A CHEAPER, CLEANER ELECTRICITY SYSTEM

Capell Aris

With a foreword by Professor Gordon Hughes

The Global Warming Policy Foundation

GWPF Technical paper 3

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Foreword

By Professor Gordon Hughes

In every competent and responsible polity it is regarded as essential that any major policy initiative or project should be accompanied by a careful project evaluation or impact assessment. This should be followed up by regular progress evaluations and an ex-post appraisal through which the effects of the policy or project can reasonably be compared with expectations at the outset. The goal is to learn the lessons of experience and to improve the design of future initiatives. Following such an approach is Treasury doctrine in the UK, and is urged on international organisations and developing countries. Unfortunately, actual practice within the UK is much more patchy; preaching is one thing, practice quite another.

The absence of systematic and honest policy appraisal is especially notable in the field of energy policy. Most of the impact assessments of energy policies have been characterised by a combination of dogma and wishful thinking. There has been extreme reluctance to carry out ex-post appraisals to assess whether the original – or, even, modified – goals have been achieved and at what cost. The example of the program to install smart meters is a classic example of the failures that can result from a reliance on policy dogma in place of independent appraisal.

The paper by Capell Aris examining the outcome of policies to promote renewable energy in power generation is a model example of an ex-post policy assessment. It compares a simple and reasonable counterfactual with what was actually achieved. It shows that cumulative costs and emissions of carbon dioxide would have been lower under the counterfactual than under the policies that were actually adopted. That advantage will not be eliminated if we project forward to 2030. In terms of the stated goals of controlling energy costs and reducing carbon emissions, policies to support the growth of renewable generation have been a failure.

All kinds of excuses will no doubt be offered – in particular, the role of European Union targets for renewable energy and the 'unforeseen' collapse in world gas prices. However, it should be remembered that the Renewables Obligation targets and supporting subsidies were introduced in 2002, well before the adoption of EU targets and before the increases in gas prices after 2005. The deficiencies and cost of renewable policies highlighted by this paper are the consequence of a home-grown failure of energy policy. It is an evasion to place the blame for this policy on the European Union's Renewables Directive of 2009.

We need more ex-post appraisals of the kind carried out by Capell Aris to ensure that future policymaking avoids the mistakes that have characterised decision making over the last two decades. The last refuge of policy lobbyists is that 'this time will be different'. As Dr Aris's paper shows, this is almost never true. The analysis shows that the combination of surrendering to sentiment and ignoring the conclusions of simple economic analysis leads to the adoption of policies that are costly (in economic and environmental terms) and often counterproductive.

Professor Hughes is Professor of Economics at the University of Edinburgh and has been a senior adviser on energy and environmental policy to governments and the World Bank.

About the author

Dr Capell Aris worked in the Electricity Supply Industry first as reactor physics specialist at Wylfa nuclear power station, and then at Dinorwig and Ffestiniog pumped storage stations in the control and instrumentation section and later with additional responsibility for information technology systems.

Acknowledgements

Dr Lee Moroney of the Renewable Energy Foundation and Kevin Harris of BEIS have supplied much of the information used in this paper. Dr John Constable has provided help with drafting the final text. Colin Gibson, formerly Power Network Director, National Grid Group, has contributed many of the technical insights used in determining security of supply and cost analysis.

Summary

This study is an evaluation of Great Britain's electricity generation system since 1990, with particular focus on the developments during this century. The performance parameters selected for this study are:

- the total system cost (and the per unit cost of electrical energy);
- the security of the generation system in meeting demand;
- the reduction of carbon dioxide emissions incurred during generation.

The tools used for these studies are:

- calculations of the levelised cost of electricity (LCOE), inclusive of any system integration charges required to cope with the intermittency and transmission connection of new renewable generation;
- calculations of loss of load probability (LOLP), based on a probability analysis of matching generation and demand;
- simple enumeration of emissions, based on emissions performance reports extracted from official data;
- comparison of the As-built system and various counterfactual systems, such as one in which no expansion of renewable generation takes place and instead the 'dash for gas' of the 1990s is continued into this century.

