Integration of Renewable Energies into the German Power System and Their Influence on Investments in New Power Plants

Integrated Consideration of Effects on Power Plant Investment and Operation

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von Dipl.-Ing. Ralph Oliver Harthan

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Gutachter:

Vorsitzender:	Prof. Dr.-Ing. Robert Holländer
1. Gutachter:	Prof. Dr. Thomas Bruckner
2. Gutachter:	Prof. Dr.-Ing. Manfred Fischedick

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Wissenschaftlicher Werdegang

Seit Februar 2003: Wissenschaftlicher Mitarbeiter, Öko-Institut, Schicklerstr. 5-7, 10179 Berlin. Gegenwärtige Position: Senior Researcher.

Oktober 1995 - Januar 2003: Diplom Energie- und Verfahrenstechnik, Abschlussnote: 1,3. Titel der Diplomarbeit: Thermoeconomic analysis of a multi-stage flash distillation plant. Technische Universität Berlin, Fakultät Prozesswissenschaften, Institut für Energietechnik, Berlin.

Oktober 1995 - Januar 2003: Diplom Technischer Umweltschutz, Abschlussnote: 1,2. Titel der Diplomarbeit: Development of site-dependent impact indicators for human health effects of airborne pollutants in Catalonia, Spain. Methodology and case study. Technische Universität Berlin, Fakultät Prozesswissenschaften, Institut für Technischen Umweltschutz, Berlin.

September 1984 - August 1993: Abitur, Abschlussnote: 1,0. Fanny-Leicht-Gymnasium, Stuttgart.

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Ralph Oliver Harthan

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Referat:
In dieser Doktorarbeit wird ein Modellierungsansatz für eine integrierte Betrachtung von Kraftwerksstilllegung, -investition und -betrieb vorgestellt.

In einer Fallstudie für Deutschland werden die Auswirkungen einer Integration erneuerbarer Energien auf Kraftwerksstilllegung, -investition und -betrieb im Zusammenhang mit unterschiedlichen Annahmen über die Restlaufzeit von Kernkraftwerken untersucht. Bezogen auf die Nutzung der Kernenergie wird hierbei ein Ausstiegsszenario sowie ein Laufzeitverlängerungsszenario betrachtet. Die Ergebnisse zeigen, dass die statische Stilllegung (d.h. die Betrachtung fester technischer Lebensdauern) im Fall eines Verzichts auf die Laufzeitverlängerung die im Kraftwerkspark verfügbare Leistung unterschätzt, da Retrofit-Maßnahmen (im Vergleich zur Stilllegung) nicht berücksichtigt werden. Die verfügbare Leistung im Falle einer Laufzeitverlängerung wird dagegen überschätzt, da die Möglichkeit der Kaltreserve (im Vergleich zum regulären Betrieb) vernachlässigt wird. Werden die Rückwirkungen der im Betrieb erwirtschaftbaren Deckungsbeiträge auf Stilllegungsentscheidungen ("dynamische Stilllegung") betrachtet, so wird der strompreissenkende Effekt durch die Laufzeitverlängerung im Vergleich zur statischen Stilllegung mehr als halbiert. Knappheitssitutationen unterscheiden sich nicht wesentlich mit und ohne Laufzeitverlängerung im Fall der dynamischen Stilllegung, während bei statischer Stilllegung ohne Laufzeitzeitverlängerung ein deutlich größerer Importbedarf besteht.

Die Fallstudie zeigt, dass weitere Systemflexibilitäten für die Integration erneuerbarer Energien benötigt werden. Der Anteil flexibler Kraftwerke ist größer im Fall des Kernenergieausstiegs. Der Kernenergieausstieg wirkt sich in Bezug auf die Stilllegungsdynamik positiv auf die Wirtschaftlichkeit fossiler Kraftwerke aus. Insgesamt führt der Kernenergieausstieg zu keinen mittelfristig nachteiligen Umwelteffekten, er kann sich jedoch langfristig positiv auswirken, da Lock-in-Effekte vermieden werden.

Es besteht weiterer Forschungsbedarf in Bezug auf die Berücksichtigung künftiger Flexibilitätsoptionen und ein neues Marktdesign.

Abstract

The increasing share of renewable energies in the power sector influences the economic viability of investments in new conventional power plants. Many studies have investigated these issues by considering power plant operation or the long-term development of the power plant fleet. However, power plant decommissioning, investment and operation are intrinsically linked. This doctoral thesis therefore presents a modelling framework for an integrated consideration of power plant decommissioning, investment and operation.

In a case study focusing on Germany, the effects of the integration of renewable energies on power plant decommissioning, investment and operation are evaluated in the context of different assumptions regarding the remaining lifetime of nuclear power plants. With regard to the use of nuclear power, a phase-out scenario and a scenario with lifetime extension of nuclear power plants (by on average 12 years) are considered. The results show that static decommissioning (i.e. considering fixed technical lifetimes) underestimates the capacity available in the power sector in the scenario without lifetime extension since retrofit measures (versus decommissioning) are not taken into account. In contrast, capacity available in the case of nuclear lifetime extension is overestimated since mothballing (versus regular operation) is not considered. If the impact on decommissioning decisions of profit margins accrued during power plant operation are considered ("dynamic decommissioning"), the electricity price reduction effect due to a lifetime extension is reduced by more than half in comparison to static decommissioning. Scarcity situations do not differ significantly between the scenarios with and without lifetime extension with dynamic decommissioning; in contrast, there is a significantly higher need for imports without lifetime extension with static decommissioning.

The case study demonstrates that further system flexibility is needed for the integration of renewable energies. It can be further concluded that the share of flexible power plants is higher with the phase-out of nuclear power plants. With regard to the decommissioning dynamics, the phase-out can be considered as beneficial for the economic viability of fossil power plants. Furthermore, the phase-out does not, overall, lead to environmental disadvantages in the medium term, but may be beneficial in the long run since lock-in effects are avoided.

Further research is required with regard to the consideration of future flexibility options and a new market design.

Keywords: Energy modelling, power sector, power plants, investment, decommissioning, operation, integrated consideration, retrofit, mothballing, renewables, nuclear, lifetime extension.

JEL classification: C69, Q40, Q41, Q42, Q47, Y40

Zusammenfassung

Der steigende Anteil erneuerbarer Energien beeinflusst die Wirtschaftlichkeit von Investitionen in neue konventionelle Kraftwerke. Zahlreiche Studien haben diese Aspekte in Bezug auf den Kraftwerksbetrieb oder die langfristige Entwicklung des Kraftwerksparks untersucht. Stilllegungen, Investitionen und Betrieb im Kraftwerkspark bedingen jedoch einander. Aus diesem Grund wird in dieser Doktorarbeit ein Modellierungsansatz für eine integrierte Betrachtung von Kraftwerksstilllegung, -investition und -betrieb vorgestellt.

In einer Fallstudie für Deutschland werden die Auswirkungen einer Integration erneuerbarer Energien auf Kraftwerksstilllegung, -investition und -betrieb im Zusammenhang mit unterschiedlichen Annahmen über die Restlaufzeit von Kernkraftwerken untersucht. Bezogen auf die Nutzung der Kernenergie wird hierbei ein Ausstiegsszenario sowie ein Laufzeitverlängerungsszenario (Verlängerung der Laufzeit um durchschnittlich 12 Jahre) betrachtet. Die Ergebnisse zeigen, dass die statische Stilllegung (d.h. die Betrachtung fester technischer Lebensdauern) im Fall eines Verzichts auf die Laufzeitverlängerung die im Kraftwerkspark verfügbare Leistung unterschätzt, da Retrofit-Maßnahmen (im Vergleich zur Stilllegung) nicht berücksichtigt werden. Die verfügbare Leistung im Falle einer Laufzeitverlängerung wird dagegen überschätzt, da die Möglichkeit der Kaltreserve (im Vergleich zum regulären Betrieb) vernachlässigt wird. Werden die Rückwirkungen der im Betrieb erwirtschaftbaren Deckungsbeiträge auf Stilllegungsentscheidungen ("dynamische Stilllegung") betrachtet, so wird der strompreissenkende Effekt durch die Laufzeitverlängerung im Vergleich zur statischen Stilllegung mehr als halbiert. Knappheitssitutationen unterscheiden sich nicht wesentlich mit und ohne Laufzeitverlängerung im Fall der dynamischen Stilllegung, während bei statischer Stilllegung ohne Laufzeitzeitverlängerung ein deutlich größerer Importbedarf besteht.

Die Fallstudie zeigt, dass weitere Systemflexibilitäten für die Integration erneuerbarer Energien benötigt werden. Der Anteil flexibler Kraftwerke ist größer im Fall des Kernenergieausstiegs. Der Kernenergieausstieg wirkt sich in Bezug auf die Stilllegungsdynamik positiv auf die Wirtschaftlichkeit fossiler Kraftwerke aus. Insgesamt führt der Kernenergieausstieg zu keinen mittelfristig nachteiligen Umwelteffekten, er kann sich jedoch langfristig positiv auswirken, da Lock-in-Effekte vermieden werden.

Es besteht weiterer Forschungsbedarf in Bezug auf die Berücksichtigung künftiger Flexibilitätsoptionen und ein neues Marktdesign.

Schlagwörter: Energiemodellierung, Stromsektor, Kraftwerke, Investition, Stilllegung, Betrieb, integrierte Betrachtung, Retrofit, Kaltreserve, erneuerbare Energien, Kernkraft, Laufzeitverlängerung.

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The investment model ELIAS was developed during several years of work at the Öko-Institut e.V. I especially wish to express my gratefulness to Dr. Dierk Bauknecht for developing ELIAS with me in the initial phase and for his support and fruitful discussions during its further development. I wish to thank Dr. Felix Christian Matthes for providing the spark for the development of ELIAS and for his continuous support and discussion. Special thanks go to Charlotte Loreck for enriching and fruitful discussions. Many thanks to Vanessa Cook for her thorough proofreading of the report. Finally, I wish to thank the Energy and Climate Division of the Öko-Institut e.V. in Berlin, especially Dr. Martin Cames and Julia Repenning, for supporting my dissertation and for enabling my stay in Leipzig.

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Glossary

Abbreviations

Variables available in both minuscule and majuscule refer to specific values or shares (minuscule, such as costs per kW or %) and absolute values (majuscule, such as costs).

Latin

a	Year
A	Annuity
ag, AG	Credit for avoided grid use
b, B	Bonus
BM	Benchmark
C	Cost
CC	Combined cycle
CCR	CO_2 costs and revenues
CCS	Carbon capture and storage
CF	Compliance factor
CHP	Combined heat and power
cik, CIK	Contribution in kind
cp	Capacity payment
CR	Cost-relevant
CRF	Capital recovery factor
ct, CT	CO_2 tax
CO_2	Carbon dioxide
Cond	Condensing-type
D	Dynamic, Decommissioned
dc, DC	Demolition costs
DH	District heating
DO	Demand-oriented
e	Euler's number, equivalent
e, E	Emissions
ED	Electricity demand

EEX	European Energy Exchange
EF	Emission factor
el	Electric(al), electricity
ELIAS	Electricity Investment Analysis
elt, ELT	Electricity tax
EU	European Union
EU ETS	European Union Emissions Trading Scheme
EUA	European Union Allowance
f	Function
F	Fuel consumption
FC	Fuel costs
fi, FI	Feed-in tariff
ft, FT	Fuel tax
g	Gramme
GDR	German Democratic Republic
GHG	Greenhouse gas
GJ	Gigajoule
GT	Gas turbine
GWh	Gigawatt hour
h	Hour
hc, HC	Heat credit
HC	Hard coal
hist	Historical
i	Discount rate
I	Incumbent, Input
ic, IC	Investment costs
icc, ICC	Interest costs during construction
ICR	Interest costs during repayment
inc, INC	Insurance costs
IND	Industry
IRR	Internal rate of return
j	Power plant, technology
k	Hour

kW	Kilowatt
kWh	Kilowatt hour
LB	Lower bound
lc, LC	Labour costs
LCA	Life Cycle Assessment
LG	Lignite
$LCOE$	Levelised costs of electricity
LULUCF	Land use, land-use change and forestry
M	Mothballed
mc	Marginal cost
MICOES	Mixed-Integer Cost Optimization Electricity System
min	Minute, Minimum
ML	Manning level
Mt	Million tons
MW	Megawatt
MWh	Megawatt hour
n	Depreciation period, number
N	New
NAP	National Allocation Plan
NG	Natural gas
NI	New investment
NPV	Net present value
O	Output
OA	Overallocation
ORC	Organic Rankine Cycle
p	Price
P	Capacity
PC	Personal costs
PV	Photovoltaics
pm, PM	Profit margin
Q	Heat production
R	Revenue
RF	Retrofit

RFC	Retrofit costs
RP	Repayment
S	Static
smc, SMC	Service and maintenance costs
ST	Steam turbine
t	Time (year), Ton
T	Time
th	Thermal
TIC	Total investment costs
TJ	Terajoule
TWh	Terawatt hour
UB	Upper bound
US	United States
VBA	Visual Basic for Applications
voc, VOC	Variable operating costs
W	Electricity generation
wLTE, w	With lifetime extension
woLTE, wo	Without lifetime extension
x	Step width

Greek

δ	Relative deviation
Δ	Gap, difference
η	Efficiency
κ	Uncertainty factor
ν	CHP coefficient
σ	Standard deviation
τ	Annual operating hours
χ	Share

1. Motivation and Structure of this Doctoral Thesis

In its so-called 'Energy Concept', the German government considers "securing a reliable, economically viable and environmentally sound energy supply [as] one of the great challenges of the 21st century" [BMWi and BMU, 2010]. And further, "Germany is to become one of the most energy-efficient and greenest economies in the world while enjoying competitive energy prices and a high level of prosperity" (ibid.). Among its priorities in the power sector, the promotion of renewable energies constitutes "the cornerstone" (ibid.). Furthermore, in its initial version of September 2010, the Energy Concept provided for a lifetime extension of nuclear power plants. However, in the aftermath of the nuclear incident in Fukushima in March 2011 and subsequent discussions on the safety of nuclear reactors, the German government decided to repeal the extension and stipulated an accelerated phase-out of nuclear power plants [Bundesregierung, 2011].

With an increased penetration of renewable energies, especially fluctuating sources like wind and solar, the availability of sufficient generating capacity to ensure that the load demand is covered at all times becomes an issue (system reliability). Furthermore, the transformation of the energy sector has economic consequences. The integration of renewable energies and the length of the remaining lifetime of nuclear power plants affect the electricity market and thus the electricity price as a fundamental determinant for industry and households. In addition, impacts on operating hours and electricity prices due to the integration of renewable energies and the remaining lifetime of nuclear power plants may pose challenges to the profitability of conventional power plant operation and investment (economic effectiveness). Finally, the integration of renewable energies and the length of the remaining lifetime of nuclear power plants affect greenhouse gas emissions of the power sector (environmental benefits). System reliability, economic viability and environmental effectiveness condition each other and are therefore the key issues examined in this thesis.

Scientists have investigated the impact of an increased promotion of renewable energies and of a potential lifetime extension or an accelerated phase-out of nuclear power plants on the energy system. In doing so, different aspects of either (short-term) power plant operation (and impacts on the spot market price) or the (long-term) development of the power plant fleet are analysed. In case that the approach focuses on power plant operation, assumptions are often made with regard to a (prescribed) decommissioning of power plants and the investment in new power plants. If the long-term development of the power sector is analysed, assumptions are often made with regard to future electricity prices and operating hours. However, power plant decommissioning, investment and operation are intrinsically linked and therefore need to be considered in an integrated manner.

The objective of this doctoral thesis is to develop a modelling framework for an integrated consideration of power plant decommissioning, investment and operation. The centrepiece is the development of the power plant investment model ELIAS (Electricity Investment Analysis). The most recent feature of this model is a dynamic decommissioning rationale including the possibility of mothballing and the option of retrofit measures as an alternative to new capacity investment. Also, operating hours from a dispatch model are considered in the investment analysis. The approach includes the coupling of ELIAS with the power plant dispatch model MICOES (Mixed-Integer Cost Optimization Electricity System) to enable consideration of feedback mechanisms between power plant decommissioning, investment and operation.

This dissertation is structured as follows: Chapter 2 provides an overview of the challenges in the energy sector from an environmental, economic and technical point of view including an overview of corresponding research. Chapter 3 describes the methodological approach of ELIAS and of an integrated consideration of short-term power plant operation and long-term power plant decommissioning and investment. Chapter 4 contains a documentation of the power plant investment model ELIAS. In Chapter 5, a case study demonstrating the application of ELIAS and of the modelling framework to evaluate the effects of the integration of renewable energies in the power system in the context of the remaining lifetime of nuclear power plants is presented. Finally, Chapter 6 provides a summary, conclusions and an outlook on further potential improvements of the modelling approach and identifies open research questions.

2. Challenges in the Energy Sector

2.1. Climate Change

Many scientists consider climate change as the most important environmental challenge facing mankind today. Limiting the increase of the global temperature to a maximum of 2 °C above pre-industrial levels has been acknowledged by a wide range of nations as an overarching policy goal, in the adoption of the “Cancún Agreements” in December 2010 in Cancún, Mexico [UNFCCC, 2010].

In order to achieve this climate target, deep cuts in greenhouse gas (GHG) emissions are required. On a national level, the German government envisages reducing GHG emissions by 40% up to 2020 and by 80 to 95% up to 2050 (compared to 1990 levels) [Bundesregierung, 2011], which is in line with the recommendations by the German Advisory Council on Global Change [WBGU, 2009].

Options for such significant cuts of greenhouse gas emissions are evaluated by a range of studies. For instance, [Edenhofer et al., 2009] compare the results of different models regarding global mitigation strategies for several sectors. For Germany, a detailed breakdown of a potential greenhouse gas reduction path is provided by [Kirchner et al., 2009].

In 2008, electricity and heat production accounted for 47.3% of greenhouse gas emissions in Germany[1]. The energy sector is therefore the most important source for achieving emission reductions. The centrepiece of German energy policy is the promotion of renewable energies. The stated policy goal of the German government in its Energy Concept ([BMWi and BMU, 2010], [Bundesregierung, 2011]) is that renewable electricity generation should make up at least 35% of overall electricity generation by 2020, 50% by 2030 and 80% by 2050. Other important elements are the increase of energy efficiency, the promotion of carbon capture and storage (CCS), the continued support of combined heat and power (CHP), the accelerated phase-out of nuclear power plants, an increased share of electric vehicles as well as the extension of the power grid.

[1] According to the National Inventory Report 2010 [Umweltbundesamt, 2010], total greenhouse gas emissions in Germany amounted to 958.9 Mt CO_2e in 2008 (without CO_2 from land use, land-use change and forestry (LULUCF)). Emissions from fuel combustion in power plants, large boilers and for the generation of process heat (in furnaces, kilns, etc.) are included in the categories “energy industries” (357.4 Mt CO_2e) and “manufacturing industries and construction” (95.9 Mt CO_2e) and cover public electricity and heat generation as well as the transformation sector (e.g. refineries) and the industrial sector (industrial power plants, process furnaces).

In order to assess whether the power sector is capable of reaching the outlined climate policy objectives, the share of different generation technologies and fuel types is fundamental. Renewable energy sources do not have net direct greenhouse gas emissions, whereas for fossil power plants, emissions depend on the fuel type and the conversion efficiency. Among fossil-fired power plants, lignite-fired power plants have the highest specific CO_2 emissions (due to the high emission intensity of lignite and, compared to other technologies, their moderate electric efficiency), whereas emissions are lowest for combined cycle natural gas-fired power plants (due to the low emission intensity of natural gas and the high electric efficiency), hard coal-fired power plants lie in between[2].

2.2. Economic Principles of Power Plant Investment and Operation

One rationale for *investments* in the power market is that technologies are built on the basis of levelised costs of electricity (LCOE), a concept which allows for "analysing the various generation options available to investors in a given market" and for "identifying the least cost option among alternative generation investments" [IEA et al., 2010][3].

Power plant *dispatch* in liberalised electricity markets is determined by the so-called merit order, which ranks power plants according to their marginal generation costs (comprising fuel costs, CO_2 costs and other variable operating costs[4]). In each hour, the last power plant dispatched to meet the power demand sets the electricity price (corresponding to the short-term variable generation costs of that unit) which then applies to all operating power plants (cp. [Erdmann and Zweifel, 2010] and [Ströbele et al., 2010]).

Figure 2.1 shows a stylised German merit order[5]. To determine the merit order, power

[2] However, all energy sources feature *indirect* greenhouse gas emissions. These comprise for instance upstream emissions for fuel transport and processing. [IPCC, 2011] finds that GHG emissions determined by Life Cycle Assessment (LCA) are still significantly lower for renewable energies (between 4 and 46 g CO_2e/kWh) than for fossil options (between 469 and 1,001 g CO_2e/kWh (excluding emissions from land-use change). However, with regard to fuels of biogenic origin, direct or indirect land-use changes due to the production of biomass may "decrease or increase terrestrial carbon stocks" (ibid.). In consequence, "the GHG balance may be affected by land use changes and corresponding emissions and removals" (ibid.).

[3] There are also other concepts of evaluating new investments from a financial perspective such as the internal rate of return (IRR), the net present value (NPV), the benefit/cost ratio or the payback period [Khatib, 2003].

[4] Such as for flue gas desulphurisation.

[5] The actual capacity available in a certain hour may differ from the presented merit order. Especially, renewable capacity varies over time. Also, conventional power plants may be shut off at some point in time, for instance for plant revision.

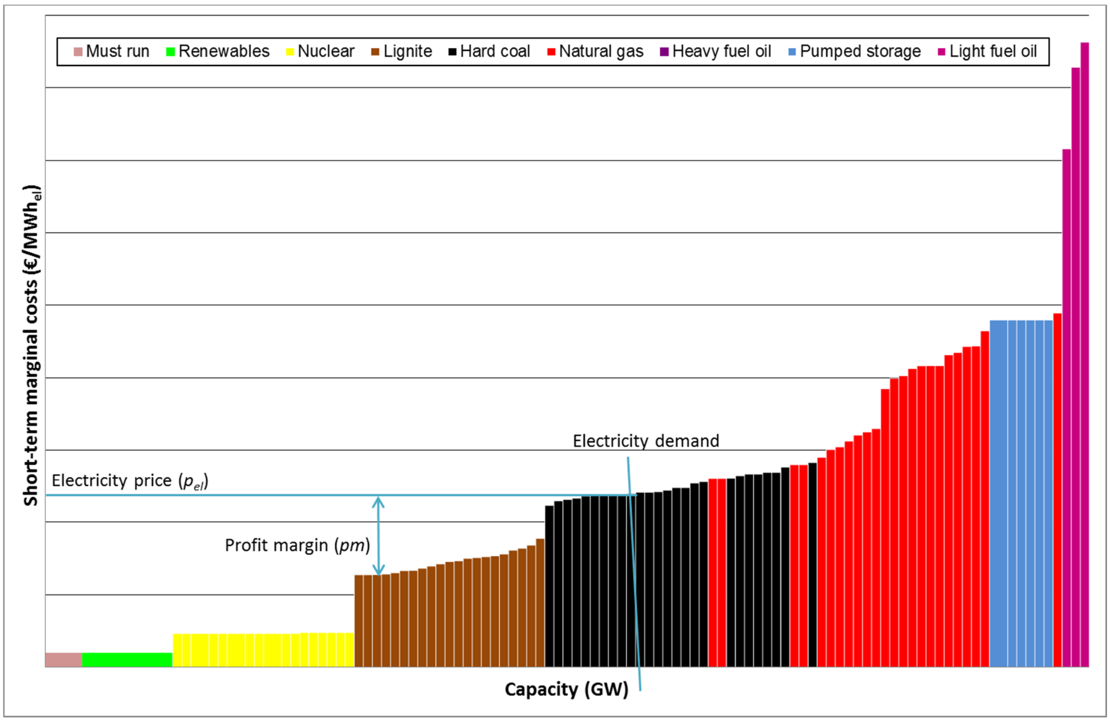

Figure 2.1.: Stylised German merit order (Source: MICOES model results for 2008, author's own adaptations)

plants are sorted according to their short-term marginal costs. Must-run[6] and renewable power plants[7] operate irrespective of the market. For this reason, they are dispatched first. They are followed in ascending order of marginal generation costs by nuclear, lignite, hard coal and natural gas power plants as well as peaking units (gas turbines, pumped storage, oil power plants)[8]. For a given electricity demand at one point in time, the last power plant dispatched (a hard coal-fired power plant in the graph) sets the electricity price (p_{el}). All infra-marginal units, i.e. power plants operating at lower marginal costs than the electricity price earn a profit margin (pm), or the so-called infra-marginal rent, as the difference between the electricity price and the marginal costs (shown for a lignite-fired power plant in the graph).

Besides cost advantages of power plants over competing technologies in terms of levelised cost of electricity for investment and marginal generation costs for operation, power plants must be economically profitable, taking into account costs and revenues in the planning period. Annual profit margins must be sufficiently high to encourage

[6] E.g. blast furnace gas power plants or waste incinerators with electricity generation.
[7] Due to their fixed feed-in tariff for every unit of electricity produced and preferential grid access.
[8] As can be seen in the graph, the position of some power plants may also deviate from the mentioned order. For instance, a new efficient natural gas-fired power plant may be ranked before an old hard coal-fired power plant with a low efficiency due to lower marginal generation costs ensuing.

capacity *investment* and to ensure continued *operation* of existing power plants (against the option of mothballing or decommissioning)[9].

When considering the profitability of an *investment* based on *costs* of electricity, it must be ensured that these costs are recovered. This means, electricity prices and operating hours must be sufficiently high in order to yield adequate profit margins to repay the investment. In this regard, *costs* determined ex-ante during construction must be recovered during several years of operation; however corresponding market conditions cannot be exactly predicted during the investment phase. The uncertainty especially refers to fuel costs or CO_2 allowance prices which affect power plant operation and thus influence the electricity price and corresponding revenues, but also to technical conditions such as the increase of fluctuating renewable energy sources like wind or solar which require conventional power plants to be able to follow the residual load[10] in a flexible manner. In this regard, an investor who is deciding whether or not to build a new power plant needs to evaluate potential future market conditions in order to know whether the investment will be profitable overall.

Once an investment has been made, capital costs become *sunk costs*, i.e. costs have incurred and may not be recovered[11]. In consequence, these costs are not decision-relevant for power plant *operation*. As stated above, power plants operate if their marginal generation costs are lower than that of the last unit dispatched. In order to make power plant operation profitable, the profit margin resulting from annual operating hours, marginal generation costs, and the electricity price, must be sufficient to cover annual fixed costs (which are not sunk and therefore are decision-relevant) such as personal costs or (fixed) service and maintenance costs.

Figure 2.2 shows a stylised German price duration curve. A power plant with the short-term marginal costs mc and corresponding annual operating hours τ yields a profit margin whenever the electricity price is higher than the marginal costs, resulting in the annual profit margin (PM, shaded blue area). This annual profit margin is used to cover annual fixed costs and to repay the capital investment (see above).

New power plants have advantages over incumbent technologies since the electric efficiency is usually higher and annual fixed costs are lower[12]. If the electricity price is

[9] Cp. [Erdmann and Zweifel, 2010, p. 315 ff] for a discussion of power plant planning under competition conditions.

[10] The residual loads corresponds to the total load demand less must-run and renewable generation.

[11] Cp. [Khatib, 2003] for a discussion of sunk costs in the power sector.

[12] For instance, automatisation may lead to a lower labour demand and thus reduced (fixed) personal costs.

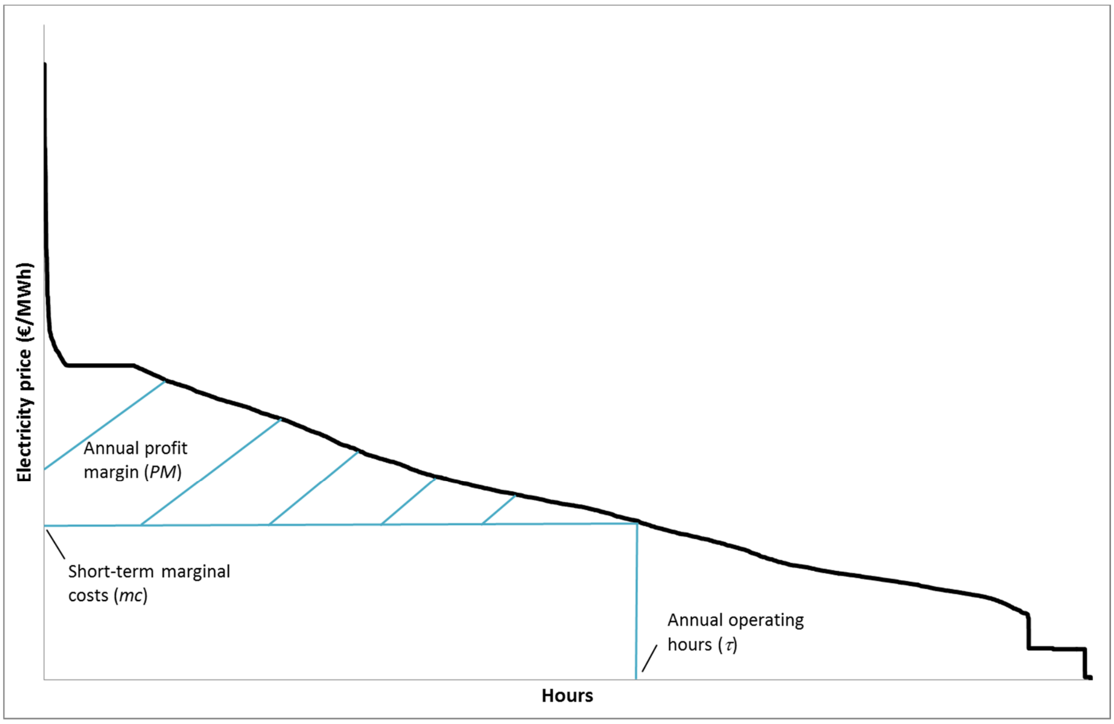

Figure 2.2.: Stylised German price duration curve (Source: MICOES model results for 2008, author's own adaptations)

predominantly determined by incumbent power plants (which have lower efficiencies), new power generators may, for some time, incur profit margins which may be sufficient to cover annual fixed costs and to recover investment costs. Over time, the power plant's efficiency deteriorates due to wear and tear and more efficient power plants go online. Thus the relative position of the incumbent power plant in the merit order deteriorates and it is eventually decommissioned (or mothballed). Ideally, once the power plant is decommissioned, it has recovered all capital costs and yielded an additional profit.

Some economists argue that this *marginal pricing concept* may not provide sufficient revenues to incentivise investments in new power plants under certain circumstances. This is the so-called *missing money problem* (e.g. [Cramton and Soft, 2006], [Joskow, 2006])[13]. Besides the general challenge for new power generators to make an investment in a new power plant profitable considering the market situation of incumbent power plants, other externally influenced interventions affect the electricity market and thus the medium- and long-term profitability of power plants. These interventions, may, for example, refer to regulation in the electricity market or to technology-specific policy interventions.

[13] Although not referred to as missing money problem, the issue of adequate pricing, especially with regard to peak load, was already investigated by [Boiteux, 1960].

As regards regulation in the electricity market, for instance, in the US, where the term of 'missing money problem' was first introduced[14], a regulated price cap introduced to mitigate high peak prices in scarcity situations led to missing incentives for new investments, since high revenues during these hours were not available. According to [Hogan, 2005], resource adequacy (i.e. sufficient revenues) for new investment would be available if electricity prices were allowed to rise beyond the price cap reflecting opportunity costs of decreasing load or providing additional generation.

Concerning technology-related policy interventions, in the current discussion on the integration of renewable energies, several authors argue that guaranteed feed-in tariffs make renewable electricity generators must-run power plants, i.e. they operate whenever the sun shines, the wind blows or biomass is available. In consequence, the dispatch of renewable energies is independent of the market. Yet, renewable electricity affects costs and revenues of the remaining power system, i.e. conventional power plants. [Bode, 2006] provides both an (analytical and a numerical) analysis with regard to the impact of renewable electricity generation on the wholesale power price "assuming a simple competitive power market". In an example calculation, he finds that depending on the amount of renewable electricity generated and the slope of the supply curve, the wholesale electricity price may decrease by up to 13.33%. In a model analysis of the impact of the German renewable support scheme on the electricity market, [Bode and Groscurth, 2006] find that for an increase of renewable capacity by 40 GW and in a scenario with elastic electricity demand, the wholesale electricity price decreases by 10.2%. [Sensfuß et al., 2008] analyse the effects of renewable electricity generation on spot electricity prices using an agent-based simulation model. They estimate a decrease of spot prices in Germany by 7.8 €/MWh in 2006 due to renewable electricity. [Rathmann, 2007] argues that renewable electricity generation lowers electricity prices due to the fact that fossil-fired electricity generation is reduced, thus leading to lower CO_2 allowances prices, which in turn lead to decreasing electricity prices. [Traber and Kemfert, 2009] analyse incentives to invest in new thermal power plants under an increasing share of wind electricity. They find that electricity prices are reduced and incentives for investments in power plants, especially new gas-fired power plants (combined cycle, gas turbines), decrease as well. A further increase of wind electricity is expected to exacerbate the lack of attractiveness of new gas-fired units. They conclude that this leads to a discrepancy between the need for more flexible generation units and the decrease of attractiveness of such power

[14] According to [Hogan, 2005], this term was introduced in 2003.

plants. [Bode and Groscurth, 2010b] argue that profit margins for both incumbent and new power plants will decrease significantly with the continued build-up of photovoltaic cells which produce electricity predominantly around noon, thus leading to a decrease in electricity prices when electricity revenues are usually high in Germany.

In Germany, the operation of nuclear power plants is regulated by law [AtG, 2011]. Since nuclear power plants have low marginal generation costs, the remaining lifetime has consequences for the price formation on the spot market, which in turn also influences the profitability of operation of other conventional power plants.

The regulated phase-out of nuclear power plants in Germany, as agreed between the German government and electric utilities in 2000 [Bundesregierung, 2000], provided some certainty about the decommissioning of a significant share of power plant capacity and thus on investment incentives in the power market. In this regard, the extension of lifetime by 12 years on average as decided in the initial version of the German Energy Concept in 2010 [BMWi and BMU, 2010] would lead to a longer availability of low-cost power generation and thus to a further exacerbation of the situation of missing incentives for investment in power plants. [Bruckner et al., 2010] argue that the extension of lifetime[15] could lead to a decrease of spot electricity prices of up to 7 €/MWh. As a consequence, fossil-fired power plants would experience a loss of profit margin of up to € 40 billion[16]. They furthermore conclude that the need and the incentives for investments in new generation capacity would decrease significantly, thus endangering other policy goals such as the promotion of cogeneration. [Lienert et al., 2010] expect increasing spot prices in all scenarios (with and without lifetime extension), primarily due to rising fuel and CO_2 prices. However, spot prices in 2020 with a lifetime extension of nuclear power plants by eight years are expected to be 15% lower than without such an extension. One core driver of this effect is the assumed lower CO_2 price with lifetime extension[17].

Following the nuclear incident in Fukushima and in the context of the decision of the German government to repeal the lifetime extension and to accelerate the phase-out of nuclear power plants [Bundesregierung, 2011], implications for the electricity sector were

[15] By eight years, as assumed in the study.

[16] Profit margins that are not realised "by all operators of fossil-fired power plants together [..] (in nominal terms, cumulated until 2030, not discounted)" [Bruckner et al., 2010].

[17] The CO_2 price is determined by an international market, with the EU Emissions Trading Scheme (EU ETS) accounting for a large share. For 2020, the EU ETS envisages a maximum of 1,720 million allowances [The European Parliament and the Council, 2009]. According to [Lienert et al., 2010], a lifetime extension of nuclear power plants to 40 years leads to CO_2 emission reductions in the German power sector of 40 Mt in 2020, corresponding to 2.3% of the EU emission budget. It is therefore questionable whether a significant effect on the CO_2 price and thus on electricity prices as found in the study can be expected.

analysed in a range of studies[18]. [r2b, 2011] evaluates the effects of an accelerated phase-out of nuclear power plants until 2017 in comparison to the lifetime extension of nuclear power plants as previously decided in the Energy Concept [BMWi and BMU, 2010] for the time period of 2012 to 2020. According to the study, CO_2 allowance prices generally increase up to 2020 due to GHG reduction targets. However, in the scenario with an accelerated phase-out, allowance prices are significantly higher (38 €/EUA[19] in 2020 versus 28 €/EUA for the lifetime extension of nuclear power plants)[20]. Whereas the electricity price tends to be stable with lifetime extension, it increases considerably with the accelerated phase-out (reaching 68 $€_{2011}$/MWh in 2020 in comparison to 57 $€_{2011}$/MWh with lifetime extension). The shortfall of nuclear capacity is compensated for by hard coal-fired power plants (mostly old power plants since these remain longer operational due to higher electricity prices) and (mostly newly-built) gas-fired power plants. Furthermore, new lignite power plants are built and net electricity imports increase with the accelerated phase-out. [Knopf et al., 2011] evaluate the effects on electricity prices and CO_2 emissions for a phase-out of nuclear power plants by 2015, 2020, 2022 in comparison to the initial lifetime extension to 2038. They find that electricity prices increase for all phase-out scenarios until 2020 and the return to the levels of 2010 by 2030. The earlier the phase-out year, the higher the price increase during the first years. Besides the new fossil capacity currently under construction, 8 GW of additional capacity is needed by the respective phase-out years of 2015, 2020 and 2022. This capacity may be provided by new fossil power plants or by leaving existing power plants in operation for a longer time than initially planned. CO_2 emissions temporarily increase with an accelerated phase-out, the earlier the phase-out year, the higher the increase. [Enervis, 2011], by comparing a phase-out by 2020 with the initial lifetime extension of nuclear power plants, finds that an accelerated phase-out leads to a strong incentive to invest in new generation capacity, especially in the case of combined cycle natural gas-fired power plants. It argues that electricity prices are predominantly influenced by fuel and CO_2 allowance prices. Therefore, with an expected general increase in coal and gas prices, electricity prices increase, too. Furthermore, spot market prices are temporarily (2014-2021) higher

[18] In the following, only those studies are described that evaluate medium- and long-term effects on the electricity market, i.e. spanning over several years. Other studies assess short-term effects on electricity prices and imports ([BDEW, 2011], [Kemfert and Traber, 2011], [Matthes et al., 2011a], [Matthes et al., 2011b], [ZNES, 2011]). Further studies evaluate grid aspects of an accelerated phase-out of nuclear power plants ([Kunz et al., 2011], [ZNES, 2011]).

[19] European Union Allowance, corresponding to one ton of CO_2e.

[20] See Footnote 17; the same applies here.

with an accelerated phase-out in comparison to lifetime extension. [Samadi et al., 2011] provide a comparison of different studies and statements related to the price effects of an accelerated nuclear phase-out.

It may be argued that the missing money problem is resolved by itself. If incentives to invest in new power plants or to operate existing power plants are not sufficient, a scarcity situation arises leading to peaking prices, which provide sufficient profit margins. However, high prices only prevail as long as scarcity prevails. Once additional capacity has been built, the scarcity situation is removed and prices decrease again[21]. Furthermore, the use of scarcity pricing requires the possibility of immediate demand response to peaking prices, which is not yet available[22]. [Joskow, 2006] finds that one major aspect of the missing-money problem is the “failure of wholesale spot market prices for energy and operating reserves to rise to high enough levels during periods when generating capacity is fully utilized”.

Moreover, technical safety criteria are not compatible with scarcity pricing. Whereas in other markets temporary scarcities may not pose significant problems for the consumer, shortages in the power market may have significant damaging effects on society due to the limited storability of electricity and the corresponding risks of brownouts[23] or blackouts. These kinds of effects could be observed during the Californian electricity crisis in 2000 and 2001 [Jansen et al., 2003]. In this regard, [Joskow, 2006] argues that engineering criteria such as the operating margin “have been carried over without much if any changes into the world of liberalised electricity markets”.

Other scientists argue that utilities may exert market power and thus influence electricity prices, reaping additional revenues. [Weigt and von Hirschhausen, 2008] find in a comparison of model results with German spot prices on the European Energy Exchange (EEX) in 2006 that model results are 11% lower than the average spot market price. In peaking situations, the price differential is even higher (30%). The authors conclude that these differences add up to € 3.6 billion for the whole year. Furthermore, they find that under competitive conditions (model results), only nuclear power plants are

[21] This phenomenon is also known as the ’pork cycle’. This term was originally used to describe the price cycle in the pork market [Hanau, 1928].

[22] Demand-response measures are already in place in industry and commerce, but also to some extent in households. These comprise measures for direct control (to alleviate peak load situations) and time-of-use tariffs for electricity (for instance, to incentivise electricity use in electric storage heating systems during low load periods) [Timpe et al., 2010]. [U.S. Department of Energy, 2006] and [Strbac, 2008] contain a classification of different demand-response options. [Torriti et al., 2010] describe European experiences with demand-response measures. More flexible measures based on innovations in information and communication technology (such as so-called smart meters) are currently under research.

