



Leopoldina  
Nationale Akademie  
der Wissenschaften

acatech  
DEUTSCHE AKADEMIE DER  
TECHNIKWISSENSCHAFTEN

UNION  
DER DEUTSCHEN AKADEMIEN  
DER WISSENSCHAFTEN

February 2025  
Discussion Paper

# Nuclear Fission, Natural Gas, Geothermal Energy, Nuclear Fusion

## The Future Role of Baseload Power Plants

P. Stöcker | B. Erlach | S. Wurbs | F.-D. Drake | M. Fishedick | J. Hanson | H.-M. Henning |  
W. Kiewitt | J. Kreusel | A. Moser | W. Münch | K. Pittel | A. Reuter | D. U. Sauer |  
W.-P. Schill | H. Spliethoff | C. Stephanos | C. Weber | A. Weidlich

Discussion Paper



## Contents

Abbreviations & Glossary .....	4
1 Introduction .....	7
2 What are base-load power plants? .....	9
2.1 Nuclear power plants.....	11
2.2 Natural gas combined cycle power plants with carbon capture .....	13
2.3 Geothermal electricity generation .....	15
2.4 Nuclear fusion power plants.....	16
3 Relevance of base-load power plants in the energy system.....	18
3.1 Climate-neutral scenarios with and without base-load power plants .....	18
3.2 Security of supply and cost effectiveness .....	20
Focus on: The difference between the macroeconomic and the microeconomic perspective.....	22
3.3 System stability .....	24
3.4 Import dependency .....	25
3.5 Acceptance.....	25
4 Base-load power plants in the German/European energy system up to 2045.....	27
4.1 Potential capacity of analysed base-load power plant types until 2045.....	27
4.2 The impact of base-load power plants on electricity production.....	28
4.3 Optimal base-load power plant locations from a system perspective.....	30
4.4 Impacts of base-load power plants on the structure of the energy system .....	31
4.5 Change in total costs with base-load power plants .....	33
5 Long-term economic options for base-load power plants beyond 2045.....	36
6 Summary and outlook .....	40
7 Appendix.....	42
7.1 A brief look at the ENERTILE energy system model from the Fraunhofer ISI .....	42
7.2 Estimating the variable costs of power plants with CCS.....	43
7.3 Development of remuneration rates for PV and wind power in Germany.....	44
7.4 Geographical distribution of nuclear power plants modelled in the long-term scenarios.....	44
7.5 LCOE of the various technologies depending on capacity utilization.....	45
Literature .....	47
Contributors .....	53

Fact sheet / February 2025

# Nuclear Fission, Natural Gas, Geothermal Energy, Nuclear Fusion: The Future Role of Baseload Power Plants

## What is a base-load power plant?

Due to the investment costs involved, **base-load power plants** have to be in operation almost continuously in order to be profitable. Typical base-load technologies are currently nuclear power plants and lignite-fired power plants.

**Residual-load power plants** are a different case. Although these are also always available, they are only occasionally actually operating – e.g. at the times when solar and wind energy are not supplying sufficient power. Residual-load power plants have comparatively low investment costs, but high fuel costs. One example of this technology is hydrogen-fuelled gas turbine power plants.

## Assessment of low-CO<sub>2</sub> base-load technologies

- **Nuclear power plants** come with unanswered questions on safety, final deposition and proliferation. Most current new construction projects are running significantly behind schedule and over budget.
- **Natural gas power plants with CO<sub>2</sub> capture** could probably be realised on a large scale within the next 20 years. One challenge will be developing the infrastructure for CO<sub>2</sub>.
- **Geothermal energy** has low potential for electricity generation in Germany; here it is better suited to providing heat.
- **Nuclear fusion** will not be able to make a notable contribution to electricity generation until after 2045, it is expected.

## A secure energy supply is possible without base-load power plants

A reliable climate-compatible electricity supply is possible through the interplay of solar and wind energy with storage systems, flexible power consumption and residual-load power plants. The expansion of renewable energy and the European electricity and hydrogen grids is expected to cover Europe's electricity needs and most of the demand for hydrogen across the continent.

## But base-load power plants could still contribute to the energy supply

Detailed modelling shows that base-load technologies can be integrated into an energy system dominated by solar and wind energy. The key here is a flexible hydrogen system that enables the power plants to run at high capacity utilization. During times when demand is low, their power would be used for electrolysis, allowing hydrogen imports to be reduced. Base-load technologies make little difference to the need to expand and develop the electricity and hydrogen grids, and should also have no impact on the transition to electric mobility and heat pumps. They make sense primarily when they are more cost effective than the alternatives. New base-load power plants do, however, represent a rather more long-term option, given their long construction and usage times.

## Base-load power plants do not have a substantial impact on overall costs

The modelling shows that – even based on optimistic assumptions – the overall system costs of transforming to climate neutrality by 2045 are at the same level with the addition of base-load power plants as in the reference scenario, which focuses primarily on solar and wind energy. Additional risks arise through cost increases and delays in the construction of base-load power plants, which can be caused both by the lower technological maturity of the technologies involved and by the typical complexity of large individual projects.

## Abbreviations

€/kW <sub>el</sub>	Euros per kilowatt of net electrical capacity
€/MWh <sub>el</sub>	Euros per megawatt hour of electricity produced
€/MWh <sub>th</sub>	Euros per megawatt hour of heating value
BMWK	Federal Ministry for Economic Affairs and Climate Action
CAPEX	Capital expenditure
CCGT plant	Combined cycle gas turbine plant
CCS	Carbon capture and storage
EDF	Électricité de France, French power company
EGS	Engineered/enhanced geothermal system
EPR	European Pressurized Reactor
ESYS	Energy Systems of the Future
FOM	Fixed operation and maintenance cost
Fraunhofer ISI	Fraunhofer Institute for Systems and Innovation Research ISI
GHG	Greenhouse gas
GW	Gigawatts
IAEA	International Atomic Energy Agency
IDC	Interest during construction
LCOE	Levelized cost of electricity
LTS	Long-term scenarios (Langfristszenarien)
MW	Megawatts
NPP	Nuclear (fission) power plant
PRIS	Power Reactor Information System
PV	Photovoltaics (solar)
RTE	Réseau de Transport d'Electricité, France's transmission system operator
SMR	Small modular reactor
TRL	Technology readiness level
TWh	Terawatt hours
VOC	Variable operating costs

## Glossary

<b>AP1000</b>	A commercial nuclear power plant design from American company Westinghouse. It is the latest evolution of Westinghouse's nuclear power plant technology and borrows from Combustion Engineering's "System 80+". It is designed for a net electrical output of 1.1 GW.
<b>Base load</b>	The minimum demand for electricity – and therefore the amount of electricity required – that arises and needs to be covered at any given time.
<b>Baseload power plant</b>	A power plant optimised to provide a continuous supply of electricity with minimised variable costs. With all known technologies, the fixed costs involved are comparatively high, but high capacity utilization means these costs are spread over a large amount of generated energy.
<b>Carbon Capture and Storage</b>	The capture and permanent storage of CO <sub>2</sub> that would otherwise be emitted into the atmosphere.
<b>Interest during construction</b>	The costs incurred for interest on the pre-financing of the construction work already carried out. These are in addition to the investment costs and rise disproportionately with increasing construction time.
<b>European Pressurized Reactor</b>	A commercial nuclear power plant design from French company Framatome/EDF. It represents the latest evolution stage of European nuclear power plant technology and builds on the experience gained as part of the nuclear power programmes in Germany and France. Its net electrical output is approximately 1.6 GW.
<b>Full-load hours</b>	A measure describing the capacity utilization of a plant. Annual power generation is divided by the plant's capacity to show how many hours it would have needed to be running at full capacity in order to generate the same quantity of power.
<b>Natural gas combined cycle power plant / natural gas CCGT</b>	A power plant that makes maximum use of the energy content of the natural gas burned to generate electricity. To this end, the hot flue gas of the gas turbine(s) is used to operate a downstream steam turbine.
<b>Interconnected grid</b>	A large-scale, synchronous electricity grid based on three-phase current. An example is the interconnected continental European grid that extends from North Africa to Türkiye and Ukraine.
<b>Intermittent renewable electricity generators</b>	Electricity generators using renewable sources that are not available on an uninterrupted basis. The two key technologies here are solar photovoltaics and wind farms.
<b>Inverter</b>	A device without internal moving elements that converts the form of electrical energy. This conversion can be from alternating current to direct current or vice versa, a change in frequency or voltage and thus the current strength.
<b>Leap innovation</b>	A ground-breaking development that leads to a rapid and significant shift in the realizable properties of a technology.
<b>Levelized cost of electricity</b>	The full costs involved in generating a unit of electricity. Generally specified for a power plant in isolation, without taking into account expenditure required elsewhere (system integration).
<b>Long-term scenarios</b>	The project <i>Long-term Scenarios for the Transformation of the Energy System in Germany</i> (or "Langfristszenarien 3"/"Long-term Scenarios 3" for short) conducted by the Fraunhofer ISI for the BMWK simulates a number of comprehensive scenarios for the future development of Germany's energy supply using a combination of several detailed models.
<b>Natural gas with CCS scenario</b>	A path calculation scenario involving the construction of additional new natural gas CCGT power plants and assumed capture and storage of the CO <sub>2</sub> emissions from these plants.
<b>NPP scenario</b>	A path calculation scenario involving the construction of additional new nuclear power plants.
<b>Nuclear fusion power plant</b>	In this power plant concept of the future, electricity is generated via energy released through fusion of light atomic nuclei. Demonstrating the feasibility of this technology is the subject of current research.
<b>Nuclear power plant</b>	A power plant in which electricity is generated via energy released through fission of heavy atomic nuclei.
<b>System frequency</b>	The frequency with which the periodic change of current and voltage in the electricity grid is repeated. In Europe the grid runs at a frequency of 50 hertz.

<b>Path calculation</b>	Modelling of the transition path of the energy system over an extended time period. In the LTS and modelling by the Fraunhofer ISI, the starting point is the situation today, moving on through successive steps in intervals of five years.
<b>Peak load</b>	The maximum level of demand for electricity and therefore the required generation capacity that will occur – and need to be covered – at any one time.
<b>Reactive power</b>	A phenomenon occurring with alternating current in which more current flows through the cables than would actually be necessary to transmit the transferred power. Although generally undesirable, reactive power can also be useful: the energy flows in an interconnected grid can be influenced by selectively feeding in reactive power.
<b>Frequency-response governor</b>	Means for operating a steam power plant at slightly below the rated capacity. In most cases, this is primarily achieved through a reduction of the steam flow by slightly throttling the turbine valve.
<b>Reference scenario</b>	Starting and comparison point for the path calculations. Largely reflects the <i>LTS T45-Strom*</i> scenario (published in February 2024), but for reducing the minimum added capacity of solar and wind energy in Germany to half compared to the current policy targets.
<b>Residual load</b>	The amount of electricity demand not covered by simultaneous generation of electricity by intermittent renewable sources.
<b>Residual-load power plant</b>	A power plant that can be started up or shut down quickly and can generate electricity on a flexible basis. At any time it can even out insufficient power supply from intermittent renewable sources or excessive demand.
<b>Scenario</b>	Definition of a specific development (usually in the future) of the parameters in a model.
<b>Small modular reactor</b>	A new type of reactor design for nuclear power plants that is smaller than reactors for generating electricity commonly found today and which offers modular scalability. It is supposed to be standardized and suitable for manufacture in larger quantities in a production plant.
<b>System integration</b>	Steps and measures necessary to integrate an electricity-generating unit into the power supply while ensuring constantly reliable load coverage.
<b>Technology readiness level</b>	A scale originally employed in the space sector for assessing and classifying the development status of a technology. The scale ranges from TRL 1 (description of the principle) to TRL 9 (successful regular use).
<b>Three-phase alternating current</b>	An alternating current with three phases – i.e. an electrical system in which each connection of the individual components has three conductors. On each of the three conductors, the current and voltage form a sinusoidal curve with the same frequency, but have a phase difference of one third of a cycle.
<b>Variable operating costs</b>	All costs incurred when operating a plant, depending on capacity utilization. These include primarily energy costs – e.g. for fuel – but also other consumption costs or usage-dependent maintenance costs.

## 1 Introduction

Germany is committed to achieving net zero greenhouse gas emissions by 2045. This target, which is enshrined in the Federal Climate Action Act, has significant implications for the German energy sector. It is envisaged that, by 2045, the main final energy carriers will be electricity<sup>1</sup>, hydrogen and hydrogen derivatives, and heat – all from renewable sources. Moreover, the current policy target requires that at least 80 percent of electricity should already come from renewable sources, mainly solar and wind power, by 2030. There is also an ambition to significantly increase the use of electricity across a range of different sectors (electric mobility, heat pumps, etc.) through “sector coupling”. It is envisaged that renewable fuels – derived mainly from green hydrogen and biomass – will be used in sectors where electricity is not a practical option.

The fundamental transformation that this entails for the electricity sector has already begun. In the past, electricity was mainly produced by “dispatchable” coal-fired, gas-fired and nuclear power plants that could generate power at all times. In the future, solar and wind power will account for a growing proportion of electricity production. However, since they do not always generate enough electricity to meet demand, they will need to be supported by electricity storage systems, demand flexibility and dispatchable power plants fired by biomass and hydrogen or its derivatives. Since the dispatchable power plants will mainly be used when there is not enough solar and wind power to meet demand, they will probably operate at medium-to-low capacity utilization. Existing lignite-fired and nuclear baseload power plants that were designed for continuous operation are already increasingly being retired from the system, either because of legislation requiring them to be shut down or on economic grounds.

The potential future role of low greenhouse gas (GHG) emitting baseload power plants is a recurring theme in the public and policy debate in Germany. Views tend to be highly polarised, with some actors questioning whether a reliable and affordable electricity supply is possible without baseload power plants, and others insisting that they will no longer have a place in a system where the role of intermittent renewable energy keeps growing. The reasoning behind this second stance is that the capacity utilization of all dispatchable power plants will continue falling to a point where baseload power plants can no longer pay back their (high) investment costs.

The debate surrounding baseload power plants is also driven by differences of opinion regarding nuclear power. These differences are relevant to the electricity supply for Europe as a whole, given that some EU countries plan to keep using nuclear power, a conventional baseload technology. The debate is also being fuelled by advances in nuclear fusion research.

Against this backdrop, the ESYS working group *Baseload power plants in a greenhouse gas-neutral European energy system* investigated what, if any, benefits could be anticipated for the energy supply in Germany and Europe as a whole from the future deployment of baseload power plants in a restructured energy system. The working group explored the technologies that could definitely or potentially be used for low GHG emitting baseload power plants and outlined the role that they might play in the future energy system. Simulations were carried out to show how new baseload power plants might affect the energy system and the extent to which they could help to optimise the cost of electricity. The Fraunhofer Institute for Systems and Innovation Research (Fraunhofer ISI) carried out scenario analyses based on the long-term scenarios (LTS) using the ENERTILE energy system model. The scenarios’ assumptions and findings were analysed, discussed and interpreted by ESYS experts.

---

<sup>1</sup> While “electrical energy” is more physically accurate, in the interest of conciseness and readability this paper uses the term “electricity”, which is well established in common usage.

This discussion paper presents the conclusions that the working group drew from the analyses. Published at the same time, the report “Modellgestützte Systemanalyse zur potentiellen Rolle von Grundlastkraftwerken im Rahmen eines dekarbonisierten europäischen Energiesystems” (German only) describes the findings of the Fraunhofer ISI scenario analysis in detail. [1]

## 2 What are base-load power plants?

The term “baseload power plant” is somewhat misleading, since **base load** puts the emphasis on demand for electricity rather than on its generation. Base load refers to the minimum load that needs to be covered at any given time (Figure 1). **Intermediate load** is the minimum load that occurs during the day, between 8 a.m. and 8 p.m. **Peak load** is the additional load that only occurs at certain times.

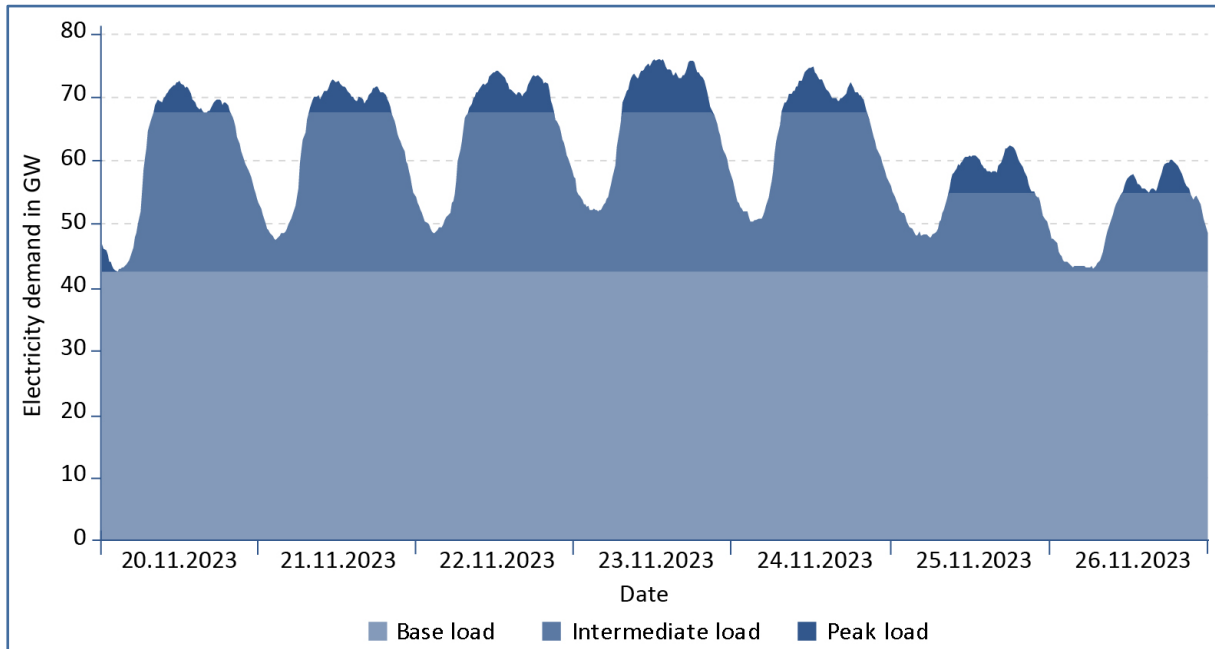


Figure 1: Breakdown of electricity demand into base, intermediate and peak load (idealised depiction of calendar week 47 in 2023). Source: authors’ own illustration based on data for Germany taken from [www.energy-charts.info](http://www.energy-charts.info).

Before the emergence of intermittent renewable energy, electricity demand was met by a mix of dispatchable power plants. Different power plant types are best suited to covering different load segments, depending on their technical design and cost structure (comprising both fixed and variable costs):

- **Baseload power plants** have low variable costs. In the past, these were largely made up of fuel costs. Conventional baseload power plants are lignite-fired and nuclear plants with a typical capacity utilization of more than 6,000 hours a year. This high capacity utilization means it doesn’t matter so much if they have higher fixed costs (principally investment and construction costs). Conventional baseload power plants only have limited dispatchability and it takes a relatively long time to start them up and shut them down.
- **Intermediate-load power plants** like hard coal-fired plants and combined cycle gas turbine (CCGT) plants have a lower capacity utilization. Their variable and fixed costs are in the mid-range and they have good dispatchability.
- Most **peak-load power plants or peaker plants** are gas turbine power plants with comparatively high fuel costs but low construction and investment costs per unit of installed capacity. Hydro storage power plants and increasingly battery plants are also used. Peaker plants have a short start-up time and very good dispatchability.

It is important to draw a clear distinction between baseload power plants and power plants that are base-load **capable**. A base-load capable power plant is able to operate at nominal load at all times, regardless of external factors such as the weather. All fuel-fired power plants (plants that use fuels such as coal, gas, oil, hydrogen or biomass), geothermal power plants and to some extent also run-of-the-river and pumped storage hydropower plants fall into this category.

The main types of installation that are not base-load capable, i.e. not able to supply power continuously, are solar photovoltaic systems (PV) and wind farms. To ensure reliable load coverage at all times, an electricity system where solar and wind power are the main energy sources must therefore also have some power plants with good dispatchability and/or power storage systems. These are needed to cover the **residual load** – the difference between supply and demand (Figure 2). In PV-/wind-based systems, they are also referred to as **residual-load power plants**. Demand flexibility can also help to cover the residual load.

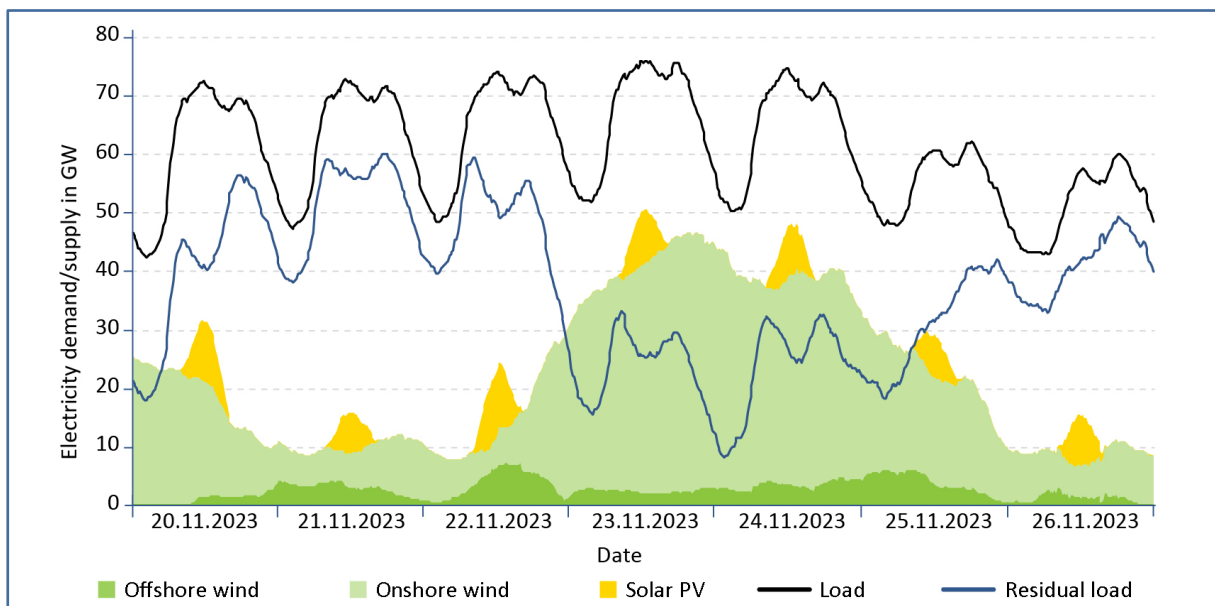


Figure 2: The residual load is the load not covered by solar PV and wind power (calendar week 47 in 2023). Source: authors' own illustration based on data for Germany taken from [www.energy-charts.info](http://www.energy-charts.info).