The findings of this study are that generation costs have increased markedly since 2002, and that consumers' electricity bills have risen accordingly.

Calculated LOLP values throughout the period remained low, but from 2016 have risen significantly, even with inclusion of all interconnectors to the European generation system. Emissions of carbon dioxide have fallen sharply in the last five years, but the majority of this fall has been due to a recent switch from coal generation to gas generation.

Since generation from coal has almost ceased, the cost of future emissions cuts through expansion of renewable generation will begin to rise steeply. The counterfactual gas system would significantly outperform the As-built system in both cost and emissions terms.

Continuation of the counterfactual gas scenario to 2030, with some expansion of the nuclear fleet, reveals that such a system is capable of holding prices down and delivering further emissions cuts. The gas system also performs well against all of National Grid's 'Future Energy Scenarios'. The present generation system is thus at a difficult crossroads. Any further expansion of renewables will:

- increase the probability that the system will fail to meet demand (in a future when we will become ever more dependent on energy for economic progress, national security, health, and entertainment);
- increase the cost of electricity to all consumers – even if renewable capital costs were zero, their system integration and operation and maintenance costs would make their electricity more expensive to consumers than that generated from modern gas turbines;
- lead to rising costs to cut emissions as the renewable fleet displaces zero-emissions nuclear, and low-emissions gas.

1 Introduction

In 2017 the electricity generation system of Great Britain had a capacity of 100 gigawatts (GW), including 33 GW of wind, solar and biomass generation, and delivered 336 terawatt hours (TWh) of electrical energy. Annual domestic electricity bills averaged around £533 per household.* In 1996, capacity was 73 GW, production 364 TWh, and annual domestic bills were £446 per household.[1–3] Over this period, carbon dioxide emissions from electricity generation had fallen from 529 to 258 tonnes per gigawatt hour (GWh). Can this obviously dramatic transformation of the UK generation system be pronounced a success, or could more have been achieved, and if so at what cost?

This paper analyses the electricity generation system we have built (the 'As-built' system) between 1990 and 2017: the performance parameters determined for this system are costs, the carbon dioxide emissions reductions it has delivered, and its effect on security of supply.

The results for the As-built system are compared with two counterfactual systems, both of which exclude all renewable generation and incorporate a modest increase in nuclear generation. These are:

- a gas-dominated system, in which combined-cycle gas turbines (CCGTs) replace most coal-fired generation, along the lines of the 'dash for gas' of the 1990s;
- a system with an expanding coal fleet.

The methods and data underlying this paper are mainstream in nature, and should be uncontroversial: The costing analysis developed in this paper uses an approach based on the 'levelised cost of electricity' (LCOE) method, which provides an economic assessment of the average total cost to build and operate a power-generating asset over its lifetime divided by the total energy output of the asset over that lifetime.[4–7] Security of supply delivered by the generation system is assessed by calculating the 'loss of load probability' (LOLP).[8–10] Data comes from such standard sources as:

- the Renewable Energy Foundation[11]
- the *Digest of United Kingdom Energy Statistics* (DUKES).[1]

DUKES supplies carbon dioxide emissions rates per gigawatt hour for all fossil-fuelled technologies, allowing a simple determination of total system emissions.