[23] Drop in voltage.

able to cover fixed costs, whereas under real-world conditions both nuclear and coal-fired power plants can cover their fixed costs. Since regulation in liberalised markets aims at reducing market power, additional revenues due to market power can only be accrued to the extent that the regulator is not able (or willing) to restrict market abuse.

Another option for addressing the investment dilemma is to artificially reduce power plant capacity which leads to increasing electricity prices. The accelerated phase-out of nuclear power in Germany [Bundesregierung, 2011] can be considered as such. For fossil-fired power plants, in response to the initially planned lifetime extension of nuclear power plants, [VKU, 2010] called for decommissioning of old inefficient (coal-fired) power plants with an electric efficiency lower than 39%. Similarly, the feed-in of renewable electricity can be restricted, e.g. curtailment of wind energy production in situations of high wind and low demand or limitation of capacity additions under feed-in tariff schemes. [Bode and Groscurth, 2010a] advocate capping yearly capacity additions of photovoltaics to between 500 and 3,000 MW in Germany as long as the current market design does not allow for sufficient incentives for investments in back-up power plants and as long as the issue of electricity storage remains unresolved. [Nicolosi and Fürsch, 2009] argue that renewable support schemes could be modified in a way to allow "wind power to reduce its infeed and provide positive and negative reserve power" instead.

In general terms, policy uncertainty such as that related to climate policy or the initially planned lifetime extension of nuclear power plants acts as a deterrent to investment ([Joskow, 2006], [IEA, 2007] [Bode and Groscurth, 2009], [Garz et al., 2009], and [Matthes and Hermann, 2009]).

Another description of the lack of incentives for investments in new power capacity in liberalised markets can be found in [Weber, 2002].

[Groscurth and Bode, 2009] and [Bode and Groscurth, 2009] find that the liberalised electricity market does not - even disregarding climate policy restrictions and the increase of renewable energy - provide sufficient incentives to invest in new power plants.

It can therefore be concluded that the 'investment dilemma' is not a new phenomenon induced by renewable electricity generation. However, due to their must-run characteristics, renewable energies exacerbate this problem.

In addition to the spot market, other revenue streams may provide additional profit margins, such as the operating reserve market. For instance, due to their high flexibility, gas turbines are attractive generators for this market. Considering the fact that the integration of fluctuating renewable energy sources will require more flexibility of the remaining power generators, operating reserve revenues may become an important revenue stream [Peek, 2010].

In addition, discussion is ongoing on adapting the market design in order to ensure resource adequacy for the operation of existing power plants and the investment in new capacity ([Roques, 2008], [Joskow, 2008], [De Vries and Heijnen, 2008]). Capacity payments are discussed as an option; power plants receive a payment for the capacity which is available for dispatch, independently of whether it actually goes online. [Joskow, 2006] argues that 'capacity obligations' could be introduced in which load serving entities would be required to ensure a certain generating capacity beyond the annual peak load providing a pre-defined capacity margin. A capacity market would provide corresponding prices for making this capacity available. [Cramton and Soft, 2006] compare different market designs for resource adequacy and advocate using a combination of the spot pricing concept, allowing high peaking prices, and capacity markets. In response to the new energy-economic framework conditions stemming from the decision on an accelerated phase-out of nuclear power plants in Germany, [Töpfer et al., 2011] advocate using capacity markets in order to remunerate services for grid stability and the provision of capacity. In the bidding process, the location of capacity may also be considered in order to account for transmission requirements.

A further option are direct investment subsidies, for instance for novel technologies [Council of the European Union, 2008][24]. [Bode and Groscurth, 2009] give an overview of potential measures to increase the attractiveness of investments in new power plants.

2.3. Investment Demand and Lock-in

Many scholars assume that investments in *new* conventional[25] power plants are needed (e.g. [Groscurth and Bode, 2009], [Garz et al., 2009]). This investment may serve as replacement for existing power plants[26], for the provision of back-up capacity for renewable electricity generation [Traber and Kemfert, 2009] or for replacing nuclear capacity de-

[24] "Between 2013 and 2016, Member States may also use revenues generated from the auctioning of allowances to support the construction of highly efficient power plants, including new energy power plants that are CCS-ready. For new installations exceeding the degree of efficiency of a power plant according to [. . .] the Commission Decision of 21 December 2006 [. . .] the Member States may support up to 15% of the total costs of the investment for a new installation that is CCS-ready" [Council of the European Union, 2008].

[25] In the following, 'conventional' power plants are defined as either fossil-fired or nuclear power plants.

[26] For instance, [Lienert et al., 2010] and [Bruckner et al., 2010] assume that existing power plants are retired, once they reach the end of their technical lifetime.

commissioned as a consequence of the nuclear phase-out[27]. However, investment in new capacity with a long technical lifetime may entail the risk of *lock-in* [Klaus et al., 2009]. 'Lock-in' means that an investment may be adequate in the short and medium term, but not be effective in the long run.

Additional conventional capacity may be needed in the short and medium term in order to provide back-up capacity for renewable generation, but may be obsolete in the long run when other flexibility options (such as demand-response, grid extension, or electricity storage) become widely available. Furthermore, new conventional capacity investment has to be appraised in the context of the renewable electricity target of 50% by 2030 and 80% by 2050 (Section 2.1). This means that most power plants built today would gradually need to be decommissioned between 2030 and 2050, before the end of their technical lifetime[28]. Operating hours would decrease and thus revenues to cover annual fixed costs. Power plants would have to be mothballed or decommissioned, leaving stranded investments.

New fossil-fired power plants may lead to CO_2 reductions in the short run (improved efficiency, fuel switch), but - due to the nature of long-lived capital stocks - make deep cuts in emissions in the medium and long run expensive or infeasible. [Garz et al., 2009] find that if long-term climate policy goals are broken down to the power sector, as little as five new coal-fired power plants of 2,000 MW each would consume the corresponding emission budget in 2050. From an economic point of view, fossil-fired power plants then require increasing amounts of additional emission allowances at increasing prices. For some power plants (especially emission-intensive ones), this may lead to shrinking profit margins and thus to the risk of unprofitable operation, which in turn would lead to decommissioning or mothballing. Alternatively, technical options such as carbon capture and storage (CCS) could be a solution. However, CCS technology is still being researched. Furthermore, additional capital investment would need to be made with long depreciation periods, thus increasing the overall risk of unprofitable investments. The lock-in effect may therefore also increase long-term climate mitigation costs[29].

[27] [Bundesregierung, 2011] calls for 10 GW of additional capacity until 2020 in addition to the power plants currently under construction. [UBA, 2011] argues that up to 5 GW of additional capacity may be needed until 2017 for an accelerated phase-out of nuclear power plants. This capacity may be covered by additional renewable capacity, efficient gas-fired power plants (including CHP), energy efficiency and retrofit measures. Similarly, [Matthes et al., 2011b] find that 5 GW of additional capacity may be required up to 2020, which may be covered by biomass or gas-fired power plants (including CHP).

[28] With the average technical lifetime of many fossil-fired power plants as 40 years (Section 5.1).

[29] [Edenhofer et al., 2009] call for halting "investments into conventional coal-fired power generation capacity [..] immediately. Otherwise, the aggravated lock-in into long-lived carbon-intensive infrastructure will significantly raise mitigation cost."

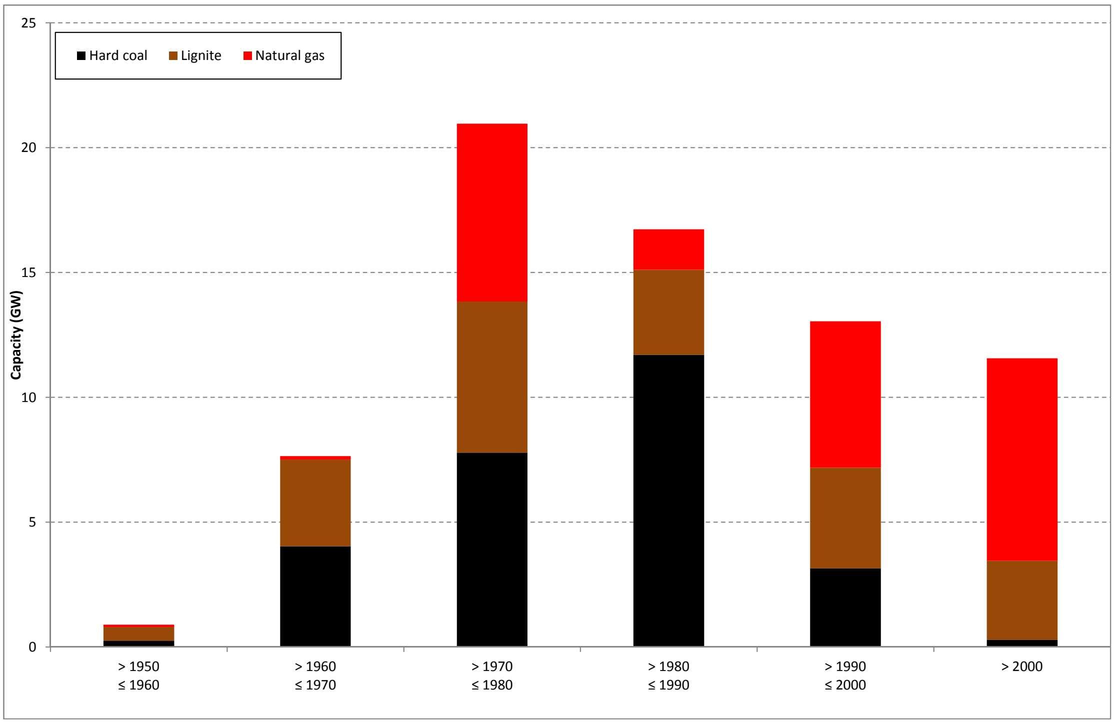

Figure 2.3.: Vintage structure of the German power sector, 2008 (Source: [Platts, 2009], [Statistisches Bundesamt, 2008], author's own calculations)

[Bode and Groscurth, 2009] find that newly-built power plants may become unprofitable even before the end of their technical lifetime. However, they argue "that an early shut-down of a power plant will likely be the object of intense lobbying from various sides, both for each individual plant as well as with respect to the climate change targets as a whole".

In consequence, the mentioned risks of lock-in would either mean that new power plants become stranded investments or that the existence of a newly-built long-lived capital stock jeopardises the above-mentioned policy goals.

An option for mitigating this investment risk for new generation capacity could be to resort to more short- and medium-term solutions (such as retrofit) until more clarity on market design (e.g. the introduction of capacity markets) and technical innovations (such as storage options, smart grids, CCS, etc.) is available.

Retrofit refers to upgrading existing and installing new equipment, especially in order to extend the lifetime of the power plant and to increase its efficiency[30]. Figure 2.3 (values in Table B.1 in Appendix B) shows the vintage structure of German fossil-fired

[30] [Nichols et al., 2008] give an overview of efficiency gains for several retrofit measures in coal-fired power plants. Other retrofit measures comprise adding carbon capture systems to existing power plants [Geisbrecht and Dipietro, 2009]. However, this falls outside the focus of this dissertation.

power plants[31]. 12% of German power plants (mostly coal-fired power plants) are older than 40 years. On the one hand, this may indicate that new capacity to replace these old power plants will be needed shortly. On the other hand, it may be interpreted as meaning that the design technical lifetime of 45 years for old coal-fired power plants (Section 5.1.1) may be extended by retrofit measures, thus gaining additional years of operation[32]. Investments in German natural gas-fired power plants were generally made more recently[33], so that these will not require significant short-term replacement or retrofit. It has to be noted that investments in retrofit generally face the same challenges as investments in new capacity (investment must be recovered during the planning period). However, the associated risk is smaller since the investment sum is smaller and the repayment period is shorter.

2.4. Technical Determinants of Power Plant Operation

Besides economic considerations, technical limitations of power plant operation also need to be taken into account. Since renewable electricity is fed into the grid preferentially [EEG, 2011], conventional power plants have to provide sufficient back-up capacity to address the fluctuating nature of renewable electricity (especially wind and photovoltaics). From a short-term perspective, generating capacity has to be provided to the power system in order to make up for the (forecasted) shortfall of renewable electricity during certain hours (e.g. short-term wind calm). Furthermore, generating capacity must be available as operating reserve for (unplanned) fluctuations of renewable electricity supply. From a medium- and long-term perspective, electricity must also be provided during periods of overall scarcity of renewable sources (e.g. wind calm for several days).

Discussion is ongoing as regards what technologies may be suitable for providing these different flexibility needs. Besides conventional generation capacity, renewable generators may become more flexible[34]. Furthermore, flexibility could be provided by demand-response measures which allow shifting load demand from periods with low availability

[31] [Pahle, 2011] provides an overview of the history of investments in power plant capacity during recent decades, resulting in the current vintage structure.
[32] As a matter of fact, many power plants in Germany had to be retrofitted with flue gas cleaning equipment in the 1980s as mandated by legislation (the so-called Large Combustion Plant Directive).
[33] One important reason for this was the replacement of old lignite-fired power plants in the former GDR with modern gas-fired units (especially in municipal utilities and industry) after German reunification [Matthes, 2000, pp. 481-482].
[34] For instance, biomass-fired power plants.

Parameter	Source	Nuclear	Lignite	Hard coal	NG GT	NG CC	NG ST
Start-up time (h)	(a)	6-50	2-5	2-5	<0.25	n.a.	2-5
Start-up time (h)	(b)	n.a.	2	2	0	1	1
Min. load (%)	(a)	30-50	40-60	40-60	20-50	n.a.	20-30
Min. load (%)	(b)	20-60	40	38	20	33	38
Min. downtime (h)	(b)	n.a.	6	2	2	2	0
Min. uptime (h)	(b)	n.a.	6	4	4	4	1
Part load eff. loss (%)	(a)	5	5-10	5-10	20	n.a.	10
Part load eff. loss (%)	(b)	5	5	6	22	11	6
Ramp rate (%/min.)	(a)	5-10	2-6	2-6	10-25	n.a.	4-10
Ramp rate (%/min.)	(b)	3.8-10	3	4	20	6	6

Table 2.1.: Flexibility parameters of thermal power plants (NG: natural gas, GT: gas turbine, CC: combined cycle, ST: steam turbine) (Source: [Timpe et al., 2010] (a), [Hundt et al., 2009] (b))

of renewable energy to periods with abundance[35]. Electrical storage systems[36] could store electricity for different time periods. Finally, grid extension[37] may equilibrate load supply and demand over a larger area, thus providing additional flexibility. An overview of different flexibility options is provided by [Timpe et al., 2010].

The most prominent flexibility parameters of thermal power plants are (Table 2.1[38]):

- **Ramp rate:** The ramp rate defines the short-term ability of a power plant to change its load (%/min). The higher the ramp rate, the faster a power plant can react to changes in load demand or fluctuating renewable energy supply. The ramp rate is generally higher for natural gas than for nuclear and coal-fired power plants.

- **Minimum load:** The minimum load defines the minimum capacity a power plant generates when online. The lower the minimum load, the wider the usable capacity range and thus the more flexible. The minimum load is generally higher for nuclear and coal-fired power plants than for gas-fired units.

- **Start-up and shut-down times:** The start-up and shut-down times define the time needed to go online or to shut down. The shorter this time, the faster a power plant can react to load changes or fluctuations of renewable energy. The start-up time is generally longest for nuclear power plants, followed by coal-fired units. Gas power plants (especially gas turbines) have shorter start-up times.

[35] Already today some cold storage buildings can be steered by the needs of the electricity system. In situations of high load demand, cooling can be switched off for some hours (within specified temperature limits). During situations of low load or high availability of wind electricity, the cooler is switched on.
[36] Such as pumped storage, compressed air storage, or battery-electric systems.
[37] Such as the European super-grid or the planned NorGer cable between Germany and Norway.
[38] As for nuclear power plants, a more detailed evaluation of technical data for different power plant types and configurations is included in [Hundt et al., 2009].

- **Minimum uptime, minimum downtime:** Minimum uptime and minimum downtime define the number of hours that a power plants needs to be online or offline, before it can change the operating status. The shorter the minimum uptime and downtime, the more flexibly a power plant can be switched on or off in response to changes in load demand or renewable energy supply. Long minimum uptimes can be found for lignite-fired power plants, short minimum uptimes for gas turbines.

- **Part load efficiency loss:** When running at part load, the electric efficiency of power plants decreases in comparison to full load, which leads to increasing marginal generation costs. The lower part load efficiency losses, the more inclined a power plant operator will be to move to part load if a decrease of generation capacity is required. Part load efficiency losses are generally higher for gas-fired units (especially gas turbines) than for coal-fired and nuclear power plants.

Generally, it can be concluded that gas-fired power plants are more flexible than coal-fired or nuclear power plants. In this regard, it needs to be gauged whether incumbent and new power plants provide the necessary flexibility to adapt to the fluctuating nature of renewable energy sources or whether they may conflict with renewable electricity supply from a technical perspective.

Many of these technical parameters also have economic implications and thus influence power plant operation from an economic point of view. For instance, the mentioned fact that power plants operating at part load have a lower electrical efficiency than at full load leads to increasing marginal generation costs. Similarly, bringing into service and shutting down involves costs (such as additional fuel costs during start-up). Furthermore, frequent changes of the operating status lead to thermal and mechanical stress to components and thus to wear and tear. [Lefton and Besuner, 2006] give an overview of costs associated with cycling of coal-fired power plants.

In addition to these technical and techno-economic limitations, other economic considerations are relevant for determining whether a power plant is dispatched. For instance, power plants participating in the operating reserve market are required to make capacity available independently of the spot market situation. For instance, in order to provide negative operating reserve, a power plant needs to be online (in order to be able to reduce load), even if the residual load is low.

It can be concluded that the consideration of the merit order alone is not sufficient to ensure an efficient dispatch including the ability to integrate renewable energy in a flexible manner; other technical and economic considerations need to be taken into account. Several scholars have addressed different aspects of this issue.

[Fischedick et al., 2009] claim that nuclear power plants are the least flexible power plants in the system and that due to safety reasons, a shut-down of nuclear power plants is avoided whenever possible. Furthermore, they argue that nuclear power plants can barely contribute to balancing fluctuating renewable energy supply; in contrast they increase the need for additional flexibility. The authors claim that negative electricity prices on the German electricity exchange in October 2008 were not only due to a high availability of wind during these hours, but also to the fact that 13 GW of nuclear power plants were still online and could not be shut down fast enough.

[Ludwig et al., 2010] give an overview of flexibility parameters of German nuclear power plants. They conclude that for load changes with a ramp rate of up to 2%/min (partly also for higher ramp rates) in the load range between 50% and 100%, there are significant operational experiences. Further, they argue that from a safety perspective, there are no concerns to operate nuclear power plants in a load following mode as required for the integration of renewable energies. Also, the number of admissible load changes is still high for German nuclear power plants. They also argue that power plants can be taken off the grid and be switched on again quite fast if nuclear power plants are operated in the captive mode or if plant load is zero, but the plant is still hot.

[Ludwig and Breyer, 2010] argue that ramp rates of nuclear power plants of 2% to 10% are possible depending on the load (between 20% and 100% of full load). Start-up from cold state takes several hours up to days. They further conclude that the ramp rates of nuclear power plants are higher than of most fossil-fired power plants.

Similarly, [Hundt et al., 2009] argue that German nuclear power plants can be operated with ramp rates of 3.8 to 5.2%/min in a load range of 50% to 100% of full load. They find that with a share of renewable electricity of 30% and 40%, a volatile residual load due to fluctuations can still be covered both with and without lifetime extension of nuclear power plants. Moreover they argue that with a share of renewable electricity beyond 40%, storage systems and a flexible control of renewable electricity are required in order to ensure a stable electricity supply.

From these studies, it can be concluded that ramp rates of nuclear power plants do not constitute a problem for operation in load-following mode in order to adapt to fluctuating renewable energy supply. However, it remains open whether frequent shut-down and bringing-into-service (i.e. going below the minimum load) is feasible (or recommendable) with nuclear power plants. Furthermore, minimum uptime and downtime of nuclear power plants need further consideration (especially regarding hot and cold state). In addition, renewable electricity supply should make up 35% in 2020 and 50% by 2030 [BMWi and BMU, 2010]. The scenario with a share of renewables beyond 40% mentioned by [Hundt et al., 2009] (above) may therefore be relevant as early as 2024[39]. However, since the phase-out of nuclear power plants in Germany is to be concluded by 2022 at the latest [Bundesregierung, 2011], the increased promotion of renewable energy as envisaged in the German Energy Concept probably does not conflict with the remaining lifetime of nuclear power plants.

[Nicolosi, 2010] argues that there may be market situations in which 'negative flexibility' (i.e. the ability of power plants to reduce their capacity) becomes tight. This is the case if power plants are not able to reduce their capacity since they are committed, for instance, within the scope of the operating reserve market or if they are not willing to shut down due to high start-up costs and opportunity costs in case the power plant cannot get online fast enough once the market situation is favourable again. In an empirical analysis of situations during which negative prices on the German electricity market occurred in 2008 and 2009, he finds that both nuclear and lignite-fired power plants showed little flexibility in adapting their capacity. Total generation of nuclear power plants was never below 60% of available capacity and of lignite-fired power plants never below 45%, even with negative prices, with generation in the bulk of situations above 90% and 80%, respectively. In contrast, hard coal and natural gas-fired power plants showed a wide range of flexibility (10% to 100% and 10% to about 90%, respectively). He also finds that for negative tertiary reserve, prices were highest in negative spot price situations. He concludes that "the flexibility of the aggregated supply side is probably lower than expected, since all technologies show limited bandwidths of flexibility and altogether were not able to reduce the generation below 46% of the available capacity" and that "especially base load technologies showed thresholds that seem to be at relatively high levels". With regard to the statement that "the whole German nuclear fleet would be able to ramp-down 9.6 GW within 15 min" as argued by [Hundt et al., 2009], he concludes that "the utilisation of this potential is not observable in the data".

It can therefore be concluded that technical restrictions play a role with regard to the flexible dispatch of power plants, especially of base load generators (nuclear, lig-

[39] Linear interpolation of targets.

nite). Ramp rates do not seem to pose major challenges with regard to load following. However, minimum load, minimum uptime and downtime as well as associated costs (for shut-down, start-up) in combination with market-related aspects (e.g. provision of regulation reserve) may result in a less flexible power fleet than it may appear at first sight. Therefore, when evaluating the flexibility of a power system, these aspects need to be taken into account.

3. Methodology

The modelling approach developed as part of this dissertation comprises two parts: the development of the investment model ELIAS and the coupling of ELIAS with the existing power plant dispatch model MICOES[40]. Section 3.1 describes the selection of the model approach for ELIAS and its interfaces to MICOES. In Section 3.2, the integrated application of ELIAS and MICOES is described. A detailed documentation of ELIAS including the mathematical description is included in Chapter 4.

3.1. Selection of the ELIAS Model Approach

Energy-economic models can be classified on the basis of a range of features. With regard to the modelling perspective, *bottom-up* models can be distinguished from *top-down* models. Further, models can be designed as *simulation* or *optimisation* models.

Bottom-up models feature an engineering perspective and comprise detailed technology-specific information. Their main advantage is that effects are modelled with a high level of detail such as the effects of policy measures on power plant operation or investment. However, these models neglect interactions with the rest of the economy (such as the interplay of economic growth and energy prices). In contrast, *top-down models* describe effects in the overall economy, including feedbacks between sectors. However, technologies are usually reflected at a higher level of aggregation. [Schumacher, 2007] provides a comparison of design features of bottom-up and top-down models.

Simulation models are based on assumptions about the characteristics of the system and aim at understanding "the behaviour of the system or [evaluating] strategies for the operation of the system. Assumptions are made about this system and mathematical algorithms and relationships are derived to describe these assumptions - this constitutes a 'model' that can reveal how the system works" [Smith, 2000]. In contrast, *optimisation models* aim at finding the optimum system configuration by maximising or minimising a target function (such as system costs or CO_2 emissions), respecting system constraints.

[40] The initial version of MICOES was developed at the Technical University of Berlin [Theofilidi, 2008] and is currently being further developed and used at the University of Leipzig ([Bruckner et al., 2010], [Knopf et al., 2011]). A short description is available in Appendix A.

Another important design feature of energy system models is the chosen time perspective. *Myopic* models determine the outcome based on the information available for the current time step, whereas *perfect foresight* models consider both current and future information in their decision-making. Models may further cover a short time period (such as a week or a year) or spread over long periods (such as several years or decades). The time period, in turn, is fundamental for the model resolution (e.g. hours or years).

[Krey, 2006], [Schumacher, 2007], [Gaidosch, 2008] and [Genoese, 2010] provide an overview of different modelling approaches and energy-economic models.

In the following, the model approach of the investment model ELIAS (Electricity Investment Analysis) is selected based on the above-mentioned criteria and a more specific discussion of model design features (not) available in current investment models.

The objective of ELIAS is to describe the development of the power plant fleet over a time period of years to decades. Since key effects of the power system such as costs or CO_2 emissions depend on the choice of technologies, ELIAS is designed as a *bottom-up engineering model* comprising a wealth of technology options. There are no interactions with other sectors or the overall economy. Corresponding inputs such as electricity demand or fuel prices are determined exogenously[41].

The power sector corresponds to a long-lived capital stock with technical lifetimes of power plants of usually several decades. Therefore, for the investment decision, the development of energy-economic framework conditions (such as the development of fuel prices) needs to be considered over a long time period. Similarly, energy and climate policy objectives span over a long time period (such as greenhouse gas reduction targets or the substitution of fossil energy carriers by renewable energies) and influence power plant investment and operation. Hence, a myopic perspective reflecting current energy-economic conditions only would not be appropriate as modelling approach. Therefore, in order to accommodate a long-term perspective, ELIAS considers the development of core parameters (such as fuel or CO_2 allowance prices) in the depreciation period in its investment rationale and assumes that these are known at the time of the investment decision.

Since ELIAS aims at describing investments in new power generation capacity for the

[41] Interactions with other sectors can be accommodated in the model, though. For instance, in a (recurring) project for the German environmental ministry, electricity demand is determined in other sectoral models and included as input in ELIAS. Electricity prices derived based on the power plant structure in ELIAS are returned to the sectoral analyses in order to evaluate whether these affect the degree to which energy efficiency measures are taken up [Matthes et al., 2009].

power sector as a whole over a long time period, no agent-specific modelling is carried out, but it is assumed that the investment is made by an ideal-typical investor[42].

ELIAS is based on the assumption that the magnitude of capacity additions of different technology options are a function of levelised cost of electricity ($LCOE$)[43]. The lower $LCOE$, the higher the capacity added. However, a bandwidth of technologies is added as a function of their distance from the cheapest technology. In this regard, ELIAS differs from an optimisation approach which, if overall levelised costs of electricity of capacity investments were minimised, would lead to a penny-switching effect, i.e. the cheapest technology (even with a marginal difference to other options) would be allocated the totality of capacity additions (if not constrained by other restrictions). In reality, investors face uncertainties with regard to investment assumptions and have other non-economic decision criteria (such as fuel availability[44] or specific technology needs[45]). Therefore, an approach optimising levelised costs of electricity only would not yield plausible results. For this reason, a simulation approach with an 'optimisation facet' (the lower the levelised cost of electricity, the higher the capacity added) is chosen (Section 4.5.2).

One major shortcoming of some investment models is that capacity additions are estimated with little or no feedback to market (power plant operation) conditions. This is often reflected by an assumed decommissioning of power plants after a pre-defined technical lifetime. For instance, the PowerACE model [Genoese, 2010], an agent-based simulation model, includes a power plant investment module. Spot and forward prices of electricity in the PowerACE model serve as an input for determining the profitability of different technology options and thus the distribution of capacity additions among power plant types. In this regard, future power plant operating conditions are reflected in the investment decision[46]. However, power plant decommissioning is defined exogenously.

[42] However, agent-specific preferences may be reflected in technology-specific parameters. For instance, an ideal-typical investor may have different requirements regarding the financial yield (reflected as discounting rate) or the payback period (reflected in the assumed planning period), depending on the perceived perception of risk of different technologies.

[43] It has to be noted, though, that the LCOE concepts faces limitations. For instance, [Joskow, 2011], in an analysis of dispatchable (conventional) and intermittent (renewable) technologies, argues that "traditional levelized cost comparisons fail to take account of the fact that the value (wholesale market price) of electricity supplied varies widely over the course of a typical year". [IEA et al., 2010] states that the LCOE concept "provides useful insights in evaluating investments and formulating policies". Nevertheless, "this methodology, as with other analytical instruments, faces some real limitations" (ibid.), including the fact that the "LCOE approach does not adequately reflect the market" (ibid).

[44] For instance, a utility involved in lignite mining may have preferences to built a lignite-fired power plant instead of other technology options.

[45] For instance, a CHP plant in order to supply heat to an existing heat grid.

[46] A power plant is only operated if its marginal operation costs are lower than the spot price in the same

Other models do consider power plant investment and dispatch in an integrated manner. However, calculation is carried out from the system perspective of optimal capacity expansion rather than from an investor's perspective. For instance, the linear optimisation model DIME[47] simulates "dispatch as well as investment decisions" by minimising "total discounted costs based on the assumption of a competitive generation market" [Bartels, 2009]. The model allows for installations to "be retired for economical reasons before their technical lifetime expires" in cases when "their production costs exceed sales revenues" (ibid.). Simulations can be carried out for different step years, for each of which "retirement and commissioning of installations [..] is calculated" (ibid.). The objective function includes both costs related to investment and dispatch of power plants as well as cost effects "outside the model boundaries", such as related to "space heating systems that had to be deployed alternatively" (ibid.). In this regard, overall system costs are minimised. In consequence, feedbacks between power plant operation and investment (which are relevant for the investment decision from an investor's perspective) are dealt with in the model, but cannot be separated from overall system effects (which relate to an optimal capacity expansion strategy for the whole energy system). The DIMENSION model is "a linear energy system model [...] which optimises the future development of electricity generation capacities and their dispatch in Europe" [Richter, 2011, p. 1]. It "is being developed to consolidate different simulations of [...] past projects" (ibid., p. 3.) carried out with the DIME model. Improvements comprise "a module to include demand side management [...] and another module to simulate the dispatch of battery electric vehicles" (ibid., p. 3.). The overall capacity decommissioned is determined as "the sum of capacity that is worn out due to lifetime restrictions and of capacity that is decommissioned endogenously for economic reasons" (ibid., p. 6). A solution is obtained by minimising the objective function, which consists of "the accumulated discounted costs" (ibid., p. 16.) comprising variable costs, investment costs, fixed operation and maintenance costs as well as ramp-up costs (ibid., p. 16, equation (23)). In this regard, the decommissioning and investment rationale corresponds to the DIME model. THEA[48] is a "linear optimization and dispatch model" [Nicolosi, 2011]. "Under the assumption of perfect competition and foresight of a well informed benevolent planner, the investment and dispatch costs are minimized" (ibid.). The investment decision

hour.

[47] Dispatch and Investment Model for Electricity Markets in Europe. This model was used for deriving energy scenarios for the German Energy Concept [Schlesinger et al., 2010].

[48] The High Temporal Resolution Electricity Market Analysis Model.

is “based on a full dispatch year” and is calculated iteratively with the dispatch part of the model “until the predefined convergence criterion is fulfilled” (ibid.). Generally, “the gap between incumbent generation capacity and the peak load requirement has to be met by endogeneous investments” (ibid.). In this regard, THEA accounts for feedbacks between power plant investment and operation, however these relate to a system perspective (“benevolent planner”, “peak load requirements”) rather than to an investor’s perspective.

However, power plant operation and investment are interdependent. Furthermore, in liberalised markets, operation and investment is decided upon based on economic considerations from an operator’s or investor’s rather than from a system perspective. The more profitably a power plant can be operated (in terms of operating hours and electricity revenues), the more likely an incumbent power plant is operated or retrofitted instead of being mothballed or decommissioned. Similarly, the more profitable the operation of a new power plant is expected, the more likely this technology will be built. Incumbent or newly built power plants, in turn, affect the structure of the power sector and thus market conditions (electricity price, operating hours), which again have an influence on the operation of individual power plants. Furthermore, technical restrictions (such as the requirement of load covering at all times) need to be reflected, which are usually included in short-term market models such as PowerFlex [Koch and Bauknecht, 2010] or MICOES (Appendix A). In order to reflect these aspects, power plant operation and investment need to be considered in an integrated way and from the perspective of a power plant operator or investor. In this regard, [Genoese, 2010, p. 105] finds that short-term market analyses are far more advanced than long-term simulation. For this reason, he argues, there is need for further methodological development, especially regarding interactions of short-term electricity markets and long-term investment decisions.

The modelling approach proposed in this thesis closes this gap. ELIAS is designed in a way that allows incorporating modelling results of a merit order model in its decommissioning rationale and investment decision. Similarly, capacity additions estimated by ELIAS serve as an input to the merit order model. ELIAS calculates the future power plant structure stepwise[49] (i.e. for individual years with a defined step width), which allows a feedback with the merit order model. The ability to consider power plant op-

[49]However, this step-wise modelling approach must be differentiated from the so-called time-step approach. Whereas the presented modelling approach takes future energy-economic conditions into consideration, time-step approaches are myopic; the decision rationale is based on the conditions in the current modelling year only [Krey, 2006].

eration results as well as power plant decommissioning and investment in an integrated and consistent manner is one of the core features of ELIAS.

Investments in new generation capacity are affected by a range of policy interventions. For instance, CO_2 emissions trading has an effect both on power plant operation (opportunity costs of emission allowances affect marginal generation costs) and investment (allocation of allowances affects levelised costs of electricity in the planning period). In this regard, the PowerACE model [Genoese, 2010] considers different allocation rules such as auctioning, benchmarking, or grandfathering. Similarly, the DIME model considers "political restrictions such as the use of nuclear power and objectives on climate protection" [Bartels, 2009]. ELIAS is especially designed to evaluate all kinds of policy interventions on power plant investment with a high level of detail. In this regard, input-related policies such as emissions trading, fuel or CO_2 taxes, and output-related policies (such as feed-in tariffs or bonuses) are incorporated in the model. These can directly be applied to the investment analysis or, where appropriate, be provided to the merit order model for consideration in power plant dispatch. Potential future policy interventions (e.g. costs and revenues related to the provision of flexibility in a new market design such as capacity payments) can be added to the model.

3.2. Integration of Power Plant Investment and Operation

As outlined in Section 3.1, the proposed modelling approach is an integrated consideration of power plant investment and operation. For the purpose of the case study, the investment model ELIAS and the power plant dispatch model MICOES are coupled (Figure 3.1). Decisions on investments in new power plants are made from a microeconomic perspective, that is from the perspective of an ideal-typical investor considering levelised cost of electricity as the most important decision variable (ELIAS). Power plant operation is determined by minimising overall electricity generation costs (marginal generation costs including start-up and shut-down costs) (MICOES). Investments in new power plants are made as a function of decommissioning of power plants and the development of the electricity demand. The structure of the new power plant fleet is then fed into the merit order model MICOES which determines the dispatch of power plants and corresponding operating hours and electricity revenues. Market results determined in MICOES are then fed back to ELIAS as a core input for the decommissioning rationale and the investment decision.

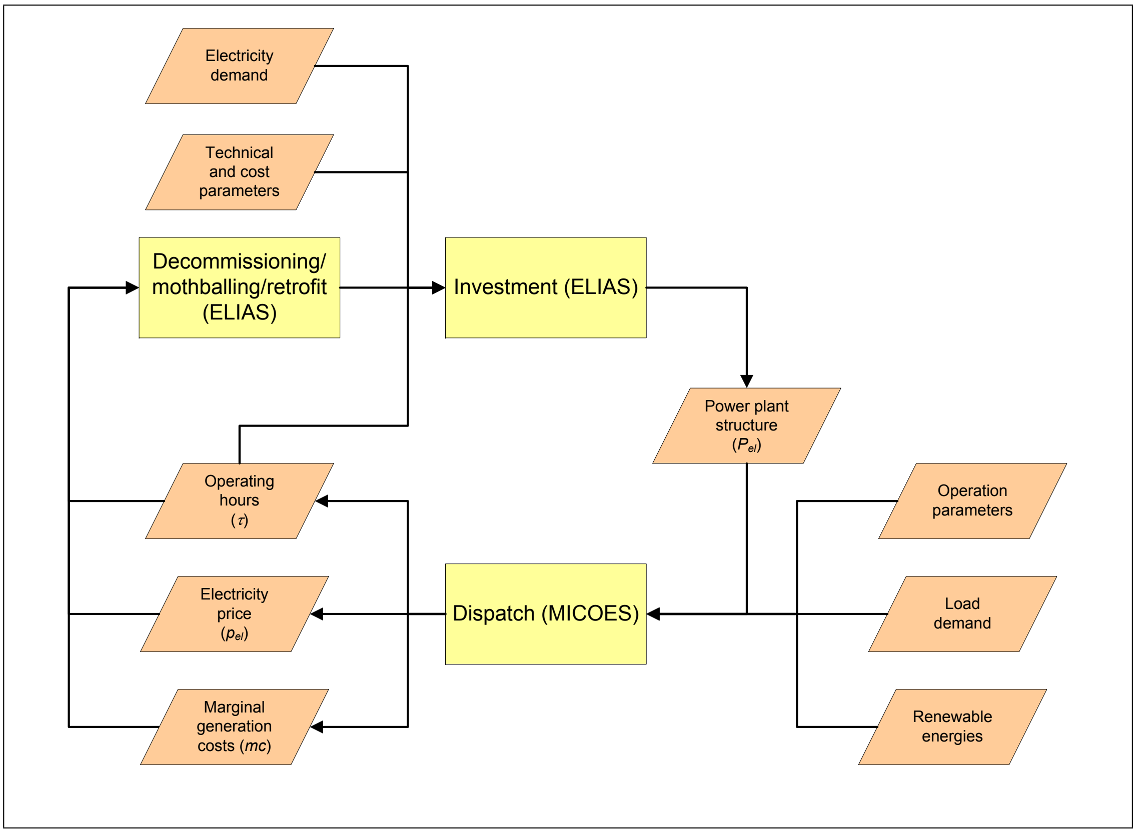

Figure 3.1.: Interactions between power plant investment (ELIAS) and operation (MICOES) (Source: author's own presentation)

Iterations between ELIAS and MICOES are carried out stepwise, i.e. for each step year, power plant decommissioning and investment are iterated against the ensuing results of the spot electricity market (operating hours, electricity revenues) until decommissioning and investment and thus the power plant fleet become stable. Once stability is reached for one step year, the iteration moves on to the next step year. Iteration has to be performed in a stepwise manner since investments in new power plants in step year t influence power plant operation and investment in the next step year $(t + x)$[50].

There are two fundamental feedbacks between power plant decommissioning, investment and operation:

- **Decommissioning/investment demand (electricity gap):** Results of the spot electricity market (operating hours, electricity revenues) influence whether an incumbent power plant can be operated profitably. In consequence, power plants may be mothballed or decommissioned or their lifetime may be extended by retrofit. Subsequently, the need for new investment is determined. The overall

[50] x corresponds to the step width which may be one year or five years, for instance.

capacity of new power plants added, in turn, affects power plant operation. In this regard, there is an interaction between power plant operation and the *magnitude* of new capacity additions[51].

- **Investment decision**: The type of power plants added depends on the levelised costs of electricity. One major determinant for these levelised costs of electricity are the expected operating hours. The higher the operating hours, the more profitable is an investment. The type of new power plants, in turn, affects the structure of the power sector and thus power plant operation. In this regard, there is an interaction between the *type* of power plants added and power plant operation.

Feedbacks between the investment decision (type of power plant) and power plant operation are generally less strong than for decommissioning (magnitude of capacity additions). This is due to the fact that the investment decision is based on operating conditions over a long planning period. Furthermore, the more distant future operating conditions, the smaller the influence on today's investment decision due to the effect of discounting. In contrast, operating conditions in a specific year have a short-term effect on decommissioning, mothballing and retrofit.

The number of iterations necessary to yield a stable power plant structure in a step year and thus to move on to the next step year generally depends on whether *static* or *dynamic* decommissioning is selected:

- **Static decommissioning:** With static decommissioning, power plants are decommissioned at the end of the technical (or regulated) lifetime. Mothballing and retrofit are not considered. Therefore, the magnitude of power plants decommissioned is not influenced by power plant operation. However, the type of power plants added depends on the operating hours and thus on power plant operation. The type of power plants, in turn, affect the merit order and thus power plant operation. Since decommissioning is fixed ex-ante, convergence time is moderate.

