Decarbonizing the European Electricity Sector

Modeling and Policy Analysis for Electricity and CO_2 Infrastructure Networks

Dissertation

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Abstract

This dissertation uses three models to analyze different decarbonization strategies for combating global climate change: The cost minimizing mixed-integer model *CCTS-Mod* examines the economics of Carbon Capture, Transport, and Storage (CCTS) for the electricity and industry sector; the welfare maximizing quadratically constrained model *ELMOD* focuses on different trajectories for renewable energy sources (RES) and transmission grid expansions; and the equilibrium model *ELCO* combines the insights of the individual sectors to a combined CCTS and electricity investment and dispatch model.

Modeling results show that an investment in CCTS is beneficial for the iron and steel sector once the CO_2 certificate price exceeds 50 €/t CO_2. The threshold is 75 €/t CO_2 for the cement industry and 100 €/t CO_2 for the electricity sector. Additional revenues from using CO_2 for enhanced oil recovery (CO_2-EOR) lead to an earlier adoption of CCTS in the North Sea region. The lack of economies of scale results in increasing CO_2 storage costs of more than 30%, while transport costs even double. Research from the last years, however, indicates that CCTS is unlikely to play an important role in decarbonizing the electricity sector. The identified reasons for this are incumbents' resistance to structural change, wrong technology choices, over-optimistic cost estimates, a premature focus on energy projects instead of industry, and the underestimation of transport and storage issues.

Keeping global temperature rise below 2°C therefore implies the phase-out of fossil-fueled power plants and, in particular, of CO_2-intensive coal power plants. The low CO_2 price established by the European Emissions Trading Scheme is insufficient to induce a fuel switch in the medium term. Therefore, supplementary national measures are necessary to reduce coal-based power generation; i.a. feed-in tariffs for RES, minimum CO_2 prices, or emissions performance standards. Analyses for Germany show that a coal phase-out before 2040 is possible without risking resource adequacy at any point. Enabling a smooth transition encourages other countries to take the German Energiewende as a blueprint to combat global warming, even if this implies a coal phase-out.

Keywords: Carbon capture, CCS, CCTS, coal, CO_2, decarbonization, Energiewende, energy economics, electricity, mixed complementarity problem (MCP), modeling, policy analysis

Zusammenfassung

Die vorliegende Arbeit untersucht und quantifiziert mit Hilfe drei verschiedener Modelltypen den möglichen Beitrag verschiedener Dekarbonisierungsoptionen: Das gemischt-ganzzahlige Modell *CCTS-Mod* berechnet, welchen Beitrag die Vermeidungstechnologie der CO_2-Abscheidung, -Transport und -Speicherung (engl. carbon capture, transport, and storage, CCTS) im Stromsektor und in der Industrie erzielen kann; das Strommarktmodell *ELMOD* quantifiziert die Impliaktionen verschiedener Ausbaupfade erneuerbarer Energien (EE) und den hierfür benötigten Stromleitungsausbau; und das Modell *ELCO* verknüpft die Erkenntnisse des Strommarktes und der CCTS Technologie in einem Gleichgewichtsmodell.

Modellergebnisse zeigen, dass CCTS in der Industrie eine mögliche Dekarbonisierungsoption darstellt, da sie sich im Stahlsektor bereits ab CO_2-Zertifikatspreisen von 50 €/t CO_2 und im Zementsektor bereits ab 75 €/t CO_2 lohnt. Für den Stromsektor hingegen rentiert sich der Einsatz von CCTS erst ab CO_2-Preisen jenseits von 100 €/t CO_2. Zwar kann die Wirtschaftlichkeit in Einzelfällen durch die Nutzung der CO_2-EOR (enhanced oil recovery) Technologie gesteigert werden. Der Verlust von Skaleneffekten führt allerdings zu einer Steigerung der CO_2-Speicherkosten um 30% sowie zu einer Verdopplung der Transportkosten. Die Erfahrungen der letzten Jahre stellen daher in Frage, ob CCTS für den Stromsektor eine relevante Dekarbonisierungsoption darstellt. Die Gründe hierfür sind u.a. fehlende Anreize für betroffene Akteure, falsche Technologieauswahl, zu optimistische Kostenschätzungen, der Fokus auf Kraftwerke an Stelle von Industrieanlagen sowie die Vernachlässigung von Transport- und Speicherproblematiken.

Ohne die Verfügbarkeit dieser Technologie ist zur Einhaltung der vereinbarten Klimaschutzziele deshalb ein Austieg aus der Kohleverstromung mittelfristig notwendig. Da der europäische Emissionshandel hierfür als alleiniges Instrument nicht ausreichend ist, werden auch in Zukunft nationale Zusatzmaßnahmen wie die Förderung von EE, ein möglicher CO_2-Mindestpreis oder CO_2-Grenzwerte notwendig sein. Analysen für Deutschland zeigen, dass ein solcher Kohleausstieg bis 2040 ohne Strukturbrüche und sozialverträglich möglich ist.

Schlüsselwörter: CCS, CCTS, CO_2-Abscheidung, CO_2, Dekarbonisierung, Energiewende, Energiewirtschaft, Kohle, Mixed Complementarity Problem (MCP), Modellierung, Politikanalyse

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Thank you for everything!

Rechtliche Erklärung

Hiermit versichere ich, dass ich die vorliegende Dissertation selbstständig und ohne unzulässige Hilfsmittel verfasst habe. Die verwendeten Quellen sind vollständig im Literaturverzeichnis angegeben. Die Arbeit wurde noch keiner Prüfungsbehörde in gleicher oder ähnlicher Form vorgelegt.

Berlin, 3. März 2016 Pao-Yu Charly Robin Oei

Overview

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List of Abbreviations

CCS	Carbon Capture and Storage
CCTS	Carbon Capture, Transport, and Storage
CCU	Carbon Capture and Usage
CDM	Clean Development Mechanism
CfD	Contracts for Differences
CM	Capacity Market
CPF	Carbon Price Floor
CPS	Carbon Price Support
CO	Carbon monoxide
CO_2	Carbon dioxide
DC	Direct current
DCLF	Direct current loadflow model
DIW Berlin	German Institute for Economic Research (German: Deutsches Institut für Wirtschaftsfoschung)
DOGF	Depleted oil and gas fields
DSM	Demand-side management
EC	European Commission
EEPR	European Energy Program for Recovery
EEX	European energy exchange
EMF	Stanford Energy Modeling Forum
EMR	Electricity Market Reform
ENTSO-E	European Network of Transmission System Operators for Electricity
EP	European Parliament
EPEC	Equilibrium Problems with Equilibrium Constraints
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
EPS	Emissions performance standard
ETS	Emissions Trading System
EU	European Union
EUA	EU-ETS allowances
FLH	Full load hour
GAMS	General Algebraic Modeling System

GHG	Greenhouse gas
Gt	Gigaton
GW	Gigawatt
GWh	Gigawatt hour
h	Hour
IAM	Integrated Assessment Models
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
JI	Joint Implementation
KKT	Karush-Kuhn-Tucker
kW	Kilowatt
kWh	Kilowatt hour
Lcoe	Levelized cost of electricity
LP	Linear Problem
MCP	Mixed Complementarity Problem
MIP	Mixed Integer Problem
mn	Million
MPEC	Mathematical Program/Problem with Equilibrium Constraints
MSR	Market Stability Reserve
MW	Megawatt
MWh	Megawatt hour
Mt	Million t
NEP	Grid Development Plan (German: Netzentwicklungsplan)
NER300	New Entrance Reserve
NIMBY	Not in my backyard
NGO	Non-governmental organization
NLP	Non-Linear Problem
NO_x	Nitrogen oxide
NPV	Net present value
NREAP	National renewable energy action plan
NRW	Northrhine Westphalia
NTC	Net transfer capacity
O_2	Oxygen

OCGT	Open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
OPEX	Operating expenditure
O&M	Operation and management
ppm	parts per million
PTDF	Power transfer distribution factor
PV	Photovoltaics
QCP	Quadratically Constrained Problem
RE	Renewable energies
RES	Renewable energy sources
ROI	Return on investment
ROW	Right of way
R&D	Research and development
SDG	Sustainable development goals
SO_2	Sulfur dioxide
SRU	German Advisory Council on the Environment (German: Sachverständigenrat für Umweltfragen)
t	Ton
trn	Trillion
TSO	Transmission system operator
TWh	Terrawatt hour
TYNDP	Ten-year network development plan
UBA	Federal Environment Agency (German: Umweltbundesamt)
UK	United Kingdom
UN	United Nations
USA	Unites States of America
WEO	World Energy Outlook

1 Introduction

1.1 Motivation

Some coincidental decisions sometimes create a surprisingly consistent pathway when viewed in retrospect. This is the case when looking back on the role of CCTS during my years of studies: I was in my second undergraduate year when I attended a lecture in the atrium of the TU Berlin. While the overall topic was decarbonization technologies, there was one presentation by a Siemens representative that caught my attention: The vision of a technology that would enable the continuous burning of fuels without fear of global warming – carbon capture, transport, and storage (CCTS): The technology consists of three stages, starting with capturing CO_2 from large stationary emitters such as power plants or industrial facilities, then transporting it to an underground storage site, and compressing it in suitable geological formations. The representative from Siemens, however, did not receive the hoped-for praise for the technologic invention in the open discussion after the talk. The students – even at a technical university – instead turned out to be more concerned with questions of morality, comparing the technology to nuclear energy due to the unsolved question of long-term storage. I found the topic quite fascinating, but did not worry too much about which side had the better arguments.

Some years later, in 2009, I needed a controversial, yet accessible, topic to present at an assessment center of the *Studienstiftung des deutschen Vokes* (*German National Academic Foundation*); CCTS came to mind. The session went very well as the other students had never heard of this technology, but were eager to discuss it. It was shortly after this event that I joined a study project on CCTS at the Workgroup of Infrastructure Policy, my later workplace. It was there, only a few months later, that Andreas Tissen, Roman Mendelevitch, and I succeeded in programming the first version of CCTS-Mod – a mixed integer framework for modeling a cost-optimal European CO_2 network – which we later presented at the IAEE conference in Vilnius in August 2010. More than five years have passed since then and the maturity of CCTS technology has barely changed despite the ongoing academic discussions. But no matter how unsuccessful the commercial application of CCTS has been so far, I can surely say that some people – and I include myself here – have learned a lot, enjoying this interesting, ongoing debate.

I started my dissertation with a focus on modeling approaches, but later combined it with policy analysis for electricity and CO_2 infrastructure networks. Every model, no matter how complex and brilliant it might be, depends on the quality of its input data as well as its robustness to unpredictable external shocks, e.g. technological breakthroughs or political decisions. This, however, should not undermine the usefulness of models that can give useful insights about possible future events. The models in this dissertation were used to obtain insights and evaluate alternatives of political measures for a decarbonization of the European electricity sector. In this respect, a special emphasis is placed on the future development and deployment of CCTS in the electricity sector. Both the electricity and CCTS sectors have been studied in the past, but typically separate from one another. Not including interdependencies, however, leads to misleading results and poor interpretations.

Visiting numerous power plants, testing sites for CO_2 capture or storage, coal mines, as well as renewable sites and high voltage lines has contributed significantly to my motivation to keep on writing, but also to the quality of the dissertation itself. Talking to relevant actors from academia, politics, practitioners as well as affected people not only helps in acquiring better data for modeling exercises, but also for improving the understanding of the underlying problems and perspectives. The difficulty is connecting these pieces of information without losing track of the overall picture; or as put at a public hearing regarding the possible construction of electricity lines through Franconia, *“We sometimes have to broaden our perspective and should not only worry what is best for us, but what is best for overall Bavaria.”*

The remainder of this opening chapter continues with an introduction into the ongoing debate of combating climate change resulting from increasing global greenhouse gas (GHG) emissions. This leads to an overview of different global climate policy instruments and a debate on fossil subsidies and their external costs. Mitigating GHG emissions implies a decarbonization of the electricity sector; the next section covers pathways to achieve this transformation and their consequences. CCTS, one possible solution to this problem, is explained in more detail. The fourth section describes different modeling techniques that can be used to assess the research questions developed in the previous sections. A detailed outline of the dissertation is then followed by an outlook for future research.

1.2 Decarbonizing the electricity sector

1.2.1 The connection between climate change and fossil fuels

The sustainable development goals (SDG) adopted at the United Nations Sustainable Development Summit in September 2015, building on the Millennium Development Goals adopted in 2000, include tackling climate change as one of its key targets (UN, 2015). This need for combating global warming is by now widely accepted across governments (Leader of the G7, 2015; World Summit of the Regions, 2014), various international institutions (IPCC, 2014a; World Bank Group, 2015), as well as religious groups (e.g. Roman Catholic Church: Pope Franziskus, 2015; the Islamic community: IICCS, 2015; and the Lutheran Protestant Church: EKLR, 2015). A temperature rise of more than 2°C above the average global temperature of pre-industrial times would lead to severe environmental and economic costs for society (Stern, 2007). The Intergovernmental Panel on Climate Change (IPCC) calculated a remaining budget of 870-1,240 billion t CO_2 from 2011 through 2050 to have a more than 50% chance of achieving this target (IPCC, 2014a). 2014 provided a small sign of hope for the international aim of combating climate change: global energy-related CO_2 emissions stagnated for the first time, despite ongoing economic growth of three percent.

A major challenge in tackling global warming is the reduction of GHG emissions. Burning fossil fuels is the biggest source behind rising global GHG emissions. Thus the majority of global fossil-fuel reserves, equivalent to 11,000 billion t of CO_2, must not be burnt (Meinshausen et al., 2009). Studies by McGlade and Ekins (2015) and by Bauer et al. (2013) estimate that, depending on various scenarios, 70-90% of coal, 30-60% of gas and 30-60% of oil reserves of the world must not be burnt to meet the internationally-agreed climate target of avoiding more than a 2°C temperature increase.[1] Therefore, effective policies to curb fossil fuel and, in particular, coal consumption are needed as quickly as possible. The projections of McGlade and Ekins (2015) result in a maximum budget of 90 exajoules of coal annually between 2010 and 2050 in order to achieve the 2°C target – where even most optimistic baseline scenarios of the International Energy Agency (IEA, 2014a) project annual coal consumption of at least 145 exajoules. Steckel et al. (2015) even predict a "renaissance of coal" in non-OECD countries that would jeopardize all climate targets.

[1] The high variance is partly due to the uncertainty of global diffusion of nuclear energy and CCTS. The latter is especially used in combination with biomass to create "negative emissions" in many climate scenarios from 2040 onwards (Kemper, 2015).

The constant, ongoing, exploration for new fossil resources, despite the awareness of climate change, has led to reserves (11,000 bn t CO_2) that exceed the allowed budget (870-1,240 bn t CO_2) by a factor of 10. This so-called carbon bubble might burst once stringent climate policies force giving up already discovered reserves. The consequence would be stranded investments in carbon-intensive infrastructure by both countries and companies with big fossil reserves. Many state-owned and pension funds would suffer since they have invested in resource businesses. The global divestment campaign is encouraging investors to redirect their investments from carbon intensive industries into more sustainable sectors. An increasing number of pension and insurance funds, including the Norwegian Government Pension Fund Global as well as the Axa and Allianz insurance companies, have already altered their investment strategies for a combination of economic and moral reasons (HSBC, 2012; Leaton, 2011; Marshall, 2013).

1.2.2 Internalizing negative externalities through climate change policy schemes

The burning of fossil fuels is behind a long list of negative external effects, including emissions of carbon dioxide (CO_2), nitrogen oxides (NO_x), sulfur dioxide (SO_2), mercury, dust, small particlulates, and noise (EC, 2003). Burning coal results in external costs of between 80 and 100 €/MWh, according to a study for the European Commission (EC) by Ecofys (2014). This is triple the 2015 average German electricity wholesale price. Moreover, extracting resources leads to indirect pollution, to large-scale devastation, and forces the relocation of thousands of people. However, developing countries especially lack the technological and financial means to adopt more sustainable electricity generation technologies. International resource companies, on the other hand, reap large profits and sometimes even receive state subsidies (“polluter profits”) (Richards and Boom, 2015). The Organisation for Economic Co-operation and Development (OECD, 2015) published a study that improves the understanding of the range and magnitude of fossil fuel subsidies in different countries. They counted almost 800 individual policies that support the production or consumption of fossil fuels in OECD countries and six large partner economies (Brazil, the People’s Republic of China, India, Indonesia, the Russian Federation, and South Africa) with an overall value of US$160-200 billion annually over the 2010-14 period. A global study by the International Monetary Fund (IMF, 2015) find an overall figure of 6.5% of global GDP, including direct subsidies as well as indirect ones, which includes when countries set energy taxes below levels that fully reflect the environmental damage associated with energy consumption.

Individuals, non-governmental organizations (NGOs), national governments, and international bodies have started to recognize the negative externalities of fossil fuels and are seeking to introduce new policies. These "polluter pays" policies should counteract the negative effects, eventually reducing the consumption of fossil fuels. Such policies, however, face the general problems of a public good, as non-participating actors also profit from mitigation policies through a free-rider effect. The literature differentiates between supply-side policies targeting the extraction of fossil fuels and demand-side policies that provide indirect incentives to reduce fossil fuel consumption. Until now, demand-side policies have received more attention and have been most commonly introduced in practice. Examples include market-based mechanisms (such as a tax or a cap-and-trade system on emissions) as well as direct regulation to subsidize low-emissions energy sources, promote energy efficiency, or impose emissions standards.

The European Union failed to implement a direct CO_2 pricing scheme, such as a CO_2 tax, due to the needed unanimous agreement to pass it. The second best option was the European Emissions Trading System (EU-ETS), which was implemented in 2005. The EU-ETS is still the largest connected CO_2 trading platform world-wide. Similar CO_2 trading schemes are implemented in other regions, e.g. in several states of the USA and Canada. China is also testing a trading system in some provinces and is planning to launch a national scheme in 2017 (Ecofys et al., 2015). Market-based mechanisms, like the cap-and-trade EU-ETS, are economically efficient, but have only generated low-carbon prices in practice (averaging 7 US$/t$CO_2$ in 2014 (IEA, 2015)).

The low EU-ETS CO_2 price has three main reasons: I) Existing information asymmetries between polluting entities and regulating bodies resulted in an initial overallocation of allowances on its starting date in 2005 (Corbach, 2007); II) too liberal rules for the import of credits through the Clean Development Mechanism (CDM) and Joint Implementation (JI) schemes led to an even higher surplus of certificates during the second phase from 2008-2012; and III) outer shocks such as the effects of the financial crisis reduced the demand for certificates since 2008 (Hu et al., 2015). Much higher carbon prices are necessary to drive low-carbon technology innovations (IEA, 2014b). As a consequence, several countries are implementing additional national measures in addition to the EU-ETS. These include, among others, different types of feed-in tariffs and market premia, a minimum CO_2 price, emissions performance standard (EPS) (Oei et al., 2014b), and the introduction of different types of capacity markets (Beckers and Hoffrichter, 2014) (see Chapter 2).

A strand of literature criticizes demand-side climate policies for their paradoxical effects. Such policies are, in the absence of full participation in a global climate policy, susceptible to carbon leakage: Emission-intensive activities shift to non-participating countries, so that emissions reductions in the participating countries are partly offset by emissions increases in the non-participating countries (Hagem and Storrøsten, 2016). Additionally, a "green paradox" is postulated, where the expectation of future demand-side policies induces resource producers to increase their present rates of extraction in order to maximize profits (Sinn, 2015, 2008a, 2008b). This leads to rising emissions and is the opposite of the original intent of climate policy schemes. Moreover, Coulomb and Henriet's (2014) "grey paradox" states that climate measures, such as carbon taxation, might increase the revenue of some fossil fuel owners (e.g. natural gas), if a dirtier abundant resource (e.g. coal) is taxed higher.

Hoel (2013) shows that a properly designed supply-side policy, e.g. one that targets high-cost coal deposits for closure, is able to eliminate the "green paradox." The strand of similar literature on supply-side policies, mostly targeting coal extraction as most carbon-intensive fuel, is growing (Asheim, 2012; Fæhn et al., 2014). Harstad (2012) is one of the first to propose a detailed supply-side policy. His proposal utilizes existing markets for coal deposits, whereby a coalition of participants purchases the extraction rights for high-cost coal deposits. The participants then constrain the global supply of coal by abstaining from mining those coal deposits, in conjunction with reducing their domestic demand; a first-best solution for the coalition may be attained. A modified version of Harstad's proposal by Collier and Venables (2014) pursues the closure of the entire coal industry in sequential groupings of major producing countries (starting with the USA, Australia, and Germany), with emphasis on the use of moral pressure to achieve this. Compensation for closure can be paid via a ring-fenced cap-and-trade scheme for the extraction of fossil fuels. Eisenack et al. (2012), as well as Kalkuhl and Brecha (2013), calculate the effects of compensating owners of oil, gas and coal reserves by a carbon permit grandfathering rule. Martin (2014) reasons that the regulation of commodity exports on the basis of their harmful or unethical end use is a widely accepted principle and, thus, should be extended to coal. Richter et al. (2015) propose a carbon tax imposed on the supply-side. Thereby, a production tax generates better outcomes than an export tax, but also impacts domestic consumers.

1.2.3 The role of carbon capture, transport, and storage in a decarbonized electricity sector

1.2.3.1 Different strategies for achieving a decarbonization of the electricity sector

Enabling a decarbonization of the electricity sector is crucial for keeping global temperature rise under 2°C, as mitigating emissions in other sectors is more difficult and costly (Öko-Institut and Fraunhofer ISI, 2014). However, international consensus on how to achieve a decarbonization of the sector is lacking. Even within the EU, a multitude of approaches exist: Germany started down a path called *Energiewende* ("energy transformation" in English). It includes a shut down of all nuclear capacities by 2023, a strong reduction of GHG emissions of 80-95% by 2050 (base year 1990) implying a mid-term coal phase-out, a large-scale roll-out of renewable energy sources (RES) contributing to at least 80% of electricity production in 2050, as well as increasing energy efficiency (see Chapter 6). RES consequently became the biggest contributor to gross electricity production in 2014, contributing about 30% of German electricity production in the first half of 2015.

The German Energiewende proves that a decarbonization of the electricity sector in combination with a shut down of all nuclear capacities is (technically) manageable and economically viable. As a result, learning effects and reduced investment costs enabled a market-driven worldwide roll-out. By 2014, 144 countries had set renewable targets (Burck et al., 2015). Consequently, the resulting new global installations in 2014 outnumbered the combined new fossil and nuclear capacities (Burck et al., 2015). In addition, EU net electricity generation installations from 2000-2014 were mainly driven by wind (117 GW) and Photovoltaics (PV) (88 GW). On the other hand, other electricity sources, such as nuclear (-13 GW), coal (-25 GW) and oil (-25 GW), experienced a negative net capacity effect (EWEA, 2015). Between these two poles, the future role of natural gas is still open: Its net capacity increased by 101 GW (from 2000-2014) but many operators observe negative cash flows due to low runtimes and low electricity wholesale prices (Holz et al., 2015b).

Some countries, such as France, still rely on substantial nuclear capacities. The World Nuclear Industry Status Report, however, reveals such visions of a nuclear renaissance are very unlikely. The reasons for this are increasing costs, technologic barriers, and the still unsolved problem of nuclear waste disposal (Schneider et al., 2015). The United Kingdom promotes a mixed strategy of RES, nuclear power, and CCTS, a decarbonization option explained in more detail in the following section.

1.2.3.2 The vision of the CCTS technology

One technology supported by many power utilities for combining coal electrification with decarbonization is CCTS. The technology consists of three stages starting from capturing CO_2 from large stationary emitters, such as power plants or industrial facilities, then transporting it to an underground storage site, and then compressing it in suitable geological formations. Most studies refer to this technology as CCS, though neglecting the essential "T" representing the important transportation part of the value chain.

The idea that CCTS could be part of a path toward a sustainable energy system emerged in the late 1990s and became even more prominent with the IPCC (2005a) special report. The vision of the technology includes three main applications:

- The electricity sector: burning fossil fuels without the negative externalities of CO_2 emissions to complement the low-carbon technologies RES and nuclear.
- The industry: decarbonizing several industry branches, e.g. iron and steel or cement that still lack other decarbonization options.
- Negative emissions: combining a CO_2-neutral biomass power plant with a CO_2 capturing unit results in negative net emissions, compensating for unabatable emissions in other sectors (Kemper, 2015).

Consequently, the IEA Roadmap (2009a) estimated that reducing CO_2 emissions by 50% in 2050 compared to the 1990 level, without the use of CCTS, would increase global mitigation costs by up to 71%. Even higher cost increases of 29-297% are confirmed by scenarios of the newest report from the IPCC (2014a) for reaching the 2°C target without CCTS technology. The large-scale combination of the CCTS value chain, however, is still not proven, as documented in a special issue by Gale et al. (2015) commemorating the 10th anniversary of the IPCC (2005a) special report. Experiences show that applying CCTS as decarbonization technology for the electricity sector is unlikely as RES provide a cheaper alternative. The only existing CCTS small-scale applications are in combination with CO_2-Enhanced Oil Recovery (CO_2-EOR) (Hirschhausen et al., 2012a). Such carbon capture and usage (CCU) concepts, including CO_2-EOR or urea production, however, have limited global potential and have very low CO_2 mitigation effects: In CO_2-EOR processes the majority of the injected CO_2 diffuses the underground storage together with the additionally extracted oil (Gale et al., 2015; Oei et al., 2014b).

As visualized in Figure 1, there are three different CO_2 capture technologies: Post-combustion, Pre-combustion, and oxyfuel (Abanades et al., 2015; Fischedick et al., 2015). A post-combustion unit, developed in the early 1980s, captures the CO_2 out of the flue gas (Idem et al., 2015; Liang et al., 2015). The pre-combustion technology uses a gasification process to decompose the fuel and pure oxygen into a hydrogen synthesis gas (syngas), consisting of hydrogen (H_2) and CO_2. The CO_2 is then separated, leaving a hydrogen-rich fuel for further combustion processes (Jansen et al., 2015). In the oxyfuel capturing process, the coal is burnt in an atmosphere of pure oxygen (O_2) and CO_2. The resulting flue gas is not diluted with other components, such as nitrogen. It mostly consists of CO_2 and water vapor (H_2O), which can then be separated (Stanger et al., 2015). All three technologies have high installation costs and performance penalties of around 10% points loss of process net efficiency (drop from around 40% power plant effecieny to around 30% depending on the fuel and capture technology). Post-combustion, however, has the advantage that it could be retrofitted to plants that are constructed as "capture-ready" (Fischedick et al., 2015; Rubin et al., 2015).

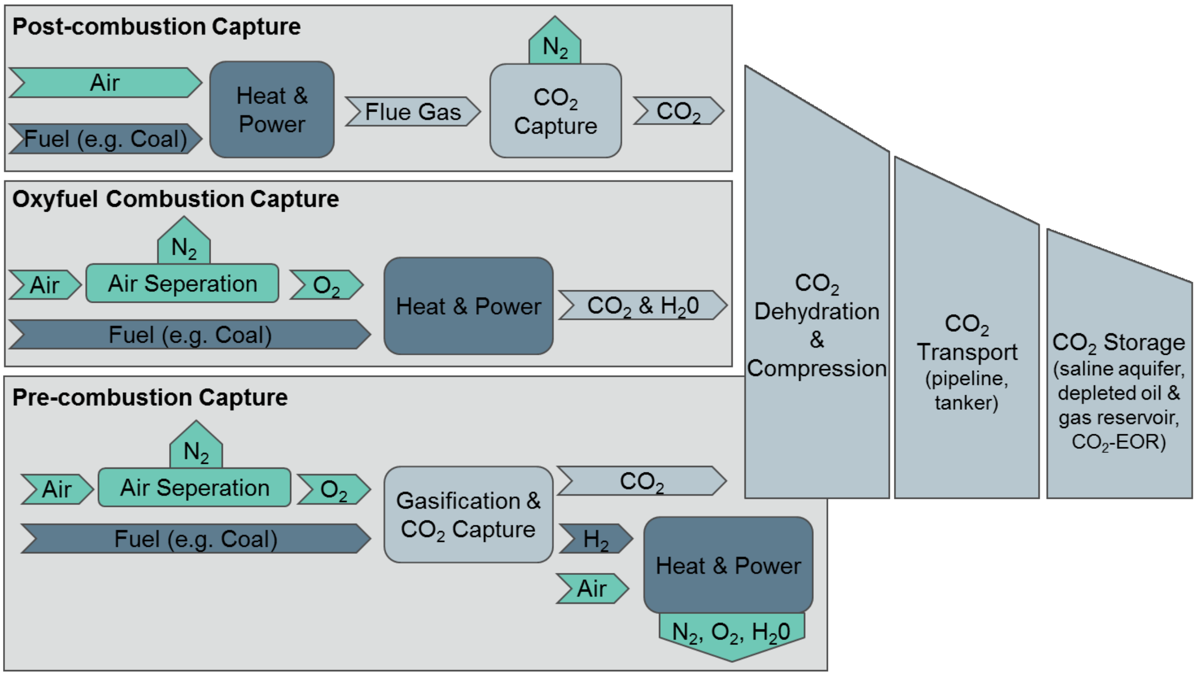

Figure 1: The process chain of carbon capture, transport, and storage.

Source: Own depiction based on Fischedick et al. (2015).

Captured CO_2 is transported via a network of pipelines or by tankers. The transport is usually in liquid or super-critical state and is similar to transporting natural gas or crude oil. As in the oil and gas industry, pipeline transport is in general more economical for larger quantities; tankers are cheaper in the case of small quantities from pilot projects to offshore storage sites (Geske et al., 2015a, 2015b). The biggest cost components are the construction costs of the network. Variable transportation costs, which are small in comparison, cover the electricity needs of the compression units and pumping stations (Fischedick et al., 2015; Oei et al., 2014a).

Geologic formations suitable for CO_2 storage need to come with layers of porous rock (e.g. sandstone) or cavities deep underground that are sealed upwards with multiple layers of non-porous rock (e.g. granite) (Herold et al., 2011; Krevor et al., 2015). This precondition limits the technical storage possibilities to deep saline aquifers (Bachu, 2015; Birkholzer et al., 2015), coal beds, as well as abandoned and active crude oil or gas fields. Oil and gas reservoirs that have held oil and natural gas for millions of years generally present a lower risk of leakage but are mostly of smaller capacity than saline aquifers. The injected liquid CO_2 spreads through the formation until it is trapped by the upper sealing (Emami-Meybodi et al., 2015). Injection into reservoirs has been executed since the mid 1990s in the oil and gas industries, yet only very limited experience with respect to permanent CO_2 storage exists (Jenkins et al., 2015; Jones et al., 2015). This leads to high uncertainty regarding the costs, overall storage potential, and long-term environmental effects. Public acceptance issues of the last years have eliminated the option of onshore storage in most populated areas, leaving only the limited option of more expensive offshore storage (Ashworth et al., 2015; Hirschhausen et al., 2012a).

1.2.3.3 Differences between vision and reality of CCTS deployment

The discussion on CCTS has centered on the role of CCTS in the power sector, even though renewables present a cheaper decarbonization alternative. But CCTS may also be applied in other sectors, e.g. iron and steel, cement and refining, where chemical processes emit large amounts of CO_2. Switching to renewable sources and/or increasing process efficiency will result in partial emissions reductions in the medium term, e.g., estimates of 35% in the iron and steel sector, 35% in cement and 20% in clinker production (Öko-Institut, 2012). Low-carbon substitutes to the conventional production of these raw materials, such as magnesium cement or the electrolytic production of iron, may become available in the future. However, the extent to which they might be applied on a large scale or whether they are economically viable is unknown. At the same time an application in these sectors will face lower capture costs than in the energy sector, due to the higher CO_2 concentration in the flue gas (Herold et al., 2011; Ho et al., 2011; Öko-Institut, 2012) (see Chapter 3 and 4).

Eckhause and Herold (2014) show that the success of a global CCTS rollout depends on the existing governmental funding schemes. Splitting funding over a number of projects in general increases the likelihood of success in finding a new technology. This, however, also creates the risk that the split funds are insufficient to produce any successful project, as happened in the case of European CCTS funding. The EC tried funding numerous projects of different capturing technologies (pre-combustion, post-combustion, oxyfuel), various sources (power plants, industry) and numerous countries (DE, ES, FR, GB, IT, NL, PL, RO) via the European Energy Program for Recovery (EEPR) and two follow-up New Entrance Reserve (NER300) programs (Lupion and Herzog, 2013). All projects, however, withdrew their applications during the process, were shut down, or have kept postponing their final investment decision for several years (Hirschhausen et al., 2012a) (see Chapter 5).

There still exists a cognitive dissonance in the prediction of top-down models, which continue to place hope in the CCTS-technology, and bottom-up experiences: On the one hand, longer-term energy system models insist on the need of CCTS to attain ambitious decarbonization scenarios (IPCC, 2014a). This is due to the lack of alternatives for decarbonizing the industry (e.g. steel and cement) or compensating for other unabatable emissions through negative CO_2 emissions through the combination of biomass and CCTS (Bauer, 2015; IPCC, 2014a; Kemper, 2015). The EU Energy Roadmap 2050 still projects on average 133 GW of CCTS power generation capacity by 2050, which is equivalent to 1 Gt CO_2 captured per year (EC, 2011). The World Energy Outlook by the IEA (2014a) even estimates more than 800 GW of globally installed CCTS capacity by 2040 in their 450 ppm scenario. First movers, such as the U.S., Canada, Norway, and the UK, on the other hand, have shifted their attention toward CO_2-EOR. This has little to do with the original idea of CO_2 mitigation through CCTS, as the newly extracted oil and gas leads to additional CO_2 emissions (Gale et al., 2015; MIT, 2007). European countries with formerly ambitious research and development (R&D) and demonstration objectives, such as the Netherlands, Germany, and Poland, have shelved all their pilot projects. The world's two largest coal burning nations, instead of becoming interested beneficiaries of the technology, are pursuing their own, very modest research (China) or ignoring CCTS altogether (India) (GCCSI, 2014; Wuppertal Institute, 2012).

1.2.4 Using mathematical frameworks for modeling electricity and CO_2 infrastructure networks

1.2.4.1 Choosing the appropriate model setting

To quantitatively assess the effects of different policies requires mathematical techniques. Such frameworks can capture both the strategic setting in which different actors with various incentives interact, as well as the technological and regulatory constraints. This part concentrates on methodological options for designing modeling frameworks to incorporate the knowledge gained in the previous sections on electricity and CO_2 networks. Existing literature on energy system modeling contemplates several different modeling approaches: Energy system models such as PRIMES (Capros et al., 1998), MARKAL (Fishbone and Abilock, 1981), EFOM (Finon, 1979) or POLES (Criqui, 1996) are able to convey the “big picture” of what is happening in different linked sectors of an energy system. These technology-oriented models focus on the energy conversion system, on the final demand (e.g. efficiency measures) and the supply side (e.g. electricity generation). They cover several sectors, linking them e.g. through endogenous fuel substitution. They are mostly solved by optimization or simulation techniques when minimizing system costs or maximizing the overall welfare. They assume perfect competition as these model types only have limited possibilities to incorporate market power.

In contrast to energy system models, other smaller, partial equilibrium sector models exist, including the World Gas Model (Egging et al., 2008), COALMOD (Haftendorn and Holz, 2010; Holz et al., 2015a), GASMOD (Holz et al., 2008), and OILMOD (Huppmann and Holz, 2012). These equilibrium models concentrate on one commodity and are able to model strategic exertion of market power by individual players that influence the price through their output decision. These sector models are able to examine various game-theoretical settings, thus examining sectors on a more detailed level. On the other hand, these models do not include linkages with other sectors and, therefore, fail to assess cross-sector effects (e.g. cross-fuel substitution). Huppmann and Egging (2014) start closing this gap by constructing the multi-sector resource market and energy system equilibrium model, MULTI-

MOD. The model incorporates endogenous fuel substitution and is therefore able to calculate carbon leakage effects in the energy sector between countries as well as sectors.

Different chapters of this thesis describe various mathematical models that were developed or adjusted to examine infrastructure development subject to different policy measures (see Figure 2). The choice of the most suitable model type and data set depends on the underlying research question and can be varied in different scenarios. The size of the data set used depends on various aspects such as the number of actors (e.g. nodes, technologies, firms), the time intervals analyzed (e.g. every minute or 5 years), and time periods (e.g. examining 1 day or 50 years). Model complexity varies with respect to the market assumptions (perfect competition, cooperative, non-cooperative), number of stages (one, two, n), information levels (deterministic or stochastic), as well as the number and kind of technical constraints. The model characteristics chosen define what kind of modeling formulation is needed for solving the problem. The more complex the problem and the larger the data set, the greater is the resulting modeling computation time. Limited computation resources are often a problem for solving models that include a realistic dataset, despite technical improvements with respect to hardware as well as solution algorithms.

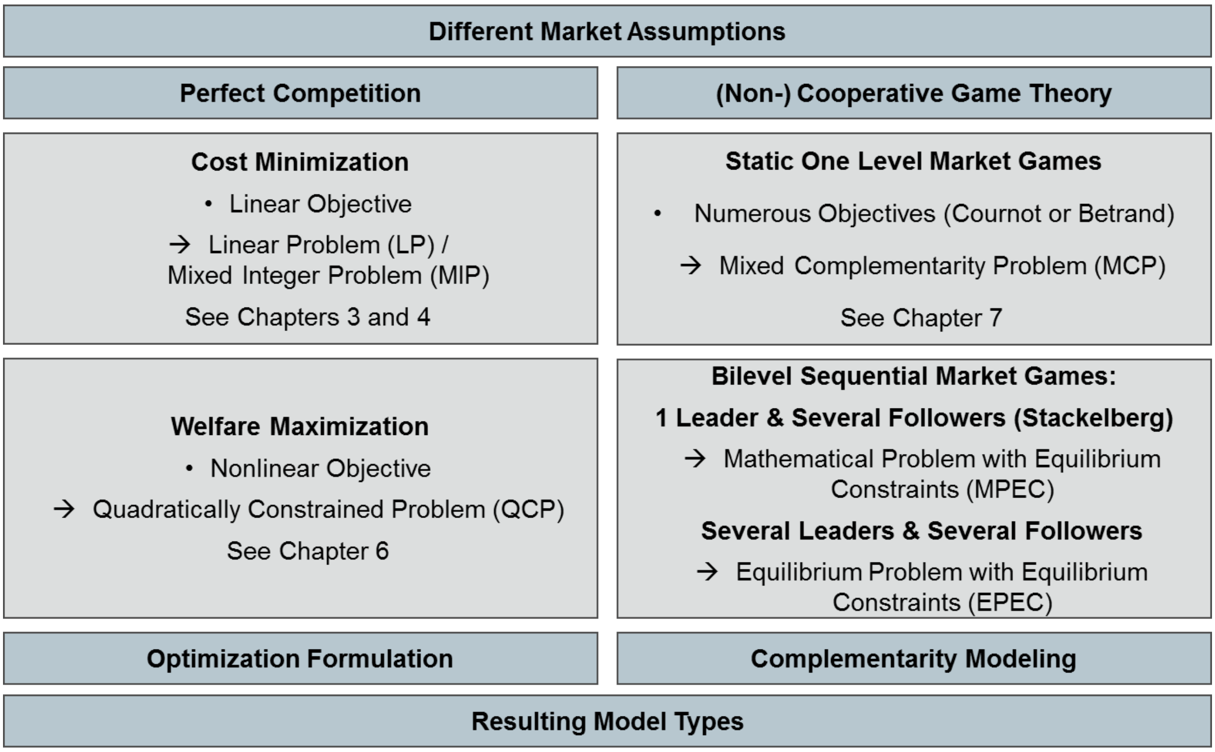

Figure 2: Different modeling types
Source: Own depiction based on Gabriel et al. (2012).

1.2.4.2 Developing a CCTS model that represents economies of scale in transporting CO_2

Models of the electricity, gas and oil sector typically focus on optimizing or upscaling the existing infrastructure. Modeling a CCTS network, however, provides the opportunity and challenge to model a completely new infrastructure network incorporating capture, transportation, and storage entities from scratch. The EC projected the need for a European CO_2 transport network of over 20,000 km by 2050 (JRC, 2011). The existing technical, planning, and acceptance issues of constructing infrastructure networks (e.g. power lines or highways) demonstrate the difficulties of such an undertaking. The costs for large-scale pipeline networks are characterized by economies of scale, which incentivize clustering CO_2 sources before transporting larger volumes via bigger trunk lines to a sink. The newly developed model CCTS-Mod, therefore, includes discrete pipeline diameters (see Chapter 3 and 4). This allows for a representation of economies of scale when transporting CO_2 but also increases the computation time substantially as it uses a Mixed Integer Problem (MIP) model to calculate a cost minimal CCTS infrastructure. CCTS-Mod, similar to other energy sector models, assumes perfect competition as well as perfect foresight. This underestimates the overall costs, but allows for calculating a cost optimal infrastructure network from a central planners' perspective.

1.2.4.3 Respecting Kirchhoff's Laws when modeling the electricity sector

The main difficulty when modeling electricity networks is how to include Kirchhoff's and Ohm's laws. Including real and reactive power flows leads to an increase in computational complexity and solving time. Schweppe et al. (1988) therefore formulated the simplified direct current loadflow model (DCLF), which is the basis for the later model ELMOD developed at TU Dresden (Leuthold et al., 2012, 2008). ELMOD is applied to analyze various questions on market design, congestion management, and investment decisions with a geographical focus on Europe. The bottom-up model combines electrical engineering and economics in a Quadratically Constrained Problem (QCP) with a welfare maximizing objective function. A modified version of ELMOD is used in Chapter 6 to quantify the need for electricity transmission capacity investments in Germany; either through strengthening the alternating current (AC) grid or the creation of new high voltage direct current (DC) trunk lines from the North to the South of Germany. Additional scenarios include various potentials and regional dispersion of RES, demand-side management (DSM) and storage options.

1.2.4.4 Combining all insights into one model

The last Chapter 7 focusses on combining the individual sectors CCTS (Chapter 3-5) and electricity (Chapter 6) into a combined CCTS, electricity investment, and dispatch model, ELCO. ELCO is formulated as equilibrium model, where different types of technologies are able to compete against one another for the cheapest generation portfolio. The underlying complementarity problem includes different objective functions for various players. Such non-cooperative game settings assume that each player chooses the most profitable strategy for himself, rather than assuming a social planner maximizing aggregate welfare. This is contrary to cooperative game settings, such as a monopoly or cartel setting. Static games can be solved as Cournot (1838) game in quantities or as Bertrand (1883) game in prices. ELCO assumes a Cournot game setting where suppliers decide simultaneously on the quantities to offer, given their competitors' offers and the known profit functions of all players. Mixed Complementarity Problems (MCP) can be used to solve such research questions. A Nash equilibrium is reached when no player has an incentive to deviate unilaterally from his chosen strategy given the strategy of the others. The solutions of an MCP depend on the starting values as different solutions with different objective values are possible, and hence are more difficult to interpret.

1.2.4.5 Excursus on bilevel sequential market games

While this dissertation does not go beyond the use of MCPs, Gabriel et al. (2012) also present applications of MCP extensions for sequential games, which require a format such as Mathematical or Equilibrium Problems with Equilibrium Constraints (MPEC or EPEC). The best known example for a dynamic (multi-stage) game is the Stackelberg game, which can be set up as an MPEC. This leader-follower market game consists of sequential moves in two stages: The Stackelberg leader decides on his optimal quantity knowing how the followers will react to it. After observing the quantity supplied by the leader, the followers decide on their optimal quantities to offer on the market. Most model settings assume a Cournot game setting among the followers. EPECs assume several leaders on the upper level that compete against one another in a non-cooperative manner. Each leader thereby takes into account the reaction of one or several followers. The lower level consists of another group of followers competing against one another in a MCP. There are several different solution techniques for complementarity models that were used to analyze multi-level sequential market games

(Gabriel and Leuthold, 2010; Huppmann, 2013; Huppmann et al., 2013; Richter et al., 2015; Siddiqui and Gabriel, 2012). However, the mathematical complexity of MPECs and, in particular, EPECs does not enable these modeling types to solve large scale models with big data sets, as analyzed in Chapters 3, 4, and 6.

1.3 Outline of the dissertation

The outline of the dissertation is divided into three parts (see Figure 3): The first part consists of Chapter 2, which examines policy options for a decarboninzation of the electricity sector. The second part is dedicated to CCTS with numerical modeling exercises in Chapters 3 and 4, followed by a policy analysis in Chapter 5. The third part consists of two different models: Chapter 6 focuses on the electricity sector. Chapter 7 combines the insights of multiple policy options (identified in Chapter 2), the individual sectors CCTS (Chapter 3-5) and electricity (Chapter 6) into a combined CCTS, electricity investment, and dispatch model.

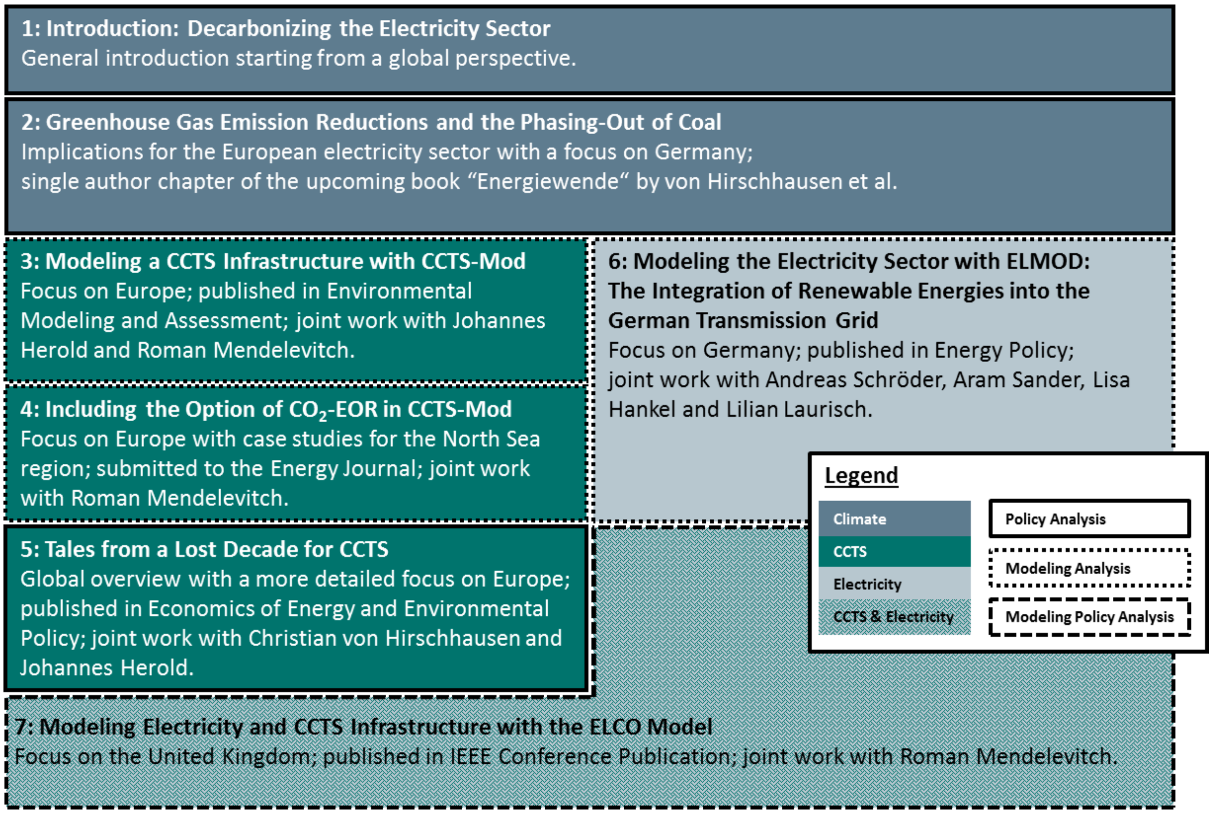

Figure 3: Outline of the dissertation

1.3.1 Chapter 2: Examining policy options for a decarboninzation of the electricity sector

Coal-fired power plants are responsible for approximately one-third of total carbon dioxide emissions in Germany. The 2015 price for CO_2 emissions allowances under the EU-ETS, however, is too low for a market-driven transition from coal to less CO_2-intensive energy sources, such as natural gas, in the near future. Failure to reduce the persistently high level of coal-based power generation puts Germany's short- and long-term climate targets at risk and undermines a successful Energiewende. Consequently, the introduction of the market stability reserve as well as the adjustment of the reduction factor are important, yet not sufficient, changes to strengthen the EU-ETS.

Some countries in the EU and North America are a step ahead, having already implemented some complementary instrument measures, e.g. the UK (CO_2 emissions performance standard (EPS) and a carbon price floor), the USA (EPS and an additional retirement plan for older plants), and Canada (EPS). In this context, Chapter 2 analyzes policies to reduce GHG emissions and the phasing-out of coal in the German electricity sector. Possible accompanying measures to reduce coal-based power generation in Germany include minimum fuel efficiency or greater flexibility requirements, national minimum prices for CO_2 emission allowances, capacity mechanisms, a residual emissions cap for coal-fired power plants, EPS, capacity mechanisms and alternative transmission expansion policies. All these national policy measures could be implemented in parallel to the desired reform of the EU-ETS. A strengthened EU-ETS supplemented by national instruments forms a framework to secure a continuous reduction of GHGs in line with national and European climate targets.

Limiting German GHGs, thus meeting the climate target automatically, implies a coal phase-out in Germany by the 2040s. The coal phase-out in Germany is a process that started, affected by German reunification, long before the Energiewende. Analyses show that an overall phase-out by 2040 is possible without risking resource adequacy at any point. The majority of actors, including but not limited to renewables, even benefit from such a trend. The resulting net employment effects differ across regions and sectors but are expected to be positive for the aggregate of all regions. Nevertheless, it is important and crucial that all affected parties – including politicians, unions, workers, NGOs and scientists – work together to enable a smooth transition going forward. It is only then that other countries, like China and India, can be encouraged to take the German example as a blueprint to combat global warming, even if this implies a coal phase-out.

1.3.2 Chapter 3-5: The vision of CCTS as low-carbon solution for the electricity and industry sector

The potential contribution of CCTS to the decarbonization of the electricity and industry sector is calculated in a numerical, model-based analysis in Chapter 3, followed by a more sophisticated model including the option of CO_2 enhanced oil recovery (CO_2-EOR) in Chapter 4 and a policy analysis in Chapter 5.

Chapter 3 presents a mixed-integer, multi-period, welfare-optimizing network model for Europe, called CCTS-Mod, used to analyze the economics of CCTS in the wake of expected rising CO_2 prices. The model incorporates endogenous decisions on carbon capture, pipeline and storage investments, as well as capture, flow and injection quantities based on given costs, CO_2 prices, storage capacities and point source emissions. Given full information about future costs of CCTS technology and CO_2 prices, the model determines a cost minimizing strategy on whether to purchase CO_2 certificates, or to abate the CO_2 through investments into a CCTS-chain on a site by site basis. We apply the model to analyze different scenarios for the deployment of CCTS in Europe, e.g. under high and low CO_2 prices, respectively. CCTS can contribute to the decarbonization of Europe's industry sectors (in particular iron, steel and cement industry), as long as assuming sufficient on- or offshore storage capacities. The power sector has higher capture costs and invests in the CCTS technology at higher CO_2 certificate prices than the industry.

An improved data set of costs in Chapter 4 reveals more realistic insights, as early cost projections turned out to be too low. The chapter analyzes the layout and costs of a potential CO_2 infrastructure in Europe over the time horizon up to 2050 based on a critical review of the current state of the CCTS technology. The mixed-integer model CCTS-Mod is applied to compute a CCTS infrastructure network for Europe, examining the effects of different CO_2 price paths with different regional foci. Scenarios assuming low CO_2 certificate prices lead to extremely limited CCTS development in Europe. The iron and steel sector starts deployment as soon as the CO_2 certificate price exceeds 50 €/tCO_2. The cement sector starts investing at a threshold of 75 €/tCO_2, followed by the electricity sector when prices exceed 100 €/tCO_2. Results on the degree of deployment of CCTS are found to be more sensitive to variable cost of CO_2 capture than to investment costs. Additional revenues from using the CO_2 for enhanced oil recovery (CO_2-EOR) in the North Sea would lead to an earlier adoption of CCTS, independent of the CO_2 certificate price. This case may become especially relevant for the UK, Norway, and the Netherlands. Assuming uncoordinated and scattered CCTS deployment doubles the cost of CO_2 transport and increases storage costs by 30%.

Chapter 5 analyzes the discrepancy between the high hopes placed on CCTS and the meager results observed in reality, discussing several possibilities underlying this lost decade for CCTS. The high hopes placed in this technology by industry and policymakers alike could not be met as the expected number of demonstration projects required for a breakthrough did not follow. Possible explanations for the lost decade are incumbents' resistance to structural change, wrong technology choices, over-optimistic cost estimates, a premature focus on energy projects instead of industry, and the underestimation of transport and storage issues. The low performance of CCTS applications in the electricity sector also questions other options of decarbonizing parts of the industry or using biomass units with CCTS to compensate for unabatable emissions in other sectors. This cognitive dissonance, in which top-down Integrated Assessment Models (IAM) continue to place high hopes in CCTS-technology to meet the 2°C target, while bottom-up analysis takes failed pilot demonstration projects as proof of limited potential, is likely to continue for quite some time.

1.3.3 Chapter 6-7: Modeling policy options in a combined electricity and CCTS framework

The last part of the dissertation focuses on a better representation of the electricity sector in Chapter 6 and the new model ELCO combining an electricity network model with a complete representation of the CCTS value chain in Chapter 7.

Chapter 6 presents a quantitative assessment of the need for electricity transmission capacity investments in Germany by 2030. Congestion is investigated in three scenarios that differ in the location of power generation resources and the realization of line expansion projects. Results show that the Ten Year Network Development Plan (TYNDP) of the European Commission and overlay line projects proposed in 2011 are not sufficient measures to cope with the increasing demand for transmission capacity. Moving generation closer to demand centers can partly relieve grid bottlenecks by 2030. The introduction of a high-voltage direct current (HVDC) backbone grid, on the other hand, does not relieve congestion significantly.

Chapter 7 aims at closing the research gap between electricity market models, which do not put any emphasis on CCTS, and models of CCTS infrastructure development, which neglect how the technology is driven by decisions in the electricity market. It presents a two-sector electricity-CO_2 (ELCO) modeling framework. Players can invest into various types of generation technologies including renewables, nuclear and CCTS. The detailed representation of CCTS comprises also industry players (iron and steel as well as cement), as well as CO_2 transport and storage including the option for CO_2-EOR. The model also simulates interactions of the energy-only market with different forms of national policy measures. All players maximize their expected profits based on variable, fixed and investment costs as well as the price of electricity, CO_2 abatement costs and other incentives, subject to technical and environmental constraints. Demand is inelastic and represented via a selection of type hours. The model framework allows for regional disaggregation and features simplified electricity and CO_2 pipeline networks. The model is balanced via a market clearing for the electricity as well as the CO_2 market. The equilibrium solution is subject to constraints on CO_2 emissions and renewable generation share. The model is applied to a case study of the UK Electricity Market Reform to illustrate the mechanisms and potential results attained from the model.

1.3.4 Chapter origins and own contribution

Table 1 displays the pre-publications and further information on the individual contribution for each chapter of the dissertation.

Table 1: Chapter origins

	Dissertation Chapters	*Pre-Publications*	*Own contribution*
2	Greenhouse Gas Emission Reductions and the Phasing-Out of Coal	Chapter 3 in the upcoming book "Energiewende" by von Hirschhausen et al. (forthcoming)	Single author chapter
3	Modeling a Carbon Capture, Transport, and Storage Infrastructure for Europe	Environmental Modeling and Assessment 05/2014; December 2014, Vol. 19, Issue 6, pp 515-531; Zeitschrift für Energiewirtschaft Volume 35, Number 4, p. 263-273, 2011; DIW Berlin Discussion Paper No. 1052, 09/2010, Berlin.	Joint work with Johannes Herold and Roman Mendelevitch. Pao-Yu Oei and Roman Mendelevitch jointly developed the model, and its implementation in GAMS. Andreas Tissen was also involved in developing a first draft of the model. The writing of the manuscript was executed jointly.
4	Development Scenarios for a CO_2 Infrastructure Network in Europe	Submitted to the Energy Journal; Resource Markets Working Paper WP-RM-36 at University of Potsdam, 2013.	Joint work with Roman Mendelevitch. Pao-Yu Oei and Roman Mendelevitch jointly developed the model and its implementation in GAMS. Pao-Yu Oei had the lead in analyzing the political setting for CCTS in the EU. Roman Mendelevitch had the lead in collecting data on CO_2-EOR, and analyzing the results. The writing of the manuscript was executed jointly.
5	How a "Low-carbon" Innovation Can Fail - Tales from a Lost Decade for Carbon Capture, Transport, and Storage	Economics of Energy and Environmental Policy, 2012, Vol.1, No.2, 115-123.	Joint work with Christian von Hirschhausen and Johannes Herold. The writing of the manuscript was executed jointly. Pao-Yu Oei had the lead in data collection and including modeling insights into the paper. He updated the original article with respect to international running and cancelled CCTS projects from 2012–2015.
6	The Integration of Renewable Energies into the German Transmission Grid	Energy Policy, Volume 61, October 2013, p. 140–150; Electricity Markets Working Paper WP-EM-48. TU Dresden, 2012.	Joint work with Andreas Schröder, Aram Sander, Lisa Hankel and Lilian Laurisch. Pao-Yu Oei and Andreas Schröder jointly developed the model, its implementation in GAMS and had the lead in the writing of the manuscript. TU students Jenny Boldt, Felix Lutterbeck, Helena Schweter, Philipp Sommer and Jasmin Sulerz contributed in reviewing input data for the model.
7	The Impact of Policy Measures on Future Power Generation Portfolio and Infrastructure – A Combined Electricity and CCTS Investment and Dispatch Model	Submitted as DIW Berlin Discussion Paper; IEEE Conference Publication for the 12th International Conference on the European Energy Market (EEM), May 2015.	Joint work with Roman Mendelevitch. Pao-Yu Oei and Roman Mendelevitch jointly developed the model and its implementation in GAMS. Pao-Yu Oei was in charge of the implementation of the UK case study. Roman Mendelevitch had the lead in collecting data. The writing of the manuscript was executed jointly.

