Modeling transitional measures to drive CCS deployment in the European power sector

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Abstract

The paper presents a modeling study focusing on carbon capture and storage (CCS) as a decarbonization option for European power. In addition, the analysis assesses various support schemes designed to incentivize deployment of demonstration CCS projects. Public grants, feed-in premiums and emission portfolio standards are evaluated. For the analysis, we use a multi-horizon stochastic investment model for the European power system that combines long-term capacity expansion with operational modeling under different load and generation scenarios. The first part of the analysis finds an optimal deployment of 163 GW CCS generation capacity by 2050. The effects of not having a CCS option available are higher emissions, at a higher cost. The analysis of transitional measures shows that co-funding of capital costs is only effective in supporting deployment of demonstration CCS with low fuel costs. Feed-in premiums are found to be the most viable option as it promotes competitiveness of the demonstration plants in the short-term dispatch. The cost of the support schemes had a net present value of 8.7–12.6 bn€ for a 5 GW CCS deployment by 2020. A generator emission performance standard of 225 gCO_2/kWh significantly increased CCS deployment, however, it also resulted in a transitory period with high electricity prices.

1 Introduction

Europe has set ambitious targets for carbon emission reduction in the coming decades. According to the EU Commission's *Roadmap 2050*, the total domestic emissions are to be reduced by 80 % of the 1990's level by 2050, which implies a more or less full decarbonization of the power sector (European Commission, 2011). Carbon capture and storage (CCS) is considered by the EU Commission to be a crucial technology for enabling a cost effective transition to a low carbon European energy system. This was emphasized in the Roadmap 2050 report, and recently confirmed in a separate communication on CCS (European Commission, 2013).

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The anticipated potential of CCS in contributing to long-term emission reduction and climate change mitigation globally is highlighted by IEA's scenario analysis in its annual World Energy Outlook publications. The WEO-2012 report finds that in a 450 ppm stabilization scenario, carbon capture and storage contributes to 17 % emission reduction in the energy sector by 2035, compared to the less ambitious New Policies Scenario (IEA, 2012). For comparison, renewables are found to contribute to a 23 % reduction of energy sector emissions. In a special report released in 2013, IEA explored the consequences of delaying large-scale CCS deployment by ten years, from 2020 to 2030, in a 450 ppm scenario (IEA, 2013). Their conclusion was that the additional global cost of power sector decarbonization would amount to more than $1 trillion.

Nevertheless, despite strong political support at an EU level, and recognition by the IEA as an important technology with significant carbon emission reduction potential, CCS for power generation appears to have a bleak future in Europe for the time being. Several large-scale CCS demonstration projects have been on the drawing board (Global CCS Institute, 2014), but to date, not a single one has been initiated and successfully proven the viability of a complete carbon capture, transportation and storage process for use in commercial power generation.[1] Reasons for the disparity between the optimistic expectation and the disappointing reality for CCS over the last decade is discussed in von Hirschhausen et al. (2012). Three factors are highlighted: resistance against structural change in the industry, overly optimistic assumptions regarding CCS in modeling studies and wrong focus in terms of technologies and sectors by policymakers. Although these explanations have merit in retrospectively understanding why CCS has failed to materialize as a possible low-carbon option, there are other issues which are even more relevant for understanding the current challenge of establishing demonstration projects.

The only technology neutral driver for low-carbon investments in Europe today is the EU Emission Trading System (ETS). Through this system a carbon price is generated, which is intended to increase the competitiveness of low-carbon power generation technologies vis–á–vis fossil technologies. However, the price of EU allowances (EUAs) has seen low levels, well below 20 €/tCO_2 (down to 5 €/tCO_2 mid-2013), since the downturn in the European economy began in 2008. Reduction in economic activity in the EU, influx of offsets (emission reduction projects implemented outside of the EU that can be used to reduce allowance requirements) and policies interacting with the EU ETS such as financial support for renewable technologies are cited as reasons (de Perthuis and Trotignon, 2014).[2] Without a sufficiently high price for allowances, CCS simply will not be competitive. The exact level needed, however, depends on several factors such as the investment cost of CCS projects. As an indicative result, Lohwasser and Madlener (2012) find, using the European power market model HECTOR, that a level above 30 €/tCO_2 is necessary to support investments of coal CCS if the capital costs are 2500 €/kW or higher (which is in line with the capital costs used in the industry report on CCS costs published by ZEP (2011)). Oei et al. (2014) show, using a model where the CCS transport and storage infrastructure expansion is explicitly optimized, that a carbon price of 50 €/tCO_2 in 2050 only leads to industry using CCS. A carbon price level of 75 €/tCO_2 is needed for CCS to play a role

[1] There are currently two CCS facilities operating in Europe, the Sleipner and Snøhvit CO_2 storage projects. However, both projects are dedicated to natural gas processing, not power generation. In 2014 the Boundary Dam CCS Project in Saskatchewan, Canada, became the first commercial CCS (coal) power plant to come in to operation. The plant can generate 115 MW and utilizes the captured CO_2 for enhanced oil recovery (EOR), creating additional revenue streams. Although the successful deployment of the Boundary Dam project is an important milestone on the road towards commercial scale CCS there is still a need to prove applicability of non-EOR CCS for power generation.

[2] Koch et al. (2014) present an empirical analysis of the strength of various explanatory variables used to understand the EU ETS price collapse. They find that traditional theories such as reduced economic activity, RES support policies and the use of offsets are not sufficient to explain the variation in the EU ETS price. As an alternative, lack of credibility is suggested as a possible cause of the price collapse.

in the power sector.

There have been attempts to establish public co-funding of CCS demonstration projects in Europe. At an EU level, two funding programs have been initiated, the European Energy Programme for Recovery (EEPR) and NER300. Six projects have received support from EEPR while no CCS projects were granted funding in the first application round of the NER300. Lupion and Herzog (2013) provide a detailed account of the political process in the EU to establish funding of CCS demonstration projects, and shortcomings of the NER300 in that respect. By the end of 2014 all but two of the EEPR projects, the Don Valley project in the UK and the ROAD project in the Netherlands have been canceled (Global CCS Institute, 2014).

There are several support mechanisms which can be used for CCS as discussed by Groenenberg and de Coninck (2008) and von Stechow et al. (2011). Investment support programs or a guaranteed price for electricity produced, like the feed-in tariffs received by renewables in Germany, are some possible options to help reduce risk for investors and incentivize development. Other more direct control mechanisms can also be used such as imposing strict emission standards, either for single plants or a portfolio of plants. This has already been adopted in the UK Energy Act 2013 where the limit is set to 450 gCO_2/kWh for new power plants operating as baseload, which excludes unabated coal (Energy Act, 2013). In the US, the Environmental Protection Agency (EPA) established, in its Clean Power Plan (CPP), emission performance rates for coal fired and natural gas fired power plants (Environmental Protection Agency, 2015). The rates are set such that unabated coal plants cannot meet the limit, while efficiently run natural gas combined cycle plants can, even without CCS.[3]

In Europe, CCS stakeholders, comprising utilities, environmental NGOs, research institutions, have formed an association called the European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP). In 2012, ZEP published a report recommending a selection of different support schemes to be implemented for CCS in addition to the EU ETS (ZEP, 2012). The message in the report is clear: demonstration projects are a precondition for commercial deployment, and no demonstration projects will be realized without a secure environment for the long-term investments.