In the current strategy for the period to 2045, the majority of residual-load power plants are gas-fired power plants. While these will initially be fired by natural gas, in the longer term the aim is to transition to hydrogen and/or its derivatives (such as methanol, ammonia and synthetic hydrocarbons). In all the net zero scenarios analysed, residual-load power plants play a significant role (60 to 180 gigawatts (GW) in Germany in 2045) alongside power storage systems and demand flexibility measures [2]. Since they are only used as and when necessary, residual-load power plants are likely to have low-to-medium capacity utilization. A study carried out by the Fraunhofer ISE found their capacity utilization to be anywhere between just a few hours and a maximum of 3,800 full-load hours a year [3]. This means that residual-load power plants do not fall under the definition of base-load power plants.

This paper and the modelling that underpins it focus solely on the role of base-load power plants and do not consider residual-load power plants. It is currently possible to envisage four low GHG emitting<sup>2</sup> base-

<sup>2</sup> No technology can truly be said to have zero GHG emissions over its entire life cycle if GHG emissions are generated during its production and installation, in the upstream chain or in downstream processes. Some technologies also generate hard-to-abate residual emissions during operation, either because it is not technically possible to capture all the emissions and some escape, or because the extraction of the fuel required to power the technology releases emissions. To achieve net zero GHG, these emissions must be reduced and any remaining emissions offset by capturing CO<sub>2</sub> from the atmosphere.

load technologies: nuclear power plants (NPPs), natural gas combined cycle (NGCC) power plants with carbon capture and storage, geothermal power plants and potentially also nuclear fusion power plants, although the latter are still at the development stage.

This paper does not consider biomass power plants. Although they could in principle operate continuously, the reality is that there is only a limited supply of biomass. It is thus unlikely that biomass plants will be used to generate anything other than very small amounts of electricity. Due to their relatively high variable costs, if they are used at all it will be to cover the residual load.

## 2.1 Nuclear power plants

Nuclear power plants (NPPs), which have already been around for 70 years, generate electricity by nuclear fission. The first nuclear reactors that started to appear from the mid-1950s on (such as the Magnox reactors in the UK and the UNGG reactors in France) were relatively small and clearly designed for dual military-civilian use. By the 1970s, however, larger-scale, higher-capacity nuclear power plants designed solely for commercial operation started supplying electricity to the grid. While the number of new plants grew strongly for a time, it flattened out globally towards the end of the 1980s. Since then, the number of new connections to the grid has been just enough to maintain a constant global operational capacity, outside of China, of approximately 320 GW [4].

The main design focus of modern NPPs is on the cost of producing electricity and on safety measures to prevent radiation from escaping in the event of an accident or attack. The French P4 and N4, Germany's Konvoi and South Korea's APR-1400 are all examples of reactor types designed to operate cost-effectively while also being significantly safer than earlier plants. The most recent designs, such as the European Pressurised Reactor (EPR) and the AP1000, aim to maximise NPPs' inherent operational safety<sup>3</sup> and improve their profitability at the same time. However, because these are very complex, large-scale power plants, it has not been possible to operate the facilities built so far in a way to recover their total cost [5].

According to an in-depth UK study, current NPP projects in the western world are exceeding their original budget severalfold, chiefly due to supply chain issues, high labour costs and project mismanagement [6]. The upshot is that the total cost of both the Westinghouse AP1000 in the United States [7] and the EPR in Flamanville, France [8; 9] is approximately 12,000 euros per kilowatt of net electrical capacity (€/kW<sub>el</sub>). The cost of the EPR project in Olkiluoto, Finland, is about €10,000/kW<sub>el</sub> [6]. Meanwhile, although it is not yet possible to definitively forecast the total cost of the fourth EPR in Europe, currently still under construction at Hinkley Point in the UK, the latest figures reported by EDF are even higher than those for the EPR in Flamanville [10].

There is some disagreement about whether, as first-of-a-kind (FOAK) instances of a new reactor design, it is inevitable that these projects will be more expensive, and about the likelihood of subsequent power plants with the same design being cheaper [6; 11]. A study published by the French transmission system operator Réseau de Transport d'Electricité (RTE) in 2021 projects a total cost of just €6,900/kW<sub>el</sub> for the new EPR 2 model due to be commissioned in 2040 [9]. However, according to reports in the media, EDF has revised this total cost estimate upwards to €8,900/kW<sub>el</sub><sup>4</sup> over the past couple of years to reflect inflation and the sharp rise in construction sector costs [12; 13].

<sup>3</sup> This includes safety measures such as core catchers that are designed to contain and cool the core material in the event of a nuclear meltdown, or double-shell reactor buildings designed to remain intact in a meltdown scenario. Considerable effort has also been put into passive safety design. In the event of an accident, this should allow the reactor to remain in a safe and controllable condition without the need for outside interventions from the control room or the operation of cooling systems.

<sup>4</sup> The exact figures reported suggest that EDF has revised the investment costs for the 6 reactors upwards by 30 percent, from 51.7 billion euros to 67.4 billion euros in total. That is equivalent to an increase in the specific cost from €5,400/kW<sub>el</sub> to €7,000/kW<sub>el</sub>. Together with the interest during construction (IDC), which the RTE study estimates at 28 percent of the investment costs, this means that the total cost has increased from €6,900/kW<sub>el</sub> to €9,000/kW<sub>el</sub>.

In China, two new-generation NPPs including both an EPR and an AP1000 type reactor have been commissioned with a less drastic cost overrun of slightly over 50 percent and a construction period that was twice as long as originally planned [11]. At approximately €3,000/kW<sub>el</sub>, the effective construction costs of these power plants are significantly lower than similar projects in the West. However, labour costs in China are correspondingly lower [14], and it is labour costs that account for the bulk of an NPP's direct and indirect construction costs [6]. It is thus unlikely that Europe will be able to replicate these lower costs.

The construction periods for NPPs are invariably either long or very long. While the most rapidly completed recent projects worldwide have taken 8 to 10 years [6], the construction period for the European EPR projects is over 15 years [11].

Some European countries' energy policies rely on a mix of nuclear power and renewable energy. Following extensive research [9], French President Emmanuel Macron's government decided to supplement the expansion of PV and (offshore) wind power with the construction of six EPR 2 plants by 2050, and to look into the construction of a further eight of these power plants [15]. Nuclear power plays a similarly important role in Slovakia. Bulgaria, Poland, Romania, Sweden, Czechia and Hungary are all planning to build new NPPs to generate electricity. [16]

There is much debate and disagreement about the cost-effectiveness and above all the safety risks of nuclear power. There is no consensus among the experts about the risk of accidents leading to radioactive contamination of the environment, and there is still no completely satisfactory solution for safely disposing of the radioactive waste generated by NPPs. Moreover, it is virtually impossible to effectively monitor whether a growing number of countries building nuclear power plants are also using the technology for military purposes – i.e. to develop nuclear weapons.

In addition to building new power plants, another option discussed as a means of supplementing the electricity supply is to extend the lifetime of existing NPPs. In Germany, this would only be theoretically possible for those recently decommissioned power plants that have not yet reached an advanced stage in the dismantling process. In addition to the legal barriers, which cannot be overcome without the necessary political will, this option also faces various practical obstacles. Before it can be implemented, the reactors themselves, their operating crews – which are no longer all fully available – and all the various upstream and downstream stages in the supply chain would first need to be readied for recommissioning. It would also be necessary to carry out maintenance and repairs that the operators had intentionally left undone ahead of the plant's decommissioning. And the plant's safety measures would also have to be brought up to the latest standards, unless these standards were watered down. New fuel assemblies would need to be procured, qualified personnel recruited and space made for additional spent fuel assemblies in the interim and final repositories. Finally, before Germany could start using nuclear power again, it would need to find a responsible entity. The previous NPP operators have made it clear that they are not interested in this role. [17]

**Summary:** In technical terms, nuclear power plants are a fundamentally feasible baseload power plant option. However, due to their safety risks and the downstream problems caused by their radioactive waste, it is the working group's view that their use should only be considered – if at all – if there are clear and highly probable economic benefits.

## 2.2 Natural gas combined cycle power plants with carbon capture

Natural gas-fired power plants with carbon capture and storage (CCS) are another potential low-carbon solution for generating electricity. The key steps in the CCS process involve the capture, transport and storage of the CO<sub>2</sub>. There are two different technical approaches to capturing the carbon in a power plant. The first involves removing the CO<sub>2</sub> from the flue gas of a conventional gas turbine (post-combustion capture). In this approach, the gas turbine process itself remains unchanged. The second solution involves a new power plant design with an efficient, integrated carbon capture process (oxyfuel process).

The low concentration of CO<sub>2</sub> in the flue gas means that the post-combustion capture process is both energy-intensive and costly. On the plus side, however, existing power plants could be retrofitted with this technology. Although higher capture rates are possible in principle, much of the literature assumes that, for technical and economic reasons, between 90 and 95 percent of the CO<sub>2</sub> will actually be captured [18]. The energy consumed by the carbon capture process reduces the power plant's net efficiency by around 7 percentage points [18]. As a result, a CCGT power plant requires about 13 percent more fuel with CCS than without it, not counting the energy required to transport and store the captured CO<sub>2</sub>. While the first coal-fired power plants with carbon capture are now operating in the US, gas-fired power plants with carbon capture are still at the demonstration stage. [19]

Since the flue gas from the oxyfuel process is mainly made up of water vapour and CO<sub>2</sub>, it is very easy to separate the CO<sub>2</sub> from this mix. The Allam cycle is a promising approach for the oxyfuel process that is already at an advanced stage of development. It can capture almost 100 percent of the CO<sub>2</sub> emissions while maintaining a similar level of efficiency to a combined cycle power plant without CCS. However, this process requires its own special power plant technology, meaning that existing power plants cannot be retrofitted. A 50 megawatt (MW) demonstration plant is currently operating in Texas. [20]

In order to transport large, continuously produced quantities of CO<sub>2</sub> to a storage facility, the power plant must be connected to a CO<sub>2</sub> pipeline. The construction of a CO<sub>2</sub> storage and transport infrastructure in Germany is in any case a fundamental requirement for storing hard-to-abate emissions, mainly from the cement industry, which is necessary if net zero greenhouse gas emissions is to be achieved. However, this infrastructure would need to be much larger if it had to deal with significant additional CO<sub>2</sub> from the electricity sector. Germany's Carbon Management Strategy sanctions the use of carbon capture by natural-gas-fired power plants, and the EU is also working hard to develop a regulatory framework for CCS and is seeking to promote the construction of a pan-European transport and storage infrastructure.

The Sleipner Project in Norway has been permanently storing CO<sub>2</sub> in a saline aquifer since 1996, while research is ongoing into methods of storing CO<sub>2</sub> in other geological formations. [19] In Europe, there is particular potential for storing carbon under the North Sea [21]. In 2023, the Danish Greensand project opened the first site that will store CO<sub>2</sub> from other countries, including Germany, in a depleted oil field [22; 23].

Despite their carbon capture, natural-gas-fired power plants with CCS still generate GHG emissions. As a rule, current CCS technology deployed in an economically viable manner doesn't capture 100 percent of the CO<sub>2</sub> emissions. It is also necessary to factor in the upstream chain emissions, especially due to methane leaks, that occur during the extraction and transport of the natural gas fuel. Methane, which is the primary component of natural gas, is a potent greenhouse gas. The first ever EU Methane Regulation was adopted in May 2024 in order to reduce methane emissions from the extraction and use of fossil fuels [24]. To achieve net zero GHG emissions, the remaining emissions would need to be offset by additional carbon

removals. Depending on the assumed duration of the GHG impact and the level of residual and upstream chain emissions, these removals would need to be somewhere between ten percent and well over 100 percent of the direct emissions (captured by CCS) of a natural-gas-fired power plant [18; 25].

Conventional gas-fired power plants can be divided into two categories: simple open cycle gas turbine power plants and combined cycle gas turbine (CCGT) plants, where a gas turbine and steam turbine operate in tandem. Although simple gas turbine power plants have low investment costs, they have higher variable costs due to their lower efficiency (about 40 percent, compared to 60 percent for CCGT plants). They are thus best suited for use as residual-load power plants with low capacity utilization rather than for continuous operation. Since the focus of this paper is on base-load power plants, only CCGT power plants will be considered from this point on. However, their cost structure also differs from the other technologies examined. Their investment costs are comparatively lower and their variable operating costs comparatively higher, meaning that they usually operate most cost-effectively at medium capacity utilization.

Variable costs are a key factor in the assessment of natural-gas-fired power plants with CCS, since they determine when and to what extent these power plants are used. They include all expenditure not associated with the construction and operational readying of the power plant itself, especially the cost of the natural gas fuel and the cost of carbon capture and storage. The simulations in this paper do not include the cost of offsetting upstream chain emissions and emissions that escape during the carbon capture process, or the transport and temporary storage costs for both the natural gas and the CO<sub>2</sub>. Excluding these costs, the variable costs for conventional natural gas combined cycle power plants with CCS come to between 36 and 110 euros per megawatt hour (€/MWh<sub>el</sub>). For further details, see 7 Appendix under “7.2 Estimating the variable costs of power plants with CCS”.

Especially in Germany, a lack of public acceptance could prove a significant barrier to the use of natural-gas-fired power plants with CCS. Local opposition was among the factors responsible for bringing a number of CCS pilot projects to a halt some 10 to 15 years ago. Since then, there has been widespread hostility towards the technology in Germany, although the most recent studies point to a more neutral public attitude towards CCS. [26] The past few years have seen the emergence of a broad public consensus that it will be impossible to achieve net zero without using CCS for hard-to-abate emissions (mainly from the cement industry). However, also sanctioning CCS for emissions that are not hard-to-abate, which would include emissions from power plants, would risk breaking this consensus and losing the recently built public support for carbon management as a whole. It is thus important to carefully weigh up and clearly communicate the pros and cons of natural-gas-fired power plants with CCS. [27] The technology’s opponents are also particularly concerned about the health risks to people living in the vicinity of CO<sub>2</sub> transport and storage infrastructure [19].

Most established scenarios for achieving net zero in Germany include CCS for hard-to-abate industrial emissions, but do not currently envisage its use in power plants. However, Joint Research Centre scenarios for the EU do envisage the long-term use of coal-fired and gas-fired power plants with CCS. In these scenarios, gas-fired power plants with CCS account for around 5 percent of total electricity generation in 2050 [28].

**Summary:** It is the working group’s view that widespread deployment in the EU by 2045 is more feasible for natural gas combined cycle power plants with CCS than for the other technologies described in this chapter. However, this technology option also comes with its own risks, especially in terms of climate policy.

### 2.3 Geothermal electricity generation

The use of geothermal energy involves harnessing the thermal energy stored in the underground and constantly being supplied by the Earth's core. Geothermal energy has the potential to play a part in Germany's energy transition, especially in the heating and to some extent also the cooling sectors. However, its use for electricity generation is likely to be more limited. This is because geothermal electricity generation in industrial-scale facilities requires geothermal heat at relatively high temperatures of between 150 and 180 degrees Celsius. There are only a handful of locations in Germany where this is available at accessible depths [29]. Moreover, even with these high temperatures, it is (and will remain) only possible to achieve low electrical efficiencies of 7 to 17 percent [30].

Electricity can be generated from geothermal resources with temperatures as low as 70 to 80 degrees Celsius, but this has hitherto only been done at a small scale, and only produces a positive energy output under favourable conditions such as a natural water current with a high flow rate [31]. If the geothermal heat has to be pumped to the surface, its extraction consumes a substantial part of the electricity generated, even with higher temperatures. Since geothermal resources with higher temperatures are typically found at greater depths, it is generally necessary to drill to depths of well over 1,000 metres to enable geothermal electricity generation. [30]

Local geology is key to determining how difficult and costly it is to extract geothermal energy. Hydrothermal systems are currently the most widely used method. These exploit water-bearing rock layers with natural hydraulic conductivity (hot water aquifers). In Germany, the only locations with suitable geology are the North German Basin, the Upper Rhine Graben in the southwest, and the Molasse Basin in the south of the country [32]. In Europe, most of the favourable locations for geothermal electricity generation – places where sufficiently high temperatures can be accessed without having to drill too deep – are in Italy, Iceland and Türkiye [33].

Locations with low-permeability or non-water-bearing fissured rock layers require technical geothermal systems known as hot dry rock (HDR) or engineered/enhanced geothermal (EGS) systems. Unlike hydrothermal systems, these can be located almost anywhere, since they do not rely on hot water aquifers. Fluid is injected into the rock to create or expand cracks in it. However, exploiting these reservoirs is a more challenging process that calls for significantly greater investment than the installation of hydrothermal systems. While commercial hydrothermal systems are already in operation, EGS systems are currently confined to a handful of pilot facilities. Moreover, the anticipated advances in EGS technology have failed to materialise in the last few years [33].

In 2021, the global installed capacity for geothermal power generation was 16 GW [31], 877 MW of which was in the EU [33]. Approximately 90 percent of the EU's installed capacity is in Italy [33], while geothermal generates just 0.2 percent of the electricity in the EU [34]. The installed capacity in Germany is as little as 45 MW electric and is made up of small installations with a maximum capacity of 5.5 MW electric [35]. The power plants in favourable locations in Italy have a capacity of over 100 MW [36]. Geothermal electricity generation is growing sluggishly compared to other renewables – the installed capacity in the EU has risen by just 12 percent since 2010 [33].

Many experts do not believe that geothermal electricity generation will play a significant role in Germany in the future, either. It is not even included as a technology option in the established net zero scenarios for

Germany (see, for example, the meta-study of the Kopernikus project Ariadne [2]). And it is also not deemed significant in scenarios for the EU [28]. Nevertheless, geothermal could conceivably make a relevant contribution to future electricity generation if the cost of drilling the necessary wells and other extraction operations were to come down significantly as a result of experience gained from building geothermal heating systems or via technological breakthroughs. A limited amount of geothermal electricity production could also be commercially viable in specific combinations with other uses/additional revenue streams such as hydrothermal lithium extraction [37].

Exploration risk is a major barrier to geothermal projects. Some of an installation's key performance parameters can only be assessed once a well has been drilled, which requires a substantial upfront investment [30]. Moreover, the planning and construction times are relatively long [34]. Public opposition due to concerns about earthquakes can also be a barrier, especially for EGS systems but also for hydrothermal systems [33].

**Summary:** The working group involved in this study believes that the economic potential of geothermal electricity production between now and 2045 is low for Europe as a whole, and very low for Germany. While a greater role cannot be ruled out thereafter, it will depend on a number of requirements being met, including lower costs and greater public acceptance.

## 2.4 Nuclear fusion power plants

Starting in the 1950s, efforts to harness nuclear fusion for electricity production were largely driven by the prospect of developing a new means of generating electricity that is not dependent on the weather. While the physical processes underlying fusion technology are largely understood, its technological implementation is proving to be extremely challenging, and it is still hard to say when it may actually be achieved. Although there are several research facilities around the world, there are still no prototypes for any of the fusion concepts, let alone any fusion power plants capable of operating commercially. This applies equally to both of the main technology concepts currently being pursued: magnetic confinement fusion (also known as magnetic fusion) and inertial confinement fusion, which includes laser fusion. Should it prove possible to implement fusion technology, it could contribute to a net zero GHG electricity supply in years to come.

Based on current knowledge, it is likely that most fusion power plants would be in the 1 to 2 GW range<sup>5</sup> [38; 39; 40], comparable to today's nuclear and lignite-fired power plants. Fusion power plants would probably have high investment costs and low operating and fuel costs and thus be likely to operate at high capacity utilization [38; 39; 41]. Accordingly, nuclear fusion power plants would fulfil the definition of base-load power plants.

In recent years, scientific advances have been achieved at research institutions such as the National Ignition Facility (NIF/laser fusion) in the USA, the Joint European Torus (JET/magnetic confinement fusion) in the UK, and the German Wendelstein 7-X and ASDEX Upgrade (magnetic confinement fusion) research facilities. These advances have fuelled debate among policymakers and the public about whether nuclear fusion

<sup>5</sup> Magnetic confinement fusion power plants in particular could have an output in this range, but a handful of developers are also working on smaller reactors. Using a mix of magnetic and inertial confinement fusion, the startup General Fusion is planning an initial power plant with an electrical output of approximately 300 MW, composed of two 150 MW machines running in tandem.

could potentially play a role in the future energy supply. The technology is still mostly at the basic research stage, although some components are now progressing to the applied research stage. The most advanced approaches currently have a technology readiness level (TRL) of 3 to 5, which means they are somewhere between the “experimental proof of concept” stage and, at the very most, the “technology validated in relevant environment” stage [42]. In addition to the technology’s general complexity, particular challenges include the fuel supply, the fact that several reactor components have yet to be developed, and the need for materials that are sufficiently neutron-resistant and able to withstand extremely high temperatures.

The experts estimate that the first prototype or commercial power plant will only be able to start supplying power to the grid in 20 to 25 years’ time at the very earliest – and this will require extensive public and private investment and coordinated cooperation between all the stakeholders [42]. It is thus highly unlikely that fusion power plants will be able to contribute to achieving net zero in Germany by 2045 and in the rest of the EU by 2050. At this point, it is still too early to reliably predict whether they might be able to supply commercially competitive electricity in the second half of the century.