1.4 Research outlook: The road after Paris or designing the exit game

Combating global climate change implies the decarbonization of the electricity sector, a major contributor to global GHG emissions. My research shows that CCTS is unlikely to play an important role in doing so. Therefore, keeping global temperature rise under 2°C implies the phase-out of fossil-fueled power plants and leaving the majority of coal (and also to a smaller extent gas and oil) resources in the ground. Reducing GHG emissions and containing the burning of fossil fuels can only be incentivized economically when internalizing the external effects. Moreover, to create incentives for their participation, such policies must support developing countries in transitioning to low-carbon energy systems in a way that does not undermine their development goals. The reduction of GHGs therefore does need a continuous regulatory approach. This is different from RES and efficiency targets, which only need a regulatory approach for the start (kick-off) and then are incentivized through the market. However, taking previous experience into account, it seems unrealistic that all participating countries will agree on a first-best global climate policy that will be sufficient to reach the maximum warming of 2°C (Cole, 2015). A polycentric approach, according to Ostrom (2010), suggests additional policy schemes for various regions as well as sectors. This is in line with findings of our research that shows some sectors need individual treatment and specifically-tailored sector solutions (Hirschhausen et al., 2013). Overall, regional approaches, such as e.g. the German Energiewende, under a common set of EU-wide rules seem to be a promising way for climate policies to facilitate sustainable growth (Gawel et al., 2014).

Relying on various polycentric approaches also for different sectors highlights the importance of future research regarding sector interlinkages. This dissertation examines interlinkage effects between electricity and CO_2 networks; additional linkages, however, also exist with other sectors, such as water and food. Existing river basin models already include the effect of hydroelectricity, but do not examine the overall linkages between the sectors (Oei and Siehlow, 2014). Water demand for coal mining sites and power plants has already led to conflicting water interests between the electricity, agricultural, and domestic household sectors (Wuppertal Institute, 2012). This conflict might worsen since global temperatures rise and in addition new technologies, such as CCTS, lead to an 33% to 90% increase in water demand for electricity (Tidwell et al., 2013; Zhai et al., 2011). In addition, an increasing cultivation of energy crops for biomass CCTS utilization has significant effects on the agricultural sector and food security (Kemper, 2015). The nexus of electricity, water and food is, consequently, of growing importance and could benefit from additional research.

Developing new algorithms and expanding models to incorporate such cross-sector effects is an important aspect of energy and climate research. Jefferson (2014), however, warns that relying only on model projections can structure and distort our vision when trying to predict future events. Instead he emphasizes the importance of history: we should not just try to learn from our past mistakes, but also our positive experiences. Thus, past experiences, e.g. from the industrialization, the reunification or the shut down of nuclear plants in Germany, should be studied more closely in order to come up with strategies to structure the upcoming transition to a decarbonized electricity system in the best possible way. Enabling a smooth transition in first-mover countries like Germany will make it easier to encourage others to do likewise. Therefore, the successful phase-out of coal in Germany is an important step in combating global climate change. Distribution effects among affected sectors, regions, and people, however, complicate this problem. Evaluating a “fair” allocation of resources thereby depends heavily on the underlying definitions of fairness and requires interdisciplinary research (Breyer and Kolmar, 2010).

Another important aspect, which is directly connected to distributional effects and often mentioned as a potential barrier for climate change policies, is the issue of acceptance. The German Energiewende shows that society is sometimes even more progressive than the government and, in particular, large incumbent companies. People were asked by the official press office of the German government to state their preferred electricity fuels for a future electricity system in 20 to 30 years (Bundesregierung, 2015). The results were kept from the public, but provide interesting insights on acceptance issues: Renewables emerged as big winners of the survey with 85% (photovoltaics) and 77% (wind) support. Public consensus on the shut down of nuclear power plants is clearly visible, as only eight percent of those surveyed were in favor of nuclear energy. But public support for coal power plants is even lower, at five percent. The numbers show that the coal phase-out is already widely accepted across German society. It is now up to politicians not to withhold such findings, but instead to start structuring this coal phase-out. Doing so, in partnership with relevant actors from academia, politics, practitioners, and the affected population, facilitates a smooth transition pathway that can serve as a template to other countries.

2 Greenhouse Gas Emission Reductions and the Phasing-Out of Coal

2.1 Introduction: reducing greenhouse gases in the electricity sector

The reduction of greenhouse gas (GHG) emissions, in particular carbon dioxide (CO_2), is a major objective of the German Energiewende.[2] In contrast to the shut down of Germany's nuclear power plants there is a broad consensus on this goal for many years. Thus, the *"energy concept*" of the German government of 2010 already aimed at a reduction of GHG of 80-95% by 2050 (compared to the base year 1990) (Bundesregierung, 2010). This is in line with other countries' or regions' objectives, such as the UK or France (80% reduction by 2050) or the EU (likewise 80-95% reduction by 2050).

In contrast to other sectors such as transport, agriculture, or heating, the reduction of CO_2 emissions in the electricity sector can be achieved at relatively moderate cost. This is due to available low-cost alternatives, mainly renewable energy sources. A large number of studies indicate a pathway to obtain an almost complete decarbonization of Germany's electricity generation by 2050, amongst them the regular "lead studies" for the government (Nitsch, 2013), as well as from the Federal Environmental Agency (Umweltbundesamt: Klaus et al., 2010) and the German Advisory Council on the Environment (SRU, 2013). Likewise, modeling results of the European Energy Roadmap commissioned by the European Commission (EC, 2011) suggest that the electricity sector could be decarbonized to -97% at the horizon 2050. However, this assumes a major shift in the electricity mix, away from fossil fuels towards low-carbon generation technologies. In fact, when excluding the option of a carbon capture technology, achieving ambitious climate objectives in Germany (and elsewhere) implies phasing-out both hard coal and lignite.

This chapter provides an overview of the GHG emission reduction targets of Germany and the progress so far, with a focus on the electricity sector. The electricity sector can play an important role as a forerunner for decarbonization, provided that the appropriate regulatory framework is adopted. Due to insufficient price signals at least in the next decade, the European Emissions Trading System (EU-ETS) will not achive this objective on its own and

[2] This chapter is a single author publication based on the third chapter in the upcoming book "Energiewende" by von Hirschhausen et al. (forthcoming).

has to be complemented by appropriate national instruments. A variety of such measures are being discussed and have partially been implemented in Germany (Gawel et al., 2014; Oei et al., 2014b).

The chapter is structured in the following way: The upcoming section 2.2 summarizes Germany's greenhouse gas emissions reduction targets and relates them to European targets. Germany has played a leading role and it continues to do so as the overall European effort to reduce GHGs is continuing as well (-40% by 2030 and a similar -80-95% target for 2050). Section 2.3 focuses on coal electrification, and its role in the German energy sector, acknowledging that the continued use of coal would render the GHG reduction targets unachievable when excluding the option CCTS. We differentiate between hard coal, which is phased out gradually due to economic reasons (lacking competitiveness), and lignite, which is particularly CO_2-intensive and has high external costs but is still competitive. Section 2.4 discusses the influence of the EU-ETS as well as various additional national instruments, amongst them a CO_2 emissions performance standard (EPS), a CO_2 floor price, or a phase-out law. In Section 2.5, we show that a medium-term coal phase-out is compatible with resource adequacy in Germany. The resulting structural change in the affected local basins can be handled with additional schemes, thus posing no major obstacle to the coal phase-out. Section 2.6 concludes with a summary of chapter 2.

2.2 GHG emissions targets and recent trends in Germany

2.2.1 German GHG emissions targets to 2050

Combating climate change through GHG emissions reduction has a long tradition in Germany. Chancellor Helmut Kohl announced the first CO_2 reduction target of 25% until 2005 (base year 1990) at the first international climate conference in Berlin in 1995. Two years later Germany signed the Kyoto Protocol pledging a 21% GHG emission reduction target compared to the base year 1990 until 2012. This reduction target shows Germany's contribution to the burden sharing agreement within the European Union as it lies significantly above the overall European reduction of 8%. In 2007, Germany announced the target of 40% less GHG emissions in 2020 compared to 1990. The government also strongly supported the targets fixed by the European Union in its 2008 energy and climate package, i.e. a 20% reduction by 2020, and it tried (unsuccessfully) to increase the overall European target to 30% in the subsequent years (Hake et al., 2015). The German *"energy concept"* of 2010 then set the long-term GHG reduction targets that became a fundamental pillar of the Energiewende (base year: 1990): -40% by 2020, -55% by 2030, -70% by 2040, and -80-95% by 2050 (Bundesregierung, 2010).

Generally speaking, GHG emissions are decreasing in Germany, but significant efforts are required to maintain this downward trend. Figure 4 shows annual GHG emissions in Germany since 1990, divided into sectors governed under the EU-ETS (i.e. electricity, steel, energy-intensive industries) and so-called "non-ETS" sectors. It further differentiates hard coal and lignite, and indicates the reduction path until 2050 (-80-95%). The overall decline in GHG emissions becomes particularly visible in two major reduction periods: i) the economic recession in East Germany after reunification (1990-1994), and ii) the global economic and financial crisis (2008-2010). Even though these two periods account for a large part of the GHG reductions, the overall trend shows a clear decline of emissions.

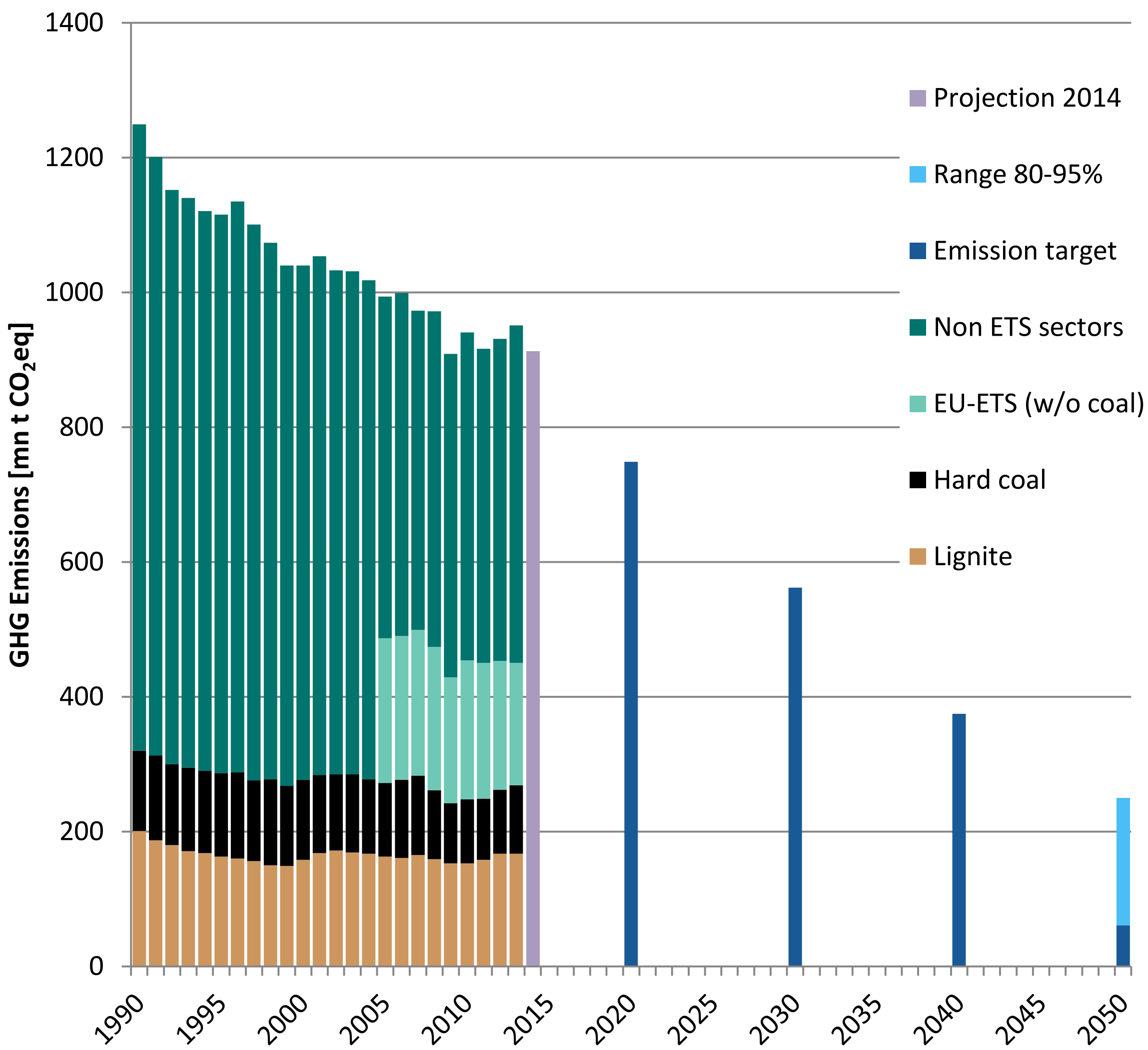

Figure 4: GHG emissions and emission targets in Germany from 1990 until 2050

Source: Umweltbundesamt (2014).

Achieving a long term GHG emissions reduction of up to 95% until 2050 in Germany requires drastic measures across all emitting sectors. Figure 5 shows the distribution of GHG emissions in Germany across different sectors in 1990 and 2012 compared to two different reduction scenarios for 2050 assuming 80 and 90% GHG emissions reduction, respectively. All sectors need to reduce their emissions until 2050, but their reduction potential varies, depending on existing mitigation options.

Within the energy sector, electricity is by far the largest emitter of GHG (around 75%). In the electricity sector, low-carbon alternatives are already in place, mainly renewable wind and solar technologies. These continue to benefit from cost decreases. Other energy sector emissions come from refineries that have much higher specific abatement costs compared to coal power plants. Overall, the energy sector is expected to contribute the largest absolute as well as relative reduction share of -86%/-99% compared to the base year 1990. Equivalent reduction shares are needed in the industry (-84%/-90%), trade & commerce (-91%/-95%), households (-87%/-89%)[3], transport (-85%/-85%) and the waste sector (-90%/-91%). In the latter sectors, emissions reductions are possible but require more specific action and entail higher costs.[4] GHG Emissions from agriculture, in particular NO_x from fertilizers and CH_4 in livestock farming, are most difficult to reduce and will therefore become the biggest emitters in 2050. Their reduction levels in the 80% reduction scenario nearly remain at 2012 levels at around -25%. Projections in the 90% reduction scenario account for a 54% reduction of agriculture at best (Öko-Institut and Fraunhofer ISI, 2014).

[3] See also Michelsen, Neuhoff and Schopp (2015): Using Equity Capital to Unlock Investment in Building Energy Efficiency? DIW Economic Bulletin 19/2015. p. 259-265. DIW Berlin, Germany.

[4] See Projektionsbericht der Bundesregierung (2015), gemäß Verordnung 525/2013/EU; BMVI (Hg.) (2014): Verkehrsverflechtungsprognose 2030. Los 3: Erstellung der Prognose der deutschlandweiten Verkehrsverflechtungen unter Berücksichtigung des Luftverkehrs. Intraplan Consult, BVU Beratergruppe Verkehr+Umwelt, Ingenieurgruppe IVV, Planco Consulting; Kirchner et al. (2009): Modell Deutschland—Klimaschutz Bis 2050: Vom Ziel Her Denken. Tech. rep., WWF Deutschland.

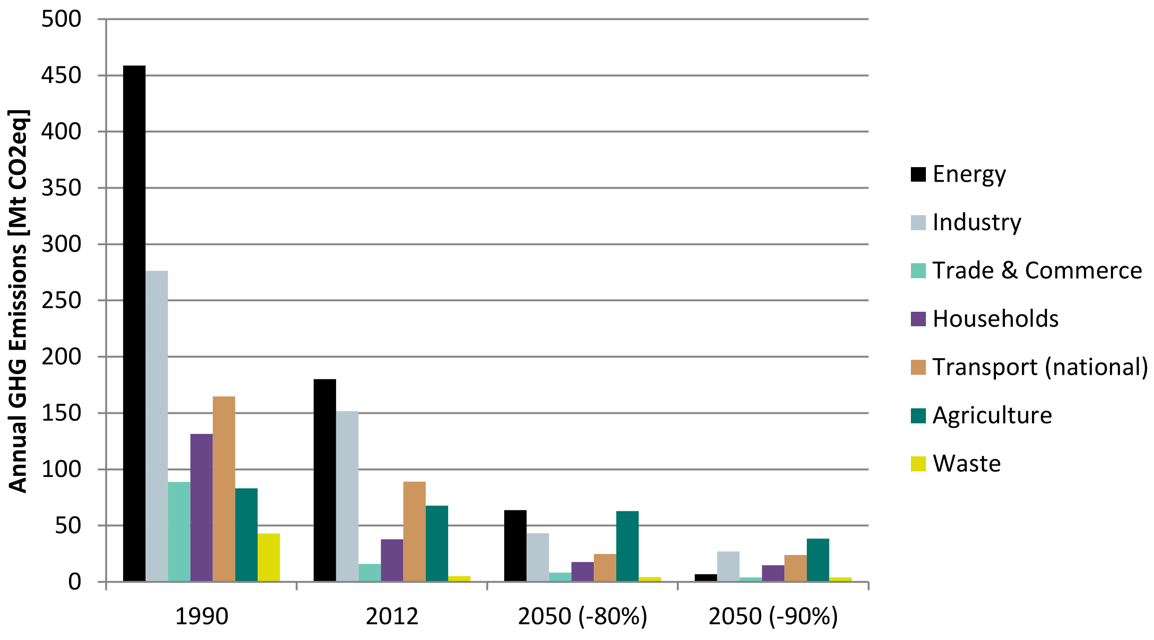

Figure 5: Distribution of German GHG emissions per sector

Source: Öko-Institut and Fraunhofer ISI (2014).

2.2.2 Ambitious targets at the State level as well

The low-carbon transformation requires a multitude of instruments at different levels of government, from global to local. Germany is a good example for this polycentric approach: in addition to the European and the national levels, the federal states ("Laender") also play a key role in the Energiewende, both as drivers and executers of climate policies. In fact, all 16 federal states have defined their own climate targets, and some of them are now legally binding. Baden-Württemberg, Bremen, North Rhine-Westphalia (NRW), and Rhineland-Palatinate have all signed laws to reduce their GHG emissions with concrete targets for 2020 and 2050. Similar agreements or draft laws exist in other federal states (see Table 2).

Brandenburg aims at a CO_2 emissions reduction of 72% until 2030 (base year 1990) while Saxony wants to reduce CO_2 emissions by 25% until 2020 (base year 2009). This is of particular relevance as electricity production in these two states is dominated by lignite capacities. Federal states in the Northern part of Germany mostly benefit from increasing wind power capacities to reduce their GHG emissions from the power sector. Bavaria and Baden-Württemberg in the South, on the other hand, are planning to replace their nuclear and coal capacities and substitute them with a mix of PV and gas power plants. All states, however, have at least some kind of climate agreements targeting emissions reductions, the expansion of renewable energy sources, and the improvement of energy efficiency.

Table 2: Overview of climate protection laws (top) and other agreements or drafts (bottom) by German Ferderal States (Laender)

Federal state	GHG-Target 2020 (base: 1990)	GHG-Target 2050 (base: 1990)
Baden-Württemberg	-25%	-90%
Bremen	-40%	-80-95%
North Rhine-Westphalia	-25%	-80%
Rhineland-Palatinate	-40%	-90%
Other climate agreements or drafts for planned climate protection laws		
Bayern	below 6t CO_2 annually per person	
Berlin	draft: -40% until 2020, -60% until 2030, -85% until 2050 (base: 1990)	
Brandenburg	-72% until 2030 (base: 1990)	
Hamburg	-30% until 2020, -80% until 2050 (base: 1990)	
Hessen	supports the German and European CO_2 reduction targets	
Lower Saxony	-40% until 2020, -80-95% until 2050 (base: 1990)	
Mecklenburg-Western Pomerania	-40% until 2020 (base: 1990)	
Saarland	-80% until 2050 (base: 1990)	
Saxony	-25% until 2020 (base: 2009)	
Saxony-Anhalt	-47.6% until 2020 (base: 1990)	
Schleswig-Holstein	-40% 2020, -55% 2030, -70% 2040, -80-95% 2050 (base: 1990)	
Thuringia	-10% until 2020 (base: 2010)	

Source: Information based on climate policies of the individual Laender[5]

2.2.3 Low-carbon transformation and the phasing-out of coal

The low-carbon transformation and the move towards renewables is now broadly accepted in most countries of the Western world. The main challenge in national and international climate targets is a continous phase out of the remaining global coal-fired power gen-

[5] Baden-Württemberg: http://bit.ly/1KLWkYO; Bremen: http://bit.ly/1PdkBwX; NRW: http://bit.ly/1KLWcZl; Rhineland-Palatinate: http://bit.ly/1dNlWJP; Bayern: http://bit.ly/1zBm355; Berlin: http://bit.ly/1c5AF1J; Brandenburg: http://bit.ly/1KLWwaB; Hamburg: http://bit.ly/1FPAROw; Hessen: http://bit.ly/1c5R9H0; Lower Saxony: http://bit.ly/1yJ0QBk; Mecklenburg-Western Pomerania: http://bit.ly/1EQfLhd; Saarland: http://bit.ly/1E8Ydu6; Saxony: http://bit.ly/1Cc4CJ6; Saxony-Anhalt: http://bit.ly/18hvERG; Schleswig-Holstein: http://bit.ly/1JQmcFe; Thuringia: http://bit.ly/1P0vzFW;. Last download May 5th, 2015.

eration.[6] Yet, the transition from fossil-fuel-based electricity generation to renewables is difficult as long as the negative externalities of fossil fuels are not taken into account in the cost of power generation. The list of externalities ranges from global effects such as global warming to local contamination from pollutants such as NO_x, SO_2, mercury, small particles and noise emissions. It also includes irregularities in groundwater and water pollution (e.g. through iron oxides) as well as relocations of towns and villages to make way for mines, resulting in thousands of people loosing their homes. The New Climate Economy report (2014) has put emphasis on the negative externalities of coal, and several studies show that the monetized negative externalities from coal electrification often exceed electricity prices.[7]

In the absence of abatement technologies, such as carbon capture (discussed in more detail in Chapters 3, 4 and 5), decarbonizing the electricity sector implies phasing-out coal altogether (Hirschhausen et al., 2012a). The consensus on the need to phase-out coal goes beyond the expert energy community, and now reached the mainstream, as shown by statements from the Group of Seven (Leader of the G7, 2015), the encyclical of pope Franziskus (2015) as well as the Islamic community (IICCS, 2015). Likewise the Intergovernmental Panel on Climate Change (IPCC) in its Fifth Assessment Report sees no long-term prospects for coal-based power generation (IPCC, 2014b).

2.3 Significant CO_2 emissions from hard coal and lignite in Germany

As a traditional coal country, the German energy mix before the Energiewende was very CO_2-intensive, and dominated by hard coal and lignite (see Figure 4). In 2012, coal electrification emitted 265 Mt of CO_2, which is equivalent to 84% of the total CO_2 emissions produced from power generation in Germany.[8] Additional pressure on CO_2 mitigation will come from the shut down of the remaining nuclear power plants until 2022 (9 GW in 2015), which will have to be substituted in the electricity mix. Against this background, Germany is running the risk of falling short on its CO_2 emissions reduction targets. The federal ministry for

[6] This section is based on a comprehensive study by Oei et al. (2014b) on phasing-out coal, in particular lignite.

[7] These costs are paid by society and therefore not taken into account by the polluting entity. See Ecofys (2014): Subsidies and costs of EU energy. Study for the European Commission; Climate Advisors (2011): The Social Cost of Coal: Implications for the World Bank. Washington, USA; and EC (2003): External Costs. Research results on socio-environmental damages due to electricity and transport. Brussels, Belgium.

[8] See AG Energiebilanzen (2014): Bruttostromerzeugung in Deutschland von 1990 bis 2013 nach Energieträgern; Umweltbundesamt (2013): Entwicklung der spezifischen Kohlendioxid-Emissionen des deutschen Strommix in den Jahren 1990 bis 2012. Climate Change 07.

the environment, nature conservation, and nuclear safety (BMU, 2012) and the German Advisory Council on the Environment (SRU, 2015) therefore highlight the need for a coal phase-out in the 2040s (see Figure 6).

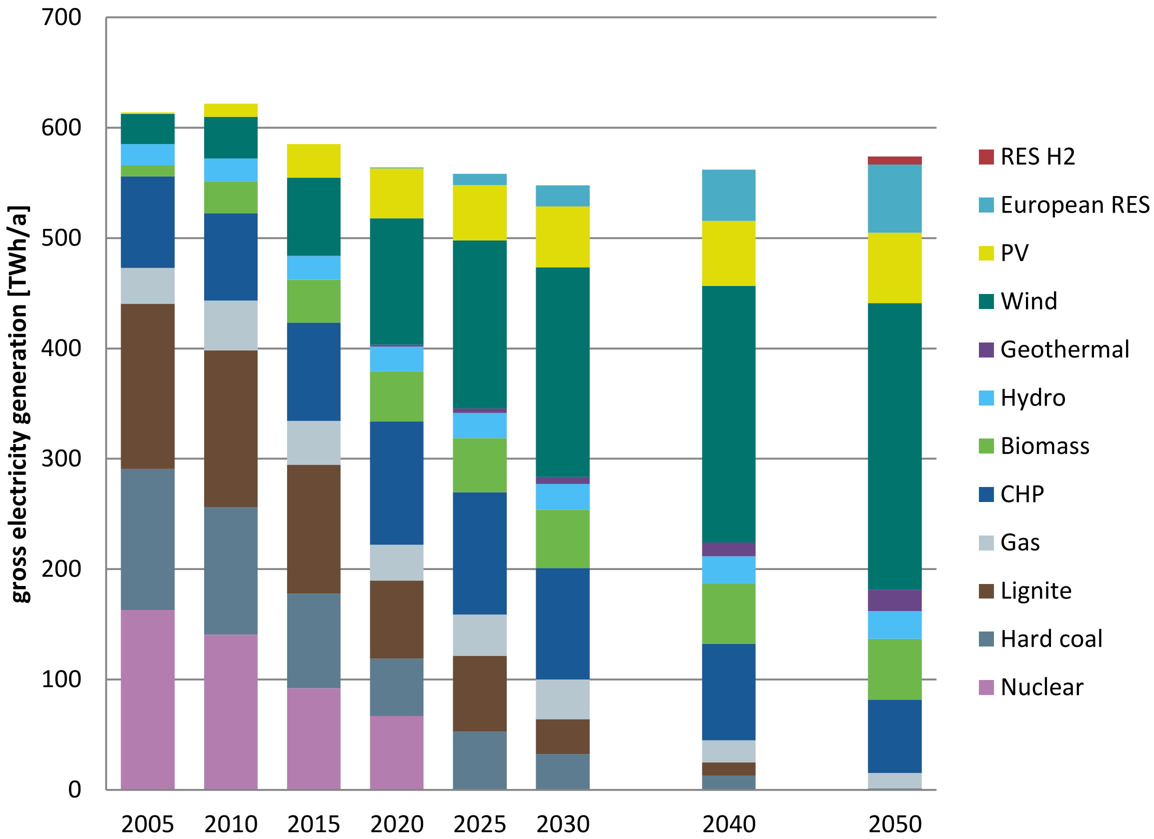

Figure 6: Generation mix in the German electricity sector from 2005-2050

Source: BMU (2012).

2.3.1 Electricity generation from hard coal

In 2013, a total of 122 TWh of electricity was generated by the 25 GW of Germany's hard-coal-fired power plants (cf. 2012: 116 TWh). This is equivalent to 98 Mt of CO_2.[9] Most of these plants are located at rivers in NRW (around 13 GW) and Baden-Württemberg (around 5 GW) or near the coast. The majority of active hard coal power plants in 2015 were constructed before 1990, mostly in the 1980s. Only 2.3 GW of new capacities were built from 1990 until 2010. The big energy utility companies such as RWE, E.ON, Vattenfall and Steag, however, returned to invest in new hard-coal-fired units in the 2010s, underestimating the speed of the Energiewende and overestimating future demand (see Figure 7) (Kungl, 2015). Increasing shares of renewable energy sources (from 9% in 2004 to 26% electricity

[9] AG Energiebilanzen (2014): loc. cit.; Umweltbundesamt (2013): loc. cit.

production in 2014) reduced the residual electricity demand. The resulting overcapacities of conventional power plants, together with decreasing EU-ETS certificate prices and low global coal prices, caused lower wholesale prices and reduced the load factor of the entire fleet. The average load factor of hard coal fired power plants dropped to 40% in 2011 (from 50% in 2005) compared to an unchanged high load factor of 80% for lignite power plants. As a result, operators had to account for impairment losses on hard-coal-fired power plants. In addition, stricter environmental regulations, construction problems and opposition by affected residents delayed the construction of some new coal power plants. Rising costs led to some of these projects being shelved. Low wholesale electricity prices also resulted in the closure of several older units that had become unprofitable due to low efficiency rates. This effect is very likely to continue in the near future as older less efficient hard-coal-fired units will be the first ones to be overtaken in the merit-order by gas-powered units if the price for CO_2 allowances increases. The overall setting makes retrofitting hard coal power plants uneconomic and therefore leads to a continuous market-driven phase-out of hard coal electricity in Germany (Oei et al., 2014e).

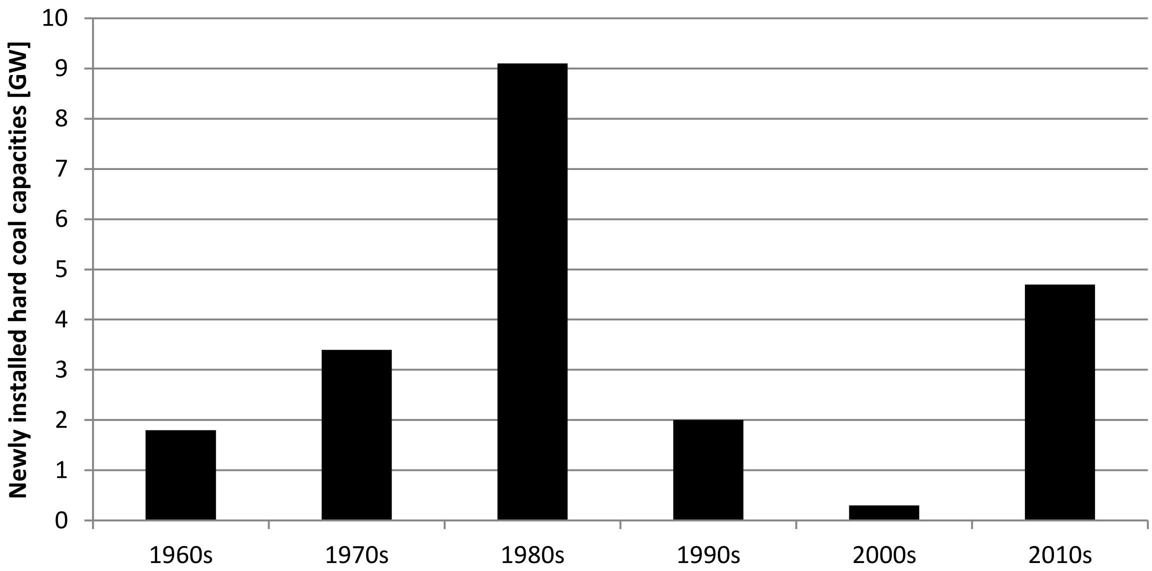

Figure 7: Startup years of active hard coal power plants in Germany in 2014

Source: Own depiction, on the basis of BNetzA (2014a) power plant database.

2.3.2 Electricity generation from lignite

In 2015, an overall capacity of around 20 GW at more than 60 lignite-fired units is located mainly in the Rhineland (around 10 GW), in central Germany and Helmstedt (around 3

GW) as well as in Lusatia (around 7 GW) (see Figure 8). In 2014, lignite-based power generation increased slightly compared to the previous years, totaling around 156 TWh in 2014 (26% of electricity generation).

The decline of lignite electricification becomes inevitable when sticking to the long-term agreed climate targets at the German, the European and the global level. Emitting 1,161 g CO_2/kWh per unit of electricity produced, lignite is by far the biggest producer of greenhouse gas emissions in the German energy mix (cf. hard coal: 902 g CO_2/kWh; natural gas: 411 g CO_2/kWh).[10] With annual emissions of 170 MtCO_2 lignite makes up around 50% of the emissions of the German power sector and is therefore incompatible with GHG reduction targets of 80-95% until 2050. Analyses of power plant and grid capacity for the mid-2020s in addition show that lignite will become less relevant for Germany's energy mix (Gerbaulet et al., 2012a, 2012b; Mieth et al., 2015b).

Given the uncertain future of lignite-based power generation, it is hardly surprising that there is controversy surrounding lignite mining districts that includes matters of i.e. employment, reallocation, and environmental aspects. In March of 2014, for instance, the NRW coalition government announced its decision to reduce the mining area at Garzweiler II so as to prevent the relocation of further 1,400 residents. This decision is the first of its kind in Germany. In the Eastern German Laender, there are similar controversial debates surrounding decisions to create new opencast mines (Welzow-Süd TF II and Jänschwalde Nord in Brandenburg, Nochten II in Saxony) or expand existing ones (Vereinigtes Schleenhain in Saxony). A decision taken on Garzweiler by the German Federal Constitutional Court in 2013 has supported legal action from affected villagers. Unlike in the 20th century, in the era of Energiewende fossil fuel mining can no longer be seen as a public interest decision that justifies serious infringements on the fundamental right to own property.[11]

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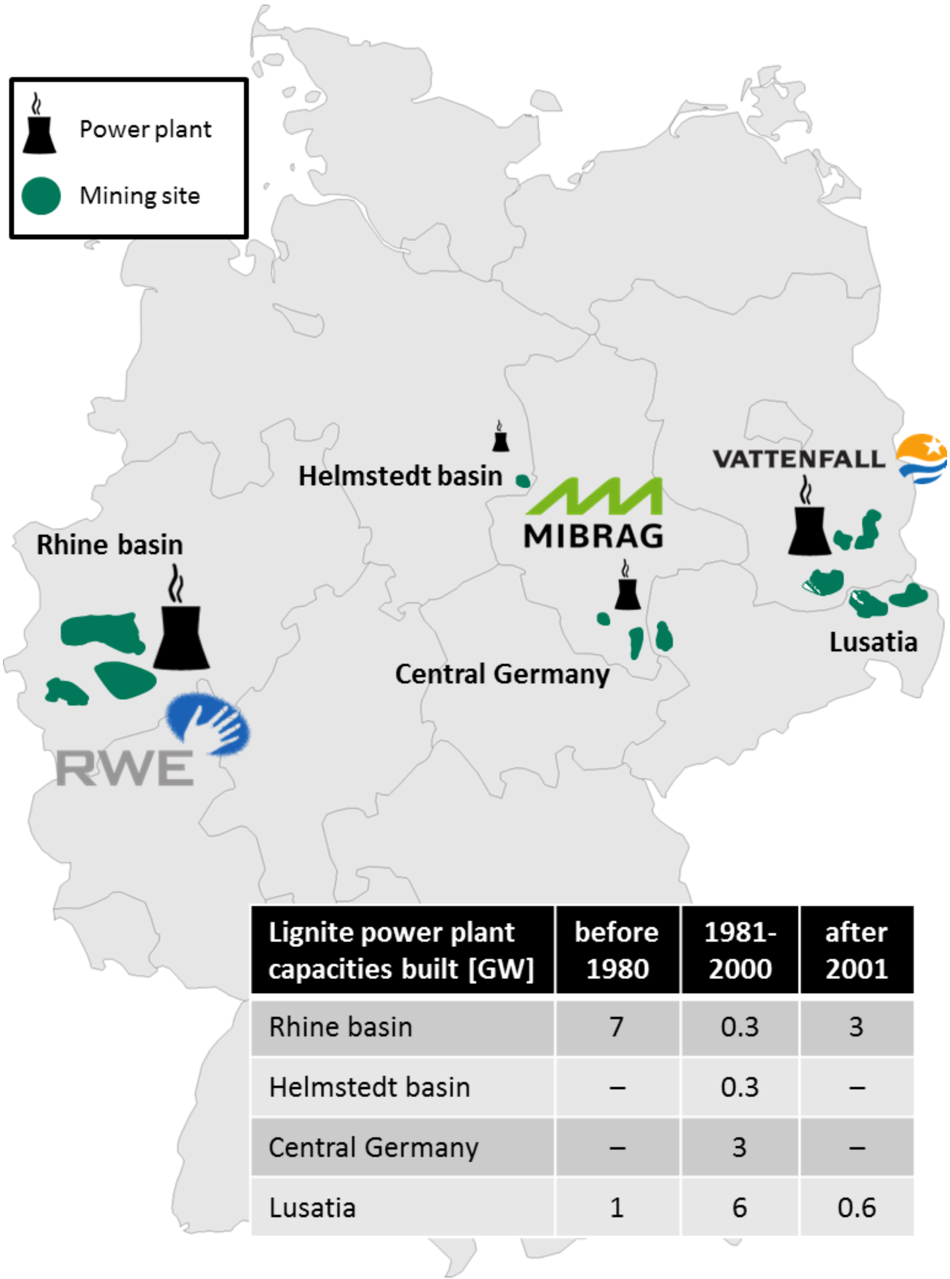
[10] The average CO_2 emission factors refer to power consumption for the year 2010, see UBA (2013): Entwicklung der spezifischen Kohlendioxid-Emissionen des deutschen Strommix in den Jahren 1990 bis 2012. Petra Icha, Climate Change 07/2013. More modern plants, in contrast, emit around 940 g/kWh for lignite, 735 g/kWh for hard coal, and 347 g/kWh for natural gas-based power plants, see UBA (2009): Klimaschutz und Versorgungssicherheit. Entwicklung einer nachhaltigen Stromversorgung, Climate Change 13.

[11] See Ziehm, „Neue Braunkohlentagebaue und Verfassungsrecht – Konsequenzen aus dem Garzweiler-Urteil des Bundesverfassungsgerichts". Kurzgutachten im Auftrag der Bundestagsfraktion von Bündnis 90/Die Grünen.



Lignite power plant capacities built [GW]	before 1980	1981-2000	after 2001
Rhine basin	7	0.3	3
Helmstedt basin	–	0.3	–
Central Germany	–	3	–
Lusatia	1	6	0.6

Figure 8: Remaining lignite basins and power plants in Germany in 2015.

Source: Own depiction, on the basis of BNetzA (2014a) power plant database.

2.4 Instruments to accelerate the coal phasing-out

2.4.1 European level: reform of the European Emissions Trading System

The EU-ETS is one of the European Union's central instruments for combating climate change. In the medium term, however, emissions trading is not expected to give sufficiently strong price signals to drive a shift towards low-carbon energy sources. The marginal costs of lignite electrification in Germany lie below those of gas (CCGT) power plants as long as CO_2 prices do not exceed 40-50 €/tCO_2. Switch prices from older hard coal power plants to new gas power units are in the range of 20-40 €/tCO_2. Switch prices mostly depend on the fuel costs as well as on the power plant efficiency and can therefore vary for each unit (see Figure 9) (Oei et al., 2014b).

Thus, while action is needed to stabllize the EU-ETS in the medium term, it has also become clear that it can not be the only instrument to promote decarbonization at the European level. In 2013, the structural surplus of certificates exceed the allowances for more than 2 billion t CO_2. The EC (2014a) expects the surplus to remain of the same magnitude at least until the end of the third trading period in 2020. Canceling this surplus woud have been an important signal to retain the credibility and steering capacity of the EU-ETS. This proposal, however, didn't receive sufficient political support on the EU level as some countries, e.g. Poland, opposed it. The possible solutions to the surplus problem being discussed by the European Commission will apply to the fourth trading period beginning in 2021. In this phase, a Market Stability Reserve (MSR) will be introduced as agreed by the Council in September 2015.[12] Nevertheless, the expected certificate surplus leads us to believe that the European system will have a limited impact on compliance with short- and medium-term national emissions targets. For this reason, additional national instruments are under discussion which could be introduced in parallel to emissions trading.

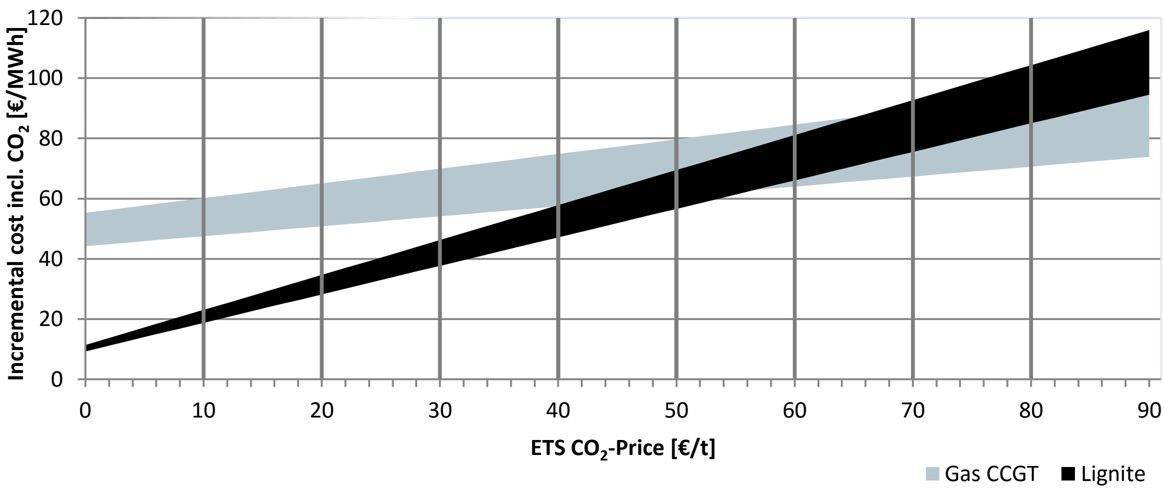


Figure 9: Marginal cost of lignite and gasfired (CCGT) power generation depending on the CO_2 price
Source: Oei et al. (2014b).

[12] For a surplus of more than 833 million allowances, a mechanism would automatically transfer 100 million allowances to the reserve to ensure that emissions certificates are sufficiently scarce on the emissions trading market. If the number of permits in circulation dips below the surplus threshold of 400 million, allowances would be released from the reserve again. However, the absolute number of certificates issued is not to be changed by the MSR mechanism. See also W. Acworth (2014): "Can the Market Stability Reserve Stabilise the EU-ETS: Commentators Hedge Their Bets, DIW-Roundup 23, 4.

2.4.2 Towards more specific climate instruments

It is clear that if the GHG targets set out by the German government are to be met, addiditional action is required in all sectors, including the electricity sector. Governmental thinking has evolved in this respect, and as the discussion on GHG targets advanced, the approach became more specific. Previously either focusing on the overall EU-ETS targets European-wide or on national non-ETS targets, the discussion now also includes specific national targets for the electricity sector. The grand coalition of Christian and Social Democrats has agreed on a Climate Action Plan ("Aktionsprogramm Klimaschutz 2020") in 2014 to counteract the rise of emissions in 2012-2014. This action plan restricts coal usage to make it possible to reach Germany's CO_2 reduction targets. Moreover, according to an analysis by *Agora Energiewende,* the aim should be to cut lignite and hard coal-based power generation by 62% and 80% by 2030, respectively.[13] Reducing power sector emissions also plays a major role in the national Climate Protection Plan 2050 ("Klimaschutzplan 2050"), which is currently open for consultation.

The German government therefore pursues different instruments to combat climate change at different levels (e.g., Germany-wide and at the EU level) and uses instruments with different mechanisms. The government is aiming to contribute to (national) targets being met by pushing for an ambitious structural reform of the EU-ETS as well as including options for additional measures in the specific German context of the Energiewende. The aim of this polycentric approach is not to establish mutually exclusive instruments or mechanisms, but to take action in several areas simultaneously. The German government cites three possible courses of action: greater commitment outside the framework of the EU-ETS, a focus on an ambitious structural reform of the EU-ETS, and flanking measures within the context of the Energiewende (BMUB, 2014).

As a consequence several older coal power plants are expected to be shut down to reduce the existing overcapacities. Support for such an agreement has been signaled by different players such as EnBW and 70 municipal utilities.[14] These companies would profit

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[13] See Graichen and Redl (2014): Das deutsche Energiewende-Paradox: Ursachen und Herausforderungen; Eine Analyse des Stromsystems von 2010 bis 2030 in Bezug auf Erneuerbare Energien, Kohle, Gas, Kernkraft und CO_2-Emissionen. Agora Energiewende. Berlin.

[14] Handelsblatt (2015): Stadtwerke gegen RWE http://www.handelsblatt.com/politik/deutschland/klimaabgabe-plaene-stadtwerke-gegen-rwe/11677972.html ; Süddeutsche Zeitung (2015): Dicke Luft in der Strombranche http://www.sueddeutsche.de/wirtschaft/klimaschutz-dicke-luft-in-der-strombranche-1.2502249 .

from higher load factors for their gas utilities and the rise in wholesale electricity prices. The energy-intensive industry, on the other hand, benefits from low wholesale prices and therefore opposes any measures that might lead to a price increase. The major argument from these industry branches is the fear of a deindustrialization as Germany would no longer be able to compete with lower production costs in foreign countries. Various studies, however, have shown that a moderate increase of the electricity price would only have limited effects on the competitiveness of German industry.[15]

2.4.3 National level: a variety of instruments

Some countries in the EU but also across the Atlantic have taken initiative by adopting complementary measures; namely the UK (CO_2 emissions performance standards (EPS) and a carbon price floor), the USA (EPS and an additional retirement plan for older plants), and Canada (EPS). In this context, this chaper analyzes policies to reduce German power sector GHG emissions in general and phasing-out of coal in particular. Possible accompanying measures to reduce coal-based power generation in Germany include minimum fuel efficiency or greater flexibility requirements, national minimum prices for CO_2 emissions allowances, capacity mechanisms, a residual emissions cap for coal-fired power plants, emissions performance standards, and policies regulating transmission grids (see Table 4). In Germany, these could be implemented in parallel to the desired EU-ETS reform and will be described in more detail in the following sections.[16]

2.4.3.1 Emissions performance standard

In addition to the EU-ETS, another means of tackling the emissions problem is the introduction of CO_2 limits in the form of an EPS. Following Canadian and Californian initiatives, the UK has already incorporated this measure into an amendment of its *Energy Act* adopted in December 2013 (The Parliament of Great Britain, 2013). The UK EPS prevents the construction of new unabated coal-fired power plants, i.e. units that do not make use of carbon capture, transport, and storage (CCTS). The Canadian EPS also affects existing power plants when they reach the age of 45 to 50, depending on the year of their commissioning. The

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[15] See Agora Energiewende (2014): Comparing Electricity Prices for Industry. Analysis. An Elusive Task - Illustrated by the German Case. Berlin; and Neuhoff et al. (2014): Energie- und Klimapolitik: Europa ist nicht allein. (DIW Wochenbericht Nr. 6/2014) DIW Berlin.

[16] This section is based on a comprehensive study by Oei et al. (2014) on phasing-out coal, in particular lignite.

introduction of an EPS in EU Member States (and thus in Germany, too) conforms with European Law as set out in Article 193 of the Treaty on the Functioning of the European Union (TFEU).[17]

In a study on the potential effects of an EPS in Germany, we have quantified the effects of a CO_2-emissions limit of 450 g CO_2/kWh for newly constructed as well as retrofitted plants (Ziehm et al., 2014). This provision would put a halt to the construction of new coal-fired power plants. In addition, existing plants that have been in operation for 30 years or more could be subject to an annual emissions cap.[18] Such regulation aims at tackling especially the oldest and least efficient power plants. In this case, the performance standard involves limiting the maximum net annual emissions to ~3,000 t CO_2/MW.[19] Depending on the given emissions factor and efficiency of individual plants, this is equivalent to a load factor of around 90-100% for CCGT power plants, 40-50% for hard coal fired power plants, and around 30-40% for lignite power plants. Separate regulations would be applicable to combined heat and power (CHP) plants. In the scenario, hard coal fired power plants with a total output of around 10.5 GW and lignite plants with around 9.5 GW would be affected by such a regulation for existing plants starting in 2015. The annual power generation of these plants would thus fall by 45 TWh. The net emissions reduction effect depends on whether these generation volumes are substituted by additional renewable capacities, gas generation with lower CO_2 volumes or an increase of newer unrestricted hard coal units.[20] The number of coal-fired power plants falling under this regulation would increase over time since retrofit measures would not be allowed, nor the construction of new plants. The implementation of an EPS therefore leads to a continuous reduction of coal generation as well as CO_2 emissions (see Figure 10).

[17] See Ziehm and Wegener (2013): Zur Zulässigkeit nationaler CO_2-Grenzwerte für dem Emissionshandel unterfallende neue Energieerzeugungsanlagen. Deutsche Umwelthilfe. Berlin.

[18] Following the considerations made with regard to the nuclear phase-out, the basis of the 30-year-limit is the amortization plus a given profit realization period.

[19] Calculation basis: gas power plant emissions data (450 g CO_2/kWh), the total annual operating hours at 80% capacity: 450 g CO_2/kWh × 8760 h × 0.8 = 3154 t CO_2/MW.

[20] A reduction of German production also reduces net exports and consequently increases generation and emissions in neighbouring countries. A more recent study shows that the net CO_2 reduction effect in the European electricity sector is around 50% of the German reduction when introducing a national EPS (Oei et al., 2015a).

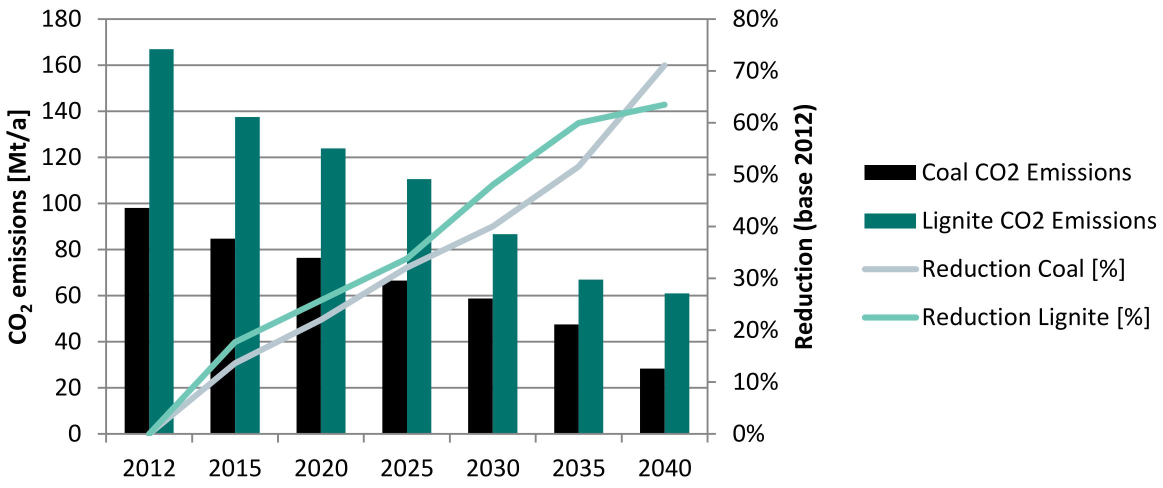

Figure 10: Effect of an Emissions Performance Standard on coal electrification in Germany.
Source: Ziehm et al. (2014).

2.4.3.2 Carbon floor price

To strengthen the effect of the EU-ETS, a minimum price for CO_2 emissions could be set at the EU level. However, national governments could also set their own individual minimum prices to help meet climate targets. In 2013, for example, the UK introduced an additional tax on carbon dioxide emissions in the power sector known as the Carbon Price Floor (CPF). Together, the tax and CO_2 price make up a "minimum price" for CO_2 emissions. For the 2013/14 financial period, the minimum price was £16 (around €20) for each ton of CO_2 emitted.[21]

In Germany, the introduction of a minimum CO_2 price in the form of an additional tax on the purchase of CO_2 emissions allowances, as proposed in a bill by the green party Bündnis 90/Die Grünen, would be possible.[22] Under energy tax laws in Germany, power plant operators are exempt from the existing energy tax, and plans are in place to remove this tax altogether. In all likelihood, however, a government-fixed minimum price on carbon emissions would have very little impact on coal-based power generation unless switch prices to gas are being met (see Figure 9).

[21] See HM Revenue & Customs (2014): Carbon price floor: reform and other technical amendments. Originally, the CPF was to increase linearly to 30 £/t by 2020/2021, but this figure was frozen at 18 £/t for the rest of the decade. The reason for this decision was the large gap between the CPF and the CO_2 price in the EU-ETS scheme, which might have had a negative impact on the competitiveness of the UK's domestic industry.

[22] A Climate Change Act bill recently proposed by the parliamentary group Bündnis 90/Die Grünen calls for the introduction of a minimum price for CO_2 similar to that in the UK. According to the bill, the CO_2 price was to start at 15 €/t in 2015 and increase by 1 €/t per annum until 2020, See Deutscher Bundestag (2014): Entwurf eines Gesetzes zur Festlegung nationaler Klimaschutzziele und zur Förderung des Klimaschutzes (Klimaschutzgesetz), Bundestag printed paper 18/1612.

2.4.3.3 Minimum efficiency and greater flexibility requirements

Innovations in the energy sector have focused on increasing efficiency levels. The main motivation behind this, however, was competition and not regulatory measures. However, further advances due to coal pre-drying or retrofit measures would only lead to insignificant increases in efficiency of a few percent. In Germany, a bill to introduce a minimum efficiency level put forward by the parliamentary group Bündnis 90/Die Grünen in the German Bundestag in 2009, for example, failed.[23] The bill proposed an amendment to the Federal Immission Control Act (Bundesimmissionsschutzgetz, BImSchG) which would have required all newly built power plants to have a minimum efficiency of 58%. Existing hard coal and lignite power plants would have to have a minimum efficiency factor of 38 and 36%, respectively. In 2020, these figures were to be increased to 40 and 38%. The existing legal hurdle for efficiency requirements was also to be removed. At 40% efficiency and above, the introduction of minimum efficiency levels for power plants, including existing plants, would affect more than 10 GW of lignite and 10 GW of hard coal capacity in Germany. However, if a general, non-technology-specific minimum efficiency requirement were to be introduced, this would affect not only coal-fired power plants but also open cycle gas turbines (OCGT) that have similar efficiencies to coal-fired power plants. Owing to their flexibility, however, open-cycle gas turbines are an essential part of an energy mix based on a high percentage of fluctuating renewable energy sources.

Given the steady increase in the share of RES in the German energy mix, the flexibility of conventional power plants becomes increasingly important. The key benchmarks for flexibility are the short-term ability to change production levels, minimum must-run generation, the start-up as well as ramping times, and the minimum run-time of a power plant. Irrespective of what fuel is used, steam power plants in particular face certain technical restrictions. Combined cycle gas power plants (CCGT plants) use the waste heat generated by the gas turbine to fuel a secondary steam process and therefore reach higher efficiency values. They are, however, not as flexible as open-cycle gas turbines that run without steam. Both the minimum generation (must-run) and the maximum start-up times of CCGT plants are therefore similar to those of coal-fired power plants (see Table 3) (VDE, 2012).

[23] See Deutscher Bundestag (2009): Neue Kohlekraftwerke verhindern – Genehmigungsrecht verschärfen: Beschlussempfehlung und Bericht des Ausschusses für Umwelt, Naturschutz und Reaktorsicherheit.

Table 3: Technical properties of gas and coal power plants

	Ramp-up [h]	Min load [%]	Efficiency at full nomial power P_n [%]	Efficiency at 50% nominal power P_n [%]
OCGT	< 0,1	20 – 50	30 – 35	27 – 32
CCGT normal	0,75 – 1,0	30 – 50	58 – 59	54 – 57
CCGT flexible	0,5	15 – 25	> 60	52 – 55
Coal normal	2 – 3	40	42 – 45	40 – 42
Coal flexible	1 – 2	20	45 – 47	42 – 44

Source: VDE (2012).

Minimum efficiency and flexibility requirements would affect either open cycle or combined cycle gas power plants in addition to coal-fired power plants. These instruments are therefore not ideally suited for reducing coal-based power generation unless they are introduced as fuel-specific.

2.4.3.4 Coal phase-out law

A coal phase-out law sets a fixed phase-out schedule based on i) a limit for fullload-hours or ii) CO_2 emissions. A specific scenario on the basis of fullloadhours for coal power plants was described in a study conducted by Ecofys on behalf of Greenpeace in 2012.[24] The alternative option is CO_2 allowances that are allocated to the individual power plants on the basis of "historical" emissions (free allocation) or by means of individual auctions. A coal phase-out law can include the option for transferring remaining fullloadhours or CO_2 emissions from one power plant to another. Transferring run-times in between lignite plants also effects the extraction in the respective open-cast mines, which could result in additional relocations of people living in this area. A conceivable solution would be to impose requirements that a transfer of emissions permits is only allowed if the new configuration does not lead to a higher number of needed relocations.

2.4.3.5 Introducing capacity mechanisms

Elements of climate policies can be taken into account in the design of capacity mechanisms. Capacity mechanisms, such as a capacity reserve, include payments for select-

[24] See Klaus, Beyer, and Jaworski (2012): Allokationsmethoden der Reststrommengen nach dem Entwurf des Kohleausstiegsgesetzes - Verteilung der Reststrommengen und Folgenabschätzung für den Kohlekraftwerkspark; Studie von Ecofys im Auftrag von Greenpeace.

ed capacities to secure resource adequacy of electricity generation. One example is the German "Climate Action Plan" of 2015 which includes an explicit reference to coal policy, and provides a platform for negotiations with the operators to reduce CO_2 emissions.[25] The configurations of capacity mechanisms strongly affect the energy mix and, consequently, the CO_2-intensity of future power generation. Discussions surrounding capacity mechanisms therefore have to take climate policy into account. Put simply, the more the existing power plant fleet is being supported, the more CO_2 intensive the future fleet will be. Having an instrument to promote less CO_2 intensive gas power plants (for example, via the establishment of minimum flexibility requirements or EPS as criteria), however, would help make these plants more profitable.[26]

It would also be possible to transfer coal-fired power plants into a capacity reserve of some kind. Such a reserve would help cut emissions while retaining capacity. In turn, investment incentives for gas power plants would increase, and power plant operators would be given compensation for complying with the given capacity requirements. We use a detailed model of the German electricity market to simulate a range of different scenarios of closing down coal power plants (Reitz et al., 2014a). The main scenario consists of the additional closure of 3 GW of hard coal, and 6 GW of lignite plants, leading to about 23 Mt of avoided CO_2 emissions. Lignite power would lose strongly (-40 TWh), whereas natural gas would benefit (+26 TWh). Hard coal, too, would slightly increase generation (+13 TWh). A second scenario assumes a shut down of 3 GW of hard coal and 10 GW of lignite capacities resulting in an emission reduction of 35 Mt of CO_2 (see Figure 11). With increasing wholesale prices, the EEG surcharge declines, so that consumer prices would be less affected than the wholesale price.[27] We conclude that a structured shut-down of old and inefficient coal plants facilitates the accomplishment of GHG reduction goals, while at the same time improving the market situation and preventing the need for CO_2-intensive and expensive capacity

[25] In the Netherlands, for example, agreements were made with individual operators, who, owing to a Dutch tax on coal electrification being abolished, had agreed to the closure of coal-fired power plants with a total capacity of 3 GW earlier than planned by 2017.