In this paper we investigate the potential role of large-scale commercial CCS deployment in a cost efficient decarbonization of the European power sector using an investment model optimizing capacity expansion in power systems. The model used is the European Model for Power system Investments (with high shares of) Renewable Energy (EMPIRE), which is a multi-horizon stochastic programming model (Skar et al., 2016). It considers both long-term and short-term dynamics, by incorporating multiple investment periods and sequential hourly market clearing for selected periods of the year. Investment decisions are made subject to uncertainty about future operating conditions, such as load levels and intermittent power generation. The multi-horizon formulation allows for these features to be included simultaneously, without suffering from the curse of dimensionality (Kaut et al., 2014). In order to avoid overly optimistic assumptions favoring CCS, a frequently occurring weakness in previous studies as pointed out by von Hirschhausen et al. (2012), conservative cost estimates developed by ZEP are used. In addition, this study utilizes input data based on the European reference scenario 2013 published by the European Commission (2014), which reflects the currently low levels of the allowance price in the EU ETS. The modeling results show that, driven by carbon price in the EU reference scenario, an emission reduction of more than 80 % is achieved by 2050 compared to 2010 levels, when CCS is available. The total CCS deployment is 163 GW, or a 14 % share of the total installed capacity,

[3] In the CPP the final emission performance rates set by the EPA are 1,305 $lbsCO_2$/MWh (592 gCO_2/kWh) for existing steam generation units (usually meaning coal fired power plants) and 771 $lbsCO_2$/MWh (350 gCO_2/kWh) for existing natural gas CCGT units. These limits apply at a state level, and it is up to the state's legislatures to adopt policies to meet them (by 2030).

in 2050. Without CCS, results show that only a 63 % reduction in emissions are achieved from 2010 to 2050, for the same carbon price.

Following the analysis of the role of commercial CCS in Europe, we present a study of transitional measures to drive investment in demonstration CCS projects. Three mechanisms are modeled in EMPIRE with the goal of deploying 5 GW of CCS capacity before 2025: capital grants, feed-in premium and emissions performance standard. The effectiveness of these measures to spur investments, their cost and potential reception by industry and other stakeholders are evaluated and discussed. Through this analysis we attempt to shed light on what it would take to achieve CCS deployment in Europe, as is the ambition of the European Commission. This can be seen as a complement to the work published in the ZEP report "CO_2 capture and storage (CCS) – Recommendations for transitional measures to drive deployment in Europe", where EMPIRE was also used. Investment subsidies for CCS have previously been analyzed in an European context by Lohwasser and Madlener (2013). In their study, endogenous learning for CCS is implemented in the power market simulator HECTOR, and the effectiveness of different levels of investment subsidies and R&D support on CCS market diffusion are tested. Our study extends the body of research on this field by comparing additional support policies previously not considered in similar studies.

This paper has the following structure: Section 2 introduce the modeling framework used in the analysis along with a description of how the different support mechanisms for demonstration CCS are implemented. Section 3 presents a decarbonization study of the European power sector, with a special focus on the role of CCS. The results from the modeling of transitional measures for demonstration CCS is given in Section 4. Lastly, the conclusions from the two analyses are presented in Section 5.

2 Methodology

The analysis presented in this paper is based on results from EMPIRE. A complete mathematical description of EMPIRE is provided in Skar et al. (2016), while a short description is presented in the following section. Previous use of the EMPIRE includes a study of the European electricity system for several global climate mitigation strategies (Skar et al., 2014), and three studies of CCS potential in Europe by the ZEP market economics group (ZEP, 2013, 2014, 2015).

2.1 EMPIRE – The European Model for Power System Investments with Renewable Energy

EMPIRE is an investment model for the European power system formulated as a multi-horizon stochastic program. A fundamental challenge of investment modeling for large-scale power systems is that the economics of investments are determined by their impact on the system's operation (and cost). Power systems are recognized for having significant heterogeneity in operating conditions, both in a spatial and temporal dimension, which is important to represent in the modeling. As intermittent renewable generation sources, such as wind and solar, continue to increase their share in the energy mix, an increased variability in the short-term dynamics of the power systems is to be expected. The ability to control generation to supply load throughout the system is then reduced. This increases the need for transmission, energy storage and flexible generation technologies. From an investment planning perspective it is difficult to predict how the intermittent generation will correlate with load in the short-term, which introduce uncertainty in the planing. In addition to short-term dynamics there are long-term dynamics to consider as well. Changes in fuel prices and demand for electricity, in particular, are drivers for investments. All these aspects are addressed in EMPIRE by including multiple investment periods (long-term dynamics), multiple sequential market-clearing steps (short-term dynamics) and multiple stochastic scenarios for data affecting the short-term operation of the system (short-term uncertainty). By using a multi-horizon tree formulation we avoid that the optimization problem explodes in size due to the curse of dimensionality. See Kaut et al. (2014) for more detail on the methodology and Skar et al. (2016) for its application to EMPIRE.

The basic structure of the investment and operation decision process in EMPIRE is as follows: for a number of strategic (five year) time periods indexed by $\mathcal{I} = \{1, \ldots, I\}$ investments can be made in generation, interconnector and storage capacities. For $i \in \mathcal{I}$ we let the size of the investment in capacity for generator $g \in \mathcal{G}$, where $\mathcal{G}$ is the set of all generators, be x_{gi} and the total costs incurred be c^{gen}_{gi}. For every strategic time period, $i \in \mathcal{I}$, EMPIRE includes an annual economic (spatial) dispatch of the system. In order to reduce the size of the dispatch problem a selected number of dispatch hours $\mathcal{H}$ are considered to represent a year. The set $\mathcal{H}$ is sub-divided into seasons, indexed by $s \in \mathcal{S}$, for which inter-temporal constraints such as ramping and energy storage cycling are enforced in the dispatch. Two types of seasons are considered in EMPIRE, regular seasons and peak load seasons, with different number of hours. The purpose of the regular seasons is to provide a good representation of normal operation of the system, driving the energy mix and accounting for most of the annual operating costs, whereas the extreme load seasons drives the need for installed capacity in high load situations. In EMPIRE investments are made subject to uncertainty about operating conditions in future periods. This is incorporated by considering multiple annual economic dispatch problems with different parameter data, indexed by a finite set Ω. Every stochastic scenario,[4] $\omega \in \Omega$, is associated with a probability, π_ω. The operational cost associated with the dispatch comprise of annual generation cost, and the cost of energy not supplied (if the system is incapable of satisfying demand at all times). We assume a linear production cost model for generators. The short-run marginal cost (SRMC)[5] of generator $g \in \mathcal{G}$ is denoted by q^{gen}_{gi}, and $y^{\text{gen}}_{ghi\omega}$ denotes its generation output in dispatch hour $h \in \mathcal{H}$ (period $i \in \mathcal{I}$, stochastic scenario $\omega \in \Omega$). In the EMPIRE objective function the *expected* annual operational costs are optimized together with the investment costs (all discounted at rate r).

$$\begin{aligned}\min_{\substack{\boldsymbol{x}_{i\in\mathcal{I}},\\ \boldsymbol{y}_{i\in\mathcal{I},\omega\in\Omega}}} z = \sum_{i=1}^{I}(1+r)^{-5(i-1)} \times \Big\{ \sum_{l\in\mathcal{L}} CAPEX^{\text{trans}}_{li} + \sum_{b\in\mathcal{B}} CAPEX^{\text{stor}}_{bi} \\ \sum_{g\in\mathcal{G}} c^{\text{gen}}_{gi} x^{\text{gen}}_{gi} + \vartheta \sum_{\omega\in\Omega} \pi_\omega \sum_{s\in\mathcal{S}} \alpha_s \sum_{h\in\mathcal{H}_s} \Big[\sum_{g\in\mathcal{G}} \big(q^{\text{gen}}_{gi} y^{\text{gen}}_{ghi\omega}\big) + \sum_{n\in\mathcal{N}} ENS_{nhi\omega} \Big] \Big\} \quad (1)\end{aligned}$$

We use $CAPEX^{\text{trans}}_{li}$ and $CAPEX^{\text{stor}}_{bi}$ to denote costs associated with investment in capacity for interconnector $l \in \mathcal{L}$, and capacity for energy storage unit $b \in \mathcal{B}$, respectively. $ENS_{nhi\omega}$ is used to denote the cost of energy not supplied at node $n \in \mathcal{N}$ for dispatch hour $h \in \mathcal{H}$. Season weights, α_s, $s \in \mathcal{S}$, are used to scale hourly decision variables or parameters (i.e. those indexed by $h \in \mathcal{H}$) to compute their contribution to annual total figure. The factor ϑ scales annual values to five year values, which done since the elements of $\mathcal{I}$ represents five year time blocks.

