selection of the number of to-be-refurbished or new-built pipelines as a function of scenario for each regional relation assuming that a bi-directional operation can be taken care of by adapted compressor stations.
- Agreement on refurbishment (A) or new-built (N) for each regional interface and time step.
- Calculation of expected total investments for each regional interface and time step.

Table 27: Distances and specific assumptions for building or converting hydrogen pipelines between regions (here base scenario)

	Regions	N ↔ W	W ↔ S	S ↔ E	E ↔ N	W ↔ E	N ↔ S
	Cable length[1]	300 km	300 km	350 km	230 km	290 km	600 km
Increment[2]	[GW]			8			
Adaptation	[M€/km]			1.0			
New build	[M€/km]			3.6			
Adaptive-potential[3]	[# lines]	2	1	0	0	0	0
	[GW]	8	8	0	0	0	0
Demand „Base-scenario“	2025 [GW]	2.8	0	0	1	0	2.3
	2030 [GW]	3.2	0	0	1.4	0	2.8
	2035 [GW]	4.1	0	0	1.9	0	3.8
	2050 [GW]	17	0	0	8.1	0	16.2
A/N[4]	2025	A			N		N
	2030						
	2035						
	2050	A					
Total-investment	2025 [M€]	300			828		2.160
	2030 [M€]						
	2035 [M€]						
	2050 [M€]	300					

[1] deviates from focus areas for NO → WE (300 km), WE → SO und NO → SO (600 km) according to concrete data of OGE (cable length Oldenburg → Werne → Norden from Bavaria about 600 km).

[2] Cable diameter design DN1200, pressure 67.5 MPa and max. flow speed of 10m/sec. Minor higher energy demand can be gained by velocity adaption, this way at for example an increment of 8 GW there is no need to build a new cable. (In principle up to max. double capacity of 16 MPa at 20 m/sec).

[3] An adaptive potential in 2050 is meant, this way a 100% conversion to H_2 in parallel cables would be thinkable.

[4] Adaptation (A) or new build (N)

For calculating the operating costs of methane and hydrogen grids the following rough estimate was done in coordination with OGE:

- Total costs (capital and operating costs) for the German methane transport grid RP3 (from NEP-Gas 2016.2): €1,781,654,674 p.a.
- Methane consumption in all of Germany (average of upper and lower heating value) (from NEP-Gas 2016.2): 771 TWh p.a.
- Specific annual total costs of methane gas (NEP-Gas 2016.2): 2.31 €/MWh
- Specific annual total costs of hydrogen: (assumption: 4/3*CH_4) (NEP-Gas 2016.2): 3.08 €/MWh

When comparing these numbers with a price of natural gas of ~30 €/MWh, gas transport related costs are in the order of 10% of the total costs, which is insignificant given the total cost of gas supply.

4 COST AND BENEFIT ANALYSIS FOR PTG APPLICATIONS

This chapter presents the results of an actual cost-benefit analysis for the PtG applications. First, in chapter 4.1, we explain in more detail the results from the base scenario ("Slow energy transition"), followed by the results from the other two scenarios "Fast energy transition" and "Focus PtG" in chapter 4.2. The comparison of the use cases per scenario in both chapters is carried out at an aggregated level because of the multitude of detailed results. Detailed results are therefore presented only with a focus on the transport sector and only for the base scenario and the scenario "Focus PtG", as the resulting insights can be transferred to both other use cases. Towards the end, both chapters also address the secondary energy infrastructures and end-user applications.

4.1 Results from the reference scenario

4.1.1 Comparison of PtG application cases in the reference scenario

As described in chapter 2, the major task of scenario and use case modelling is to minimise the total costs of the energy system under a set of given constraints. This chapter explains the results of the base scenario in Figure 21 using the cumulative total costs, comprising all cost contributions until 2050. These cost contributions are made up of the annuity based investments for new plants as well as the annual operating costs such as for maintenance or for fossil primary energy.

However, the analysis does not take into account the annuities for already existing plants such as today's power plant stock including fossil and renewable plants, the present electricity transport grid, or already deployed end-use technologies such as conventional gasoline or diesel cars. As a consequence, only expenditures for a future refurbishment or extension of the energy system are addressed including energy transport, secondary infrastructure such as battery charging or hydrogen refuelling stations, and end-use technologies such as BEVs or FCEVs for the transport sector.

In addition, the costs in our analysis represent gross costs which would at least partly also incur even if the energy system will not be converted to renewable energies. The consequence is that a part of the required investments e.g. in new vehicles, power plants, grids etc. would have to be accounted for in any case, i.e. regardless of the technology chosen. Therefore, this analysis does not provide differential costs for decarbonisation of the energy system as only a comparison with a truly "fossil" scenario would give a justifiable basis for such comparison which, however, was not a part of this study. Nevertheless, this study provides a sound comparison of different PtG application areas, specifically also with a view to a strict "all electric" world.

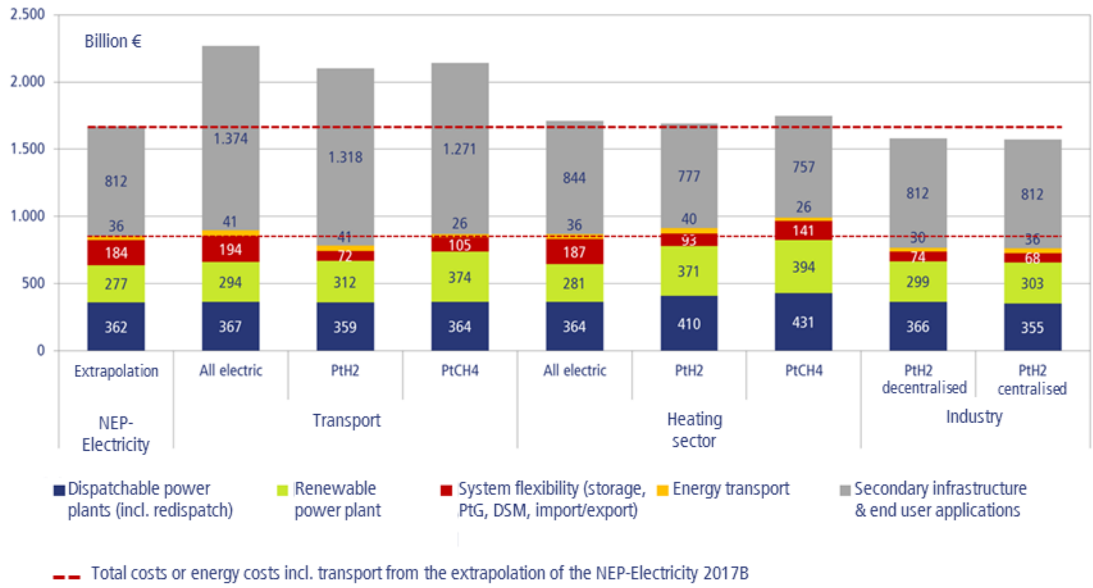


Figure 21: Cumulated total cost in billion € until 2050 in the base scenario

The highest cumulative total costs by 2050 of about 2,100 B€ to 2,300 B€ occur in the transport sector whereas the industry sector is characterised by the lowest costs of about 1,600 B€. The heating sector is in the middle between both above mentioned sectors at 1,700 B€ to almost 1,800 B€. As indicated in Figure 21 this is due to the specific cost structure. While the energy costs (i.e. production in fossil and renewable power plants, flexibility contributed by energy storages, PtG, DSM, and import/export as well as long distance energy transport) are roughly in the same order of magnitude for all use cases at ca. 760 B€ to 1,000 B€, the costs for secondary infrastructure and end-use technologies (i.e. secondary infrastructure and end users) have a large impact on the total costs.

As defined in chapter 3.3, the costs for the end-use technologies in the transport sector (i.e. charging or refuelling stations and vehicles) are significantly higher than the corresponding costs in the heating sector (i.e. electric heat pumps and H_2- or CH_4-heating appliances), due to different penetration rates of the end-use applications in both sectors. In the industry sector the end-use technologies account for the smallest expenditures remaining at the same level as from the extrapolation of the NEP-Electricity 2017B. This is due to the fact that in this study hydrogen in the industry is assumed as a final product and requires no specific end-use technologies as the electrolysis costs replacing steam methane reforming plants are already included under costs for system flexibility. As a consequence, the comparison of the costs for introducing PtG between the different sectors is only partly meaningful, whereas the comparison of different introduction scenarios (“all electric” vs “PtH_2” vs “$PtCH_4$”) within each sector provides relevant insights.

The remaining costs for end-use application in industry of 812 B€ are due to the minimum number of BEVs and heat pumps as defined by the extrapolation the NEP-Electricity 2017B (also see definition of scenarios and use cases in chapter 3). In contrast, the end-use costs in the transport and heating sectors are higher than the ones from the extrapolation of NEP-Electricity 2017B, as both cases account for a significantly higher number of zero emission vehicles and heating appliances. Note that the costs for end-use technologies specifically in the comparison of different use cases will be studied in more detail in chapter 4.1.3.

Interestingly, the above mentioned observations do not hold for the energy costs including energy transport (i.e. total costs without costs for the end-use technologies) due to two opposing effects. On the one hand, the larger the electricity demand the higher the costs for energy provision (summing up the costs for dispatchable and renewable plants) in all end-use sectors. The following two examples illustrate this effect: (1) due to the lowest GHG emission reduction targets the extrapolation of NEP-Electricity 2017B is characterised by the lowest costs for energy production (640 B€) as compared to all other cases (645 B€ to 825 B€); (2) due to the higher conversion losses the PtG case has higher energy costs ($PtCH_4$ higher than PtH_2) than the respective "all electric" case. In the heating sector this increase is specifically pronounced, as here the difference in electricity demand between electric heat pumps and H_2 or CH_4-production to be used in H_2- and CH_4 heating appliances is very large. In fact, the electricity demand and the associated electricity costs in this sector for PtG are much higher than in all others. In general, the share of renewable power plants in electricity production rises significantly until 2050 for all cases. However, cumulated over time the renewable power plants are responsible for only about 40% to 50% of the total energy production costs within the entire time horizon until 2050, also due to the decreasing specific renewable power plant costs.

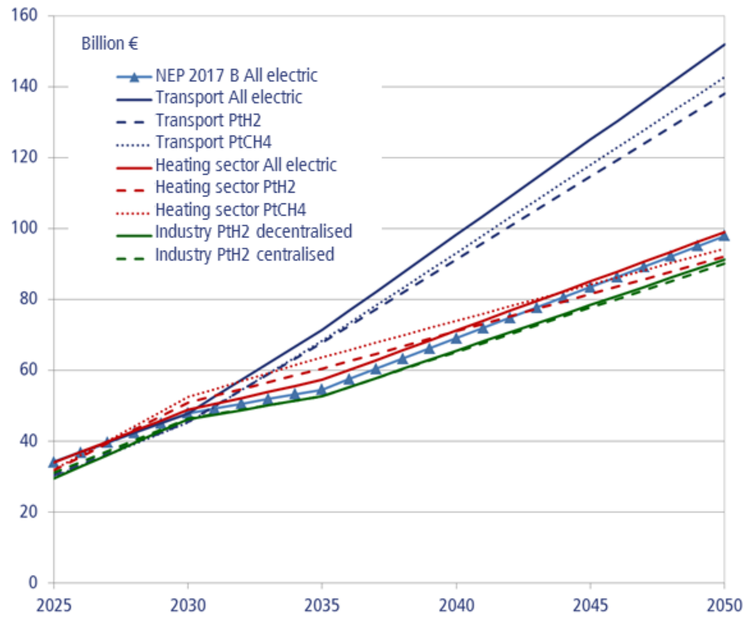
On the other hand, the technology choice has a major impact on the flexibility costs of the energy system. While stationary batteries in the "all electric" case have a large influence on flexibility costs (close to 200 B€), the PtG technology can benefit from the low costs for large-scale storage in the seasonal context even though electrolysis has high incremental cost in the early introduction phase. Hence, the flexibility costs in all PtG cases of about 70 B€ to 140 B€ are lower than in the "all electric" case. Depending on the effect, the advantage of the good energy storability can more than compensate the disadvantage of the higher PtG conversion losses resulting in lower (PtH_2 for all sectors and $PtCH_4$ in the transport sector) or sub-proportional rise ($PtCH_4$ in the heating sector) of the energy costs including energy transport in comparison to the "all electric" case.

At this point it is worth mentioning that the overall energy costs for PtH_2 in the transport and industry sectors are even lower than from the extrapolation of the NEP-Electricity 2017B despite the more ambitious GHG emission reduction goals. Yet, the energy supply costs comprise the largest share of the total energy costs. The energy transport costs of about 25 B€ to 40 B€ are at the same level for all energy carriers and all end-use cases and contribute only a small share to the total energy costs. However, it t should be noted that in Figure 21 costs for transporting hydrogen and synthetic methane in the existing gas grid are excluded, similar to the assumptions made for the exisiting electricity grid and other system components (see sections 2.1 and3.3.2).

Nevertheless, we assess the operation and maintenance costs of the gas grid required for the corresponding H_2 and CH_4 transport in a dedicated ex-post calculation. Based on the assumptions from the NEP-Gas 2016.2, we consider specific transport costs for hydrogen of 3.08 €/MWh and for synthetic methane of 2.31 €/MWh (see also chapter 3.3.10). For the base scenario, this would cause additional costs of 5 M€/a to 50 M€/a by 2025 (lower value for the transport sector, higher for the heating sector) and 120 M€/a to 250 M€/a by 2050 (lower value for the industry sector and higher for the heating sector). When looking at the cumulative costs, this would result in additional costs of ca. 2 B€ for the transport sector (PtH_2 somewhat lower than PtCH_4), ca. 3 B€ to 5 B€ in the heating sector (lower bandwidth PtCH_4, upper bandwidth PtH_2), and 1.4 B€ in the centralised industry case. This ex-post analysis demonstrates that additional pipeline costs would have no impact on the quality of the simulation results.

In total, the energy costs including energy transport cover a bandwidth from B€ 760 (centralised PtH_2 in industry) to 992 B€ (PtCH_4 in the heating sector) whereas the costs for the NEP-Electricity 2017B projections are in between at 860 B€.

The development of the annual energy costs (including transport) in Figure 22 (bottom) shows that the energy costs for the "all electric" cases in all sectors and from the extrapolation of NEP-Electricity 2017B are at a comparativly high level. In the mid-term until 2035 these costs are similar for all cases, however they tend to diverge with a growing decarbonisation of the energy system until 2050. The costs in the heating sector are slightly above those from the extrapolation of the NEP-Electricity 2017B due to more ambitious climate policy goals, but they are lower than the costs in the transport sector. This observation relates to the different development of the pre-defined electricity and flexibility needs (i.e. in pariticualar the need for stationary batteries) in the different energy sectors (i.e. by 2050 more electricity is consumed in the transport than in the heating sector). When looking at the total costs (Figure 22 top) this development is further itensified by the costs for the end-use technologies as BEVs are specifically more expensive than electric heat pumps.



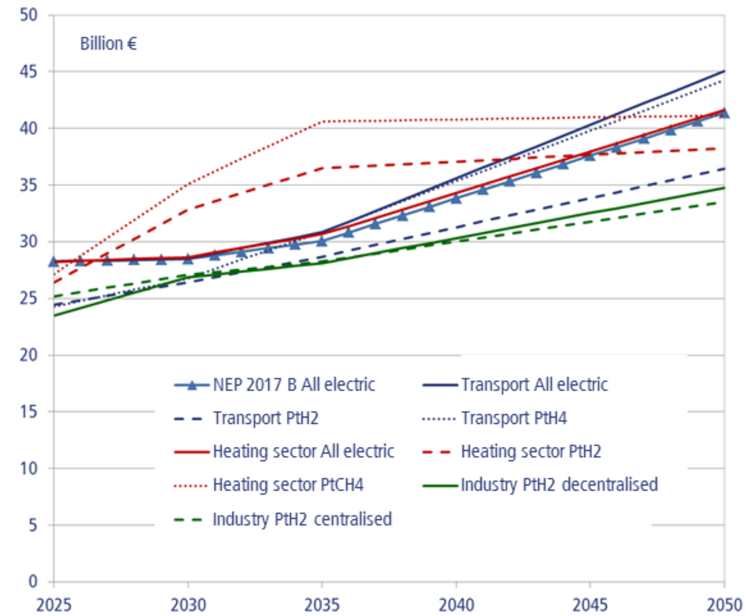


Figure 22: Development of annual total cost (top) and of energy cost incl. transport (bottom) in billion € until 2050 in the base scenario

The costs from the PtH_2 case in all sectors are always lower than in the respective "all electric" cases as the advantages of PtH_2 in view of the (cost) efficient energy storability more than compensates for the larger conversion losses. In the transport and industry sectors the annual energy costs for PtH_2 (including transport) are even below the costs from the extrapolation of NEP-Electricity 2017B. For the heating sector, both observations are only valid in the short- (i.e. in 2025) and in the long-term (2050) as the ramp-up of renewable electricity production as well as the reduction of the specific cost for electrolysis, H_2-storage and stationary develop differently until 2050. Therefore the overall advantage of PtH_2or "all electric" depends on which development is more pronounced. In this context, the specific characteristic of heating market is that in this sector PtH_2 requires much more electricity for the same final energy (electric heat pumps are clearly more efficient than H_2 appliances) and a larger energy storage (resulting from the strong seasonality of the heating demand). The simulations also show that in the long-term in the industry sector the falling storage costs of salt caverns in the centralised PtH_2 case (in comparison to below ground pipe storage in the decentralised PtH_2 case) are lower than the costs for hydrogen transport within the gas grid (from the region "North" to industrial sites). Therefore, the centralised PtH_2 case is more cost-efficient than the decentralised PtH_2 case (with electrolysers located at the industry site).

In case of $PtCH_4$ the cost development is similar to the PtH_2 case. Concerning the total and energy costs, the $PtCH_4$ case falls in between the PtH_2 and the "all electric" case. On the one hand, the storability and gas transport are easier for synthetic methane than for hydrogen, and also the CNG vehicles and refuelling stations cost less than comparable hydrogen equipment. On the other hand, significantly more electricity is required for the same driving distance or heat supplied as the methanation plants have lower efficiencies and, in the transport sector, the internal combustion engine is less efficient than an electric motor combined with a fuel cell. Still, the CH_4 production and CH_4 storage make the system flexibility cheaper in comparison to the stationary batteries in the "all electric" case despite the conversion losses.

All in all and in perspective to 2050, the total costs for all technologies in the transport sector („all electric", PtH_2 and $PtCH_4$) are much higher than from the extrapolation of NEP-Electricity 2017B as the end-user specific costs (i.e. vehicles and charging/refuelling stations) rise considerably with a growing vehicle fleet. This effect is less pronounced in the heating sector than in the transport sector as the specific end-use costs (i.e. for heating appliances) are lower than the energy costs and hence have a smaller share in total costs.

Figure 23 displays the cumulative GHG emission savings for all sectors and technologies, their development over time being in the same order of magnitude. In total, in the 25 years between 2025 and 2050 more than 7 Bt_{CO2} are avoided in the power, transport, heating, and industry sectors by developing renewable electricity generation capacity. This quantity is equivalent to an average annual savings of ca. 270-280 Mt_{CO2}. For 2030 the GHG emission savings are in the order of 215 Mt_{CO2} (focus transport) and 230 Mt_{CO2} (focus heating), for 2050 between 390 Mt_{CO2} (focus heating) and 420 Mt_{CO2} (focus transport) compared to 1990 levels. The lower limit is determined by the NEP-Electricity 2017B having the lowest climate protection target. On the one hand, the minor variation between the individual curves is caused by the different sectoral focus with different today's GHG intensities. On the other hand, the variation can be explained by the different modelling results for the power sector for which only a GHG emission ceiling has been set, with the actual results derived from the economic optimisation of the system under given boundary conditions.

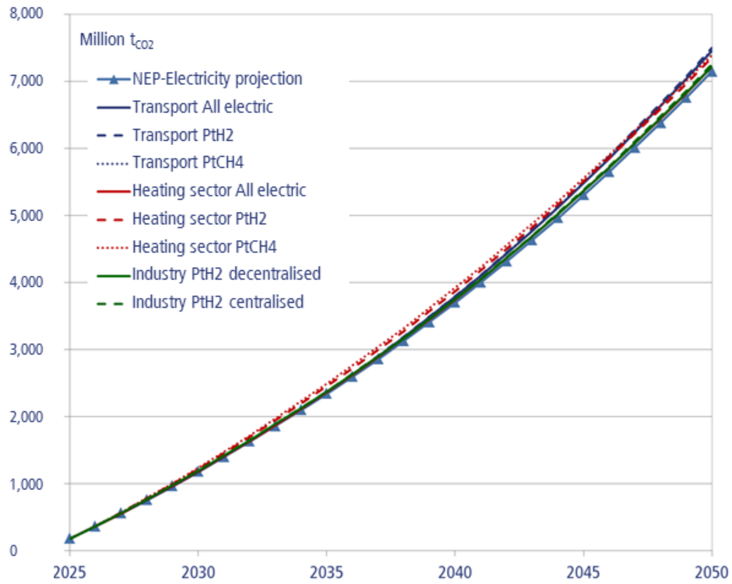


Figure 23: **Cumulated GHG reduction in Mt_{CO2} until 2050 in the base scenario**

The relative and specific „GHG-avoidance costs" are calculated by dividing the cumulative total and energy costs (including energy transport) by cumulative GHG emissions. In this way, the different sectors and technologies can be compared on the same basis (see also Figure 24). While the specific total costs vary between 200 and 300 €/t_{CO2} depending on the use case, the specific energy costs are between 100 and 120 €/t_{CO2}. In principle, it can also be observed that the structure of GHG avoidance costs and the relation between the different end-use sectors is analogous to the absolute total and energy costs in Figure 21. The highest GHG avoidance costs (related to total costs) are observed in the transport sector and the lowest in the industry sector. By applying the PtG technology, the GHG avoidance costs can be significantly reduced as compared to the "all electric" case, partly even being lower than the GHG avoidance costs calculated for the NEP-Electricity 2017B.

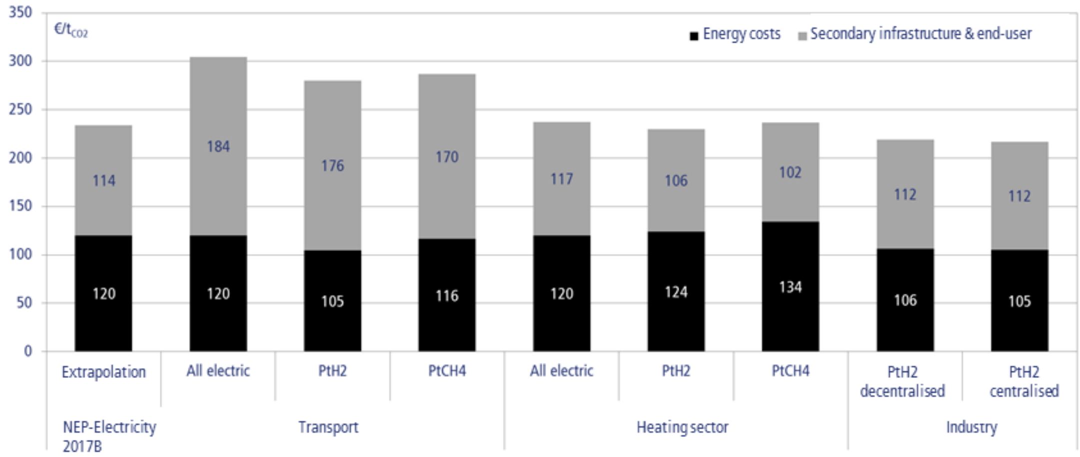


Figure 24: Cumulated GHG avoidance cost in €/t_{CO2} until 2050 in the base scenario

To benefit from the PtG technology a massive increase of electrolysis capacity is required for the corresponding end-use cases. As shown in Figure 25, an electrolysis capacity of 67-90 GW_{el} needs to be built up in the PtH_2 case and of 94-117 GW_{el} in the $PtCH_4$ case. The difference between the PtH_2 and $PtCH_4$ cases results from the conversion losses of the methanation process and hence the higher demand for H_2 in the $PtCH_4$ case. The difference between the sectors result from the individual pre-defined demand for H_2 and CH_4. Morover, already in the short-term until 2025 a ramp-up of electrolyser capacity of about 12-19 GW_{el} is required, in parallel to the growing demand from the individual sectors. In part, the capacities developed in the previous time step are still sufficient to cover the demand in a given time step (e.g. in the case of the transport and industry sectors between 2025 and 2030), but in the long-term a massive ramp-up of the electrolyser capacity is needed for reaching the GHG reduction targets (see development between 2035 and 2050).

