Zero emissions platform

CO_2 Capture and Storage (CCS)

Recommendations for transitional measures to drive deployment in Europe

European Technology Platform for Zero Emission Fossil Fuel Power Plants

Contents

The Zero Emissions Platform (ZEP)

Founded in 2005, the Zero Emissions Platform (ZEP) is focused on CCS as a critical technology for achieving Europe's energy, climate and societal goals. A coalition of over 200 members from 19 countries – representing academics, scientists, European utilities, petroleum companies, equipment suppliers and environmental NGOs – ZEP serves as an advisor to the European Commission on the research, demonstration and deployment of CCS.

Key conclusions

The European Commission has confirmed that Europe cannot be decarbonised cost-effectively – and maintain security of energy supply – without CO_2 Capture and Storage (CCS). Indeed, with fossil fuels currently meeting over 80% of global energy demand and as much as 85 GW of additional capacity expected in Europe alone, CCS is "vital for meeting the Union's greenhouse gas reduction targets".[1]

Yet the benefits of CCS go far beyond that of climate change mitigation: with annual investments worth billions of euros, CCS will create and preserve jobs, boost industry and fuel economic growth, ensuring Europe remains competitive on the world stage as a leader in low-carbon energy technologies.

- **New model shows the lowest-cost route to decarbonising European power**

In order to identify how low-carbon technologies can decarbonise European power most cost-effectively in the horizon to 2050, the Zero Emissions Platform (ZEP) has developed a model based on an existing model from the Norwegian University of Science and Technology (NTNU) and linked to the Global Change Assessment Model (GCAM).

ZEP's model is designed to select the lowest-cost investments to meet expected electricity demand, while replacing plants that exceed a defined lifetime – country by country. It is unique in that it not only takes into account optimised operating costs hour-by-hour, but a dispatch model of renewable power[2] based on capacity factors and historic weather data. *N.B. The baseline case did not include explicit EU or Member State subsidies for any technology.*

- **By 2030, CCS will play a critical role in reducing emissions at lower cost – driven by the ETS**

Cases studied in the baseline modelling show that the wide and progressive use of lignite, coal, gas and biomass with CCS between 2030 and 2050 – combined with hydro, wind and solar – is the lowest-cost route to reducing emissions from electricity generation,[3] driven by the EU ETS. Given the assumptions made, the model suggests that a CO_2 price ramp rising from current low levels through 35-40 €(2010)/tonne at 2030 is sufficient for CCS to be deployed, taking into account cost learning curves. However, this relies on CCS demonstration projects delivering results *before* 2020 to reduce costs, so that the next wave of projects can commence from the early 2020s,[4] leading to wide deployment by 2030.

The generation mix, including CCS, reduces emissions by 76% in 2050 (compared to 1990 levels); without CCS, this figure drops to just 34%. CCS also reduces the total cost of electricity to the consumer by 4-10% (compared to cases without CCS). Finally, CCS combined with sustainable biomass is shown to be effective as the only large-scale technology that can actually *remove* CO_2 from the atmosphere.

As the EU Energy Roadmap 2050 carries a CCS (for power) deployment rate of ~4 GW p.a. in the 2030s to ~11 GW p.a. in the 2040s, this sets the pace for deployment from 2020 to 2030 to be ~1 GW p.a. in 2020 to ~3 GW p.a. in 2030 – and a minimum set of 3-5 demonstration projects between 2015 and 2020.

- **Transitional support measures are essential to ensure CCS is widely deployed by 2030**

The modelling assumes that the ETS will be the most cost-efficient mechanism for driving decarbonisation in the long term, as shown in Figure 4, page 20. In the short term, however, the price of Emission Unit Allowances (EUAs) has fallen to a level where it provides no incentive to invest (€2.5-5/tCO_2 in Q2 2013). This situation will continue until the ETS has undergone structural reform – in particular setting a tighter cap out to 2030 and beyond, as part of a holistic EU Energy and Climate Policy framework. Yet even if action is

[1] http://ec.europa.eu/energy/coal/ccs_en.htm
[2] Although the model is restricted to the wholesale electricity market, test cases with lower electricity demand reflect the increased use of distributed generation
[3] By over 80% (over 2010 levels) by 2050 using GCAM's economic price assumptions. As overall CO_2 emissions from European power decreased by ~18% between 1990 and 2010, this is equivalent to over 90% emissions reduction over 1990 levels.
[4] Based on investment costs and cost learning curves provided by ZEP member organisations

taken now, it will still not result in EUA prices that are high and robust enough to deploy CCS in time to meet EU climate targets.

In the meantime, EU policy currently offers targeted support (e.g. feed-in-tariffs) to wind, solar, biomass, biofuels etc. – but not CCS. Indeed, few Member States[5] have a national strategy for CCS development and fewer still have targeted policies to facilitate demonstration and deployment. ZEP focused on measures that would create minimal distortion to the liberal markets of Europe and a minimal subsidy that could otherwise increase the cost to consumers or taxpayers.

- **Identifying the most effective measures to incentivise CCS demonstration and early deployment**

In the next stage of the modelling, ZEP therefore added[6] various support measures for CCS in order to test their effectiveness in incentivising demonstration and early deployment projects in Europe. (This was based on a defined volume of 5 GW by 2025 as an example, but a larger volume may also be achieved.) The conclusions were as follows:

- **Public grants need to cover capex *and* opex to incentivise CCS 'first movers'**. This is because capex grants alone – even equivalent to 100% of the marginal capital costs of CCS – do not ensure that CCS power plants will be dispatched, as the operating costs of electricity production may still be higher than electricity prices for demonstration and early deployment projects. Both capex *and* opex support is therefore needed to ensure CCS plants are dispatched and first movers are compensated for taking the lead in CCS deployment.

  ZEP therefore recommends establishing a 'CCS Fund' large enough to support EU demonstration projects in both the power and industrial sectors, but which takes into account the lessons learned from recent EU funding schemes. Funding could come from the Commission (e.g. by setting aside sufficient EUAs from the New Entrants Reserve, or earmarking funds from the EU budget, not unlike the European Energy Programme for Recovery (EEPR)) and from Member States (e.g. by using some of the proceeds from ETS auctions, or already established national carbon taxation schemes).

- **Feed-in premia (FiPs)[7] offer investors the greatest security of income** – a proven method for supporting new low-carbon energy technologies. This is because well-designed FiPs provide support to power plants in a form that best ensures them access to the electricity grid, reducing both revenue risk and price risk for investors. This correspondingly lowers the cost of capital. Only the technological risk therefore remains, as is typical for projects at this stage of development. In other words, if construction and operational costs are greater than expected, these are borne by the developer.

- **CCS certificates are a potential option, but require careful design**. The modelling, which could not simulate a market for CCS certificates (CCSCs) – only the effect of a functioning CCSC market – estimated that 25% and 35% of opex support advances lignite and gas CCS respectively. ZEP recognises that when considering this option, specific issues have to be addressed, such as the high transaction costs incurred in setting up the system, while the market for such a small volume could be open to competitive misbehaviour. Furthermore, investors still carry the main risk since forecasting the CCSC price may be challenging and the return on investments may fall if it is low. In the certificate system, power plant receives money only if it is actually operated – unless, under the scheme, plants are guaranteed to dispatch and operate over the lifetime of the project. ZEP would be pleased to provide further advice to the EU and Member States on the feasibility and design of such a scheme.

- **Emission performance standards (EPS) in the short term will not incentivise CCS in Europe**. If an EPS is set at 450g/kWh in 2030, the effect in 2025 does not advance early CCS, while the effect in

[5] The UK being the notable exception
[6] Each measure was implemented in the model at a value selected following research to measure its effectiveness
[7] FiPs are similar to feed-in tariffs (FiTs)in that both offer long-term contracts providing cost-based financial support to new generating technologies. Whereas FiTs offer a fixed price for the electricity produced in place of the market price, FiPs give producers a premium that supplements wholesale electricity revenues. These premia can either be fixed, exposing producers to market dynamics, or flexibly top up market revenues to a pre-determined 'strike price', as with contracts for difference.

2050 is small. It would also lead to a shift to gas, and not CCS, in the early years. An EPS set at 225g/kWh in 2030, on the other hand, prevents investment in unabated gas and gas with CCS is selected; it then advances lignite, coal and gas CCS and by 2050 increases the total level of CCS deployment. Due to the grandfathering of existing plants, an EPS therefore cannot be expected to be introduced and enforced before 2030, by which date CCS technology is expected to be mature.

In order to assist governments, ZEP would be pleased to model specific test cases on request.

- **CCS will create *and* preserve hundreds of thousands of jobs across Europe**

Based on the modelling, the deployment of CCS in Europe will create *and* secure an estimated total of 330,000 jobs[8] in fuel supply, CCS equipment manufacture, plant operation and CO_2 storage facility operation, while creating a whole new infrastructure for CO_2 transport and storage which can also be utilised by energy-intensive industries (e.g. steel, cement, refining etc.).

- **CCS will strengthen security of energy supply for Europe**

The rapid growth of renewables in Europe, alongside the exploitation of indigenous fuel sources, is an important step towards ensuring diversity in energy supply. However, the modelling shows that intermittent renewable generation needs to be supported by conventional power plants operating in base-, medium- *and* peakload. Without CCS, this support would come from a narrower range of fuels. With CCS, support will be provided by a mix of gas, lignite and coal – the latter being indigenous to Europe, thus strengthening security of energy supply.

- **Modelling results for CCS are insensitive to input variations**

The sensitivity of the model and input data was assessed by varying assumptions in the GCAM model, fuel prices, CO_2 prices and electricity demand: cases included a 25% increase in fuel prices, 100% increase in fuel prices, a reduction in CO_2 price and a reduction in European electricity demand. While modelling results are always dependent on the inputs, it was found that the results of the baseline case were insensitive to these changes in terms of CCS deployment.

- **Urgent policy actions are needed to deliver EU energy and climate goals for 2030**

If the European power industry is to reduce CO_2 emissions substantially and cost-effectively by 2050, the modelling shows that CCS must play a significant role in any future energy system. Yet without transitional support measures for CCS demonstration and early deployment, CCS will not be widely deployed in time to meet EU climate targets.

Transitional measures are also needed to stimulate CCS in industry sectors *beyond* power[9] (e.g. iron, steel, cement, refining) – now expected to deliver 50% of the global emissions reductions required from CCS by 2050.[13] Indeed, in some industries, it is the *only* means of achieving deep emission cuts. Several have almost pure CO_2 streams, dramatically reducing the cost of CO_2 capture, while clustering different CO_2 sources will result in significant economies of scale for both industrial *and* power projects.

Finally, in order to fulfil the significant potential of Bio-CCS,[11] negative CO_2 emissions via the capture and storage of biogenic CO_2 must also be rewarded under the ETS – to the same extent as for fossil CCS.

The window of opportunity is vanishing fast. Transitional support measures are vital to ensure early CCS demonstration in Europe – and wide deployment by 2030. 'Business-as-usual' is not an option.

---

[8] Including both the construction and operational period

[9] See ZEP's report: "CCS in energy-intensive industries: an indispensable route to an EU low-carbon economy": www.zeroemissionsplatform.eu/library/publication/222-ccsotherind.html

1 CCS in Europe: critical for jobs, industry *and* the environment

1.1 EU climate targets cannot be achieved cost-effectively without CCS

The European Commission's Communication on CCS[1] reaffirms its critical role in meeting Europe's energy, climate *and* societal goals:

- **CCS clusters will create thousands of skilled jobs**, distributed throughout the entire economy – from engineering to manufacturing to operations management, and many other specialist roles (see section 1.3). CCS clusters could also generate, both directly and indirectly, an economic impact totalling billions of euros as early as 2030[10] – along with the potential to export this know-how worldwide.

- **CCS will also preserve thousands of jobs in industries *beyond* power**,[9] such as iron, steel, cement, refining (see section 1.3). Indeed, in some sectors, CCS is the *only* means of achieving deep emission cuts. Energy-intensive industries are the backbone of manufacturing value chains for both traditional *and* emerging technologies – including renewable energy.

- **CCS will also complement the large-scale deployment of intermittent renewable energy** with low-carbon baseload *and* balancing generation – ensuring a reliable energy supply.

- **Bio-CCS[11] is the only large-scale technology that can *remove* CO_2 from the atmosphere** – in both power and industrial sectors. When combined with sustainably sourced biomass, it means CCS can move beyond zero emissions to deliver net negative emissions (in addition to any CO_2 reductions achieved by replacing fossil fuels with the biomass). Certain biofuels production routes could provide 'low-hanging fruits' for early, low-cost CCS deployment and in the US, Bio-CCS is already being deployed at industrial scale.

- **Europe cannot be decarbonised cost-effectively *without* CCS**: for example, a 10-year delay in CCS deployment will increase the global costs of decarbonising the power sector alone by €750 billion.[12]

- **CCS must therefore account for ~20-30% of the EU's total CO_2 reductions by 2050[13]** in the power sector, while industrial applications are expected to account for half of the global emissions cuts required by 2050 from CCS.[12] To put into perspective, one average 900 MW CCS coal-fired power plant (when operated in baseload) can abate ~5 million tonnes of CO_2 a year – equivalent to 1,000 wind turbines.

With annual investments worth billions of euros, CCS will therefore create *and* preserve jobs, boost industry and fuel economic growth, enabling Europe to compete on the world stage as a leader in low-carbon energy technologies. However, while it has all the skills, technology and expertise required, it is currently falling behind countries such as Canada, Australia, China and the US in the demonstration and deployment of CCS.

1.2 CCS will lower the cost of European power *and* complement other low-carbon power options

Billions of euros have already been invested in CCS by industry and plants such as Sleipner and Snøhvit in Norway are already storing ~1.7 million tonnes of CO_2 a year. However, CCS is at a different stage from other low-carbon technologies: while individual elements of the value chain are proven, it still needs to be scaled up to large, integrated demonstration projects, with huge potential to drive costs down – from both technology improvements and economies of scale. This is why confidence in the technology is so high and why final investment decisions have already been taken on large-scale demonstration projects worldwide.

[10] www.co2sense.co.uk/files/2113/5031/6058/CCS_CO2Sense_Exec_summary_FINAL.pdf

[11] See "Biomass with CO_2 Capture and Storage (Bio-CCS) – The way forward for Europe" published by ZEP and the European Biofuels Technology Platform, 2012: www.zeroemissionsplatform.eu/library/publication/206-biomass-with-co2-capture-and-storage-bio-ccs- the-way-forward-for-europe.html

[12] International Energy Agency

[13] http://ec.europa.eu/energy/energy2020/roadmap/doc/com_2011_8852_en.pdf

The ZEP cost reports[14] also give confidence that following a successful demonstration, CCS will lower the cost of power[15] and complement the full low-carbon power portfolio, including on-/offshore wind, solar power and nuclear. This is echoed in the report published by the UK's CCS Cost Reduction Task Force in May 2013.[16] Early movers will therefore incur significant upfront costs, with little transport and storage infrastructure in place and an uncertain environment for long-term investment. As with any low-carbon technology, investors in CCS need a stable, predictable pathway for deployment.

1.3 CCS will create jobs *and* preserve thousands of jobs across Europe

In the years to come, the EU will benefit greatly from the creation of green jobs. Notable studies have shown that the renewable energy sector generates many jobs.[17] It is essential to promote this low-carbon transition.

However, policies aimed at 'greening' the economy will have an impact on employment in many carbon-intensive sectors and require the adaptation of skills and working methods. In order to reap the full employment benefits, it is therefore necessary both to support emerging green sectors *and* promote emissions reductions in traditional industries.

Here CCS will play a critical role: rather than dividing societies into low-carbon 'winners' and 'losers', it will make the low-carbon transition much more socially inclusive by creating *and* securing hundreds of thousands of jobs in power and other energy-intensive industries. For example, studies have shown that CCS demonstration projects such as White Rose[18] will directly contribute to the creation of 2,500 jobs for 3-5 years in construction and 91 jobs during operation.

More significantly, as the EUA price increases, CCS will also help preserve very many jobs in mining, electricity generation and energy-intensive industries included in the ETS. Just to give one example, the modelling shows that without CCS, electricity generation from lignite will be drastically reduced in the EU by 2030 due to the rising cost of CO_2 emissions. Because lignite power plants rely on local mining, phasing them out completely could come at a cost of 25,000 direct jobs and a further 63,000 indirect jobs in Germany alone.[19] If this is extrapolated to include *all* EU lignite mining and electricity generation, this totals as many as 182,000 direct and indirect jobs.

CCS can also be applied to energy-intensive sectors (e.g. iron, steel, cement, refining etc.) – sectors that the OECD has specifically identified as facing significant challenges as a result of rising CO_2 prices.[20] Together, these industries represent ~1.3 million jobs in the EU,[21] further highlighting the crucial role CCS plays in an overall policy framework that enables the EU to reconcile its reindustrialisation targets with the steep emissions reductions necessary to tackle climate change.

1.4 If urgent policy action is taken, CCS can still be widely deployed by 2030

Until recently, Europe led the world in supporting CCS, yet in the past 18 months it has been unable to deliver any large-scale CCS demonstration projects. There was deep disappointment that no projects were selected in Phase I of the 'NER300'[22] – despite the fact that it was set up expressly to "help stimulate the construction and operation of up to 12 commercial (CCS) demonstration projects" (Article 10a.8, EU ETS

---

[14] www.zeroemissionsplatform.eu/library/publication/165-zep-cost-report-summary.html

[15] €70-90/MWh for CCS with coal, €70-120/MWh with gas, operating in baseload (7,500 hours equivalent full load each year); fuel costs for coal and natural gas are 2.0-2.9 €/GJ and 4.5-11.0 €/GJ respectively

[16] A collaboration between Department of Energy and Climate Change, The Crown Estate and industry: www.gov.uk/government/publications/ccs-cost-reduction-task-force-final-report

[17] Ecorys (2012), 'The number of Jobs dependent on the Environment and Resource Efficiency improvements'

[18] CO2Sense (2012), 'The national, regional and local economic benefits of the Yorkshire and Humber carbon capture and storage cluster'

[19] Energy Environment Forecast Analysis (2011), 'Die Rolle der Braunkohlenindustrie für die Produktion und Beschäftigung (The role of the lignite industry in economic output and employment)'.

[20] OECD (2012), "The Jobs Potential of a shift towards a low-carbon economy", pp. 44-49

[21] Figures from Eurostat

[22] In 2008, the EU agreed to set aside 300 million EUAs from the New Entrant Reserve (NER) under the EU Emissions Trading Scheme (ETS) Directive to demonstrate CCS and innovative renewable energy technologies

Directive); and that only one CCS application was submitted for Phase II. Yet viable projects are still being actively progressed in several European countries.

The window of opportunity is vanishing fast. Additional policy action is therefore vital to ensure early CCS demonstration in Europe – and wide deployment by 2030. 'Business-as-usual' is not an option.

It is the lack of a solid business case that is still hampering the development of CCS in Europe, i.e. the absence of:

1. Transitional measures to cover the incremental costs of demonstration and early deployment projects in order to ensure power plant operation *over the lifetime of the project*
2. Long-term investor confidence, i.e. a robust, predictable EUA (Emission Unit Allowance) price under the ETS
3. A robust regulatory framework: the current regime[23] imposes unreasonable – and unnecessary – burdens, risks and uncertainties on storage providers, creating investment hurdles not confidence.

All three factors have a strong interdependency and are a prerequisite for demonstration, post demonstration and the wider deployment of CCS.

1.5 Transitional measures are essential to drive CCS demonstration and deployment

EU policy currently offers targeted support (e.g. feed-in-tariffs) to wind, solar, biomass, biofuels etc. – but not CCS. Indeed, few Member States[24] have a national strategy for CCS development and fewer still have targeted policies to facilitate demonstration and deployment. CCS has therefore had to rely solely on the ETS.

In the long term, ZEP believes the ETS to be the most cost-efficient mechanism for driving decarbonisation in the EU: a high EUA price will increase the marginal cost of unabated generation, making CCS economically competitive. However, the financial crisis has created an oversupply of EUAs which has driven the EUA price down to a level where, in the short term, it provides no incentive to invest (€2.5-5/tCO_2 in Q2 2013).

This situation will continue until the ETS has undergone structural reform – in particular setting a tighter cap out to 2030 and beyond, as part of a holistic EU Energy and Climate Policy framework for 2030. Yet even if action is taken now, it will still not result in EUA prices that are high and robust enough to deploy CCS at the rate required to achieve energy and climate goals for 2030.

Transitional support measures for CCS are therefore essential to cover the incremental costs of demonstration and early deployment projects – and create a level playing field with other low-carbon technologies. Such measures should have the least possible negative effect on the ETS, with a phasing-out plan developed as the ETS strengthens and the technology matures, allowing CCS to stand on its own merits in the longer term. Investors, on the other hand, need to be sure that *the power plant can dispatch and operate over the lifetime of the project* so that the return on the CCS element is indeed realised. The goal: to provide a robust, predictable revenue stream and earn an appropriate level of return for investors.

In 2012, ZEP published its report, "*CO_2 Capture and Storage: Creating a secure environment for investment in Europe*,"[25] which provided recommendations for transitional measures urgently needed to support investment in CCS (see Annex III for a review of these measures based on their status in the EU and beyond.) Using state-of-the-art modelling, ZEP has now gone further and assessed which measures would be most effective for key countries in order to drive CCS demonstration and deployment in time to meet EU climate goals – for the *cost-effective* decarbonisation of Europe.

---

[23] Directive on the geological storage of carbon dioxide (2009/31/EC)
[24] The UK being the notable exception
[25] www.zeroemissionsplatform.eu/library/publication/211-ccs-market-report.html

2 Current status of the European electricity market

2.1 The critical role of the merit order in revenue risk

As well as the Levelised Cost of Electricity (LCoE) of a technology, its position in the merit order has important implications for its commercial attractiveness. New plants with high upfront costs, such as CCS, may require high load factors in order to recoup investments and generate an acceptable return for operators, and uncertainty surrounding the load factor is a commercial barrier to deployment.

What is the merit order?

Electricity is generally dispatched to the grid through a form of 'merit order' and the variable operating cost of different generators – also known as their marginal cost of production – determines which units the power system dispatches to meet electricity demand at any given moment. The electricity price is determined by the plant with the highest cost which is still needed to satisfy the demand.

Strictly speaking, there is no fixed 'merit order' in liberalised electricity markets such as in the EU: generators are free to trade as they see fit within the constraints of their operating characteristics and the regulatory framework. However, it is a useful shorthand to describe what typically happens in the market, i.e. a plant that has high upfront capital costs and low variable operating costs (e.g. nuclear power) will normally run whenever it is physically capable of doing so, however low the electricity market price. Progressively higher variable cost facilities will operate according to seasonal and daily demand variation, as market prices rise.

It is important to note that this 'conventional' dispatch order does not necessarily reflect the LCoE of various energy sources, their environmental sustainability, or the long-term costs of the system as a whole. The disaggregated decisions of individual competing agents in the electricity market therefore do not ensure system-wide optimisation of lowest LCoE in the short term. In the long term, however, the system optimises itself towards lowest LCoE by bringing in new optimised capacity with a view to its expected utilisation – provided policy changes take into account investment cycles typical in the power sector (30-60 years).

Although the merit order minimises the operating costs of an existing power generation portfolio, it does not ensure that the total fixed costs of a majority of power plants are covered by the electricity price.

Traditionally, low marginal cost fossil plants (e.g. highly efficient coal and lignite) rank high on the merit order just behind nuclear, dominating baseload generation and receiving high load factors.[26] Older, less efficient coal plants and combined cycle gas facilities operate as mid merit, while open cycle gas plants and oil provide rapid response peaking plant.

However, the traditional merit curve is undergoing change with the deployment of large-scale incentives for renewable generation at national and EU level. Renewable energy sources (RES) such as wind are characterised by high capital cost and very low marginal cost, as the technology has zero fuel costs. Whenever the wind is blowing, the electricity produced is therefore sold onto the market regardless of the price, receiving the highest dispatch priority. On top of this, the EU requires Member States to give RES priority access to the grid.[27]

The result is a shifting of the traditional merit curve, with intermittent RES – whenever available – occupying baseload, alongside inflexible, low marginal cost nuclear generation. Lignite, coal and gas capacity is displaced, migrating to mid-merit generation (Figure 1 below). This effect is anticipated to accelerate as the

[26] Vivideconomics (2011) Productivity Commission Electricity dispatch regimes
[27] Article 16. Directive 2009/28/EC

deployment of RES ramps up. (N.B. the shape of the merit order changes significantly day-to-day, depending on the renewable electricity in the grid).

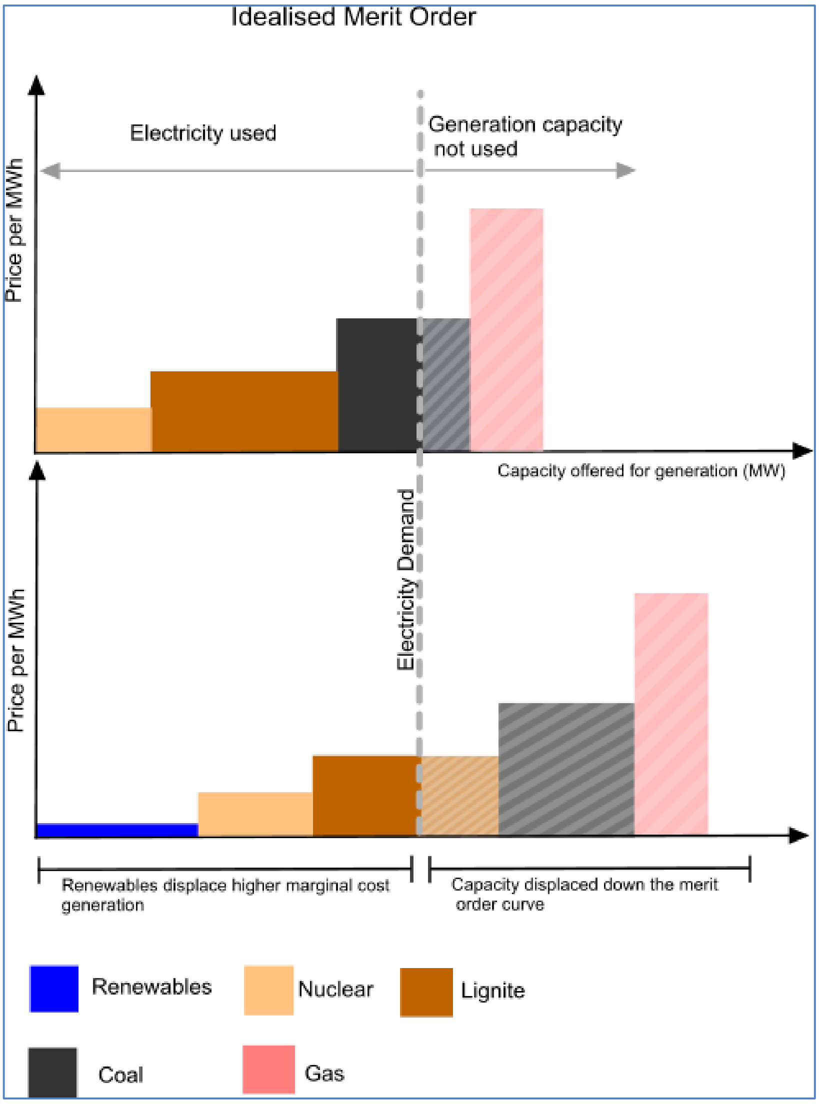


Figure 1: Impact of RES on electricity market dispatch

The EU electricity market is currently characterised by a low EUA price, combined with high levels of intermittent renewables generation. Under these abnormal conditions, the even higher marginal cost of CCS generation means that it would have a poor ranking in the merit order. This, in turn, would reduce its load factor, curtailing revenue generation. (E.ON estimates coal CCS load factor in the UK to be between 60-80% to 2025, declining to 45-60% by 2035 with the prevailing market structure.[28])

The lower dispatch of electricity from a capital-intensive investment such as a CCS plant will substantially increase revenue risks, making it difficult to secure higher shares of debt funding. Uncertainty surrounding expected load factors may therefore dissuade investment in CCS, as much of the risks of this investment would have to be internalised.

[28] E.ON in the UK response to DECC Call for Evidence on 2050 Pathways Analysis, www.eon-uk.com/2050_pathways_response.pdf

Figure 2 below shows the LCoE and CO_2 avoidance costs from an optimised coal-fired power plant with CCS at increasing load factors. It illustrates that achieving high plant availability is key to keeping CCS costs competitive as both costs decrease as plant load factor increases.

As CCS is expected to remain relatively capital intensive in the coming decades, prospective operators will seek high utilisation of their facilities. CCS operating as baseload enables the plant to be operated in the most economically efficient manner – a decrease of yearly full load operating hours from just 7,500 to 5,000 increases the LCoE by 25%. In fact, the high availability of power plants with CCS – including at yearly peak time – is a key benefit of the technology and should be taken into account by energy planners.

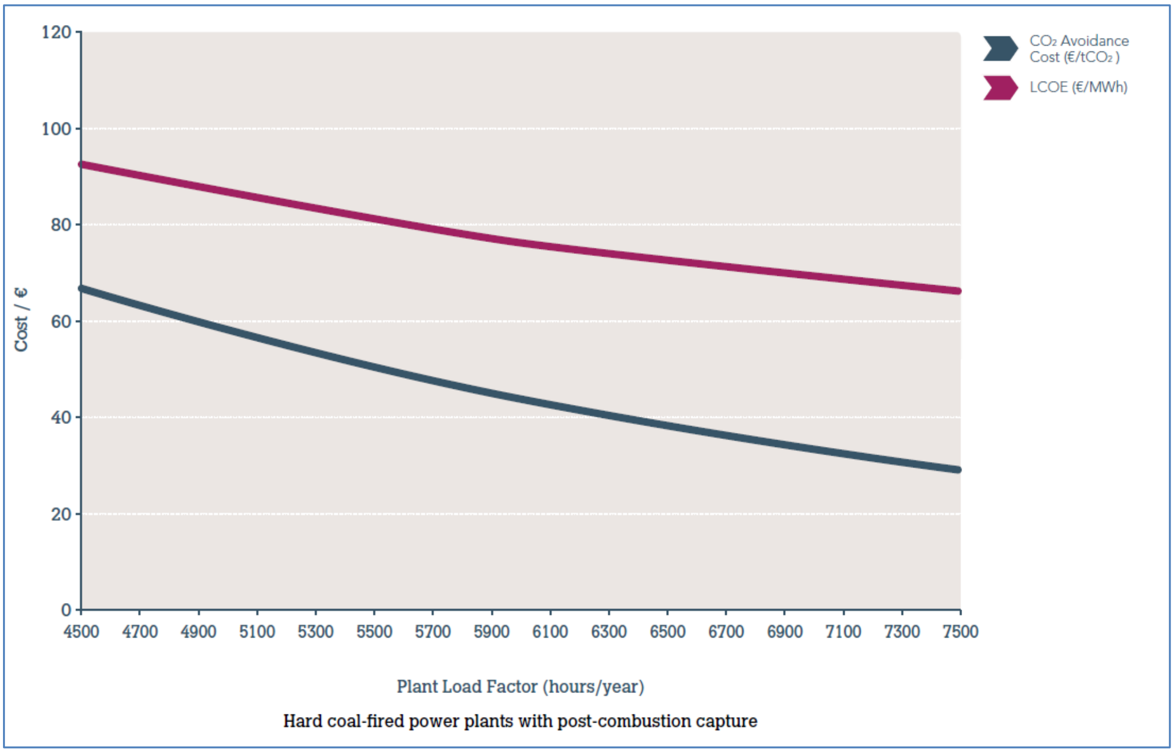


Figure 2: Dependence on Plant Load Factor for optimised coal-fired power plants[29]

CCS facilities will also likely be required to operate with a degree of flexibility in order to provide low-carbon system support services. Many techniques exist to further increase the operational flexibility of coal or gas CCS plants, such as temporarily reducing the rate of capture, storing amine for post combustion, buffering hydrogen for later use at an IGCC plant, or storing oxygen in the case of an oxy-fuel plant. However, such modifications may further increase the capital outlay and operational costs of CO_2 transport and storage.[30]

2.2 CCS electricity needs to be sufficiently rewarded

Within the framework of strong, targeted support for intermittent RES, the load factor of CCS can be increased by displacing unabated generation in the merit order. As the short-term marginal cost of unabated coal or gas is the cost of fuel, the EUA price, and operating and maintenance costs, this can be achieved via the following policy approaches:

[29] "The Costs of CO_2 Capture, Transport and Storage", p.30, ZEP 2011: www.zeroemissionsplatform.eu/library/publication/165-zep-cost-report-summary.html

[30] Lohwasser, Madlener (2009) "Impact of CCS on the Economics of Coal-Fired Power Plants – Why Investment Costs Do and Efficiency Doesn't Matter" E.ON Energy Research Center

1. *Directly modify the electricity dispatch system to reflect the value of low-carbon generation*
   In some regulated electricity markets (e.g. China), modifying the rules that determine the dispatch order of generation capacity could also be used to preferentially dispatch low-carbon generation 'out of merit'. EU system operators do have some leeway to classify units as running in out-of-merit dispatch so as to provide reactive power to support transmission grids and hold units as "spinning-reserve". However, the aim of this is to substantially reduce the market clearing price at times when rapidly increasing demand would otherwise cause it to spike. Running large-scale CCS out of merit would therefore be in conflict with the basic operating principles of a common liberalised electricity market that the EU has worked to attain since 1996.