The dispatch constraints included in EMPIRE comprise of hourly

1. Node load balance constraints (balancing generation, load, storage handling and transmission exchange)

[4]The word scenario is used both for data representing long-term dynamics (such as the baseline scenario) and for stochastic data representing uncertainty in the short-term economic dispatch. To distinguish the two types scenarios we refer to the latter case, i.e. data indexed by Ω, consistently as *stochastic scenarios*.

[5]The SRMC includes marginal fuel cost, variable operation and maintenance cost, carbon emission cost and carbon capture and storage cost (when applicable).

2. Capacity constraints (for generator output, interconnector loading, energy storage charging/discharging)

3. Ramping constraints

4. Storage energy balance constraints

In addition both seasonal and annual energy production from regulated hydro generators are constrained. Capacity investments are also subject to constraints, both in terms of sizing of an investment per period $i \in \mathcal{I}$ and the total installed capacity. Further details, along with the full mathematical formulation of EMPIRE, can be found in Skar et al. (2016). EMPIRE is implemented in the FICO® Xpress Optimization Suite (FICO®, 2015).

2.2 Modeling transitional measures to support CCS in EMPIRE

The following sections describe how the different support policies for demonstration CCS projects are implemented in EMPIRE.

2.2.1 Public grants

The public grant scheme was represented in EMPIRE by reducing the investment cost parameter for demonstration plants. We let pg_{gi} denote the public grant support and $\mathcal{G}^{\text{demo}}$ the set of all CCS demonstration plants and adjust the investment costs as follows

$$\tilde{c}_{gi}^{\text{gen}} = c_{gi}^{\text{gen}} - pg_{gi}, \qquad g \in \mathcal{G}^{\text{demo}}, i \in \{2, 3\}. \tag{2}$$

The adjusted investment cost parameters replace the original cost parameter for demonstration plant investment variables in the objective function Eq. (1). The support is limited to the second and third time blocks of the analysis, starting 2015 and 2020, respectively. The 2015 net present value of the policy cost is the discounted sum of the support paid to demonstration project $g \in \mathcal{G}^{\text{demo}}$, which is pg_{gi} times the investment x_{gi}^{gen}. The expression is given as

$$\text{Public grant scheme cost} = \sum_{i=2}^{3} (1+r)^{-5(i-2)} \sum_{g \in \mathcal{G}^{\text{demo}}} pg_{gi} x_{gi}^{\text{gen}}. \tag{3}$$

2.2.2 Feed-in premium

Many European countries have successfully used feed-in schemes to promote renewable generation technologies (Jenner et al., 2013). There are several ways to design a feed-in support system, however it is common to broadly distinguish between feed-in tariffs (FIT), a minimum rate received for electricity produced by a supported generator, and feed-in premiums (FIP), which is a premium paid on top of the electricity price.

In this analysis several versions of a FIP scheme have been evaluated: supporting each demonstration technology with a certain percentage of their short-run marginal cost (SRMC), supporting demonstration projects with a single flat rate and a differentiated support where demonstration gas CCS receives the first type of FIP and lignite and coal receive a flat rate. We also consider the effect choosing one of two different expiry dates for the support scheme.

As with the public grant scheme the feed-in premium policies are implemented by reducing cost coefficients in the objective function, however, these policies affect the variable operational costs. The feed-in premium support is given by fip_{gi}, which gives the following adjusted operational cost

$$\tilde{q}^{\text{gen}}_{gi} = q^{\text{gen}}_{gi} - \mathit{fip}_{gi}, \qquad g \in \mathcal{G}^{\text{demo}},\ i \in \{2, \dots, I_{\text{fip}}\}. \tag{4}$$

The feed-in premium support is set to last until investment period I_{fip}. The 2015 net present value of FIP support cost is computed as

$$\text{FIP scheme cost} = \sum_{\omega \in \Omega} \pi_\omega \sum_{i=2}^{I_{\text{fip}}} (1+r)^{5(i-2)} \vartheta \sum_{s \in \mathcal{S}} \alpha_s \sum_{h \in \mathcal{H}_s} \sum_{g \in \mathcal{G}^{\text{demo}}} \mathit{fip}_{gi} y^{\text{gen}}_{ghi\omega}. \tag{5}$$

In this expression the product $\mathit{fip}_{gi} y^{\text{gen}}_{ghi\omega}$ is the feed-in premium paid to the CCS demonstration project $g \in \mathcal{G}^{\text{demo}}$ in dispatch hour $h \in \mathcal{H}_s$, in season $s \in \mathcal{S}$, and investment period i. This is scaled by α_s and ϑ to get the total support in investment period i, which is discounted and summed to get the total net present value. Note that this is the *expected* FIP cost over all stochastic operational scenarios used in EMPIRE.

2.2.3 Emission performance standard

An emission performance standard (EPS) is a control mechansim which limits the specific emissions, i.e. ratio of emissions to electricity generation, either from indvidual plants or a portfolio of plants. The EPS policies are implemented in EMPIRE using constraints. For individual generators the EPS constraints are

$$(se_{gi} - eps) \cdot y^{\text{gen}}_{ghi\omega} \leq 0, \qquad g \in \mathcal{G}, h \in \mathcal{H}, i \in \mathcal{I} \setminus \{1\}, \omega \in \Omega, \tag{6}$$

where eps is the limit and se_{gi} is the specific emissions for generator $g \in \mathcal{G}$ in year $i \in \mathcal{I}$. This constraint effectively shuts off production from generators for which the specific emissions are higher than the EPS.

The portfolio EPS limit constrains the ratio of total emission to total generation, which can be formulated as follows[6]

$$\sum_{s \in \mathcal{S}} \alpha_s \times \sum_{h \in \mathcal{H}_s} \sum_{g \in \mathcal{G}} (se_{gi} - eps) \cdot y^{\text{gen}}_{ghi\omega} \leq 0, \qquad i \in \mathcal{I} \setminus \{1\}, \omega \in \Omega. \tag{7}$$

3 The least cost route to a decarbonized European power sector

The main scenario developed in this study, our Baseline scenario, is constructed based on data from the EU 2013 Reference scenario (European Commission, 2014). Assumptions regarding fuel prices, carbon price and demand for electricity is shown in Figure 1. This scenario has been selected as it provides an accurate description of current conditions and represents a conservative view of the EU allowance (EUA) price development and electricity demand growth over the coming decade. The low level of the EUA price in the near-term reduces the competitiveness of CCS, which should be included in the analysis in order not to be overly optimistic. From 2030 to 2050, the EUA price is shown to increase, reflecting progressive stringency in the EU ETS. Demand for electricity is also shown to increase in the same period which is a result of economic development and more reliance on electricity as an energy carrier in the scenario data.