[26] See Matthes et al. (2012): Fokussierte Kapazitätsmärkte. Ein neues Marktdesign für den Übergang zu einem neuen Energiesystem. Öko-Institut e.V. - LBD-Beratungsgesellschaft mbH - RAUE LLP. Berlin

[27] The effects of this modeling approach, however, focus on Germany only. Including the neighbouring countries would lead to a small shift of production and emissions from Germany to its neighbours.

mechanisms.[28] Emissions of other pollutants such as NO_x, SO_2, small particles and mercury are also reduced. In addition, less coal electrification reduces the need for new mines, resulting in a double dividend for affected residents and the environment.[29]

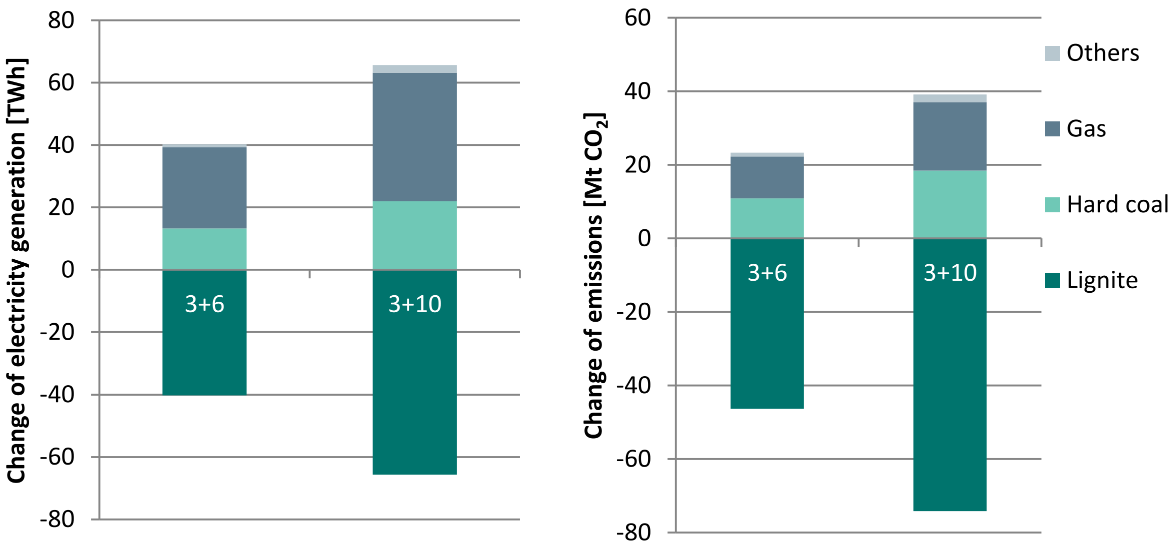

Figure 11: Change of electricity generation (left) and CO_2-emissions (right) in the different scenarios (shut down of 3 GW hard coal and 6/10 GW of lignite) in the year 2015.

Source: Reitz et al. (2014a).

2.4.3.6 Introducing a "climate contribution" fee

Along the lines of a minimum CO_2 price, the German Ministry for Economy and Energy (BMWi) in the first half of 2015 proposed the introduction of a "climate contribution" (German: "Klimabeitrag") to achieve a reduction of 22 $MtCO_2$, in addition to the reduction foreseen in the "Business as Usual – BAU" scenario (so-called "Projektionsbericht", submitted to the EU). The "climate contribution" is an additional financial levy paid by power plant operators to the German state addressing primarily old and CO_2-intensive coal power plants. A level of 18 €/tCO_2, in combination with a free allocation of 3-7 $MtCO_2$/GW of plant capacity (depending on the age of the plant) is appropriate to assure a 22 $MtCO_2$-reduction by 2020. Figure 12 shows the effects of different parameterizations of the climate contribution

[28] The German Ministry for Economy and Energy (BMWi) decided in November 2015 to move 2.7 GW of old lignite capacities into a reserve for climate reasons. An analysis shows that this reserve, however, is too small to reach Germany´s 2020 climate targets (Oei et al., 2016, 2015a).

[29] This study only analyses the situation in Germany. It neglects that a reduction of German production also reduces net exports and consequently increases generation and emissions in neighbouring countries. More recent studies shows that the net CO_2 reduction effect in the European electricity sector is around 50% of the German reduction when introducing national measures (Oei et al., 2015a, 2015b).

and the corresponding effect on the reduction of CO_2-emissions compared to the BAU scenario without the fee. A reduction of the climate contribution, e.g. in the range of 12-16€/tCO_2, and/or an increase of the free allocation to older power plants, would weaken the effects. The climate contribution includes the option for power operators to emit beyond their free allocation levels when decommissioning additional EU-ETS CO_2-certificates (Oei et al., 2015b).

The introduction of the climate contribution, similary to most of the other described additional measures, mainly affects older and CO_2-intensive lignite power plants in NRW and Lusatia (“Lausitz”, see Figure 8 on page 34). Critics feared that this might result in the rapid closure of many plants combined with job losses. A premature closure of most power plants, however, is unlikely as the measure would only have resulted in a reduction of full load hours. This hardly affects employment in the power plants. In addition, many of the older plants are scheduled to go offline in the 2020s, anyway, and the reduction of their workforce is not related to the climate contribution. Indirect effects, i.e. in lignite mining, heating plants or chemical industries would likely also be mild.

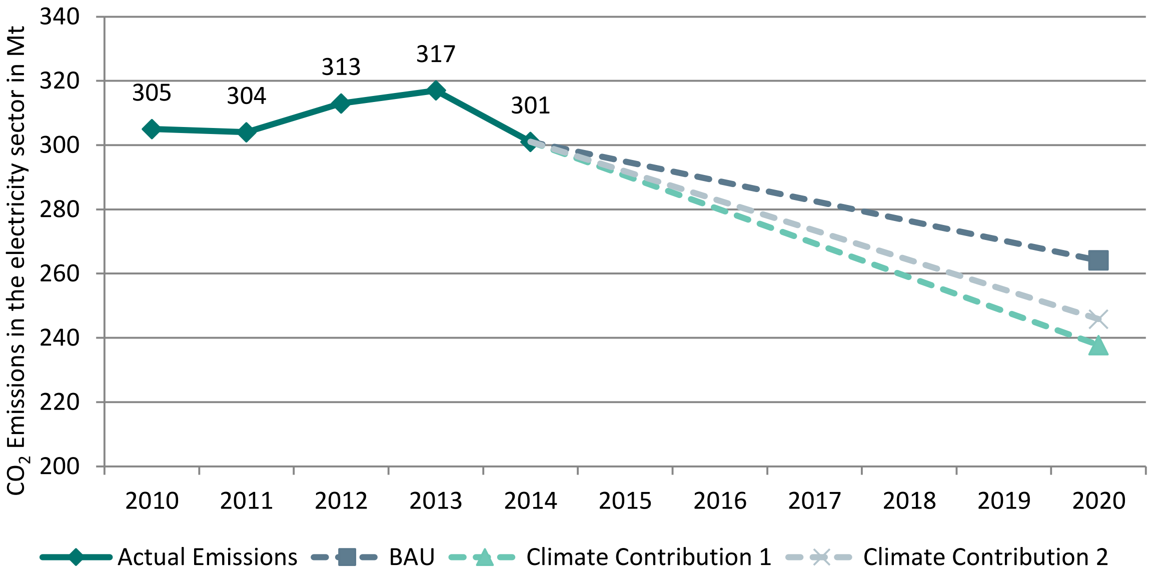

Figure 12: CO_2 emissions in Germany with and without the introduction of the climate contribution.
Source: Oei et al. (2015b).

2.4.3.7 Transmission corridors and lignite basins

Limiting available transmission capacity, thus constraining the access of lignite basins to far-away electricity consumers is yet another instrument to reduce lignite power generation. Brancucci (2013) and Abrell and Rausch (2015) use a bottom-up and top-down perspectiveIn to show that an increase of high-voltage electricity lines favours coal electrification if their external costs are not sufficiently internalized. The argument applies to the German situation as well. In fact, discussions in Germany center around the planning of three high-voltage direct current (DC) lines which were supposed to transport wind energy generated in the North to the southern demand centers (see Chapter 6): Two out of the three planned corridors have their starting point in the lignite regions of NRW and Eastern Germany, respectively. They would therefore enable a continuously high lignite electrification even at times of high wind generation in Northern Germany. The excess electricity could then be exported to neighboring countries, replacing foreign gas power plants. The higher CO_2 output, however, would increase German as well as the European GHG emissions. In a study on the low-carbon energy strategy of the State of Bavaria, Mieth et al. (2015a) provide bottom-up calculations of the effects of an additional HVDC-line from the lignite basins of East Germany to Southern Germany. They confirmed the effect known from the literature, i.e. the new line would lead to about 10 TWh more lignite electrification.[30]

In this context, Germany also emerged as the first country in which the CO_2 intensity of electricity was explicitely capped by the network regulator. In fact, the 2015-based ten-year-network-development-plan (TYNDP) for Germany was the first to include explicit CO_2 targets for network planning: Future electricity transmission planners now have concrete CO_2 targets that need to be respected in their calculations and will align the planning of new lines with the objectives of the Energiewende (Mieth et al., 2015b). The caps have been fixed at 187 Mt of CO_2 for 2025, and 134 Mt for 2035 and correspond to the reduction target of -55% in 2030 (compared to 1990). This target reflects a proportional reduction of the electricity sector and should be increased as emission reductions in other sectors, are possible, but require more specific action, and higher costs.

[30] Operators of lignite power plants would still sell their electricity on the national wholesale market, leading to higher dispatch costs.

Table 4: Possible instruments for reducing coal-based power generation (in the German context)

PROPOSED MEASURE	EXPECTED EFFECT	POSSIBLE ADVANTAGES	POSSIBLE SHORTCOMINGS	PROPOSED / DISCUSSED BY
EU-ETS reform	Price signal through the introduction of market stability reserve (MSR); additional measures: 900 mn EUA from backloading directly in MSR, start of MSR in 2017 instead of 2021	EU-wide instrument; thus, no cross-border leakage effects targets several sectors besides electricity	Structural reforms uncertain from today's perspective; the extent of the impact is unpredictable due to high surplus of certificates	German government (2014)
CO_2 floor price	CO_2 certificates would become more expensive	Investment security for operators	Feasible prices probably too low to result in a switch from lignite towards natural gas in the short-term	BÜNDNIS 90/DIE GRÜNEN (2014)
Minimum efficiency	Closure of inefficient power plants	More efficient utilization of raw materials	Open cycle gas turbines (OCGT) could also be affected; complex and time-consuming test and measurement processes	BÜNDNIS 90/DIE GRÜNEN (2009)
Flexibility requirements	Closure or singling out of inflexible power plants	Better integration of fluctuating renewable energy sources	Combined cycle gas turbines (CCGT) could also be affected; complex and time-consuming test and measurement processes	Matthes et al. (2012)
Coal phase-out law	Maximum production [TWh] or emissions allowances [tCO_2] for plants	Fixed coal phase-out plan & schedule investment security	Outcome of auctioning of allowances would be difficult to predict	Greenpeace (2012), DIE LINKE (2014)
Emissions performance standard (per unit; for new plants and retrofits)	Restrictions for new plants and retrofits (without CO_2 capture) [< x g/MWh]	Prevention of CO_2- intensive (future stranded) investments	Minor short-term reduction in emissions	IASS Potsdam (2014), Ziehm et al. (2014), BÜNDNIS 90/DIE GRÜNEN (2015), Oei et al. (2014c, 2014d)
Emissions performance standard (emissions cap for existing plants)	Reduce load factor for depreciated coal-fired power plants (e.g. > 30y) [< x g/MW]	Preservation of generation capacities	Negative impact on economic efficiency of power plants might lead to closure of older blocks	IASS Potsdam (2014), Ziehm, et al. (2014) , BÜNDNIS 90/DIE GRÜNEN (2015); Oei et al (2015a)
Capacity mechanisms or reserve for coal plants	Incentive for construction of less CO_2-intensive power plants when including environmental criteria	Support of gas power plants; or moving coal power plants into a reserve to reduce their emissions and prevent supply bottlenecks	Difficult to set up critieria that is in line with EU state aid laws if payments should only be given to selected units	Matthes et al. (2012), Reitz et al. (2014a, 2014b); Oei et al (2015a)
Climate contribution fee	Additional levy for old CO_2 intensive power plants	Limiting output of most CO_2 intensive generation facilities; preserving capacities; compatible with EU-ETS	Older units might become uneconomic if the fee is too high	BMWI (2015), Oei et al. (2015b)
Reduced transmission grid expansion	Increased congestions might prohibit lignite electrification in times of high renewable energy production	Re-dispatch of less CO_2-intensive capacities; less investment costs for transmission lines	Transmission grids might be needed for renewables in the long run.	Mieth et al. (2015b), Schröder et al. (2013b, 2012), Oei et al. (2012)

Source: Own depiction based on Oei et al. (2014b).

2.5 Effects on resource adequacy and structural change

There is no doubt that if the German government is serious about its climate targets, coal will have to be gradually phased-out of the electricity mix as CCTS is not regarded as viable option for Germany. This section looks at two potential effects of the coal phase-out on resource adequacy and structural change in the major coal regions.

2.5.1 Coal plant closures and resource adequacy

A German coal phase-out has various effects on electricity generation, wholesale and consumer prices as well as revenue streams. These effects depend on the chosen instruments and their specifications. Some general findings, however, are very similar throughout all options (Oei et al., 2015b, 2014b). The following section therefore shows some representative modeling results until 2035. They assume a gradual phase-out of coal generation capacities with no retrofits according to the scenario framework by the BNetzA (2014b) (see Table 5). In Oei et al. (2015b), we have developed two scenarios to analyse different policy instruments, which both assume the same power plant capacities:

- the green scenario includes a fee on electricity from coal, in the spirit of the so-called "climate contribution" that restricts the loadfactors of older coal power plants (see Chapter 2.4.3.6);
- the black scenario, a business-as-usual (BAU) scenario.

Table 5: Generation capacities in Germany until 2035

in GW	2013	2020	2025	2035
Nuclear	12.1	8.1	-	-
Lignite	21.2	20.0	12.6	9.1
Hard coal	25.9	26.0	21.8	11.1
Gas	26.7	19.2	25.4	32.7
Hydro	3.9	4.0	4.0	4.2
Wind onshore	33.8	52.2	63.8	88.8
Wind offshore	0.5	6.5	10.5	18.5
Biomas	6.2	7.2	7.4	8.4
Solar	36.3	48.2	54.9	59.9
Pumped Hydro	6.4	7.8	8.3	12.5
Others	4.7	2.2	2.8	2.4
Total	165.6	201.4	211.5	247.6

Source: BNetzA (2014b).

Germany has increased its electricity exports continuously in the last years to an all time high of 35 TWh in 2014. This has led to decreased gas electricity production in neighbouring countries. Modeling results show that this rise of export quantities is going to continue in the black BAU scenario to figures above 50 TWh. Such a rise also implies increasing congestion at cross-border interconnectors. A gradual coal phase-out would halt rising exports in 2020 slightly above the level of 2014 and reduce line congestions. Germany would still remain an exporter of electricity with a volume of around 10 TWh in 2035 (see Figure 13).

The effect of the gradual coal phase-out on wholesale electricity prices is relatively low, since Germany is integrated into the central European electricity grid. The price increase remains in the range of 2-3 €/MWh (0.2-0.3 cent/kWh). The price effect on households and small industry consumers will be dampened by a simultaneous reduction of the renewables levy ("EEG-Umlage"); the overall rise is likely to be in the range of 1-2 €/MWh (0.1-0.2 cent/kWh). At under 40 €/MWh until 2035, the wholesale electricity price lies still below the price of the years 2010-2012. The coal phase-out therefore has, contrary to some media coverage, only litte effect on the competitiveness of German energy-intensive firms. Neuhoff et al. (2014) show that electricity prices anyhow only contribute to less than 5% of overall production costs for most sectors. Additional factors that have a stronger effect are resource prices for hard coal, gas and oil. Prices in 2015 for all these resources are still below 2008 values, before the economic crisis, and are therefore in favour of these firms. The increase of the wholesale price for the time after 2020 in the modelling runs, in addition, represents a benefit to the majority of utilities through additional revenues for all remaining generation capacities: the overall annual benefit sums up to around €500 million. Mostly newer hard coal plants as well as some natural gas plants benefit from this effect (in addition to nuclear power plants in 2020). For older and more CO_2-intensive coal plants, the reduction of full load hours might overcompensate for the price effect (see Figure 14).

The low level of wholesale electricity prices until 2035 is an indicator for the existing overcapacitites in the European electricity sector.[31] This effect is still visible in 2035 despite the shut down of all remaining German nuclear power plants in 2023 and the assumed gradual coal phase-out (20 GW in 2035 compared to 46 GW in 2013). Modeling the implementa-

[31] Additional effects are the low EU-ETS CO_2 certificate and global coal prices.

tion of an additional climate levy (green scenario) secures the set CO_2 targets for 2020 and 2035 without endangering security of supply at any point. Germany even remains an electricity exporter in the range of ~10 TWh in 2035. The majority of utilites in Germany but also abroad even profit from the limitation of coal electrification in the green scenario.

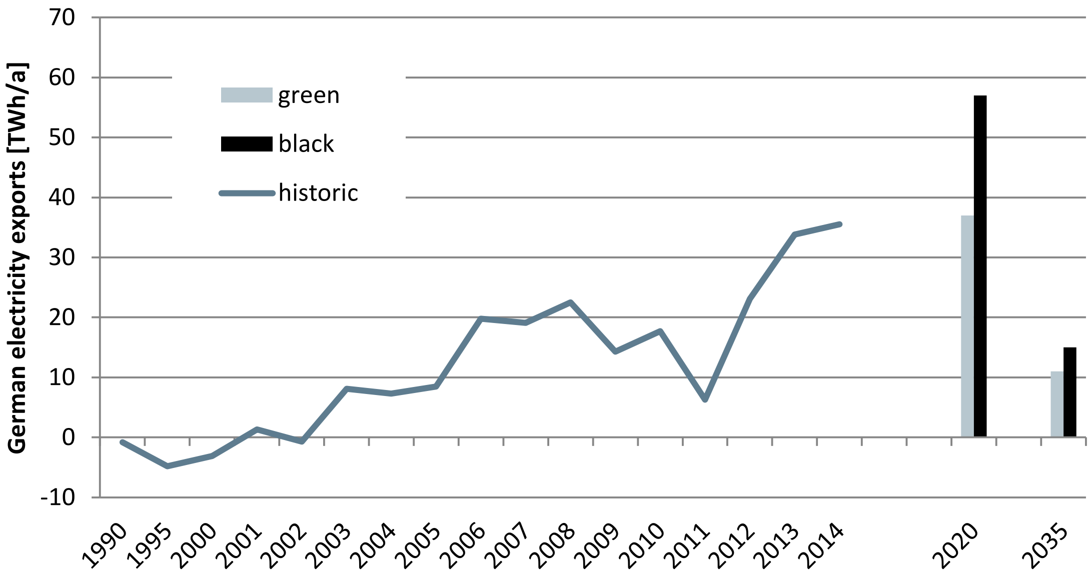

Figure 13: Electricity exports from Germany to its neighbouring countries.

Source: Oei et al. (2015b).

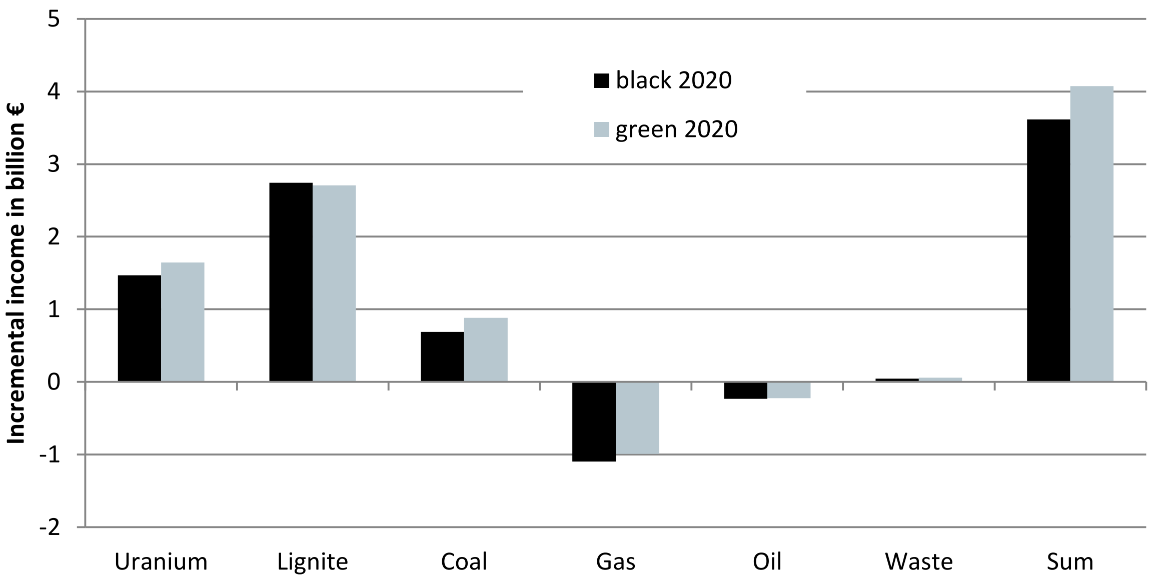

Figure 14: Revenue from electricity sales in 2020

Source: Oei et al. (2015b).

All modeling results depend on future assumptions and were therefore tested by more than 600 runs with sensitivity analysis with respect to input parameters such as full load hours of renewables, EU-ETS CO_2 price or different variations of the climate levy. One major influence, however, that is often not sufficiently included in national discussions is the development in neighbouring countries and the countereffects in Germany. The ENTSO-E (2014) published four visions which resemble possible European development pathways and were represented in various modelling runs. The visions vary on the integration of the European electricity market as well as to their contribution to the climate targets for 2050.[32] The results show that the longterm decline of German CO_2 emissions (301 Mt in 2014) are influenced to a bigger extent by the development in its neighbours states (difference between visions: 20-26 Mt) than with or without the introduction of an additional national instrument (difference between black and green scenario: 3-9 Mt). It is therefore in the interest of Germany that other neighbouring countries also take action, and complement the EU-ETS with national instruments to enable a generation portfolio in line with the European climate targets (Visions 3 & 4).[33]

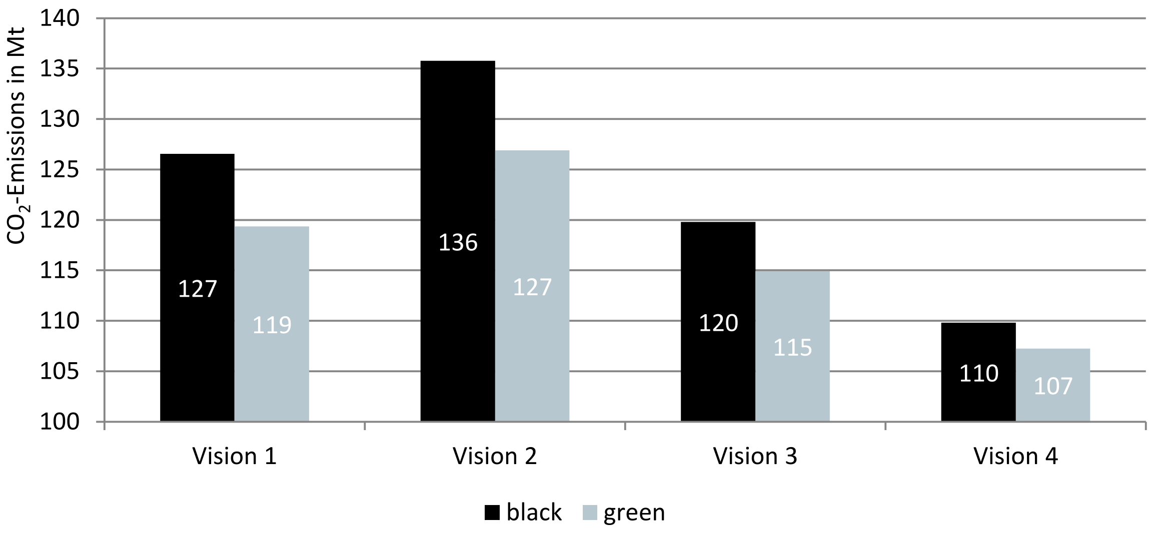

Figure 15: German CO_2-emissions in 2035 depending on the development in the neighbouring countries

Source: Oei et al. (2015b).

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[32] Vision 1 "Slow Progress" assumes little European integration and delayed climate action. The second Vision "Money Rules" also does not reach the climate targets but is based on strengthed European intergration. The climate targets of the Roadmap 2050 are reached in the third "Green Transition" as well as in the fourth vision "Green Revolution". "Green Transition", in contrary to "Green Revolution", assumes little European integration.

[33] This is also due to the fact that the Visions assume different generation capacities in the other countries. Generation capacities for Germany, however, were left constant throughout all runs.

2.5.2 Regional structural change almost completed

2.5.2.1 Aggregate employment effects

When considering the structural change at the level of the lignite mining basins, one has to recall the last three decades. This was a period of constant structural change in West Germany and particularly strong change in East Germany following reunification. In the 1980's the lignite industry still accounted for more than 350,000 direct and indirect jobs. The transition process after German reunification and continuous industrialization, however, led to radical reorganizations. The resulted steep fall in employment to 50,000 jobs in 2002 therefore marks the beginning of a lignite mining phase-out especially in Eastern Germany, at a time when the Energiewende had just started (Statistik der Kohlenwirtschaft e.V., 2015).

The reduction in hard coal mining employment was even bigger, with a fall from up to 600,000 direct employees in the 1950s to 30,000 in 2005. Figures in 2013 were only 10,000, including older employees in partial retirement. Shutting down the last deep-cast mines of the RAG Deutsche Steinkohle AG in NRW in 2018, when production subsidies will expire in line with EU state aid law, marks the next step of the German coal phase-out (Statistik der Kohlenwirtschaft e.V., 2015).[34]

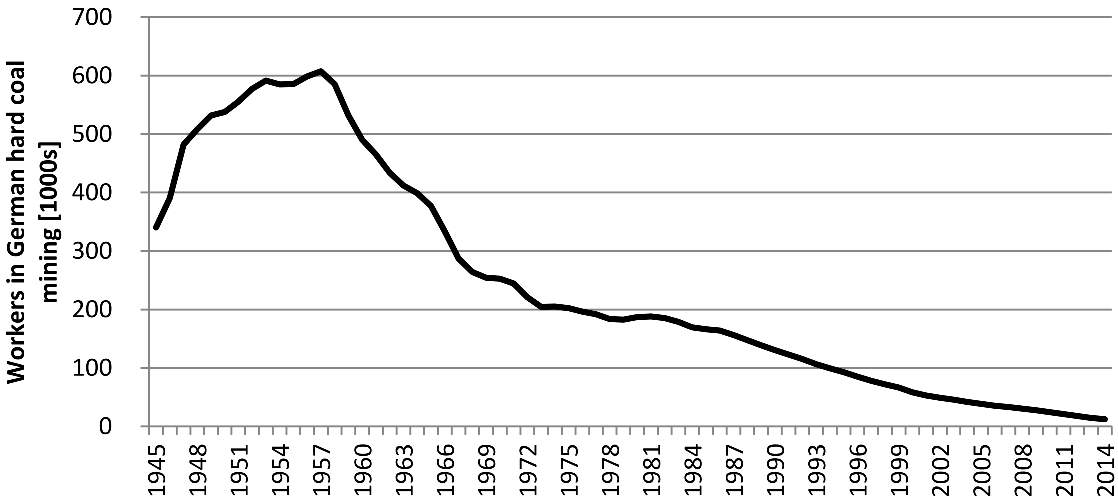

Figure 16: Workers in German hard coal mining from 1945-2014

Source: Statistik der Kohlewirtschaft (2015).

[34] Nearly 90% of Germany´s burnt hard coal is therefore imported, mostly from outsided the EU. The top suppliers in 2013 were Russia (12.5 Mt), USA (12 Mt) Colombia (10 Mt), and South Africa (3.2 Mt). Considering also the local conditions for affected workers, residents and the environment in these regions is crucial for a global perspective of the Energiewende. Bündnis 90/Die Grünen therefore call for the enforcement of higher local safety and environmental regulations as a condition for continous supply contracts with the German power plant operators. See Deutscher Bundestag (2014): Import von Steinkohle Nach Deutschland. Antwort der Bundesregierung auf Kleine Anfrage der Fraktion BÜNDNIS 90/DIE GRÜNEN Drucksache 18/2315. Berlin.

Overall, while West Germany witnessed a gradual decrease of employment, East Germany saw a radical cut in the early 1990s, but also a continous albeit less steep decrease of employment since then. Thus, although the remaining coal phase-out will be challenging, one can conclude that structural change in the affected regions has already largely happened.

The coal phase-out is having two major effects on employment in the electricity sector: First a reduction of jobs in mining and coal electrification and second, as a counter-effect, an increase of jobs in the renewables sector. Jobs in the renewables sector exist in different stages of the value chain (e.g. invention, construction or maintenance) as well as throughout the country (the North specializing more on wind power; the South of Germany focusing on PV). Due to the success of the Energiewende in Germany and abroad, employment figures rose to more than 371,000 in 2013 (Lehr et al., 2015). The renewables sector has consequently become the most important electricity sector in terms of employment, overtaking the coal sector in the last two decades (see Figure 17).

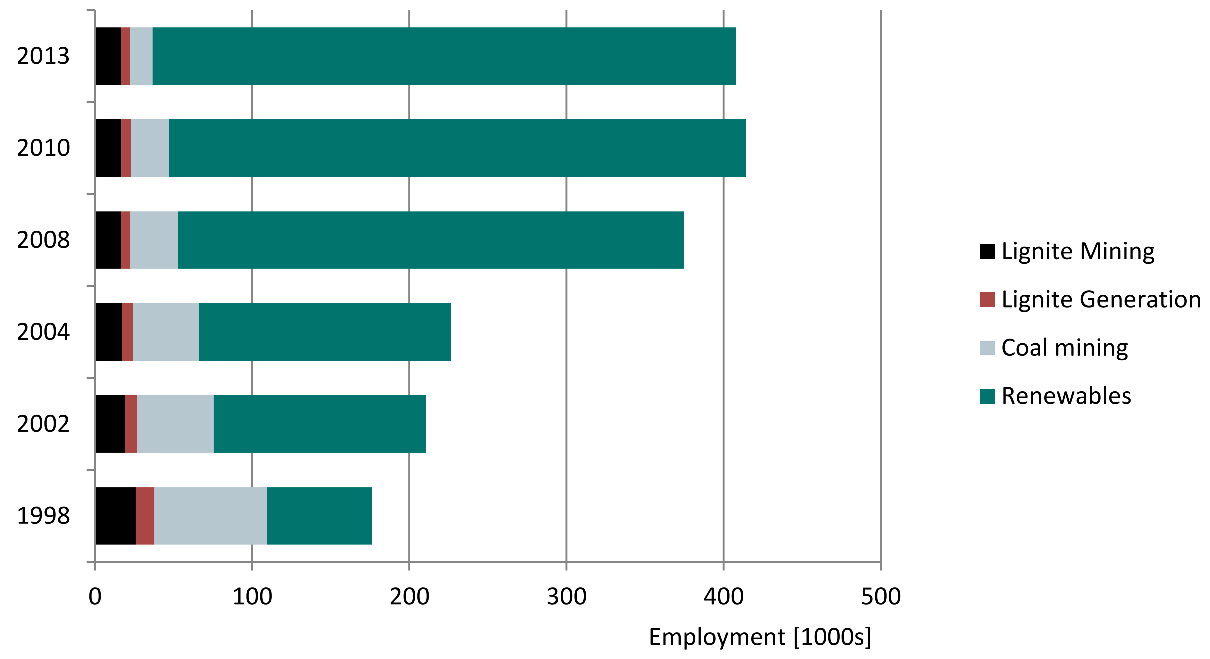

Figure 17: Employment in the coal and renewables sector from 1998 to 2013

Source: Own calculations based on Lehr et al. (2015) and Statistik der Kohlewirtschaft (2015).[35]

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[35] Additional 5,000 employees work in German hard coal power plants in 2014. Their number, however, is not depicted due to a lack of data for the previous years. See Lehr et al. (2015): Beschäftigung durch erneuerbare Energien in Deutschland: Ausbau und Betrieb, heute und morgen. DIW Politikberatung kompakt 101. DLR,

Employment effects of the Energiewende, however, differ for specific regions. The positive effects of newly created jobs in the renewable sector is spread relatively evenly across the county. Jobs in the coal and in particular in the lignite sector, however, are mostly concentrated in the mining regions and are on average also better paid. As a result, most regions in Germany highly profit from the Energiewende, while the situation in NRW and Lusatia is more complex.

2.5.2.2 Regional effects

In all German lignite and hard coal mining regions, mining activities and power plant operation have declined dramatically in the last decades. Shutting down all remaining mines and plants until the 2040s should be organized in a way that minimizes the social impacts as much as possible so as not to undermine the acceptance of the Energiewende. This is possible as more than 70% of the employees in the coal sector are aged 40 and older (Statistik der Kohlenwirtschaft e.V., 2015). Shutting down the plants in accordance with the retirement of its personnel therefore causes only little layoffs. Also, a large number of workers is and will still be working in the sector of renaturation in the mining regions for decades and therefore even profit from the closing of plants and mining sites. New jobs, however, also need to be created especially in the affected regions to secure job opportunities for the upcoming generations. The Energiewende enables this transition towards more sustainable jobs in the industry, services, tourism and in particular the renewable energy sector. In 2015, in fact, even in those Laender with lignite mining (NRW, Brandenburg, Saxony, and Saxony-Anhalt) more people are already employed in the renewable energy sector than in the coal industry (Lehr et al., 2015; Statistik der Kohlenwirtschaft e.V., 2015).

2.6 Conclusion: options for decarbonizing the German electricity sectors and resulting consequences

Coal-fired power plants are responsible for around a third of the total carbon dioxide emissions in Germany. Failure to reduce the persistently high level of coal-based power generation puts Germany's climate targets and undermines a sustainable and successful Energiewende. The government is consequently publishing a national Climate Protection Plan 2050 ("Klimaschutzplan 2050") in 2016, where power generation is expected to play a

DIW Berlin, ZSW, GWS, Prognos; and Statistik der Kohlenwirtschaft (2015): Datenübersichten zu Steinkohle und Braunkohle in Deutschland.

major role. Furthermore, the scenario framework proposed by the German regulator (BNetzA) suggests a reduction of CO_2-emissions towards 187 Mt (2025) and 134 Mt (2035). This can be achieved through a reduction of most of the lignite power plant production, and a continuing increase in the share of renewables. All federal states consequently have committed themselves to respective climate targets. The government of NRW was the first to constrain the use of the existing mine Garzweiler. This prevents the relocation of further 1,400 residents. In Eastern Germany, too, there is no need to open up new lignite mines (Hirschhausen and Oei, 2013a, 2013b).

Current prices for CO_2 emissions allowances in the European Emissions Trading System (EU-ETS) make a market-driven transition from coal to less CO_2-intensive energy sources such as natural gas unlikely in the near future. Missing the 2020 climate targets, however, also puts the longterm targets and therefore the entire Energiewende in jeopardy. This is where additional national instruments to accompany the EU-ETS come into play and are also implemented in various countries. An analysis of the discussed options concludes that:

- The introduction of national CO_2 emissions performance standard (EPS) for new and existing fossil-fired power plants could be contemplated as a specific means of reducing coal-based power generation, e.g. taking into account the plant age structure;
- a national CO_2 floor price would presumably not be sufficient to effect a switch from lignite to natural gas in the near future;
- minimum efficiency and flexibility requirements for power plants do not directly aim at a reduction of CO_2 emissions and, depending on specifics, would also affect gas power plants;
- a coal phase-out law with fixed production or emissions allowances for coal-fired power plants could prescribe a schedule for phasing-out coal-based power generation in Germany and therefore provide investment security for all affected parties;
- older plants could be integrated into a capacity reserve to compensate the operators and at the same time prevent scarcity of generation capacity;
- the discussed “climate contribution” fee for old coal power plants, as proposed by the German Ministry for Economy and Energy in 2015, would be another cost-efficient instrument. It is also compatible with the EU-ETS, as certificates are taken from the market and no leakage effect occurs;

- future electricity transmission planners now have concrete CO_2-targets that need to be respected in their calculations and will influence the planning of new lines in a way which is more aligned with the Energiewende.

From a European perspective, the interaction between the German and European power sectors will intensify in the future. Modelling analysis on the basis of the European Scenario Outlook & Adequacy Forecast (SOAF) confirms that aggregate CO_2-emissions in the European power sector will only meet the climate targets if some neighbouring countries also take action in addition to Germany, and complement the EU-ETS with national instruments to reduce their CO_2-emissions.

The EU-ETS, however, is and remains a central component of EU policy on combating climate change despite its currently limited steering capacity. The agreed on introduction of the market stability reserve as well as the planned adjustment of the reduction factor are therefore important – but insufficient – changes to strengthen the EU-ETS. Cancelling the existing surplus of more than 2 billion allowances would be an important additional signal to retain the credibility of the EU-ETS and bolster European climate policy. A strengthened EU-ETS supplemented by national instruments forms a suitable framework to secure a continuous reduction of greenhouse gases in line with national and European climate targets.

Limiting German GHGs and meeting the climate target automatically implies a coal phase-out in Germany until the 2040s. The coal phase-out in Germany is a process that has already started with the country's continuous industrialization after the 1950s – long before the Energiewende had started. A further step was German reunification, which led to a radical contraction of the lignite industry in East Germany. Analysis shows that an overall phase-out until the 2040s is possible without jeopardizing resource adequacy at any point. The majority of power sector actors, including but not limited to renewables and gas operators, even profit from such a trend. The resulting net employment effects differ across regions and sectors but are expected to be positive for all regions. It is nevertheless important and crucial that all affected parties including politicians, unions, workers, NGOs and scientists work together to enable a smooth transition for the upcoming decades. It is only then that other countries, such as China or India, can be encouraged to copy Germany's example to combat global warming even if this implies a coal phase-out.

3 Modeling a Carbon Capture, Transport, and Storage Infrastructure for Europe

3.1 Introduction: the impact of the carbon capture, transport, and storage technology

The ongoing Carbon Capture, Transport, and Storage (CCTS) discussion originates from multiple perspectives: On the one hand, longer-term energy system models insist on the need of CCTS to achieve ambitious decarbonization scenarios (IEA, 2009b).[36] On the other hand, progress in advancing the technology on the ground has been modest thus far (Herold et al., 2010a; Hirschhausen et al., 2012a). The IEA underlines in its "Energy Technology Perspectives 2012" study that its importance with on overall 20% contribution to achieving emission reduction goals and an 40% cost increase in absence of the technology (IEA, 2012). At the same time they acknowledge the real danger that the ambitious development plans for CCTS demonstration in Europe will remain unfulfilled. Among other concerns, the institutional question about regulatory and environmental issues with storage could substantially hinder the deployment. In December 2012 the European Commission decided not to consider any CCTS project in the first round of the NER300 funding program, but supporting 23 renewable energy projects with €1.2 bn, instead. The lack of financial guarantees from project partners and member states as well as insufficiently advanced project status highlighted the uncertain future of CCTS in Europe (EC, 2012).

To date, the discussion has centered on the role of CCTS in the power sector (Tavoni and Zwaan, 2011), yet the technology also holds promise for the iron and steel, cement as well as refining sectors where chemical processes emit large amounts of CO_2. Switching to renewable sources and/or increasing process efficiency will result in partial emissions reductions in the medium term, e.g., 35% in the iron and steel sector, 35% in cement and 20% in clinker production (Öko-Institut, 2012). Low-carbon substitutes to the conventional produc-

[36] This chapter is published in the Journal of Environmental Modeling and Assessment 05/2014; December 2014, Volume 19, Issue 6, pp 515-531 (Oei et al., 2014a). Previous versions were also published in Zeitschrift für Energiewirtschaft Volume 35, Number 4, p. 263-273, 2011 (Oei et al., 2011) and as DIW Berlin Discussion Paper No. 1052, 09/2010 (Mendelevitch et al., 2010; Oei et al., 2010). Joint work together with Johannes Herold and Roman Mendelevitch. Pao-Yu Oei and Roman Mendelevitch jointly developed the model, and its implementation in GAMS. Andreas Tissen was also involved in developing a first draft of the model. The writing of the manuscript was executed jointly

tion of these raw materials, such as magnesium cement or the electrolytic production of iron, may become available in the future. However, the extent to which they could be applied on a large scale as well as prove economically viable is unknown. Thus the CCTS technology remains the only short-and midterm CO_2 mitigation option for these sectors. At the same time an application in these sectors will lead to lower capture costs than in the energy sector due to the higher CO_2 concentration in the flue gas (Ho et al., 2011; Öko-Institut, 2012).

Despite this fact industrial partners have made only little effort to bring forward CCTS projects. Most industrial companies also lack the financial possibilities to invest into a demonstration unit including transport and storage of CO_2. One major argument against putting pressure on industrial facilities in Europe, is the fear of losing international competitiveness when facing higher production costs due to CCTS. This apprehension was, for example, present in the design of the allocation scheme for EU-ETS emission allowances. The pure grandfathering approach did not put any pressure on the emission efficiency of existing facilities (as widely criticized e.g. in IETA, 2012) and thus free allowances were used instead of pushing for CCTS. The only two large-scale industry CCTS demonstration projects in Europe, ULCOS Florange (a steel making plant in Lorraine, France), and Green Hydrogen (a hydrogen plant in Rotterdam, Netherlands) initially applied for NER300 funding, but then, in 2012, withdrew their application (MIT, 2012). It is worth noting that those industry CCTS projects that are currently operating face favorable and very site-specific conditions. Either CO_2 capture is disproportionally inexpensive due the specific process (e.g. Ethanol Production, in Decatur, Illinous, USA), or the CO_2 has to be captured regardless in order to market the product (e.g. natural gas with a too high CO_2-concentration as in e.g. Sleipner field, Norway), or additional revenue from CO_2 enhanced oil recovery changes the economics of the CCTS project (e.g. Weyburn Project in Saskatchewan, Canada). Von Hirschhausen et al. (2012a) analyzed the discrepancy between the hopes put into the technology and its state of development (see Chapter 5). In addition to the points mentioned above, they found that there was a lack of technological focus on cheap capturing technologies. Also, too optimistic expectations on cost reductions and learning curves, as well as the fact that the costs and complexity related to regulatory issues of CO_2 transport as well as regulatory and technological issues of CO_2 storage were neglected. Moreover, persisting negotiations and complicated environmental assessments for CO_2 storage fueled by "not in my backyard" (NIMBY) concerns hindered the implementation of planned demonstration projects. Against this background the question arises of what contribution the CCTS technology can realistically make toward European CO_2 emission reduction.

We apply the CCTS-Mod Model to analyze the potential development of a CCTS infrastructure in Europe. In particular, we investigate the nature of the CO_2 transport infrastructure that would emerge in Northwest Europe, i.e. in Germany and its neighboring states. Several scenarios, differing by the estimate of geological storage available, the availability of onshore storage, and the expected CO_2 certificate price in 2050, are run. We find that under certain extreme assumptions, such as a relatively high CO_2 price, and very optimistic CO_2 storage availability, a large-scale CCTS roll-out might indeed be expected. However, in a more realistic scenario, including lower storage availability and public resistance to onshore storage, a large-scale roll-out is not going to happen. In all scenarios, CCTS deployment is highest in CO_2 intensive non-energy industries, where emissions cannot be avoided by fuel switching or alternative production processes.

The next section 3.2 provides an overview of existing literature and models, both theoretical and applied, e.g. to North America or Europe. Section 3.3 specifies our own model, called CCTS-Mod and its data. We then apply CCTS-Mod to analyze the potential development of a CCTS infrastructure in Europe under certain scenarios in Section 3.4. Section 3.5 summarizes the findings and provides conclusions.

3.2 Modeling CO_2-infrastructure

Recent literature points out that the real bottlenecks to CCTS deployment are transport and storage infrastructure (Herold et al., 2010b). Against this background, only a few simplified CCTS models actually address the pipeline transport of large volumes of CO_2. The Global Energy Technology Strategy Program (GTSP) modeled the adoption of a CCTS system within three fossil fuel-intensive electricity generation regions of the U.S. The results show that CCTS implementation depends more on CO_2 injection rates and total reservoir capacity than on the number of potential consumers who would use the CO_2 for enhanced oil recovery (CO_2-EOR) (Dooley et al., 2006).

McPherson et al. (2009) and Kobos et al. (2007) introduced the "String of Pearls" concept to evaluate and demonstrate the means for achieving an 18% reduction in carbon intensity by 2012 in Texas using CCTS. Their dynamic simulation model connects each CO_2

source to the nearest sink and automatically routes pipelines to the next neighboring sink, thus creating a trunkline connection for all of the sinks. While the model can determine an optimal straight-line pipeline network, it is not possible to group flows from several sources to one sink. Fritze et al. (2009) developed a least-cost path model connecting each source with the nearest existing CO_2 sink. The chapter examines a hypothetical case of main trunk lines constructed by the U.S. Federal Government and its influence on the total costs. However, no economies of scale are implemented for construction, as the costs of building the public trunk lines are greater than the potential costs of private enterprises. Nevertheless public trunk lines allow greater network flexibility and redundancy which can lead to cost savings in times of emergency and when storage capacity needs to be balanced.

Middleton et al. (2007) designed the first version of the scalable infrastructure model SimCCS based on mixed integer linear programming (MILP). With its coupled geospatial engineering-economic optimization modeling approach, SimCCS minimizes the costs of a CCTS network capturing a given amount of CO_2. An updated version by Middleton and Bielicki (2009), comprising of 37 CO_2 sources and 14 storage reservoirs in California, simultaneously optimizes the model according to the amount of CO_2 to be captured from each source; the siting and construction of pipelines by size; and the amount of CO_2 to be stored in each sink. The decisions are endogenous, but the total amount of CO_2 to be stored is exogenous. Economies of scale are implemented via possible pipeline diameters in four-inch steps, each with its own cost function. Kuby et al. (2011) extend a smaller version of the model that employs twelve sources and five sinks in California with a market price of CO_2 as well as a benefit when used in CO_2-EOR. This model minimizes the costs of CCTS, but only examines one period. Their findings of a CO_2 price sensitivity analysis indicate that infrastructure deployment is not always sensitive to the price of CO_2. Kazmierczak et al. (2008) and Neele et al. (2009) develop an algorithm to create a low-cost network and a decision support system to evaluate the economical and technical feasibility of storage. A realistic estimate of the economic feasibility of a potential CCTS project is possible, but there is no detailed planning at the project level.

In summary, only a few models include economies of scale in the form of possible trunk lines, but they operate on a static level or are based on an exogenously set amount of CO_2 to be stored. Therefore the models exclude the option of buying CO_2 certificates instead of investing in CCTS infrastructure. We introduce a scalable mixed integer, multi-period, welfare-optimizing CCTS network model, hereafter CCTS-Mod. The model incorporates endogenous decisions on carbon capture, pipeline, and storage investments as well as capture, flow and injection quantities based on exogenous costs, a CO_2 certificate price path, a comprehensive set of emissions point sources from European power and industry sectors as well as on- and offshore storage sites in depleted hydrocarbon fields and saline aquifers. Our model runs in five-year periods beginning in 2005 and ending in 2050. Capacity extensions can be used in the period after construction for all types of investments in the model. Sources and sinks are linked to nodes according to their geographical position and pipelines are constructed between neighboring nodes. To ensure a better resolution no aggregation of sources/sinks at a node takes place. The distance between two neighboring nodes can be chosen flexibly, making CCTS-Mod scalable and thus allowing different degrees of resolution. Economies of scale are implemented by discrete pipeline diameters with respective capacities and costs.

3.2.1 Mathematical representation of CCTS-Mod

Figure 18 illustrates the decision path of CCTS-Mod based on the CO_2 disposal chain when using the CCTS technology. Each producer of CO_2 must decide whether to release it into the atmosphere or store it via CCTS. The decision is based on the price for CO_2 certificates and the investment required for the capture unit, the pipeline and the storage facilities, and the variable costs of using the CCTS infrastructure.

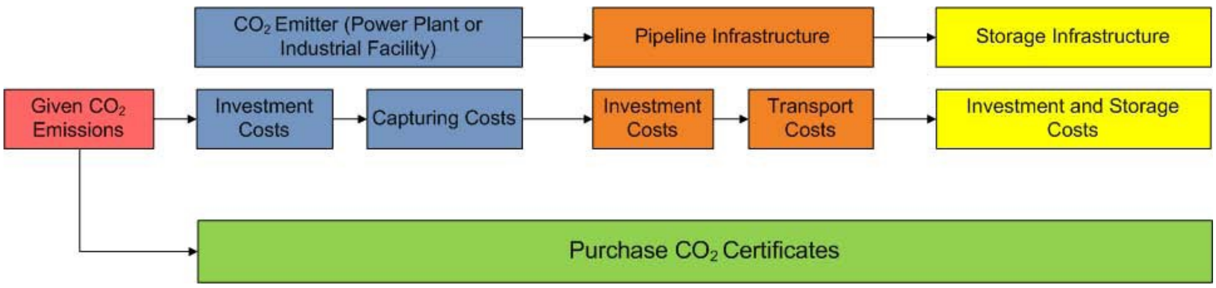

Figure 18: Decision tree in the CO_2 disposal chain of the CCTS-Mod

Source: Own depiction.

We apply a stylized institutional setting to a vertically integrated CCTS chain. A single omniscient and rational decision-maker has perfect foresight and makes all investment and operational decisions.[37] Under these simplifying assumptions we run the model using a single cost minimization.

We define the objective function to be minimized as follows:

$$\min_{\substack{x_{Pa},inv\_x_{Pa},\\ z_{Pa},f_{ija},inv_{f_{ijda}},\\ plan_{ija},y_{Sa},inv\_y_{Sa}}} \sum_a \Bigg[\left(\frac{1}{1+r}\right)^{(year_a - year_{start})}$$
$$\cdot\Bigg(\sum_P [(c\_ccs_{Pa} + (1 - capt\_rate)\cdot cert_a)\cdot x_{Pa} + c\_inv\_x_P \cdot inv\_x_{Pa}$$
$$+ cert_a \cdot z_{Pa}]$$
$$+ \sum_i \sum_j \left[E_{ij}\cdot\left(c\_f\cdot f_{ija} + \sum_d \left(c\_inv\_f_d \cdot inv\_f_{ijad}\right) + c\_plan \cdot plan_{ija}\right)\right]$$
$$+ \sum_S [c\_inv\_y_{Sa}\cdot inv\_y_{Sa}]\Bigg)\Bigg] \tag{1}$$

With:

$$x_{Pa}, inv\_x_{Pa}, z_{Pa}, f_{jia}, y_{Sa}, inv\_y_{Sa} \geq 0 \tag{2}$$

$$inv\_f_{ijda} \in N_0 \tag{3}$$

$$plan_{ija} \in [0; 1] \tag{4}$$

The first term of the objective function 1 is the discount factor, where *r* is the interest rate, $year_a$ is the starting year of period *a* and *start* is the starting year of the model. From here, we can split the objective function 1 into three parts representing the three steps of the CCTS chain. For the first step the decision variables are the dimensioning of the capture system inv_x_{Pa} and the level of CO_2 emission that are cycled through the capturing system ($x_{Pa} \cdot capt\_rate$ represents the amount of CO_2 actually captured by the facility). An individual

[37] The model tends to overestimate the potential for CCTS. Considering the large number of different players and technologies, the uncertainties regarding CO_2 prices, learning rates, legal issues, permitting, certification of storage capacity, and further policy measures would increase the total costs. Real costs are therefore expected to be higher and come along with a lower deployment of CCTS in the future.

variable is declared for each emitter *P* in each period *a*. The parameter *capt_rate* represents the maximal possible percentage of captured CO_2, thus certificates still have to be purchased at the price of $cert_a$ for the remaining fraction. It is kept constant at 0.9 for all scenarios.

The second part represents the transportation step. The decision variables are: f_{ija} declares the CO_2 flow from node *i* to *j* in period *a*; inv_f_{ijda} denotes the number of pipelines to be built between node *i* and *j* with the diameter *d* in period *a*; $plan_{ija}$ is a binary variable (see Equation 4) and has the value one if a pipeline route between node *i* and *j* is planned and licensed in period *a*, and zero otherwise. Routing of pipelines is a central aspect of our study; we implement a detailed process of pipeline building by introducing the planning variable and, thus, separate the planning and development costs from the rest of the capital costs. Additional pipelines on already licensed routes do not face licensing or planning costs. The desired effect is that new pipelines are routed along existing lines as observed in reality.

The third part represents storage. The decision variables are: y_{Sa}, which is the quantity stored in storage facility *S* in period *a*, and inv_y_{Sa}, which denotes the investments in additional annual injection capacity. Variable costs of CO_2 storage are considered negligible as they sum up to less than 7-8 % of the overall storage costs (see Section 3.3.3 for further explanations).

All decision variables have to be non-negative (see Equation 2). Additionally, the number of pipelines to be constructed on one route inv_f_{ijda} are discretized (see Equation 3).

In the objective function each decision variable is multiplied by its respective cost factor. E_{ij} is a distance matrix indicating whether two nodes *i* and *j* can be connected directly. If possible, the values of the matrix give the distances between *i* and *j* in kilometers. Scaling is easily done by varying the distance between nodes and their number and the spatial focus can range from regional to world-wide depending on research question and existing data sources.

The model is restricted by:

$$x_{Pa} + z_{Pa} = CO2_{Pa} \qquad \forall P, a \tag{5}$$

Equation 5 defines that a facility's CO_2 stream can be treated in two ways, or a mixture of it: CO_2 emissions can either be balanced with CO_2 certificates (z_{Pa}), or the CO_2 can be cycled through a capture system (x_{Pa}). Note that even if the entire CO_2 stream is treated in the capturing facility (i.e. x_{Pa}= CO_2) a fraction of (1-*capt_rate*) · x_{Pa} is released into the atmosphere and needs to be balanced with CO_2 certificates (c.f. equation 1).

$$\sum_i f_{ija} - \sum_i f_{jia} + \sum_P \left(match_{P_{Pj}} \cdot x_{Pa} \cdot capt_{rate} \right) - \sum_S \left(match_{S_{Sj}} \cdot y_{Sa} \right) = 0 \quad \forall j, a \tag{6}$$

Equation 6 specifies the physical balance condition, which states that all flows feeding into a node j must be discharged from the same node. *match_*P_{Pj} declares whether producer *P* is located at node *j*, while *match_*S_{Sj} declares whether a sink *S* is located at node *j*. The amout of CO_2 that is transported and stored through the system is equal to the amount actually captured at the respective facility (x_{Pa} · *capt_rate*).

$$x_{Pa} \leq \sum_{b<a} (inv\_x_{Pb}) \qquad \forall P, a \tag{7}$$

The capturing capacity of each producer *P* in period *a* is given in equation 7. Note that all terms in this inequality are decision variables, meaning that injection in period *a* can only happen if the capacity was expanded prior to period *a*.

$$f_{jia} \leq \sum_{b<a} \sum_d (cap\_d_d \cdot inv\_f_{ijdb}) + \sum_{b<a} \sum_d (cap\_d_d \cdot inv\_f_{jidb}) \qquad \forall i, j, a \tag{8}$$

The capacity restriction of pipelines in Equation 8 works similarly to Equation 7.

$$y_{Sa} \leq \sum_{b<a} i\,nv\_y_{Sb} \qquad \forall S, a \tag{9}$$

Inequality 9 states that the annual injection rate of a storage facility *S* is limited to the sum of investments in annual injection capacity *inv_*y_{Sb} from previous periods *b*.

$$\sum_a (5 \cdot y_{Sa}) \leq cap_{stor_S} \quad \forall S \tag{10}$$

Inequality 10 restricts the amount of CO_2 injected into reservoir *S* to its overall physical capacity. The multiplication by 5 resembles the amount of years per period *a*. Planing, licensing, and optimal routing of pipelines is ensured via Equation 11 where max_pipe is the maximum number of pipelines that can be built on a licensed route. The model is solved in the General Algebraic Modeling System (GAMS) using the CPLEX solver.

$$\sum_{d}(inv\_f_{ijda}) \leq max_{pipe} \cdot \sum_{b<a}(plan_{ijb}) \quad \forall i,j,a \tag{11}$$

3.3 Application of the model for Europe and used data

3.3.1 CO_2 emission sources

Our European emission data covers the EU27 plus Switzerland and Norway. It includes industry facilities from iron and steel production, the cement and clinker production as well as oil refineries. Furthermore waste-, natural gas-, lignite- and coal-fueled power plants that emit more than 100,000 tCO_2 per year are included. Facilities below this emission level are considered too small to justify the investment into capture, transport, and storage. Data on the average annual CO_2 emissions of individual plants, location and age are taken from Platts (2011a) and EEA (2011). We assume a lifetime of 55 years for lignite and hard-coal plants and 40 years for natural gas (NGCC) plants. Industrial facilities are assumed to be reconstructed with the same characteristics and on the same site once their economical lifetime ends. Projections on new power plant capacity installation are taken from VGB Power Tech (2011), covering 66 GW of NGCC, 7.6 GW of lignite and 35 GW of coal plants. Due to capacity aging and scrapping of old plants, this results in a decrease in fossil fuel capacity until 2050.