Electrolysers and hydrogen storage are the two key options for flexibility in the energy system as the other options (DSM, curtailment of renewable supply, import/export) are limited by model assumptions (see chapter 3) or cannot be used in some situations (e.g. use of flexible power plants in times of power surplus). As such, electrolysis is used in the energy system as an important flexible load and its capacity sizing is based on critical hours with surplus power. Therefore electrolysis utilisation is only 1,000 full load hours in the short-term until 2030 and 2,000 full load hours thereafter. At this point it is worth mentioning that these values are average figures and the actual utilisation of individual electrolysers might be higher. Whether an electrolyser can be operated economically for the stabilisation of the energy systems also from a business perspective depends on a number of different influence factors and should be assessed in more detail in further research. The low electrolyser utilisation reflects the discrepancy between the system and business perspective, both depending on the actual rules for the future energy markets.

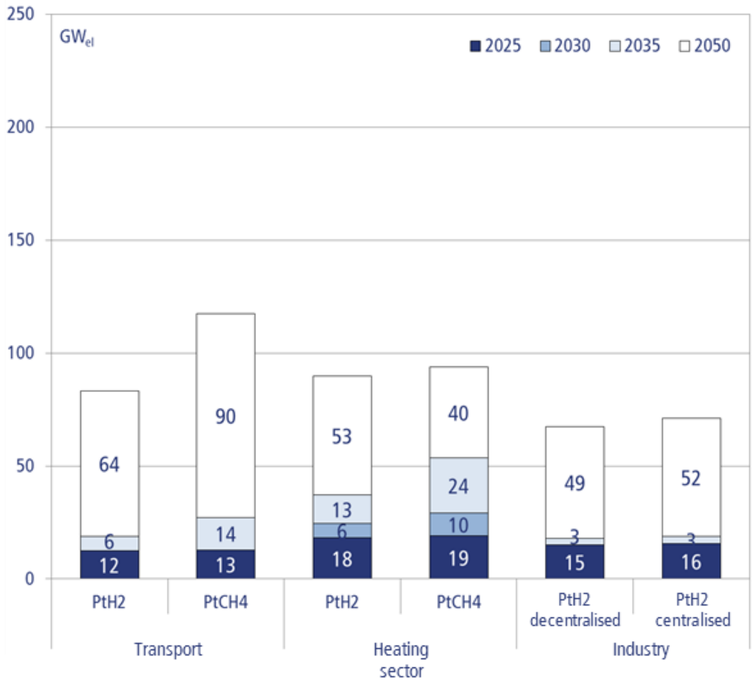


Figure 25: Optimal development of the installed electrical capacity of the electrolysis in GW$_{el}$ until 2050 in the base scenario

Figure 26 depicts the necessary extension of the HVDC grid between the four regions. According to our calculations, no further lines need to be developed beyond the HVDC expansion of 10 GW$_{el}$[7] from NEP-Electricity 2017B until 2050. The conclusion is that today's existing high voltage grid (including the NEP-Electricity 2017B enhancements), extended by the HVDC links planned until 2035 will be sufficient for the sector integration and the required development of renewable electricity. Only a massive extension of intermittent power supply partly due to sector integration increases the inter-regional energy balancing and requires further grid develop. Assuming the four grid nodes of this study, an additional 12 GW$_{el}$ beyond the 10 GW$_{el}$ from NEP-Electricity 2017B (i.e. 6 additional HVDC connections at 2 GW each; in total summing up to 22 GW$_{el}$ or 11 HVDC connections) will be needed for the extrapolation of the NEP-Electricity 2017B. This grid extension also applies to the integration of electricity and heating sectors, meaning that

[7] The most recent version of NEP-Electricity 2017 (scenario B) foresees a development of four HVDC lines in total connecting southern with northern Germany, each one at a capacity of 2 GW$_{el}$. As the connections DC1 and DC2 represent one major joint connection but in reality are composed of the individual connections North to West (DC1) and West to South (DC2) they are treated as two separate lines with corresponding distances in our model.

the additional electric heat pumps in the "all electric" case do not require any additional grid extension.

Figure 26: **Necessary development of HVDC transmission lines in GW_{el} until 2050 in the base scenario**

In the transport sector the electricity consumption from renewables is higher than in the heating sector such that in this case an additional 18 GW_{el} connection capacity (or 9 additional HVDC lines; summing up to 28 GW_{el} or 14 HVDC lines) need to be developed by 2050 to supply an electricity system with a large number of BEVs. Interestingly, the flexible use of onsite electrolysis in the industry case reduces the necessary grid extension by 8 GW_{el} (or 4 HVDC connections) in comparison to the extrapolation of NEP-Electricity 2017B down to 4 GW_{el} (or 2 additional HVDC connections; summing up to 14 GW_{el} or 7 HVDC connections in total) by 2050.

These numbers demonstrate that the extension of the electricity grid only becomes relevant for a very high level of intermittent electricity supply (ca. 450 TWh). Up to this level the highest and high voltage grid as well as the 10 GW_{el} HVDC capacity are sufficient for the electricity transport between the four nodes, even taking into account the electricity transit through Germany between the neighbouring countries. However, as the required grid capacity is based on the peak demand the result of this study is very sensitive to the assumptions on the regional distribution of electricity demand, renewable and flexible power plants as well as electrolysis and energy storage capacity and. The electricity grid extension can be reduced by adequate allocation and operation of the concerned facilities (in particular the electricity storage such as stationary batteries in the "all electric" case).

In the PtH_2- and $PtCH_4$-cases an adequate use of input parameters suppresses power grid extension beyond the plans from NEP-Electricity 2017B in our model. In this context, hydrogen and synthetic methane are transported through the existing gas grid from the North, where large electrolysis and methanation plants are located, to the other regions. Hence, additional HVDC connections (i.e. beyond the NEP-Electricity 2017B levels) with a capacity between 4 GW_{el} (focus industry) and 18 GW_{el} (focus transport) can be avoided until 2050 through PtG and a meaningful use of the gas transport infrastructure. In both cases the gas grid capacity is characterised by a stepwise increase. According to the growth in energy demand growth of the different end-user cases the biggest increments occur in 2050 for transport and industry sectors (centralise electrolysis case). In the heating sector the H_2 and CH_4 demand increases in a more linear manner, being different than in both other sectors.

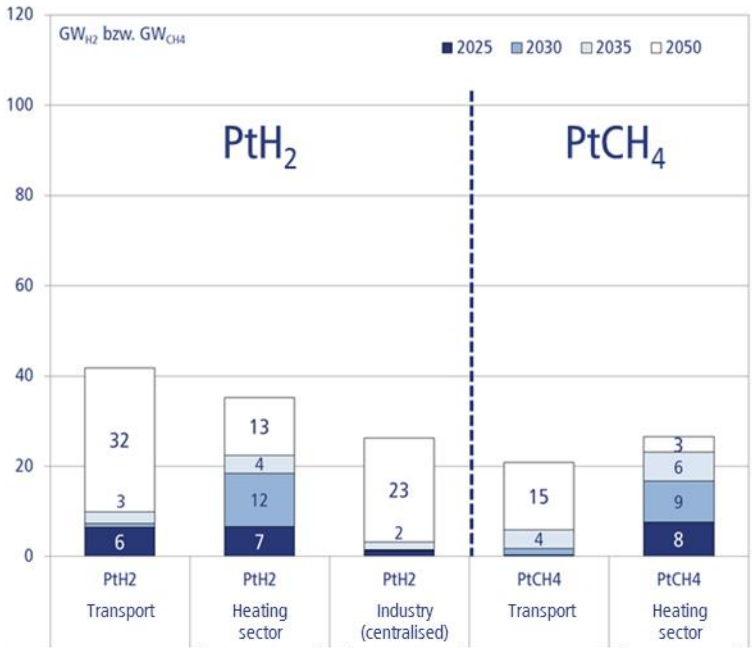


Figure 27: **Necessary capacities of gas transport pipelines in GW_{H2} or GW_{CH4} until 2050 in the base scenario**

In conclusion, in the transport case 42 GW of hydrogen grid capacity are need which can be achieved by refurbishing existing natural gas pipelines. The heating sector would require only 35 GW of gas grid capacity, even though the hydrogen demand is higher and has a more seasonal profile. This can be explained by additional hydrogen storage capacities at the refuelling stations, which are fully exploited in the first modelling step without regional restrictions and hence require an additional inter-regional hydrogen transport to or from these storage facilities. Only 26 GW of gas grid capacity are needed to supply industry with hydrogen from centralised electrolysis plants as the total hydrogen demand is assumed to be much lower than for the other two end-user cases.

In the $PtCH_4$ case only 21 GW (transport sector) and 26 GW (heating sector) of gas grid capacity would be required, the difference stemming from the larger demand seasonality in the heating sector. In principle, the $PtCH_4$ case requires smaller transport capacities than the PtH_2 case. This is mainly due to different regional distribution of hydrogen and methane storage facilities (hydrogen in underground salt caverns in the North, methane storages distributed equally across all of Germany) being a sensitive parameter for H_2 and CH_4 transport of gas.

4.1.2 Detailed results from the transport sector in the reference scenario

In this chapter the results and relationships from the previous chapter will be explained in more detail using the transport sectors as example. It starts with an overview of the overall energy system, followed by the presentation of results concerning the flexibility options and energy transport.

Overview of the overall energy system

Figure 28 shows the development of annual total costs for the transport sector in the base scenario. In the first time step the costs of30-35 B€ are rather low and are in the same order of magnitude for the "all electric" and both PtG cases. In this early phase, the costs for the dispatchable fossil power plants dominate contributing the major share of electricity supply. Renewable electricity production and end-use technologies (charging or refuelling stations and vehicles) contribute a similar cost share (ca. 6 B€/a), each of both having a limited impact on total costs as in this time step by definition renewable power plants are developed only moderately and only few zero-emission vehicles are on the road. Nevertheless, the benefits of good energy storability via PtG more than compensate the disadvantages of a higher energy demand in both PtH_2- and $PtCH_4$-cases in this time step such that the total costs as well as energy costs (25-28 B€/a) are lower than in the "all electric" case.

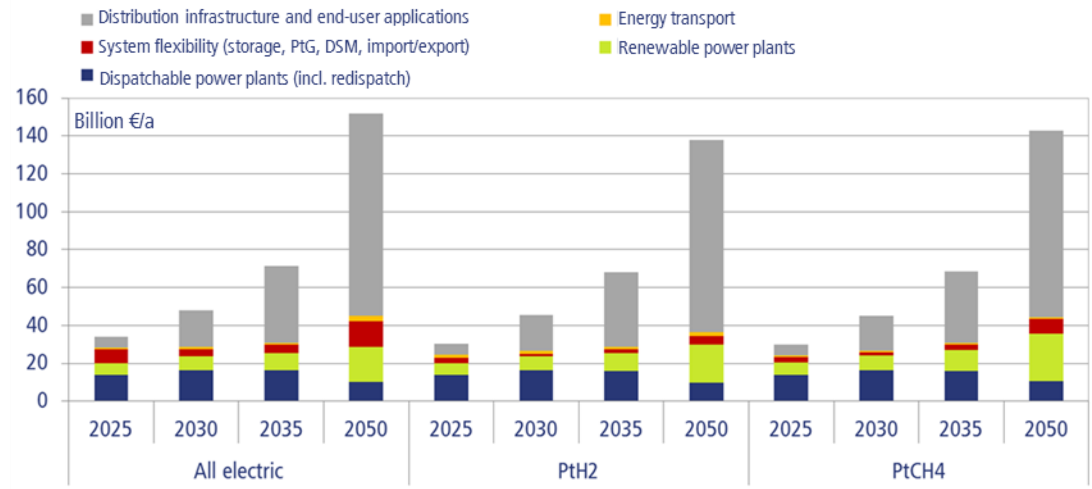


Figure 28: Annual total cost in billion €/a in the transport sector in the base scenario

The electricity demand from other sectors increases with improving decarbonisation of the energy system, in this case specifically from the operation of zero-emission vehicles. In the medium-term this energy demand will be supplied by fossil and dispatchable as well as new renewable power plants, such that both cost contributions rise slowly by 2035. In this phase dispatchable power plants also contribute to system flexibility at the same time. Afterwards the costs for dispatchable power plants decrease whereas the costs for new renewable power plants rise along with their massive roll-out and amount to 18-25 B€/a or ca. 41%-57% of the energy costs (including energy transport) by 2050 (12%-18% of total costs).

The costs for system flexibility decrease in the short-term (caused by the reduction of electricity imports between 2025 and 2030), yet rise again to ca. 5-13 B€/a thereafter following the increasing build-out of renewable power capacity until 2050. The lowest costs for flexibility result in the PtH_2 case as hydrogen can be stored efficiently and needs less energy for production than synthetic methane[8]. The highest costs are calculated for the “all electric” case as stationary batteries for direct electricity storage are comparatively expensive, increasing the energy costs including production, flexibility measures and energy transport to up to 37-45 B€/a by 2050.

With a growing share of zero-emission vehicles also the costs for the end-user technologies rise substantially, increasing the energy costs two-to threefold in the long-term. Even though the cost difference between BEVs, FCEVs, and CNG vehicles and also

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[8] As $PtCH_4$ requires more energy for the production of synthetic methane more renewable power plants have to be added than in the PtH_2 case, which will in turn require a higher degree of flexibility in the electricity system, i.e. by adding more energy storage capacities

the corresponding infrastructures are rather small in the long-term, the CNG vehicles have the lowest end-user technology costs in all time steps as CNG cars and refuelling infrastructure are very cost efficient. The energy transport costs are at a comparable and stable level of 1-2 B€/a and play a minor role. Depending on the technology, the total costs vary between 138 and 153 B€/a, with a ranking of PtH_2 before $PtCH_4$ and "all electric".

The results demonstrate that the energy costs are influenced by a trade-off between energy storage need, renewable electricity capacity increase, and utilisation of flexible power plants as well as other flexibility options. What is more, the electricity demand from various sectors (in total and by profile) is a key parameter in determining the system costs. As a consequence, the total costs are lower in the heating sector than in the transport sector as the end-user technologies are cheaper (heating appliances are cheaper than cars). However, for PtH_2 and $PtCH_4$ the energy costs (including energy transport) are higher for the heating sector than for the transport sector as heating systems based on H_2 and CH_4 are typically less efficient than BEVs and FCEVs, respectively (and as electric heat pumps in comparison to the "all electric" case). These conversion losses are the reason for a larger electricity demand and in perspective an intensified build-up of renewable electricity capacity and flexibility options.

Since no further end-user technologies are considered for industry in this study because electrolysis directly replaces steam methane reforming, the total costs in this sector are lower than in the transport and heating sectors. By using hydrogen for energy storage and the low specific storage costs the energy and total costs in this sector are even lower than from the extrapolation of NEP-Electricity 2017B even though more GHG emissions are avoided.

Figure 29 depicts the annual electricity production (positive values) and its utilisation (negative values) for the transport sector over time. In total, the gross electricity demand for all applications rises from ca. 570 TWh_{el} up to between 660 TWh_{el} ("all electric") and 790 TWh_{el} ($PtCH_4$ case) as the electricity savings in traditional electricity use (e.g. for lighting or electric home appliances) are overcompensated by the additional electricity use in all other sectors (transport and heating sectors). The difference between "all electric", PtH_2 and $PtCH_4$ for each year are proportional to the conversion losses of the corresponding end-user technologies (vehicles/heating appliances) and corresponding H_2- and CH_4-production (electrolyser efficiency vs. methanation plant).

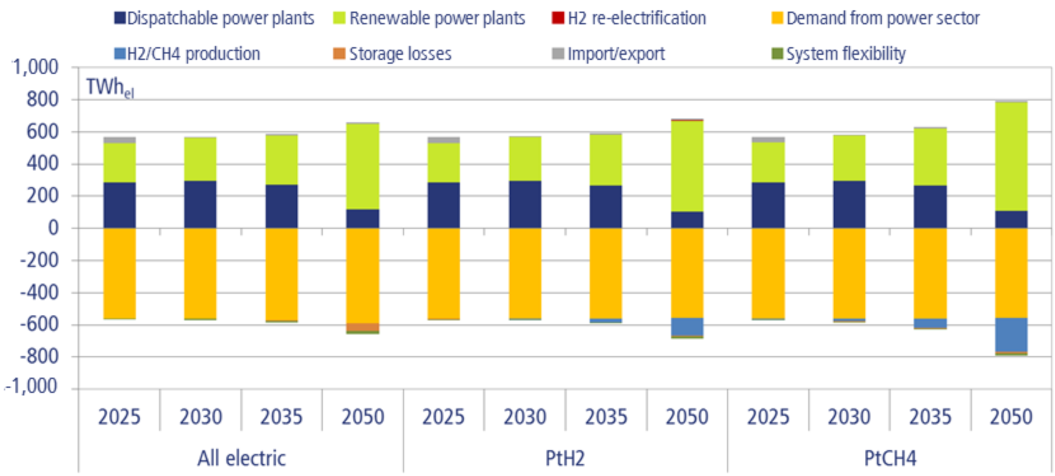


Figure 29: Annual electricity generation (positive values) and usage (negative values) in TWh$_{el}$ in the transport sector for the base scenario

The electricity demand will be delivered mostly by fossil power plants (slightly more than 50%) in the medium-term (2025 to 2030) which will be steadily replaced by renewable power plants (more than 80% by 2050). The intermediate increase of power supply from dispatchable power plants between 2025 and 2030 can be attributed to the pre-defined discontinuation of electricity imports being compensated by conventional power plants. For the PtH_2 case a small share of the electricity demand (max. 1% in 2050) is covered by direct re-electrification of hydrogen. In the $PtCH_4$ case synthetic methane can be stored and then also used to provide system flexibility, however, limited to very few cases due to the poor roundtrip efficiency.

These developments are also mirrored in the mix of dispatchable power plants (see also Figure 30). Lignite and hard coal power plants are completely pushed out of the market until 2050. The major contribution to system flexibility is provided by natural gas based power plants (gas turbines and combined cycle (gas & steam) power plants), which comprise the largest capacity of ca. 40 GW$_{el}$ by 2025 and 48-60 GW$_{el}$ by 2050. In an intermediate period this capacity is even larger, as these power plants are needed to provide additional power for growing electricity demand in line with the pre-defined ramp-up of renewable capacities and phase-out of coal plants. In the PtH_2 case further gas turbines of about 10 GW$_{el}$ are required for hydrogen re-electrification to ensure adequate system flexibility. In the $PtCH_4$ case this task is provided directly by natural gas power plants, which can be run with both natural gas and synthetic methane.

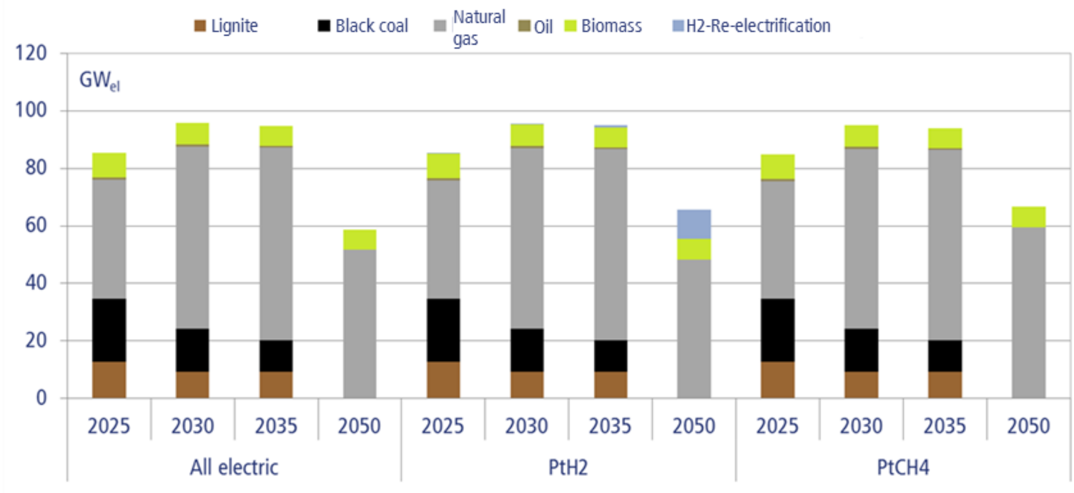


Figure 30: Installed capacity of flexible power plants in the transport sector in GW_{el}

The biomass potential (including the electrification of waste) in this study is considered as limited and the capacity of the associated power plants slightly decreases from 9 GW_{el} to 7 GW_{el} for all use cases also in accordance with the NEP-Electricity 2015B and 2017B. All in all, the capacity of dispatchable power plants rises from 85 GW_{el} in 2025 to 95 GW_{el} in 2030 and 2035 and thereafter decreases to 59-67 GW_{el} until 2050 according to the development of the renewable power plants. The upper limit corresponds to the PtG cases which typically have a larger need for an increase in renewable power plant capacity (caused by the higher electricity demand through higher conversion losses) and hence for system flexibility.

Flexibility options in the energy system

The need for flexibility in the energy system becomes visible in Figure 31 showing the annual flexibility costs. In the "all electric" case, the flexibility costs mostly relate to the annual costs for energy storage (mainly based on corresponding annuities). Although the required storage capacity grows continuously (see Figure 32) the annual storage costs slowly decrease in the medium-term as a consequence from a significant reduction of specific costs for stationary batteries. In the long-term, these cost are more than doubled (from ca. 5 B€/a to almost 13 B€/a). In the PtG case costs for electrolysis and methanation plants are dominating. With growing H_2- and CH_4-fuel demand, additional production capacities must be developed such that the plant costs increase from close to 0.9 B€/a by 2025 to more than 3 B€/a by 2050 in the PtH_2 case, and from 0.9 B€/a in 2025 to 6 B€/a in 2050 in the $PtCH_4$ case. The difference between both PtG cases is due to higher conversion losses of the methanation process and less efficient energy use of CH_4 in internal combustion engines. In both cases the costs for energy storage play only a minor role. The major reason for the cost increase between 2035 and 2050 originates from the growing energy storage demand due to rising renewable electricity supply in view of fulfilling the 2050 climate policy targets.

Also the costs for other flexibility options (DSM, import/export) are rather small and in the same order of magnitude for all use cases. The reduction of these costs between 2025 and 2030 is caused mostly by the pre-defined reduction of electricity imports and in the "all electric" case by falling battery prices.