- **Dynamic decommissioning:** With dynamic decommissioning, decommissioning, mothballing or retrofit of a power plant depend on power plant operation. The lower the electricity price (electricity revenues) and operating hours, the more power plants are decommissioned or mothballed for economic reasons. However,

[51] In addition to the magnitude of capacity decommissioned or mothballed, also the *type* of power plants decommissioned or mothballed affect the merit order and thus power plant operation.

a smaller amount of remaining capacity leads to increasing electricity prices and operating hours and thus to more power plants staying operational, returning from mothballing state or investing in retrofit. This, in turn, leads to decreasing electricity prices and operating hours and thus to an increased decommissioning and mothballing. This so-called 'pork cycle' (see Footnote 21) requires several loops of iteration until the magnitude of power plants decommissioned, mothballed or retrofitted is stable. As for static decommissioning, the type of power plants added is also affected by the iteration.

4. Electricity Investment Analysis (ELIAS)

In the following, the model focus of ELIAS and the development of features since inception is described (Section 4.1). In Sections 4.2 to 4.6, the model structure and the different modules are explained.

4.1. Model Focus and Development

As established in Section 3.1, ELIAS is a bottom-up simulation model for investments in power plants. Based on the decommissioning of power plants as well as on the development of electricity demand, the need for investment in new power capacity is determined. New generation capacity is added assuming an ideal-typical investor who knows all costs in the depreciation period. The investment is cost-driven, i.e. the lower the levelised costs of electricity, the higher corresponding capacity additions of the technology. A bandwidth of technologies is added as a function of their distance from the cheapest technology. ELIAS incorporates results of a dispatch model in its decommissioning rationale and investment decisions. Similarly, capacity investments determined by ELIAS serve as an input for the selected dispatch model. ELIAS calculates the future power plant structure stepwise (i.e. for individual years with a defined step width).

The main focus of ELIAS at inception was to evaluate energy-economic framework conditions and political legislation with regard to their impact on investments in new power plants and the ensuing power plant structure, fuel mix and CO_2 emissions from an ideal-typical investor's perspective [Bauknecht et al., 2005]. Typical analyses included the impact of different fuel or CO_2 allowance prices ([Krey et al., 2007], [Matthes et al., 2008]) or the impact of policy instruments including different design options such as emissions trading [Matthes et al., 2006] or the promotion of CHP [Horn et al., 2007]. Furthermore, in a recurring project, policies and measures are evaluated with regard to their individual and joint contribution to greenhouse gas mitigation ([Markewitz et al., 2008], [Matthes et al., 2009]). For this reason, three cost types are included in ELIAS: costs related to power plant construction and (technical) operation (technical costs), additional (policy-induced) costs related to fuel consumption (input-related costs, such as fuel tax or emissions trading), and additional (policy-induced) costs and revenues related to electricity (and heat) production (output-related costs and revenues, such as feed-in tariffs, CHP bonus, etc.). Besides investment according to the economic attractiveness, minimum and maximum power plant additions for certain technologies can be defined.

At the outset, ELIAS was based on the assumption that power plants are decommissioned at the end of their technical lifetime. However, experiences in the electricity market show that power plants may be decommissioned earlier or later than the technical lifetime depending on whether power plant operation is profitable. In the most recent version of ELIAS, power plants may be mothballed if economic profitability is not ensured or decommissioned earlier than is the case with the technical lifetime if regulation enforces an early shut-down. Furthermore, incumbent power plants may carry out retrofit measures and thus be able to operate longer than the technical lifetime.

In the initial version of ELIAS, the calculation of levelised costs of electricity was based on typical operating hours, i.e. the operation of power plants was fixed ex-ante. However, anticipated electricity market conditions such as expected fuel or CO_2 allowance prices, electricity demand and the availability of must-run electricity generation and electricity generation with preferential access (such renewable electricity generation or co-generation) significantly affect the number of operating hours. The most recent version of ELIAS includes dynamic operating hours, i.e. the capacity factor may change over time, influencing the economic profitability in each year and the investment in new power plants. Operating hours need to be provided by a dispatch model.

Feedbacks between power plant investment and operation by coupling ELIAS with a dispatch model were first implemented in a study assessing the future of CHP generation [Groscurth et al., 2008]. Other studies considering short- and long-term effects relate to the integration of renewable energies in the German power system ([Harthan et al., 2011], [Harthan et al., 2012]), to the effects of electric vehicles on the power sector ([Loreck, 2011], [Zimmer et al., 2011], [Hacker et al., 2011]), and to an updated evaluation of the contribution of German policies and measures to greenhouse gas mitigation.

At inception, ELIAS considered up to 50 technologies which were further differentiated by their vintage. The current version of ELIAS allows for the consideration of 100 technologies, 50 for incumbent power plants and 50 for capacity investments. The model furthermore distinguishes between individual power plant blocks above a user-specified threshold (currently 100 MW_{el}) both for incumbent and new power plants. Smaller units are aggregated according to technology, fuel type and construction year.

During the work on this thesis, ELIAS has thus evolved from a static investment model to considering feedbacks between power plant investment and operation in a dynamic way. This enables the analysis of short-term (operation) and long-term (decommissioning and investment) effects in an integrated way. Complex energy-economic challenges such as the effects of fluctuating renewable electricity generation, the phase-out of nuclear energy, or charging of electric vehicles on the power system can be evaluated with the ELIAS model and the integrated modelling approach.

4.2. Model Structure

ELIAS comprises four modules for data input, processing and output (Figure 4.1):

1. **User settings:** Data specified in this module serve as input for the investment analysis and capacity addition modules. These comprise technical, cost and energy-economic data as well as specifications of policy interventions and scenario settings.

2. **Investment analysis:** This module is a data processing unit. On the basis of technology-specific data drawn from the user settings module, an investment analysis is carried out for all technologies selected for the scenario period. The results of this module are levelised costs of electricity for each technology in a certain construction year which serve as input for the capacity additions module.

3. **Capacity additions:** This module is also a data processing unit. First decommissioning, mothballing and retrofit of power plants is determined based on information in the user settings module and results from the dispatch model. Based on levelised costs of electricity from the investment analysis module and other information from the user settings module, the module determines capacity investments for each technology in each year of the scenario period. It updates the structure of the power sector based on the vintage structure of incumbent power plants and new power plants entering the system.

4. **Analysis:** This module is a data output and evaluation unit. It contains the results from the capacity additions module such as the structure of the power sector, fuel consumption, or CO_2 emissions as well as other relevant information.

Core features of ELIAS (decommissioning and capacity additions) are implemented in Visual Basic for Applications (VBA) for Microsoft Excel. Furthermore, data input and

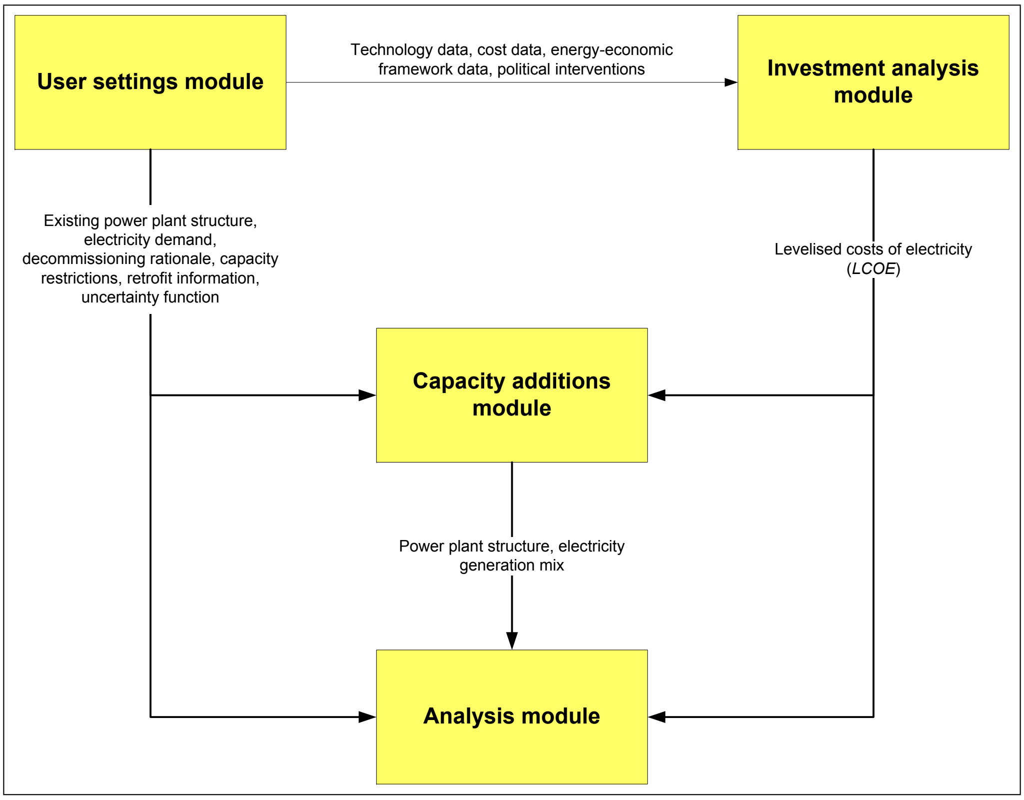

Figure 4.1.: Structure of ELIAS (Source: author's own presentation)

data processing are performed by VBA and directly by Microsoft Excel. The analysis of results is based on Microsoft Excel. The calculation of a scenario spanning over four step years (e.g. 2015, 2020, 2025 and 2030) takes about three hours[52], depending on the scenario settings, provided that enough calculation capacity is available[53].

In the following sections, the four modules are described in more detail[54].

4.3. User Settings Module

The user settings module serves as a data input file. Some parameters (such as electric capacity or discount rate) correspond to a single value. For other parameters, the model allows introducing a time series reflecting changes with regard to different construction years (such as electric efficiency) and in the scenario period (such as fuel prices) or both (such as for feed-in tariffs or bonuses for renewable electricity or CHP generation). Data may be technology-specific (e.g. electric efficiency) or independent of technology (such as fuel prices or electricity demand).

[52]This refers to the stand-alone calculation in ELIAS. Iterations with a merit order model with several model runs require significant more time, depending on the scenario settings.
[53]3 GHz and 2 GB RAM, or more.
[54]The description refers to the model version as of January 2011.

4.3.1. Technical Data

For incumbent power plants, only a limited amount of technical data is necessary since no investment analysis is performed. For new power plants, all technical data relevant for its operation and for the investment are required. All technical data refer to yearly average data[55], i.e. no variations during the lifetime of a power plant[56] are considered.

1. **Technology name:** A maximum of 100 technologies can be specified, out of which 50 for incumbent power plants and 50 for capacity investments.

2. **Technical lifetime:** The design technical lifetime ($T_{technical}$) for each technology has to be specified (years (a)).

3. **Block size (electrical capacity):** The typical block size in terms of installed net electric capacity (P_{el}) for each technology as well as upper and lower limits of block capacity[57] has to be specified (MW).

4. **Thermal capacity (useful heat):** The typical installed net thermal capacity (P_{th}) for each technology as well as upper and lower limits of block size has to be specified (MW). The thermal capacity refers to the maximum output of useful heat of CHP plants for district heating or industrial process heat networks.

5. **Electric efficiency:** The electric efficiency (η_{el}) for each technology (%) has to be introduced as a function of the construction year. Efficiency gains due to retrofit measures may be considered (p. 37).

6. **Annual operating hours:** Annual operating hours related to the production of electricity (τ_{el}) at full load have to be specified for each technology (h/a). These values result from calculations in the dispatch model (Section 3.2).

7. **Share of CHP mode:** For CHP plants, the share of operating hours of CHP heat production (χ_{CHP}) related to overall operating hours for electricity production has to be defined (%). In the case of back pressure CHP plants, χ_{CHP} is 100 % while for extraction-condensing turbines a value between 0 % and 100 % can be chosen[58].

[55] E.g. average electric efficiency, average electric and thermal capacity in case of CHP plants, etc.
[56] Such as the decrease of plant efficiency due to equipment degradation or varying efficiencies as a function of the power plant load (full load, part load). An exception is the increase of electric efficiency due to retrofit (Section 4.3.2).
[57] This allows the model to translate continuous capacity additions in discrete power plant blocks.
[58] For district heating CHP plants, heat demand and thus χ_{CHP} depends to a large extent on temperature, whereas process heat demand in industrial CHP plants mainly depends on production. Some dispatch

8. **CHP coefficient:** For determining the heat production of incumbent CHP plants, a CHP coefficient ν (kWh_{el}/kWh_{th}) has to be specified for each CHP technology[59].

4.3.2. Cost Data

For existing power plants, cost data are only relevant for retrofit measures and the decommissioning rationale (with dynamic decommissioning) while for new power plants, data for the investment analysis have to be introduced.

1. **Investment costs:** Specific investment costs (ic) need to be specified (€/kW_{el}) for each technology.

2. **Contribution in kind:** Besides direct investment costs, further contributions in kind (cik) such as the costs for land, infrastructure or auxiliary devices are relevant for the investor. These have to specified as a share of investment costs (%).

3. **Commitment interest (interest costs during construction):** During construction, the loan agreed with the bank (or other lender) is gradually used for paying the construction progress leading to interest payments. Furthermore, interests are also accrued for the provision of the loan although the loan is not yet fully drawn upon during construction. Such interest costs during construction (icc) are specified as a share of investment costs (%).

4. **Depreciation:** Depreciation is a method of attributing the purchase cost of the power plant (investment costs, contributions in kind, commitment interests) across the useful life. For this purpose, a depreciation period (n) has to be specified for each technology (years (a)). The depreciation period corresponds to the *planned* useful life, is the basis for the investment analysis and is relevant to the depreciation in fiscal terms. The depreciation period may be shorter than the actual lifetime of the power plant. In ELIAS, linear depreciation is applied.

5. **Personal costs:** For each technology, the required manning level (ML, number of employees) and annual labour costs (lc, €/(employee · a)) have to be specified.

6. **Service and maintenance costs:** Annual specific service and maintenance costs (smc) have to be specified for each technology (€/(kW_{el} · a)).

model allow for the heat demand to be met by CHP plants as well as other sources (such as boilers). Also, CHP plants may run in cogeneration or electricity-only mode. Therefore, χ_{CHP} may also be obtained from model results.

[59] ν may be derived from historic production data.

7. **Insurance costs:** Annual insurance costs (*inc*) have to be specified for each technology as a share of investment costs (%).

8. **Variable operating costs:** Specific variable operating costs (*voc*), such as cost for flue gas cleaning, have to be specified for each technology (€/$\mathrm{MWh_{el}}$).

9. **Demolition costs:** At the end of the technical lifetime, specific demolition costs (*dc*) are accrued (€/$\mathrm{kW_{el}}$).

10. **Retrofit costs:** Power plant operators may carry out retrofit measures which allow operating the power plant beyond the nominal technical lifetime. Retrofit costs (RFC) have to be specified as a share of specific service and maintenance costs (χ_{RF}, %)[60]. Besides the increase of technical lifetime, retrofit may lead to an increase of the electric efficiency ($\Delta_{\eta,RF}$) (expressed as relative increase ($\frac{\eta_{Retrofit}}{\eta_{Design}} - 1$) (%)) or to a decrease of specific service and maintenance costs ($\Delta_{smc,RF}$, expressed as percentage share of specific service and maintenance costs before retrofit (%)).

4.3.3. Energy-Economic Framework Data

Energy-economic framework data influence the investment decision and are related to the energy sector as a whole.

1. **Discount rate:** In order to make technologies comparable which differ in their sizes and lifetimes or which have cost and revenue flows at different points in time, all costs and revenues have to be discounted yielding the present value (value at the beginning of the discounting period). The discount rate (i) needs to be specified (%) for each technology. Investors' expectations may also be reflected in the discount rate[61].

2. **Fuel price:** Fuel price (p_{fuel}) scenarios have to be specified (€/$\mathrm{GJ_{fuel}}$). Different scenarios for the same type of fuel can be applied to different technologies[62].

3. **Heat credit:** The heat credit (*hc*) is an important revenue stream for CHP plants. Besides policy influences (p. 40), the heat credit is influenced by fuel prices for heat production. Different scenarios may be defined (€/$\mathrm{GJ_{th}}$).

[60] Costs for retrofit investment are distributed across its depreciation period, yielding annual costs.
[61] See also Footnote 42.
[62] Large utilities, for instance, may be able to negotiate better prices for natural gas for large power plants than households or small commerces may achieve for small block heat and power plants.

4. **CO_2 allowance price:** Different scenarios for the CO_2 allowance price (p_{CO_2}) in the scenario period may be defined (€/t CO_2).

5. **Imposition of capacity additions and capacity restrictions:** Lower bounds (LB) and upper bounds (UB) can be introduced which specify the minimum or maximum electricity generation by a certain technology in a certain year (TWh). These bounds can be used for different situations such as:

   a) Some technologies feature a certain amount of electricity production which can be considered as not being influenced by the power market[63];

   b) the development of certain technologies is exogenously determined[64]; or

   c) a maximum electricity generation is determined by political decisions[65] or energy-economic framework conditions in the respective country[66].

6. **CO_2 emission factors of fuels:** For the determination of CO_2 emissions from power plants, CO_2 emission factors (EF) of fuels are required (t CO_2/TJ). These may reflect national or regional circumstances (such as specific fuel qualities).

4.3.4. Policy Interventions

Governments as well as supra-national (such as the European Union) or international bodies (such as the United Nations) can introduce and influence policies and measures which have an impact on the construction and operation of power plants. ELIAS allows for different policy instruments to be chosen and for corresponding design parameters to be defined. To date, the following policy instruments have been implemented in ELIAS:

Input-related policy interventions

Input-related policy interventions refer to the amount of fuel used or corresponding CO_2 emissions.

1. **Fuel tax:** A fuel tax (ft) may be defined (€/GJ_{fuel}) for each technology type[67] in the scenario period.

[63] For instance, the operation of must-run power plants such as using blast furnace gas or refinery gas is dominated by the conditions in the steel or oil industry, respectively, rather than the power market.
[64] For instance, the development of renewable electricity may correspond to a governmental target.
[65] Such as the maximum amount of electricity benefiting from a certain government incentive.
[66] For instance, the development of heat grids takes some time and the overall CHP potential is technically restricted, which restricts the maximum overall uptake of CHP. Another example is the limited availability of fuels in certain areas (such as lignite or hydro resources).
[67] The fuel tax has to be defined for technologies using a specific fuel and not for fuels generally since governments may apply fuel taxes to certain technologies only. In Germany, for instance, until 2006, a

2. **Emissions trading:** Emissions trading may be selected as a policy option and several design options (and combinations thereof) can be chosen:

   a) *Auctioning:* With auctioning, CO_2 emission allowances generally have to be purchased; CO_2 emissions and the CO_2 price have a direct impact on additional costs and therefore on the investment decision. If relevant, an auctioning share ($\chi_{auction}$) can be chosen which defines the share of actual CO_2 emissions which has to be purchased (and is not allocated for free)[68].

   b) *Benchmark-oriented allocation:* In this design option, allowances are allocated in relation to benchmarks for electricity (and heat production). A reduction of this allocation by a compliance factor may be imposed. Other rules such as the transfer rule may be applied. The following parameters can be chosen:

      i. Benchmark for electricity production: A CO_2 benchmark for electricity (BM_{el}) can be defined for each year in the scenario period which specifies allowances allocated for each unit of electricity (g CO_2/kWh_{el}).

      ii. Benchmark for heat production: A CO_2 benchmark for heat production (BM_{th}) can be defined for each year in the scenario period, which specifies allowances allocated for each unit of CHP heat (g CO_2/kWh_{th}).

      iii. Restriction of over-allocation: If benchmarks are applied, an overallocation of allowances may occur[69]. A maximum share of overallocation (χ_{OA}) may be defined (%).

      iv. Compliance factor: The amount of allowances allocated may be reduced by the application of a compliance factor (CF), which defines the share of allowances effectively allocated (%)[70]. The compliance factor may change

fuel tax on natural gas was applied to power plants producing electricity only while CHP plants were exempt.

[68] For instance, in the European Emissions Trading Scheme (EU ETS), as of 2013, emission allowances for power plants producing electricity only will be fully auctioned, whereas CHP will have to purchase emission allowances related to their electricity production, but will receive a (partly) free benchmark-oriented allocation for the heat produced. This can be translated into an auctioning share.

[69] This is the case, for instance, if power plants have a higher electric efficiency than used as the basis for deriving the benchmark or for CHP plants, which in the case of an allocation according to an electricity and heat benchmark, are allocated more emissions than are actually produced by the plant. Example: In the second phase of the EU ETS (2008-2012), the CO_2 emission benchmark for electricity generation from new natural gas-fired power plants was set at 365 g CO_2/kWh [ZuG 2012, 2007]. A new high efficient combined cycle power plant may reach an electric efficiency of up to 60%. Considering a CO_2 emission factor of 56,100 kg/TJ for natural gas [IPCC, 2006], the power plant has specific CO_2 emissions of 337 g CO_2/kWh. Provided that the allocation is not restricted otherwise, an overallocation of 8% takes place.

[70] The application of a compliance factor reduces overall allowances allocated in line with the overall

over time. An exemption of certain technologies from the application of the compliance factor for a certain time may also be specified ($T_{exemption}$).

v. Transfer rule: A transfer rule can be specified for an operator building a new power plant that decommissions an old (more polluting) power plant. Specific CO_2 emissions (related to the power plant decommissioned) ($e_{CO_2,\ transfer}$, g CO_2/kWh$_{\mathrm{el}}$) can be specified that are used as basis for the allocation of emissions for a defined period of time ($T_{transfer}$).

c) *Demand-oriented allocation (grandfathering):* In this design option, the level of allowances allocated is oriented towards actual or historical plant emissions. Further rules (such as the transfer rule or the compliance factor mentioned above) may be applied.

d) *Other design options:* Other design options can be incorporated such as a CHP bonus[71] $b_{CHP,\ ETS}$ (t CO_2/GWh$_{\mathrm{el,\ CHP}}$).

3. **CO_2 tax:** A CO_2 tax (*ct*) may be defined (€/t CO_2), which is imposed on the actual CO_2 emissions of the power plant.

Output-related policy interventions

Output-related policy interventions relate to the secondary or final energy produced by a power plant, i.e. to electricity or heat production.

1. **Heat credit:** For CHP plants, heat revenues (heat credit, *hc*) may be incorporated in the investment calculation (€/GJ$_{\mathrm{th}}$). Besides general energy-economic framework conditions (p. 37), policy interventions may be relevant[72].

2. **Credit for avoid grid use:** Decentralised electricity generators such as small CHP plants may directly feed in electricity at the low or medium voltage grid level. This avoids grid-use on higher voltage levels. A credit for such avoided grid use (*ag*) may be defined in the model (€/MWh$_{\mathrm{el}}$).

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emission reduction target. Example: if, according to the applicable allocation rule, an installation is eligible for an allocation of 1,000 EUA, the application of a compliance factor of 95% leads to an effective allocation of 950 EUA.

[71] Free allocation of CO_2 allowances as a function of CHP electricity production. This option was applied in Germany during the first period of the EU ETS.

[72] For instance, the applicable heat credit may be increased if upstream emissions trading or a CO_2 tax is introduced which affects heat plants currently outside the scheme. The applicable heat credit can be estimated based on heat costs in a heat-only boiler. With a CO_2 price signal for the boiler, heat prices would rise, leading to a higher applicable heat credit for CHP plants.

3. **Feed-in tariffs or bonuses:** Certain technologies are actively promoted by governments by providing a feed-in tariff (fi) (such as for renewable electricity) or by giving a bonus (b) on top of the electricity price (such as for CHP electricity in Germany). Such revenues (€/MWh$_{el}$) can be defined in the model.

4. **Electricity tax:** An electricity tax (elt) may apply to technologies (€/MWh$_{el}$).

Other policy interventions

Capacity payments: Specific capacity payments (cp) may be introduced (€/kW$_{el}$) to address the missing money problem (Chapter 2) or to remunerate system services[73].

Other policy options can also be incorporated in the model. For instance, technology research and promotion programmes may be reflected in decreasing investment costs. Such policy measures have to be implemented specifically for each technology.

4.3.5. Scenario Settings

Scenario settings may be defined for the scenario as a whole or for individual technologies.

Overall scenario-related settings

1. **Base year power plant structure:** The power plant structure includes all operational power plants in the base year according to technologies, fuel types, and vintages. Power plants may be introduced block-wise (typically for large combustion plants) or aggregated (for smaller units, must-run or renewable power plants).

2. **Basis for the investment decision:** Basis for the investment decision are levelised costs of electricity, which may consider a) technical costs, b) technical costs including input-related costs, or c) technical costs including input-related costs and output-related costs and revenues (Section 4.1).

3. **Electricity demand:** Different scenarios for electricity demand may be defined.

[73]For instance, capacity payments may be paid to power plants which remain operational, although operating revenues are not sufficient to cover operating and annual fixed costs, as medium-term back-up for situations in which fluctuating renewable energies do not provide sufficient capacity, or to short-term peaking or back-up generators such as gas turbines or electricity storage devices. However, due to open questions regarding the future market design, this option is not yet implemented in the current version of the model.

4. **Uncertainty factor:** An uncertainty factor (κ) needs to be defined. The uncertainty factor determines the degree to which technologies other than the cheapest one are considered within the scope of capacity investments (Section 4.5).

5. **Scenario period:** A scenario period has to be specified defining the first and the last modelling year[74] as well as the base year to which all data need to be calibrated. A step width for faster calculation can be chosen. Levelised costs of electricity may or may not be averaged over the length of each step width.

Technology-specific scenario settings

1. **Consideration of the technology type for capacity additions:** This is a flag defining whether certain technologies are considered for capacity investment.

2. **Block-wise or aggregated capacity investment:** Capacity investment may be reflected as individual power plant blocks or as an aggregate for a certain technology type. For instance, power plant technologies bidding on the electricity market may be added as individual power plant blocks, whereas must-run or renewable electricity power plants may be considered as aggregates only.

3. **Decommissioning rationale:** In ELIAS, three different rationales for decommissioning of power plants may be chosen:

   a) *Dynamic decommissioning of power plants:* Decommissioning, mothballing and retrofit of power plants occur as a function of the profitability of power plant operation.

   b) *Technical lifetime:* Power plants are decommissioned at the end of the (design) technical lifetime.

   c) *Regulated lifetime:* A block-specific regulated lifetime for individual power plants may be defined.

4.3.6. Initial Values

Initial values have to be defined for the investment decision and for (dynamic) decommissioning. These are updated once dispatch results of the new power plant structure are available from the merit order model. The following initial values are required:

[74] Up to 2050.

- average annual operating hours (for decommissioning and investment),
- average annual electricity revenues (for decommissioning), and
- average annual marginal generation costs (for decommissioning).

4.4. Investment Analysis Module

In this chapter, equations related to the investment analysis in ELIAS are described. Section 4.4.1 describes fundamental equations for performing an investment analysis. Sections 4.4.2 to 4.4.4 cover specific equations related to the costs for power plant investment and operation as well as additional costs (and revenues) related to the input (fuel) and the output (electricity and, in the case of CHP plants, heat). Equations are based on literature for analysing investments in the power sector (cp. [Bejan et al., 1996], [IEA et al., 2010] and [Moomaw et al., 2011]) and model-specific adaptations.

4.4.1. General Equations Related to Power Plant Investment

When considering an investment in a new power plant, costs and revenues occur at several points in time during the planning period. However, as [Bejan et al., 1996, p. 353] put it, “a dollar in hand in today is worth more than a dollar received in one year from now because the dollar in hand now can be invested for the year”. Therefore, in order to make cash flows at different points in time comparable, future cash flows are discounted by a discount rate i in order to yield the so-called net present value (NPV). In ELIAS, all cash flows are assumed to be payments in arrears (postnumerando), i.e. all payments are due at the end of the respective year[75]. With n being the depreciation period, i the discount rate and t the point in time (year), the NPV then reads[76]

$$NPV = \sum_{t=1}^{n} \frac{Net\ cash\ flows(t)}{(1+i)^t} \tag{4.1}$$

Since ELIAS is a cost-based model (Section 4.1), the investment decision is based on the levelised costs of electricity (LCOE), which is “the most transparent consensus measure of generating costs and remains a widely used tool for comparing the costs

[75]In reality, cash flows occur throughout the year. However, since actual payment dates may differ depending on the cash flow, all payments are accounted at the end of the respective year. The same holds true for the initial capital investment which is repaid during the depreciation period. At the end of each year, a fix repayment is due as well as interest costs for the capital not yet repaid.
[76]The equation is adapted from [Moomaw et al., 2011, p. 5].

of different power generation technologies in modelling and policy discussions. The calculation of the LCOE is based on the equivalence of the [net] present value of the sum of discounted revenues and the [net] present value of the sum of discounted costs", whereby the LCOE "is equal to the price for output [..] that would equalise the two discounted cash flows" [IEA et al., 2010]. In ELIAS besides costs, revenues[77] may be relevant to an investment decision (such as feed-in tariffs, bonuses, etc.). Considering all costs and relevant revenues ($C(t)$, $R(t)$) as well as the electricity generation ($W(t)$) in the planning period (n) and using the discount rate (i), the equation then reads[78]

$$\sum_{t=1}^{n} \frac{LCOE \cdot W(t)}{(1+i)^t} = \sum_{t=1}^{n} \frac{C(t) - R(t)}{(1+i)^t} \tag{4.2}$$

The equation can be further re-arranged, as follows[79].

$$LCOE = \frac{\sum_{t=1}^{n} \frac{C(t)-R(t)}{(1+i)^t}}{\sum_{t=1}^{n} \frac{W(t)}{(1+i)^t}} \tag{4.3}$$

In a simplified case, the annual electricity generation can be considered as constant (W) in the planning period. With the enumerator of equation (4.3) being the net present value (NPV) of the power plant investment and by introducing the capital recovery factor (CRF)[80], $LCOE$ reads

$$LCOE = \frac{NPV \cdot CRF}{W} \tag{4.4}$$

$$CRF = \frac{i\,(1+i)^n}{(1+i)^n - 1} \tag{4.5}$$

The equation can be further simplified by introducing the annuity A, which is "a series of equal-amount transactions occurring at equal time intervals (periods). Usually, the time period corresponds to one year" [Bejan et al., 1996].

$$LCOE = \frac{A}{W} \tag{4.6}$$

[77] Other than revenues from electricity sales which are reflected by the LCOE itself.
[78] The equation is derived from [Moomaw et al., 2011, p. 5] with adaptations related to end-of-year accounting and to relevant revenues.
[79] In this equation, it may appear that electricity generation is discounted. However, this is a result of the re-arrangement of equation (4.2) considering the discounting of costs and revenues. See also [Branker et al., 2011, p. 3].
[80] Compare [Bejan et al., 1996] and [Moomaw et al., 2011] for the definition of the CRF.

$$A = NPV \cdot CRF \tag{4.7}$$

However, the assumption that electricity generation remains constant does not hold true in many cases. The dispatch of power plants (and the electricity generation) depends on market fundamentals such as fuel or CO_2 allowance prices. Furthermore, the construction and decommissioning of other power plants in the market affects the dispatch. In addition, the increased generation of renewable electricity leads to generally decreasing operating hours in conventional power plants. Since the feedback between power plant dispatch and power plant investment is the core aspect of this dissertation, the investment analysis also needs to consider variable electricity generation over time.

With variable electricity generation ($W(t)$) as equal to the product of the electric capacity (P_{el}) (assumed constant) and time-dependent annual operating hours ($\tau(t)$), equation (4.3) then reads

$$LCOE = \frac{\sum_{t=1}^{n} \frac{C(t)-R(t)}{(1+i)^t}}{P_{el} \cdot \sum_{t=1}^{n} \frac{\tau(t)}{(1+i)^t}} \tag{4.8}$$

4.4.2. Technical Costs

Technical costs comprise costs which are necessary for power plant construction (including capital costs) and operation (including fuel, maintenance, and labour costs).

Repayment: Due to "physical deterioration, technological advances, and other factors" [Bejan et al., 1996], the value of a power plant investment decreases over time. This is reflected by the so-called depreciation. Furthermore, "depreciation is a mechanism for repaying the original amount obtained from debt holders if the debt is to be retired" (ibid.). The basis of depreciation is the total amount of capital invested, which comprises the actual investment costs for the power plant, contributions in kind as well as interest costs during construction[81].

Investment costs (IC) accrue for the investment in the power plant itself and correspond to the cost of investment of a turn-key plant [Schneider, 1998]. Investment costs are calculated on the basis of the installed electric capacity (P_{el}) and the specific

[81] Total capital expenditures may be broken down to even more cost components (cp. [Bejan et al., 1996, p. 336]). However, for the purpose of modelling and due to the need for corresponding data acquisition for a range of technologies in a long scenario period, capital expenditures are considered in a more aggregated manner as described by [Schneider, 1998].

investment costs (ic, expressed in €/kW$_{\mathrm{el}}$).

$$IC = P_{el} \cdot ic \tag{4.9}$$

Besides the investment for the power plant itself, the investor needs to provide additional contributions in kind such as land, infrastructure or auxiliary installations (cp. [Bejan et al., 1996] and [Schneider, 1998]). These contributions in kind (CIK) can be estimated as a share of turn-key investment costs (cik, expressed in %) [Schneider, 1998].

$$CIK = IC \cdot cik \tag{4.10}$$

In addition, during design and construction of the power plant, "parts of the investment must be released to finance design studies, civil engineering work, purchase and installation of equipment and so forth" [Bejan et al., 1996]. In consequence, capital is used "without obtaining any revenue" (ibid.) during that time. Corresponding interests costs during construction (ICC) can be estimated as a share of turn-key investment costs (icc, expressed in %) [Schneider, 1998].

$$ICC = IC \cdot icc \tag{4.11}$$

Total investment costs (TIC) are then calculated as the sum of investment costs (IC), contributions in kind (CIK) and interest costs during construction (ICC).

$$TIC = IC + CIK + ICC \tag{4.12}$$

The annual repayment rate ($RP(t)$) is then calculated by distributing total investment costs (TIC) across the depreciation period (n). In the following, linear depreciation is assumed[82], i.e. the same repayment rate is due in every year of the depreciation period.

$$RP(t) = \frac{TIC}{n} \tag{4.13}$$

Interest costs: During repayment, interests have to be paid for the capital borrowed (total investment costs, TIC) and not yet repaid ($RP(t)$). With the debt being repaid, annual interest costs during repayment ($ICR(t)$) (with the interest rate i) decrease over time.

[82] [Bejan et al., 1996] give an overview of different depreciation methods.

$$ICR(t) = \left(TIC - \sum_t RP(t)\right) \cdot i \tag{4.14}$$

Personal costs: For operation, maintenance and administration of the power plant, staff is required. Corresponding annual personal costs ($PC(t)$) are a function of the manning level of the power plant (ML, number of employees) and annual labour costs per employee ($lc(t)$, €/(employee·a)).

$$PC(t) = ML \cdot lc(t) \tag{4.15}$$

Service and maintenance costs: Additional annual costs arise for service and maintenance, such as for regular inspection or repair measures. Annual service and maintenance costs ($SMC(t)$) depend on the installed capacity (P_{el}) and annual specific service and maintenance costs ($smc(t)$, €/(kW_{el}·a)).

$$SMC(t) = P_{el} \cdot smc(t) \tag{4.16}$$

Insurance costs: Additional costs are incurred for the insurance of the power plant. Annual insurance costs ($INC(t)$) are determined as a share (inc, %) of total investment costs[83].

$$INC(t) = TIC \cdot inc \tag{4.17}$$

Fuel costs: Annual fuel costs ($FC(t)$) are based on the annual fuel consumption ($F(t)$) and the fuel price in the respective year ($p_{fuel}(t)$, €/GJ_{fuel}). Annual fuel consumption is in turn dependent on annual electricity generation ($W(t)$) and electric efficiency (η_{el}).

$$F(t) = \frac{W(t)}{\eta_{el}} \tag{4.18}$$

$$FC(t) = F(t) \cdot p_{fuel}(t) \tag{4.19}$$

Variable operating costs: Besides fuel costs and CO_2 allowances costs (Section 4.4.3), other variable operating costs accrue. These relate to "costs for operating supplies

[83] It is assumed that the power plant itself, but also the corresponding infrastructure and auxiliary facilities are insured. For this reason, the insurance premium refers to the total investment costs.

other than fuel costs (e.g., raw water and limestone), catalysts, chemicals, and disposing of waste material" [Bejan et al., 1996]. Annual variable operating costs $VOC(t)$ are a function of the electricity generated in the respective year ($W(t)$) and the annual specific variable operating costs ($voc(t)$, €/$\mathrm{MWh_{el}}$).

$$VOC(t) = W(t) \cdot voc(t) \tag{4.20}$$

Demolition costs: At the end of the technical lifetime, demolition costs (DC) accrue, determined by the electric capacity (P_{el}) and specific demolition costs (dc, €/$\mathrm{kW_{el}}$).

$$DC = P_{el} \cdot dc \tag{4.21}$$

Net present value of technical costs: The net present value of all technical costs ($NPV_{technical}$) is then calculated by discounting all cost flows as follows.

$$\begin{aligned} NPV_{technical} = & \sum_{t=1}^{n} \frac{ICR(t) + PC(t) + SMC(t) + FC(t) + VOC(t)}{(1+i)^t} \\ & + \frac{(RP + INC)}{CRF} + \frac{DC}{(1+i)^n} \end{aligned} \tag{4.22}$$

4.4.3. Input-Related Costs

Input-related costs refer to costs which are applicable to the amount of fuel consumed (fuel tax) or the related CO_2 emissions (CO_2 tax or CO_2 emissions trading).

Fuel tax: Governments may impose a tax on different fuel types[84]. The annual fuel tax ($FT(t)$) is then calculated by multiplying the annual fuel consumption ($F(t)$) with the applicable specific fuel tax in the respective year ($ft(t)$, €/$\mathrm{GJ_{fuel}}$).

$$FT(t) = F(t) \cdot ft(t) \tag{4.23}$$

CO_2 emissions trading: A fundamental aspect of emissions trading is the way CO_2 allowances are allocated. One the one hand, allowances may be auctioned. This means that each operator (incumbent or new entrant) purchases the amount of certificates

[84]For instance, until 2006 in Germany, a tax on natural gas was imposed for electricity generation in power plants without heat extraction [Matthes et al., 2009].

needed. On the other hand, allowances may be allocated by a state entity following defined allocation rules. Allocation may take place according to benchmarks based on best available practices or technologies. Especially for incumbent power plants, allocation may also take place based on actual or historical levels of emissions (demand-oriented allocation (grandfathering)). Different combinations of these approaches are possible. The number of allowances that have to be purchased influence the investment since they constitute an additional cost flow. Allocation rules are therefore crucial for the profitability of power plants. [Ellerman et al., 2007] and [Ellerman et al., 2010] provide a comprehensive overview of the European Emissions Trading Scheme (EU ETS) and the allocation of allowances. [Pahle, 2011] discusses the development of German allocation rules since inception of the EU ETS and provides a model-based analysis of the impact of German allocation rules on the investment in new power plants[85]. Similarly, analyses of the impact of allocation rules on power plant investment in Germany using the ELIAS model can be found in [Matthes et al., 2006] and [Matthes et al., 2008].

The following equations reflecting emissions trading were derived for German allocation rules[86], but may also be adapted to specifications in other countries.

Generally, CO_2 costs or revenues ($CCR(t)$) related to emissions trading depend on the cost-relevant CO_2 emissions regarding a certain allocation rule ($E_{CO_2,CR}(t)$) and the CO_2 allowance price ($p_{CO_2}(t)$, €/t CO_2). Cost-relevant emissions refer to the amount of CO_2 emissions that effectively have to be purchased or may be sold. For instance, emission allowances allocated for free may not suffice to cover the plant's CO_2 emissions, or more allowances may be allocated than actually are needed for plant operation[87].

$$CCR(t) = E_{CO_2,CR}(t) \cdot p_{CO_2}(t) \tag{4.24}$$

Cost-relevant CO_2 emissions depend on the selected allocation rule[88]:

Auctioning: With auctioning, emission allowances generally have to be purchased. However, under certain conditions, a share of allowances may be allocated for

[85] He finds that "technology specific new entrant provisions [i.e. fuel-specific benchmarks] have substantially increased incentives to invest in hard coal plants [compared] to natural gas at the time of the ETS onset" [Pahle, 2011]. And further, "full auctioning of permits or a single best available technology benchmark would have made natural gas the predominant technology of choice" (ibid.).

[86] At this point, I wish to thank Verena Graichen for extensive discussions on allocation rules of the first German National Allocation Plan (NAP) and their implications for the investment analysis in ELIAS.

[87] Please note that in contrast to power plant dispatch [Sijm et al., 2006], opportunity costs associated with the free allocation of CO_2 allowances are not considered in the investment analysis.