2. *Significantly increase the costs of operating an unabated plant via the EUA price (Figure 3 below)*
   This policy approach increases the marginal cost of unabated generation, requiring operators to purchase EUAs. Reducing the competitiveness of unabated capacity relative to CCS capacity would give CCS a place in the mid-merit that would ensure investors of a sufficient return. However, the current low EUA price means that the scenario depicted in Figure 3 has not materialised, undermining investor confidence.

3. *Provide a sufficient reward to generate CCS electricity*
   Without a high enough EUA price to penalise unabated electricity generation, additional revenues for CCS – such as a FiP – are essential to supplement the wholesale electricity price, decrease the relative marginal costs of CCS and ensure it a high enough place in the merit order. Without such support, even if the technology were deployed, there would be no commercial rationale to operate the plant.

For example, the UK's contracts for difference (CfD) will reduce the short-term marginal cost of CCS by the strike price less the reference price. UK studies[31] have shown that if set correctly, this will be sufficient for CCS plants to displace unabated facilities in the merit order curve – independent of the EUA price – resulting in significantly higher load factors.

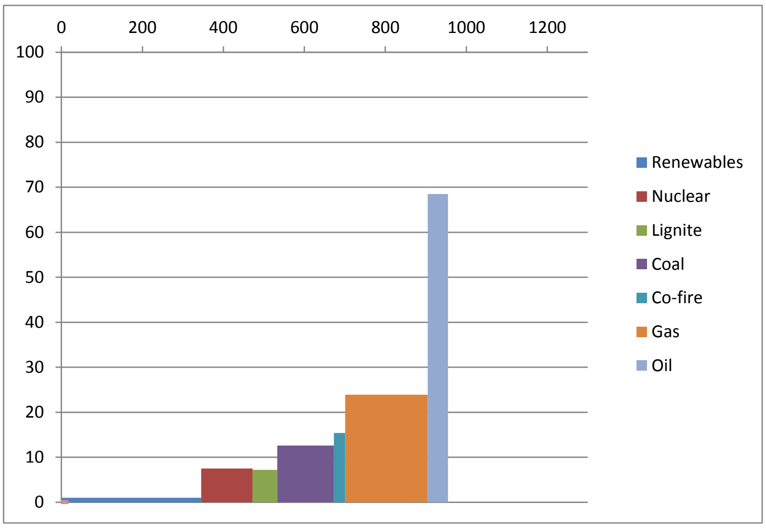
Two EU-level precedents already exist for providing priority dispatch in the electricity market: RES are ensured priority access with the 2009 Renewable Energy Directive[32], while the 2012 Energy Efficiency Directive mandates priority access for high efficiency combined heat and power facilities (with provisos that this does not endanger grid stability).[33] Although it is left to Member States to decide how to implement this, feed-in tariffs (FiTs) and green certificate schemes not only ensure sufficient and predictable income for operators, but improved position in the merit order for these technologies.

[31] For example: "LCP's assessment of the dispatch distortions under the Feed-in Tariff with Contract for Differences policy", 2012: www.gov.uk/government/uploads/system/uploads/attachment_data/file/48443/5693-lcp-assessment-of-the-dispatch-distortions-under-t.pdf

[32] Article 16. Directive 2009/28/EC

[33] Article 15. Directive 2012/27/EU

2010



2030

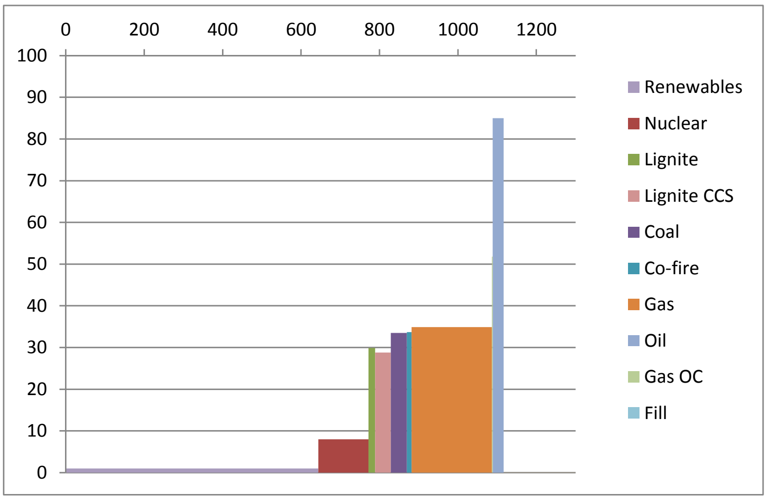


Figure 3: Merit order simulation from the modelling for 2010 and 2030 (€/MWh vs GW capacity)

3 Modelling the lowest-cost route to decarbonising European power

3.1 Uniquely designed to select the lowest-cost investments, country by country

ZEP has developed a model of the European power industry, based on an existing model from the Norwegian University of Science and Technology (NTNU) and linked to the Global Change Assessment Model (GCAM). The model searches for the lowest-cost solution for the power market by selecting appropriate new investments to meet expected electricity demand and replacing retired plants that exceed a defined lifetime – country by country. It also models the costs of inter-country trading and investments needed in additional inter-country high voltage links.

The GCAM model provides inputs on the global economy, energy demand and CO_2 price, according to several scenarios. ZEP selected the 'Global 20-20-20'scenario[34] equivalent to EU policy and the 450 ppm scenario[35] equivalent to global emission targets for input on the EUA price, fuel commodity prices, energy demand in the power sector in Europe and economic growth. The NTNU model also includes a dispatch model based on a merit order concept that can model the effect of dispatching conventional and intermittent RES capacity, taking in account the capacity factor of intermittent RES using historic weather data by country on a stochastic basis.

First, baseline test cases were run to establish the current electricity generation infrastructure of Europe, based on published data for 2012 and a calculated projection of new-build power plants from now until 2050, taking into account (see Annex I for details):

- Published government capacity constraints (e.g. nuclear)
- Physical constraints (e.g. onshore wind)
- Technology investment costs and cost learning curves provided exclusively by ZEP member organisations, based on existing pilot and planned demonstration projects[10]
- Operating costs for each plant type (including maintenance, fuel and CO_2 prices), using data from ZEP member organisations, global fuel and CO_2 prices from GCAM as they progress over time for both the EU and global scenarios, and the global model for economic development to 2050. The costs of the various technologies evolved in 5-year steps; the costs of CCS were taken from the ZEP cost reports.[9] The costs of all technologies, including CCS, reduce with time due to learning curve effects, while performance was calculated to increase progressively. The costs of CO_2 transport and storage (500 km to an offshore deep saline aquifer) were included rather than local onshore storage because ZEP recognises that offshore storage is easier to permit and is the higher cost case for the model. The cost of transporting electricity from offshore wind farms was also included.

The model calculated the level of CO_2 emissions reductions in 2050 country by country and for Europe as a whole. This resulted in a reduction of 72% overall for electricity generation in Europe, compared to 2010.

3.2 Testing the sensitivities

Sensitivity cases were then run using the 20-20-20 scenario in place of the GCAM 450 ppm scenario (see Annex II for details). Electricity demand in the 450 ppm scenario increases to 2050 because a high level of electrification of transport is modelled which implies higher low-carbon electricity generation. Overall energy use is not incompatible with demand reduction in current electricity use. The CO_2 price is lower in the 20-20-20 scenario, but the modelling showed that it was still high enough to drive 64 GW of coal CCS towards 2050. Sensitivities were run to reduce the demand in Europe to a level equivalent to today, simulating a very

[34] A global extension of the EU '20-20-20' policy, this defines individual and progressive goals for emissions reduction, share of renewable energies, energy efficiency improvements and share of biofuels in transport for every region in the world

[35] Limits atmospheric CO_2-equivalent concentrations by placing a price on GHG emissions, equivalent to keeping the rise in average global temperature to 2°C by 2100. N.B. The European modelling does not ensure that global targets will be met by the calculated investments in electricity infrastructure.

strong demand management policy and 149 GW of coal CCS was selected at 2050. This indicates that whether electricity demand increases in order to electrify transport, or is maintained flat by demand reduction (as is the policy of some Member State governments), the role of CCS in the generation portfolio remains the same.

Sensitivity cases were also run with all fuel prices increased by 25% and 100% respectively. The effect of +25% showed a moderate shift from unabated gas to RES, lignite and coal. The effect of 100% increase was a shift from unabated gas to RES, lignite and coal and an earlier introduction of lignite and coal CCS. At 2050, 71 GW of lignite CCS, 89 GW of coal CCS and 81 GW of gas CCS were selected, as well as 94 GW of CCS with biomass co-firing. This shows that there is a price relationship between coal and biomass at which the model selects biomass co-firing over pure coal.

90% CO_2 capture from a 10% biomass co-firing plant results in almost net zero CO_2 emissions, provided the biomass is sustainably sourced. The 10% of CO_2 created, but not captured, by the plant can be offset by the 10% of the fuel that came from sustainable biomass. Under these fuel price conditions, it may be concluded that a 100% biomass CCS plant would also be selected since if 10% gives a lower cost, so also does 100%. Such plants would be CO_2 negative, i.e. remove CO_2 from the atmosphere to a volume of 90% of their stack emissions. Bio-CCS is the only industrial-scale method of *removing* CO_2 from the atmosphere and if sufficient sustainable biomass was grown and harvested, on an annual short cycle basis, this case indicates that negative emissions could be achieved. It is nearly twice as effective in reducing emissions as the same GW of wind or solar plant which are almost neutral on CO_2 emissions, but can never remove CO_2 from the atmosphere.

Test cases varying the relative fuel prices between coal and gas showed that a shift occurs between lignite, coal and gas to reflect the lowest cost. The amount of CCS deployed changes, as well as the split between RES, nuclear and fossil CCS. However, this shows that the baseline case modelling of a ramp-up of CCS remains true for the range of sensitivities tested.

Next, cases were run to ascertain the effects of 'policy' constraints on the level of implementation of a technology in a given country (potentially in addition to the published constraints mentioned above). It was observed that lignite with CCS, then coal with CCS, were the preferred investments in the later years of the modelling, once political constraints on nuclear in Germany, Switzerland and France had come into effect and onshore wind sites were full. In order to represent a greater level of variation in the generation mix, a constraint was also imposed on the maximum level of lignite (representing the current level + 10% for countries with lignite) and a maximum level of coal (representing the current level + 10% per country).

After lignite and coal, CCS was next attractive for biomass co-firing (90% coal, 10% biomass). Indeed, left unconstrained, the model selected biomass co-firing CCS before gas CCS. However, since the availability of biomass in large volumes is uncertain, the model included total biomass co-firing CCS within the coal capacity constraint. To illustrate an alternative scenario, Figure 12 shows a sensitivity case with a maximum of 15 GW biomass co-firing with CCS across Europe, in addition to the coal capacity constraint. The result is that 15 GW is selected in preference to gas CCS – further confirming that biomass has a large potential for negative CO_2 emissions if combined with CCS.

Finally, the effect of the modelling on CO_2 reductions in Europe was also evaluated against some government policy targets: first, each case was run with no further constraint on CO_2 reductions, then again with a constraint to achieve over 80% reduction by 2050 (compared to today). The results were broadly similar by country – both in terms of CCS deployment *and* level of emissions reduction. The level of reduction varies from 70-85% from 2010 to 2050 which is broadly in line with EU policies. It was therefore decided to remove this constraint so that further cases do not force the model to achieve 80% CO_2 reduction and ensure that the results are based on the lowest-cost investments to meet electricity demand. It also means that the resulting emissions reductions can be compared.

3.3 The baseline case

After completing the sensitivities, three capacity cases were then applied (see Annex I for details):

1. *Partial constraint*: legally binding and known government constraints on the power sector and physical maximum capacity constraints due to geography
2. *Full constraint*: including ‘anticipated capacities’ set by government, but also projections by bodies such as the Eurelectric
3. *Partial constraint (1) + additional constraint on lignite and coal*: the model calculates that lignite CCS is the lowest-cost electricity production source in Europe. The model therefore calculates a high volume of lignite CCS in countries with lignite fuel and that generators would produce electricity for export across Europe. Even through this is realistically possible, it was decided to constrain the baseline model to allow only the current lignite fleet, plus 10% per lignite country. An additional constraint of 80%+ reduction in CO_2 emissions was also included.

A baseline case was therefore selected, comprising:

- 450 ppm GCAM input data with unmodified fuel, CO_2 prices and electricity demand
- Lignite and coal capacity constraint set at today’s level + 10%
- No 80% emissions reduction constraint
- No explicit EU or Member State subsidies for *any* technology.

Figures 4-11 below show the results of the baseline case to 2050. As the cases for the 20-20-20 and 450 ppm scenarios gave broadly similar results, only those for the latter are shown (see Annex II for more details and test cases for the 20-20-20 scenarios). A shift from unabated coal to unabated gas occurs between 2012 and 2025 when CO_2 prices are low to medium, followed by a shift to lignite CCS in 2030, coal CCS, then gas CCS, as CO_2 prices rise above €40/tonne towards 2050.

Figures 8 and 9 show the mix of electricity generation and power plant capacities by 2050, as modelled (see Table 1).

Fuel	TWh	%	GW	%
Lignite CCS	465	8	66	6
Coal CCS	1,279	23	183	15
Gas CCS	591	11	80	7
(Total CCS)	**(2,335)**	**(42)**	**(329)**	**(28)**
RES	1,447	26	549	46
Unabated gas	818	15	191	16
Nuclear	938	17	126	10
Total	**5,539**	**100**	**1,195**	**100**

Table 1: The mix of electricity generation and power plant capacities by 2050, as modelled

Figure 10 shows the reduction in annual European CO_2 emissions from 2010 to 2050. The baseline case achieves 72% reduction from electricity generation compared to 2010 levels and 76% reduction compared to 1990 levels. In the cases where CCS is not deployed, Europe achieves less than half the reductions compared to the CCS cases – and misses EU climate targets by a significant degree.

Figure 11 shows the capacity factors for existing fossil fuel plants and new CCS plants as they are introduced and operated; the model steadily reduces the capacity factor of existing plants as they age. New lignite, coal and gas CCS plants run in baseload up to 2050. Renewables balancing is achieved by old unabated fossil fuel plants (mostly gas) until they are retired, then by the new unabated gas plants with steadily falling capacity factors out to 2050. This shows that the CCS plant operating cost assumptions for baseload are valid in the model.

Figure 12 shows a case where biomass co-firing was permitted up to 15 GW.

Figure 13 shows the total power plant capacity and generation mix for the baseline case with 100% fuel price increase.

Figure 14 shows the total power plant capacity and generation mix for the baseline case with no CCS permitted.

Figure 15 shows emissions reductions for the European power industry to 2050, as modelled for the sensitivity cases. It shows that the cases where CCS is not permitted have far higher emissions due to the fossil fuel generation required for load balancing the renewables portfolio.

Figure 16 compares the costs of European electricity generation from 2010 to 2050 for four cases modelled:

1) Baseline
2) Baseline with no CCS permitted
3) Baseline with fossil fuel prices increased by 100%
4) Baseline with increased fuel prices and no CCS no permitted.

This shows that the cost of European electricity generation to the consumer would be reduced by 4% (or €11 billion) in the baseline case and 10% (or €43 billion) in the case with higher fuel prices. In short, CCS is very effective in reducing the cost of power – compared to a scenario *without* CCS – in a Europe committed to reducing emissions via the EUA price under the ETS.

Figure 17 shows the CO_2 stored as calculated by the model over the period 2010 to 2050. In the baseline case, over 240 Mt CO_2/year are stored by 2030 and over 1,400 Mt CO_2/year by 2050. The case with increased fossil fuel price achieved a similar result, but storage commenced earlier. The cases with reduced demand for power showed that by 2050 over 700 Mt CO_2 are stored every year and not emitted to the atmosphere.

During the period of deployment, an average of 16 GW of CCS is deployed each year in the baseline case, balanced between lignite/coal and gas. It is estimated that an average 450 MW CCS project[18] could secure 2,500 jobs over the three years of construction and 91 jobs in operation. By extrapolation, ZEP estimates that the deployment of CCS across Europe would create or secure 260,000 jobs in the equipment supply industry and create 65,000 jobs in the operation of the plants. Section 1.3 gives the example that lignite mining and related electricity generation in Europe employs ~182,000 jobs – while hundreds of thousands of jobs are also involved in the production of hard coal and gas – and many of these jobs could be at risk.

The cases studied in the baseline modelling show that CCS must be a critical component of Europe's future energy system if EU CO_2 reduction targets are to be met – at a relatively lower cost to the consumer. CCS also enables the use of a range of indigenous fuels in Member States and creates or preserves hundreds of thousands of jobs, while complementing and supporting the growth of renewables.

These results confirm the findings of the IEA and other experts, and show the local benefit to each of the regions and countries of Europe in deploying CCS. However, they also show that in the absence of any earlier incentives, the EUA price will not be high enough until 2030 to incentivise CCS demonstration and early deployment projects. These need to deliver results *before* 2020 so that the next wave of projects can commence from the early 2020s, leading to wide deployment by 2030.

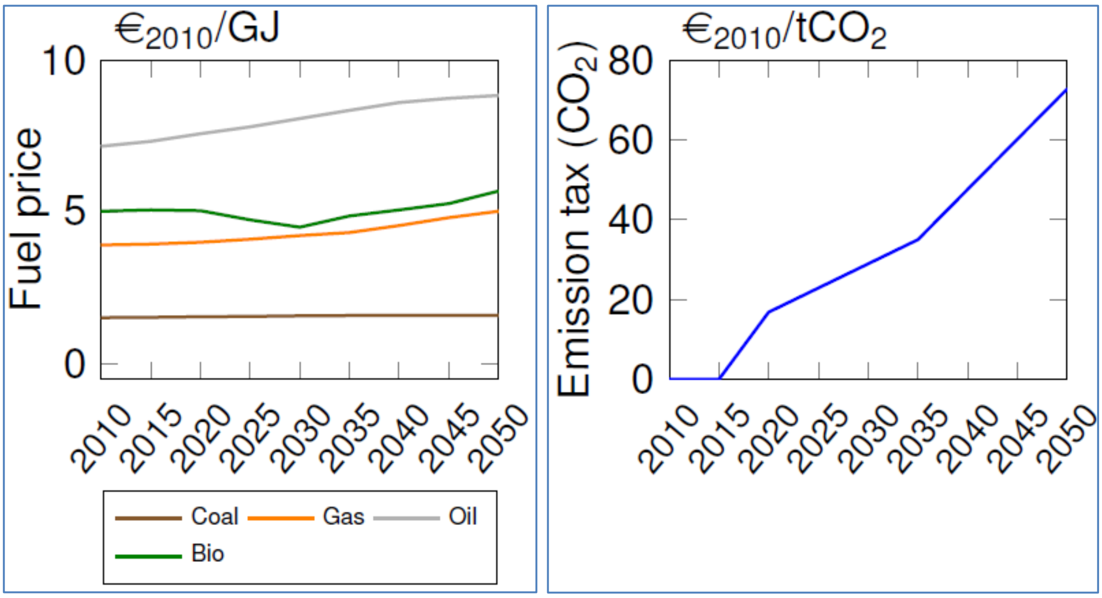


Figure 4: Baseline case: fuel and CO_2 prices for the GCAM 450 ppm scenario

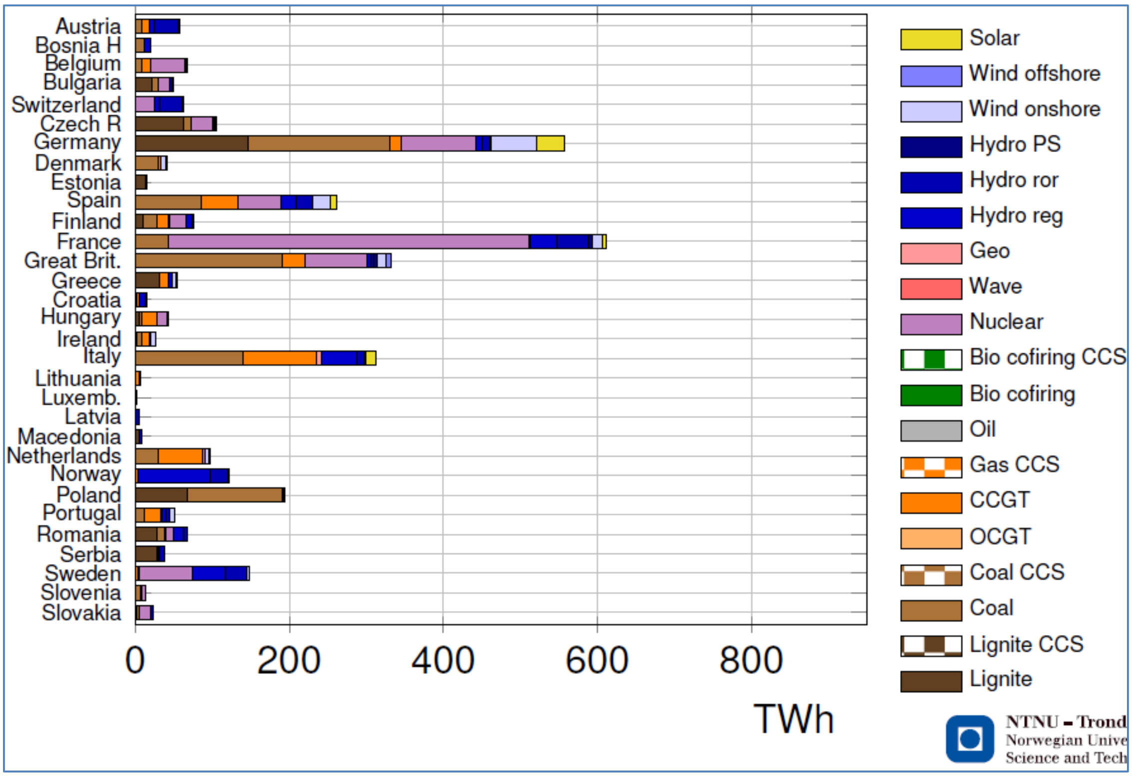


Figure 5: Baseline case: the current electricity generation mix in Europe (2010)

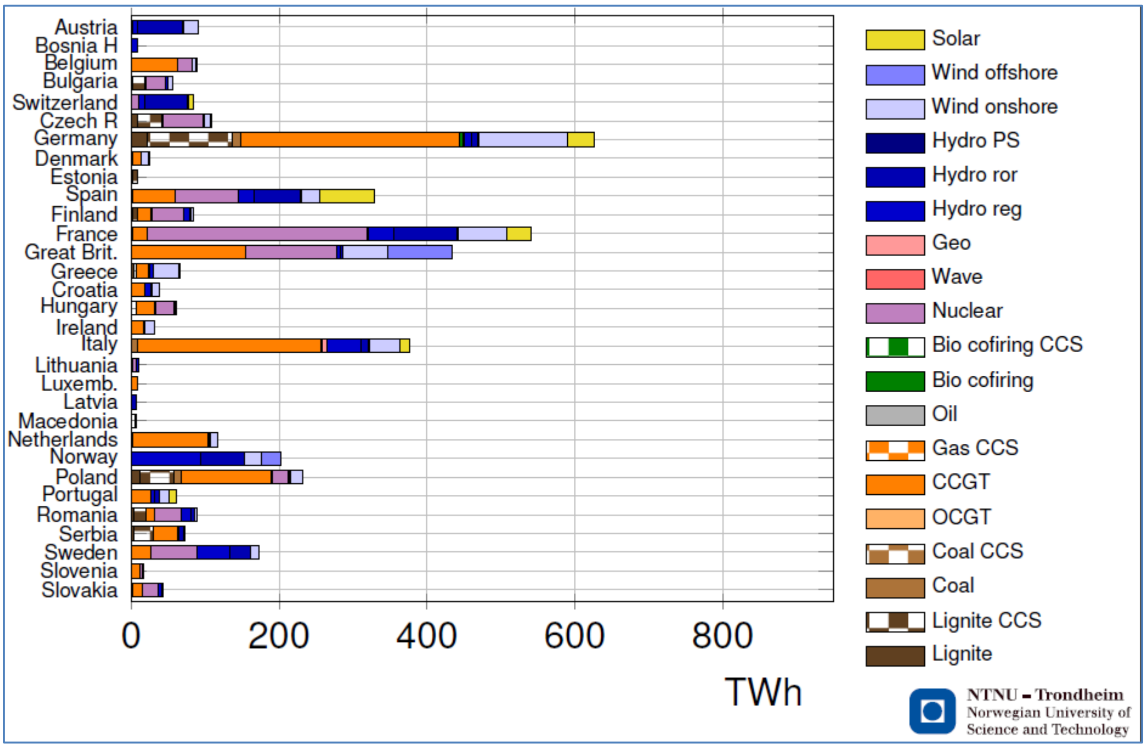


Figure 6: Baseline case: the electricity generation mix in 2030

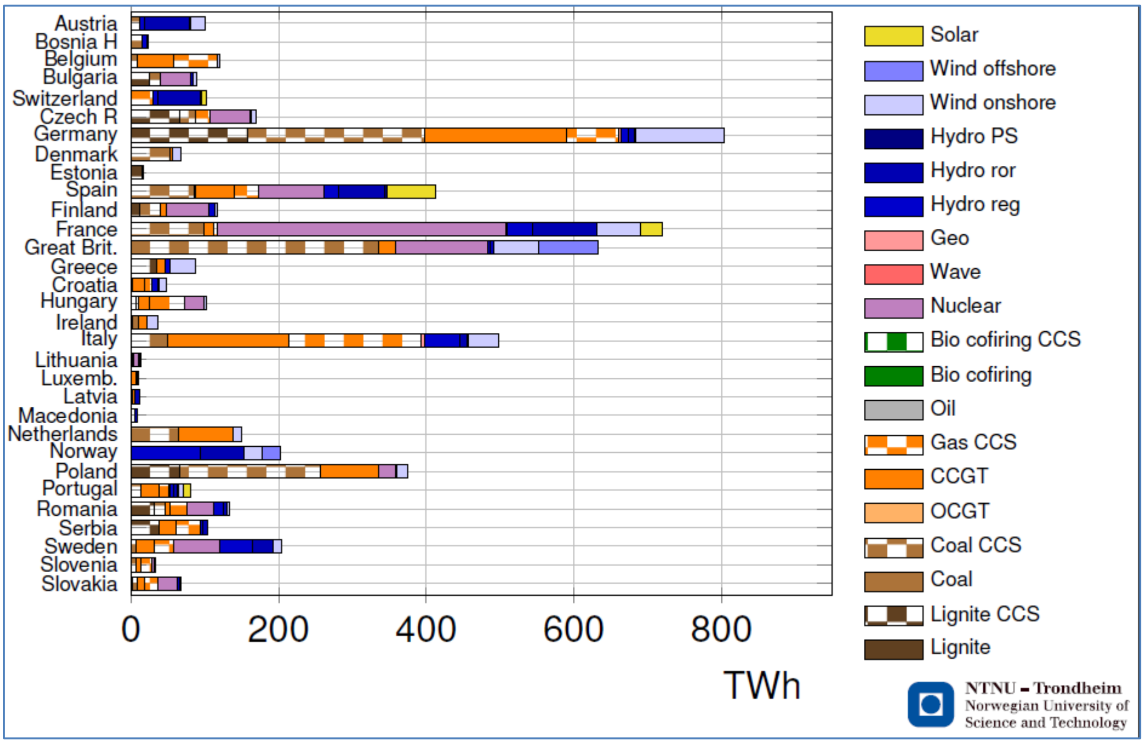


Figure 7: Baseline case: the electricity generation mix in 2050

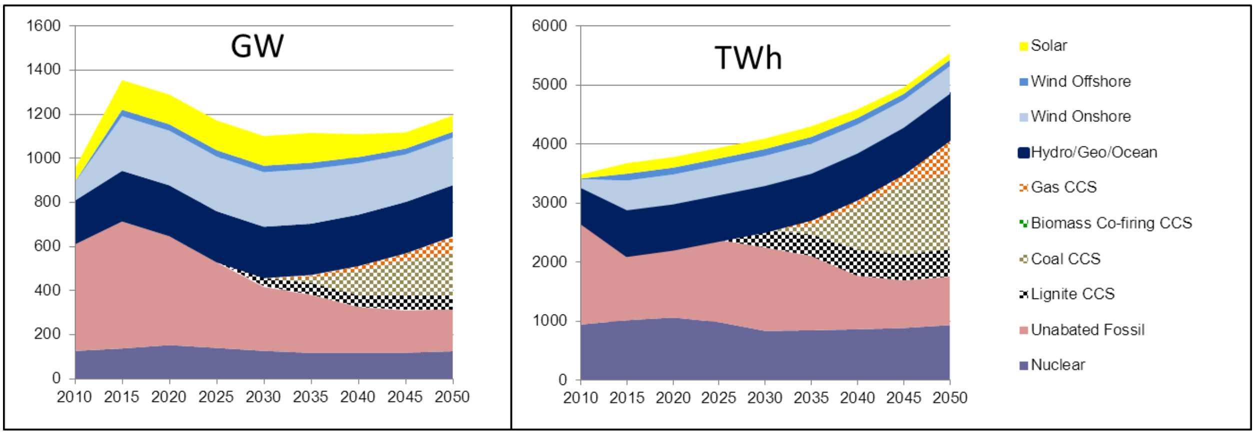


Figure 8: Baseline case: European total power plant capacity split by fuel (GW vs. year) and European electricity generation by fuel (TWh vs. year)

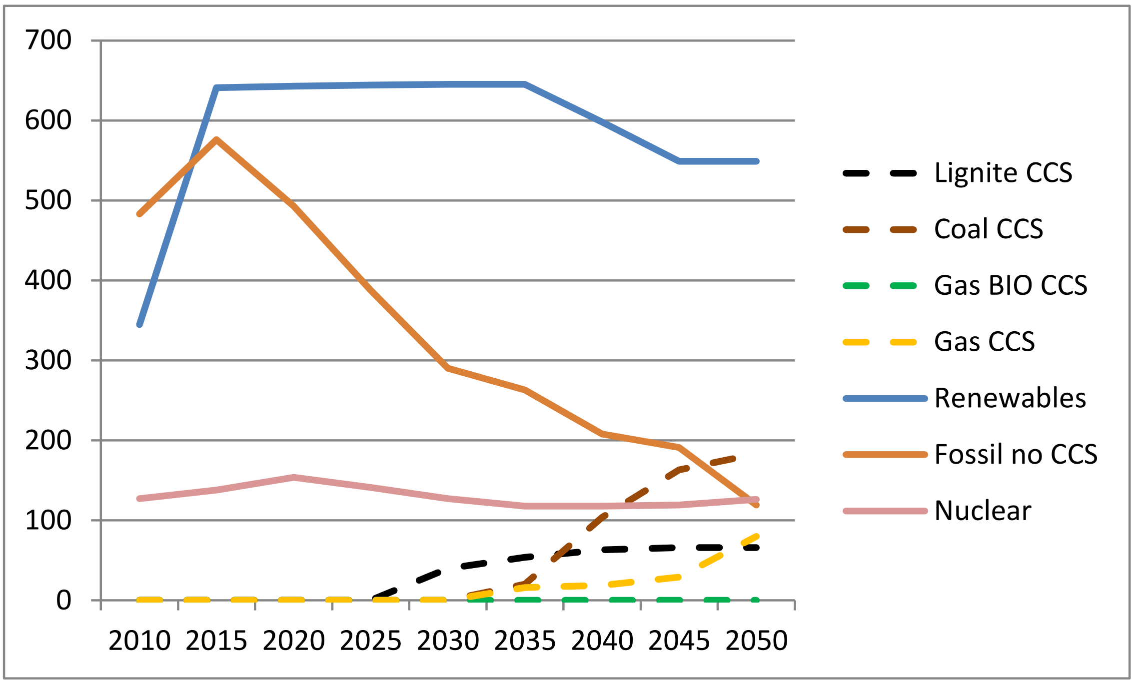


Figure 9: GW Europe – the deployment of CCS by fuel for the baseline case (by fuel vs. year)