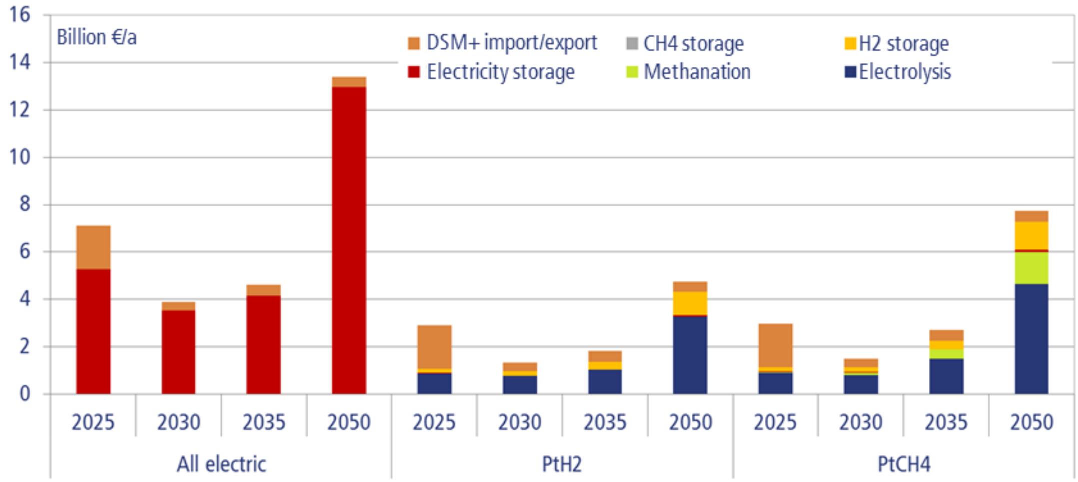


Figure 31: **Annual costs of system flexibility in the energy system in billion €/a in transport sector for the base scenario**

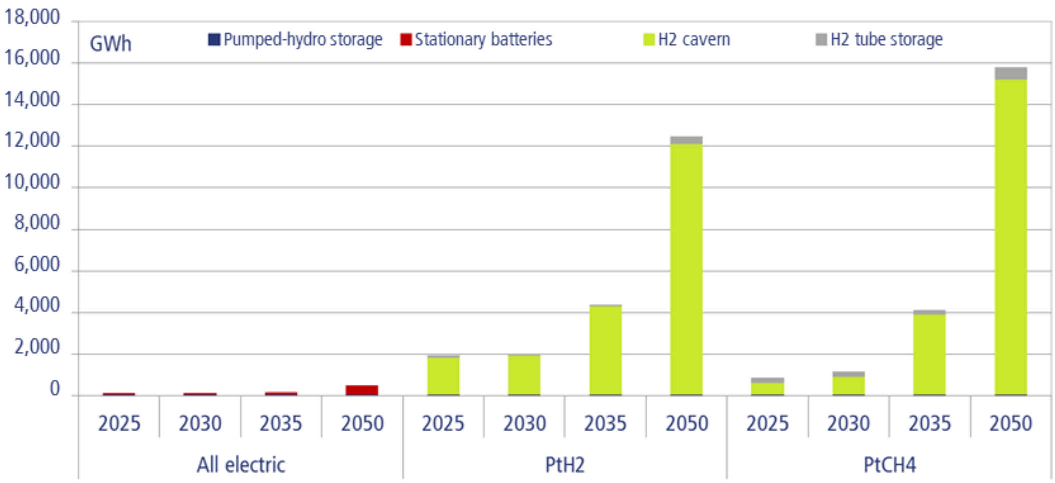


Figure 32: **Storage size in GWh in the transport sector for the base scenario**

Due to expensive stationary battery technology the "all electric" case foresees only small storage capacities of 93 GWh_{el} in 2025 to 460 GWh_{el} in 2050. In the PtG case large-scale hydrogen storage capacities (mainly salt caverns) of 0.8-1.9 TWh_{H2} by 2025 and 12-

16 TWh_{H2} by 2050 are built due to the very low specific storage costs. For all use cases also pumped-hydro storage capacities of 50 GWh_{el} are available.

For all cases various storage technologies are combined in capacity and operating mode to minimise system costs. As an example, in the PtH_2 case energy is not only stored in salt caverns but also in H_2 tube storage systems and in 2050 furthermore in additional stationary batteries. While salt caverns are used for storing energy on a seasonal basis to balance long-term fluctuations (with a small number of cycles), H_2 tube storage systems, stationary batteries and pumped-hydro storage facilities serve for balancing short-term fluctuations in the electricity system (with a large number of cycles). In the $PtCH_4$ case the existing CH_4 storages are also used.

Similar to storage capacities the curtailment of intermittent power supply increases with growing renewable capacities. In the "all electric" cases the curtailment becomes specifically pronounced due to the smallest storage capacities. Accordingly, the level of curtailment increases from close to 5 TWh_{el} in 2025 to almost 20 TWh_{el} by 2050. In the PtH_2 cases this quantity is much lower at ca. 4 TWh_{el} by 2025 to 12 TWh_{el} by 2050. In the $PtCH_4$ case the level of curtailment of 5 TWh_{el} by 2025 and 20 TWh_{el} by 2050 is similar to the "all electric case" but it is much lower in the years in-between (however still higher than in the PtH_2 case) due to the different increase of renewable power capacity for the different cases.

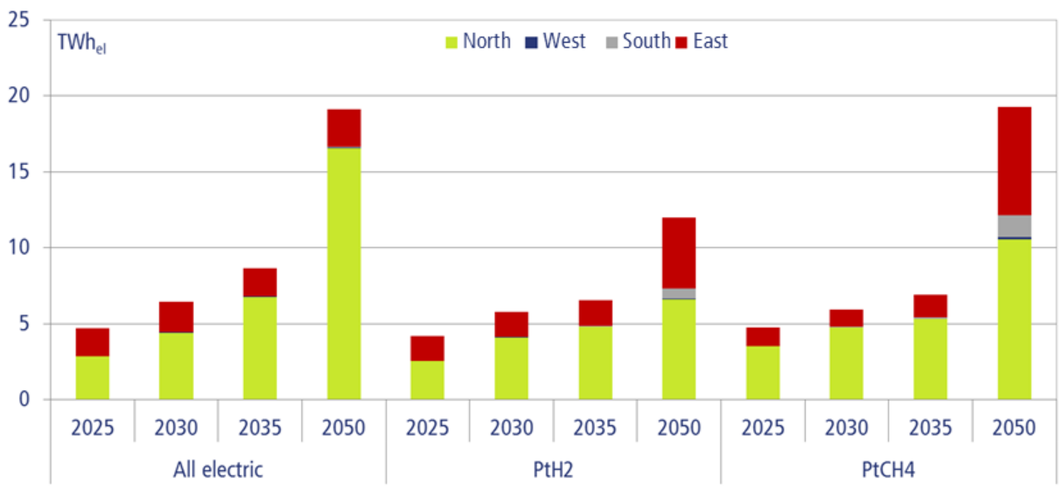


Figure 33: Curtailment of renewable electricity plants in TWh_{el} in the transport sector for the base scenario

The curtailment is mostly related to wind power in the regions North and East and reaches 4% of total electricity produced by renewable power plants. In both PtG cases, curtailment can be observed also in the regions South and West in very few occasions i.e. in hours when additional renewable power supply from both regions (e.g. PV electricity from the South) required for H_2 or CH_4 production in the region North surpasses the West/North and South/North grid capacities. In such situations the electricity demand for electrolysis can be reduced or additional power plants in the North can increase their production in the context of redispatch.

As explained in the previous chapter, electrolysers are not only used for the production of hydrogen as a vehicle fuel but also to provide system flexibility as the potential of other flexibility options is limited this study. For this reason the installed electrolyser capacity is large and its utilisation with less than 2,500 full load hours rather poor (see Figure 34). Yet, this is only an average number and individual plants can operate at higher utilisation rates. The difference between PtH_2- and $PtCH_4$ cases results from conversion losses of the methanation plant as well as from the lower efficiency of internal combustion engines and hence a higher hydrogen consumption in the case of $PtCH_4$.

In contrast, methanation plans in the $PtCH_4$ cases are typically much better utilised with up to 5,000 full load hours due to the use of H_2 buffer storage (see Figure 35). This utilisation again represents only an average value and individual plants can have higher utilisation rates. Accordingly, methanation plants have clearly smaller capacities of 0.5 GW_{H2} by 2025 and almost 28 GW_{H2} by 2050. The capacity development over time follows again the CH_4 demand from the transport sector. Furthermore, the decreasing electrolyser utilisation in the $PtCH_4$ case between 2035 and 2050 can be attributed to the more than proportional increase of renewable electricity production in this case (partly a result of higher conversion losses in the $PtCH_4$ case). As other flexibility options are limited in 2050 electrolysers are increasingly used as a flexible load hence leading to their lower utilisation.

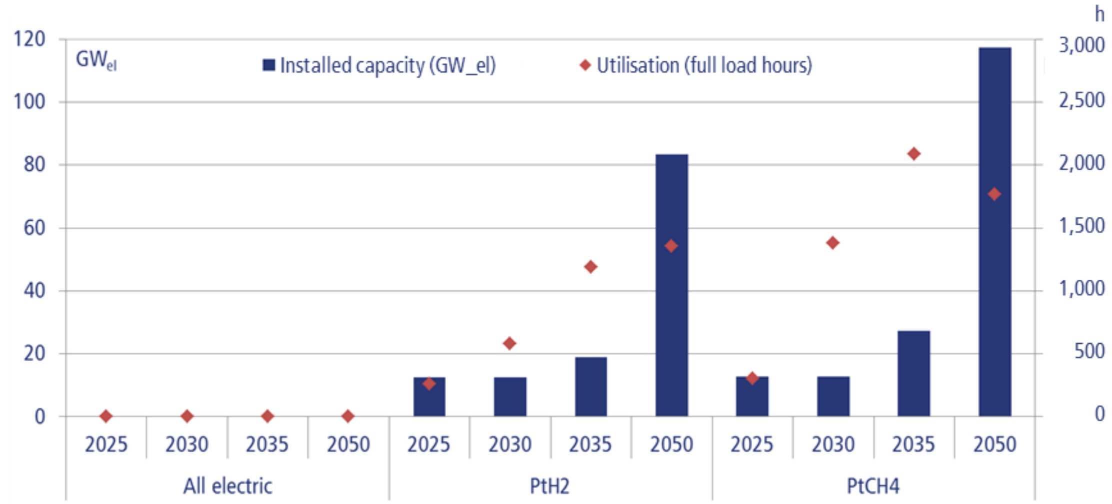


Figure 34: Installed electrolyser power of in GW_{el} in the transport sector for the base scenario

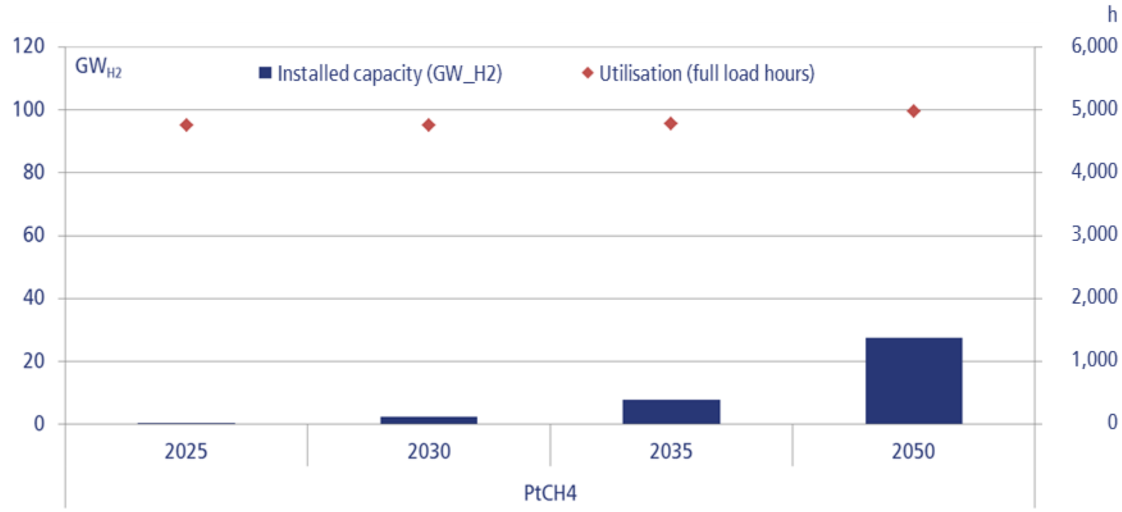


Figure 35: **Installed capacity in GW_{H2} and utilisation of the methanation plant in full load hours for the transport sector in the base scenario**

Energy transport

The modelling results for the energy transport in the transport sector correspond to the explanations from the previous chapter. As summarised in Figure 36 electricity is the major energy carrier in the underlying system (ca. 160 TWh_{el} in 2025 and 140-150 TWh_{el} in 2050). The variation in electricity transport between the four regional nodes is due to different capacities of fossil and renewable power plants as well as the differences in their regional distribution. Hence the electricity transport grows in the short-term until 2030 and decreases thereafter with rising renewable production indicating an improving regional congruency between power supply and demand. Energy transport of hydrogen and synthetic methane play a minor role in the energy system in the medium-term until 2035 (up to 12 TWh_{H2} or 25 TWh_{CH4}). The growing number of zero-emission vehicles improves the contribution of hydrogen and synthetic methane as a universal energy carrier (59 TWh_{H2} and 91 TWh_{CH4} by 2050, respectively).

Figure 37 depicts the electricity trade balance between the four regions for the different cases. According to this graph, electricity is mostly transported from the wind-rich regions North and East into the regions West and South. The distribution of the trade balances to the four regions remains identical for all time steps. As shown in Figure 38 the existing grid capcities together with the gird enchancment as projected by NEP-Electricity2017B are sufficient for most cases. Only in the "all electric" case in 2050 a HVDC connection is needed from North to South, comprising a total capacity of 14 GW_{el} (i.e. 10 GW_{el} beyond the NEP-Electricity 2017B) as well as a connection from North to West of 10 GW_{el} (i.e. 8 GW_{el} beyond the NEP-Electricity 2017B). Note that the electricity transport relates to all transport capacities including highest and high voltage AC grid and not only the additional HVDC connections in Figure 38.

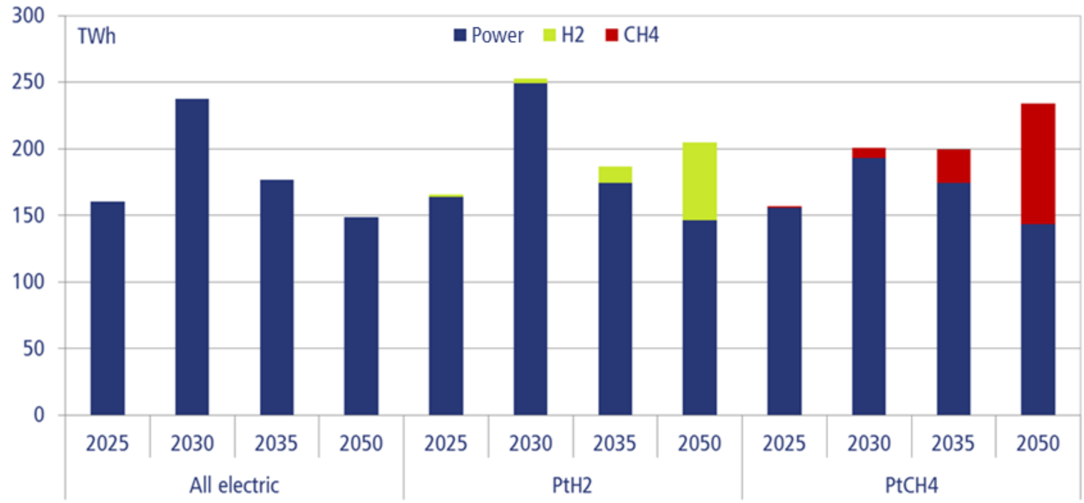


Figure 36: **Energy transmission between the regions according to energy carrier in TWh for transport sector in the base scenario**

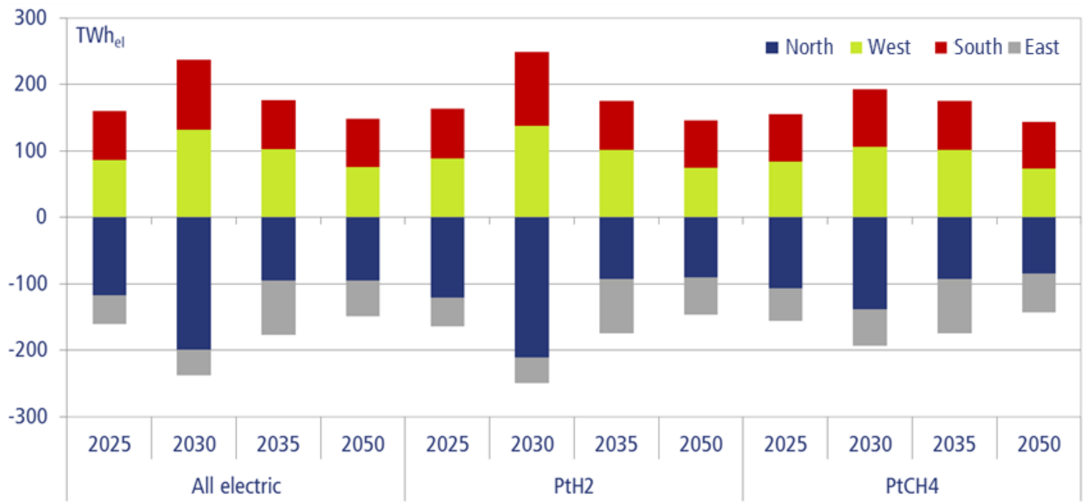


Figure 37: **Trade balance between the regions (Inflow = positive / outflow = negative) in TWh_{el} for the transport sector in the base scenario**

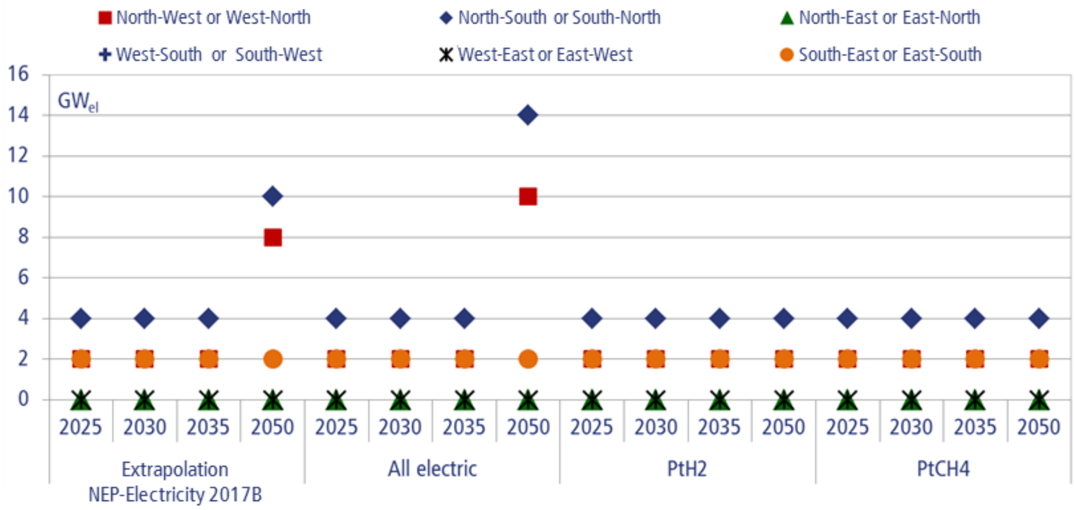


Figure 38: **Required transport grid extension (HVDC connections) in GW$_{el}$ for the transport sector in the base scenario (data for extrapolation of the NEP-Electricity 2017B in 2050 are modelling results)**

Figure 39 shows the inter-regional trade balances for the gases hydrogen and synthetic methane. As the entire electrolysis and methanation capacities are located in the region North both hydrogen and synthetic methane are transported to the other regions from the region North according to the corresponding demand. As for electricity, the regional and temporal distribution between the regions West, South and East remains unchanged for all time steps.

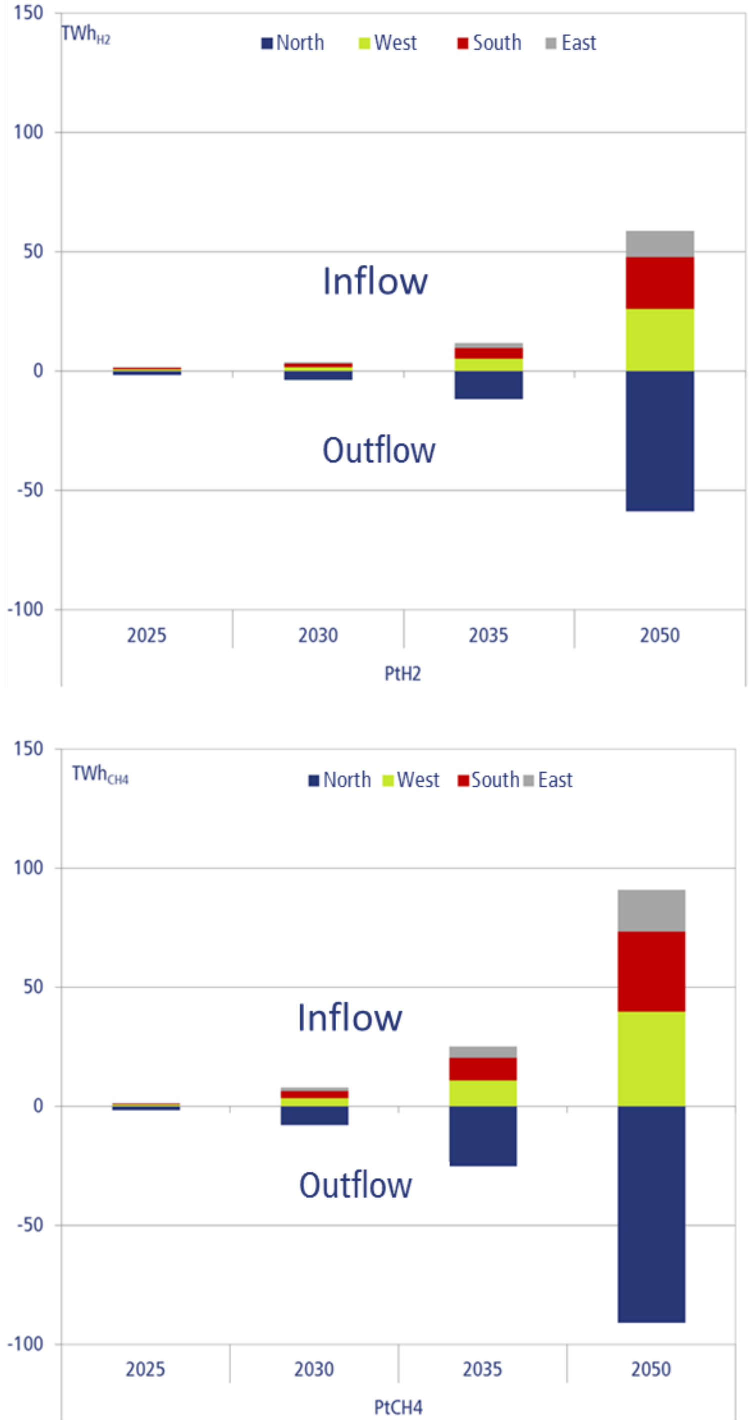


Figure 39: **Balance of the H_2- and CH_4 transport (top and bottom, respectively) between the four regions in TWh_{H2} and TWh_{CH4} for the transport sector in the base scenario**

In general, the value of the PtG technology for providing flexibility is overstated and the corresponding costs underestimated by concentrating the electrolysis plant capacity in the region North. As salt caverns for cheap underground hydrogen storage only exist in the North the distribution of electrolysis plants to all other regions would pose a challenge for utilising the salt caverns as a gas storage. As a consequence, electrolysis in the regions West, South and East would be either disconnected from salt cavern necessitating the use of expansive H_2 tube storage or energy transport via H_2 pipelines to the salt caverns in the region North would become necessary. Both cases would result in higher costs (more expensive storage or additional hydrogen pipelines) which however are not included in our model. The focus on the region North for placing the PtG plants is mostly justified by the fact that the salt caverns represent a cheap and thus an important storage option, however, being limited to northern Germany for geological reasons.

This limitation is also due to the modelling approach as the decision for storage investments and operation is based on the copperplate assumption in the first modelling step (i.e. unlimited energy transport capacity). In the consecutive second modelling step, the regional distribution of electrolysis, storage and power plant capacities as well as the optimisation of energy transport.

The need for transport capacities und their utilisation for hydrogen and synthetic methane follows the associated trade balances (see Figure 40 and Figure 41). The major pipelines in respect to transport capacity and transported energy amounts, are the North-West and North-South connections: ca. 17 GW_{H2} or 23-27 TWh_{H2}/a as well as 8-9 GW_{CH4} or 34-40 TWh_{CH4}/a by 2050. The North-East pipeline is smaller by 50% and also transports half the energy. In general, the CH_4-pipelines are better utilised than the H_2-pipelines. For more details on H_2 and CH_4 transport see explanations in the previous chapter.