Throughout this study it has been assumed that large scale biomass generation such as Drax power station produces no net carbon dioxide emissions, despite the emissions consequent on drying the wood prior to combustion and cross-Atlantic transportation. This is clearly a generous assumption, and understandably controversial, but it is, as a matter of fact, the UK government's own position. Less favourable assumptions with regard to the emissions reductions arising from the use of biomass for electricity would clearly strengthen the general conclusions reached here. A brief review of historic generation capacity and production data sets the background for this assessment.[12]

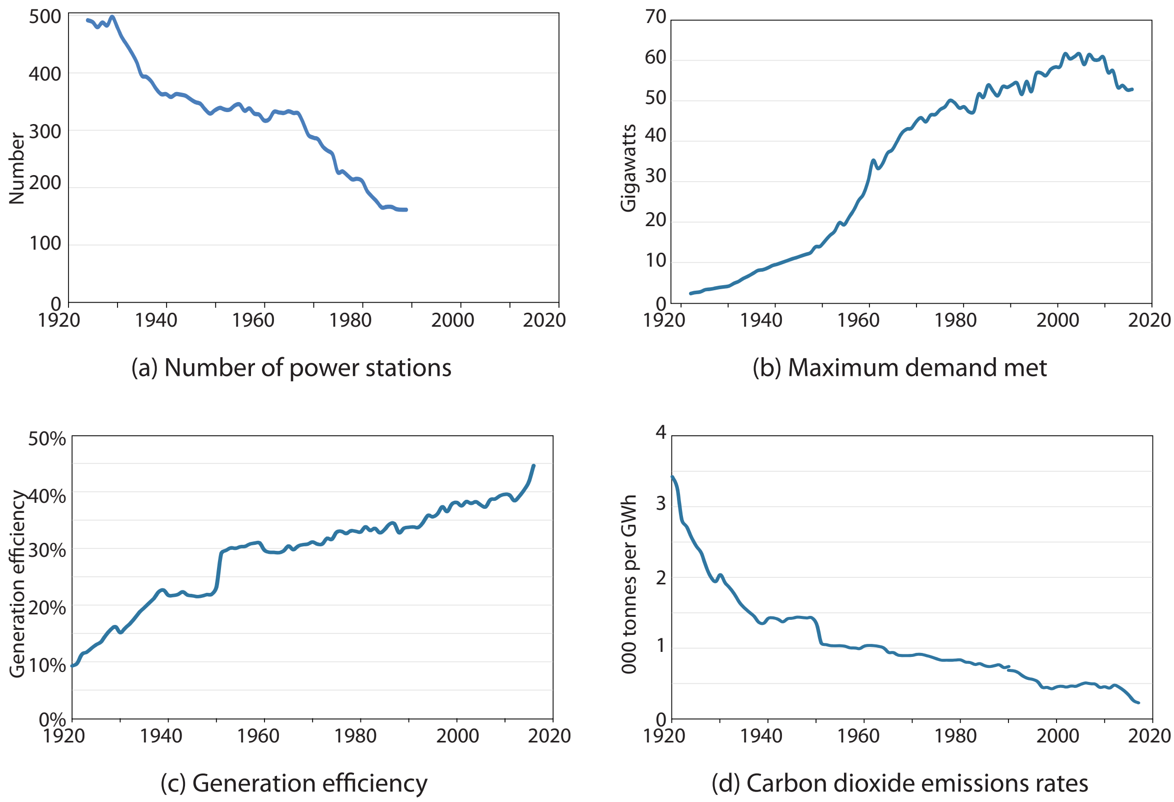
2 The British electricity industry: an historic perspective

2.1 1920 to 1990

Between 1920 and the year 2000 the electricity generation and transmission system of Great Britain changed from one dominated by small generation stations, mostly supplying iso-

* 2016 data.

lated distribution grids within cities and towns, and frequently under municipal control, to a system of larger generators connected to energy consumers by a distribution grid. Over this period, the number of power stations fell steadily, and the move to progressively larger generation plants with higher thermal efficiency drove down costs and carbon dioxide emissions.[12] The scale of this transition is revealed in the following four graphs (Figure 1).



(a) Number of power stations

(b) Maximum demand met

(c) Generation efficiency

(d) Carbon dioxide emissions rates

Figure 1: The progress of the UK's electricity supply industry from 1920.