One advantage of fusion power plants over nuclear fission power plants is that they would pose less of a threat to humans and the environment. The neutrons released from nuclear fusion reactions activate the materials in the reactor core. This creates low-level to intermediate-level radioactive waste that must be safely stored for approximately 100 years. However, high-level radioactive waste like the spent fuel rods from nuclear fission plants is not usually produced. There is also no danger of an uncontrollable chain reaction with nuclear fusion – if the pressures or temperatures are lower than necessary or the fuel supply is interrupted, the nuclear fusion reaction very quickly stops of its own accord. As far as we can currently tell, if a radiation incident did occur, its impacts would be confined to the fusion plant site and its immediate surroundings [39; 43; 44]

Another advantage over nuclear fission power plants is that the potentially greater availability of fuel and the option of breeding fuel inside the reactors themselves would reduce dependency on fuel suppliers. The most likely fuel candidates are the hydrogen isotopes deuterium ( $^2\text{H}$ ) and tritium ( $^3\text{H}$ ) – based on current knowledge, these are the most promising fuels for successful implementation of fusion reactions. As much as possible of the radioactive isotope tritium would be obtained as a by-product from the reactor itself. It would not be necessary to maintain large supplies of fuel in the reactor chamber. [39; 44]

**Summary:** On balance, although nuclear fusion could potentially be a promising energy source in the long term, it is unlikely that it will be able to contribute meaningfully to electricity supply before the second half of the century. It is still too soon to reliably predict whether it will ultimately be possible to implement the technology at all, let alone operate it commercially.

### 3 Relevance of base-load power plants in the energy system

Base-load power plants such as lignite-fired power plants and NPPs have so far formed an essential part of energy supply in the electricity sector, providing a number of functions across various areas. They

- help to ensure the security of electricity supply thanks to their high availability and the generation of large amounts of energy,
- support system stability with their large synchronous generators and
- can reduce critical dependency on imports by developing additional local energy sources (lignite, geothermal energy and, looking further ahead, hydrogen isotopes) or making use of resources that are storable for a long time (fuel elements).

Alongside the question of how to substitute these contributions, cost effectiveness and social acceptance are also important considerations when assessing future relevance. The distinction between a macroeconomic and a microeconomic perspective is of considerable importance for interpreting the findings of any economic evaluation of base-load power plants.

Before discussing the relevant assessment aspects in more detail, this chapter first summarizes the results of scenario studies from recent years – mainly for Germany, but also looking at France. This provides an overview as well as a context for understanding the modelling presented later in this paper. Achieving climate neutrality by the year 2045 or 2050 is assumed to be a key requirement in all cases.

#### 3.1 Climate-neutral scenarios with and without base-load power plants

Numerous scenario studies for Germany tackle the question of how energy supply can be transformed to 100 percent renewables by 2045. The investigations conducted on behalf of a range of clients and by various teams of authors come to the unanimous conclusion that this is possible with ambitious expansion of PV and wind energy, battery storage and long-term hydrogen storage systems with hydrogen power plants. For a number of years now, such studies have hardly given any consideration to base-load power plants [2; 26; 45].

Battery storage systems and flexible electricity consumers (controlled charging of electric vehicles, heat pumps with heat storage) can create short-term flexibility. This helps, for example, to shift excess PV power from the midday period to the evening hours or to make use of surplus supply. The role of dispatchable power plants is therefore increasingly shifting towards compensating for more prolonged shortfalls, including extreme situations such as “dunkelflaute” periods (when output from solar panels and wind turbines is minimal for several days or even weeks). The energy scenarios and the current strategy of both the German government and business community primarily foresee the use of gas-fired power plants for this purpose, which initially run on natural gas and later on hydrogen or its derivatives.

In order to achieve an energy system based on 100 percent renewables in Germany by 2045, net annual growth rates of around 20 GW of PV (until 2040) and 8 GW of wind power (until 2035) are envisaged [46].<sup>6</sup> This is certainly ambitious, yet it also appears feasible. In 2023, the increase in PV capacity doubled compared to the previous year, to 15 GW. Expansion of wind power capacity, meanwhile, has also exceeded 5 GW per year several times in the past and has increased again in recent years. Although the pace of growth is lower than for PV, a record number of permits were granted in the first half of 2024. Permits have

<sup>6</sup> The gross installations required to achieve the growth in installed capacity set out in law are only slightly higher – at 21-22 GW a year for PV and 9 GW a year for wind power.

thereby reached a level commensurate with the targeted increases in capacity, at least enabling this hurdle to be overcome for the first time [47]. In addition to simplified planning and approval processes, the increasing size of the individual wind turbines and the growing proportion of large-scale PV farms play an important part in achieving the expansion targets, since construction can be further streamlined as a result.

At the most recent PV and wind energy auctions conducted by Germany's Bundesnetzagentur (electricity, gas, telecommunications and postal infrastructure authority), contracts were awarded to bids ranging from 3.62 ct/kWh to 9.48 ct/kWh [48; 49; 50; 51]. Over the last two to three decades, technological progress and mass production have led to a moderate decrease in the cost of producing electricity from wind turbines and a very sharp decrease in production costs for PV systems (for details see chapter 7 Appendix under "7.3 Development of remuneration rates for PV and wind power in Germany"). Further reductions in costs for PV power are expected over the next few years [52; 53]. In the case of wind power, rising costs for construction work and materials have resulted in a slight increase in cost for Germany. Costs are currently stagnating at this level and there is no sign of a return to the downward trend in nominal costs of the past [54].

Also beyond Germany, the rapid expansion of renewable energies already taking place worldwide looks set to continue. In 2023, for instance, global annual capacity additions increased by almost 50 percent to over 500 GW. This marked the 22nd year in succession that the rate of expansion picked up, driven mainly by growth in PV power in China, as well as in wind power. Germany accounted for around 3 percent of the global expansion of renewable energies in 2023 [55]. Continuing this growth and thus pressing ahead with the restructuring of the German energy system that is currently underway would be beneficial for continuity and predictability. An increased focus on base-load power plants, on the other hand, would involve a sharp turn with regard to energy supply in the electricity sector because – in contrast to renewable energy plants – no base-load power plants have been built in Germany for over 10 years.

The aforementioned "Futurs énergétiques 2050" study conducted by RTE for France in 2021 opens up a different perspective. Its results likewise show that PV and wind power have evolved into competitive options for electricity production, without which climate neutrality cannot be achieved by 2050. However, the study concludes that, under the assumptions made, large-scale construction of new NPPs in tandem with PV and wind power would be the most cost-effective option for achieving climate neutrality. According to the study, this conclusion could be undermined by two developments, each of which would be sufficient on its own to have an impact on economic efficiency. Firstly, if the study's assumed reductions in costs for NPPs fail to materialise, with PV and wind power becoming cheaper at the same time. Secondly, cost effectiveness could also be affected if NPPs were to be burdened with higher refinancing rates than PV and wind farms. Significant uncertainties are outlined for the scenarios based both on 100 percent renewables and construction of new NPPs, albeit in different areas [9; 56].

### What can be expected from energy system scenarios?

Scenarios are not predictions – they are *not* intended to forecast the future. Instead, scenarios are meant to illustrate consistent and plausible development trajectories and compare possible paths into the future in the form of a what-if analysis.

There are uncertainties about how things will develop in the future in many areas. This applies, for instance, to technology costs, which are dependent on technological progress, commodity prices and other developments in world markets. As well as natural gas and oil prices, prices for raw materials such as metals and rare earths, for example, can also fluctuate sharply and unpredictably due to geopolitical factors. The degree to which the assumed potential for solar and wind energy can be exploited and whether the power grid can be expanded to the required extent depend, among other things, on social acceptance. The same is true of the construction of nuclear power plants and power plants with CCS. Scenarios are therefore underpinned by a wealth of assumptions, which are in turn always influenced by current knowledge and associated expectations.

The scenario analyses developed as part of this working group allow the impact of the modelled base-load power plants on the total cost of the energy system presented to be evaluated. Besides the electricity production costs of the power plants themselves, the costs of power grids and flexibility options (storage systems, flexible power plants to cover peak loads) are also factored in. The calculations therefore show whether low-GHG base-load power plants would make it cheaper to supply electricity compared to a system based entirely on renewable energy – taking into account the costs of system integration. The scenarios also show how base-load power plants would impact the rest of the energy system by affecting power grid expansion, storage requirements and cross-border electricity trading, for example. They therefore make it possible to assess the extent to which strategies for other areas of the energy system (e.g. grid expansion plans for electricity and hydrogen, power plant strategy) would have to be adapted if German policymakers were to decide in favour of a targeted expansion of low-GHG base-load power plant capacity.

## 3.2 Security of supply and cost effectiveness

Security of supply means that there is enough energy available overall and at all times to meet the demand for the various forms of energy. This notably includes maximized long-term planning capability and reliability on the demand side, ensuring there is never any need for rationing or even power cuts, and making sure energy is supplied at competitive prices. In order to guarantee security of supply, the construction of new plants must therefore be adapted to evolving demand and the lifespan of the existing plants and infrastructure in such a way that the total production potential is at least sufficient. However, each additional unit results in excessive costs if it is not ultimately required. This would have the effect of reducing overall economic efficiency, meaning that overambitious expansion also needs to be avoided. “Minimize costs while ensuring security of supply” is the common optimization goal for energy system models in order to develop sound solutions in the face of these conflicting objectives. This also applies to the modelling that serves as the basis for chapters 4 and 5. Uncertainties regarding future developments represent a major challenge here, and these increase the further into the future we look.

If base-load power plants were to form part of the energy supply base, this would diversify the supply side, increasing the security of supply in principle. However, this only applies to the extent that they are affordably and reliably available as an option. Otherwise, the expected effect will not be delivered to the desired extent and the additional technologies that are introduced could ultimately generate added costs without a commensurate benefit in return.

Two of the potential technologies identified for increasing capacities of base-load power plants are built (NPPs) or predicted to be built (nuclear fusion) as large-scale plants with capacities of one GW or more per unit. Such a large-scale project generally requires long planning and construction times before the plant begins operating, and the initial investment can often only be recouped if the plant is in use for a very long time. NPPs, for example, are typically assumed to have an operational life of 60 years [6]. The total duration of such a base-load power plant project (70 to 80 years) is therefore approximately three times that of PV and wind power projects, meaning the project has to be set out much further in advance and cover a much longer timespan. This involves a higher decision-making risk as, once the assessment has been made, it must prove to be correct for a very long time and prediction accuracy quickly decreases as the forecasting horizon increases [57]. At the same time, however, the level of uncertainty and the risk from unfavourable future developments both drop: once a power plant of this kind has successfully started operating and has proven to do so reliably, its generating capacity will be available for a very significant period and will not need to be restored over and over again by constructing replacement facilities.

Another consideration for large-scale projects is what happens when the construction work runs over schedule and over budget. Compared both to other technologies in the electricity industry [58] and to other industries [59], regular and often disproportionate increases in construction time and construction costs have been observed in large-scale construction projects for base-load power plants. This applies not only to the NPPs already discussed in detail, but also, for example, to major hydropower plant projects. The development of small modular reactors (SMRs) with a power capacity of less than 300 MW is intended to counter this in the case of NPPs. This aims to eliminate the drawbacks of individual large-scale projects by harnessing the benefits of streamlined, standardized production and thus improving competitiveness against PV and wind farms again [59; 60; 61]. The impact on economic efficiency remains questionable to say the least, however, as this would go some way to eroding the key advantage of large power plants, namely economies of scale. It is therefore unclear whether the change would yield a positive result overall in the form of lower electricity costs [62]. As yet, there is no prototype for an SMR. Only recently, a project to construct an SMR power plant that had already got underway in Idaho Falls in Utah, USA was halted due to spiralling cost estimates, despite pledges of government support [63; 64; 65]. On the other hand, some venture capitalists in the USA have recently resumed channelling money into the development of concepts with the aim of putting the first plants into operation from 2030 [66; 67].

Long project durations also normally make it more difficult to finance investments through private-sector loans (a criterion known as “bankability”). Obtaining funding for base-load power plants on economically viable terms can therefore be challenging, and this challenge is generally overcome worldwide by offering extensive government loan guarantees or other such safeguards. Besides the interest rate for financing, the construction period is the biggest lever for limiting total costs [11] (see also Figure 3 in the “Focus on” section below).

In Germany, the industrial expertise required for all base-load power plant technologies is not fully available at present, with the exception of natural gas with CCS. As a result, this would mean either relying on external partners to help construct these power plants or requiring additional time to build up the necessary expertise.

When it comes to natural gas combined cycle power plants with CCS, on the other hand, the picture is better in Germany as the industrial expertise for this is already broadly in place here. The logistics for the transport and storage of the captured carbon dioxide pose the main implementation risks here. It can also be assumed that the prices actually paid for CCS will converge with the prices for emission allowances. As a result, the uncertainties arising from the market for emission allowances, together with the price

uncertainties arising from the market for natural gas, are likely to have an indirect impact on the economic efficiency of operating these power plants and may impair their long-term predictability, meaning that certain financial safeguards might become a necessity here too.

Restructuring energy supply to be climate neutral requires high levels of additional investment, which goes far beyond simply expanding GHG-neutral energy sources. However, this investment has to be weighed up against the direct and indirect costs of alternative development trajectories for society as a whole. Due to the complex interrelationships, this comparison can only be quantified in approximate terms using estimations [68]. Such an estimate by the ifo Institute, for example, indicates that the systemic costs of energy supply following restructuring are likely to be similar to those today. At the same time, it judges the amount of additional investment required in the meantime for developing a GHG-neutral energy supply to be acceptable [68] – see also Chapter 4.5. A study by PWC compares the cost of a rapid transition completed exactly on time in 2045 to a slower one that continues at today's speed. It comes to the conclusion that, although accelerating restructuring will greatly increase the amount of investment necessary and require it to be made sooner than with a hesitant approach, by 2050 the investment will have already more than paid for itself through lower energy costs [69].

### Focus on: The difference between the macroeconomic and the microeconomic perspective

When calculating the cost effectiveness of a project, two different viewpoints can be taken into account. On the one hand, there is the macroeconomic perspective, which seeks to evaluate the project's contribution to the overall economy and society at a national or international level and how it fits within that same context. And on the other, there is the microeconomic or business outlook, which focuses on the individual economic benefits for the actors investing in the project (for example, companies or households). The two calculation logics are comparable in many respects, as should be the case; macroeconomic welfare is, after all, the aggregate of all economic actors' individual welfare. But there is a significant difference in the interest rates applied.

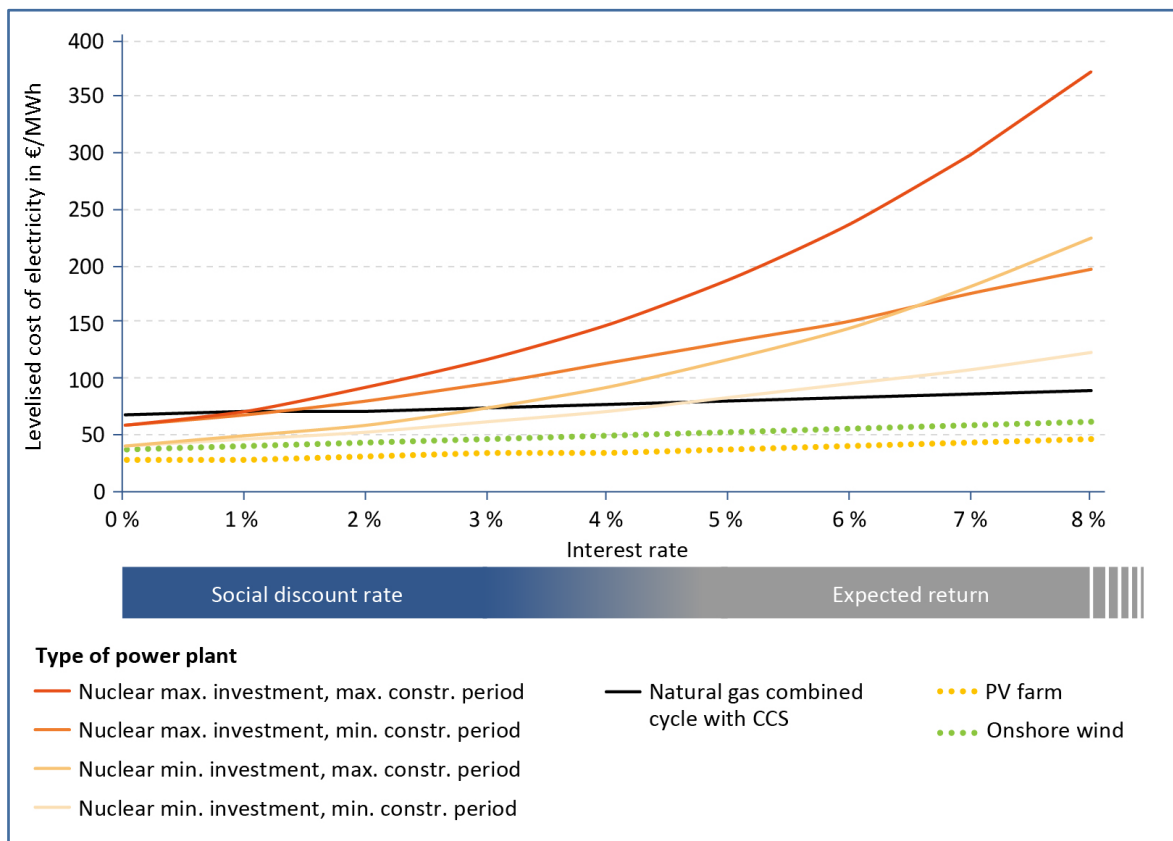
When taking a macroeconomic perspective<sup>7</sup>, the social discount rate is often used as the interest rate. There are a number of approaches for defining and determining this rate, which are each derived differently. They calculate the discount rate on the basis of, for example, intergenerational equity, empirical findings on time preferences, expectations of economic growth or interest rates for capital market investments with the lowest risk. The value determined in this way is generally in the range from 0 to 4 percent (adjusted for inflation), depending on whether the focus is more on intergenerational equity (lower end of the range) or empirical analyses of market interest rates (upper end) [70].

By contrast, the microeconomic view centres on return on investment and the associated question of whether it can provide added value for the investor when measured against the financing costs, or which alternative out of a choice of several could be expected to offer the greatest added value. This is all subject to commercial interest rates, which are typically higher than the social discount rate. Since future financing terms and market conditions are not yet (fully) known when making a long-term capital commitment, long-term investments usually imply higher financial risks for market players. In view of this, energy system models factor in a risk premium for all investments in the form of higher interest rates compared to the macroeconomic perspective. Market-related risks are generally significantly lower in economic sectors with established markets and stable overall conditions than for innovative,

<sup>7</sup> While these models take a macroeconomic perspective, they do not generally factor in feedback effects from the rest of the national economy outside the energy sector.

brand new technologies. The return expected by investors also affects whether they ultimately put forward their funds. In the field of energy technologies, business capital costs are also largely dependent on whether the state provides safeguards against or underwrites market and other risks, and to what extent.

The long construction periods and high investment costs for nuclear power plants lead to a particularly large discrepancy between the results of a macroeconomic and a microeconomic calculation – as Figure 3 illustrates. A macroeconomic levelized cost of electricity (LCOE) of 50 to 90 €/MWh<sub>el</sub> according to the calculations here from the Fraunhofer ISI at an interest rate of 2 percent contrasts with figures of, for example, 141 to 221 \$/MWh<sub>el</sub> (130 to 205 €/MWh<sub>el</sub>) as estimated by Lazard/Roland Berger with a microeconomic approach and a 7.7 percent interest rate [71].



**Figure 3: Levelized cost of electricity from nuclear power plants with their characteristically long construction periods as a function of the interest rate applied compared to PV farms, onshore wind power and natural gas combined cycle power plants with CCS.** Variation of the parameters investment (7,000 to 12,000 €/kW<sub>el</sub>, excluding IDC) and construction period (5 to 20 years, this is used together with the interest rate to calculate the IDC) for nuclear power plants. An investment of 1,200 €/kW<sub>el</sub> and a construction period of 3 years are taken as a basis for natural gas combined cycle power plants with CCS; for PV and wind power, it is assumed that the construction period is less than one year. In order to simplify calculation of the IDC, a linear increase in capital commitment during the construction period has been assumed. Source: authors' own illustration based on the assumptions in the LTS from the Fraunhofer ISI [83] for scenario year 2045, supplemented by own calculations.

Given current cost parameters and commercial interest rates, nuclear power plants have a clear cost handicap compared to renewable technologies in particular. In the case of PV and wind farms or gas-fired power plants, the interest rate applied has a much smaller effect on the LCOE due to the short construction periods and lower specific investment costs. Without government measures, such as funding part of the investment costs and/or underwriting the associated risks, there is little prospect of investment in base-load technologies on a larger scale, with the exception of natural gas combined cycle

power plants – unless there is a significant reduction in costs and/or construction periods for nuclear power compared to today. However, appropriate government and regulatory instruments could have the effect of reducing business risks. It has become clear in recent years though that there are limits to the state’s ability to underwrite business risks. By contrast, many PV and wind farms would already be economically viable from a business perspective even without specific government funding measures, especially if carbon prices were to increase. Nevertheless, appropriate government and regulatory instruments could also mitigate business risks here and thus produce more favourable financing terms, resulting in lower LCOE costs.

### 3.3 System stability

System stability encompasses all appropriate measures for maintaining a normal supply of electricity and/or restoring it after a power failure. In addition to generating sufficient amounts of energy, the following measures are crucial for ensuring a secure, safe supply of electricity that is always available:

- The provision of balancing power, i.e. on-demand adjustment of electricity production, whose various versions differ in terms of their scope, reaction time and activation mechanism. This allows the system to respond immediately to any deviations between planned and actual power generation and consumption. The balancing power also serves to balance supply and demand in the event of a component in the electricity system failing (a power plant, a transmission line or a larger consumer).
- Black start capability to restart the system following an outage. For this, it is particularly crucial to be able to restart generation in the absence of grid power and restore supply to a part of the grid when it is shut down.
- Reserve capacity that is designed to ensure the system can continue to operate even if one of its components fails (N-1 redundancy).
- The instantaneous reserve, which stabilises the frequency of the three-phase current in the grid for a short time. It is also important for providing the very high short-circuit current needed to maintain angular stability in the event of a short circuit. Up to now, sufficient instantaneous reserve has always been provided by the rotating mass of synchronous machines. In future, power-electronic “grid-forming” inverters could also help to provide the instantaneous reserve, although they need to be specially designed to do so.
- Voltage stability, which is achieved by providing reactive power to maintain a normal voltage level throughout all areas of the grid. A locally distributed system of voltage stability management is becoming more and more important, especially with the increasing variability of grid states caused by distributed fluctuating power sources.

