

Electricity in Europe: exiting fossil fuels?

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Abstract: There are many options for generating electricity with low carbon emissions, and the electrification of heat and transport can decarbonize energy use across the economy. This places the power sector at the forefront of any move away from fossil fuels, even though fossil-fuelled generators are more dependable and flexible than nuclear reactors or intermittent renewables, and vital for the second-by-second balancing of supply and demand. Renewables tend to supplement, rather than replace, fossil capacity, although output from fossil-fuelled stations will fall and some will have to retire to avoid depressing wholesale power prices. At times of low demand and high renewable output prices can turn negative, but electricity storage, long-distance interconnection, and flexible demand may develop to absorb any excess generation. Simulations for Great Britain show that while coal may be eliminated from the mix within a decade, natural gas has a long-term role in stations with or without carbon capture and storage, depending on its cost and the price of carbon.

Keywords: electricity generation, fossil fuels, carbon capture and storage, renewable generators, electricity prices

JEL classification: Q4, L94

I. Introduction

Europe hosts around 450 GW of fossil-fuelled power stations, 200 GW each of coal and gas, and 50 GW of oil (Bassi *et al.*, 2015). These plants, pictured in Figure 1, have a ‘like for like’ replacement cost in the order of £500 billion. They provide 40 per cent of Europe’s electricity but are responsible for around 1.4 GT of carbon dioxide (CO₂) emissions per year (30 per cent of Europe’s total) (Eurostat, 2015). Most of the scenarios for climate stabilization considered by the IPCC (2014) require a rapid increase in the worldwide share of low-carbon electricity, with renewables (chiefly biomass, hydro, wind, and solar), nuclear, and stations with carbon capture and storage (CCS) needing to rise from around 30 per cent today to 80 per cent or more by 2050. To meet the 2009 Copenhagen Accord commitment to limit temperature rises to 2 degrees, leaders of the

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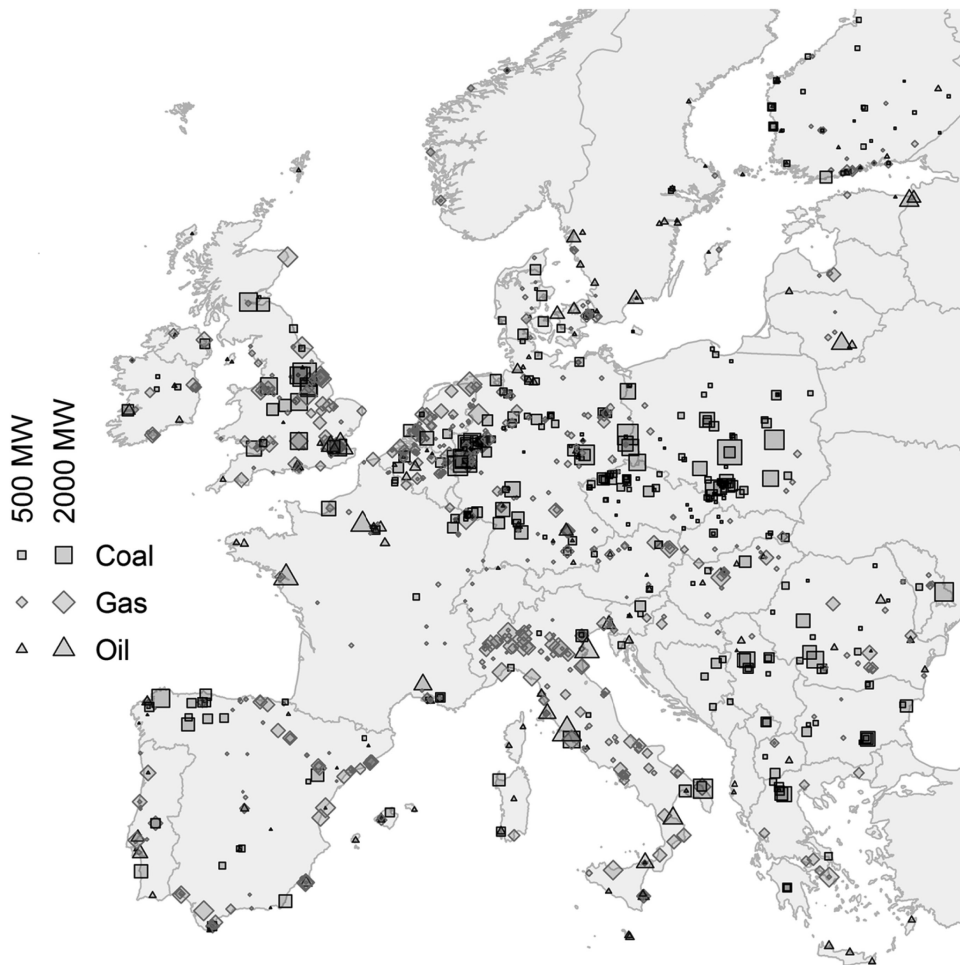
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Figure 1: A map of Europe's installed fossil power stations as of 2012, with marker size proportional to capacity



G7 industrial nations have called for the decarbonization of the world economy over the course of this century (G7Germany, 2015), and organizations such as the Global Apollo Programme aim to render fossil fuels obsolete by developing renewable base-load generation that is cheaper than coal by the 2020s through a global R&D effort (King *et al.*, 2015).

The obvious corollary is that existing fossil-fuelled stations may become obsolete before the end of their decades-long technical lifetimes. Around 210 GW of Europe's fossil capacity is under the age of 40, and 115 GW under the age of 25. Around 30 per cent of this young capacity (35 GW) is located in Germany, 15 per cent in Poland, and 8 per cent in the UK. Three utilities stand out: RWE, Vattenfall, and E.ON each own 10–15 GW that is under 40 years old; with 13 GW of Vattenfall's fossil assets being under 25 years old. Closing power stations before they are fully depreciated creates large financial losses, and European utilities wrote down their fossil-fuelled stations by

almost €7 billion in 2013 (Caldecott and McDaniels, 2014). They also closed or mothballed 21 GW of gas-fired plant in 2012–13; 11 GW of this was less than 10 years old.

This was not meant to happen: gas is often seen as the ‘bridging fuel’ with lower emissions than the coal it should replace during the transition to a truly low-emission power system (Helm, 2012). The decision to close gas instead of coal stations can be explained by their relative profitability: coal and carbon emissions permits are relatively cheap at present.¹ However, it shows that conventional wisdom may be misleading when applied to a system as complex as the electricity industry. The aim of this paper is a deeper examination of the future role of fossil fuels within the European power sector.

We start by showing why electricity is well-suited for early decarbonization, and how it can then play an important role in reducing other energy-related emissions. Section II also shows that several routes have been proposed for decarbonizing electricity, with different mixes of the main low-carbon technologies: renewables, nuclear power, and CCS. Section III outlines the many technical challenges in generating and delivering electricity, and the advantages of fossil fuels in keeping the system stable. The following section shows how power markets have developed to meet the challenge of trading electricity and discusses the policies used in Europe to promote decarbonization. It also shows how the growth of renewable power creates new challenges for fossil-fuel generators: depressing wholesale prices and even sending them negative. Section V uses simulations of the British market to focus on the factors that will affect the role of fossil generators over the coming decades. In section VI, we conclude that technical complexities and economic realities mean it will be very hard to completely exit from fossil fuels, but this still allows significant decarbonization, which will be deepened if CCS is deployed on a large scale.