Source: DECC/BEIS.[12]

As is apparent from the charts, the single most important change was the rise in efficiency, achieved by moving to larger, steam turbines operating at higher pressures and temperatures, and their connection to a national grid system that allows grid managers to allocate a grid-stabilisation role to specific generators as necessary.

Since 1920, with only minor trend reverses, the system's carbon dioxide emissions fell, a process that was helped, from 1958, with the introduction of nuclear power stations. Electricity prices fell too (Figure 2), with important consequences for manufacturing and domestic costs.

2.2 1990 to 2017

Privatisation of the electricity supply industry, including generation, transmission and distribution, occurred in 1990. Generation capacity ranged initially between 60 and 70 GW but surged from 2003 onwards and is now close to 100 GW. From 1993, a 'dash for gas' saw increasing electricity generation using combined-cycle gas turbines (CCGTs), but this surge faltered and, by 2017, apart from one station, most were at least 16 years old. Sizewell B

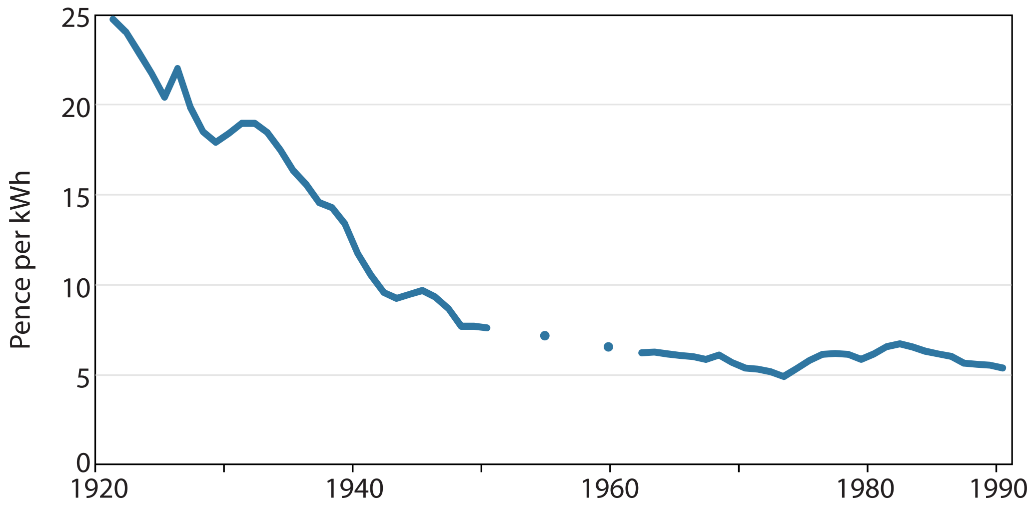
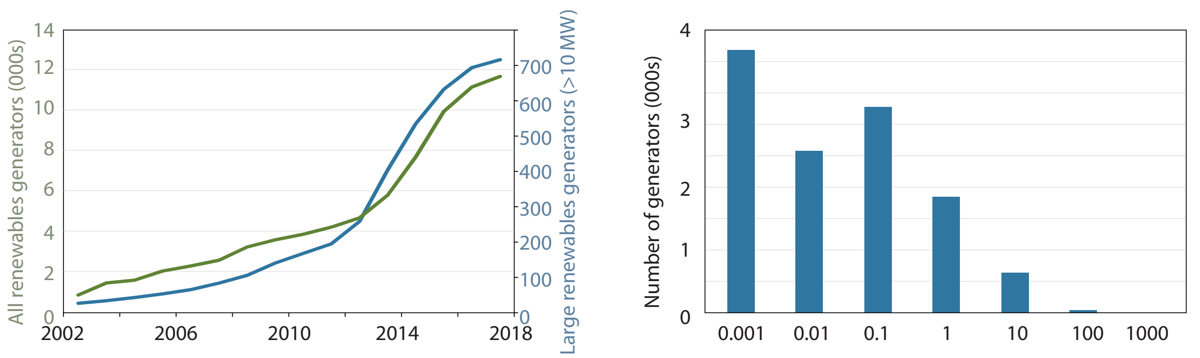


Figure 2: Electricity prices 1920–1990.
Source: DECC/BEIS.[12]

was commissioned in 1995 but there have been no new nuclear stations since then, and the entire Magnox fleet was retired between 1989 and 2015. Coal-fired capacity has generally declined throughout this period and is now falling rapidly towards full closure in 2022–2023.