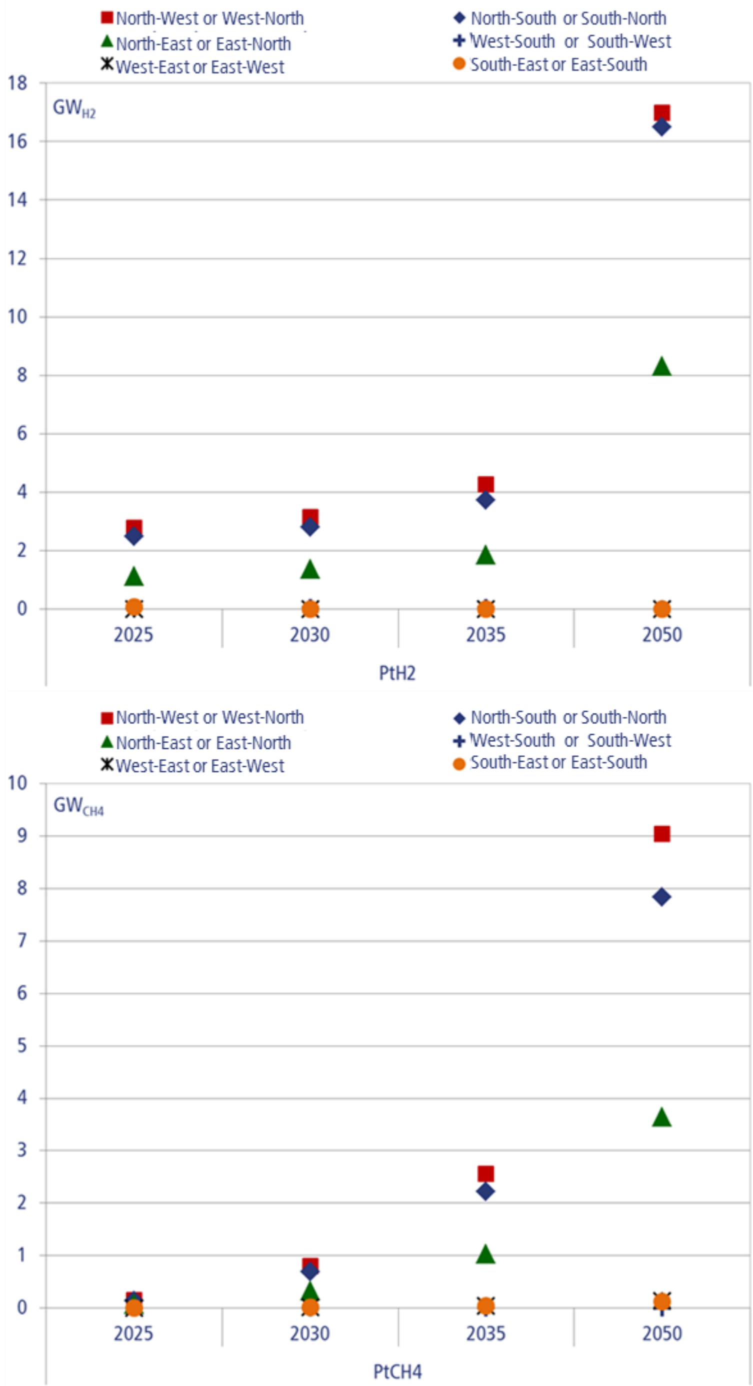


Figure 40: Necessary capacities for H_2- and CH_4 pipelines (top and bottom, respectively) in GW_{H2} or GW_{CH4} for the transport sector in the base scenario

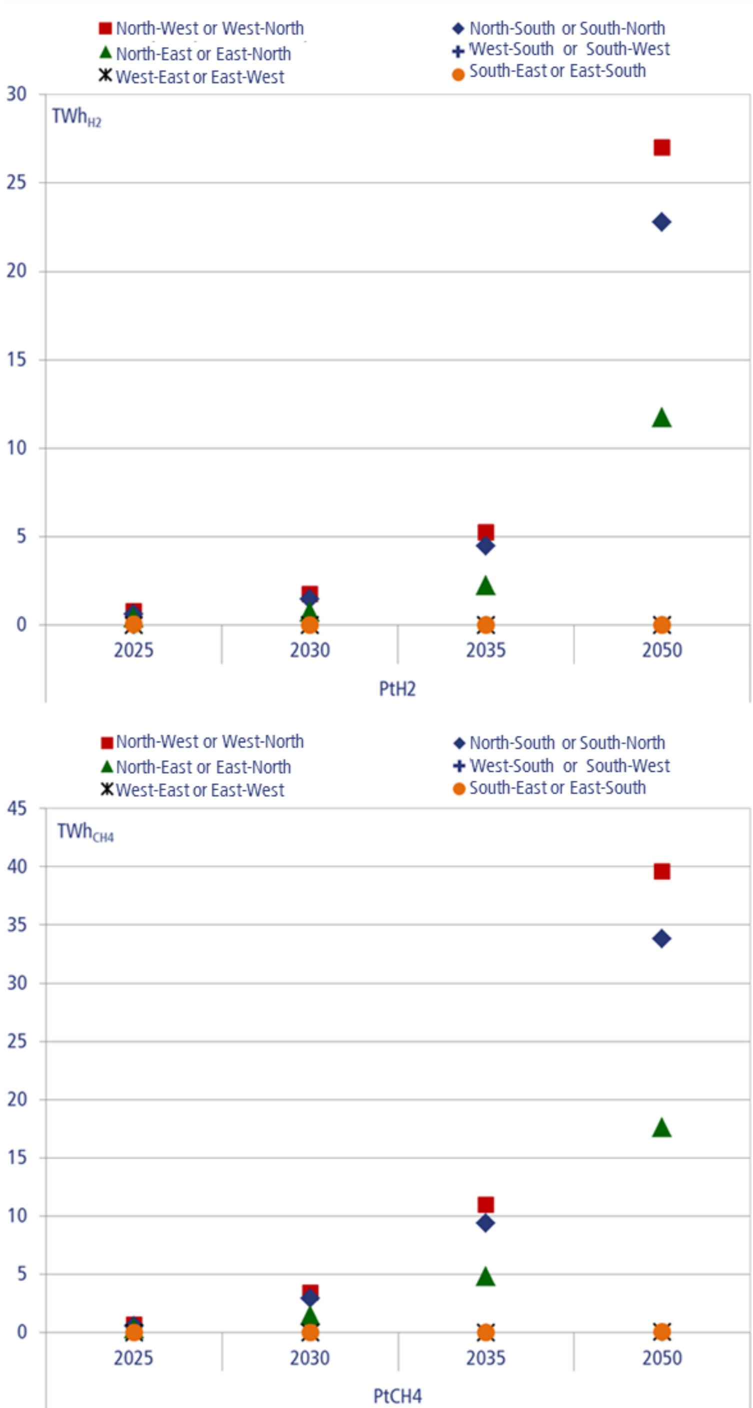


Figure 41: Necessary energy transmission for H_2- and CH_4 pipelines (top and bottom, respectively) in TWh_{H2} or TWh_{CH4} for the transport sector in the base scenario

4.1.3 Secondary infrastructure and end-use applications in the reference scenario

As explained in the previous chapter, costs related to end-user application are a relevant element of the total cost of the various use cases. Figure 42 shows annual costs for the respective secondary infrastructure and end-user applications in each sector. For the transport sector it includes the costs only for zero-emission vehicles as well as the corresponding refuelling infrastructure and in the heating sector for the heating systems.

The highest costs occur in the transport sector, increasing from 1.4-1.6 B€/a. in 2020 to 82-91 B€/a in 2050 with the largest contribution by the vehicles (at least 85%) in all time steps. In contrast from the economic perspective, the infrastructure required for refuelling or re-charging plays only a minor. In comparison to other propulsion systems, $PtCH_4$ in the transport sector offers the lowest cost since the corresponding vehicles and refuelling stations are about 9% cheaper than other technologies. However, CNG-vehicles have the disadvantage of lower fuel conversion efficiencies and hence of larger need for and cost from renewable energy production.

The highest end-user costs occur for BEVs in the “all electric” case. While BEV vehicle costs are similar in comparison to FCEV and CNG vehicles in the long-term, the charging infrastructure for BEVs is significantly more expensive than the refuelling infrastructure for H_2 and CH_4. This is mainly driven by the cost for wall boxes for charging at home, which are rather cheap on per-unit basis but are required in large quantities (0,85 wall boxes per vehicle; see section 3.3). In contrast, refuelling stations for H_2 or CH_4 are rather expensive on per-unit basis but able to serve a large number of vehicles at the same time period due to the shorter refuelling times. At this point it is important to mention that this cost analysis does not yet include any additional investments in distribution grid enhancement (wires, transformer, and stationary storage facilities). In the medium- and long-term these grid enhancement costs may be significantly higher than the costs for hydrogen refuelling infrastructure.

Costs associated with heating applications, 3-4 B€/a in 2020 and 13-17 B€/a in 2050, are well below those in the transport sector. In this context, electric heat pumps are more expensive than the H_2 or CH_4 heating systems. The significant cost premium of hydrogen-based heating systems compared to CH_4 will reduce to a moderate difference in the medium- to long-term.

In the industry case we neglect costs related to end-user applications as hydrogen produced by electrolysis is considered as desired final product.

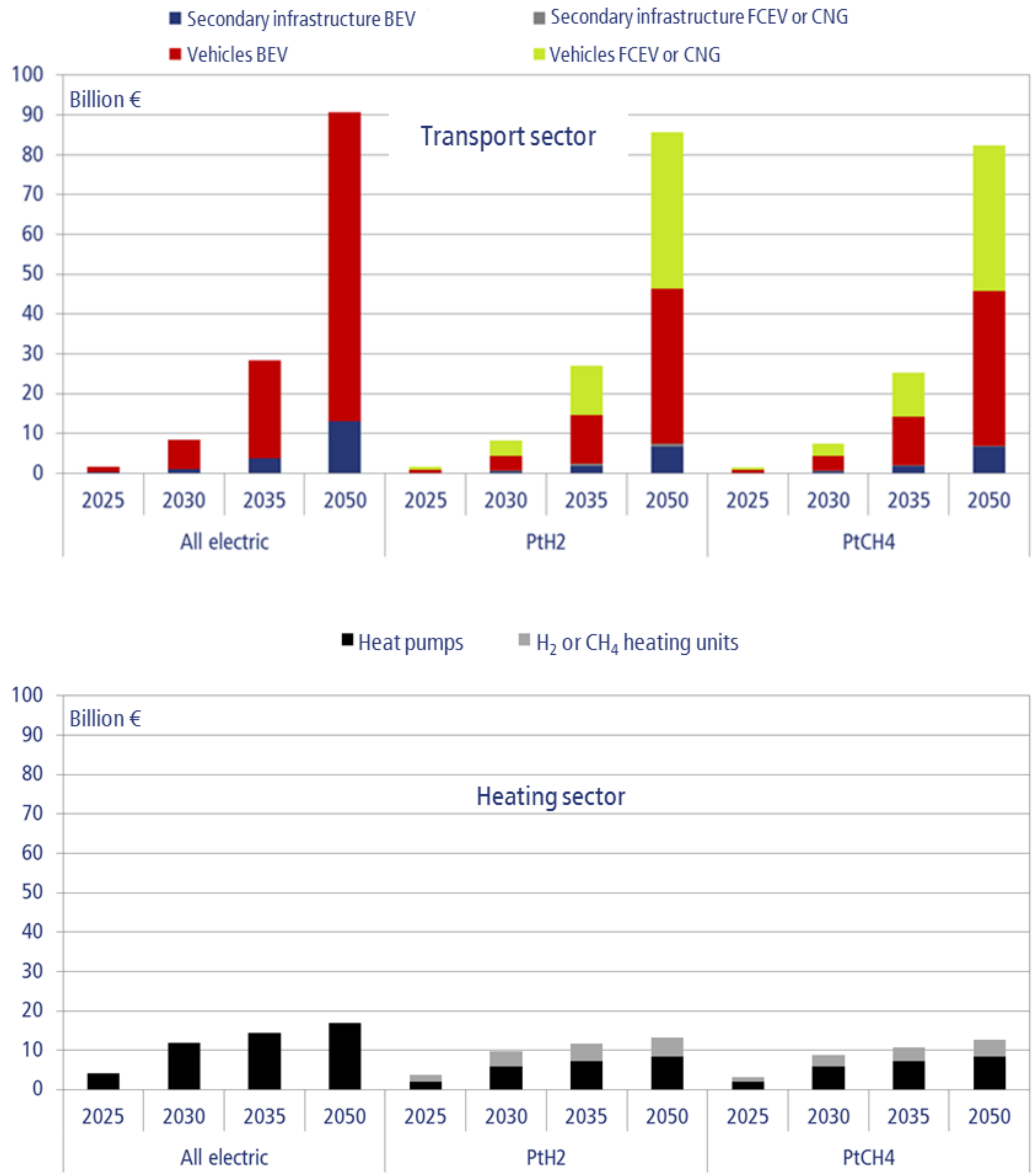


Figure 42: **Annual cost for secondary infrastructure and end-user applications in billion €/a in transport (top) and heating sector (bottom) in the base scenario for the transport sector (top) and heating sector (bottom)**

The building of the H_2 and CH_4-refuelling infrastructure has been modelled with the tool H2INVEST developed by LBST. Starting from a given number of zero-emission vehicles, in a first step their regional distribution to German counties is determined. The evolution of the fleet in space and time is simulated based on national and regional statistical data including regional vehicle penetration, population density, and purchasing power. The tool takes into account past developments in each county as well as in neighbouring counties, since refuelling infrastructure improvements nearby may impact adoption rates in the target region. Refuelling stations for long-distance transport on highways are also accounted for based on traffic densities at German highways. In a second step, the distribution of a predefined number of refuelling stations is optimised by minimising the average distance to the next refuelling station for all users, assuming an equal distribution within each country using a simplified geometry.

The resulting deployment and utilisation of H_2 refuelling stations shows that in the base scenario until 2025 only small and medium-size refuelling stations are added. Larger refuelling stations will only be built after 2025, when a larger FCEV fleet will need to be served. The number of refuelling stations increases by a factor of 10 from 600 in 2025 up to 6,000 in 2050. Thereof depending on the time step, 95 to 355 stations will be located along highways, serving long-distance travel between metropolitan regions. Initially, station deployment will focus on these metropolitan regions, gradually expanding into the more rural areas. In general, the refuelling infrastructure deployment depends on the vehicle market development; however, it runs ahead of the actual vehicle ramp-up. As a result, in the short- to medium-term the utilisation is below 50%, but increases to above 70% in the long term when additional demand can be absorbed by an increased station utilisation avoiding the development of new sites.

Deployment for CH_4 refuelling stations evolves similar to that of H_2. In an initial phase until 2030, the number of refuelling stations remains rather stable with 1,000-1,250 stations, based on the fact that existing 900 CNG stations already provide a decent coverage. After 2030, like in the PtH_2 case, the number of stations shows a stronger increase. This also holds for the stations along highways. Station utilisation gradually increases from an initial level above 50% (i.e. higher than initially for PtH_2) to above 70%.

The BEV charging infrastructure is expected to have a major impact on the power distribution network. However, this has not yet been analysed for a long term perspective with high BEV penetration rates. A limited literature review provides following semi-quantitative insights:

- Essentially all available literature analysing the effects of BEVs on the distribution grid limit themselves to BEV penetration rates of not more than 20%, well below the 50% to 100% shares considered in this study[9]. Generally, the results from the corresponding analyses reveal that the current grid is able to cope with lower BEV penetration rates, however assuming adequate load management for BEV charging. However, when

[9] The dena *Leitstudie Integrierte Energiewende* published in June 2018 after finalising this study includes a scenario with high BEV penetration (>20%) and identifies an overall investment need of ~150B€ for the low voltage distribution grid; see https://www.dena.de/themen-projekte/projekte/energiesysteme/dena-leitstudie-integrierte-energiewende/

allowing users to, Cost-optimised charging from the end-user perspective (i.e. i.e. charge when electricity prices are low) results in grid congestion already at BEV penetration rates of 10-20% due to high simultaneity factor of power demand within the distribution grid.

- The resulting investment needs within the distribution grid strongly depend on the respective scenario and underlying assumptions. The few available results exhibit a large bandwidth (e.g. 21-42 € additional grid enhancement cost per BEV for a 2,5% share [LBD 2012], ca. 200 € per BEV in [Probst 2014] for up to 12,5% BEV penetration, 530- 3200 € distribution grid investment per BEV depending on charging power [Eckhardt 2011] at up to 12,5% BEV share or 200 € (with smart charging) to 1000 EUR per BEV in [EC 2013] based on analyses of Électricité Réseau Distribution France)
- The literature review does not identify any analyses for a BEV penetration rates above 20% dealing with consequences from the integration of user-friendly charging infrastructure into distribution grid. In November 2017 Ludwig-Bölkow-Stiftung started a study supported by ADAC-Stiftung, analysis the impact of BEV charging together with the electric heat pumps on the distribution network.

4.2 Results from other scenarios

Results for the other scenarios "Fast energy transition" and "Focus PtG" are presented in the following chapter. Compared to the base scenario, these build on more ambitious greenhouse gas (GHG) reduction targets (95% GHG reduction from the 1990 baseline in the power sector until 2050 vs. 80% in the base scenario) and on lower PtG technology costs (20% less than in the base scenario) – see also section 3.1. The more ambitious GHG reduction goals reflect in a stronger expansion of renewable energy generation to satisfy the higher demand as well as in a larger penetration of end-user applications in the respective sectors (i.e. more zero-emission vehicles, heat pumps etc. than ion the base scenario). All scenarios differ in their respective potential for other flexibility options like demand side management, , curtailment, redispatch, and import/export, the latter having e.g. a large potential in the "Fast energy transition" scenario compared to a small potential in the "Focus PtG" scenario. The most relevant effects and mechanisms have already been described in the previous chapter. In the following, we will in particular focus on the differences between the two scenarios and with the base scenario. Using the transport sector in the "Focus PtG" scenario as an example, we will take a look at some details within the results.

4.2.1 Comparison of PtG application cases in scenarios „Fast energy transition" and „Focus PtG"

The comparison of cumulated total costs until 2050 in Figure 43 shows that the ambitious climate protection goals in both the „Fast energy transition" and „Focus PtG" scenario lead to higher total costs compared to the base scenario in all sectors and for all applications. As already discussed, in these scenarios the necessary addition of renewable energy generation capacity along with the corresponding requirement for higher generation flexibility leads to increased energy costs (including energy transport). Both scenarios also include a higher number of zero-emission vehicles and heating systems (heat pumps as well as H_2 and CH_4 heating appliances), also renderig end-user application costs higher.

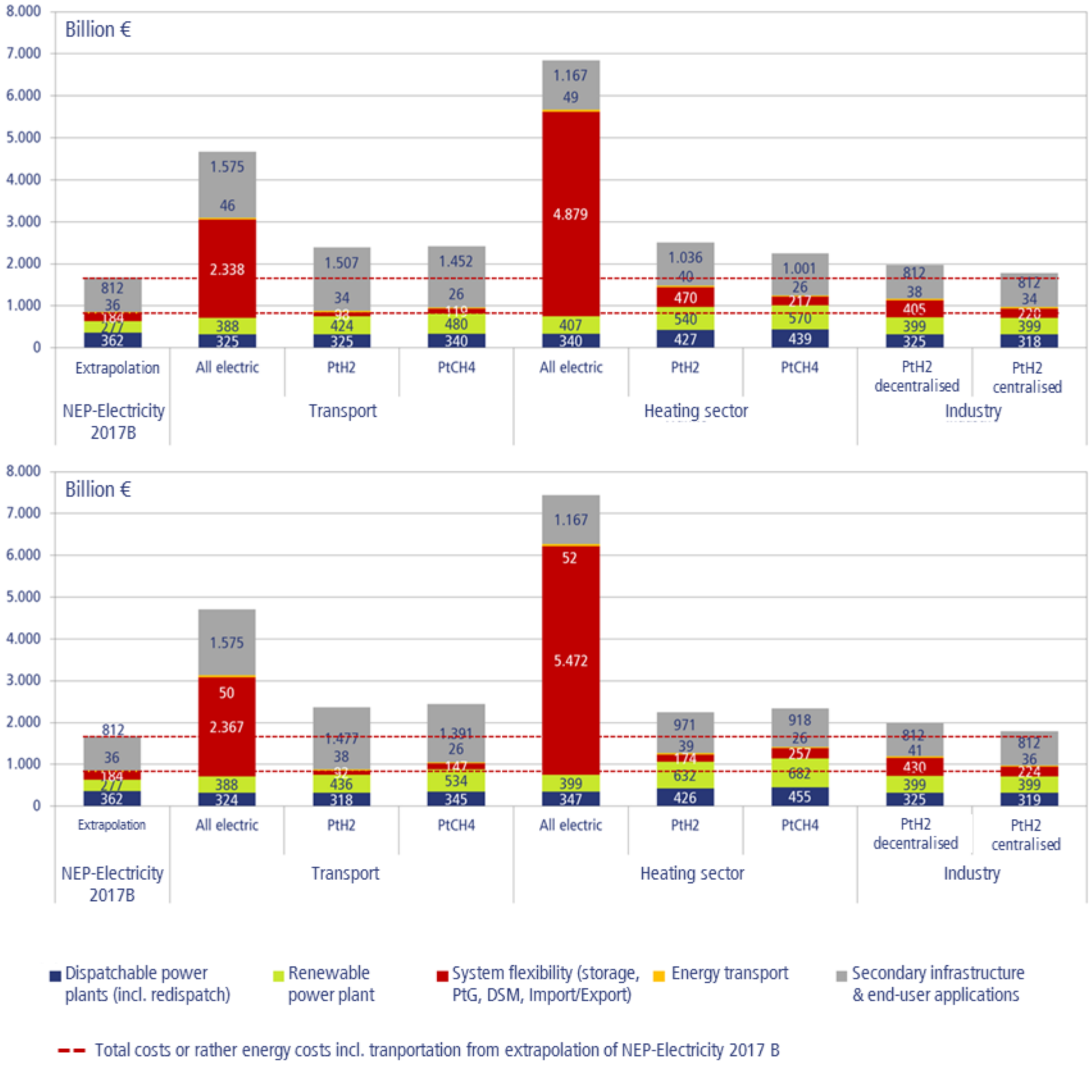


Figure 43: Cumulated total cost in billion € until 2050 in scenario „Fast energy transition" (top) and „Focus PtG" (buttom)

Particularly noteworthy is the cost increase in the "all electric" case, which exhibits a 2x and 4x higher cost in the transport and heating sectors, respectively, compared to the base scenario, primarily driven by the required efforts to provide flexibility. The 95%

greenhouse gas emission reduction goal (compared to the 1990 baseline) calls for a high share of renewables in power generation. As a result, the required flexibility in the energy system necessitates significant large-scale seasonal storage capacity at levels well above those in the base scenario. The high specific cost of stationary batteries, which are the main flexibility option in the „Fast energy transition" and the „Focus PtG" scenario, leads to high electricity storage costs for the "all electric" case in both scenarios. In the context of seasonal energy storage, PtH_2 and $PtCH_4$ technology is significantly cheaper on per-MWh basis than batteries (in the „Fast energy transition" and „Focus PtG" scenarios it is by definition even cheaper than in the base scenario). Therefore the costs for system flexibility are significantly lower in both PtG cases than in the "all electric" case.

Overall, cumulated total costs for both PtG applications are at a similar level of 1,800 B€ and 2,500 B€. According to the different seasonal energy storage requirement within each sector the total costs in the "all electric" case amount to ca. 4,700 B€ in the transport sector and 6,000 B€ to 7,400 B€ in the heating sector (the upper value corresponds to scenario "Focus PtG" due to limited potential of other system flexibility options such as demand side management, curtailment, etc.). PtG-technology hence offers 50% lower costs in the transport sector and 70% lower cost in the heating sector compared to the strict "all electric" world. This clearly shows that using batteries for seasonal storage is prohibitively expensive and that PtG technologies are an essential element of an ambitious energy transition.

For the PtG cases the total cost essentially consist of the same elements as in the base scenario with a dominant contribution of the cumulated costs from end-user applications until 2050. Only the "all electric" cases in the „Fast energy transition" and „Focus PtG" scenario are different, where costs for generation flexibility are dominant in the transport and heating sector due the high cost of stationary batteries. Like in the base scenario, energy transport costs only play a minor role. The ex-post analysis of gas grid maintenance costs shows that, these do not fundamentally change the picture. They are, however, higher than in the base scenario. Cumulated costs amount to 3-10 B€ in the „Fast energy transition" scenario and 4-12 B€ in the „Focus PtG" scenario.