II. Decarbonizing the economy

Electricity generation, heat, and transport consume broadly equal shares of Europe’s primary energy, but the options for generating electricity without carbon emissions are relatively strong and numerous. These include a range of renewable technologies, nuclear power, and CCS fitted to large fossil or biomass stations. Electricity is unique in that it also has the potential to bridge across into transport and heat by powering vehicles and heating, decarbonizing and reducing the fossil content of these hard-to-treat sectors. The UK’s Committee on Climate Change (CCC), for example, recommends a strategy of decarbonizing electricity generation during the 2020s and then rapidly electrifying heat and transport (CCC, 2013). The millions of vehicles and heating systems which currently burn oil and gas could instead be converted to burn fuels derived from biomass; however, the availability of sustainable biomass supplies is limited.² Burning biomass in power stations equipped with CCS offers the prospect of negative emissions and could be important in deep decarbonization scenarios.

¹ The United States is exporting coal displaced from its power stations by shale gas, while Japan’s gas imports rose after its post-Fukushima nuclear shut-down. The price in the EU Emissions Trading System (ETS) is low because of the ease with which a recession-hit continent can meet emissions limits set in better times.

² Torija de Lucas (2013) estimates the maximum potential of biogas in 2030 to be 5.5 per cent of the UK’s primary energy.

Electric vehicles (EVs) are a major unknown in future energy scenarios. They are poised to take a significant share of light- and medium-duty road transport in the coming decades, but vie with biofuels and hydrogen fuel cells. EV markets are expanding rapidly with growth rates of 50–100 per cent per annum, but they still form less than 1 per cent of the total market (Liebreich, 2015; ACEA, 2015).³ The technology must improve to compete with conventional fossil vehicles, due to the limited driving range (150–300 km, compared to 750 km) and cost premium. However, incumbent and new auto manufacturers are investing heavily, which is driving down costs at a similar rate to silicon photovoltaics, halving every 6–7 years (Liebreich, 2015). The key advantage of EVs is their higher fuel economy: 1 GJ of electricity will deliver a driving distance 3–4 times greater than 1 GJ of petrol or diesel (Pollet *et al.*, 2012). It takes far more primary energy to fuel a vehicle with 1 GJ of electricity than with 1 GJ of petrol, but if the electricity is from low-carbon sources, the reduction in emissions is large.

Electric heat pumps (air source, geothermal, or solar-assisted) compete with solar thermal and biomass burners for removing fossil fuels from residential and commercial heating.⁴ They are already widely used in Europe,⁵ particularly in the hydro-rich countries of Scandinavia and central Europe, and feature heavily in the UK's plans for decarbonizing the heat sector (CCC, 2013). As with EVs, heat pumps are more expensive than conventional gas boilers, but offer greater efficiency. They produce 3–4 units of heat per unit of electricity consumed when installed and operated correctly (as in German field trials), or 2.5–3 units when operated less than ideally (as in UK field trials) (Staffell *et al.*, 2012).

Electricity thus has a major enabling role in decarbonizing the wider economy by powering cleaner and more efficient devices, which could dramatically increase the demand for it. It is easier to change the contents of a pie when the size of that pie is growing, so electrification of other sectors may therefore be a catalyst for, as well as a response to, the decarbonization of electricity systems. For example, UK demand is projected to rise from 335 TWh/year in 2010 to between 400 and 600 TWh/year across a range of scenarios for 2050, despite strong assumptions about energy efficiency measures (Boßmann and Staffell, 2015). Looking across Europe, the European Renewable Energy Council (EREC) projects a 55 per cent share of electric vehicles in 2050, which would consume around 400 TWh per year, adding ~20 per cent to Europe's current electricity consumption (EREC, 2013). Electric heating could cause a similar increase, although this would be highly heterogeneous due to the seasonal nature of heat demand. France, for example, saw peak demand rise 28 per cent from 78 to 101 GW between 2001 and 2012 due to the addition of around 3m electric heaters, while annual demand only grew by 8 per cent. Similar effects would be seen in Britain and Germany if they followed the decarbonization plans set out in the UK Carbon Budgets and the Energiewende (Boßmann and Staffell, 2015).

Those decarbonization plans are very different, reflecting the range of options available. Germany's Energiewende (Energy Transition) sees 55–60 per cent of electricity coming from renewables by 2035. Combined with much greater energy efficiency, this

³ With 97,500 sales in 2014, battery electric and plug-in hybrid vehicles make up 0.8 per cent of new car registrations in Europe.

⁴ Micro-CHP (combined heat and power) is another class of technologies that promises decarbonization by improving efficiency while still burning natural gas (Staffell *et al.*, 2015).

⁵ Around 7.5m heat pumps operate in Europe, with annual sales of around 750,000 (EHPA, 2014).

would allow Germany to phase out nuclear power by 2022 (a response to Japan's 2011 Fukushima disaster) and still cut carbon emissions. In the short term, however, the 11 GW of wind and 30 GW of solar photovoltaic (PV) added between 2008 and 2013 have done no more than offset the emissions cost of closing 8 GW of nuclear stations in 2011.

In contrast, the UK government favours building new reactors, offering a long-term fixed-price contract and a loan guarantee to EDF Energy and China General Nuclear Power Corporation. Renewable generation had risen from 3.5 to 17.8 per cent of electricity output in the decade to 2014; however, the election of a majority Conservative government in May 2015 saw cuts to support for new onshore wind and solar generators.

This is despite the renewable energy targets set out in the EU's 2020 Climate and Energy Package. That policy, confirmed in 2009, set out three curiously symmetric targets for 2020: to improve Europe's energy efficiency by 20 per cent, to cut carbon emissions by 20 per cent from 2005 levels, and to get 20 per cent of its primary energy from renewable sources. Averaged over the EU-27, the national plans implied that one-third of electricity, and hence 9 per cent of overall primary energy consumption, would be renewable (ECN, 2011).⁶ By 2013, renewables generated 25.4 per cent of the EU's electricity (up from 17 per cent in 2008), and the European Commission was consulting on targets for 2030. Cutting carbon emissions by 40 per cent from 1990 levels was expected to imply that renewable energy would make up 27 per cent of primary energy, and 45 per cent of electricity generation (European Commission, 2014). By 2050, the IEA's 2 degrees scenario predicts that 68 per cent of the EU's electricity would come from renewables and 23 per cent from nuclear power. Fossil fuels (predominantly natural gas) would contribute the remaining 9 per cent, mainly from stations with CCS.

Some studies imply even greater shares of renewable electricity. Lund and Mathiesen (2009) analyse a 2050 vision of Denmark where local renewable energy resources (largely biomass and wind) meet all of its energy needs. Connolly *et al.* (2011) show that a similar approach could be feasible for Ireland; Jacobson and Delucchi (2011) suggest that the entire world's energy needs could be met from hydro, wind, and solar, although Trainer (2012) suggests that this would need an uneconomically large amount of spare capacity and storage to ride through periods of low wind or solar output. The next section explains why it is so difficult to rely on renewables alone for electricity generation.

III. The electricity industry

There are several problems with electricity as a commodity.