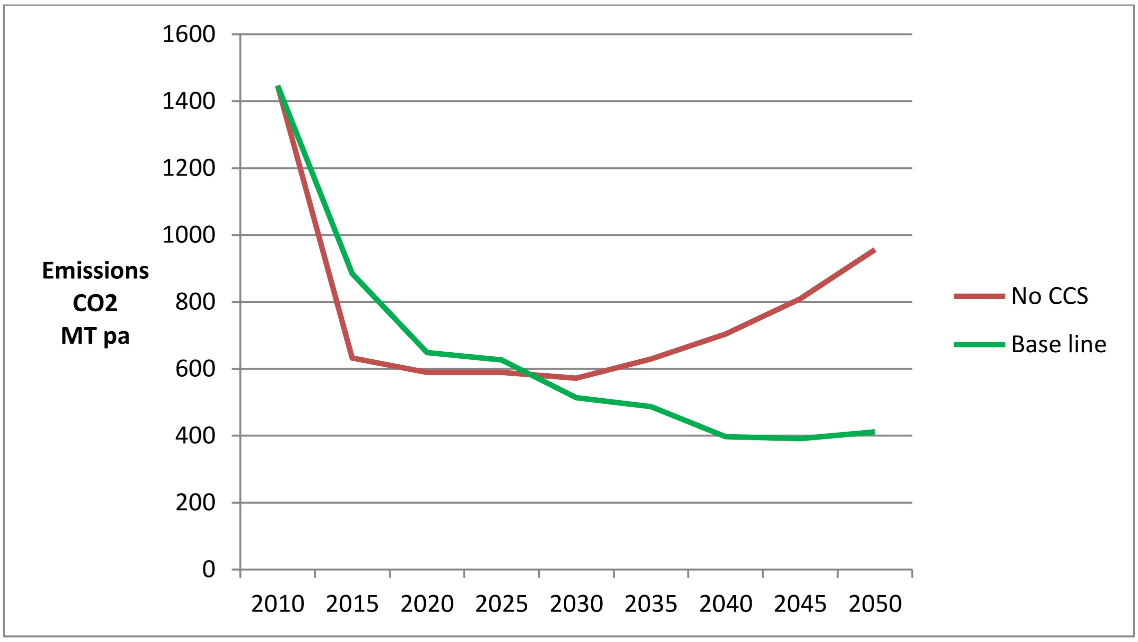


Figure 10: Mt CO_2/annum in Europe vs. year – a 72% reduction in CO_2 emissions from electricity generation from 2010 to 2050 (76% from 1990); with no CCS, the reduction is just 34%

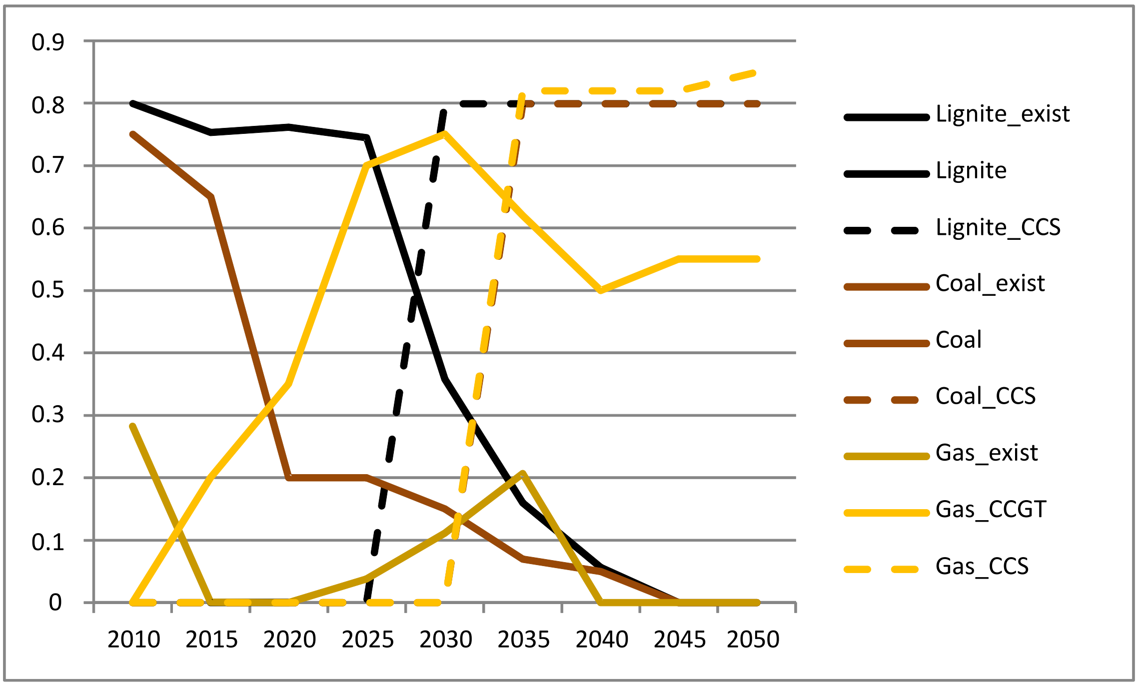


Figure 11: Capacity factor vs. year for existing fossil fuel and new plants (CCS plants run in baseload)

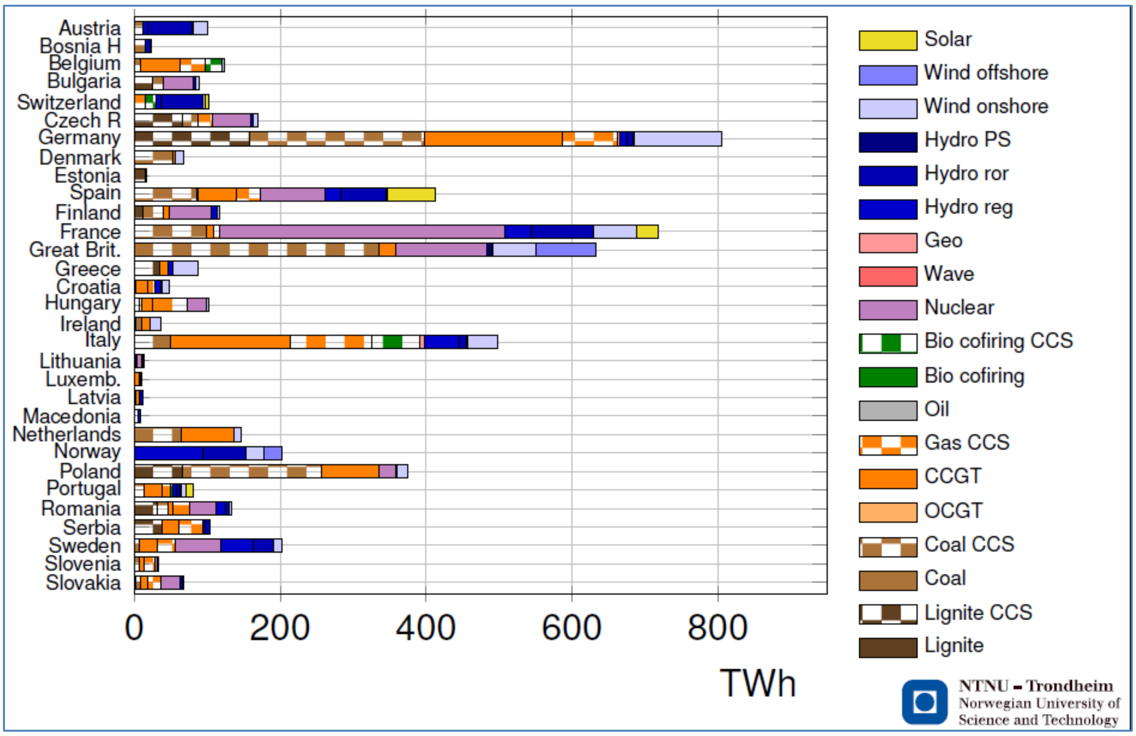


Figure 12: The electricity generation mix in 2050 with 15 GW of biomass co-firing with CCS permitted and implemented (by country in TWh/annum)

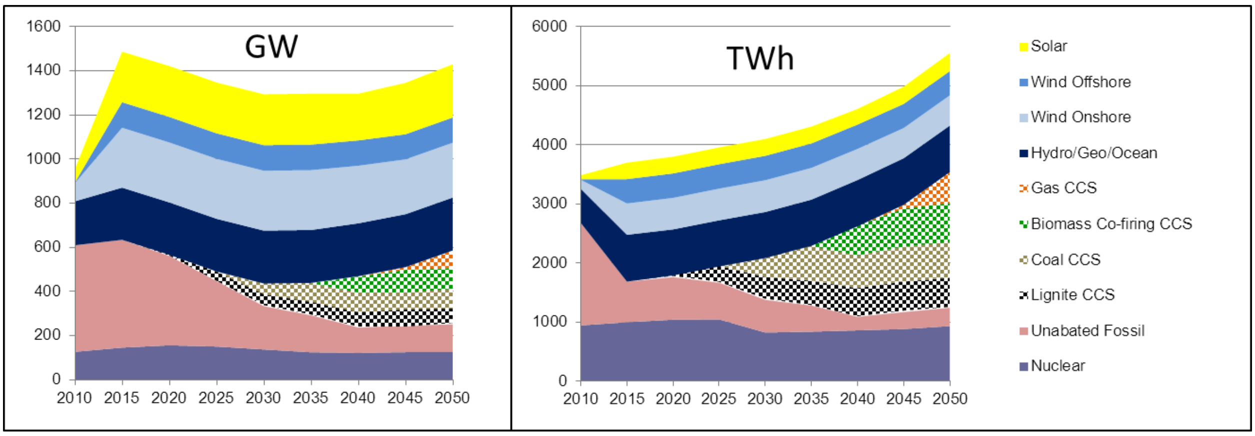


Figure 13: Total power plant capacity GW and mix TWh/annum 2010 to 2050 for the baseline case with +100% fuel price

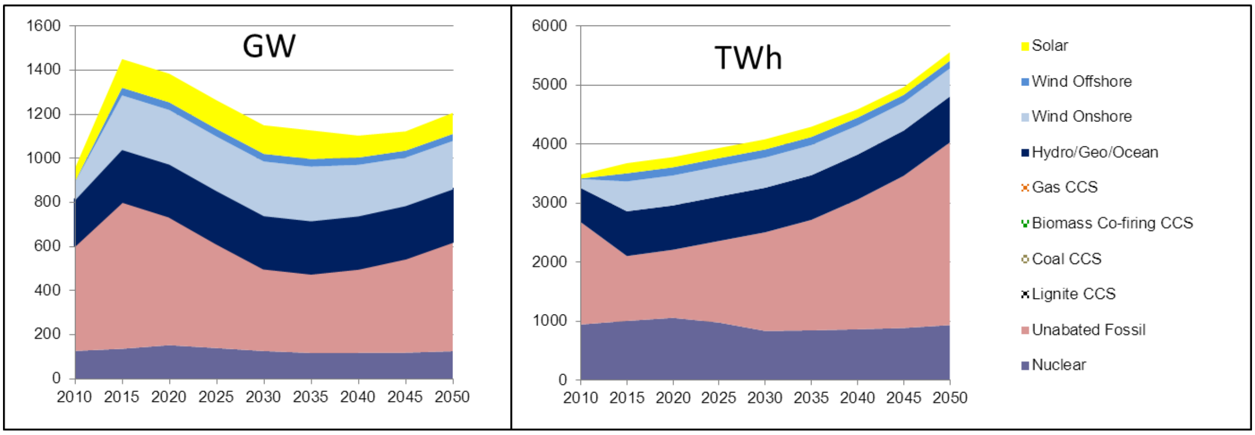


Figure 14: Total power plant capacity in GW and generation mix in TWh/annum from 2010 to 2050 (baseline case with no CCS)

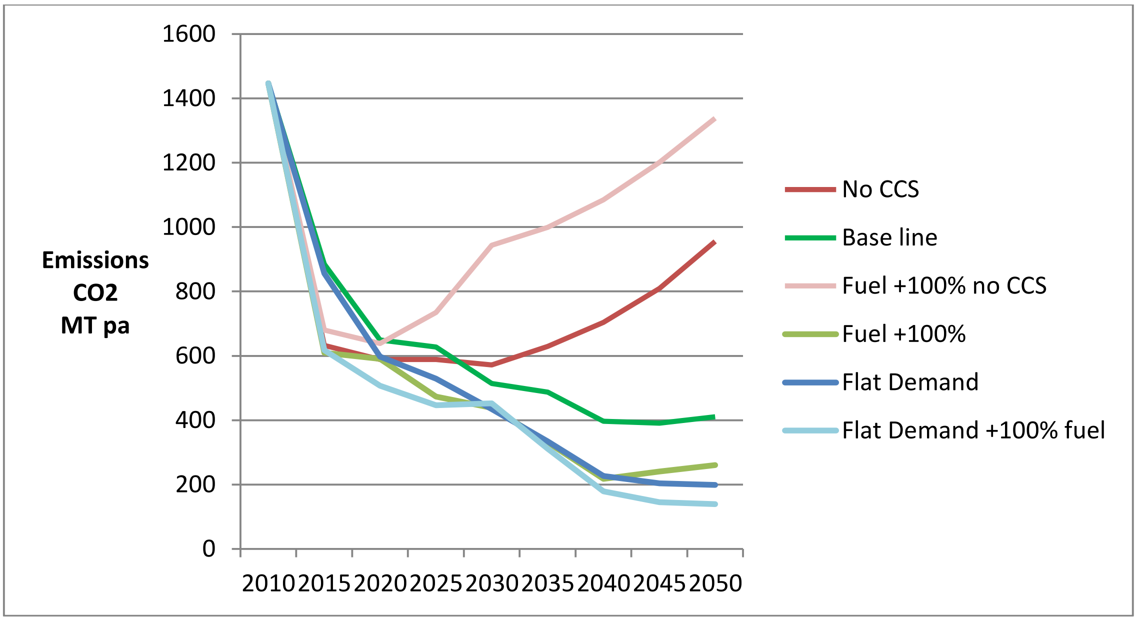


Figure 15: Emissions reductions in the European power industry to 2050 for six cases

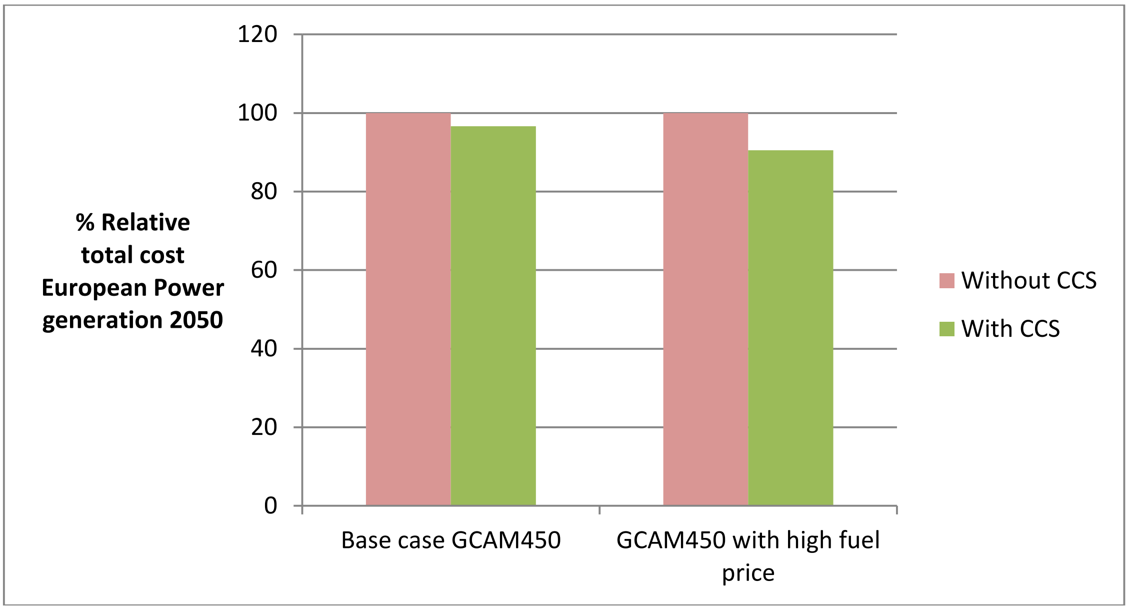


Figure 16: Cost of electricity in 2050 showing emissions reductions achieved by CCS (baseline and high fossil fuel cases)

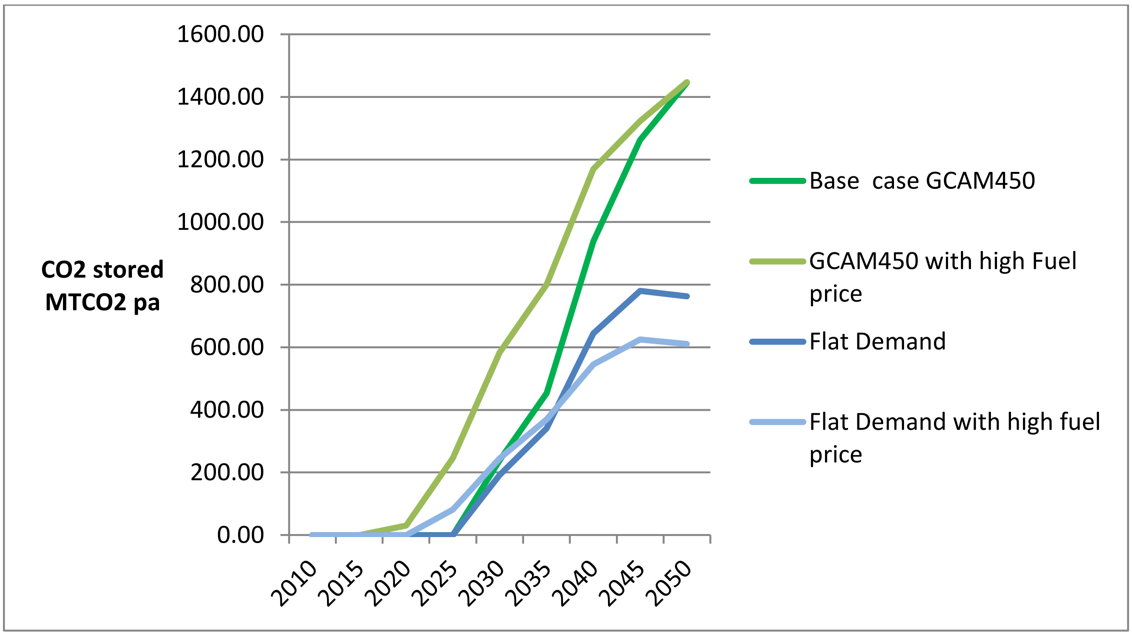


Figure 17: CO_2 captured and stored to 2050 for four cases (baseline, high fuel price, flat demand and flat demand with high fuel price)

4 Modelling transitional measures for CCS

4.1 Identifying the most effective measures to drive CCS demonstration and early deployment

Having created a baseline which demonstrated that, despite its critical role in reducing CO_2 emissions, CCS will not be widely deployed in Europe before 2030 in the current investment climate, ZEP then selected various 'transitional measures' and implemented them in the model to measure their effectiveness.

The modelling results show the predicted impact of the measure on the deployment of a defined volume of CCS up to 2025, representing demonstration and early demonstration projects.

4.2 Modelling results

4.2.1 Public grants: need to cover both capex and opex to incentivise first movers

Capex grants for CCS all reduce the cost of capital for the construction of an end-to-end power plant system (or other industry installation) with CO_2 capture, transport and storage. These are, by nature, limited to a defined volume of CCS projects for which the grant is applied: 5 GW was assumed across Europe for all types of fossil fuel (coal, lignite, gas). These grants may be provided upfront, thus reducing the real cost of capital.

A grant equivalent to 100% of the additional capital costs of CCS was modelled for each of the fuel types. However, Figure 18 shows that compared to the baseline, no CCS was implemented up to 2025 as a result. This is because capex grants alone do not ensure that CCS power plants will be dispatched, as the operating costs of electricity production may still be higher than electricity prices for demonstration and early deployment projects. Both capex *and* opex support is therefore needed to ensure CCS plants are dispatched and first movers are compensated for taking the lead in CCS deployment.

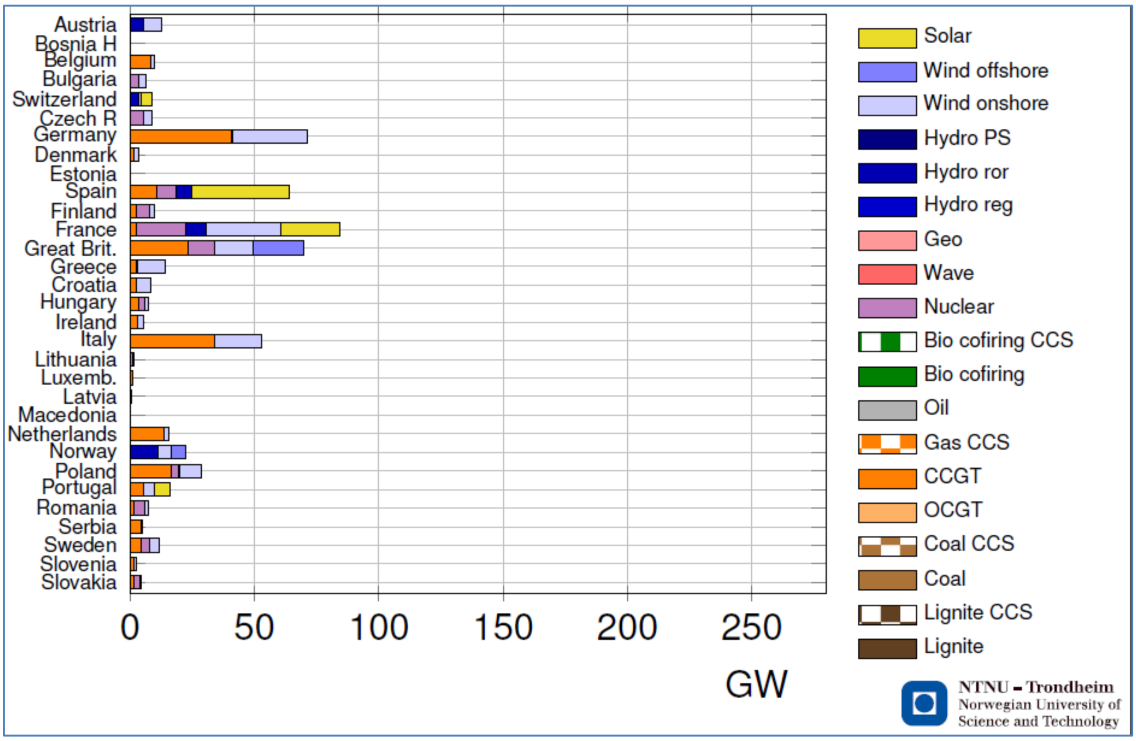


Figure 18: No CCS was implemented up to 2025 as a result of a 100% capex grant since opex support is also needed (by country vs. GW)

4.2.2 Feed-in premia: offer investors the greatest security of income

Due to the ability of feed-in tariffs (FiTs) to limit the risk to taxpayers, while proving highly successful in driving renewable energy deployment, they have become increasingly popular throughout Europe. As of 2012, 24 Member States have implemented FiTs, with 20 using them as the primary renewable energy support mechanism.[36] In the EU, it is estimated that 85% of all new wind systems and nearly 100% of all new solar photovoltaic systems since 1997 have been installed with FiTs.[37] A 2005 Commission study concluded that "well-adapted feed-in tariff regimes are generally the most efficient and effective support schemes for promoting renewable electricity."[38]

Feed-in premia (FiP)[7] or contracts for difference (CfD) schemes for CCS would most likely be applied at national – not EU – level, as proposed in the UK and Romania. However, they could be incentivised via EU policy and targets which would then place obligations on Member States to achieve. The effect of such schemes is to allocate the cost of installing and operating the selected technology to electricity consumers across all technologies.

In this case, the effect on the whole system was modelled in order to reduce the number of combinations required. A FiP was calculated based on the LCoE for each fuel type, plus a margin of 10%, as policymakers usually seek to ensure that their policies are effective. This was allocated to the first 5 GW of CCS across Europe, wherever it was selected by the model. After this volume, CCS could still be selected, but would not benefit from the FiP. Once allocated, the plant retains it for life.

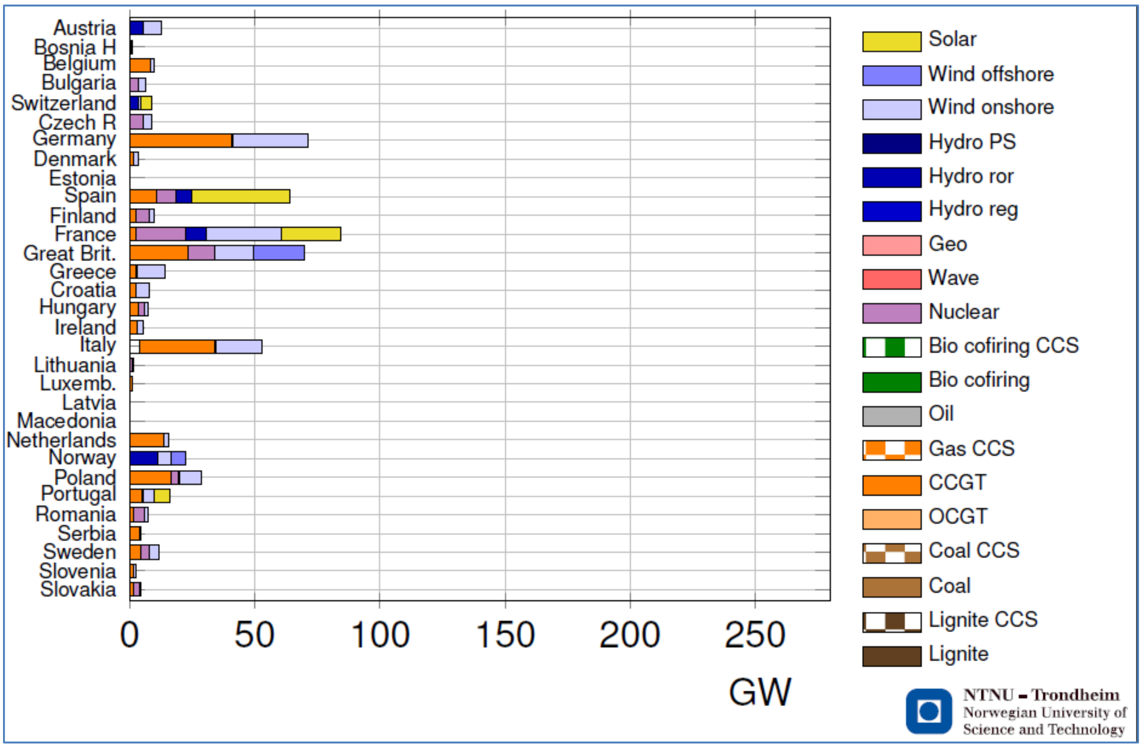


Figure 19: Compared to the baseline, 5 GW of CCS was rapidly implemented on coal plants via a FiP

Figure 19 shows that compared to the baseline, 5 GW of CCS was rapidly implemented on coal plants. (ZEP does not recommend over-reliance on the location selected as this is the result of small differences in

[36] Ragwitz, Winkler (2012) "Recent developments of feed-in systems in the EU – A research paper for the International Feed-In Cooperation". A report commissioned by the Ministry for the Environment, Nature Conservation and Nuclear Safety.
[37] 8th International Feed-in Cooperation Workshop on 18 and 19 November 2010
[38] Communication from the Commission: The support of electricity from renewable energy sources, COM(2005) 627 final

the costs of the technology.) The model predicts that these 5 GW would be dispatched to run from the date of installation until 2050. From 2030, when the CO_2 price is high enough, other CCS plants are then added with lignite, coal and gas *without* the FiP.

The case was then re-run *without* the 10% margin, with the same result. It was also re-run with the 5 GW defined volume increased to 50 GW, which was also implemented by the model. A FiP would therefore be an effective method for whatever defined volume was selected. In this case, the reduction in emissions from European power was 80% compared to 1990 levels. These results show that a FiP on CCS would not only be effective in incentivising early CCS deployment, but also accelerating emissions reductions.

The modelling shows that FiPs, or similar mechanisms, are an effective and proven option, offering investors the greatest security of income. This is because well-designed FiPs provide support to power plants in a form that best ensures them access to the electricity grid, reducing both revenue risk and price risk for investors. This correspondingly lowers the cost of capital. However, unlike 'guaranteed rate of return' contracts, the technological risk remains with the developer. In other words, if construction and operational costs are greater than expected, these are borne by the developer.

4.2.3 CCS certificates: a potential option, but require careful design

In order to examine the effect of any possible measure designed to force CCS into the electricity market, a CCS introduction scheme was also calculated. The scheme supported the equivalent of 5 GW of CCS installed by 2025 and was operated for the lifetime of the plant, with no priority of dispatch. It was implemented in the model as a linear ramp from 0 GW in 2020, up to 5 GW in 2025.

The model interpreted this required capacity as a constraint and construction was allocated. In order to measure the system cost level needed to deliver 5 GW of CCS precisely, a series of cases were modelled with increasing incentives. The result: the modelling estimated that 25% and 35% of opex support implemented the defined volume of lignite and gas CCS, respectively.

A CCS certificate scheme is one way of ensuring a volume of CCS. It would be applied mainly at EU level and create a new market for such certificates across borders. The purpose of such schemes is to ensure that the additional cost of installing and operating CCS technology is reallocated to the other operators in the same market. However, due to the complexity of a parallel CCS certificate market for CCS demonstration projects and existing EUA and electricity markets, determining the possible effect on CCS deployment is beyond the capability of the model.

Certificate schemes incentivise investment in the selected technology and redistribute the cost to the rest of the market. The tradability of certificates allows market actors who are most able to reduce emissions to make up for those who are less able to do so, ensuring that certificate obligations – and hence emissions reductions – are met in the most economically efficient manner. EU-wide trade also contributes to a more efficient market for CCS certificates with higher liquidity and increased turnover. This stimulates greater effectiveness and increased downward pressure on CCS generation costs than purely national measures.

However, because it is a market-based system, an EU CCS certificate scheme does not offer market actors revenue stability over the lifetime of the plant and would therefore be less effective than a FiP in driving deployment. This is especially true of CCS due to the long lead times and technical investment risks. In particular, the following are stumbling blocks:

1. **Unpredictable production levels:** because CCS certificates would initially be issued to a small number of plants, and because it would be difficult to predict the precise ramp-up of production from these plants, significant changes in the scarcity – and hence price – of certificates should be expected in the early stages of the scheme.
2. **Market power:** the very limited number of suppliers of CCS certificates, and the large number of companies on the demand side, would give CCS suppliers huge market power that may lead to competitive misbehaviour.

3. **Priority dispatch:** unlike FiPs, certificate schemes do not guarantee all CCS plants dispatch – just the most competitive plants at any given time. This leaves CCS operators with the risk of stranded assets.
4. **Interaction with other policies:** parallel energy policies at both national and EU level have the potential to distort the market price of certificates. This is especially significant because every EU CCS project to date has relied upon several funding mechanisms.
5. **Administrative costs**: there are additional costs involved in implementing a CCS certificate scheme:
   - *Costs of implementation*: including the training of relevant parties, consultancy costs and the need for extensive IT equipment (trading platform)
   - *Operating costs*: mainly personnel, including consultants and experts involved in certification, monitoring and reporting
   - *Costs of certificates trading*.

The negative effects of 1-3 above can be somewhat mitigated through design. For example, putting in place floor and cash-out prices would ensure a degree of revenue stability for market actors and help to cement a CCS plant's position in the dispatch curve. However, even with such measures, greater investment risks would remain and dispatch would not be fully guaranteed. This could effectively increase the cost of any EU-funded 'first-mover' CCS projects – and by extension, the eventual cost to consumers – because project financers would discount future revenues from the mechanism. As investment risk in demonstration projects should be limited as far as possible to technical risks, a CCS certificate system is less suited to starting up a new technology than measures that guarantee fixed operating revenues, such as FiPs.