The total number of implemented emission sources in 2010 totals 2725 facilities, with emissions of 2.122 $GtCO_2$ annually. These divide into 1476 (1.527 $GtCO_2$/a) fossil fueled power plants and 1249 (0.595 $GtCO_2$/a) industrial facilities. The graphical distribution of the included point sources is shown in Figure 19.

The CCTS investment costs for the sectors considered in this chapter are presented in Table 6.[38] Costs estimates for the power generation sector are available from various sources (Finkenrath, 2011; IPCC, 2005a; Tzimas, 2009; WorleyParsons and Schlumberger, 2011; ZEP, 2011a). They all share the same general trend of lower capital cost for coal-fired generation compared to gas-fired power plants when calculated in € per tCO_2. In the more recent stud-

[38] The depicted costs for CO_2-capture do only cover the costs for the capturing unit itself, i.e. similar to retrofitting costs to an existing facility without CO_2-capture. Overall system costs may vary depending on different generation types (power plants) or industrial facility.

ies a great share of the variation in the cost figures is attributed to changing raw material prices and different assumptions on the risk premium attributed to this immature technology. Costs for industry capture are gaining increased attention (see e.g. Kuramochi et al., 2012; Öko-Institut, 2012). Rubin et al. (2007) examines learning rates of different climate protection technologies and estimates learning rates for carbon capture that we apply to our data from 2020 onwards.

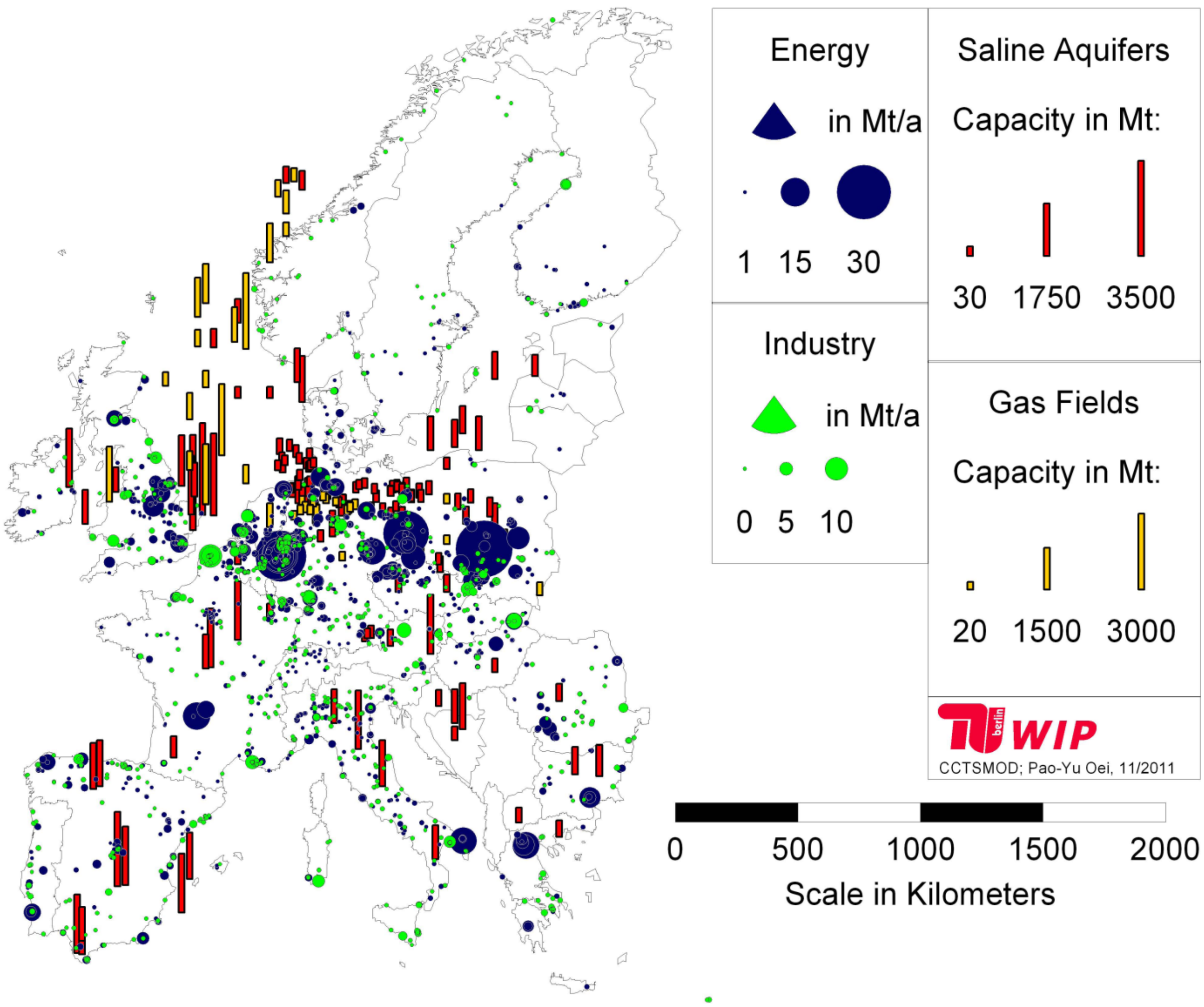

Figure 19: CO_2 emission sources and storage potential

Source: Own depiction

Table 6: Investment costs for capture facilities in € per annual tCO_2 emissions (dimensioning of capturing sytem)

Technology	2010	2020	2030	2040	2050
Coal	150	150	139	119	93
Lignite	116	116	107	92	72
NGCC	275	275	255	218	171
Cement	135	135	125	107	84
Iron and Steel	117	117	108	93	73
Refineries	210	210	195	167	131

Source: Own calculation based on various sources (Ho et al., 2011; Öko-Institut, 2012; Rubin et al., 2007; Tzimas, 2009).[39]

Table 7: Variable costs in €/tCO_2 treated in the capturing system

Technology	2010	2020	2030	2040	2050
Coal	32	32	31	31	31
Lignite	29	29	29	29	28
NGCC	47	47	45	44	44
Cement	17	17	17	17	17
Iron and Steel	16	16	16	16	16
Refineries	47	47	45	44	44

Source: Own calculation based on various sources (Ho et al., 2011; Öko-Institut, 2012; Rubin et al., 2007; Tzimas, 2009).

The variable costs of capture have two components: Variable costs of operation and maintenance and an energy penalty for additional energy input needed for the capturing process. Total variable costs are given in Table 7. For coal and lignite plants we apply the post-combustion capture technology. We assume the oxy-fuel process for the iron and steel and the cement sectors as proposed by Öko-Institut (2012). In this case, the variable costs of capture are mainly driven by the price for the electricity needed for the air separation unit. We assume a fixed price of 70 €/MWh, which remains constant. In refineries, we assume

[39] Typically, investment and operating costs for CO_2 capture are given in terms of MW and MWh, respectively. These figures refer to a specific capture rate (i.e. when making this investment one is able to capture a portion of the CO_2 otherwise emitted into the atmosphere). The basic unit of the CCTS-Mod is tCO_2. Thus we converted the figures accordingly to arrive at a per tCO_2 based figure.

post-combustion capture. Due to the low CO_2 concentration in the flue gas and the high diversity of the fuels and processes used in refineries, variable costs are comparable to those in natural gas plants (Ho et al., 2011).

3.3.2 CO_2 transport

Pipeline transportation is commonly considered as the most economically viable on-shore transport solution that can carry the quantities emitted by large-scale CO_2 sources. Onshore transport faces few technological barriers due to experience in the gas and oil sector and the CO_2 industry for CO_2-EOR in the USA. CO_2 pipelines represent a typical network industry and are characterized by high upfront, sunk investment costs. Variable costs are comparatively insignificant and primarily include expenditures for fuelling compressors.

According to Heddle et al. (2003), right of way (ROW) costs account for four to nine percent of total gas pipeline construction costs depending on the diameter of the pipe, which we used to derive our values of the plan parameter. ZEP (2011b) presents a comprehensive study on CO_2 transportation costs for different setting of transport networks. Calculated transport costs in € per tCO_2 range from 2 to 20 depending on the network setting. Associated capital costs range between €0.08 and €0.15 per tCO_2 and kilometer of pipeline. Topographic features, such as mountains or densely populated areas, are often neglected in studies as they need additional data and increase the computing time. Including such features, however, would lead to a strong increase of the transport costs or even infeasibilities of some projects (e.g. due to mountain ranges).

To account for the uncertainty associated with topographic features, public resistance, and environmental concerns as uncertain utilization rates we employ a higher value of 0.087 € per tCO_2, cm of pipeline diameter, and km of pipeline. Economies of scale associated with CO_2 pipeline transport pipelines are depicted through the five possible diameters with associated annual transport capacity (see Table 8).

Table 8: Investment cost by pipeline diameter and respective annual transport capacity

Diameter [m]	Annual transport capacity [$MtCO_2$/ a]	Investment costs [per tCO_2 and km]
0.2	6	0.29
0.4	18	0.19
0.8	71	0.10
1.2	174	0.06
1.6	338	0.04

Source: Own calculations based on Ainger et al. (2010) and IEA (2005).

For operation and management (O&M) costs, ZEP (2011b) give values of €0.005 to €0.01 per tCO_2 per kilometer. IEA (2005) arrive at similar operation costs varying between €0.01 and €0.025 per km per year depending on pipeline diameter and total pipeline length, including costs for booster stations; we thus use a value of €0.01 per year per km per tCO_2 transported. Including the flow-dependent cost component ensures the shortest possible routing for the CO_2. Planning and development (P&D) costs include ROW costs, land purchase and routing costs which occur only for the first pipeline built on a certain route. This leads to the construction of pipelines along corridors.

3.3.3 CO_2 storage

Data on CO_2 storage is difficult to come by and verify. Using available data, we derive our own estimates of location and capacity of the European on- and offshore storage. The exact location of the storage fields is being modeled as closely to the geological formation as possible. Various sources are used to get data for the UK and for offshore storage beneath the North Sea (Bentham, 2006; Bentham et al., 2008; Brook et al., 2009; Hazeldine, 2009). Greenpeace (2011) give good estimates for storage potential in Germany, while Radoslaw et al. (2009) focus on Poland. The feasibility study for Europe-Wide CO_2 Infrastructure from the European Commision (Ainger et al., 2010) and the Geo Capacity (2009) project are used to estimate storage potential when no more accurate country specific study was available to the public. These studies, however, only grant public access to storage data on a 50x50km grid. This means that some of these formations might consist of several smaller neighbouring aquifers. The example of Germany shows that the majority of the aggregated storage potential can actually be found in small reservoir of 50 Mt or less (Greenpeace, 2011). The exploration of such small reservoirs is uneconomical, given a bad ratio of investment costs and exploitable storage capacity. The overall storage potential of Europe is thus over-estimated in these scenarios due to the lack of more detailed information. The total storage capacity is set to 94 Gt, spread among 41 Gt saline aquifers and 3 Gt depleted gas fields onshore and, offshore, 30 Gt saline aquifers and 20 Gt depleted gas fields (see Table 29 in the Appendix).

According to Heddle et al. (2003) costs for CO_2 storage are determined by factors including: type of storage facility, storage depth, permeability, number of injection points, injection pressure, etc. Therefore, total storage costs vary significantly in different studies (RECCS, 2010). A characteristic value for a storage project is the sum of costs per injection well including site development, drilling, surface facilities, and monitoring investments for a given annual CO_2 injection rate. Storage investments exhibit a strong sunk cost character and according to IEA (2005) variable costs total only seven to eight percent. Therefore, we implement storage costs on a total costs basis (see Table 9). A more recent estimate of storage costs from IEA GHG and ZEP (2011) examining different settings and uncertainties on technological and regulatory issues arrive at figures similar to those presented above.

Table 9: Site development, drilling, surface facilities and monitoring investment cost for a given annual CO_2 injection rate per well

Technology	Natural gas field		Saline aquifer	
	Onshore	Offshore	Onshore	Offshore
Drilling length [m]	3000	4000	3000	4000
Well injection rate [($MtCO_2$/a)]	1.25	1.25	1	1
Corrected well injection rate [$MtCO_2$/a][40]	0.4	0.4	0.33	0.33
Drilling costs [€ per m]	1750	2500	1750	2500
Investment in surface facilities [M€]	0.4	25	0.4	25
Monitoring investments [M€]	0.2	0.2	0.2	0.2
Wells per location	6	6	6	6
Total drilling costs [M€]	5.25	10	5.25	10
Total capital costs per well [M€]	5.6	14.5	5.6	14.5
O&M and monitoring costs [%]	7	8	7	8

Source: Own calculations based on IEA (2005).

[40] According to Gerling (2010), an annual injection rate of 300,000 to 400,000 tCO_2 per well is more realistic for most formations.

One option that is said to improve the economics of CO_2 storage and CCTS in general is CO_2-EOR (IEA and UNIDO, 2011). The technology is increasingly used in the USA and Canada (MIT, 2012) and might also be an option to provide additional investment incentive for CCTS projects in Europe. Studies look intensively into the interaction of these two technologies. Some regional studies on the UK and Norwegian potential (Kemp and Kasim, 2013; Klokk et al., 2010) as well as larger scope studies (e.g. on the North Sea region (Mendelevitch, 2014) or the US (Davidson et al., 2011)) are also available. In general, it is up to future research to determine whether the combination of the two technologies can still be considered as CO_2 abatement, when taking into account the emissions from additionally recovered oil and assessing different injection strategies (see e.g. ARI and Mezler-Consulting, 2010). For our approach we do not consider CO_2-EOR as a storage option (see Chapter 4).

3.4 Different scenarios and their results analyzing political and geological uncertainties

The level of uncertainty about the size and configuration of the pipeline network emanates from the uncertainty about future carbon policies, the level of deployment of renewable energy technologies, as well as the suitability and usability of geological formations to store captured CO_2. Different scenarios are implemented with a linear increase in CO_2 prices from 15 €/t in 2010 until 2050. For the base case the CO_2 certificate price increases from 15 €/t in 2010 to 75 €/t in 2050. Additionally, we define a scenario with a higher (100 €/tCO_2) and a lower (50 €/tCO_2) CO_2 price in 2050. We do not implement a correlation between CCTS deployment and the price for CO_2. We also consider the possibility that onshore storage may not be possible in Europe, due to technical, political, or whatever other reasons. In that case, storage would need to take place offshore, mainly in the North Sea, and the total storage potential would be significantly reduced, from 94 Gt (on- and offshore) to only 50 Gt. The respective scenario key assumptions are shown in Table 10.

Table 10: Key scenario assumptions

Scenario	CO_2 price in 2050 [€/tCO_2]	Storage on/offshore	CO_2 storage capacity [Gt]
Ref75	75	on and offshore	94
Off75	75	offshore	50
On50	50	on and offshore	94
Off50	50	offshore	50
On100	100	on and offshore	94
Off100	100	offshore	50

Source: Own depiction.

3.4.1 Reference scenario: certificate price increasing to 75 €/tCO_2 in 2050

3.4.1.1 On- and offshore storage

Our Reference scenario simulates the cost-optimal deployment of a European CCTS infrastructure for the period 2010-50 given a CO_2 certificate price starting at €15 in 2010 and rising to €75 in 2050. Point source emissions, storage sites and potential pipelines are mapped on a spherical grid covering Europe. The distance between two neighboring grid nodes is two degrees (on average about 200 km).

In this Reference scenario, 758 Mt of CO_2 emissions are captured, transported, and stored annualy through CCTS in 2050. CCTS implementation begins in 2020 with the first investments. The capturing process starts five years later in both the iron and steel as well as in the cement sectors. CCTS infrastructure gradually ramps up from 2020 to 2040 (see Figure 20). At first, the industrial facilities with lower capturing costs situated close to potential storage sites are the predominant users of CCTS. Industrial CCTS penetration reach a capturing rate of 370 MtCO_2 per year in 2050. With rising CO_2 prices CCTS becomes a more attractive abatement option for the power sector. The annual rate of stored CO_2 from power generation reaches 390 Mt in 2050 (see Table 11 for an overview of key results).

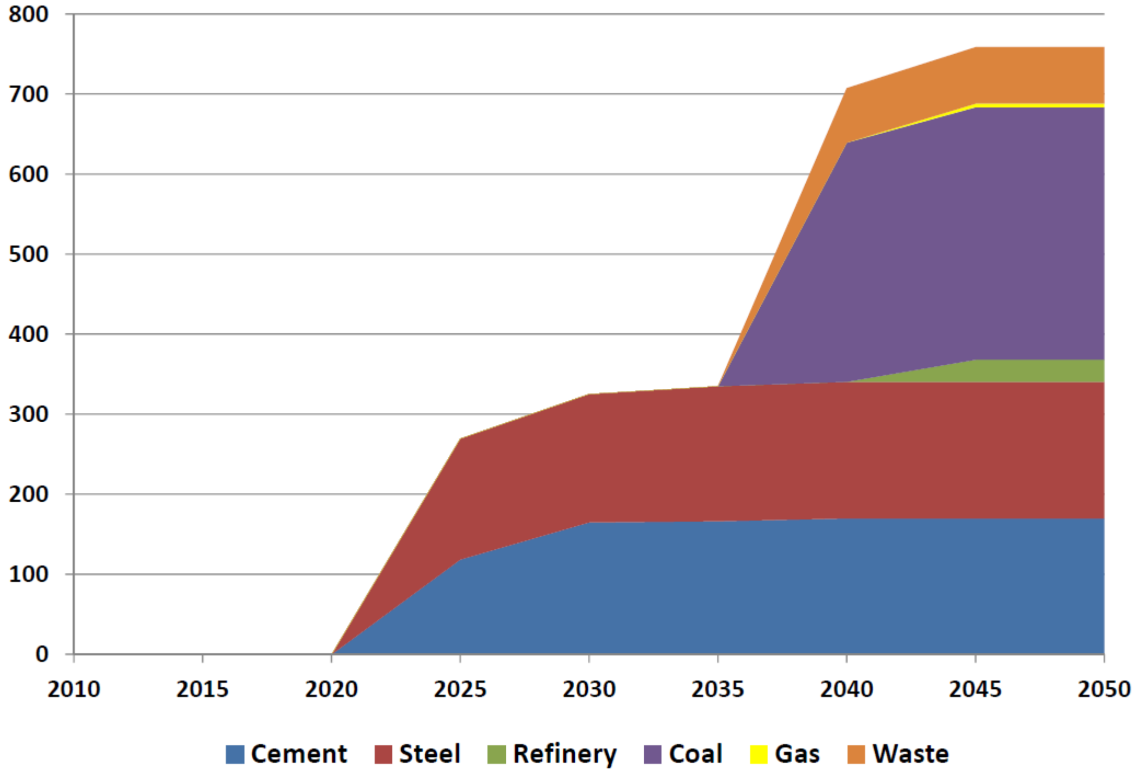

Figure 20: Storage by sectors in $MtCO_2$, Ref75

Source: Own depiction.

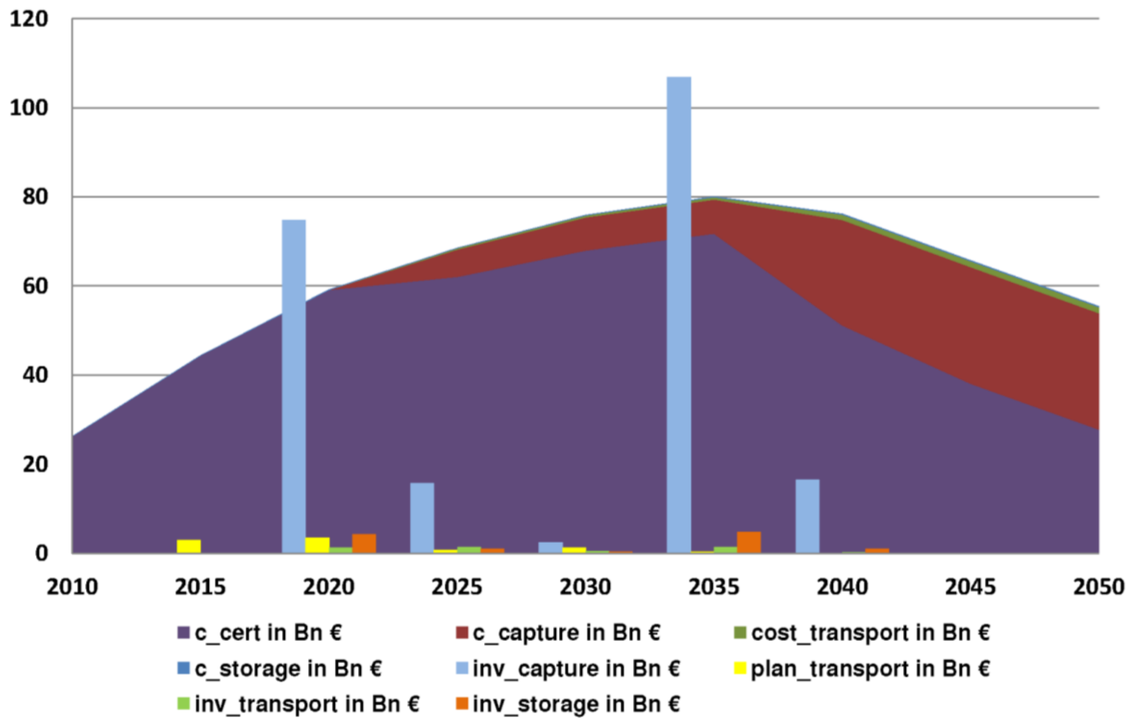

Figure 21: Infrastructure investment and variable costs in €bn, Ref75

Source: Own depiction.

Over the 40 year modeling time horizon, total investment costs along the CCTS value chain sum up to €240 bn. Given a total quantity of avoided emissions of 15.8 $GtCO_2$, this breaks down to investment cost of €15.3 per tCO_2 avoided. Total variable costs sum up to €515 bn, or €33 per tCO_2 avoided. Although this number may appear low, we note that most capture occurs in the industrial sector in the early years. The costs of the capturing process hereby comprise around 90% of the total costs while the transport and storage only have minor impacts assuming an optimal grid and storage planning (see Figure 21).

We note that under the applied CO_2 price path, CCTS is an option primarily for countries with a regional proximity between CO_2 intensive regions and storage sites. The technology is mostly implemented by Poland, Germany, the Netherlands, Belgium, France, and the UK. Moreover, we find no interconnected, transnational transportation network (see Figure 22). As industry facilities will be the first-movers, they drive the layout of the pipeline network.

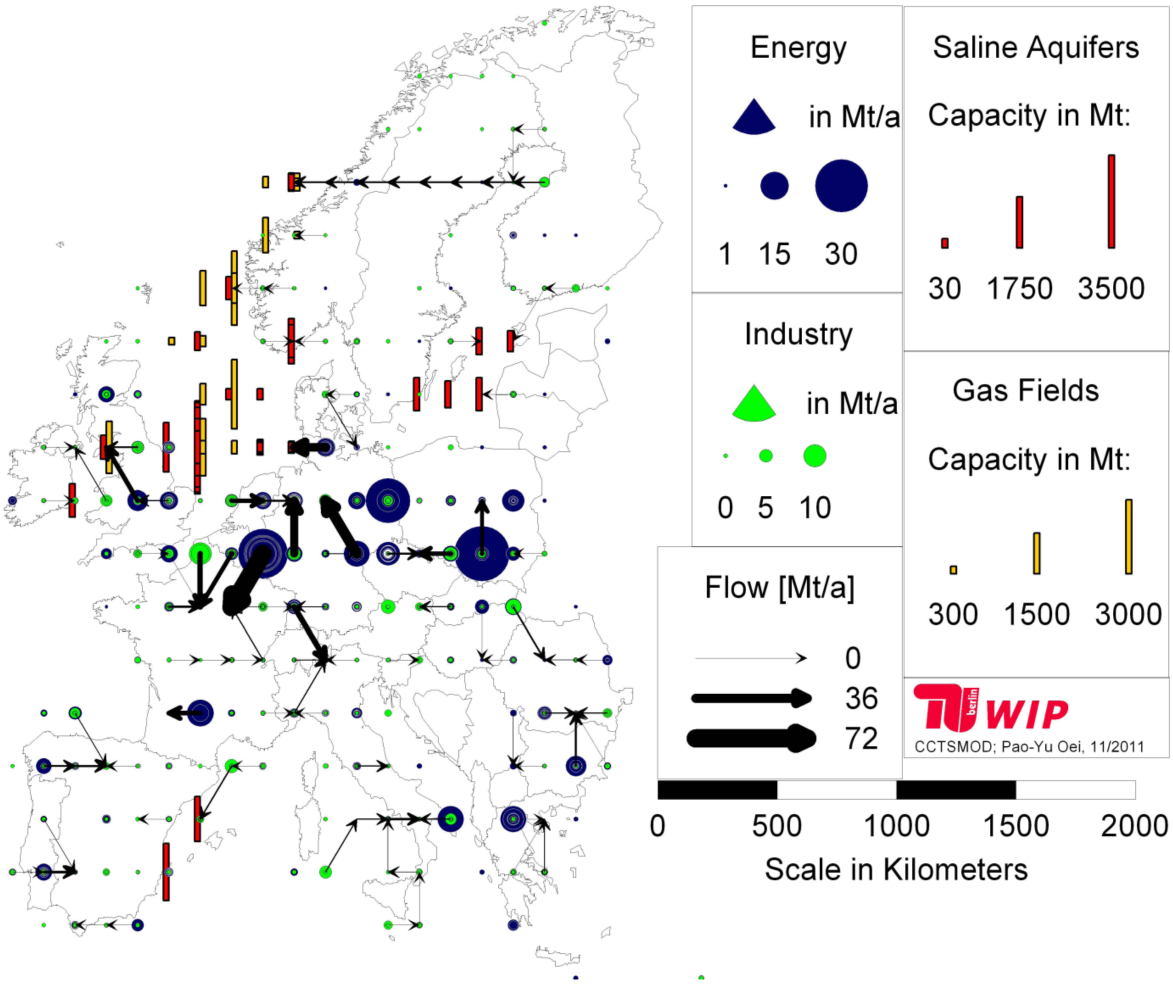

Figure 22: CCTS infrastructure in 2050, Ref75

Source: Own depiction.

3.4.2 Offshore storage only

Due to longer transport distances and more expensive storage, this subscenario leads to a deployment of CCTS on a lower level compared to the Reference scenario in Section 3.4.1. Over the 40 year modeling time horizon, total investment cost along the CCTS value chain total €145 bn. Capture investment occurs in two waves, the first in industry in 2025 and the second in the power sector in 2040 (see Figure 23 and Figure 24). This is a delay of 5 years compared to the reference scenario (see Figure 20 and Figure 21). Given a total quantity of avoided emissions of 7.5 $GtCO_2$, this breaks down to investment costs of €19.4 per tCO_2 avoided, an increase to the reference scenario of 22%. Total variable costs sum up to €266 bn, or €35.4 per tCO_2 avoided. With only a slightly higher participation of the power sector, this increase in the average variable costs of CO_2 abatement compared to the reference scenario is explained by longer transport distances and more expensive offshore storage.

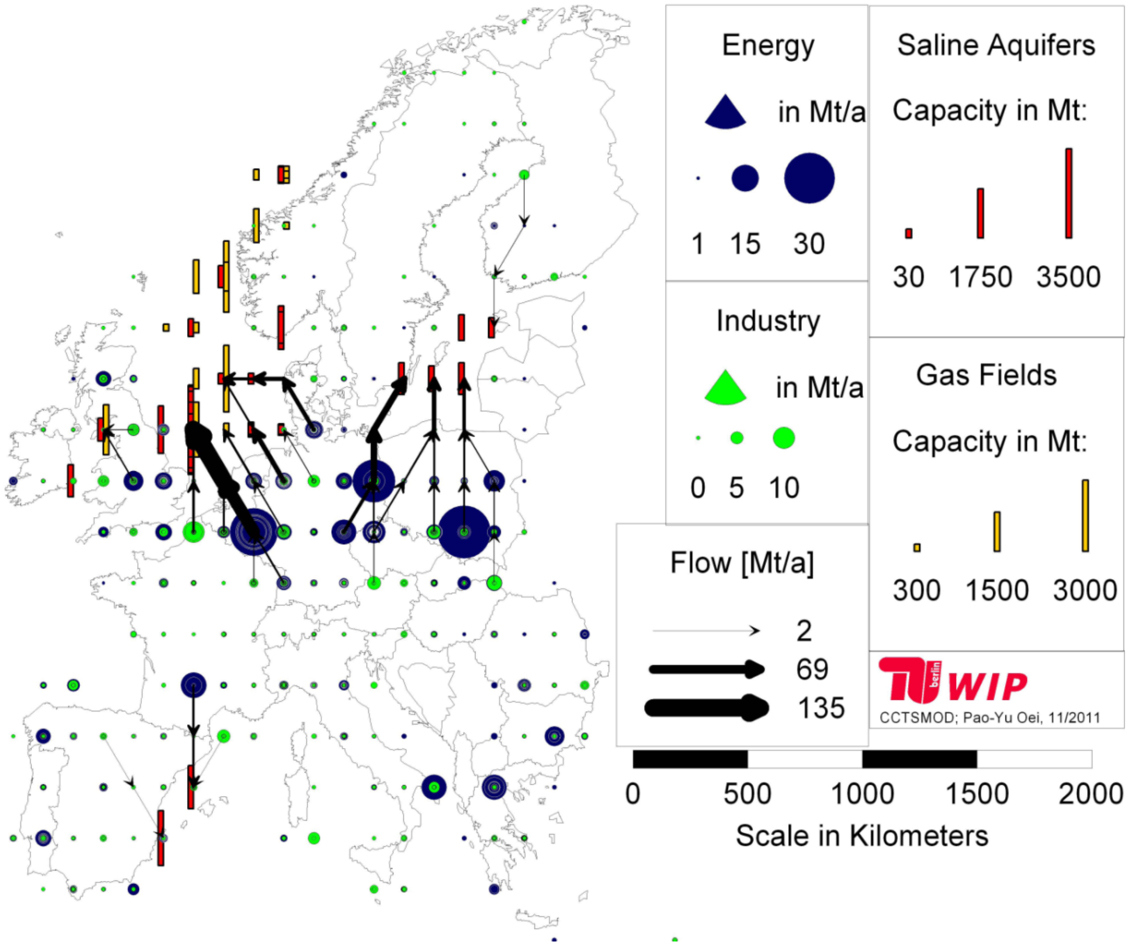

Figure 23: CCTS infrastructure in 2050, Off75

Source: Own depiction.

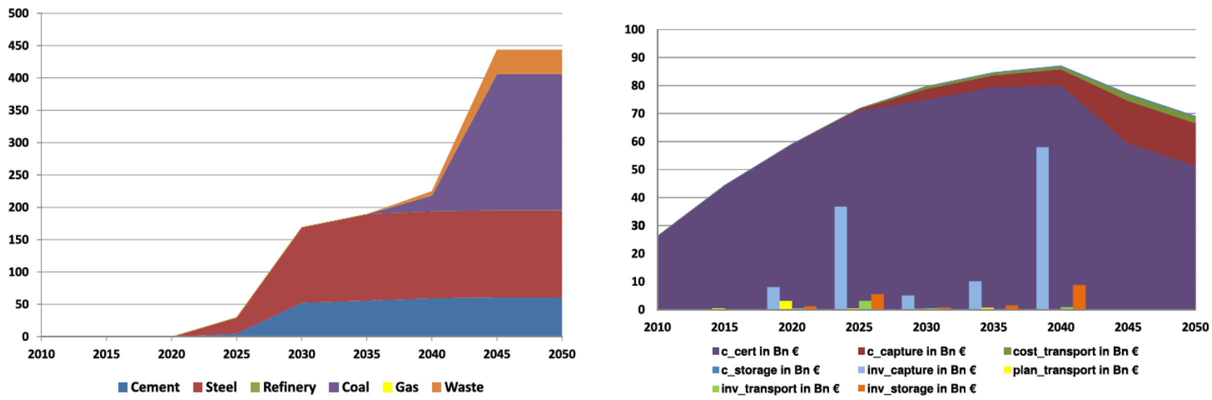

Figure 24: Storage by sector in $MtCO_2$ and infrastructure investment and variable costs in €bn, Off75
Source: Own depiction.

We also note a lower participation of the cement sector in CCTS whereas capture in the iron and steel sector remains at the same level. This is explained by higher capture costs in the cement industry (see Table 6), but also by the geographical distribution of industrial facilities: while emitters in the iron and steel sector are generally located close to the coast, cement kilns are often located close to inland mining facilities. Thus, a possible strategy could be to form regional clusters that could more easily benefit from economies of scale in transport.

Results of an offshore only scenario for Germany on a much higher resolution (distance between nodes only 50 km) show a greater drop in CCTS deployment compared to the results presented in this chapter (Oei et al., 2011). The primary reason for that is the distance of 200 km in between nodes which strongly overestimates economics of scale in transportation since many emitters are grouped and also often set closer to storage sites than in reality. Yet the distance, and therefore the total number of nodes for a modeling region, is limited by computational runtime which increases exponentially with the number of nodes. The scenarios in this chapter, which use 460 nodes, require a runtime between 48 and 72 hours on a machine with 8 cores and 30 GB RAM[41].

[41] 2x Intel Xeon X5355 2.66 GHz Quad-Core, 8 MB Cache

3.4.3 Certificate price increasing to 50 €/tCO_2 in 2050

3.4.3.1 On- and offshore storage

Earlier results of the CCTS-Mod focusing only on Germany show that an increase in the CO_2 certificate price to €50 per tCO_2 leads to an application in industry only (Oei et al., 2011). Those findings are confirmed by the CCTS-Mod on the European level as well. The lower costs of capture again lead to investments in the steel industry first, followed by the cement industry five years later (see Figure 46 in the Appendix).

The CCTS technology primarily remains an abatement option for large industry clusters with a regional proximity to storage sites in Northern Europe. This excludes small and mid-scale facilities in the European hinterland. However, with a total storage of 5.6 GtCO_2 over the next 40 years, this scenario shows the potential for CCTS in the iron and steel and cement sector even at a low CO_2 certificate price. Investment cost along the CCTS value chain totals €81.4 bn. This leads to average investment costs of €14.6 per tCO_2 avoided. Total variable costs sum up to €134 bn, or €24 per tCO_2 avoided.

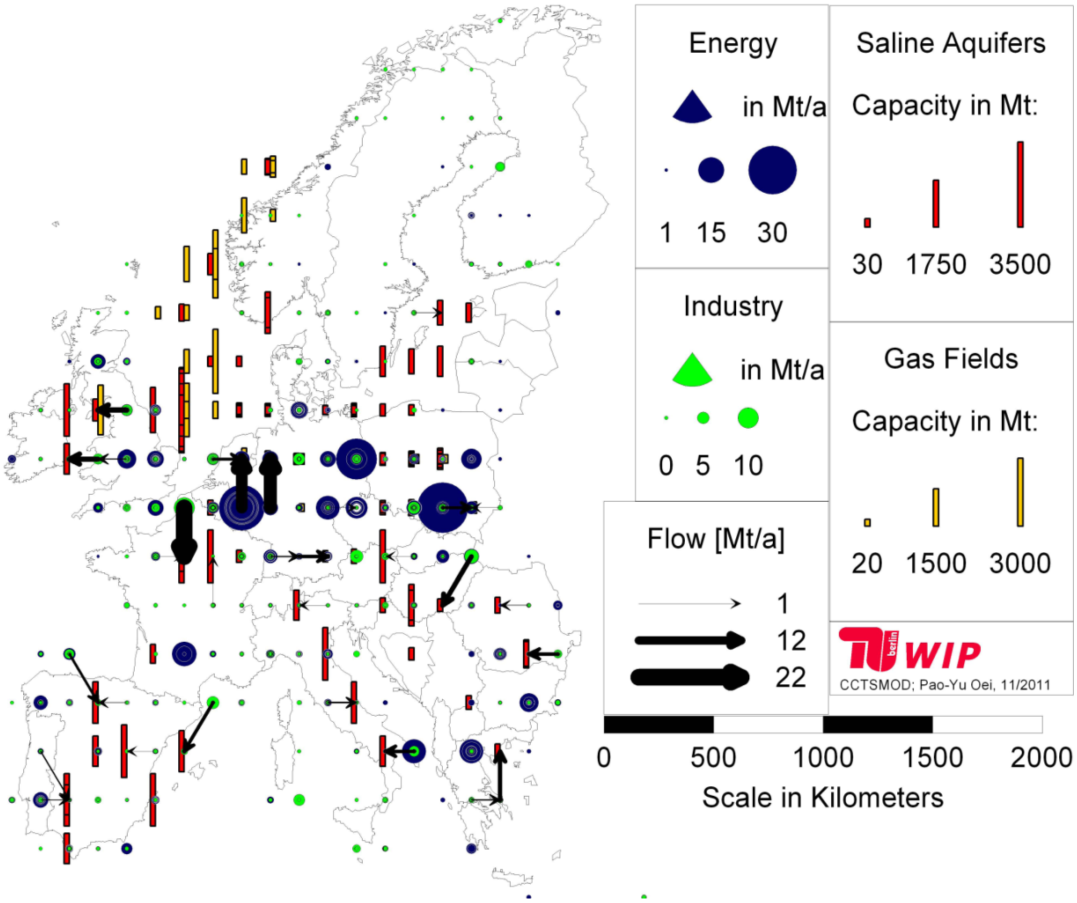

Figure 25: CCTS infrastructure in 2050, On50

Source: Own depiction.

3.4.3.2 Offshore storage only

In the case of offshore storage only the total storage is reduced to 2.1 $GtCO_2$ over the next 40 years at total investment cost of €40 bn. This leads to average investment costs of €18.5 per tCO_2 avoided. Several industrial facilities are located far from any offshore site and thus do not invest in CCTS. They are relatively scattered and cannot form large enough emission clusters to benefit from economies of scale with transporting the CO_2 over longer distances. The total variable costs sum up to €58 bn, or €26.4 per tCO_2 avoided. Average variable costs are much lower in case of the certificate price remaining below €50 as the high cost power sector is not investing in the CCTS technology.

This scenario highlights the importance of available onshore sinks, especially for the promotion of the CCTS technology at moderate CO_2 prices. However, the debate on onshore storage in several European countries (e.g., the Netherlands and Germany) indicates that this storage option could be ruled out by regulation.

3.4.4 Certificate price increasing to 100 €/tCO_2 in 2050

3.4.4.1 On- and offshore storage

This scenario results in a total storage of 24.7 $GtCO_2$ over the next 40 years, a significant increase compared to the reference scenario. The same is true for the investment costs along the CCTS value chain, which increases to €380 bn. This leads to average investment costs of €15.4 per tCO_2 avoided. Total variable costs increase to €929 bn, or €38 per tCO_2 avoided. This can be explained primarily by the higher participation of the power sector in CCTS.

3.4.4.2 Offshore storage only

This scenario results in a total storage of 19 $GtCO_2$ over the next 40 years. The investment costs along the CCTS value chain add up to €359 bn or an average of €18.7 per tCO_2 avoided. The total variable costs are €796 bn or €41.5 per tCO_2. The cost increase is based on longer transport distances and the greater participation of the power sector.

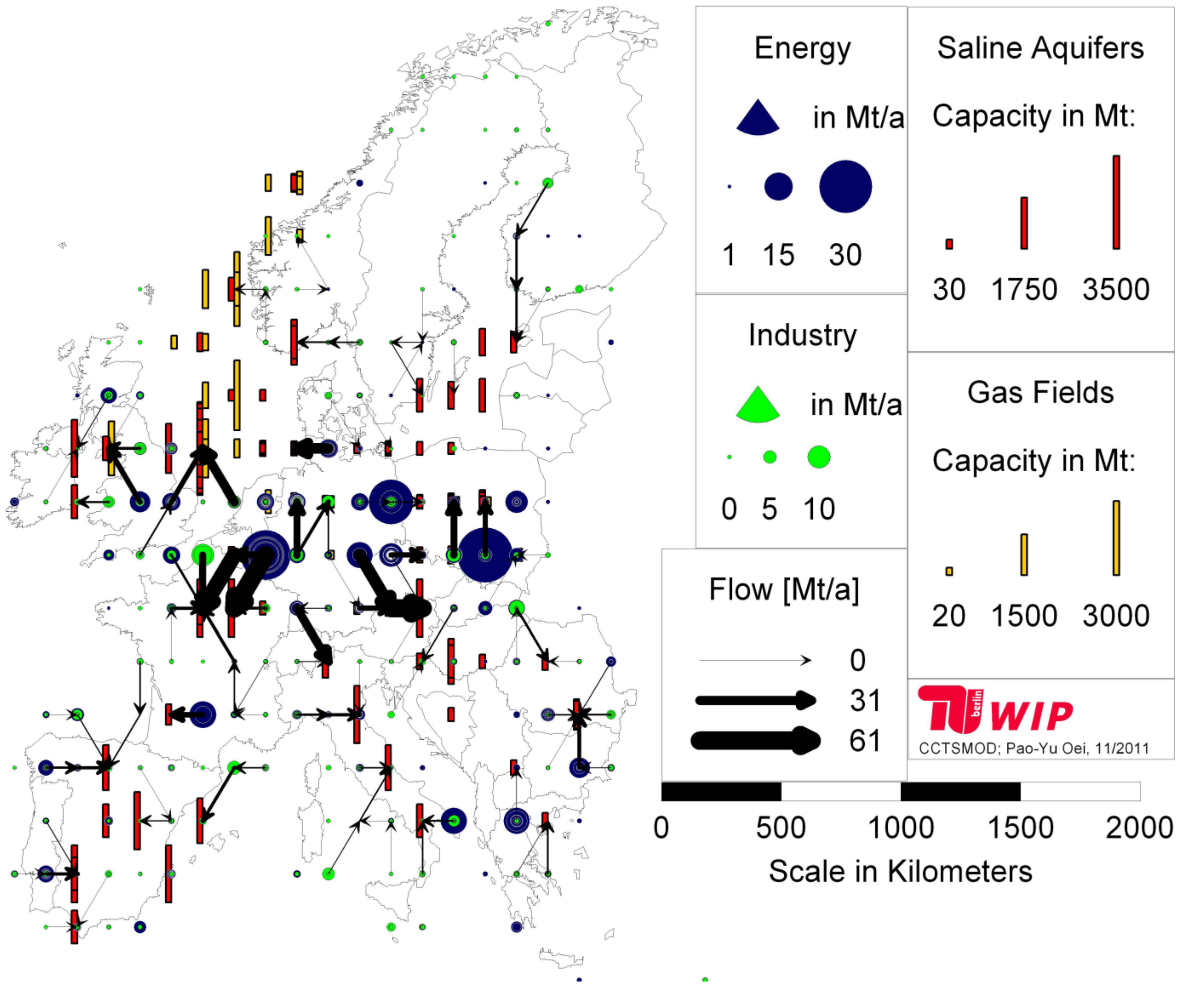

Figure 26: CCTS infrastructure in 2050, On100

Source: Own depiction.

Table 11 provides a summary of the scenario results, in terms of the required pipeline network, total stored emissions, the share of emissions that originate from industrial sources, remaining storage potential, as well as total costs for CCTS (fixed and variable).

Table 11: Overview of scenario results

Scenario	Pipeline Network [km]	Stored Emissions [$GtCO_2$]	Origin from industry [%]	Storage left in 2050 [$GtCO_2$]	CCTS inv. costs [bn]	CCTS var. costs [bn]
Ref75	20,400	15.8	63	78.2	240	515
Off75	9,800	7.5	65	42.5	145	266
On50	6,600	5.6	100	88.4	81.4	134
Off50	4,300	2.1	100	47.9	40	58
On100	23,600	24.7	53	69.3	380	929
Off100	37,400	19	57	31	359	796

Source: Own calculation.

3.5 Conclusion: the future of a CCTS roll-out in Europe

The role of CCTS in future decarbonization portfolios is highly uncertain. Part of this uncertainty is due to a lack of objective information and independent economic analysis. To improve the situation, we develop a model suggesting optimal strategies for deploying a carbon capture, transport, and storage infrastructure. The model integrates technical details, focussing on a simple decision rule on whether "to capture or not to capture": emitters can pay a given CO_2 price, or else engage into CCTS to abate their CO_2; the model will minimize the costs of both, purchase of CO_2 certificates and CCTS-infrastructure.

With respect to the existing literature, we include new features into the model, such as the explicit recognition of planning costs, as well as the option to combine CCTS in the industry and the electricity sectors. The model suggests that under certain assumptions, CCTS may contribute to the decarbonization of Europe's industry and energy sectors. However, only if the CO_2 certificate price rises to €75 by 2050 and sufficient CO_2 storage capacity is available both on- and offshore, will CCTS have the potential to play a role in future energy technologies.

Our results indicate that given an increase in the CO_2 certificate price up to 50€/tCO_2 in 2050, deployment will be limited only to industrial applications in the iron and steel as well as cement sectors. The infrastructure will remain regional without Europe-wide integration. However, European cooperation could still be of benefit in areas where emission sources and sinks are divided by national borders and for offshore storage solutions.

In all scenarios, industry plays an important role as a first mover to induce deployment. A decrease of available storage capacity or a lower increase in future CO_2 certificate prices could significantly reduce the role of CCTS as a CO_2 mitigation technology, and especially its role in the decarbonization of the electricity sector. We also observe an initial decline in per unit expenditures for CO_2 transport in scenarios with broad CCTS utilization, due to economies of scale. In later periods this effects is, however, partly offset by increasing transport distances due to the development of more distant storage resources, once the close and cheap ones are exhausted.

In this context, the storage capacity left at the end of the modeling horizon in 2050 might also be misleading, at first sight. In a post-2050 horizon, cheap storage resources are used up and more distant and costly storage sites will need to be developed. On the other hand, experience gained with developing and operating CO_2 storage sites can also modulate this costs escalation or even lead to overall cost reductions. A quantification of the different effects is up to future research. Another aspect often being neglected is the need for reserving affordable storage options when hoping for negative CO_2 emissions through Biomass–CCTS in some decades. Such and other competing concepts for utilizing underground resources (compressed air storage, natural gas / oil storage, geothermal power and / or heat recovery) make it difficult to estimate the remaining usable storage potential for CCTS.

Given continued social and political opposition to onshore storage, CO_2 abatement by means of CCTS, seems only viable with respect to offshore storage. We suggest that policymakers give first priority to CCTS for coastal areas and small industrial sites where CO_2 transport does not require intensive infrastructure investments to prove the technology's viability, especially in the industry sector. The additional costs of longer pipelines and higher costs for storage development in all offshore scenarios lead to a delay in the CCTS implementation of at least five years. However, in reality, this could well be offset by shorter planning processes if the public accepts offshore transport and storage.

Note that our model runs assume a single planner basing its investment decision on full insights into remaining storage capacities, the future CO_2 price development and actions of all other emitters. The outcomes therefore overestimate the potential for CCTS investment. The key uncertainty of the model is the CO_2 certificate price; its influence on the CCTS-deployment can be seen in the different scenario runs. The variable capturing costs are the second biggest uncertainty of the model and are mainly driven by the electricity price. An increase of these capturing costs would slow down the deployment of CCTS. Transport costs sum up to 10%, while storage costs lie below 5% of the overall CCTS-costs in all onshore scenarios. These figures, however, nearly double in the offshore scenarios. Mapping emission sources and sinks to nodes also affects the results, mainly by underestimating the necessary transport infrastructure and overestimating economies of scale. Future research should focus on advanced modeling techniques reducing model runtime to enable a European model run with a higher resolution.

Our scenario analysis underlines that the future development of an integrated CCTS infrastructure is highly sensitive to assumptions regarding the future CO_2 certificate prices and the availability of storage resources. If CCTS is to become a cornerstone of a future low-carbon industry and power generation sector policy makers have to commit to clear and reliable targets regarding the future CO_2 prices, or provide alternative long-term investment incentives. Getting the industry sector back into the CCTS debate will help to change the public opinion towards CCTS, when confronted to the lack of alternatives. Based on the persistent experience of canceled and postponed CCTS demonstration projects and reluctant institutional and private investors the authors doubt that CCTS will become the integrated pan-European industry once envisioned by EU-level policy makers.

4 Development Scenarios for a CO_2 Infrastructure Network in Europe

4.1 Introduction: an update on the deployment of CCTS in Europe

Carbon capture, transport, and Storage (CCTS) was originally seen as a central element for decarbonized electricity systems, worldwide (e.g. IEA, 2010).[42] The International Energy Agency (IEA) consequently underlined its importance with a 20% contribution to achieving emission reduction goals and 40% cost increase for decarbonization in its absence (IEA, 2012). Estimates for the European energy system assumed 77 (IEA, 2012) to 108 GW (EC, 2011) of power generation capacity to be equipped with CCTS and a CO_2 transport network of over 20,000 km by 2050 (JRC, 2011). The reality, however, is in great contrast to these expectations. Not a single full-scale CCTS project with long-term geological storage has yet been realized in the world (GCCSI, 2014). At the same time, CO_2 transport infrastructure projects have been removed from the list of critical infrastructure projects of the EU (EC, 2013a). Furthermore, the London Protocol still prohibits the movement of CO_2 across marine borders for the purposes of geological storage (GCCSI, 2014). Facing these adverse developments, academia as well as technical reports became more balanced or even critical with respect to CCTS deployment (Hirschhausen et al., 2012a).

The gridlock in the deployment of CCTS can be partly explained by the low level of the EU Emissions Trading System (EU-ETS) CO_2 price which remained in the range of three to eight €/tCO_2 since the start of the third trading period in 2013. Such low prices – with little hope for a significant rise in the coming years (Hu et al., 2015) – give insufficient incentives for investment into mitigation technologies such as CCTS. Investment costs for renewables, on the contrary, have profited from high learning curves and became a much cheaper abatement option. Even additional financial schemes such as the European Energy Program for Recovery (EEPR) proved unsuccessful in enabling projects (GCCSI, 2014). The New En-

[42] This chapter is submitted to the Energy Journal. A previous version has been published as Resource Markets Working Paper WP-RM-36 at University of Potsdam (Oei and Mendelevitch, 2013). It is joint work together with Roman Mendelevitch. Pao-Yu Oei and Roman Mendelevitch jointly developed the model and its implementation in GAMS. Pao-Yu Oei had the lead in analyzing the political setting for CCTS in the EU. Roman Mendelevitch had the lead in collecting data on CO_2-EOR, and analyzing the results. The writing of the manuscript was executed jointly.

trance Reserve (NER300) program, originally designed to provide up to €9 bn of funds to renewables and CCTS projects, ended up with a budget of only €1.5 bn as its revenue was based on the sales of 300 million CO_2 allowances. As a consequence, none of the 12 CCTS projects that applied for funding in the first round were supported (Lupion and Herzog, 2013). In July 2014 the second round of the NER300 granted €300 million to the UK White Rose CCS Project. Meanwhile, the original project timeline was pushed back by two years, aiming at completion only in 2020 (EC, 2014b; Szabo, 2014). The project outcome became even more unlikely when one of the main investors decided to draw back in September 2015.[43] Martinez Arranz (2015) identifies various blind spots in the EU demonstration programs, as Europe, in comparison to other regions, is a relatively resource-poor but advanced economy. He therefore recommends a stronger focus on the industrial use of CCTS as well as other non-CCTS mitigation possibilities in the power sector.

At the European level, the directive on the geological storage of CO_2 (so-called "CCS Directive") is the central regulatory element intended to govern the process of CCTS commercialization (EC, 2013b). However, it limits the scope of underground storage to a non-commercial size and is not sufficient for large scale projects (Triple EEE Consulting, 2014). Although focusing on the storage part of the technology chain, the Directive also requires "CCTS readiness" for new fossil generation capacities. Lacking a clear definition of this "readiness", the Directive leaves space for interpretation. A review process of the Directive in 2014 highlighted the need for running CCTS demonstration projects in Europe. In particular, it criticizes the lack of progress of CCTS for industrial applications such as steel or cement facilities, which account for one quarter of the world's energy-related CO_2 emissions. One possible option that many stakeholders requested during the review process was a successor NER300 scheme from 2020 onwards to support future projects (Triple EEE Consulting et al., 2015).

Complementary to price incentives, in some countries CCTS is promoted via climate-oriented regulation or in combination with enhanced oil recovery (CO_2-EOR) projects. The introduction of emissions performance standards (EPS) in the UK, Canada and the US restrict the annual amount of CO_2 emissions per installed unit of generation capacity and thereby

[43] Drax pulls out of £1bn carbon capture project http://www.bbc.com/news/business-34356117 (16/10/2015).

the operation of new coal power plants without CO_2 capture[44]. Using the captured CO_2 for EOR purposes contradicts the idea of long-term geological storage but significantly improves the economics of a CCTS project. Successful projects like Boundary Dam in Saskatchewan, Canada (in operation since October 2014) as well as the majority of upcoming projects in 2016-17 (e.g. Kemper County Energy Facility and Petra Nova Carbon Capture Project in the US) are associated with CO_2-EOR. Only little progress, however, is visible in the EU as only a few riparian states of the North Sea have an option for CO_2-EOR application. Nevertheless, the EU framework for climate and energy still aims at a commercial CCTS deployment by the middle of the next decade (EC, 2014c).

In this chapter we present model analysis and interpretation on the potential role of CCTS to support the EU energy system transition to meet emissions reductions goals that are consistent with an international goal of staying below 2°C of global warming. Our hypothesis is that CCTS – contrary to the dominant belief until recently – will at best be a niche technology applied in regions with highly conducive conditions, e.g. parts of the North Sea, but that due to its cost disadvantage and recent setbacks in many EU countries, it will not contribute significantly to overall EU decarbonization. The next section 4.2 provides a non-technical description of our CCTS-Mod; a multi-period, scalable, mixed integer framework calculating beneficial investments in the CO_2-chain (capture, transport, storage). Section 4.3 presents the results of the European-wide results. We find no role for CCTS in the 40% mitigation scenarios; in the 80% mitigation scenarios, some CO_2-intensive industries might start to abate, followed by the energy sector at a high CO_2 price (above 100 €/tCO_2). We consider this scenario unlikely, though, because most of the countries involved have already given up CCTS as a mitigation option, e.g. Germany, Poland, France, and Belgium. Section 4.4 then focuses on an alternative driver for CO_2-abatement through CO_2-EOR. We find that for North Sea riparian countries that have not given up on CO_2 capture, mainly the UK and Norway, the use of CO_2 for EOR might be an economic option, depending on the oil price and the price of CO_2 certificates. Once CO_2-EOR resources are fully exploited, further CO_2 capture activity is solely incentivized by the CO_2 certificate price, which has to cover at least the variable costs but also potential new investment costs. Also, the speed and extend of the deployment is

[44] The UK has introduced an Electricity Market Reform (The Parliament of Great Britain, 2013), where one of the four pillars builds on EPS benchmarked against gas-fired electricity generation,; similarly, the US (EPA, 2012, final rule pending for submission to the federal register since 05.08.2015) and Canada (Parliament of Canada, 2012) have introduced EPS for new electricity generation units.

highly dependent on assumptions for initial technology costs and learning effects. Section 4.5 concludes, analyzing the chances for a regional vs. European-wide CCTS application depending on the availability of CO_2-EOR and other storage potentials.

4.2 Model, data, and assumptions

4.2.1 The model CCTS-Mod

For our numerical analysis we use the "CCTS-Mod" (Oei et al., 2014a) of Chapter 3. The model is a multi-period, scalable, mixed integer model coded in GAMS (General Algebraic Modeling Software) and solved with a CPLEX solver. For each power plant or industrial facility covered in our input database (see section 4.2.2) an omniscient planer decides on whether to invest into a CCTS chain or to buy CO_2 certificates instead. The model decides in favor of CCTS whenever future costs of CO_2 certificates exceed the total costs of CO_2 capture, transport, and storage. In this case, investments into a capture unit facing respective capital costs have to be made. It takes five years after the investment decision before the capture unit becomes operational. Whenever the facility is actually used to capture the CO_2, variable costs are induced. The capture rate is capped at 90%. CO_2 capture has to be balanced with CO_2 transport and storage. Again, respective infrastructure investments have to be made taking into account a construction period of five years. Capital costs for transport cover right of way (ROW) costs and other investment cost parameters. If a new pipeline is constructed along a route that is already developed, ROW costs do not apply. This ensures that transportation routes are bundled in corridors, which is consistent with practices for laying pipelines for natural gas or crude oil. The construction of a pipeline is a binary decision with discrete pipeline diameters and associated throughput volumes. CO_2 storage is again subject to a five year construction period and has associated variable and capital costs.

A refined version of the model which is used for the model runs of this chapter includes the option to use captured CO_2 for enhanced oil recovery. CO_2-EOR storage is associated with additional investment and variable costs for equipment and operation respectively, but generates revenues from oil recovered with each ton of CO_2 stored. The simplified decision path of the CCTS-Mod is illustrated in Figure 27. A more detailed model description (though without the option of CO_2-EOR) can be found in Chapter 3. The model is well-based in the literature on CCTS infrastructure models, building on models developed by Middleton and Bielicki (2009) and Morbee et al. (2012).

Thus, the main drivers of the model are location and volumes of CO_2 emissions, storage capacities, investment and variable costs of each stage of the CCTS technology chain, and the assumptions on future CO_2 certificate and oil prices. Several uncertainties are in place regarding the model: First, the cost minimizing approach does underestimate the real costs of the CCTS technology, as we assume perfect foresight as well as a vertically integrated CCTS chain. Second, the model assumes the existence of certain technologies that have not been proven to work in practice on a larger scale. The "cost" estimates for CO_2 capture and storage are especially uncertain, and most likely highly underestimated. The model also does not take into account the transaction costs of bringing the immature technology to implementation, to build the infrastructure or to develop the storage sites; nor do we include costs due to rising public opposition.