1. Failure to match supply and demand to within a few per cent for a few seconds leads to the system collapsing, which can take days to restore and cost billions in lost productivity (RAEng, 2014).
2. It is only possible to store in meaningful quantities using pumped hydro storage (where geography allows), or with a revolution in other storage technologies.

⁶ The plans gave 14 per cent from wind, 10 per cent from hydro, 6 per cent from biomass, and 3 per cent from solar PV.

3. Demand varies significantly over time due to human behaviour, typically ranging from 60 to 150 per cent of the annual average.
4. Demand is inflexible and so must be followed by supply: relatively few customers can actively manage their consumption, and until the 'smart meter' revolution gains a purpose, only a few large industrial consumers can respond to real-time price signals.
5. Many of the technologies for supplying electricity are also inflexible, or unpredictable due to unplanned outages or weather variability; so they cannot be precisely commanded like a dimmable light bulb.

These problems require two broad responses. First: build more capacity than is needed, sizing the system to meet peak demand plus a 'capacity margin' of typically 10–30 per cent. This ensures redundancy, so that if some plants are unavailable at the time of peak demand, it can still be met without having to disconnect customers. Second: keep more capacity online than is needed to meet current demand, holding back some controllable stations as 'reserve'. Should a generator then suddenly fail, or demand turn out to be higher than forecast, some of this spare capacity will be able to pick up the shortfall very rapidly.

Fossil-fuelled stations are suited for both of these contingencies. Simple gas turbines and gas engines are relatively cheap to build (although expensive to run) and so are economical to use as 'spare' capacity for meeting infrequent peak demands. Fossil stations are also controllable, and often highly flexible, and so fossil (or equally flexible hydro) stations prove essential for keeping the system in balance.

Non-fossil plant, with the exception of hydro, is less able to deal with these problems. Nuclear is very expensive to build (although cheap to run), and so relies on high utilization to recover its costs. Most reactor designs are also inflexible, running at full power (except when they break down) rather than ramping up and down to follow changes in demand. Renewables are also costly to build and reliant on the weather, so their output is unpredictable and uncontrollable. They only make a minimal contribution towards peak demand when their output is required the most, and cannot be used for maintaining system balance.

The need for balancing is inherent in the physics of alternating current (AC) power systems. Conventional power stations generate electricity by rotating a magnet inside a coil of wire, causing electrons to flow back and forth down the wire. If more (or less) energy enters the power system than is used by consumers, the frequency of this rotation will speed up (or fall). If the frequency moves outside a narrow tolerance (± 1 per cent), generators and other equipment risk being damaged and so disconnect themselves from the system. The failure of a single large generator or transmission line could, in principle, cause the frequency to fall to a level where other generators would disconnect and millions of people might be blacked out, as experienced in the US and Europe in 2003 and 2006 (RAEng, 2014).

Fossil-fuelled power stations have some useful characteristics in this context. The mass of the generator and the turbine together means that the system has some 'inertia', which slows the rate at which their rotation frequency falls after a failure. There will usually be some excess steam within the station's boiler that can be released to give a quick boost to output before the reserves kick in.

Fossil stations also have disadvantages. Power stations have a minimum stable level of generation, and a typical coal-fired unit cannot run at less than 50 per cent of its

capacity. Starting a unit is expensive, in part because fuel has to be burned to heat it before any electricity can be produced, but mainly because the thermal stress involved in heating and cooling turbines shortens their lifetime. Generators are sometimes willing to *pay* to produce power overnight in order to avoid shutting down, and stations with low variable costs may reduce output to allow those with higher variable costs to escape the cost of starting up.

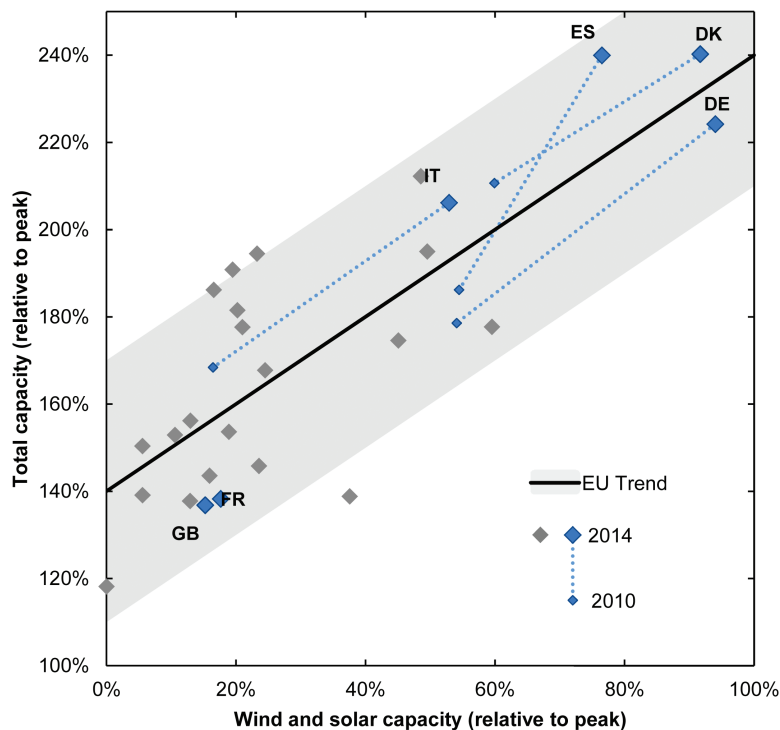
Many low-carbon generators have different characteristics. Hydro stations are extremely flexible and do not have significant start-up costs, and so they are often used to provide reserve. Nuclear stations also use steam turbines and have inertia, and some designs can generate at less than full output; this has allowed the French company EDF to use nuclear power to meet around 85 per cent of the country's electricity demand (ENTSO-E, 2015). Operating a reactor at less than full power means its fuel is used less efficiently, and raises the average cost of generation significantly as the capital costs are so high. In the short term, those capital costs are sunk, of course, but they should be taken into account when deciding what to build, a decision that depends on how the stations can expect to operate (Green, 2005).

In principle, wind turbines can provide reserve by turning their blades slightly out of the wind, reducing their power output in the same way as fossil stations, ready to move back to full power if needed. However, both wind and solar are either converted to, or generate, direct current (DC) rather than AC power, and must connect to the grid indirectly through power electronics. They would naturally have no inertia, although experiments in providing 'synthetic inertia' through power electronics are being conducted. The lack of inertia is not a problem when asynchronous generators only meet a small part of demand, but the Irish power system, for example, now has enough wind farms to sometimes meet more than half of demand. At these times, some have to be constrained off to ensure that at least 50 per cent of demand is met from generators that can provide inertia.

The biggest problem with wind and solar generators is that their output depends on the weather. Their contribution to peak demands can be very low, and so adding them to a power system does little to reduce the amount of 'firm' capacity needed. This is seen across Europe's current energy system in Figure 2, which compares the amount of intermittent renewables to the amount of total capacity installed in countries, both relative to their peak demand. Even with no variable renewables, a typical security margin is to aim to have capacity sufficient to meet 120 per cent or more of peak demand, and countries with depressed demand or past over-investment may have more than this. Adding wind or solar capacity appears to raise the total capacity at least one-for-one.