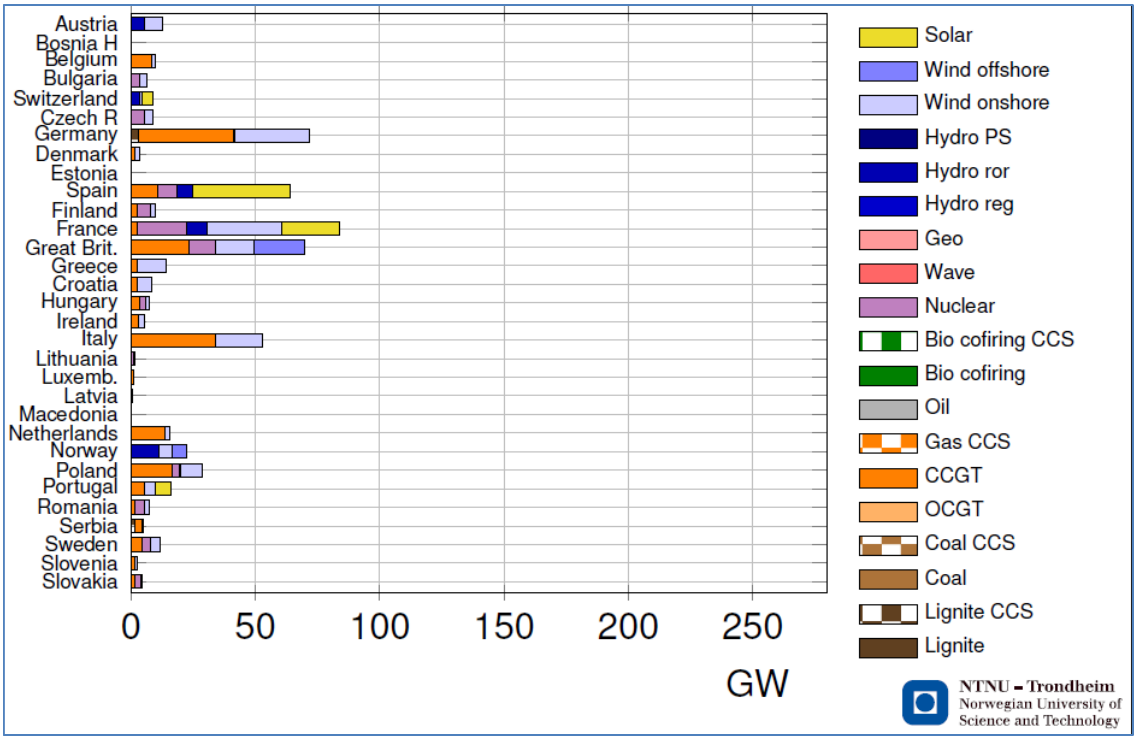


Figure 20: Compared to the baseline, CCS was implemented by 2025 on lignite plants via 25% opex support (by country vs. GW)

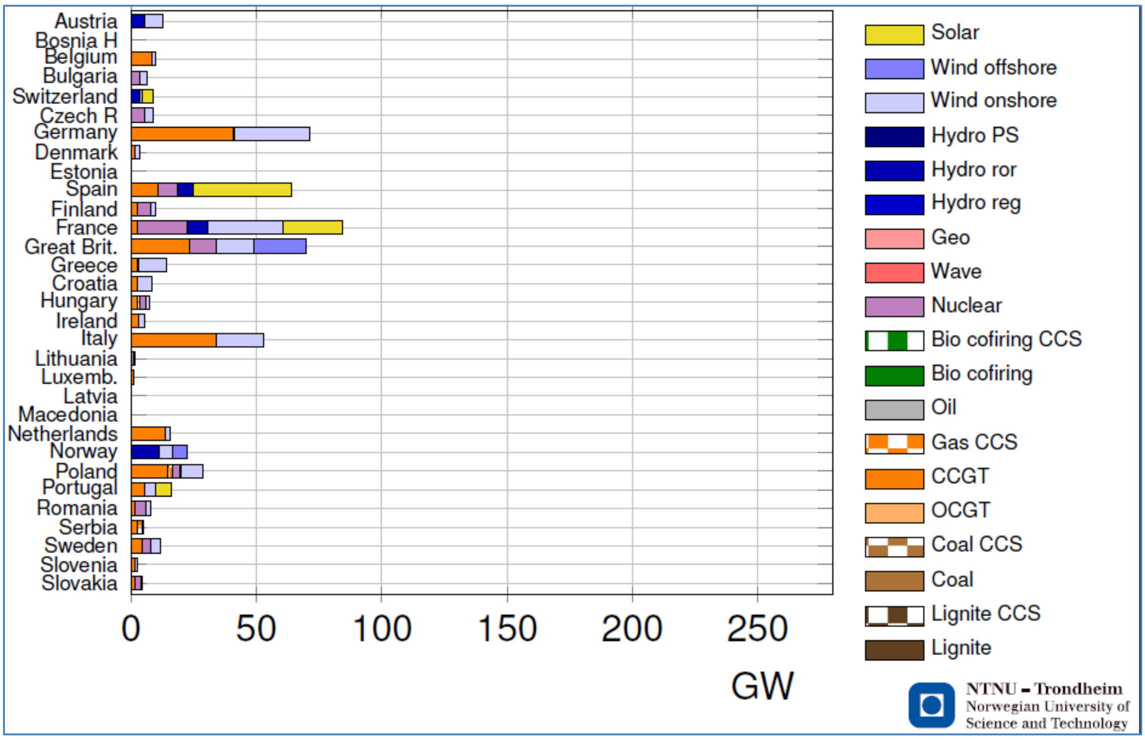


Figure 21: Compared to the baseline, CCS was implemented by 2025 on gas plants via 35% opex support (by country vs. GW)

4.2.4 Emission performance standard: in the short term, will not incentivise CCS in Europe

Two emission performance standards (EPS) were modelled and applied EU-wide: 450g/kWh from 2015 with grandfathering to 2030 and 225g/kWh from 2015 with grandfathering to 2030 (Figures 22-25). These were implemented in the model by excluding the operation of plants exceeding the EPS limit in terms of emissions. Since the model has 'perfect foresight' concerning electricity demand, fuel cost and CO_2 price, plants that will not be selected to run in the future are not selected for construction.

EPS have been introduced in the UK and some countries outside the EU in order to avoid new coal-fired power plants without CCS. However, the modelling does not predict that an EPS will result in an accelerated introduction of CCS as investment decisions need to be taken in the near future: an EPS could be announced, but is not likely to take full effect until 2030, at the earliest. The short-term effect of an EPS at 450g/kWh in 2030 would therefore be a switch from coal to unabated gas in 2020 because the model anticipates the EPS and predicts investments that would be compliant. In the longer term, the baseline case already concludes that CCS will be widely deployed after 2030 when the CO_2 price is sufficiently high.

The modelling shows that an EPS at 225g/kWh in 2030 disincentivises gas without CCS. In the short term, it results in a shift to increased wind, nuclear and solar in 2020. By 2025, it already advances CCS on lignite coal and gas. Beyond 2030, the modelling shows a wider deployment of CCS on new-build coal and all gas plants which would result in greater CO_2 reductions in 2050, but at a higher cost than the baseline case.

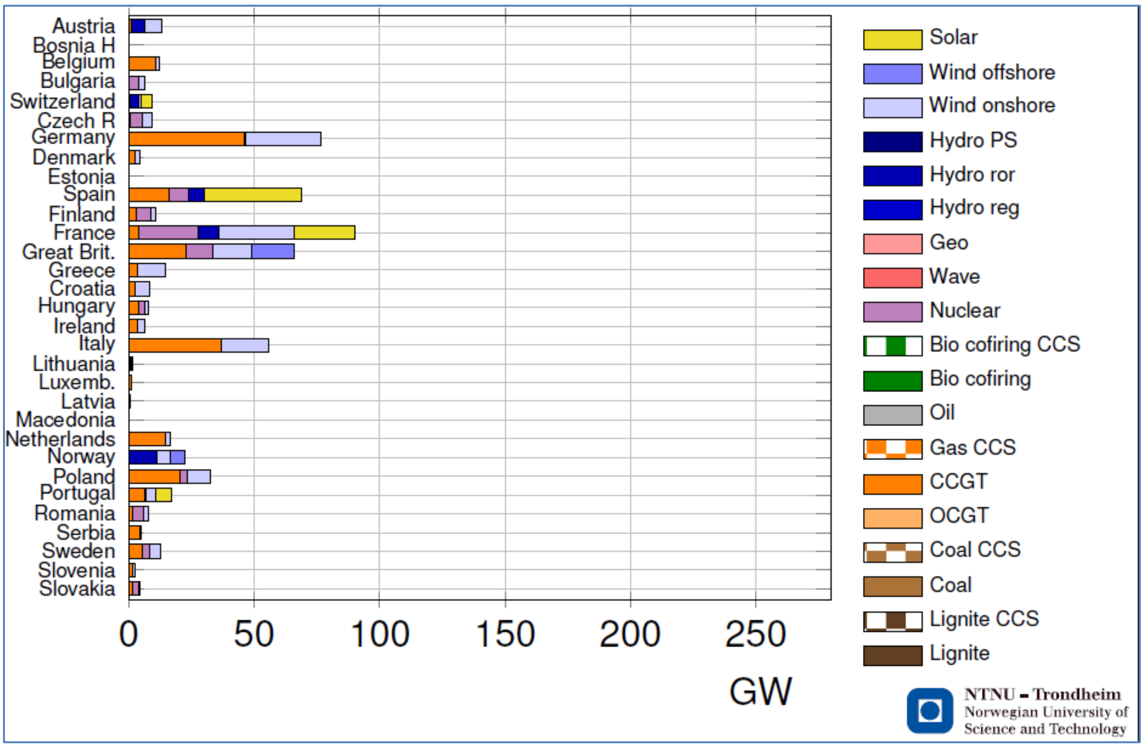


Figure 22: An EPS set at 450g/kWh in 2030 does not advance CCS in 2025 (country vs. GW)

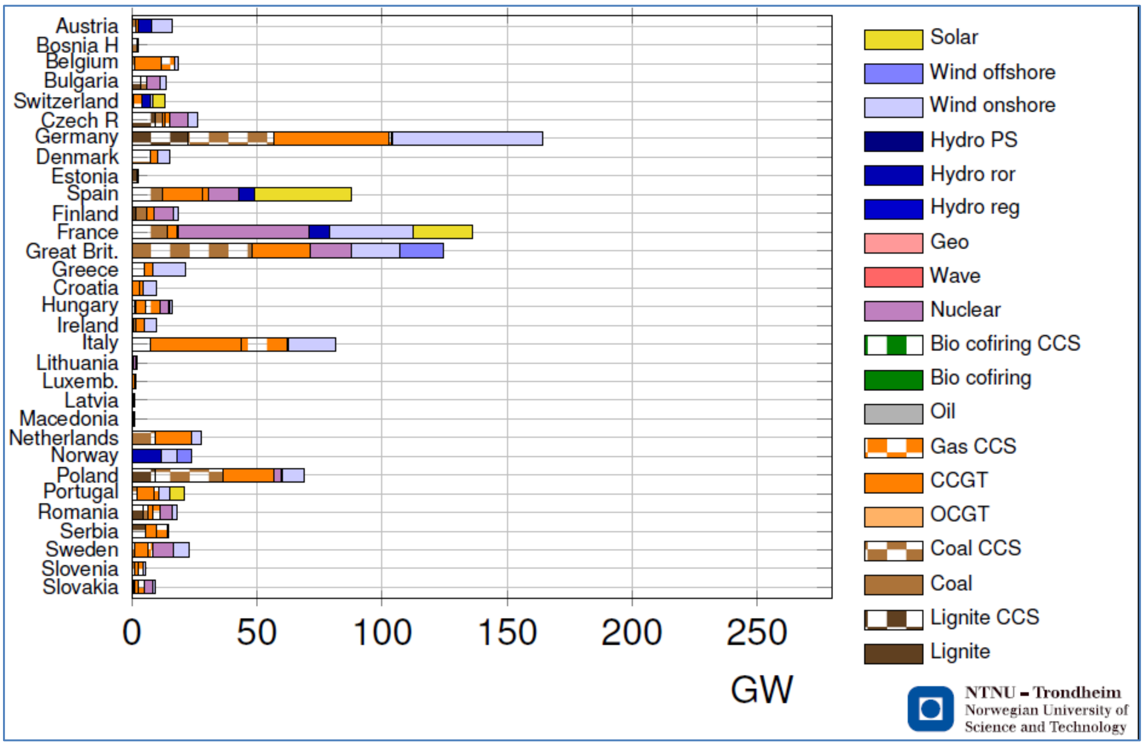


Figure 23: An EPS set at 450g/kWh in 2030 has a small effect in 2050 compared to the baseline case (country vs. GW)

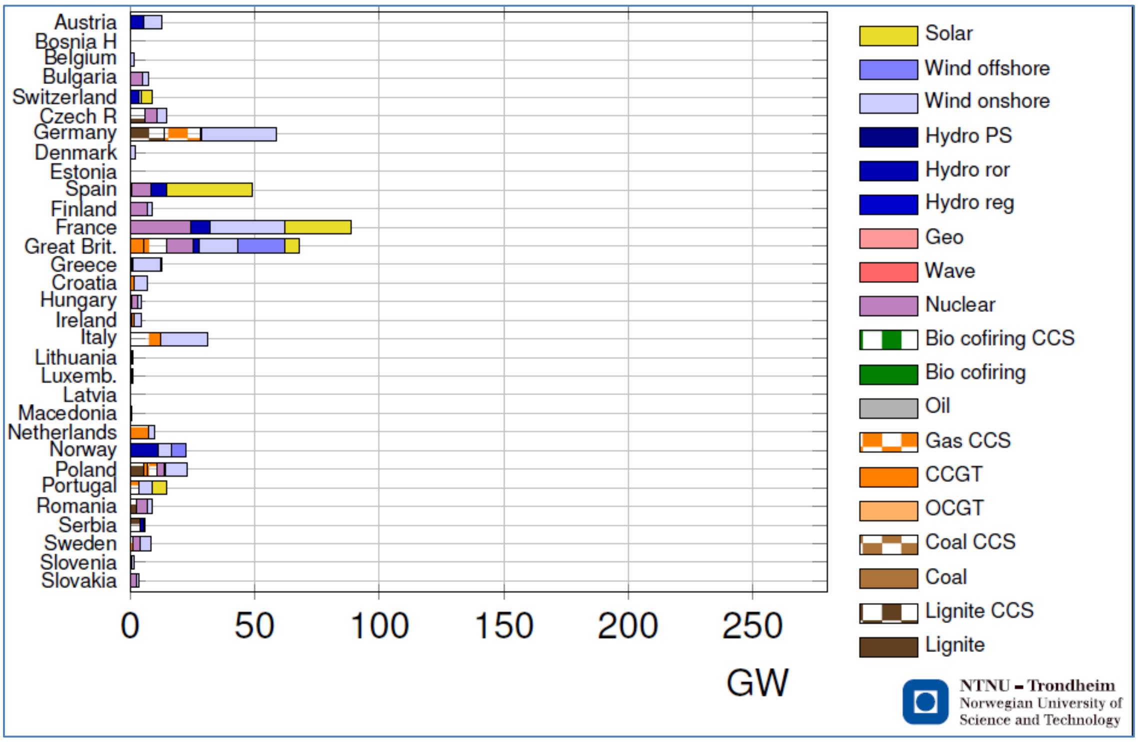


Figure 24: An EPS set at 225g/kWh in 2030 prevents investment in unabated gas and increases RES, nuclear and CCS (country vs. GW)

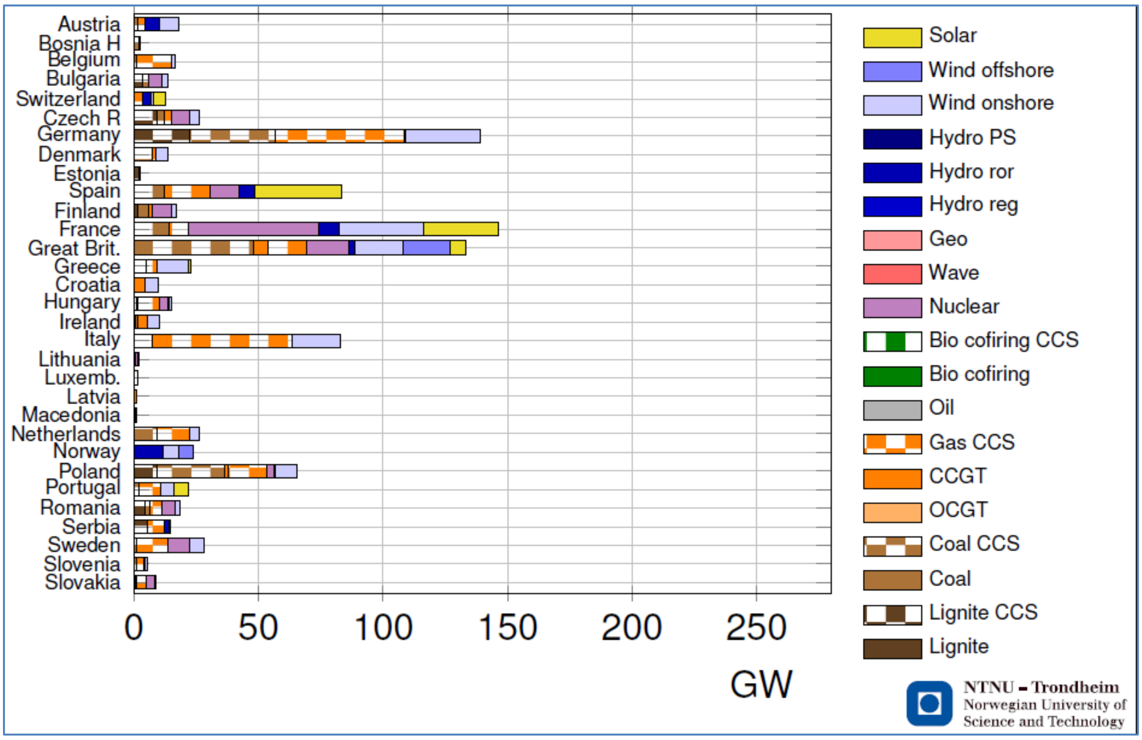


Figure 25: An EPS set at 225g/kWh in 2030 advances gas, lignite and coal CCS and by 2050 increases the total level of CCS deployment (country vs. GW)

Sensitivity cases with the EPS made effective from 2015 produced a very similar result to the case where it is effective from 2030. This is because the model assumes that the investor will anticipate the EPS and make similar decisions, independent of the introduction date. ZEP is concerned that, i.a., a stand-alone EPS introduced in the EU would be set at a level closer to 450g/kWh, which will incentivise the substitution of coal with unabated gas, instead of delivering near-term CCS deployment in the power sector.[39]

EPS are attractive to policymakers due to their simplicity of implementation, predictable results and low direct cost to the state. However, an EPS may effectively result in a technological mandate depending on what level the EPS is set. This can be unattractive to policymakers due to a reluctance of governments to be seen to be 'picking winners'. A side effect of an overly strict or early EPS in the absence of other supporting policies may be underinvestment, as operators avoid deploying mitigation technologies, preferring instead to substitute fuel or process – with the resulting impact on energy supply diversity, security and higher costs.

4.2.5 CCS will play a critical role in reducing CO_2 emissions at lowest cost

Figure 26 below shows European CO_2 emissions reduction to 2050 for each of the cases shown. The steep early reduction is due to the roll-out of RES in the relevant countries up to the limit for physical constraints (onshore wind) and allowing dispatch to meet demand. Subsequent reductions come from fuel switching to gas until the CO_2 price is higher enough to incentivise CCS. Then CCS takes over and reduces European power emissions by 72-86% compared to 2010 for the 450 ppm CCS cases. This is equivalent to 76-89% compared to 1990 levels.

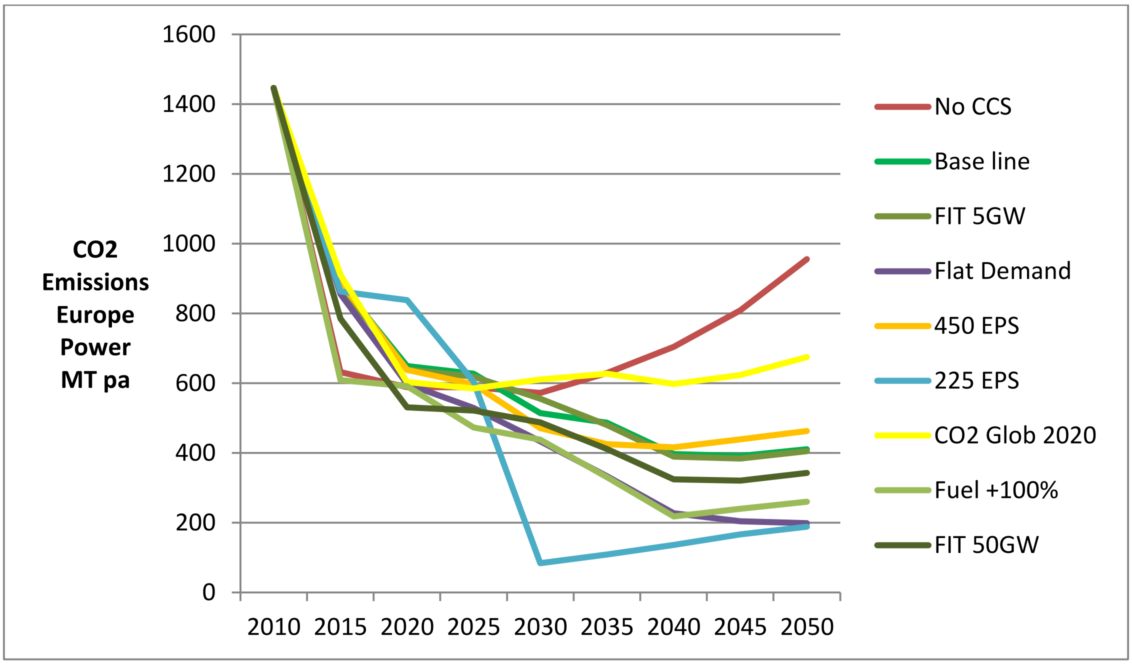


Figure 26: European CO_2 emissions, showing reductions to 2050 in Mt CO_2 p.a. for each of the cases

In some cases, the rise in emissions towards 2050 is due to the increase in demand modelled in the 450 ppm scenario. This rise is not visible in the 'flat' demand case. It is also not visible in the high fuel price case because the increase in demand for power is more than offset by CCS-enabled CO_2 reductions.

[39] Bloomberg New Energy Finance, 2011. Emission Performance Standards: Impacts of power plant CO_2 emission performance standards in the context of the European carbon market, Bloomberg New Energy Finance

An EPS set at 450/kWh is not effective in reducing emissions. At 2050, emissions are actually calculated as higher than the baseline case. This is because an EPS at this level is a disincentive to invest in CCS. It causes a shift to unabated gas which is then 'locked in' later in the modelling.

An EPS set at 225/kWh is effective in reducing emissions by driving CCS on all fossil fuels. Because the model has 'perfect foresight', the EPS is effective even if the date of enforcement moves from 2030 to 2015. (The model knows that the legislation will be effective at whatever date and makes investments to suit.)

At only 34%, the case with no CCS shows the lowest emissions reduction in 2050. This shows the critical importance of CCS in decarbonising Europe at lowest-cost.

The test case with the FiP permitted on 50 GW shows that a FiP can potentially incentivise the early construction of a defined volume greater than 5 GW if so selected.

4.3 Summary tables

Tables 2 and 3 below summarise the modelling results and the impact of each measure on the deployment of coal (hard and lignite) and gas CCS in 2025 and 2050, respectively. A total volume of 5 GW was defined for FiP and an ensured volume of CCS (CCS certificates scheme); for the other measures, the volume of CCS was unconstrained, but could have been modelled when conditions were advantageous.

Country	Baseline 450 ppm - no 80% reduction target	Baseline 450 ppm + 15 GW biomass co-firing	Baseline 450 ppm fuel price sensitivity + 100%	Baseline 450 ppm energy demand sensitivity (2010 = Constant)	Baseline Global 20-20-20 scenario CO_2 price sensitivity €40/t max.	Baseline + 100% capex grant for 5 GW	Baseline + FiP LCoE + 10% for 5 GW	Baseline + 25% opex support for 5 GW	Baseline + 50% opex support for 5 GW	Baseline + EPS 450g in 2030	Baseline + EPS 225g in 2030
Coal UK	0	0	0	0	0	0	0	0	0	0	0
Gas UK	0	0	0	0	0	0	0	0	0	0	9
Coal Neths.	0	0	0	0	0	0	0	0	0	0	0
Gas Neths.	0	0	0	0	0	0	0	0	2	0	8
Coal Poland	0	0	6	0	0	0	0	0	0	0	5
Gas Poland	0	0	0	0	0	0	0	0	0	0	4
Coal Germany	0	0	16	0	0	0	0	3	0	0	14
Gas Germany	0	0	0	0	0	0	0	0	0	0	14
Coal Romania	0	0	3	0	0	0	0	0	0	0	3
Gas Romania	0	0	0	0	0	0	0	0	0	0	0
Coal Norway	0	0	0	0	0	0	0	0	0	0	0
Gas Norway	0	0	0	0	0	0	0	0	0	0	0
Coal France	0	0	0	0	0	0	0	0	0	0	0
Gas France	0	0	0	0	0	0	0	0	0	0	0
Coal Europe*	0	0	44	0	0	0	5	5	0	0	34
Gas Europe*	0	0	0	0	0	0	0	0	5	0	57

* Totals include all countries modelled, not only those specified in the table

Table 2: A summary of the modelled installed CCS capacity in GW in 2025 (coal values shown are a total of lignite plus coal)

Country	Baseline 450 ppm - no 80% reduction target	Baseline 450 ppm + 15 GW biomass co-firing	Baseline 450 ppm fuel price sensitivity + 100%	Baseline 450 ppm energy demand sensitivity (2010= Constant)	Baseline Global 20-20-20 scenario CO_2 price sensitivity €40/t max.	Baseline + 100% capex grant for 5 GW	Baseline + FiP LCoE + 10% for 5 GW	Baseline + 25% opex support for 5 GW	Baseline + 50% opex support for 5 GW	Baseline + EPS 450g in 2030	Baseline + EPS 225g in 2030
Coal UK	48	48	11	9	9	48	48	48	48	48	48
Bio co-firing CCS UK	0	0	37	0	0	0	0	0	0	0	0
Gas UK	0	0	0	0	0	0	0	0	0	0	16
Coal Neths.	9	9	8	9	9	9	9	9	9	9	9
Bio co-firing CCS Neths.	0	0	1	0	0	0	0	0	0	0	0
Gas Neths.	0	0	1	0	0	0	0	0	2	0	13
Coal Poland	37	37	28	11	10	37	37	37	37	37	37
Bio co-firing CCS Poland	0	0	9	0	0	0	0	0	0	0	0
Gas Poland	0	0	12	0	0	0	0	0	0	0	16
Coal Germany	57	57	41	53	23	57	57	60	57	57	57
Bio co-firing CCS Germany	0	0	18	0	0	0	0	0	0	0	0
Gas Germany	10	10	4	0	0	10	10	9	10	1	52
Coal Romania	7	7	6	5	5	7	7	7	7	7	7
Bio co-firing CCS Romania	0	0	0	0	0	0	0	0	0	0	0
Gas Romania	3	3	4	0	0	3	3	3	3	3	5
Coal Norway	0	0	0	0	0	0	0	0	0	0	0
Bio co-firing CCS Norway	0	0	0	0	0	0	0	0	0	0	0
Gas Norway	0	0	0	0	0	0	0	0	0	0	0
Coal France	14	14	13	14	0	14	14	14	14	14	14
Bio co-firing CCS France	0	0	2	0	0	0	0	0	0	0	0
Gas France	1	1	0	0	0	1	1	0	0	0	8
Coal Europe*	249	249	160	149	64	249	254	254	249	249	249
Bio co-firing CCS Europe*	0	15	94	0	0	0	0	0	0	0	0
Gas Europe*	80	66	81	0	0	80	79	79	85	56	268

* Totals include all countries modelled, not only those specified in the table

Table 3: A summary of the modelled installed CCS capacity in GW in 2050 (coal values shown are a total of lignite plus coal)

5 Recommended CCS measures by country

5.1 United Kingdom

CO_2 emissions by sector
The UK's 2008 Climate Change Act set legally binding targets to reduce greenhouse gas (GHG) emissions by at least 34% by 2020 and at least 80% by 2050 (over 1990 levels). After nearly two decades of gradual emissions reductions, the UK's overall emissions declined particularly sharply in 2009 as a result of the global economic slowdown, before increasing again slightly in 2010.

CO_2 emissions by sector (Mt)						
	Power industry	Other industry	Transport	Household and small businesses	Other	Total
1990[40]	203.5	167.3[41]	119.6	79.0	22.70[42]	592.0
2010[36]	157.0	126.7[41]	119.1	86.5	8.46[42]	497.8

Structure of the electricity market
Gas provided the largest share of UK electricity generation in 2011 (43.4%), followed by coal (29.1%) and nuclear (11.3%). Starting from a relatively low baseline in the mid-1990s, RES – in particular, biomass and wind – have enjoyed strong rates of growth. In 2011, the contribution of all RES to UK electricity generation was 9.4%.

~40% of all current UK generation capacity is due to close by 2025 and the Government is currently putting in place a host of policies to incentivise private investment in the infrastructure necessary to replace this old capacity, as well as meet strongly growing demand. The planned decarbonisation of the UK's heat and transportation sectors will also contribute to the expected doubling of electricity demand by 2050.

Installed generating capacity by source (GW-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2011[43]	10.1	10.7	25.5	0	34.1	8.7	89.1
Annual electricity generation by source (TWh-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2011[44]	38.3[45]	69.0	108.6	0	146.8	5.1[46]	367.8

Existing support measures for low-carbon energy technologies
A CO_2 floor price has been in place in the UK since April 2013 and is set to rise steadily to 2020. However, in order to further accelerate progress towards meeting national decarbonisation targets, the Government has proposed an "Electricity Market Reform (EMR)" programme. The legislation to enable these proposals is contained within the Energy Bill currently before Parliament. This will, in principle, put in place public policy support for all low-carbon power options.

Long-term feed-in tariff contracts for difference (CfD) will be introduced, offering technology-specific, centrally-set strike prices for nuclear, large-scale RES and CCS, while capping prices in times of generation scarcity. Because CfD terms will distinguish between intermittent and baseload low-carbon generation, as

[40] www.gov.uk/government/uploads/system/uploads/attachment_data/file/180823/ghg_national_statistics_release_2011_final_results.pdf
[41] Business + industrial processes
[42] Agriculture + land use change + waste management
[43] www.gov.uk/government/publications/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes
[44] www.gov.uk/government/uploads/system/uploads/attachment_data/file/65841/7345-elec-gen-2008-2011-et-article.pdf
[45] Thermal renewables + non-thermal renewables + hydro + wastes
[46] Oila + other thermal

well as investment risk profile (e.g. for early CCS projects),[47] it is highly likely that they will be effective in driving CCS deployment. The intention is also to introduce a CfD to promote flexible generation when this is necessary.

Some have commented that the Government is essentially subordinating liberalisation to environmental concerns, accepting a significant degree of government intervention and a reduction in the role of market forces to determine the energy mix. They argue that the EMR programme reveals the fundamental clash between the liberalisation and decarbonisation agendas across the EU.[48]

Regulatory constraints
The current Energy Bill introduces an emissions performance standard (EPS) which limits emissions to around half that produced by unabated coal. This policy reaffirms a political commitment to incremental decarbonisation, reassuring market actors of the long-term necessity of CCS for continued fossil fuel use. It also underpins measures in place that requires at least 300 MW of CCS to be installed on new coal-fired power stations and for all new combustion power stations to be CO_2 capture-ready. However, in the UK context, it is much more likely to deliver increased unabated gas in the power sector in the near term, rather than CCS deployment.

Recommendations based on the modelling results
The UK's set of measures seems likely to be successful in implementing CCS demonstration projects in the UK and the modelling shows that FiTs, which provide support to CCS in a very similar way to CfDs, will incentivise investment in CCS up to 2030. In combination with CCS certificates and other grant schemes, the UK would therefore be an attractive place for the first projects to be built. However, the UK's EPS scheme, which will prevent unabated coal being built, may represent a disincentive for new-build coal plants with CCS until the technology is well proven and fully mature.

5.2 The Netherlands

CO_2 emissions by sector
CO_2 emissions per capita in the Netherlands reflect its relatively large industry and economy, and are consequently above EU-average – comparable with Germany and Poland, but significantly higher than French emissions. Government policy has aimed at reducing emissions by improving energy efficiency and switching to less CO_2-intensive fuels, and progress has been made over recent decades.

However, such emissions reductions have been more than compensated by increased emissions as a result of economic growth – especially growth in exports. Policy measures affecting marginal costs of CO_2-intensive products (e.g. an international system of emissions trading) could impact on future demand for these products – thereby decreasing emissions – but this could affect the country's competitive position.

CO_2 emissions by sector (Mt)						
	Power industry	Other industry	Transport	Household and small businesses	Other	Total
1990[49]	52.50	42.42	25.87	36.32	10.15	167.26
2010[49]	61.11	52.04	33.35	41.56	6.14	194.20

Structure of the electricity market
The Dutch electricity market is configured as follows:

- It is a lowest marginal cost market, therefore giving priority of dispatch to RES (not CCS)
- It is an 'energy only' market
- It has specific provisions to prevent instability of the grid in case of oversupply.

[47] Written Ministerial Statement on energy policy (Oct 2010), Commentary on EMR White Paper
[48] Malcolm Keay (2013): "The UK Electricity Market Reform and the EU", Oxford Institute for Energy Studies
[49] http://wds.iea.org/WDS/Common/Login/login.aspx

Installed generating capacity by source (GW-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2010[49]	3.19	0.49	4.16	-	18.80	-	26.64
Annual electricity generation by source (TWh-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2010[49]	10.40	4.00	21.90	-	78.00	0.10	114.40

Existing support measures for low-carbon energy technologies
There is no intention to introduce generic measures for low-carbon energy technologies, such as adjusting the ETS via a CO_2 floor price, or establishing an EPS, CfD, or capacity market for reserve electricity generation.