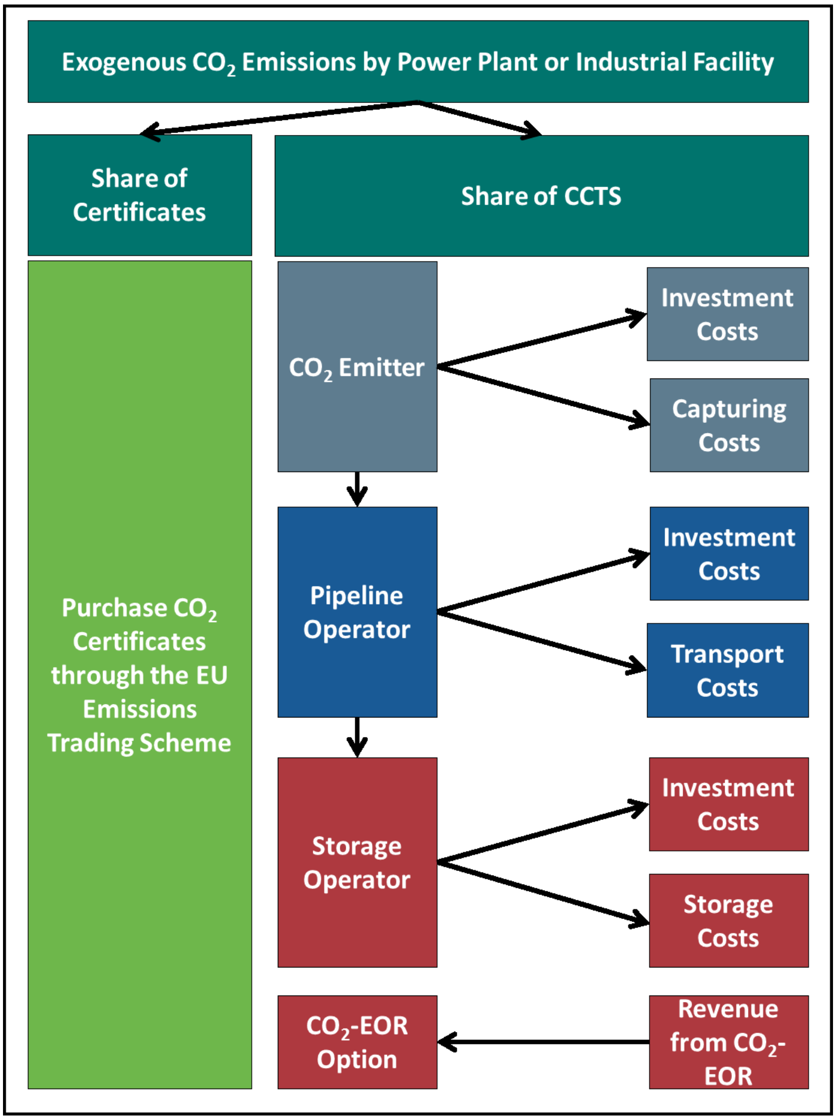

Figure 27: Decision tree of the model CCTS-Mod with the option of CO_2-EOR.

4.2.2 European data set

Data was collected for the period from 2015 to 2055.[45] A detailed description of the cost data can be found in Mendelevitch (2014). The scope of this study includes all members of the EU as well as Switzerland and Norway, and their respective Exclusive Economic Zones (EEZs). Data on location and emission volumes of refineries, steel and cement production facilities as well as coal- and gas-fired power plants is taken from a database developed earlier in Chapter 3.

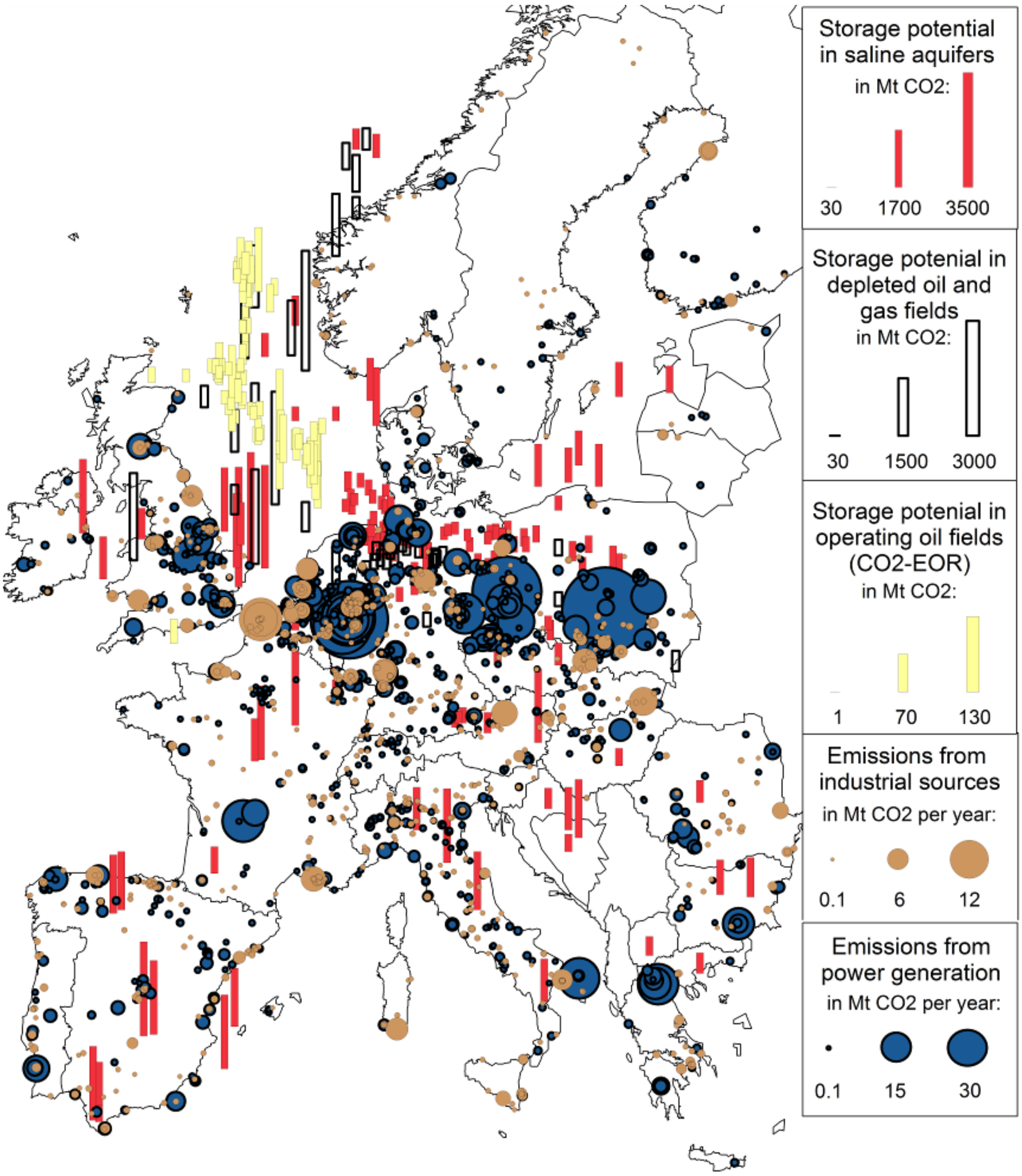

Figure 28: Distribution of CO_2 sources and storage sites by type and volume in the data set.

Source: Own illustration based on Oei et al. (2014a) and Mendelevitch (2014).

45 Note that model results for 2055 will not be interpreted. This last period is introduced to include an additional payback period and to allow for investment in 2050.

The database assumes an economic lifetime of 40 years for gas-fired and 50 years for coal-fired power plants. Power generation facilities are supposed to be shut down and not replaced after the economic lifetime is reached while industrial plants are assumed to be replaced by a facility with similar characteristics. The same database was used for location and capacities of potential storage in depleted hydrocarbon fields and saline aquifers. Data on location and volumes of CO_2-EOR storage sites is taken from Mendelevitch (2014). Figure 28 illustrates the distribution of emission sources and their respective emission volumes for 2010 as well as the distribution of storage sites by type and their respective capacities. It visualizes the fact that emission sources and storage sites are not equally spread across Europe. While the largest emission sources are located in the Rhine Area, the largest storage capacities can be found offshore in the UK and Norwegian EEZs.[46] Denmark, UK and Norway are the only countries that have potential for CO_2-EOR in their parts of the North Sea. Strong opposition in several European countries has formed against onshore CO_2 storage. All scenarios in this chapter therefore only include the option of storing the CO_2 in offshore fields.

4.2.3 Assumptions for all scenarios

Two key parameters drive the results of our model runs: On the one hand CCTS deployment is triggered by the CO_2 certificate price path which governs the profitability of the CCTS technology in comparison to balancing CO_2 emissions with purchased CO_2 certificates. If in the long run, anticipated prices are higher than the costs of using the technology chain, then CCTS is employed. We use two possible price pathways generated by the PRIMES model (EC, 2013c) which represent the outcomes of two sets of scenarios for climate change mitigation policy up to 2050 (see Table 12). The 40% scenarios include the EU 2020 targets as well as a 40% greenhouse gas (GHG) reduction by 2050 compared to 1990. The 80% scenarios are more ambitious including an 80% GHG reduction by 2050. All scenarios do not allow for emission trading across macro regions (but trade within macro regions, e.g. within the EU through a cap and trade system). They include moderate assumptions on efficiency gains and availability of nuclear and renewable energies (see Holz and von Hirschausen (2013) and Knopf et al. (2013) for a detailed description of the underlying assumptions).

[46] The estimates for possible storage locations are based on studies which mostly offer data on a 50 x 50 km grid. Some of these formations, however, consist of several smaller neighboring aquifers. The exploration of small reservoirs is less economical, given a bad ratio of investment costs and exploitable storage capacity. The overall storage potential of Europe is thus overestimated in this chapter due to the lack of more detailed information.

Table 12: CO_2 certificate price path in the different scenarios.

	Scenario	2015	2020	2025	2030	2035	2040	2045	2050
Certificate price in €/tCO_2	40%	14	17	27	37	45	52	52	52
	80%	18	25	39	53	75	97	183	270

Source: Knopf et al. (2013).

The availability of storage capacity is the second decisive parameter. Especially France, Germany and Belgium have their storage resources mostly in onshore saline aquifers and depleted hydrocarbon fields. However, onshore storage is associated with significantly higher complexity of regulation and a higher number of stakeholders involved. The Global CCS Institute has performed a comprehensive assessment of CO_2 storage readiness on a country level and come to the conclusion that Norway is the only European country currently ready for a wide-scale CO_2 storage deployment (GCCSI, 2015). Germany, the Netherlands and UK are the only countries that are at least ranked advanced. The report revealed a high correlation between a country's ranking and the existence of an advanced hydrocarbon industry, and its dependence of fossil resources. Following long debates, onshore storage was excluded as a storage option in Germany (Hirschhausen et al., 2012b; Schumann et al., 2014, p. 2), Denmark (Brøndum Nielsen, n.d.), the UK and Netherlands (GCCSI, 2012). Analogous developments are conceivable for other countries, leaving offshore storage as the only remaining storage option in Europe. Accordingly, none of the Europe-based large-scale integrated CCTS projects listed in the Global CCS Institute database include onshore CO_2 storage (GCCSI, 2014). Therefore, in all presented scenarios onshore storage capacity is not available, which reduces total available storage capacity from 94 GtCO_2 to 50 GtCO_2 in the European-wide scenarios and from 56 GtCO_2 to 42 GtCO_2 for the scenarios which focus on the North Sea region. As a consequence, France and Belgium lose most of their domestic storage potential. Despite a number of minor storage resources (1.2 GtCO_2) in saline aquifers in the German North Sea, the situation in Germany is similar.

The resulting scenarios shown in Table 13 differ in their respective CO_2 price path, the availability of storage potential (offshore with vs. without CO_2-EOR) and geographical coverage (European-wide vs. the North Sea region vs. selected countries). Section 4.3 describes the European scenarios (*EU_40%* and *EU_80%*) while section 4.4 further analyzes regional scenarios (*NorthSea_40%*, *NorthSea_80%* and *DNNU_80%*).

Table 13: List of scenario assumptions

Scenario	*Coverage*	*CO_2 price in 2050*	*Storage availability*
EU_40%	Europe	52 €/t	Offshore only
EU_80%	Europe	270 €/t	Offshore only
NorthSea_40%	North Sea region	52 €/t	Offshore only + CO_2-EOR
NorthSea_80%	North Sea region	270 €/t	Offshore only + CO_2-EOR
DNNU_80%	DK, NL, NO, UK	270 €/t	Offshore only + CO_2-EOR

4.3 Results of the European-wide scenario analysis

4.3.1 EU_40% scenario

CCTS starts being deployed from the year 2035 onwards when the CO_2 certificate price passes the 40 €/tCO_2 threshold. Nevertheless only a very small annual amount of around one MtCO_2 is being captured and stored in offshore hydrocarbon fields as well as saline aquifers. Hydrocarbon fields are the cheapest storage option when excluding CO_2-EOR, but are not available at all locations. Four iron and steel factories in Norway and Estonia are the only emitters that invest in capture technology, benefiting from the lower variable and fixed costs assumed for this industry. The investing factories are located at the coast which leads to lower transport costs than for other industrial facilities. The overall costs sum up to €0.2 bn of investment costs and an additional €0.4 bn of variable costs until 2050.

4.3.2 EU_80% scenario

The increase of the CO_2 price in the *EU_80%* scenario is steeper than in the *EU_40%* scenario. The price increases gradually until a stronger rise kicks off in 2030, resulting in its final value of 270 €/tCO_2 in 2050. CCTS deployment starts once the CO_2 price exceeds 40 €/tCO_2 which happens in the year 2030 due to the steep path increase. The first investments into the CCTS technology can be seen in the previous years (2020-2025). The iron and steel sector is – similar to previous modeling runs in Chapter 3 – again the first mover until some cement works start capturing CO_2 from 2035 onwards (see Figure 29). At that point a certificate price of 75 €/tCO_2 is reached and a total of 300 MtCO_2 is annually stored in offshore hydrocarbon fields and saline aquifers. CCTS becomes economical for power plants and refineries as soon as the price exceeds 100 €/tCO_2 in the year 2040. Still rising prices above 180 €/tCO_2 in 2045 lead to additional economic incentives for more distant power plants to invest in further CCTS deployment. Annual captured emissions sum up to more than 1 billion t CO_2 from 2040 to 2045. These emissions are then transported via a pipeline network of 44,800 km to different storage locations. Total captured emissions start decreasing after 2045 due to the phase-out of several older power plants. 12.2 GtCO_2 is stored in offshore storage sites until 2050. 55% of these emissions originate from industrial sources.

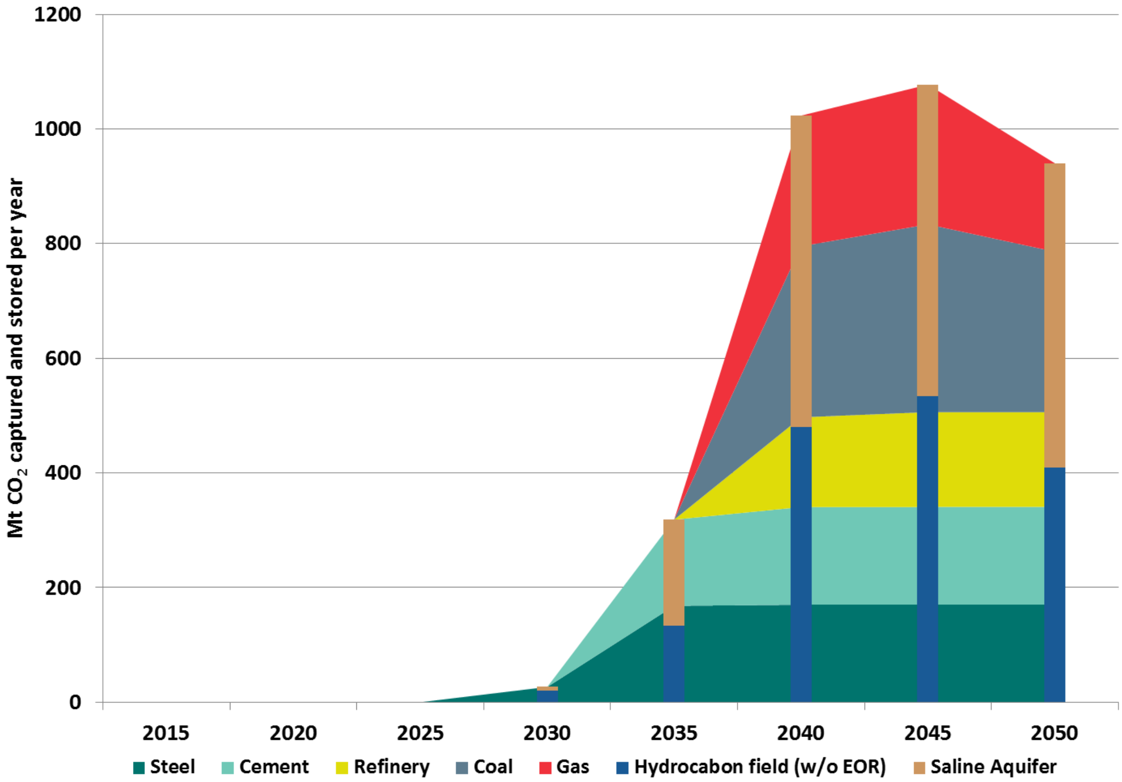

Figure 29: Captured CO_2 emissions by source and storage type over time in the *EU_80%* scenario.

The capturing costs have the highest share (60-70%) in variable as well as fixed costs of the CCTS chain (see Figure 30). The infrastructure costs of storage comprise around 30% of the total investment costs, but have relatively small share of total variable costs of 10%. Transport costs depend very much on the location of each facility and range around 10-15% in variable and fixed costs. This step of the CCTS technology chain is also the driver making CCTS a more beneficial option for facilities closer to possible storage sites. This can be clearly seen as the first movers are mostly located near the North Sea where the highest offshore storage potential can be found. The overall investment costs until 2050 exceed €300 bn with an additional €730 bn of variable costs.

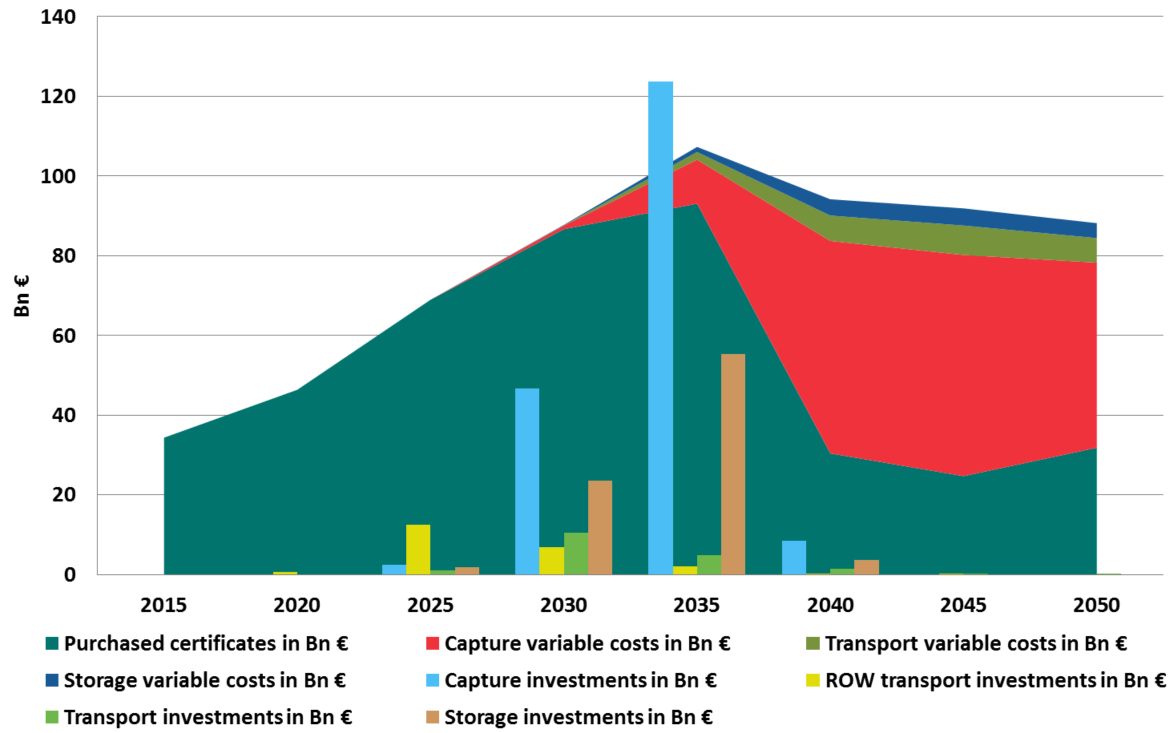

Figure 30: Cost distribution over the whole timespan in the *EU_80%* scenario in €bn.

4.3.3 Sensitivity to investment and variable costs

Many cost studies of the CCTS technology chain name the capture stage as most cost intensive for both investment and variable costs (e.g. The Crown Estate et al., 2013). To assess the sensitivity of the resulting CCTS infrastructure to these cost parameters we simulated four additional scenarios: Two where we double the capital costs (Inv_200%) and variable costs (Var_200%) respectively, one with double capital and variable costs (Inv&Var_200%), and one with variable and capital costs both increased by 50% (Inv&Var_150%).[47] Table 14 provides the input values for the sensitivity analysis and reference values from CCTS-Mod and the PRIMES model of the European Commission (EC, 2013c) for comparison. The capital costs used for the base run are 25-30% below the input values in the PRIMES model. For variable costs no values for comparison were available.

[47] The given costs only include the additional variable and fixed costs for equipping a power plant or industrial facility with a capturing unit compared to a facility without a capturing unit.

Table 14: Input parameters for sensitivity analysis, and reference values for comparison.

Input Parameter	Variation	2015	2020	2020	2030	2035	2040	2045	2050
Capital cost in €/tCO₂y	*Base Case*[48]	*175*	*175*	*162*	*149*	*138*	*127*	*118*	*108*
	Inv&Var_150%	*263*	*263*	*243*	*224*	*207*	*191*	*177*	*162*
	Inv_200%	*350*	*350*	*324*	*298*	*276*	*254*	*236*	*216*
	PRIMES[49]		*211*		*202*				*153*
Variable cost in €/tCO₂	*Base Case*[48]	*64*	*64*	*63*	*62*	*61*	*60*	*59*	*58*
	Inv&Var_150%	*96*	*96*	*95*	*93*	*92*	*90*	*89*	*87*
	Var_200%	*128*	*128*	*126*	*124*	*122*	*120*	*118*	*116*

Source: EC (2013c) and Mendelevitch (2014).

In all sensitivity runs the increase in costs has led to a significant delay in the first deployment of the CCTS technology. Figure 31 (left side) shows that while in the base run CCTS is first introduced in 2030, in the *Inv_*200% and Inv*&Var_150%* scenario the technology is first used in 2035, and only in 2040 in the other two scenarios. The figure also illustrates the sensitivity of total costs and length of the pipeline network until 2050. For all sensitivity runs cost figures are 5-25% higher than in the base case, showing an increasing sensitivity over the model horizon due to the accumulation of higher variable costs. Figures on CO_2 capture, storage and pipeline network are lower for the sensitivity runs than for the base case, with the gap narrowing between 2040 and 2050 (see Figure 31, right side). For the two scenarios *Inv_200%* and *Inv&Var_150%* the overall impact on key results like capture, and storage amounts and length of pipeline infrastructure is at most 10% or less. By contrast, doubling the variable capture costs has a strong impact on the length of the pipeline network with a decrease of over 35% compared to the base case. The future development of a CCTS infrastructure is therefore more sensitive to its variable than its investment costs. However, the deployment of the CCTS technology as a whole is not very sensitive to even drastic increases in capture costs, given high CO_2 certificate prices in the end of the modeling horizon (270 €/tCO_2) and the lack of alternative technologies, as both prevailing in this modeling framework.

[48] Data specification used for coal-fired power plants in (Mendelevitch, 2014)

[49] EC (2013); based on emission factor 0.9 tCO_2/MWh, load factor 86%, reference power plant: 2100€/kW overnight capital costs

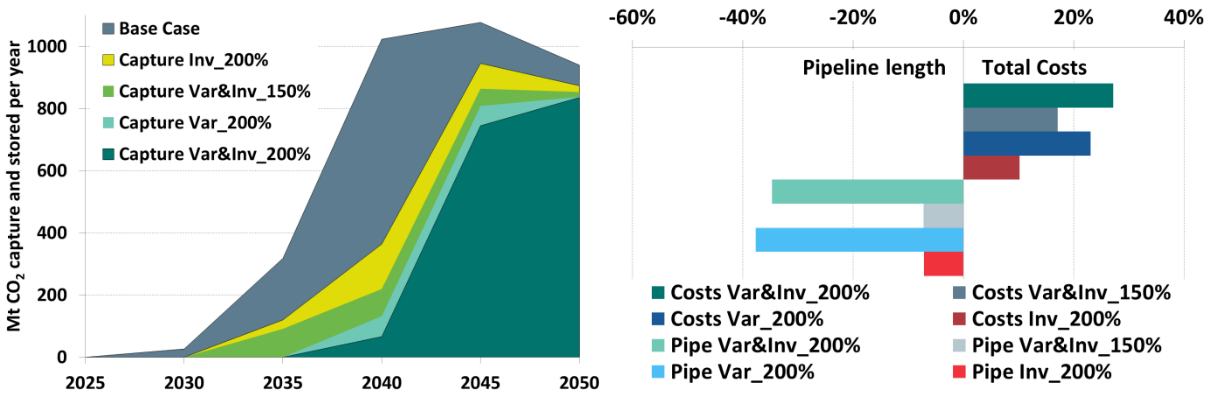

Figure 31: Sensitivity of captured amounts over the model horizon (left side), and total costs and length of the pipeline network in 2050 (right side).

4.3.4 Summary of the European-wide scenarios

Table 15 summarizes the results of the different Europe-wide scenarios. In the *EU_40%* scenario only four iron and steel factories in Norway and Estonia invest in the capture technology as they profit from the industry's low variable and fixed costs. These facilities additionally benefit from their ideal location close to storage sites in the North Sea, minimizing costs associated with CO_2 transport. CCTS cannot be considered as an abatement option for power plants if CO_2 prices hardly rise above 50 €/tCO_2. Sensitivity analysis shows that the future development of a CCTS infrastructure is more sensitive to its variable than its investment costs.

The *EU_80%* scenario arrives at CO_2 certificate prices around 250 €/tCO_2 in the year 2050. Under this assumption, investing in the CCTS technology is cost-efficient for all emitters, with industry still being the first mover. However, from today's perspective, these modeling results seem unrealistic. Even under the assumption of one omniscient planner, a CO_2 pipeline network of at least 45,000 km covering great parts of Europe would be needed, with overall system costs of €800-1,000 bn. The construction of such a huge new infrastructure network is highly dependent on the public acceptance, especially in densely populated regions like Europe (Gough et al., 2014). Considering the number of different parties, technology stages, insecurities regarding CO_2 prices, learning rates and further policy measures, one comes to the conclusion that the necessary infrastructure and investment costs would be several times higher. This questions the fact whether CCTS may be able to fulfill its role as a decarbonization technology of Europe. The following section 4.4 therefore focuses on a regional CCTS deployment around the North Sea only.

Table 15: Summary of the European-wide results.

Scenario	*Pipeline Network [tsd. km]*		*Stored Emiss. until [GtCO₂]*		*Origin. from industry [%]*	*Storage capacity left in 2050 [GtCO₂]*	*CCTS invest. costs [€bn]*	*CCTS var. costs [€bn]*
	2030	*2050*	*2030*	*2050*				
EU_40%	-	<1	-	0.02	100	50.0	0.2	0.4
EU_80%	-	45	-	12.2	55	37.9	306.6	731.2

4.4 Regional focus: CO_2-enhanced oil recovery options in the North Sea

The planned demonstration projects with the highest chance of realization are all close to the North Sea and are aiming for offshore storage with additional profit generated from CO_2-EOR (GCCSI, 2014). The following scenarios depicted in sections 4.4.4 and 4.4.5 assess the implications of CO_2-EOR for the development of a CCTS infrastructure with a focus on the North Sea Region. Several of these countries such as Germany and France are, however, unlikely to take part in any future CCTS deployment.[50] Different national strategies towards implementation of CCTS, instead of a joint European energy strategy, thus seem most likely at the moment. Section 4.4.6 therefore includes a regionally focused analysis of four European countries where a joint CCTS and CO_2-EOR deployment is most likely: Denmark, the Netherlands, Norway, and the UK (DNNU). One interesting aspect analyzed in this section is whether the employment of CO_2-EOR by a limited number of countries increases costs due to a lack of economies of scale during the use of CO_2-EOR and later. The assumed price paths are the same as in the previous scenarios.

4.4.1 The role of CO_2 reuse for CCTS

CO_2-EOR is the most mature CO_2 reuse technology and has been practiced since the 1980s in the USA and Canada (cf. GCCSI, 2011a). The application of other technologies that are in the commercialization phase like Bauxite residue carbonation and using CO_2 in metha-

[50] This is partly due to rising public opposition (NIMBY, not in my backyard, effect) as well as different national interests (e.g. France focusing on nuclear energy, Germany on the other hand on renewable energy sources).

nol production is very site specific and requires favorable local conditions. The use of CO_2 in enhanced coal bed methane recovery, as a working fluid in enhanced geothermal systems, as feedstock in polymer processing, and for algae cultivation are all technologies that need to be further developed and proven in real world pilot or demonstration scale applications. The global market for CO_2 reuse for all technologies has a volume of approximately 80 Mt per year, which is equivalent to the annual emissions of the four biggest lignite power plants in Germany. CO_2-EOR in the USA and Canada account for the biggest share with 50 Mt per year. 80% of the CO_2 is supplied from natural CO_2 sources at a price in the order of 15-19 US$/t$CO_2$. In total, anthropogenic CO_2 emissions can only be offset to a few percent from current and potential future demand for CO_2 reuse. Although reuse has very limited potential it can generate modest revenues for a selection of near term CCTS projects. Its impact to global CO_2 abatement, however, depends on the application as e.g. CO_2-EOR and using CO_2 in methanol production have no positive climate effect due to the latter burning of the product (Gale et al., 2015).

IEA and UNIDO (2011) give a similar assessment of the role of CO_2-EOR for the development of the CCTS technology appraising it as an important way to add value to a CCTS operation. The IEA (2012) is analyzing the role of this technology. It acknowledges that CO_2-EOR not only offers a way to partly offset the costs of demonstrating CO_2 capture but also to drive the evolution of CO_2 transportation infrastructure, and incorporates opportunities for learning about certain aspects of CO_2 storage in some regions. Several studies have looked into the economics of CO_2-EOR on a regional and national scale: e.g. the application of the technology in the UK Central North Sea/Outer Moray Firth region (Kemp and Kasim, 2013; Scottish Centre for Carbon Storage, 2009) and the Norwegian continental shelf (Klokk et al., 2010), and have found substantial potential for the combination of the two technologies and associated benefits.

4.4.2 CO_2-EOR resources in the North Sea

The analysis of the role of CO_2-EOR for the development of a CCTS infrastructure requires a comprehensive estimation of the potential for CO_2-EOR in the North Sea region. Mendelevitch (2014) performed an intensive literature review and presents own estimates to compile a consistent database of CO_2-EOR potentials in the North Sea region. Data availability diverges significantly between the different countries of the North Sea Region. Therefore, different approaches have been chosen for the individual countries. CO_2 injection potentials are considered as the net amount of CO_2 that can be stored during the CO_2-EOR process and includes a constant recycling ratio of 40% following Gozalpour et al. (2005).

For the UK Mendelevitch (2014) finds 54 candidate fields with an estimated net injection potential ranging between 2 and 89 $MtCO_2$ (Forties field). Total UK potential sums up to 572 $MtCO_2$ which corresponds to 1733 Mbbl additional oil recovery potential. For Norway he identifies seven candidate fields with an estimated net injection potential ranging between 4 and 130 $MtCO_2$ (Ekofisk field). Total storage potential in Norwegian oil fields in the North Sea add up to 314 $MtCO_2$ which corresponds to an additional oil recovery potential of 951 Mbbl. For Denmark the study finds 14 candidate fields with an estimated net injection potential ranging between 3 and 88 $MtCO_2$ (Dan field). Total storage potential in Danish oil fields sums up to 348 $MtCO_2$ which corresponds to an additional oil recovery potential of 1054 Mbbl. Other riparian countries of the North Sea do not exhibit substantial oil resources and are therefore not included in the analysis.

4.4.3 Costs and revenue of CO_2-EOR

To assess the economics of a prospective CO_2-EOR infrastructure correctly, it is crucial to accurately estimate the costs associated with it. Mendelevitch (2014) draws on various case studies on CO_2-EOR projects in the North Sea to develop an inventory of the main investment and operating costs components (see Table 16).

Based on the cost components mentioned above investment costs add up to 103.9 €/tCO_2 stored per year and operating costs add up to 36.8 €/tCO_2 stored. Without costs for CO_2 import the costs for oil supply from CO_2-EOR in the North Sea Region are in the range of €12-17 per bbl incremental oil (depending on site specific CO_2 utilization rates), which is consistent with estimates from OECD and IEA (2008), giving a range of US$40-80 per bbl (including costs of CO_2 supply) for long-term oil supply from CO_2-EOR.

Expectations about the development of the crude oil price determine the attractiveness of CO_2-EOR operations. The price not only has to cover investment and variable costs of incremental oil production but also has to refinance the capture and the transport of the CO_2. DOE/IEA (2012) present a compilation of different oil price projections for the Western Texas Intermediate (WTI) crude oil price for the period up to 2035. The chosen medium oil price path represents an average of the price projections while the lower price path marks their lower bound. To provide a rough estimate of the profitability of combining CCTS with CO_2-EOR, Table 17 compares cost and revenue items for a generic example. The sales price of additionally produced crude oil and the assumed CO_2 certificate price (as negative opportunity costs) of the respective year constitute the potential revenue side. On the costs side, investment and variable costs for each of the stages of the CCTS technology chain are included. Even for the high frist-of-a-kind investment costs assumed for 2015 and 2020 the combination of the two technologies yields considerable profit of 100 €/tCO_2 and higher. The two most critical assumptions are the "bbl crude oil per tCO_2 injected" conversion rate and assumptions on the future development of oil prices. Until now, CO_2-EOR operations are only performed onshore. Employing the technology in the North Sea is associated with additional technological and therefore also financial risk which is not taken into account in this calculation.[51]

Table 16: CAPEX and OPEX cost components for CO_2-EOR installation.

CAPEX cost component	€ mn
1) Survey costs to examine the reservoir characteristics with respect to CO_2-EOR	1.50
2) Platform construction/restructuring costs to adapt to CO_2-EOR requirements, including	
a) surface facilities costs to pretreat the CO_2 before injection	17.5
b) recycle installments to separate, compress and re-inject CO_2	7.1
3) Well drilling costs for new injection wells	52.5
4) Monitoring and verification facility	3% of CAPEX
OPEX cost component	**€ mn/MtCO_2**
1) Facility operation	5% of CAPEX
2) Oil production	12.1
3) CO_2 recycling	5.2
4) CO_2 compression and injection	8.7
5) Monitoring and verification	0.4

Source: Mendelevitch (2014).

[51] A CO_2 utilization rate of 0.33 tCO_2/bbl (Mendelevitch, 2014) and 1.25$/€ is being used. Additional capture costs for a coal-fired power plant equipped with post-combustion capture are calculated including a 5% discount rate and 30 years of operating life. The transport costs are estimated by assuming a 500 km long pipeline, with a lifetime of 30 years and a 5% discount rate. CO_2-EOR equipment is expected to have a much shorter operating life of 10 years and the same discount rate of 5%.

Table 17: Cost and revenue items for the deployment of CCTS-EOR

Input Parameter		*Variation*	*2015*	*2020*	*2030*	*2040*	*2050*
Crude Oil Price in		\$/bbl	92	106	118	123	135
		€/tCO_2	222	255	282	294	324
Certificate price (40% Scenarios)		€/tCO_2	14	17	37	52	52
Subtotal: returns		€/tCO_2	236	272	319	346	376
Capture	*Capital cost*	€/tCO_{2y}	175	175	149	127	108
	Variable cost	€/tCO_2	64	64	62	60	58
	Σ	€/tCO_2	75	75	72	68	65
Trans-port	*Capital cost*	€/tCO_{2y}	57	57	57	57	57
	Variable cost	€/tCO_2	5	5	5	5	5
	Σ	€/tCO_2	9	9	9	9	9
Storage	*Capital cost*	€/tCO_{2y}	104	104	104	104	104
	Variable cost[52]	€/tCO_2	37	37	37	37	37
	Σ	€/tCO_2	50	50	50	50	50
Subtotal: CCTS costs			134	134	131	127	124
Total: Returns – Costs		€/tCO_2	102	138	188	219	252

Source: Mendelevitch (2014).

4.4.4 Regional scenario: NorthSea_40% scenario with CO_2-EOR option

The *NorthSea_40%* scenario assumes the same CO_2 price path as the *EU_40%* scenario (see Table 12). Scenario results show that the use of CCTS is still most economical for the industrial sector, particularly iron and steel making plants. These facilities invest in a CCTS infrastructure from 2015 to 2020 in order to gain profits from additionally recovered oil from CO_2-EOR from 2025 onward. After the exhaustion of most of the CO_2-EOR fields in 2035, new storage sites in saline aquifers and depleted hydrocarbon fields closer to the shore are being used (see Figure 32 for the CO_2 flows in 2050). In this scenario, a total of 2.5 bn tCO_2 is stored until 2050 with annual storage volumes of around 100 MtCO_2. The required CO_2

[52] Variable costs of CO_2 storage include operational costs (OPEX) of oil production (see Table 16).

transport network spans approximately 15,000 km. The scenario indicates that the CO_2-EOR technology could lead to additional early economic incentives for the construction of a CCTS infrastructure. Existing infrastructure can be used after the exploitation of the CO_2-EOR potential in the North Sea as soon as the CO_2 price is high enough. In case of the CO_2 price path remaining around 50 €/tCO_2 like in the *EU_40%* scenario, it is, however, still only economical for several industrial facilities such as steel or cement. The investment costs sum up to €50 bn with additional variable costs of €150 bn until 2050. Revenue from selling additionally recovered crude oil sums up to €300 bn. Thus, even if investments in CCTS infrastructure are more than recovered, CO_2 price signals far beyond 50 €/tCO_2 are needed to establish long-term use of CCTS.

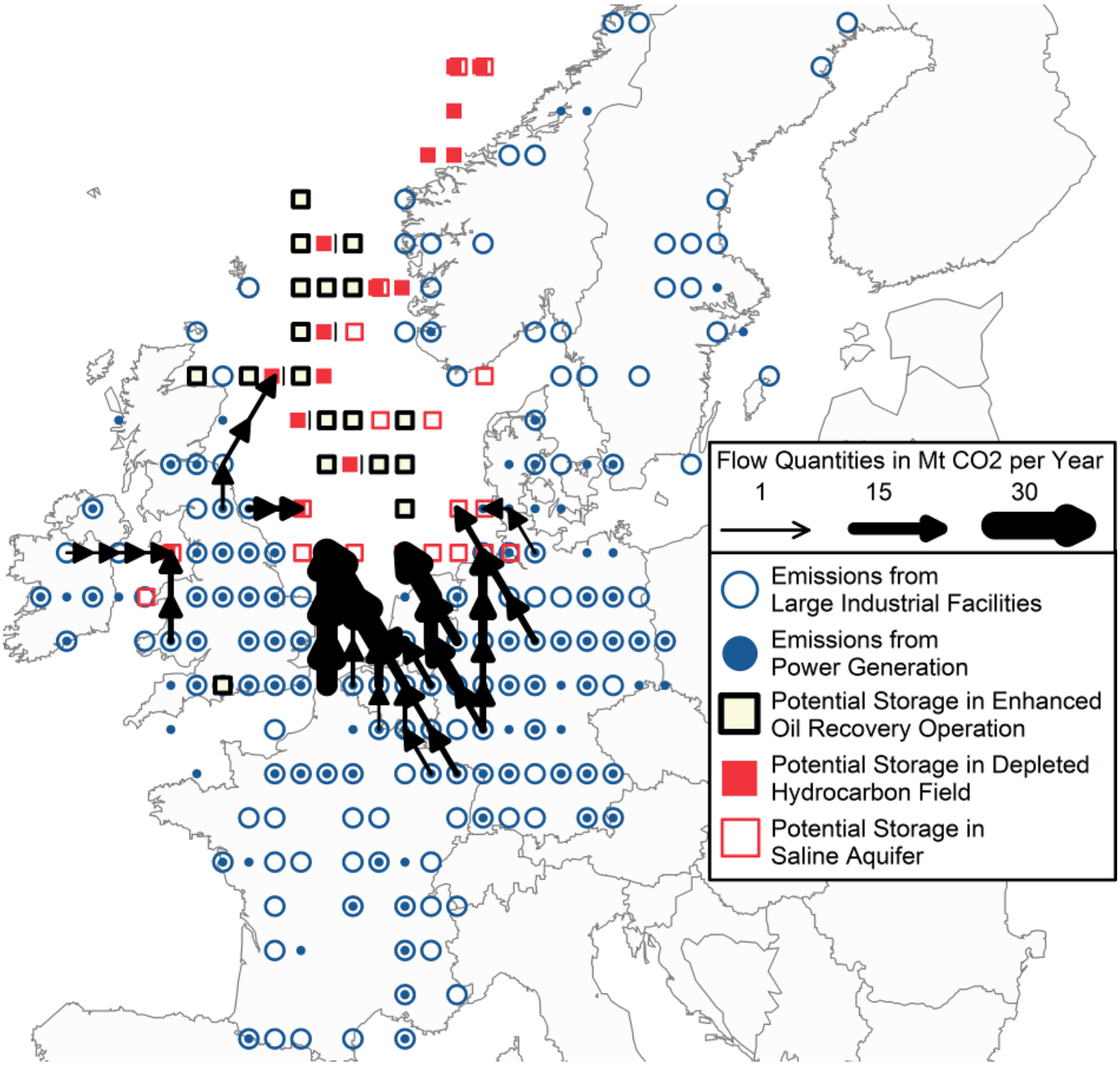

Figure 32: CO_2 flows in the *NorthSea_40%* scenario in 2050 after CO_2-EOR-fields are exploited.

4.4.5 Regional scenario: NorthSea_80% scenario with CO_2-EOR option

The *NorthSea_80%* scenario assumes the same CO_2 price path as in the *EU_80%* scenario (see Table 12). Until 2035 – the point when the CO_2-EOR operation stops due to depletion – results of the *NorthSea_80%* scenario are very similar to those of the respective *NorthSea_40%* scenario. From 2020 onwards an average of 100 $MtCO_2$ is transported each year from steel and cement facilities into CO_2-EOR operations in the North Sea (see Figure 33). Once CO_2-EOR resources are depleted, further CO_2 capture activity is solely incentivized by the CO_2 certificate price, which has to cover at least the variable costs but also potential new investment costs. New storage in non-CO_2-EOR locations is being developed close to the shore and close to already existing transport routes. From 2035 onwards, with prices exceeding 75 €/tCO_2, additional more distant industrial facilities start running their capturing units. Similar to the results from the respective *EU_80%* scenario without the CO_2-EOR option, power plants only start capturing their CO_2 from 2040 onward. The network required to accomplish the CO_2 transport spans 27,000 km connecting the sources to the North Sea storage sites (see Figure 34). The investment costs sum up to €190 bn and there are an additional €540 bn variable costs over the whole time period until 2050 (see Figure 35). Revenues from selling additionally recovered crude oil sum up to €300 bn, similar to the results in the *NorthSea_40%* scenario. However, in contrast to the *NorthSea_40%* scenario, in this scenario the high CO_2 price creates also enough incentive to pursue CCTS even after the depletion of CO_2-EOR resources and eventually leads to a full deployment of the technology in the modeled sectors.

Note that the total amount of CO_2 captured is lower than in the *EU_80%* scenarios without the CO_2-EOR option because this analysis is concentrating on the riparian countries of the North Sea only. However, like in the *EU_80%* scenario, all examined industrial facilities and power plants start using the CCTS technology at some point; with the industry still holding the higher share of total stored emissions over time.

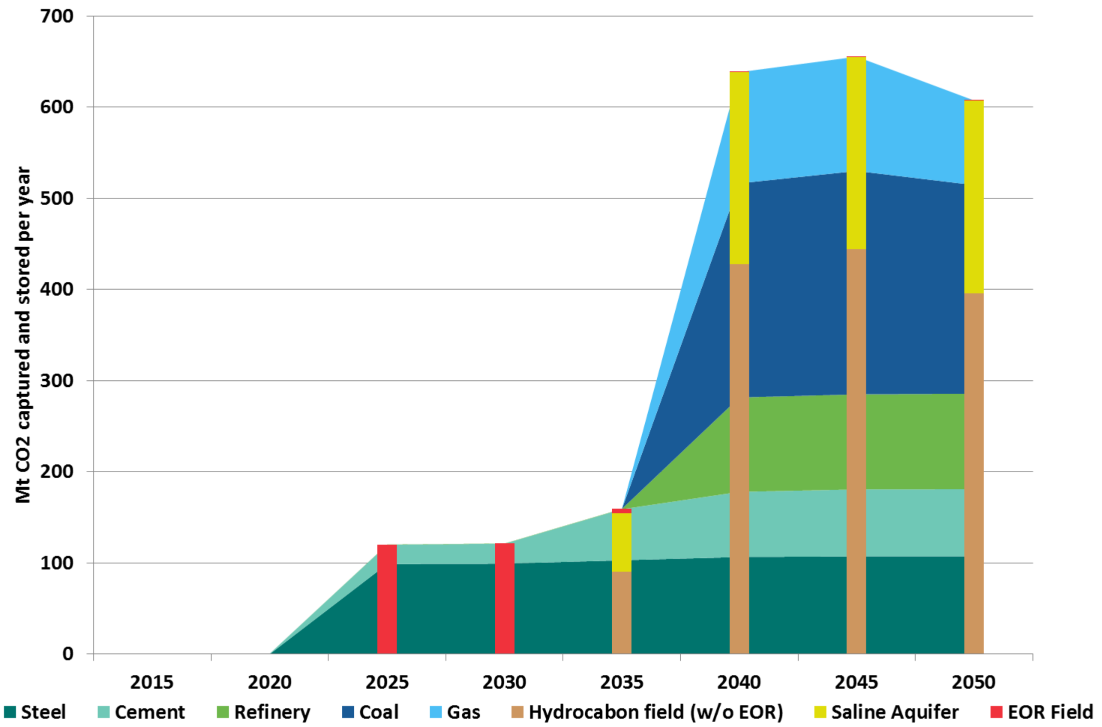

Figure 33: Captured CO_2 emissions by sector and storage type over time in the *NorthSea_80%* scenario.

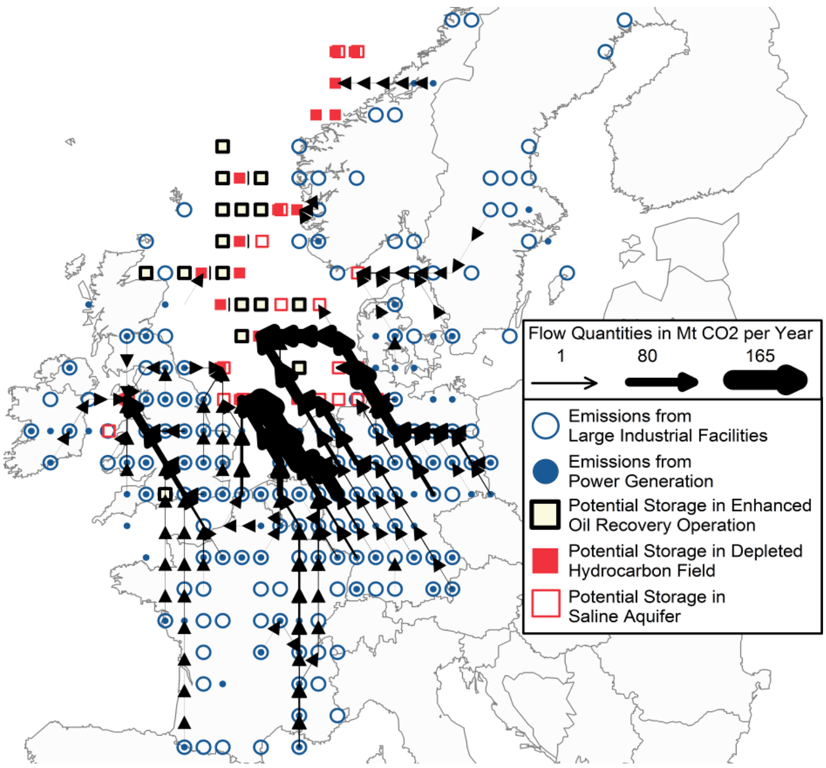

Figure 34: CO_2 flows in the *NorthSea_80%* scenario in the year 2050 after CO_2-EOR fields are exploited.

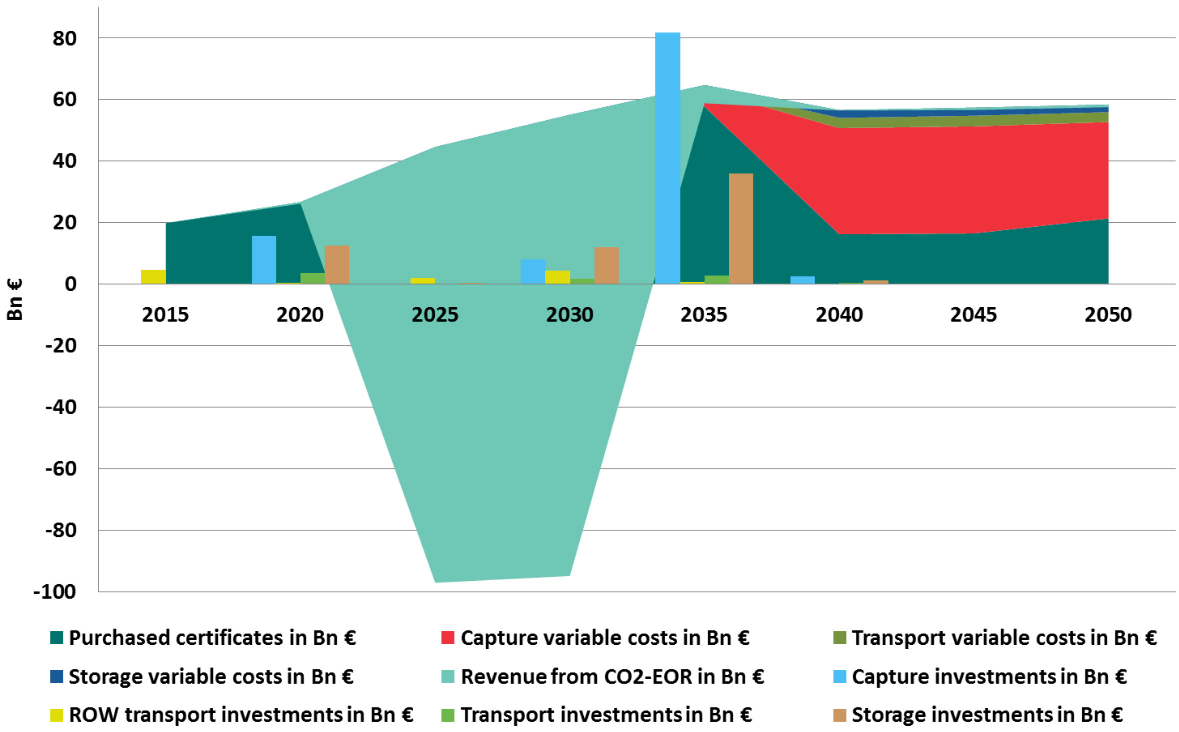

Figure 35: Cost distribution over the whole timespan in the *NorthSea_80%* scenario in €bn.

4.4.6 Regional scenario: DNNU_80% scenario focusing on CO_2-EOR in DK, NL, NO and UK

Against the background of negative public opinion towards CCTS and lack of industry and policy commitment in Germany, but also in France, Belgium and Sweden, we examine an additional scenario where only Denmark, the Netherlands, Norway and the UK have the possibility to use the CCTS technology. By contrast to the other European countries, these four have a higher potential to use the captured CO_2 to generate additional revenue in the domestic oil industry, or at least still back the application of CCTS in the industry sector (like in the Netherlands). Moreover, UK and Norway are still the only two signatories to the amended London Protocol to allow transnational CO_2 transport for offshore storage (GCCSI, 2014), and these four are among the most advanced countries to be ready for large-scale CO_2 storage operation (GCCSI, 2015). Our goal is to compare these results to the results of the other scenarios and to examine to which extent CCTS deployment is reduced due to a lack of economies of scale.

Similar to the previous scenarios, the use of CCTS is mainly economical for the industrial sector, particularly iron and steel making plants. In the *DNNU_80%* scenario facilities invest in a CCTS infrastructure from 2015 to 2020 in order to gain profits from additionally recovered oil from CO_2-EOR from 2025 onward. Around 100 MtCO_2 is stored annually until the full exhaustion of the CO_2-EOR resources, 10 to 15 years after the beginning of the operation (with a concentration in the first ten years). From 2035 onwards, additional storage sites in saline aquifers and depleted hydrocarbon fields closer to the shore are used by industrial facilities already equipped with CO_2 capture. With CO_2 prices exceeding 75 €/tCO_2 in the *DNNU_80%* scenario, additional, more distant industrial facilities start investing in capture units. Power plants only start using the CCTS chain from 2040 onwards, similar to the outcome of previous scenarios without the CO_2-EOR option.

For the period of the CO_2-EOR boom (2025-2035), the results of the *DNNU_80%* scenario on length of the pipeline network are similar to those of the *NorthSea* scenarios. While distances to deliver CO_2 up to the shore are shorter on average, CO_2 from the UK takes especially long routes offshore to arrive at CO_2 storage sites with CO_2-EOR option (see Figure 36). The overall installed pipeline network in 2030 covers over 11,000 km (10,200 in the *NorthSea* scenarios) Similarly, the values for average investment in CO_2 transport and CO_2 storage per MtCO_2 per year during the initial phase in 2025 do not change for the *DNNU* scenario (cf. Table 18).[53] Due to a similar deployment of the technology no economies-of-scale effect between the *NorthSea_80%* scenario in 4.5 and the *DNNU_80%* scenario can be observed during this period. However, the *DNNU_80%* scenario exhibits a shift in CO_2-EOR utilization. We find that UK CO_2-EOR storage potential used by France and Belgium in the other scenarios is now intensively used to store domestic CO_2 from UK (increase of 46 MtCO_2 per year for the period from 2025 to 2040 in the UK). The same effect but to a smaller extent (9 MtCO_2 per year) can be observed with Norway. Danish oilfields that stored CO_2 from Germany in the other scenarios, now increasingly receive CO_2 from the Netherlands (increase of 27 MtCO_2 captured per year in the Netherlands in the period from 2025 to 2040). At the same time, capture activity in Denmark does not change significantly. After the CO_2-EOR boom, the storage volumes for the four countries do not differ between the different scenarios. A clear economies-of-scale effect can be observed for the post-CO_2-EOR period. In 2040 average investment costs in both CO_2 transport and storage infrastructure are there-

[53] To assess economies of scale for the CO_2-EOR boom period one has to compare 2025 values from Table 18. Values for 2030 also include investments for non-CO_2-EOR induced CO_2 transport and storage, as investments the model features a 5 year construction period before infrastructure can be used.

fore much higher for the *DNNU* scenario compared to the *NorthSea* scenarios. CO_2 storage costs increase by more than 30% in 2040 while transport costs even double (cf. Table 18). The constructed transport network is much smaller than in the *NorthSea_80%* scenario (13,600 km compared to 26,800 km) which is due to a smaller observed area and the lack of economies of scale. The Table 19 summarizes the key results of the *NorthSea* and *DNNU* scenarios. Due to their regional focus, volumes of CO_2 stored and required transportation distances in these scenarios are likely to be shorter than in the European-wide scenarios of section 4.2.3.

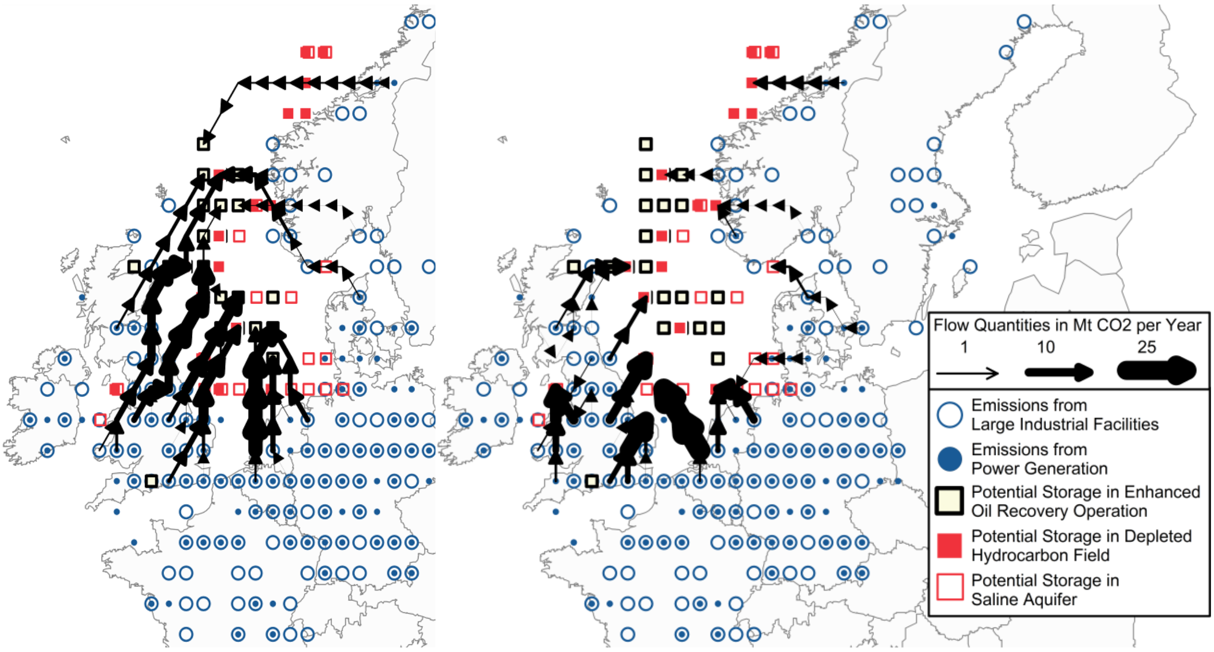

Figure 36: CO_2 flows in the *DNNU_80%* scenario in 2025 using the CO_2-EOR-option (left) and in 2050 after CO_2-EOR-fields are exploited (right).

Table 18: Average investment costs in CO_2 transport and CO_2 storage per $MtCO_2$ per year, comparing the *NorthSea_80%* and *DNNU_80%* scenarios.