Once the share of variable renewable generators becomes large, errors in forecasting their output will also increase the amount of reserve needed. Gross *et al.* (2006) found estimates that reserves equal to 5–10 per cent of installed wind capacity are needed. Despite claims that running fossil stations part-loaded would eliminate the emissions savings from wind, evidence from Texas (which has a high share of wind generators) shows that wind generators displace emissions equivalent to a mix of gas- and coal-fired generation, at a rate of between 430 and 560 kg of CO₂ per MWh (Cullen, 2013; Kaffine *et al.*, 2013). In the UK, displaced emissions are 562 kg of CO₂ per MWh (Thomson, 2014).

It is conceivable that balancing will become more difficult in the future due to greater reliance on unpredictable renewable generators, more embedded generation (which

Figure 2: Renewable and other installed capacity across the member states of Europe

Notes: All countries are shown in 2014, small diamonds show selected countries in 2010.

is not metered by, and thus invisible to, the system operator), and the retirement of old fossil plant with sunk capital costs (ideal for low utilization peaking operation). However, 'smart' ICT technology could counter these trends.

Unmanaged charging of electric vehicles is likely to occur after the last journey of the day, which coincides with peak demand in many countries, requiring investment in additional capacity and lowering system utilization. If charging can be combined with smart communications technology, there is potential for using EVs as a trough-filling technology, analogous to the pumping of water in hydro storage plants. This could assist the integration of large quantities of variable renewables, with vehicles parked at workplaces using the peak afternoon output of solar, and parked at home keeping overnight demand high.

Smart controls on electric heating could potentially minimize their impact on peak demand by deferring operation for a short time (e.g. shifting evening heating from 7 to 9 pm), similar to frequency-responsive refrigerators. However, they still pose problems for the electricity industry as substantial uptake of electric heating will increase winter demand, further exacerbating the winter/summer gradient in cold and temperate countries. These changes to the load curve would decrease asset utilization, requiring either an increase in peak prices or capacity payments (Boßmann and Staffell, 2015).

Storing surplus renewable energy until it is needed could also solve some of these problems. Denmark is able to export surplus wind power to Norway, which alters its

hydro generation in response (Green and Vasilakos, 2012; Mauritzen, 2013), but only some countries have access to large amounts of hydro storage. Other technologies are mainly at the demonstration stage, although they could be valuable for the UK power system as soon as the late 2020s (Strbac *et al.*, 2012) due to its lack of interconnection, and the cost of batteries is falling rapidly (Liebreich, 2015). In contrast, it is easy and inexpensive to stockpile coal and oil at a power station or to store gas until it is needed for generation.

Fossil fuels can also be moved to allow power stations to be built close to loads, reducing the need for expensive long-distance transmission lines. Moving electricity is complex; power flows through all available lines between generators and loads, and a fault in one component could overload a distant part of the network. System operators have to keep every line within its limits, and must sometimes run expensive generators close to demand in preference to cheaper, but distant, alternatives. This is a particular problem for wind farms, since the windiest sites are often remote from centres of population. In contrast, small distributed generators can be sited close to loads (rooftop PV panels are literally above them), which reduces the flows on the grid, but can cause power to flow ‘backwards’ from local distribution up to national transmission level, forcing the system to operate in unintended ways (Staffell *et al.*, 2015). Isolated micro-grids with renewables and storage may well be a cheaper alternative than expanding the traditional grid into sparsely populated regions of developing countries. However, Europe’s already extensive grid means consumers benefit from economies of scale and greater security of supply, and those that remain connected to it will need to contribute towards its sunk costs, even if they are self-generating much of their energy.

IV. Electricity markets and the impacts of decarbonization

The many technical limitations described above mean that electricity markets have to be carefully designed to keep the system running securely. For decades, markets had little role in electricity, since the industry was organized around vertically integrated monopoly to ensure adequate coordination. It was only towards the end of the twentieth century that Chile (in 1982), England and Wales (in 1990), and Norway (in 1991) showed that large amounts of power could be traded on a spot market while system operators still ensured the electrical constraints were met. Since that time, the electricity industry has been liberalized and wholesale markets introduced in many countries around the world, including the EU and large parts of the US.

Most electricity trading is bilateral and in advance, allowing generators and retailers (or large consumers) to lock in to prices ahead of time (Green, 2008). The main ‘spot markets’ actually run the day before real time, giving time for schedules to be planned, and setting prices and quantities for each hour (or half-hour) of the following day. In reality, demand and supply will not match the previous day’s schedules due to imperfect demand and weather forecasts, random fluctuations, and mechanical problems.

To minimize the risk of failures, a single system operator is responsible for coordinating every large generator within their area. System operators ensure that some generators in ‘spinning reserve’ are always able to increase output rapidly after a failure, and instruct generators to adjust their outputs to keep the system in balance. Energy

storage and consumers with load management may also respond, but the flexibility of fossil-fuelled generators means they have always carried out the bulk of these adjustments in the past. Flexible generators can earn a market premium from being able to change output rapidly, charging a high price to produce more power and only buying back previously scheduled electricity for a very low price. The cost of balancing the system may be distributed evenly across all consumers, or targeted at consumers and generators who have deviated from their scheduled positions. The choice between these alternatives will become more important if balancing volumes rise in a less predictable low-carbon system.

Decarbonizing Europe's mainly liberalized electricity market requires specific policies. The flagship is the international EU Emissions Trading System (ETS). This requires every significant installation in affected sectors (including power generation, oil refineries, and cement works) to surrender one EU Allowance (EUA) for every tonne of CO₂ emitted. When the ETS started in 2005, almost all EUAs were given to firms without charge, but the expectation of scarcity made them valuable. This raised the marginal cost of fossil-fuelled generation, creating significant rents for most generators when permit prices were passed through to wholesale power markets. It also gave an incentive to shift from coal to gas generation, causing EU power sector emissions to fall by 3 per cent in 2005 (Delarue *et al.*, 2010). Permit prices fell dramatically the following year when generators realized that too many had been allocated to constrain their decisions. The market was reset with fewer permits in 2008, and prices were higher until the financial crisis struck and demand for electricity (and permits) fell below previously predicted levels. The price has remained below €10 per tonne of CO₂ since 2012, too low to provide an incentive to invest in low-carbon plant.

Most renewable generators are more expensive than conventional generators (excluding the cost of externalities) and their average costs are above current wholesale market prices. This might change in future as learning by doing (and by R&D) cuts the cost of renewable capacity, but at present, government support is needed to make it an attractive investment. Most EU countries have provided this in the form of Feed-in Tariffs (FITs). These require an electricity company to buy all the power generated for several years at a pre-set price, passing on the cost to consumers. FITs generally offer the lowest risk to renewable investors and are associated with lower costs of capital and hence relatively low overall costs. They do not reflect the market value of the electricity produced, and so an alternative policy is to require generators to sell power in the market before receiving a top-up payment. The top-up may come as a fixed Premium FIT, from the tax system (e.g. the Federal Renewable Energy Tax Credit used in the US) or by making electricity retailers buy Tradable Green Certificates from renewable generators.