[6] $\sum_{i=1}^{N} a_i x_i \big/ \sum_{i=1}^{N} c_i x_i \leq b \quad \overset{\sum_i c_i x_i > 0}{\iff} \quad \sum_{i=1}^{N} (a_i - c_i \cdot b) \cdot x_i \leq 0$

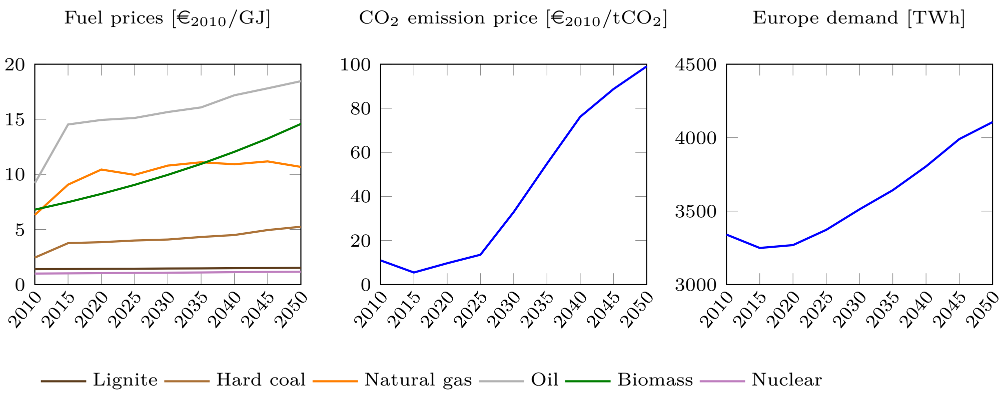

Figure 1: EU 2013 Reference scenario data used by EMPIRE. Fuel prices for hard coal, natural gas and oil have been collected directly from European Commission (2014). The initial lignite price is based on ZEP (2011) and prices of uranium and biomass have been derived from VGB (2011). The price levels are assumed to increase by 1%, 2% and 10% every five years for lignite, uranium and biomass respectively.

Table 1: Cost parameters for post-demonstration CCS

	2025	2030	2035	2040	2045	2050
Capital cost [€$_{2010}$/kW]						
Lignite CCS	2600	2530	2470	2400	2330	2250
Coal CCS	2500	2430	2370	2300	2230	2150
Gas CCS	1350	1330	1310	1290	1270	1250
Bio 10pcnt cofir. CCS	2600	2530	2470	2400	2330	2250
Efficiency [%]						
Lignite CCS	37	39	40	41	42	43
Coal CCS	39	40	41	41	42	43
Gas CCS	52	54	56	57	58	60
Bio 10pcnt cofir. CCS	39	40	41	41	42	43
CCS T&S cost [€$_{2010}$/tCO_2]	19	18	17	15	14	13

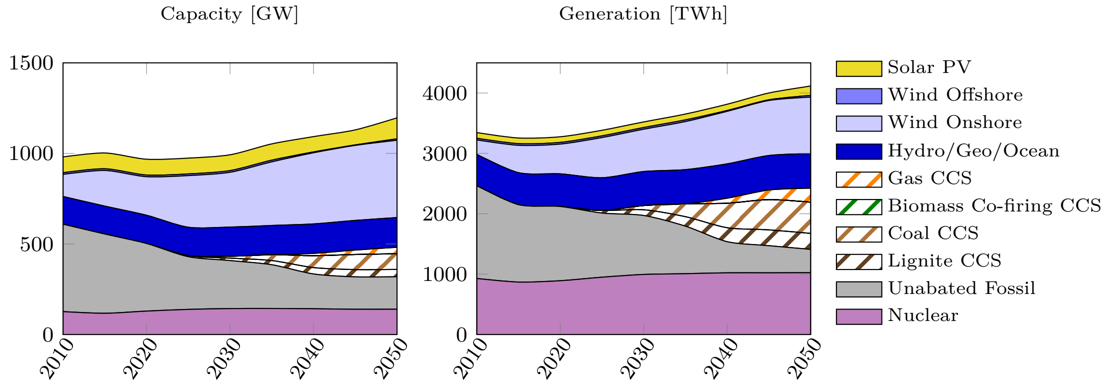

Figure 2: Optimal generation capacity and generation mix in the Baseline scenario.

In the Baseline scenario we assume that CCS demonstration plants have been successfully deployed, leading to availability of post-demonstration plants from 2025. The post-demonstration plants experience a gradual reduction in capital costs, heat rate improvements and decrease in CO_2 transport and storage cost. The data used for the post-demonstration plants were provided by participants of ZEP's working group for market economics II in the work leading to the report ZEP (2013). A list of the CCS cost and generation efficiency data used in this analysis can be found in Table 1. Expansion of CCS infrastructure is not considered directly as the capital costs of infrastructure investments are embedded in transport and storage costs used in the operational expenditures of CCS plants. See Oei et al. (2014) for a more thorough analysis of CCS infrastructure in Europe. In this analysis we do not consider investments in new interconnector or energy storage capacities. This entails a very conservative view of future infrastructure development, reflecting possible situations such as strong public opposition to new transmission lines. In Skar et al. (2016) the sensitivity of CCS deployment to assumptions regarding grid expansion was evaluated.

3.1 Baseline results

The development of generation capacity and generation mix for the European power sector under the Baseline scenario is shown in Figure 2. EMPIRE computes a significant expansion of onshore wind capacity between 2010 and 2030, from a starting point of 122 GW to just above 300 GW. During the same time-period 360 GW of fossil fuel (lignite, coal, gas and oil) capacity is retired. About 165 GW of new unabated fossil generation capacity is built, in addition to 24 GW of lignite and coal CCS capacity. The first investment in CCS occurs in 2025 when 6 GW of lignite CCS is deployed (4 GW in Germany and 2 GW in Poland). By 2050 all the capacity initially operational in 2010 has been retired, replaced by newer and alternative technologies. The total unabated fossil capacity is 180 GW, which generates 385 TWh of electricity. For CCS technologies the installed capacities are 41 GW for lignite, 86 GW for coal and 36 GW for gas, generating 265 TWh, 517 TWh and 233 TWh, respectively. The total 163 GW of CCS capacity makes up 14 % of the total installed capacity in Europe, while the share of the generation mix is 25 %. Intermittent generation, i.e. wind and solar power, sees an increase of its share in the generation mix, from 11 % in 2010 to 27 % in 2050. The total renewable energy share (including hydro power) ends up at 41 % in 2050.