[88] Combinations of allocation rules are also possible. For instance, a portion of the allowances may be allocated for free (e.g. using benchmark allocation) and another portion may be auctioned.

free[89]. Cost-relevant CO_2 emissions are therefore the product of actual plant CO_2 emissions ($E_{CO_2,plant}(t)$) and the auctioning share ($\chi_{auctioning}(t)$, %).

$$E_{CO_2,CR,auctioning}(t) = E_{CO_2,plant}(t) \cdot \chi_{auctioning}(t) \tag{4.25}$$

Benchmark-oriented allocation: With this option, allocation occurs according to one (or two) benchmarks. These may reflect best practice of all power plants (uniform benchmark, i.e. the lowest level of specific CO_2 emissions of *all* power plants types) or of certain technologies (fuel-specific benchmark, e.g. best practice technology of *coal* power plants)[90]. With benchmark allocation, CO_2 allowances are allocated on the basis of CO_2 emissions per unit of product (electricity, useful heat) exhibited by the benchmark technology. Generally, if the CO_2 emissions of the plant ($E_{CO_2,plant}(t)$) are higher than allocated according to the related benchmark(s), allowances for the emission difference have to be purchased and thus become cost-relevant for the investment. Benchmarks may refer to the electricity produced (BM_{el}, g CO_2/kWh_{el}) or additionally, in the case of combined heat and power (CHP) plants, to the production of useful heat (BM_{th}, g CO_2/kWh_{th}). Over-allocation may occur if power plants operate more efficiently, i.e. with less CO_2 emissions, than the benchmark(s). Over-allocation may be restricted to a maximum share ($\chi_{OA}(t)$, %). In addition, the allocation may be reduced by applying the so-called compliance factor ($CF(t)$, %)[91]. A technology may be exempt from the application of the compliance factor for a certain time ($T_{exemption}$), during which CF equals 1.[92]

The following equations define the cost-relevant CO_2 emissions for a power plant[93] ($E_{CO_2,CR,BM,Cond}(t)$) for a certain electricity generation (W) and for a CHP plant ($E_{CO_2,CR,BM,CHP}(t)$) with Q being the production of useful heat.[94] Negative cost-

[89] See also Footnote 68.

[90] This is an important distinction. In the German NAP I and II, fuel-specific benchmarks were applied. A natural gas-fired power plant was granted 365 g CO_2/kWh_{el} whereas a coal-fired power plant was granted 750 g CO_2/kWh_{el}. In consequence, there was no incentive to shift from a more emission-intensive hard coal-fired power plant to a natural gas-fired power plant. In contrast, a best practice benchmark of *all* power plants types (e.g. a uniform benchmark of 365 g CO_2/kWh_{el}) would have provided incentives to invest in natural gas-fired power plants since additional CO_2 costs would accrue for the hard coal-fired power plant [Pahle, 2011] (cp. Footnote 85).

[91] When applying the compliance factor, only a certain share of CO_2 allowances calculated according to the benchmark is effectively allocated.

[92] This means that allocation is not reduced during this period.

[93] Condensing-type (Cond) power plants and other power plants producing electricity only.

[94] The equations need to be adapted to the specific conditions of the trading scheme. For instance, the

relevant emissions mean that emission allowances may be sold.

$$E_{CO_2,CR,BM,Cond}(t) = \begin{cases} -\chi_{OA} \cdot E_{CO_2,plant}(t) & \text{if } \chi_{OA} \text{ specified and } BM_{el} \cdot W \cdot CF(t) - E_{CO_2,plant}(t) > \chi_{OA} \cdot E_{CO_2,plant}(t) \text{ (Overallocation restricted to a maximum share)} \\ E_{CO_2,plant}(t) - BM_{el} \cdot W \cdot CF(t) & \text{all other cases} \end{cases} \tag{4.26}$$

$$E_{CO_2,CR,BM,CHP}(t) = \begin{cases} -\chi_{OA} \cdot E_{CO_2,plant}(t) & \text{if } \chi_{OA} \text{ specified and } (BM_{el} \cdot W + BM_{th} \cdot Q) \cdot CF(t) - E_{CO_2,plant}(t) > \chi_{OA} \cdot E_{CO_2,plant}(t) \text{ (Overallocation restricted to a maximum share)} \\ E_{CO_2,plant}(t) - (BM_{el} \cdot W + BM_{th} \cdot Q) \cdot CF(t) & \text{all other cases} \end{cases} \tag{4.27}$$

A transfer rule, which allows the transfer of eligible CO_2 emissions from an old to a newly-built plant, may be applied for a certain time ($T_{transfer}$)[95]. In that case, the benchmarks are replaced with the specific CO_2 emissions of the power

electricity generation may be based on typical or actual (historical) operating hours. In the second NAP in Germany, standard capacity factors were applied which translate into constant electricity (and heat) generation. Similarly, benchmarks may be a function of time or be held constant (as assumed in the equation). A temporary exemption from the application of the compliance factor, as included in the first NAP (2005-2007) in Germany, is also not included since it is not relevant any more.

[95] This rule provides incentives for decommissioning an old emission-intensive power plant and for replacing it with a new less emitting power plant since emission allowances may be (partially) carried over to the new plant, thus providing additional revenues by selling the surplus allowances.

plant decommissioned ($e_{CO_2,transfer}$, g CO_2/kWh$_{\text{el}}$). As for benchmark allocation, a compliance factor may be applied.

$$E_{CO_2,CR,transfer}(t) = E_{CO_2,plant}(t) - e_{CO_2,transfer} \cdot W \cdot CF(t)\Big|_{t \leq T_{transfer}} \tag{4.28}$$

Demand-oriented allocation (grandfathering):[96] With demand-oriented allocation, cost-relevant CO_2 emissions are based on actual or historical CO_2 emissions ($E_{CO_2,plant,hist}$) and the application of a compliance factor.

$$E_{CO_2,CR,DO}(t) = E_{CO_2,plant}(t) - E_{CO_2,plant,hist} \cdot CF(t) \tag{4.29}$$

Other design options: Other design options may be implemented such as a CHP bonus (b_{CHP}, t CO_2/GWh$_{\text{el}}$) yielding an extra allocation for CHP electricity (W_{CHP})[97].

$$E_{CO_2,CR,CHP,bonus}(t) = -b_{CHP} \cdot W_{CHP} \tag{4.30}$$

CO_2 tax: A CO_2 tax may be imposed on fuels[98]. The annual CO_2 tax ($CT(t)$) is determined by multiplying annual CO_2 emissions ($E_{CO_2}(t)$) with the applicable CO_2 tax ($ct(t)$, €/t CO_2). Annual CO_2 emissions are determined by multiplying the annual fuel consumption ($F(t)$) with the corresponding CO_2 emission factor (EF_{CO_2}, t CO_2/TJ).

$$E_{CO_2}(t) = F(t) \cdot EF_{CO_2} \tag{4.31}$$

$$CT(t) = E_{CO_2}(t) \cdot ct(t) \tag{4.32}$$

Net present value of input-related costs and revenues: The net present value of all input-related costs and revenues (NPV_I) is then calculated as follows.

[96] Grandfathering is relevant for incumbent power plants. However, the corresponding allocation rule has been incorporated in ELIAS in order to reflect a potential situation in which emission allowances are allocated to new entrants on the basis of demand for actual plant operation.
[97] This bonus was applicable during the first period of the EU ETS in Germany (2005-2007).
[98] Whereas the energy tax usually relates to the fuel's energy content, the CO_2 tax relates to the carbon content of fuel. [Andersen, 2010] discusses experiences in Europe with carbon taxation.

$$NPV_I = \sum_{t=1}^{n} \frac{FT(t) + CCR(t) + CT(t)}{(1+i)^t} \tag{4.33}$$

4.4.4. Output-Related Costs and Revenues

Output-related costs and revenues refer to costs and revenues applicable to the output produced (electricity and, in the case of CHP plants, useful heat).

Heat credit: Besides the generation of electricity, CHP plants provide as additional output useful heat for district heating or as industrial process heat. Therefore, the corresponding revenues for heat sales have to be considered in the investment analysis. The annual heat credit ($HC(t)$) relates to the annual quantity of useful heat ($Q(t)$) generated in a CHP plant multiplied with a specific heat credit ($hc(t)$, €/$\mathrm{GJ_{th}}$) in the respective year.

$$HC(t) = hc(t) \cdot Q(t) \tag{4.34}$$

Avoided grid use: Decentralised electricity generators such as CHP plants may feed in electricity at the low or medium voltage level, which reduces costs for the high voltage line. The annual revenue for avoided grid use ($AG(t)$) then relates to the annual amount of electricity ($W(t)$) generated and exported to the grid at a low voltage level and the specific credit for avoided grid use ($ag(t)$, €/$\mathrm{MWh_{el}}$) in the respective year.

$$AG(t) = ag(t) \cdot W(t) \tag{4.35}$$

Feed-in tariffs or bonuses: Certain technologies (such as renewables or CHP) are promoted by a feed-in tariff or a bonus[99]. Feed-in tariffs ($fi(t)$, €/$\mathrm{MWh_{el}}$) or bonuses ($b(t)$, €/$\mathrm{MWh_{el}}$) per unit of electricity produced are applied to the annual amount of electricity generated ($W(t)$) (and eligible for the revenue[100]), yielding the annual revenues from the feed-in tariff ($FI(t)$) and the bonus ($B(t)$), respectively.

$$FI(t) = fi(t) \cdot W(t) \tag{4.36}$$

[99] While a feed-in tariff refers to a guaranteed price for the electricity generated, a bonus is paid on top of the market electricity price.

[100] For instance, in Germany, a bonus for CHP electricity production is only granted for the share of electricity generated in CHP mode. This means for an extraction-condensing type CHP plant, only a share of the overall electricity produced is eligible for the CHP bonus.

$$B(t) = b(t) \cdot W(t) \tag{4.37}$$

Electricity tax[101]: An electricity tax ($elt(t)$, €/MWh$_{\text{el}}$) per unit of electricity produced may be imposed on the annual amount of electricity ($W(t)$) generated, yielding the annual electricity tax ($ELT(t)$).

$$ELT(t) = elt(t) \cdot W(t) \tag{4.38}$$

Net present value of output-related costs and revenues: The net present value of all output-related costs and revenues (NPV_O) is then calculated as follows.

$$NPV_O = \sum_{t=1}^{n} \frac{ELT(t) - (HC(t) + AG(t) + FI(t) + B(t))}{(1+i)^t} \tag{4.39}$$

4.4.5. Total costs

The sum of technical costs ($NPV_{technical}$), input-related costs (NPV_I) and output-related costs and revenues (NPV_O) yields the total costs (NPV_{total}).

$$NPV_{total} = NPV_{technical} + NPV_I + NPV_O \tag{4.40}$$

Equation (4.8) can then be further re-arranged yielding the $LCOE$.

$$LCOE = \frac{NPV_{total}}{P_{el} \cdot \sum_{t=1}^{n} \frac{\tau(t)}{(1+i)^t}} \tag{4.41}$$

4.5. Capacity Additions Module

In this module, the investment demand is determined based on the (endogenous) decommissioning of power plants and the expected (exogenous) development of electricity demand (Section 4.5.1). The ensuing electricity gap is covered by considering the results of the investment analysis as well as model restrictions (Section 4.5.2)[102].

[101] An electricity tax is usually imposed on electricity supplied to final consumers (such as households or industry). An electricity tax should therefore only be incorporated in a scenario if the legislation in place allows for differentiation of the electricity tax according to fuel or technology types.

[102] The initial version of the capacity additions module was predominantly developed by Dr. Dierk Bauknecht. The description included in this section describes the module in its current version including further developments, such as the dynamic decommissioning rationale.

4.5.1. Investment Demand

The investment demand (in terms of electricity generation (TWh)) corresponds to the electricity gap ($\Delta_{el}(t)$), which is based on annual electricity generation in power plants that are decommissioned ($W_D(t)$) or mothballed ($W_M(t)$) by the model and the expected development of the annual electricity demand ($ED(t)$)[103].

$$\Delta_{el}(t) = W_D(t) + W_M(t) + (ED(t) - ED(t-1)) \tag{4.42}$$

$W_D(t)$ and $W_M(t)$ are derived from the electric capacity decommissioned ($P_D(t,j)$) or mothballed ($P_M(t,j)$) of all respective power plants (j) in a certain scenario year (t), multiplied with the annual operating hours ($\tau(t,j)$).

$$W_D(t) = \sum_j P_D(t,j) \cdot \tau(t,j) \tag{4.43}$$

$$W_M(t) = \sum_j P_M(t,j) \cdot \tau(t,j) \tag{4.44}$$

Mothballing is the temporary removal from service of a power plant, which is generally still ready for operation from a technical (lifetime) and regulatory (operation permit) perspective, whereas decommissioning refers to the permanent shutdown of a power plant. Decommissioning or mothballing may take place according to one of the following rationales (Figure 4.2):

- **Dynamic decommissioning:** A conventional power plant operates in the electricity market, considering other restrictions such as ramp rates or minimum uptimes and downtimes, if in certain hour (k) in a certain year (t) its short-term marginal generation costs ($mc(k,t)$) are lower or equal than that of the last unit dispatched, which sets the market clearing price ($p_{el}(k,t)$) on the spot market. The difference between the spot market price and short-term marginal costs constitutes the hourly profit margin (or the so-called infra-marginal rent) ($pm(k,t)$). With τ being annual operating hours, during which the power plant operates below or at the margin, and $P_{el}(k,t)$ the current power output[104], the annual profit margin

[103] In terms of net electricity generation (W_{el}).

[104] Since power plants may be operated in part load, $P_{el}(k,t)$ may differ between hours. In practice, in ELIAS, the electric capacity is kept constant, whereas changes in the operational state of power plants (part load) are reflected in the operating hours provided by the dispatch model (which refer to operation at full load).

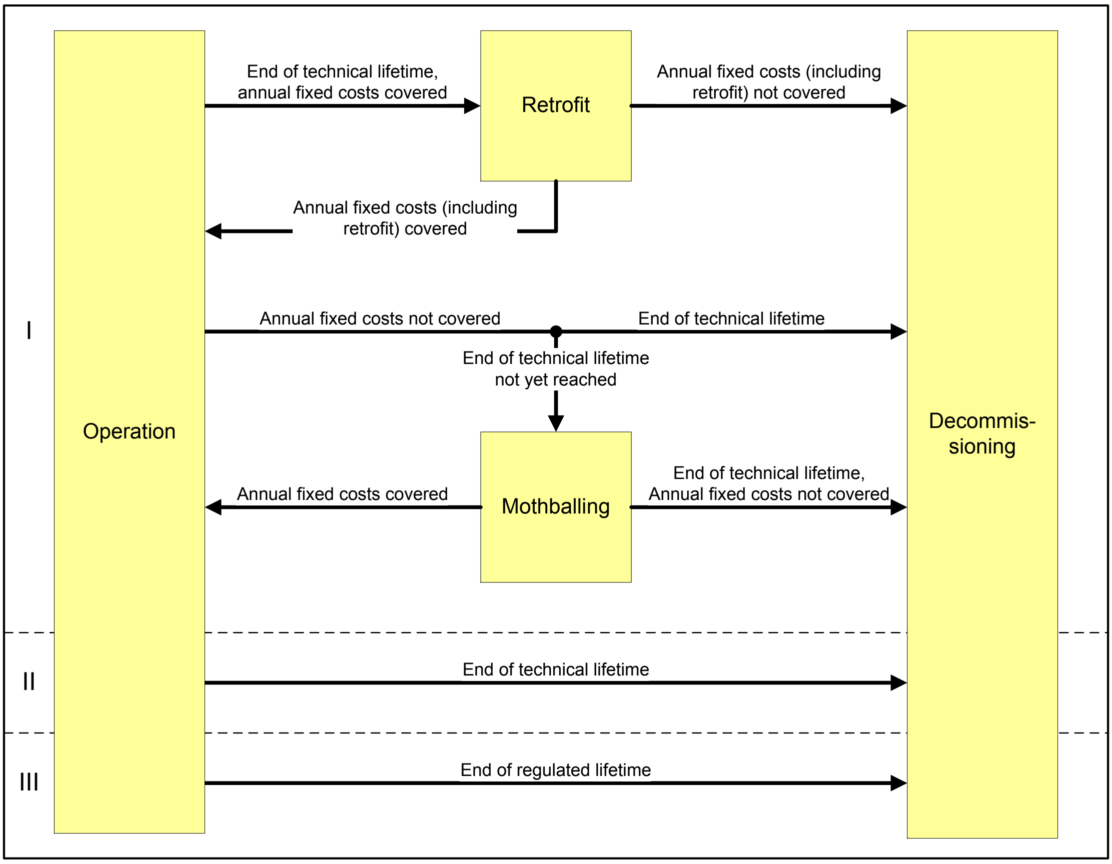

Figure 4.2.: Decommissioning rationales (I: dynamic decommissioning, II: technical lifetime, III: regulated lifetime) (Source: author's own presentation)

($PM(t)$) of a power plant can be calculated as follows (cp. Figure 2.2).

$$PM(t) = \sum_{k=1}^{\tau} P_{el}(k,t) \cdot (p_{el}(k,t) - mc(k,t)) \tag{4.45}$$

It is only profitable to run a power plant if annual fixed costs (personal costs ($PC(t)$), service and maintenance costs ($SMC(t)$) (Section 4.4.2) and, if relevant, retrofit costs ($RFC(t)$)) are covered by the annual profit margin.[105]

$$PM(t) \overset{!}{>} PC(t) + SMC(t) + RFC(t) \tag{4.46}$$

If these costs are not covered, the power plant is mothballed[106] or, if the plant has reached the end of its technical lifetime, decommissioned. ELIAS allows for the

[105] However, costs incurred for the investment are not taken into account as these are considered as *sunk* and are therefore not decision-relevant for power plant operation (p. 6).

[106] Mothballing is an optional setting in ELIAS. If deactivated, the power plant is decommissioned forthwith.

time period (years) during which such losses are accepted before the power plant is mothballed or decommissioned to be defined.

Retrofit costs ($RFC(t)$) arise if an operator wishes to operate the power plant beyond the design technical lifetime. Corresponding investment costs (such as for the replacement of turbine blades or the installation of a topping gas turbine) are considered as a relative increase of annual service and maintenance costs (χ_{RF}, %)[107]. Retrofit may also reduce annual service and maintenance costs by a certain percentage ($\Delta_{smc,\ RF}$, %).

$$RFC(t) = P_{el} \cdot smc(t) \cdot (\chi_{RF} - \Delta_{smc,\ RF}) \tag{4.47}$$

If other revenue streams become relevant in a future market design such as capacity payments (Section 4.3.4), the decommissioning rationale can be further adapted.

- **Technical lifetime:** Technical lifetime is considered as the relevant decommissioning rationale if electricity production is a by-product or if retrofit measures are not relevant which could extend the technical lifetime of the power plant. Power plants using fuels derived from industrial processes (such as refinery gas, coking gas, or blast furnace gas) or from waste (waste incinerators with electricity generation) as well as renewable electricity generation[108] are considered under this category.

- **Regulated lifetime**: The number of years a power plant operates may also be regulated (Section 4.3.5). This is the case, for instance, if the operating permission explicitly states an end time for commercial operation[109].

[107] In fact, retrofit involves investment at a certain point in time. After the investment, these costs can be considered as sunk and are therefore no longer decision-relevant for power plant operation. However, in ELIAS, retrofit is not restricted to a certain time period. Under dynamic decommissioning, the lifetime of power plants is not restricted as long as annual profitability is ensured (including the consideration of retrofit costs). In this regard, it is assumed that a gradual retrofit is carried out. Corresponding investment costs are therefore translated into an annual increase of service and maintenance costs which are relevant for every year the power plant remains in operation beyond the design technical lifetime. Annual retrofit costs are then decision-relevant according to equation (4.46).

[108] Repowering of wind turbines is not considered here since old turbines are replaced by new ones, which are considered as newly-commissioned in ELIAS. If current renewable electricity promotion schemes (such as the feed-in tariff in Germany) are complemented (or in the long term replaced) by market-driven approaches, retrofitting may become relevant also for renewable electricity generation, for instance for electricity generation from biomass. In this case, the dynamic decommissioning rationale would be relevant.

[109] As for nuclear power plants in Germany.

4.5.2. Investment Decision

In this step, the electricity gap ($\Delta_{el}(t)$, TWh) is covered by investments in new power plants[110]. For this purpose, the share of each power plant technology ($\chi_{NI}(t,j)$) in the overall new investment needs to be determined. $\chi_{NI}(t,j)$ corresponds to the new investment ($NI(t,j)$, TWh) of a power plant technology (j) in relation to the overall new investment required (corresponding to the electricity gap) in each year (t).

$$\chi_{NI}(t,j) = \frac{NI(t,j)}{\Delta_{el}(t)} \tag{4.48}$$

The investment decision is based on the levelised costs of electricity (LCOE) of the considered power plant technologies (cp. p. 43). Consequently, a fully rational investor would invest in the technology with the lowest LCOE. This would mean that the complete electricity gap ($\Delta_{el}(t)$) is covered by one technology only. This corresponds to the rationale in optimisation models.

However, in practice, there are other considerations besides mere cost aspects which influence the investment decision. [Pahle, 2011] provides an analysis of "potentially influential economic, technological and socio-political factors" of "investments in liberalized electricity markets". In assessing the reasons for "Germany's dash for coal" (ibid., p. 36), he argues that "the most clear cut approach so far is provided by economic theory, which states that capital and operation costs, broken down to levelized unit costs, are the determinants for technology choice" (ibid., p. 39). However, there are further aspects such as "siting, public acceptance, and political support" (ibid., p. 39). For instance, "nuclear power plants will be replaced with other base load technologies [..]; primarily hard coal, and lignite where available" (ibid., p. 44). Furthermore, "location factors" are important, such as "fuel supply and transport, cooling, network connection and site synergies like existing infrastructure and additional supplementary installations (e.g. filters)" (ibid., p. 44). Also, he finds that "in the long run operation costs for coal are lower and less risky than for natural gas" (ibid., p. 46)[111].

It can therefore be concluded that the LCOE is a valid basis for the investment decision, but other factors also need to be considered. For this reason, new capacity investment is distributed over a range of technologies as a function of LCOE, with the

[110] The overall investment demand refers to electricity generation (TWh). The calculation of corresponding capacity (P_{el}, MW) is carried out in equation (4.55).

[111] In ELIAS, the level and trajectory of fuel prices are considered in the investment analysis. However, the *risk* associated with a chosen fuel price scenario is not reflected in the LCOE.

cheapest technology being assigned the bulk of investment and other technologies being built as a function of their distance from the cheapest technology. The distribution function is represented as monotonically decreasing with LCOE. It is assumed that LCOE is the most important decision factor; therefore a function needs to be chosen that assigns new investments to technologies according to the rationale 'the closer to the cheapest technology, the more likely the technology is considered for investment'. For this reason, an exponential distribution is chosen[112].

Hence, the share in capacity additions ($\chi_{NI}(t,j)$) of each power plant technology (j) in a certain year (t) is modelled as a function of the distance of each power plant's costs ($LCOE(t,j)$) from the lowest cost of all technologies ($LCOE_{min}(t)$) as well as an uncertainty factor (κ), as follows.

$$\chi_{NI}(t,j) = \frac{e^{(LCOE_{min}(t)-LCOE(t,j))\cdot\kappa}}{\sum_j e^{(LCOE_{min}(t)-LCOE(t,j))\cdot\kappa}} \tag{4.49}$$

The uncertainty factor (κ) describes the shape of the exponential function and is therefore crucial for the investment decision, with the following two extrema:

- $\kappa = 0$: In this case, the exponential function results in an equal distribution of investments across technologies, independent of the LCOE. This is not a plausible assumption.

- $\kappa \to \infty$[113]: This case corresponds to the concept of the rational investor. Only the technology with the lowest LCOE is invested in. Any technology with (minor) differences in LCOE is not built (penny-switching). As described above, this is also not a plausible assumption.

Figure 4.3 gives an overview of the shape of the uncertainty function for different values of the uncertainty factor (κ).

One way of determining the parameterisation of κ is to evaluate ex-post the capacity additions of different power plant technologies during a certain period. Corresponding

[112] Exponential distributions are also used in the modelling of lifetimes [Hartung et al., 2005]. Similarly, in physics, the so-called Boltzmann distribution is expressed as an exponential function and describes the particle number density as a function of their respective energy levels [Meschede, 2006, p. 224]. Other functions are generally also conceivable, such as a linear function or $1/x$, which are also monotonically decreasing. However, the latter, $1/x$, is not suitable since it yields an infinite value for the cheapest technology (distance to cheapest technology is nil). Furthermore, other approaches of distributing investment demand over a bandwidth of technologies are a topic for further research (Section 6.3).

[113] Due to the shape of the exponential function, equation (4.49) yields values close to zero already with $k = 1$ (for typical LCOE).

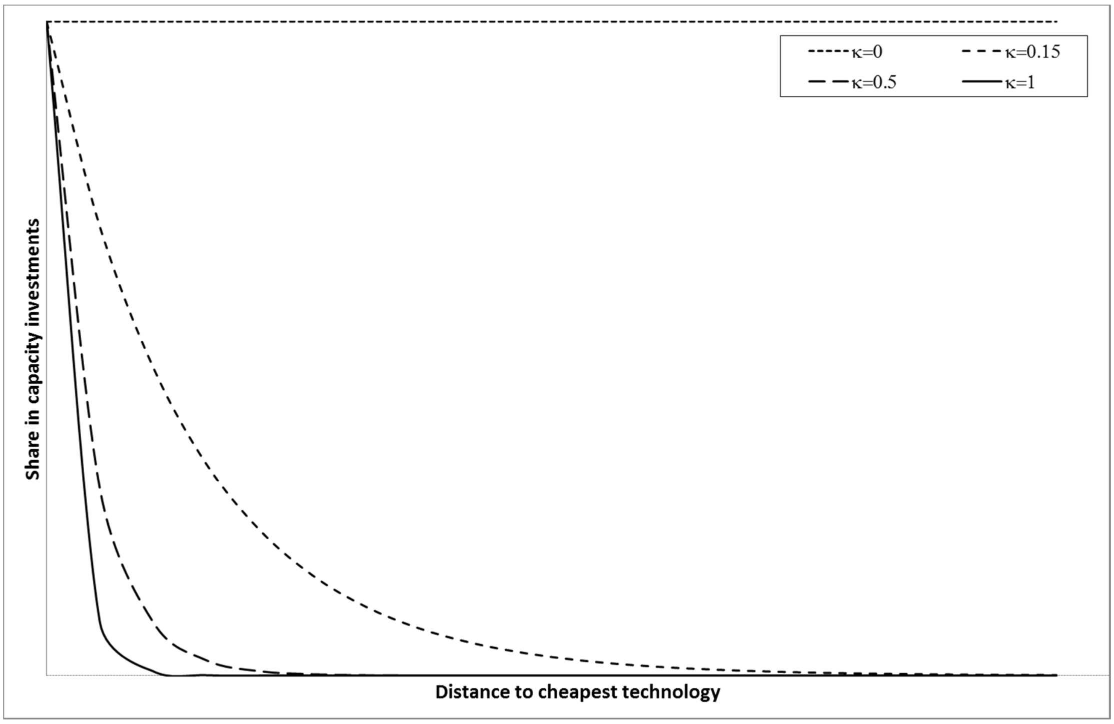

Figure 4.3.: Uncertainty function (Source: author's own presentation)

shares ($\chi_{NI}(i,j)$) can thus be calculated. However, in order to derive the uncertainty factor (κ) which best fits the exponential curve, the underlying assumptions regarding the LCOE are needed. Since the planning and construction of a power plant spans over several years[114], the LCOE at the time of planning and when the investment decision is taken, may be different from the LCOE at the time of commissioning since major assumptions (such as investments costs, fuel or CO_2 allowance costs) may have changed in the meantime. Furthermore, cost assumptions of power plant investors are usually not publicly available. In addition, new investments considered at a certain point in time provide a snap shot, but may be biased with regard to the long-term trend. For instance, uncertainty related to policy development (cp. p. 12) may lead to delays or even cancellation of power plant projects, thus the timing of commissioning and the technology mix of new investments at a certain point in time may not correspond to new investments that would occur without such delays. Therefore, for the modelling so far, κ is derived from discussions with relevant stakeholders in the power sector on the attractiveness of different power plant options and set at $\kappa = 0.15$[115] [Matthes, 2006].

[114] The construction time amounts to two years for gas-fired power plants and four years for coal-fired power plants [Schneider, 1998, p. 17].

[115] For demonstration purposes, it is assumed that there are two technology options for investment only. The cheapest technology features an LCOE of 60 €/MWh and the second cheapest technology 65 €/MWh. Considering a total investment demand of 2,000 MW, $\kappa = 0.15$ means that 1,358 MW are

The initial shares in new investment of each power plant ($\chi_{NI,initial}(t,j)$) are then applied to the electricity gap ($\Delta_{el}(t)$), yielding the preliminary (initial) new investment ($NI_{initial}(t,j)$) for each technology.

$$NI_{initial}(t,j) = \chi_{NI,initial}(t,j) \cdot \Delta_{el}(t) \tag{4.50}$$

Then lower and upper bounds ($LB(t,j)$, $UB(t,j)$) are applied (Section 4.3.3) which restrict and impose new investments, yielding adjusted new investments ($NI_{adjusted}(t,j)$)[116].

$$NI_{adjusted}(t,j) = f\left(NI_{initial}(t,j), LB(t,j), UB(t,j)\right) \tag{4.51}$$

Finally, new investments have to be further adjusted in a way that the overall electricity gap ($\Delta_{el}(t)$) is matched, respecting upper and lower bounds. The optimisation algorithm for the adjustment requires that the relative deviation ($\delta(t,j)$) between the final share of new investments in each technology ($\chi_{NI,final}(t,j)$) and the initial share of new investments ($\chi_{NI,initial}(t,j)$) be as small as possible. This ensures that the final distribution of power plant investment follows the initial distribution (exponential function) to the highest possible extent (respecting upper and lower bounds).

$$\delta(t,j) = \frac{\chi_{NI,final}(t,j) - \chi_{NI,initial}(t,j)}{\chi_{NI,initial}(t,j)} = \frac{\chi_{NI,final}(t,j)}{\chi_{NI,initial}(t,j)} - 1 \tag{4.52}$$

The final distribution of power plant investment is thus obtained by minimising the standard deviation ($\sigma(t)$) of the deviation of all power plant investments ($\delta(t,j)$) (with n being the number of technologies and $\bar{\delta}(t)$ the average of the deviations of all power plant investments) between final and initial distribution, respecting lower and upper bounds as well as the electricity gap as modelling constraints. This optimisation is performed by a solver implemented in VBA.

Objective function:

$$\min \sigma(t) = \sqrt{\frac{\sum_j \left(\delta(t,j) - \bar{\delta}(t)\right)^2}{n}} \tag{4.53}$$

built in the cheapest technology and 642 MW in the second cheapest technology. As topic for further research, κ chosen here should be verified based on empirical data as outlined above (Section 6.3).

[116] For instance, from a cost perspective, a lignite power plant may be the most attractive option. However, due to resource limitations (availability and exposure of pits), the adjusted capacity additions may be lower. Similarly, a power plant, the construction of which is driven by other considerations (e.g. a refinery power plant), may be added although in terms of LCOE, it would not be attractive.

The final new investment ($NI_{final}(t,j)$) then reads as follows.

$$NI_{final}(t,j) = \chi_{NI,final}(t,j) \cdot \Delta_{el}(t) \tag{4.54}$$

Once the final new investments ($NI_{final}(t,j)$) in terms of electricity generation (TWh) for each technology are determined, the corresponding installed power plant capacities ($P_{NI}(t,j)$) (MW_{el}) are calculated by considering the respective operating hours of each new power plant ($\tau(t,j)$, h/a) (Section 4.3.6).

$$P_{NI}(t,j) = \frac{NI_{final}(t,j)}{\tau(t,j)} \tag{4.55}$$

Generally, ELIAS allows for continuous (in mathematical terms) new investments; the capacity added is then converted into discrete power plant blocks, the size of which has to be defined in the user settings module (Section 4.3.1).

4.6. Analysis Module

The analysis module is used for formatting and displaying data related to scenario calculations with the ELIAS model. Relevant input data from the user settings module are replicated in order to document major scenario settings. These comprise for instance information on electricity demand, fuel and CO_2 prices, policy interventions or lower and upper bounds. Furthermore, important results from the investment analysis module (such as LCOE) and the capacity additions module (such as intermediate and final calculation results) are displayed. Important model results include electricity and heat generation, installed electrical capacity, primary energy demand, and CO_2 emissions. Results can be differentiated according to existing power plants and new investments. Further analyses can be customised such as the development of CHP or CCS. The analysis module furthermore provides data interfaces so that model results can be used as input to other evaluations.

5. Case Study

In the following, a case study is presented demonstrating the application of the modelling approach to two scenarios. The calculations were performed between Summer 2010 and early 2011 as part of a joint research project by Öko-Institut e.V. and the University of Leipzig [Harthan et al., 2012]. In this study, the first scenario describes the investment and operation of power plants in Germany, assuming a phase-out of nuclear power plants as initially agreed in 2000 [Bundesregierung, 2000]. The second scenario corresponds to a situation in which lifetime extension of nuclear power plants as included in the initial version of the German Energy Concept [BMWi and BMU, 2010] is implemented as originally decided. However, in the aftermath of the nuclear incident in Fukushima, the German government repealed its decision on the lifetime extension of nuclear power plants and agreed on an accelerated phase-out as stipulated in the updated Energy Concept [Bundesregierung, 2011]. As shown in Section 5.1.1, the original phase-out [Bundesregierung, 2000] and the newly-decided accelerated phase-out [Bundesregierung, 2011] are broadly comparable when it comes to the overall phase-out trajectory. In this regard, the two scenarios (without lifetime extension, with lifetime extension) presented in this case study can be considered as an approximative analysis of the effects of the accelerated phase-out (situation since mid-2011) in comparison to the lifetime extension of nuclear power plants (situation at the end of 2010).

Against the background of these two scenarios, the impact of renewable electricity generation on power plant investment and operation is evaluated. In order to assess the impact of interactions between power plant operation, decommissioning and investment, two different decommissioning rationales are considered for each scenario (Table 5.1):

- **Static decommissioning:** With static decommissioning, all power plants are decommissioned at the end of their technical or regulated lifetime. The feedback

Decommissioning rationale	Scenario	
	Without lifetime extension	With lifetime extension
Static	woLTE_S	wLTE_S
Dynamic	woLTE_D	wLTE_D

Table 5.1.: Scenario definition (Source: author's own presentation)

of power plant operation on investment is restricted to the influence on levelised costs of electricity (by considering operating hours in the investment analysis).

- **Dynamic decommissioning:** With dynamic decommissioning, power plant operation affects decommissioning, mothballing and retrofit of fossil-fired electric[117] power plants and thus the need for new investment. In the case of unprofitable operation, power plants are mothballed[118] or decommissioned. If power plants can be operated profitably, retrofit measures are carried out, thus extending the operational lifetime. As for static decommissioning, feedbacks of power plant operation on levelised costs of electricity are considered. Other power plant types are decommissioned at the end of their technical or regulated lifetime (Section 5.1.1).

In-depth discussion focuses on ELIAS modelling results. Results obtained in the MICOES model are discussed for aspects which are relevant for the feedback between power plant operation and investment (such as annual operating hours). A more detailed discussion of MICOES model results (such as the hourly generation pattern) is provided in the report of the corresponding project [Harthan et al., 2012].

Section 5.1 describes the most important model data and scenario settings. Section 5.2 presents the results of the two scenarios for both decommissioning rationales.

5.1. Model Data and Scenario Settings

Model data and scenario settings comprise overarching energy-economic framework conditions (Section 5.1.1), assumptions with regard to technical and cost data of power plants (Section 5.1.2) and the consideration of policy measures (Section 5.1.3). The scenario period spans from 2008 to 2030.

5.1.1. Energy-Economic Framework Conditions

The need for new capacity is determined by the development of the electricity demand and the decommissioning of power plants (Section 4.5.1). With regard to the electricity demand, the reference scenario ("with-measures scenario") of the "Policy scenarios

[117] The focus of this study is on the profitability of power plants producing electricity only. Therefore, the term "electric power plants" is used in some cases in order to be unambiguous. In other cases, "power plants" refers to power plants producing electricity only as opposed to "CHP power plants" which include heat extraction. For hard coal- and lignite-fired power plants the attribute "condensing" also indicates that the power plant produces electricity only.

[118] Five years, including the current year, of unprofitable operation are required before mothballing or decommissioning takes place.

	2008	2015	2020	2025	2030
W_{el} (TWh)	598.9	588.0	585.9	590.5	592.6

Table 5.2.: Net electricity generation, 2008-2030 (Source: [AGEB, 2008], [Matthes et al., 2009], author's own calculations)

Technology	Decommissioning rationale Static	Decommissioning rationale Dynamic
Electric power plants		
Coal	40 (N), 45 (I)	Model result
Natural gas (steam cycle, combined cycle)	30 (N), 40 (I)	Model result
Gas turbine (single cycle)	30	
CHP power plants		
Coal	35 (N), 50 (I)	
Natural gas (steam cycle, combined cycle)	25 (N), 50 (I)	
Block heat and power plants	20	
Gas turbine	30	
Other power plants		
Heavy fuel oil, light fuel oil	35	
Blast furnace gas	30	
Refinery gas	30	
Coking gas	30	
Waste	35	
Other	35	

Table 5.3.: Lifetime of fossil-fired power plants (I: incumbent, N: new) (Source: Assumptions by Öko-Institut e.V., author's own assumptions)

V" project is selected [Matthes et al., 2009] (Table 5.2)[119]. It comprises all policies and measures implemented up to 2008. Relevant for the scenario modelling is the net electricity generation (W_{el}), which considers network losses and electricity consumption in the transformation sector besides the electricity consumption in final consumption sectors (industry, tertiary sector, households, transport). Export may add up to the electricity generation for domestic demand, depending on the model results.

Decommissioning of power plants depends on the rationale chosen (static or dynamic). With static decommissioning, all power plants are shut down at the end of the technical or regulated lifetime. With dynamic decommissioning, for large power plants producing electricity only (lignite, hard coal, and natural gas (steam cycle, combined cycle)), decommissioning is determined as a function of the economic profitability of power plant operation (model result). Power plants may be mothballed or decommissioned, or retrofit measures may be carried out. Other power plants are decommissioned at the end of the technical (or regulated) lifetime since their operation is mainly determined by other fac-

[119] With the base year derived from the German Energy Balance [AGEB, 2008].

tors than the electricity market. In this regard, must-run power plants[120], combined heat and power (CHP) plants, gas turbines (single cycle) and renewable electricity generators are decommissioned at the end of their technical lifetime. The technical lifetime depends on the technology and on whether it is new (N) or incumbent (I)[121]. CCS power plants are assumed to have the same technical lifetime as the power plants of the same type without CCS. Table 5.3 provides an overview of the lifetimes of fossil-fired[122] power plants as used in this case study.

For nuclear power plants, the German Atomic Energy Act passed in 2002 envisaged the phase-out of nuclear power plants after 32 years of operation on average [Bundesregierung, 2000]. According to the initial version of the Energy Concept agreed in 2010, nuclear power plants commissioned up to 1980 should be granted a lifetime extension of 8 years, more recent power plants of 14 years [BMWi and BMU, 2010]. With the accelerated phase-out agreed in the aftermath of the nuclear incident in Fukushima (2011), several nuclear power plants were decommissioned immediately and the remaining plants gradually go offline, with the last reactor being shut down at the end of 2022 at the latest [Bundesregierung, 2011].

Both the initial phase-out decision [Bundesregierung, 2000] and the lifetime extension according to the initial version of the Energy Concept [BMWi and BMU, 2010] refer to an extension in terms of years. However, the corresponding legal text stipulates an overall amount of electricity generation for each plant. By considering historic and current annual production as well as potential future changes, the phase-out year for each nuclear power plant can be determined. In contrast, the decision on the accelerated phase-out [Bundesregierung, 2011] includes specific dates for the latest possible decommissioning year of each nuclear power plant. Table 5.4 gives an overview of the estimated phase-out years for the situation without lifetime extension (as decided in 2000) and with lifetime extension (as decided in 2010) and compares them to the decommissioning years for the accelerated phase-out (as decided in 2011).

It is evident from Table 5.4 that the decommissioning years according to the accelerated phase-out are broadly comparable to the initial phase-out decision agreed in 2000. Notwithstanding, there are differences for individual power plants. However, in the

[120] For instance, power plants using blast furnace gas or refinery gas.

[121] For existing power plants, a longer technical lifetime is assumed than for new power plants. This is due to retrofits carried out in the 1980s (Footnote 32).

[122] Including power plants using waste or "other fuels". The regulated remaining lifetime of nuclear power plants is included in Table 5.4. The development of renewable capacity is exogenously fixed (Table 5.13).