Generation from renewable energy sources started in 1990, supported by the Non-Fossil Fuel Obligation, which was introduced that year, but remained at a small scale until the 2002 report of the Royal Commission on Environmental Pollution[13] and the 2003 *Energy White Paper*.[14] New policy instruments, in particular the Renewables Obligation, were introduced,[14] and renewables capacity surged. There are now about 13,000 renewable generators of larger scale, well over 20 times the number of stations in 1920, many embedded in distribution grids (Figure 3). In addition, there are nearly 800,000 small-scale generators, such as rooftop solar panels. Renewable generators remote from load centres require new transmission or distribution connections, and general system reinforcement.



(a) Numbers of renewable generators

(b) Number of renewable stations by log nameplate capacity

Figure 3: Expansion of the renewable generation fleet since 2002.
Source: Renewable Energy Foundation data.[11]

During this expansion of renewable generation, little dispatchable, fossil-fuelled plant has been built; of the 2017 generation capacity, only 66 GW is dispatchable. Maximum demand peaked at 61 GW between 2001 and 2005 but had dropped to 52 GW by 2017. Production peaked in 2005 at 399 TWh but has declined to 336 TWh, of which 15 TWh is imported (see Figures 4 and 5a). All fossil fuel prices experienced a price surge between 2000 and 2015 (Figure 5b).

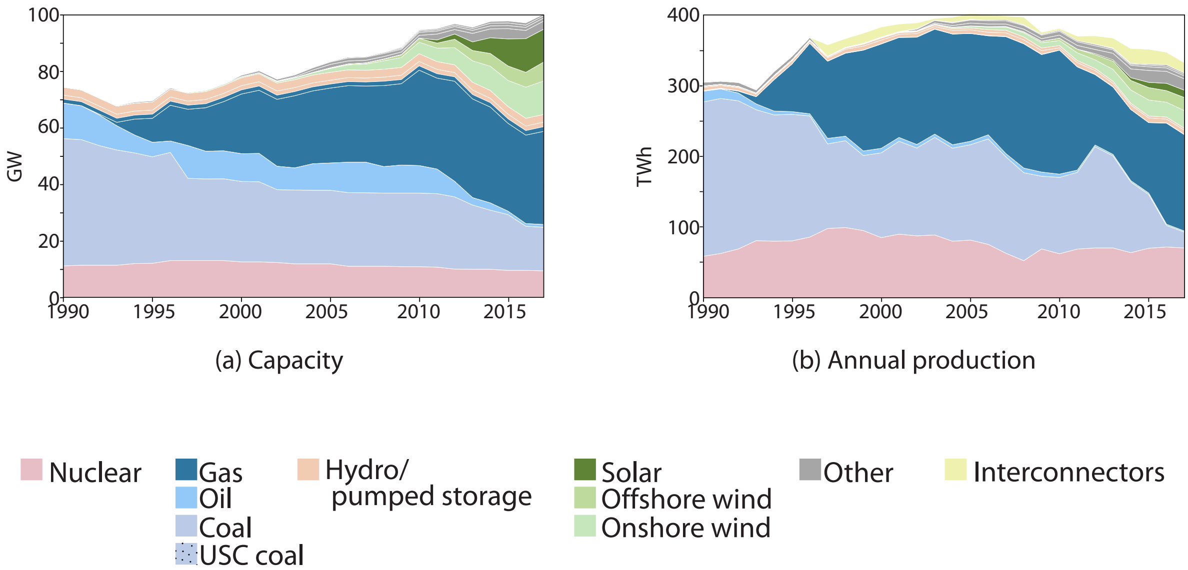


Figure 4: GB electricity generation capacity and production between 1990 and 2017. Sources: DUKES[1] and K. Harris[2].