Interestingly, PtH_2 appears more attractive in the „Focus PtG" scenario. On the one hand energy cost is higher due to the higher demand caused (75% instead of 50% of the end-user applications are covered by PtG with lower efficiency) and additional limitation of other system flexibility options. On the other hand PtG end-user applications with the required infrastructure are cheaper than purely electric applications. For PtH_2 the latter advantages outweigh the higher energy cost.

Based on total costs, using PtH_2 is the best option in the industry sector (in both scenarios) and in the heating sector (in the "Focus PtG" scenario). The difference between the heating and transport sector is rather small, since the disadvantageous seasonality of heating demand largely balances the low cost advantage of heating appliances (compared to no pronounced seasonality in transport but higher end-user application costs). Like in the base scenario, based on energy costs including energy transport PtG technology has particular advantages in the industry and transport sectors. However, due to the more ambitions GHG reduction goals, the resulting energy cost and total costs are higher than the corresponding values from the extrapolation of NEP-Electricity 2017B.

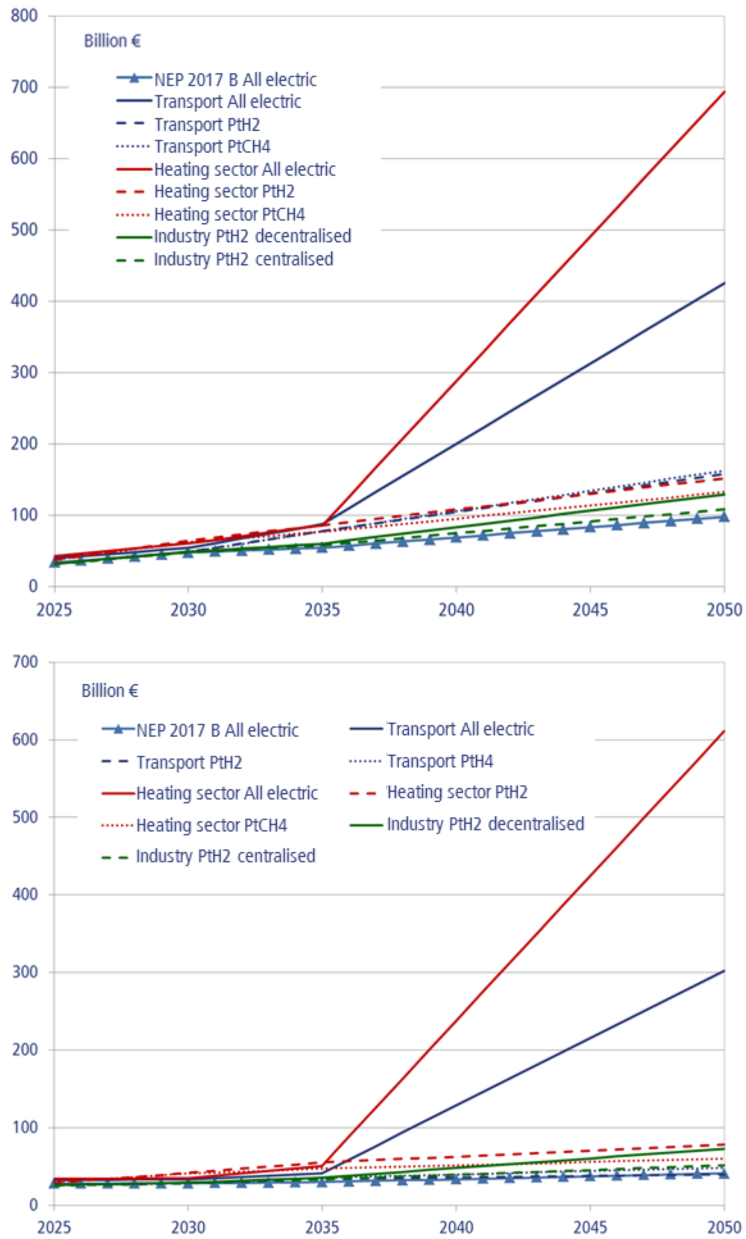


Figure 44: Annual total costs (top) and energy cost incl. energy transport (bottom) in billion € until 2050 in the "Fast energy transition" scenario

Figure 44 and Figure 45 show annual costs by application and sector for both scenarios. It can be clearly seen that beyond 2035 "all electric" costs (total costs and energy costs including energy transport) in the transport and heating sector are significantly higher than for the other cases.

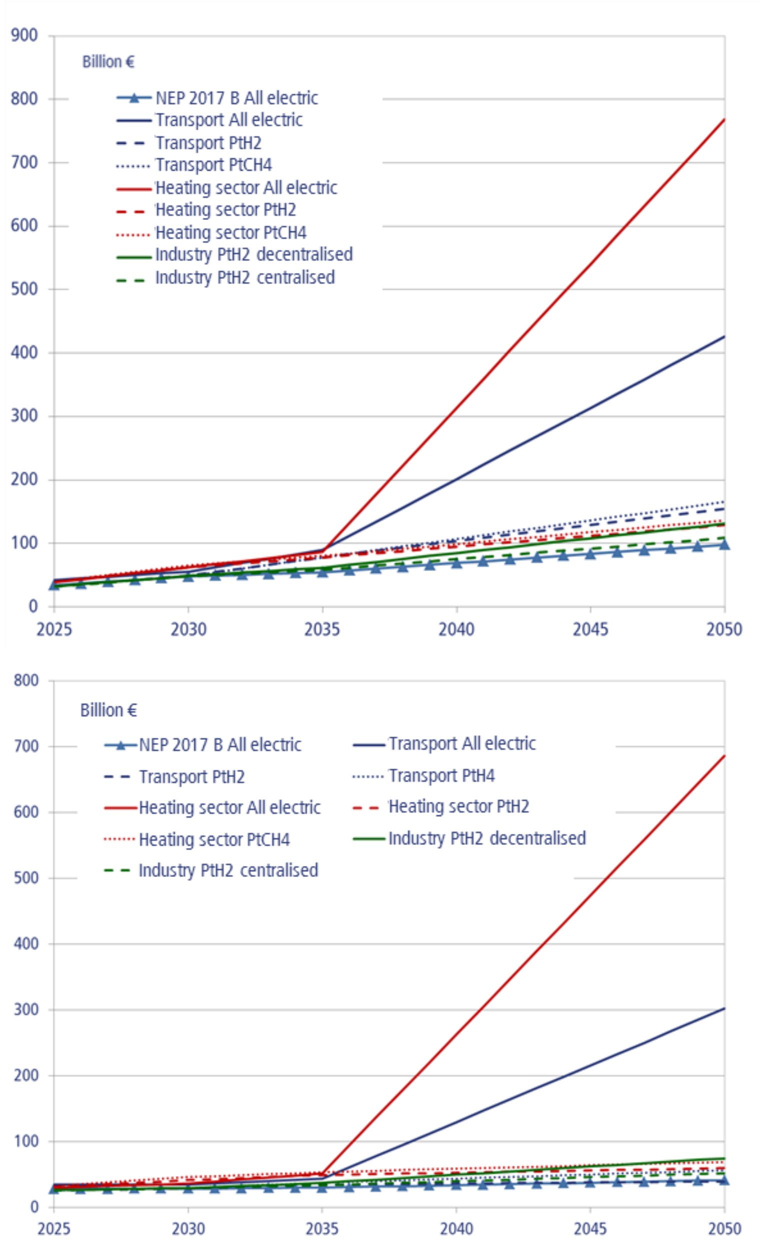


Figure 45: Annual total costs (top) and energy cost incl. transport (bottom) in billion € until 2050 in the "Focus PtG" scenario

Figure 46 shows that cumulated greenhouse gas (GHG) emission reductions do not differ between both scenarios. By definition, overall GHG reductions of 8-9 Bt_{CO2} until 2050 are significantly higher than in the extrapolation of NEP-Electricity 2017B and in the base scenario (ca. 7 Bt_{CO2}). Annual GHG emission savings on average amount to 300 million t_{CO2}. The reduction effect (on average ca. 300 M t_{CO2}/a) is most pronounced in the long-term driven by the massive expansion of renewable energy generation and the associated increased sector integration.

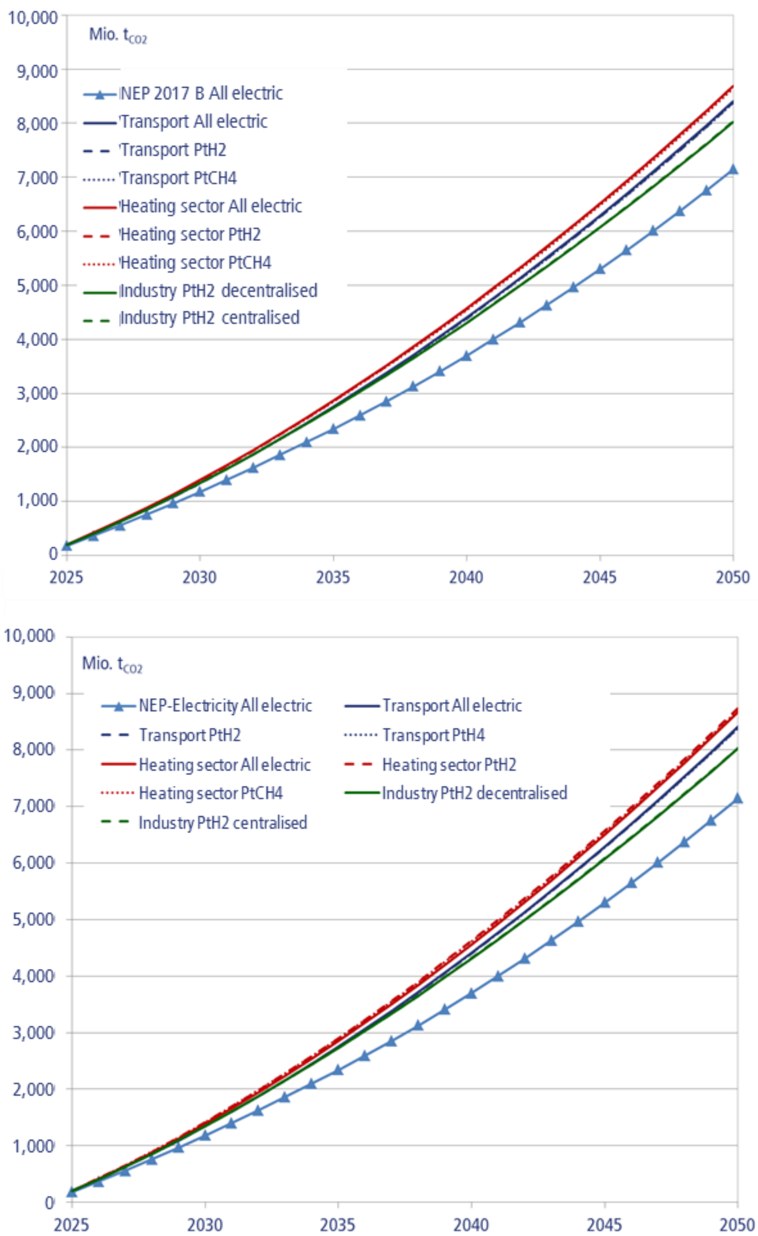


Figure 46: Cumulated GHG emission reduction in Mio.t_{CO2} until 2050 in the "Fast energy transition" scenario (top) and "Focus PtG" scenario (bottom)

Overall, GHG reduction in the heating sector is somewhat higher than for transport, and both are slightly better than the industry sector. Like in the base scenario, this is a result of the varying GHG-intensity of the respective applications, the relative size of the sectors (energy-wise), as well as of the individual penetration rates of the various end-user technologies.

GHG avoidance costs are calculated by dividing absolute cumulated costs by the corresponding amount of GHG emissions saved until 2050 (see Figure 47). In the "Fast energy transition" scenario, GHG avoidance costs range from 220 to 800 €/t_{CO2} and from 220 to 870 €/t_{CO2} in the "Focus PtG" scenario when using total costs as a reference. As discussed before, costs result much higher in the "all electric" case for both the transport and heating sectors. The lowest GHG avoidance costs result for the industry sector like in the base scenario.

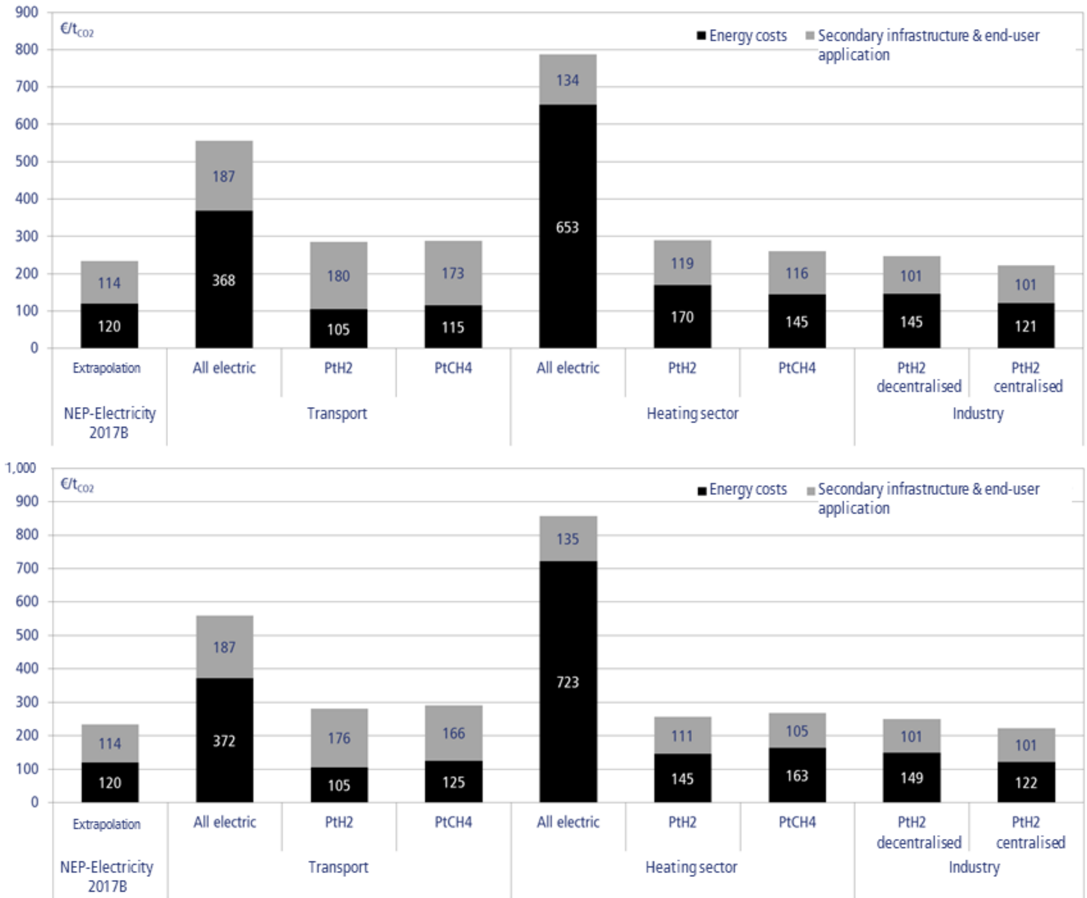


Figure 47: Average GHG avoidance costs in €/t_{CO2} until 2050 in the "Fast energy transition" (top) and the "Focus PtG" (bottom) scenario

On the whole, GHG avoidance costs in both scenarios are higher than in the base scenario and the extrapolation of NEP-Electricity2017B. This is however somewhat compensated by the higher total GHG emission reduction underlying the "Fast energy transition" and the "Focus PtG" scenarios. As a result, GHG avoidance costs for the central PtH_2 case in the industry sector are even lower than from extrapolation of NEP-Electricity 2017B.

Figure 48 shows the expansion in installed electrolyser capacity. Generally, the increased demand for hydrogen or synthetic methane leads to a corresponding installation of electrolysers. This is particularly pronounced in the heating sector, where the demand is driven by more ambitious GHG reduction goals as well as the move towards PtG in both scenarios. As a result, installed electrolyser capacity in the heating sector grows to 149 GW_{el} (PtH_2) and 160 GW_{el} ($PtCH_4$) in the "Fast energy transition" scenario and to 160 GW_{el} (PtH_2) and 209 GW_{el} ($PtCH_4$) in the "Focus PtG" scenario. The generally higher capacity for $PtCH_4$ reflects the higher conversion losses in methanation and end-user applications.

Notably, the electrolyser capacity in transport and industry is not higher than in the base scenario in spite of the increased H_2 or CH_4 demand. This is caused by the strong expansion of renewable power generation driven by the more ambitions GHG reduction goals, leading to a higher and more continuous availability of renewable power as well as an increased number of full load hours and thus more cost-efficient use of the electrolysis.

Electrolysis is a key element of the energy system in both scenarios also providing an essential contribution to the power system flexibility. This is exemplified in the faster expansion of electrolyser capacities in the medium-term (until 2035) compared to the base scenario. Since electrolysis addresses the H_2 and CH_4 demand while at the same time providing system flexibility to balance fluctuating generation, both functions can dominate in one or the other direction depending on the boundary conditions.

The significant increase in renewable energy generation capacity in the "Fast energy transition" and the "Focus PtG" scenarios also leads more HVDC transmission lines in comparison to the base scenario. However, the HVDC transmission line expansion planned in the NEP-Electricity2017B (10 GW transmission capacity by 5 HVDC lines[10]) satisfies the transmission requirements in all scenarios at least until 2030.

[10] Like in the base scenario, the DC1 and DC2 lines in NEP-Electricity 2017B are viewed as two separate lines.

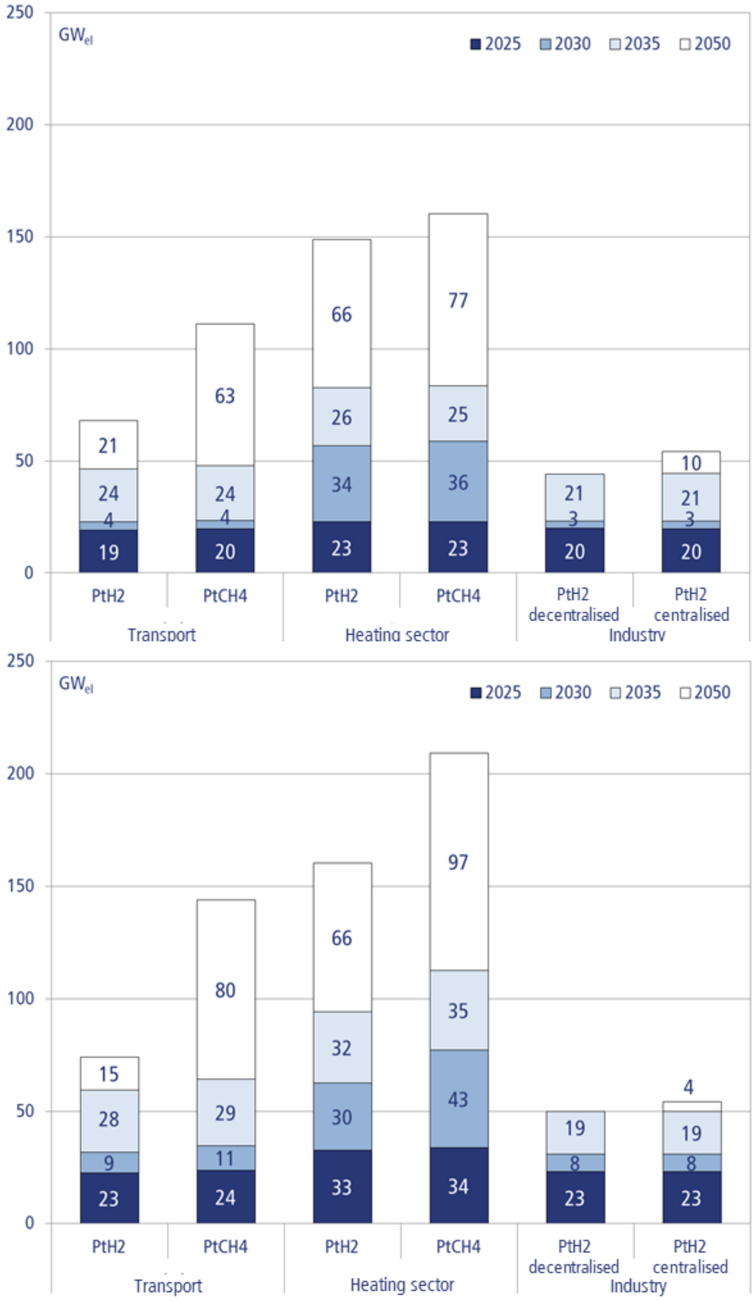


Figure 48: Optimised expansion of electrolyser capacity in GW_{el} until 2050 in the "Fast energy transition" (top) and the "Focus PtG" (bottom) scenario

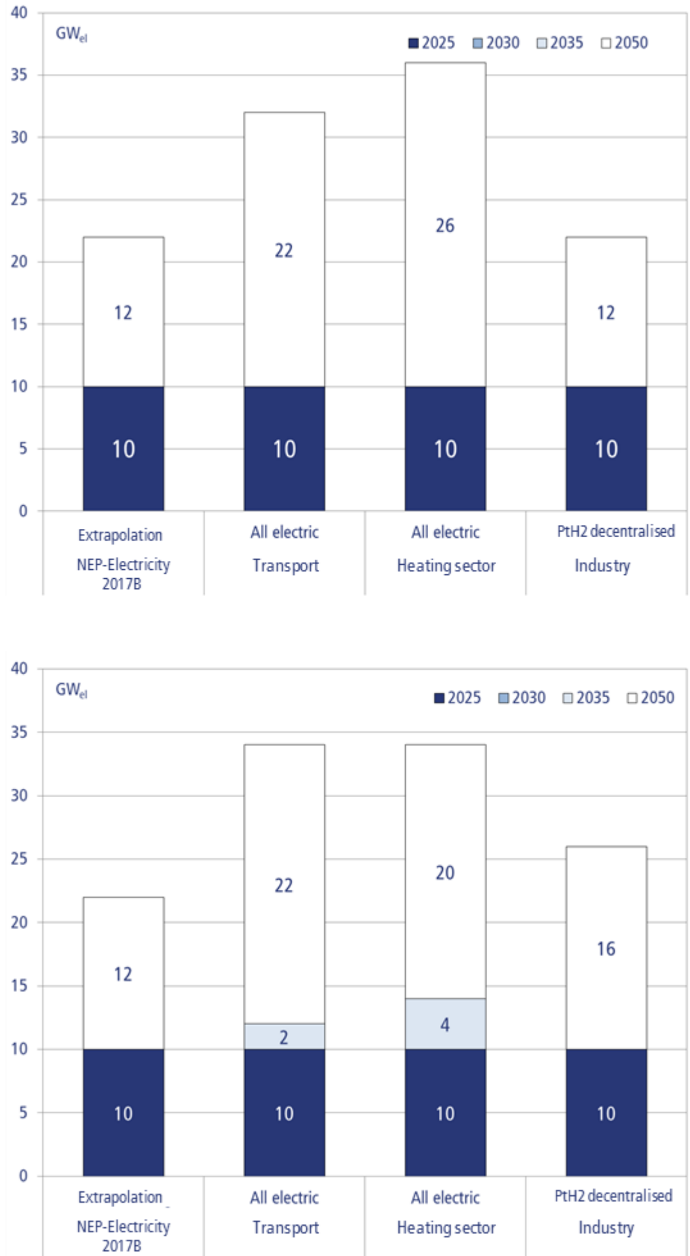


Figure 49: Required extension of HVDC transmission capacity in GW_{el} until 2050 in the "Fast energy transition" (top) and the "Focus PtG" (bottom) scenario

In the „Fast energy transition" scenario a further HVDC line expansion is only needed in 2050, driven most strongly by the heating sector (26 GW, 13 lines), followed by the transport sector (22 GW, 11 lines) and the extrapolation of the NEP-Electricity 2017B (12 GW, 6 lines), since the heating sector requires the largest expansion of renewable generation capacities. The decentralised industry case (12 GW, 6 lines) does not require lines beyond NEP-Electricity2017B but still shows an expansion requirement well above the base scenario. Here, the benefit of flexible electrolyser operation onsite is overcompensated by the disadvantage of higher energy demand.