Power plant	Capacity (MW)	Construction year	Phase-out year (year of decision) Without lifetime extension (2000)	With lifetime extension (2010)	Accelerated phase-out (2011)
Biblis A	1,163	1974	2011	2021	2011
Biblis B	1,234	1976	2014	2023	2011
Brokdorf 1	1,405	1986	2021	2033	2021
Brunsbüttel 1	765	1977	2014	2022	2011
Ems (Lingen) 1	1,329	1988	2027	2038	2022
Grafenrheinfeld 1	1,276	1982	2016	2030	2015
Grohnde 1	1,357	1985	2020	2034	2021
Gundremmingen B	1,275	1984	2020	2033	2017
Gundremmingen C	1,349	1985	2022	2034	2021
Isar 1	865	1979	2011	2020	2011
Isar 2	1,412	1988	2022	2034	2022
Krümmel 1	1,330	1984	2023	2034	2011
Neckarwestheim 1	797	1976	2011	2021	2011
Neckarwestheim 2	1,329	1989	2025	2037	2022
Philippsburg 1	879	1980	2011	2022	2011
Philippsburg 2	1,384	1985	2020	2033	2019
Unterweser 1	1,338	1978	2013	2022	2011

Table 5.4.: Net electric capacity and phase-out year of German nuclear power plants according to different phase-out decisions (Source: [Platts, 2009], estimations by Öko-Institut e.V., author's own estimations, [Bundesregierung, 2011])

context of modelling, only those differences are relevant which influence the installed nuclear capacity in the corresponding scenario years of 2015, 2020, 2025 and 2030. Any difference in the years in between is therefore not relevant from a modelling perspective. Hence, four differences can be highlighted:

- The nuclear power plant Ems (Lingen) 1 is decommissioned in 2022 with the accelerated phase-out, but in 2027 with the phase-out as agreed in 2000. Thus, in the modelling year 2025 with the accelerated phase-out, nuclear capacity is 1.3 GW lower than with the phase-out agreed in 2000.

- Grafenrheinfeld 1 is decommissioned in 2015 according to the accelerated phase-out and in 2016 according to the agreement in 2000. Thus, for the modelling year 2015, with the accelerated phase-out, 1.3 GW less nuclear capacity is available.

- Grohnde 1 is decommissioned in 2021 with the accelerated phase-out and in 2020 according to the agreement in 2020. In consequence, with the accelerated phase-out, 1.4 GW *more* capacity is available for the modelling year 2020.

Technology	2009	2010	2011	2012	Total
			- MW -		
Lignite	0	2,100	670	0	2,770
Hard coal	0	750	0	5,510	6,260
Natural gas	876	480	606	0	1,962
Total	876	3,330	1,276	5,510	10,992

Table 5.5.: Electric capacity and commissioning years of power plants currently under construction, 2009-2012 (Source: Database compiled by Öko-Institut e.V., author's own calculations)

- Krümmel 1 remains shut down as of 2011 with the accelerated phase-out, whereas it remains in operation until 2023 according to the phase-out decision of 2000. In consequence, for the modelling years 2015 and 2020, 1.3 GW less capacity is available with the accelerated phase-out.

Summing up, in 2015 2.6 GW and in 2025 1.3 GW less of nuclear capacity is available with the accelerated phase-out in comparison to the phase-out decision in 2000. For the years 2020 and 2030, there are no[123] differences between both scenarios. The differences between both phase-out trajectories can be regarded as minor in comparison to the overall installed capacity (below). Therefore, the scenario "without lifetime extension" can be considered as a plausible representation of the situation with the accelerated phase-out.

Table B.2 in the appendix gives an overview of the German power plant structure and the consideration of technologies blockwise or as aggregates. In addition, several power plants are currently under construction (Table 5.5)[124]. However, they are not included in the existing power plant stock and not affected by the modelling (with the first scenario year being 2015). In consequence, these power plants are introduced as a minimum capacity investment. The electrical capacity is translated into an electricity generation bound by using operating hours from MICOES model results.

The construction of lignite-fired power plants is restricted by the availability of lignite pits in Germany. Based on forecast ranges of lignite extraction [Ziesing et al., 1999], it is estimated that electricity generation from new lignite-fired power plants (including CCS plants) is restricted to 65 TWh in 2020 and 111 TWh in 2030.

[123] Disregarding the minor difference of 0.1 GW in 2020.

[124] All power plants expected to be commissioned between the base year (2008) and the first scenario year (2015). Power plants labelled as 'in the planning stage' are not considered. In ELIAS, this capacity is further translated into individual blocks according to the specified typical block size in ELIAS. The resulting number of power plants does not, however, necessarily match the number of power plants in construction since these may have block sizes differing from the definition in ELIAS.

Fuel	2008	2015	2020	2025	2030
Natural gas (€$_{2008}$/GJ)	9.32	9.72	10.98	11.58	12.30
Hard coal (€$_{2008}$)/GJ)	4.37	3.77	4.13	4.31	4.52
Light fuel oil (€$_{2008}$/GJ)	16.99	14.39	16.35	17.32	18.52
Heavy fuel oil (€$_{2008}$/GJ)	9.38	9.07	10.36	10.99	11.78
Lignite (€$_{2008}$/GJ)	1.12	1.18	1.22	1.26	1.30
Uranium (€$_{2008}$/GJ)	0.97	0.97	0.97	0.97	0.97
CO_2 price (€$_{2008}$/t)	22.7	22.5	31.2	33.8	36.4

Table 5.6.: Fuel and CO_2 allowances prices (Source: [Matthes, 2010], [Matthes et al., 2009], [PointCarbon, 2010], assumptions by Öko-Institut e.V. and University of Leipzig (2010), author's own calculations)

The construction of CHP plants is limited to the availability of (new) heat sinks. Based on a study on CHP potentials [Horn et al., 2007], electricity generation from new industrial CHP plants is restricted to 17 TWh (2020) and 34 TWh (2030). It is further assumed that electricity generation from new CHP plants supplying district heat is restricted to 20 TWh (2020) and 30 TWh (2030).

CCS power plants are assumed to become commercially available by the year 2025 [Schlesinger et al., 2010].

Electricity generation from blast furnace gas, refinery gas, coking gas, mine gas, waste incineration and other fuels is assumed to be constant in the scenario period. For oil-fired power plants (light fuel oil, heavy fuel oil) and pumped storage power plants, it is assumed that the corresponding capacity remains constant in the scenario period.

Fuel (p_{fuel}) and CO_2 allowance prices (p_{CO2}) are another major factor influencing power plant investment and power plant operation. Fuel prices for hard coal, natural gas and oil are taken from an estimation based on the "Annual Energy Outlook 2010" by the Energy Information administration as well as historical regression analyses [Matthes, 2010]. The lignite price stems from the "Policy scenarios V" project [Matthes et al., 2009][125]. Similarly, the CO_2 price is taken from [Matthes et al., 2009][126]. The fuel price for uranium[127] is an assumption defined by Öko-Institut e.V. and the University of Leipzig (Table 5.6)[128].

For CHP plants, heat revenues (heat credit, HC) have to be taken into account. For CHP plants feeding heat into the district heating network, it is assumed that gas-fired

[125] Converted into 2008 prices.

[126] Data for 2008 derived from daily EUA (European Union Allowance) prices [PointCarbon, 2010]. Values converted to 2008 prices.

[127] Only relevant for MICOES model calculations (power plant dispatch) since investment in new nuclear power plants is not permitted in Germany.

[128] All fuel prices are prices at plant gate and therefore include transport costs.

Heat purpose	2008	2015	2020	2025	2030
District heating networks (€$_{2008}$/GJ$_{th}$)	15.01	15.45	16.83	17.49	18.29
Industrial process heat (€$_{2008}$/GJ$_{th}$)	9.32	9.72	10.98	11.58	12.30

Table 5.7.: Heat credit for CHP plants (Source: [Matthes, 2010], author's own assumptions and calculations, assumptions by Öko-Institut e.V.)

boilers in households would be used as an alternative to district heating. Consequently, the heat credit per unit of useful heat (hc) can be estimated by considering household prices for natural gas (including transport costs and price mark-ups for small consumers) and the thermal efficiency of average gas-fired boilers (90%). For CHP plants supplying process heat to industrial facilities, it is assumed that in the absence of the CHP plant, heat would be provided by heat-only gas-fired calorific value boilers (thermal efficiency of 100%). The heat credit in this case corresponds to the gas price (Table 5.7).

A discount rate (i) of 9% is assumed. Emission factors of fuels used in the modelling are included in Table B.3 in the appendix[129].

5.1.2. Technical and Cost Data of Power Plants

Tables 5.8 and 5.9[130] present the most important technical and cost parameters[131] of typical[132] fossil-fired power plants producing electricity only and CHP power plants in ELIAS for the year 2015[133].

The specifications of power plants equipped with carbon capture are based on large fossil power plants and modified to account for the additional carbon capture equipment [Matthes et al., 2009]. An efficiency penalty of 9 percentage points is assumed in order to account for the power consumption for CO_2 capture. For coal-fired CCS power plants, additional investment costs of 1,000 €/kW$_{el}$ and for gas-fired CCS power plants of 600 €/kW$_{el}$ are assumed. The manning level, service and maintenance costs as well as variable operating costs are scaled with the investment costs. A capture efficiency of CCS of 90%[134] is assumed. Furthermore, costs for CO_2 transport and final storage

[129] The fuel category "other" is allocated the emission factor of hard coal, and blast furnace gas the emission factor of natural gas.

[130] Specific CO_2 emissions refer to direct emissions of the CHP plant only. CO_2 reductions due to displacement of heat-only boilers in households and industry are not accounted for here.

[131] All technical data are net values.

[132] These ideal-typical design options are used for determining levelised costs of electricity only. In terms of the actual capacity, the plant size may vary within pre-defined limits (Section 4.3.1).

[133] It should be noted that the depreciation period is shorter than the design technical lifetime (Table 5.3). In financial terms, the investment has to be repaid within the depreciation period. However technically, the power plant may be operated for the whole technical lifetime (or longer if retrofit measures are carried out).

[134] The share of CO_2 which is effectively removed from the flue gas.

Parameter	Unit	Hard coal	Lignite	Natural gas combined cycle		GT
Electric capacity (P_{el})	MW	750	950	800	400	250
Electric efficiency (η_{el})	%	48.0	44.5	61.4	61.4	38.5
Investment costs (ic)	$€_{2008}/kW_{el}$	1,300	1,486	681	743	409
Depreciation period (n)	a	30	30	20	20	20
Manning level (ML)	Employees	86	103	43	26	15
Service and mainten. costs (smc)	$€_{2008}/(kW_{el} \cdot a)$	26.8	37.5	11.8	11.8	6.4
Insurance costs (inc)	% of IC	0.5	0.5	0.5	0.5	0.5
Variable operating costs (voc)	$€_{2008}/MWh_{el}$	2.0	2.3	0.5	0.5	0.5
Specific CO_2 emissions (e_{CO2})	g CO_2/kWh_{el}	705	906	328	328	524

Table 5.8.: Technical and cost data of fossil-fired power plants (GT: gas turbine), 2015 (Source: [Schneider, 1998], [Schulz et al., 2005], author's own assumptions and calculations, assumptions by Öko-Institut e.V.)

		Natural gas combined cycle			Hard coal	
Parameter	Unit				IND	DH
Electric capacity (P_{el})	MW	30	100	407	320	320
Thermal capacity (P_{th})	MW	40	110	426	550	550
Electric efficiency (η_{el})	%	41.1	45.7	49.1	33.7	42.5
Share of CHP mode (χ_{CHP})	%	80	80	60	80	60
Investment costs (ic)	$€_{2008}/kW_{el}$	1,238	805	681	1,733	1,733
Depreciation period (n)	a	15	15	15	15	15
Manning level (ML)	Employees	6	22	34	172	172
Service and mainten. costs (smc)	$€_{2008}/(kW_{el} \cdot a)$	50.0	32.5	27.5	70.0	70.0
Insurance costs (inc)	% of IC	2.0	2.0	2.0	2.0	2.0
Variable operating costs (voc)	$€_{2008}/MWh_{el}$	2.0	2.0	2.0	2.0	2.0
Specific CO_2 emissions (e_{CO2})	g CO_2/kWh_{el}	490	441	410	1,005	796

Table 5.9.: Technical and cost data of fossil-fired CHP power plants (IND: Industry, DH: district heating), 2015 (Source: author's own assumptions and calculations, assumptions by Öko-Institut e.V.)

Parameter	Unit	Hard coal	Lignite	Natural gas CC
Electric capacity (P_{el})	MW	750	950	800
Electric efficiency (η_{el})	%	39.0	35.5	52.4
Investment costs (ic)	€$_{2008}$/kW$_{\mathrm{el}}$	2,300	2,486	1,281
Depreciation period (DP)	a	30	30	20
Manning level (ML)	Employees	152	173	81
Service and maintenance costs (smc)	€$_{2008}$/(kW$_{\mathrm{el}}$·a)	47.4	62.8	22.2
Insurance costs (inc)	% of IC	0.5	0.5	0.5
Variable operating costs (voc)	€$_{2008}$/MWh$_{\mathrm{el}}$	3.5	3.8	0.9
CO_2 transport and storage	€$_{2008}$/GJ$_{\mathrm{fuel}}$	1.02	1.21	0.60
Specific CO_2 emissions (e_{CO2})	g CO_2/kWh$_{\mathrm{el}}$	87	114	38

Table 5.10.: Technical and cost data of fossil-fired power plants equipped with carbon capture (CC: combined cycle), 2015 (Source: [Matthes et al., 2009], author's own assumptions and calculations)

Parameter	Value
Contribution in kind (cik)	15% of investment costs
Interest costs during construction (icc)	Included in investment costs
Annual labour costs (lc)	60,000 €$_{2008}$/employee
Demolition costs (dc)	45 €$_{2008}$/kW$_{\mathrm{el}}$

Table 5.11.: Other cost parameters of fossil-fired power plants (including CHP plants) (Source: Assumptions by Öko-Institut e.V., author's own assumptions)

are set at 12 €/t CO_2 [Umweltbundesamt, 2009]. These translate into a 'fuel surcharge' depending on the carbon content (Table 5.10).

Other cost parameters that are applicable to all large power plants (including CHP power plants) and not varied over time are included in Table 5.11.

Since capacity additions of must-run and renewable power plants are defined exogenously, corresponding technical and cost data are not required.

With dynamic decommissioning, for incumbent power plants (coal- and gas-fired power plants generating electricity only), annual variable and fixed operating costs are relevant. For estimating the fuel consumption, electric efficiencies are derived based on [Schröter, 2004]. The manning level is derived based on the values for new power plants considering an increase depending on the construction year[135]. Service and maintenance costs as well as variable operating costs are set at the same value as for new power plants.

Retrofit costs depend on the type and age of the power plant as well as the kind of measures carried out. Due to the heterogeneity of measures, 'ideal-typical' retrofit costs cannot be determined. For this case study, example retrofit costs are derived based on a

[135]The older a power plant, the more personnel is assumed to be needed for the same plant size.

Source	Net electricity generation (TWh) 2008	2015	2020	2025	2030
Hydro	18.0	21.6	23.2	23.7	24.3
Wind	40.6	73.5	110.5	146.6	182.6
Onshore	40.6	64.3	76.0	82.1	88.2
Offshore	0	9.2	34.5	64.5	94.4
Photovoltaics	4.4	21.4	34.6	41.8	49.0
Biomass	29.0	38.3	46.6	48.9	52.0
Biogas, sewage gas, etc.	13.0	17.1	21.0	22.5	24.1
Solid biomass	14.5	16.9	21.4	22.1	23.7
Biogenic waste	1.4	4.3	4.3	4.3	4.3
Geothermal	0	0.4	1.2	2.7	4.2
Renewables import	0	0	2.5	20.0	37.5
Total	92.0	155.2	218.6	283.7	349.6

Table 5.12.: Net electricity generation from renewable sources in Germany, 2008-2030 (Source: [Nitsch, 2010], [Statistisches Bundesamt, 2008], [Statistisches Bundesamt, 2010], author's own assumptions and calculations, assumptions and calculations by the Institute for Infrastructure and Resources Management (University of Leipzig))

statement on the costs of a complete overhaul of a steam turbine cycle[136]. Retrofit costs (χ_{RC}) then correspond to an increase of 31% of annual service and maintenance costs (author's own calculations)[137]. Similarly, an increase of the electric efficiency ($\Delta_{\eta,RC}$) of 4.7% (relative) due to retrofit is estimated (author's own calculations)[138].

5.1.3. Policy Instruments

The most prominent policy instrument in the context of this case study is the promotion of renewable electricity generation in Germany. According to the German Renewable Energy Sources Act [EEG, 2011], renewable generators receive a fixed tariff for every kilowatt hour of electricity generated. Tariffs are differentiated with respect to technology and plant size. Furthermore, special bonuses (technology bonus[139], bonus for renewable resources[140], CHP bonus) are available. Tariffs decrease over time[141]. In the case of photovoltaics (PV), further cuts during the fiscal year are possible taking into account the capacity of PV added until a certain point in time [BMU, 2011]. Gen-

[136] "€ 20 to 60 million for a middle-sized power plant" [Nikolaus, 2009] (translated).
[137] Investment costs for retrofit are annualised over a depreciation period of 10 years.
[138] For instance, retrofit of a power plant with an initial electrical efficiency of 38% would lead to an effiency after retrofit of $38\% \cdot (1 + 4.7\%) = 39.8\%$.
[139] For plants with upgrading of biogas to natural gas quality, and for the use of innovative technologies, such as the Organic Rankine Cycle (ORC) or Sterling engines.
[140] For the exclusive use of renewable biomass sources (i.e. no biomass waste).
[141] The later the construction year, the lower the tariff.

	Net electric capacity (GW)				
Source	2008	2015	2020	2025	2030
Hydro	3.5	4.9	5.2	5.3	5.5
Wind	23.8	36.4	45.4	54.6	63.6
Onshore	23.8	33.4	35.5	37.0	38.8
Offshore	0	3.0	9.9	17.6	24.8
Photovoltaics	5.9	26.8	41.6	48.3	55.0
Biomass	4.3	5.6	6.7	7.1	7.5
Biogas, sewage gas, etc.	2.6	2.6	3.1	3.4	3.6
Solid biomass	1.6	1.9	2.5	2.7	2.9
Biogenic waste	0.2	1.1	1.1	1.1	1.1
Geothermal	0	0.1	0.2	0.4	0.6
Renewables import	0	0	0.6	3.8	7.1
Total	37.5	73.8	99.7	119.6	139.3

Table 5.13.: Net electric capacity from renewable sources in Germany, 2008-2030 (Source: [Nitsch, 2010], [Platts, 2009], [Statistisches Bundesamt, 2008], [Statistisches Bundesamt, 2010], [BMU, 2009], [FNR, 2007], author's own assumptions and calculations)

erally, feed-in tariffs can be introduced in ELIAS. However, since renewable capacity additions are fostered by governmental incentives and preferential feed-in applies, thus corresponding to a secure business case, the market-driven rationale as for conventional power plants is not suitable. Furthermore, renewable capacity additions are also dependent on other factors, such as the availability of sufficient production capacity, the allocation of land (e.g. for new wind parks) or progress made with regard to infrastructure (such as the connection of offshore wind parks to the grid). For this reason, renewable capacity addition is fixed exogenously. The dynamics of capacity additions are taken from the so-called "Lead Study" on the promotion of renewable energy which is regularly commissioned and updated by the German Ministry for the Environment, Nature Conservation and Reactor Safety [Nitsch, 2010]. Tables 5.12 and 5.13[142] give an overview of the development of renewable energies in Germany up to 2030 in terms of electricity generated and electrical capacity installed.

The European Emissions Trading Scheme (EU ETS) influences power plant operation (by altering the merit order due to additional CO_2 allowance costs) and investment (by using altered operating hours and by the need to factor in CO_2 allowance costs in the investment analysis). As regards the third period of the EU ETS (2013-2020)[143], it is

[142]Base year in both tables adapted based on statistics. Differences to [Nitsch, 2010] may arise from different fuel and technology classifications. Furthermore, pumped storage electricity generation (included under 'hydro') is a MICOES model result. For this reason, there may be a difference in hydro generation compared to [Nitsch, 2010]. Further minor differences in the tables are due to rounding.

[143]This is the first period relevant for this case study.

assumed that CO_2 allowances are generally auctioned for the share of emissions related to electricity generation. For heat-related CO_2 emissions in CHP plants, a benchmark allocation as included in the German allocation rules for the second period (2008-2012) is assumed. For heat generation from gas-fired CHP plants, a free allocation (heat benchmark, BM_{th}) of 225 g CO_2/kWh$_{\mathrm{th}}$ and for other fuels, of 345 g CO_2/kWh$_{\mathrm{th}}$ is assumed. Furthermore, standard operating hours (7.500 h/a) are used for the allocation [ZuG 2012, 2007][144]. The resulting auctioning share ($\chi_{auctioning}$) is estimated based on allocated allowances and actual CO_2 emissions. Consequently, the auctioning share varies between scenarios due to differing operating hours. An example calculation of the auctioning share for two different CHP plants is included in Table B.4 in the appendix[145]. As of 2021, it is assumed that all power plants have to purchase all necessary CO_2 allowances ($\chi_{auctioning}$=100%).

Regarding cogeneration, a bonus (b_{CHP}) of 15 € per megawatt hour of electricity produced in CHP mode is granted under the German CHP Act [KWKG, 2009] to new CHP plants. The bonus is limited to a maximum of 30,000 operating hours or six years (four years for industrial CHP plants), whichever is reached first. The bonus is granted to CHP plants commissioned up to 2016. For this reason, this policy measure is only relevant for the scenario year 2015[146].

Furthermore, for decentralised electricity generators, a bonus for avoided grid use (ag) is relevant. For large CHP plants feeding into the medium voltage grid, a bonus of 5 € per megawatt hour of electricity generated is assumed.

Finally, the accelerated phase-out of nuclear power plants is a major policy decision influencing operation and investment of power plants. The corresponding parameterisation is addressed in Section 5.1.1 above.

[144] This assumption was used for the parameterisation of the case study in summer 2010. In a more recent decision at the end of 2010, it was decided that free allocation is reduced from 80% (2013) of free allocation related to the heat benchmark to 20% (2020) [European Commission, 2010]. Furthermore, an annual decrease of 1.74% of emission allowances applies based on the overall cap reduction.

[145] Operating hours used in the calculation are for illustrative purposes only. In the model runs, actual model values are used. A negative auctioning share indicates that more allowances are allocated for free than are actually needed. This is especially relevant if standard operating hours are significantly higher than actual operating hours.

[146] The German CHP Act was amended in July 2011 [KWKG, 2011], in which the applicability was extended up to the year 2020. Furthermore, the restriction to four and six years, respectively, was lifted. However, these updates could not be considered since the modelling was already concluded at the time when the law was amended.

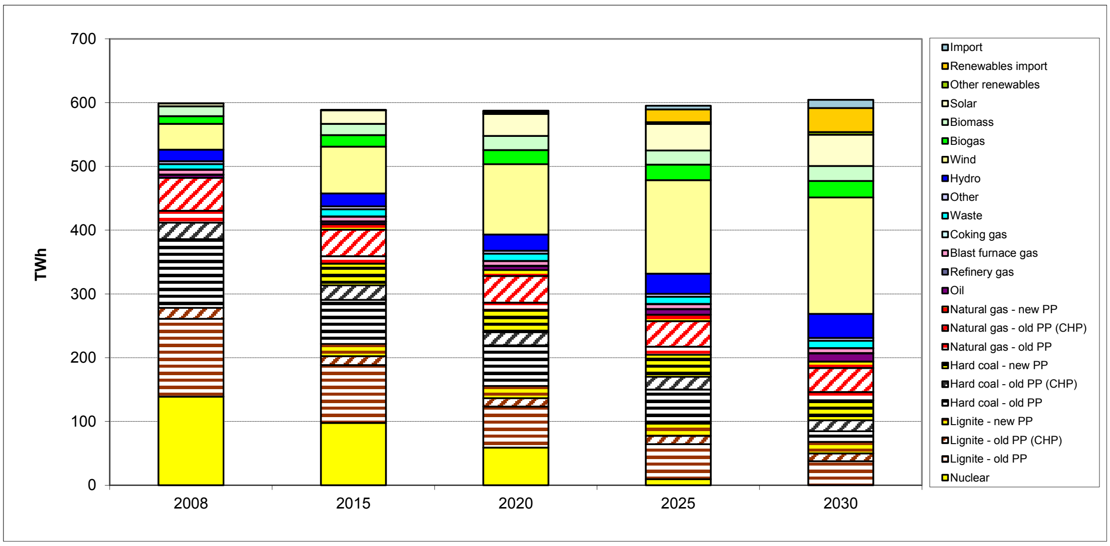

Figure 5.1.: Net electricity generation without lifetime extension (static decommissioning) (woLTE_S), 2008-2030 (Source: ELIAS model results)

5.2. Results and Discussion

In this section, iterated modelling results between ELIAS and MICOES are presented and discussed for the scenarios with and without the lifetime extension of nuclear power plants for both static (Section 5.2.1) and dynamic (Section 5.2.2) decommissioning[147]. Section 5.2.3 compares the results of the two decommissioning rationales.

5.2.1. Static Decommissioning

Figure 5.1[148] and Table 5.14 show the net electricity generation without lifetime extension of nuclear power plants for static decommissioning (woLTE_S). Renewable energy accounts for more than half (59.6%) of overall electricity generation in 2030[149]. Nuclear power plants are gradually phased out. In 2025, only two nuclear power plants still operate (Table 5.4), in 2030, there is no more nuclear electricity generation. Electricity generation both from lignite and hard coal is halved between 2008 to 2030 (from

[147]Operating hours of power plants are a core result used for the discussion of the different scenarios and decommissioning rationales. In the following, average operating hours presented correspond to the electricity generation in different categories (fuel type, technology) divided by the corresponding available capacity. In this regard, a power plant which is mothballed (with dynamic decommissioning), but is generally available (i.e. the operating licence is still valid) leads to decreasing operating hours of this category. However, decommissioned power plants are not considered in the calculation of average operating hours, since they are not available any more.
[148]For easier reading, the legend of power plant types is also available in larger font size in Figure C.1 in Appendix C.
[149]Including imported electricity from renewables. The total electricity generation from renewable energies may differ from Table 5.12 due to the endogenous calculation of pumped storage electricity generation in MICOES (see Footnote [142]).

	2008	2015	2020	2025	2030
			- TWh -		
Nuclear	139.1	97.9	59.2	9.6	0
Lignite	139.3	123.9	96.7	87.2	68.2
new PP	0	19.3	19.2	19.3	18.2
incumbent PP	122.1	90.5	64.4	54.9	37.7
incumbent PP (CHP)	17.2	14.1	13.2	13	12.2
Hard coal	133.9	126.0	119.0	107.9	65.2
new PP	0	34.2	34.6	34.5	31.3
incumbent PP	107.7	69.0	63.7	53.4	16.7
incumbent PP (CHP)	26.2	22.8	20.7	20.0	17.2
Natural gas	70.0	62.0	62.8	62.7	60.8
new PP	0	8.8	9.4	10.0	10.2
incumbent PP	18.5	11.4	11.5	12.6	13.0
incumbent PP (CHP)	51.5	41.7	41.9	40.1	37.6
Renewables	90.6	151.1	218.1	289.2	360.5
Other	26.2	27.7	30.2	32.9	36.9
Import	0	0.1	1.6	5.7	13.0
Total	598.9	588.8	587.7	595.2	604.6
CHP (total, excl. renew. CHP)	94.9	78.6	75.7	73.1	67.0
Domestic demand	598.9	588	585.9	590.5	592.6
Export	0	0.7	1.7	4.7	12.0
CO_2 emissions (Mt)	305.2	260.3	226.1	207.4	156.2

Table 5.14.: Net electricity generation and CO_2 emissions without lifetime extension (static decommissioning) (woLTE_S), 2008-2030 (Source: ELIAS model results)

139.3 TWh to 68.2 TWh and 133.9 TWh to 65.2 TWh, respectively), with new power plants accounting for about one quarter (18.2 TWh) of lignite electricity production and about one half (31.3 TWh) of hard coal electricity production in 2030. The electricity generation of natural gas-fired power plants decreases by 13.1% (from 70.0 TWh to 60.8 TWh) in the same period. The fossil fuel mix is shifted from a coal-dominated electricity generation (79.6% lignite and hard coal in 2008) to about equal shares of lignite (35.1%), hard coal (33.6%) and natural gas (31.3 %) in 2030. This is due to the fact that the coal-fired power plant fleet is older than gas-fired power plants, thus incumbent gas-fired units remain operational for longer (Figure 2.3). Furthermore, the operating hours of lignite-fired power plants decrease in the scenario period, whereas they are stable for hard coal power plants and increase for gas-fired power plants[150] (Table C.1 in

[150]This may appear counterintuitive at first sight since lignite-fired power plants have lower marginal operating costs than hard coal-fired and natural gas-fired power plants. However, due to the increase of renewable electricity generation, electricity demand is met by renewables to a large extent in certain hours. In consequence, even low-cost lignite-fired power plants have to operate in part load or are switched off, which leads to decreasing operating hours. Also, export of electricity increases in these situations. At the same time, the need for peaking capacity (and import) generally increases since

Appendix C), which adds to the shift in fuel mix. New fossil-fired[151] (lignite, hard coal and natural gas-fired) power plants are commissioned in 2015 only. These correspond entirely to the power plants already currently under construction (Table 5.5)[152]. No model-driven (i.e. beyond the application of the minimum bound in 2015) construction of new fossil-fired power plants takes place throughout the scenario period[153]. In scarcity situations (capacity is not sufficient to meet the residual load), electricity is imported. In this regard, the fluctuating nature of renewable energy is expressed by an increasing share of import in order to meet the load demand. Import reaches 13.0 TWh in 2030. Also, peaking electricity generation by pumped storage (17.6 TWh in 2030, subsumed under 'hydro') and by oil-fired units (12.7 TWh in 2030, subsumed under 'other') is significant. Similarly, export also increases (to 12.0 TWh in 2030). Export is driven by the fact that during some hours renewable electricity generation is higher than the load demand (negative residual load), but also by the fact that due to technical and cost constraints (Section 2.4), some conventional power plants remain online although load demand is low. The latter is especially relevant for power plants with long minimum uptimes or minimum downtimes or which feature high start-up or shut-down costs. Since no model-driven fossil-fired power plants are built during the scenario period, fossil CHP electricity generation[154] is reduced by almost one third in the scenario period (from 94.9 TWh in 2008 to 67.0 TWh in 2030). In 2030, fossil CHP electricity generation accounts for 11.1% of electricity generation (15.8% in 2008). Similarly, no CCS power plants are built in the scenario period. Due to the sharp increase of renewable electricity generation and to the changing fuel mix, CO_2 emissions are almost halved (-48.8%) in the scenario period, reaching 156.2 Mt CO_2 in 2030 (305.2 Mt CO_2 in 2008). A detailed breakdown of CO_2 emissions is included in Table C.4 in Appendix C[155].

fluctuating renewables do not cover the load demand at all times. This leads to increasing operating hours of natural gas-fired power plants. A more detailed discussion of effects of renewable electricity generation on the remaining power plant fleet can be found in [Harthan et al., 2012].

[151] In the following, 'fossil-fired' refers to power plants using lignite, hard coal and natural gas. Power plants on the basis of other fossil fuels such as blast furnace gas, refinery gas, or oil, are included in the category 'other' and determined by the application of bounds (p. 69).

[152] The corresponding electricity generation varies over time (Table 5.14) due to changing operating hours resulting from dispatch modelling (Table C.1 in Appendix C).

[153] For reasons of completeness, the full costs of electricity generation for new electric and CHP power plants are displayed for the year 2020 in Tables C.2 and C.3 in Appendix C. It should be noted that the CHP bonus is only applicable until 2016 [KWKG, 2009]. Therefore no revenues accrue for CHP plants commissioned in 2020.

[154] In the following, CHP electricity generation refers to the electricity generated in CHP plants, independently of whether the plant is run in cogeneration mode or not.

[155] CO_2 emissions under the category "renewables" stem from mine gas which is a fossil fuel, but which is counted as a renewable energy corresponding to its inclusion in the renewable promotion scheme [EEG, 2011].

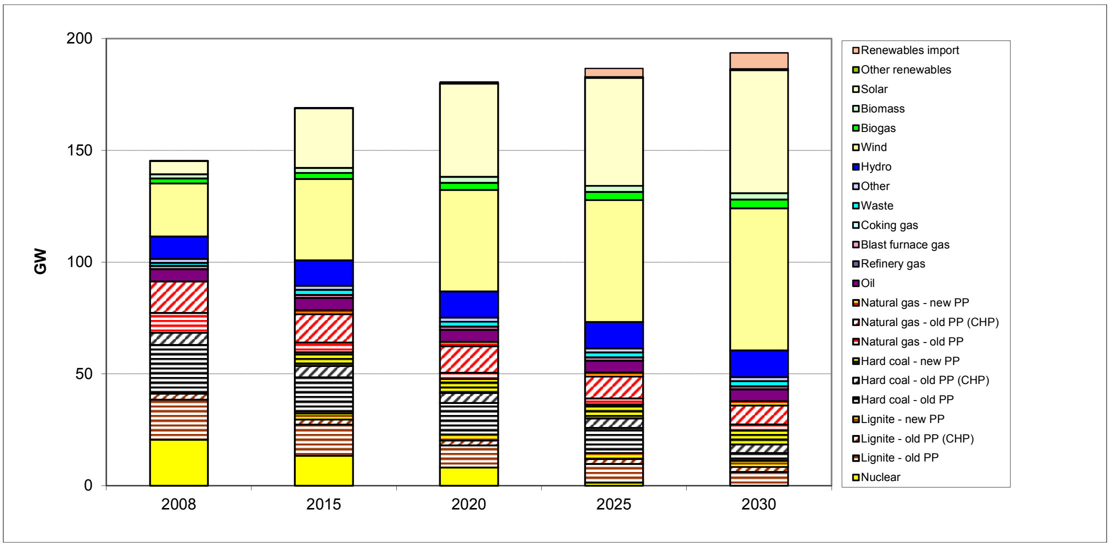

Figure 5.2.: Net electric capacity without lifetime extension (static decommissioning) (woLTE_S), 2008-2030 (Source: ELIAS model results)

Figure 5.2 (Table C.5 in Appendix C) shows the development of electric capacity in the scenario period. 74.9% of electric capacity (145.0 GW) is made up by renewable energy in 2030, corresponding capacity more than triples in the scenario period (from 43.8 GW in 2008). Due to the very limited amount of new fossil-fired power plants, fossil capacity is reduced by almost half (from 70.9 GW in 2008 to 37.8 GW in 2030) and nuclear capacity completely disappears in the scenario period. The decreasing conventional capacity against the background of fluctuating renewable energy leads to a significant increase of import and export between 2020 and 2030 (Table 5.14).

Figure 5.3 and Table 5.15 display electricity generation with the lifetime extension of nuclear power plants for static decommissioning (wLTE_S). As for the scenario without lifetime extension, more than half of overall electricity generation in 2030 stems from renewable energy. In contrast to the phase-out scenario, nuclear electricity generation in 2030 (77.5 TWh) still accounts for 12.8% of overall electricity generation, which is more than half (55.7%) of nuclear generation in 2008 (139.1 TWh). This is due to the fact that in 2030, ten nuclear power plants (12.2 GW) are still in operation (Table 5.4). Coal-fired electricity generation decreases by more than 60% (from 139.3 TWh in 2008 to 52.4 TWh in 2030 for lignite and from 133.9 TWh in 2008 to 50.3 TWh for hard coal in 2030), gas-fired generation by almost 40% (from 70.0 TWh in 2008 to 43.9 TWh in 2030). As for the scenario without lifetime extension, the fossil fuel mix is shifted towards higher shares of natural gas (30.0% electricity generation from natural gas,

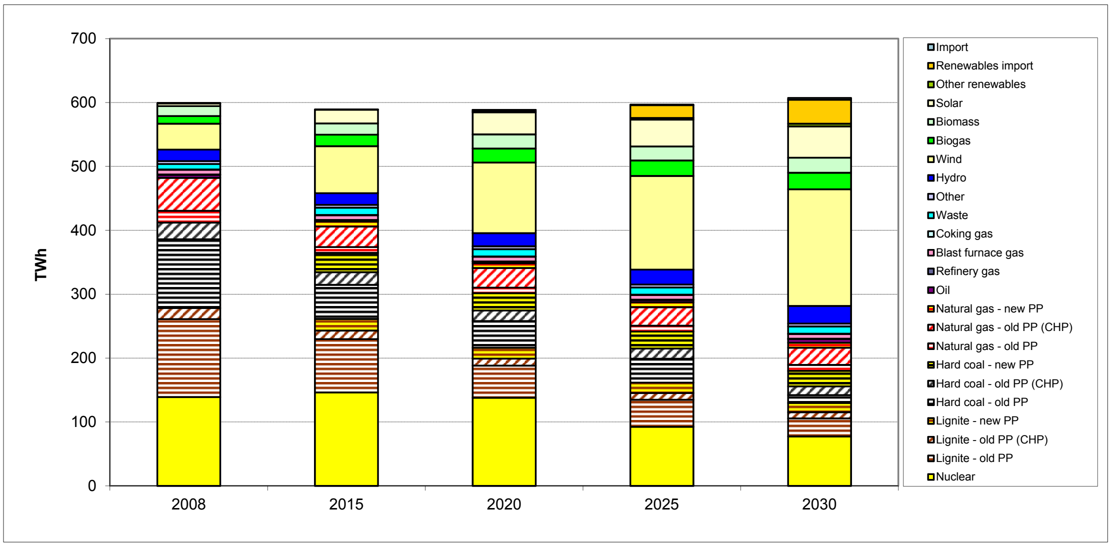

Figure 5.3.: Net electricity generation with lifetime extension (static decommissioning) (wLTE_S), 2008-2030 (Source: ELIAS model results)

	2008	2015	2020 - TWh -	2025	2030
Nuclear	139.1	146.3	138.1	92.5	77.5
Lignite	139.3	115.0	78.2	69.2	52.4
new PP	0	18.3	17.0	16.3	14.5
incumbent PP	122.1	83.5	50.2	42.4	28.3
incumbent PP (CHP)	17.2	13.3	11.0	10.5	9.6
Hard coal	133.9	103.4	85.6	79.9	50.3
new PP	0	30.3	27.2	26.6	24.2
incumbent PP	107.7	53.3	41.8	37.4	12.3
incumbent PP (CHP)	26.2	19.8	16.6	15.9	13.7
Natural gas	70.0	48.8	46.5	45.8	43.9
new PP	0	7.7	7.4	7.8	7.8
incumbent PP	18.5	9.0	8.4	9.1	9.3
incumbent PP (CHP)	51.5	32.1	30.7	29.9	26.8
Renewables	90.6	149.2	213.4	280.7	350.4
Other	26.2	26.3	26.7	27.7	30.0
Import	0	0	0.1	0.9	2.9
Total	598.9	589.2	588.5	596.8	607.3
CHP (total, excl. renew. CHP)	94.9	65.2	58.3	55.5	50.1
Domestic demand	598.9	588	585.9	590.5	592.6
Export	0	1.1	2.6	6.3	14.7
CO_2 emissions (Mt)	305.2	227.6	174.2	160.1	120.7

Table 5.15.: Net electricity generation and CO_2 emissions with lifetime extension (static decommissioning) (wLTE_S), 2008-2030 (Source: ELIAS model results)

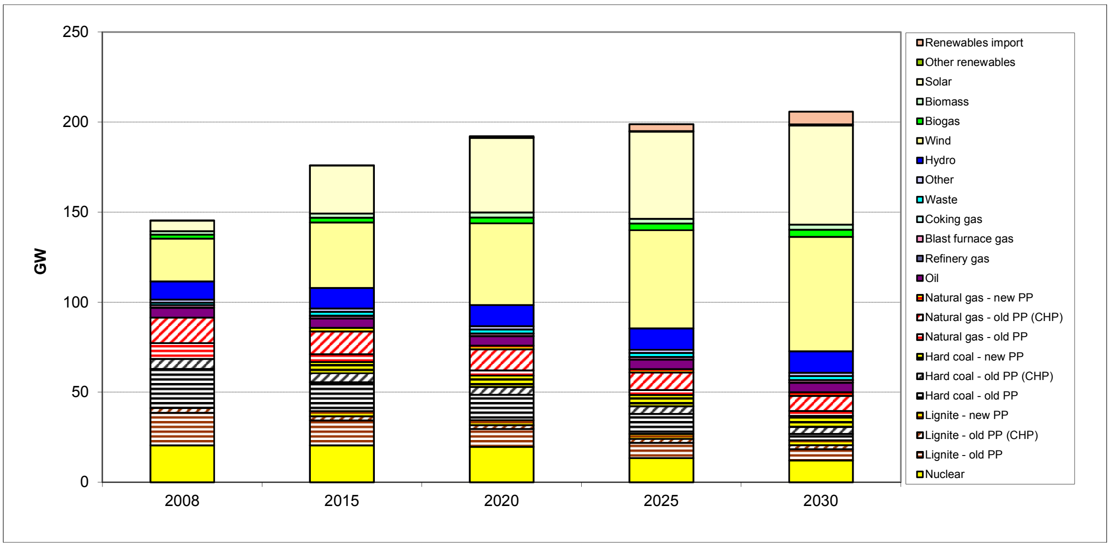

Figure 5.4.: Net electric capacity with lifetime extension (static decommissioning) (wLTE_S), 2008-2030 (Source: ELIAS model results)

70.0% from hard coal and lignite in 2030). Correspondingly, operating hours decrease significantly for lignite- and hard coal-fired power plants and first slightly decrease, then increase (although at a low level) for natural gas-fired units (Table C.6 in Appendix C). New power plants are only commissioned in 2015, corresponding to power plants already under construction[156]. Import of electricity increases moderately to 2.9 TWh in 2030. Similarly, peaking electricity generation by pumped storage (7.4 TWh in 2030, subsumed under 'hydro') and by oil-fired units (5.8 TWh in 2030, subsumed under 'other') is moderate. Export reaches 14.7 TWh in 2030. Fossil CHP electricity generation decreases by almost half (47.1%) in the scenario period (from 94.9 TWh in 2008 to 50.1 TWh in 2030), reaching a share of 8.3% of overall electricity generation in 2030 (15.8% in 2008). CO_2 emissions decrease by more than 60% (from 305.2 Mt CO_2 in 2008 to 120.7 Mt CO_2 in 2030). A detailed breakdown of CO_2 emissions is included in Table C.9 in Appendix C.