Because low-carbon energy technologies are not competitive against conventional power, there is a grant scheme that subsidises renewable electricity called SDE+. This is an innovative scheme which awards a feed-in tariff (FiT) to specific projects for a fixed time period,[50] based on an annual competition. As the awards and levels of the FiT are based on the most competitive offer, the cheapest low-carbon electricity available is selected and receives a FiT of 6 cents/kWh or more. However, the SDE+ scheme is not open to all low-carbon technologies, only RES – for CCS it is not an option.

The annual budget for SDE+ was €22 million in 2012, €30 million in 2013. Total budget spend on grant schemes during the current Cabinet (2012-2016) will reach €1.8 billion.

The Dutch government is not in favour of a national capacity market due to its transboundary effects; it believes that improved electricity trading could resolve issues regarding intermittency and reserve capacity.

Regulatory constraints
There is a national 'energy deal' of stakeholders (government, industry, interest groups) in the making. The details are not yet in the public domain, but from information available it appears to steer the composition of the low-carbon energy portfolio and therefore represents a market distortion by national stakeholders. The deal includes:

- A rise in the share of wind energy (both on- and offshore)
- The closure of a number of old coal-fired power plants (five between 2015 and 2017).

Nuclear power is currently not on the political agenda.

Recommendations based on the modelling results
In any scenario, Dutch electricity generation is expected to be dominated by fossil fuels and, to a lesser extent, wind energy. CO_2 abatement can therefore only be achieved by the large-scale deployment of CCS, provided there is a level playing field with other low-carbon technologies – although cost-competitive, CCS is currently not bankable.

It is therefore recommended that the Dutch government develops policies which:

- Make CCS progressively bankable as a cost-effective technology for reducing large-scale CO_2 emissions in both power *and* energy-intensive industries.
- Ensure a level playing field for all low-carbon technologies, such that the most cost-competitive are implemented. Transitional measures such as FiTs, 'CCS fund', or certificate schemes should therefore be considered, taking into account the role played by other low-carbon technologies in the energy mix and issues such as base- and peak-load generation, intermittency and compensation of intermittency etc.

[50] 10 years, with plans to extend to 15 years

5.3 Poland

CO_2 emissions by sector

Poland's energy sector accounted for 54% of overall CO_2 emissions in 2010, a slight decrease compared to 1990. It is one of the most CO_2-intensive in Europe, with the Bełchatow power plant the largest single CO_2 emission source in Europe, emitting 30 million tonnes of CO_2 per year.

The energy sector is defined by two key characteristics:

1) It is heavily dependent on coal and lignite, which accounted for almost 90% of Poland's electricity in 2010, with only 3% from natural gas and 6% from RES.
2) Its generating fleet is not all state-of-the-art in terms of efficiency and will require significant replacement in a few years.

CO_2 emissions by sector (Mt)						
	Power industry	**Other industry**	**Transport**	**Household and small businesses**	**Other**	**Total**
1990[49]	61.11	51.08	25.87	19.18	17.14	174.38
2010[49]	151.71	61.19	33.35	20.52	21.04	287.81

Structure of the electricity market

The Polish energy market has its origins in the Energy Law Act of April 1997. More than 75% of electricity generation is still under state control. 2011 was the first full year where producers were obliged to sell at least 15% of annual electricity generation at the power exchange, which was introduced in 2010.

Installed generating capacity by source (GW-net)							
	RES	**Nuclear**	**Coal**	**Lignite**	**Gas**	**Other**	**Total**
2010[49]	3.55	-	20.17	8.09	1.02	-	32.83
Annual electricity generation by source (TWh-net)							
	RES	**Nuclear**	**Coal**	**Lignite**	**Gas**	**Other**	**Total**
2010[49]	10.1	0	84.5	44.7	4.5	0	143.8

Existing support measures for low-carbon energy technologies

Poland has a support scheme for RES which means that electricity and heat producers:

- Receive green certificates for the renewable energy they produce. These can currently be traded for ~4 ct/kWh
- Are obliged to include renewable energy for end consumers (a given percentage of their electricity production), or pay a substitution fee.

In addition, there are several schemes that are not RES-specific and companies can also use the Joint Implementation mechanism under the Kyoto Protocol. There is no EPS in Poland for CO_2 emissions.

With regard to CCS, legal regulations and support measures have not yet been implemented in Poland. However, a study[51] was carried out by demosEUROPA, Centre for European Strategy, with the support of the Global CCS Institute.

Regulatory constraints

There are no particular regulatory constraints on low-carbon energy technologies in Poland.

[51] "How to efficiently implement CCS in Poland? Polish CCS Strategy": http://demosservices.home.pl/www/files/How%20to%20efficiently%20implement%20CCS%20in%20Poland_report_demosEUROPA.pdf

A Government Commissioner for Nuclear Power in Poland was appointed in January 2009 and devised the Polish Nuclear Energy Programme (transfrontier consultations are underway). In November 2009, the Council of Ministers adopted the Polish National Energy Policy until 2030 (PEP), with a strong commitment to maintain domestic coal and lignite as the primary fuel for electricity generation, as it is low cost and guarantees national energy independence and security.

Recommendations based on the modelling results
Poland has substantial coal and lignite reserves and therefore strong reasons to develop lignite and coal CCS plants. However, unlike for renewables, there is currently no national policy or support scheme aimed at making CCS bankable – the only incentive is the ETS. It is therefore recommended that the Polish government:

- Reflects on the need to develop a policy that makes CCS bankable as a very cost-competitive means of reducing CO_2 emissions
- Develops a support scheme that creates a level playing field for CCS and renewable energies.

5.4 Germany

CO_2 emissions by sector
Overall CO_2 emissions in Germany reduced by 23.4% between 1990 and 2011. Although the power sector and other industries have reduced their emissions considerably, in 2011 they still accounted for 43.8% and 21% of overall emissions, respectively.

CO_2 emissions by sector (Mt)						
	Power industry	Other industry	Transport	Household and small businesses	Other	Total*
1990[52]	423.4	235.5	162.4	204.5	16.1	1041.9
2011[52]	349.5	167.4	155.6	121.3	4.3	798.1

* Excludes land use, land use change and foresting

Structure of the electricity market
The share of RES capacity in Germany has increased from less than 10% in 1990 to over 40% in 2012, with the share of RES in overall electricity generation increasing from ~5 % to over 20% in the same period. Nevertheless, the contribution of electricity generation based on fossil fuels has remained almost constant – 55% to 60% – whereas nuclear power has declined from over 30% to ~15%. (Germany has decided to withdraw from nuclear power until the end of 2022.)

Installed generating capacity by source (GW-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2012[53]	75	12	29	22	23	10	171
Annual electricity generation by source (TWh-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2012[53]	133	85	111	129	81	22	561

Existing support measures for low-carbon energy technologies
While Germany has no existing support measures for CCS, power production from RES benefits from feed-in tariffs (FiT):

[52] UBA, National Trend Tables for the German Atmospheric Emission Reporting 1990 – 2011, December 2012
[53] Prognos report, November 2012

- FiT (2012) for onshore wind is 8.93 ct/kWh for the first five years, then (depending on the wind quality of the site) 4.87-8.93 ct/kWh for a further 15 years
- FiT (2012) for offshore wind is 15.00 ct/kWh (13.00 ct/kWh after 1st January 2016) for the first 12 years, then 3.5-13.00 ct/kWh (depending on distance to the coast and water depth) for a further eight years
- FiT (2012) for PV is dependent on the installed capacity: <10 kW 19.50 ct/kWh, <1 MW 16.50 ct/kWh and 1-10 MW 13.50 ct/kWh for 20 years. Degression for new PV plants is 1% per month. Once 52,000 MW is installed (expected in 2015 latest), no more new PV plants will be funded.
- FiT (2012) for hydro is dependent on installed capacity: <10 MW 5.50 ct/kWh, <20 MW 5.30 ct/kWh, <50 MW 4.20 ct/kWh and >50 MW 3.40 ct/kWh for 20 years. Degression for new plants is 1% per year.

Regulatory constraints
Electricity prices have increased from ~20 ct/kWh in 2006 to today's ~29 ct/kWh for private end customers. This is mainly due to various taxes and levies which accounted for 50% of the price in April 2013, including more than 5 ct/kWh due to the Renewable Energies Act levy.

The Government has agreed on a pathway to a low-carbon economy, with a target of 80% of power production based on RES in 2050 and an overall CO_2 emissions reduction of 80% (over 1990 levels), including 95% reduction in the energy sector. With nuclear energy not accepted and the availability of wind and solar power limited, fossil fuel power plants will therefore be essential to ensure security of energy supply. Even if they supply only 20% of power production by 2050, it will not be possible to achieve CO_2 reduction targets without CCS in the power sector and other industries.

There is no political or public acceptance of onshore CO_2 storage. The 'CCS Directive' (2009/31/EC) has been transposed via the KSpG, which became law in August 2012. The main features of the KSpG are:

- Only a limited number of demonstration CO_2 storage sites are permitted to be built until 2017 (max. 1.3 Mt/a per project, 4 Mt/a in total).
- Federal states are responsible for permitting CO_2 storage projects.
- The opt-out clause allows federal states to declare CO_2 storage in certain areas inadmissible.
- Liability for storage is 40 years, starting on the day of decommissioning (the CCS Directive only requires 20 years)
- There is no agreement regarding the Economic Exclusive Zone (EEZ).
- The KSpG will be reviewed in 2018, taking into account experiences gained in national and international projects.

In short, the KSpG places obstacles in the way of CCS projects that are almost impossible to overcome.

Recommendations based on the modelling results
With its coal and lignite reserves and the decision to retire nuclear, Germany has much to gain from CCS. However, it currently has very low acceptance, at least for onshore CO_2 storage. The cost-optimised modelling results for 2050 implements CCS on the maximum available capacity of lignite and coal, operated in baseload. Gas capacity is also partly equipped with CCS, depending on the overall CO_2 reduction target.

The modelling shows onshore wind to be attractive and maximum available capacity is implemented by 2050. Offshore wind is not considered mainly due to a slightly lower capacity factor compared to Norway and the UK. The existing solar PV base is not modelled to be replaced when it is retired as it is not an attractive option for northern Europe. Until the acceptance issue is resolved, it seems unlikely that any incentive will be effective in implementing CCS in Germany.

5.5 Romania

CO_2 emissions by sector

In 1990, a decline in economic activities and energy consumption in Romania resulted in a decrease in overall emissions. However, these started to increase in 1996 due to economic revitalisation, although the recent economic crisis led to a reduction in 2011 compared to 2008 levels. The power sector is a significant contributor, accounting for 47.83% of overall emissions in 2011.

CO_2 emissions by sector (Mt)						
	Power industry	Other industry	Transport	Household and small businesses	Other	Total
1990[54]	155.2	55.5	11.9	14.3	2.5	239.4
2011[54]	36.5	15.7	14.4	9.2	0.5	76.3

Structure of the electricity market

The Romanian energy system has progressed from a vertically integrated model to a decentralised system and in July 2007 the market fully opened so that consumers could switch their supplier. In 2011, the energy mix was made up of 39% coal, 28% RES (hydro, wind, biomass), 14% hydrocarbons and 19% nuclear.[42] With the exception of a few small hydro electric power plants, Romania does not have a privatised electricity generation sector and power plants are state owned.

Installed generating capacity by source (GW-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2011[55]	6.883	1.295	1.200	4.148	3.596	0	17.122
Annual electricity generation by source (TWh-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2011[55]	16.073	10.796	3.250	18.790	8.059	0	56.968

Existing support measures for low-carbon energy technologies

Producers of RES electricity benefit from green certificates (GC) for electricity delivered to suppliers or consumers:

- New hydro power plants ≤10 MW receive 3 GC/1 MWh for 15 years
- New wind power plants receive 2 GC/1 MWh up to 2017 and 1 GC/MWh from 2018 for 15 years.

According to the National Regulation Authority for Energy (ANRE), GC can currently be traded as low as 28.8 €/GC and as high as 58.8 €/GC. However, this support scheme may be modified by the Government in 2013, based on an overcompensation calculation made by ANRE.

There are no existing support measures for CCS in Romania.

Regulatory constraints

Romanian legislation currently does not exclude nuclear or any other energy-producing technology.

Recommendations based on the modelling results

Four measures are recommended for the country: first, structural funds for 2014-2020 should be dedicated to financing CCS demonstration projects. Second, there should be a support scheme at EU level for priority of dispatch for fossil-fired power plants that install low-carbon technology. Third, hydrocarbon producers should be obligated to use enhanced extraction methods (Enhanced Oil/Gas Recovery). Finally, dedicated

[54] National Inventory Report, 2013 – National Agency for Environmental Protection
[55] Transelectrica website and National Institute for Statistics – Energy Balance

financial instruments should be established to develop European infrastructure for CO_2 transport and storage.

5.6 Norway

CO_2 emissions by sector

Overall CO_2 emissions in Norway increased by almost 30% in 2011, compared to 1990 levels. However, in contrast to many other European countries, the power sector accounted for only a small share – less than 5%. The main contributors were industry sectors – in particular, the offshore petroleum and transport sectors which together accounted for 91% of emissions.

CO_2 emissions by sector (Mt)						
	Power industry	Other industry	Transport	Household and small businesses	Other	Total
1990[56]	0.3	18.7[57]	13.0[58]	2.5	0.2	34.7
2011[56]	2.1	24.1[57]	16.8[58]	1.4	0.2	44.6

Structure of the electricity market

Norway belongs to the joint Nordic and Baltic electricity market run by Nord Pool Spot, which comprises a day ahead market, an intra-day balancing market and a real-time market. Norway is currently sub-divided into five bidding areas with separate electricity prices. Since the bulk of electricity – 95% of total generation in 2011 – is generated from hydropower, prices are heavily dependent on climatic conditions, especially in-flow to hydro reservoirs. In 2011, exports totalled 14.3 TWh and imports 11.3 TWh, yielding a net export of 3.0 TWh.[59]

Installed generating capacity by source (GW-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2011[60]	30.5[61]	0	0	0	1.6[62]	0	32.1
Annual electricity generation by source (TWh-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2011[63]	122.8[61]	0	0	0	4.8[62]	0	127.6

Existing support measures for low-carbon energy technologies

As of 1st January 2012, a joint green certificate (GC) market was established in Norway and Sweden, whereby power producers receive a GC for every MWh of renewable electricity generated by plants built between 2009 and 2020. As producers are obligated to cover a quota of the electricity they sell with GC, this establishes a market, which will run until 2035. The goal: to incentivise investments of 26.4 TWh/year in new, renewable electricity production in these countries by 2020.

There is currently no support scheme in place for commercial CCS plants in Norway. CCS is a priority for the Norwegian Government, which has implemented an offshore CO_2 tax and, through concessions, contributed to the establishment of the offshore Sleipner CCS facility (sour gas separation) and CCS at the LNG plant, utilising gas from the Snøhvit field.

---

56 Statistics Norway (www.ssb.no/en) Table: 08940: Greenhouse gases, by source, energy product and pollutant
57 Petroleum sector + mining + other industry
58 Road transportation + domestic aviation & maritime + fisheries (excluding international aviation and maritime emissions)
59 Statistics Norway: www.ssb.no/en/energi-og-industri/statistikker/elektrisitetaar
60 Statistics Norway (www.ssb.no/en), Table: 08298: Power stations, by size (maximum output) and type of power
61 Hydro (regulated and run-of-the-river plants) and wind
62 Gas + other thermal (not distinguished in statistics)
63 Statistics Norway (www.ssb.no/en), Table: 08308: Production of electricity, by type (GWh) (C)

Regulatory constraints
There are no explicit regulatory constraints in terms of which generation technologies can enter the electricity market in Norway. However, new projects need to obtain a licence from NVE[64] in order to ensure compliance with current regulations, e.g. permitted pollution levels, environmental protection plans etc. Nuclear power has not been on the political agenda in recent years. New fossil fuel-fired power plants will not be given concessions to operate without CCS.

Recommendations based on the modelling results
The Government concluded in September 2013 that a planned full-scale CCS facility at Mongstad will be discontinued. The plan for a full-scale CCS plant in Norway by 2020 is maintained; at present, locations other than Mongstad are being reviewed. A revised strategy now includes a programme to ensure the financial and other conditions necessary to result in at least one such project by 2020.

5.7 France

CO_2 emissions by sector
In 2012, the energy sector was not the main contributor to overall CO_2 emissions in France – it was the transport sector (35.2%), followed by the Household and small businesses sector (21.7%). However, overall emissions have decreased as a result of the recent economic crisis, compared to 1990 levels.

CO_2 emissions by sector (Mt)						
	Power industry	Other industry	Transport	Household and small businesses	Other	Total
1990	67	111	118	85	9	390
2012[65]	52	83	124.1	84	9.2	352.3

Structure of the electricity market
In 2012, the energy mix was made up of 75% nuclear, 12% hydro, 9% hydrocarbons and 5% wind, photovoltaic, biomass and waste.[52] The present Government has reaffirmed the key role of nuclear in the energy mix, but with a share not exceeding 50% in 2025.

Installed generating capacity by source (GW-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2012[66]	37.7	63.1	7.9	0	10.5	0	119.2
Annual electricity generation by source (TWh-net)							
	RES	Nuclear	Coal	Lignite	Gas	Other	Total
2012[66]	89	405	18	0	23	7[67]	542

Existing support measures for low-carbon energy technologies
There are various feed-in tariffs (FiT) for RES in France:

- *Onshore wind*: 85€/MWh for the first 10 years, then 28-85€/MWh for a further five years (depending on the wind quality of the site)
- *Offshore wind*: the level is determined after a tender process. The first round of projects (2.2 GW) was awarded a FiT of 220-230€/MWh in April 2012.
- *Small- and medium-scale rooftop PV panels*: 308€/MWh for small installations of < 9kW, with complete integration on the roof; 173€/MWh for installations of < 36kW, with simplified integration

[64] Norwegian Water Resources and Energy Directorate, the Norwegian energy regulator
[65] Estimated figures: CITEPA, April 2013 (excluding overseas territories, land use change and forestry)
[66] RTE, January 2013 (excluding overseas territories)
[67] Fuel oil

on the roof; 160€/MWh for medium-scale installations (36-100kW), with simplified integration on the roof. N.B. All values are for Q2 2013 and subject to revision every quarter.

- *Large PV installations* (large-scale rooftop panels > 100kW, ground-mounted PV plants): the level of FiT is determined after a tender process which occurs several times a year. FiTs are 80-160€/MWh (Q2 2013) and awarded on a project-by-project basis
- *Biomass power plants*: the level is determined after a tender process, but are around 140€/MWh.

There are no existing support measures for CCS in France.

Regulatory constraints
Unlike renewables, there is currently no national policy or support scheme aimed at making CCS bankable: no FiTs, capital grants, EPS, or CCS certificate schemes. The only incentive to invest in CCS is the ETS.

Recommendations based on the modelling results
French electricity generation is expected to be dominated by nuclear energy, hydro-electricity, wind and solar. Nevertheless, the modelling results show that significant emissions reductions will only be achieved by deploying CCS at large scale – provided there is a level playing field with other cost-competitive, low-carbon technologies.

It is therefore recommended that the French government:

- Develops a policy which makes CCS progressively bankable, provided it is a cost-competitive means of reducing CO_2 emissions compared with other technologies in both the power sector and other energy-intensive industries.
- Develops a policy and support scheme that creates a level playing field between low-carbon technologies, allowing the most cost-competitive to be implemented. In this regard, transitional measures such as FiTs, 'CCS fund', or certificate schemes could be considered, taking into account the role played by other low-carbon technologies in the generation mix (i.e. baseload, intermittent energy, compensation of intermittency, peakload etc.).

Annex I: Model equations and cost parameters

Nomenclature

Symbol	Description
Sets	
N	Nodes (one per country)
G	Generators. The set G_n is the set of all generators at node n
L	Transmission lines (exchange corridors) between neighbouring nodes in the transmission system
$\mathrm{A}_n^{\mathrm{in/out}}$	Arcs to/from neighbouring nodes in the transmission system. N.B. For every line connecting two nodes in the transmission system, there exist two arcs. These are used to represent directional flow.
H	Operational hours. The set H_s is the set of all operational hours in season s. The H_s^- is the set of all operational hours except the first hour in season s.
S	Seasons (4 regular seasons with 24 hours and 5 peakload seasons with 5 hours)
Ω	Stochastic scenarios
T	Aggregate generation technologies (E.g. coal, gas, wind, solar etc.).
Decision variables	
x_{gi}^{gen}	Investment in capacity for generator g time period i
x_{lj}^{tran}	Investment in capacity for transmission line l time period i
$y_{ghi\omega}^{\mathrm{gen}}$	Production on generator g, operational hour h, year i, stochastic scenario ω.
$y_{ahi\omega}^{\mathrm{flow}}$	Flow on arc a, operational hour h, year i, stochastic scenario ω
$y_{nhi\omega}^{\mathrm{pump}}$	Energy used for pumping on pump p, operational hour h, year i, stochastic scenario ω
$y_{nhi\omega}^{\mathrm{LL}}$	Load shedding at node n, operational hour h, year i, stochastic scenario ω
$w_{nhi\omega}^{\mathrm{upper}}$	Water level upper reservoir for pump storage in node n, op. hour h, year i, scenario ω.
Parameters	
δ_i	Discount factor year i (at rate interest rate r this is $\delta_i = (1+r)^{-5i}$)
α_h	Operational hour scale factor. This factor represents the total number of hours in a year represented by the operational hour h. Summing a variable/parameter scaled by α_h for all $h \in \mathrm{H}$ yields a yearly total. E.g., $\sum_{h\in\mathrm{H}} \alpha_h \xi_{nhi\omega}^{\mathrm{load}}$ is the total electric energy consumption for node n in year i, scenario ω.
p_ω	Probability of scenario ω for the stochastic parameters
c_{gi}^{gen}	Total cost (fixed and capital costs) incurred by investing in 1 MW new capacity for generator g
c_{li}^{tran}	Total cost (fixed and capital costs) incurred by investing in 1 MW new exchange capacity for line l
q_{gi}^{gen}	Variable costs (fuel + emissions + Operation & Maintenance (O&M)) incurred by producing 1 MWh of electric energy on generator g in year i
q_{ni}^{VoLL}	Cost of using load shedding variable $y_{nhi\omega}^{\mathrm{LL}}$
$\xi_{nhi\omega}^{\mathrm{load}}$	Load at node n in operational hour h, year i, stochastic scenario ω

$\xi_{ghi\omega}^{\text{gen}}$	Available share of generation capacity for generator g in operational hour h, year i, stochastic scenario ω. N.B. for thermal generation technologies and regulated hydro power, the availability parameters are constant across all $\omega \in \Omega$. For intermittent RES, such as solar and wind, this parameter represents normalised production values.
$\xi_{gsi\omega}^{\text{RegHydroLi}}$	Total energy available for production in season s
ρ_{gi}	Retired share of generator g's initial capacity by year i
γ_{g}^{gen}	Limit on total upward ramping as a fraction of total installed capacity for generator g
$\overline{x}_{g0}^{\text{gen}}$	Initial installed capacity generator g
$\overline{x}_{l0}^{\text{tran}}$	Initial exchange capacity line l
$\overline{x}_{tn*}^{\text{gen}}$	Upper bound on (period-wise/cumulative) investments in new capacity for generator g
$\overline{x}_{l*}^{\text{tran}}$	Upper bound on (period-wise) investments in new exchange capacity line l
η_{a}^{line}	Exchange losses on arc a (given as a share of the total flow)
η_{n}^{pump}	Pump efficiency for pump storage in node n
hr_{gi}	Heat rate generator g, year i
e_{f}	Carbon content fuel f
EPS_{ni}	Emission performance standard node n, year i

Model equations[68]

Objective function: to minimise net present value of investments and operation decisions

$$\min_{\mathbf{x},\mathbf{y}} z = \sum_{i\in \mathrm{I}} \delta_i \times \left\{ \sum_{g\in \mathrm{G}} c_{gi}^{\text{gen}} x_{gi}^{\text{gen}} + \sum_{l\in \mathrm{L}} c_{li}^{\text{tran}} x_{li}^{\text{tran}} + \sum_{\omega\in\Omega} p_\omega \times \sum_{h\in \mathrm{H}} \alpha_h \times \sum_{n\in \mathrm{N}} \left(\sum_{g\in \mathrm{G}_n} \left[q_{gi}^{\text{gen}} y_{ghi\omega}^{\text{gen}} \right] + q_{ni}^{\text{VoLL}} y_{nhi\omega}^{\text{LL}} \right) \right\} \quad (0.1)$$

Investment constraints for generation capacity (period-wise and cumulative)

$$\begin{aligned} &\sum_{g\in \mathrm{G}_{nt}} x_{gj}^{\text{gen}} \le \overline{x}_{nti}^{\text{gen,Period}}, \quad n\in \mathrm{N}, t\in \mathrm{T}, i\in \mathrm{I}. \\ &\sum_{j=1}^{i} \sum_{g\in \mathrm{G}_{nt}} x_{gj}^{\text{gen}} \le \overline{x}_{nt}^{\text{gen,Cumulative}} - (1-\rho_{gi})\overline{x}_{g0}^{\text{gen}}, \quad n\in \mathrm{N}, t\in \mathrm{T}, i\in \mathrm{I}. \end{aligned} \quad (0.2)$$

Investment constraints for transmission (exchange) capacity

$$x_{li}^{\text{tran}} \le \overline{x}_{li}^{\text{tran,Period}}, \quad l\in \mathrm{L}, i\in \mathrm{I}. \quad (0.3)$$

Load constraints (production + net import + load shedding = load + pumping)

$$\sum_{g\in \mathrm{G}_n} y_{ghi\omega}^{\text{gen}} + \sum_{a\in \mathrm{A}_n^{\text{in}}} (1-\eta_a^{\text{line}}) y_{ahi\omega}^{\text{flow}} - \sum_{a\in \mathrm{A}_n^{\text{out}}} y_{ahi\omega}^{\text{flow}} - y_{nhi\omega}^{\text{pump}} + y_{nhi\omega}^{\text{LL}} = \xi_{nhi\omega}^{\text{load}}, \; n\in \mathrm{N}, h\in \mathrm{H}, \omega\in\Omega, i\in \mathrm{I}. \quad (0.4)$$

[68] The model was implemented and solved using FICO® Xpress Optimization Suite

Generation capacity constraint

$$y^{\text{gen}}_{ghi\omega} \le \xi^{\text{gen}}_{ghi\omega} \times \left((1-\rho_{gi})\overline{x}^{\text{gen}}_{g0} + \sum_{j=1}^{i} x^{\text{gen}}_{gj}\right), \quad g \in \mathrm{G}, h \in \mathrm{H}, i \in \mathrm{I}, \omega \in \Omega. \tag{0.5}$$

Upward ramping constraints

$$y^{\text{gen}}_{ghi\omega} - y^{\text{gen}}_{g(h-1)i\omega} \le \gamma^{\text{gen}}_{g} \times \left((1-\rho_{gi})\overline{x}^{\text{gen}}_{g0} + \sum_{j=1}^{i} x^{\text{gen}}_{gj}\right), \quad g \in \mathrm{G}^{\text{Thermal}}, s \in \mathrm{S}, h \in \mathrm{H}^{-}_{s}, i \in \mathrm{I}, \omega \in \Omega, \tag{0.6}$$

Flow constraint – limit flow on arcs (arcs are directional, lines are symmetric)

$$y^{\text{flow}}_{ahi\omega} \le \overline{x}^{\text{tran}}_{l0} + \sum_{j=1}^{i} x^{\text{tran}}_{lj}, \quad l \in \mathrm{L}_{n}, a \in \mathrm{A}_{l}, h \in \mathrm{H}, i \in \mathrm{I}, \omega \in \Omega. \tag{0.7}$$

Hydro energy constraint – limit total hydropower production within a season (due to water availability)

$$\sum_{h \in \mathrm{H}_s} y^{\text{gen}}_{ghi\omega} \le \xi^{\text{RegHydroLim}}_{gsi\omega}, \quad g \in \mathrm{G}^{\text{RegHydro}}, s \in \mathrm{S}, i \in \mathrm{I}, \omega \in \Omega. \tag{0.8}$$

Pump-storage upper reservoir balance and limit

$$\left.\begin{aligned} w^{\text{upper}}_{n(h-1)i\omega} + \eta^{pump}_{n} y^{\text{pump}}_{nhi\omega} - y^{\text{gen,pump}}_{nhi\omega} &= w^{\text{upper}}_{nhi\omega} \\ w^{\text{upper}}_{nhi\omega} &\le \overline{w}^{\text{upper}}_{n} \end{aligned}\right., n \in \mathrm{N}, h \in \mathrm{H}_{s}, i \in \mathrm{I}, \omega \in \Omega. \tag{0.9}$$

Emission performance standard (per generator, assume g burns fuel f)

$$y^{\text{gen}}_{ghi\omega} \times hr_{gi} \times e_{f} \le EPS_{ni}, \quad n \in \{\text{selected nodes}\}, g \in \mathrm{G}_{n}, h \in \mathrm{H}, i \in \mathrm{I}, \omega \in \Omega. \tag{0.10}$$

N.B. All decision variables are assumed to be non-negative.

Cost parameters

Investment costs

The investment cost parameters used in the Ramona-EL model, c^{gen}_{gi} and c^{tran}_{li} for generation and transmission capacity respectively, are derived from three data parameters. These are capital costs, lifetime and fixed O&M costs. Consider as an example, investment in new capacity for generator g (e.g. CCGT in Germany) in year i. Denote by C^{capcost}_{gi} the capital cost for new capacity (in €/kW), t^{life}_{gi} the lifetime (in years) and $C^{\text{fixedO\&M}}_{gi}$ the fixed O&M costs (in €/kW/yr) for g in year i. The procedure for calculating c^{gen}_{gi} involves two steps: first, the capital cost is spilt into annual payments of equal size so that the full cost is amortised over t^{life}_{gi} years. The fixed O&M cost is added to the annualised capital cost payments yielding an annual payment accounting for all capacity related costs

$$C^{\text{ann}}_{gi} = \frac{r}{(1+r) \times \left[1-(1+r)^{-t^{\text{life}}_{gi}}\right]} \times C^{\text{capcost}}_{gi} + C^{\text{fixedO\&M}}_{gi}. \tag{0.10}$$

The parameter c^{gen}_{gi} used in the Ramonal-EL model is then the sum of all payments made within the analysis horizon. We let $i \in \mathrm{I}$ be the index of every five year period in the model, i.e., $\mathrm{I} = (1, 2, \ldots, I)$. As we assume that every investment is made at the beginning of a five-year time period, the total number of payments, n, from year i until the horizon I is given by

$$n = \min(5 \times (I - i + 1), t^{\text{life}}_{gi}) \tag{0.10}$$

Summing all n payments yields a year i value of the total capacity cost of

$$c_{gi}^{\text{gen}} = \frac{1-(1+r)^{-n}}{1-(1+r)^{-1}} \times \frac{C_{gi}^{\text{ann}}}{5} \times 1000. \qquad (0.10)$$

We divide by 5 and multiply by 1,000 to obtain the average annual per MW costs, which can be added to the annual operational costs in the objective function.