The problem with not linking FIT payments to the market value of renewable power is that high levels of renewable output have significant effects on the level and pattern of wholesale prices. Wind and PV generators have marginal costs of practically zero, and thus displace fossil-fuel generators with higher marginal costs, which inevitably reduces wholesale prices. The first renewable generators may produce energy of above-average value, for example if prices and wind speeds are both highest in winter. As more wind farms are added, however, windy winter days start to see lower prices than calm days, and this reduces the relative value of wind power. The stronger the correlation between any one generator's output and that of other weather-dependent renewables, the lower

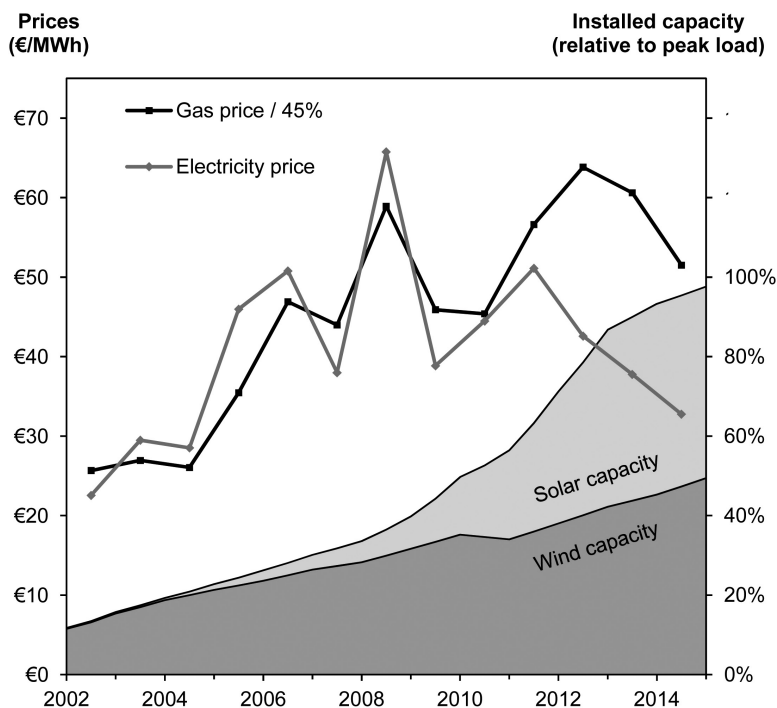
the price it will receive. Hirth's (2013) literature survey suggests that if wind power provides 30 per cent of a system's energy, or solar PV 10–15 per cent, they will have a market value 30 per cent below the time-weighted average price.

This effect will be exacerbated, at least in the short term, if the entry of renewable capacity is not matched by the exit of other plants. An industry with excess capacity will see lower average prices. Figure 3 shows the annual average prices of electricity in Germany's EEX day-ahead market and of imported natural gas (divided by 0.45 to reflect the thermal efficiency of a typical station), together with wind and solar capacity divided by the peak demand in each year (typically 74–79 GW).

German wholesale electricity prices have varied substantially with the cost of imported natural gas, but the link between wholesale electricity and natural gas prices breaks down after 2011 when the amount of solar capacity increased significantly. The retail prices that households pay doubled during this period to around €300/MWh, in part due to the renewable support levy which stood at €62/MWh in 2014. In contrast, the wholesale price fell towards the €30/MWh level of the early 2000s, depressed by excess capacity. In the medium term, firms might close some fossil plants to remove the excess capacity, but they are often reluctant to take such an irreversible decision until they are sure that market conditions will not improve, or that a rival will not close one of its stations first.

A number of markets have experienced negative prices in particular hours as the share of renewable output grows. When demand is low and weather conditions favourable, the potential renewable output is so high that it cannot be accepted without turning

Figure 3: Energy prices and renewable capacity in Germany



off some fossil-fuelled stations. Restarting these stations once conditions change would be expensive, and it may be essential to keep them running so that the system can withstand sudden failures. Renewable generators may have negligible marginal costs, but if they receive output-related subsidies, then the opportunity cost of not running is equal to the subsidy forgone. Asking for a negative price in order to reduce output reflects this.

Changes to the subsidy regime (such as paying for potential rather than actual output) could remove negative prices, but markets with high proportions of renewables or nuclear could still see many hours when the marginal cost of generation is close to zero. Could the cost of capacity be covered within the current paradigm of European electricity markets, which are built around trading *energy*? In theory, an energy-only market with the right amount of capacity will see peak prices rising to the level needed to remunerate all generators, including those which are only needed at peak times, but in practice, prices often remain too low at those times, the so-called ‘missing money’ problem.

With a high level of renewable capacity, peak prices depend on the combination of high demand and low renewable output. Since both demand and output are uncertain, this makes peaking generators’ revenues very volatile from year to year, and investment in them less attractive. A sensible response is a well-designed capacity market, which gives a revenue stream to power stations that are likely to contribute to meeting peak demand. The so-called ‘capacity option’ design gives successful generators an annual payment per kW of capacity, takes a penalty equal to the market price during any peak hours when the generator is not available, and claws back the per-kW payment if electricity prices turn out to be high enough to cover a peaking generator’s costs. It offers insurance against revenue variability as well as additional income.

Even with a capacity market to remunerate peaking stations, an energy market with power prices frequently hitting zero would be unfamiliar territory. The problem is not that wind or solar generators have no fuel costs—neither do hydro stations—but that their output is lost forever if it cannot be used at the present time. Flexible fossil generators save fuel costs if they do not run, and hydro stations with reservoirs can use their water later. The ability to store water means that generating now (instead of later) has an opportunity cost, and this ‘shadow value’ of water helps determine market prices. Wind and PV generators do not have this option, but as their market shares increase, they will occasionally have so much available output that it cannot be absorbed by consumers’ demand.

There are possible solutions. One is to increase the capacity of interconnectors to other countries, so that the renewable output can be absorbed by more consumers. This may require physical investment, but better market mechanisms can also allow more trade. When new companies joined the PJM market in the US, trade over the existing wires rose sharply (Mansur and White, 2012). Trade between neighbouring countries normally covered by the same weather systems, however, would do little to change the balance between renewable output and demand.

A second option is to increase the amount of electricity storage, which will raise demand for power at times when it would otherwise have to be spilled. A third is demand response, which is normally seen as shorthand for reducing load at peak times, but can also be valuable raising demand when there is surplus renewable output. The electrification of heat and transport offers possibilities here. Electricity may be used to heat water in advance of need, and smart charging for electric vehicles could be timed

to coincide with the cheapest power. It is technically possible for electric vehicles to also release power back to the grid when capacity is short, but if this significantly shortened the life of an expensive battery by increasing its number of discharge cycles, the ‘vehicle to grid’ approach might be uneconomic.

The final option might be imposed by the market. If inflexible stations frequently run when prices are zero or negative, they could quickly become unprofitable. As discussed above, they might not be closed at once, but they would eventually be replaced by more flexible stations. [Green and Vasilakos \(2011\)](#) model a long-run equilibrium for Great Britain with a large amount of wind generation and show that it would have less nuclear and more peaking capacity than one with little renewable output. They also show that the long-run time-weighted average price is insensitive to the amount of renewable power, since there is entry or exit by baseload stations until this price just covers their costs. The problem with looking for a long-run equilibrium is that it may never be achieved, and so the next section simulates investment and closure decisions taking place over time.