Figure 5.4 (Table C.10 in Appendix C) shows the development of the electric capacity. It differs from the scenario without lifetime extension only in the fact that some nuclear power plants still operate in 2030. Corresponding capacity decreases by more than 40% (from 20.5 GW in 2008 to 12.2 GW in 2030). 70.5% of electric capacity is made up by renewable energy in 2030. Fossil capacity is almost halved in the scenario period.

Table 5.16 compares net electricity generation and CO_2 emissions for static decommissioning with and without the lifetime extension of nuclear power plants. Most evi-

[156]For reasons of completeness, full costs of electricity generation for new electric and CHP power plants are displayed for the year 2020 in Tables C.7 and C.8 in Appendix C.

	2008	2015	2020	2025	2030
			- TWh -		
Nuclear	0	48.4	78.9	82.9	77.5
Lignite	0	-8.9	-18.5	-17.9	-15.8
new PP	0	-1.0	-2.2	-3	-3.7
incumbent PP	0	-7.0	-14.2	-12.5	-9.5
incumbent PP (CHP)	0	-0.8	-2.1	-2.5	-2.6
Hard coal	0	-22.6	-33.4	-28.0	-14.9
new PP	0	-3.9	-7.4	-7.9	-7.1
incumbent PP	0	-15.7	-21.9	-16.0	-4.4
incumbent PP (CHP)	0	-3.0	-4.1	-4.0	-3.4
Natural gas	0	-13.2	-16.4	-16.9	-16.9
new PP	0	-1.1	-2.0	-2.2	-2.4
incumbent PP	0	-2.4	-3.2	-3.5	-3.7
incumbent PP (CHP)	0	-9.7	-11.2	-11.1	-10.8
Renewables	0	-1.9	-4.8	-8.5	-10.2
Other	0	-1.4	-3.5	-5.2	-6.9
Import	0	-0.1	-1.5	-4.8	-10.1
Total	0	0.4	0.9	1.6	2.8
CHP (total, excl. renewable CHP)	0	-13.4	-17.4	-17.6	-16.8
Domestic demand	0	0	0	0	0
Export	0	0.4	0.9	1.6	2.8
CO_2 emissions (Mt)	0	-32.7	-51.8	-47.3	-35.5

Table 5.16.: Difference between net electricity generation and CO_2 emissions with and without lifetime extension (static decommissioning) (wLTE_S, woLTE_S), 2008-2030 (Source: ELIAS model results)

dently, electricity generation from nuclear power plants is almost 80 TWh higher with lifetime extension between 2020 and 2030. The corresponding electric capacity is still 12.2 GW in 2030 with lifetime extension (Table C.10 in Appendix C) whereas nuclear power plants are already phased out in the scenario without lifetime extension. Overall, nuclear capacity is about 12 GW higher between 2020 and 2030 with lifetime extension. Additional nuclear electricity generation with lifetime extension is compensated by decreasing fossil-fired electricity generation, which is almost 70 TWh in 2020 and almost 50 TWh in 2030 lower than without lifetime extension. Operating hours of fossil-fired power plants are therefore significantly lower with lifetime extension in comparison to the case without lifetime extension (Tables C.1 and C.6 in Appendix C). Electricity generation from pumped storage power plants (included as 'hydro' under renewables) in 2030 is 10.2 TWh lower in comparison to the scenario without lifetime extension (see Footnote 142). Electricity generation in peaking oil units (subsumed under 'other') is almost 7 TWh lower in 2030 than without lifetime extension. Also, import in 2030 is

Scenario	2008	2015	2020	2025	2030
	- €/MWh -				
woLTE_S	65.9	59.0	82.8	104.0	121.8
wLTE_S	65.9	47.5	57.0	66.8	72.8
Difference	0	-11.5	-25.9	-37.2	-49.0

Table 5.17.: Spot electricity price with and without lifetime extension (static decommissioning) (wLTE_S, woLTE_S), 2008-2030 (Source: MICOES model results)

drastically reduced by 10.1 TWh between the two scenarios. This indicates that due to the higher nuclear capacity with lifetime extension, load demand can be met with less need for peaking units and import. Export in 2030 slightly increases by about 3 TWh in comparison to the case without lifetime extension. This may be due to the fact that for techno-economic reasons (Section 2.4), nuclear power plants remain online, also during some situations in which the load demand is low (or the residual load is even zero or negative). CHP electricity generation is 16.8 TWh lower in 2030 with lifetime extension since, besides CHP production for heat production as driven by temperature, CHP plants generate less additional electricity because low-cost nuclear capacity is available in the power system[157]. Corresponding to the decrease of fossil-fired electricity generation, CO_2 emissions are also significantly lower (by 35.5 Mt CO_2 in 2030) with lifetime extension.

Table 5.17 provides a comparison of spot electricity prices with and without lifetime extension of nuclear power plants for static decommissioning. Electricity prices in the scenario without lifetime extension increase by 84.9% (from 65.9 €/MWh in 2008 to 121.8 €/MWh in 2030) in the scenario period. This is due to increasing fuel and CO_2 allowances prices (Table 5.6), but also due to the fact that import[158] increases significantly. It can be concluded that the significant increase of zero-cost[159] renewable electricity generation does not compensate for the price increases due to the mentioned other factors. With lifetime extension, the electricity prices increases by only 10.5% (from 65.9 €/MWh in 2008 to 72.8 €/MWh in 2030) in the scenario period. In 2020, electricity prices are more than 25 €/MWh and in 2030, almost 50 €/MWh lower with

[157] According to the MICOES model rationale, CHP power plants are considered as must-run units in situations in which ambient temperature requires heat production. Spare capacity (when CHP capacity is not fully utilised while heat demand is low or absent) can be used for additional electricity generation. For this share, the CHP plant is dispatched according to its marginal generation costs.

[158] The import price is set at 300 €/MWh in MICOES.

[159] Marginal electricity generation costs are set at 0 €/MWh for all renewable technologies in MICOES. For wind, hydro, solar and geothermal energy, fuel costs are zero and variable generation costs are small. For biomass, fuel costs arise. However, for all renewable sources, marginal generation costs are not relevant for dispatch due to the fixed guaranteed feed-in tariff.

lifetime extension in comparison to the situation without lifetime extension. This is due to the fact that significantly less import is required and peaking units are less utilised (Table 5.16), but also due to the fact that significant additional low-cost electricity generation capacity (nuclear) is available with lifetime extension.

However, the static decommissioning rationale neglects important feedbacks between the electricity market and decommissioning, since decommissioning is fixed exogenously. Therefore, in order to judge whether static decommissioning is a plausible assumption, the profitability of power plant operation needs to be considered. Both the electricity price (and thus electricity revenues) and operating hours of fossil-fired power plants are lower with lifetime extension in comparison to the case without lifetime extension. Power plants may therefore not be able to cover their fixed operating costs and may thus, in a dynamic approach, be mothballed or decommissioned. In turn, with higher electricity prices and operating hours as in the scenario without lifetime extension, power plant operators may be willing to invest in retrofit measures, thus leading to a later decommissioning of power plants. If feedback mechanism between the electricity market and decommissioning are considered, available capacity and thus electricity prices may be similar in the scenario with and without the lifetime extension of nuclear power plants.

Figure 5.5 (corresponding values in Table C.11 in Appendix C) gives an overview of the profitability of operation[160] of fossil-fired electric[161] power plants in relation to the spot electricity price[162]. It can be seen that in 2015 the operation of more than 20 GW of power plant capacity is unprofitable in the scenario with lifetime extension, most of them hard coal-fired power plants (15.6 GW), but also natural gas-fired power plants (5.5 GW), whereas in the scenario without lifetime extension only a very limited capacity of incumbent natural-gas fired power plants is unprofitable[163]. What is more, with lifetime extension, even natural gas-fired capacity currently under construction (Table 5.5) is unprofitable in 2015 (2.0 GW). In 2020, no power plants are unprofitable in the scenario without lifetime extension. With lifetime extension, still several gas-fired units are unprofitable (4.3 GW), among them the newly-built capacity.

[160] Operation of a power plant is not profitable if the profit margin does not cover fixed operating costs according to equation (4.46).

[161] Only electric power plants without heat extraction are displayed since for these power plants, the operational lifetime may be determined as a function of profitability (in the case of dynamic decommissioning), whereas for other power plants decommissioning at the end of the technical or regulatory lifetime applies (Table 5.3).

[162] In the graph, only the scenario years 2015 and 2020 are displayed, since unprofitable operation occurs. In 2025 and 2030, operation is always profitable for all power plants (Table C.11 in Appendix C).

[163] Two power plants with a total capacity of 28 MW. Due to the small magnitude, it is not visible in the graph and the table.

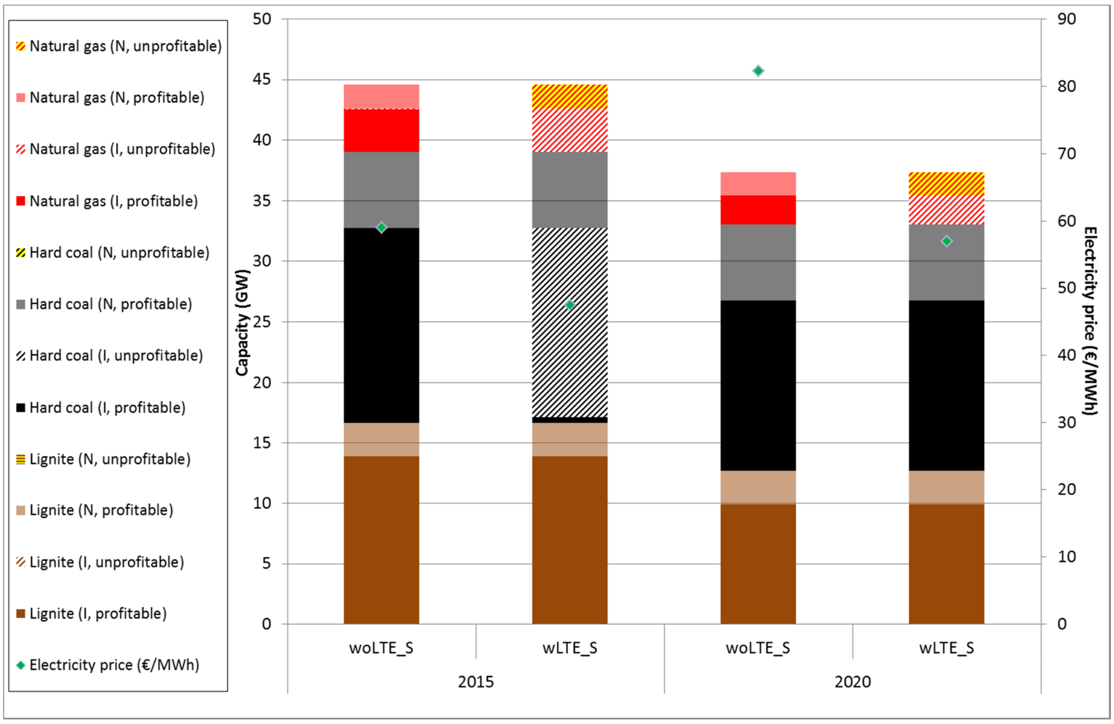

Figure 5.5.: Profitability of fossil-fired electric power plants (I=incumbent, N=new) and electricity price with and without lifetime extension (static decommissioning) (wLTE_S, woLTE_S)), 2015-2020 (Source: ELIAS model results, MICOES model results)

From these considerations, it can be concluded that the assumption of static decommissioning is not consistent with the economic conditions of power plant operation. It can therefore be expected that considering dynamic decommissioning, with lifetime extension, additional capacity (especially hard coal and natural gas) is mothballed or decommissioned. Furthermore, profitable power plants may invest in retrofit measures, thus providing additional capacity. Since profitability is generally lower with lifetime extension, it can be expected that retrofit measures are implemented to a lesser extent in that scenario. In consequence, available capacity is expected to be similar in the scenario with and without the lifetime extension of nuclear power plants. Static decommissioning is therefore not a plausible assumption. For this reason, the consideration of interactions between decommissioning and power plant operation is necessary.

5.2.2. Dynamic Decommissioning

Figure 5.6 and Table 5.18 show the development of net electricity generation in the scenario without the lifetime extension of nuclear power plants with dynamic decommissioning (woLTE_D). Renewable energy accounts for more than half (57.0%) of overall

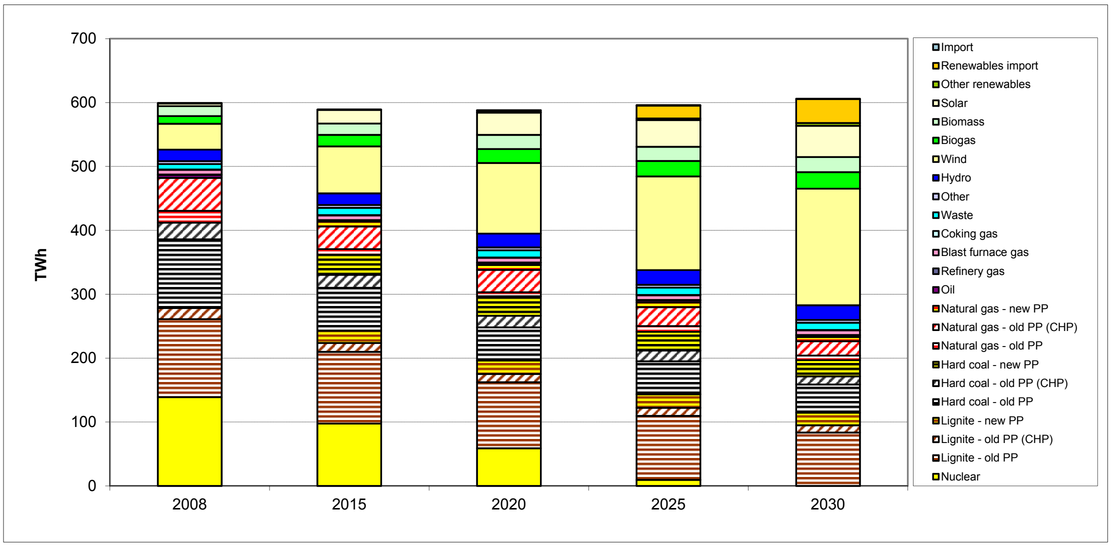

Figure 5.6.: Net electricity generation without lifetime extension (dynamic decommissioning) (woLTE_D), 2008-2030 (Source: ELIAS model results)

electricity generation in 2030. Nuclear power plants are gradually phased out; by 2030, nuclear power plants have stopped production. With regard to fossil-fired power plants, electricity generation from lignite decreases moderately in the scenario period by 17.6% (from 139.3 TWh in 2008 to 114.7 TWh in 2030) while electricity generation in hard coal-fired power plants and natural gas-fired power plants decreases significantly during the same period (by 38.6%, from 133.9 TWh to 82.2 TWh, and by 48.3%, from 70.0 TWh to 36.2 TWh, respectively). New power plants account for 17.2% (lignite), 30.8% (hard coal) and 17.6% (natural gas) of electricity generation within the respective technology in 2030. The fossil fuel mix becomes more coal-dominated (84.5% (2030) vs. 79.6% (2008) of coal-based electricity generation). Operating hours decrease by 26.1% and 30.9% between 2008 and 2030 for lignite and hard coal-fired power plants, respectively, and by 9.6% for natural gas-fired units (Table D.1 in Appendix D)[164]. The combination of these two effects (more coal-based electricity in the generation mix with strongly decreasing operating hours of coal-fired units and moderately decreasing operating hours in gas-fired power plants) indicates that in the scenario period more natural gas-fired units are decommissioned and less frequently retrofitted than coal-fired power plants. New fossil-fired power plants are mostly commissioned in 2015. These correspond to the power plants already under construction (Table 5.5). In 2020, a small lignite-fired power plant is built. No further investments in conventional capacity take place in 2025 and 2030. In

[164]See discussion in Footnote 150.

	2008	2015	2020	2025	2030
			- TWh -		
Nuclear	139.1	97.6	58.9	9.6	0
Lignite	139.3	145.3	137.3	133.9	114.7
new PP	0	19.1	21.0	21.2	19.8
incumbent PP	122.1	112.4	103.4	100.1	83.6
incumbent PP (CHP)	17.2	13.9	12.9	12.6	11.4
Hard coal	133.9	119.1	100.7	97.7	82.2
new PP	0	31.5	30.5	29.3	25.3
incumbent PP	107.7	67.2	52.1	51.6	44.2
incumbent PP (CHP)	26.2	20.4	18.2	16.8	12.6
Natural gas	70.0	51.6	48.9	46.2	36.2
new PP	0	7.5	7.8	7.6	6.4
incumbent PP	18.5	8.7	6.2	9.0	7.2
incumbent PP (CHP)	51.5	35.3	35.0	29.5	22.6
Renewables	90.6	149.1	214.4	280.5	345.5
Other	26.2	26.2	27.4	27.5	26.9
Import	0	0	0.3	0.8	0.6
Total	598.9	589.0	588.1	596.1	606.1
CHP (total, excl. renew. CHP)	94.9	69.6	66.0	58.8	46.6
Domestic demand	598.9	588.0	585.9	590.5	592.6
Export	0	0.9	2.2	5.6	13.5
CO_2 emissions (Mt)	305.2	275.9	249.8	241.8	205.8

Table 5.18.: Net electricity generation and CO_2 emissions without lifetime extension (dynamic decommissioning) (woLTE_D), 2008-2030 (Source: ELIAS model results)

this regard, almost no model-driven construction of new fossil-fired power plants takes place[165]. This is due to the fact that, with dynamic decommissioning, retrofit measures may be carried out and thus power plants may be operated beyond their design technical lifetime (provided that operation is profitable), thus (partly) compensating for the electricity generation of power plants decommissioned or mothballed. Furthermore, the sharp increase of renewable electricity generation significantly reduces the need for new investment. Import of electricity increases slightly, reaching 0.6 TWh in 2030. Similarly, peaking electricity generation by pumped storage (2.5 TWh in 2030, subsumed under 'hydro') and by oil-fired units (2.7 TWh in 2030, subsumed under 'other') is modest. Export increases to 13.5 TWh in 2030. Fossil CHP electricity generation is reduced by about half in the scenario period (from 94.9 TWh in 2008 to 46.6 TWh in 2030), accounting for 7.7% of electricity generation in 2030 (15.8% in 2008). Similarly, no CCS power plants are built in the scenario period. Due to the sharp increase of renewable electric-

[165]For reasons of completeness, full costs of electricity generation for new power plants are displayed for the year 2020 in Tables D.2 and D.3 in Appendix D.

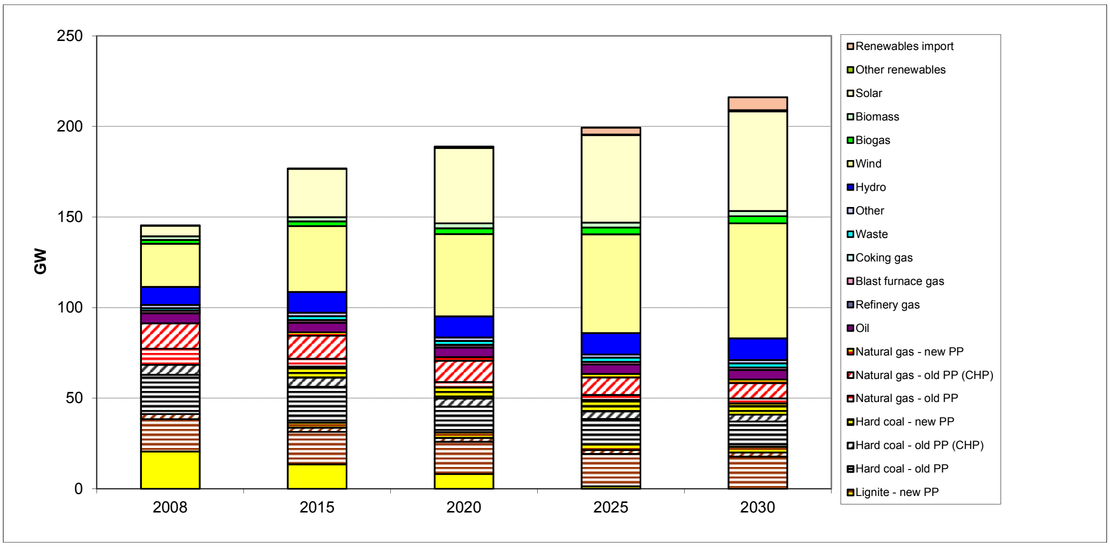

Figure 5.7.: Net electric capacity in the dynamic decommissioning scenario without lifetime extension of nuclear power plants (woLTE_D), 2008-2030 (Source: ELIAS model results)

ity and thus compensating for the increase of the share of coal-based generation, CO_2 emissions decrease by one third (32.6%) in the scenario period, reaching 205.8 Mt CO_2 in 2030 (305.2 Mt CO_2 in 2008). A detailed breakdown of CO_2 emissions is included in Table D.4 in Appendix D.

Figure 5.7 (Table D.5 in Appendix D) shows the development of electric capacity in the scenario period. 67.1% of capacity (145.1 GW) is made up by renewable energy in 2030. The capacity of lignite-fired power plants increases by 11.5% in the scenario period (from 20.7 GW in 2008 to 23.1 GW in 2030). This is due to the fact that most incumbent power plants are still in operation and 3.1 GW of new capacity is added until 2020. The capacity of hard coal-fired power plants decreases by 11.6% (from 27.2 GW in 2008 to 24.1 GW in 2030). This is due to the fact that the capacity of incumbent electric and CHP power plants decreases by about one third (from 21.7 GW in 2008 to 14.1 GW in 2030 and from 5.5 GW in 2008 to 3.8 GW in 2030, respectively) and 6.3 GW of new capacity is commissioned up to 2015 (Table 5.5). The capacity of natural gas-fired units decreases by 42.8 % (from 23.0 GW in 2008 to 13.1 GW in 2030). This is owing to the decommissioning of a large share of incumbent electric (from 8.9 GW in 2008 to 2.7 GW in 2030) and CHP (from 14.1 GW in 2008 to 8.4 GW in 2030) power plants. The effect is only partly compensated by the commissioning of 2.0 GW of new capacity by 2015. The decommissioning dynamics explain the shift to a more coal-based generation mix (p. 86). Overall, fossil capacity is only moderately reduced by 15.0% in the scenario

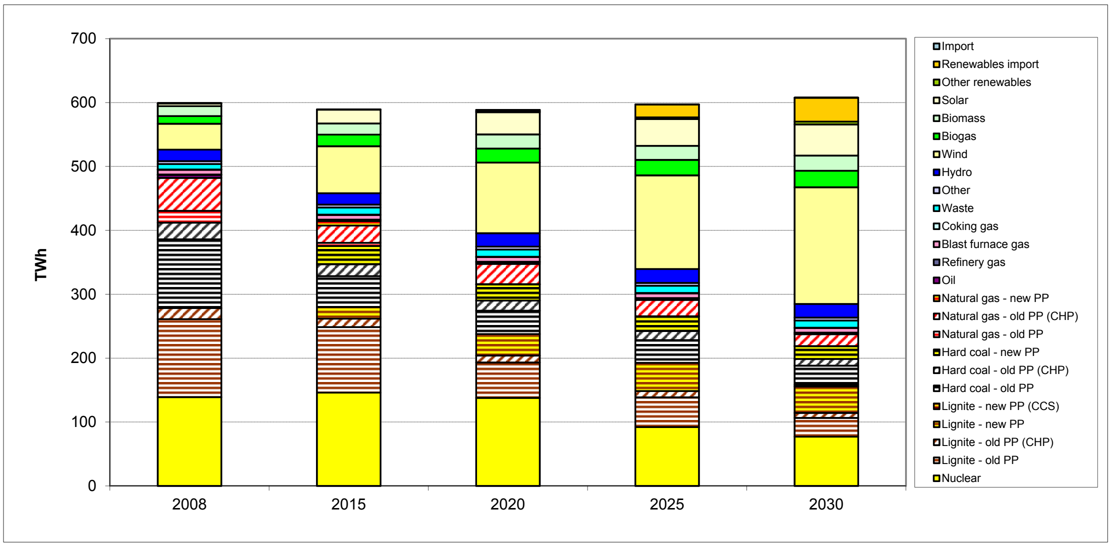

Figure 5.8.: Net electricity generation with lifetime extension (dynamic decommissioning) (wLTE_D), 2008-2030 (Source: ELIAS model results)

period (from 70.9 GW in 2008 to 60.3 GW in 2030). This explains the relatively low share of import for covering the load during scarcity situations (Table 5.18).

Figure 5.8 and Table 5.19 show electricity generation with the lifetime extension of nuclear power plants (wLTE_D). As without lifetime extension, more than half of overall electricity generation in 2030 stems from renewable energy (56.6%). Nuclear electricity generation in 2030 (77.1 TWh) accounts for 12.7% of overall electricity generation. Coal-fired electricity generation decreases by almost half (from 139.3 TWh in 2008 to 81.0 TWh in 2030 of lignite-fired generation and from 133.9 TWh in 2008 to 60.6 TWh of hard coal-fired generation in 2030), gas-fired generation, in turn, by almost three quarters (-73.4%) (from 70.0 TWh in 2008 to 18.6 TWh in 2030). New generation capacity of lignite-fired power plants accounts for 54.0% of lignite-based electricity production in 2030. This is due to significant capacity additions of lignite-fired power plants (mostly conventional, a small fraction of which with CCS) in the scenario period. Other power plant types are commissioned in 2015, corresponding to the power plants already under construction (Table 5.5), but not in later years since lignite-fired power plants constitute by far the technology option with the lowest costs of electricity of all technologies (Tables 5.20 and 5.21)[166].

For lignite-fired power plants without CCS, the contribution of capital costs to the *LCOE* is moderate (between natural gas units (combined cycle) and hard coal power

[166]In 2030, 34 MW of new hard coal-fired capacity is built. However, this is rather an effect of calculation precision than real capacity addition. For this purpose, it is not further discussed at this stage.

	2008	2015	2020	2025	2030
			- TWh -		
Nuclear	139.1	146.0	137.9	92.1	77.1
Lignite	139.3	134.0	99.9	100.6	81.0
new PP	0	18.2	33.7	44.1	41.2
new PP (CCS)	0	0	0	0	2.5
incumbent PP	122.1	102.6	55.2	46.6	29.4
incumbent PP (CHP)	17.2	13.2	11.0	9.9	7.8
Hard coal	133.9	95.5	77.7	72.7	60.6
new PP	0	28.4	25.4	23.0	19.9
incumbent PP	107.7	48.3	36.6	35.6	30.2
incumbent PP (CHP)	26.2	18.8	15.7	14.1	10.5
Natural gas	70.0	38.9	32.1	25.8	18.6
new PP	0	6.8	0	0	0
incumbent PP	18.5	5.1	0.3	0.2	0.1
incumbent PP (CHP)	51.5	27.0	31.8	25.6	18.5
Renewables	90.6	148.9	213.9	279.2	344.1
Other	26.2	26.0	27.0	26.6	26.1
Import	0	0	0.2	0.3	0.2
Total	598.9	589.2	588.6	597.3	607.8
CHP (total, excl. renew. CHP)	94.9	59.0	58.4	49.6	36.9
Domestic demand	598.9	588	585.9	590.5	592.6
Export	0	1.2	2.7	6.8	15.2
CO_2 emissions (Mt)	305.2	239.7	183.2	175.6	142.2

Table 5.19.: Net electricity generation and CO_2 emissions with lifetime extension (dynamic decommissioning) (wLTE_D), 2008-2030 (Source: ELIAS model results)

Cost component	HC	LG	NG CC 800 MW	NG CC 400 MW	GT	HC CCS	LG CCS	NG CC 800 MW CCS
				- €/MWh -				
Capital costs	41.3	30.6	25.1	20.7	209.4	52.3	41.6	35.6
Fixed oper. costs	12.3	10.3	5.7	4.5	51.4	15.6	14.0	8.2
Variable oper. costs	2.0	2.3	0.5	0.5	0.5	3.5	3.8	0.9
Fuel costs	33.1	10.3	67.8	67.8	109.7	50.1	25.0	83.1
CO_2 costs	23.9	30.6	10.9	10.9	17.6	2.9	3.9	1.3
LCOE	112.5	84.1	110.0	104.5	388.6	124.5	88.4	129.0

Table 5.20.: Cost components and levelised costs of electricity (*LCOE*) of power plants (HC: hard coal, LG: lignite, NG: natural gas, CC: combined cycle, GT: gas turbine, CCS: carbon capture and storage) with lifetime extension (dynamic decommissioning) (wLTE_D), 2020 (Source: ELIAS model results)

plants)[167] and CO_2 costs are highest among all technologies. Nevertheless, due to the low fuel costs (Table 5.6), overall levelised costs of electricity of lignite-fired power plants without CCS are the lowest among all options. For lignite-fired power plants with CCS, capital costs are higher than for the configuration without CCS (due to the additional investment for the CO_2 capture installation) and fuel costs are higher (due to the lower electric efficiency and since fuel costs include transport and storage costs of CO_2 (Table 5.10)). However, CO_2 costs are significantly lower, since no allowances have to be purchased for the amount of CO_2 captured and stored underground. Overall, lignite-fired power plants with CCS are the second most competitive technology option in 2020[168]. New hard coal-fired power plants make up 32.9% of electricity generation from hard coal in 2030. Corresponding power plants are already built by 2015 (Table 5.5). As regards, natural gas, new power plants do not contribute to electricity generation from natural gas in 2030 (0%). Although by 2015 new capacity is added (Table 5.5), it is not in use between 2020 and 2030 since it is mothballed (below). Overall, the fossil fuel mix becomes more coal-dominated (88.4% of coal-based electricity generation in 2030 vs. 79.6% in 2008). Operating hours in the scenario period decrease by about half for all fossil fuel types between 2008 and 2030 (Table 5.22). Most natural gas-fired electric power plants are mothballed or decommissioned, leading to very low operating hours[169]. Import of electricity increases slightly to 0.2 TWh in 2030, export reaches 15.2 TWh. Fossil CHP electricity generation decreases by more than half (-61.2%) in the scenario period (from 94.9 TWh in 2008 to 36.9 TWh in 2030), reaching a share of 6.1% of overall electricity generation in 2030 (15.8% in 2008). CO_2 emissions decrease by more than half (from 305.2 Mt CO_2 in 2008 to 142.2 Mt CO_2 in 2030). A detailed breakdown of CO_2 emissions is included in Table D.6 in Appendix D.

Figure 5.9 (Table D.7 in Appendix D) shows the development of electric capacity in the scenario period. 63.9% of electric capacity (145.1 GW) is made up by renewable energy in 2030. The capacity of lignite-fired power plants increases by 11.0% (from 20.7 GW in 2008 to 23.0 GW in 2030). Many incumbent lignite-fired power plants are decommissioned (electric power plant capacity in operation decreases from 18.0 GW

[167] Generally, capital costs per installed capacity (€/kW) are highest for lignite power plants. However, due to significantly lower operating hours for hard coal- and natural gas-fired power plants (Table 5.22), specific capital costs (€/MWh) as part of the *LCOE* are lower for lignite than for hard coal power plants.

[168] The *LCOE* discussed here are for demonstrating the general influence of cost components for individual power plant types. With regard to lignite-fired power plants with CCS, these are assumed to be commercially available only in 2025 (p. 69).

[169] See Footnote 147.

Cost component	NG CC 30 MW	NG CC 100 MW	NG CC 407 MW	HC - IND	HC - DH
			- €/MWh -		
Capital costs	36.9	21.4	28.6	82.9	82.9
Fixed oper. costs	18.6	11.6	13.9	46.8	46.8
Variable oper. costs	2.0	2.0	2.0	2.0	2.0
Fuel costs	102.3	91.9	85.6	46.4	36.8
CO_2 costs	15.1	13.8	12.4	29.4	24.5
Heat credit	-44.9	-37.0	-39.8	-57.8	-65.4
Avoided grid use	-5.0	-5.0	-5.0	-5.0	-5.0
CHP bonus	0	0	0	0	0
LCOE	125.0	98.8	97.7	144.7	122.7

Table 5.21.: Cost components and levelised costs of electricity (*LCOE*) of CHP power plants (NG: natural gas, HC: hard coal, CC: combined cycle, IND: industry, DH: district heating) with lifetime extension (dynamic decommissioning) (wLTE_D)), 2020 (Source: ELIAS model results)

	2008	2015	2020	2025	2030
			h/a		
Nuclear	6,782	7,128	7,027	6,842	6,328
Lignite	6,730	5,812	5,297	4,734	3,528
new PP		6,568	6,008	5,528	4,412
new PP (CCS)					6,690
incumbent PP	6,787	5,710	4,986	4,199	2,659
incumbent PP (CHP)	6,349	5,701	5,045	4,547	3,601
Hard coal	4,914	3,488	3,140	3,134	2,661
new PP		4,539	4,062	3,672	3,168
incumbent PP	4,951	3,000	2,601	2,801	2,370
incumbent PP (CHP)	4,767	3,746	3,548	3,343	2,793
Natural gas	3,047	2,054	1,926	1,793	1,416
new PP		3,452	0	0	0
incumbent PP	2,080	1,201	96	89	47
incumbent PP (CHP)	3,656	2,122	2,685	2,644	2,189

Table 5.22.: Operating hours of conventional power plants with lifetime extension (dynamic decommissioning) (wLTE_D), 2008-2030 (Source: MICOES model results, author's own aggregation)

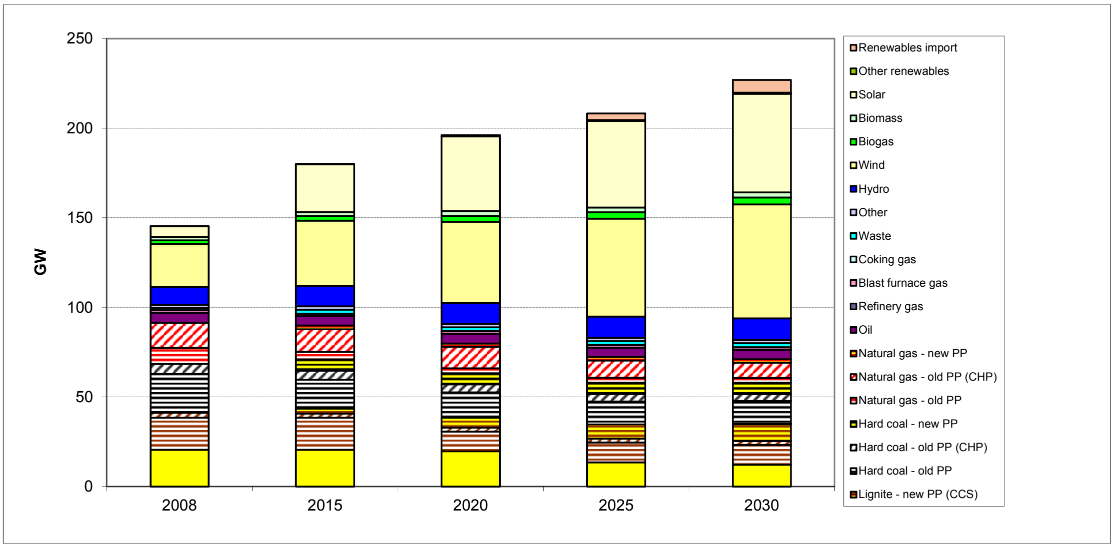

Figure 5.9.: Net electric capacity with lifetime extension (dynamic decommissioning) (wLTE_D), 2008-2030 (Source: ELIAS model results)

in 2008 to 11.1 GW in 2030) while significant new lignite-fired condensing capacity is added until 2030 (9.3 GW without CCS, 0.4 GW with CCS in 2030). The capacity of hard coal-fired power power plants decreases by 16.4% (from 27.2 GW in 2008 to 22.8 GW in 2030) with new capacity (6.3 GW by 2015, Table 5.5) partly compensating for decreases of incumbent capacity, especially of power plants without heat extraction (from 21.7 GW in 2008 to 12.7 GW in 2030). The capacity of natural gas-fired units decreases by 42.7% (from 23.0 GW in 2008 to 13.2 GW in 2030). This is attributable to the decommissioning of a large share of incumbent electric (-69.1%, from 8.9 GW in 2008 to 2.7 GW in 2030) and CHP (-40.0%, from 14.1 GW in 2008 to 8.5 GW in 2030) power plants. The effect is only partly compensated by the commissioning of 2.0 GW of new capacity by 2015. The decommissioning and investment dynamics explain the shift to a more coal-based generation mix (p. 91). Overall, fossil capacity is reduced moderately by 16.9% in the scenario period (from 70.9 GW in 2008 to 58.9 GW in 2030). This explains the reatively low share of import for covering the load during scarcity situations (Table 5.19). However, significant capacity is decommissioned requiring additional new capacity (lignite) to be built[170].

[170] At first sight, it may appear counter-intuitive that significant incumbent lignite-fired capacity is decommissioned and replaced by new lignite-fired power plants. This is due to the fact that the operation of many incumbent power plants is not profitable, which enforces decommissioning and leads to investment demand (Section 4.5.1). Since capacity investment is cost-based, the technology with the lowest cost of electricity receives the highest share of capacity additions; in this case, these are lignite-fired power plants. In this regard, decommissioning of incumbent lignite-fired power plants and investment in new lignite-fired capacity are determined independently in ELIAS.

	2008	2015	2020	2025	2030
			- TWh -		
Nuclear	0	48.4	79.0	82.5	77.1
Lignite	0	-11.3	-37.5	-33.3	-33.7
new PP	0	-0.9	12.6	22.9	21.5
new PP (CCS)	0	0	0	0	2.5
incumbent PP	0	-9.7	-48.2	-53.6	-54.1
incumbent PP (CHP)	0	-0.7	-1.9	-2.7	-3.5
Hard coal	0	-23.6	-23.0	-25.0	-21.6
new PP	0	-3.1	-5.1	-6.3	-5.4
incumbent PP	0	-18.9	-15.5	-16.0	-14.0
incumbent PP (CHP)	0	-1.7	-2.5	-2.7	-2.1
Natural gas	0	-12.7	-16.9	-20.4	-17.5
new PP	0	-0.8	-7.8	-7.6	-6.4
incumbent PP	0	-3.7	-5.9	-8.8	-7.1
incumbent PP (CHP)	0	-8.3	-3.2	-3.9	-4.1
Renewables	0	-0.3	-0.6	-1.3	-1.4
Other	0	-0.2	-0.4	-0.9	-0.8
Import	0	0	-0.1	-0.5	-0.4
Total	0	0.3	0.5	1.2	1.7
CHP (total, excl. renew. CHP)	0	-10.7	-7.6	-9.3	-9.8
Domestic demand	0	0	0	0	0
Export	0	0.3	0.5	1.2	1.7
CO_2 emissions (Mt)	0	-36.1	-66.6	-66.3	-63.6

Table 5.23.: Difference between net electricity generation and CO_2 emissions with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D), 2008-2030 (Source: ELIAS model results)

Table 5.23 compares net electricity production with and without lifetime extension for the dynamic decommissioning rationale. Due to the extension of lifetime of nuclear power plants, corresponding electricity generation is significantly higher in comparison to the scenario without lifetime extension (about 80 TWh between 2020 and 2030). Fossil-fired power plants, in turn, generate less electricity with lifetime extension. As regards lignite power plants, overall electricity generation is more than 30 TWh lower with lifetime extension for the years 2020 to 2030 in comparison to the case without lifetime extension. Especially, incumbent condensing power plants significantly decrease electricity production in comparison to the scenario without lifetime extension, by about 50 TWh between 2020 and 2030. This is also reflected by significantly decreasing operating hours (Table 5.22). As stated above (p. 91 and Footnote 170), new power plants are built in the scenario with lifetime extension. This translates into more than 20 TWh of additional electricity generation from new lignite-fired condensing power plants in 2025 and 2030 and to a small additional amount (2.5 TWh) from lignite-fired power plants

	2008	2015	2020 - GW -	2025	2030
Nuclear	0	7.0	11.5	12.1	12.2
Lignite	0	0	-4.2	-1.9	-0.1
new power plants	0	0	2.5	4.9	6.3
new power plants (CCS)	0	0	0	0	0.4
incumbent power plants	0	0	-6.8	-6.8	-6.8
Hard coal	0	-3.7	0	-1.4	-1.3
incumbent power plants	0	-3.7	0	-1.4	-1.4
Natural gas	0	0	0	0	0
Total	0	3.4	7.2	8.9	10.8

Table 5.24.: Difference between net electric capacity of conventional power plants with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D), 2008-2030 (Source: ELIAS model results)

with CCS in 2030[171]. However, operating hours of the new condensing lignite-fired power plants without CCS also decrease by 32.8% between 2015 and 2030 (Table 5.22). Hard coal-fired electricity generation decreases by more than 20 TWh for the years 2020 to 2030 with lifetime extension in comparison to the case without lifetime extension. Both incumbent and new power plants feature significant decreases of operating hours (Table 5.22). Similarly, natural gas-fired electricity generation decreases by about 20 TWh for the years 2020 to 2030 with lifetime extension in comparison to the situation without lifetime extension. Very low operating hours (Table 5.22) and corresponding electricity generation (Table 5.19) indicate that almost all (both incumbent and new) electric power plants are mothballed[172]. Import decreases slightly (by 0.4 TWh in 2030) with lifetime extension compared to a situation without lifetime extension. Peaking oil units (under 'other') and pumped storage (under 'hydro') generation decreases also slightly (by 0.8 TWh and 1.4 TWh in 2030, respectively) compared to the case without lifetime extension. This indicates that the phase-out of nuclear power plants does not lead to significantly more scarcity situations in comparison to the scenario with lifetime extension. Export increases slightly (by 1.7 TWh) with lifetime extension compared to the scenario without lifetime extension. CHP electricity production decreases by almost 10 TWh in 2025 and 2030. CO_2 emissions decrease significantly with lifetime extension compared to the case without lifetime extension, by more than 60 Mt for 2020 to 2030.