The need for an expansion of the HVDC capacity emerges somewhat earlier in the „Focus PtG", scenario, where 2 GW for transport and 4 GW for the heating sector are already required in 2035. On the whole, however, the required capacity extension until 2050 is the same for both sectors. The limitation of other flexibility options in the „Focus PtG" scenario also lead to one additional line (2 GW) in the transport sector compared to the „Fast energy transition" scenario, while the heating sector requires one line less due to the higher battery storage capacities with corresponding flexibilities In this case larger batteries able to absorb generation peak appear to be the better alternative (as other flexibility options are limited by definition).

These relationships also show that results strongly depend on the assumptions on the capacities and distribution of the respective devices for power generation, storage, and consumption. The decentralised industry case requires with 16 GW (2 lines) more HVDC transmission capacity in the „Focus PtG" scenario than in the base scenario and the „Fast energy transition" scenario. Moreover, for a change, both scenarios in all applications also require additional lines beyond NEP-Electricity 2017B in the PtH_2 case: 4 GW each in transport and in the centralised industry case in the „Fast energy transition" scenario, and 4 GW (transport) and 6 GW (centralised industry case) in the „Focus PtG" scenario. The additional capacity serves to transport excess power from PV plants in the South to the electrolysers in the North. However, these lines are not required in the $PtCH_4$ case due to the different availability and geographic location of flexible generation and storage capacities, particularly combined cycle gas turbines and power plants as well as battery storage. Such a seemingly unfavourable regional distribution of power generation and energy flows (with consequential grid expansion requirements) may results, because initial investment decisions in the modelling are taken independent of the grid simulations.

The increasing H_2 und CH_4 demand in the various scenarios leads to a corresponding need for earlier expansion of H_2 und CH_4-transmission capacities (see Figure 50). The PtH_2-case in the „Fast energy transition" scenario (same gas transmission capacities) and the centralised industry case (slightly lower gas transport capacities) in both scenarios are an exception, resulting mainly from the less than proportional expansion of electrolyser plants and the different level of using H_2 for power generation. The need for gas transport capacities is highest in the "Focus PtG" scenario, caused by the inherently larger focus on PtG end-user applications.

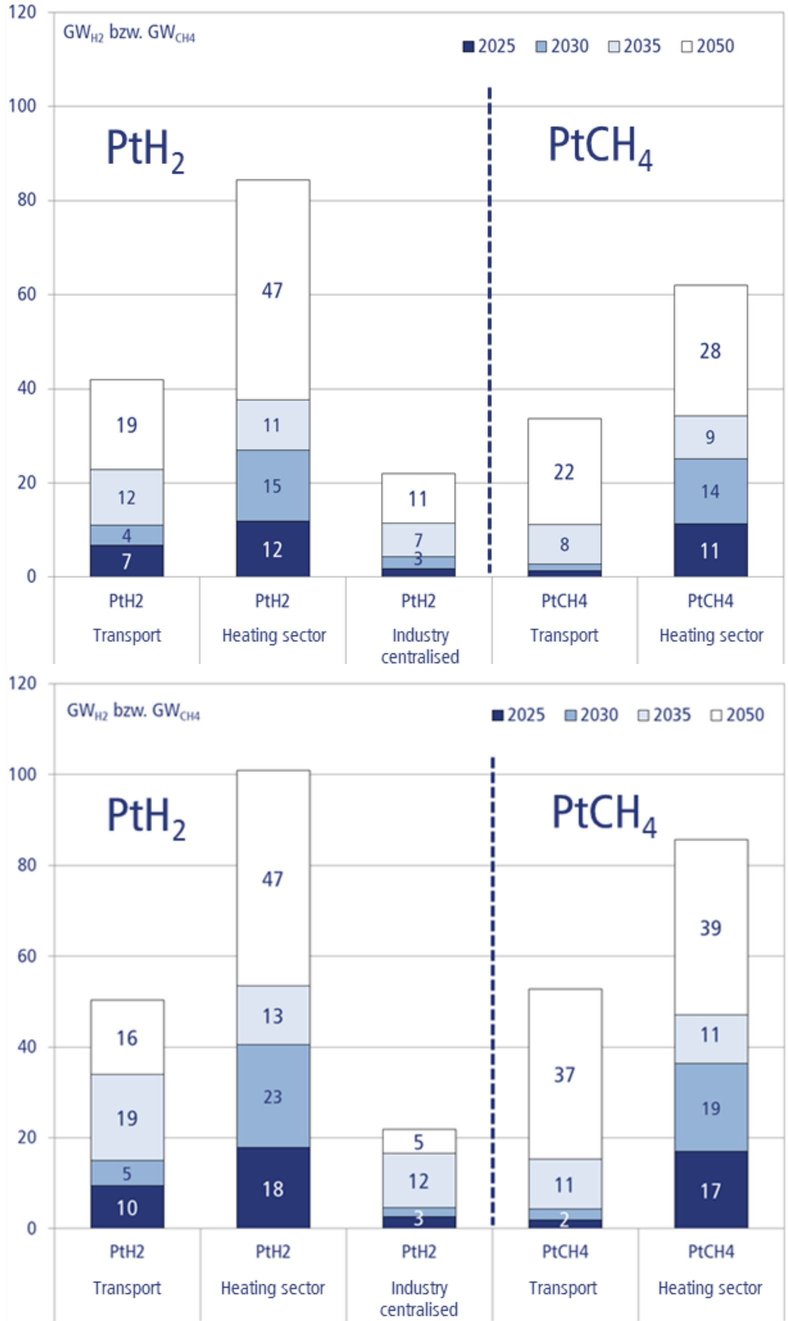


Figure 50: Required gas transmission capacities in GW_{H2} and GW_{CH4} until 2050 in the "Fast energy transition" (top) and the "Focus PtG" (bottom) scenario

Overall, required hydrogen transport capacities range from 22 GW_{H2} (centralised industry case, both scenarios) to 100 GW_{H2} (heating sector, "Focus PtG" scenario) and synthetic methane transport capacities from 22 GW_{CH4} (transport sector, „Fast energy transition" scenario) to 86 GW_{CH4} (heating sector, "Focus PtG" scenario). The currently available gas transport capacities estimated by OGE and Amprion (i.e. 51 GW North-West and 133 GW South-West; see section 3.3.10.2) between the respective regions actually appear large enough to satisfy these needs. With that, new transmission lines would not be required. However, this only holds true when looking at each sector separately and assuming no further gas transport between European countries through Germany as a transit country, which may lead to bottlenecks in particular between the North and West regions.

4.2.2 Detailed results from the transport sector in the „Focus PtG" scenario

In this chapter we will at more detailed results, using the transport sector in the "Focus PtG" scenario as an example like we in the base scenario. After an overview of the overall energy system we will focus on flexibility options and energy transport.

Overview of the overall energy system

The more ambitious GHG reduction goals in the "Focus PtG" scenario lead to slightly higher total costs (ca. 32-42 B€; see Figure 51). The same holds for the individial cost positions exept for the flexibility costs in the PtH_2 case where the by definition 20% lower PtG costs render electrolysis and the resulting flexibility cheaper than in the base scenario. However, this does ot apply to the $PtCH_4$ case where the higher flexibiliy requirement, caused by the increased power demand for CH_4 production, overcompensates the PtG cost reduction. Nevertheless, the relative contribution of the individual cost positions is similar to the base scenario: flexible power generation plants have the largest share, closely followed by flexibility and end-user applications at about the same level (ca. 7-10 B€/a.) while enery transport only plays a minor role (ca. 1 B€/a). Moreover, total costs as well as energy costs incl. transport are lower than in the "all electric" case.

Like in the base scenario, total costs in the "Focus PtG" scenario increase over time along with a proceeding transition of the energy system. Causes are the growing investment into new power generation capacities, replacing aging existing plants, as well as the successive decarbonisation of the energy system and the corresponding increase in energy demand (particularly from the transport sector), need for flexibility (due to more intermittently generating renewables), and volume of end-user applications (zero-emission vehicles and refuelling infrastructure).

Cost development in the medium-term is comparable to the base scenario. Although cost for flexible generation capacity grows initially, it reduces again in the longer term. This happens in parallel to the strong expansion of renewable generation capacity and correspondingly increasing supply costs of fossil power End-user application costs increase along with the number of zero-emission vehicles on the road, actually surpassing energy costs in all cases after 2035. Energy transport costs remain comparably low, even though costs for gas pipelines slightly increase with a growing use of H_2 and CH_4.

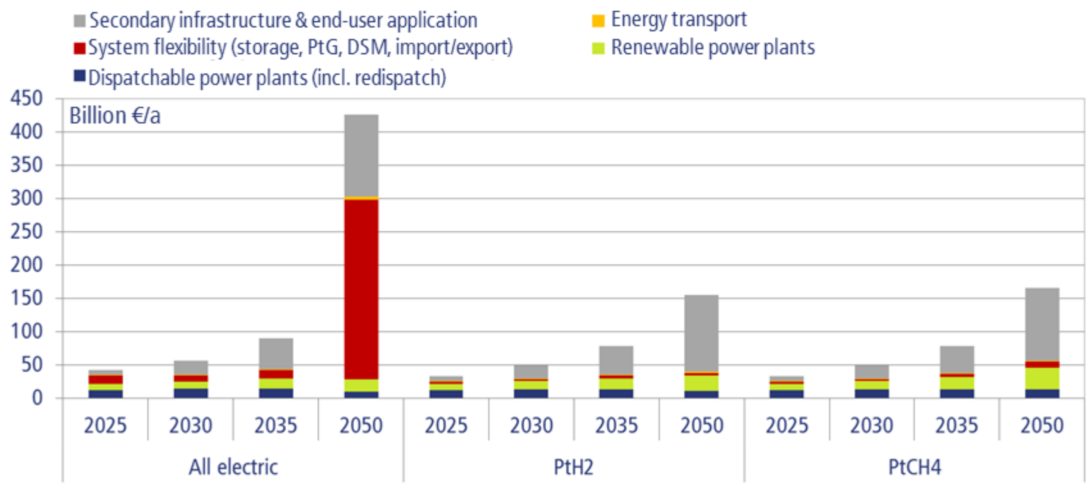


Figure 51: Total annual costs in billion €/a for the transport sector in the „Focus PtG" scenario

Particularly noteworthy is the long-term cost development in the last time step. In 2050 flexibility costs dominate in the "all electric" case, being about double that of all other costs at a level of 270 B€/a., driven largely by using batteries for seasonal storage, while in the PtH_2 and $PtCH_4$ case flexibility only accounts for 15-20% (ca. 4-9 B€/a) of total costs. This is the most striking difference to the base scenario, resulting mainly from the ambitious GHG reduction goals in the "Focus PtG" scenario, as discussed previously. In the long term, energy costs incl. transport in the "all electric" case are at 302 B €/p (thereof only 10 and 19 B€/a for flexible and renewable generation, respectively) and total costs at 426 B€/a with 120 B€/a for end user applications.

In the PtG case, energy costs incl. transport only amount to 40-56 B€/a (higher value for $PtCH_4$ due to the associated conversion losses) where 10-13 B€/a and 23-33 B€/a result from flexible and renewable generation, respectively. On the other hand, end-user application costs (i.e. for vehicles and refuelling infrastructure) are much higher than energy costs (ca. 109 B€/a for $PtCH_4$ and 115 B€/a for PtH_2), leading to total costs of 155-165 B€/a (higher value for $PtCH_4$). Since end-user application costs are similar for all application cases, the difference in total costs is largely driven by variations in power demand (PtG cost disadvantage due to conversion losses) and need for flexibility options (significant PtG advantage through cost effective seasonal storage).

The ambitious GHG reduction goals in the "Focus PtG" scenario and the associated higher number of zero-emission vehicles also lead to a larger power demand compared to the base scenario (see Figure 52). This is reflected in the higher direct power demand for BEVs as well as for H_2 and CH_4 fuel production. The difference to the base scenario steadily increases until 2050, gross power demand increasing from between 573 TWh/a („all electric") and 583 TWh/a ($PtCH_4$) in 2025 to between 635 TWh/a („all electric") and

942 TWh/a ($PtCH_4$) in 2050. While at the same time renewable generation curtailment increases compared to the base scenario, storage losses in the “Focus PtG” scenario remain overall lower. This is due to the larger storage capacities operating at less full-load cycles per year in the “Focus PtG” scenario. The generally observed gradual substitution of flexible fossil generation plants by renewable generation is more pronounced in the “Focus PtG” scenario.

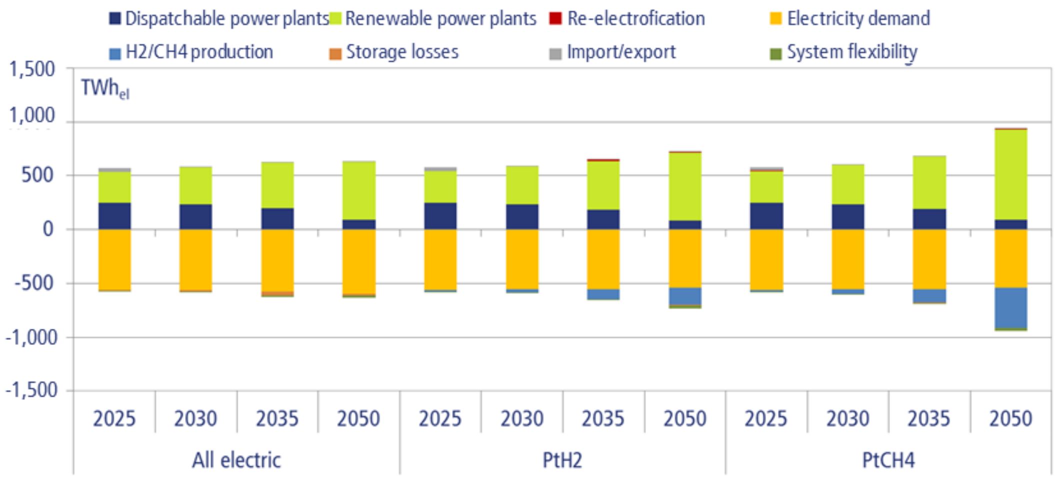


Figure 52: **Annual power generation (positive values) und power use (negative values) in TWh_{el} for the transport sector in the „Focus PtG“ scenario**

Figure 53 shows the capacity of dispatchable power plants over time. Like in the base scenario, flexible generation capacity reduces over time in the „all electric“(from 78 to 60 GW) and PtH_2-case (from 78 to 71 GW), being gradually substituted by renewable capacity. The installed capacity in 2025 is slightly lower than in the base scenario, but shows a less pronounced reduction until 2050. However, the installed capacity increases in the $PtCH_4$-case (from 77 GW in 2025 to 126 GW in 2050).

Two effects working in opposite directions are responsible for these developments. On the one hand, flexible and renewable power generation plants compete for power production, leading to flexible generation being gradually substituted by renewable power plants. On the other hand, the energy system requires significantly more flexibility beyond a certain share of renewable generation, which can be provided by storage but also by flexible generation. The first effect dominates the comparison between base and “Focus PtG” scenario in the short to medium-term (i.e. in 2025), while the second effect becomes particularly relevant when looking at installed capacities in the “Focus PtG” scenario in the $PtCH_4$-case, where the conversion losses require larger intermittent generation capacities (notably in 2050).

In addition, the "Focus PtG" scenario also shows a larger power generation capacity from H_2 as a result of higher level of seasonal storage by PtG. This is particularly noticeable in the $PtCH_4$-case, exhibiting a H_2-based power generation capacity of almost 46 GW, while the base scenario does not have any such capacities at all. Still, both scenarios are in general characterised by a reduced capacity of coal power plants, limited biomass power generation, and a dominating share in the secured capacity (32-74 GW depending on year and application) of natural gas based power plants. The "Focus PtG" scenario also exhibits an increased demand for secured capacity in the PtH_2 and $PtCH_4$-case.

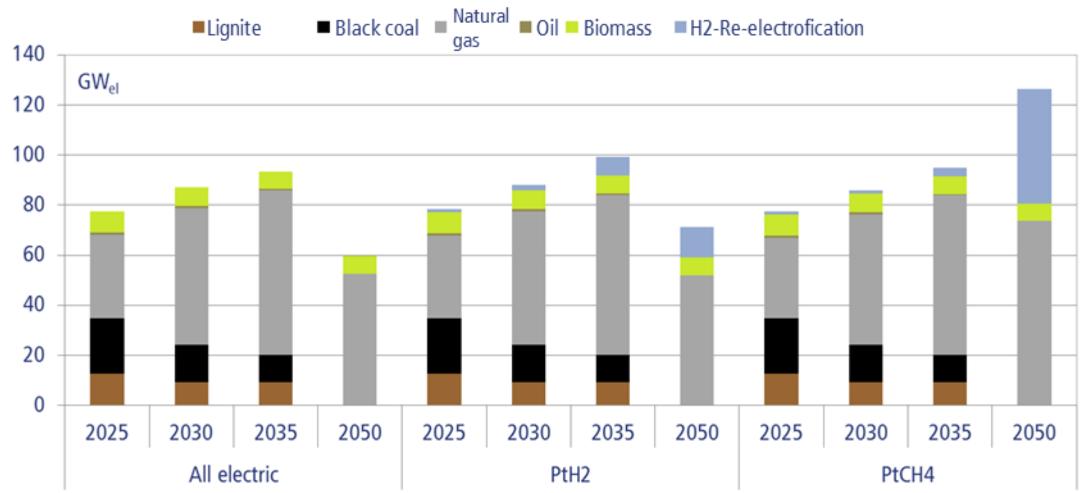


Figure 53: Installed flexible generation capacity in GW_{el} for the transport sector in the „Focus PtG" scenario

Flexibility options in the energy system

In general, flexibility costs in the „Focus PtG" scenario follow a similar trajectory as in the base scenario. They are higher in the "all electric" case for all time steps as a result of battery cost. While flexibility costs are lower in the medium-term (2025 to 2030) caused by reductions in imports and battery prices, they subsequently rise again until 2050 because of the strongly increasing renewable generation capacity. In the "all electric" case cost are dominated by battery costs and in the PtH_2 and $PtCH_4$-case by the cost of electrolysers and methanation. Demand side management and power import generally play a minor role (with the exception of PtH_2 and $PtCH_4$ in 2025).

As discussed above, contrary to the base scenario battery costs are increasing with growing demand for seasonal storage, particularly in 2050, in spite of falling battery prices. At 270 B€/a in 2050 they are by a factor of 24 higher than in 2025. Moreover, while flexibility costs for both PtG cases are higher than in the base scenario in 2035, this reverses in 2050, driven be the lower specific PtG technology cost in the „Focus PtG" scenario (-20% in comparison to the base scenario) as well as by the flexibility available from the larger installed capacity of flexible generation plants.

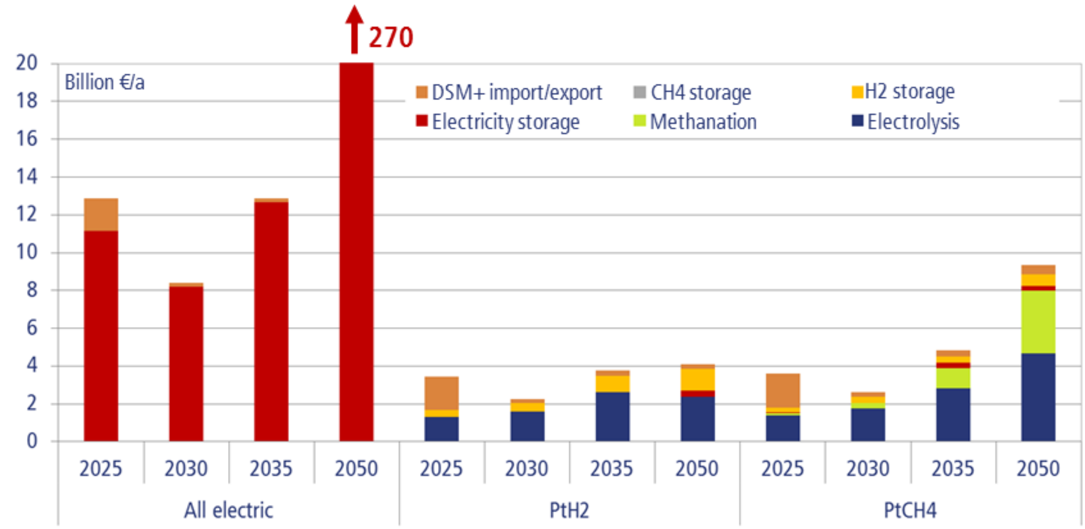


Figure 54: Annual costs for flexibility options in the energy system in billion €/a for the transport sector in the „Focus PtG" scenario

On the whole, compared to the base scenario storage capacity is larger for all years and cases in the „Focus PtG" scenario (see Figure 55). This is particularly visible for the "all electric" case with 10 TWh_{el} of stationary batteries in 2050. In the PtH_2 case H_2 storage capacity increases from 5 TWh_{H2} in 2025 to over 16 TWh_{H2} in 2050, and in the $PtCH_4$-case from 4 TWh_{H2} in 2025 to over 10 TWh_{H2} in 2050.

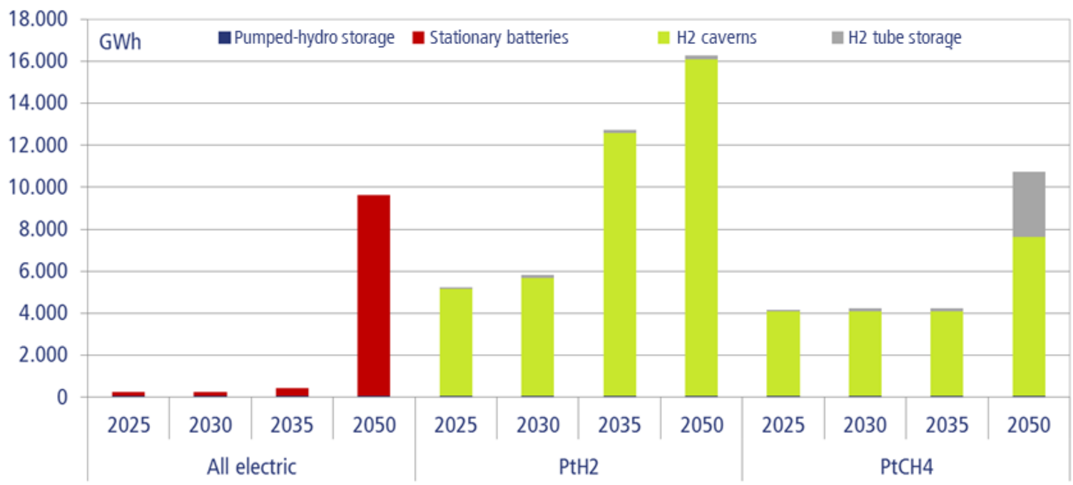


Figure 55: Storage capacity in GWh for the transport sector in the „Focus PtG" scenario

Compared to the base scenario, the H_2 storage capacity in the $PtCH_4$-case is still lower than in the „Focus PtG" scenario, where underground tube storage is used and seasonal storage is provided to a larger extent by storing CH_4. In combination with larger H_2-based power generation plants, the larger H_2 tube storage capacity is actually used as a means to supply peak power. This shows how the model combines available technologies in an individually optimised way.

When comparing to the base scenario, renewable energy curtailment is slightly higher in the "Focus PtG" scenario as a result of the increased renewable generation capacity expansion. While in the mid-term curtailment is more pronounced in the "all electric" case (like in the base scenario), the opposite is true in the long-term until 2050. The higher medium-term curtailment in the "all electric" case as compared to the PtG cases is caused by the lower storage capacity resulting from expensive batteries and the resulting reduced ability to deal with excess power. However, in the long-term, the higher GHG emission reduction in the power sector requires a very efficient energy usage in the "all electric" case, leading to larger storage capacities. On the other hand, both PtG cases assume a renewable energy generation capacity expansion over-proportional to electricity demand, leading to more excess power and the above mentioned observation on curtailment (also in comparison to the base scenario). We conclude that extending renewable generation capacity in the "all electric" case would increase energy cost but possibly, at the same time, reduce the required storage capacity and associated costs significantly if we allow a less efficient energy use and accept a higher level of curtailment.