Short-term marginal costs (SRMC)

In the Ramona-EL model we have assumed that the cost of generation is linear as a function of the output. Thus in year i the cost of generating $y_{ghi\omega}^{\text{gen}}$ MWh of electricity on generator g in an operational hour $h \in \mathrm{H}$ (and stochastic scenario $\omega \in \Omega$), is given by

$$C_{gi}^{\text{var}}(y_{ghi\omega}^{\text{gen}}) = q_{gi}^{\text{gen}} y_{ghi\omega}^{\text{gen}}. \qquad (0.10)$$

We refer to the factor q_{gi}^{gen} (unit €/MWh) as the short-run marginal costs (SRMC). The SRMC has three components: a fuel component (assumed zero for renewables), an emissions cost component (assumed zero for renewables and nuclear) and a variable cost component. Assume that generator g uses fuel f with price p_{fi} (unit €/GJ) in year i. Assume also that the emissions associated using fuel f is e_f (unit tCO_2/GJ) and the price for CO_2 emission is $p_{\text{CO}_2,i}$ (unit €/tCO_2) in year i. The variable O&M costs is denoted by $C_{gi}^{\text{vO\&M}}$ (unit €/MWh). For a generator with heat rate hr_{gi} in year i the SRMC is defined as

$$q_{gi}^{\text{gen}} = hr_{gi} \times (p_{fi} + e_f \times p_{\text{CO}_2,i}) + C_{gi}^{\text{vO\&M}}.$$

Technology costs

Technology *2010*	Investment cost *€/kW of Capacity*	Life time *years*	Fixed O&M *€/kW/Yr*	Variable O&M *€/MWh*	Efficiency *%*	Retirement factor
Lignite existing	0	40	32.40	0.48	0.351	0.00
Lignite	1600	40	32.40	0.48	0.430	0.00
Lignite CCS	0	0	0.00	0.00	0.000	0.00
Lignite CCS support*	2600	40	79.65	1.18	0.310	0.00
Coal existing	0	40	31.05	0.46	0.374	0.00
Coal	1500	40	31.05	0.46	0.450	0.00
Coal CCS	0	0	0.00	0.00	0.000	0.00
Coal CCS support*	2500	40	78.30	1.16	0.330	0.00
Gas existing	0	30	19.50	0.45	0.480	0.00
Gas OCGT	400	30	19.50	0.45	0.400	0.00
Gas CCGT	650	30	30.38	0.45	0.601	0.00
Gas CCS	0	0	0.00	0.00	0.000	0.00
Gas CCS support*	1350	30	77.63	1.16	0.480	0.00
Oil existing	0	40	19.50	0.00	0.376	0.00
Bio existing	0	40	48.36	0.00	0.382	0.00
Bio 10% co-firing	1600	40	32.40	0.48	0.450	0.00
Bio 10% co-firing CCS	0	0	0.00	0.00	0.000	0.00

Nuclear	3000	60	134.46	1.80	0.360	0.00
Wave	6050	25	153.85	0.00	1	0.00
Geo	5500	40	92.31	0.00	1	0.00
Hydro regulated	3000	60	125.00	0.00	1	0.00
Hydro run-of-the-river	4000	60	125.00	0.00	1	0.00
Hydro PS	1250	60	108.00	0.00	1	0.00
Wind onshore	1200	25	54.40	0.00	1	0.00
Wind offshore	4080	25	137.97	0.00	1	0.00
PV Solar	1900	25	19.50	0.00	1	0.00

* For demonstration and early deployment projects supported by transitional measures

Technology 2015	**Investment cost** €/kW of Capacity	**Life time** years	**Fixed O&M** €/kW/Yr	**Variable O&M** €/MWh	**Efficiency** %	**Retirement factor**
Lignite existing	0	40	32.40	0.48	0.354	0.25
Lignite	1600	40	32.40	0.48	0.438	0.00
Lignite CCS	0	0	0.00	0.00	0.000	0.00
Lignite CCS support*	2600	40	79.65	1.18	0.310	0.00
Coal existing	0	40	31.05	0.46	0.377	0.25
Coal	1500	40	31.05	0.46	0.455	0.00
Coal CCS	0	0	0.00	0.00	0.000	0.00
Coal CCS support*	2500	40	78.30	1.16	0.330	0.00
Gas existing	0	30	19.50	0.45	0.489	0.10
Gas OCGT	400	30	19.50	0.45	0.403	0.00
Gas CCGT	650	30	30.38	0.45	0.601	0.00
Gas CCS	0	0	0.00	0.00	0.000	0.00
Gas CCS support*	1350	30	77.63	1.16	0.480	0.00
Oil existing	0	40	19.50	0.00	0.376	0.28
Bio existing	0	40	47.35	0.00	0.384	0.14
Bio 10% co-firing	1600	40	32.40	0.48	0.455	0.00
Bio 10% co-firing CCS	0	0	0.00	0.00	0.000	0.00
Nuclear	2838	60	130.73	1.75	0.361	0.14
Wave	5669	25	153.85	0.00	1	0.00
Geo	5500	40	92.31	0.00	1	0.00
Hydro regulated	3000	60	125.00	0.00	1	0.00
Hydro run-of-the-river	4000	60	125.00	0.00	1	0.00
Hydro PS	1250	60	108.00	0.00	1	0.00
Wind onshore	1188	25	53.51	0.00	1	0.00
Wind offshore	3930	25	132.77	0.00	1	0.00
PV Solar	1788	25	20.31	0.00	1	0.00

* For demonstration and early deployment projects supported by transitional measures

Technology 2020	Investment cost €/kW of Capacity	Life time years	Fixed O&M €/kW/Yr	Variable O&M €/MWh	Efficiency %	Retirement factor
Lignite existing	0	40	32.40	0.48	0.356	0.38
Lignite	1600	40	32.40	0.48	0.445	0.00
Lignite CCS	0	0	0.00	0.00	0.000	0.00
Lignite CCS support*	2600	40	79.65	1.18	0.310	0.00
Coal existing	0	40	31.05	0.46	0.379	0.38
Coal	1500	40	31.05	0.46	0.460	0.00
Coal CCS	0	0	0.00	0.00	0.000	0.00
Coal CCS support*	2500	40	78.30	1.16	0.330	0.00
Gas existing	0	30	19.50	0.45	0.498	0.32
Gas OCGT	400	30	19.50	0.45	0.405	0.00
Gas CCGT	650	30	30.38	0.45	0.601	0.00
Gas CCS	0	0	0.00	0.00	0.000	0.00
Gas CCS support*	1350	30	77.63	1.16	0.480	0.00
Oil existing	0	40	19.50	0.00	0.376	0.44
Bio existing	0	40	46.34	0.00	0.386	0.29
Bio 10% co-firing	1600	40	32.40	0.48	0.460	0.00
Bio 10% co-firing CCS	0	0	0.00	0.00	0.000	0.00
Nuclear	2675	60	126.99	1.70	0.363	0.29
Wave	5288	25	153.85	0.00	1	0.00
Geo	5500	40	92.31	0.00	1	0.00
Hydro regulated	3000	60	125.00	0.00	1	0.00
Hydro run-of-the-river	4000	60	125.00	0.00	1	0.00
Hydro PS	1250	60	108.00	0.00	1	0.00
Wind onshore	1175	25	52.63	0.00	1	0.00
Wind offshore	3780	25	127.57	0.00	1	0.00
PV Solar	1675	25	21.13	0.00	1	0.00

* For demonstration and early deployment projects supported by transitional measures

Technology 2025	Investment cost €/kW of Capacity	Life time years	Fixed O&M €/kW/Yr	Variable O&M €/MWh	Efficiency %	Retirement factor
Lignite existing	0	40	32.40	0.48	0.358	0.59
Lignite	1600	40	32.40	0.48	0.453	0.00
Lignite CCS	2600	40	51.37	3.28	0.373	0.00
Lignite CCS support*	2600	40	79.65	1.18	0.310	0.00
Coal existing	0	40	31.05	0.46	0.381	0.59
Coal	1500	40	31.05	0.46	0.465	0.00
Coal CCS	2500	40	46.96	2.46	0.385	0.00

Coal CCS support*	2500	40	78.30	1.16	0.330	0.00
Gas existing	0	30	19.50	0.45	0.506	0.58
Gas OCGT	400	30	19.50	0.45	0.408	0.00
Gas CCGT	650	30	30.38	0.45	0.601	0.00
Gas CCS	1350	30	46.88	1.85	0.521	0.00
Gas CCS support*	1350	30	77.63	1.16	0.480	0.00
Oil existing	0	40	19.50	0.00	0.376	0.67
Bio existing	0	40	45.33	0.00	0.388	0.43
Bio 10% co-firing	1600	40	32.40	0.48	0.465	0.00
Bio 10% co-firing CCS	2600	40	51.37	3.28	0.385	0.00
Nuclear	2513	60	123.26	1.65	0.364	0.43
Wave	4906	25	153.85	0.00	1	0.00
Geo	5500	40	92.31	0.00	1	0.00
Hydro regulated	3000	60	125.00	0.00	1	0.00
Hydro run-of-the-river	4000	60	125.00	0.00	1	0.00
Hydro PS	1250	60	108.00	0.00	1	0.00
Wind onshore	1163	25	51.74	0.00	1	0.00
Wind offshore	3630	25	122.37	0.00	1	0.00
PV Solar	1563	25	21.94	0.00	1	0.00

* For demonstration and early deployment projects supported by transitional measures

Technology	**Investment cost**	**Life time**	**Fixed O&M**	**Variable O&M**	**Efficiency**	**Retirement factor**
2030	*€/kW of Capacity*	*years*	*€/kW/Yr*	*€/MWh*	*%*	
Lignite existing	0	40	32.40	0.48	0.360	0.71
Lignite	1600	40	32.40	0.48	0.460	0.00
Lignite CCS	2530	40	50.04	3.28	0.385	0.00
Lignite CCS support*	2600	40	79.65	1.18	0.310	0.00
Coal existing	0	40	31.05	0.46	0.383	0.71
Coal	1500	40	31.05	0.46	0.470	0.00
Coal CCS	2430	40	45.85	2.46	0.395	0.00
Coal CCS support*	2500	40	78.30	1.16	0.330	0.00
Gas existing	0	30	19.50	0.47	0.515	0.90
Gas OCGT	400	30	19.50	0.47	0.410	0.00
Gas CCGT	680	30	35.10	0.52	0.613	0.00
Gas CCS	1330	30	50.45	1.92	0.538	0.00
Gas CCS support*	1350	30	77.63	1.16	0.480	0.00
Oil existing	0	40	19.50	0.00	0.376	0.76
Bio existing	0	40	44.33	0.00	0.390	0.57
Bio 10% co-firing	1600	40	32.40	0.48	0.470	0.00
Bio 10% co-firing CCS	2530	40	50.04	3.28	0.395	0.00

Nuclear	2350	60	119.52	1.60	0.365	0.57
Wave	4525	25	153.85	0.00	1	0.00
Geo	5500	40	92.31	0.00	1	0.00
Hydro regulated	3000	60	125.00	0.00	1	0.00
Hydro run-of-the-river	4000	60	125.00	0.00	1	0.00
Hydro PS	1250	60	108.00	0.00	1	0.00
Wind onshore	1150	25	50.85	0.00	1	0.00
Wind offshore	3480	25	117.17	0.00	1	0.00
PV Solar	1450	25	22.75	0.00	1	0.00

* For demonstration and early deployment projects supported by transitional measures

Technology	Investment cost	Life time	Fixed O&M	Variable O&M	Efficiency	Retirement factor
2040	*€/kW of Capacity*	*years*	*€/kW/Yr*	*€/MWh*	*%*	
Lignite existing	0	40	32.40	0.48	0.364	0.95
Lignite	1600	40	32.40	0.48	0.475	0.00
Lignite CCS	2400	40	47.39	3.28	0.408	0.00
Lignite CCS support*	2600	40	79.65	1.18	0.310	0.00
Coal existing	0	40	31.05	0.46	0.387	0.95
Coal	1500	40	31.05	0.46	0.480	0.00
Coal CCS	2300	40	43.62	2.46	0.413	0.00
Coal CCS support*	2500	40	78.30	1.16	0.330	0.00
Gas existing	0	30	19.50	0.51	0.533	1.00
Gas OCGT	400	30	19.50	0.51	0.415	0.00
Gas CCGT	740	30	44.55	0.66	0.636	0.00
Gas CCS	1290	30	57.59	2.06	0.569	0.00
Gas CCS support*	1350	30	77.63	1.16	0.480	0.00
Oil existing	0	40	19.50	0.00	0.376	0.95
Bio existing	0	40	42.31	0.00	0.395	0.86
Bio 10% co-firing	1600	40	32.40	0.48	0.480	0.00
Bio 10% co-firing CCS	2400	40	47.39	3.28	0.413	0.00
Nuclear	2025	60	112.05	1.50	0.368	0.86
Wave	3763	25	153.85	0.00	1	0.00
Geo	5500	40	92.31	0.00	1	0.00
Hydro regulated	3000	60	125.00	0.00	1	0.00
Hydro run-of-the-river	4000	60	125.00	0.00	1	0.00
Hydro PS	1250	60	108.00	0.00	1	0.00
Wind onshore	1125	25	49.08	0.00	1	0.50
Wind offshore	3180	25	106.76	0.00	1	0.50
PV Solar	1225	25	24.38	0.00	1	0.50

* For demonstration and early deployment projects supported by transitional measures

Technology *2050*	Investment cost *€/kW of Capacity*	Life time *years*	Fixed O&M *€/kW/Yr*	Variable O&M *€/MWh*	Efficiency *%*	Retirement factor
Lignite existing	0	40	32.40	0.48	0.368	1.00
Lignite	1600	40	32.40	0.48	0.490	0.00
Lignite CCS	2250	40	44.73	3.28	0.430	0.00
Lignite CCS support*	2600	40	79.65	1.18	0.310	0.00
Coal existing	0	40	31.05	0.46	0.391	1.00
Coal	1500	40	31.05	0.46	0.490	0.00
Coal CCS	2150	40	41.39	2.46	0.430	0.00
Coal CCS support*	2500	40	78.30	1.16	0.330	0.00
Gas existing	0	30	19.50	0.55	0.550	1.00
Gas OCGT	400	30	19.50	0.55	0.420	0.00
Gas CCGT	800	30	54.00	0.80	0.660	0.00
Gas CCS	1250	30	64.73	2.20	0.600	0.00
Gas CCS support*	1350	30	77.63	1.16	0.480	0.00
Oil existing	0	40	19.50	0.00	0.376	1.00
Bio existing	0	40	40.30	0.00	0.399	1.00
Bio 10% co-firing	1600	40	32.40	0.48	0.490	0.00
Bio 10% co-firing CCS	2250	40	44.73	3.28	0.430	0.00
Nuclear	1700	60	104.58	1.40	0.370	1.00
Wave	3000	25	153.85	0.00	1	0.00
Geo	5500	40	92.31	0.00	1	0.00
Hydro regulated	3000	60	125.00	0.00	1	0.00
Hydro run-of-the-river	4000	60	125.00	0.00	1	0.00
Hydro PS	1250	60	108.00	0.00	1	0.00
Wind onshore	1100	25	47.30	0.00	1	1.00
Wind offshore	2880	25	96.36	0.00	1	1.00
PV Solar	1000	25	26.00	0.00	1	1.00

* For demonstration and early deployment projects supported by transitional measures

Capacity constraints on power plant construction by country

Maximum installed capacity MW

Country	Hydro storage	Hydro RoR	Hydro pumped	Nuclear	Lignite	Coal	Gas	Oil	Bio	Wind onsh.	Wind offsh.	Solar	Wave/ Ocean	Geo
AT	4,530	11,225	16,885	0	0	1,606	200,000	200,000	200,000	7,900	0	4,800		
BA	1,587	29	440	0	0	2,100	0	0	0	200	0	0	0	0
BE	0	362	1,308	0	0	1,311	200,000	200,000	200,000	2,286	3,800	4,034	0	4
BG	4,625	326	2,828	6840	3,500	2,223	200,000	200,000	200,000	3,450	0	2,203	0	0
CH	10,150	7,127	13,100	0	0	0	200,000	200,000	200,000	1,100	0	4,571	0	0
CZ	1,299	459	1,147	7200	9,500	2,925	200,000	200,000	200,000	4,000	0	2,229	0	4
DE	2,211	4,151	17,296	0	22,500	34,199	200,000	200,000	200,000	60,000	52,000	70,000	0	300
DK	0	9	0	0	0	7,566	200,000	200,000	200,000	4,700	3,309	9	0	0
EE	0	13	0	0	2,200	0	200,000	0	200,000	400	0	0	0	0
ES	39,941	9,518	13,053	11899	0	12,268	200,000	200,000	200,000	43,427	10,000	70,000	120	50
FI	6,543	356	0	8874	1,600	4,136	200,000	200,000	200,000	2,100	3,900	0	12	0
FR	20,712	15,719	13,263	65,000	0	14,080	200,000	200,000	200,000	37,500	12,500	30,000	450	80
GB	7,219	3,310	2,744	16692	0	48,035	200,000	200,000	200,000	19,363	33,000	7,000	1,500	0
GR	3,071	1,575	4,587	0	5,000	0	200,000	200,000	200,000	12,850	650	11,000	0	120
HR	1,407	430	276	0	0	270	200,000	200,000	0	5,600	0	0	0	0
HU	0	194	10,850	3372	1,000	424	200,000	200,000	200,000	1,600	0	783	0	57
IE	296	32	292	0	400	957	200,000	200,000	200,000	4,891	1,000	0	90	0
IT	12,830	8,508	8,444	0	0	7,193	200,000	0	200,000	19,090	680	30,000	7	920
LT	259	0	1,660	1563.6	0	0	200,000	200,000	200,000	500	0	180	0	0
LU	46	40	2,896	0	0	0	200,000	0	200,000	206	0	576	0	0
LV	0	1,676	0	0	0	220	200,000	200,000	200,000	236	180	18	0	10
MK	503	0	0	0	800	0	0	200,000	0	100	0	0	0	0
NL	0	227	0	3582	0	9,187	200,000	0	200,000	4,200	20,000	2,093	162	0
NO	30,390	15,000	3,659	0	0	0	200,000	0	0	6,160	5,800	0	0	0
PL	601	1,752	1,776	3,000	9,500	27,115	200,000	0	200,000	10,000	0	9	0	0
PT	16,114	29,428	14,157	0	0	1,954	200,000	200,000	200,000	9,412	75	10,000	300	75
RO	11,223	6,708	6,459	4956	4,500	2,116	200,000	200,000	200,000	2,300	1,700	500	0	0
RS	715	3,531	4,538	0	5,500	0	200,000	200,000	0	500	0	0	0	0
SE	11,477	6,559	43	8436	0	1,004	200,000	200,000	200,000	6,000	11,000	13	0	0
SI	0	3,574	0	393.53	0	1,067	200,000	200,000	200,000	860	0	225	0	0
SK	2,684	0	873	3,500	400	872	200,000	200,000	200,000	545	0	82	0	4

Sources: Reanalysis, National Renewable Energy Action Plans (NREAPs) Eurelectric Power statistics 2012, ZEP member organisations

Derived short-run marginal cost of production (2010 €/MWh)

Technology	2010	2015	2020	2025	2030	2035	2040	2045	2050
Lignite existing	8.7	8.7	25.9	32.0	38.1	44.0	56.3	68.5	80.5
Lignite	7.2	7.1	20.8	25.4	29.9	34.2	43.3	52.1	60.6
Lignite CCS	0.0	0.0	0.0	30.0	28.8	27.6	27.2	26.8	26.3
Coal existing	15.1	15.1	30.3	35.7	41.1	46.3	57.2	67.9	78.4
Coal	12.6	12.6	25.0	29.3	33.5	37.6	46.2	54.6	62.7
Coal CCS	0.0	0.0	0.0	34.1	33.1	32.0	31.7	31.3	30.8
Gas existing	29.8	29.4	36.2	38.7	41.3	43.6	49.3	55.0	60.1
Gas OCGT	35.6	35.6	44.4	47.9	51.8	55.2	63.2	71.0	78.5
Gas CCGT	23.9	24.0	30.0	32.7	34.9	36.8	41.5	46.2	50.4
Gas CCS	0.0	0.0	0.0	37.6	37.2	36.7	37.4	38.2	38.7
Oil existing	68.5	70.1	85.0	91.6	98.7	105.8	117.6	128.2	138.5
Bio existing	47.4	47.5	47.3	44.3	42.0	45.2	47.0	48.9	52.6
Bio 10% co-firing	15.4	15.4	26.6	30.2	33.7	37.7	45.5	53.2	60.8
Nuclear	7.5	7.6	7.8	8.0	8.2	8.4	8.8	9.3	10.1
Wave/Ocean	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geo	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro regulated	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro run-of-the-river	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro PS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind onshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind offshore	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bio 10% co-firing CCS*	0.0	0.0	0.0	35.9	34.2	33.0	31.9	30.9	29.9
Lignite CCS support*	31.6	31.7	33.7	33.3	32.9	32.4	32.7	33.0	33.2
Coal CCS support*	36.3	36.4	38.3	38.1	37.8	37.5	37.7	37.9	38.1
Gas CCS support*	38.0	38.3	39.4	40.0	40.7	41.3	43.1	45.1	46.8

* For demonstration and early deployment projects supported by transitional measures

Initial installed capacity 2010-2012 (MW)

Country	Hydro storage	Hydro RoR	Hydro pumped	Nuclear	Lignite	Coal	Gas	Oil	Bio	Wind onsh.	Wind offsh.	Solar	Wave/ Ocean	Geo
AT	2,453.0	5,645.3	4,285.0	0.0	0.0	1,226.0	4,298.0	359.0	1,211.0	1,013.0	0.0	170.0	0.0	1.0
BA	1,587.0	29.0	440.0	0.0	0.0	1,725.0	0.0	52.5	0.3	0.0	0.0	0.0	0.0	0.0
BE	0.0	113.0	1,308.0	5,927.0	0.0	1,156.0	5,444.0	741.0	617.6	722.0	88.0	1,812.3	0.0	0.0
BG	2,027.0	143.0	938.0	1,900.0	3,064.0	1,151.0	789.0	275.0	0.0	800.0	0.0	25.0	0.0	0.0
CH	8,350.0	3,770.0	1,400.0	3,250.0	0.0	0.0	546.0	84.0	179.0	42.0	0.0	71.0	0.0	0.0
CZ	780.0	276.0	1,147.0	3,900.0	8,971.0	1,776.0	453.0	123.0	7.0	218.0	0.0	1,959.0	0.0	0.0
DE	1,374.2	2,631.8	6,991.0	13,000.0	21,000.0	27,000.0	23,000.0	10,000.0	8,000.0	30,000.0	60.0	33,000.0	0.0	10.0
DK	0.0	9.0	0.0	0.0	0.0	4,899.0	2,917.0	1,077.0	1,017.0	2,934.0	868.0	0.0	0.0	0.0
EE	0.0	4.0	0.0	0.0	2,000.0	0.0	184.0	0.0	76.0	149.0	0.0	0.0	0.0	0.0
ES	13,231.0	3,153.0	2,667.0	7,483.0	0.0	12,210.0	27,123.0	4,376.0	752.0	20,155.0	0.0	4,736.0	0.0	0.0
FI	2,750.0	310.0	0.0	2,730.0	1,441.0	2,699.0	2,842.0	1,349.0	1,790.0	197.0	0.0	0.0	0.0	0.0
FR	13,515.0	7,612.0	4,263.0	63,100.0	0.0	7,900.0	10,500.0	9,400.0	1,400.0	7,500.0	0.0	3,500.0	240.0	26.0
GB	622.0	989.0	2,744.0	10,846.0	0.0	28,015.0	31,841.0	3,636.0	4,238.0	4,040.0	1,390.0	1,011.7	0.0	0.0
GR	2,544.0	0.0	699.0	0.0	4,456.0	0.0	4,486.0	698.0	409.0	1,460.0	0.0	1,420.0	0.0	0.0
HR	1,407.0	430.0	276.0	0.0	0.0	245.1	506.5	931.4	0.0	0.0	0.0	0.0	0.0	0.0
HU	0.0	50.0	50.0	1,892.0	841.0	385.0	4,217.0	422.0	374.0	330.0	0.0	0.0	0.0	0.0
IE	215.0	32.0	292.0	0.0	344.0	855.0	3,205.0	1,255.0	77.0	2,052.0	36.0	0.0	0.0	0.0
IT	9,211.7	4,764.9	7,543.9	0.0	0.0	19,905.0	46,921.0	7,613.0	1,918.0	364.0	0.0	12,750.0	0.0	754.0
LT	115.0	0.0	760.0	0.0	0.0	0.0	2,377.0	148.0	34.0	161.0	0.0	0.0	0.0	0.0
LU	17.0	15.0	1,096.0	0.0	0.0	0.0	505.0	0.0	13.0	50.0	0.0	27.0	0.0	0.0
LV	0.0	1,550.0	0.0	0.0	0.0	0.0	900.0	30.0	13.0	31.0	0.0	0.0	0.0	0.0
MK	503.0	0.0	0.0	0.0	800.0	0.0	0.0	270.0	0.0	0.0	0.0	0.0	0.0	0.0
NL	0.0	38.0	0.0	485.0	0.0	4,161.0	17,853.0	0.0	1,430.0	2,013.0	228.0	113.0	0.0	0.0
NO	21,867.4	5,938.6	1,269.0	0.0	0.0	0.0	915.0	0.0	0.0	430.0	0.0	0.0	0.0	0.0
PL	141.2	411.7	1,776.0	0.0	9,732.6	20,367.7	944.2	0.0	380.0	1,100.0	0.0	0.0	0.0	0.0
PT	1,421.0	2,595.0	1,035.0	0.0	0.0	1,756.0	4,501.0	2,835.0	647.0	4,256.0	0.0	122.0	5.0	25.0
RO	3,810.0	2,277.0	1,000.0	1,295.0	4,148.0	1,200.0	3,596.0	0.0	14.0	400.8	0.0	0.0	0.0	0.0
RS	397.0	1,852.0	614.0	0.0	3,936.0	0.0	359.0	27.0	0.0	0.0	0.0	0.0	0.0	0.0
SE	9,677.2	6,522.8	43.0	9,150.0	0.0	130.0	1,005.0	3,764.0	2,683.0	1,797.0	76.0	0.0	0.0	0.0
SI	0.0	1,027.0	0.0	656.0	0.0	896.0	380.6	123.4	51.0	0.0	0.0	0.0	0.0	0.0
SK	1,694.0	0.0	873.0	1,820.0	365.0	481.0	1,783.0	85.0	50.0	0.0	0.0	488.1	0.0	0.0

Sources: Eurelectric Power Statistics 2012, Entso-E, ZEP member organisations, NREAP, ISOs and market operators: National Grid, Red Elèctrica, Terna, EEX

Limitations of the modelling

The optimisation model depicts a simplified picture of the future and various investment parameters, resulting in several limitations that should be taken into account. The output of the model is largely based on forecasts of what the prices of fuels and technologies will be in the future. However, the way in which the policies are modelled here effectively assumes that both policymakers and investors can flawlessly predict such prices.[69] This makes it impossible to calculate meaningfully the way in which transaction costs might affect certain CCS incentives, such as certificate schemes. It also precludes the fact that unforeseeable changes in the broader energy system may affect the relative competitiveness of fuels and technologies.

Moreover, several assumptions have been made in order to simplify the modelling of policy measures in this study. For example, the EPS modelled are implemented at a specific date and do not foresee variable models of grandfathering periods for existing plants, such as reduced operating hours. An EPS introduction in both 2030 and 2015 was tested; the difference in the modelling results was negligible. This is because the model has perfect foresight and therefore makes the same investment decisions (since the 15-year difference is well within the lifetime of new plants). Small changes to the design of market-based instruments can have a significant impact on their real-world effectiveness, but the modelling performed here cannot capture differences in the administration of policies.

The possibility of biomass co-firing and running CCS plants with partial capture was also not explored. In the real world, certain CCS plants will have the option of tailoring the blend of biomass and coal in their feedstock, as well as the percentage of emissions they capture, in order to optimise revenues according to fluctuating electricity, fuel and CO_2 prices. However, modelling the infinite possible permutations of this

[69] The modelling also does not reflect the impact on dispatch of negative electricity prices

proved impractical. For each time period studied in the model, generating technologies had fixed operating parameters and therefore costs.

However, whilst the above should be borne in mind, the impact of potential limitations is minor and does not undermine the modelling results.

Annex II: Data for baseline and test cases

Figures 27-31 show further results of the baseline case to 2050 (see also Chapter 3).