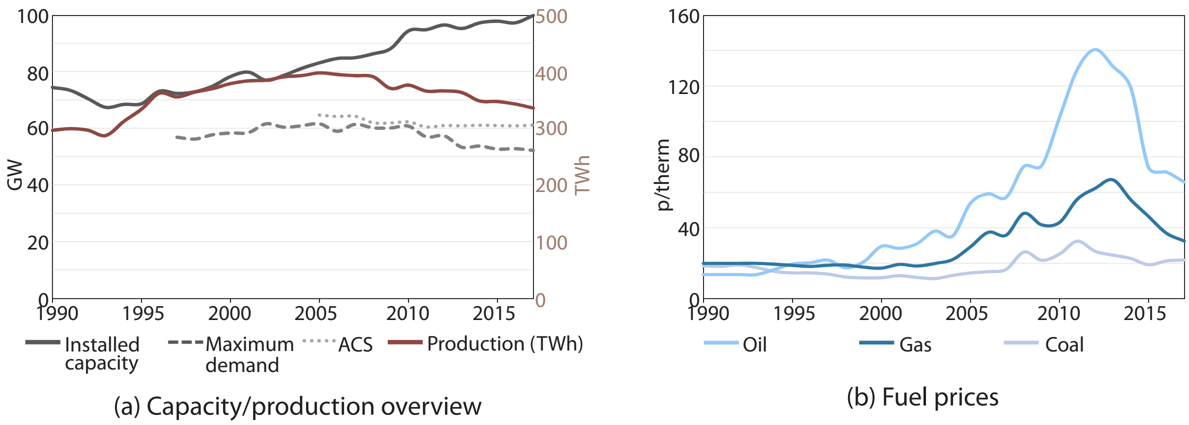


Figure 5: GB electricity generation overview, and the variation of fossil fuel costs since 1990. ACS: average cold spell. Sources: DUKES[1], K. Harris[2] and DECC/BEIS.[3,15]

The average cold spell (ACS) demand (see Figure 5a), which is determined by National Grid, represents the maximum demand expected during each year and is used for forward planning of grid capacity. The ACS data here is extracted from National Grid's Future Energy Strategies (2016).[16]

3 Using levelised cost of electricity to determine total system costs

3.1 An introduction to LCOE

The basis of the cost analysis in this paper is the so-called 'levelised cost of electricity' (LCOE). LCOE provides an economic assessment of the average total cost to build and operate a power-generating asset over its lifetime divided by the total energy output of the asset over that lifetime:[4–7]

$$\text{LCOE} = \frac{\text{(Net present value of lifetime costs of electricity generation)}}{\text{(Net present value of lifetime generation)}}$$

LCOE is a view of energy costs restricted to the viewpoint of the owner/operator of the generating plant; in the present case that owner can be considered to be all energy users in Great Britain.

The technique requires the gathering of historical data on the costs of:

- plant planning, construction and commissioning
- operational performance and maintenance
- project financing (including investment borrowing mechanisms and debt placement during operation)
- charges for connection to the transmission system
- business rates
- decommissioning.

Discounted cash flow analysis is used at several stages, and the model used in this study (see Section 3.3) can incorporate a variety of debt arrangements.

The UK government's Department for Business, Energy and Industrial Strategy (BEIS), and before it the Department of Energy and Climate Change (DECC), has carried out LCOE studies[7] for a wide range of generation technologies and provides summary data for each technology's costs for specified load factors, generation life, fuel costs and other parameters.