	Coverage	*2025*	*2030*	*2035*	*2040*
Avg. Invest. in CO_2 Transport per $MtCO_2$ per year	All North Sea Region	0.07	0.09	0.11	0.03
	DK, NL NO, UK	0.07	0.07	0.09	0.07
Avg. Invest. in CO_2 Storage per $MtCO_2$ per year	All North Sea Region	0.10	0.11	0.16	0.10
	DK, NL NO, UK	0.10	0.10	0.16	0.15

Table 19: Summary of regional results.

Scenario	Pipeline Network [1000s km]		Stored Emiss. until [$GtCO_2$]		Origin. from indus-try [%]	Storage left in 2050 [$GtCO_2$]	CCTS invest. costs [€bn]	CCTS var. costs [€bn]
	2030	*2050*	*2030*	*2050*				
NorthSea_40%	14.2	15.4	0.6	2.5	100	40.0	47.2	150.0
NorthSea_80%	10.2	26.8	0.6	8.5	54	34.6	191.9	539.3
DNNU_80%	11.0	13.6	0.6	3.1	57	36.4	61.7	232.4

4.5 Conclusion: the importance of CO_2-EOR for a European CCTS roll-out

In this chapter we present scenario analysis and interpretation on the potential role of CCTS to support the EU energy system transition to meet emissions reductions goals that are consistent with an international goal of staying below 2°C of global warming. The assumptions of the moderate scenarios include a CO_2 price of 50 €/tCO_2 in 2050 which triggers hardly any CCTS development in Europe.

Additional revenues from applying CO_2 enhanced oil recovery (CO_2-EOR) in the North Sea lead to an earlier adoption of CCTS starting in 2025 independent from the CO_2 certificate price. The lifespan of most of the CO_2-EOR operations is expected to be around ten years. It is followed by conventional CO_2 storage in nearby depleted hydrocarbon fields and saline aquifers if the CO_2 certificate price exceeds the sector-specific thresholds to cover variable costs of carbon capture. Generally, the use of CO_2 for EOR projects is criticized by environmental organizations as the overall CO_2 mitigation effect is negative if considering the CO_2 content of the additional extracted oil.

More stringent climate scenarios aim at an 80% GHG reduction until 2050. The resulting CO_2 price of 270 €/tCO_2 in 2050 pushes all EU-ETS industry and energy sectors to use CCTS at some point. It is, however, the iron and steel sector which starts with the deployment as soon as the CO_2 certificate price rises above 50 €/tCO_2 in 2030. The cement sector follows some years later at a threshold of around 75 €/tCO_2. It is only with CO_2 certificate prices exceeding 100 €/tCO_2 that CCTS becomes lucrative for the electricity sector. Sensitivity analysis shows that the future development of a CCTS infrastructure is more sensitive to its variable than its investment costs. The use of onshore storage sites is unlikely in Europe due to high public resistance, increasing the transport distances. The resulting CO_2 transport network required to connect emission sources and storage sites across Europe would comprise of up to 45,000 km of pipeline and store up to 1,000 $MtCO_2$ per year.

Taking into account the realities that confront CCTS in the EU, political and public opposition has left only a handful of countries that still consider building CCTS in the medium term. A 20% CCTS penetration rate in the European power sector as calculated in the *DNNU_80%* scenario in 2050 thus seems more realistic. Concentrating on Denmark, the Netherlands, Norway and the UK, this scenario shows an increased utilization of CCTS-EOR especially in the UK and the Netherlands. However, a lack of economies of scale leads to increasing average costs, once the CO_2-EOR-fields have been exploited: CO_2 storage costs increase by more than 30% in 2040 while transport costs even double.

A critical point of our analysis is that the employed model CCTS-Mod is purely cost-driven and does not include any specific bound on the CCTS penetration. The model assumes a cost-minimizing player with perfect foresight and therefore tends to overestimate the potential for CCTS. Additional legal and environmental issues with respect to transboundary CO_2 transport as well as CO_2 storage and liability issues are not included in the model. Real costs are expected to be higher and come with a lower deployment of CCTS in the future. Considering the large number of different players and technologies, the insecurities regarding CO_2 prices, learning rates, legal issues, public resistance and further policy measures strongly questions the fact whether CCTS may be able to fulfill its role as a bridging technology for the decarbonization of Europe.

The driver behind all global CCTS projects that will become operational in the near future or have started operation recently (e.g. Boundary Dam, Canada) is CO_2-EOR. The underlying regulatory frameworks and support schemes can primarily be regarded as a cross-subsidization of the petroleum industry, while progressing the CCTS technology is of secondary interest. This is underpinned by observations in the Gulf States, USA and Canada, where the legislative framework on CO_2-EOR with CO_2 recycling is established, while the framework for long-term storage (which would be the primary goal of CCTS) is underdeveloped. The same is true for Europe, where the emergence of a regionally focused network around the North Sea, including only some riparian countries using offshore CO_2 storage with CO_2-EOR, is the most likely option. The mirage of a Pan-European network for CCTS in the EU-ETS industry and energy sectors, like envisioned in some long-term scenario projections, seems out of reach at present due to a combination of a lack of financial incentives as well as too little political and public support for CCTS as a mitigation technology. Further research, however, is needed to evaluate the effects of the newest European reforms (e.g. the reform of the EU Emissions Trading System ETS) as well as national regulations (e.g. emissions performance standards (EPS) and contract for differences (CfD) in the UK) on the development of CCTS.

5 How a "Low-carbon" Innovation Can Fail - Tales from a Lost Decade for Carbon Capture, Transport, and Storage

5.1 Introduction: historic review on the CCTS technology in the last decade

When academic discussion about a technology called Carbon Capture, Transport, and Storage (CCTS) first came to public attention in 2005, many observers considered the new technology a viable breakthrough in making use of "sustainable fossil fuels".[54] Yet, ten years later, we observe the cancellation of many formerly promising projects throughout the world. This chapter discusses the current state of CCTS and explores why the technology has failed to meet the expectations of its stakeholders. We analyze the downside risks of innovations in low-carbon technologies and identify the potential reasons for failure. An important lesson, too, is the problem of heavy reliance upon modeling, when we know in reality that models provide insights, not numbers. Too many optimistic figures were used by too many modelers (including ourselves) to support and promote the CCTS story.

This chapter is based on analytical studies as well as an extensive personal record of research and policy consulting. Following this introduction, Section 5.2 tells the story of CCTS over the last ten years – from the ambitious goals set out (e.g. those reported in IPCC (2005a)) and later replicated in many policy and research papers (e.g. the so-called "Blue Map Scenario" in IEA (2009a)) – to the "black winter" of 2011, when the cancellation of two key demonstration projects, Longannet (Scotland) and Jänschwalde (Germany), implied an end to the idea of a global rollout in the foreseeable future. Section 5.3 provides potential explanations for the failure followed by the conclusion in Section 5.4.

[54] An earlier version of this chapter is published in the Journal of Economics of Energy and Environmental Policy (EEEP), 2012, Vol.1, No.2, 115-123 (Hirschhausen et al., 2012a). It is joint work together with Christian von Hirschhausen and Johannes Herold. Pao-Yu Oei had the lead in data collection and including modeling insights into the paper. He also updated the original article with respect to international running and cancelled CCTS projects between 2012 and 2015 (especially in chapter 5.2.2).

5.2 CCTS: initial expectations and real-world results

5.2.1 High hopes

The idea that CCTS could constitute a low-carbon technology on the path towards a sustainable energy system emerged in the late 1990s. Climate change was becoming a global issue, and a general consensus emerged on the need to intensify research and development efforts beyond nuclear fission and fusion that governed the majority of civil and military energy research since the 1950s. Clearly, individual parts of the CCTS value-added chain already existed: i) CO_2 capture was common in various industries for various production requirements; ii) CO_2 transportation by pipelines was already used in the U.S. for some time; and iii) both natural underground (caverns) and artificial (manmade tanks) gas storage were prevalent. However, the combination of these parts had never been practiced, and still does not exist on a commercial scale in the year 2015. The growth of policy documents and academic literature published towards the middle of the decade suggests that (assuming a time lag of several years before prominent ideas become peer-review published) the turn of the century can be considered as the birth of the global vision for CCTS (see e.g. IPCC, 2005a; Jaccard, 2007; MIT, 2007 for important milestones in this process).

Soon, the climate, innovation, and conventional energy community became carried away by the idea of large-scale deployment of CCTS. The sudden rise in popularity can be explained by the fact that it married industrial and policy interests and stakeholder communities that usually opposed or ignored one another: The traditional fossil fuel burning industry believed in a device that would extend an otherwise endangered industry, renewable advocates believed that biomass with CCTS would save the 2°C goal of climate policy, the nuclear/hydrogen community discovered a new ally in CCTS, and the research and development (R&D) community joined in with pleasure as research funds flowed.

It came as no surprise that this general ardor produced visions of the future where CCTS – if it was not the silver bullet – became an essential element in any proposed low-cost climate policy scenario. Both the OECD governments (e.g. IEA, 2009a), and the climate and energy system modeling community (e.g. Leimbach et al., 2010) assumed that ambitious climate targets could not be reached without CCTS. Thus, the IEA (2009a) expected that overall costs to reduce emissions to 2005 levels by 2050 would increase by 70% absent CCTS technology. Among the CCTS abatements until 2050, 55% were supposed to come from fossil fuel electricity generation (coal and gas), 16% from industry, and 29% from upstream capture (e.g. gas processing and fuels transformation). There were two key assumptions: i) CCTS represented relatively cheap CO_2-abatement, and ii) biomass-CCTS might achieve negative emissions.

The IEA (2009a) also translated these targets into a timeline of real projects to be carried out until 2050 in order to comply with certain climate targets. Its "Blue Map Scenario" provided a detailed plan for the CCTS rollout, including regional, sectoral, and temporal objectives. Demand for transportation facilities was estimated at 200,000-360,000 km of pipelines in 2050, mostly in North America, China, and OECD Europe. The demand for storage capacity would be met by the worldwide development of storage facilities accumulating 145 $GtCO_2$ by 2050. The IEA roadmap also set milestones for the short-term horizon in line with announcements in 2008 by the G8 to develop 100 CCTS projects from 2010 to 2020. Whereas the initial goals of 38 electricity projects and 62 industry projects already appeared optimistic on a global scale, the number of projects soon even rose exponentially to 1,632 (energy) and 1,738 (industry) by 2050, with a total amount of CO_2 captured of 10 Gt annually and total investment costs of US$5.8 trn. These global expectations are also visible in the Energy Roadmap of the European Comission (EC, 2011): In the reference scenario, CCTS power plant capacity increases from zero GW to more than 100 GW by 2050; while in other scenarios the corresponding figure is up to 193 GW ("diversified supply technology scenario"); even in a scenario where the availability of the technology is delayed, the capacity of CCTS power plants is still expected to be 148 GW in the year 2050.

5.2.2 Meager results

Today, the high hopes for CCTS are far from becoming reality and the energy and heavy industries which initially pursued CCTS development have backed off. First movers, such as the USA, Canada, and Norway, have shifted attention to traditional uses of captured CO_2 for enhanced fossil fuel recovery, which has little to do with CCTS (MIT, 2007). European countries with ambitious R&D and demonstration objectives, such as the UK, the Netherlands, Germany, and Poland, have delayed or shelved all major pilot projects. The world's two largest coal burning nations, instead of becoming interested customers of the technology, are pursuing their own, very modest research (China) or ignoring CCTS altogether (India). Strictly speaking, not a single CCTS project has been realized, in the sense of an operation at significant scale that captures, transports, and stores CO_2 permanently. Within the OECD, very few operations have been developed or tested out of a total of 69 practical projects planned (Herold et al., 2010b). Since their small sizes, from 5-35 MW_{th}, qualify them only as pilot projects, little information can be deduced regarding the potential technical and economic aspects of these demonstration plants.

Several country-specific, modest attempts to get CCTS chains at scale to work commercially support our theory of a lost decade for CCTS. There is a striking discrepancy between the ambitious targets set out for the technology and the failure of all countries to engage in a sustainable development path for the CCTS value-added chain: Thus, the United States*,* a global leader in CCTS development, has only very few partial projects already operating and all of them are in combination with CO_2-EOR (see GCCSI (2014) for a detailed listing). Large amounts of public funds were allocated.[55] However, Future Gen, the federal government's flagship project of an integrated, pre-combustion CCTS-chain conceived in the early 2000s, is still unrealized. Five years into the project set-up, this public-private partnership to be developed in the state of Illinois ended in 2009.[56]

Canada has quite rapidly abandoned its initial push for broad deployment of CCTS, deciding to return to using CO_2 for EOR/EGR as practiced for decades, rather than pursuing permanent storage. The technological approach in Alberta, the country's largest fossil fuel producing region, can be considered representative for the strategy of relying on CO_2-EOR/EGR instead of CCTS: Three of the four pilot projects to which the provincial government has pledged CDN$2 bn are CO_2-EOR-focused, whereas only one, the Shell Quest Project, foresees the capture of 1.2 Mt of CO_2 annually and storing it in a company-owned site near the province of Saskatchewan.

Australia is pursuing some demonstration projects; A$1.68 bn has been allocated to partly fund CCTS flagship projects in addition to A$400 mn for the National Low Emissions Coal Initiative. The revenues of the carbon tax will be used in a A$10 bn fund to promote investment in renewables and energy conservation and efficiency technologies. There is

[55] Including: US$3.4 bn mandated by the American Recovery and Reinvestment Act of 2009 to expand and accelerate the commercial deployment of CCTS technology; US$800 mn allocated via the Department of Energy's Clean Coal Power Initiative to expand the range of technologies, applications, fuels, and geological formations that are tested; and US$1.52 bn for an industrial carbon capture and storage initiative, a two-part competitive solicitation for large-scale CCTS from industrial sources (for details see Herold et al. (2011)).

[56] A follow-up project, Future Gen 2.0, is now supposed to retrofit an idle coal plant in Meredosia, Illinois, that should connect to a storage site 150 miles away.

public opposition to CCTS projects, and the perceived need to mitigate process-based emissions from industrial activities. Transportation is particularly challenging due to very poor sink-source matching, with thousands of kilometers of pipeline transport needed.

Europe, too, has little to offer in terms of CCTS success stories, despite substantial EU and national funding in the early phase, and a CCTS-Directive obliging all Member States to establish an appropriate legal framework. All six projects identified to receive EU-EEPR-support in 2008[57] have either been postponed or cancelled (Herold, 2012). After the announcement of Norway to abandon its pilot project at Mongstad (once hailed as the "second landing on the moon"), the UK is the only country that has maintained a list of potential projects. Table 20 provides a list of (failed) projects, indicating the large discrepancy between the initial hopes and reality. The UK had been particularly innovative with a supposedly incentive-compatible scheme introduced in 2007 backed by £1 bn in additional national funds. A tender was specified in which the government would repay all additional costs related to the introduction of CCTS. Of only three projects submitted in 2009[58], two withdrew the same year and the remaining project (Longannet), which did not meet the technical criteria, was cancelled in winter 2011. One of the few remaining projects, White Rose, is also on the verge of cancelation as one of its main investors drew back in September 2015.[59]

The failure of CCTS technology is confirmed by a Communication report from the EC (2013d) on the future of carbon capture and storage in Europe. The EC notes that all efforts, despite having been afforded lucrative financial support, have not led to the construction of a single demonstration plant. The blame for this has been attributed to both the energy industry itself and the restrained policies of member states. The Communication also illustrates that of all the planned demonstration projects not one has taken the planned development path and there is little chance of a demonstration power plant being built any time soon.

[57] Each pilot project was given €180 mn. from the EEPR (with one exception, that received € 100 mn.), another €3-5 bn. were earmarked for CCTS from the sale of CO_2-certificates in the "NER-300" program.

[58] RWE`s new coal plant at Tilbury in Essex; E.ON's new coal plant at Kingsnorth in Kent; and Scottish Power`s Longannet in Fife, Scotland.

[59] Drax pulls out of £1bn carbon capture project http://www.bbc.com/news/business-34356117 (16/10/2015).

Germany, traditionally leaning towards carbon-intensive power plants, is a striking example of initial enthusiasm and later abandonment of the concept of an integrated CCTS value-added chain. CCTS rapidly became popular among politicians as a potential low-carbon technology whereby German industry, heavily reliant on coal-fired power plants and with an important industrial base, could develop a comparative economic advantage. In 2009, Vattenfall constructed the first small pilot plant (30 MW thermal oxyfuel; shut down in 2014), which was to be followed by a demonstration plant in 2015 (Jänschwalde, 250 MW oxyfuel and 50 MW slipstream post-combustion); in West Germany, RWE planned an integrated gasification combined cycle (IGCC) pre-combustion capture demonstration facility in Hürth. However, all demonstration plants have been cancelled. Strong resistance on the federal level also resulted in the failure of the German Parliament to implement the EU Directive in 2009 and 2011. In October 2011, German Environmental Minister Norbert Röttgen closed the debate, stating that, "CCTS was not necessary to succeed the energy transformation in Germany".[60]

The Netherlands, the second-biggest CCTS supporter of the EU Directive after the UK, announced in February 2011 that it would not allow any onshore CO_2 storage due to strong public resistance. The only industrial project green hydrogen was canceled shortly aftwards in 2012. The only remaining demonstration projects, Maasvlakte, a 250 MW post-combustion facility keeps being postponed and relies on offshore gas fields as storage options in conjunction with EGR, not CCTS.

[60] Märkische Oderzeitung, 29.10.2011

Table 20: Running and cancelled CCTS projects in Europe

Project	Jäns-chwal-de	Por-to-Tolle	ROAD	Belch atow	Com-pos-tilla	Don Val-ley	C-GEN	Long annet Pro-ject	Geti-ca	UL-COS	Green Hyd-rogen	White Rose (UK Oxy)	Peel Energy	Pe-ter-head	Tees-side (Es-ton)	Eems haven	Pega-sus	Ma-ritsa	Mong stad	Captain Clean Energy
Country	DE	IT	NL	PL	ES	UK	UK	UK	RO	FR	NL	UK	UK	UK	UK	NL	NL	BG	NO	UK
Capture	Oxy	Post	Post	Post	Oxy	Pre	Pre	Post	Post	Post	Pre	Oxy	Post	Post	Pre	Post	Oxy	Post	Post	Pre
Storage	SA	SA	DOG	SA	SA	EOR	SA	EOR	SA	SA	EGR	SA	DOG	DOG	SA	EOR	DOG	SA	SA	SA
Capacity [MW]	250	250	250	260	320	650	450	330	250	Steel	H_2	430	400	400	400	250	340	120	630	400
Startup planned in 2011	2015	2015	2015	2015	2015	2015	2015	2015	2015	2016	2016	2016	2016	2016	2016	2017	2017	2020	2020	-
Startup status in 2014	2011 shut down	2020	2017	2013 shut down	2018	2018	2016 /7	2011 shut down	2016	2018	2012 shut down	2020	2012 shut down	2017	2018	2013 shut down	2013 shut down	2013 shut down	2013 shut down	2018

Source: Own illustration based on GCCSI (2014, 2011b) and Oei et al. (2014b).

Capture options: Pre – Pre-combustion; Post – Post-combustion; Oxy – Oxyfuel capture.

Storage options: SA – saline aquifer; DOG – depleted oil or gas field; EOR – CO_2-EOR usage; EGR – CO_2-EGR usage.

Little support for a breakthrough of CCTS can be expected from emerging countries, even though they are potentially the largest coal users in the world. China, the global leader in emissions, is supporting national policies to foster economic growth and subsidize cheap energy. CCTS has only recently gained attention and there are still no running pilot projects in 2015 (GCCSI, 2014). Two of the originally most promising projects, the IGCC Greengen project in Beijing and the Shenhua Coal-to-Liquids Plant in Tainji, originally supposed to go online in 2016 have both been postponed until 2020. India, is targeting electrification and the provision of cheap, reliable power to rural sectors as 40% of the population still lack electricity. Their storage sites, in addition, are located far from potential CO_2-separation units, and would require major transnational CO_2-pipelines. Thus, CCTS ranks low on the government's energy policy agenda (Wuppertal Institute, 2012).

5.3 Potential explanations for the lost decade

We do not know if there will be a second chance for CCTS and it is not the objective of this chapter to speculate about its future. However, we have sufficient empirical evidence for the following explanations about why CCTS has failed.

5.3.1 Incumbent resistance against structural change

The simplest interpretation may also be the most controversial one, i.e. large-scale deployment of CCTS failed because key stakeholders lacked incentives. In one sense, innovation means "creative destruction", and if the value of a creation is much lower than the rents destructed, some stakeholders are likely to resist. In the lost decade, two particular players could have accelerated the deployment of CCTS – fossil fuel based utilities and the equipment industry. However, we suggest that each may have had more to lose than to gain from the widespread deployment of CCTS. The survival of profitable but "dirty" old plants would have been endangered if it had been shown that a few CCTS demonstration plants were indeed able to produce almost CO_2-free electricity. From the perspective of equipment producers, the risk of seeing their traditional market, coal and gas power plants, destroyed for the sake of an uncertain benefit from the sale of CCTS equipment may have acted as a serious constraint to full engagement in CCTS.

Imagine the following industrial economic setting: perhaps 2-4 suppliers obtain significant oligopoly rents from selling coal- and gas-burning equipment to a tight oligopoly of utilities, i.e. 2-4 per country/region. This situation creates rents from the tight bilateral oligopoly, from which all participating agents profit (with the exception of the final electricity customer). Now suppose one equipment supplier and one utility decide to jointly invest in CCTS, for which they receive some public support. In the case of success: i) the equipment supplier's profits from further sales of CCTS have to over-compensate the lost rents from traditional coal- and gas-burning equipment; and ii) the utility has to fear the obligatory installation of carbon capture equipment, e.g. as an emissions performance standard, which means giving up the traditional business model. If the expected profits from this "hit and run" strategy are lower than the profits attained in the status quo, then each utility and the equipment supplier may agree to invest some resources in R&D – but not enough to make the CCTS chain a success. Policymakers, unaware of this behavior or unable to stop it, become passive observers in this game due to existing information asymmetries between regulation entities and the industry, and more research funding is unlikely to lead to higher success rates.

5.3.2 Impacts of a "wrong" technology choice

An interpretation based on the economics of innovation and standardization might suggest a "wrong" technology choice by policymakers. Instead of putting most eggs into the secure basket of an established technology like post-combustion, efforts were made to let "1,000 CCTS-flowers" grow, including ones that were highly unlikely to succeed.

Textbook economics suggests that competition between energy technologies is generally conducive to technical progress. However, CCTS in the early 2000s was not a textbook case. In hindsight, it is interesting that so little effort was undertaken to promote post-combustion, the only technology available that could have jumpstarted CCTS immediately. Indeed, Gibbins and Chalmers (2008) argued early on that post-combustion was the only technology which a rapid rollout of CCTS could depend upon: Post-combustion was technologically the most advanced technology, could rely on broad experience, particularly in industry, and could easily be applied to retrofit existing coal power plants. Most important, post-combustion technology could be demonstrated effectively at less than full-scale (e.g. at "10% slipstream" scale). By contrast, neither the oxyfuel nor the pre-combustion technologies were ready for larger demonstration projects, and both had significant disadvantages, e.g. requiring new installations and more complex conversion processes. One insight gained from examining the lost decade is that instead of focusing on post-combustion capture, resources and time were allocated to technologies that were less well-known, less likely to succeed, and less compatible with the existing system, e.g. no possibility to retrofit. Gibbins and Chalmers (2008) argued that post-combustion technology could have advanced the learning cycles significantly, since the technologies requiring further development did not involve changes to base-load design.

Why was the evident frontrunner in the technological competition not chosen to champion an already risky new technology? Why did policymakers fail to insist on the implementation of a superior technology earlier? If CCTS were really to become significant in the fight against climate change, a more risk-averse, conservative strategy should have been chosen, instead of allowing the "markets" to decide which technology to choose for 2030 and beyond.

5.3.3 Over-optimistic cost estimates

Another interpretation of the lost decade are over-optimistic cost estimates that drove expectations for CCTS beyond reasonable limits. Driven by favorable assumptions, CCTS appears as the least cost technology in many energy system models. Among other assumptions is the belief that rapid diffusion of CCTS in the energy sector will cause a rapid decline in average costs. Add to this the assumption of low transportation and storage costs and the neglect of transaction costs (i.e. the costs of implementing CCTS as well as acceptance issues), and the result is CCTS available at "costs" that defy all competition. Climate scenarios until 2100 therefore predict an enormous market share of CCTS – mostly in combination with biomass which is considered as a silver bullet for climate models.

Our empirical evidence suggests that a functioning CCTS value-added chain that provided reasonable cost estimates was wishful thinking. Consider the data used in the PRIMES-model (Capros et al., 1998) of the European Commission (EC, 2011), where the capital costs of a pulverized coal supercritical CCS oxyfuel plant are almost halved, from 3482 €/kW in 2010 to 1899 €/kW in 2050 (constant € of 2010). Thus, CCTS always remains significantly lower in capital costs than, for example, offshore wind (4203 €/kW in 2010, with almost no decline to 3805 €/kW in 2050, (EC, 2011)). Moreover, what if, as Rai et al. (2010) have implied, a new technology may turn out to be more expensive over time, perhaps due to a lack of standardization, as in the case of U.S. nuclear power plants?

5.3.4 Premature focus on energy instead of industry

While the global power sector is responsible for the largest share of CO_2 emissions, world-wide industry accounted for approximately 40% of total energy-related CO_2 emissions in 2008 (IEA, 2009a). The three major industrial emitters are iron and steel, cement and klinker, and the refining sector. Avoiding CO_2 emissions in the industrial sector is more important than in the electricity sector, because in most industries low-carbon substitute technologies are more difficult to develop than in the electricity sector, and avoidance costs through potential use of CCTS can also be cheaper. Comparing the (uncertain) costs of CO_2 capture between energy and industry reveals that capturing is significantly cheaper in the iron and steel and the cement industries. Oei et al. (2014a) used a scalable, mixed integer, multi-period, cost-minimizing network model for Europe, called CCTS-Mod, to indicate that industry already has a significant cost advantage over CCTS in the energy sector at CO_2-prices of 40-50 €/t. By contrast, the energy sector begins to utilize CCTS only at CO_2-prices above 75 €/t (see Chapters 3 and 4).

5.3.5 Underestimating transport and storage

While much research was undertaken and many models developed concerning the "capture" aspect of CCTS, stakeholders to a large extent underestimated transport and storage, the other two elements in the value-added chain. Such neglect likely affected the cost estimates of both as well as the simple feasibility of CCTS's binding constraints on transportation (mainly for legal reasons) and for storage (mainly for geological reasons and issues of public acceptance) during the lost decade.

Transport was the most neglected component. Initially it was assumed that capture would take place close to storage sites, but real-world cases revealed otherwise.[61] Australia's potential network spans several thousands of km. Some of our own estimates suggest a

[61] The model for the EC (2011) neglects transportation costs in the first deployment phase completely: "Pilot CCS plants envisaged for 2020 are assumed to have reserved specific sites for CO_2 storage at rather short distances with small marginal costs for storage."

pipeline network of more than 50,000 km in Europe (See Chapters 3 and 4 or Oei et al., 2014a), and estimates are in the hundreds of thousands of km for the U.S. (MIT, 2007). Thus, transportation costs do have a strong impact on costs, as do the institutional obstacles to be overcome to plan, build, finance, and regulate new transnational transportation networks.

With respect to storage, the lost decade failed to recognize the challenge of an orderly, cost-efficient, and long-term solution. Although CO_2 injection into reservoirs has been performed for decades, only a few operations exist aimed at permanent storage, such as beneath the Sleipner Field (Norway) or in In Salah (Algeria). The storage potential of depleted oil and gas fields is limited. Saline aquifers that theoretically have a higher storage potential (1,000 up to 10,000 $GtCO_2$ according to IPCC (2005b)) have proven unworkable for storage time spans of centuries (see chapter 3). CO_2-EOR/EGR requires oil and gas fields which still hold a significant quantity of original oil in place (about 60%), and cannot be counted as permanent storage. Due to environmental concerns, ocean storage of CO_2 is no longer considered. In addition, current political events reveal that onshore storage is unlikely to be accepted by the public. This leaves only the option of offshore storage sites and increases global storage scarcity. Attaching very low costs to storage ignores these complications.[62]

5.4 Conclusion: a lost decade for the CCTS technology

This chapter has discussed how CCTS, once considered as a carbon-free technology with the potential to produce negative emissions, has so far failed to become a key technology for the low-carbon transformation of the global energy system, and an important vector of climate policies. In CCTS's lost decade, policy and modeling communities provided numerical data that falsely supported CCTS. Even today, many baseline scenarios of integrated assessment and energy system models still include CCTS as an important abatement technology by 2050 and beyond. We conclude it is likely that we will have to live for quite some time with this cognitive dissonance in which top-down models continue to place hope in the CCTS-technology by reducing its expected fixed and variable costs, whereas bottom-up researchers continue to count failed pilot demonstration projects as proof of potential.

[62] The model for the EC (2011) assumes relatively low marginal costs of storage of 6 €/t CO_2 for the first 20 Gt stored.

6 The Integration of Renewable Energies into the German Transmission Grid

6.1 Introduction: modeling the electricity sector

The geographic disconnect between power generation resources and demand hubs is an important issue in the European electricity sector.[63] Moreover, as the projected share of renewable generation in the European Union is likely to triple by 2030, a temporal misalignment of demand and non-dispatchable fluctuating resources is set to become a challenge for electricity grid planners. In the light of recent policy proposals to expand electricity grids so as to better incorporate renewable energy resources into the system, different studies examine their suitability on an EU-wide scale (Leuthold et al., 2012; Schaber et al., 2012; Tröster et al., 2011) and national scale in Germany (DENA, 2010; TSO, 2011). The project of Tröster et al. (2011) makes use of a comprehensive alternating current (AC) load flow model to investigate transmission needs on a European level and covers the years 2030 and 2050. A peculiarity of their study is that renewable energy generation projections are fairly optimistic with 68% and 97% of generation in 2030 and 2050, respectively. While the study is good in its geographic coverage of entire Europe, it does not allow for detailed conclusions regarding specific countries since its grid representation is relatively coarse. The same holds true for Schaber et al. (2012) who focus on European transmission grid expansions with the aim of better integrating fluctuating renewable energies. Inner-German grid congestion and capacity expansion requirements are scrutinized in the study of DENA (2010), where infrastructure needs are determined for the time range up to 2020. Although the study qualifies as the national reference study it is widely criticized for a lack of transparency (Jarass, 2010) and its short temporal horizon of 2020 (Hirschhausen et al., 2010). Neither does this study allow for reproduction and scrutiny nor does it offer a place for visionary concepts of grid expansion over a long-term horizon. A long-term perspective is necessary for electricity infrastructure where excessive lead times make project planning a long-lasting endeavour. The present

[63] This chapter is based on an article in the Journal of Energy Policy, Volume 61, October 2013, p. 140–150 (Schröder et al., 2013b). An earlier version was published as Electricity Markets Working Paper WP-EM-48. TU Dresden, 2012. It is joint work together with Andreas Schröder, Aram Sander, Lisa Hankel and Lilian Laurisch. Pao-Yu Oei and Andreas Schröder jointly developed the model, its implementation in GAMS and had the lead in the writing of the manuscript. The TU students Jenny Boldt, Felix Lutterbeck, Helena Schweter, Philipp Sommer and Jasmin Sulerz contributed in reviewing input data for the model.

chapter is intended to address the shortcomings of the mentioned studies by applying a European-wide model with a high resolution of Germany for the year 2030. Such model allows for conclusions in relation to specific line expansion projects in Germany and it also accounts for fundamental system changes likely to occur by 2030 on a European scale.

The research community has produced a number of insights into applied analyses of transmission infrastructure needs in various case studies. Mills et al. (2011) perform an analysis of grid integration of renewable energy resources for the Western U.S. grid. George and Banerjee (2011) do likewise for a specific Indian region. The benefits of an overlay transmission grid network in the United States are outlined in Krishnan et al. (2013), who indicate that variability of renewable energy justifies investments into a resilient, flexible overlay grid. None of the mentioned studies cover the European dimension addressed specifically here in this chapter. Schaber et al. (2012) come close to the work performed here but focus on variability in renewable energy provision in entire Europe, not providing detailed needs of specific transmission line expansions. A recent work of de Nooij (2011) concentrates a cost-benefit approach on two specific interconnectors in Europe, pointing out the importance of taking into account generator investment plans when planning transmission investment as done in this chapter.

Concurrent to the ongoing efforts in the research community, policy makers and industry have begun the process of planning an overlay transmission grid network for Germany and neighboring states. In view of the need for advanced transmission grid planning, the 3rd energy package of the European Commission mandated the European Network of Transmission System Operators (ENTSO-E) to establish a Ten-Year Network Development Plan (TYNDP) in which specific transmission projects are outlined. It is the first policy effort to bring forward coordinated long-term planning processes for European power transmission infrastructure. The German political situation is characterized by the implementation of the TYNDP through the National Grid Development Plan ("Netzentwicklungsplan"). The ongoing process defines the need for additional transmission capacity within Germany for the next 20 years on a running yearly basis. Paragraph 12 of the renewed German Energy Industry Act (Bundesregierung, 2011a) required Transmission System Operators (TSOs) to establish a first plan for infrastructure needs by 2012. TSOs were requested to come up with a power flow model of transmission requirements for Germany based on scenarios that have been approved by the federal regulatory authority, the Bundesnetzagentur (BNetzA). A scenario draft is published in a preliminary (BNetzA, 2011a) and a definitive version (TSO, 2011). The chapter here picks up BNetzA's call for a transmission infrastructure plan and proposes solutions for the 2030 horizon with a focus on the German grid, embedded in the European context. Three scenarios are designed that describe alternative approaches to accomplish the fundamental shift in energy supply that Germany is striving for. For quantification, a variant of the state-of-the-art direct current (DC) load flow model ELMOD (Leuthold et al., 2008; Weigt et al., 2010) is applied to a regionally disaggregated electricity grid under a welfare-maximizing regime.

Further methodological details can be found in section 6.2, following this introduction and literature review. Section 6.3 describes input parameters. Section 6.4 presents the three scenarios of interest. Results and their discussion are outlined in section 6.5, with section 6.6 providing the concluding remarks to this chapter. A more detailed analysis, including the mathematical formulation, extensive data calculations and further scenario results can be found in Boldt et al. (2012).

6.2 Mathematical description of the electricity model: ELMOD

The DC load flow model ELMOD is used as basis and complemented with several features as detailed hereafter. The mathematical formulation is based on an optimization problem that maximizes social welfare and is solved in GAMS (General Algebraic Modeling System) as a quadratic constrained problem (QCP) using the CPLEX solver.

The model applies a welfare maximizing approach with a target function maximizing consumer and producer surplus. The objective function of the model (see Eq. 12) maximizes social welfare

$$\max W = \left[\sum_t \left(\begin{array}{c} \left(q_{area}(t) - Cost_{var}(t)\right) \\ -\sum_{s,n} g_{up}(t,s,n) \cdot Cost_{ramp}(s) \\ -\sum_n Cost_{DSM}(s) \cdot DSM_{OUT\,l,m,h}(t,n) \end{array} \right)\right] \tag{12}$$

where the demand function may be described as

$$q_{area}(t) = \sum_{n} a(t,n) \cdot q(t,n) + 0.5 \cdot m(t,n) \cdot q(t,n)^2 \tag{13}$$

with the slope including the demand elasticity ε and load level λ

$$m(t,n) = \frac{p_{ref}(t)}{\varepsilon \cdot \lambda \cdot q_{ref}(t)} \tag{14}$$

and the intercept

$$a(t,n) = p_{ref}(t) - \lambda \cdot q_{ref}(t) \cdot m(t,n). \tag{15}$$

The cost function summarizes all variable costs

$$Cost_{var}(t) = \sum_{s,n} G(t,s,n) \cdot c(s). \tag{16}$$

The bi-linear program is constrained by a nodal energy balance which states that the difference between generation and demand at a specific node, net of storage, demand shifting and load in- or outflow, must equal zero (see Eq. 17). The nodal balance constraint has to be true for any node at any point in time.

$$\begin{aligned} \sum_{s} G(n,s,t) &+ wind_{max}(t,n) + hydro_{max}(t,n) + pv_{max}(t,n) \\ &+ \sum_{st}\big(S_{IN}(st,n,t) - S_{OUT}(st,n,t)\big) + AC_{netinput}(t,n) \\ &+ DC_{netinput}(t,n) + DSM_{OUT\,l,m,h}(t,n) - DSM_{IN\,l,m,h}(t,n) \\ &- q(t,n) = 0 \end{aligned} \tag{17}$$

A generation capacity constraint incorporates technical generation limits of each plant type at each node and time (see Eq. 18). Production cannot be higher than the maximum net generation capacity. Net generation capacity equals gross capacity multiplied by the technology specific availability factor.

$$G(t,s,n) \leq rev(s) \cdot G_{max}(n,s) \tag{18}$$

Ramp-up constraints limit the amount of capacity that can be ramped up in one time period for each technology (see Eq. 19-21). Ramping costs included in the objective function equal the product of ramped capacity and a technology-specific cost parameter.

$$Lim_{ramp} \geq G(t,s,n) - G(t-1,s,n), \tag{19}$$

$$Lim_{ramp} = Perc_{ramp} \cdot G_{max}(n,s), \tag{20}$$

$$g_{up}(t,s,n) \geq G(t,s,n) - G(t-1,s,n). \tag{21}$$

The model includes both AC and DC flows with the respective constraints:

$$AC_{lineflow}(l,t) - \sum_{n} ptdf(l,n) \cdot AC_{netinput}(t,n) = 0 \tag{22}$$

$$-AC_{p_{max}}(l) \leq AC_{lineflow}(l,t) \leq AC_{p_{max}}(l) \tag{23}$$

$$\sum_{n} AC_{netinput}(t,n) = 0. \tag{24}$$

As well as for DC load flow constraints:

$$DC_{netinput}(t,n) - \sum_{n} DC_{netinput}(t,n) \cdot DC_{incidence}(dcl,n) = 0 \tag{25}$$

$$-DC_{p_{max}}(dcl) \leq DC_{lineflow}(l,t) \leq DC_{p_{max}}(dcl) \tag{26}$$

$$\sum_{dcl} DC_{lineflow}(dcl,t) = 0. \tag{27}$$

The model is based on unweighted Power Transfer Distribution Factors (PTDFs) to determine electrical flows inside its grid.[64] These PTDFs describe the flow through any individual line in dependence on the feed-in of one unit of electricity at some specified hub. They take into account that power does not necessarily flow across the shortest distance, but antiproportional to the existing electric resistance. This nature of power flows gives rise to so-called loop-flows in meshed grids. Implicitly, the PTDF matrix respects the Kirchhoff's rules that define the relationship between electric tension and currents:[65] The flow on a specific line is therefore determined by all net inputs into all adjacent nodes multiplied by their respective PTDF (see Eq. 22). Line flow constraints state that the electricity flowing through a line cannot be greater than the maximum capacity of that line, in absolute terms. Since electricity can flow in both directions and the line flow can thus be positive or negative, two separate constraints are included guaranteeing that the line flow does not exceed its capacity limit in either direction (see Eq. 23). At each node in- and outgoing electricity flows needs to net to zero (see Eq. 24) and the directed sum of the electrical potential differences (voltages) around every closed circuit (loop) equals zero. By reducing the maximum line capacity below its technical potential by 20%, the n-1 security criterion is accounted for and it functions as reliability margin. A similar reasoning applies to the modelling of DC line flows. The net input into a DC line is determined by the line flows of the DC lines multiplied by their factor in the incidence matrix (see Eq. 25). As in the case of AC lines, DC lines have a certain technical power limit that cannot be exceeded at any point in time. Therefore, two constraints are included thus guaranteeing that the power flowing through a line does not exceed its technical power limit (see Eq. 26). Note that the model neglects transmission losses. This is done to keep the model tractable and to omit non-linear elements where possible.

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[64] Including only demand or (net) generation as indicator for weighted PTDFs might distort the results especially due to shifting renewable generation portfolios over time, while considering hourly changing net generation exceeds the calculation capacity.

[65] The PTDF of a line, with respect to generation from a specific node, is the product of the susceptance matrix and the inverse admittance matrix. The susceptance matrix is the product of the incidence matrix and a vector, including data regarding the resistance, reactance and voltage level of each line. The admittance matrix is the product of the susceptance matrix and the incidence-matrix. These factors describe the flow through each individual line when feeding one MW into the grid at any point and taking it out at a specified hub. On the basis of the PTDFs the line flows for each line can be determined in the model (Duthaler et al., 2007; Schweppe et al., 1988).

The model includes storage and demand-side management (DSM) as measures to flexibilize load. Constraints are included stating that at each point in time at each node, storage in- and outflow cannot be greater than the corresponding storage power limit (see Eq. 28-32). We use the formulation of a storage state variable which indicates the state-of-charge.

$$S_{LEVEL}(st,n,t) = \left(S_{LEVEL}(st,n,t-1) - S_{OUT}(st,n,t) + S_{IN}(st,n,t) \cdot S_{eff}(st)\right). \quad (28)$$

Regarding the implementation of storage technologies, the model considers storage power limits

$$S_{IN}(st,n,t) - S_{IN_{max}}(st,n,t) \leq 0, \quad (29)$$

$$S_{OUT}(st,n,t) - S_{OUT_{max}}(st,n,t) \leq 0, \quad (30)$$

and storage capacity limits

$$S_{cap_{max}}(st,n) \geq S_{LEVEL}(st,n,t). \quad (31)$$

An overall storage balance guarantees that the storage device left at the same state-of-charge as in the beginning

$$\sum_t S_{IN}(st,n,t) \cdot S_{eff}(st) - S_{OUT}(st,n,t) = 0. \quad (32)$$

It is further assumed that consumers have the possibility to shift their electricity consumption for a limited time range through DSM (see Eq. 33-35). When shifting load, consumers get compensated depending on the amount of demand that is shifted. The compensation costs are included in the objective function (see Eq. 12). DSM constraints for different cost segments restrict the amount of shiftable load

$$DSM_{IN_{l,m,h}}(t,n) - DSM_{MAX_{l,m,h}}(t,n) \leq 0, \quad (33)$$

$$DSM_{OUT_{l,m,h}}(t,n) - DSM_{MAX_{l,m,h}}(t,n) \leq 0.$$

(34)

A balance condition ensures that load is shifted only within a certain time frame t-1 and t+1

$$DSM_{IN_{l,m,h}}(t-1,n) - DSM_{OUT_{l,m,h}}(t+1,n) = 0. \tag{35}$$

Finally, an additional constraint (see Eq. 36) ensures that total yearly demand equals the predetermined level of model-wide total consumption x [TWh] to ensure a certain comparability of the different scenarios

$$\sum_{t,n} q(t,n) = x\ . \tag{36}$$

6.3 Application of ELMOD for the German electricity sector and used data

In this section, basic input parameters and assumptions of the model are explained. The analysis considers an hourly time resolution. It comprises 21 European countries, and disaggregates Germany into 18 zones as defined in DENA (2010). This results in a 41-node base model with Denmark being composed of two nodes. Note that while the model considers 234 AC lines and 35 DC lines, power transmission distribution factors (PTDF) are used to aggregate inter-zonal lines. The calculation of PTDFs is based on the ELMOD database including 3,449 European high-voltage lines at 220 and 380 kV level (Leuthold et al., 2012). The model is applied to four distinct representative weeks in the year 2030 and all input parameters are calibrated so as to match realistic projections for that year. Conclusions are only drawn on results for Germany.

6.3.1 Electricity grid

In order to model the German power market for 2030, assumptions are made about the evolution of the electricity grid, both for Germany and the rest of Europe. The section here outlines the additions that are made to the grid in place in early 2012. A number of grid expansion projects that are under consideration, in planning or in an early construction phase as of 2012 are applied exogenously to the model. German legislature, European TSOs (ENTSO-E) and regional TSOs indications are the basis for qualified projections of the 2030

European grid. The Energy Line Extension Act (Bundesregierung, 2011b) prioritizes a series of national projects that have reached either late planning or early construction phases. For transmission projects at the international level the TYNDP (ENTSO-E, 2010) identifies a number of projects, of which only several are picked for the application here (see Table 30 and Table 31 in the Appendix). The upgrade of existing or construction of new lines between Germany and its neighbours provides additional power exchange capacities and increases security of supply. Since most of the projects are commissioned before 2017, they are assumed to be completed and operational by 2030. The transmission network topologies in Germany and its neighbouring countries are also displayed in Figure 42 in the results section.

6.3.2 Electricity demand

According to the Federal *"Energy Concept"* on Environmentally Sound, Reliable and Affordable Energy Supply (Bundesregierung, 2010), the German government is aiming for a demand reduction of 25% between 2008 and 2050. This amounts to approximately 16% until 2030, when applying a compound annual growth rate. It is thus assumed that there is a yearly demand for electricity of 463 TWh in 2030 in Germany as reference point. On an European level, the model uses hourly load values of the year 2010 provided by the European Network of Transmission System Operators for Electricity (ENTSO-E, 2011). Total German demand is allocated to the 18 model nodes inside Germany based on population data.

6.3.3 Renewable energies

The "Renewable Energy Policy Country Profiles" study (EcoFys et al., 2011) is used as a consistent basis for renewable energy production data in Europe. The study predicts the potential of electricity generation by 2030 per technology for EU-27 countries. These projections were directly derived from the National Renewable Energy Action Plans (NREAPs) for each country in the year 2020, and reflect the official renewable energy target of each country. The 2030 forecasts also take into account existing national renewable energy support policies as well as expert opinions, providing a higher level of detail than other comparable studies. Electricity generation data for wind, PV, hydro, wave and tidal, geothermal and biomass are converted into installed capacity using technology- and country-specific full load hour assumptions taken from the NREAPs and recent projections in EcoFys et al. (2011). 2,906 TWh of renewable generation are expected in the EU-27 in the year 2030. Both, on-and offshore wind, contribute a significant portion of total renewable generation with 19% and 17%, respectively. Another 16% of PV generation increases the total portion of fluctuating renewable energy resources to 52%. For countries with a single node representation in the model, the generation capacity is aggregated. For Germany, however, a greater level of detail is needed to guarantee accuracy. Total capacity is broken down to 18 DENA zones in a way that is plausible given geographic potential and local development plans. As there is no exact data on the regional distribution of renewable generation in Germany in the EcoFys et al. (2011) study, this information is adopted from the TSOs scenario pathway mentioned earlier (TSO, 2011). After applying that distribution onto the capacities given in the EcoFys et al. (2011) study, a regional breakdown of 2030 renewable capacity in Germany is obtained (see Table 21).

Table 21: Breakdown of RES generation capacities on Dena zones for 2030 in GW

DENA Zone	Geo-thermal	Hydro-power	Photo-voltaics	Wave & Tidal	Onshore Wind	Offshore Wind	Biomass	Sum
21	0.61	0.00	2.74	1.74	5.47	10.97	0.25	21.76
22	0.00	0.05	2.04	1.74	2.47	5.48	0.54	12.32
23	0.00	0.06	2.51	0.00	2.60	0.00	0.59	5.76
24	0.24	0.00	4.08	0.00	1.11	0.00	0.20	5.63
25	0.15	1.85	10.58	0.00	0.50	0.00	0.92	14.01
26	0.10	1.23	7.40	0.00	0.34	0.00	0.61	9.69
41	0.10	0.49	3.04	0.00	0.63	0.00	0.33	4.59
42	0.20	0.98	5.83	0.00	1.26	0.00	0.65	8.93
71	0.00	0.03	1.37	0.00	1.41	0.00	0.32	3.13
72	0.00	0.05	2.97	0.00	1.73	0.00	0.39	5.14
73	0.00	0.04	2.23	0.00	1.30	0.00	0.29	3.86
74	0.06	0.02	2.31	0.00	1.02	0.00	0.25	3.65
75	0.30	0.00	4.45	0.00	0.97	0.00	0.25	5.97
76	0.05	0.62	3.70	0.00	0.17	0.00	0.31	4.84
81	0.00	0.00	2.92	1.74	4.48	5.48	2.89	17.51
82	0.00	0.12	0.00	0.00	0.04	0.00	0.12	0.29
83	0.00	0.00	2.46	0.00	2.23	0.00	0.43	5.12
84	0.00	0.12	2.06	0.00	1.65	0.00	1.35	5.19
Sum	1.82	5.66	62.69	5.22	29.39	21.93	10.68	137.38

Source: Own Calculation based on EcoFys et al. (2011).

Since biomass and geothermal are dispatchable technologies, their generation is controllable and does not need to be determined as time series. For the fluctuating renewable energy resources, hourly feed-in-series are elaborated to model the actual generation mix over the course of a year.

- Wind power output is derived from a representative wind park as a function of wind speed. 6-hourly wind speed data is retrieved from ECMWF-ERA Interim Re-Analysis for 2005 (Dee et al., 2011) and interpolated values are derived. Data is available for a coordinate grid of 1.5 by 1.5° density, with 18 area points available for Germany. The advantage of using wind speed data over simple output time series is that offshore and onshore wind output can be disentangled and derived separately, which is done for Germany here. For other countries, their geographic centre is chosen as single reference point. Note that the Interim Re-Analysis consists of a mixture of forecast and actual measures. Grid cells cover a large area and thus build average values for specific grid cells. When validating the simulation model with actual feed-in data, an R^2 of 70-80% can be achieved depending on the grid regions.
- Solar power output derivation is also based on meteorological data. Hourly irradiation values for 2005 (SoDa, 2005) are used and converted into power output taking into account pre-conversion losses, inverter losses, thermal losses and conduction losses (Quaschning, 2009) and efficiency reductions with a performance ratio. The same geographic reference points are used as for wind power derivation;
- as opposed to solar or wind power, hydropower features a fairly continuous generation profile, so there is no need for an accurate hourly generation time series. Still, seasonal variations in generation can be observed. For this reason, a generation profile by month is adopted here. Generation data from the years 2008, 2009 and 2010 is extracted from Eurostat (2011) and used as a basis for the time series calculations of hydropower.

6.3.4 Conventional electricity generation

Since the NREAPs and the EcoFys et al. (2011) study do not provide any information on electricity generation from conventional resources, we refer to a study by the EC (2010) for 2030 data on a European level. Regarding data on non EU-members, public and private studies of the respective countries were examined. A higher degree of resolution is applied to Germany for which data in the Platts (2011b) database, a BNetzA (2011b) list and the original ELMOD database (Leuthold et al., 2012) is triangulated. This data is extended with projected new investments (VGB PowerTech, 2011) and we remove those plants which are likely to be decommissioned by 2030. For the reference scenario, it is implicitly assumed that the geographic spread of power plants does not alter until 2030. Generation costs, particularly short-term variable costs play a crucial part in the model since they determine the sequence in which power plants are dispatched. Adding to this, ramping costs further complicate the dispatch order of power plants. Table 22 presents assumptions on marginal generation cost assuming a CO_2 certificate price of 50 €/tCO_2. Fluctuating renewable energies such as wind and photovoltaics have no fuel costs at all, and are therefore always in merit if not internalizing external costs. Deep geothermal energy does not incur any fuel cost either, but its variable operation and maintenance costs of around 1.5 €/MWh reflect the marginal generation costs. Biomass plants in Europe are able to run on a variety of fuels, and their costs are aggregated at 50 €/MWh (BMU, 2010). More details about the costs, also including ramping costs and limits can be found in the study by Boldt et al. (2012).

Combined heat and power (CHP) generation is included in the analysis. Some power plants show “must run” characteristics, i.e. they generate electricity whenever they are required to produce heat. For power plants for public supply this is especially the case in winter, when district heating systems are online. In order to allocate CHP capacity to fuel type, a forecast on the share of fuel types of CHP has been made. The forecast takes into account long-term trends of CHP development and displays a significant growth of the gas and renewable energy share, a considerable decline in coal and oil utilization and a sharp decline of the share of other fuels, mainly due to the shut down of nuclear energy. The share of must-run CHP renewable energy is not modelled separately, as renewable energies are generally considered as must run facilities. In the analysis a maximum installed capacity of 15 GW for must run non-renewable CHP plants is estimated for 2030. This maximum is reached in winter, in autumn and spring it amounts to 10 GW while in summer it is 5 GW. The assumption represents 42% of the overall German CHP capacity if an installed capacity of 35.7 GW for the year 2030 is taken as basis (BMU, 2010).

Table 22: Costs for fossil-based energy generation including CO_2 costs

	MCoE + CO_2 [€/MWh_{el}]
Lignite	51.69
Hard Coal	63.69
Gas	74.91
Oil	142.84
Uranium	9.93

Source: Own depiction based on BMU (2010) and EWI et al. (2010).

6.3.5 Infrastructure cost

Infrastructure cost needs to be taken into account into the overall analysis of transmission line extensions. These costs comprise line extension cost on the one hand and generation capacity costs on the other hand. We assume an operational life of 40 years with an interest rate of 7% to annualize these infrastructure costs.

The cost of upgrading the transmission grid depends on the length, type, capacity and terrain of the underlying transmission lines. High-voltage AC is the cheapest technology of power transmission and well established in today's power system. No large cost reductions are expected throughout the modelling horizon. Based on already built or pending project cost specifications (Tröster et al., 2011), AC line extension cost are set at 400 €/MW and km. For a long-distance power transmitting DC lines have many advantages compared to AC lines with the same power rating. While DC lines are mainly limited by a maximum conductor temperature, the capacity of AC lines is also limited by high reactive power consumption. The DC line extension cost is set at €0.7-€0.8 mn/km at a 3,000 MW power rating with 500-600 kV voltage capacity. An AC line with the same power rating would cost €1.22 mn/km. It is obvious that DC lines have lower unit cost than AC lines mainly as a result of a lower number of parallel lines needed. This cost advantage is reduced by the cost for converter station costs which cost about 150,000 €/MW. Hence, landside DC lines pay off over long distances.

The 2030 projection of generation capacity capital cost is mainly based on values derived from the World Energy Outlook 2011 (IEA, 2011) and can be found in Boldt et al. (2012). For established generation technologies it is assumed that lower capital costs due to steep learning curves are offset with increasing costs for materials, labor and space by 2030.

For upcoming renewable technologies, substantial reductions of investment costs will take place due to economies of scale, learning curves and research & development.

6.4 Different scenarios of renewable energies integration

A scenario analysis is conducted that revolves around a central reference case. The variations on the 'Reference Scenario' explore alternative possible states of the 2030 power market: while the 'Strategic South Scenario' mainly differs from the Reference Scenario in its generation structure, the 'DC Highways Scenario' focuses on alternative transmission topology. The scenarios encompass assumptions regarding demand, generation, fuel and certificate prices, grid expansions and political motives.

The Reference Scenario depicts a state of the European electricity market that is probable under the condition that additional policies support the development of RE and infrastructure development in Germany and Europe. No significant changes to climate and energy policies are made over the course of the next 20 years. Shutting down all nuclear power plants in Germany, as appointed by a 2011 amendment to the Nuclear Energy Act, will see the last nuclear power utility be decommissioned the grid in the year 2022. Newly constructed fossil-based power plants are assumed to be built at the same locations where old ones have been closed.

The Strategic South Scenario investigates an alternative to the expansion of transmission networks on a North-South axis. The research question behind the scenario is whether the strategic placement of conventional power plants close to load centres, as well as an equal distribution of renewable energy resources between North and South can substitute the construction of transmission to a certain extent. The Strategic South Scenario consists of two major changes compared to the Reference Scenario: First, while in the Reference Scenario new conventional power plants are built on the location of old power plants exiting the grid, they are now, as the name of the scenario indicates, being placed strategically along the metropolitan and industrialized areas of West and Southwest Germany. Especially the flexibility of additional gas turbines allows them to serve as back-up capacity for peak demand hours. Second, there is a reallocation of renewable capacity from Northern Germany to the centres of high demand. The reduction of offshore wind energy capacity in the North goes with increasing renewable technologies (such as PV and onshore wind) in the Southwest without affecting the total ratio of renewable versus conventional generation. Offshore wind is reduced in the Strategic South Scenario by nearly 19 GW and half of onshore and PV capacities are shifted from the North to the South. See Figure 37 for a comparison of wind capacity in the Reference and Strategic South Scenarios. It is apparent that generation in the Strategic South Scenario is explicitly larger in the zones of high demand (24, 25, 26, 41, 42, 72, 73, 74, 75 and 76; see Figure 38 for the exact location of the zones) than in the Reference Scenario owing to the reallocation of resources.

The third scenario variation, the DC Highways Scenario, explores the possibilities of using state-of-the-art DC transmission technology to alleviate congestion on the high-voltage AC grid. Since projected and existing offshore wind capacity is located mainly in the North, transmission capacities on the north-south-axis are considered as efficient to relieve congestion. This discussion has gained some momentum in late 2011 when first insights into a DC-Overlay master plan have emerged, showing first sketches of the three DC lines' pathway, see Figure 38.