Results for installed capacity and generation mix for the ten countries with highest electricity

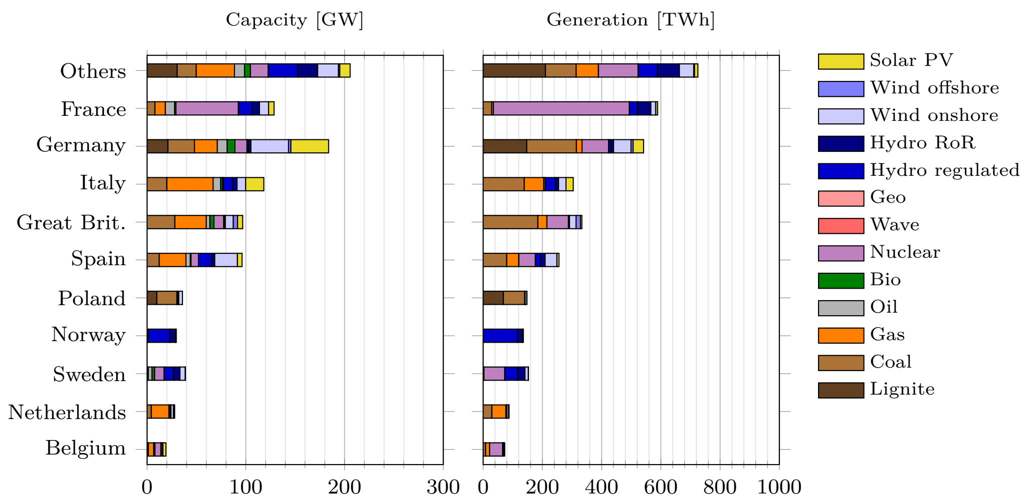

Figure 3: Country-wise Baseline scenario result generation capacity and generation mix in 2010.

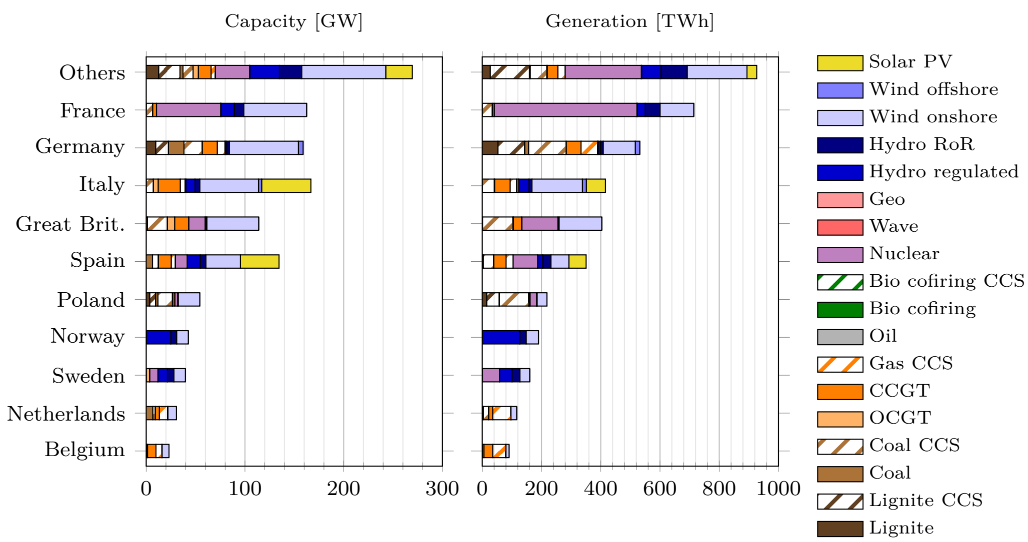

Figure 4: Country-wise Baseline scenario result generation capacity and generation mix in 2050.

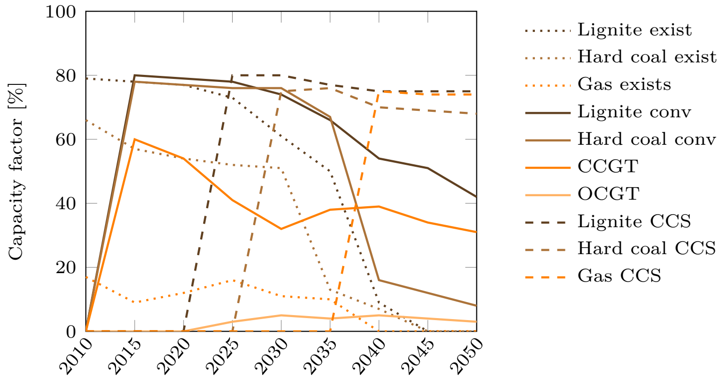

Figure 5: European capacity factors for fossil fuel plants in the Baseline scenario

demand is shown in Figures 3 and 4, for 2010 and 2050, respectively. Three countries, Great Britain, Germany and Poland, have 50 % of the installed CCS capacity in Europe, with hard coal CCS being the most significant technology. These countries have a total of 53 GW hard coal CCS capacity installed, which makes up a 67 % share of their total CCS capacity. Gas CCS capacity is also fairly concentrated, with the Netherlands, Germany and Belgium being the three countries with highest installed capacity, 63 % of Europe's total.

A useful metric for understanding the competitiveness of different technologies is their capacity factors, the ratio of actual production to the nominal production over a given time period. Investments with high capital costs, such as CCS, typically require a significant utilization to achieve a sufficient return. The Baseline capacity factors for the main fossil fuel technologies are shown in Figure 5. As expected, the utilization of existing capacity decreases as newer and more efficient technologies enter the market. From 2015, newly built unabated lignite and hard coal plants are used as baseload generation, with capacity factors close to 80 %. CCGT plants are used as intermediate generation, with a capacity factor starting at 60 % in 2015. However, as lignite and coal CCS is deployed from 2020 and 2025, the capacity factor for CCGT drops to less than 40 %. Beyond 2035 the conventional coal capacity built after 2010 faces a steep decline in utilization, to less than 20 %. By 2040 the assumed price for carbon has reached a level close to 80 €/tCO_2, which makes the cost of dispatching unabated coal plants prohibitively high during normal operation. This effectively shows a result which might be obvious, but still worth mentioning, even new and advanced coal fired power plants built over the course of the coming decade cannot be expected to be competitive as baseload for more than 20–25 years, much less than their technical lifetime. All of the CCS technologies that are deployed, immediately enter operation as baseload generation, with capacity factors between 70–80 %.

3.2 Consequences of an absence of CCS as low-carbon option

The Baseline results are, as a result of the principles behind the construction of EMPIRE, the cost optimal development of the European power sector under the EU 2013 Reference scenario assumptions. In order to assess the effect of not having a CCS option available, as an alternative scenario, EMPIRE was setup for an optimization with CCS technologies disabled in a scenario labeled Baseline-NoCCS. The resulting capacity and generation mixes are shown in Figure 6. In this scenario unabated fossil fuel technologies continue to have a reasonably high share in the generation mix. Roughly 25 % of the electricity generated in 2050 comes from unabated fossil

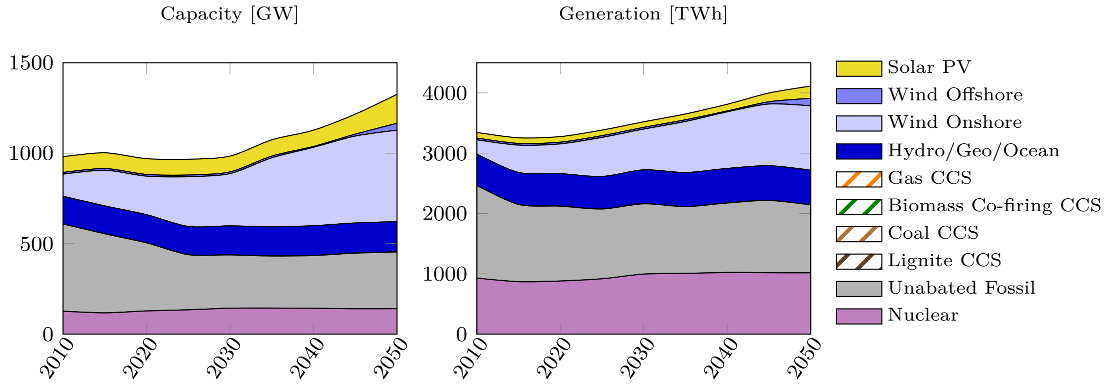

Figure 6: Optimal generation capacity and generation mix in the Baseline-NoCCS scenario