Also here, curtailment most prominently affects wind power in the North, even if there is an increasing curtailment of PV power in the South in the "Focus PtG" scenario. Compared to the base scenario, there is also higher curtailment in the West region, notably in the "all electric" case.

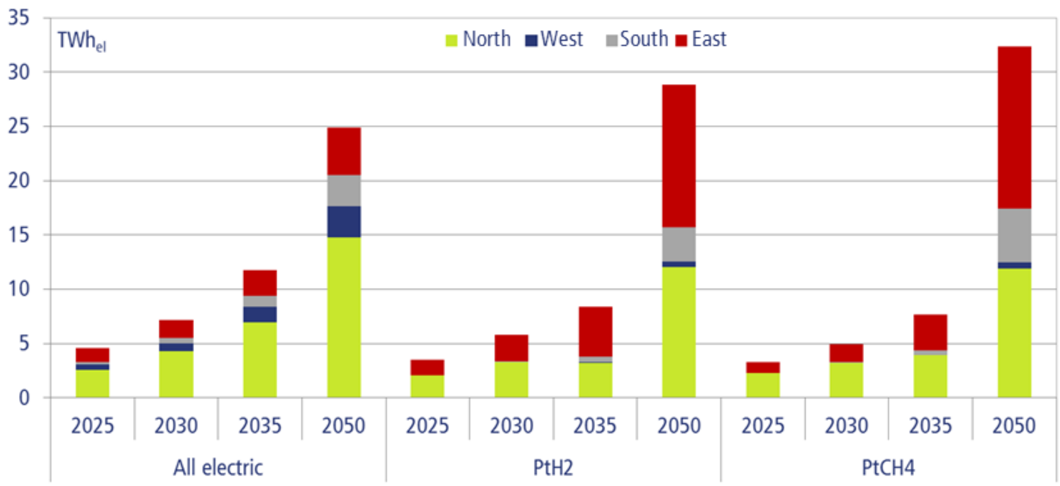


Figure 56: Renewable energy generation curtailment in TWh$_{el}$ for the transport sector in the „Focus PtG" scenario

Like in the base scenario, electrolyser capacity extension and utilisation grow with increasing decarbonisation of the power and transport sector to 74 GW at more than 2,000 full-load hours (PtH_2 case) and 144 GW at 2,500 full-load hours ($PtCH_4$ case) – see Figure 57. Utilisation figures reflect average values of all plants and individual electrolysers may have a higher utilisation. The differences between the two cases is a result of the conversion losses in methanation and in methane-fuelled vehicles. As discussed in the previous section, the 2050 electrolyser capacity is lower than in the base scenario as a consequence of the hourly availability of renewable generation plants and the synergistic use of the electrolysers for H_2 and CH_4 production and as a flexibility option. However, the need to incrase electrolyser capacity arises earlier than in the base scenario with capacities of 23-24 GW_{el} in 2025 and 59-64 GW_{el} in 2035. On the whole, electrolysers achieve a better utilisation in the "Focus PtG" scenario, leading to a lower cost of hydrogen to be supplied as a fuel (PtH_2 case) or as an intermediate product for synthetic methane production ($PtCH_4$ case).

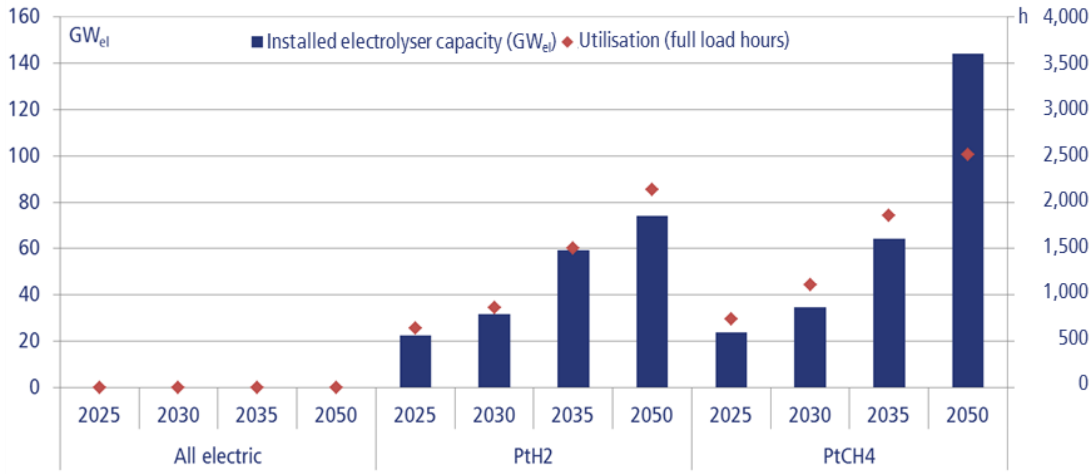


Figure 57: Electrolysis capacity in GW_{el} for the transport sector in the „Focus PtG" scenario

On the other hand, the "Focus PtG" scenario exhibits a larger need for methanation capacity in the $PtCH_4$ case. The installed capacity increases from ca. 4 GW_{H2} in 2025 to over 94 GW_{H2} in 2050. This results in a reduced utilisation, which at 1600-2500 full-load hours is significantly below the base scenario. Reasons include the higher CH_4 demand as well as by the limits to other flexibility options in this scenario, since due to the higher demand methanation plants can make less use of the H_2 buffer storage and have to additionally provide a contribution to system flexibility. For the same reason, FCEVs benefit more from a higher electrolyser utilisation than methane vehicles, where the cheaper H_2 production is offset by the lower utilisation of the methanation. Still electrolyser and methanation costs increase less than proportional to the capacity extension as specific technology costs decrease significantly over time.

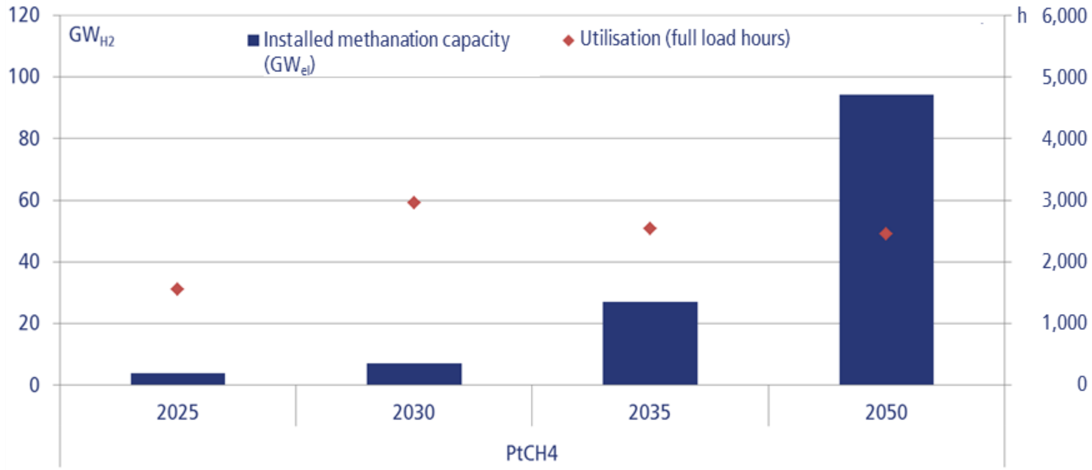


Figure 58: Installed capacity and full load hours of methanation plants in GW$_{H2}$ (as an input for the methanation plants in the model) for the transport sector in the „Focus PtG" scenario

Energy transport

Like in the base scenario, electric power is the prime energy carrier also in the "Focus PtG" scenario (see Figure 59). More ambitious GHG reduction goals with higher renewable generation capacity generally lead to more energy transport. This is particularly pronounced in both PtG cases. The "all electric" case is an exception, where electricity transport increases less than in the base scenario and even decreases in 2030, mainly as a result of increased battery capacities and their regional distribution in relation to energy demand. This shows the important role of battery storage in deriving power transmission capacities.

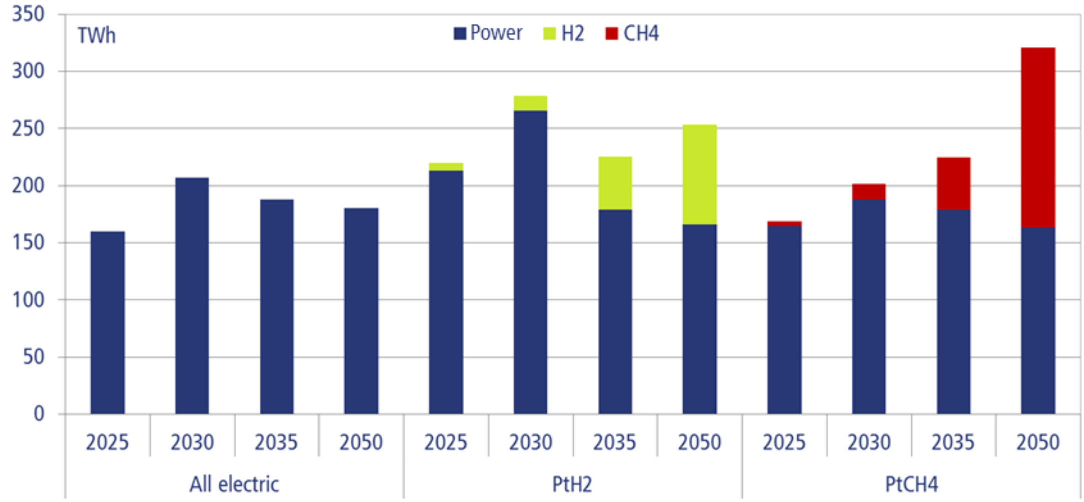


Figure 59: Energy transmission between regions per energy carrier for the transport sector in the „Focus PtG“ scenario

Still, like in the base scenario, on an annually averaged basis power flows from the North and East to the South and West regions. As shown in Figure 60, only the overall volumes vary but the structure of power flows is essentially the same as in the base scenario. The increase of 6 GW (3 lines) in power transmission capacity beyond the base scenario is exclusively due to the North-South link in order to transport additional wind power from the North to the South (see Figure 61).

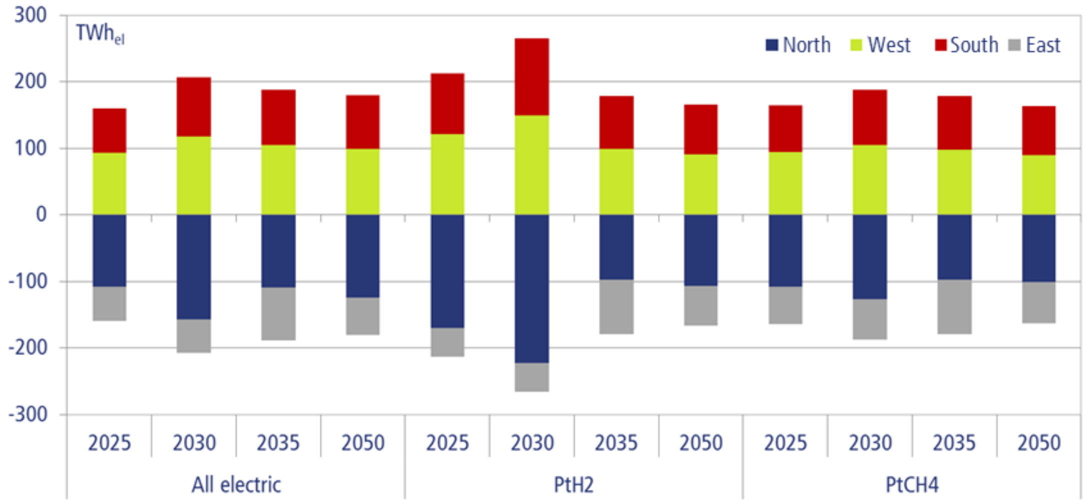


Figure 60: Net power trading balance between regions (inflow= positive values / outflow = negative values) in TWh$_{el}$ for the transport sector in the „Focus PtG“ scenario

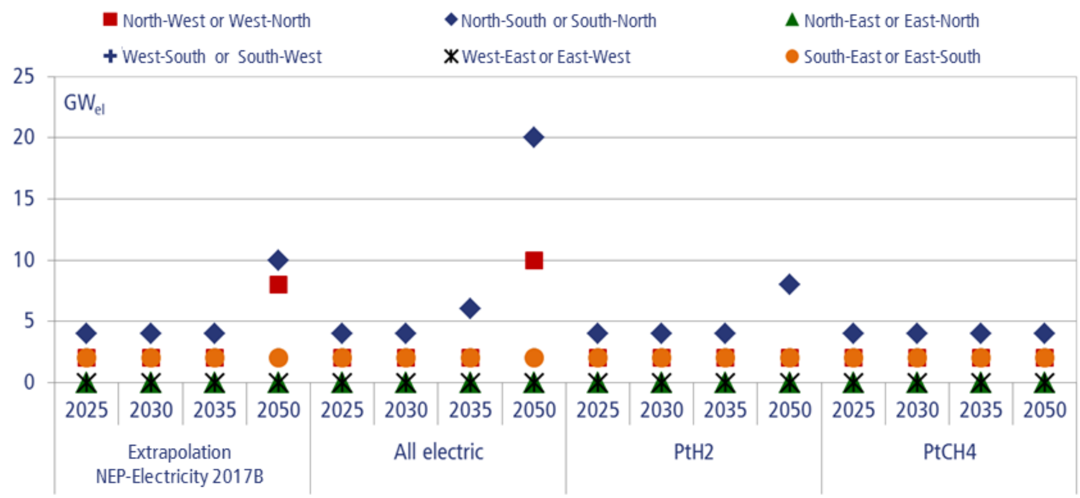


Figure 61: **Required HVDC transmission capacity in GW_{el} for the transport sector in the „Focus PtG" scenario (values for NEP 2017B in 2050 are modelling results)**

Surprisingly, the PtH_2 case also adds 2 HVDC-lines (4 GW) between North and South beyond the 4 GW transmission capacity already foreseen in NEP-Electricity 2017B. These are necessary to transmit excess PV power from the South to the electrolysers in the North. However, this is not necessary in the $PtCH_4$-case due to the different size and location of flexible generation plants and storage capacities. Such a seemingly sub-optimal regional distribution of generation and storage capacities in the PtH_2 case may result, since investment decisions in the first modelling step are taken independent of the grid simulation.

The higher demand for H_2 and CH_4 fuel as well as the stronger focus on FCEVs and CNG-vehicles in the "Focus PtG" scenario also leads to a significant increase in H_2 and CH_4 transport volumes (see Figure 62 and Figure 64) and in transport capacities required between the North and the other regions (see Figure 63). Compared to the situation today, individual transport pipelines (e.g. along the North-West connection) may be experiencing congestion issues in the long-term. However, this requires a more detailed investigation. Nevertheless, the structure of the resulting transport requirements is very similar to the base scenario.

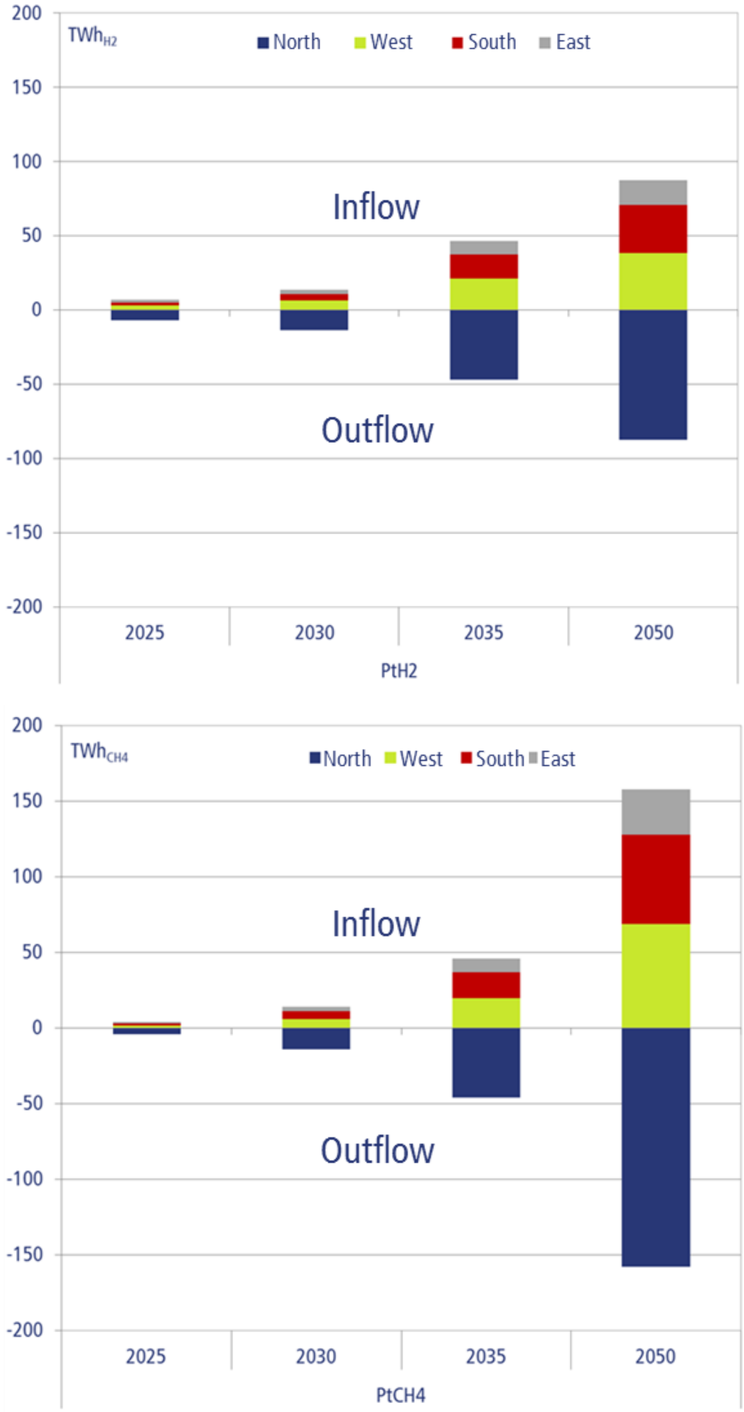
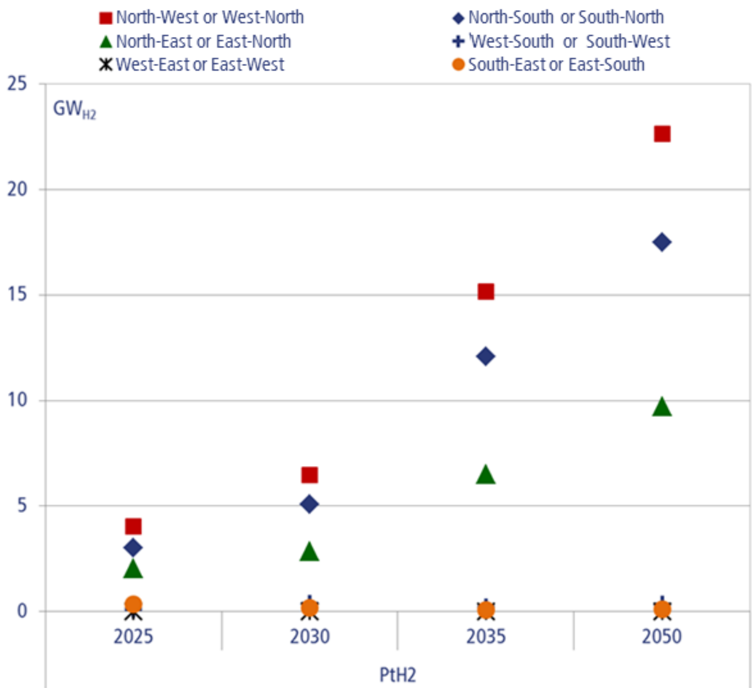


Figure 62: **Balance of H_2- (top) and CH_4 transport (bottom) between regions in TWh_{H2} and TWh_{CH4} for the transport sector in the „Focus PtG" scenario**



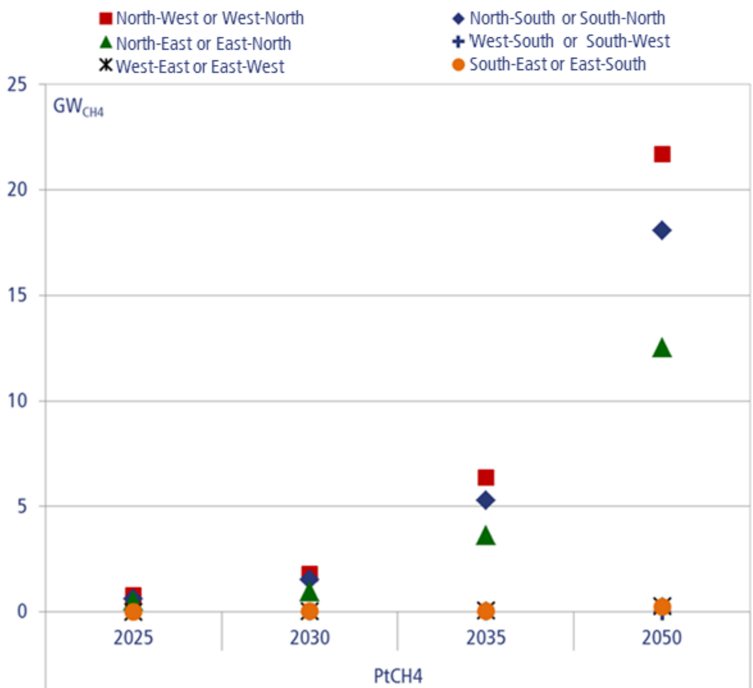
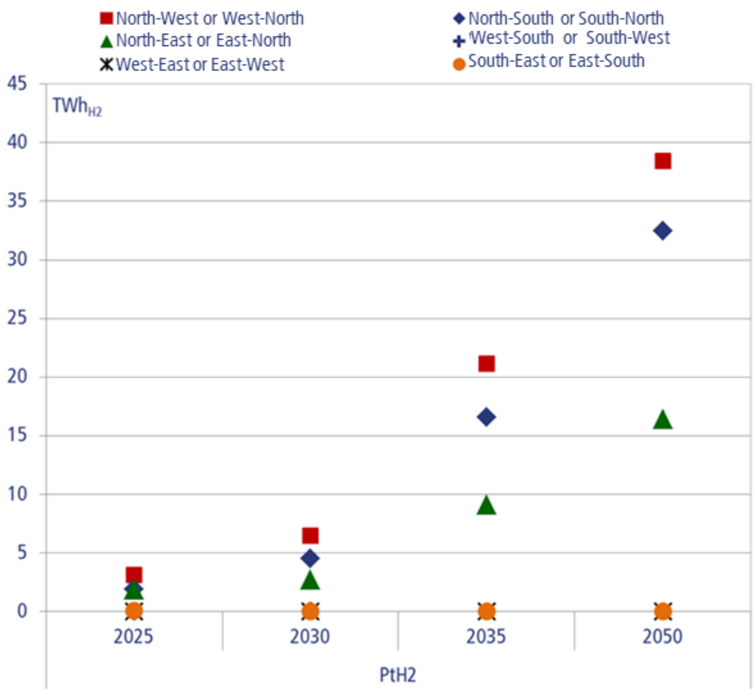


Figure 63: **Required H_2 (top) and CH_4 (bottom) gas transport capacities in GW_{H2} and GW_{CH4} for the transport sector in the „Focus PtG“ scenario**



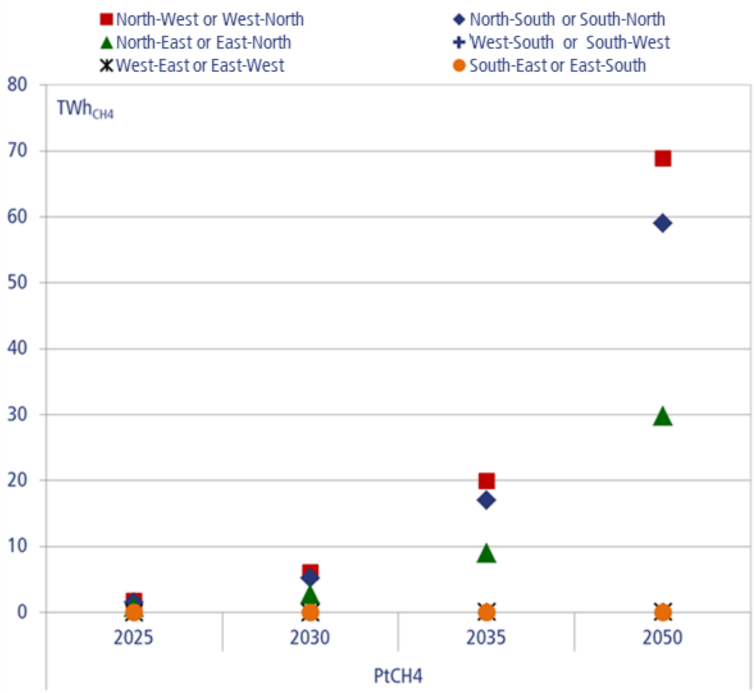


Figure 64: Required energy transport for H_2 (top) and CH_4 (bottom) in TWh_{H2} and TWh_{CH4} for the transport sector in the „Focus PtG" scenario

4.2.3 Secondary infrastructure and end-user applications in scenarios „Fast energy transition“ and „Focus PtG“

Figure 65 and Figure 66 show the cost of end-user applications in the "Fast energy transition" and "Focus PtG" scenarios for the selected application areas (i.e. only vehicles and refuelling stations in the transport sector etc.). Generally, the more ambitious GHG reduction targets lead to higher end-user application costs in comparison to the base scenario. For the transport sector in 2025 these costs amount to ca. 2.7 B€/a, and to 93-110 B€/a in 2050. In this context, the "Focus PtG" scenario exhibits lower costs as it includes a smaller number of BEV charging station but a larger number of refuelling stations for H_2 and CH_4, which are specifically much cheaper than BEV charging points. Apart from that, the cost structure is comparable to the base scenario. In the heating sector the end-user costs amount to 5-8 B€/a. in 2025 and 27-42 B€/a. in 2050, depending on the scenario and technology case. The heat pump costs are again higher in comparison to the H_2- or CH_4-appliances being reflected in the difference between the scenario results. No end-user application costs are contained in the industry case.