With their large, continuously grid-connected synchronous generators, base-load power plants have so far automatically provided a substantial part of the instantaneous reserve and reactive power capacity in the grid. They also continue to be used to provide balancing power. In principle, they could contribute to the reserve capacity, but they do not have black start capability as they need a live grid to start up.

Base-load power plants are not suited for use as reserve capacity due to their cost structure. The exception to this could be existing base-load power plants that are not operating at full capacity. Otherwise, it is more cost effective to use power plants requiring less investment to provide reserve capacity. Batteries offer a more efficient and now also more economical means of supplying balancing power. These are increasingly

replacing the conventional system of frequency response governors at thermal power plants. And when it comes to rotating masses, again it is not so much the base-load power plant that matters as the permanently grid-connected generator. Synchronous couplings have been around for over 50 years that allow the generator of a gas-fired power plant to keep rotating permanently connected to the grid, even when the turbines are stationary [72].

This means, therefore, that system stability can still be guaranteed without base-load power plants, even for a system of electricity supply based entirely on renewable energies. Besides energy storage systems such as battery and pumped storage and gas-fired power plants (regardless of the fuel used), the aforementioned inverters with grid-forming properties can also help to achieve this [73]. Newly built base-load power plants in a future energy system could contribute to system stability, but they are not essential to it and their presence would probably not have a significant impact on the overall cost of ensuring system stability.

### 3.4 Import dependency

Base-load power plants can reduce imports of electricity and chemical energy carriers. Depending on the technology in question, these are replaced by additional imports of other energy carriers (fuel elements for NPPs and natural gas for natural-gas-fired power plants with CCS) or by local sources (for geothermal power and nuclear fusion). Base-load power plants therefore lead either way to an improvement in the import situation by replacing the import of energy carriers that are complex to transport with others that are more easily transportable and/or more readily storable, or even reducing overall imports.

With regard to Germany, imports of electricity and hydrogen are meant to originate almost exclusively from other European countries in the LTS. Since these countries can be classified as relatively reliable trading partners, the risk of import dependency is deemed to be fairly low. Unlike natural gas and uranium, which only occur in certain geological environments, hydrogen can in principle be produced in many countries. The number of potential source countries is therefore higher, meaning that a diversification strategy can reduce dependence on individual countries – provided that hydrogen production and transport capacities are expanded rapidly and widely enough to meet growing demand.

### 3.5 Acceptance

There is a high level of support for the expansion of renewables within Germany society in general. In a representative survey, more than 80 percent of respondents agreed overall with the further expansion of wind power, at least two thirds would have few or no concerns about the construction of new wind turbines in the vicinity of their home, and about 80 percent had few or no reservations about existing turbines in their vicinity [74]. According to another recent survey, around 70 percent of those questioned had a positive view of solar parks close to where they lived as well as of the continued expansion of renewable energies in general [75]. Despite these high approval rates, however, there has certainly been local resistance to projects – most notably the construction of wind farms.

Since base-load power plants involve a few large projects rather than a multitude of small ones, it is perhaps society's view of the technology in general that is the decisive factor more than acceptance at a local level. This view varies for the base-load technologies investigated and may also change over time. Surveys on nuclear energy, for example, reveal that it depends on the implementation details: in one such survey conducted by news magazine *Der Spiegel*, a large majority of respondents were in favour of extending plant lifetime, yet, at the same time, the majority were opposed to the construction of new NPPs [76]. More

recent surveys on CCS also show that the population's very negative stance has shifted to a more neutral attitude in the last few years [26]. What is important is that policymakers clearly explain the measures taken, place them in the context of the system as a whole and justify them – including against possible alternatives – while also underlining their role as part of the overall roadmap towards climate neutrality.

### Summary of Chapter 3:

Base-load power plants are not an essential requirement for any of the aspects considered here. Security of supply and cost effectiveness are probably the areas where they have the greatest impact. The following section therefore describes the consequences base-load power plants would have for the energy system and under what circumstances this would have beneficial effects based on energy system analyses conducted by the Fraunhofer ISI. As detailed in Chapter 2, only NPPs and natural gas with CCS could realistically be implemented on a sufficiently large scale by 2045. Chapter 4 therefore focuses on how a hypothetical ambitious expansion of these two technologies would affect the transition to climate neutrality. The main question regarding the development of geothermal energy and nuclear fusion for supplying electricity involves the cost threshold that would have to be achieved for economically viable use, as it is highly unlikely they would be crucial for supply security. Since they could be an option in the long term, however, Chapter 5 looks even further ahead to consider how all base-load technologies might help to optimise energy system costs in the long term.

## 4 Base-load power plants in the German/European energy system up to 2045

This chapter describes the findings of energy system modelling carried out by the Fraunhofer ISI relating to the construction of additional base-load power plants between now and 2045. The length of time required to build new plants means that if construction is to be realistically completed by 2045, the process would need to be set in motion right away using one or both of the technologies that are currently available on an industrial scale, i.e. NPPs and/or natural gas with CCS. Consequently, the modelling concentrates on the expansion of these two technologies in the *NPP*<sup>8</sup> and *gas with CCS* scenarios. A third scenario was also modelled as a *reference* scenario. This scenario is almost entirely the same as the *LTS T45-Strom\** scenario, except that it specifies 50 percent lower values for the minimum increase in PV and wind capacity in Germany. The purpose of this change is to allow the model's simulations more freedom with regard to the choice of power generation technology.

### 4.1 Potential capacity of analysed base-load power plant types until 2045

It is still 20 years until 2045 – the same length of time since EDF made the decision to build the EPR in Flamanville in 2004 [77]. The first test start-up of the EPR took place in autumn 2024, and the reactor could start operating in the near future. Especially for NPPs, this begs the question of how much additional capacity can be built by 2045 under optimistic assumptions.

Table 1 shows the additional base-load capacity assumptions used in the Fraunhofer ISI simulations. The capacities for Germany and Europe are in addition to the already installed and planned NPPs in the LTS for European countries other than Germany. These installed capacities were fixed parameters in the model.

Location	2035	2040	2045
Germany	0 GW	10 GW	20 GW
Europe (excluding Germany)	0 GW	20 GW	40 GW

Table 1: Additional installed capacity of nuclear power plants/natural-gas-fired power plants with CCS in the simulations.

This study's installed base-load power plant capacity assumption for Germany in 2045 is more or less the same as the maximum capacity of the NPPs that were connected to the grid in Germany for a longer period. Their capacity stood at 22.7 GW [4] between 1994 and 2003, accounting for up to 30 percent of annual electricity generation at the time. [78]. The projected rise in electricity demand means that the additional 20 GW in the simulations would account for about 13 percent of annual electricity generation in 2045.

The sum of the model's 60 GW additional NPP capacity assumption for Europe as a whole and the NPPs already included in the LTS gives a total generating capacity of 115 GW in 2045, approximately 100 GW of which would still need to be built from scratch by this date. This would require an extremely ambitious average of 10 GW a year additional capacity to come online from 2035. By way of comparison, an average of almost exactly 10 GW a year of additional nuclear power plant capacity was built in the current EU member states plus the UK and Switzerland between 1980 and 1989, more than 20 years after the first NPP for electricity production started operating (Figure 4). In view of these figures, the working group does not

<sup>8</sup> The ISI scenarios do not explicitly model NPPs here. Instead, they model generic base-load power plants without specifying any one particular technology. However, they are interpreted as NPPs in this paper, since the ESYS working group's analysis presented in Chapter 2 identifies NPPs, alongside natural gas combined cycle power plants with CCS, as the only base-load technology that could be available on an industrial scale by 2045.

consider it feasible to build additional capacity any faster than the modelled rates. Even an alliance of European countries advocating the expansion of NPPs only believes it feasible to build an additional 50 GW of capacity by 2050 [5].

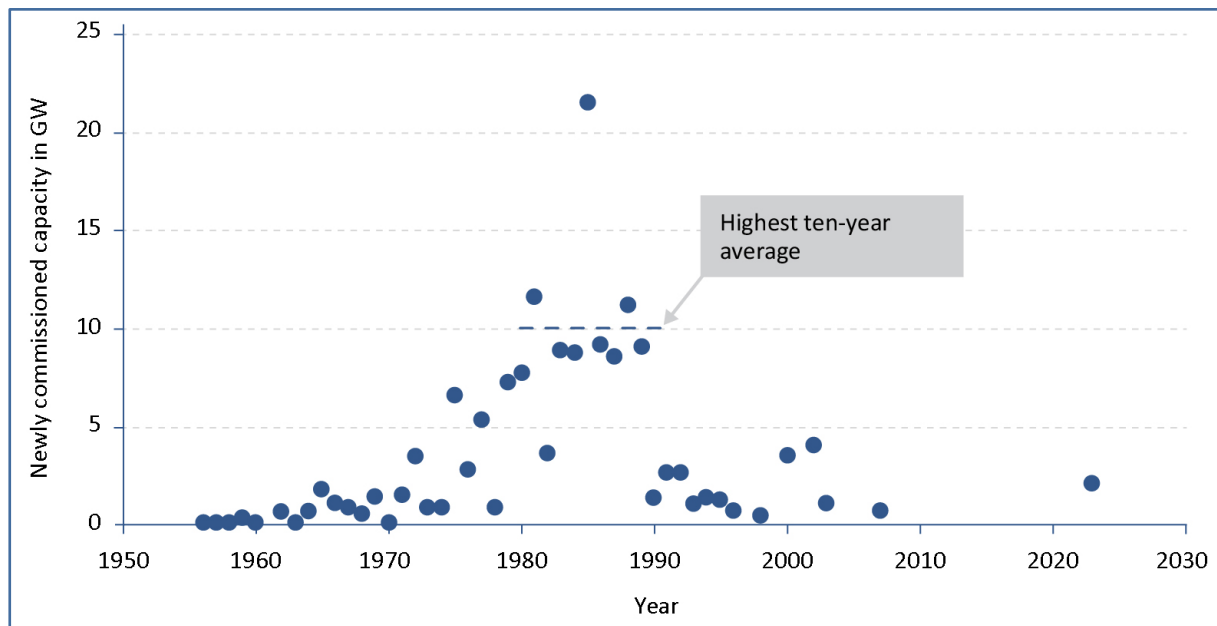


Figure 4: Newly commissioned nuclear power plants in the current EU member states plus the UK and Switzerland. The dotted line represents the highest 10-year average, which occurred between 1980 and 1989. Source: authors' own illustration based on data from the IAEA's PRIS [4].

The same capacity growth rate assumptions used for NPPs were also used for natural gas combined cycle power plants with CCS. This was primarily to make it easier to compare the results rather than being based on an estimate of what is actually feasible.

The 2021 German Federal Climate Action Act requires the energy industry to reduce its GHG emissions by 108 million tonnes a year in the period to 2030 [79; 80]. This is almost a further 50 percent lower than the levels already achieved in 2020 and 2023, and is equivalent to just one third of the emissions produced in 2017, at a time when electricity demand is projected to rise due to increased electrification. It will therefore be necessary to forge ahead rapidly with the transformation of electricity generation in order to meet the climate targets without jeopardising security of supply.

New base-load power plants will be unable to contribute to this transformation before 2030 due to the much longer time required for their planning and construction. This assertion is supported by estimates for the new power plants for which preparations are already underway under the plans in the Power Plant Security Act (formerly "Power Plant Strategy"). Even though these gas-fired power plants are easier and faster to build than base-load power plants, industry experts consider it unlikely that they will be fully operational by 2030. [81]

## 4.2 The impact of base-load power plants on electricity production

The simulations indicate that the electricity generated by NPPs and natural-gas-fired power plants with CCS in Germany would primarily replace the country's electricity imports, to almost the same extent in both cases (see Figure 5). The 130 terawatt-hour (TWh) net electricity import figure for Germany in both of these scenarios is around 20 percent lower than in the *reference* scenario. These power plants also replace

electricity from hydrogen power plants, reducing hydrogen power generation by approximately 40 percent. In the *NPP* scenario, there is also a slight reduction in the need for onshore wind power generation (-6 percent) and a very small reduction in the electricity generated by PV farms (-2 percent). In the *natural gas with CCS* scenario, on the other hand, there is only a slight reduction in onshore wind generation (-3 percent). The construction of additional base-load power plants in Germany also has an impact on the European energy system. By limiting Germany’s electricity imports and, to a lesser extent, its demand for hydrogen, it reduces the need to expand renewables, especially in other European countries.

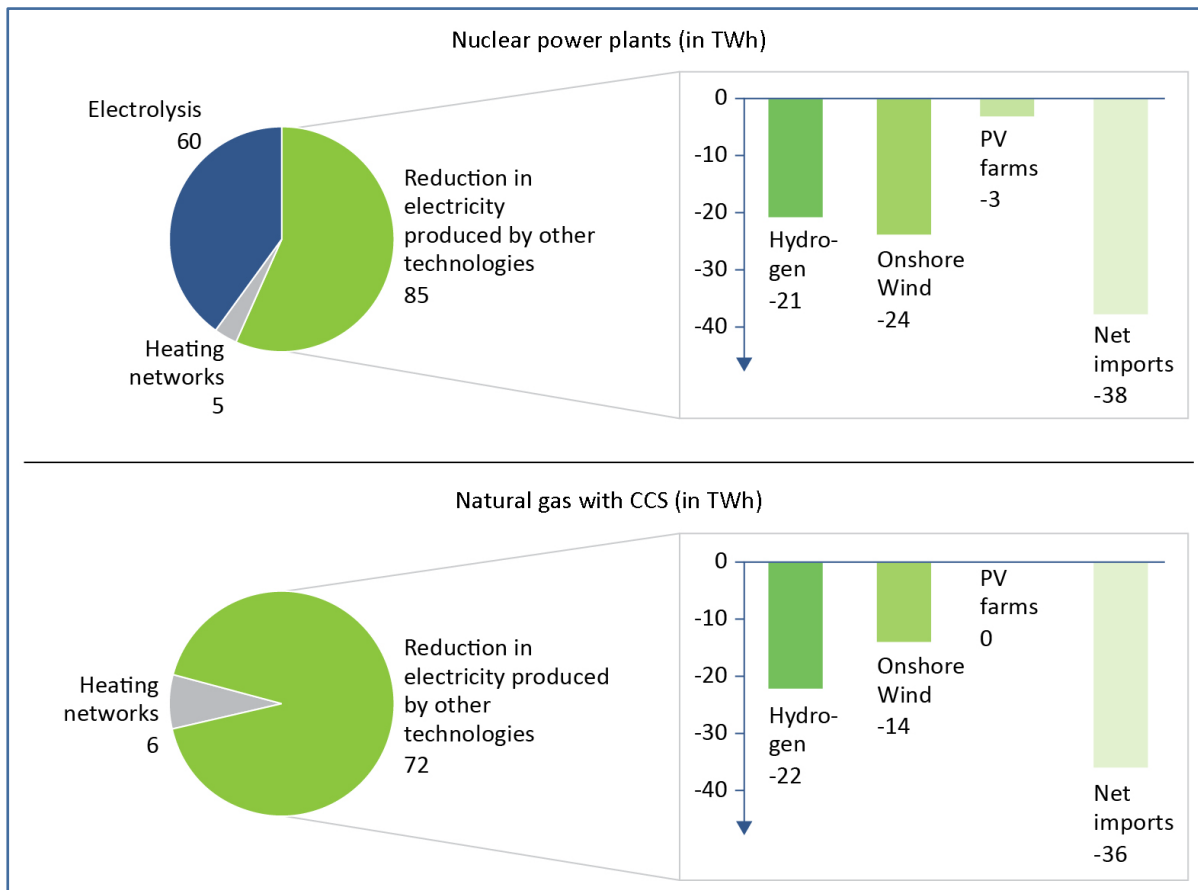


Figure 5: How the electricity from the additional power plants would be used in Germany in 2045 (left side) and reduction in other types of electricity generation compared to the *reference* scenario (right side), both for Germany. Source: authors’ own illustration based on the Fraunhofer ISI report [1].

In both scenarios with base-load power plants, there is a slight rise in the percentage of electricity used for district heating networks due to an increase of just under 10 percent in the number of large heat pumps. The largest single share of the total electricity generated by NPPs is used for hydrogen production (for more details, see Chapter 4.4).

The NPPs have a high capacity utilization of 7,200 full-load hours in the simulations. Once they have been built, their relatively low variable costs mean that it makes macroeconomic sense for them to generate as much electricity as possible. On the other hand, the higher variable costs of natural-gas-fired power plants with CCS mean that they only operate at medium capacity utilization, responding flexibly to the availability of PV and wind power. In the summer, they are thus only used during early mornings, late evenings and at night, when no solar power is being fed into the grid. This paper did not investigate whether these power plants can actually be technically designed to operate with such a high degree of flexibility, although this is

a fundamental requirement for the implementation of the *natural gas with CCS* scenario. The expansion of renewable energy and power storage systems leads to a reduction in the capacity utilization of the combined cycle natural gas turbine plants with CCS from 4,400 to 3,500 full-load hours between 2040 and 2045. The model shows that both types of base-load power plant can in principle still make a meaningful contribution to the electricity supply when used in conjunction with intermittent renewables. The question of whether it is also economically viable to build these base-load power plants in view of the relevant investment costs is discussed in Chapter 4.5.

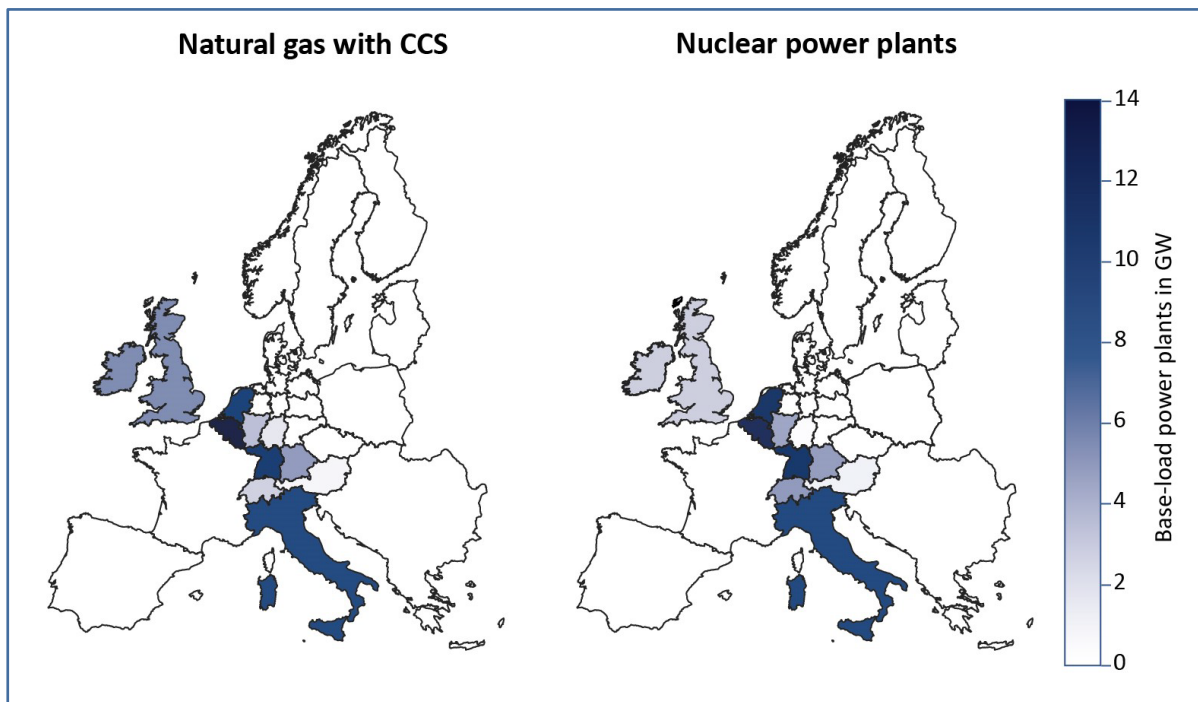
Hydrogen power plants are used in all the scenarios to cover the times when wind and solar power are in short supply. However, these plants have a very low capacity utilization of 600 to 800 full-load hours in 2045. In the two scenarios with base-load power plants, hydrogen power plants only generate electricity at times when the base-load power plants are operating at full capacity. As a result, in both of the base-load power plant scenarios, Germany's required hydrogen power plant capacity of 50 GW in 2045 is about 20 percent lower than in the *reference* scenario.

In terms of the impacts on Europe as a whole, the additional base-load power plants replace some renewable energy production. In Germany, the simulations indicate that this would mainly affect onshore wind, while in other European countries the impact would be greater on PV farms. The base-load power plants reduce the expansion of renewable energy across the whole of Europe by 5 percent in the *natural gas with CCS* scenario and 10 percent in the *NPP* scenario. A 60 GW increase in base-load power plant capacity is accompanied by a 70 to 100 GW reduction in onshore wind capacity and a 95 to 230 GW reduction in solar capacity (in both cases, the lower value is for the *natural gas with CCS* scenario and the higher value is for the *NPP* scenario). Nevertheless, PV and wind remain by far the most important electricity sources in all the scenarios and undergo a very strong expansion to around three times the current installed capacity by 2045.

### 4.3 Optimal base-load power plant locations from a system perspective

Since the location of the base-load power plants affects factors such as the required expansion of the power grid, the choice of location influences the total system costs. From a cost perspective, the optimal location is determined by, among other things, the region's renewable energy potential and electricity demand, and by the NPPs in other European countries already modelled in the LTS (see chapter 7 Appendix under "7.4 Geographical distribution of nuclear power plants modelled in the long-term scenarios").

The simulations indicate that, in order to optimise the total system costs for the whole of Europe, the additional base-load power plants should ideally be built within a large corridor stretching from London in the north across the Netherlands, Belgium and western and southern Germany to northern Italy in the south (Figure 6). It is also necessary to take into account the currently operational and planned nuclear power plants, which is why there are some nuclear power plants outside of this corridor in the scenarios. These are mostly in France, which has a large number of nuclear power plants.