plants (mostly natural gas fired CCGTs and OCGTs which account for 70 % of the total fossil generation), 25% comes from nuclear power and remaining generation comes from renewables. A comparsion of pathways for carbon emissions, European average power price and the 2050 system costs, in the vanilla Basline and Baseline-NoCCS scenarios are shown in Figure 7. The two scenarios diverge from 2025, once CCS is deployed in the Baseline scenario. The Baseline-NoCCS scenario has a less steep emission reduction trajectory than the Baseline scenario, and the total reduction in 2050 relative to 2010 is only 63 % when CCS is not allowed, compared to 82 % when the CCS technologies are available. The power price, found as the average marginal cost of electricity over all countries and hours, is similar for the two scenarios up until 2035. Then the Baseline price starts leveling out and the Baseline-NoCCS price continue to increase for another decade. In 2050 the Baseline-NoCCS scenario has a 10 % higher price for electricity than the Baseline scenario. As the deployment of renewables is higher in the Baseline-NoCCS scenario the fuel costs are significantly lower. However, as the additional cost of covering carbon emissions, and the cost of capacity, are much higher, the total difference in 2050 annual costs between the scenarios is 17.6 bn€. The effect of not having the CCS option is clear, the power sector emissions will be much higher, too high to meet the European Commission's ambitous Roadmap 2050 goals, and at the same time the cost will be higher.

3.3 Related modeling studies focusing on CCS

Over the recent years there have been notable modeling studies done with the focus on the role of CCS in the European sector. Odenberger and Johnsson (2010) applied a capacity investment model, with a detailed electricity generation system description, to assess the optimal development of the European power sector for three different scenarios. Their focus was specifically on the potential of CCS to meet emission reduction targets. In their base scenario, assuming a continued growth of electricity demand and a cap on emissions (85 % in 2050 relative to 1990), the results showed an optimal deployment of 300 GW of coal CCS, capturing 1.8 GtCO_2/an, by 2050.

Lohwasser and Madlener (2012) discuss the economics of CCS for coal plants and emhpesises that investment costs are a significantly more important factor than efficiency loss in energy conversion when it comes to economic viablity for coal CCS. The HECTOR model, an electricity market simulation model with endogenous capacity investments, was used to analyse coal CCS deployment in Europe. With assumptions on investment costs and conversion efficiency based

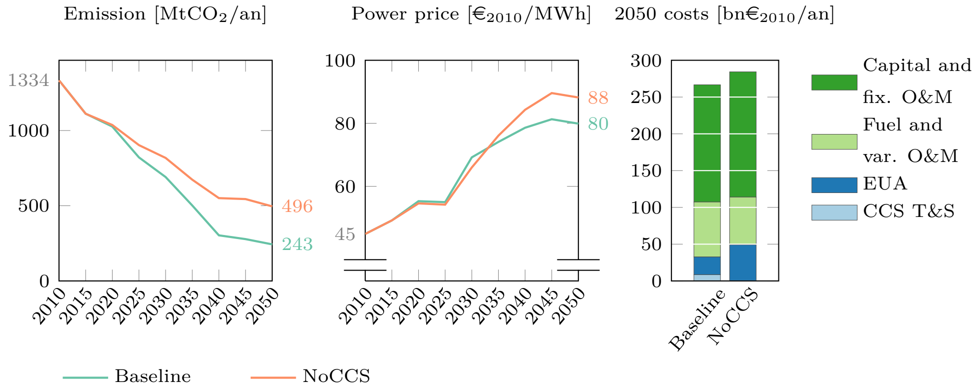

Figure 7: Emission, annual European power price and 2050 annual electricity cost for the Baseline and Baseline No-CCS scenarios.

on an averages from a wide selection of sources found in an extensive litterature review, the study showed a deployment of 143 GW hard coal generation capcity with CCS by 2030. The investments in CCS are driven by the EU ETS, which in the base scenario is assumed to develop from 20 €/tCO_2 in 2010 to 49 €/tCO_2 in 2030.

Jägemann et al. (2013) use the DIMENSION model to investigate decarbonization scenarios for the European power sector. Restrictions on availability of nuclear power and CCS are explored as alternative assumptions. In their scenario for economic conditions labeled baseline, the additional cumulative system cost over the period 2010 to 2050 of a 80 % reduction target increased by 16 bn€$_{2010}$ when nuclear investments are allowed but CCS is not available. The total installed CCS capacity by 2050 in this scenario is modest, about 40 GW lignite CCS. However, the CCS share of the total generation mix is reported to be 11 %, which is significant. The additional cost of not having CCS when nuclear power is not available is found to be 82 bn€$_{2010}$.

There are several differences in terms of CCS deployment between the different studies. Compared to Odenberger and Johnsson (2010) the baseline results from EMPIRE show a little bit more than half the total CCS deployment. Although the first CCS investments computed by EMPIRE occur in 2025, the total capacity does not exceed 100 GW until 2040, which shows a shift of ten years in time for large-scale deployment compared to Lohwasser and Madlener (2012). The more conservative CCS deployment found by EMPIRE results can be explained by higher investment costs and a carbon price which remains low until 2025. Compared to Jägemann et al. (2013) the total CCS investments computed by EMPIRE are more than four times larger. This can be explained by the fact that nuclear power investments are significantly limited (although available) in EMPIRE, while in the particular scenario where the reported CCS capacity was 40 GW in Jägemann et al. (2013) nuclear power was not restricted.

4 Securing a deployment of 5 GW demonstration CCS by 2020

In the Baseline scenario it is assumed that commercial CCS availability will start at 2025, followed by rapid technology improvement. The realism of such an assumption is of course questionable

Table 2: Economic parameters used for CCS demonstration projects in EMPIRE

Project type	Capital cost [€$_{2010}$/kW]	Efficiency [%]
Lignite CCS	2600	31
Coal CCS	2500	33
Gas CCS	1350	48

unless demonstration projects[7] are successfully initiated prior to commercial deployment. In the following we therefore take a closer look at mechanisms for incentivizing CCS demonstration plants.

The amount of capacity eligible for support under the public grant and feed-in premium policies was set to a total of 5 GW. EMPIRE was left free to allocate capacity, up to this limit, between lignite, coal and gas CCS, based on each technology's competitiveness under the given support scheme. In the emission regulation scenario EMPIRE was free to deploy as much of the CCS demonstration projects as it found optimal, albeit without any reduction of cost through support measures.

Three different CCS demonstration project types were included in the modeling, all of which being available from 2015. The investment cost and efficiencies are shown in Table 2. In the Baseline scenario neither of these projects were deployed using their default data.

4.1 Public grants

Public grants, in the form of an upfront payment used to decrease the investment cost of the CCS demonstration plants, were evaluated at levels ranging from 50–200 % of the *additional* CCS capital cost. For conventional, unabated, lignite technology the capital cost is 1600 €/kW, while the cost for demonstration lignite CCS is 2600 €/kW. The public grant schemes therefore would provide a subsidy of 500 €/kW in a 50 % case, 1000 €/kW in a 100 % case and 2000 €/kW in the 200 % case. The same applies for coal CCS, which is modeled with a capital cost of 1000 €/kW above its conventional counter-part. For gas CCS the additional cost (compared to CCGT) is 700 €/kW. In the 200 % support case the support received by gas CCS is actually slightly higher than the total capital cost.