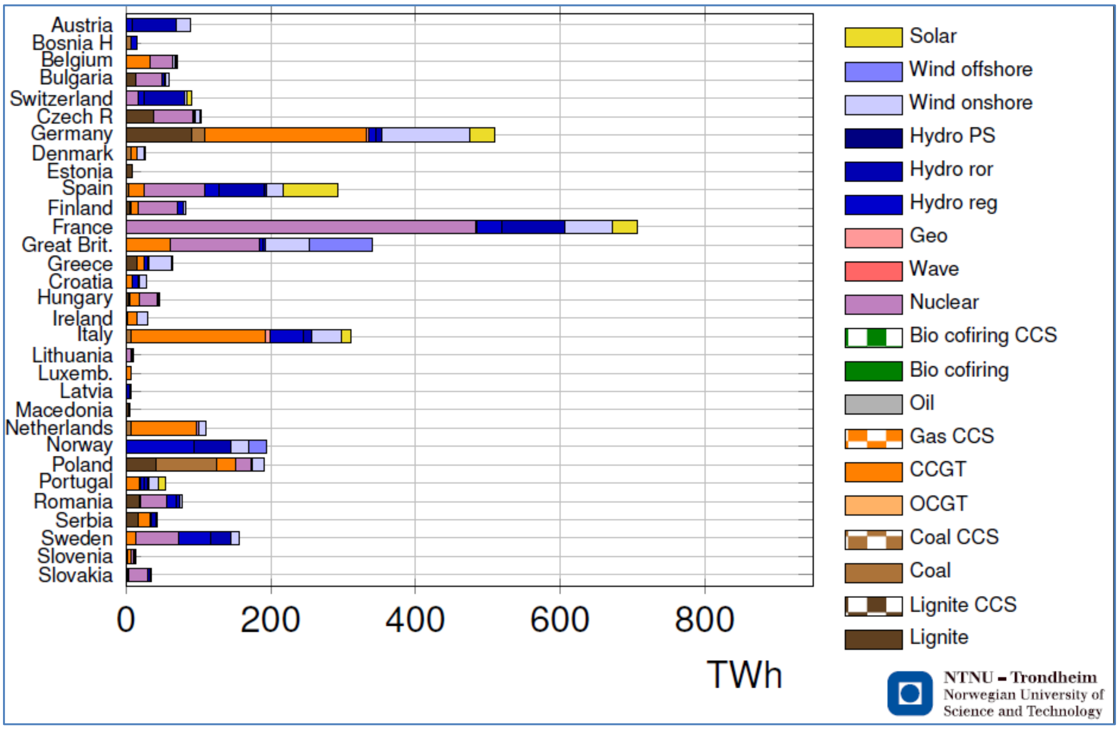


Figure 27: Baseline case: the electricity generation mix in Europe in 2020

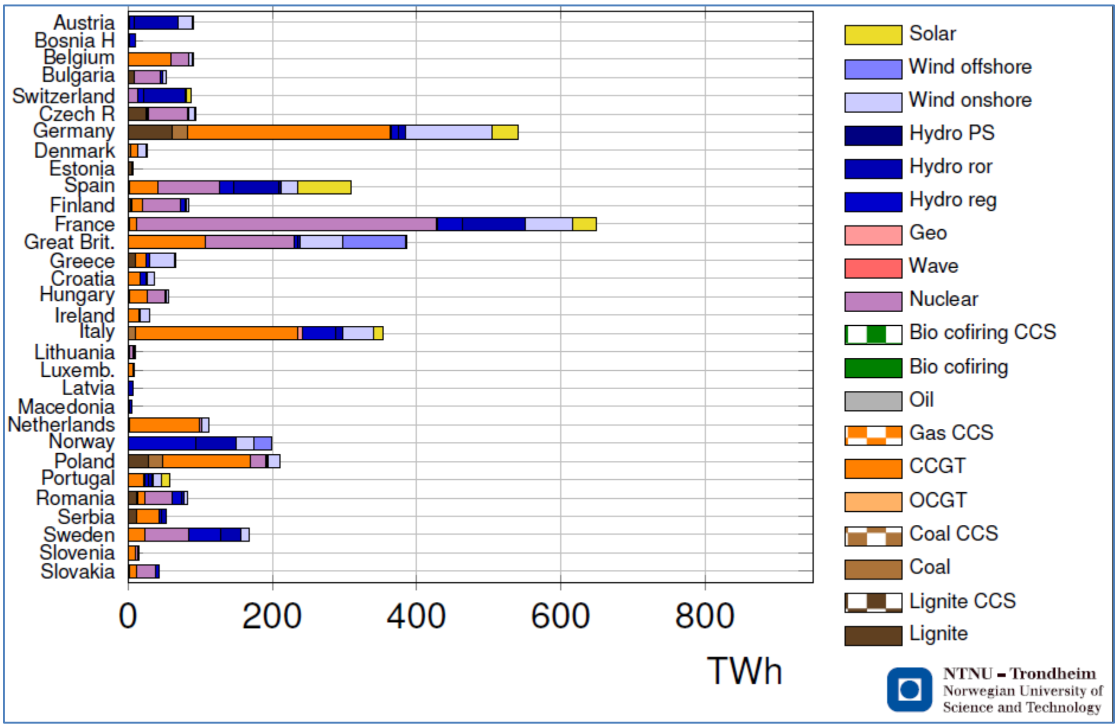


Figure 28: Baseline case: the electricity generation mix in Europe in 2025

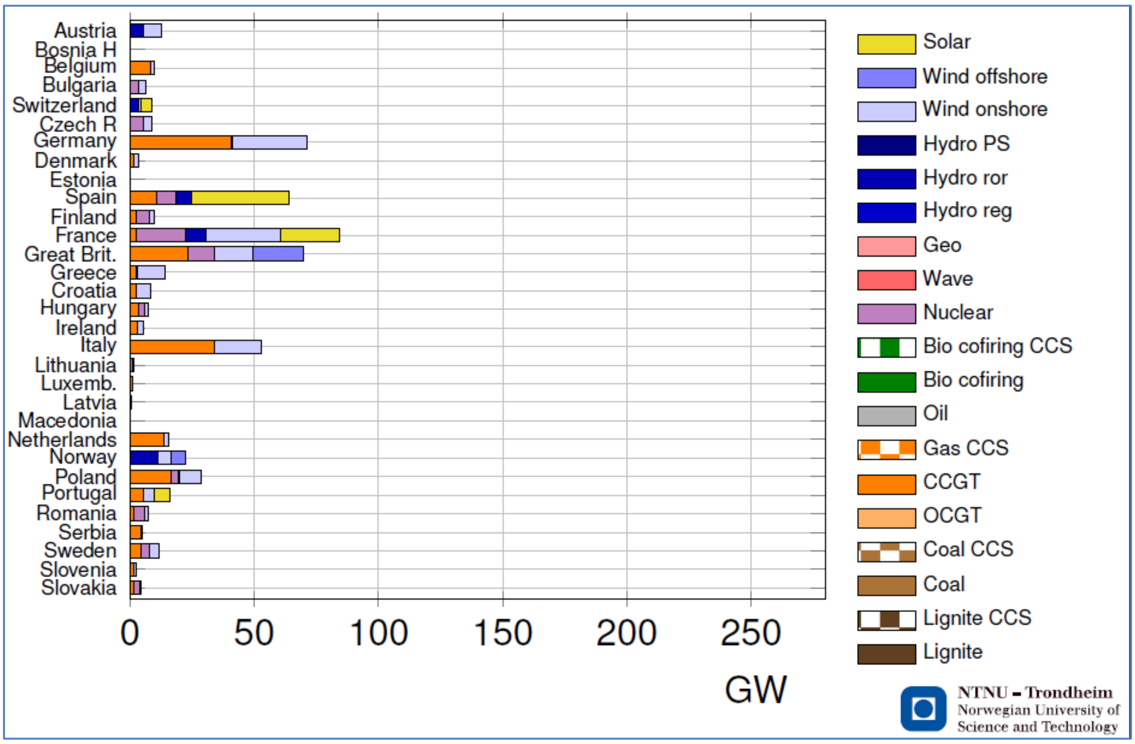


Figure 29: Baseline case: cumulative new power plant capacity by 2025

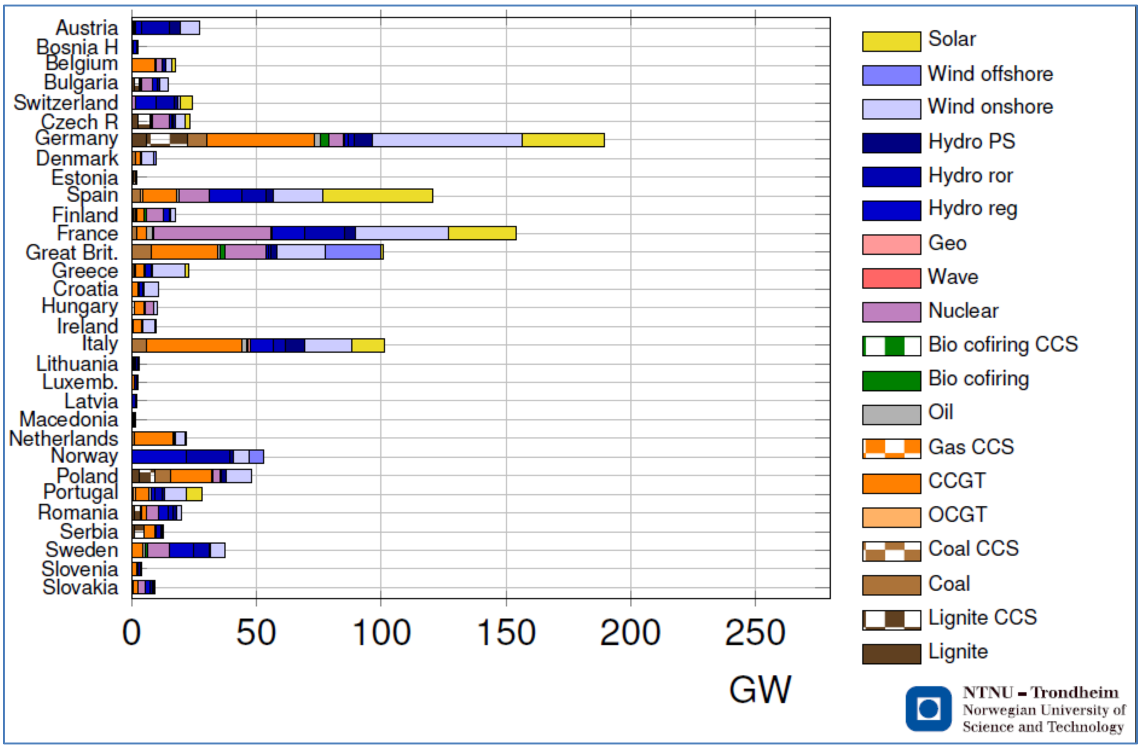


Figure 30: Baseline case: total power plant capacity in 2030

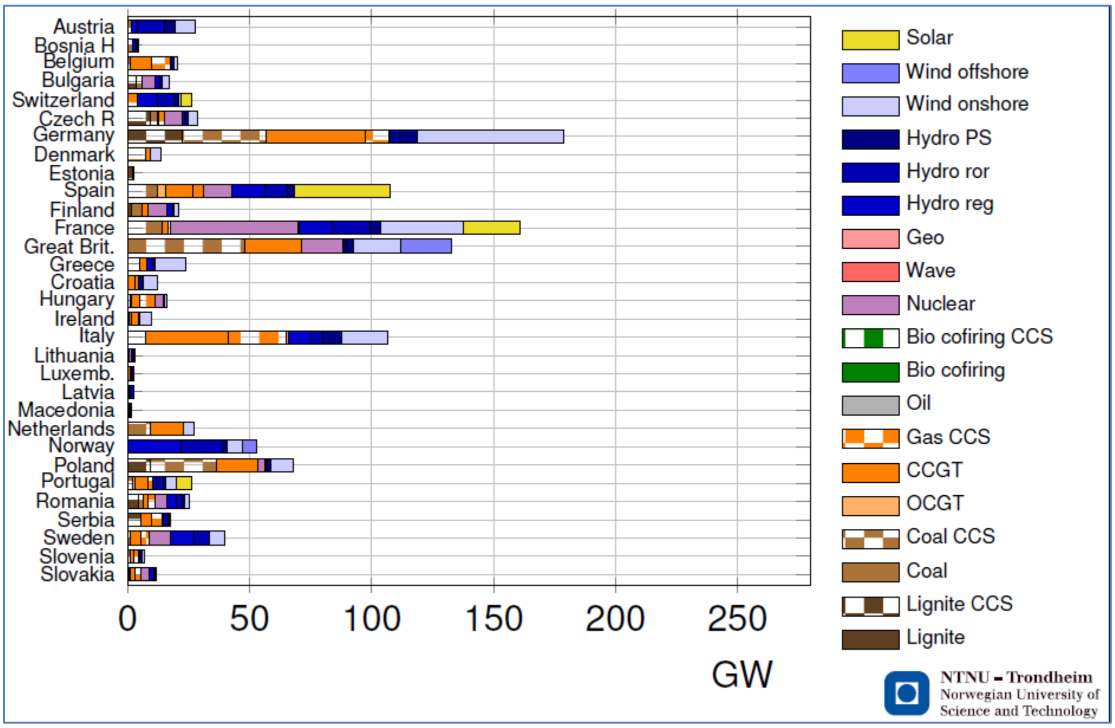


Figure 31: Baseline case: total power plant capacity in 2050

Figures 32-35 show the baseline case with 100% increase in fuel prices compared to GCAM 450 input in order to test sensitivity. This results in a shift from gas to RES and an increase in biomass co-firing with CCS. European emissions are also greatly reduced by the higher fuel prices.

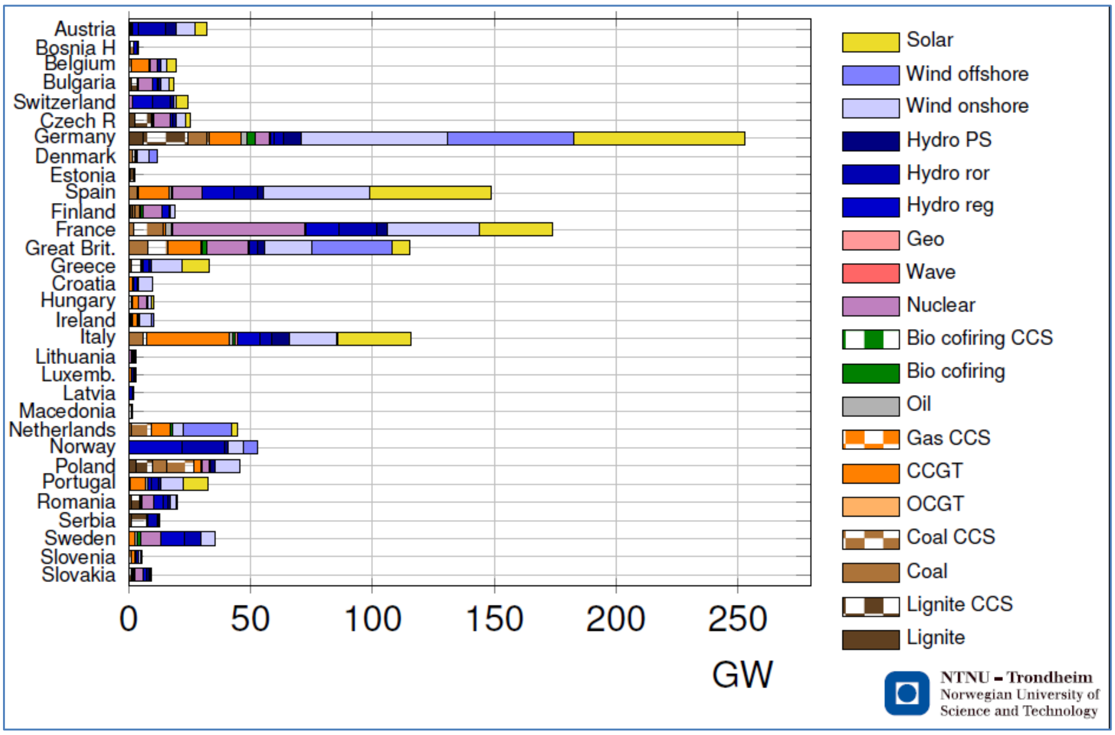


Figure 32: Total power plant capacity in 2030 – baseline case with 100% increase in fuel prices

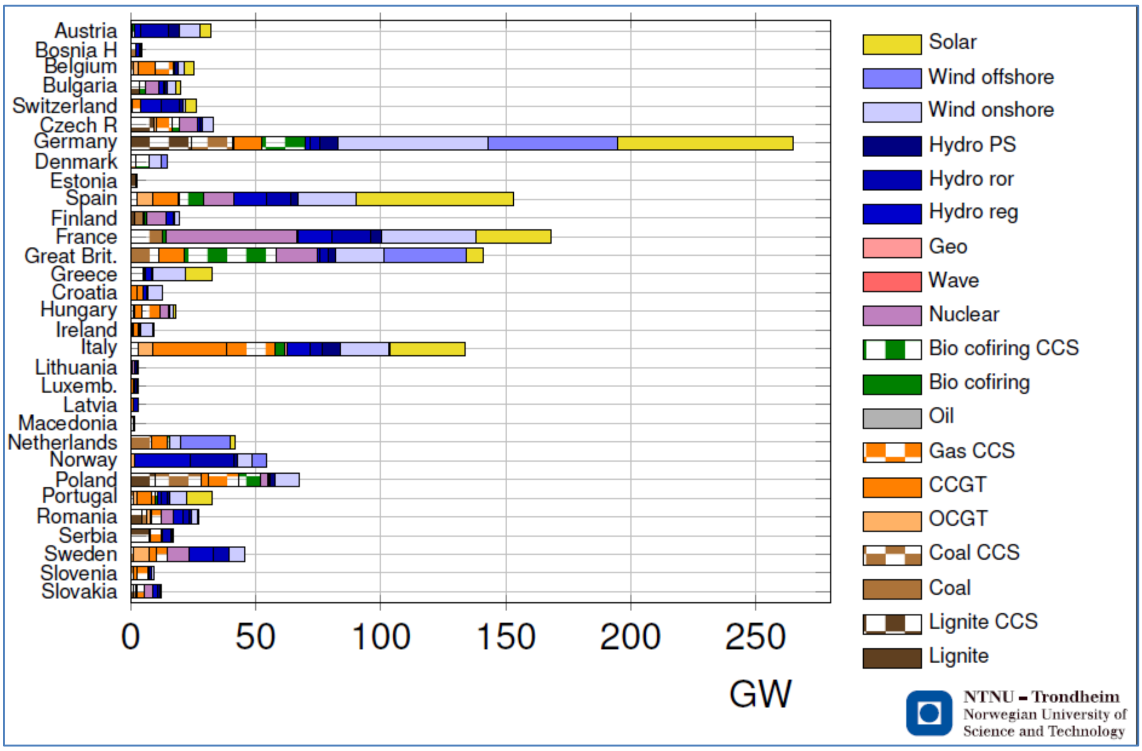


Figure 33: Total power plant capacity in 2050 – baseline case with 100% increase in fuel prices

Figures 34 and 35 show the baseline case with no increase in electricity demand from 2010.[70] The effect is a reduction in power plant construction – particularly for gas as it is the highest-cost fossil fuel – and all CCS is focused on coal. European emissions are also greatly reduced due to lower demand.

[70] Equivalent to German Government policy

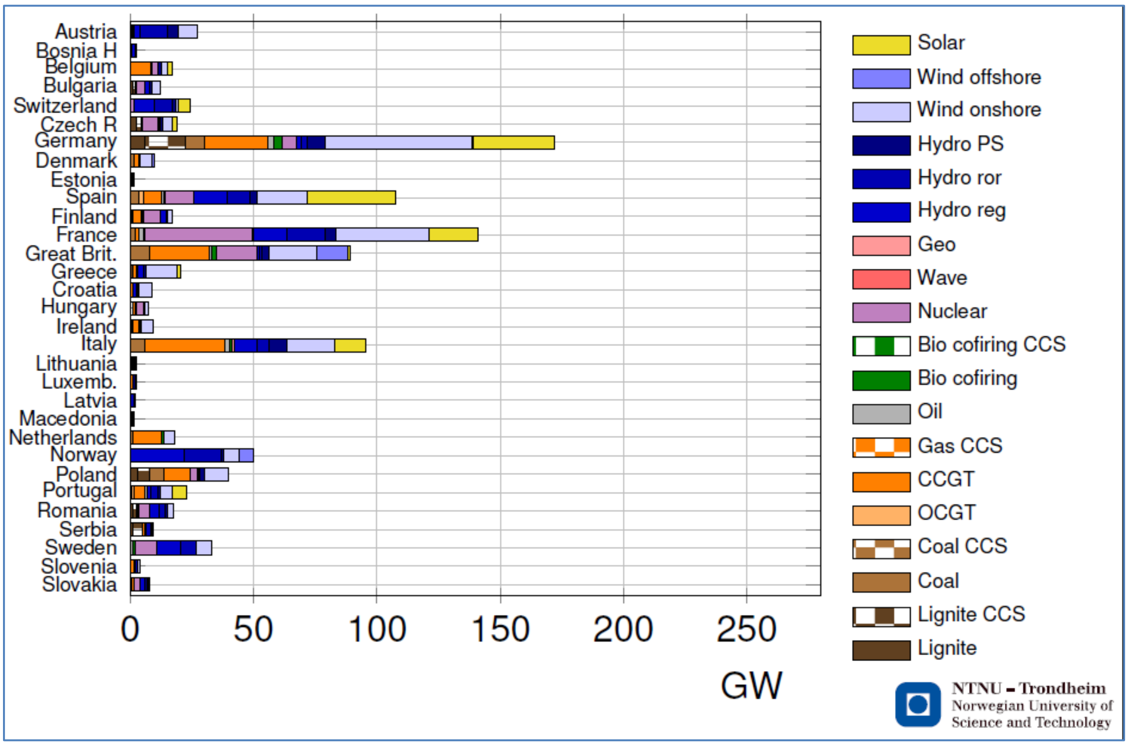


Figure 34: Total power plant capacity in 2030 – the baseline case with no increase in electricity demand compared to 2010. This case tests the impact of demand on CCS deployment. Even with no demand increase, CCS is selected. The baseline GCAM 450 scenario shows a strong increase in demand that is above some European government policy targets.

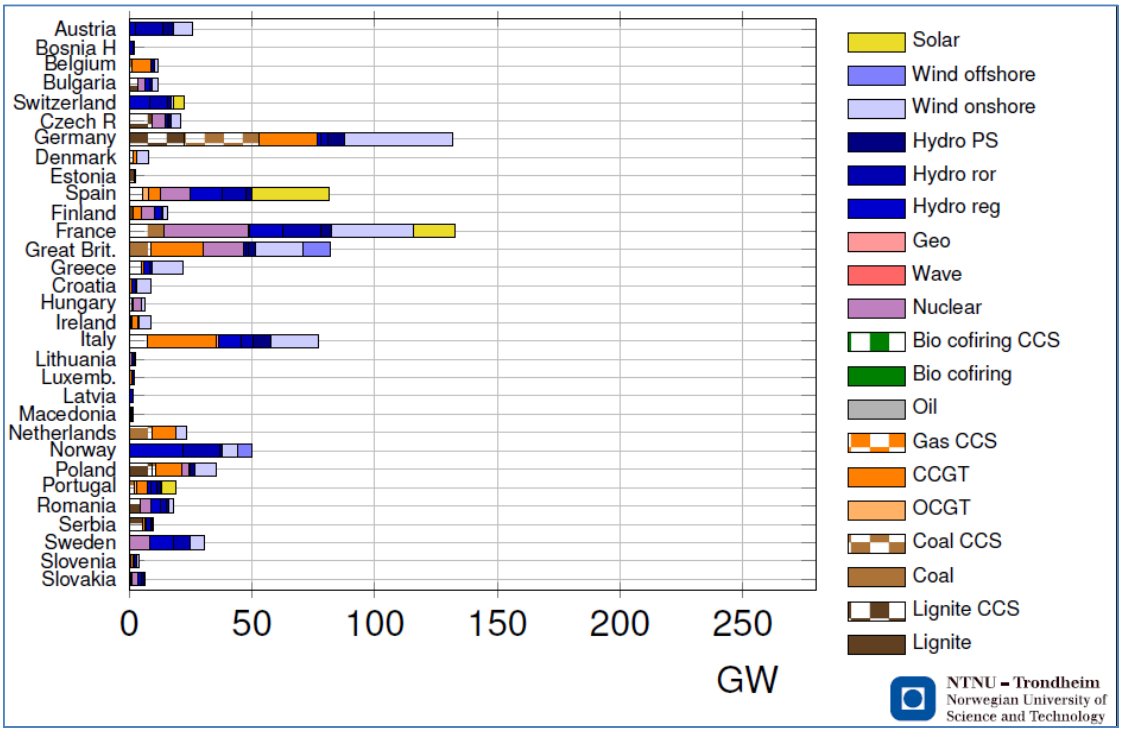


Figure 35: Total power plant capacity in 2050 – the baseline case with no increase in electricity demand compared to 2010. This case tests the impact of demand on CCS deployment. Even with no demand increase, CCS is selected. Investment in gas is reduced and CCS is focused on coal.

Figures 36-38 show the GCAM 20-20-20 scenario test case with a lower CO_2 price (<€40 tCO_2 in 2030). The effect is driven by the lower CO_2 price which reduces the demand for emissions reduction and therefore CCS. There is more unabated gas. Even at €40 tCO_2, the incentive is higher enough to introduce CCS on coal. This is important because it shows the critical importance of the EUA price in driving CCS deployment in the absence of any other support measures.

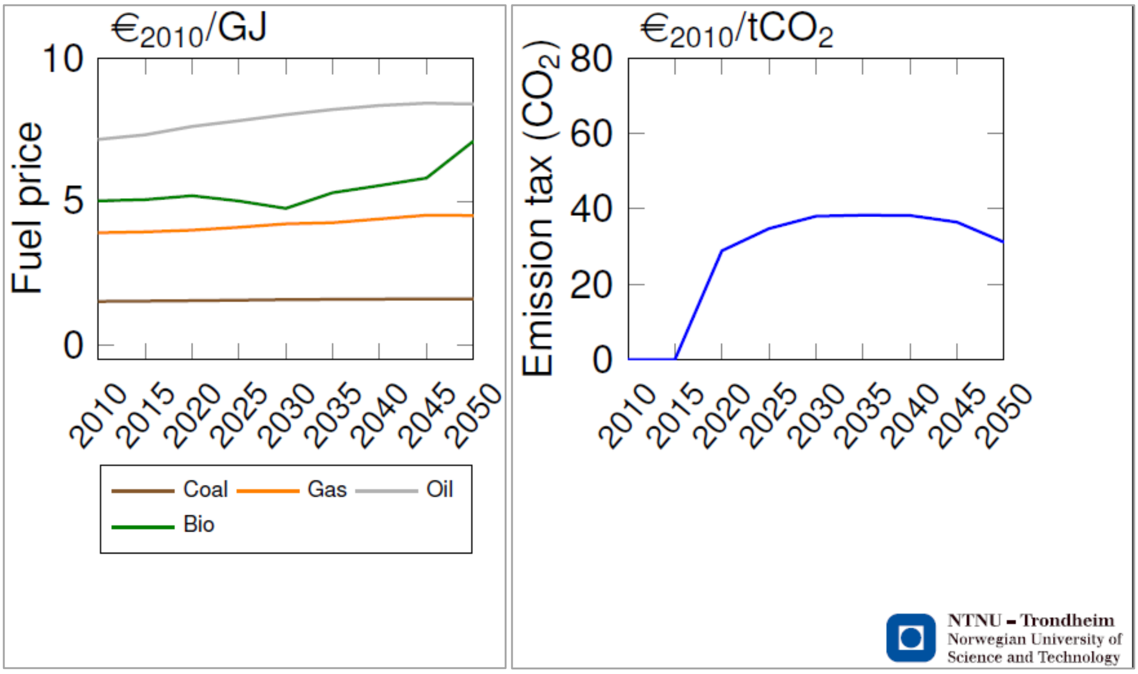


Figure 36: The GCAM Global 20-20-20 input data. The CO_2 price peaks below €40 tCO_2 in 2030. This case shows that while a rising EUA price is essential to CCS deployment in the absence of other incentives, €40 tCO_2 is sufficient after 2030 to drive large-scale deployment.

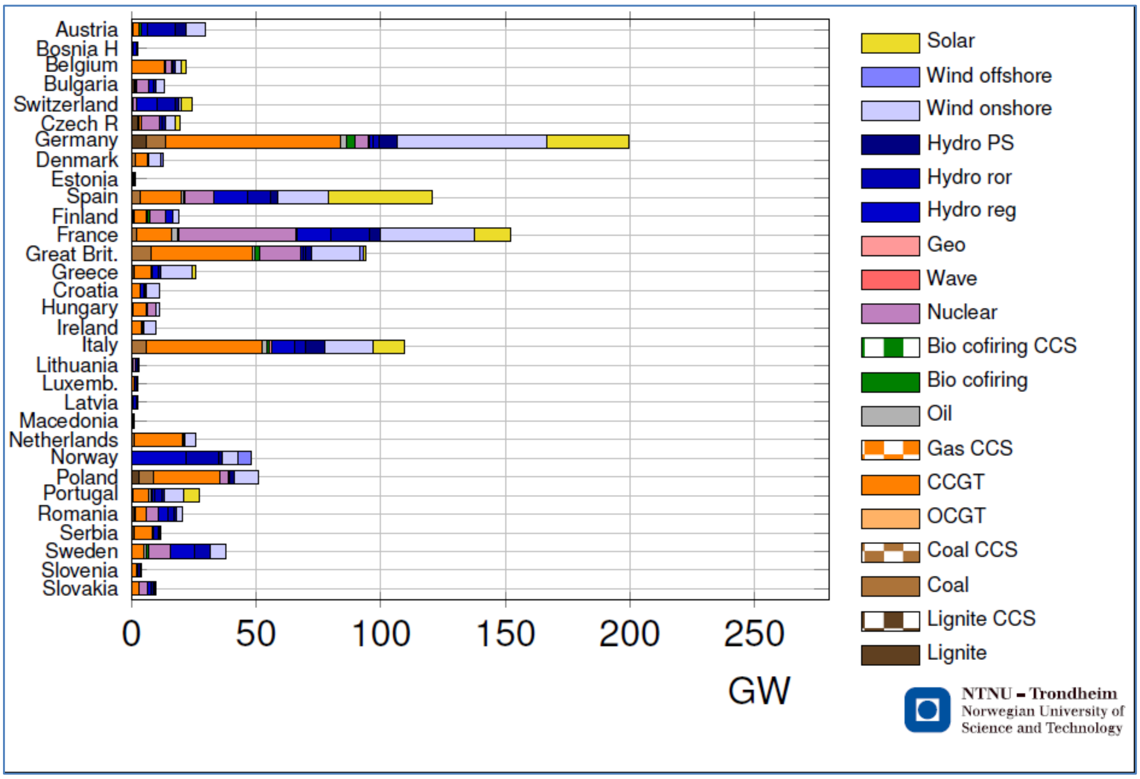


Figure 37: Total power plant capacity in 2030 – GCAM Global 20-20-20 input assumptions

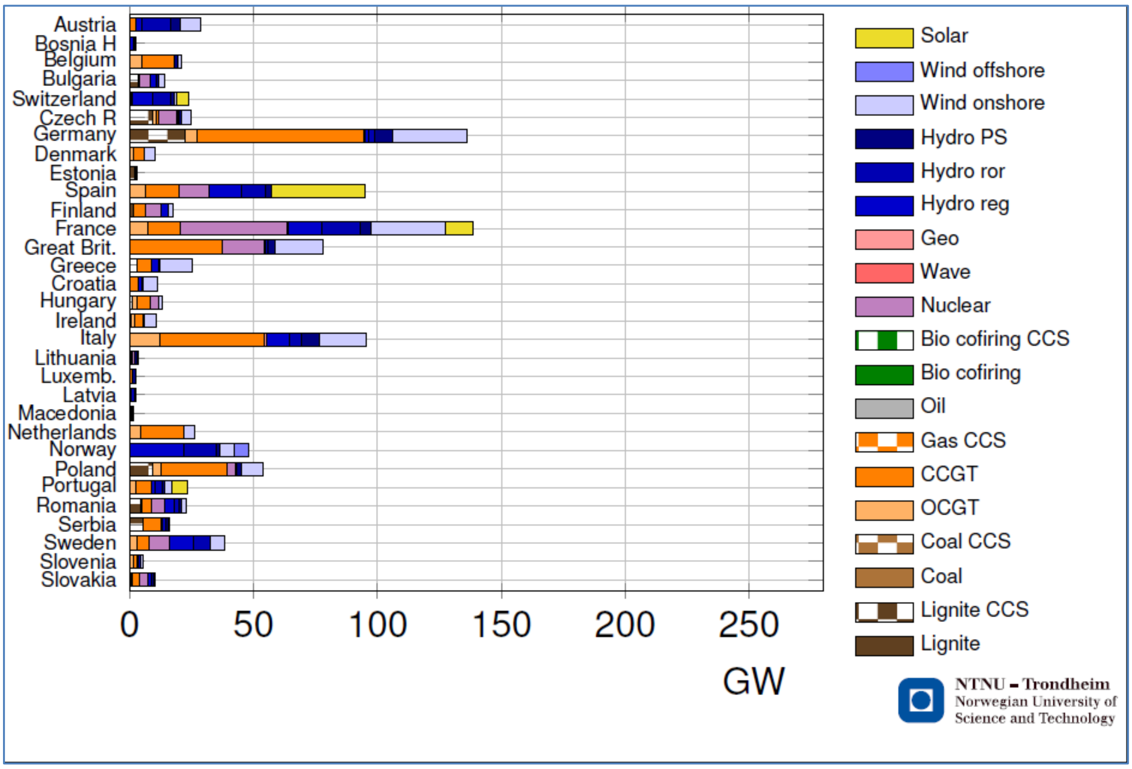


Figure 38: Total power plant capacity in 2050: GCAM Global 20-20-20 input assumptions are sufficient to drive CCS deployment on coal after 2030

Figures 39-40 show that the effect of releasing biomass co-firing with CCS from the coal constraint is that Bio-CCS is selected before gas CCS. If sufficient sustainable biomass fuel sources are available, Bio-CCS could therefore take off, creating fossil fuel power plants with zero-CO_2 emissions – or even net *negative* emissions.

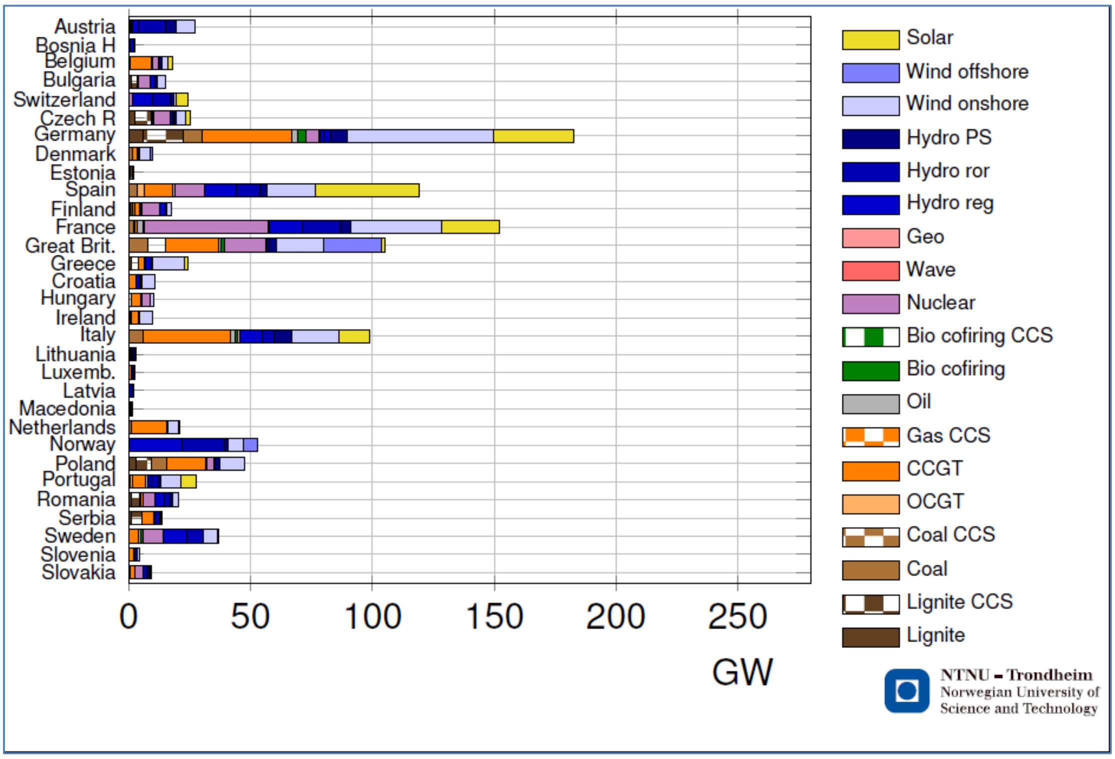


Figure 39: Total power plant capacity for the baseline case in 2030 with no constraint on biomass co-firing with CCS

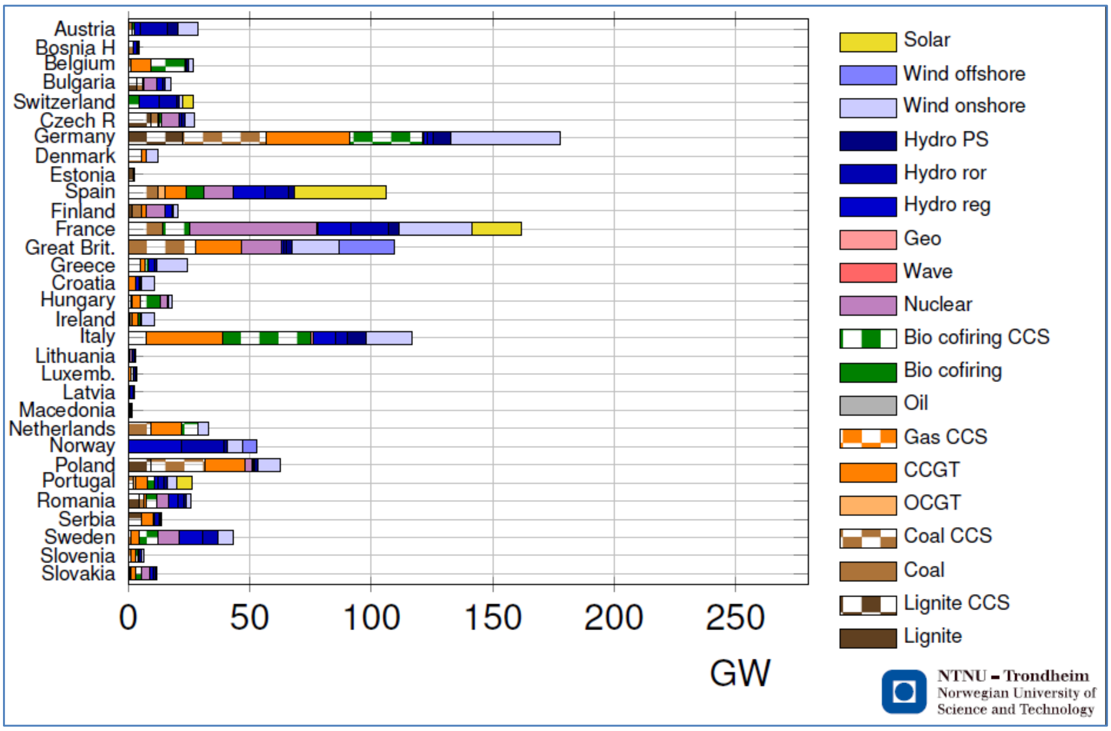


Figure 40: Total power plant capacity in 2050 showing the baseline case with no constraint on biomass co-firing with CCS. The result is that it is widely deployed in place of gas (assuming sufficient sustainable biomass is available).