**Figure 6: Simulated additional base-load power plant locations in Europe in 2045.** Existing NPPs and those modelled in the LTS are not included in the figures, but are shown in the see chapter 7 Appendix under “7.4 Geographical distribution of nuclear power plants modelled in the long-term scenarios”. Source: authors’ own illustration based on the Fraunhofer ISI report [1].

In practice, the choice of location will not only be determined by the modelled costs. Other aspects also come into play, for example public acceptance, regulatory and economic conditions and regional specificities in the countries in question. As a result, the optimal locations from a commercial perspective may differ from the locations identified in this paper due to differences in individual countries’ electricity market designs, tax regimes and subsidies or regulatory conditions in general. The additional costs to the system as a whole entailed by choosing a different location to those proposed above (for example the extra power grid expansion costs) have not been calculated.

#### 4.4 Impacts of base-load power plants on the structure of the energy system

The location of the additional base-load power plants in central Europe means that the model envisages something of a shift in European electricity production away from the continent’s periphery and towards its centre. As a result, in the *NPP* scenario some hydrogen production also moves from peripheral parts of Europe to the locations of the NPPs in central Europe. This leads to a pronounced increase in Germany’s electrolysis capacity, accompanied by a fall in its electricity and hydrogen imports.

##### 4.4.1 The hydrogen system

A well-developed hydrogen system forms a key part of the European energy system in all the scenarios. Hydrogen and its derivatives are used in industry and as energy carriers in hard-to-electrify parts of the transport and heating sectors. In the electricity sector, hydrogen is used as a seasonal energy storage medium. Surplus electricity is converted into hydrogen by electrolysis during the sunny months of March to October. The hydrogen is then converted back into electricity during the winter, helping to cover the increased electricity demand for the heat pumps used to heat buildings.

In the simulations, the high capacity utilization of the NPPs is mainly made possible by demand for hydrogen, which is flexible thanks to cavern storage. In Germany, around 40 percent of the electricity generated by the NPPs is used to produce hydrogen by electrolysis. This replaces hydrogen imports to Germany from southern, northern and eastern Europe. Hydrogen is produced at times when there is a surplus of electricity. At times when there is a high residual load, on the other hand, the electricity from base-load power plants partly replaces the reconversion of hydrogen into electricity. This reduces electricity generation from hydrogen in Germany by approximately 40 percent and overall hydrogen demand by around 10 percent.

The *NPP* scenario's installed electrolyser capacity of 33 GW in Germany in 2045 is more than 40 percent higher than in the *reference* scenario. Due to the somewhat higher capacity utilization of electrolysis, hydrogen production actually rises by more than 50 percent, from 76 to 118 TWh. This increase in domestic production means that less hydrogen has to be imported. The pure hydrogen imports originating solely from other European countries in the scenarios fall from 312 to 230 TWh. Natural gas-fired power plants with CCS also partially replace the reconversion of hydrogen into electricity, reducing Germany's hydrogen imports to 274 TWh. This is less than in the *NPP* scenario because the electricity from the natural-gas-fired power plants with CCS is not used for electrolysis, since hydrogen produced in this way could not compete with cheaper hydrogen imports.

At European level, the base-load power plants actually lead to a slight reduction in installed electrolysis capacity and hydrogen production, rather than the increase seen in Germany. This is because less hydrogen is needed for electricity production. Hydrogen imports to Europe are already very low in the *reference* scenario (50 TWh in 2045), with most of them coming to Italy by pipeline from the MENA region. In both base-load power plant scenarios they decline even further, to 30 TWh.

The average electrolyser capacity utilization for Europe as a whole is 2,800 full-load hours in the *reference* and *natural gas with CCS* scenarios. The higher figure of 3,060 full-load hours in the *NPP* scenario is due to the fact that electricity production is a little more evenly distributed over time in this scenario. This could have a positive impact on electrolysers' profitability. In Germany, electrolyser capacity utilization is around 500 full-load hours higher in all the scenarios.

#### 4.4.2 Energy transport networks

In the scenarios with additional base-load power plants, these are located in regions with the highest net energy imports. While this reduces net electricity and hydrogen flows to central Europe from the peripheral regions where demand is lower, the main directions of trade remain unchanged. In general, the required transport capacities tend to decline by less than the net flows. Consequently, the construction of additional base-load power plants would have less of an impact on the macroeconomically optimal power grid and hydrogen network expansion than we might initially suspect given the reduction in imports.

In Germany, most of the base-load power plants are located in the south of the country. This does not cause any change to the line capacities for electricity, but it does reduce the net amounts of electricity transported. In the *NPP* scenario, less electricity needs to be transported to southern Germany from the windy regions in the north and from eastern to central and western Germany, while for hydrogen, there is a reduction in the transport capacity from central to western Germany. The net energy flows for hydrogen are reduced on the routes from northern and southern to western Germany and from eastern to central Germany.

### 4.4.3 Long-term storage

The need for hydrogen storage caverns declines in both scenarios with additional power plants. It falls by roughly 10 percent in the *NPP* scenario and by as much as about 20 percent in the *natural gas with CCS* scenario, since this scenario still envisages the use of natural gas with its own storage infrastructure. This applies equally to Europe as a whole and to Germany. The differences between the *natural gas with CCS* scenario and the *reference* scenario are otherwise smaller than for the *NPP* scenario. This is because the power plants' lower capacity utilization means they produce less electricity and thus do not lead to the installation of additional electrolyzers in central Europe.

It should be noted that the *natural gas with CCS* scenario still requires some ongoing operation of natural gas networks and storage systems alongside the hydrogen infrastructure, in order to ensure the supply to the natural-gas-fired power plants. In the *reference* and *NPP* scenarios, on the other hand, this infrastructure can be gradually retired as the hydrogen networks and storage systems expand. Pipelines and storage facilities will also need to be built to transport and store the CO<sub>2</sub> captured in the natural-gas-fired power plants. This study did not investigate the extent of possible synergies or competition with regard to transport and storage capacity between the gas-fired power plants with CCS and other CCS applications (hard-to-abate emissions, DAC, etc.). If consideration is given to the option of using gas-fired power plants with CCS, it will be necessary to think carefully about the parallel natural gas and hydrogen infrastructures and the implications for the CO<sub>2</sub> infrastructure.

### 4.4.4 Sector coupling and demand flexibility

In the heating and mobility sectors, where particularly large cuts in greenhouse gas emissions are still needed, it makes little difference whether the electricity used comes from PV and wind farms or base-load power plants. Either way, electrification – in other words the switch to electric mobility and heat pumps – remains key to achieving net zero in these sectors. In the simulations, the availability of additional base-load power plants results in a slight increase in the percentage of heat pumps used for district heating. The transport sector and decentralised heating in buildings were not specifically investigated in any detail.

Sector coupling and the increased use of digital technology are opening up new demand-side management opportunities, making it possible to adjust electricity consumption to the intermittent supply of solar and wind power, at least to some extent. However, demand-side management can also be used to store the electricity that is produced almost continuously by NPPs at times when it is surplus to demand. Although the energy system is thus always going to benefit from sector coupling and digitalisation, demand flexibility and the expansion of the power grid are even more important in an energy system with 100 percent renewable energy than in a system where some electricity is generated by base-load power plants. Accordingly, the simulations indicate a tendency for a somewhat larger number of base-load power plants to be built in order to optimise the cost of electricity in scenarios with less demand flexibility or where the power grid is not expanded by as much.

## 4.5 Change in total costs with base-load power plants

Compared with base-load technologies, the electricity production costs of PV and wind energy are already lower today (see also Chapter 3.1). However, the electricity production costs of a single technology are only of limited significance when viewed in isolation, as other components (grids, power storage systems, residual-load power plants, etc.) are required to ensure reliable electricity supply. Due to their higher electricity production costs, base-load power plants could only contribute to a lower-overall-cost electricity supply if their system integration costs were considerably lower than for PV and wind energy. This may be

the case if, for example, they significantly reduce the need for power storage systems and/or power grid expansion – i.e. if savings achieved through their integration into the power supply system more than offsets their higher electricity production costs.

Figure 7 shows the development of the total annual cost of electricity, hydrogen and district heating presented in the ENERTILE model. The costs in relation to the total quantity of electricity used in these three areas remain almost constant in all scenarios over the entire period at between 51 and 55 €/MWh<sub>el</sub>. It is important to emphasize again at this point that here we are looking at costs from a macroeconomic viewpoint (see “Focus on: The difference between the macroeconomic and the microeconomic viewpoint” in Chapter 3).

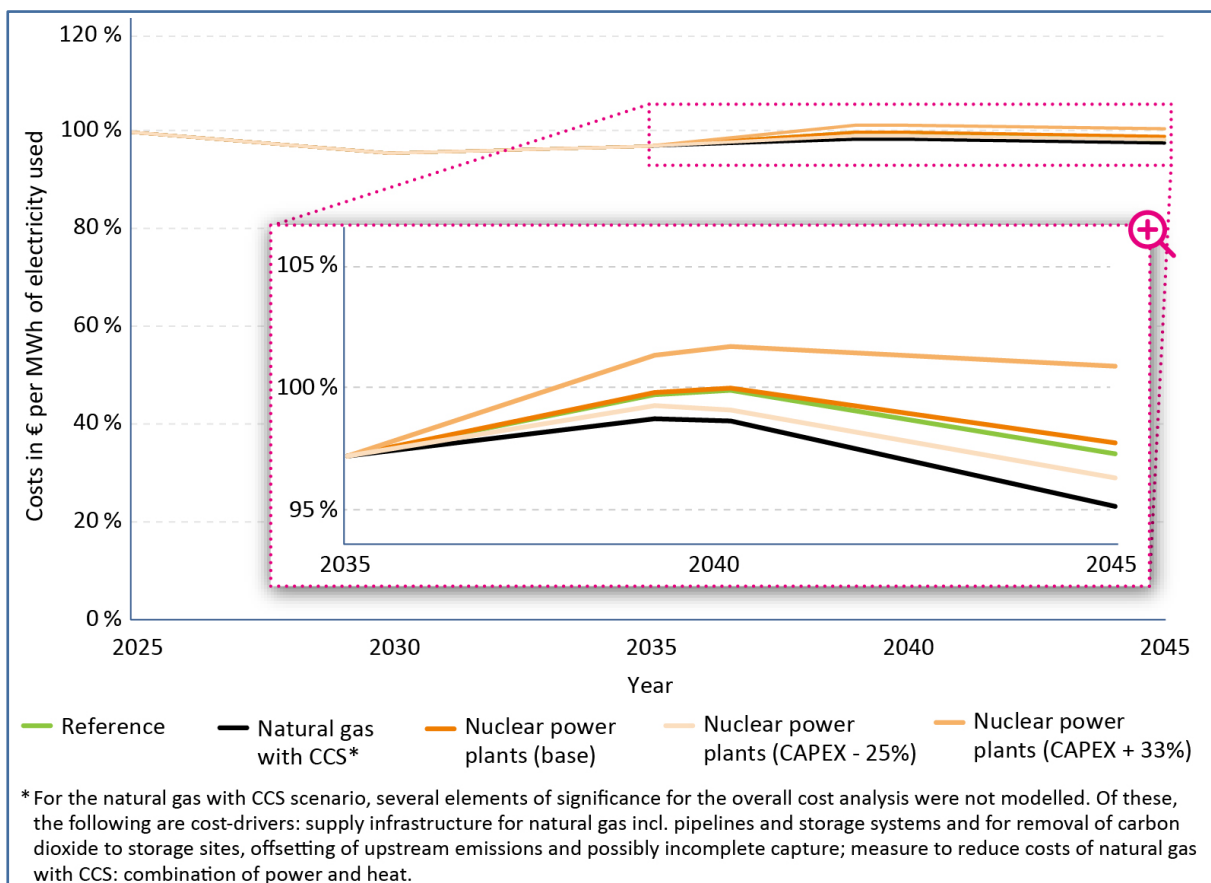


Figure 7: Specific total annual costs of the components of the European electricity, hydrogen and district heating supply included in the ENERTILE model, in relation to the total quantity of electricity used in these three areas. Source: authors’ own illustration based on the Fraunhofer ISI report [1].

At the same time, the differences between the scenarios are small. In the medium base case with assumed costs of the NPPs until commissioning of 10,000 euros per kilowatt (€/kW<sub>el</sub>) – comparable with the most recently completed NPPs in Europe – and 15 €/MWh<sub>el</sub> variable costs, the annual total cost with additional NPPs is 0.5 percent higher than without them. If costs are 7,500 €/kW<sub>el</sub>, the NPPs bring a saving of 1 percent over the reference scenario. But if the trend goes the other way and the costs of the NPPs rise to 15,000 €/kW<sub>el</sub>, this leads to an increase in total cost of 3.75 percent.

For natural gas CCGT power plants with CCS, the costs up to commissioning are estimated at 1,250 €/kW<sub>el</sub> with 53 €/MWh<sub>el</sub> variable costs. In the simulations, this produces a total cost saving of 2 percent over the reference scenario. However, it should be noted that some cost components are not shown in the model.

This relates to pipelines and power storage systems for the natural gas supply, which – in a scenario featuring natural gas power plants – would need to be maintained in addition to the development of hydrogen transportation and power storage infrastructure. The cost of CO<sub>2</sub> transportation to the storage facilities is likewise not taken into account. Since not all of the CO<sub>2</sub> will be captured, there will also be residual emissions that will need to be offset through removal of CO<sub>2</sub> from the atmosphere. Methane emissions generated in the extraction and transportation of the natural gas will have to be offset as well. However, using the power plants for combined heat and power generation – which is similarly not considered by the model – could have a cost-reducing effect. To assess whether macroeconomic cost savings can be expected by incorporating natural gas power plants with CCS, more detailed modelling taking into account the factors referred to above would have to be carried out. For natural gas power plants with CCS – as is the case for NPPs – neither a clear advantage nor a clear disadvantage can be derived from the cost analysis in the model used.

In the simulations, additional base-load power plants only have a minor influence on the total costs of the energy supply system. In view of the uncertainties regarding how the costs of base-load power plants – as well as those of renewable energies, power storage systems and hydrogen technologies – might develop, no clear conclusion can therefore be drawn on the impact of base-load power plants on the total cost of the energy system in the future. However, the simulations also show no significant possible savings arising from the realization of additional base-load power plants.

#### Summary of Chapter 4:

In an energy system dominated by PV and wind power, there is room for base-load power plants to coexist with these electricity-generating technologies. The key here is a flexible hydrogen system that can even out usage peaks and production surpluses. The approaches pursued so far as part of the energy transition – expanding the generation of renewable energies, sector coupling and electrification, expansion of the electricity grid and development of a hydrogen system – also remain key pillars en route to a climate-neutral energy system if base-load power plants are involved.

However, base-load power plants certainly have an impact on the energy system when it comes to individual elements – e.g. on the required capacity of electrolyzers and their geographical distribution. Base-load power plants could reduce the need for electricity imports and imports of pure hydrogen from Europe to Germany.

The simulations indicate that the macroeconomic costs are only slightly affected by incorporating base-load power plants up to 2045. The change in macroeconomic costs is significantly smaller than the uncertainty regarding the future cost curve of electricity generation using the various technologies, the development of power storage and transport infrastructure, etc.

## 5 Long-term economic options for base-load power plants beyond 2045

The aim of the analysis in this chapter is to assess the scope that might arise for base-load power plants within the net zero GHG energy system beyond 2045 – in a constellation that minimises macroeconomic costs. The results are intended primarily to act as a benchmark for the development of certain base-load technologies – namely nuclear fusion, geothermal energy for electricity production and possibly also nuclear fission via SMRs.

Working on the optimistic assumption that base-load power plants are available that work out significantly cheaper than the power plants currently under construction, these would be installed in Germany with capacity of up to 100 GW in the scenarios from 2045 (see Figure 8). The expansion is now model endogenous here and no longer exogenous, as in Chapter 4. In this case, expansion of PV and wind energy would be reduced to the minimum figure given in the modelling (50 percent of today's expansion targets up to 2045 set by policymakers). The reconversion of hydrogen would disappear almost entirely if base-load power plants played a major role. In addition, if extremely large quantities of electricity are generated by base-load power plants, imports and exports of electricity balance each other out over the year. However, electricity will continue to be traded across national borders.

In all scenarios where base-load power plants are incorporated into the system, these plants run at high capacity utilization levels. At low variable costs of up to 15 €/MWh<sub>el</sub>, they achieve 7,000 full-load hours a year; at variable costs of 40 €/MWh<sub>el</sub>, they still record around 6,000 full-load hours a year. Given their high capacity utilization, the contribution of these plants to electricity generation is considerable – at up to 60 percent with very low cost parameters.

The decisive factor for the expansion of the base-load power plants is the sum of investment and the further costs up to commissioning (these primarily include interest during construction (IDC), which result from pre-financing of the high capital requirements over the long construction period). Here, the maximum total cost level at which base-load power plants may still be profitable is around 10,000 €/kW<sub>el</sub>. If total costs up to commissioning are any higher, no base-load power plants will be installed in the various scenarios – even if operating costs are low.

If total costs are close to that 10,000 €/kW<sub>el</sub> profitability cut-off point, expansion in the various scenarios is heavily dependent on the variable costs. With low variable costs, base-load power plants up to 70 GW will still be added, but if variable costs are 40 €/MWh<sub>el</sub> such plants will no longer be incorporated.

Chapter 2.1 explains that the new construction projects for latest-generation NPPs currently underway or recently completed all stand at or above the profitability cut-off point set out here. Even the lower cost assumptions on which the expansion plans in France are based have since been corrected to a level that is only slightly lower. If the rising cost trend continues in the course of further planning – and the empirical data shows a very high probability of this (see Chapter 3.2) – the macroeconomic profitability cut-off point would quickly be exceeded.

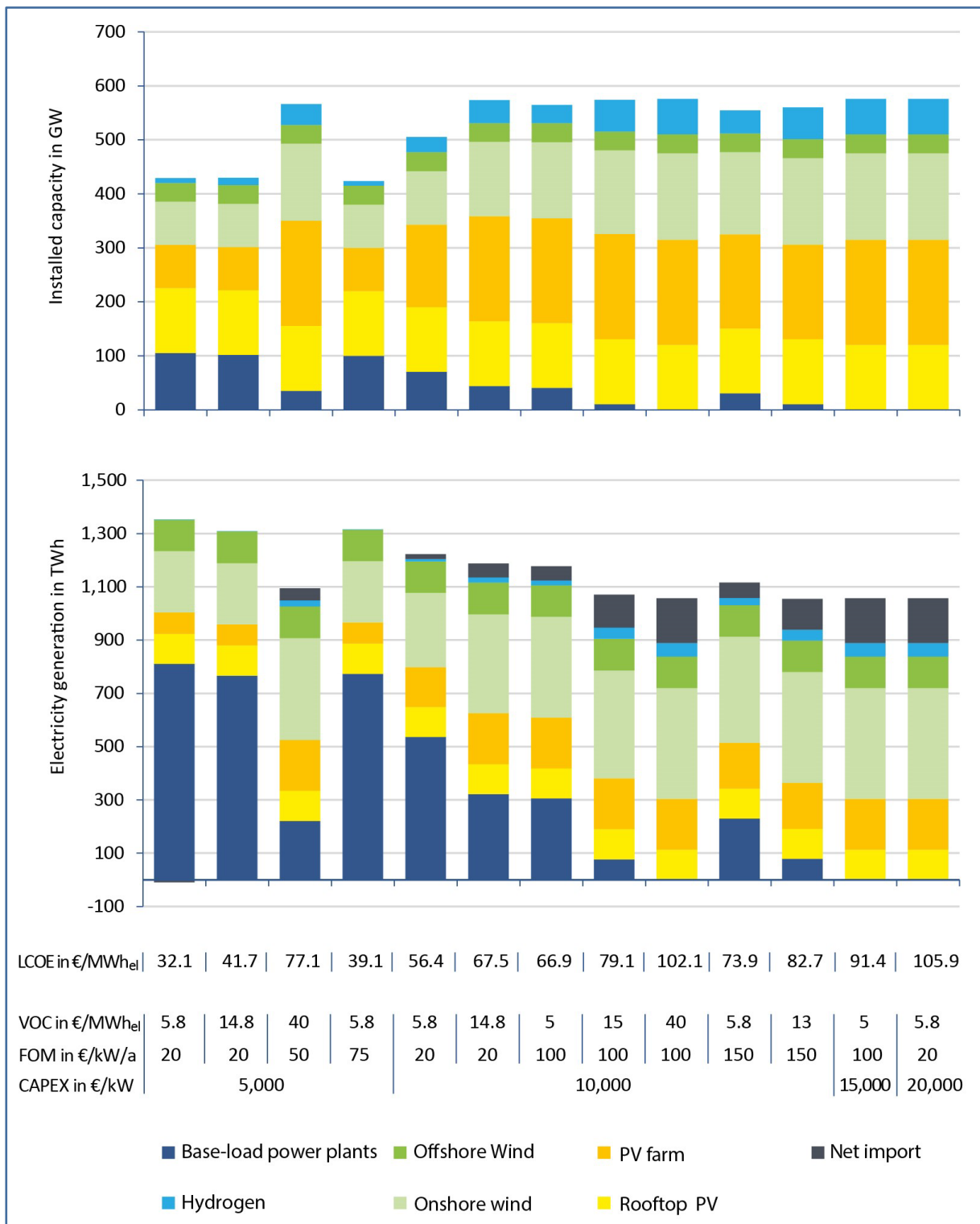


Figure 8: Installed capacity (top) and electricity generation (bottom) of the various technologies in the “after 2045” parameter variation in Germany. “VOC” stands for “variable operating costs”. Source: authors’ own illustration based on the Fraunhofer ISI report [1].