V. The role of fossil fuels in low-carbon electricity

In this section we focus on the British electricity market and the fate of fossil and other types of generation over the coming decades. We focus on the transition from 2010 to 2050, using a central scenario from the British government, but allow the carbon price, the level of renewable capacity, and the cost of CCS to vary in turn. We find that natural gas is tenacious, with capacity remaining at current levels regardless of these key uncertainties. By contrast, coal disappears from the system rapidly, being eradicated within as little as a decade. CCS is necessary to achieve the deepest carbon reductions, but it is the eventual mix of nuclear and fossil which dominates emissions reductions. We assume that there is no political limit on the amount of nuclear capacity built in Great Britain; changing this assumption would have significant impacts on our results. Renewable generators can displace output from fossil fuel stations, but do not displace the fossil capacity; in fact we show below that adding more renewables means *more* fossil capacity becomes economical to build.

For these simulations, we use MOSSI (Merit Order Stack with Step Investments), a dynamic investment and dispatch model of the British wholesale electricity market ([Green and Staffell, 2013](#); [Mac Dowell and Staffell, 2015](#)). Firms invest in power stations they expect to be profitable over their working lifetimes, and close them if they cannot cover their variable costs. The model stacks available stations in order of marginal cost and runs the cheapest to meet demand in each period; the wholesale price equals the marginal cost of the most expensive generator required. At times of low demand and high renewable output, some renewable generators are constrained off to allow inflexible nuclear stations to continue running. We do not model the other technical constraints discussed in section III, but have found that this is not needed to give good predictions of capacity needs and annual outputs ([Staffell and Green, 2015](#)).

Profit-maximizing investment and retirement decisions are made every 2 years over the course of the twenty-first century, determined by the cost of each technology (and how rapidly these decline through learning) and the revenues they expect to earn in the future. Plants able to return a profit after returns to capital are built, and those unable

to cover their short-run costs retire early. The equilibrium is found when no more potential capacity is expected to break even in both its first year and over its lifetime.

The optimal capacity mix is taken forward to the next period, and the model resolved with an updated profile for demand, and prices for fuel, carbon, and technologies. This process loops until the model reaches 2100; the initial investment decisions are then revisited in turn, and adjusted in the light of prices and profits projected for later decades, to ensure that each investment covers its costs over its lifetime. This cycle repeats until all decisions are consistent.

We focus on the transition from 2010 to 2050, simulating the market out until 2100 to capture developments in later decades which affect the profitability of investments made over the next 20 years. We use the Department of Energy and Climate Change's Central pathway for future fuel prices, which rise slightly until 2020 then remain flat thereafter. We vary future carbon prices from £0 to £250 per tonne, assuming they change linearly from £15 per tonne in 2010 to the specified value in 2050, then remain constant. We assume no subsidy or state interventions for thermal generators, and treat renewable capacity as exogenous. Our central trajectory is given in [Green and Staffell \(2013\)](#), and sees 30 GW of wind capacity and 20 GW of solar PV in 2040; we consider higher and lower cases with approximately +50 per cent and -30 per cent of the central case.

Much of the British power sector's transition is already locked in by the need to replace ageing assets: 7 GW of nuclear and 21 GW of coal reach the end of their technical lifetime by 2025, meaning 40 per cent of current capacity needs replacing over the coming decade. Coal retirements have been pushed forwards by clean air legislation: the Large Combustion Plant Directive (LCPD) closed 7.5 GW in the last 3 years; while the Industrial Emissions Directive (IED) will force at least another 10.5 GW into retirement by the early 2020s ([Gross et al., 2014](#)). Rather than targeting facilities with high carbon emissions, these directives seek to reduce sulphur, nitrogen oxides, and particulates. The ETS also has the power to render existing capacity uneconomical if carbon prices rise sufficiently: around £20–30/T is sufficient to switch the merit order, making gas the lower cost option for baseload.

In our simulations, new coal plants are only built with 2050 carbon prices under £30/T, well below predicted levels. If the 2050 carbon price exceeds £100/T (giving £36/T in 2020) then existing coal plants begin to retire early. We show results for a price of £200/T in the left-hand panel of [Figure 4](#), where coal retires 6–10 years early, leaving just 5 GW operating in 2020, compared to 14 GW if carbon prices remained constant.

These retirements do not displace fossil fuels from the UK mix. In the short-term, coal is replaced almost 1:1 by combined-cycle gas turbines (CCGTs), as new wind and solar does little to displace reliable capacity. Total fossil capacity over the next 10 years follows a consistent path regardless of the carbon price, as shown in [Figure 5](#). Beyond 2025 we see significant divergence: fossil capacity grows to meet demand with low carbon prices, or levels off with higher carbon prices as it loses out to new nuclear build. This capacity begins to be decarbonized using gas-CCS from the 2030s onwards, given high enough carbon prices.

In the right panel of [Figure 5](#) we find that a scenario with more renewable capacity actually requires more fossil capacity after 2040. This is because the additional renewable output forces a reduction in nuclear capacity; otherwise there would be too many

Figure 4: Evolution of the plant mix and energy output over 100 years, with CO₂ priced at £200/T by 2050⁷

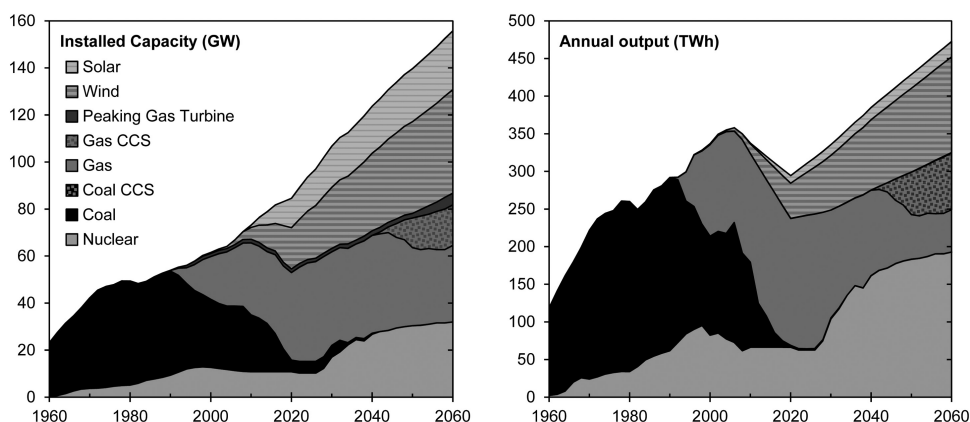
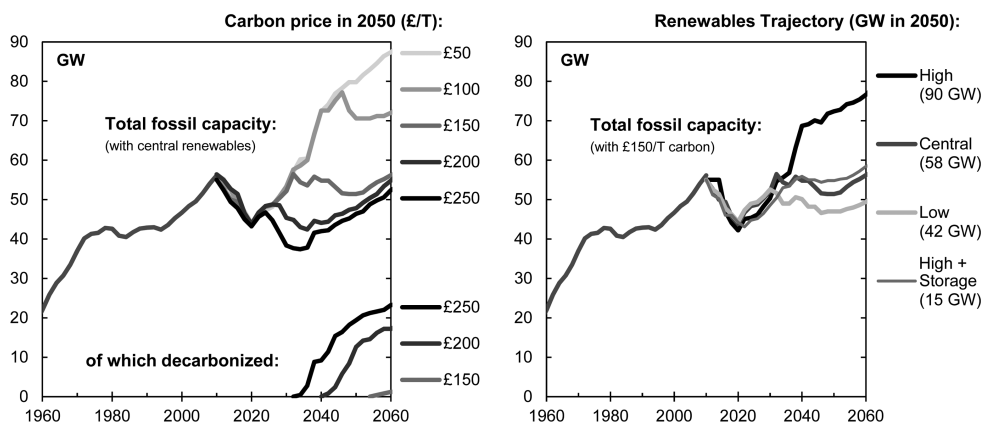


Figure 5: Sensitivity of the installed fossil capacity to carbon price and investment in renewables



hours with excess supply and hence negative prices.⁸ With low and central projections for renewable capacity, and carbon priced at £150/T, the level of fossil capacity remains around current levels. With the high renewables scenario (which has 30 GW of wind and 21 GW of solar in 2025, rising to 57 GW and 33 GW in 2050), nuclear remains suppressed below current capacity until the 2080s, and fossil (in the form of unabated CCGTs) expands dramatically to provide balancing.