Table 5.24 shows differences of net electricity capacity between the case with and without the lifetime extension of nuclear power plants for dynamic decommissioning.

[171]See Footnote 170.
[172]Cp. Footnote 147.

Scenario	2008	2015	2020	2025	2030
	€/MWh				
woLTE_D	65.9	49.8	65.3	71.8	64.2
wLTE_D	65.9	44.0	56.2	56.3	47.2
Difference	0	-5.7	-9.1	-15.5	-17.1

Table 5.25.: Spot electricity price with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D), 2008-2030 (Source: MICOES model results)

Lifetime extension leads to an additional 12 GW of nuclear capacity for the years 2020 to 2030 in comparison to the scenario without lifetime extension. As regards fossil-fired power plants, the total capacity does not differ significantly between the two scenarios. However, for lignite-fired power plants, 6.8 GW less of incumbent condensing power plants are available with lifetime extension due to earlier decommissioning compared to the case without lifetime extension. This is compensated by additional new condensing capacity of 6.3 GW without CCS and 0.4 GW with CCS by 2030. With regard to hard coal, in 2015, 3.7 GW less are available due to earlier decommissioning with lifetime extension. In 2020 and 2025, this capacity is also no longer available without lifetime extension, so there are no more differences between the two scenarios. Furthermore, by 2030, additional 1.4 GW of incumbent condensing hard coal-fired power plants are decommissioned with lifetime extension[173]. There are no differences in natural gas-fired capacity between the scenarios with and without lifetime extension due to the fact that natural gas-fired power plants are generally newer than coal-fired power plants (Figure 2.3) and since no additional capacity is built in addition to the power plants already under construction. Overall, in 2030 10.8 GW more installed conventional capacity is available with lifetime extension.

Table 5.25 gives an overview of spot electricity prices with and without lifetime extension for dynamic decommissioning. With lifetime extension, electricity prices are between 11.5% (5.7 €/MWh) in 2015 and 26.6% (17.1 €/MWh) in 2030 lower compared to the scenario without lifetime extension. This can be explained by more conventional power plant capacity with lifetime extension at low marginal generating costs (nuclear, new lignite-fired power plants). However, differences between both scenarios are significantly lower than calculated for static decommissioning (Table 5.17).

[173] Minor differences in 2030 between the overall hard coal capacity and the capacity of incumbent condensing power plants are due to a minor capacity addition of hard coal-fired power plants in 2030 (Footnote 166).

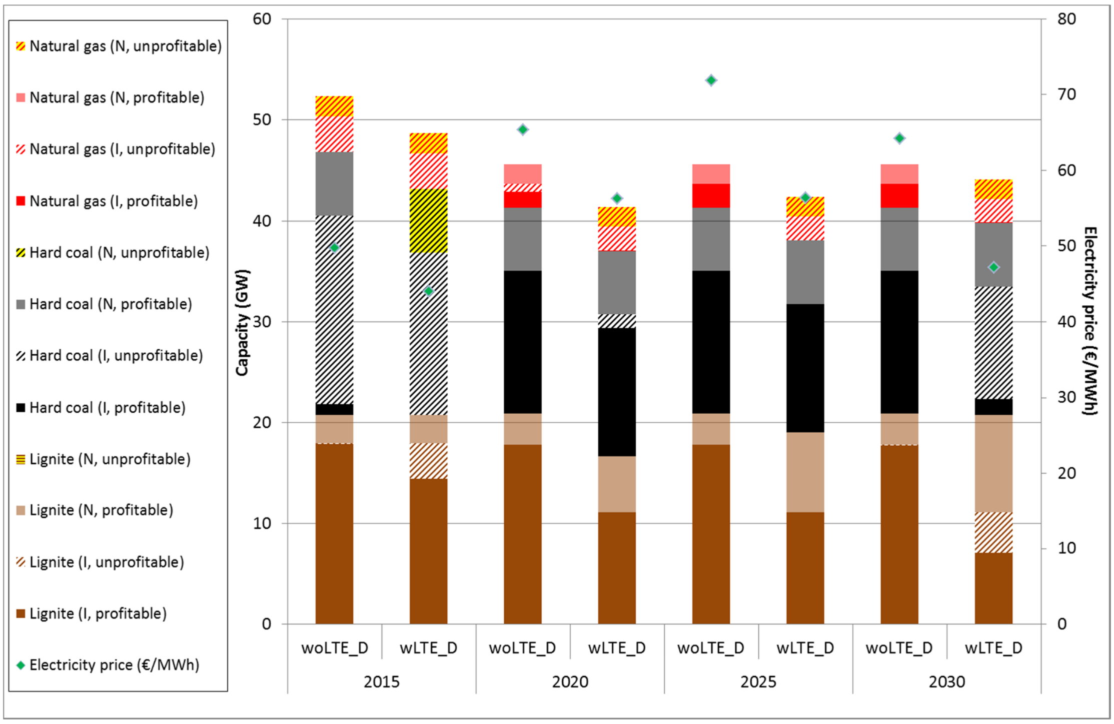

Figure 5.10.: Profitability of fossil-fired electric power plants (I=incumbent, N=new) and electricity price with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D)), 2015-2030 (Source: ELIAS model results, MICOES model results)

In order to explain the decommissioning dynamics with and without lifetime extension, in the following the profitability of electric fossil-fired power plants[174] and its effects on mothballing, retrofit and decommissioning are discussed.

Figure 5.10 (values in Table D.8 in Appendix D) gives an overview of the profitability of fossil-fired electric power plants with and without lifetime extension in relation to the electricity price for dynamic decommissioning. In 2015, 3.5 GW of lignite-fired capacity becomes unprofitable with lifetime extension, whereas almost no capacity (0.1 GW) is unprofitable without lifetime extension. This can be explained by shrinking profit margins with lifetime extension due to decreasing operating hours (Table D.1 in Appendix D and Table 5.22) and generally lower electricity revenues as expressed by the electricity price. In terms of capacity, this explains part of the difference of 6.8 GW of incumbent condensing lignite-fired capacity in 2020[175] between the scenario with lifetime extension compared to the scenario without lifetime extension (Table 5.24). With regard to hard coal-fired incumbent power plants, less power plants are unprofitable with lifetime ex-

[174] Cp. Footnote 161.
[175] For the time difference between the year of unprofitable operation and decommissioning or mothballing, see Footnote 118.

tension in 2015 (16.1 GW against 18.7 GW). At first sight, this is counter-intuitive since operating hours and electricity revenues are lower with lifetime extension. However, this phenomenon can be explained by the fact that in 2015 more coal-fired capacity (3.7 GW, Table 5.24) is already decommissioned with lifetime extension. This capacity is therefore not included in Figure 5.10. Incumbent natural gas-fired units are equally unprofitable with and without lifetime extension in 2015 (3.6 GW each). The same applies for natural gas-fired units currently under construction (2.0 GW). Hard coal-fired power plants currently under construction (6.3 GW) are unprofitable with lifetime extension, but not without lifetime extension. Similarly, in 2020 and 2025, more power plants (especially natural gas-fired) are unprofitable with lifetime extension. However, the overall magnitude is significantly smaller than in 2015. This is due to the fact that many power plants that are unprofitable in 2015 are already decommissioned by 2020. In 2030, 19.5 GW of capacity (4.0 GW lignite, 11.2 GW hard coal, 4.3 GW natural gas) are unprofitable with lifetime extension in contrast to only 0.1 GW (lignite) without lifetime extension. However, most corresponding effects (decommissioning, mothballing) are only visible after 2030[176]. Newly-built natural gas-fired power plants (2.0 GW) are unprofitable in the whole scenario period with lifetime extension. For hard coal-fired power plants currently under construction, unprofitable operation occurs in 2015 with lifetime extension.

Power plants may be mothballed, i.e. temporarily taken out of service, if power plant operation is unprofitable, or retrofitted and operated beyond the design technical lifetime if operation is still profitable. Mothballing and retrofit effects are therefore expected to be linked to the considerations on the profitability of power plants. Figure 5.11 (values in Table D.9 in Appendix D) and Figure 5.12 (values in Table D.10 in Appendix D) give an overview of mothballing and retrofitting of fossil-fired electric power plants in the scenario period.

Corresponding to the amount of unprofitable power plant capacity (Figure 5.10), the overall capacity mothballed increases with lifetime extension of nuclear power plants and reaches a maximum of almost 6 GW in 2020. Mothballing without lifetime extension is only relevant for the year 2020 and to a minor extent (less than 1 GW). Mothballed capacity with lifetime extension of nuclear power plants accounts for 1.2 GW of incumbent natural gas-fired power plants in 2015. In 2020, both incumbent natural gas-fired

[176]In the case of unprofitable operation, decommissioning only takes place once the end of the technical lifetime has been reached. Furthermore, mothballing only becomes effective once five unprofitable years of operation have been reached (Footnote 118).

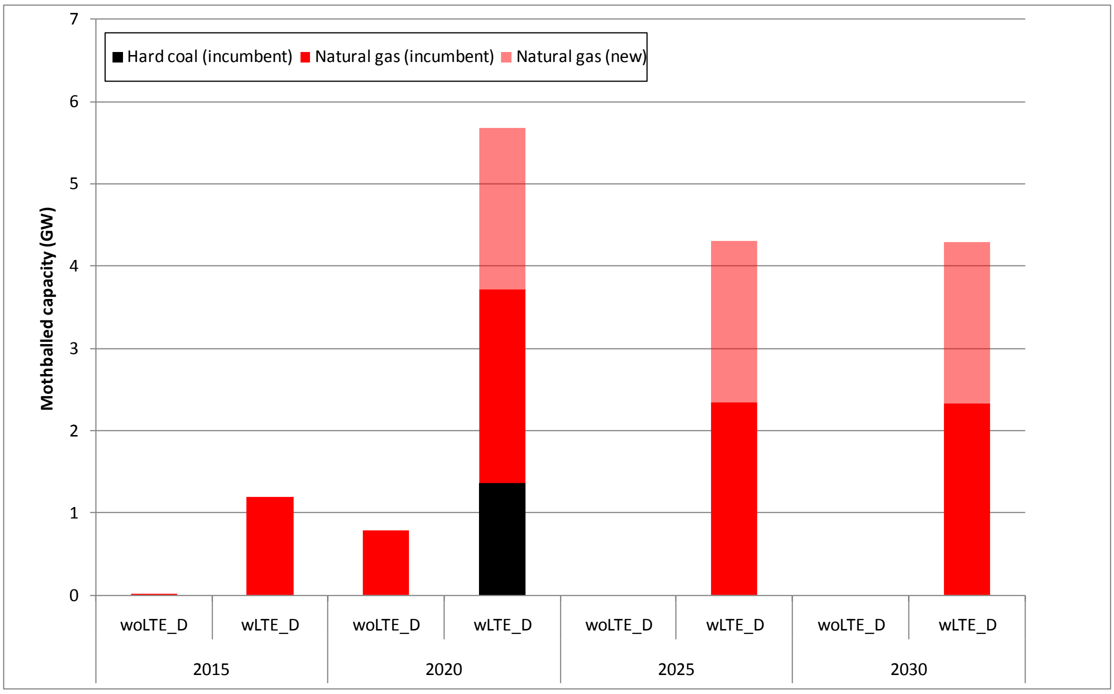

Figure 5.11.: Mothballed capacity of fossil-fired electric power plants with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D), 2008-2030 (Source: ELIAS model results)

(2.4 GW) and hard coal-fired (1.4 GW) power plants are mothballed in addition to 2.0 GW of natural gas-fired power plants currently under construction. Both incumbent and new natural gas-fired power plants remain mothballed for the rest of the scenario period[177]. Unprofitable power plants at the end of their technical lifetime are decommissioned rather than mothballed. For this reason, mostly natural gas-fired power plants are mothballed, whereas unprofitable hard coal power plants are mostly decommissioned and only to a minor extent mothballed. Similarly, there is no mothballing of lignite power plants, but significant decommissioning (Figure 5.13 below).

Retrofit is carried out with and without lifetime extension and predominantly for lignite- and hard coal-fired power plants. Natural gas-fired units are only retrofitted to a minor extent since they are generally newer. Due to their general lack of profitability (Figure 5.10), many of them are mothballed instead (Figure 5.11). The lifetime of the bulk of retrofitted hard coal-fired power plants is extended by up to 5 years, some by up to 10 years. As regards lignite-fired power plants, the length of the extended lifetime reaches mostly up to 10 years (with lifetime extension of nuclear power plants) and

[177] In consequence, natural gas-fired power plants currently under construction may be considered as stranded investments since fixed operating costs are not covered. Thus profit margins for covering capital costs cannot be reaped either.

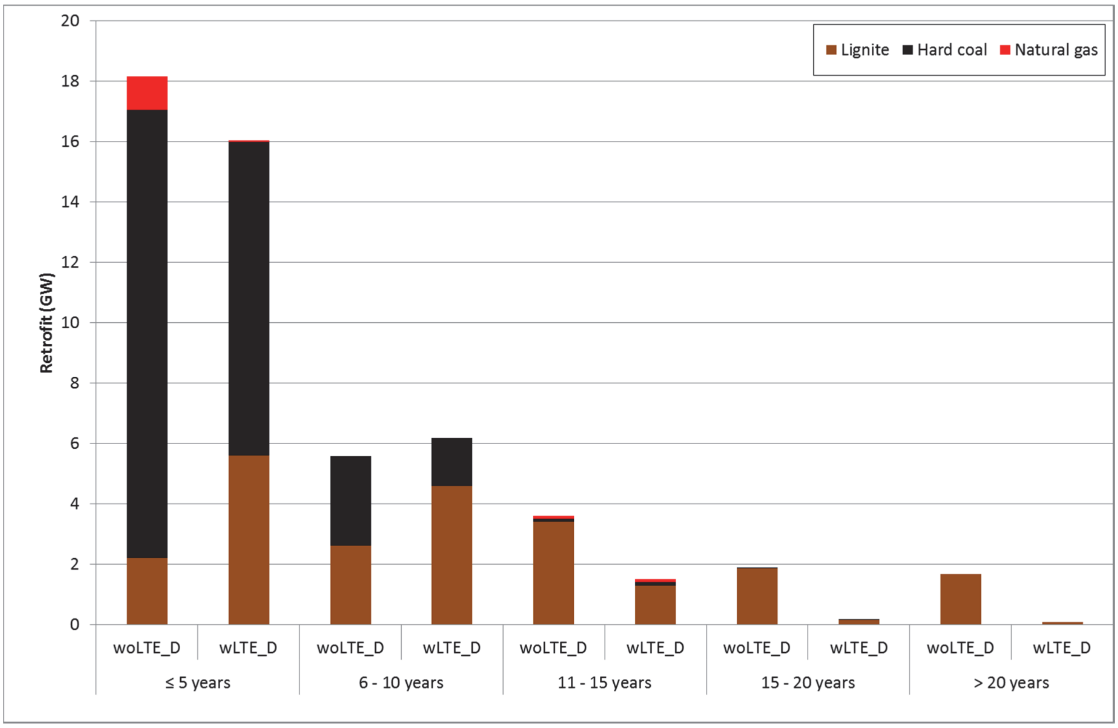

Figure 5.12.: Retroffited capacity and length of extended lifetime of fossil-fired electric power plants with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D) (Source: ELIAS model results)

15 years (without lifetime extension of nuclear power plants), with some power plants (especially in the scenario without lifetime extension of nuclear power plants) remaining in operation for even longer years. Generally, the length of the extended lifetime due to retrofit is shifted to fewer years and the overall retrofitted capacity is smaller with the lifetime extension of nuclear power plants.

Figure 5.13 (values in Table D.11 in Appendix D) gives an overview of decommissioned capacity of fossil-fired electric power plants with and without the lifetime extension of nuclear power plants. Analogously to the higher lack of profitability of power plants with lifetime extension (Figure 5.10), there is generally more decommissioned capacity with lifetime extension in comparison to the case without lifetime extension. Whereas in the scenario without lifetime extension nearly no lignite-fired power plants are decommissioned, 6.9 GW are decommissioned in 2020 in the scenario with lifetime extension. This is consistent with the lack of profitability of a significant share of lignite capacity in 2015 (Figure 5.10) as well as the fact that retrofit is used to a lesser extent and for fewer years with lifetime extension of nuclear power plants (Figure 5.12). Furthermore, mothballing is not relevant for lignite-fired power plants (Figure 5.11). For hard coal-

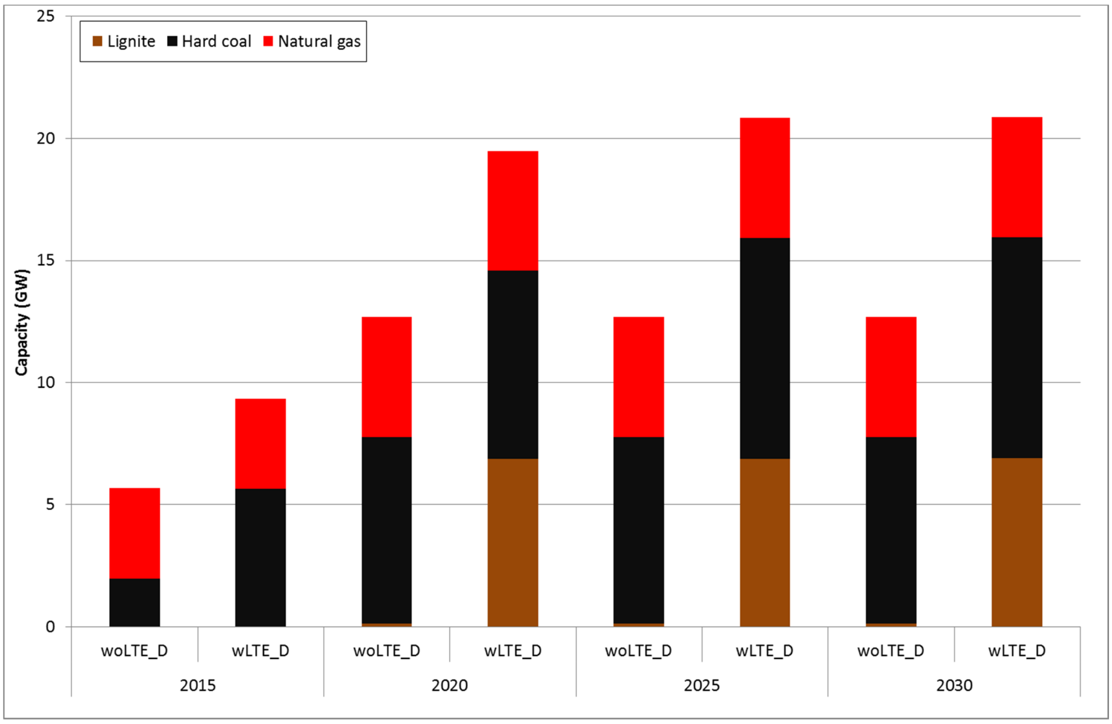

Figure 5.13.: Decommissioned capacity of fossil-fired electric power plants with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D) (Source: ELIAS model results)

fired power plants, decommissioning is higher in all years (especially in 2015, 2025 and 2030) with lifetime extension in comparison to the case without lifetime extension. However, differences are modest; decommissioning reaches 7.6 GW in 2025 without lifetime extension and 9.0 GW with lifetime extension. This is consistent with a moderately higher lack of profitability of hard coal-fired power plants (Figure 5.10) and moderately less retrofit (and for fewer years) (Figure 5.12) with lifetime extension compared to the case without lifetime extension as well as with the (limited) extent of mothballing with lifetime extension (Figure 5.11). There is no difference in decommissioning of gas-fired power plants between both scenarios (3.7 GW in 2015 and 4.9 GW thereafter for both scenarios). Although profitability is generally lower with lifetime extension in comparison to the case without lifetime extension (Figure 5.10), due to the generally younger age of natural gas-fired power plants, profitability affects mothballing (Figure 5.11) rather than decommissioning.

From these considerations, it can be concluded that the lifetime extension of nuclear power plants compared to the scenario without such an extension generally leads to an increased lack of profitability of power plants (Figure 5.10). Significant capacity is

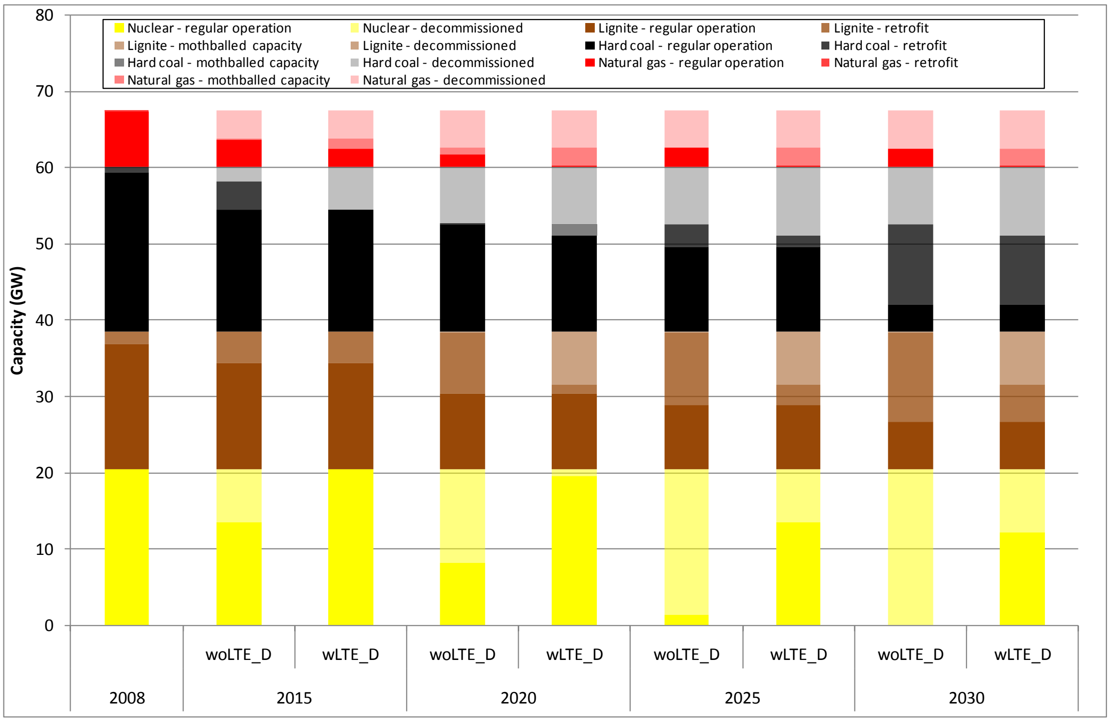

Figure 5.14.: Overview of capacity of incumbent electric power plants according to the operational state (in operation, retrofitted, mothballed, decommissioned) with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D), 2008-2030 (Source: ELIAS model results)

mothballed beyond the extent which takes place without the lifetime extension of nuclear power plants. Natural gas-fired power plants (both incumbent and new) are most affected by mothballing with lifetime extension (Figure 5.11). Furthermore, lifetime extension of nuclear power plants leads to less power plant capacity being retrofitted and for fewer years (Figure 5.12). Lignite- and hard coal-fired power plants are especially affected by this phenomenon. The lack of profitability of power plants also leads to an increased decommissioning of incumbent lignite and hard coal-fired power plants (Figure 5.13), which is consistent with the lesser extent of retrofit measures carried out in these power plants. Figure 5.14 (values in Table D.12 in Appendix D) gives an synopsis of these effects for incumbent electric power plants. Significant shifts between “retrofit” and “decommissioned”, “regular operation” and “mothballed” can be observed due to the mentioned effects resulting from lifetime extension of nuclear power plants.

It can therefore be concluded that the static decommissioning rationale significantly underestimates available capacity in the scenario without lifetime extension since retrofit measures (vs. decommissioning) are not taken into account. Similarly, capacity available with lifetime extension is overestimated since mothballing (versus regular operation) is

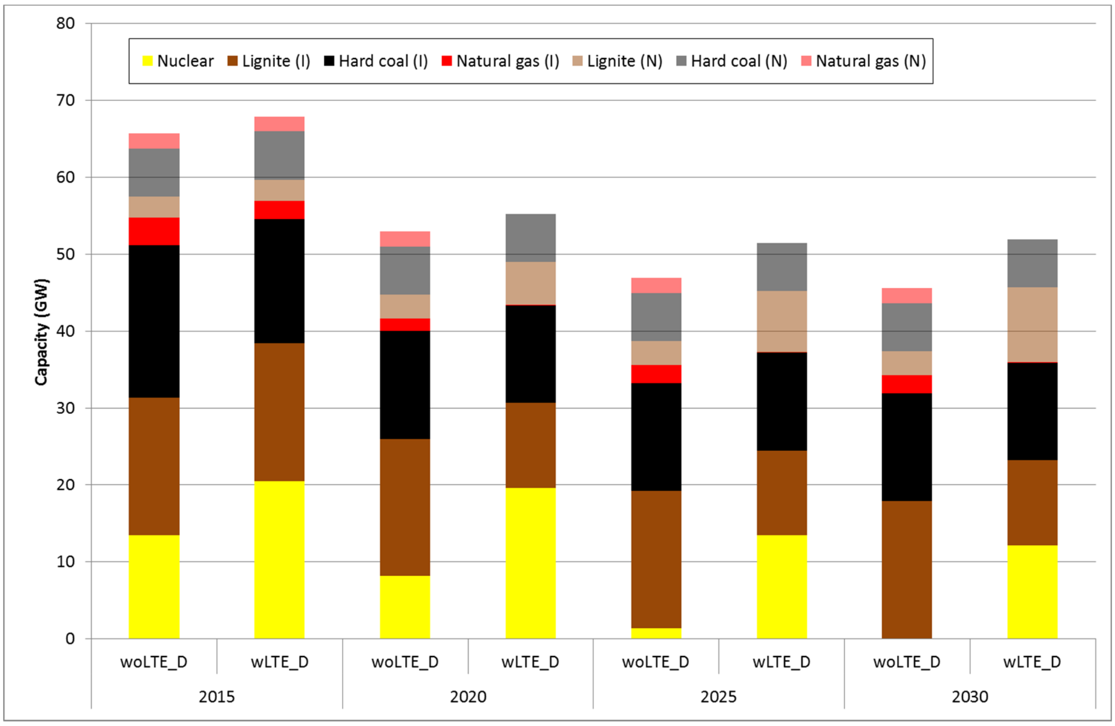

Figure 5.15.: Capacity of electric power plants in operation (I: incumbent, N: new) with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D), 2008-2030 (Source: ELIAS model results)

not considered. In consequence, capacity actually in operation (i.e. without mothballed capacity) is similar in the scenario with and without lifetime extension. Figure 5.15 (corresponding values in Table D.13 in Appendix D) compares the overall capacity of electric power plants in operation for the scenario with and without lifetime extension for the dynamic decommissioning rationale[178]. As expected (p. 85), with dynamic decommissioning, available capacity is similar in the scenario with and without lifetime extension. With lifetime extension, available capacity is, at 2.3 GW in 2020 and 6.4 GW in 2030, only moderately higher than in the scenario without lifetime extension. What is more, due to the dynamics of decommissioning and mothballing, with lifetime extension significantly less flexible natural gas- and hard coal-fired power plants are in operation, however more baseload power plants (nuclear, lignite).

5.2.3. Comparison of Static and Dynamic Decommissioning

With static decommissioning, capacity of electric power plants in operation is about 12 GW higher between 2020 and 2030 with lifetime extension compared to the case

[178]Table D.13 in Appendix D also includes renewable and must-run capacity.

without lifetime extension (p. 82). In contrast, with dynamic decommissioning, the difference is reduced to 2.3 GW (2020), 4.6 GW (2025) and 6.4 GW (2030) (Figure 5.15 and Table D.13 in Appendix D). This corresponds to the expectations regarding decommissioning, mothballing and retrofit in a dynamic approach stated above (p. 85).

As a consequence of similar capacity in operation in the scenario with and without the lifetime extension of nuclear power plants with dynamic decommissioning, the electricity price reduction effect due to lifetime extension with dynamic decommissioning compared to static decommissioning is decreased by more than half (electricity price reduction effect due to lifetime extension of 9.1 €/MWh (dynamic) vs. 25.9 €/MWh (static) in 2020 and 17.1 €/MWh (dynamic) vs. 49.0 €/MWh in 2030, Tables 5.17 and 5.25).

Similarly, scarcity situations as expressed by the need for imports do not differ significantly between the scenarios with and without lifetime extension with dynamic decommissioning (0.4 TWh higher import in 2030 for the scenario without lifetime extension), as opposed to a significantly higher need for imports with static decommissioning (10.1 TWh higher import in 2030 without lifetime extension). The same holds true for the difference in the need of peaking generating units (pumped storage, peaking oil units) (Tables 5.16 and 5.23).

What is more, with dynamic decommissioning, flexible natural gas-fired power plants mostly do not operate with the lifetime extension of nuclear power plants, but are mothballed (Figure 5.11) whereas mothballing is not taken into account with static decommissioning. Generally, with dynamic decommissioning, the scenario with lifetime extension features a higher availability of lignite and nuclear power plants and a lower availability of natural gas and hard coal power plants as opposed to the scenario without lifetime extension (Figure 5.15), whereas with static decommissioning the only difference relates to the amount of nuclear capacity in the system.

Both scenarios (with and without lifetime extension) feature significant increases of exports (Tables 5.14, 5.15, 5.18 and 5.19), with higher values for the situation with lifetime extension. Export generally increases with additional renewable energies due to an increasing number of hours with a negative residual load over time. Furthermore, a higher share of export with lifetime extension is due to the fact that more baseload generators (nuclear, lignite) are in operation. Export is slightly higher for the dynamic decommissioning rationale than for the static rationale due to the fact that more lignite-fired power plants are in the system (Tables C.5 and C.10 in Appendix C and Tables D.5

and D.7 in Appendix D).

It can therefore be concluded that static decommissioning in comparison to dynamic decommissioning overestimates the capacity available in the system with lifetime extension of nuclear power plants and corresponding reduction effects of the electricity price. Similarly, scarcity situations without lifetime extension in comparison to the situation with lifetime extension are overestimated with static decommissioning. Furthermore, the static decommissioning rationale does not detect the decrease of available flexible (natural gas, hard coal) capacity with lifetime extension.

6. Summary and Conclusions

In the following, a summary of the proposed modelling approach and the results of the case study is presented (Section 6.1). Furthermore, conclusions of this dissertation are drawn in Section 6.2 and an outlook with respect to opportunities for further improvement of the modelling approach is given in Section 6.3.

6.1. Summary

Motivation

The German government declared the promotion of renewable energy as the cornerstone of its Energy Concept in 2010. Furthermore, in the aftermath of the nuclear incident in Fukushima, the government decided to accelerate the phase-out of nuclear power plants. With an increased penetration of renewable energies, especially fluctuating sources like wind and solar, the availability of sufficient generating capacity to cover the load demand at all times becomes an issue (system reliability). Furthermore, the integration of renewable energies and the remaining lifetime of nuclear power plants affect the electricity market and thus the electricity price as a fundamental determinant for industry and households. In addition, impacts on operating hours and electricity prices due to the integration of renewable energy and the remaining lifetime of nuclear power plants may pose challenges to the profitability of conventional power plant operation and investment (economic effectiveness). Finally, the integration of renewable energies and lifetime extension affect greenhouse gas emissions of the power sector (environmental benefits). System reliability, economic viability and environmental effectiveness condition each other and are therefore the key issues examined in this dissertation.

Many studies so far have investigated the impact of an increased promotion of renewable energies as well as of a potential lifetime extension or an accelerated phase-out of nuclear power plants on the energy system by considering different aspects of (short-term) power plant operation or the (long-term) development of the power plant fleet. If power plant operation is evaluated, assumptions are often made with regard to the decommissioning of power plants and the investment in new power plants. If the long-term development of the power sector is analysed, assumptions are often made with regard to future electricity prices and operating hours. However, power plant decommissioning, investment and operation are intrinsically linked and therefore need to be considered in an integrated manner.

Approach

This doctoral thesis presents a modelling framework for an integrated consideration of power plant decommissioning, investment and operation. The centrepiece of this dissertation is the development of the power plant investment model ELIAS (Electricity Investment Analysis). The most recent feature of ELIAS is the integration of a dynamic decommissioning rationale including mothballing and the option of retrofit measures as an alternative to new capacity investment. Furthermore, operating hours from a dispatch model are considered for power plant investment. The approach includes the coupling of ELIAS with the power plant dispatch model MICOES for consideration of feedback mechanisms between power plant decommissioning, investment and operation.

Case study

In a case study focusing on Germany, the effects of the integration of renewable energies on power plant decommissioning, investment and operation are evaluated against the background of the remaining lifetime of nuclear power plants. Two scenarios are compared: a phase-out scenario and a scenario with the lifetime extension of nuclear power plants. In order to identify the value added by the proposed modelling approach, two different decommissioning rationales are compared. With static decommissioning, it is assumed that power plants are decommissioned at the end of their technical or regulated lifetime. The feedback of power plant operation on investment is restricted to the influence on levelised costs of electricity (by considering operating hours in the investment decision). With dynamic decommissioning, power plant operation (and thus operating hours and electricity revenues) affects decommissioning, mothballing and retrofit and thus the need for investment. As for static decommissioning, power plant operation influences levelised costs of electricity.

Static Decommissioning

With static decommissioning, electricity generation from nuclear power plants is significantly higher with lifetime extension (in comparison to the situation without lifetime extension), which is compensated by decreasing fossil generation. Moreover, there are significantly less scarcity situations in which peaking generators and import are required, which improves system reliability. Furthermore, the electricity price is significantly lower (almost 50 €/MWh in 2030), which increases the economic attractiveness of electricity. Moreover, CO_2 emissions are significantly lower (more than 35 Mt CO_2 in 2030).

However, the static decommissioning rationale neglects important feedbacks between the power market and decommissioning since decommissioning is fixed exogenously. Both the electricity price (and thus electricity revenues) and operating hours of fossil-fired power plants are lower with lifetime extension. In consequence, the operation of a significant capacity of hard coal-fired power plants, but also natural gas-fired power plants is unprofitable with lifetime extension. What is more, with lifetime extension, natural gas-fired power plants currently under construction are unprofitable. From these considerations, it can be concluded that the assumption of static decommissioning is not consistent with the economic conditions of power plant operation.

Dynamic Decommissioning

With dynamic decommissioning, additional nuclear generation with lifetime extension is compensated by decreasing fossil-fired generation. Operating hours and electricity revenues of fossil power plants are lower in comparison to the scenario without lifetime extension. This leads to unprofitable operation of a significant capacity of hard coal-, lignite- and natural gas-fired power plants. In consequence, many lignite (up to 7 GW)[179] and hard coal (up to 4 GW) power plants are decommissioned in addition to the scenario without lifetime extension. Furthermore, a large number of power plants (up to 5 GW) are mothballed in addition to the scenario without lifetime extension, especially natural gas-fired, including power plants currently under construction. Retrofit takes place with and without lifetime extension, especially for lignite and hard coal power plants. However, with lifetime extension, fewer power plants are retrofitted and the extended lifetime is shorter. Due to increased decommissioning and mothballing as well as less retrofit with lifetime extension, many incumbent power plants are not available for operation. In consequence, with lifetime extension, additional capacity is needed to partly make up for the shortfall of incumbent capacity. Due to the lowest electricity generation costs, lignite-fired capacity is built. Without lifetime extension, no additional

[179] Depending on the scenario year.

capacity (besides the power plants currently under construction) is commissioned. The combination of these effects leads to a similar capacity being available with and without lifetime extension. In consequence, scarcity situations and the need for peaking generators do not differ significantly between the scenario with and without lifetime extension. The electricity price with lifetime extension is less than 20 €/MWh in 2030 lower than without lifetime extension. CO_2 emissions are lower with lifetime extension (more than 60 Mt CO_2 in 2030).

Comparison of Static and Dynamic Decommissioning

The static decommissioning rationale significantly underestimates capacity available for operation in the scenario without lifetime extension since retrofit measures (versus decommissioning) are not taken into account. Similarly, capacity available with lifetime extension is overestimated since mothballing (versus regular operation) is not considered. Whereas with static decommissioning, conventional capacity in operation is about 12 GW higher in 2030 with lifetime extension, in a dynamic approach, the difference is 6 GW in the same year. As a consequence, the electricity price reduction effect due to lifetime extension with dynamic decommissioning in comparison to static decommissioning is decreased by more than half. Similarly, scarcity situations as expressed by the need for imports do not differ significantly between the scenarios with and without lifetime extension with the dynamic decommissioning rationale, as opposed to a significantly higher need for imports without lifetime extension in the static decommissioning approach. The same holds true for the need for peaking units. What is more, with dynamic decommissioning, flexible natural gas-fired power plants mostly do not operate with lifetime extension, but are mothballed. Generally, with dynamic decommissioning, the scenario with lifetime extension features a higher share of lignite and nuclear power plants and a lower share of natural gas and hard coal power plants in comparison to the scenario without lifetime extension. Both scenarios (with and without lifetime extension) feature significant increases of exports, with higher values for lifetime extension. Export is slightly higher for dynamic decommissioning than for static decommissioning due to the fact that more lignite-fired power plants are in the system.

6.2. Conclusions

The application of the modelling approach to the case study shows that power plant operation has significant impacts on decommissioning, mothballing and investment, which in turn influences power plant operation. This dissertation therefore closes a methodological gap by providing a modelling approach for considering power plant decommissioning, investment and operation in an integrated manner. This is fundamental for addressing new energy challenges such as the integration of fluctuating renewable energy sources or the effects of an increased electrification of road transport. This enables power plant investors and policy makers alike to make more informed decisions regarding system reliability, economic effectiveness and environmental benefits. In this regard, the modelling approach provides a contribution to addressing the uncertainty regarding economic investment and operation of power plants and to considering long-term energy policy objectives and its feedbacks. More robust decisions can be taken with regard to avoiding unprofitable (stranded) investments and lock-in effects.

System reliability

The case study demonstrates that further system flexibility, such as grid extension or storage options, is fundamental for the integration of renewable energies. There are no significant differences with regard to the need for imports and exports between the scenario with and without lifetime extension. However, the share of flexible power plants (natural gas, hard coal) is higher with the accelerated phase-out and the share of baseload generators (nuclear, lignite) lower. It can therefore be concluded that the accelerated phase-out of nuclear power plants does not pose major additional challenges to system reliability, but may be beneficial due to the higher share of flexible power plants.

Economic effectiveness

With lifetime extension, the electricity price is reduced in comparison to the scenario without lifetime extension (by a maximum of 17 €/MWh) due to the availability of additional low-cost generating options (nuclear). However, the profitability of fossil-fired power plants is reduced due to decreasing operating hours and electricity revenues. This leads to an increased decommissioning (especially lignite and hard coal) and mothballing (especially natural gas) of power plants. This entails the risk that capital costs of these investments cannot be recovered.