For the base-load power plants to be incorporated into the energy system, the macroeconomic LCOE calculation for them must not exceed 90 €/MWh<sub>el</sub> in the various scenarios; at a higher LCOE level, they would no longer be competitive. Figure 9 shows that the installed capacity of base-load power plants in a cost-optimised system is heavily dependent on their electricity production costs. By way of comparison:<sup>9</sup> In ENERTILE, the LCOE of PV power in Germany for 2045 is modelled at 30 – 40 €/MWh<sub>el</sub> (farm) / 60 – 70 €/MWh<sub>el</sub> (rooftop installations) and the LCOE of wind power at 30 – 80 €/MWh<sub>el</sub> (onshore) / 70 – 100 €/MWh<sub>el</sub> (offshore). For Europe, the LCOE is generally in the same range; only for PV power in southern Europe does it drop by up to 10 €/MWh<sub>el</sub> (farm) and up to 20 €/MWh<sub>el</sub> (rooftop installations). Substitution during optimisation will only happen for the lower-cost intermittent renewable electricity generator option in each case (PV farms and onshore wind power). This is due to the fact that the two more expensive variants (rooftop PV and offshore wind) in all scenarios in Germany will only be expanded up to the specified minimum level and the optimiser therefore has no scope for further reduction. For the incorporation of base-load power plants into the electricity generation system to have the effect of reducing macroeconomic costs, their LCOE would need to be at roughly the same level as PV and wind power facilities.

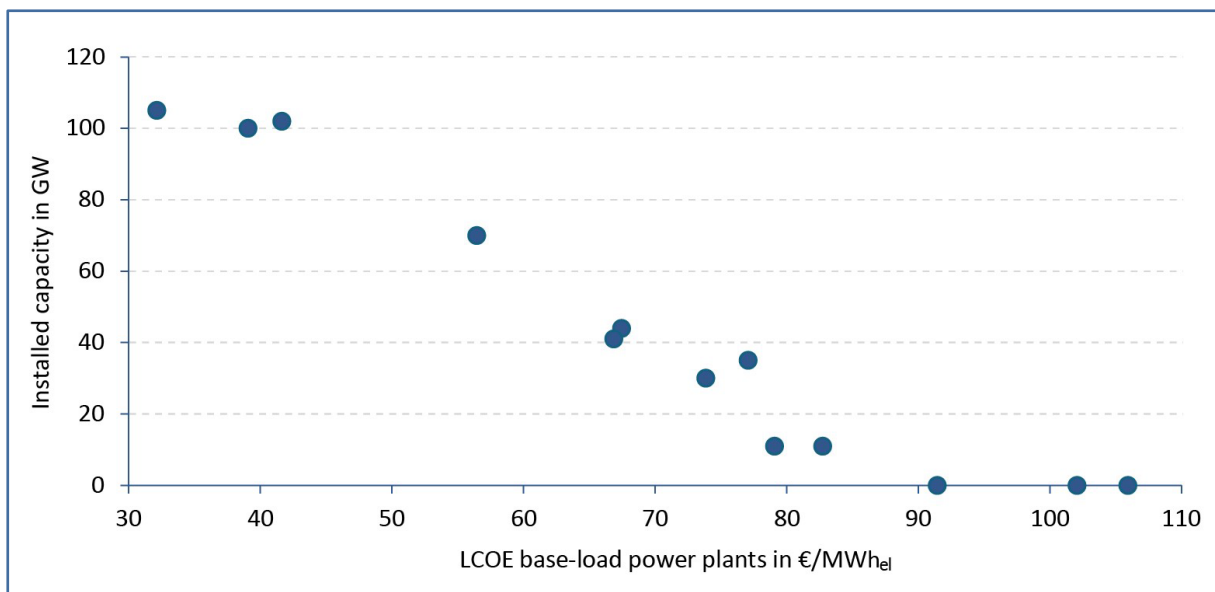


Figure 9: Installed capacity of additional base-load power plants in Germany depending on their electricity production costs. Source: authors' own illustration based on the Fraunhofer ISI report [1].

The costs of other components of the energy system were not adjusted in the investigations carried out here, but were adopted unchanged from the LTS. This paper therefore leaves a relevant question unanswered: to what extent would developments diverging from the assumptions in the LTS influence the profitability of the base-load power plants? The costs of the other components could, in principle, be both above and below the assumptions made and this deviation could also vary between the individual technologies. In view of the sustained cost degenerations observed (particularly in solar power and battery storage) – which appear set to continue for some time – it seems plausible that low-GHG base-load power plants would need to be even more cost-efficient over the long term than outlined above in order to be competitive against a mix of renewable energies and power storage systems.

<sup>9</sup> This is less about a direct comparison of the LCOE (which has, at most, limited significance, as already discussed elsewhere). Rather, it is intended to enable an assessment of the LCOE level of electricity generation in the model as a whole.

### Summary of Chapter 5:

Base-load power plants would need to become a considerably lower-cost proposition compared to the new construction projects for nuclear power plants currently being rolled out in Europe if they are to make a significant long-term contribution to a cost-efficient electricity supply. If they can come up with a cost structure that keeps the expenditure requirement very low, the modelling suggests they can play a prominent role in the system. However, in the view of the working group, this should not be expected in the foreseeable future. The cost reductions necessary for this to happen would not be achievable through gradual development of the existing nuclear power technology in Europe. From today's perspective, leap innovations would be required – such as technical breakthroughs in the design of SMRs, in drilling and extraction technology for geothermal energy or in the development of nuclear fusion power plants. However, this does not take into account potential negative sides of these technologies, such as safety and environmental risks.

## 6 Summary and outlook

For decades, base-load power plants have been a central pillar of the electricity supply in Germany and Europe. However, in recent years they have come under growing economic pressure from the development and increasing application of new technologies. Even some existing and now depreciated power plants are struggling to operate profitably in the electricity market. The restructuring of the energy system and thus the transformation of the electricity supply is far from over – on the contrary, the process is expected to continue gathering speed. Sector coupling will significantly increase the importance of the electricity system and link it more closely with the rest of the energy system. Given the availability of a sufficient number of cost-effective alternatives, base-load power plants will not hold the high level of importance they used to have for the foreseeable future. However, that does not mean that they will no longer be considered as part of the energy supply: if they meet the requirements placed on them in terms of economy, safety/security and climate policy, they can still provide a valuable addition to the energy supply base.

This study shows that the integration of additional low-GHG base-load power plants is technically feasible from a systemic point of view by 2045 at an ambitious 20 GW in Germany and 60 GW in Europe. But the analysis also highlights that integration of this kind will have barely any impact on the energy costs of the system as a whole – i.e. between -1 to -2 percent and +4 percent, and therefore clearly within the window of uncertainty resulting from technological developments and cost movements in all areas. Imports of electricity and hydrogen will be affected. The hydrogen system will play an important role, as its seasonal flexibility enables base-load power plants to achieve high capacity utilization, making them more cost effective.

Two key messages can be taken from the results. Firstly, energy supply costs will not rise or fall fundamentally with the addition of hypothetical base-load power plants within the overall supply system. And secondly, the question of costs is central to the market penetration of all climate-friendly base-load technologies – assuming they are available at all in the future. It is therefore the responsibility of the companies and stakeholders who are developing or driving progress with the relevant technologies to estimate the costs of their technology realistically and, at the same time, keep an eye on the costs of alternative technologies.

Here, attention should also be paid to policymakers and possible state support: Given the cost structures as things stand and how they are currently expected to develop, an expansion of base-load power plants with purely market-based financing would appear to be unrealistic. This raises the question of what added value would be generated by such state support. The results of the modelling and the assessment of the working group suggest there are no clear macroeconomic cost benefits to date that – beyond research and development expenditure – make a clear case for systematic government support for the construction or operation of base-load power plants.

It is also clear that additional base-load technologies could make little meaningful contribution to the energy supply before 2040. The climate goals in the energy sector and security of energy supply up to 2030 must therefore be achieved in any case through the expansion of renewable energy production; up to 2040, this essentially holds true as well. For key building blocks that are necessary for the implementation of the energy transition – e.g. electrification in the heating and transport sectors and in industry, the development of a hydrogen system and the expansion of the electricity grid – hardly anything would change even after 2040, as these are equally required in a system including base-load power plants.

The following can be stated about the technologies being considered:

- Nuclear fusion may become a potentially interesting energy source, but in this case it is unlikely to make a significant contribution until the second half of the century. It has so far been difficult to come to any reliable conclusions as to the economic efficiency of nuclear fusion in a German energy system that by then will already be net zero GHG.
- Geothermal electricity generation is already operational today and offers a noteworthy option in niche applications. However, significant development advances would need to be made to enable larger-scale expansion.
- Nuclear power plants are already available on a large scale today. Challenges for successful application stem from safety risks and the issue of radioactive waste, but above all from insufficient economic efficiency. Promising approaches are being discussed to tackle some of the problems. However, ideas such as SMRs or advantageous new reactor concepts have yet to be implemented in real plants worldwide.

Regarding the potential role of natural gas power plants with CCS in Europe's energy supply, preliminary assessments tend to be positive with regard to their feasibility and benefits, but even more detailed analyses would be essential to make a reliable judgment. This would also be relevant in view of the planned approval of natural gas power plants with CCS as part of Germany's Carbon Management Strategy. The additional infrastructure costs for natural gas and CO<sub>2</sub> transportation, in particular, would need to be looked at more closely. In order to produce a reliable assessment of economic viability, calculations with a comprehensive simulation would be absolutely essential and additional sensitivity analyses – including of the price of natural gas – would make sense. The level and handling of residual emissions caused by incomplete carbon capture and methane emissions in the upstream chain should also be highlighted. Further issues that should be investigated with regard to natural gas power plants with CCS are included in the recently published ESYS Discussion Paper on carbon management [27].

If the expansion of base-load technologies is systematically pursued in the longer term, the power plants would need to be integrated into an energy system based largely on intermittent renewable energies. The large-scale integration of base-load power plants is possible in principle in terms of the systems and technology involved. Whether it makes economic sense depends on if – through significant advances with the relevant base-load technologies involved – the climate-neutral electricity production costs of these power plants can be brought well below the levels currently estimated for the new construction of nuclear power plants.

## 7 Appendix

### 7.1 A brief look at the ENERTILE energy system model from the Fraunhofer ISI

The scenario analysis presented here was conducted by the Fraunhofer ISI using its ENERTILE [82] energy system model. The modelling is based on the LTS *T45-Strom\** scenario [83].

The “Long-term Scenarios” project develops detailed scenarios for the future development of Germany’s energy supply within a European context. The calculations are carried out using a network of various models for individual sub-areas. The project was headed by the Fraunhofer ISI, which is involved in the model network with its ENERTILE energy system model. The modelling and analysis of scenarios carried out for the ESYS working group only used ENERTILE, i.e. not the rest of the model network.

ENERTILE maps generation, grids and storage systems for electricity and hydrogen as well as the conversion of electricity to hydrogen and vice versa. The provision of heat for grid-based heat supply systems is also part of the model. The model covers Europe geographically (EU 27 plus the UK, Norway and Switzerland, split into 27 regions). The focus is on Germany. To provide the context of time, the weather year 2010 is broken down into an hour-by-hour model<sup>10</sup>. ENERTILE works internally using the linear optimisation method as part of a macroeconomic approach: it simulates a “central planner” with a perfect overview of the entire simulation period in all the details contained in the model and strives for the global optimum. One advantage of this approach is that the result is clearly mathematically defined and comprehensible and can be modelled effectively with today’s computers. However, it represents an ideal case scenario that cannot be realized in reality. The aim is to cover the stipulated demand for energy at the lowest possible cost while complying with the specified maximum GHG emissions. The costs include the operating and investment costs for the plants included in the system (converted to an annuity). The interest rate used to calculate the annuities is two percent and, in line with the macroeconomic approach, is at the low end of social discount rates. Despite all the detail in the model, when interpreting the results we should take into account that it is a highly aggregated abstraction of reality.

The self-contained optimisation of a year – including hourly utilization planning and the necessary expansion, taking existing capacities into account – represents the core functionality of ENERTILE. A development path extending over many years can be created on this basis by jointly optimizing a series of annual operations. Three path calculations were carried out for the results in this paper, extending from today’s system up to the target year for net zero GHG in Germany (2045). In addition, a parameter variation for the target system in 2045 was carried out to provide an outlook for the subsequent period, whereby the cost parameters of the base-load power plants, the specified minimum expansion of renewable energies, the expansion of the grids and the flexibility available in the electricity system were varied.

The assumptions and parameters on which the modelling is based are taken from the LTS *T45-Strom\** scenario. The only assumption that deviates here is the specified minimum expansion of PV and wind power in Germany. The expansion targets set by policymakers are specified in the LTS *T45-Strom\** scenario. In order to create greater scope in the optimisation for the use of base-load power plants, the minimum expansion of PV and wind power in Germany was set to half of the current targets stipulated by

---

<sup>10</sup> The weather year 2010 was a bad one for renewable energies – at least in Germany – in a long-term context; specific earnings from wind power were at the lower end of the expected range. Accordingly, the results of the modelling depict the downside of intermittent renewable energies and provide some margin in average or even good weather years.

policymakers in the path runs and for the parameter variation. Further expansion of PV and wind power in the model is possible as part of the cost optimization.

Only using ENERTILE means it is not possible to map the long-term elasticity of final energy demand between the various energy carriers. This means, for example, that the shares of batteries, fuel cells, motors, etc. for the mobility sector or industrial demand are determined on the basis of the optimal distribution determined in the LTS for the *T45-Strom\* scenario*. This approach was chosen in view of the enormous computational effort involved, but it should be a manageable limitation compared to the LTS, since base-load power plants provide electricity and therefore the effects of their integration are mainly concentrated on the provision of electricity and possibly hydrogen, both of which are represented in ENERTILE.

## 7.2 Estimating the variable costs of power plants with CCS

In the past, natural gas cost between 15 and 50 €/MWh<sub>th</sub> [84] liquefied ex terminal in the USA. The lower limit of this cost range corresponds to the assumptions in the LTS of 15 €/MWh<sub>th</sub> for natural gas in 2040 and 2045. The 7 percentage point reduction in efficiency results in additional costs in the range of 3.3–11 €/MWh<sub>el</sub> in relation to the electricity generated. When it comes to the captured CO<sub>2</sub> there are further costs of 10–30 €/t<sub>CO2</sub> for storage (operation of the storage system and compression) [85] and 10 €/t<sub>CO2</sub> for refilling washing solution [86], which are added after conversion via the emission factor of 0.379 t<sub>CO2</sub>/MWh<sub>el</sub> (55.8 t<sub>CO2</sub>/TJ natural gas [87] at 53 percent efficiency 0.379 t<sub>CO2</sub>/MWh<sub>el</sub>). This calculation is also shown in Table 2.

	Natural gas CCGT	Hard coal	Lignite
<b>Fuel costs (per heating value)</b>	15–50 €/MWh <sub>th</sub> [84]	7–19 €/MWh <sub>th</sub> [88]	7 €/MWh <sub>th</sub> [89]
<b>Efficiency with CCS</b>	53%	40%	35%
<b>Variable costs CCS [85;86]</b>	20–40 €/t <sub>CO2</sub>	20–40 €/t <sub>CO2</sub>	20–40 €/t <sub>CO2</sub>
<b>Emission factor fuel [87]</b>	55.8 t <sub>CO2</sub> /TJ	94 t <sub>CO2</sub> /TJ	Min. 97.5 t <sub>CO2</sub> /TJ
<b>Emission factor electricity</b>	0.379 t <sub>CO2</sub> /MWh <sub>el</sub>	0.846 t <sub>CO2</sub> /MWh <sub>el</sub>	Min. 1.003 t <sub>CO2</sub> /MWh <sub>el</sub>
<b>Fuel and CCS costs (per generated electricity)</b>	36–110 €/MWh <sub>el</sub>	34–81 €/MWh <sub>el</sub>	40–60 €/MWh <sub>el</sub>

Table 2: Variable costs of natural gas power plants with CCS and for coal (for comparison).

A value at the lower end of the range (50 €/MWh<sub>el</sub>) for the cost of fuel and CCS at natural gas power plants with CCS was used in the Fraunhofer ISI's modelling, plus 3 €/MWh<sub>el</sub> variable maintenance costs for the power plant itself. This figure is an optimistic assumption from today's perspective, but technological developments – based on the Allam power plants mentioned earlier, for example – could also lead to cost reductions compared to the assumed level. If the variable costs were higher than the LCOE of wind power, the power plants would probably only achieve low utilization rates in pure residual load operation in the optimization of the model, which means e.g. hydrogen-powered residual-load power plants may jeopardise their macroeconomic viability (see chapter 7 Appendix under “7.5 LCOE of the various technologies depending on capacity utilization”).

Coal-fired power plants with CCS are not a viable option for economic reasons. Alongside variable costs at a comparable level to natural gas, the residual emissions not included in the modelling here – which would need to be offset – are significantly higher, and the investment costs are also higher than those for gas-fired power plants.

The costs of transporting the captured carbon dioxide, which are not included in the variable costs here, can vary greatly depending on the quantity of CO<sub>2</sub> involved and the length and characteristics of the route. Studies assume a range between 1.5 €/t<sub>CO2</sub> for large quantities over short overland distances by pipeline [19] and 60 €/t<sub>CO2</sub> for small quantities over long distances (500 kilometres) by train [90].

### 7.3 Development of remuneration rates for PV and wind power in Germany

The nominal remuneration rates paid for wind power in Germany are today slightly below the level of 1991 and 2000, and were even lower for a long time between 2000 and the present day. That equates to more than a halving of the actual costs. For PV power, the initially extremely high remuneration rates since 2000 have dropped nominally to around a tenth of their original level and are now even below the rates for wind power. The nominal remuneration rate for wind power under the Electricity Feed-in Act of 1991 was 16.61 Pf/kWh (equivalent to 8.49 ct<sub>1991</sub>/kWh at the time; value today: 16.0 ct<sub>2023</sub>/kWh) based on the average electricity price in the previous year [91]. The German EEG legislation of 2000 set out a basic remuneration of 6.19 ct<sub>2000</sub>/kWh (9.57 ct<sub>2023</sub>/kWh) with initial remuneration of 9.1 ct<sub>2000</sub>/kWh (14.07 ct<sub>2023</sub>/kWh) for wind power<sup>11</sup> and a minimum remuneration of 50.62 ct<sub>2000</sub>/kWh (78.26 ct<sub>2023</sub>/kWh) for PV [92]. In the most recent tenders, the average figure for PV farms was 5.11 ct/kWh and for onshore wind power it was 7.33 ct/kWh [48; 50]. The remuneration rate for small rooftop PV installations is currently 8.03 ct/kWh (partial feed-in) to 12.73 ct/kWh (full feed-in) [93].

### 7.4 Geographical distribution of nuclear power plants modelled in the long-term scenarios

Figure 10 shows the distribution of the NPPs modelled in the LTS across the regions modelled for the scenario year 2045; these are largely concentrated in France. Small numbers are located in the UK and in the Balkans. There are also individual power plants in Finland, Czechia and the Baltic States.

<sup>11</sup> The initial remuneration was paid for at least the first five years. Depending on the yield quality of the site over this period, the payment period for the initial remuneration was extended, so that the average remuneration over the full period ultimately decreased as the yield quality increased. The average remuneration over the full 20 years was generally between 6.92 ct<sub>2000</sub>/kWh (10.7 ct<sub>2023</sub>/kWh) and the initial remuneration of 9.1 ct<sub>2000</sub>/kWh.

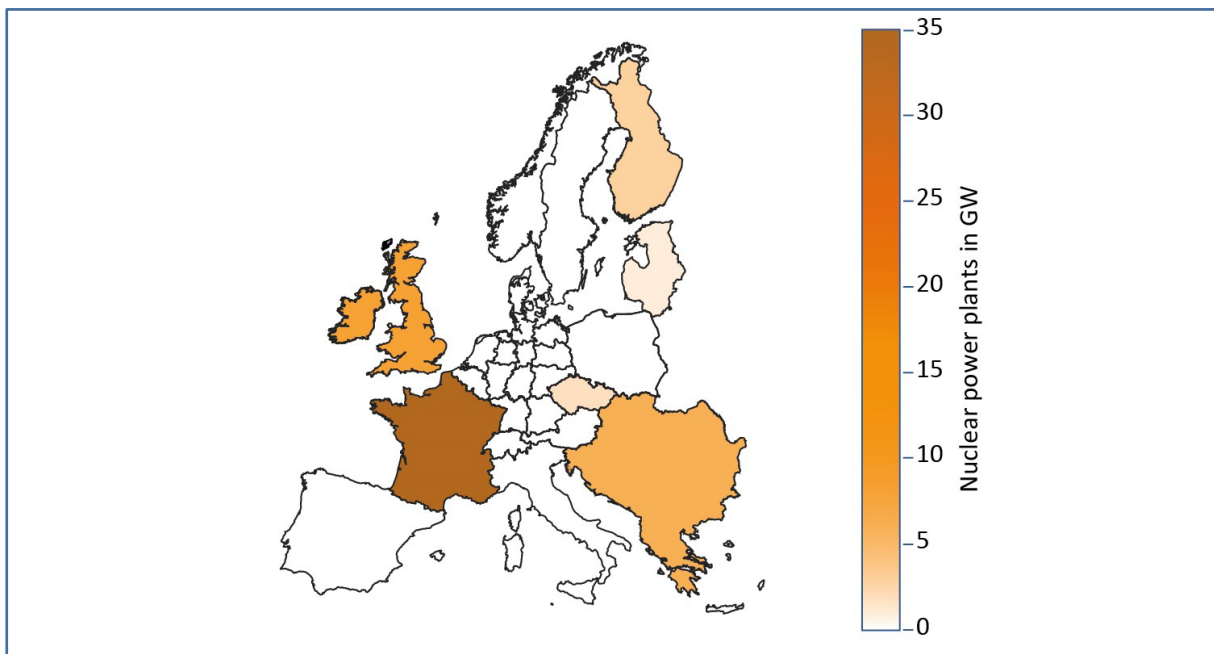


Figure 10: Locations of the NPPs modelled for the LTS in the scenario year 2045. Source: authors' own illustration based on the assumptions in the LTS from the Fraunhofer ISI.

## 7.5 LCOE of the various technologies depending on capacity utilization

When putting together an initial and brief comparative overview, LCOEs are a suitable tool for standardizing the different cost structures of the various electricity generation technologies in relation to the electricity generated (across power plants). In addition to the interest rate for calculating the annuity, the degree of utilization in the form of the achievable annual capacity utilization also plays a role here.