Energy storage is a substitute for fossil plant, however. It raises the effective demand for power at times of high renewable output and low consumer demand, reducing the number of negative prices for a given capacity mix and allowing nuclear capacity to

⁷ We adopt the UK government's assumption (DECC, 2012) that overall electricity demand (shown in the right-hand panel) falls until 2020 due to efficiency measures, then increases once new sources of demand (heat and transport) come online.

⁸ This assumes renewable generators continue to be granted 'firm' grid connections, which guarantee their payment regardless of whether their energy can be delivered to market, and thus cause negative wholesale prices.

replace fossil stations. Adding 1 GW of storage for every 6 GW of renewables in the high renewables plus storage scenario, we get a similar mix of gas and nuclear capacity to the central renewables scenario.

Even if fossil capacity remains at current levels, its energy output does not. Falling demand and more renewables mean that fossil output declines rapidly during the 2020s. Nuclear capacity grows strongly with high carbon prices, reducing output from fossil fuels to 101 TWh by 2030, a third of its 2008 peak. Asset utilization will therefore fall dramatically, reflecting the fact that old coal and gas stations are better suited for peaking than nuclear or renewables.

The end state of this transition looks very different depending on the cost of technologies, fuel, and carbon. With high carbon prices, a mix of nuclear and gas-CCS provides the necessary decarbonization; this mix is particularly sensitive to fuel prices and the cost of adding the necessary capture, transportation, and storage equipment on to fossil plants. We do not find coal-CCS to be attractive under any conditions due to the £1,000/kW premium over gas-CCS and the lower efficiency (Green and Staffell, 2013).

Nuclear costs are known to be high after recent experience in Europe; however, the eventual cost of CCS is less certain. The only full-scale project to have been built, Boundary Dam in Canada, cost around £8,000/kW (Bassi *et al.*, 2015), which even with a first-of-a-kind premium makes nuclear look comparatively cheap. In Figure 6 we vary the cost of adding CCS to power stations around the central assumption of £600/kW, which equates to £1,300/kW for gas-CCS and £2,300/kW for coal-CCS in 2010, declining thereafter. If adding CCS to power stations was completely free it would take a large share of the capacity mix, although it would not entirely displace unabated gas due to the higher running costs. This share falls dramatically as the cost of CCS rises, and it is only economical below £700/kW (i.e. £1,400/kW for gas-CCS) in 2040 with carbon price on a trajectory to £200/T. A higher carbon price would give more investment by 2040; a price of £100/T would only give an incentive to build CCS if it cost less than £200/kW (£900/kW for gas-CCS). Strong uptake of CCS reduces power sector emissions to half their level without the technology; with the £200/T carbon price in Figure 6, emissions in 2040 are 30 MT/year without CCS (costing > £700/kW) and 14.5 MT/year with it (< £400/kW).

Carbon emissions fall dramatically during the 2010s due to the switch from coal to gas, as in Figure 7. With a carbon price above zero, emissions stabilize through the 2020s at around 60 MT/year (one-third of historic levels); but making further cuts requires a carbon price of over £150/T, the level which allows CCS into the mix. A carbon price of £200/T (in 2010 money values) is needed to achieve the 90 per cent cut from 1990 emissions envisaged by the CCC.

Power prices continue their recent trajectory, rising rapidly with our assumed fuel and carbon costs. The prices in Figure 7 exclude renewable subsidies, so consumer prices would be higher. Once the carbon price is sufficient to make new nuclear stations economic, they set the time-weighted average price. This means that prices are not sensitive to further increases in the carbon price, or to changes in fuel prices. Beyond 2030 with carbon prices above £100/T we see no difference when we vary fuel prices by ± 40 per cent from the central case. This implies that higher carbon prices will not increase the revenues received by renewable stations and may be inadequate to incentivize them unless renewable costs are low enough.

Wholesale electricity prices become more widely distributed, as in Figure 8. Renewables are constrained for 13 per cent of the year, giving rise to negative prices.

Figure 6: The capacity mix in 2040 for £200/T carbon and a range of costs for adding CCS to fossil plants