Natural gas-fired power plants currently under construction remain mothballed for most of the scenario period with lifetime extension. It is therefore probable that these investments are not able to recover their capital costs and become stranded investments in this scenario.

Furthermore, due to the exacerbated decommissioning dynamics with lifetime extension, additional generation capacity is needed, which is covered by lignite-fired condensing power plants as the power plants with the lowest levelised costs of electricity. However, with further increases of renewable electricity generation and thus further decreasing profit margins of conventional power plants, and considering long depreciation periods, it is questionable whether capital costs of these power plants can be recovered.

It can therefore be concluded that the decommissioning dynamics as induced by lifetime extension are not synchronised with the build-up of renewable capacity. In this regard, repealing the lifetime extension and introducing an accelerated phase-out of nuclear power plants facilitates the integration of increasing shares of renewables in the power system.

Environmental benefits

CO_2 emissions are significantly lower with the lifetime extension of nuclear power plants (about 60 Mt). However, due to the integration of the German power sector in the EU Emissions Trading Scheme, overall CO_2 emissions are capped. Therefore additional emission reductions taking place in the power sector of one country are consumed elsewhere and there is no net reduction. Since long-term emission targets for the trading scheme are fixed, no additional climate mitigation benefits can be reaped with lifetime extension of nuclear power plants. What is more, with additional (emission-intensive) lignite-fired power plants commissioned with lifetime extension, long-term climate mitigation objectives may be jeopardised. In this regard, repealing the lifetime extension and introducing an accelerated phase-out of nuclear power plants does not lead to environmental disadvantages in the medium term, but may be beneficial in the long run since lock-in effects are avoided.

6.3. Outlook

The modelling approach could be further improved in a way to address new challenges of the energy system, such as regarding flexibility options or the future market design.

With regard to system flexibility, imports and exports in dispatch modelling could consider boundary conditions in greater detail. For instance, electricity exchange capacity with neighbouring countries could be included considering the market situation in each country. This would allow the costs and revenues of imports and exports to be determined in a more dynamic approach. Demand-side management measures including load management in industry and households, currently subsumed under 'import' and 'export', could also be included. Also, the dispatch rationale of storage options requires further research. Similarly, flexible technologies could be included as investment options in ELIAS.

Concerning the market design, the issue of the missing-money problem should be examined further. For instance, in the scenario with lifetime extension, additional lignite capacity is added. However, it is uncertain whether the spot market provides sufficient revenues for recovering the investment. Besides electricity revenues on the spot market, power plants may tap revenues on the operating reserve market. Corresponding revenues may become more important with an increased penetration of fluctuating renewable energy. Dispatch modelling could be further improved in such a way that both the spot and the operating reserve markets are integrated. A corresponding feedback of revenues to ELIAS would further improve the dynamic decommissioning rationale. Similarly, flexible technologies with low operating hours (e.g. gas turbines) are not competitive considering the levelised costs of electricity and are therefore not built under the model. Therefore, the ways in which corresponding revenues of technologies in operating reserve markets could be incorporated in the model should be examined in more depth, so that investments in these technologies can be made endogenously.

Discussion is ongoing on the potential establishment of capacity markets as a complement to the spot market. In what way these markets could be considered in the dispatch as well as in the decommissioning and investment rationale of power plants should be investigated. Similarly, further research is necessary on the (endogenous) consideration of storage options and grid extension in dispatch and investment modelling. In this regard, it should be evaluated how the current cost-based approach in ELIAS could be complemented so that revenues are also considered.

Moreover, capacity investments in ELIAS occur according to levelised costs of electricity considering a bandwidth of technologies to avoid penny-switching. This is generally a sensitive parameter. The corresponding uncertainty factor (κ) should be better verified based on empirical data. Furthermore, additional rationales for the investment decision should be examined.

Renewable electricity generation is currently defined exogenously. However, with more market-based approaches available, these could be incorporated both in the dispatch and the investment models. Relevant aspects to be examined include marginal generation costs of renewable generators or revenues by the provision of operating reserve capacity.

Retrofit costs are currently incorporated in ELIAS as an additional share of fixed operating costs. Due to the heterogeneity of retrofit measures, further research is required with regard to actual costs and the ensuing extension of lifetime.

Combined heat and power (CHP) power plants are currently considered as must-run power plants in MICOES (as a function of temperature). In a further development of the modelling approach, the dispatch rationale of CHP power plants may be enhanced in such a way that heat may either be provided by the CHP plant, by heat-only boilers or by renewable energy sources (e.g. using heat pumps). This would allow for a more endogenous treatment of CHP electricity generation and its feedbacks with the electricity and heat markets. Similarly, the corresponding investment rationale for CHP power plants could be improved in ELIAS.

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A. MICOES - Model Description

MICOES[180] is a model for optimisation of power plant dispatch used at the University of Leipzig, Germany. It is especially designed to reflect supply and demand decisions for short-term electricity contracts. The market for regulation reserve is incorporated in the model by restrictions. This enables spot prices on the German electricity exchange to be explained.

With regard to the mathematical implementation, MICOES is a mixed-integer model based on the GAMS programming language.

The input to the model stems from a database with fossil-fired power plants in operation in Germany (blockwise for a unit capacity greater than 100 MW, aggregates for smaller units). For each power plant, installed net capacity and electric efficiency are available (or estimated from literature). Furthermore, technical restrictions of thermal power plants such as minimum load, load change ratios, minimum downtime, minimum uptime, derived from literature, are incorporated in the model.

The objective of the model is the cost-optimal coverage of a given electricity demand. For this purpose, the residual load in Germany is used which is estimated by subtracting the feed-in of renewable energy sources (preferential feed-in) and (industrial) must-run generation from the load demand.

For meeting the electricity demand, power plants are dispatched according to their position in the so-called merit order. In this regard, marginal generation costs of power plants are a function of fuel costs, electric efficiency, costs for CO_2 allowances as well as other variable costs. However, MICOES goes beyond the approach of a mere merit order model by incorporating additional costs for bringing into service and shutting down power plants. The duration which a power plant has been shut down also influences the calculation of the costs for bringing the power plant into service.

In addition, all power plants must meet the above-mentioned technical restrictions at all times.

Electricity generation from CHP power plants is modelled as must-run electricity

[180] This model description is a translation (slightly adapted) of a corresponding document in German [Böttger, 2010]. A description of the development of MICOES at inception is available in [Theofilidi, 2008]. A recent application of the model is described in [Bruckner et al., 2010] and [Knopf et al., 2011].

generation as a function of ambient temperature.

Although MICOES is a national electricity market model, it includes exports and imports. During hours of peak load, electricity may be imported at a given electricity price. Similarly, during hours of low demand, electricity may be exported. Capacities for exports and imports correspond to German border transfer capacities.

As model output, hourly spot prices and, for each power plant, electricity generation, profit margin and CO_2 emissions are calculated.

B. Model data

Construction year	≤ 1960	> 1960 ≤ 1970	> 1970 ≤ 1980	> 1980 ≤ 1990	> 1990 ≤ 2000	> 2000
Fuel	Installed capacity (MW_{el})					
Hard coal	257	4.032	7.782	11.700	3.151	294
Lignite	541	3.475	6.059	3.410	4.032	3.158
Natural gas	97	140	7.119	1.621	5.865	8.115

Table B.1.: Vintage structure fossil-fired power plants in Germany, 2008 (Source: [Platts, 2009], [Statistisches Bundesamt, 2008], author's own calculations)

Technology	Blockwise	Aggregates - MW -	Total
Nuclear	20,486	0	20,486
Lignite	18,887	1,787	20,675
Condensing	16,776	1,198	17,974
CHP	2,112	589	2,701
Hard coal	25,619	1,597	27,217
Condensing	20,750	982	21,732
CHP	4,869	616	5,485
Natural gas	16,004	6,953	22,957
Steam cycle	3,635	374	4,009
Steam cycle - CHP	1,149	605	1,754
Combined cycle	3,132	146	3,278
Combined cycle - CHP	6,477	1,526	8,003
Gas turbine	473	1,117	1,591
Gas turbine - CHP	1,137	2,236	3,373
Light fuel oil	570	3,053	3,624
Steam cycle	143	707	849
Gas turbine	428	2,030	2,458
Heavy fuel oil	1,307	528	1,835
Other fuels	0	4,441	4,441
Waste (fossil)	0	1,110	1,110
Blast furnace gas	0	1,322	1,322
Renewables	0	43,936	43,936
Hydro	0	3,507	3,507
Pumped storage	0	6,494	6,494
Wind onshore	0	23,747	23,747
Solar	0	5,877	5,877
Geothermal	0	4	4
Solid biomass	0	1,587	1,587
Vegetable oil	0	409	409
Landfill gas	0	116	116
Biogas	0	1,406	1,406
Sewage gas	0	320	320
Mine gas	0	312	312
Waste (biogenic)	0	156	156
Total	82,874	62,296	145,170

Table B.2.: Structure of the power sector in Germany, 2008 (Source: [Platts, 2009]; [Statistisches Bundesamt, 2008], [Statistisches Bundesamt, 2010], [BMU, 2009], [FNR, 2007], author's own calculations)

Category	Emission factor ($t\ CO_2/TJ$)
Lignite	112
Hard coal	94
Natural gas	56
Light fuel oil	74
Heavy fuel oil	78
Coking gas	40
Refinery gas	60
Mine gas	55
Waste (fossil)	92

Table B.3.: CO_2 emission factors (Source: [Umweltbundesamt, 2010])

Parameter	Unit	NG CC CHP	Hard coal CHP (DH)	Reference
Electric capacity (P_{el})	MW	407	320	Table 5.9
Thermal capacity (P_{th})	MW	426	550	Table 5.9
Specific CO_2 emissions (e_{CO2})	g CO_2/kWh_{el}	410	796	Table 5.9
Operating hours (τ)	h/a	5.000	5.000	Model results
Share of CHP mode (χ_{CHP})	%	60	60	Table 5.9
Actual values				
Electricity production (W_{actual})	GWh	2,035	1,600	Calculated
Heat production(Q_{actual})	GWh	1,278	1,650	Calculated
CO_2 emissions ($E_{CO_2,actual}$)	1,000 t	834	1,274	Calculated
Values for allocation				
Operating hours ($\tau_{Standard}$)	h/a	7,500	7,500	[ZuG 2012, 2007]
Heat benchmark (BM_{th})	g CO_2/kWh_{th}	225	345	[ZuG 2012, 2007]
Heat production ($Q_{allocation}$)	GWh	3,195	4,125	Calculated
CO_2 allocation ($E_{allocated}$)	1,000 t	719	1,423	Calculated
Auctioning share ($\chi_{auctioning}$)	%	13.8	-11.7	Calculated

Table B.4.: Example calculation of the auctioning share for two CHP plants (Source: [ZuG 2012, 2007], author's own calculations)

C. Static Decommissioning

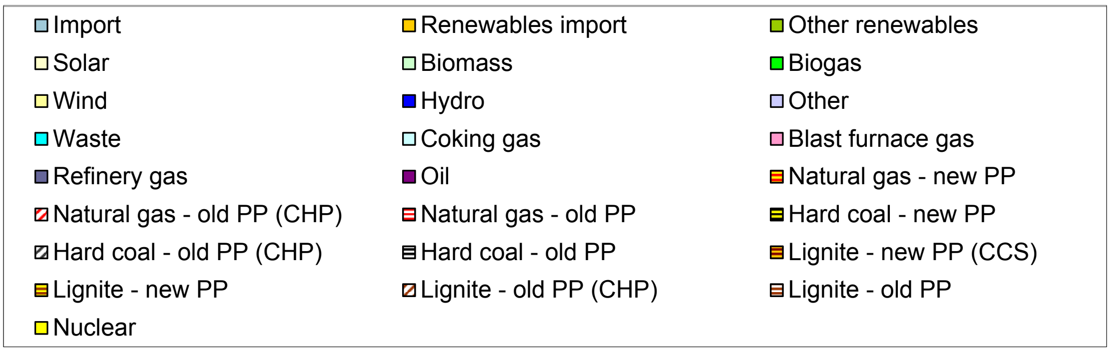

Figure C.1.: Legend of power plant types (Source: ELIAS)

	2008	2015	2020 h/a	2025	2030
Nuclear	6,782	7,281	7,261	7,230	
Lignite	6,730	6,534	6,518	6,524	6,115
new PP		6,971	6,934	6,968	6,584
incumbent PP	6,787	6,521	6,504	6,515	6,078
incumbent CHP PP	6,349	6,093	6,054	5,992	5,620
Hard coal	4,914	4,603	4,812	4,986	4,810
new PP		5,458	5,530	5,513	5,000
incumbent PP	4,951	4,288	4,534	4,784	4,707
incumbent CHP PP	4,767	4,550	4,676	4,740	4,590
Natural gas	3,047	3,277	3,779	4,366	4,636
new PP		4,508	4,781	5,091	5,218
incumbent PP	2,080	2,697	4,060	4,560	4,749
incumbent CHP PP	3,656	3,281	3,546	4,163	4,464

Table C.1.: Operating hours of conventional power plants without lifetime extension (static decommissioning) (woLTE_S), 2008-2030 (Source: MICOES model results, author's own aggregation)

Cost component	HC	LG	NG CC 800 MW	NG CC 400 MW	GT	HC CCS	LG CCS	NG CC 800 MW CCS
				- €/MWh -				
Capital costs	27.6	24.6	17.1	20.7	209.4	52.3	41.6	35.6
Fixed oper. costs	8.2	8.3	3.9	4.5	51.4	15.6	14.0	8.2
Variable oper. costs	2.0	2.3	0.5	0.5	0.5	3.5	3.8	0.9
Fuel costs	33.2	10.3	67.9	67.8	109.7	50.1	25	83.1
CO_2 costs	23.9	30.8	10.9	10.9	17.6	2.9	3.9	1.3
Heat credit	0	0	0	0	0	0	0	0
Avoided grid use	0	0	0	0	0	0	0	0
CHP bonus	0	0	0	0	0	0	0	0
LCOE	95.0	76.3	100.4	104.5	388.6	124.5	88.4	129.0

Table C.2.: Cost components and levelised costs of electricity (*LCOE*) of power plants (HC: hard coal, LG: lignite, NG: natural gas, CC: combined cycle, GT: gas turbine, CCS: carbon capture and storage) without lifetime extension (static decommissioning) (woLTE_S), 2020 (Source: ELIAS model results)

Cost component	NG CC 30 MW	NG CC 100 MW	NG CC 407 MW	HC - IND	HC - DH
			- €/MWh -		
Capital costs	36.9	21.4	28.6	82.9	82.9
Fixed operating costs	18.6	11.6	13.9	46.8	46.8
Variable operating costs	2.0	2.0	2.0	2.0	2.0
Fuel costs	102.3	91.9	85.6	46.4	36.8
CO_2 costs	15.1	13.8	12.4	29.4	24.5
Heat credit	-44.9	-37.0	-39.8	-57.8	-65.4
Avoided grid use	-5.0	-5.0	-5.0	-5.0	-5.0
CHP bonus	0	0	0	0	0
LCOE	125.0	98.8	97.7	144.7	122.7

Table C.3.: Cost components and levelised costs of electricity (*LCOE*) of CHP power plants (NG: natural gas, HC: hard coal, CC: combined cycle, IND: industry, DH: district heating) without lifetime extension (static decommissioning) (woLTE_S), 2020 (Source: ELIAS model results)

	2008	2015	2020	2025	2030
			- Mt CO_2 -		
Lignite	141.2	118.5	89.6	79.7	61.4
new PP	0	16.7	16.6	16.7	15.8
incumbent PP	124.1	88.3	60.6	50.8	34.1
incumbent CHP PP	17.0	13.5	12.4	12.2	11.5
Hard coal	112.1	97.5	90.9	81.5	47.5
new PP	0	23.0	23.3	23.2	21.1
incumbent PP	90.0	55.6	50.8	42.1	12.7
incumbent CHP PP	22.1	18.9	16.8	16.1	13.8
Natural gas	30.7	24.5	24.4	23.5	22.2
new PP	0	2.8	2.9	3.1	3.2
incumbent PP	7.8	4	3.9	4.3	4.5
incumbent CHP PP	22.9	17.7	17.5	16	14.5
Renewables	1.0	1.0	0.9	0.9	0.9
Other	20.3	18.9	20.3	21.8	24.2
Total	305.2	260.3	226.1	207.4	156.2

Table C.4.: CO_2 emissions without lifetime extension (static decommissioning) (woLTE_S), 2008-2030 (Source: ELIAS model results)

	2008	2015	2020 - GW -	2025	2030
Nuclear	20.5	13.4	8.1	1.3	0
Lignite	20.7	19.0	14.8	13.4	11.1
new PP	0	2.8	2.8	2.8	2.8
incumbent PP	18.0	13.9	9.9	8.4	6.2
incumbent CHP PP	2.7	2.3	2.2	2.2	2.2
Hard coal	27.2	27.4	24.7	21.6	13.5
new PP	0	6.3	6.3	6.3	6.3
incumbent PP	21.7	16.1	14.1	11.2	3.5
incumbent CHP PP	5.5	5.0	4.4	4.2	3.7
Natural gas	23.0	18.9	16.6	14.4	13.1
new PP	0	2.0	2.0	2.0	2.0
incumbent PP	8.9	4.2	2.8	2.8	2.7
incumbent CHP PP	14.1	12.7	11.8	9.6	8.4
Renewables	43.8	79.5	105.4	125.3	145.0
Other	10.1	10.7	10.8	10.7	10.7
Total	145.3	168.9	180.6	186.7	193.6

Table C.5.: Net electric capacity without lifetime extension (static decommissioning) (woLTE_S), 2008-2030 (Source: ELIAS model results)

	2008	2015	2020 h/a	2025	2030
Nuclear	6,782	7,143	7,038	6,879	6,374
Lignite	6,730	6,067	5,269	5,179	4,694
new PP		6,603	6,126	5,886	5,249
incumbent PP	6,787	6,013	5,072	5,031	4,547
incumbent CHP PP	6,349	5,748	5,071	4,850	4,407
Hard coal	4,914	3,778	3,461	3,693	3,707
new PP		4,835	4,352	4,254	3,873
incumbent PP	4,951	3,311	2,973	3,347	3,458
incumbent CHP PP	4,767	3,959	3,754	3,778	3,664
Natural gas	3,047	2,581	2,794	3,190	3,345
new PP		3,934	3,748	3,958	3,990
incumbent PP	2,080	2,135	2,947	3,282	3,386
incumbent CHP PP	3,656	2,520	2,598	3,007	3,182

Table C.6.: Operating hours of conventional power plants with lifetime extension (static decommissioning) (wLTE_S), 2008-2030 (Source: MICOES model results, author's own aggregation.)

Cost component	HC	LG	NG CC 800 MW	NG CC 400 MW	GT	HC CCS	LG CCS	NG CC 800 MW CCS
				- €/MWh -				
Capital costs	35.6	29.5	22.1	20.7	209.4	52.3	41.6	35.6
Fixed oper. costs	10.6	9.9	5.1	4.5	51.4	15.6	14.0	8.2
Variable oper. costs	2.0	2.3	0.5	0.5	0.5	3.5	3.8	0.9
Fuel costs	33.2	10.3	67.9	67.8	109.7	50.1	25	83.1
CO_2 costs	23.9	30.7	10.9	10.9	17.6	2.9	3.9	1.3
Heat credit	0	0	0	0	0	0	0	0
Avoided grid use	0	0	0	0	0	0	0	0
CHP bonus	0	0	0	0	0	0	0	0
LCOE	105.2	82.8	106.5	104.5	388.6	124.5	88.4	129.0

Table C.7.: Cost components and levelised costs of electricity (*LCOE*) of fossil-fired power plants (HC: hard coal, LG: lignite, NG: natural gas, CC: combined cycle, GT: gas turbine, CCS: carbon capture and storage) with lifetime extension (static decommissioning) (wLTE_S)), 2020 (Source: ELIAS model results)

Cost component	NG CC 30 MW	NG CC 100 MW	NG CC 407 MW	HC - IND	HC - DH
			- €/MWh -		
Capital costs	36.9	21.4	28.6	82.9	82.9
Fixed oper. costs	18.6	11.6	13.9	46.8	46.8
Variable oper. costs	2.0	2.0	2.0	2.0	2.0
Fuel costs	102.3	91.9	85.6	46.4	36.8
CO_2 costs	15.1	13.8	12.4	29.4	24.5
Heat credit	-44.9	-37.0	-39.8	-57.8	-65.4
Avoided grid use	-5.0	-5.0	-5.0	-5.0	-5.0
CHP bonus	0	0	0	0	0
LCOE	125.0	98.8	97.7	144.7	122.7

Table C.8.: Cost components and levelised costs of electricity (*LCOE*) of CHP power plants (NG: natural gas, HC: hard coal, CC: combined cycle, IND: industry, DH: district heating) with lifetime extension (static decommissioning) (wLTE_S)), 2020 (Source: ELIAS model results)

	2008	2015	2020	2025	2030
			- Mt CO_2 -		
Lignite	141.2	109.9	72.0	63.2	47.1
new PP	0	15.8	14.7	14.1	12.6
incumbent PP	124.1	81.4	47.0	39.2	25.5
incumbent CHP PP	17.0	12.7	10.4	9.9	9.0
Hard coal	112.1	79.4	65.0	60.2	36.6
new PP	0	20.4	18.3	17.9	16.3
incumbent PP	90.0	42.7	33.2	29.4	9.3
incumbent CHP PP	22.1	16.3	13.4	12.8	11.0
Natural gas	30.7	19.3	18.0	17.0	15.9
new PP	0	2.4	2.3	2.4	2.5
incumbent PP	7.8	3.1	2.8	3.0	3.2
incumbent CHP PP	22.9	13.8	12.9	11.5	10.3
Renewables	1.0	1.0	0.9	0.9	0.9
Other	20.3	18.0	18.2	18.8	20.1
Total	305.2	227.6	174.2	160.1	120.7

Table C.9.: CO_2 emissions with lifetime extension (static decommissioning) (wLTE_S), 2008-2030 (Source: ELIAS model results)

	2008	2015	2020	2025	2030
			- GW -		
Nuclear	20.5	20.5	19.6	13.4	12.2
Lignite	20.7	19.0	14.8	13.4	11.2
new PP	0	2.8	2.8	2.8	2.8
incumbent PP	18.0	13.9	9.9	8.4	6.2
incumbent CHP PP	2.7	2.3	2.2	2.2	2.2
Hard coal	27.2	27.4	24.7	21.6	13.6
new PP	0	6.3	6.3	6.3	6.3
incumbent PP	21.7	16.1	14.1	11.2	3.5
incumbent CHP PP	5.5	5.0	4.4	4.2	3.8
Natural gas	23.0	18.9	16.6	14.4	13.1
new PP	0	2.0	2.0	2.0	2.0
incumbent PP	8.9	4.2	2.8	2.8	2.7
incumbent CHP PP	14.1	12.7	11.8	9.6	8.4
Renewables	43.8	79.5	105.4	125.3	145.1
Other	10.1	10.7	10.8	10.7	10.7
Total	145.3	176.0	192.1	198.9	205.8

Table C.10.: Net electric capacity with lifetime extension (static decommissioning) (wLTE_S), 2008-2030 (Source: ELIAS model results)

	2015		2020		2025		2030	
	wo	w	wo	w	wo	w	wo	w
	- GW -							
Profitable	44.5	23.4	37.3	33.0	33.0	33.0	23.1	23.1
Lignite	16.6	16.6	12.7	12.7	11.2	11.2	9.0	9.0
Hard coal	22.4	6.7	20.3	20.3	17.4	17.4	9.8	9.8
Natural gas	5.5	0	4.4	0	4.4	4.4	4.3	4.3
Unprofitable	0	21.2	0	4.3	0	0	0	0
Lignite	0	0	0	0	0	0	0	0
Hard coal	0	15.6	0	0	0	0	0	0
Natural gas	0	5.5	0	4.3	0	0	0	0
Lignite (I, profitable)	13.9	13.9	9.9	9.9	8.4	8.4	6.2	6.2
Lignite (I, unprofitable)	0	0	0	0	0	0	0	0
Lignite (N, profitable)	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Lignite (N, unprofitable)	0	0	0	0	0	0	0	0
Hard coal (I, profitable)	16.1	0.5	14.1	14.1	11.2	11.2	3.6	3.6
Hard coal (I, unprofitable)	0	15.6	0	0	0	0	0	0
Hard coal (N, profitable)	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Hard coal (N, unprofitable)	0	0	0	0	0	0	0	0
Natural gas (I, profitable)	3.5	0	2.4	0	2.4	2.4	2.4	2.4
Natural gas (I, unprofitable)	0	3.6	0	2.3	0	0	0	0
Natural gas (N, profitable)	2.0	0	2.0	0	2.0	2.0	2.0	2.0
Natural gas (N, unprofitable)	0	2.0	0	2.0	0	0	0	0

Table C.11.: Profitability of fossil-fired electric power plants (I: incumbent, N: new) and electricity price with and without lifetime extension (static decommissioning) (wLTE_S (w), woLTE_S (wo)), 2015-2030 (Source: ELIAS model results)

D. Dynamic Decommissioning

	2008	2015	2020 h/a	2025	2030
Nuclear	6,782	7,258	7,225	7,217	
Lignite	6,730	6,303	5,948	5,798	4,971
new PP		6,896	6,834	6,902	6,426
incumbent PP	6,787	6,251	5,798	5,611	4,688
incumbent CHP PP	6,349	5,999	5,924	5,774	5,231
Hard coal	4,914	3,838	4,066	3,975	3,410
new PP		5,026	4,870	4,686	4,047
incumbent PP	4,951	3,401	3,697	3,660	3,138
incumbent CHP PP	4,767	4,076	4,105	3,976	3,369
Natural gas	3,047	2,728	2,941	3,210	2,753
new PP		3,836	3,961	3,894	3,239
incumbent PP	2,080	2,066	2,168	3,265	2,626
incumbent CHP PP	3,656	2,777	2,957	3,056	2,682

Table D.1.: Operating hours of conventional power plants without lifetime extension (dynamic decommissioning) (woLTE_D), 2008-2030 (Source: MICOES model results, author's own aggregation)

Cost component	HC	LG	NG CC 800 MW	NG CC 400 MW	GT	HC CCS	LG CCS	NG CC 800 MW CCS
				- €/MWh -				
Capital costs	32.9	24.4	23.7	20.7	209.4	52.3	41.6	35.6
Fixed oper. costs	9.8	8.2	5.4	4.5	51.4	15.6	14	8.2
Variable oper. costs	2.0	2.3	0.5	0.5	0.5	3.5	3.8	0.9
Fuel costs	33.1	10.3	67.4	67.8	109.7	50.1	25	83.1
CO_2 costs	23.9	30.8	10.9	10.9	17.6	2.9	3.9	1.3
Heat credit	0	0	0	0	0	0	0	0
Avoided grid use	0	0	0	0	0	0	0	0
CHP bonus	0	0	0	0	0	0	0	0
LCOE	101.7	76.0	108.0	104.5	388.6	124.5	88.4	129.0

Table D.2.: Cost components and levelised costs of electricity ($LCOE$) of fossil-fired power plants (HC: hard coal, LG: lignite, NG: natural gas, CC: combined cycle, GT: gas turbine, CCS: carbon capture and storage) without lifetime extension (dynamic decommissioning) (woLTE_D)), 2020 (Source: ELIAS model results)

Cost component	NG CC 30 MW	NG CC 100 MW	NG CC 407 MW	HC - IND	HC - DH
			- €/MWh -		
Capital costs	36.9	21.4	28.6	82.9	82.9
Fixed oper. costs	18.6	11.6	13.9	46.8	46.8
Variable oper. costs	2.0	2.0	2.0	2.0	2.0
Fuel costs	102.3	91.9	85.6	46.4	36.8
CO_2 costs	15.1	13.8	12.4	29.4	24.5
Heat credit	-44.9	-37.0	-39.8	-57.8	-65.4
Avoided grid use	-5.0	-5.0	-5.0	-5.0	-5.0
CHP bonus	0	0	0	0	0
LCOE	125.0	98.8	97.7	144.7	122.7

Table D.3.: Cost components and levelised costs of electricity (*LCOE*) of CHP power plants (NG: natural gas, HC: hard coal, CC: combined cycle, IND: industry, DH: district heating) without lifetime extension (dynamic decommissioning) (woLTE_D)), 2020 (Source: ELIAS model results)

	2008	2015	2020	2025	2030
			- Mt CO_2 -		
Nuclear	0	0	0	0	0
Lignite	141.2	143.7	134.3	130.7	111.1
new PP	0	16.5	18.2	18.4	17.1
incumbent PP	124.1	114.0	104.0	100.6	83.3
incumbent CHP PP	17.0	13.2	12.1	11.8	10.7
Hard coal	112.1	92.8	76.8	74.4	62.4
new PP	0	21.2	20.5	19.8	17.1
incumbent PP	90.0	54.8	41.5	41.1	35.2
incumbent CHP PP	22.1	16.8	14.7	13.5	10.1
Natural gas	30.7	20.4	19.1	17.1	13.1
new PP	0	2.4	2.4	2.4	2.0
incumbent PP	7.8	3.0	2.1	3.0	2.4
incumbent CHP PP	22.9	15.1	14.6	11.7	8.7
Renewables	1.0	1.0	0.9	0.9	0.9
Other	20.3	18.0	18.7	18.7	18.3
Total	305.2	275.9	249.8	241.8	205.8

Table D.4.: CO_2 emissions without lifetime extension (dynamic decommissioning) (woLTE_D), 2008-2030 (Source: ELIAS model results)

	2008	2015	2020	2025	2030
			- GW -		
Nuclear	20.5	13.4	8.2	1.3	0
Lignite	20.7	23.1	23.1	23.1	23.1
new PP	0	2.8	3.1	3.1	3.1
incumbent PP	18.0	18.0	17.8	17.8	17.8
incumbent CHP PP	2.7	2.3	2.2	2.2	2.2
Hard coal	27.2	31.0	24.8	24.6	24.1
new PP	0	6.3	6.3	6.3	6.3
incumbent PP	21.7	19.8	14.1	14.1	14.1
incumbent CHP PP	5.5	5.0	4.4	4.2	3.8
Natural gas	23.0	18.9	16.6	14.4	13.1
new PP	0	2.0	2.0	2.0	2.0
incumbent PP	8.9	4.2	2.8	2.8	2.7
incumbent CHP PP	14.1	12.7	11.8	9.7	8.4
Renewables	43.8	79.5	105.4	125.3	145.1
Other	10.1	10.7	10.8	10.7	10.7
Total	145.3	176.7	188.9	199.4	216.1

Table D.5.: Net electric capacity without lifetime extension (dynamic decommissioning) (woLTE_D), 2008-2030 (Source: ELIAS model results)

	2008	2015	2020	2025	2030
			- Mt CO_2 -		
Nuclear	0	0	0	0	0
Lignite	141.2	132.0	91.7	91.3	70.6
new PP	0	15.7	29.0	37.9	35.4
new PP (CCS)	0	0	0	0	0.3
incumbent PP	124.1	103.7	52.4	44.1	27.6
incumbent CHP PP	17.0	12.6	10.3	9.3	7.4
Hard coal	112.1	73.2	58.8	55.1	45.7
new PP	0	19.1	17.1	15.5	13.4
incumbent PP	90.0	38.6	28.9	28.2	23.9
incumbent CHP PP	22.1	15.4	12.7	11.4	8.4
Natural gas	30.7	15.7	13.4	10.2	7.1
new PP	0	2.1	0	0	0
incumbent PP	7.8	1.7	0.1	0.1	0.1
incumbent CHP PP	22.9	11.9	13.3	10.1	7.1
Renewables	1.0	1.0	0.9	0.9	0.9
Other	20.3	17.8	18.4	18.1	17.9
Total	305.2	239.7	183.2	175.6	142.2

Table D.6.: CO_2 emissions with lifetime extension (dynamic decommissioning) (wLTE_D), 2008-2030 (Source: ELIAS model results)

	2008	2015	2020	2025	2030
			- GW -		
Nuclear	20.5	20.5	19.6	13.5	12.2
Lignite	20.7	23.1	18.9	21.2	23.0
new PP	0	2.8	5.6	8.0	9.3
new PP (CCS)	0	0	0	0	0.4
incumbent PP	18.0	18.0	11.1	11.1	11.1
incumbent CHP PP	2.7	2.3	2.2	2.2	2.2
Hard coal	27.2	27.4	24.7	23.2	22.8
new PP	0	6.3	6.3	6.3	6.3
incumbent PP	21.7	16.1	14.1	12.7	12.7
incumbent CHP PP	5.5	5.0	4.4	4.2	3.8
Natural gas	23.0	18.9	16.6	14.4	13.2
new PP	0	2.0	2.0	2.0	2.0
incumbent PP	8.9	4.2	2.8	2.8	2.7
incumbent CHP PP	14.1	12.7	11.8	9.7	8.5
Renewables	43.8	79.5	105.5	125.3	145.1
Other	10.1	10.7	10.8	10.7	10.7
Total	145.3	180.1	196.2	208.4	226.9

Table D.7.: Net electric capacity with lifetime extension (dynamic decommissioning) (wLTE_D), 2008-2030 (Source: ELIAS model results)

	2015		2020		2025		2030	
	wo	w	wo	w	wo	w	wo	w
	- GW -							
Profitable	28.0	17.2	44.8	35.7	45.6	38.1	45.5	24.6
Lignite	20.7	17.2	20.9	16.7	20.9	19.1	20.8	16.8
Hard coal	7.3	0	20.3	19.0	20.3	19.0	20.3	7.8
Natural gas	0	0	3.6	0	4.4	0	4.3	0
Unprofitable	24.3	31.4	0.8	5.7	0	4.3	0.1	19.5
Lignite	0.1	3.5	0	0	0	0	0.1	4.0
Hard coal	18.7	22.4	0	1.4	0	0	0	11.2
Natural gas	5.5	5.5	0.8	4.3	0	4.3	0	4.3
Lignite (I, profitable)	17.9	14.4	17.8	11.1	17.8	11.1	17.7	7.0
Lignite (I, unprofitable)	0.1	3.5	0	0	0	0	0.1	4.0
Lignite (N, profitable)	2.8	2.8	3.1	5.6	3.1	8.0	3.1	9.7
Lignite (N, unprofitable)	0	0	0	0	0	0	0	0
Hard coal (I, profitable)	1.1	0	14.1	12.7	14.1	12.7	14.1	1.5
Hard coal (I, unprofitable)	18.7	16.1	0	1.4	0	0	0	11.2
Hard coal (N, profitable)	6.3	0	6.3	6.3	6.3	6.3	6.3	6.3
Hard coal (N, unprofitable)	0	6.3	0	0	0	0	0	0
Natural gas (I, profitable)	0	0	1.6	0	2.4	0	2.4	0
Natural gas (I, unprofitable)	3.6	3.6	0.8	2.4	0	2.3	0	2.3
Natural gas (N, profitable)	0	0	2.0	0	2.0	0	2.0	0
Natural gas (N, unprofitable)	2.0	2.0	0	2.0	0	2.0	0	2.0

Table D.8.: Profitability of fossil-fired electric power plants (I: incumbent, N: new) and electricity price with and without lifetime extension (dynamic decommissioning) (wLTE_D (w), woLTE_D (wo)), 2015-2030 (Source: ELIAS model results)

	2015		2020		2025		2030	
	woLTE	wLTE	woLTE	wLTE	woLTE	wLTE	woLTE	wLTE
	- GW -							
Incumbent	0	1.2	0.8	3.7	0	2.3	0	2.3
Lignite	0	0	0	0	0	0	0	0
Hard coal	0	0	0	1.4	0	0	0	0
Natural gas	0	1.2	0.8	2.4	0	2.3	0	2.3
New	0	0	0	2.0	0	2.0	0	2.0
Lignite	0	0	0	0	0	0	0	0
Hard coal	0	0	0	0	0	0	0	0
Natural gas	0	0	0	2.0	0	2.0	0	2.0

Table D.9.: Mothballed capacity of fossil-fired electric power plants with and without lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D)), 2008-2030 (Source: ELIAS model results)

	≤ 5 years		6-10 years		11-15 years		16-20 years		> 20 years	
	wo	w	wo	w	wo	w	wo	w	wo	w
	- GW -									
Total	18.1	16.0	5.6	6.2	3.6	1.5	1.9	0.2	1.7	0.1
Lignite	2.2	5.6	2.6	4.6	3.4	1.3	1.9	0.2	1.7	0.1
Hard coal	14.8	10.4	3.0	1.6	0.1	0.1	0	0	0	0
Natural gas	1.1	0	0	0	0.1	0.1	0	0	0	0

Table D.10.: Retroffited capacity and length of retrofitted lifetime of fossil-fired electric power plants with and without lifetime extension (dynamic decommissioning) (wLTE_D (w), woLTE_D (wo)) (Source: ELIAS model results)

	2015		2020		2025		2030	
	wo	w	wo	w	wo	w	wo	w
	- GW -							
Lignite	0	0	0.1	6.9	0.1	6.9	0.1	6.9
Hard coal	2.0	5.6	7.6	7.7	7.6	9.0	7.6	9.0
Natural gas	3.7	3.7	4.9	4.9	4.9	4.9	4.9	4.9

Table D.11.: Decommissioned capacity of fossil-fired electric power plants with and without lifetime extension (dynamic decommissioning) (wLTE_S (w), woLTE_S (wo)), 2015-2030 (Source: ELIAS model results)

	2008	2015		2020		2025		2030	
		wo	w	wo	w	wo	w	wo	w
Nuclear - regular operation	20.5	13.4	20.5	8.2	19.6	1.3	13.4	0	12.2
Nuclear - decommissioned	0	7.0	0	12.3	0.9	19.2	7.0	20.5	8.3
Lignite - regular operation	16.4	13.9	13.9	9.9	9.9	8.4	8.4	6.2	6.2
Lignite - retrofit	1.5	4.1	4.1	7.9	1.2	9.4	2.6	11.6	4.8
Lignite - mothballed capacity	0	0	0	0	0	0	0	0	0
Lignite - decommissioned	0	0	0	0.1	6.9	0.1	6.9	0.1	6.9
Hard coal - regular operation	20.9	16.1	16.1	14.1	12.7	11.2	11.2	3.6	3.6
Hard coal - retrofit	0.8	3.7	0	0	0	2.9	1.5	10.5	9.2
Hard coal - mothballed capacity	0	0	0	0	1.4	0	0	0	0
Hard coal - decommissioned	0	2.0	5.6	7.6	7.7	7.6	9.0	7.6	9.0
Natural gas - regular operation	7.2	3.6	2.4	1.6	0	2.4	0	2.4	0
Natural gas - retrofit	0.1	0	0	0	0	0	0	0	0
Natural gas - mothballed capacity	0	0	1.2	0.8	2.4	0	2.3	0	2.3
Natural gas - decommissioned	0	3.7	3.7	4.9	4.9	4.9	4.9	4.9	4.9

Table D.12.: Overview of the capacity of incumbent electric power plants according to operational state (regular operation, retrofitted, mothballed, decommissioned) with (w) and without (wo) lifetime extension (dynamic decommissioning) (wLTE_D, woLTE_D), 2008-2030 (Source: ELIAS model results)

	2015		2020		2025		2030	
	- GW -							
	wo	w	wo	w	wo	w	wo	w
Total	176.7	178.9	188.0	190.3	199.2	203.8	216.0	222.4
Incumbent	119.3	121.4	93.1	94.9	68.6	70.2	61.3	63.0
Conventional	75.4	77.6	60.5	62.3	52.1	53.7	49.0	50.7
Nuclear	13.4	20.5	8.2	19.6	1.3	13.4	0	12.2
Lignite	18.0	18.0	17.8	11.1	17.8	11.1	17.8	11.0
Hard coal	19.8	16.1	14.1	12.7	14.1	12.7	14.1	12.7
Natural gas	3.6	2.4	1.6	0	2.4	0	2.4	0
Renewable	40.8	40.8	30.4	30.4	15.1	15.1	11.1	11.1
Must run/other	3.0	3.0	2.2	2.2	1.5	1.5	1.2	1.2
New	57.4	57.4	94.9	95.4	130.6	133.6	154.7	159.4
Conventional	11.0	11.0	11.3	11.9	11.3	14.2	11.3	16.0
Lignite	2.8	2.8	3.1	5.6	3.1	8.0	3.1	9.7
Hard coal	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Natural gas	2.0	2.0	2.0	0	2.0	0	2.0	0
Renewable	39.4	39.4	75.8	75.8	111.0	111.0	134.7	134.7
Must run/other	7.0	7.0	7.8	7.8	8.3	8.3	8.6	8.6

Table D.13.: Capacity of electric power plants in operation with and without lifetime extension (dynamic decommissioning) (wLTE_D (w), woLTE_D (wo)), 2008-2030 (Source: ELIAS model results)