The LCOE illustrations in Figure 11 and Figure 12 make it clear that CCS at open cycle gas turbine power plants using natural gas would not be a preferred option from a macroeconomic viewpoint over the alternatives; a hydrogen power plant would be a lower-cost solution for all capacity utilization ranges.

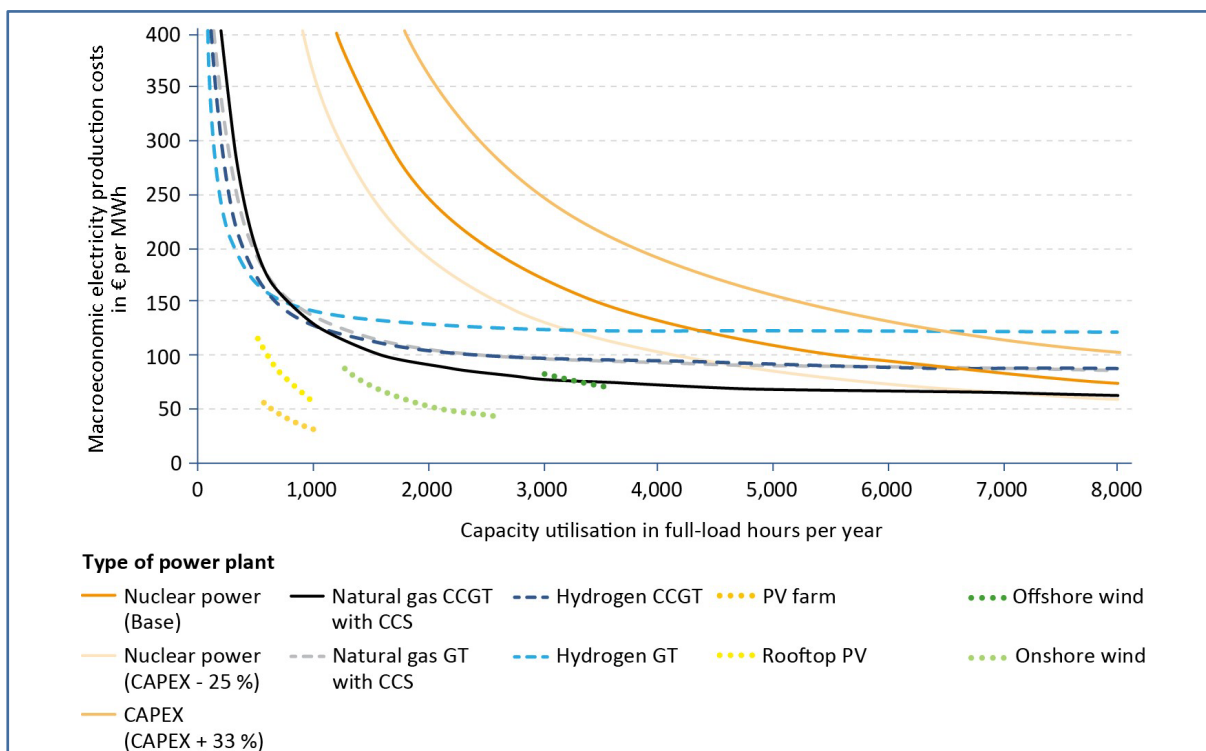


Figure 11: LCOE calculated with 2 percent interest rate for base-load power plants and natural gas CCGT power plants with CCS (solid lines), natural gas turbine power plants with CCS and hydrogen residual-load power plants (dashed lines) and PV and wind power (dotted lines) depending on capacity utilization for the scenario year 2045. Source: authors' own illustration based on the assumptions in the LTS from the Fraunhofer ISI [83] for the scenario year 2045 and on the author's own calculations.

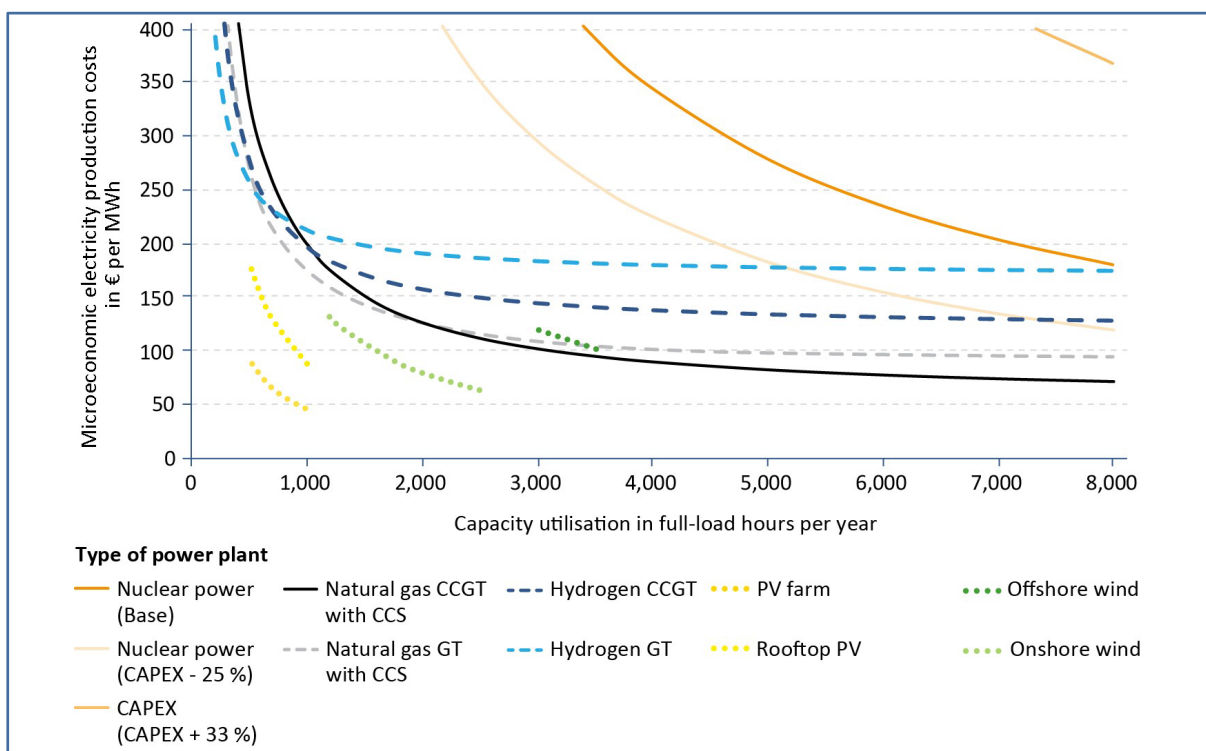


Figure 12: LCOE calculated with 8 percent interest rate for base-load power plants and natural gas CCGT power plants with CCS (solid lines), natural gas turbine power plants with CCS and hydrogen residual-load power plants (dashed lines) and PV and wind power (dotted lines) depending on capacity utilization for the scenario year 2045. Source: authors' own illustration based on the assumptions in den LTS from the Fraunhofer ISI [83] for the scenario year 2045 and on the author's own calculations.

## Literature

### 1 Fraunhofer ISI 2024

Fraunhofer Institute for Systems and Innovation Research ISI: “Modellgestützte Systemanalyse zur potentiellen Rolle von Grundlastkraftwerken im Rahmen eines dekarbonisierten europäischen Energiesystems”. URL: <https://www.isi.fraunhofer.de/de/publikationen.html> [as at: 18.11.2024]

### 2 Luderer et al. 2021

Luderer, G./Günther, C./Sörgel, D./Kost, C./Benke, F./Auer, C./Koller, F./Herbst, A./Reeder, K./Böttger, D.: *Deutschland auf dem Weg zur Klimaneutralität 2045 - Szenarien und Pfade im Modellvergleich*, 2021. URL: <https://ariadneprojekt.de/publikation/deutschland-auf-dem-weg-zur-klimaneutralitaet-2045-szenarienreport/> [as at: 24.10.2024].

### 3 Henning /Palzer 2013

Henning, H.-M./Palzer, A.: *Energiesystem Deutschland 2050*, 2013. URL: <https://www.ise.fraunhofer.de/de/veroeffentlichungen/studien/studie-energiesystem-deutschland-2050.html> [as at: 24.10.2024].

### 4 IAEA 2024

IAEA: *PRIS: Power Reactor Information System. (The Database on Nuclear Power Reactors)*, 2024. URL: <https://pris.iaea.org/pris/home.aspx> [as at: 22.09.2024].

### 5 Messad 2024

Messad, P.: “Nucléaire : comment définir le coût des futurs réacteurs en Europe ?”. In: *Euractiv*, 04.04.2024. URL: <https://www.euractiv.fr/section/energie-climat/news/nucleaire-comment-definir-le-cout-des-futurs-reacteurs-en-europe/> [as at: 24.10.2024].

### 6 Ingersoll et al. 2020

Ingersoll, E./Gogan, K./Herter, J./Foss, A.: *The ETI Nuclear Cost Drivers Project. Full Technical Report*, 2020. URL: [https://www.lucidcatalyst.com/\\_files/ugd/2fed7a\\_917857d4f3544323a84f163e5e904c23.pdf](https://www.lucidcatalyst.com/_files/ugd/2fed7a_917857d4f3544323a84f163e5e904c23.pdf) [as at: 23.09.2024].

### 7 Johnson 2024

Johnson, S.: *Plant Vogtle Unit 4 Begins Commercial Operation*, 2024. URL: <https://www.eia.gov/todayinenergy/detail.php?id=61963> [as at: 23.09.2024].

### 8 Veyrenc /Houvenagel 2022

Veyrenc, T./Houvenagel, O.: *Futurs énergétiques 2050. Rapport complet*, 2022. URL: [https://assets.rte-france.com/prod/2022-06/Futurs%20%C3%A9nerg%C3%A9tiques%202050%20\\_%20rapport%20complet.zip](https://assets.rte-france.com/prod/2022-06/Futurs%20%C3%A9nerg%C3%A9tiques%202050%20_%20rapport%20complet.zip) [as at: 23.09.2024].

### 9 RTE 2022

RTE: *Futurs énergétiques 2050: les scénarios de mix de production à l'étude permettant d'atteindre la neutralité carbone à l'horizon 2050*, 2022. URL: <https://www.rte-france.com/analyses-tendances-et-prospectives/bilan-previsionnel-2050-futurs-energetiques> [as at: 23.09.2024].

### 10 EDF 2024

EDF: “Press Release. Hinkley Point C Update” 2024. URL: <https://www.edf.fr/sites/groupe/files/epresspack/7023/Hinkley-Point-C-PR-23012024.pdf> [as at: 30.09.2024].

### 11 OECD et al. 2020

OECD/NEA Secretariat/Berthélemy, M./Soler, A. V.: *Unlocking Reductions in the Construction Costs of Nuclear: A Practical Guide for Stakeholders*. NEA no. 7530, 2020. URL: <https://cms.oecd-nea.org/upload/docs/application/pdf/2020-07/7530-reducing-cost-nuclear-construction.pdf> [as at: 23.09.2024].

### 12 Wasjbrot 2024

Wasjbrot, S.: “Nucléaire : la facture prévisionnelle des futurs EPR grimpe de 30%”. In: *Les Echos*, 04.03.2024. URL: <https://www.lesechos.fr/industrie-services/energie-environnement/exclusif-nucleaire-la-facture-previsionnelle-des-futurs-epr-grimpe-de-30-2080380> [as at: 24.10.2024].

### 13 Batinfo 2024

Batinfo: “Nuclear: The Forecast Cost of the Six Future EPRs Will Increase by 30%”. In: *Batinfo*, 05.03.2024. URL: [https://batinfo.com/en/actuality/nuclear-the-forecast-cost-of-the-six-future-EPR-will-increase-by-30\\_27545](https://batinfo.com/en/actuality/nuclear-the-forecast-cost-of-the-six-future-EPR-will-increase-by-30_27545) [as at: 24.10.2024].

### 14 Herzner 2023

Herzner, R.: *Lohnkosten. Die Lohnspirale in China dreht sich immer langsamer nach oben. Dennoch bereiten die mittlerweile hohen Lohnkosten deutschen Unternehmen Kopfzerbrechen*, 2023. URL: <https://www.gtai.de/de/trade/china/wirtschaftsumfeld/lohnkosten-234416> [as at: 30.09.2024].

### 15 GRS 2024

GRS: Nuclear energy in France, 2024. URL: <https://www.grs.de/de/kernenergie-frankreich> [as at: 30.09.2024].

### 16 Federal Ministry for Climate Action, Environment, Energy, Mobility, Innovation and Technology (BMK) o.V.

BMK: *Nuclear energy in the European Union. With some 130 reactors, approximately one third of reactors worldwide is in operation in the European Union (not dated)* URL: [https://www.bmk.gv.at/themen/klima\\_umwelt/nuklearpolitik/euratom/eu.html](https://www.bmk.gv.at/themen/klima_umwelt/nuklearpolitik/euratom/eu.html) [as at: 11.09.2024].

**17 BMWK et al. 2022**

BMWK/BMUV/RWE: *Protokoll der Telefonschaltkonferenz zur Frage der Verlängerung der Laufzeiten der Atomkraftwerke*, 2022. URL: [https://www.bmwk.de/Redaktion/DE/Downloads/P-R/protokoll-verlaengerung-der-laufzeiten-der-akw.pdf?\\_\\_blob=publicationFile&v=1](https://www.bmwk.de/Redaktion/DE/Downloads/P-R/protokoll-verlaengerung-der-laufzeiten-der-akw.pdf?__blob=publicationFile&v=1) [as at: 24.10.2024].

**18 NETL 2023**

NETL: *COST AND PERFORMANCE OF Retrofitting NGCC Units for Carbon Capture – Revision 3*, 2023. URL: <https://www.osti.gov/servlets/purl/1961845> [as at: 23.09.2024].

**19 Itul et al. 2023**

Itul, A./Diaz Rincon, A./Eulaerts, O. D./Georgakaki, A./Grabowska, M./Kapetaki, Z./Ince, E./Letout, S./Kuokkanen, A./Mountraki, A./Shtjefni, D./Jaxa-Rozen, M.: *Clean Energy Technology Observatory: Carbon Capture Utilisation and Storage in the European Union*, 2023. URL: <https://dx.doi.org/10.2760/882666> [as at: 24.10.2024].

**20 Allam et al. 2017**

Allam, R./Martin, S./Forrest, B./Fetvedt, J./Lu, X./Freed, D./Brown Jr, G. W./Sasaki, T./Itoh, M./Manning, J.: “Demonstration of the Allam Cycle: An Update on the Development Status of a High Efficiency Supercritical Carbon Dioxide Power Process Employing Full Carbon Capture”. In: *Energy Procedia*, 114, 2017, S. 5948–5966. URL: <https://doi.org/10.1016/j.egypro.2017.03.1731> [as at: 24.10.2024].

**21 acatech 2018**

acatech (pub.): *CCU and CCS – Building Blocks for Climate Protection in Industry* (acatech POSITION PAPER), Munich: Herbert Utz Verlag, 2018.

**22 Greensand 2024**

Greensand: *Project Greensand*, 2024. URL: <https://www.projectgreensand.com/en/hvad-erproject-greensand> [as at: 04.10.2024]

**23 Wintershall Dea 2023**

Wintershall Dea: *Wintershall Dea initiates first CO<sub>2</sub> storage in the Danish North Sea as part of project Greensand*, 2023. URL: <https://wintershalldea.com/de/newsroom/pi-23-05-0> [as at: 30.09.2024].

**24 Vertretung in Deutschland 2024**

European Commission: “EU-Methanverordnung verabschiedet” (press release 27.05.2024). URL: [https://germany.representation.ec.europa.eu/news/eu-methanverordnung-verabschiedet-2024-05-27-0\\_de](https://germany.representation.ec.europa.eu/news/eu-methanverordnung-verabschiedet-2024-05-27-0_de) [as at: 23.09.2024].

**25 MethaneSAT 2024**

MethaneSAT: *New Data Show U.S. Oil and Gas Methane Emissions Over Four Times Higher than EPA Estimates. (Methane Loss Rate is Eight Times Greater Than Industry Target*, 2024. URL: <https://www.methanesat.org/project-updates/new-data-show-us-oil-and-gas-methane-emissions-over-four-times-higher-epa-estimates> [as at: 23.09.2024].

**26 Ragwitz M. et al. 2023**

Ragwitz M./Weidlich, A./Biermann, D./Brandes, J./Brown, T./Burghardt, C./Dütschke, E./Erlach, B./Fischedick, M./Fuss, S./Geden, O./Gierds, J./Herrmann, U./Jochem, P./Kost, C./Luderer, G./Neuhoff, K./Schäfer, M./Wagemann, K./Wiese, F./Winkler, J./Zachmann, B./Zheng, L.: *Szenarien für ein klimaneutrales Deutschland. Technologieumbau, Verbrauchsreduktion und Kohlenstoffmanagement (Analyse)*, “Energy Systems of the Future” (ESYS) series, 2023. URL: [https://doi.org/10.48669/esys\\_2023-3](https://doi.org/10.48669/esys_2023-3) [as at: 24.10.2024].

**27 Pfeiffer et al. 2024**

Pfeiffer, J./Berit, E./Fischedick, M./Fuss, S./Geden, O./Löschel, A./Pittel, K./Ragwitz M./Stephanos, C./Weidlich, A.: *Kohlenstoffmanagement integriert denken: Anforderungen an eine Gesamtstrategie aus CCS, CCU und CDR (IMPULS)*, “Energy Systems of the Future” (ESYS) series, 2024. URL: [https://doi.org/10.48669/esys\\_2024-5](https://doi.org/10.48669/esys_2024-5) [as at: 24.10.2024].

**28 Mantzos et al. 2019**

Mantzou, L./Wiesenthal, T./Neuwahl, F./Rózsai, M.: *The POTEnCIA Central Scenario: An EU Energy Outlook to 2050*, 2019. URL: <https://dx.doi.org/10.2760/32835> [as at: 24.10.2024].

**29 Geothermal Information System 2024**

Geothermal Information System: *Overview Maps*, 2024. URL: <https://www.geotis.de/homepage/maps> [as at: 23.09.2024].

**30 Clauser /Elsner 2015**

Clauser, C./Elsner, P.: *Geothermische Kraftwerke. Technologiesteckbrief zur Analyse “Flexibilitätskonzepte für die Stromversorgung 2050”* (Materialien), “Energy Systems of the Future” (ESYS) series, 2015. URL: [https://energiesysteme-zukunft.de/fileadmin/user\\_upload/Publikationen/PDFs/ESYS\\_Technologiesteckbrief\\_Geothermische\\_Kraftwerke.pdf](https://energiesysteme-zukunft.de/fileadmin/user_upload/Publikationen/PDFs/ESYS_Technologiesteckbrief_Geothermische_Kraftwerke.pdf) [as at: 24.10.2024].

**31 IRENA /IGA 2023**

IRENA/IGA: *Global Geothermal Market and Technology Assessment*, International Renewable Energy Agency, Abu Dhabi; International Geothermal Association, The Hague, 2023.

**32 Franke et al. 2022**

Franke, D./Ladage, S./Lutz, R./Pein, M./Pletsch, T./Rebscher, D./Schauer, M./Schmidt, S./Goerne, G. von: *BGR Energiestudie 2021 – Daten und Entwicklung der deutschen und globalen Energieversorgung*, Hanover, 2022, S.1-175.

**33 Bruhn et al. 2022**

Bruhn, D./Taylor, N./Ince, E./Mountraki, A./Shtjefni, D./Georgakaki, A./Joanny Ordonez, G./Eulaerts, O./Grabowska, M.: *Clean Energy Technology Observatory. Deep Geothermal Heat and Power in the European Union*, 2022. URL: <https://data.europa.eu/doi/10.2760/181272> [as at: 24.10.2024].

**34 Dulian 2023**

Dulian, M.: *Geothermal Energy in the EU (European Parliamentary Research Service)*, 2023. URL: [https://www.europarl.europa.eu/RegData/etudes/BRIE/2023/754566/EPRS\\_BRI\(2023\)754566\\_EN.pdf](https://www.europarl.europa.eu/RegData/etudes/BRIE/2023/754566/EPRS_BRI(2023)754566_EN.pdf) [as at: 24.10.2024].

**35 Geothermal Information System 2021**

Geothermal Information System: *Geothermal electricity generation in Germany. (installed capacity [MWe], Annual production [GWh/a]*, 2021. URL: <https://www.geotis.de/geotisapp/templates/powersumstatistic.php?bula=D> [as at: 30.09.2024]

**36 Enel o.V.**

Enel: *The “Valle Secolo” geothermal power plant in Larderello, Italy*, o.V. URL: <https://www.enelgreenpower.com/our-projects/operating/geothermal-power-plant-larderello> [as at: 11.09.2024].

**37 Goldberg et al. 2022**

Goldberg, V./Nitschke, F./Kluge, T.: “Herausforderungen und Chancen für die Lithiumgewinnung aus geothermalen Systemen in Deutschland – Teil 2: Potenziale und Produktionsszenarien in Deutschland”. In: *Grundwasser*, 27, 4, 2022, S. 261–275.

**38 Griffiths et al. 2022**

Griffiths, T./Pearson, R./Bluck, M./Takeda, S.: “The Commercialisation of Fusion for the Energy Market: ‘A Review of Socio-Economic Studies’”. In: *Progress in Energy*, 4, 4, 2022.

**39 EFDA 2005**

European Fusion Development Agreement: “*Final Report of the European Fusion Power Plant Conceptual Study*”, 2005.

**40 generalfusion 2024**

generalfusion: “*Charting the path to a clean energy future with LM26*”, 2024. URL: <https://generalfusion.com/post/charting-the-path-to-a-clean-energy-future-with-lm26/> [as at: 27.07.2024].

**41 Hamacher et al. 2013**

Hamacher, T./Huber, M./Dorfner, J./Schaber, K./Bradshaw, A. M.: “Nuclear Fusion and Renewable Energy Forms: Are They Compatible?”. In: *Fusion Engineering and Design*, 88, 6, 2013, S. 657–660.