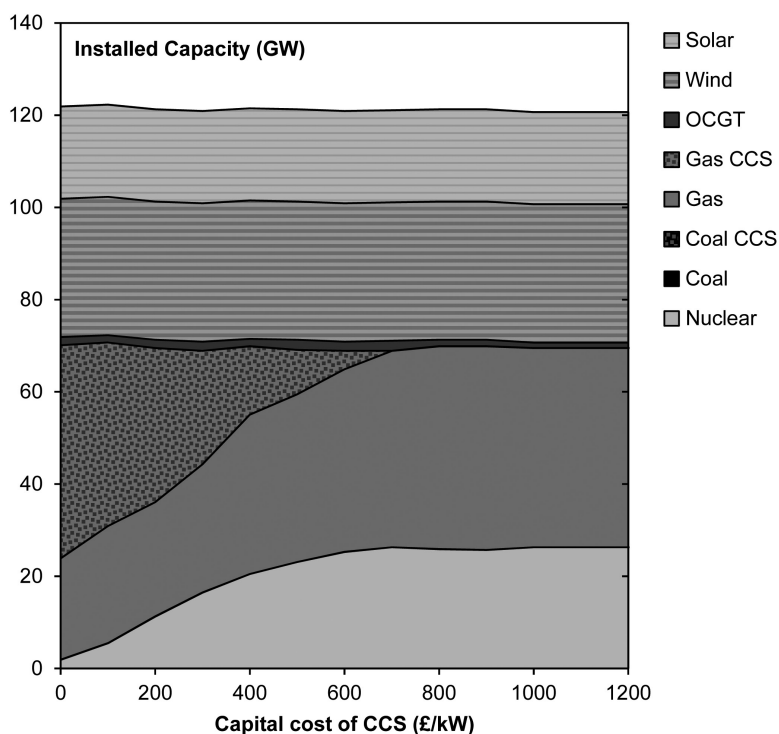
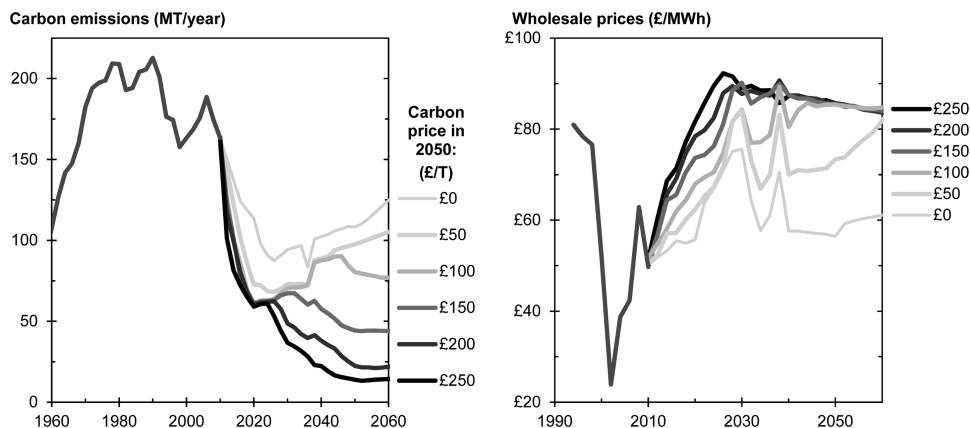
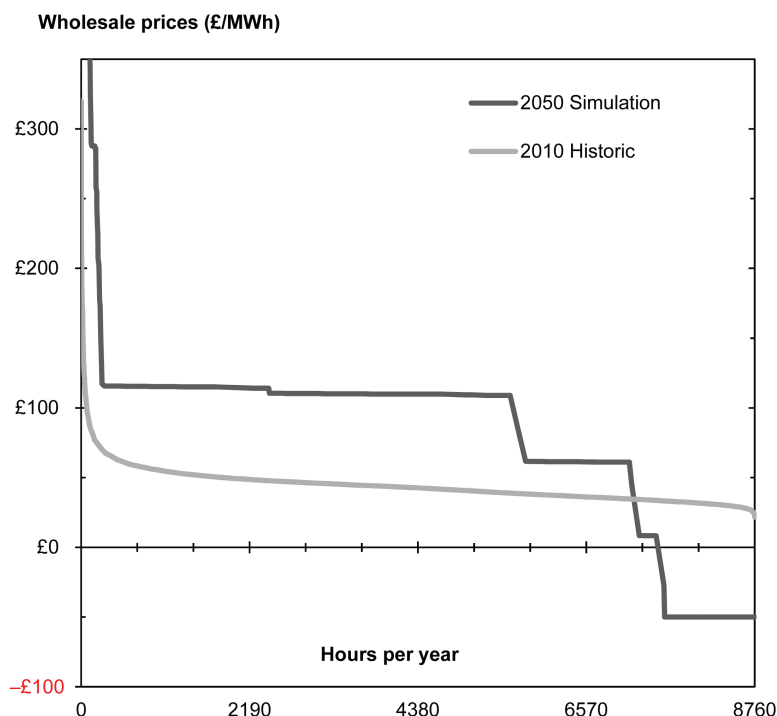


Figure 7: Evolution of prices and emissions across a range of carbon prices



This signals an opportunity for more storage and transmission than are currently included in this work; however other work (Green and Staffell, 2014, 2015) has shown that neither is likely to have significant impacts on time-weighted average prices in GB.

Figure 8: Price duration curve for 2050 with £200/T carbon

VI. Conclusion

Europe is undergoing the most radical shift in energy production since the advent of electricity for lighting and power, and since the oil-fired internal combustion engine displaced steam power a century ago. These revolutions were typical, driven by a new product which offered a better service at a lower cost. The current low-carbon revolution is not typical, in that less convenient services (inflexible and uncontrollable energy sources) with similar or higher costs are displacing the incumbent fossil-fuelled system. The important differences, invisible to consumers in an undistorted market, are the preservation of finite natural resources and the absence of carbon emissions (and thus long-term atmospheric damage).

As with any major change, there will be winners and losers. But unlike disruptive technologies such as the internet or mobile telecoms, consumers may not see benefits in the short term. Prices may rise and service quality (reliability) may fall. The benefits are longer term and involve much higher stakes—a liveable planet for future generations.

The rise of renewables is starting to squeeze fossil fuels out of the European electricity system, slightly offset by the move away from nuclear power in some countries. Heavy reliance on unabated fossil stations is incompatible with decarbonization, but CCS offers a route to continue burning gas with relatively low emissions. The flexibility of fossil-fired power stations, relative to baseload nuclear and intermittent wind or solar power, makes them an attractive option for balancing electricity demand and generation. It is also worthwhile keeping some unabated fossil stations for use at peak times—since they are rarely needed, their contribution to annual emissions is low.

Our simulations for Great Britain imply that coal will quickly be frozen out of the electricity mix, because many stations are due to retire and new stations are too expensive to build, relative to gas turbines. If the price of coal fell sufficiently relative to gas, coal could retain a role, but this would also require CCS to be effective and relatively cheap. Our simulations are based on cost predictions which see nuclear stations become profitable by the late 2020s, depending on the carbon price; if there is no nuclear renaissance in the UK, then either CCS or more renewables would be needed for decarbonization. Absorbing large amounts of intermittent output from wind and solar without flexible fossil stations will in turn require advances in energy storage, making demand more responsive, or very long-distance transmission.

The German path of expanding renewables and exiting nuclear is not necessarily a successful one. It has done little to curb coal consumption, and has dramatically altered power prices there. Average wholesale prices have fallen because of excess capacity, while retail prices for domestic consumers have risen to cover the substantial cost of subsidies. Wholesale prices have fallen or even become negative when renewable generation is too high relative to demand and other opportunities to absorb it. Excess capacity should fall as stations retire, but writing off an asset still valued at hundreds of millions of euros on a company's balance sheet is not a decision to be taken lightly; this will slow the transition. Market mechanisms may need to evolve to handle more volatile inflows from intermittent generation, and to ensure that rarely used capacity can still expect to cover its costs.

Electricity market mechanisms work well for stations that sell energy, but as the industry decarbonizes with renewables there will be greater need for other stations to sell services, such as balancing and reserve. Some countries can use hydro stations to provide these services, and energy storage may develop into a cost-effective alternative, but it is likely that the flexibility of fossil plant will still be of use. All-renewable scenarios would wish those plants to burn biomass, but sustainable biomass supplies are limited, and may be more effective as feedstock for transport fuels. Fossil fuels may soon no longer provide the bulk input for electricity generation; but rather than disappear, the role of fossil-fuelled power stations will change. It is unlikely that Europe will exit fossil fuels completely.

Epilogue

Shortly after this paper was completed the British government made two important announcements about the future of fossil fuels. It is now likely that coal-fired stations will have to close by 2025 unless they have carbon capture and storage, but the government also chose to withdraw the funding for its CCS commercialization competition. Our modelling showed that most coal-fired stations would close in the 2020s and be replaced with gas-fired stations; while a small amount of capacity would remain, its output would be very low. In line with much other work, our simulations implied that reducing electricity sector emissions to low levels requires a high carbon price and the deployment of CCS. Although a high carbon price can make CCS economically viable, that alone will not make it feasible until companies believe that the risks involved in the interdependency between power station, pipeline, and storage site are manageable.

The CCS commercialization competition would have supported one or two full-scale projects in developing both the technology and the contractual arrangements needed to make CCS a reality in the UK. Substantial government funding would have helped to offset the risks involved in first-of-a-kind projects, and crucially be the first stepping stone towards establishing a market and legal framework for these projects to operate within. The loss of this funding has made both of the candidate projects unviable, shortly before they were due to submit their final bids. Short-term cost-cutting has significantly delayed the deployment of CCS in the UK and eroded confidence in the government's support for a future with decarbonized fossil fuels.

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