The higher vehicle number leads to ca. 6,700 refuelling stations until 2050 in the "Fast energy transition" scenario and ca. 10,000 in the "Focus PtG" scenario, ensuring an appropriate fuel supply at higher vehicle penetration rates. Refuelling station also grow quicker than in the base scenario and large stations are built at an earlier stage to satisfy the higher fuel demand. Refuelling station utilisation increases significantly over time in all cases.

It is noteworthy that in the $PtCH_4$ case initially small refuelling stations are built, which are then gradually replaced by medium and later by larger and very-large ones, whereas in the PtH_2 case the deployment after 2025 already includes larger stations. This difference is mainly due to the underlying station size classification. For the PtH_2 case we adapt the official classification from H_2-Mobility GmbH, a joint venture of several industry partners deploying a nationwide hydrogen refuelling station network. According to that, the medium size refuelling station is not large enough to satisfy the growing hydrogen demand and hence large and very large stations are needed after 2025. In the $PtCH_4$ case we assume a more even distribution of station classes in respect to vehicle and demand growth. However, the influence of refuelling station classification on the overall result is rather limited.

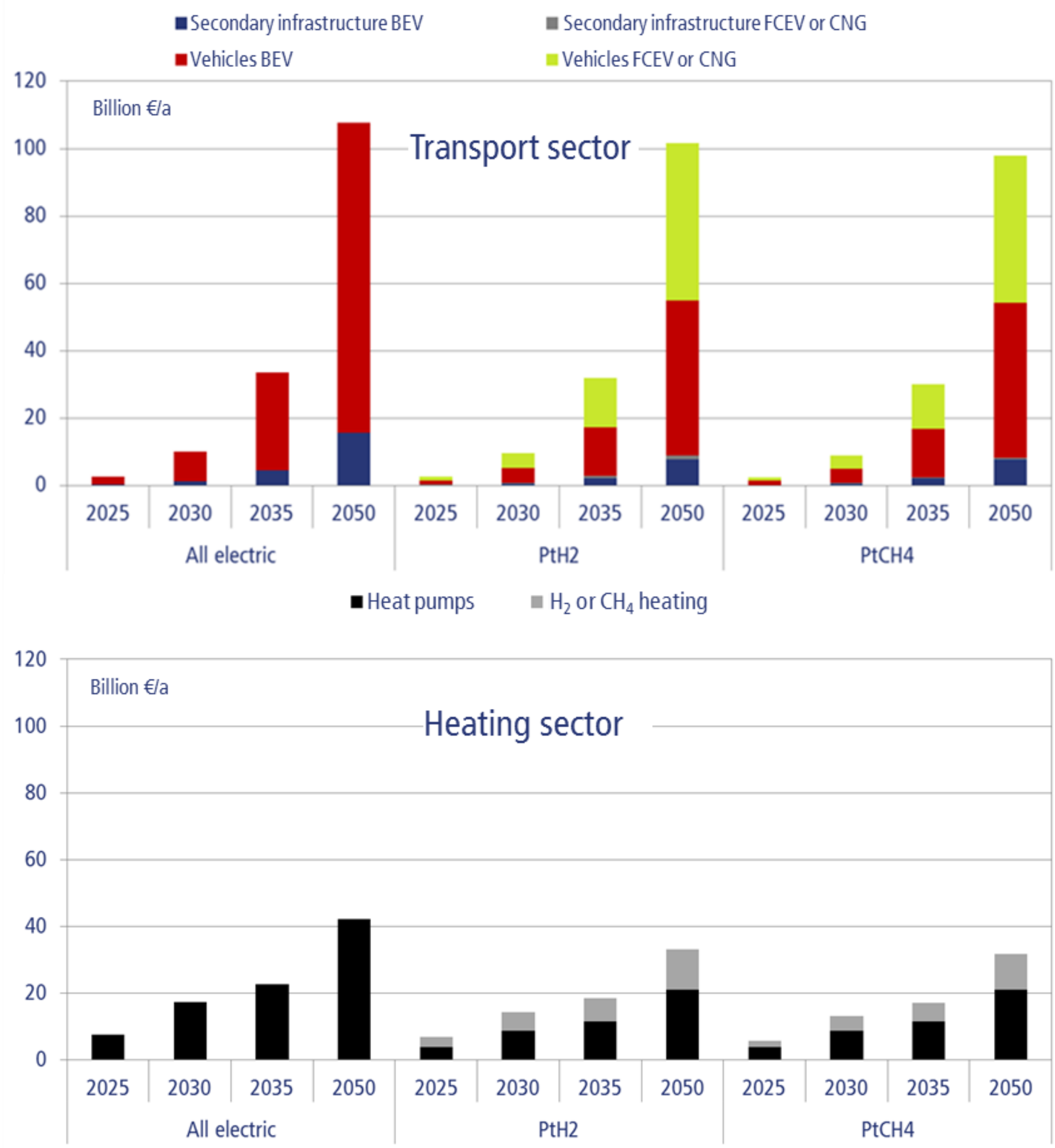


Figure 65: **Annual cost for secondary infrastructure and end-user applications in billion €/a for the transport sector (top) and the heating sector (bottom) in the "Fast energy transition" scenario**

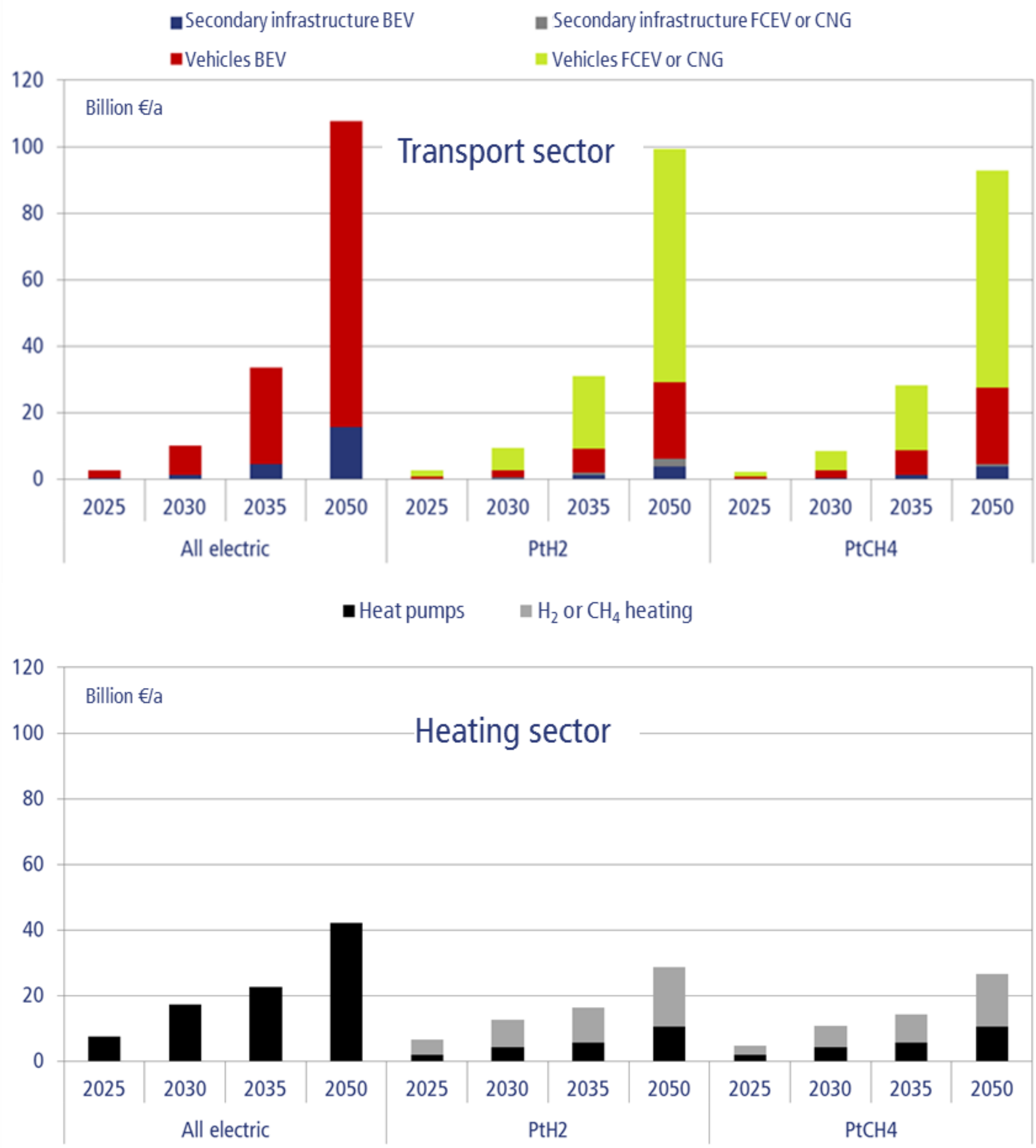


Figure 66: **Annual cost for secondary infrastructure and end-user applications in billion €/a for the transport sector (top) and the heating sector (bottom) in the "Focus PtG" scenario**

5 CONCLUSIONS

This study assesses the role of the PtG technology in the context of smart sector integration from a macro-economic perspective. It analyses the effects of integrating additional renewable electricity into the German power grid beyond the NEP-Electricity 2017B for selected early PtG cases, studied independently from each other for sectoral differentiation. The focus of the approach from an energy transport perspective was on the PtG alternatives PtH_2 and $PtCH_4$ benchmarked against the power dominated "all electric" supply case.

A custom-designed methodologic approach has been developed for this specific study goal applying simulation models to minimise the total costs of German energy supply comprising the transport, heating and industry end-use sectors independently from each other. Both time-dependent and spatial dimensions were considered. In the time-dependent dimension investment decisions, power plant operation, as well as the use of PtG plants (electrolysis and methanation), energy storage (pumped hydro, stationary batteries,H_2 and CH_4 storage), and other flexibility measures (demand side management, import/export) have been considered in hourly resolution. In the spatial dimension, the transport of the energy carriers electricity, hydrogen, and synthetic methane gas has been studied applying a simplified nodal model for the four regions (North, West, South and East). By separating both dimensions by solving both problems sequentially, a large number of user-specific alternatives and scenario variations could be analysed.

The application of both PtH_2 and $PtCH_4$ technologies to the transport (passenger cars), heating and industry (substitution of hydrogen from steam methane reforming) sectors, both in combination with the electricity sector (in longer perspective dominated by renewable power supply) have been assessed and compared with an strict "all electric" energy world (i.e. storage and transmission of electricity only). The calculations were framed by the following two boundary conditions: (1) the climate policy goals are based on but are significantly more ambitious than the ones defined for the NEP-Electricity 2017 by firmly integrating electricity in the above mentioned end-use sectors, and (2) each end-use sector is assessed independently from the other ones to better understand the possible benefit of PtG for each sector in 2025, 2030, 2035 and 2050. In this context three scenarios have been defined:

- "Base scenario" (or "Slow energy transition" scenario) characterised by a climate goal of -80% GHG emission reduction in the power sector by 2050 (based on 1990 level),
- "Fast energy transition" scenario with a GHG emission reduction target of -95% by 2050, reduced costs of PtG technology and a large portfolio of other flexibility options such as import/export, DSM etc., and finally

- "Focus PtG" scenario, also comprising a climate goal of -95% GHG emission reduction and reduced PtG technology costs, but with a limited potential of other flexibility measures and hence the increased use of PtG in the individual sectors.

Summary of results

A core outcome of the scenario analysis reveals that the PtG technology is an essential element of a future energy system characterised by large renewable electricity shares for the majority of cases assessed, even if individual sectors are studied independently from each other. This holds specifically true for those cases where the use of PtG induces large additional electricity. In principle, the energy costs in such a system become a trade-off between the costs for fluctuating and dispatchable electricity supply, the need for energy storage and the use of further flexibility options. In this context, on the one hand, the PtG technology has the disadvantage of larger energy demand due to conversion losses (higher for $PtCH_4$ than for PtH_2). On the other hand, it has the advantage of simple energy storage and transport using hydrogen or synthetic methane as universal energy carriers.

Under the specific assumptions of this study, the drawbacks of the PtG technology are overcompensated in most cases. Assuming that all end-use sectors need to be supplied by renewable electricity in the future, the benefits of the PtG technologies will become even more significant.

From a macro-economic perspective, it is important to distinguish between the energy costs (incl. transport),i.e. the costs for provision of the required energy, and the total costs which also include the costs for energy end-use (i.e. end-use technology such as zero emission vehicles and secondary energy infrastructure close to the end-user such as fuelling stations and charging stations). In all use cases, sectors and scenarios the end-user specific costs constitute a dominant share of the total costs, in the long-term possibly even surpassing the costs of supplying the energy. This holds specifically true for the transport sector for which the total car market has a high monetary value. Furthermore, $PtCH_4$ is the cheapest option in view of the end-use costs for all applications and all time steps, followed by PtH_2. From a macro-economic perspective the additional direct user costs comprise a higher share than the costs for energy transport and delivery infrastructures.

As insights into the consequences of electric or PtG applications for the required electricity and gas distribution infrastructures are not yet available these could only be considered qualitatively and ex-post within this study. A careful first order analysis reveals that the expected additional costs even increase the potential benefit of the PtG technology as compared to an "all electric" approach.

For the energy costs, the electricity demand from various sectors (in absolute figures and by profile) to be increasingly supplied by renewable electricity becomes a key parameter. Another important influencing factor is the need for increasing flexibility of the electricity system and here specifically for energy storage at large scale as the other flexibility options are assumed to be limited in potential. For the PtG cases, the flexibility costs are dominated by the costs of electrolysis and methanation plants whereas in the "all electric" cases the required investments for stationary batteries dominate. The electrolysis plants will be required already in the short-term to produce hydrogen as a universal energy carrier as well as to stabilise the electricity system (as a flexible load or through re-electrification). This is why the electrolysis capacity needs to be ramped-up early to GW scale, further increasing based on the individual use case, sector, and scenario up to between 50 and 200 GW_{el} by 2050. The downside to the ambitious ramp-up of electrolyser capacity is its relatively poor average annual utilisation of less than 4,000 full load hours. However, this number represents an average, with individual plants also having potentially higher utilisation. Keeping this in mind, the optimum macro-economic results have to be validated for their individual feasibility from a business perspective.

Another important insight of this study is that rather ambitious climate policy targets will cause a tipping point in the energy system with respect to the need for electricity system flexibility and here specifically the storage of renewable electricity. We have found that this tipping point will occur at share of about 90% to 95% of the fluctuating renewable electricity supply on gross electricity demand, which also corresponds to the more ambitious GHG emission reduction policy targets of the European Union. As a consequence, energy storages will then be no longer only used as power-related storage to overcome short-term supply shortages but mainly as long-term "seasonal" storage. The consequence for the "all electric" cases without chemical energy storage are prohibitively high energy storage costs in the "Fast energy transition" and "Focus PtG" scenarios, due to the comparatively high specific energy storage costs in stationary batteries. This effect is further amplified for an increasing electricity demand from other end-use sectors: the higher the electricity demand the higher the criticality of the system due to fixed GHG emission ceiling and thus maximum production quotas in TWh/a for flexible fossil gas peak power plants.

In contrast, the transport of electricity, hydrogen, or synthetic methane has a minor cost impact on total costs. Based on our four-region approach the grid extension plan foreseen by the NEP-Electricity 2017B will be sufficient to integrate the intermittent renewable electricity in the medium-term until 2035. However, beyond higher renewable electricity shares (ca. > 400 TWh/a) a power grid expansion will be needed, which may reach 26 GW (or 13 HVDC-connections with 2 GW each) beyond the 10 GW (or 5 connections) extension foreseen by the NEP-Electricity 2017B. It should be noted that this is the result for individual sectors only. A simultaneous introduction of additional renewable energy capacities could significantly increase the need for grid extension. The analysis shows that specifically the following connections are concerned: wind power from North/East to South/West as well as in the long-term PV electricity from South to North/West. Nevertheless, the placement of intermittent and dispatchable power plants as well as energy storage (specifically battery storage) will have a large impact on the grid capacity extension needs, if they are allowed to provide grid services.

For the transport of hydrogen and synthetic methane significant pipeline capacity of up to 100 GWH_2 in the case of PtH_2 and up to 90 $GWCH_4$ in the case of $PtCH_4$ are required. However, the operating or conversion costs of existing methane pipelines to hydrogen operation are insignificant like for the electricity grid.

In the base scenario, the highest energy supply costs incl. transport result in the heating sector due to relatively high end-use demand and hence high electricity production costs, caused by the PtG-conversion losses in the heating sector. From a system perspective, the use of PtH_2 in the transport and industry sectors is the most cost-efficient option. The specific GHG avoidance costs for these applications in €/t_{CO2} are even lower than the costs from extrapolating the NEP-Electricity 2017B (for industry even in respect to total costs). This is due to the fact that PtH_2 technology proves to be a particularly advantageous flexibility option for this application (i.e. it is a cost efficient flexibility option for low energy demand and low specific conversion losses). However, the highest total costs result in the transport sector due to the vehicles and charging or refuelling infrastructure costs. In both scenarios "Fast energy transition" and "Focus PtG", the advantage of both PtG technologies against the "all electric" case is specifically pronounced.

In the „all electric" case total costs are by a factor of 2 to 4 higher than the corresponding values in the PtG cases due to high costs of stationary batteries when operated as a seasonal energy storage. From a system perspective, the PtG technology can be used again in the most efficient way in the transport and industry sectors. Furthermore, the scenario "Focus-PtG" principally bears higher costs when compared with the "Fast energy transition" scenario due to the higher total energy demand. In conclusion, however, the individual sectors and scenarios cannot be easily compared as the end energy demand varies by definition having a significant impact on the overall result.

Interpretation of results

The results of this study demonstrate that a future application of the PtG technology has the potential to become an important pillar of the energy transition ("Energiewende"). By simultaneously using water electrolysis plants to produce hydrogen as a universal energy carrier and to provide flexibility for balancing intermittent renewable electricity, synergies from applying PtH_2 and $PtCH_4$ technologies may be leveraged early. In most cases the advantages of PtH_2 and $PtCH_4$ for efficient energy storability over-compensate the disadvantages of additional conversion losses from H_2 and CH_4 production. These advantages specifically emerge in the long-term and in connection with ambitious climate policy goals, becoming obvious when benchmarking the total energy system costs of the PtG with the "all electric" use cases. Although, PtG supports the electricity infrastructure, the transport of energy is not sufficient to demonstrate the advantage of PtH_2 or $PtCH_4$

since there is no need for additional electricity grid capacities beyond the NEP-Electricity 2017B until 2050 and since transport costs only contribute a small share to the total energy system costs.

Nevertheless, missing public acceptance may hinder the required electricity grid extension, whereas gas pipelines already exist and have the capacities to transport increasing amount of green gases such as hydrogen or synthetic methane. As a consequence, PtG technology can serve as a useful supplement to an "all electric" approach, specifically for the transport and industry sectors, due to its potential of reducing GHG emissions at specifically low costs. Yet, the market introduction of the PtG technology requires preparations for its technical development, testing, and acceptance, which needs to start early in order to reach the ambitious climate policy targets in time.

Open research questions

The analysis in this study is based on a set of simplifications which can be further assessed in more detail. One example is the limitation of the electricity and gas grid to only four regional nodes. Hence, in this way some grid-related restrictions with a potential impact on the overall results are not considered. Specifically the grid-compatible operation of power plants and storage facilities can reduce the need for power grid expansion. Also, the capacity limitations of the gas grid in the long-term, which have only been assessed ex-post, could be addressed in more detail. Further attention could also be directed at the options and actual refurbishment needs of (parts of) the existing natural gas grid to hydrogen operation. These activities should, however, be judged on the background that on economic grounds the gas grid will not be a dominant factor.

Another simplification of this study concerns the fact that the availability of cheap salt caverns for "seasonal" gas storage is considered only for northern Germany being the reason for most PtG plants to be positioned there. Another option would be to place decentralised electrolysers at refuelling stations. In this case, the salt caverns in the North would be not available for such PtG plants or, otherwise, they would need to be connected via a distribution grid. In such a case, the advantages of PtG in our analysis may be overestimated and the corresponding costs underestimated. A more detailed sensitivity analysis of different grid topologies in respect of the regional plant distribution may allow for a deeper understanding of underlying interrelations.

The analysis results show that in particular the costs of the end-use applications (BEVs and FCEVs, battery charging, and hydrogen refuelling stations) are higher in the "all electric" case than in both PtG cases. The current hypothesis is that in the long-term adaptation costs to integrate charging infrastructure for a high percentage of BEVs into the municipal electrical distribution grid will be much higher than the costs for the hydrogen refuelling infrastructure for the same percentage of FCEVs (e.g. transformers, copper cables as well as stationary battery storage at low and medium voltage level). A recent study reports expected investments for a distribution grid reinforcement of about 69 B€ (BEV) and 22.5 B€ (FCEV), however, without providing any detailed assumptions [FZJ 2017]. More recent work will analyse these costs in more detail and will provide further insights on both energy distribution options within a year.

In addition, our analysis is based on identifying the macro-economic optimum without taking into account boundary conditions from the business perspective. As one example, in the base scenario the highest macro-economic costs are calculated for the transport sector, while from the business perspective, this sector is characterised by the highest prices, since hydrogen and methane as fuels have the highest market value. This can be interpreted as an indicator for early business cases for industry. It is also an open question to which extent electrolysers can actually be operated economically under the assumptions of this study (annual full load hours, cost reduction by economies of scale, real electricity price development, etc.). A comparison of regulatory and micro-economic conditions with the macro-economic findings of this study yet needs to be undertaken to generate additional insight into the potential benefits of the PtG technology for different actors in the market.

Finally, the study analyses the integration of the electricity sector with each of the other end-use sectors separately. A holistic approach taking into consideration the complete energy system (i.e. all sectors simultaneously) and energy demand from yet not addressed renewable electricity applications such as for trucks, air and maritime transport etc. would deepen the understanding of PtG technologies and their potential benefits.

Last but not least, it is important to point out that the macro-economic costs have been calculated as gross costs meaning they include investments which need to be made anyway to replace aging assets and end-user devices. When comparing the results with avoided costs from extrapolating the current fossil world (e.g. avoided costs from oil imports etc.) the real additional costs of the energy transition and sector integration could then be quantified in more detail.

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