Figures 41-47 show the summary of capacity and generation from 2010 to 2050 for the sensitivity cases.

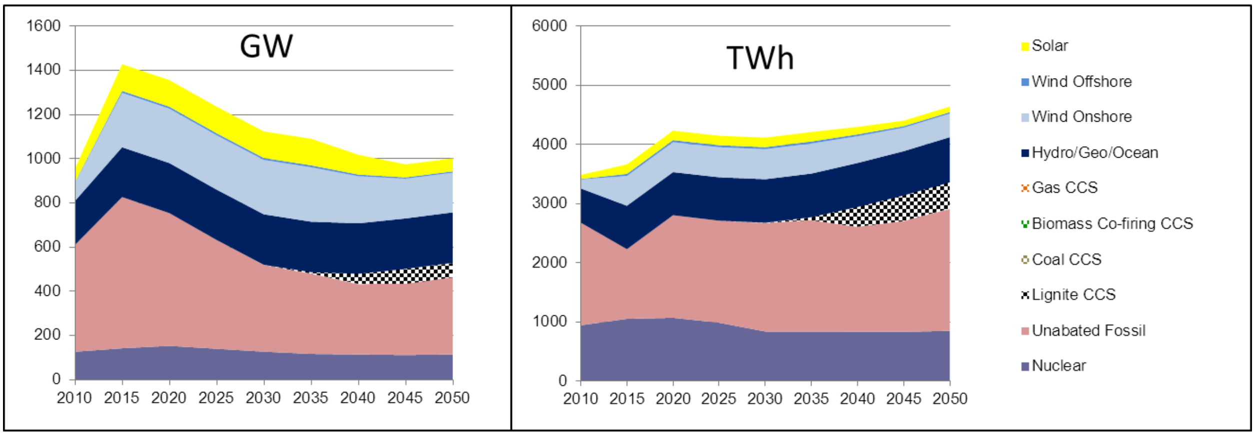


Figure 41: Total power plant capacity and generation mix for the 20-20-20 GCAM scenario: lower demand and lower CO_2 price; less CCS and more unabated fossil fuels

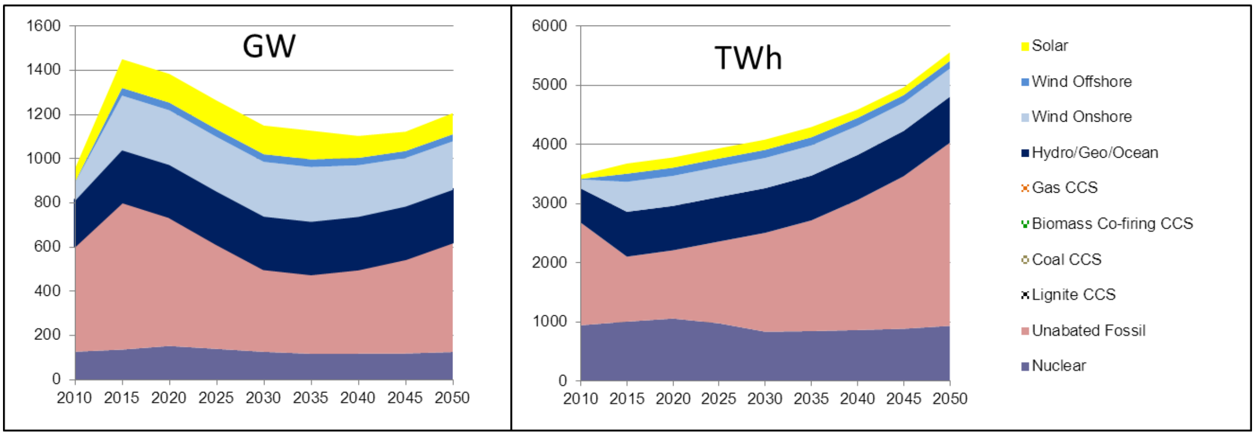


Figure 42: Total power plant capacity and generation mix for the baseline case with no CCS permitted: CCS is replaced by unabated gas

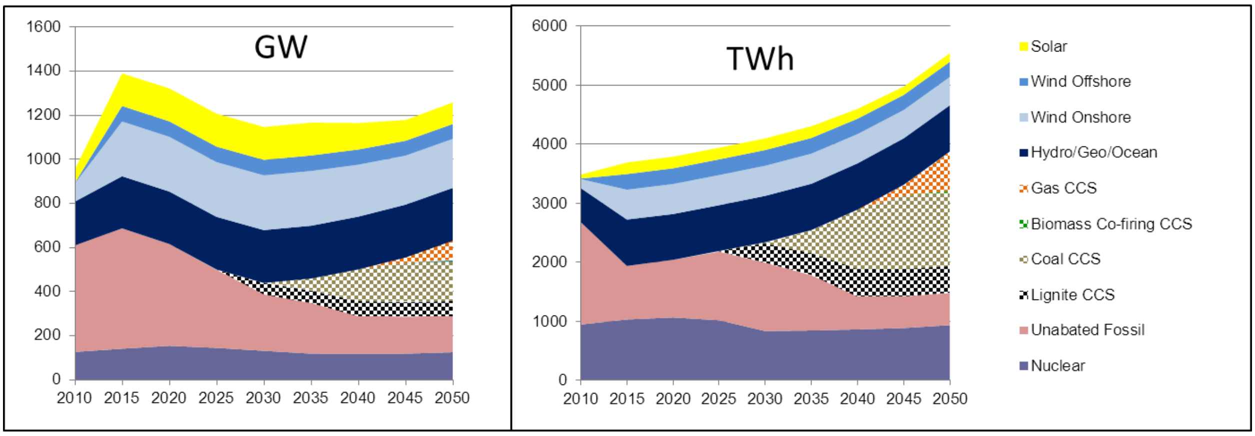


Figure 43: Total power plant capacity and generation mix for the baseline case with 25% fuel price increase: increase in renewables.

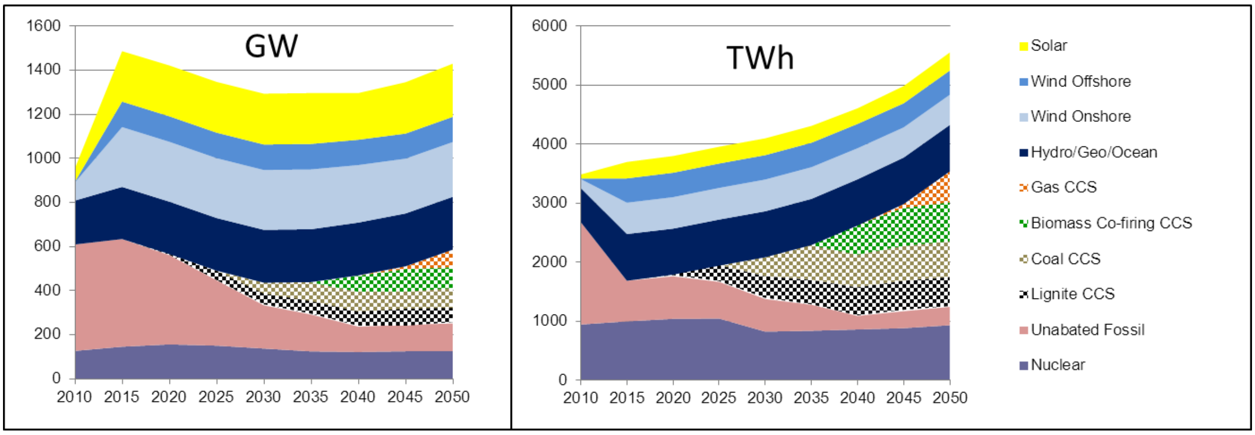


Figure 44: Total power plant capacity and generation mix for the baseline case with 100% fuel price increase: increased renewables and CCS is deployed earlier

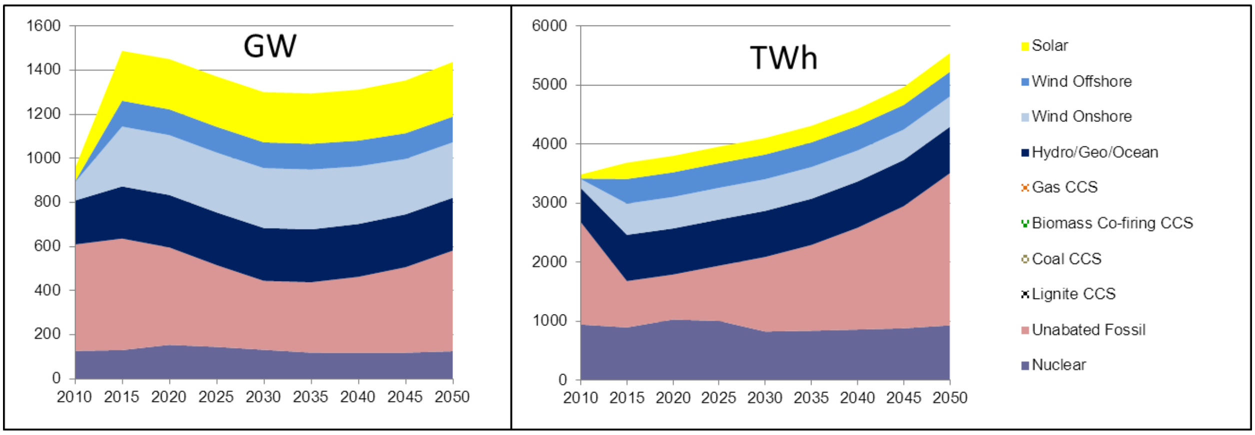


Figure 45: Total power plant capacity and generation mix for the baseline case with 100% fuel price increase and no CCS permitted: increased renewables and CCS is replaced by unabated gas

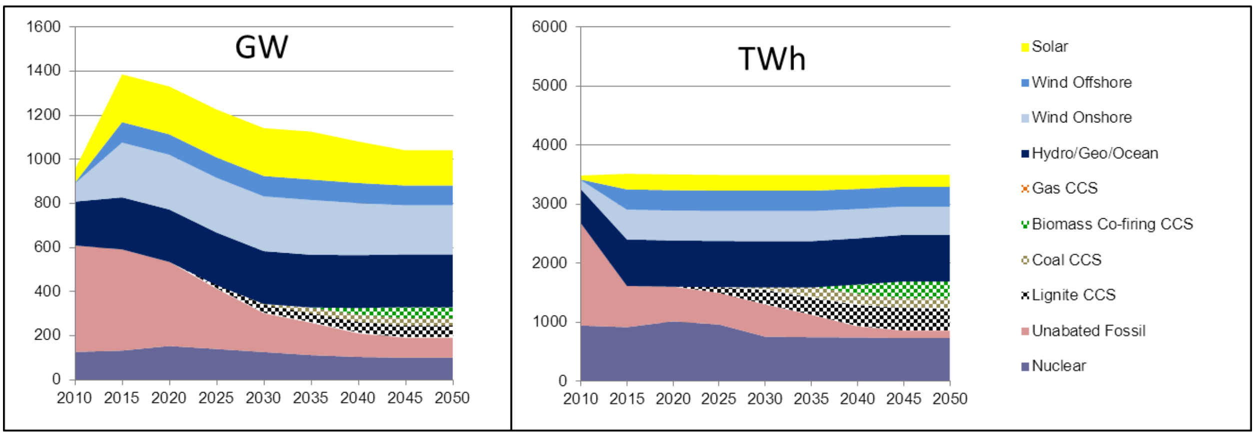


Figure 46: Total power plant capacity and generation mix for the baseline case with 100% fuel price increase and flat demand simulating strong energy demand management: less unabated gas, CCS is deployed earlier and there is more biomass co-firing with CCS

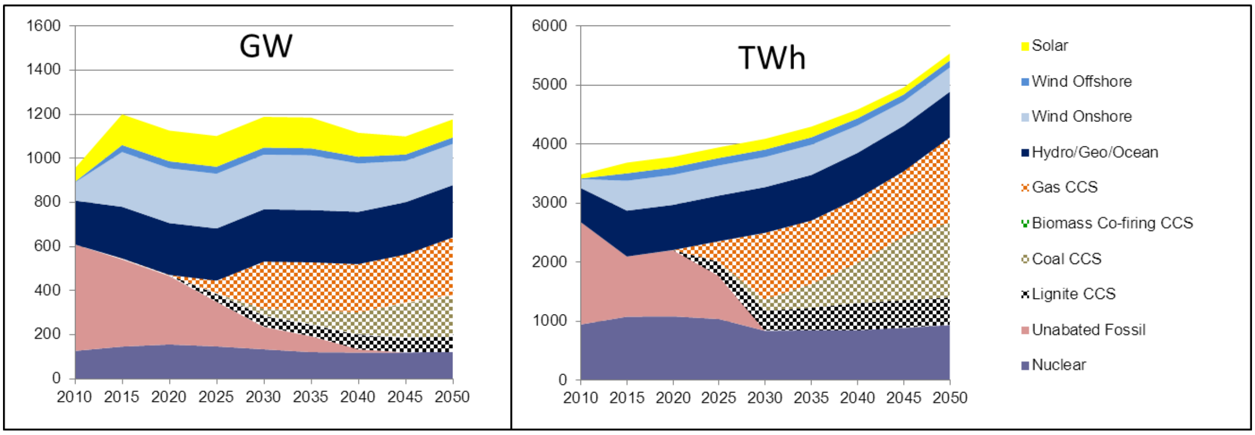


Figure 47: Total power plant capacity and generation mix for the baseline case with an EPS set at 225g/kWh imposed in 2030: more renewables and no early gas boom; earlier CCS and more CCS on gas; no unabated gas after 2030; lower emissions

Annex III: Review of policy measures in the EU and beyond

Annex III reviews the measures proposed in ZEP's 2012 report, "*CO_2 Capture and Storage: Creating a secure environment for investment in Europe,*"[71] based on their status in the EU and beyond.

Short term: 2013-2020

Temporary removal of a volume of EUAs from the EU ETS (backloading)
In July 2012, the European Commission introduced its 'backloading' proposal – the temporary removal of 900 million EUAs from the market – to be re-introduced in the third phase of the ETS. The proposal was approved by the European Parliament in July 2013. Recently, Member States have signalled agreement to a common position with the European Parliament and implementation is expected in the first half of 2014.

EU ETS structural measures
EU policymakers are considering a broader reform of the ETS via 'structural measures'. The Commission discussed six options alongside its Carbon Market Report published in November 2012[72] and discussed the merits of a seventh option in a public meeting in October 2013. Current 'frontrunner' options are: reducing the size of the ETS cap through the permanent removal of EUAs and increasing the annual linear reduction factor to increase reduction of the cap over time beyond the current 1.74%; a Permanent Adjustment Mechanism that would automatically adjust the auctioning volumes through the use of a flexible reserve to lessen excessive supply-demand imbalances is also under discussion.

Capital and OPEX grant schemes
In the EU energy sector, grants have been widely deployed to disseminate socially valuable technologies and promote private investment in the development of both market and enterprise. Such grants have been successfully administered by Member States and the EU, and there exists a wealth of institutional knowledge at both levels of government on their use. In spite of this, EU CCS demonstration projects participating in grant schemes such as the NER300,[73] EEPR[74] and the first UK CCS competition[75] have not yet been successful in realising full-scale demonstration status. The straightened fiscal circumstances and low EUA price have led to project funding gaps that Member States were reluctant to plug. This has been exacerbated by the binding legal obligation to support renewable energy in the EU, which has diverted investment away from other abatement opportunities such as CCS.

Tax breaks
Tax breaks are a well-established means of promoting renewable energy investment in the EU. Biofuels in France benefit from a partial exemption of the internal tax on petroleum products and companies may be granted a research tax credit on their environmental investments. Under the Netherlands' energy investment allowance (Energie-investeringsaftrek), solar, wind, geothermal, hydro, biomaterial and offshore technologies also benefit from an additional deduction of 41.5% of the amount invested in some qualifying assets.

The US provides several examples of how EU Member States could expand tax schemes to better promote CCS in the EU. Section 45Q of the Internal Revenue Act provides CCS facilities with tax credits of \$10/tonne of CO_2 stored in EOR and \$20/tonne of CO_2 stored in saline injection. Sections 48A and B concerning advanced coal and gasification projects have also been amended to provide an investment tax credit of between 15% and 20% on the value of CCS capital investments. Finally, a bipartisan group of lawmakers recently reintroduced a bill to provide CCS and other clean energy projects with access to a corporate tax structure that was previously only available to fossil fuel-based energy projects. If passed, the

[71] www.zeroemissionsplatform.eu/library/publication/211-ccs-market-report.html
[72] COM(2012) 652 final
[73] European Commission Memo (2012), "Questions and Answers on the outcome of the first call for proposals under the NER300 programme": http://europa.eu/rapid/press-release_MEMO-12-999_en.htm
[74] Hinc (2012) "CCS in Europe – the way forward" Demos Europa
[75] National Audit Office (2012) "Carbon Capture and Storage: Lessons from the completion for the first UK demonstration" Department of Energy and Climate Change

‘Master Limited Partnerships Equality Act’ would allow CCS plants to combine the funding advantages of corporations with the tax benefits of partnerships, spurring new private investment in CCS.

Short and medium term: 2013-2030

Feed-in tariffs

Romania has offered its CCS demonstration project, Getica CCS, a project-specific FiT for the electricity it would produce. The UK also intends FiTs to be the cornerstone of the proposed Electricity Market Reform (EMR), limiting the existing system of tradable Renewables Obligations in favour of a system-wide FiT known as a Contract for Difference (CfD).[76] The CfD is envisioned to be the first European FiT to support low-carbon, capital-intensive projects such as nuclear and CCS, while also providing support for traditional renewable generation. The CfD will function with a technology-specific, centrally-set strike price, offering a guaranteed electricity price for low-carbon generation, while capping prices in times of generation scarcity.[77] CfD terms will distinguish between intermittent and baseload low-carbon generation, as well as risk profile, such as for early stage CCS projects.[78]

Amongst the policies examined, FiTs offer investors the greatest security of income. This is because well-designed FiTs provide financial support to power plants in a form that best ensures them access to the grid, reducing both revenue risk and price risk for investors. In the EU, it is estimated that 85% of all new wind systems and nearly 100% of all new solar PV systems since 1997 have been installed with FiTs.[79]

Certificate schemes

Purchase contracts have not been applied to CCS to date, although they seem to enjoy significant support in some EU policymaking circles and have been applied to RES in EU Member States. Sweden has had its own domestic certificate market since 2003, obligating electricity suppliers to purchase certificates from renewable energy producers to cover a set proportion of their sale and use of electricity during the previous calendar year. The certificates are tradable on the Nord Pool power exchange, but expire annually creating a constant demand for them.[80]

The initial objective of the electricity certificate system was to increase electricity generation from RES by 10TWh by 2010, relative to the corresponding production in 2002. The objective has since been updated and was recently set to increase by over 25TWh by 2020, compared to 2002.[81] In 2012, Norway also joined the scheme, in line with the Swedish Government’s goal of expanding it to more countries.[82]

A similar scheme came into effect in the UK in 2002 and in Northern Ireland in 2005. The Utilities Act replaced the Non-Fossil Fuel Obligation with a Renewables Obligation. This was a quota or Renewable Energy Portfolio Standard system whereby utilities were required to purchase a certain increasing percentage of electricity from RES. The utilities would then have to provide Ofgem, the utility regulator, with Renewable Obligation certificates to prove that they had met their obligation. These certificates could be purchased directly from a generator or purchased on the market.

The Renewables Obligation also included a buyout provision (£36.99 per certificate in 2010/2011), which went into a pool to be redistributed to those utilities that participated (~£360 million in the same year).[83] As

[76] Allen & Overy (2012): “UK Electricity Market Reform: The draft Energy Bill”
[77] Department of Energy and Climate change (2011), “Planning our electric future: technical update”
[78] Written Ministerial Statement on energy policy (Oct 2010) Commentary on EMR White Paper
[79] 8th International Feed-in Cooperation Workshop on 18 and 19 November 2010
[80] Ministry of Sustainable Development (2006), ‘Fact Sheet: Renewable electricity with green certificates’, Regeringskansliet: www.government.se/content/1/c6/06/47/22/2c000830.pdf
[81] Swedish Energy Agency (2011), The Electricity Certificate System, Energimyndigheten: http://webbshop.cm.se/System/DownloadResource.ashx?p=Energimyndigheten&rl=default:/Resources/Permanent/Static/cb792e3f76a348f5aa619ca56b612149/ET2011_52w.pdf
[82] ‘Agreement between the Government of the Kingdom Of Norway and the Government of the Kingdom of Sweden on a Common Market for Electricity Certificates’: www.regjeringen.no/upload/OED/pdf%20filer/Elsertifikater/Agreement_on_a_common_market_for_electricity_certificates.pdf
[83] Department of Energy and Climate Change: www.gov.uk/government/policies/increasing-the-use-of-low-carbon-technologies/supporting-pages/the-renewables-obligation-ro

with the Swedish-Norwegian certificate scheme, the mechanism was technology non-specific, such that different RES competed against each other; however this is now under review.[84]

CCS purchase contracts
Purchase contracts have not been applied to CCS to date, although their use for other low-carbon technologies is well established. Perhaps most notably within the EU, reverse auctions were used to spur early renewable energy development in the UK through the Non-Fossil Fuel Obligation (NFFO) scheme.[85] Between 1989–1998, reverse auctions were conducted by the UK Government's Non-Fossil Purchasing Agency Limited (NFPA) for electricity generated from wind, hydro, landfill gas, sewer gas, biomass and wet farm wastes.[86]

NFFOs then required Regional Electricity Companies in England and Wales to purchase all generation offered to them through these reverse auctions. Although they were required to buy the electricity, the companies only had to purchase it at the market price.[87] The difference between the contracted price and the market price was paid by the NFPA out of the funds that came from the Fossil Fuel Levy – a tax on all electricity introduced with the scheme.[88] The NFFO scheme is no longer open to new generators, but existing contracts will continue until the last of them expires in 2019.

Capacity payments
Capacity payments have not been applied to CCS to date, although their use for energy security purposes is well established. The most basic capacity mechanism is the strategic reserve, used in Sweden, Poland and Finland. Capacity is acquired and withheld from the market as a dispatch of last resort. Often the capacity is comprised of old facilities that would otherwise be retired as uneconomical.[89] Another form of capacity mechanism is the capacity payment. Here all generators, incumbents and entrants are paid for being available.

The payments contribute towards the generators' fixed cost with the payment level set administratively. Such a payment system is in place in Ireland, Spain, Portugal and Greece.[90] The UK, through the EMR, will centrally set the net amount of capacity needed to ensure security of supply before a capacity auction. Providers of capacity successful in the auction will enter into capacity agreements, committing to provide electricity or reduce demand for electricity when needed in the delivery years in return for steady capacity payments or face financial penalties. In this way, supply security may be provided through generation and non-generation means, such as demand side response and energy storage. However, projects that receive a CfD will not be eligible to bid into the capacity market in the UK.

Loan guarantees
Loan guarantees have not been applied to CCS to date, although their use in the energy sector is well established. Perhaps the most notable use of loan guarantees in the energy sector has been by the US: Section 1703 of the Energy Policy Act of 2005 authorised the Secretary of Energy to issue loan guarantees for up to 80% of the value of projects that reduce GHG emissions and employ new or significantly improved technologies, compared to commercial technologies at the time of the guarantee.

[84] Woodman, B. and Mitchell, C. (2011). 'Learning from experience? The development of the Renewables Obligation in England and Wales 2002-2010', Energy Policy, 39(7), 3914-3921
[85] www.ofgem.gov.uk/Sustainability/Environment/NFFOSRO/Pages/NFFOSRO.aspx
[86] The original intention was to provide financial support to the UK nuclear power generators, which continued to be state owned following the liberalisation of the electricity market in 1989. The proposals were enlarged in scope before the scheme was brought into operation in 1990 to include the renewable energy sector.
[87] More specifically, the average Pool Selling Price
[88] Mitchell, C. (2000), 'The England and Wales Non-Fossil Fuel Obligation: History and Lessons', Annual Review of Energy and the Environment 25: 285–312
[89] Ewi (2012) "Investing into a sustainable electricity market design for Germany", Institute of Energy Economics. University of Cologne
[90] Commission for Energy Regulation (2011), "CER Factsheet on the Single Electricity Market": www.cer.ie; Platts (2011) "Spain's government passes decree on 2012 power capacity payments"; NEPP (2011) "Capacity mechanisms: Revived interest in capacity mechanisms throughout Europe in the face of high volumes of intermittent generation" Northern Europe Power Perspectives

The only threshold for eligibility was that projects offer a "reasonable prospect of repayment", providing a high level of effective risk subsidisation by the US Government.[91] The use of loan guarantees under the 2005 Energy Policy Act was then expanded by the American Recovery and Reinvestment Act of 2009, which amended the 2005 law by adding Section 1705, the Temporary Programme for Rapid Deployment of Renewable Energy and Electric Power Transmission Projects. To date, 28 loan guarantees totalling $26.3 billion have been issued by the Section 1703 and 1705 programmes.[92]

Loan guarantees are also used by EU institutions to facilitate investment in the energy sector, but not specifically for low-carbon projects. The Trans-European Energy Networks programme has seen numerous European Investment Fund[93] loan guarantees offered to energy infrastructure projects.[94] The European Investment Bank has also recently signed a €440-million loan guarantee with the Slovenian government for a 600 MW lignite plant in the town of Šoštanj.[95] Institutions and expertise therefore exist at EU level that can be built upon to add value to CCS deployment.

Medium to long term: 2020-2030+

A new EU Climate and Energy policy framework in 2030
Earlier in 2013, the Commission consulted stakeholders on the EU Climate and Energy Policy Framework for 2030. Several measures are likely to be discussed, including a GHG reduction target for 2030 and a new renewable energy target. Setting a tighter ETS cap for 2030, aligned with other EU policies, will ensure trade-inducing scarcity in the market and reflect the expected deployment of low-carbon energy. The Commission is expected to come up with a legislative proposal in the coming months.

The CCS Communication
The European Consultation on the CCS Communication ended in July 2013 and contributions and policy orientations are currently being evaluated. Among the options discussed to ensure the timely development of CCS were the restructuring of the ETS, the introduction of CCS certificates and emission performance standards. The introduction of new financing tools such as the NER300 was also a point raised by the Commission in its questions.

Long term: 2030+

An emission performance standard
Emission performance standards (EPS) have been implemented to help promote CCS deployment in both Canada and the US. In 2012, the Canadian Government finalised EPS affecting coal electricity generation. All new coal facilities post 2015 and existing facilities over 50 years will be mandated to reduce CO_2 emissions to the level of Combined Cycle Gas Turbine (CCGT) (420kg/MWh), requiring the application of CCS. A grace period in achieving the EPS – and thus the deployment CCS – has been set to 2025.

In the US, an array of regional and state level performance standards have emerged. California, Oregon and Washington have adopted an EPS for baseload thermal electricity generation, requiring all new-build and existing facilities entering into long-term contracts to meet an emissions performance equivalent to CCGT. Montana has implemented an EPS through the planning code, with approval of new coal-based generation conditional on meeting an EPS with CCS. In New Mexico, incentives such as tax and cost recovery are provided to coal-fired plants that meet an EPS. The state of Illinois is requiring electric utilities to enter into one or more sourcing agreements with "initial clean coal facilities".[96]

---

[91] www.gpo.gov/fd sys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf
[92] https://lpo.energy.gov/?page_id=45
[93] Funded 30% by the European Commission, 30% by banks and other financial institutions and the remaining 30% by the European Investment Bank, the EU's non-profit long-term lending institution
[94] Regulation (EC) No 680/2007 of the European Parliament and of the Council of 20 June 2007 laying down general rules for the granting of Community financial aid in the field of the trans-European transport and energy networks
[95] www.eib.org/projects/loans/2006/20060319.htm
[96] Simpson, Hausauer & Rao (2010): "Emissions Performance Standards In Selected States" Regulatory Assistance Project, research Brief

The US Environmental Protection Agency is proposing new source performance standards for CO_2 emissions from new fossil fuel electric generating units. The proposed standard will limit all new capacity to 454 kg of CO_2/MWh. The draft regulation allows new coal facilities flexibility in meeting the standard, with emissions averaged over a 30-year period. This would result in a maximum unabated operation of 10 years before the installation of CCS at a high capture rate. [97]

In the UK, any new coal capacity is already required to have a minimum of 300 MW fitted with CCS as a condition of planning consent. [98] This is anticipated to expand to a more complete EPS with the passing of the Electricity Market Reform in 2013.[99] The EMR is a series of interdependent and reinforcing policy tools designed to provide an attractive market for all forms of low-carbon electricity, while maintaining supply security and system integrity.

In the design of the EMR programme, an EPS should a) act as insurance against lock-in to high carbon generation technology b) establish a transparent framework on government expectations of CO_2 emissions from the electricity sector c) provide greater certainty for investment in low-carbon technology and d) along with other measures, facilitate the deployment of CCS. As designed, the EPS will place an annual limit on CO_2 emissions equivalent to 450 kg/MWh. The EPS will not be retroactive, only applying to new-build or extensively modified facilities. In combination with grandfathering, the EPS is set at the current level until 2045 for capacity built within its scope, creating concerns of emissions lock-in resulting from rapid expansion in natural gas generation capacity.

	UK	Canada	US
EPS (kg/MWh)	450	420	454
New units	Yes	Yes	Yes
Old units	No	Yes - Facilities > 50 years	No
Fuel	Fossil fuels	Coal	Fossil fuels
Flexibility: emissions averaging for peaking and part-time operation	Yes	Yes	Yes
CCS application	Exemption for CCS demonstration projects	CCS deployment post 2025	Emissions averaged over 30-year basis. Up to 10-year delay in CCS deployment
Implementation	2012	2012	Draft – 2012

Table 4: Emission performance standards in selected countries (proposed or in place)

[97] Baker & McKenzie (2012): “EPA publishes first-ever carbon dioxide emissions standard for new power plants with future implications for existing sources” www.lexology.com/library/detail.aspx?g=e6fc55b3-6de1-401e-99a0-2b2587e07ec9

[98] Committee, E. a. C. C., 2010. Emissions Performance Standards. First Report of Session 2010-11 Volume 1, UK: House of Commons

[99] House of Commons Energy and Climate Change Committee, 2011. Emissions Performance Standards: Government Response to the Committee's First Report of Session 2010–11, London: Energy and Climate Change Committee

Annex IV: Members of the ZEP Temporary Working Group Market Economics

Name	Country	Organisation
Daniele Agostini	Italy	ENEL S.p.A.
Heinz Bergmann	Germany	RWE
Paula Coussy	France	IFP Énergies nouvelles
Christina Hatzilau	Greece	National Technical University of Athens (NTUA)
Emmanuel Kakaras	Greece	Centre for Research and Technology Hellas (CERTH)
Juliette Langlais	Belgium	Alstom
Goran Lindgren	Sweden	Vattenfall
Chris Littlecott	UK	E3G
Guy Maisonnier	France	IFP Énergies nouvelles
Giulio Montemauri	Italy	ENEL S.p.A.
Ivan Pearson	Belgium	Bellona Europa
Anca Popescu	Romania	ISPE
Benedicte Prodhomme	France	Alstom
Hermione St. Leger	UK	St. Leger Communications Ltd.
Burkard Schlange	The Netherlands	Shell
Christian Skar	Norway	Norwegian University of Science and Technology (NTNU)
Charles Soothill	Switzerland	Alstom and Chair of ZEP TWG ME; Vice-Chair of ZEP Advisory Council
Graeme Sweeney	UK	Shell
Kazimierz Szynol	Poland	PKE S.A.
Bill Thompson	UK	BP
Asgeir Tomasgard	Norway	Norwegian University of Science and Technology (NTNU)
Marc Trotignon	France	EdF
Karl-Josef Wolf	Germany	RWE

Zero emissions platform

November 2013

www.zeroemissionsplatform.eu

European Technology Platform for Zero Emission Fossil Fuel Power Plants