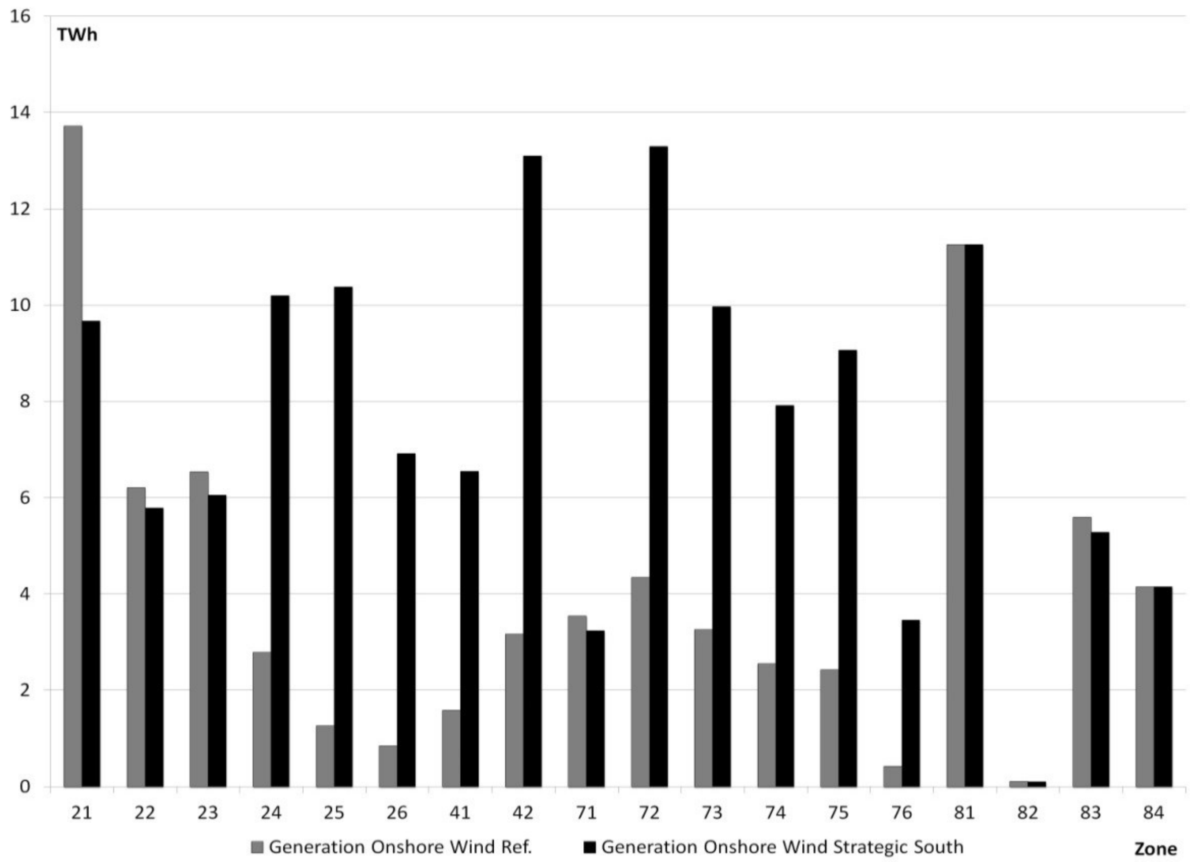

Figure 37: Onshore wind generation: Reference vs. Strategic South scenario.

Source: Own calculation based on EcoFys et al. (2011).

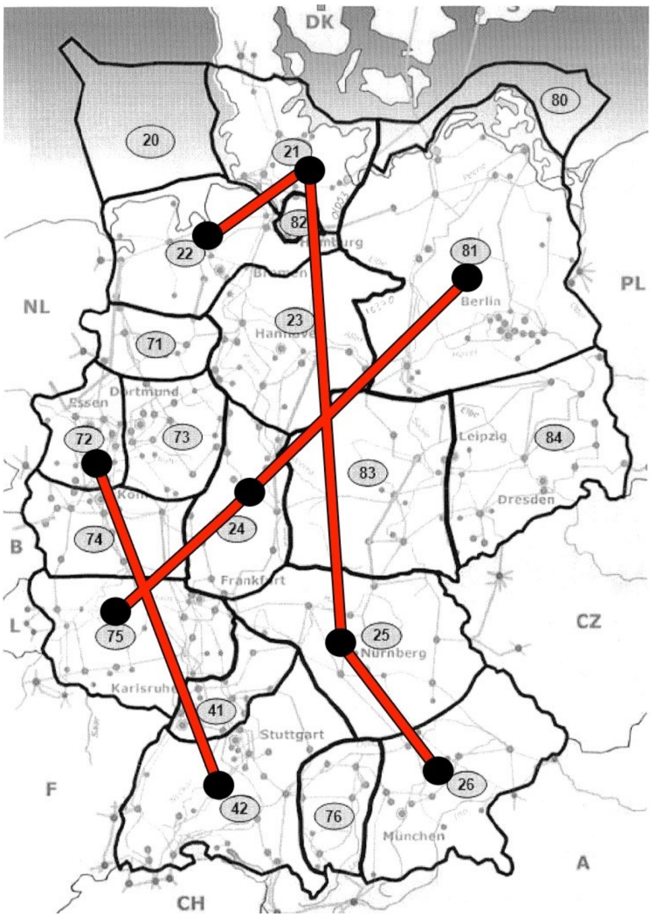

Figure 38: Proposal of DC lines by TSOs. Dark circles indicate converter stations.
Source: Own depiction based on DENA (2010).

The lines span over 2,100 km, running north to south and east to west. 50 Hertz, the transmission operator in eastern Germany, has already entered the application process for the line connecting rural Brandenburg to the densely populated Rhine-Main area. Amprion and TransnetBW, operating in western and southwestern Germany, are planning a 600 km line linking the Ruhrgebiet and Stuttgart, the state capital of Baden-Württemberg. That region is facing a shortage of 5 GW of reliable generation once the last of the nuclear power plants are shut down in 2022. TenneT, operating on a northwest to southeast axis, is planning the longest of all lines, reaching over 900 km from Schleswig-Holstein to Bavaria. Its purpose will be to haul the generation of 28 GW of offshore wind energy across the country to a populous region that will also face substantial closing of nuclear power plants. The DC Highways Scenario assumes that these projects will have reached completion and will be fully operational by 2030. The lines will start at a capacity of 1 GW with the possibility to be upgraded to 3 GW. To account for this degree of uncertainty, the three lines are modelled with 2 GW capacity. The aim of the scenario is to investigate the effects of DC overlay lines on the existing AC grid. Will the DC highways alleviate congestion on the AC grid and ease the transfer of power from north to south? All assumptions from the Reference Scenario are left intact except for the addition of the three DC lines. This methodology allows for filtering out a *ceteris paribus* effect of an overlay grid on transmission constraints in the AC grid.

6.5 Results and Discussion

Four representative weeks are chosen, one for each season of the year. The ratio between renewable generation from wind and solar (by far the largest contributors to renewable generation in Germany) against weekly demand is chosen as the main determinant for the selection of representative weeks. The comparison of the four weeks and a more elaborate explanation of the selection process can be found in Boldt et al. (2012) together with additional information on the share of renewable energies in total generation and on the import-export performance of Germany in the different weeks and scenarios.

For an in-depth comparison of transmission grid congestion, we analyse line capacity shadow prices. Shadow prices represent the total value that the operator is able to recover in form of the so called congestion rent.[66] Alternatively it can be interpreted as the contribution of line expansion to welfare when relaxing the line's capacity constraint by one MW. In a transferred meaning, values indicate the urgency or priority of line expansion.

We chose to conduct a comparative analysis of scenarios rather than interpreting absolute values with the help of a general grid-wide weekly congestion index across scenarios. It relates the sum of shadow values of all lines in each scenario in relation to the reference scenario. This congestion index is visualized in Figure 39, the congestion index of the Strategic South and DC Lines Scenario is compared to congestion index of the Reference Scenario which is normalized to one. A value of the indicator above one represents deterioration, a lower index implies an improvement compared to the reference scenario. A drop in the congestion index may be due to the fact that lines are congested at fewer times or that the value of the congestion – the price difference between the zones – may have fallen. The chart clearly shows that the Strategic South Scenario reduces the sum of the shadow varia-

[66] Depending on the regulative structure, the congestion rent is not always allocated to the network operator. In some regions, the rent has to be reallocated to consumers for example.

bles throughout all weeks compared to the Reference case. Its congestion index is 0.25. The DC Scenario paints a different picture. It increases congestion in spring and winter, and decreases congestion in summer and autumn. The congestion index of the DC Scenario is 0.97, which means that on average, congestion is decreased. Since the spread between the Reference index and the Strategic South index is largest for week 51, this particular week is chosen for a detailed analysis hereafter.

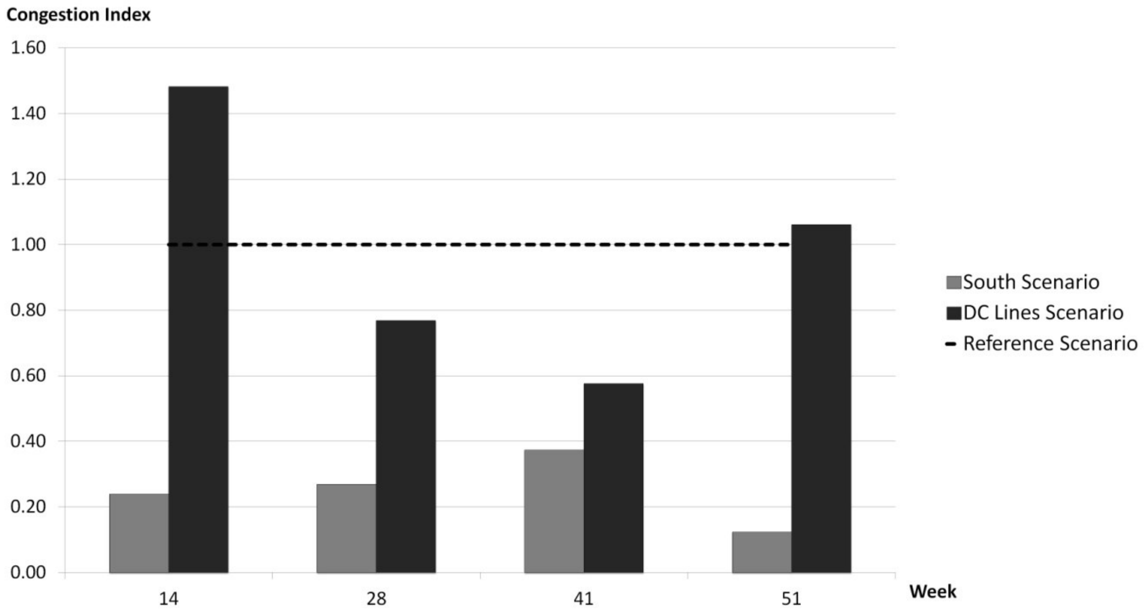

Figure 39: Congestion index for all scenarios in weeks 14, 28, 41 and 51.

Source: Own depiction.

6.5.1 Detailed results for one exemplary week

In what follows, detailed results are outlined for week 51 of the model year. Figure 40 shows the generation portfolio of week 51 in the Reference Scenario. It shows the generation mix of the specific technologies in MW for the 168 hours of one week. While the dotted black line represents demand, the cumulated areas stand for the generation share of the respective technology. The difference between total German demand and total German supply represents imports or exports for each hour. One can distinguish the intermittent renewable energies, wind and PV, the controllable renewable energies hydro, geothermal and biomass, as well as the conventional energy sources oil, gas, combined heat and power, hard coal and lignite.

Concerning the generation mix, it is striking that throughout the whole week, the wind from the north of Germany, originating mainly from the offshore wind parks in the North Sea, contributes the main share of generation in Germany. There is no generation at all from oil-fired plants. Generation of hydro power, wind from the south of Germany, geothermal, solar power and gas only represents a small fraction of total German energy supply. Electricity generation from base load technologies (lignite, hard coal, biomass and combined heat and power) accounts for an equal share of around 10 to 15%. One can observe the gas peaks which even out the intermittent renewable energy sources. During this exemplary winter week, German production exceeds German consumption and import only occurs in a few peak demand hours. Overall, Germany exports around three percent of its electricity generation.

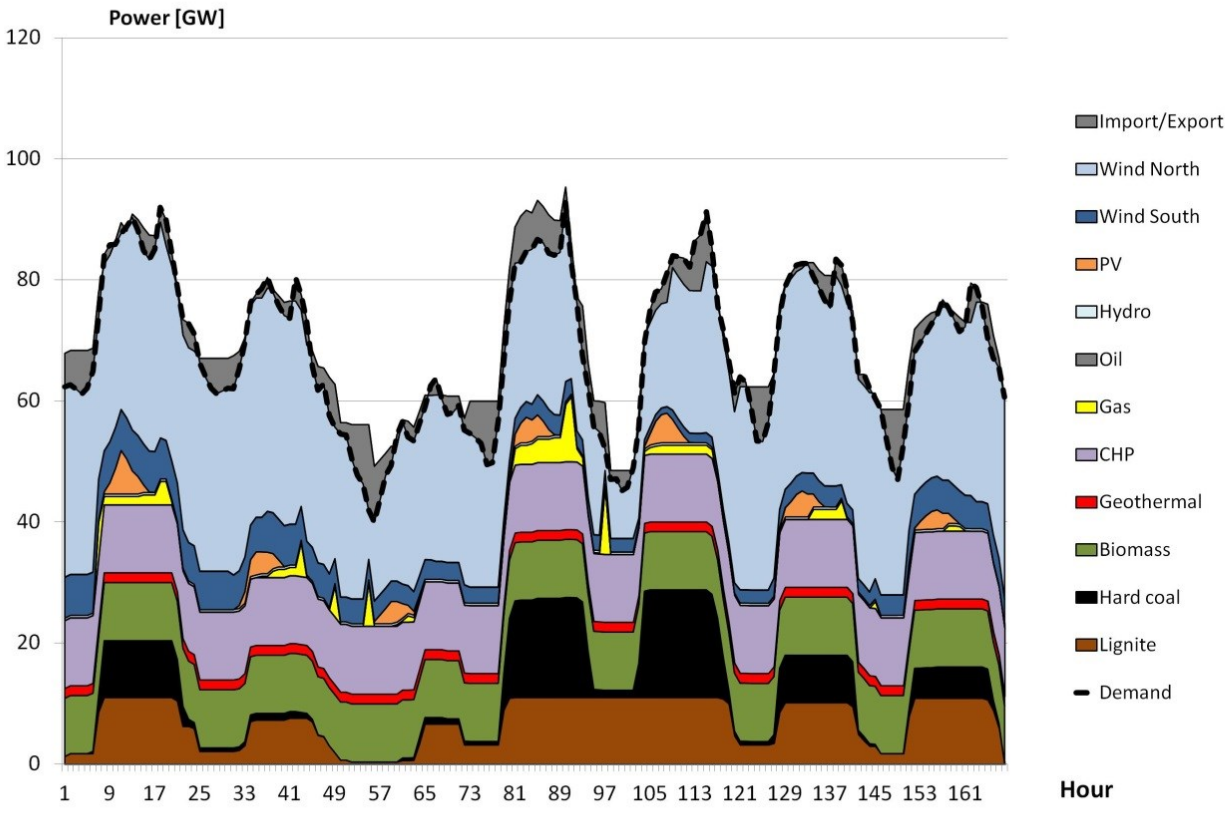

Figure 40 Generation portfolio of week 51 in the Reference scenario.
Source: Own depiction.

The generation portfolio of week 51 in the DC Highways Scenario does not change compared to the Reference Scenario owing to the similar assumptions on installed capacities. In the Strategic South Scenario there is a higher share of installed wind capacity in the south of Germany. Consequently, the generation by wind power from southern Germany increases from around 5% in the Reference Scenario to more than 27% in the Strategic South Scenario. On the other hand, one can notice the decreased generation by northern wind power. Generation by the remaining technologies in each case only differs slightly, the share of fossils increases by around 5%. The renewable energy share in the German generation portfolio remains relatively stable across all three scenarios, deviating by not more than 1%.

Figure 41 shows the import/export-balance of each node in Germany. It represents the median of net electricity generation at each node over all 168 hours of week 51. The Reference Scenario clearly shows a set of exporting nodes exclusively in the very north of Germany. Sorted in descending order by their net export amount, these are: 21, 81, 84, 22, 71, 41 and 72. For the nodes 21, 22 and 81, the reason for the high amount of exported electricity lies in the large amounts of offshore wind power in the North and Baltic Sea. Wind electrity has marginal cost of zero and is therefore cheaper than all conventional capacities. It exceeds local demand in some zones that consequently become net exporters in weeks with significant wind, such as week 51. The other four exporting nodes have a high installed capacity of onshore wind and good wind conditions over the whole year. The major importing zones of the Reference Scenario are 73, 42, 24 and 26, all located in Germany’s west and south. This is caused by the loss of large shares of installed capacity (shut down of nuclear plants) and a continuous high electricity demand.

The DC Highways Scenario brings little structural change to the national export and import patterns observed in the Reference Scenario, except in the northern German zone 21. Here, a major increase of electricity export to other zones is made possible through new DC transmission capacity to the southern load centres. A side effect is that nodal prices increase in northern exporting zones and they align with formerly high southern prices. All in all, the nation-wide export to neighbouring countries increases by 4%.

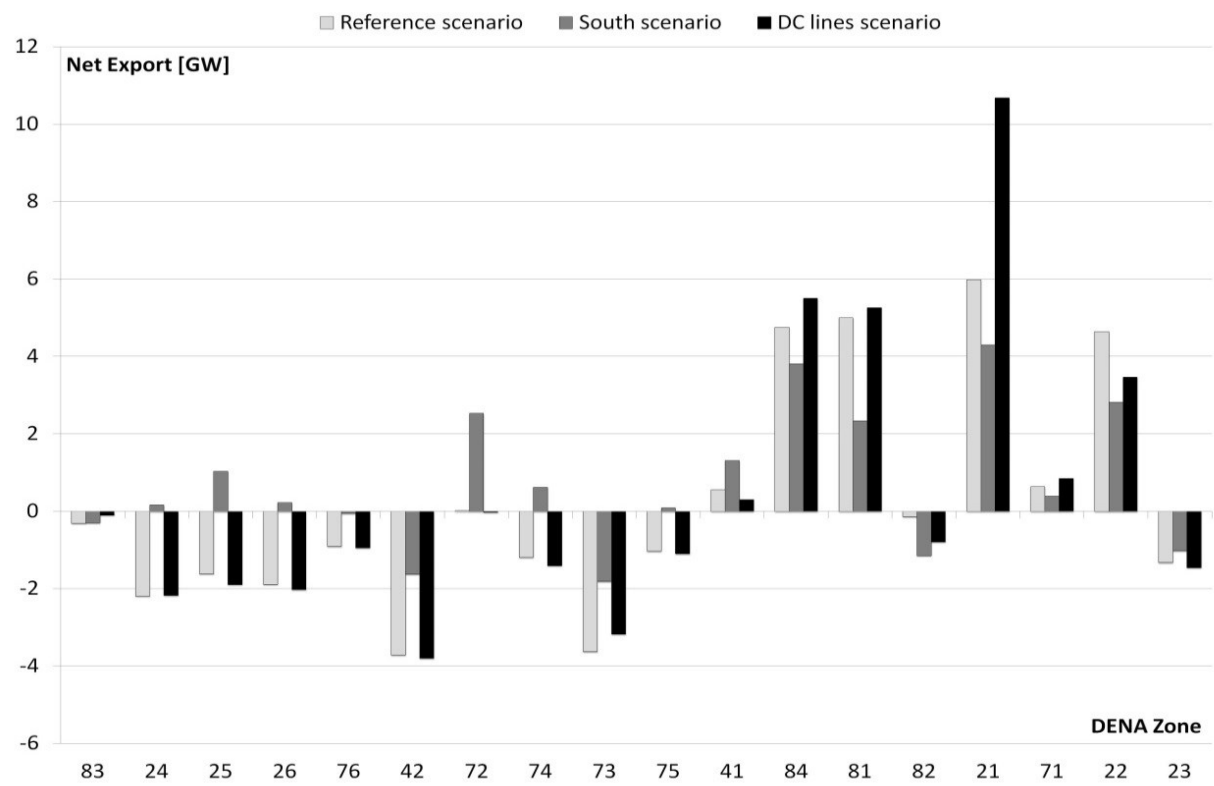

Figure 41: Net input: median of hourly import/export in German zones.

Source: Own depiction.

In the Strategic South Scenario, the national import-export pattern is fundamentally shifted. First of all, the inner-German disequilibrium between northern exporters and southern importers tends towards a balance. All nodes experiencing a major decrease in imported electricity are located in the south and west of Germany and all former main exporters experiencing a decline of net exports are located in the north of Germany. A second observation is that there is a clear shift towards more export from Germany into neighbouring countries. As a matter of fact, Germany turns from a net moderate importing (around 3% of production) in the Reference Scenario to a major net exporting country (around 17% of production). We conclude that the strategic placement of installed capacity to demand regions brings relief to the connection between exporting and importing zones and improves the overall German export ratio.

In what follows, congestion patterns in week 51 are scrutinized in detail in order to point out changes across the different scenarios. Subject of investigation is the congestion status of the German AC grid, which is evaluated by the individual shadow variables of the lines.

Figure 42 illustrates the congestions of each line in the three scenarios. Congestion is categorized in three classes depending on its severity: yellow representing light, orange medium and red strong congestion. As anticipated, there is strong congestion on the inter-connectors to northern Europe and on the inner-German line called "Rennsteig" (line from node 25 to node 83), which is an important north-south connector in development. These results show that there will be a need for further grid extension in the reference case to transport all the offshore and onshore wind energy from northern Germany to southern Germany and to the rest of Europe.

Most of the congestion in the northwest is alleviated in the South Scenario as the congestion index falls significantly for almost all inner-German lines and interconnectors. Especially the north-south connectors and interconnectors to northern Europe, which were congested in the Reference Scenario, show a strong improvement. We conclude that grid capacity planning and generation capacity planning are intertwined problems which should ideally be coordinated in conjunction so as to reduce cost from a societal perspective.

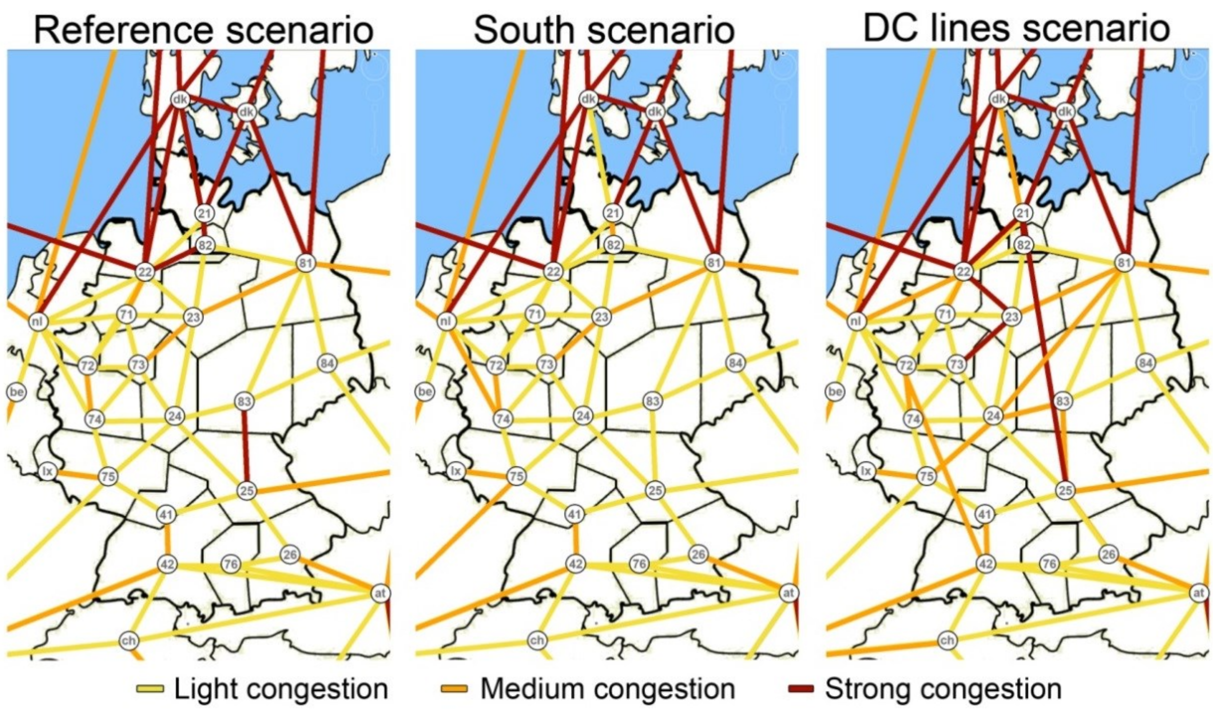

Figure 42: Line congestion in three scenarios measured in terms of shadow value.

Source: Own depiction.

A key finding of the DC Highways Scenario is that inner-German congestion is not necessarily relieved by building DC lines across the country. Even though a DC-grid enforcement reduces the congestion of some interconnectors and parallel running north-south lines, it goes along with higher congestion on other inner-German lines. The main reason for the latter is that additional congestion occurs at the starting and ending points of the DC lines as the existing AC infrastructure is not yet equipped for spreading the electricity through those "spokes" to the different consumer centres. It can be concluded that the planning of DC lines is not sufficient by itself, but needs to go hand in hand with a surrounding AC grid planning in destination zones.

6.5.2 Welfare analysis

The analysis of the impact on welfare contains results calculated from the model as well as specific costs incurred to build the infrastructure available in the scenarios. For the Reference Scenario no additional costs are added since this scenario is business-as-usual. However, for the DC Highways Scenario costs for the expansion of the DC grid are added based on cost assumptions explained previously. Moreover, infrastructure costs occur in the Strategic South Scenario due to shifts in the newly built capacity in southern Germany. It is obvious that these infrastructure costs should be taken into account for a welfare analysis.

Based on the investment costs for renewable energy, these changes lead to lower costs in total. The reason is that the investment costs for onshore wind power plants are notably lower than the costs for offshore wind power plants. In total €834 mn can be saved through the shift of capacity in the Strategic South scenario. This translates to €8.6 mn monthly when considering different physical lifetimes for technologies (PV: 25 years; on- and offshore wind and wave and tidal: 20 years).

Table 23: Overview of welfare effects summed over four representative weeks

	Reference [€mn]	*Strategic South [€mn]*	*DC Highway [€mn]*
Welfare per month	13,422	13,545	13,537
Infrastructure cost per month		-9	54
Net welfare per month	13,422	13,553	13,483
Change in %		+ 0.98 %	+ 0.45 %

Source: Own calculation based on EcoFys et al. (2011).

For the DC Highways Scenario, expansion costs with a total amount of €9 bn are assumed. This value includes variable grid costs and fixed costs for converter stations at nine nodes (both referring to a line capacity of 2 GW). Since these costs are the investment costs for a grid with an operational life of 40 years, an annuity with an interest rate of 7% is used, analog to the interest rate determined by the federal network agency BNetzA. The calculation yields to annual costs of €675 mn and to monthly costs of €54.5 mn.

In conclusion, we observe overall positive welfare effects of DC lines and a strategic placement of generation capacity close to demand centres, even after deduction of infrastructure costs, as seen in Table 23. Consequently, the placement of additional generation capacities into demand centres is found to be effective in reducing congestion. Likewise, DC lines as proposed in this study are a sensible and cost-effective approach to alleviating transmission grid congestion. The positive effect on welfare is higher in the Strategic South Scenario due to relieved congestion. In addition, further cost reductions are evoked by the major changes in installed capacity. However, also the DC Highways Scenario generates a higher welfare without any changes in the capacity. Hence, congestion relief appears to be the key driver for the improvement through new lines. However, both scenarios show that there still remains further need for grid upgrades in the ordinary AC grid. Implementing DC lines and placing capacities in the south are not sufficient measures to fully satisfy the grid requirements imposed by the 2030 energy system. The analysis points to the need for grid expansion beyond what is currently planned in the TYNDP context.

6.6 Conclusion: the integration of renewable energies into the German transmission grid

The results presented above indicate that the German AC/DC grid as planned in the TYNDP is likely to feature line congestion and it is thus not capable of fully integrating the amount of renewable energy to the extent that welfare maximization would suggest desirable. Unless transmission lines are reinforced, a welfare-optimizing dispatch of generation for Germany in a European context is thus unlikely to take place.

Throughout all three scenarios, we observe congestion centres in the northwest of Germany which extend towards the south, as well as at the interconnectors between Germany and its northern neighbours. The connections to Poland, the Czech Republic and the

Netherlands are also continuously operating at capacity limit but with a lower possible contribution to welfare optimization. As a consequence, renewable energy power originating from the northern offshore generation centres (DENA zones 21 & 22, Great Britain) does not reach German and foreign load centres in its entirety.

The modifications made in the DC Highway and Strategic South Scenario have an alleviating effect on congestion. The Strategic South Scenario shows the best results, indicating that an even distribution of generation across the country does provide an alternative to massive transmission investments. However, given that national policy is ultimately aiming for 100% of renewable generation in 2050, the reinforcement of existing and the construction of new lines seems inevitable at this point. Within the DC Highways Scenario, the AC congestion actually worsens after the introduction of the DC lines. While the north-south axis is relieved, congestion problems are transferred to starting and destination hubs and prove that there is still a need for reinforcements of the AC lines.

7 The Impact of Policy Measures on Future Power Generation Portfolio and Infrastructure – A Combined Electricity and CCTS Investment and Dispatch Model

7.1 Introduction: a review of state of the art electricity and CO_2 modeling approaches

The need for combating climate change is internationally widely accepted (World Summit of the Regions, 2014) and the role of the electricity sector as a major contributor to global GHG emission reductions is undisputed (Leader of the G7, 2015).[67] However, there exists an international dissent on how to achieve a decarbonization of the sector. Even in the EU, a multitude of approaches exist: Germany has departed on its "Energiewende" path towards a renewable energy based system, with renewable energy sources (RES) already contributing to 30% of electricity production in 2015. At the same time, France still relies on large nuclear capacities; while the United Kingdom (UK) promotes a mixed strategy of renewables, nuclear and carbon capture, transport, and storage (CCTS). The low certificate prices in the European Emissions Trading System (EU-ETS), at levels below 10 €/tCO_2 in 2015 – with little hope for a significant rise in the upcoming years (Hu et al., 2015) – however, give insufficient incentives for most of these low-carbon investments. This endangers achieving the EU climate policy targets for 2030 (EC, 2014a) and puts the global 2°C target at risk. Therefore, several countries have started or are about to start backing the EU-ETS with additional national measures. These include different types of feed-in tariffs and market premia, capacity markets, a minimum CO_2 price and emissions performance standards (EPS). Models assessing the future development of a decarbonized electricity market need to adequately incorporate such additional policy measures. In addition, interdependencies between the measures as well as feedbacks with other sectors need to be taken into account.

[67] This chapter is based on an article in the IEEE Conference Publications for the 12th International Conference on the European Energy Market (EEM), Lisbon, Portugal, 2015 (Mendelevitch and Oei, 2015). It is joint work together with Roman Mendelevitch and was started during a research stay at the International Institute for Applied Systems Analysis (IIASA) in Laxenburg, Austria in the autumn of 2014. Pao-Yu Oei and Roman Mendelevitch jointly developed the model and its implementation in GAMS. Pao-Yu Oei was in charge of the implementation of the UK case study. Roman Mendelevitch had the lead in collecting data. The writing of the manuscript was executed jointly.

Different kinds of models are used to assess the impact of policy instruments and their ability to achieve climate change policy objectives. Pfenninger et al. (2014) classify models according to the different challenges they address. They differentiate between energy system models for normative scenarios, energy system simulation models for forecasts, power systems and electricity market models for analyzing operational decisions and qualitative and mixed-methods for narrative scenarios. Energy system models such as PRIMES (Capros et al., 1998), MARKAL (Fishbone and Abilock, 1981), EFOM (Finon, 1979) or POLES (Criqui, 1996) are able to convey the “big picture” of what is happening in different linked sectors of an energy system. These technology-oriented models focus on the energy conversion system, on the demand-side (e.g. efficiency measures) as well as supply side (e.g. wide range of generation technologies). The advantages of these models are that they cover several sectors, linking them through endogenous fuel substitution. They are mostly solved by optimization or simulation techniques when minimizing system costs or maximizing the overall welfare. Fais et al. (2014) integrate different types of RES support schemes such as feed-in tariffs as well as quantity based instruments such as certificate systems in their energy system model Times-D. Their approach can be used to analyze exogenous support scheme but does not establish a link between attaining a specific CO_2 target and the level of required RES support, and does not allow analysis of long-term development. Moreover, RES generation is limited exogenously via upper bounds on annual maximum expansion. They assume perfect competition and have limited possibilities to incorporate market power.

Apart from energy system models, there is a large strand of literature that employs a partial equilibrium setting to assess one particular market, e.g. the electricity market. This allows for analyzing non-cooperative firm behavior in more detail (e.g. à la Cournot) by allowing the firms to strategically exploit their influence on the market price with their output decision. Moreover, different risk attitudes and explicit shadow prices can be easily incorporated in these settings. The models have been focusing on considerations of resource adequacy (Ehrenmann and Smeers, 2011), assessing the impact of environmental regulation (Allevi et al., 2013), renewables obligations and portfolio standards (Chen and Wang, 2013; see e.g. Gürkan and Langestraat, 2014), or congestion management of the transmission network (Kunz and Zerrahn, 2015).

One technology that is of particular interest for a future decarbonization of the electricity sector is CCTS. The technology comes with a dichotomy: On the one hand, it plays an important role in many of the possible energy system scenarios that are consistent with the EU Energy Roadmap (EC, 2013c). Accordingly, the scenarios for the newest report from the IPCC (2014a) estimate a cost increase of 29-297% for reaching the 2°C target without the CCTS technology.[68] On the other hand, despite available financial schemes and technology, CCTS has not been implemented on a large scale anywhere in the world. Various authors have addressed this discrepancy with different regional focuses (Groenenberg and de Coninck, 2008; Hirschhausen et al., 2012a; Milligan, 2014; Stechow et al., 2011). Gale et al. (2015) in addition address this topic in a special issue commemorating the 10th anniversary of the first IPCC (2005a) special report on CCTS.

Most electricity market models do not put any emphasis on CCTS, and handle the technology like any other conventional generation technology by specifying investment and variable costs and fuel efficiency. For example, Eide et al. (2014) apply a stochastic generation expansion model to determine the impact of CO_2 EPS on electricity generation investment decisions in the U.S. Their findings show a shift from fossil fuel generation from coal to natural gas rather than incentivizing investment in CCTS. Zhai and Rubin (2013) explored the "tipping point" in natural gas prices for which a coal plant with CCTS becomes economically competitive, as a function of an EPS. Middleton and Eccles (2013) calculate the price for CO_2 to be in the range of 85-135 US\$/tCO_2 (65-105 €/tCO_2) to incentivize a gas power plant to use CCTS in the USA. This simplified representation of the CCTS technology in these models, however, neglects transportation and storage aspects as well as the possibility of industrial usage of CCTS.

By contrast, if models focus on CCTS infrastructure development, they often neglect how the technology is driven by decisions in the electricity market. A series of studies analyzed the technical potential of CCTS deployment, including possible CO_2 pipeline routing (Kazmierczak et al., 2008; Kobos et al., 2007; Middleton and Bielicki, 2009; Morbee et al., 2012; Oei et al., 2014a). The construction of such large-scale new infrastructure networks is

[68] RES and nuclear provide suffient decarbonization alternatives for the electricity sector. The high cost increase, however, is caused by only limited alternative decarbonization technologies in the industry sector. Negative emissions of large-scale utilization of CCTS with biomass, in addition, compensate for unabatable emissions in other sectors (Kemper, 2015).

highly influenced by public acceptance, especially in densely populated regions such as the European Union (Gough et al., 2014). Acceptance issues as well as other technical uncertainties can lead to high cost increases of a CCTS deployment (Knoope et al., 2015). In the absence of expected technological learning and with persistently low CO_2 certificate prices CCTS projects aim at additional income through CO_2-Enhanced Oil Recovery (CO_2-EOR) (Kemp and Kasim, 2013; Mendelevitch, 2014).

Kjärstad et al. (2013) have started to close this gap by combining the techno-economic *Chalmers Electricity Investment Model* with *InfraCCS*, a cost optimization tool for bulk CO_2 pipelines along with Chalmers databases on power plants and CO_2 storage sites. Their approach, however, relies on solving both sectors consecutively starting with the electricity model without any feedback options. They, in addition, do not include CO_2 capture from industrial sources. This neglects economies of scale especially with respect to transporting CO_2 as well as scarcity effects with respect to CO_2 storage. Additional research is needed to include different policy instruments into the modeling frameworks to evaluate the effect of various measures.

This chapter presents a general electricity-CO_2 (ELCO) modeling framework that is able to simulate interactions of the electricity-only market with different forms for national policy measures as well as a full representation of the carbon capture, transport, and storage (CCTS) chain. Different measures included in the model are feed-in tariffs, a minimum CO_2 price and a CO_2 emissions performance standard (EPS). Additionally, the model includes large industrial emitters from the iron/steel and cement sector that might also invest in carbon captures facilities, increasing scarcity effects for CO_2 storage. The set-up also takes into account demand variation by type hours, the availability of more and less favorable locations for RES and endogenously accounts for limits to annual diffusion of new technologies. The model is driven by a CO_2 target and an optional RES target. This chapter is used to describe the different features and potentials of the ELCO model. We apply the model to a stylized case study of the UK Electricity Market Reform (EMR) to present a show case of our model framework.

The remaining chapter is structured as follows: The introduction is followed by a detailed description of the ELCO model in section 7.2. A case study in section 7.3 applies the ELCO model to the UK electricity market. The main policy measures are adjusted in the model to mimic the UK EMR and its long-term effects. Section 7.4 concludes with an outlook of future applications of the ELCO model.

7.2 Mathematical representation of the ELCO model

The ELCO model mimics the competition of different conventional electricity generation technologies on the electricity market and their interaction with new technologies that are financed via fixed tariffs. Each technology is represented via a stylized player that competes with one another. For a better representation of scarce CO_2 storage resources we also include a detailed representation of the complete CCTS value chain. This also includes potential CO_2 capture from the steel and cement industry. The different CO_2 storage options such as CO_2-EOR, saline aquifers and depleted oil and gas reservoirs compete against one another in the last stage of the CCTS value chain. All players maximize their respective profits subject to their own as well as joint technical and environmental constraints. Other (external) costs as well as further welfare components are not being analyzed. Regional disaggregation takes into account geographical characteristics like availability (especially with respect to maximum potential and conditions for renewables as well as CO_2 storage) and specific electricity demand.

Different policy measures such as a Carbon Price Floor (CPF), an Emissions Performance Standard (EPS) or feed-in tariffs in form of Contracts for Differences (CfD) are included in the modeling framework. The ELCO model analyzes how these policy instruments will influence the construction of new generation capacities. CfD for newly constructed low-carbon technologies can be derived endogenously using shadow variables of constraints. Assuming perfect competition between the different players, equilibrium is reached when overall system costs are being minimized subject to all constraints.

The developed model is able to assess regionally disaggregated investment in electricity generation, generation dispatch and simplified flows as well as CO_2 transport, storage, and usage for CO_2-EOR. Incorporating CO_2 capture by industrial facilities from the steel, and cement sector enables, on the one hand, the representation of economies of scale along the transport routes while, on the other hand, leading to higher scarcity effects with respect to CO_2 storage options.

7.2.1 Notations of the model

The following tables list the used sets, variables and parameters of the ELCO Model. Parameters are indicated by capital letters, variables by small sized letters and sets are resembled in subscripts. The detailed Karush-Kuhn-Tucker (KKT) conditions of the ELCO model are depicted in the Appendix 9.3.

Name	*Description*
a, aa, aaa	5 year period
h, hh	Time interval
i, ii	CO_2 sources from industry {Steel: IND_ST, Cement: IND_CE}
n, nn	Node
new(t)	Flag if a technology is newly built {0,1}
s, ss	CO_2 sinks {Saline: STO_SA, DOGF: STO_DA, EOR: STO_SA}
t, tt	Generation technologies: { - g-type existing capacities: Nuc, Coal, Gas_GT: CCGT, Gas_CC: OCGT; - g-type new capacities: COAL_NEW, CCGT_NEW, OCGT_NEW; - g_cfd-type new capacities: PV: RES_PV, Wind_on: RES_WI_ON, Wind_off: RES_WI_OF, Hydro: RES_HY, Biomass: RES_BI, Coal_CCTS, CCGT_CCTS}

Table 24: List of sets of the ELCO Model

Name	*Description*	*Unit*
co2_c(h,n,i,a)	Emissions captured from industry	[$ktCO_2$/h]
co2_s(h,n,s,a)	Storaged emissions	[$ktCO_2$/h]
co2_t(h,n,nn,a)	Flow of CO_2	[$ktCO_2$]
el_t(h,n,nn,a)	Flow of electricity	[GW]
emps(a)	Emissions Performance Standard	[$ktCO_2$/GWh]
g(h,n,t,a)	Generation of electricity	[GW]
g_cfd(h,n,t,aa,a)	Generation electricity from CfD sources	[GW]
inv_co2_c(n,i,a)	Investment in capture technology	[k€/$ktCO_2$/h]
inv_co2_s(n,s,a)	Investment in storage technology	[k€/$ktCO_2$/h]
inv_co2_t(n,nn,a)	Investment in CO_2 transport capacity	[k€/$ktCO_2$/h]
inv_el_t(n,nn,a)	Investment in electricity transport capacity	[k€/GW]
inv_g(n,t,a)	Investment in generation capacity	[k€/GW]

Table 25: List of variables of the ELCO Model

Name	*Description*	*Unit*
lambda_cap_co2_c(h,n,i,a)	Dual of CO_2 capture cap.	[k€/ktCO_2/h]
lambda_cap_co2_s(h,n,s,a)	Dual of CO_2 annual storage cap.	[k€/ktCO_2/h]
lambda_cap_co2_t(h,n,nn,a)	Dual of CO_2 transport cap.	[k€/ktCO_2/h]
lambda_cap_el_t(h,n,nn,a)	Dual of transmission cap.	[k€/GW]
lambda_cap_g(h,n,t,a)	Dual of elec. generation cap.	[k€/GW]
lambda_cap_g_cfd(h,n,t,aa,a)	Dual of elec. must run condition for RES	[k€/GW]
lambda_curt_el(h,a)	Dual of electricity curtailment	[k€/GWh]
lambda_diff_co2_c(i,a)	Dual of diffusion for CO_2 capture in industry	[k€/ktCO_2/h]
lambda_diff_co2_s(s,a)	Dual of diffusion for CO_2 storage	[k€/ktCO_2/h]
lambda_diff_g(t,a)	Dual of diffusion for renewables	[k€/GWh]
lambda_emps(n,t,a)	Dual of emps constraint	[k€/ktCO_2]
lambda_max_ind(h,n,i,a)	Dual of maximum industry emissions	[k€/ktCO_2/h]
lambda_max_stor(n,s,a)	Dual of max. CO_2 storage cap.	[k€/ktCO_2/h]
lambda_pot_g(n,t,a)	Dual of potential for renewables	[k€/GW]
lambda_target_co2(a)	Dual of CO_2 emissions constraint	[k€/ktCO_2]
lambda_target_RE(a)	Dual of renewables target constraint	[k€/GWh]
mu_co2(h,n,a)	Dual of CO_2 market clearing	[k€/ktCO_2/h]
mu_el(h,n,a)	Dual of electricity market clearing	[k€/GWh]

Table 26: List of dual variables of the ELCO Model

Name	*Description*	
ADJ_CO2(n,nn)	Flag if two CO_2-nodes are adjacent	{0,1}
ADJ_EL(n,nn)	Flag if two Elec-nodes are adjacent	{0,1}
ALPHA(t,a)	Maximal marginal CO_2-abatement	[ktCO_2/GWh]
AVAIL(h,n,t)	Availability of power plant	[%]
CO2_IND(h,n,i,a)	CO_2 emission by industry	[ktCO_2]
CO2_TARGET(a)	CO_2 target reduction for electricity sources	[%]
CP_CO2(s/i)	Planning and construction period	[years]
CP_G(t)	Planning and construction period	[years]
CPS(a)	Carbon price support	[k€/ktCO_2]
CR_G(t)	Capture rate for generation	90% or 0%
CR_IND(i)	Capture rate for industries	90%
D(h,n,a)	Electricity demand	[GW]
DF(a)	Discount factor	[%]
DIFF_CO2(s/i)	Technology diffusion factor storage / industry capture	[%]
DIFF_G(t)	Technology diffusion factor by generation technology	[%]
EF_EL(t)	Emissions factor	[ktCO_2/GWh]
EFF_CO2	CO_2-EOR efficiency	[kbbl/ktCO_2]
EUA(a)	EU-ETS allowances	[k€/ktCO_2]
FC_CO2(n,s/i,a)	Fix costs for CO_2 capture, and storage	[k€/ktCO_2]
FC_CO2_T(n,nn)	Fix costs for CO_2 transport	[k€/ktCO_2]
FC_F_E(n,nn)	Fix costs for electricity transport	[k€/GW]

Name	*Description*	
FC_G(n,t,a)	Fix costs for generation w/o. or w/ capture	[k€/GW]
I_USE_CO2(s/i,a,aa)	Flag if capacity investment from year a can be used for generation in year aa in the CO_2 sector	{0,1}
I_USE_EL(t,a,aa)	Flag if capacity investment from year a can be used for generation in year aa in the electricity sector	{0,1}
INICAP_EL_T(n,nn)	Initial capacity for electricity transport	[GW]
INICAP_G(n,t,a)	Initial capacity incl. retirement	[GW]
INTC_CO2(t)	Quadratic cost term for CO_2 operation	[k€/GWh^2]
INTC_G(t)	Quadratic integration costs for generation technologies	[k€/GWh^2]
INVC_CO2(n,s/i,a)	Investment cost for industrial CO_2 capture capacity or storage per hour	[k€/ktCO_2/h]
INVC_CO2_T(n,nn)	Investment cost for CO_2 transport	[k€/ktCO_2/h]
INVC_EL_T(n,nn)	Investment cost for electricity transport	[k€/GW]
INVC_G(n,t,a)	Investment cost for generation capacity w/o or w/ capture	[k€/GW]
LT_CO2(s/i)	Life time of industry CO_2 capture & storage technology	[years]
LT_G(t)	Life time of generation technology	[years]
MAX_INV(n,t)	Maximal potential of generation technology	[GW]
MAX_STOR(n,s)	Maximal CO_2 storage capacity	[ktCO_2]
OILPRICE(a)	Price of additional oil from CO_2-EOR	[k€/kbbl]
ONE_FUEL(t,tt)	Flag for identical fuel	{0,1}
PD(a)	Period duration (5 years)	[years]
RE_TARGET(a)	Renewables target	[%]
REF_CO2	CO_2 emissions from electricity generation in 1990	[ktCO_2]
RES_OLD(h,n,a)	Generation of already existing RE	[GW]
SP(t,a)	Strike price for CfD-technologies in first years	[k€/GWh]
START_CO2(s/i)	Starting capacity industry capture & storage technology	[ktCO_2/h]
START_G(t)	Starting capacity for generation technology	[GW]
TD(h)	Time duration of each hourly segment	[hours]
USE_CO2(s/i,a,aa)	Flag if capacity investment from years aa can be used for generation in year a in the CO_2 sector	{0,1}
USE_EL(t,a,aa)	Flag if capacity investment from years aa can be used for generation in year a in the electricity sector	{0,1}
VC_CO2(n,s/i,a)	Variable costs for CO_2 capture or storage	[k€/ktCO_2]
VC_CO2_T(n,nn)	Variable costs for CO_2 transport	[k€/ktCO_2]
VC_EL_T(n,nn)	Variable costs for electricity transport	[k€/GW]
VC_G(n,t,a)	Variable generation costs w/o. or w/ capture	[k€/GWh]

Table 27: List of parameters of the ELCO Model

7.2.2 The electricity sector

$$\Pi_{g/g\_cfd}^{ELEC} = \sum_a DF_a \cdot PD_a \left(\begin{array}{l} \sum_h TD_h \cdot \left(\begin{array}{l} g_{h,n,t,a} \cdot \left[\begin{array}{l} mu\_e_{h,n,a} \\ - \left(\begin{array}{l} EF\_EL_t \cdot (CPS_a + EUA_a) \\ + VC\_G_{n,t,a} + INTC\_G_t \cdot g_{h,n,t,a} \end{array} \right) \end{array} \right] \\ + \sum_{aa \in USE\_EL_{t,a,aa}} \left(g\_cfd_{h,n,t,aa,a} \cdot \left[\begin{array}{l} \left(\begin{array}{l} \sum_{aaa \in I\_USE\_EL_{t,aa,aaa}} \alpha_{t,aaa} \cdot \lambda_{aaa}^{target\_co2} \\ - \sum_{\substack{aaa \in I\_USE\_EL_{t,aa,aaa}, \\ t \in T\_RES}} \left[(1 - TARGET\_RE_{aaa}) \cdot \lambda_{aaa}^{target\_RE} \right] \\ + \sum_{\substack{aaa \in I\_USE\_EL_{t,aa,aaa}, \\ t \notin T\_RES}} \left[TARGET\_RE_{aaa} \cdot \lambda_{aaa}^{target\_RE} \right] \\ + SP_{t,aa} \end{array} \right) \\ - \left(\begin{array}{l} (EF\_EL_t \cdot (1 - CR\_G_t)) \cdot (CPS_a + EUA_a) \\ + EF\_EL_t \cdot CR\_G_t \cdot mu\_co2_{h,n,a} \\ + VC\_G_{n,t,a} + INTC\_G_t \cdot g\_cfd_{h,n,t,aa,a} \end{array} \right) \end{array} \right] \right) \end{array} \right) \\ - \left((FC\_G_{n,t,a} \cdot INICAP\_G_{n,t,a}) + \sum_{aa \in USE\_EL_{t,a,aa}} (FC\_G_{n,t,aa} \cdot inv\_g_{n,t,aa}) \right) \\ - \left(\sum_{aa \in USE\_EL_{t,a,aa}} INVC\_G_{n,t,aa} \cdot inv\_g_{n,t,aa} \right) \end{array} \right) \quad (37)$$

The ELCO model represents electricity generation from various technologies. Electricity generation is herby divided in the two subgroups $g_{h,n,t,a}$ and $g\_cfd_{h,n,t,aa,a}$. $g_{h,n,t,a}$ comprise generation from all existing capacities and newly built carbon-intensive capacities from coal, gas OCGT and gas CCGT. $g\_cfd_{h,n,t,aa,a}$, on the other hand, include generation from newly constructed low-carbon generation capacities from PV, wind on/offshore, hydropower, biomass, CCTS coal/gas, and nuclear that are financed via the CfD scheme. The profit function for different technologies share the common component of fix costs $FC\_G_{n,t,a}$ and annualized investment costs $INVC\_G_{n,t,a}$ depending on the investments $inv\_g_{n,t,a}$ (lowest rectangular segment). The variable costs components and revenue differ: for *g*-type technologies (upper rectangle with upper flat corners) revenue is generated from sales on the electricity market receiving the electricity price $mu\_e_{h,n,a}$. The variable cost function comprise fuel and O&M costs with a linear and a quadratic term ($VC\_G_{n,t,a}$ and $INTC\_G_t$). In addition CO_2 costs are calculated based on the emission factor EF_EL_t, multiplied with a combination of the EU-ETS CO_2 certificate price (EUA_a) and a carbon price support *(*CPS_a in case of a carbon floor price for the electricity sector). For *g_cfd*-type technologies (middle rectangle with rounded corners) revenue is generated from the new CfD scheme. The CfD strike price can be incorporated in two ways: It can either be set exogenously, differentiated by year of construction and technology type. Or the strike price is determined endogenously. In the latter case, it depends on the extent to which generation from the respective technology contributes to achieving the environmental goals (*TARGET_CO2$_a$* and *TARGET_RE$_a$*) and is incorporated in the dual variables of these constraints (see 7.2.2.1). This type also encounters additional variable cost components for possible CO_2 infrastructure (transport and storage) which are passed via the dual variable *mu_co2$_{h,n,a}$* and account for CO_2 capture rates *CR_G$_t$*. The technology specific quadratic cost term is interpreted as integration cost for increasing shares of *g_cfd*-type generation.

$$
\begin{aligned}
0 \le & \sum_h AVAIL_{h,n,t} \cdot TD_h \cdot \sum_{\substack{aa \in USE\_EL_{t,a,aa},\\ (t,tt) \in ONE\_FUEL_{t,tt}}} inv\_g_{n,tt,aa} \cdot EMPS_{aa} \\
& - \sum_h TD_h \cdot \begin{bmatrix} \left[g_{h,n,t,a} \cdot \left(EF\_EL_t \cdot (1 - CR\_G_t) \right) \right] \\ + \sum\limits_{\substack{aa \in USE\_EL_{t,a,aa},\\ (t,tt) \in ONE\_FUEL_{t,tt}}} \left[g\_cfd_{h,n,tt,aa,a} \cdot \left(EF\_EL_{tt} \cdot (1 - CR\_G_{tt}) \right) \right] \end{bmatrix} \quad \perp \quad \lambda^{emps}_{n,t,a} \ge 0
\end{aligned} \tag{38}
$$

The individual players maximize their profit subject to several constraints. The EPS constraint (38) ensures that newly constructed generation capacities do not exceed the annual allowed CO_2 emissions per GW. The overall emissions are calculated as an annual fuel and site specific sum, allowing for combined accounting of new capacities with and without CCTS.