As an illustration, under the 50 % public grant scheme a deployment of 5 GW, divided equally between coal and gas CCS, would cost 850 €/kW, or €2.1 billion in total. To put this number into perspective, the total NER300 budget in the first round was estimated to €1.3–1.5 billion (Lupion and Herzog, 2013). However, as this amount was a result of monetisation of 200 million EU allowances under the ETS, which had lower price than expected (an average sales price of €8.05), the total budget was initially anticipated to be higher. The public grant schemes considered are more expensive than the NER300 program, but still of comparable magnitude.

The results of the EMPIRE optimization of the three public grant schemes show that all support levels lower than 200 % of the additional CCS capital costs are insufficient to incentivize any of the demonstration project types. At a 200 % level, 4.1 GW of lignite CCS capacity is deployed in 2020, at a net present value of 6.5 bn€ in 2015 (discounted from 8.2 bn € in 2020). The capacity factor of the demonstration plants is close to 80 % throughout the analysis, showing that the main obstacle for this particular technology is the capital cost. At a support level of 200 % of additional CCS capital costs, gas CCS would receive 1400 €/kW, 50 €/kW more than

[7] The analysis in this paper only include CCS projects exclusively for power generation. Applications of CCS in for instance enhanced oil recovery, are not considered.

the total capital cost. Even this turns out to be insufficient to promote gas CCS, which is a clear argument to consider operational support to improve competitiveness.

4.2 Feed-in premium

Results from the feed-in premium analysis done with EMPIRE are shown in Table 3. There is a clear pattern emerging from the different cases in how the reaction is to the different FIP designs. For the SRMC based FIP, gas CCS becomes competitive before lignite and coal. This is not surprising considering that the investment cost for gas CCS is substantially lower than the other technologies, while the operational costs are high. Limiting the support to only last until 2030 has an adverse effect as it increases the support required to spur investments, making the net present value of the support scheme high as it result in expensive payouts closer in time. In order to achieve a deployment 5 GW gas CCS by 2020 we found that either 55 % of the SRMC had to be covered until 2030, or 35 % until 2050. Between 2020 and 2050 the SRMC for demonstration gas CCS is in the range of 87–94 €/MWh, which means that a 35 % support would be in the range of 30–33 €/MWh. The 2015 net present value of these schemes are 20.9 bn€ and 12.6 bn€, respectively. The levelized costs of support (LCOS), the ratio of net present value of support costs to the discounted sum of generation output, are 43.7 €/MWh and 31.3 €/MWh. If the support is less than 45 % (until 2030) or less than 30 % (until 2050), no investment in demonstration projects take place.

For the flat FIP support rate lignite CCS turns out to have an edge over the other technologies. For a support scheme limited to 2030 the level of the support needs to be above 20 €/MWh. A rate of 25 €/MWh is enough to deploy 4.1 GW of demonstration lignite CCS, at a total cost of 6.2 bn€. This is slightly cheaper than the capital grants scheme, with a cost of 6.5 bn€, which achieved the same demonstration CCS deployment. Similarly, a support of 17.5 €/MWh, lasting until 2050, is sufficient to incentivize 4.1 GW of lignite CCS. At a FIP of 20 €/MWh, lasting until 2050, the total demonstration capacity reach the 5 GW limit.

By combining the two types of FIP schemes a mix of lignite and gas CCS projects are deployed. For illustration, two different levels of the flat FIP recieved by lignite CCS, 15 €/MWh and 17.5 €/MWh, was used in combination with a 32.5 % SRMC support for gas CCS (which would be in the range of 28–30 €/MWh). For the lower FIP rate 2.8 GW lignite CCS is realized in Germany. When the FIP rate is set at a level of 17.5 €/MWh for lignite CCS, an additional 1.3 GW is built in Poland. The gas CCS projects are consistently deployed in the Netherlands and Spain.

4.3 Emission performance standard results

EMPIRE was set up to optimize investments for three types of EPS, all implemented from 2015, listed below.

1. 450 gCO_2/kWh for individual generators. Existing plants exempted.
2. 225 gCO_2/kWh for individual generators. Existing plants exempted.
3. 225 gCO_2/kWh for the European generation portfolio.

Of all the unabated fossil generation technologies included in the EMPIRE data set for this analysis, only gas CCGT, with specific emissions of 336 gCO_2/kWh, is premissable in the 450 gCO_2/kWh EPS scheme. Under the regualtion limiting specific emissions to 225 gCO_2/kWh for individual generators only the CCS technologies are able to satisfy the requirement, which essentially makes this a CCS obligation scenario.

Table 3: Results from FIP scheme EMPIRE optimizations. An asterisk is used to label deployment which partly or fully occurs in 2015, while unlabeled results occur in 2020.

Type							
Flat [€/MWh]	SRMC [%]	End	Gas [GW]	Lignite [GW]	Total [GW]	2015 NPV [bn€]	LCOS [€/MWh]
	45.0	2030	No deployment				
	50.0	2030	1.9*		1.9	6.6	40.0
	55.0	2030	5.0*		5.0	20.9	43.7
	30.0	2050	No deployment				
	35.0	2050		5.0	5.0	12.6	31.3
20.0		2030	No deployment				
25.0		2030		4.1	4.1	6.2	15.8
10.0		2050	No deployment				
15.0		2050		2.8	2.8	4.0	15.0
17.5		2050		4.1	4.1	6.6	17.5
20.0		2050		5.0	5.0	9.4	20.0
(L) 15.0	(G) 32.5	2050	1.2	2.8	4.1	6.9	18.8
(L) 17.5	(G) 32.5	2050	0.9	4.1	5.0	8.7	18.8

Unlike the financial support policies, which just slightly perturbs the overall results compared to the Baseline, the EPS constraints significantly alter the system optimization. Therefore a wider discussion of the overall system results is provided.

Results for European power sector emissions, average power price and total CCS deployment in the EPS scenarios and the Baseline scenario are shown in Figure 8. This reveals that an EPS limit of 225 gCO_2/kWh for individual generators, is sufficiently strict to open the market for deployment of CCS demonstration plants. A total of 10.6 GW of demonstration CCS capacity, of which 9.2 GW is lignite and 1.3 GW is gas, is installed during the 2020 investment period. The 450 gCO_2/kWh limit for individual generators, and the 225 gCO_2/kWh limit for the entire European fleet, on the other hand, only see deployment of post-demonstration plants, starting from 2025. As with the Baseline scenario we do not impose a precondition that demonstration plants need to be deployed in order for the post-demonstration plants to be available, which can, as discussed, be a problematic assumption.

In terms of emission reduction all of the EPS policy scenarios overachieve compared to the Baseline scenario. By 2050, the total reductions of annual emissions relative to 2010 are in the range 86–88 % for the least stringent individual limit 450 gCO_2/kWh EPS for individual generators and the 225 gCO_2/kWh portfolio limit. The 225 gCO_2/kWh EPS for individual generators achieve an emission reduction of 92 %. As existing fossil plants are exempted from the generator EPS policies, the emissions are gradually decreased for these scenarios. The implementation of a portfolio policy, without exemption for existing plants, effectively set an emission ceiling which causes a drastic short-term reduction in emissions. Eventually, when CCS becomes available, the gap between emission trajectories for the portfolio EPS scenario and the Baseline scenario becomes more narrow.