**42 Wurbs et al. 2024**

Wurbs, S./Dehlwes, S./Lübke, A./Stephanos, C./Fischedick, M./Henning, H.-M./Löschel, A./Matthies, E./Pittel, K./Renn, J./Sauer, D. U./Spiecker, known as Döhmman, I.: *Can Nuclear Fusion Contribute to a Net-Zero Energy Supply? Opportunities, Challenges and Timeframes* (Discussion Paper), “Energy Systems of the Future” (ESYS) series, 2024. URL: [https://doi.org/10.48669/esys\\_2024-8](https://doi.org/10.48669/esys_2024-8) [as at: 24.10.2024].

**43 Gonzales de Vicente et al. 2022**

Gonzales de Vicente, S. M./Smith, N. A./El-Guebaly, L./Ciattaglia, S./Di Pace, L./Gilbert, M./Mandoki, R./Rosanvallon, S./Someya, Y./Tobita, K./Torcy, D.: “Overview on the Management of Radioactive Waste from Fusion Facilities: ‘ITER, Demonstration Machines and Power Plants’”. In: *Nuclear Fusion*, 62, 8, 2022.

**44 Sánchez 2014**

Sánchez, J.: “Nuclear Fusion as a Massive, Clean, and Inexhaustible Energy Source for the Second Half of the Century: Brief History, Status, and Perspective”. In: *Energy Science & Engineering*, 2, 4, 2014, S.165–176.

**45 Stolten et al. 2022**

Stolten, D./Markewitz, P./Kraus, S./Franzmann, D./Schöb, T./Grube, T./Heinrichs, H./Gillesen, B./Linssen, J./Pflugradt, N./Risch, S./Kullmann, F./Groß, T./Maier, R./Hoffmann, M./Kotzur, L./Triesch, T.: *Neue Ziele auf alten Wegen? Strategien für eine treibhausgasneutrale Energieversorgung bis zum Jahr 2045* (Technoökonomische Systemanalyse 978-3-95806-627-4), 2022.

**46 EEG 2023**

German Renewable Energy Sources Act - EEG 2023) in the version published on 27 May 2023, last updated with Art. 3 of the Act dated 22 May 2023 (BGBl. I no. 133)

**47 FA Wind and Solar 2024**

FA Wind und Solar: *Spitzen-Halbjahr für neue Windenergie-Genehmigungen*, 2024. URL: <https://www.fachagentur-windenergie.de/aktuelles/detail/daten-zubau-windenergie-erstes-halbjahr-2024/> [as at: 28.10.2024].

**48 Bundesnetzagentur 2024**

Bundesnetzagentur: *auction for first-segment solar installations. Closing date for bids: 1 March 2024*. URL: <https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Ausschreibungen/Solaranlagen1/BeendeteAusschreibungen/Ausschreibungen2024/Gebotstermin01032024/start.html> [as at: 23.09.2024].

**49 Bundesnetzagentur 2024**

Bundesnetzagentur: *auction for second-segment solar installations. Closing date for bids: 1 February 2024*. URL: <https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Ausschreibungen/Solaranlagen2/BeendeteAusschreibungen/2024/GtFeb2024/start.html> [as at: 23.09.2024].

**50 Bundesnetzagentur 2024**

Bundesnetzagentur: *auction for onshore wind. Closing date for bids: 1 May 2024*. URL: [https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Ausschreibungen/Win\\_d\\_Onshore/BeendeteAusschreibungen/2024/GT1052024/start.html](https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Ausschreibungen/Win_d_Onshore/BeendeteAusschreibungen/2024/GT1052024/start.html) [as at: 23.09.2024].

**51 Bundesnetzagentur 2024**

Bundesnetzagentur: *innovation auction. Closing date for bids: 1 May 2024*. URL: <https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Ausschreibungen/Innovation/BeendeteAusschreibungen/GT1052024/start.html> [as at: 23.09.2024].

**52 Willuhn 2023**

Willuhn, M.: "Modulschwemme und Preissturz – Was ist bekannt?". In: *PV Magazine*, 29.09.2023. URL: <https://www.pv-magazine.de/2023/09/29/modulschwemme-und-zoelle-was-ist-bekannt/> [as at: 24.10.2024].

**53 Nijse et al. 2023**

Nijse, F. J. M. M./Mercure, J.-F./Ameli, N./Larosa, F./Kothari, S./Rickman, J./Vercoulen, P./Pollitt, H.: "The Momentum of the Solar Energy Transition". In: *Nature communications*, 14, 1, 2023, S. 6542.

**54 Lüers /Wallasch 2023**

Lüers, S./Wallasch, A.-K.: *Cost Situation of Land-based Wind Energy in Germany, as at 2023*. URL: [https://www.bmwk.de/Redaktion/DE/Downloads/E/eeg-ebwal-kostensituation-20231123.pdf?\\_\\_blob=publicationFile&v=6](https://www.bmwk.de/Redaktion/DE/Downloads/E/eeg-ebwal-kostensituation-20231123.pdf?__blob=publicationFile&v=6) [as at: 24.10.2024].

**55 IEA 2024**

IEA: *Renewables 2023. Analysis and Forecast to 2028*, 2024. URL: <https://www.iea.org/reports/renewables-2023> [as at: 24.10.2024].

**56 RTE 2021**

RTE: *Energetische Zukunftsperspektiven 2050. Wichtigste Ergebnisse*, 2021. URL: [https://assets.rte-france.com/prod/public/2022-03/Energetische%20Zukunftsperspektiven%202050\\_Wichtigste%20Ergebnisse.pdf](https://assets.rte-france.com/prod/public/2022-03/Energetische%20Zukunftsperspektiven%202050_Wichtigste%20Ergebnisse.pdf) [as at: 24.10.2024].

**57 Tetlock /Gardner 2016**

Tetlock, P. E./Gardner, D.: *Superforecasting: The Art and Science of Prediction*: Random House, 2016.

**58 Sovacool et al. 2014**

Sovacool, B. K./Gilbert, A./Nugent, D.: "An International Comparative Assessment of Construction Cost Overruns for Electricity Infrastructure". In: *Energy Research & Social Science*, 3, 2014, S. 152–160.

**59 Flyvbjerg /Gardner 2023**

Flyvbjerg, B./Gardner, D.: *How Big Things Get Done: The Surprising Factors That Determine the Fate of Every Project, from Home Renovations to Space Exploration and Everything in between*: Signal, 2023.

**60 Gearino 2023**

Gearino, D.: "What Lego—Yes, Lego—Can Teach Us About Avoiding Energy Project Boondoggles". In: *Inside Climate News*, 2023. URL: <https://insideclimatenews.org/news/02022023/inside-clean-energy-lego-building/> [as at: 24.10.2024].

**61 Flyvbjerg 2021**

Flyvbjerg, B.: "Four Ways to Scale Up: Smart, Dumb, Forced, and Fumbled" In: *SSRN Electronic Journal*, 2021. URL: <https://dx.doi.org/10.2139/ssrn.3760631> [as at: 24.10.2024].

**62 Robb Stewart /Shirvan 2023**

Robb Stewart, W./Shirvan, K.: "Construction Schedule and Cost Risk for Large and Small Light Water Reactors". In: *Nuclear Engineering and Design*, 407, 2023, S. 1–9.

**63 Rao 2023**

Rao, R.: "First U.S. Commercial Small Nuclear Reactor Axed Rising Costs Cut into NuScale's Carbon Free Power Project". In: *IEEE Spectrum*, 14.11.2023. URL: <https://spectrum.ieee.org/small-modular-reactors-nuscale> [as at: 24.10.2024].

**64 NuScale 2023**

NuScale: *NuScale Reaches Key Milestone in the Development of the Carbon Free Power Project*, 2023. URL: <https://www.nuscalepower.com/en/news/press-releases/2023/nuscale-reaches-key-milestone-in-the-development-of-the-carbon-free-power-project> [as at: 23.09.2024].

**65 NuScale 2023**

NuScale: *Utah Associated Municipal Power Systems (UAMPS) and NuScale Power Agree to Terminate the Carbon Free Power Project (CFPP)*, 2023. URL: <https://www.nuscalepower.com/en/news/press-releases/2023/uamps-and-nuscale-power-agree-to-terminate-the-carbon-free-power-project> [as at: 23.09.2024].

#### 66 Terrell 2024

Terrell, M.: *New Nuclear Clean Energy Agreement with Kairos Power*, 2024. URL: <https://blog.google/outreach-initiatives/sustainability/google-kairos-power-nuclear-energy-agreement/> [as at: 25.10.2024].

#### 67 ANS 2024

ANS: *Amazon Investing in SMRs to Deploy 5 GW by 2039*, 2024. URL: <https://www.ans.org/news/article-6480/amazon-investing-in-smrs-to-deploy-5gw-by-2039/> [as at: 25.10.2024].

#### 68 Pittel /Henning 2019

Pittel, K./Henning, H.-M.: *Was uns die Energiewende wirklich kosten wird*, 2019. URL: <https://www.ifo.de/medienbeitrag/2019-07-12/was-uns-die-energiewende-wirklich-kosten-wird> [as at: 23.09.2024].

#### 69 PwC 2024

PwC: *Beschleunigte Investitionen in den Klimaschutz lohnen sich. PwC-Studie 2024: Investitions- und Energiekosten der Energiewende*, 2024. URL: <https://www.pwc.de/de/energiewirtschaft/klimaschutzinvestitionen-lohnen-sich.html> [as at: 23.09.2024].

#### 70 Goulder /Williams III 2012

Goulder, L. H./Williams III, R. C.: *The Choice of Discount Rate for Climate Change Policy Evaluation* (NBER Working Paper Series), 2012. URL: <http://www.nber.org/papers/w18301> [as at: 24.10.2024].

#### 71 Lazard 2023

Lazard: *LCOE: Lazard's Levelized Cost of Energy Analysis*, 2023. URL: <https://www.lazard.com/media/typdxxmm/lazards-lcoepus-april-2023.pdf> [as at: 24.10.2024].

#### 72 Rühling 2024

Rühling, T.: *Netzstabilisierung mit Synchronkupplungen*, 2024. URL: <https://events.vgbe.energy/events/dampfturbinen-2024--steam-turbines-2024/10334/5HA6S/program/talk/netzstabilisierung-mit-synchronkupplungen/106874/infos> [as at: 23.09.2024].

#### 73 BMWK 2023

BMWK: *System Stability Roadmap*, 2023. URL: [https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/20231204-roadmap-systemstabilitaet.pdf?\\_\\_blob=publicationFile&v=14](https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/20231204-roadmap-systemstabilitaet.pdf?__blob=publicationFile&v=14) [as at: 24.10.2024].

#### 74 FA Wind 2023

FA Wind: *Umfrage zur Akzeptanz der Windenergie an Land*, 2023. URL: [https://fachagentur-windenergie.de/fileadmin/files/Veroeffentlichungen/Akzeptanz/FA\\_Wind\\_Umfrageergebnisse\\_Herbst\\_2023.pdf](https://fachagentur-windenergie.de/fileadmin/files/Veroeffentlichungen/Akzeptanz/FA_Wind_Umfrageergebnisse_Herbst_2023.pdf) [as at: 24.10.2024].

#### 75 E.ON 2024

E.ON: *E.ON Umfrage: Rund 70 Prozent bewerten Solarparks in Wohnortnähe und Ausbau erneuerbarer positiv*, 2024. URL: <https://www.eon.de/de/unternehmen/presse/pressemitteilung/2024/2024-02-14-eonumfrage-rund-70-prozent-bewerten-solarparks-in-wohornaehue-und-ausbau-erneuerbarer-positiv.html> [as at: 23.09.2024].

#### 76 Spiegel 2022

Spiegel: "41 percent of Germans want new nuclear power plants to be built". In: *Spiegel* magazine, 05.08.2022. URL: <https://www.spiegel.de/panorama/atom-umfrage-41-prozent-der-deutschen-wollen-neubau-von-kern-power-plants-a-a44d8513-89b3-4243-aeb5-609edf2be9f6> [as at: 24.10.2024].

#### 77 World Nuclear News 2007

World Nuclear News: *Construction of Flamanville EPR Begins*, 2007. URL: <https://www.worldnuclear-news.org/Articles/Construction-of-Flamanville-EPR-begins> [as at: 30.09.2024].

#### 78 AGEb e.V. 2023

AGEb e. V.: *Evaluation Tables on the Energy Balance for the Federal Republic of Germany 1990 to 2022*, 2023. URL: <https://ag-energiebilanzen.de/daten-und-fakten/auswertungstabellen/> [as at: 11.10.2024].

#### 79 KSG 2021

First amendment to the Federal Climate Action Act (KSG 2021), in the version published on 18 August 2021

#### 80 KSG 2024

Second amendment to the Federal Climate Action Act (KSG 2024), in the version published on 16 July 2024, last updated with Art. 1 of the Act dated 15 July 2024 (BGBl. I no. 235)

#### 81 Teuffer 2022

Teuffer, M.: *Stadtwerke werden nicht gleich loslaufen und Gaskraftwerke bauen*, 2022. URL: <https://www.energate-messenger.de/news/219130/stadtwerke-werden-nicht-gleich-loslaufen-und-gaskraftwerke-bauen> [as at: 30.09.2024].

#### 82 Enertile 2024

Enertile: *Enertile*, 2024. URL: <https://enertile.eu/enertile-en/index.php> [as at: 11.09.2024].

#### 83 Long-term scenarios 2024

Long-term Scenarios: *Long-term Scenarios*, 2024. URL: <https://langfristszenarien.de/enertile-explorer-de/> [as at: 11.09.2024].

#### 84 EIA 2024

EIA: *Price of Liquefied U.S. Natural Gas Exports*, 2024. URL: <https://www.eia.gov/dnav/ng/hist/n9133us3m.htm> [as at: 30.09.2024].

#### 85 ZEP 2019

ZEP: *The Cost of Subsurface Storage of CO<sub>2</sub>*, 2019. URL: <https://zeroemissionsplatform.eu/co2-storage-cost/> [as at: 24.10.2024]

#### 86 Gibbins 2021

Gibbins, J.: *Capture Overview: Post-Combustion Capture (PCC) Using Amines*, 2021. URL: <https://ukccsrc.ac.uk/wp-content/uploads/2021/06/21.06.29-Jon-Gibbins-Capture-overview-1-postcombustion-amines.pdf> [as at: 30.09.2024].

#### 87 Icha /Lauf 2023

Icha, P./Lauf, T.: "Emissionsfaktoren eingesetzter Energieträger zur Stromerzeugung". In: *Entwicklung der spezifischen Treibhausgasemissionen des deutschen Strommix in den Jahren 1990 - 2022*, Dessau-Roßlau, 2023.

#### 88 Federal Office for Economic Affairs and Export Control

Federal Office for Economic Affairs and Export Control: *Energie. Rohstoffe: Drittländerskohlepreis (bis 31.12.2018)*, o. V. URL: [https://www.bafa.de/DE/Energie/Rohstoffe/Drittländerskohlepreis/drittländerskohlepreis\\_node.html](https://www.bafa.de/DE/Energie/Rohstoffe/Drittländerskohlepreis/drittländerskohlepreis_node.html) [as at: 07.10.2024].

#### 89 Mier 2022

Mier, M.: "Erdgas- und Strompreise, Gewinne, Laufzeitverlängerungen und das Klima (Die Zukunft des Geschäftsmodells Deutschland)". In: *ifo Schnelldienst*, 9, 2022, S.20-26.

#### 90 VDZ 2024

VDZ: Anforderungen an eine CO<sub>2</sub>-Infrastruktur in Deutschland – Voraussetzungen für Klimaneutralität in den Sektoren Zement, Kalk und Abfallverbrennung, Düsseldorf, 2024.

#### 91 Schmelzer /Bolle 1997

Schmelzer, D./Bolle, F.: "Die preistreibende Wirkung des Stromeinspeisungsgesetzes". In: *Wirtschaftsdienst*, 77, 5, 1997, S. 284–289.

#### 92 Udo Leuschner o.V

Udo Leuschner: *Gesetz für den Vorrang Erneuerbarer Energien*, o.V. URL: <https://www.udo-leuschner.de/energie-chronik/energierecht/eeg.htm> [as at: 11.10.2024].

#### 93 Bundesnetzagentur 2024

Bundesnetzagentur: *EEG-Förderung und Fördersätze. Fördersätze für Solaranlagen*, 2024. URL: [https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/ErneuerbareEnergien/EEG\\_Foerderung/start.html](https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/ErneuerbareEnergien/EEG_Foerderung/start.html) [as at: 30.09.2024].

### Recommended citation

Stöcker, Philipp/ Erlach, Berit/ Wurbs, Sven/ Drake, Frank-Detlef/ Fishedick, Manfred/ Hanson, Jutta/Henning, Hans-Martin/ Kiewitt, Wilhelm/ Kreusel, Jochen/ Moser, Albert/ Münch, Wolfram/ Pittel, Karen/ Reuter, Albrecht/ Sauer, Dirk Uwe/ Schill, Wolf-Peter/ Spliethoff, Hartmut/ Stephanos, Cyril/ Weber, Christoph/ Weidlich, Anke: “Nuclear Fission, Natural Gas, Geothermal Energy, Nuclear Fusion. The Future Role of Baseload Power Plants” (Discussion Paper), Series on “Energy Systems of the Future” (ESYS), 2025, DOI: [https://doi.org/10.48669/esys\\_2025-1](https://doi.org/10.48669/esys_2025-1)

### Authors

Philipp Stöcker (ESYS Project Office | acatech), Dr. Berit Erlach (ESYS Project Office | acatech), Sven Wurbs (ESYS Project Office | acatech), Dr. Frank-Detlef Drake (E.ON Energy Research Center gGmbH), Prof. Dr. Manfred Fishedick (Wuppertal Institute for Climate, Environment and Energy), Prof. Dr. Jutta Hanson (Technical University of Darmstadt), Prof. Dr. Hans-Martin Henning (Fraunhofer Institute for Solar Energy Systems ISE), Wilhelm Kiewitt (50Hertz Transmission GmbH), Prof. Dr. Jochen Kreusel (Hitachi Energy), Prof. Dr. Albert Moser (RWTH Aachen University), Prof. Dr. Wolfram Münch (EnBW Energie Baden-Württemberg AG), Prof. Dr. Karen Pittel (ifo Institute), Dr. Albrecht Reuter (Fichtner IT Consulting GmbH), Prof. Dr. Dirk Uwe Sauer (RWTH Aachen University), Dr. Wolf-Peter Schill (DIW Berlin), Prof. Dr. Hartmut Spliethoff (Technical University of Munich (TUM)), Dr. Cyril Stephanos (ESYS Project Office | acatech), Prof. Dr. Christoph Weber (University of Duisburg-Essen), Prof. Dr. Anke Weidlich (Albert-Ludwigs University of Freiburg (INATECH))

### Additional contributors

Silvia Biagioli (ESYS Koordinierungsstelle | acatech)

### Coordination of production and typesetting

Annika Seiler (ESYS Project Office | acatech)

### Editorial office

Claire Stark (ESYS Project Office | acatech)

### Graphics production

Annika Eßmann (ESYS Project Office | acatech)

### Series editor

acatech – National Academy of Science and Engineering (lead institution)  
Munich Project Office, Karolinenplatz 4, 80333 Munich | [www.acatech.de](http://www.acatech.de)

German National Academy of Sciences Leopoldina  
Jägerberg 1, 06108 Halle (Saale) | [www.leopoldina.org](http://www.leopoldina.org)

Union of the German Academies of Sciences and Humanities  
Geschwister-Scholl-Straße 2, 55131 Mainz | [www.akademienunion.de](http://www.akademienunion.de)

### Right-hand cover image

ESYS illustration with material from © Yellow bird | [stock.adobe.com](https://stock.adobe.com), © Figures, © Ellery Studios

### DOI

[https://doi.org/10.48669/esys\\_2025-1](https://doi.org/10.48669/esys_2025-1)

### Project duration

03/2016 to 12/2024

### Funding

This project is funded by the Federal Ministry of Education and Research (funding code 03EDZ2016).

SPONSORED BY THE



Federal Ministry  
of Education  
and Research

## The Academies' Project "Energy Systems of the Future"

In the initiative "Energy Systems of the Future" (ESYS), acatech – National Academy of Science and Engineering, the German National Academy of Sciences Leopoldina and the Union of the German Academies of Sciences and Humanities provide input for the debate on the challenges and opportunities of the German energy transition. Within the Academies' Project, over 160 experts from the science and research communities come together in interdisciplinary working groups to develop policy options for the implementation of a secure, affordable and sustainable energy supply.

### Contact:

Dr. Cyril Stephanos  
Head of Project Office "Energy Systems of the Future"  
Georgenstraße 25, 10117 Berlin  
phone: +49 30 206 30 96 - 0  
e-mail: [stephanos@acatech.de](mailto:stephanos@acatech.de)  
web: [energiesysteme-zukunft.de/en](http://energiesysteme-zukunft.de/en)

The German National Academy of Sciences Leopoldina, acatech – National Academy of Science and Engineering, and the Union of the German Academies of Sciences and Humanities provide policymakers and society with independent, science-based advice on issues of crucial importance for our future. The Academies' members and other experts are outstanding researchers from Germany and abroad. Working in interdisciplinary working groups, they draft statements that are published in the series of papers *Schriftenreihe zur wissenschaftsbasierten Politikberatung* (Series on Science-Based Policy Advice) after being externally reviewed and subsequently approved by the Standing Committee of the German National Academy of Sciences Leopoldina.

**German National Academy  
of Sciences Leopoldina**  
Jägerberg 1  
06108 Halle (Saale)  
phone: +49 (0) 345 47239-600  
fax: +49 (0)345 47239-919  
e-mail: [leopoldina@leopoldina.org](mailto:leopoldina@leopoldina.org)

Berlin Office:  
Reinhardtstraße 14  
10117 Berlin

**acatech – National Academy  
of Science and Engineering**  
Karolinenplatz 4  
80333 München  
phone: +49 (0) 89 520309-0  
fax: +49 (0) 89 520309-9  
e-mail: [info@acatech.de](mailto:info@acatech.de)

Berlin Office:  
Georgenstraße 25  
10117 Berlin

**Union of the German Academies  
of Sciences and Humanities**  
Geschwister-Scholl-Straße 2  
55131 Mainz  
phone: +49 (0) 6131 218528-10  
fax: +49 (0) 6131 218528-11  
e-mail: [info@akademienunion.de](mailto:info@akademienunion.de)

Berlin Office:  
Jägerstraße 22/23  
10117 Berlin