The generation capacity constraints (39) and (40) differ slightly for conventional generation technologies $g_{h,n,t,a}$ and newly constructed low-carbon technologies *g_cfd$_{h,n,t,aa,a}$*, as the calculation of currently available generation capacity differs for the two cases.

$$
0 \le AVAIL_{h,n,t} \cdot \left(INICAP\_G_{n,t,a} + \sum_{aa \in USE\_EL_{t,a,aa}} inv\_g_{n,t,aa} \right) - g_{h,n,t,a} \quad \perp \quad \lambda^{cap\_g}_{h,n,t,a} \ge 0 \tag{39}
$$

$$
0 \le AVAIL_{h,n,t} \cdot inv\_g_{n,t,aa} - g\_cfd_{h,n,t,aa,a} \quad \perp \quad \lambda^{cap\_g\_cfd}_{h,n,t,aa,a} \ge 0 \tag{40}
$$

A diffusion constraint restricts the maximal annual investment depending on generation from previous periods and some initial starting value for new technologies.

$$
\begin{aligned}
0 \le & \left(START\_G_t \cdot \frac{\sum_{h,n} AVAIL_{h,n,t} \cdot TD_h}{\#of\ nodes} + \left[\sum_{h,n,aa} TD_h \cdot \left(g\_cfd_{h,n,t,aa,a-1} + g\_cfd_{h,n,t,aa,a-2} \right) \right] \right) \cdot DIFF\_G_t \\
& - \sum_{h,n,aa} TD_h \cdot g\_cfd_{h,n,t,aa,a} \quad \perp \quad \lambda^{diff\_g}_{t,a} \ge 0
\end{aligned} \tag{41}
$$

Another constraint limits the overall investment depending on a technology-specific maximal potential for each node.

$$0 \le MAX\_INV_{n,t} - \sum_{aa \in USE\_EL_{t,a,aa}} inv\_g_{n,t,aa} \quad \perp \quad \lambda_{n,t,a}^{pot\_g} \ge 0 \tag{42}$$

7.2.2.1 Shared environmental constraints for the electricity sector

All players in the electricity sector have to respect shared environmental constraints: An annual CO_2 target guarantees that the annual dispatch is lower or equal an exogenously set CO_2 reduction path.

$$0 \le PD_a \cdot \sum_{h,n,t} TD_h \cdot \left[\left(g_{h,n,t,a} + \sum_{aa \in USE\_EL_{t,a,aa}} g\_cfd_{h,n,t,aa,a} \right) \cdot \alpha_{t,a} \right] \quad \perp \quad \lambda_a^{target\_co2} \ge 0 \tag{43}$$

ALPHA$_{t,a}$ corresponds to the marginal contribution of the respective technology to the targeted CO_2 intensity for a particular year. It is positive for low-carbon technologies while having negative values for conventional generation.

$$\alpha_{t,a} = \frac{CO2\_TARGET_a \cdot REF\_CO2}{\sum_{h,n} D_{h,n,a} \cdot TD_h} - \left(1 - CR\_G_t\right) \cdot EF\_EL_t \tag{44}$$

National renewable targets setting a minimum share of renewable generation are implemented in an additional renewable constraint in some scenarios. This constraint, however, is deactivated in the scenario analyzed in this chapter.

$$0 \le PD_a \cdot \sum_{h,n} TD_h \cdot \left[\begin{array}{l} \sum\limits_{\substack{aa \in USE\_EL_{t,a,aa}, \\ t \in T\_RES}} g\_cfd_{h,n,t,aa,a} + RES\_OLD_{h,n,a} \\ -RE\_TARGET_a \cdot \sum\limits_{h,n} d_{h,n,a} \end{array} \right] \quad \perp \quad \lambda_a^{target\_RE} \ge 0 \tag{45}$$

7.2.3 The electricity transportation utility

The objective function of the electricity transportation utility is shown in the following equation: The sum of variable costs *VC_EL_T*$_{n,nn}$ and annualized investment costs *INVC_EL_T*$_{n,nn}$ equalize the hourly electricity price difference between two nodes in case of no line congestion. Possible congestion rents are kept by the transportation utility as profit. Electricity is treated as a normal transport commodity ignoring Kirchhoff`s 2nd law as network congestion is not the focus of the ELCO model.

$$\Pi^{TSO\_E} = \sum_a DF_a \cdot PD_a \cdot \sum_{n,nn} \begin{bmatrix} -\sum_h TD_h \cdot \begin{pmatrix} \left(mu\_e_{h,n,a} - mu\_e_{h,nn,a}\right) \cdot el\_t_{h,n,nn,a} \\ +VC\_EL\_T_{n,nn} \cdot el\_t_{h,n,nn,a} \end{pmatrix} \\ -\sum_{aa<a} \left(INVC\_EL\_T_{n,nn} \cdot inv\_el\_t_{n,nn,a}\right) \end{bmatrix} \tag{46}$$

The electricity utility maximizes its profits subject to the following line capacity constraint:

$$\begin{aligned} 0 \leq\ & INICAP\_EL\_T_{n,nn} + \sum_{aa<a} \left(ADJ\_EL_{n,nn} \cdot inv\_el\_t_{n,nn,aa} + ADJ\_EL_{nn,n} \cdot inv\_el\_t_{nn,n,aa} \right) \\ & -el\_t_{h,n,nn,a} \quad \perp \quad \lambda_{h,n,nn,a}^{cap\_el\_t} \geq 0 \end{aligned} \tag{47}$$

7.2.4 The industry sector

The industry is being represented by the two sectors *i*: Iron and Steel as well as cement which are most likely to use CO_2 capture as mitigation option. The objective function of the industry sectors is limited to the abatement costs linked to exogenously given historic CO_2 emissions. They include the option of either paying the EUA_a or investing into the CCTS technology with its variable costs $VC\_CO2_{n,i,a}$, fix costs $FC\_CO2_{n,i,a}$ and annualized investment costs $INVC\_CO2_{n,i,a}$. The additional costs for a possible CO_2 infrastructure (transport and storage) are being passed on from the downstream CO_2 sector via the dual variable $mu\_co2_{h,n,a}$.

$$\Pi^{IND} = \sum_a DF_a \cdot PD_a \begin{pmatrix} -\sum_h \begin{bmatrix} TD_h \cdot \begin{pmatrix} +\left(CO2\_IND_{h,n,i,a} - co2\_c_{h,n,i,a}\right) \cdot EUA_a \\ +co2\_c_{h,n,i,a} \cdot mu\_co2_{h,n,a} \\ +co2\_c_{h,n,i,a} \cdot VC\_CO2_{n,i,a} \end{pmatrix} \end{bmatrix} \\ -\left(FC\_CO2_{n,i,a} \cdot \sum_{aa \in USE\_CO2_{i,a,aa}} inv\_co2\_c_{n,i,aa} \right) \\ -\left(INVC\_CO2_{n,i,a} \cdot \sum_{aa \in USE\_CO2_{i,a,aa}} inv\_co2\_c_{n,i,a} \right) \end{pmatrix} \tag{48}$$

The industry sector maximizes its objective function subject to similar constraints as the electricity sector. A diffusion constraint restricts the maximal annual investment depending on previous investments.

$$0 \leq \left(START\_CO2_i + \sum_n \sum_{aa<a} inv\_co2\_c_{n,i,aa} \right) \cdot DIFF\_CO2_i - \sum_n inv\_co2\_c_{n,i,a} \quad \perp \quad \lambda_{i,a}^{diff\_co2\_c} \geq 0 \tag{49}$$

The annual capturing quantity is restricted by the amount of previous investments as well as the overall maximal capturing quantity per node and technology.

$$0 \le \sum_{aa \in USE\_CO2_{i,a,aa}} inv\_co2_{n,i,aa} \cdot CR\_IND_i - co2\_c_{h,n,i,a} \quad \perp \quad \lambda_{h,n,i,a}^{cap\_co2\_c} \ge 0 \tag{50}$$

$$0 \le CO2\_IND_{h,n,i,a} \cdot CR\_IND_i - co2\_c_{h,n,i,a} \quad \perp \quad \lambda_{h,n,i,a}^{max\_ind} \ge 0 \tag{51}$$

7.2.5 The CO_2 transportation utility

The CO_2 transportation utility maximizes its profit show in Equation (51). The sum of variable costs $VC\_CO2\_T_{n,nn}$ and annualized investment costs $INVC\_CO2_{n,nn}$ equalize the difference between the dual prices between two nodes.

$$\Pi^{TSO\_CO2} = \sum_a DF_a \cdot PD_a \cdot \sum_{n,nn} \left[\begin{array}{l} -\sum_h TD_h \cdot \left(\begin{array}{l} \left(mu\_co2_{h,n,a} - mu\_co2_{h,nn,a} \right) \cdot co2\_t_{h,n,nn,a} \\ +VC\_CO2\_T_{n,nn} \cdot co2\_t_{h,n,nn,a} \end{array} \right) \\ -\sum_{aa<a} \left(INVC\_CO2\_T_{n,nn} \cdot inv\_co2\_t_{n,nn,a} \right) \end{array} \right] \tag{52}$$

A pipeline capacity constraint restricts CO_2 transport:

$$0 \le INICAP\_CO2\_T_{n,nn} + \sum_{aa<a} \left(\begin{array}{l} ADJ\_CO2_{n,nn} \cdot inv\_co2\_t_{n,nn,aa} \\ +ADJ\_CO2_{nn,n} \cdot inv\_co2\_t_{nn,n,aa} \end{array} \right) - co2\_t_{h,n,nn,a} \quad \perp \quad \lambda_{h,n,nn,a}^{cap\_co2\_t} \ge 0 \tag{53}$$

7.2.6 The storage sector

Saline aquifers, depleted oil and gas fields (DOGF) and fields with the opportunity for CO_2-EOR are identified as possible storage locations *s*. The objective function of the storage operator represents the abatement costs linked to the underground storage of CO_2. For CO_2-EOR sites it includes the option of returns received from oil sales at oil price $OILPRICE_a$. The storage costs consist of the variable costs $VC\_CO2_{n,s,a}$, a quadratic cost term $INTC\_S_t$, fix costs $FC\_CO2_{n,s,a}$ and annualized investment costs $INVC\_CO2_{n,s,a}$. The dual variable $mu\_co2_{h,n,a}$ is used to pass on the overall storage costs (or in case of CO_2-EOR also possible returns) to the CO_2 transport sector.

$$\Pi^{STOR} = \sum_a DF_a \cdot PD_a \left(\begin{array}{l} -\sum_h \left[TD_h \cdot \left(\begin{array}{l} -co2\_s_{h,n,s,a} \cdot EFF\_CO2 \cdot OILPRICE_a \\ -co2\_s_{h,n,s,a} \cdot mu\_co2_{h,n,s,a} \\ +co2\_s_{h,n,s,a} \cdot VC\_CO2_{n,s,a} + INTC\_S_t \cdot co2\_s_{h,n,s,a}^2 \end{array} \right) \right] \\ -\left(FC\_CO2_{n,s,a} \cdot \sum_{aa \in USE\_CO2_{s,a,aa}} inv\_co2\_s_{n,s,aa} \right) \\ -\left(INVC\_CO2_{n,s,a} \cdot \sum_{aa \in USE\_CO2_{s,a,aa}} inv\_co2\_s_{n,s,aa} \right) \end{array} \right) \tag{54}$$

Storage entities maximize their objective functions subject to a respective diffusion constraint which limits their maximal annual investment based on previous investments.

$$0 \leq \left(START\_CO2_s + \sum_n \sum_{aa<a} inv\_co2\_s_{n,s,aa} \right) \cdot DIFF\_CO2_s - \sum_n inv\_co2\_s_{n,s,a} \quad \perp \quad \lambda_{s,a}^{diff\_co2\_s} \geq 0 \tag{55}$$

Further constraints restrict the annual storage quantities based on prior investments as well as the overall maximal storage quantity per site and technology.

$$0 \leq \sum_{aa \in USE\_CO2_{s,a,aa}} inv\_co2\_s_{n,s,aa} - co2\_s_{h,n,s,a} \quad \perp \quad \lambda_{h,n,s,a}^{cap\_co2\_s} \geq 0 \tag{56}$$

$$0 \leq MAX\_STOR_{n,s} - \sum_h \left(TD_h \cdot \sum_{aa \leq a} PD_{aa} \cdot co2\_s_{h,n,s,aa} \right) \quad \perp \quad \lambda_{n,s,a}^{\max\_stor} \geq 0 \tag{57}$$

7.2.7 Market clearing conditions across all sectors

Three market clearing conditions connect the different sites (represented as nodes) and sectors in the ELCO model: The first two represent the energy balance, while the third balances CO_2 flows. With the introduction of the CfD scheme, the electricity market is fragmented: Technologies not supported by the CfD scheme market their generation to serve residual demand that remains after subtracting supply from CfD supported technologies shown in Equation (58). The free dual variable $mu\_e_{h,n,a}$ of this equation corresponds to the price observed at the electricity wholesale market. By contrast, CfD technologies do not observe any feedback between their generation and market demand, just like in reality. Therefore, an additional curtailment constraint needs to be introduced in Equation (59), that limits total generation to meet the total demand.

$$0 = \sum_t \left(g_{h,n,t,a} + \sum_{aa \in USE\_EL_{t,a,aa}} g\_cfd_{h,n,t,aa,a} \right) + \sum_{nn} el\_t_{h,nn,n,a} - \sum_{nn} el\_t_{h,n,nn,a} - \left(D_{h,n,a} - RES\_OLD_{h,n,a} \right)$$
$$mu\_e_{h,n,a} \; (free) \quad \forall h,n,a \tag{58}$$

$$0 \le \sum_n \left(D_{h,n,a} - RES\_OLD_{h,n,a} \right) - \sum_n \sum_t \left(g_{h,n,t,a} + \sum_{aa \in USE\_EL_{t,a,aa}} g\_cfd_{h,n,t,aa,a} \right) \quad \perp \quad \lambda_{n,a}^{curt\_g} \ge 0 \tag{59}$$

The third market clearing is the CO_2 flow balance with its free dual variable *$mu\_co2_{h,n,a}$*.

$$0 = \sum_{nn} co2\_t_{h,n,nn,a} + \sum_s co2\_s_{h,n,s,a} - \sum_i co2\_c_{h,n,i,a} - \sum_t \left(\sum_{aa \in USE\_EL_{t,a,aa}} g\_cfd_{h,n,t,aa,a} \cdot EF_t \cdot CR\_G_t \right)$$
$$- \sum_{nn} co2\_t_{h,nn,n,a} \qquad mu\_co2_{h,n,a} \; (free) \quad \forall h,n,a \tag{60}$$

7.3 Case study: the UK Electricity Market Reform

The UK energy and climate policy used to be subject to a significant dichotomy between its policy targets and reality. Despite of fixed goals on final energy consumption from renewables (15% in 2020) and binding five-year carbon reduction targets towards a 80% reduction by 2050, the current energy policy framework was lacking instruments to incentivize investments that are necessary to achieve these goals. In addition, up to 20 GW of mostly coal fired generation have exceeded 40 years of age in the year 2015 and are either to be decommissioned or in need of retrofit investments. The upcoming decade therefore becomes vital for a future decarbonized electricity market to prevent stranded investments in carbon intensive power plants. The UK government decided to undertake a major restructuring of its energy policy framework, called Electricity Market Reform (EMR) (The Parliament of Great Britain, 2013). The EMR introduces four main policies to support low-carbon technologies: Contracts for Differences (CfD), Carbon Floor Price (CFP), Emissions Performance Standards (EPS) and a Capacity Market (CM).

These instruments constitute a major reform to the previous framework of the UK electricity market which was characterized by a high competitiveness and low market concentration (DECC, 2014a). Thus, its effects have been controversially discussed, e.g. by

(Chawla and Pollitt, 2013; Pollitt and Haney, 2013). Some critics question the effect the reform might have on the UK electricity market and in particular on the future of low-carbon technologies. The future generation mix will be mostly determined by the government through long-term contracts with little ability to react quickly to future changes. Major risks include possible welfare losses as well as possible breached climate targets due to stranded investments in carbon intensive power plants (a topic examined by Johnson et al. (2015) on a global level). This calls for additional research on low-carbon technologies in the UK. Chalmers et al. (2013) summarize the findings of the two-year UKERC research project on the implementation of CCTS in the UK. To our best knowledge, however, there is no model that evaluates the effects of the UK-EMR on the UK electricity market as well as on the overall CCTS value chain including also the main industrial CO_2 emitters.

The following section describes the UK-EMR and the policy measures which are included in the ELCO model.[69] The used data set and results of this case study are afterwards discussed in the sections 7.3.2 and 7.3.3.

7.3.1 Describing the instruments: Contracts for Differences, Carbon Price Floor, and Emissions Performance Standard

Contracts for Differences (CfD) were tied in the UK Energy Bill in 2013. They consist of a strike price for different low-carbon technologies resembling a fixed feed-in tariff. Generators take part in the normal electricity market but receive top-up payments from the government if the achieved prices are lower than the strike price. The government, on the other hand, receives equivalent payments from the generator if the market price exceeds the strike price. CfD and inherent strike prices are fixed for the duration of the contract. The long-term target of the CfD scheme is to find the most competitive carbon neutral technologies. In the short run, strike price levels are decided on in a technology-specific administrative negotiation process. In the long run, it is envisioned to determine a common strike price via a technology-neutral auction.

The UK government hopes that CfD enhance future investments as feed-in tariffs reduce the risk of market prices and gives incentives for cost reductions. Technologies that

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[69] The specifics of a possible capacity market in the UK are not clear yet and were therefore not included in this case study.

should be supported through CfD are various kinds of renewables (e.g. on-/offshore wind, PV, tidal, etc.) but also CCTS and nuclear. International dissent exists especially for the latter. Critics argue that a CfD for nuclear energy resembles an illegal subsidy tailored for the newly planned "Hinkley Point" project. The European Commission (EC) regulation requires implementation for an entire technology and accessibility for all possible investors. The nuclear sector, on the other hand, is due to its technology and safety specifics only open for a limited number of actors. The EC, however, decided in favour of the project after a formal investigation in October 2014, which might also have an effect on nuclear policies in other countries (Černoch and Zapletalová, 2015).

The UK introduced a Carbon Price Floor (CPF) of 16 £/tCO_2 (around 20 €/tCO_2) for the electricity generators in 2013 to reduce uncertainty for investors. The CPF consists of the EU-ETS CO_2 price and a variable climate change levy on top (carbon price support (CPS)). Forecasting errors in predicting the price of EU-ETS two years ahead can lead to distortions between the targeted and the final CPF. The climate change levy actually already exists since 2001, but the electricity sector used to be exempted from it. In 2013, the levy is expected to generate around £1 bn in the year 2013 (Ares, 2014).

Initially, the CPF was planned to be gradually increasing to reach a target price of 30 £/tCO_2 (around 38 €/tCO_2) in 2020 and 70 £/tCO_2 (around 88 €/tCO_2) in 2030. A constantly rising minimum price should ensure increasing runtimes for low-carbon technologies such as renewables, nuclear and CCTS as fossil based electricity generation becomes more expansive due to their CO_2 emissions. The British minister for finance, however, announced in March 2014 that the CPF will be frozen at a level of 18 £/tCO_2 (around 23 €/tCO_2) until 2019/20 (Osborne, 2014). The reason for this decision was the increasing discrepancy between the CPF and the EU-ETS CO_2 emission price, lowering the competitiveness of British firms. It is yet unclear, how the CPF will evolve after 2020; depending probably largely on the effect of the upcoming structural reform of the EU-ETS. The CPS only has an effect on the British electricity sector. Neither is the combustion of natural gas for heating or cooking nor are electricity imports from neighboring countries affected by this instrument. The latter is also the main reason why the CPS has not been implemented in Northern Ireland which is part of the single electricity market in Ireland. (Pollitt and Haney, 2013)

Another instrument implemented in the Energy Bill is the CO_2 Emissions Performance Standard (EPS) (The Parliament of Great Britain, 2013). It limits the maximal annual CO_2 emission of newly built or retrofitted electricity units to the ones of an average gas-fired power plant without carbon capture. Plants with higher carbon intensities like coal-fired units either have to reduce their load factor or install capture facilities for parts of their emissions. The EPS for a unit can be calculated by multiplying its capacity with 450 gCO_2/kWh times 7,446 h (equivalent to a 0.85 load factor and 8,760h per year). This results in an annual CO_2 budget of 3,350 tCO_2/MW, restricting a coal-fired unit with emissions of 750 g/kWh to a maximal load factor of 0.5 or 4,470 h per year. The goal of this regulation is to foster investment in new gas power plants as well as power plants with capturing units. Power plants with capture units are additionally exempted from EPS for the first three years of operation to optimize their production cycles. Special exemptions exist for biomass emissions of plants below 50 MW related to heat production and in the case of temporary energy shortage.

7.3.2 Data input

Electricity generation capacities as well as data for investment cost, variable cost, fixed cost, availability and life time assumptions are taken from DECC (2014b, 2013a). We assume a linear cost reduction over time for the investment cost according to Schröder et al. (2013a); variable and fixed cost remain constant. The costs are independent from power plant location; but availabilities of renewables do vary. Industrial CO_2 emissions and their location are taken from studies concentrating on CCTS adoption in the UK industry sector (Element Energy et al., 2014; Houses of Parliament, 2012). Capturing costs in the industry sector as well as costs for CO_2 storage and CO_2-EOR application are taken from Mendelevitch (2014). The fix costs are included in the variable capturing costs.

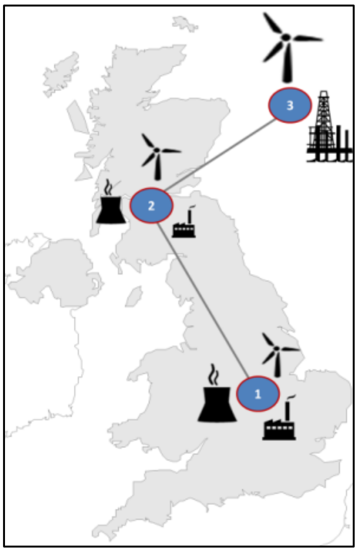

Figure 43: Simplified network

The simplified representation used for this case study consists of three nodes (see Figure 43). Node 1 and 2 represent the Northern and Southern part of the UK with their power plants and industrial facilities. A third offshore node resembles possible locations for offshore wind parks as well as CO_2 storage with and without CO_2-EOR in the North Sea. We assume electricity and CO_2 pipeline connections between node 1 and 2 as well as between node 2 and node 3. We assume a simplified electricity grid neglecting congestion between nodes in this scenario. In addition, no exchange with the neighboring countries is allowed. CO_2 pipelines can endogenously be constructed between adjacent nodes.

The CPF is assumed to remain constant at 18 £/tCO_2 (around 23 €/tCO_2) until 2020. We assume the CO_2 price to increase due to the effects of the structural reform of the EU-ETS. CPF and CO_2 price are thus assumed to have the same level from 2030 onwards, rising linearly from €35 in 2030 to €80 in 2050. We include the given price projections for the strike prices in 2015 and 2020 DECC (2013b). These technology specific differences will be linearly reduced until 2030. Starting from 2030 all technologies under the CfD will be given the same financial support via an endogenous auctioning system. The EPS is set at a level of 450 g/kWh. An annual CO_2 emissions reduction of 1% in the electricity sector is implemented leading to 90% emissions reduction in 2050 compared to 1990. No specific RES target is set. The discount rate is 5% for all players. The oil price is expected to remain at its current level of 65 €/bbl.

The annual load duration curve of UK is approximated by five weighted type hours, assuming a demand reduction of 20% till 2050 (base year 2015). This simplification does not allow for demand shifting nor energy storage in between type hours. CO_2 emissions from industrial sources are assumed to decline by 40% until 2050. The lifetime of the existing power plant fleet varies by technology between 25 (most renewables), 40 (gas) and 50 (coal, nuclear, and hydro) years.

7.3.3 Case study results

This simplified base case was created to show the characteristics and features of the ELCO model. Its results should not be over-interpreted but give an idea of the potential of the model, once its complete data set is calibrated.

The implementation of the various policy measures leads to a diversified electricity portfolio in 2050: with no specific RES target in place, renewables account for 46% of generation, gas (26%), nuclear (15%), and CCTS (13%). The majority of the investments in new renewable capacity happen before 2030. Less favorable regional potentials and technologies such as PV are only used in later periods. The implemented incentive mechanism is comparable to an auctioning system of "uniform pricing" where the last bidder sets the price. The average payments for low-carbon technologies are in the range of 80 to 110 €/MWh but depend strongly on the assumptions for learning curves and technology potentials. Different allocation mechanisms such as "pay as bid" might lower the overall system costs.

The share of coal-fired energy production is sharply reduced from 39% in 2015 to 0% in 2030 due to a phasing-out of the existing capacities (see Figure 44). New investments in fossil capacities occur for gas-fired CCGT plants, which are built from 2030 onwards. EPS hinders the construction of any new coal-fired power plant without CO_2 capture. Sensitivity analysis shows that a change of its current level of 450 g/kWh in the range of 400-500 g/kWh has only little effect: Gas-fired power plants would still be allowed sufficient run-time hours while coal-fired plants remain strongly constrained. The overall capacity of nuclear power plants is slightly reduced over time.[70] The share of renewables in the system grows continuously from 20% in 2015 to 30% in 2030 and 46% in 2050. Wind off- (41% in 2050) and onshore (25% in 2050) are the main renewable energy sources followed by hydro and biomass (together 27% in 2050).

CO_2-EOR creates additional returns for CCTS deployment through oil sales. These profits trigger investments in CCTS regardless of additional incentives from the energy market. The potential for CO_2-EOR is limited and will be used to its full extent until 2050. The maximum share of CCTS in the electricity mix is 16% in 2045. The combination of assumed ETS and oil price also triggers CCTS deployment in the industry sector from 2020 onwards (see Figure 45). The industrial CO_2 capture rate, contrary to the electricity sector, is constant over all type hours. The storage process requires a constant injection pressure, especially when connected to a CO_2-EOR operation. This shows the need for intermediate CO_2 storage to enable a continuous storage procedure and should be more closely examined in further studies. From 2030 onwards, emissions in the industrial sector are captured with the maximum possible capture rate of 90%. The usage of saline aquifers as well as depleted oil and gas fields is not beneficial assuming a CO_2 certificate price of 80 €/tCO_2 in 2050.

[70] This is influenced through the diffusion constraint which limits the maximal annual construction, esp. in early periods.

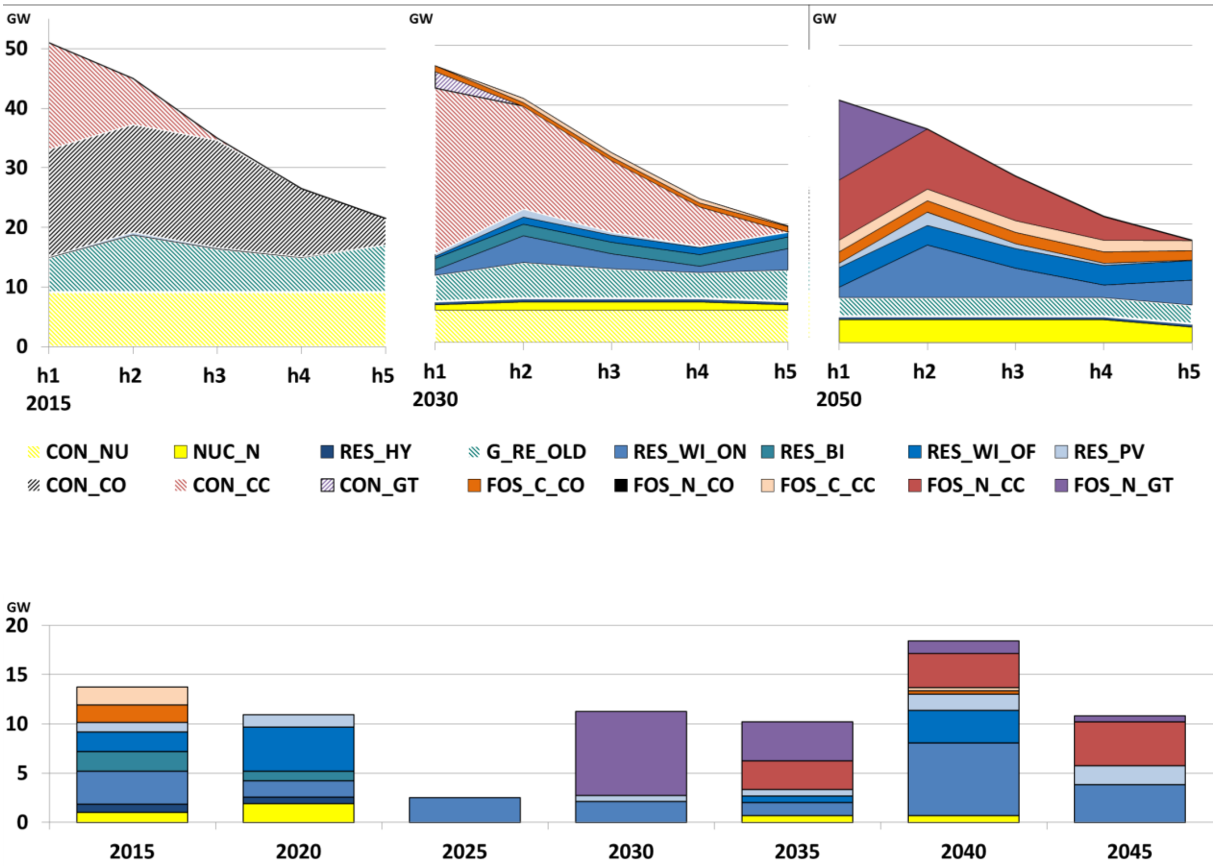

Figure 44: Electricity generation (top) and power plant investment (bottom) from 2015-2050.

Source: ELCO model results.

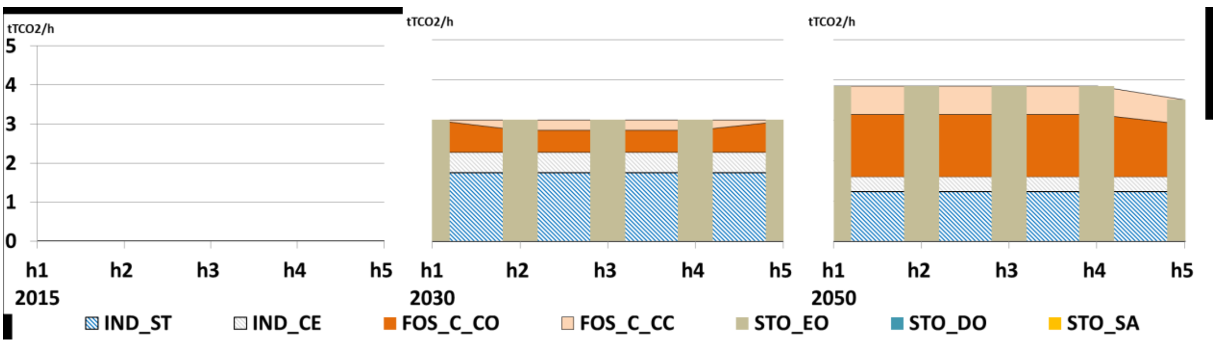

Figure 45: CO_2 capture by electricity and industrial sector (area) and CO_2 storage (bars) in 2015, 2030 and 2050

Source: Own modeling results with the ELCO model.

7.4 Conclusion: findings of an integrated electricity-CO_2 modeling approach

This chapter presents a general electricity-CO_2 modeling framework (ELCO model) that is able to simulate interactions of the energy-only market with different forms for national policy measures as well as a full representation of the carbon capture, transport, and storage (CCTS) chain. Different measures included in the model are feed-in tariffs, a minimum CO_2 price and Emissions Performance Standards (EPS). Additionally, the model includes large point industrial emitters from the iron and steel as well as cement sector that might also invest in carbon capture facilities, increasing scarcity for CO_2 storage. Therefore, the modeling framework mimics the typical issues encountered in coal-based electricity systems that are now entering into transition to a low-carbon generation base. The model can be used to examine the effects of different envisioned policy measures and evaluate policy trade-off.

This chapter is used to describe the different features and potentials of the ELCO model. Such characteristics can easily be examined with a simplified model, even though its quantitative results should not be over-interpreted. As further development steps we need to test the robustness of the equilibrium results with sensitivity analysis while increasing the regional and time resolution of the model.

The results of the case study on the UK electricity market reform (EMR) present a show case of the model framework. It incorporates the unique combination of a fully represented CCTS infrastructure and a detailed representation of the electricity sector in UK. The instruments of the UK EMR, like EPS, CfD and CPF are integrated into the framework. Also we take into account demand variation in type hours, the availability of more and less favorable locations for RES and limits for their annual diffusion. The model is driven by a CO_2 target and an optional RES target.

The next steps are to compare the costs of different incentive schemes and to analyze their effects on the deployment of different low-carbon technologies, with a special focus on CCTS with and without the option for CO_2-enhanced oil recovery (CO_2-EOR). The role of industry CCTS needs to be further considered in this context. Additionally, we plan to study the feedback effects between the CfD scheme and the electricity price, and investigate the incentives of the government which acts along the three pillars of energy policy: cost-efficiency, sustainability and security; in a two-level setting. This also includes calculating the system integration costs of low-carbon technologies. A more detailed representation of the electricity transmission system operator (TSO) as market organizer helps doing so by separating financial and physical flows. The TSO is on the one hand responsible to guarantee supply meeting demand at any time and on the other hand reimburses CfD technologies for curtailment. At a later stage, we want to use the model for more realistic case studies to draw conclusions and possible policy recommendations for low-carbon support schemes in the UK as well as in other countries.

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9 Appendix for Individual Chapters

9.1 Chapter 3: Additional data and results

Table 28: Definition of indices, parameters, and variables of CCTS-Mod

Indices	Description
Sets	
a,b	Model period
D	Pipeline diameter [m]
i,j	Node
P	Individual CO_2 producer
S	Individual CO_2 storage site
Parameters	
c_ccs_{Pa}	Variable costs of CO_2 capture for producer P [€/t CO_2 per year]
c_f	CO_2 flow costs [€/t CO_2 per year]
$c\_inv\_f_d$	Pipeline investment costs [€/km*m (diameter)]
$c\_inv\_x_P$	Investment costs of CO_2 capture for producer P [€/t CO_2 per year]
$c\_inv\_y_{Sa}$	Investment costs for storage in sink S [€/t CO_2 per year]
c_plan	Pipeline planning and development costs [€/km]
cap_d_d	Capacity of a pipeline with diameter d [t CO_2/a]
cap_stor	Storage capacity of sink S [t CO_2]
capt_rate	Capture rate for CO_2 capture [in these scenarios: 90%]
$cert_a$	CO_2 certificate price [€/ t CO_2]
$CO2_{Pa}$	Total annual quantity of CO_2 produced by producer P [t CO_2]
E_{ij}	Distance matrix of possible connections between nodes i and j
$match\_P_{Pj}$	Mapping of producer P to node j {0;1}
$match\_S_{Sj}$	Mapping of sink S to node j {0;1}
max_pipe	Maximum number of pipelines built along planned route
r	Rate of interest [%]
start	Starting year of the model
$year_a$	Starting year of the model period a
Variables	
f_{ija}	CO_2 flow from node i to j [t CO_2/a]
inv_f_{ijda}	Investment in additional pipeline capacity with diameter d
inv_x_{Pa}	Investment in additional CO_2 capture capacity from producer P [t CO_2/a]
inv_y_{Sa}	Investment in additional injection capacity of sink S [t CO_2/a]
$plan_{ija}$	Pipeline planning and development between nodes i and j
x_{Pa}	Quantity of CO_2 captured by producer P [t CO_2/a]
y_{Sa}	Quantity of CO_2 stored per year in sink S [t CO_2/a]
z_{Pa}	Quantity of unabated CO_2 emitted into the atmosphere [t CO_2/a]

Table 29: Estimated CO_2 storage potential

Country	**Saline Aquifer [GT CO_2]**	**Depleted Gasfield [GT CO_2]**	**Offshore Aquifer [GT CO_2]**	**Offshore Gasfield [GT CO_2]**	**Total [GT CO_2]**
Austria	2.30				2.30
Belgium	0.30				0.30
Bulgaria	1.70				1.70
Bosnia and Herzegovina	0.20				0.20
Czech Republic	0.70				0.70
Germany	3.80	1.60	1.20		6.60
Denmark			2.50		2.50
Spain	11.00		3.50		14.50
France	5.70				5.70
Greece	0.30				0.30
Croatia	2.80				2.80
Hungary	0.20				0.20
Ireland	2.00		1.30		3.30
Italy	5.50				5.50
Latvia			1.30		1.30
Macedonia	0.30				0.30
The Netherlands		0.70		0.50	1.20
Norway			1.90	11.90	13.80
Poland	3.70	0.70	3.50		7.90
Romania	0.40				0.40
United Kingdom			14.40	7.80	22.20
Total	40.90	3.00	29.60	20.20	93.70

Source: Own calculations based on various studies (Ainger et al., 2010; Bentham, 2006; Bentham et al., 2008; Brook et al., 2009; GeoCapacity, 2009; Greenpeace, 2011, p. 20; Hazeldine, 2009; Radoslaw et al., 2009).

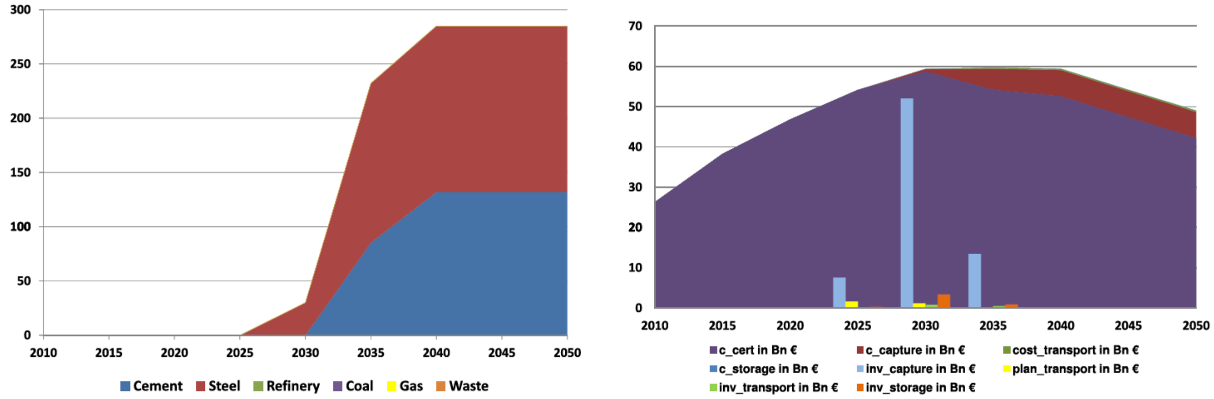

Figure 46: Storage by sector in MtCO₂ and infrastructure investment and variable costs in €bn, On50

Source: Own depiction.

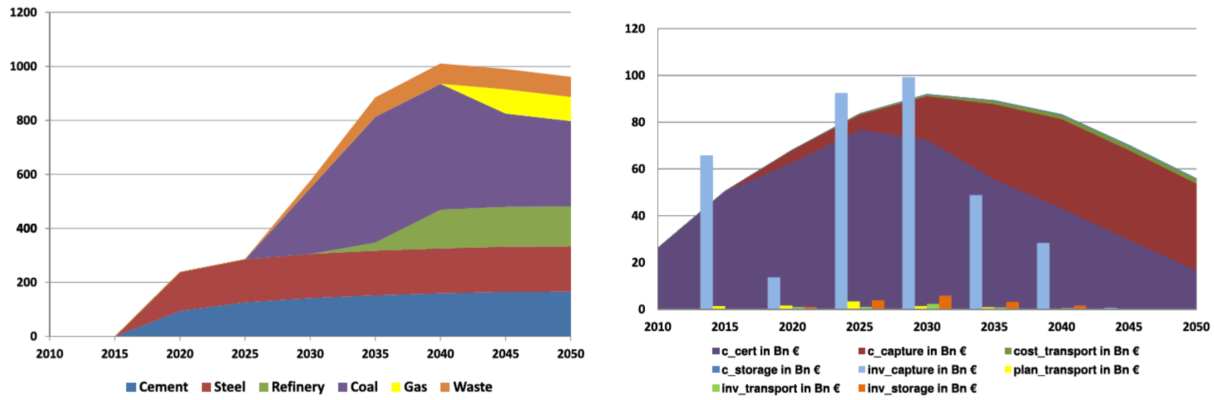

Figure 47: Storage by sector in MtCO₂ and infrastructure investment and variable costs in €bn, On100

Source: Own depiction.

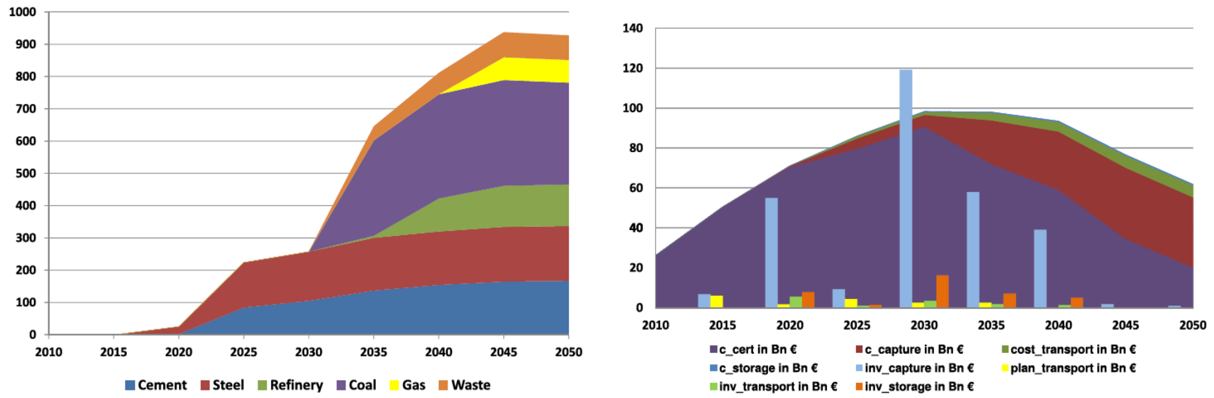

Figure 48: Storage by sector in MtCO₂ and infrastructure investment and variable costs in €bn, Off100

Source: Own depiction.

9.2 Chapter 6: List of electricity grid expansions until 2030

The following two tables are a list of additional lines which were exogenously implemented in the 2030 reference AC and DC grid.

Table 30: Additions to the AC grid until 2030

In Germany

From	To	Type
Ganderkesee	St. Hülfe	380kV
Vieselbach	Altenfeld	380kV
Altenfeld	Redwitz	380kV
Diele	Niederrhein	380kV
Wahle	Mecklar	380kV
Hamburg	Dollern	380kV
Wehrendorf	Gütersloh	380kV
Kruckel	Dauersberg	380kV

International

From	To	Type
Aldeadávila (ES)	Lagoaça (PT)	new 400 kV line
Guillena (ES)	Tavira (PT)	new 400 kV line
Moulaine (FR)	Aubange (BE)	new 220 kV line
Bressanone (IT)	Innsbruck (AT)	new 400 kV line
Okroglo (SI)	Udine (IT)	new 400 kV line
Lavorgo (CH)	Morbegno (IT)	new 400 kV line
Cornier (FR)	Piossasco (IT)	new 400 kV line
Hurva/Hallsberg (SE)	Barkeryd (NO)	new 400 kV line
St. Peter (AT)	Isar (DE)	new 380 kV
Krajnik (PL)	Neuenhagen (DE)	new 400 kV line
Plewiska (PL)	Eisenhüttenstadt (DE)	upgrade to 400 kV
Doetinchem (NL)	Niederrhein (DE)	new 400 kV line

Source: ENTSOE-E (2010) and Bundesregierung (2011b).

Table 31: Additions to the DC grid until 2030

Name	From - To	Capacity [MW]
NORNED	Netherlands - Norway	700
Baltic Cable	21 - Sweden	600
Kontek	81 - Denmark East	600
Kontiskan 2	Denmark West - Sweden	300
Skagerrak 1+2	Denmark West - Norway	500
SwePol	Poland - Sweden	600
IFA	Great Britain - France	2000
BirtNed	Great Britain - Netherlands	1000
Norwegian Interconnector	Great Britain - Norway	1400
Storebaelt	Denmark West - Denmark East	600
Nord.Link	22 - Norway	1400
NORNED2	Netherlands - Norway	700
NordSüd1	21 - 25	2000
NordSüd2	25 - 26	2000
NordSüd3	21 - 22	2000
OstWest1	81 - 24	2000
OstWest2	24 - 75	2000
Südwest	72 - 42	2000
Skagerrak 3	Denmark West - Norway	440
Skagerrak 4	Denmark West - Norway	700
East-West-Energy Bridge (Siemens)	81 - Poland	500
COBRA	Denmark West - Netherlands	700
NEMO	Great Britain - Belgium	1000
IFA 2	Great Britain - France	1000
Gunfleet Sands1	Great Britain - Netherlands	1000
Gunfleet Sands2	Great Britain - Belgium	1000
Nordseeplattformen UK - Dollert (Emden)	Great Britain - 22	1000
Nordseeplattformen - Dänemark	22 - Denmark West	2000
SwePol 2	Poland - Sweden	600
Balltic Cable 2	21 - Sweden	600
Ostseeplattformen - Schweden	81 - Sweden	600
Ostseeplattformen - Dänemark	81 - Denmark East	600
TYNDP - Sta. Llogaia (ES) - Baixas (FR)	Spain - France	2000
TYNDP - Grande Ile (FR) Piossasco (IT)	France - Italy	1000
TYNDP - Candia (IT) - Konjsko (HR)	Croatia - Italy	1000

Source: ABB Asea Brown Boveri Ltd. (2011), Edwards (2010), and La Tene Maps (2011).

9.3 Chapter 7: Karush-Kuhn-Tucker conditions of the ELCO model

9.3.1 The electricity sector

$$\frac{\partial L^{T,N}}{\partial g_{h,n,t,a}}:$$

$$0 \le \left(\begin{array}{l} DF_a \cdot PD_a \cdot TD_h \cdot \left(\begin{array}{l} -mu\_e_{h,n,a} \\ +EF\_EL_t \cdot (1-CR\_G_t)\cdot(CPS_a + EUA_a) \\ +VC\_G_{n,t,a} + INTC\_G_t \cdot g_{h,n,t,a} \\ -\lambda_a^{target\_CO2} \cdot \alpha_{t,a} \end{array} \right) \\ +TD_h \cdot \lambda_{n,t,a}^{emps} \cdot EF\_EL_t \cdot (1-CR\_G_t) + \lambda_{h,n,t,a}^{cap\_g} + \lambda_{h,a}^{curt\_el} \end{array} \right) \perp \quad g_{h,n,t,a} \ge 0 \tag{61}$$

$$\frac{\partial L^{T,N}}{\partial g\_\mathrm{cfd}_{h,n,t,aa,a}}:$$

$$\begin{array}{l} 0 \le DF_a \cdot PD_a \cdot TD_h \cdot \left(\begin{array}{l} -SP_{t,aa} - \sum\limits_{aaa \in I\_USE_{t,aa,aaa}} \alpha_{t,aaa} \cdot \lambda_{aaa}^{target\_co2} \\ - \sum\limits_{\substack{aaa \in I\_USE\_EL_{t,aa,aaa}, \\ t \in T\_RES}} \left[(1-TARGET\_RE_{aaa}) \cdot \lambda_{aaa}^{target\_RE} \right] \\ + \sum\limits_{\substack{aaa \in I\_USE\_EL_{t,aa,aaa}, \\ t \notin T\_RES}} \left[TARGET\_RE_{aaa} \cdot \lambda_{aaa}^{target\_RE} \right] \\ +EF\_EL_t \cdot (1-CR\_G_t)\cdot(CPS_a + EUA_a) \\ +EF\_EL_t \cdot CR\_G_t \cdot mu\_co2_{h,n,a} \\ +VC\_G_{n,t,a} + INTC\_G_t \cdot g\_cfd_{h,n,t,aa,a} \end{array} \right) \\ +TD_h \cdot \sum\limits_{tt \in ONEFUEL_{tt,t}} \lambda_{n,tt,a}^{emps} \cdot EF\_EL_t \cdot (1-CR\_G_t) + \lambda_{h,n,t,aa,a}^{cap\_g\_cfd} + \lambda_{h,a}^{curt\_el} \\ +TD_h \cdot \lambda_{t,a}^{diff\_g} - TD_h \cdot DIFF\_G_t \cdot \left(\lambda_{t,a+1}^{diff\_g} + \lambda_{t,a+2}^{diff\_g} \right) \quad \perp \quad g\_cfd_{h,n,t,aa,a} \ge 0 \end{array} \tag{62}$$

$$\frac{\partial L^{T,N}}{\partial inv\_g_{n,t,a}}:$$

$$0 \le \left[\begin{array}{l} \sum\limits_{aa \in I\_USE\_EL_{t,a,aa}} PD_{aa} \cdot DF_{aa} \cdot \left(FC\_G_{n,t,aa} + INVC\_G_{n,t,aa} \right) \\ -\sum\limits_h TD_h \cdot AVAIL_{h,n,t} \cdot EMPS_a \cdot \sum\limits_{\substack{aa \in I\_USE\_EL_{t,a,aa} \\ tt \in ONEFUEL_{tt,t}}} \lambda_{n,tt,aa}^{emps} \\ -\sum\limits_h \sum\limits_{aa \in I\_USE\_EL_{t,a,aa}} \left(AVAIL_{h,n,t} \cdot \lambda_{h,n,t,aa}^{cap\_g} \right) \\ -\sum\limits_h \sum\limits_{aa \in USE\_EL_{t,a,aa}} \left(AVAIL_{h,n,t} \cdot \lambda_{h,n,t,a,aa}^{cap\_g\_cfd} \right) \\ + \sum\limits_{aa \in I\_USE\_EL_{t,a,aa}} \lambda_{n,t,aa}^{pot\_g} \end{array} \right] \perp \quad inv\_g_{h,n,t,a} \ge 0 \tag{63}$$

$$\frac{\partial L^{T,N}}{\partial \lambda_{n,t,a}^{emps}}:$$

$$0 \le \begin{pmatrix} \sum_h TD_h \cdot AVAIL_{h,n,t} \cdot \sum_{\substack{aa \in USE\_EL_{t,a,aa}, \\ (t,tt) \in ONE\_FUEL_{t,tt}}} inv\_g_{n,tt,aa} \cdot EMPS_{aa} \\ -\sum_h TD_h \cdot \begin{bmatrix} \left[g_{h,n,t,a} \cdot \left(EF\_EL_t \cdot (1 - CR\_G_t) \right) \right] \\ + \sum_{\substack{aa \in USE\_EL_{t,a,aa}, \\ (t,tt) \in ONE\_FUEL_{t,tt}}} \left[g\_cfd_{h,n,tt,aa,a} \cdot \left(EF\_EL_{tt} \cdot (1 - CR\_G_{tt}) \right) \right] \end{bmatrix} \end{pmatrix} \perp \lambda_{n,t,a}^{emps} \ge 0 \tag{64}$$

$$\frac{\partial L^{T,N}}{\partial \lambda_{h,n,t,a}^{cap\_g}}:$$

$$0 \le AVAIL_{h,n,t} \cdot \left(INICAP\_G_{n,t,a} + \sum_{aa \in USE\_EL_{t,a,aa}} inv\_g_{n,t,aa} \right) - g_{h,n,t,a} \quad \perp \quad \lambda_{h,n,t,a}^{cap\_g} \ge 0 \tag{65}$$

$$\frac{\partial L^{T,N}}{\partial \lambda_{h,n,t,aa,a}^{cap\_g\_cfd}}:$$

$$0 \le AVAIL_{h,n,t} \cdot inv\_g_{n,t,aa} - g\_cfd_{h,n,t,aa,a} \quad \perp \quad \lambda_{h,n,t,aa,a}^{cap\_g\_cfd} \ge 0 \tag{66}$$

$$\frac{\partial L^{T,N}}{\partial \lambda_{n,t,a}^{pot\_g}}:$$

$$0 \le MAX\_INV_{n,t} - \sum_{aa \in USE\_EL_{t,a,aa}} inv\_g_{n,t,aa} \quad \perp \quad \lambda_{n,t,a}^{pot\_g} \ge 0 \tag{67}$$

$$\frac{\partial L^{T,N}}{\partial \lambda_{t,a}^{diff\_g}}:$$

$$0 \le \left(START\_G_t \cdot \frac{\sum_{h,n} AVAIL_{h,n,t} \cdot TD_h}{\#of\ nodes} + \left[\sum_{h,n,aa} TD_h \cdot \left(g\_cfd_{h,n,t,aa,a-1} + g\_cfd_{h,n,t,aa,a-2} \right) \right] \right) \cdot DIFF\_G_t - \sum_{h,n,aa} TD_h \cdot g\_cfd_{h,n,t,aa,a} \quad \perp \quad \lambda_{t,a}^{diff\_g} \ge 0 \tag{68}$$

9.3.1.1 Shared environmental constraints for the electricity sector

$$0 \le PD_a \cdot \sum_{h,n,t} TD_h \cdot \left[\left(g_{h,n,t,a} + \sum_{aa \in USE\_EL_{t,a,aa}} g\_cfd_{h,n,t,aa,a} \right) \cdot \alpha_{t,a} \right] \quad \perp \quad \lambda_a^{target\_co2} \ge 0 \qquad (69)$$

$$0 \le PD_a \cdot \sum_{h,n} TD_h \cdot \left[\begin{array}{l} \sum\limits_{\substack{aa \in USE\_EL_{t,a,aa}, \\ t \in T\_RES}} g\_cfd_{h,n,t,aa,a} + RES\_OLD_{h,n,a} \\ -RE\_TARGET_a \cdot \sum\limits_{h,n} d_{h,n,a} \end{array} \right] \quad \perp \quad \lambda_a^{target\_RE} \ge 0 \qquad (70)$$

9.3.2 The electricity transportation utility

$$\frac{\partial L^{TSO\_E}}{\partial el\_t}:$$
$$0 \le DF_a \cdot PD_a \cdot TD_h \cdot \left(mu\_el_{h,n,a} - mu\_el_{h,nn,a} + VC\_EL\_T_{n,nn} \right) + \lambda_{h,n,nn,a}^{cap\_el} \quad \perp \quad el\_t_{h,n,nn,a} \ge 0 \qquad (71)$$

$$\frac{\partial L^{TSO\_E}}{\partial inv\_el\_t}:$$
$$0 \le \sum_{aa>a} PD_{aa} \cdot \left(DF_{aa} \cdot INVC\_EL\_T_{n,nn} \right) - ADJ\_EL_{n,nn} \cdot \sum_{h} \sum_{aa>a} \left(\lambda_{h,n,nn,aa}^{cap\_el\_t} + \lambda_{h,nn,n,aa}^{cap\_el\_t} \right) \quad \perp \quad inv\_el\_t_{h,n,nn,a} \ge 0 \qquad (72)$$

$$\frac{\partial L^{TSO\_E}}{\partial \lambda_{h,n,nn,a}^{cap\_el\_t}}:$$
$$0 \le INICAP\_EL\_T_{n,nn} + \sum_{aa<a} \left(ADJ\_EL_{n,nn} \cdot inv\_el\_t_{n,nn,aa} + ADJ\_EL_{nn,n} \cdot inv\_el\_t_{nn,n,aa} \right) - el\_t_{h,n,nn,a}$$
$$\perp \quad \lambda_{h,n,nn,a}^{cap\_el\_t} \ge 0 \qquad (73)$$

9.3.3 The industry sector

$$\frac{\partial L^{I,N}}{\partial co2\_c_{h,n,i,a}}: \qquad \perp \quad co2\_c_{h,n,i,a} \geq 0$$
$$0 \leq DF_a \cdot PD_a \cdot TD_h \cdot \left(-EUA_a + mu\_co2_{h,n,a} + VC\_CO2_{n,i,a}\right) + \lambda_{h,n,i,a}^{max\_ind} + \lambda_{h,n,i,a}^{cap\_co2\_c} \tag{74}$$

$$\frac{\partial L^{I,N}}{\partial inv\_co2\_c_{n,i,a}}:$$
$$0 \leq \left[\begin{array}{l} \sum\limits_{aa \in I\_USE\_CO2_{i,a,aa}} PD_{aa} \cdot DF_{aa} \cdot \left(FC\_CO2_{n,i,aa} + INVC\_CO2_{n,i,aa}\right) \\ -\sum\limits_{h} \sum\limits_{aa \in I\_USE\_CO2_{i,a,aa}} \lambda_{h,n,i,aa}^{cap\_co2\_c} \cdot CR\_IND_i \\ +\lambda_{i,a}^{diff\_co2\_c} - \sum\limits_{aa>a} \left(\lambda_{i,aa}^{diff\_co2\_c} \cdot DIFF\_CO2_i\right) \end{array}\right] \quad \perp \quad inv\_co2\_c_{n,i,a} \geq 0 \tag{75}$$

$$\frac{\partial L^{I,N}}{\partial \lambda_{h,n,i,a}^{max\_ind}}: \tag{76}$$
$$0 \leq CO2\_IND_{h,n,i,a} \cdot CR\_IND_i - co2\_c_{h,n,i,a} \quad \perp \quad \lambda_{h,n,i,a}^{max\_ind} \geq 0$$

$$\frac{\partial L^{I,N}}{\partial \lambda_{h,n,i,a}^{cap\_co2\_c}}: \tag{77}$$
$$\sum_{aa \in USE\_CO2_{i,a,aa}} inv\_co2\_c_{n,i,aa} \cdot CR\_IND_i - co2\_c_{h,n,i,a} \quad \perp \quad \lambda_{h,n,i,a}^{cap\_co2\_c} \geq 0$$

$$\frac{\partial L^{I,N}}{\partial \lambda_{i,a}^{diff\_co2\_c}}:$$
$$0 \leq \left(START\_CO2_i + \sum_n \sum_{aa<a} inv\_co2\_c_{n,i,aa}\right) \cdot DIFF\_CO2_i - \sum_n inv\_co2\_c_{n,i,a} \quad \perp \quad \lambda_{i,a}^{diff\_co2\_c} \geq 0 \tag{78}$$

9.3.4 The CO_2 transportation utility

$$\frac{\partial L^{TSO\_CO2}}{\partial co2\_t_{h,n,nn,a}}:$$
$$0 \le DF_a \cdot PD_a \cdot TD_h \cdot \left(mu\_co2_{h,nn,a} - mu\_co2_{h,n,a} + VC\_CO2\_t_{n,nn}\right) + \lambda_{h,n,nn,a}^{cap\_co2\_t} \quad \perp \quad co2\_t_{h,n,nn,a} \ge 0 \tag{79}$$

$$\frac{\partial L^{TSO\_E}}{\partial inv\_co2\_t}:$$
$$0 \le \sum_{aa>a} PD_{aa} \cdot \left(DF_{aa} \cdot INVC\_CO2\_T_{n,nn}\right) - ADJ\_CO2_{n,nn} \cdot \sum_{h} \sum_{aa>a} \left(\lambda_{h,n,nn,aa}^{cap\_co2\_t} + \lambda_{h,nn,n,aa}^{cap\_co2\_t}\right)$$
$$\perp \quad inv\_co2\_t_{h,n,nn,a} \ge 0 \tag{80}$$

$$\frac{\partial L^{TSO\_E}}{\partial \lambda_{h,n,nn,a}^{cap\_co2\_t}}:$$
$$0 \le INICAP\_CO2\_T_{n,nn} + \sum_{aa<a} \left(ADJ\_CO2_{n,nn} \cdot inv\_co2\_t_{n,nn,aa} + ADJ\_CO2_{nn,n} \cdot inv\_co2\_t_{nn,n,aa}\right)$$
$$-co2\_t_{h,n,nn,a} \quad \perp \quad \lambda_{h,n,nn,a}^{cap\_co2\_t} \ge 0 \tag{81}$$

9.3.5 The CO_2 storage sector

$$\frac{\partial L^{S,N}}{\partial co2\_s_{h,n,s,a}}:$$
$$0 \le \begin{bmatrix} DF_a \cdot PD_a \cdot TD_h \cdot \begin{pmatrix} -EFF\_CO2 \cdot OILPRICE_a \\ -mu\_co2_{h,n,a} + VC\_CO2_{n,s,a} + INTC\_S_t \cdot co2\_s_{h,n,s,a} \end{pmatrix} \\ + \sum_{hh} TD_{hh} \cdot \left(\sum_{aa \ge a} PD_{aa} \cdot \lambda_{n,s,aa}^{max\_stor}\right) + \lambda_{h,n,s,a}^{cap\_co2\_s} \end{bmatrix} \quad \perp \quad co2\_s_{h,n,s,a} \ge 0 \tag{82}$$

$$\frac{\partial L^{S,N}}{\partial inv\_co2\_s_{n,s,a}}:$$
$$0 \le \begin{bmatrix} \sum_{aa \in I\_USE\_CO2_{s,a,aa}} PD_{aa} \cdot DF_{aa} \cdot \left(FC\_CO2_{n,s,aa} + INVC\_CO2_{n,s,aa}\right) \\ -\sum_{h} \sum_{aa \in I\_USE\_CO2_{s,a,aa}} \lambda_{h,n,s,aa}^{cap\_co2\_s} + \lambda_{s,a}^{diff\_co2\_s} - \sum_{aa>a} \left(\lambda_{s,aa}^{diff\_co2\_s} \cdot DIFF\_CO2_s\right) \end{bmatrix} \quad \perp \quad inv\_co2\_s_{n,s,a} \ge 0 \tag{83}$$

$$\frac{\partial L^{S,N}}{\partial \lambda_{h,n,s,a}^{cap\_co2\_s}}:$$
$$0 \le \sum_{aa \in USE\_CO2_{s,a,aa}} inv\_co2\_s_{n,s,aa} - co2\_s_{h,n,s,a} \quad \perp \quad \lambda_{h,n,s,a}^{cap\_co2\_s} \ge 0 \tag{84}$$

$$\frac{\partial L^{S,N}}{\partial \lambda_{n,s,a}^{\max\_stor}}:$$
$$0 \le MAX\_STOR_{n,s} - \sum_{h}\left(TD_h \cdot \sum_{aa \le a} PD_{aa} \cdot co2\_s_{h,n,s,aa}\right) \quad \perp \quad \lambda_{n,s,a}^{\max\_stor} \ge 0 \tag{85}$$

$$\frac{\partial L^{S,N}}{\partial \lambda_{s,a}^{diff\_co2\_s}}:$$
$$0 \le \left(START\_CO2_s + \sum_{n}\sum_{aa<a} inv\_co2\_s_{n,s,aa}\right) \cdot DIFF\_CO2_s - \sum_{n} inv\_co2\_s_{n,s,a} \quad \perp \quad \lambda_{s,a}^{diff\_co2\_s} \ge 0 \tag{86}$$

9.3.6 Market clearing conditions across all sectors

$$0 = \sum_{t}\left(g_{h,n,t,a} + \sum_{aa \in USE\_EL_{t,a,aa}} g\_cfd_{h,n,t,aa,a}\right) + \sum_{nn} el\_t_{h,nn,n,a} - \sum_{nn} el\_t_{h,n,nn,a} - \left(D_{h,n,a} - RES\_OLD_{h,n,a}\right)$$
$$mu\_e_{h,n,a} \ (free) \qquad \forall h,n,a \tag{87}$$

$$\frac{\partial L^{T,N}}{\partial \lambda_{h,a}^{curt\_el}}:$$
$$0 \le \sum_{n}\left(D_{h,n,a} - RES\_OLD_{h,n,a}\right) - \sum_{n,t}\left(g_{h,n,t,a} + \sum_{aa \in USE\_EL_{t,a,aa}} g\_cfd_{h,n,t,aa,a}\right) \quad \perp \quad \lambda_{h,a}^{curt\_el} \ge 0 \tag{88}$$

$$0 = -\left(\begin{array}{r} \sum_{t}\left(\sum_{aa \in USE\_EL_{t,a,aa}} g\_cfd_{h,n,t,aa,a} \cdot EF\_EL_t \cdot CR\_G_t\right) \\ + \sum_{i} co2\_c_{h,n,i,a} \\ + \sum_{nn} co2\_t_{h,nn,n,a} - \sum_{nn} co2\_t_{h,n,nn,a} - \sum_{s} co2\_s_{h,n,s,a} \end{array}\right) \qquad mu\_co2_{h,n,a} \ (free) \qquad \forall h,n,a \tag{89}$$