Although the EPS policies are shown to be effective as a supplement control mechanism for reducing emissions from the power sector, the effect they have on the market at the time of their implementation is dramatic. In the scenario with a 225 gCO_2/kWh EPS for individual generators the average European electricity price is 25 % higher than the Baseline scenario in 2015, and

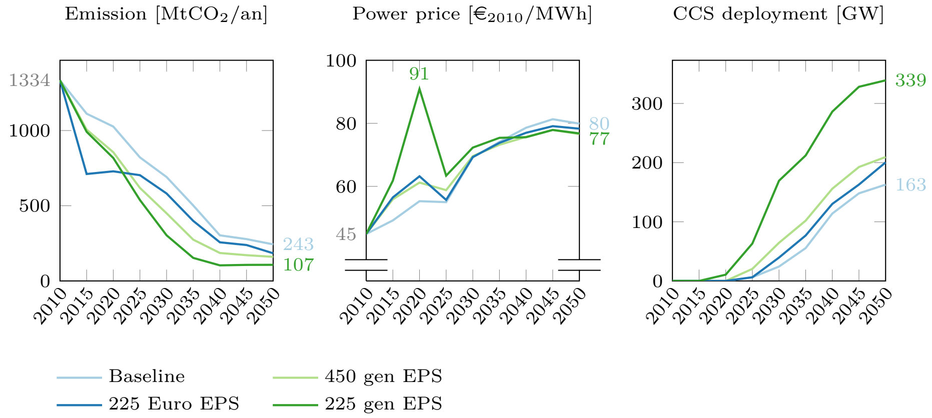

Figure 8: Emissions, power price and CCS deployment for the different EPS policy scenarios.

close to 65 % higher in 2020, reaching 91 €/MWh. The reason why the effect is strongest in the period after the policy is implemented is that by 2020 more of the generators exempted from the policy is retired. For the other EPS policies the prices are about 10–15 % higher than the Baseline prices in 2015 and 2020. Eventually the EPS scenario prices comes closer to the Baseline price, and by 2050, the Baseline price is actually above the policy scenario prices as less EUAs are required to cover emissions.

4.4 Discussion

The reason why public grants fail to incentivize investments for all but lignite CCS is clear when investigating the marginal costs of technologies in EMPIRE. Significant heat rate penalties due to the capture process, along with the additional operational costs associated with carbon transport and storage, force the CCS demonstration plants far behind in the market dispatch. The price of carbon emission is initially low in the Baseline scenario, and therefore these plants loose in competition with conventional plants to enter the dispatch under normal load conditions. When the price of emissions finally does rise to a level such that the demonstration plants become the cheaper dispatch option, compared to conventional technologies, they lose in competition with commercial CCS plants which are then deployed. This highlights an important distinction between renewable technologies and CCS demonstration projects when it comes to financial support and risk. Somewhat simplified one can say that renewables face the risk of receiving a too low price of electricity for its production, making the revenues fall short of covering the required return on capital. The production itself is largely unaffected by market uncertainty, and the revenues earned still offer some return. CCS projects, on the other hand, face the potential risk of becoming stranded assets, in the extreme case not receiving a single cent in return on the investment. This risk is present both for low and high levels of the price on carbon emissions. In particular for large-scale deployment of commercial CCS at high carbon emission prices, there is significant risk of cannibalization of market shares and low utilization of demonstration CCS plants. This effect is, as the modeling results presented here indicate, less significant for technologies with low fuel costs, such as lignite CCS. The reason is simply that lignite CCS is competitive with the commercial coal CCS and gas CCS technologies, and therefore will not be offset by these technologies in the dispatch. However, the most effective policy measure for promoting demonstration CCS, for both lignite CCS and gas CCS, is shown to be operational support, such as a feed-in premium.

The transitional measures tested in the EMPIRE is likely to receive widely different responses from stakeholders. CCS is seen by some environmental NGOs as counterproductive option for reducing emissions, with Greenpeace as the prime example. Slow technological progress, high costs and the risk of leakage from storage sites are typically cited as their primary concern (Greenpeace, 2008). Any form of public financial support of CCS that could potentially divert funding away from renewables will see opposition from groups such as Greenpeace. The power industry on the other hand will be more receptible of a carrot, such as public grants or FIP, rather than a stick approach. Moreover, support can be expected from environmental NGOs advocating for CCS, such as Bellona (Stangeland, 2007).

As discussed by Groenenberg and de Coninck (2008) a CCS obligation would likely not face opposition from environmental NGOs as the policy does not divert public funds from renewable energy projects, however, resistance would probably be large from EU Member States with generation portfolios with high shares of fossil fuels and low potential for carbon storage. In addition, resistance from the power industry due to stranded assets are to be expected, unless some from of grandfathering, in other words exemption of legacy generation assets, is granted as a part of the regulation.

5 Conclusions

The study presented in this paper adds evidence to support the conclusion reached by several preceding studies of decarbonization pathways for the European power sector, CCS is an integral part of a solution for cost-effective reduction of power generation GHG emissions. The cost and technical parameters used for modeling CCS technologies in EMPIRE, along with assumptions on development of electricity consumption and EUA price, in concert establish a conservative scenario in terms of competitiveness of carbon capture and storage. Still, by 2050, the modeling shows an optimal deployment of 163 GW of CCS generation capacity, and a 25 % CCS share of the total energy mix, divided between different fuel types. Using the EU 2013 Reference Scenario data, the analysis shows that annual emissions are reduced by 82 % from 2010 to 2050 when CCS is part of the total solution. In contrast, the emission reduction achieved with the same carbon price, without CCS available, is just 63 %, at a higher cost.

Realization of demonstration projects is a highly important as a step towards commercialization of CCS, especially for gaining experience in operating CCS plants in the European energy markets and developing the technology further. In the current situation, with a very low EUA price, transitional measures are needed to incentivize first movers on CCS. The three policy mechanisms assessed in this paper, public grants, feed-in premiums and emission performance standards, can all be devised to secure deployment of CCS demonstration projects. For lignite CCS two support schemes, the one based on co-funding of capital cost, and the one with a FIP of 25 €/MWh lasting til 2030, gave virtually the same deployment at more or less the same cost. The cost of the cheapest feed-in premium policies sufficiently generous for a deployment of 5 GW demonstration CCS capacity, is found to be in the range of 8.7–12.6 bn€. Within this range it is possible to achieve 5 GW of lignite CCS, 5 GW of gas CCS or a mix between the two technologies. The analysis illustrates an interesting difference between supporting renewable energy technologies and CCS. Whereas renewable energy naturally enters the dispatch once built, but face the risk of receiving a too low price to cover their capital costs, CCS plants face the risk of not being dispatched at all. This is particularly true for demonstration plants with high fuel costs, as they might be out-competed by unabated fossil generation at low carbon prices and by more efficient CCS if successful commercialization materialize. Operational support is therefore crucial for such projects.

When it comes to emission performance standards as a tool for promoting demonstration CCS it turns out that anything but a CCS mandate on new capacity is not likely to work. Implementing an EPS, either at a generator level or for the European generation portfolio, will push the energy mix in a less carbon-intensive direction, although as a side-effect near-term electricity prices will be high. In particular a CCS mandate policy could make prices sore, up to 64 % above a Baseline scenario in 2020. The difference in price between the Baseline scenario and the CCS mandate scenario evens out eventually, but it is unlikely that a policy causing such a high rise in prices, even if just for a transitory period, can receive the necessary political support to be implemented.

In conclusion, the European Commission's reconfirmation of its support for CCS can, based on this analysis, certainly be argued to be well-founded. Policy support measures securing the economic viability of demonstration projects are urgently needed in order to facilitate a place for CCS as a part of the solution for transitioning the European power sector into a low-carbon future.

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