3.2 Load factors and other sensitivities

There are several key sensitivities in LCOE calculations, including fuel prices and generator efficiency, and load factors. Normally, LCOE is calculated assuming that energy output is only restricted by the availability of the plant and input fuel (in other words, market demand is not taken into account as a limiting factor). However, in reality, in each year of operation, LCOE will vary with the load factor that a generator (or technology type) achieves, which in turn depends on what other generating assets are connected to the grid and the merit order - the rules governing which assets operate in practice. Until the 2001 introduction of bilateral trading between generators and supply companies, under the so-called New Electricity Trading Arrangements, load factors were largely dictated by the grid system operator. Since that time, the load factors that are achieved by traditional generation technologies, such as coal- and gas-fired power stations, will depend on how much intermittent renewable capacity is connected to the grid.

3.3 System costs

When applying LCOE analysis to an electricity *system*, a separate analysis is required for each generation technology. However, the figures will also need to be adjusted to take into account any extra system costs (system integration costs) that each type of generation imposes on the customer. For example, the costs of compensating for the uncontrolled variability or intermittency of wind and solar are included, both in an operational timescale (seconds to hours), and in a planning timescale (years to decades); and, if generation is built in locations remote from the load centres, then the extra cost of transmission capital plant is included. This total system cost can then be taken as a reasonable proxy for the price of electricity to the customer to cover generation costs. These costs were calculated using probabilistic studies, and the median values used in further cost calculations.

3.4 The IESIS model

To embody the sensitivities of costs to the parameters described above, and the system integration costs, this study uses the LCOE analysis tool developed by the Institution of Engineers and Shipbuilders in Scotland (IESIS).[4,5] In this study each generation technology has a separate spreadsheet which allows the user to enter independent variables describing capital costs, investment profiles, operational costs, fuel costs, efficiency, amongst other parameters. Since the DECC LCOE study[7] was under-pinned by costing data provided by Mott MacDonald,[17] Parsons Brinckerhoff[18] and others, the IESIS LCOE sheets are seeded with much of the source data used for the DECC study.[7] However, there are differences.

- The DECC LCOE study was published in 2013. Since then, the capital costs of nuclear construction have increased, so the IESIS calculations reflect this increase.[5] The cost of the Hinkley Point C project provides an upper limit for capital costs.
- More recent studies of offshore wind generation costs provide greater certainty about capital costs,[19] and these are incorporated into both the IESIS studies[5] and this paper. The most probable capital cost for offshore wind is taken as £3.4m/MW.
- Details of the project costs for onshore wind have appeared in press reports; a spreadsheet of these costs was published alongside the most recent IESIS study.[5] The capital cost for onshore wind is taken as £1.5m/MW. The impact of ageing on wind turbine production is taken from papers by Staffel and Green[20] and Hughes.[21]
- The capital cost for solar generation (in 2015) is taken as £840,000/MW.[22] Solar panel ageing data follows the work of Jordan and Kurtz.[23]
- Data published in 2015 for ultra-super-critical (USC) coal generation were taken from the levelised cost analysis of VGB Powertech.[6]
- Each of the IESIS LCOE calculations now includes a cost for decommissioning, ignored in the DECC study.
- Each of the IESIS LCOE calculations excludes all carbon tax charges; DECC included such taxes in their costs.
- The IESIS sheets for all generators include optional system integration costs, covering mitigation of intermittency, provision of response and reserve if the generator type cannot provide these grid services, and the costs of any new distribution or transmission charges required for grid connection. The impact of including these system integration costs is discussed in Section 4. (Improved accuracy of calculated generation

costs can probably only be achieved by undertaking full system studies). DECC ignored system integration costs.

This study takes advantage of a facility in the IESIS spreadsheets that allows the user to explore the sensitivity of the levelised cost to varying parameter costs, each with a different probability. Up to four parameters can be selected for inclusion in this sensitivity analysis. This analysis reports how costs vary with load factors (which here will be the annual load factors), fuel costs and efficiency improvements. By using the historical probability distribution profiles for each of these, it is possible to establish a profile for the costs of the various technologies, as shown in Figure 6.

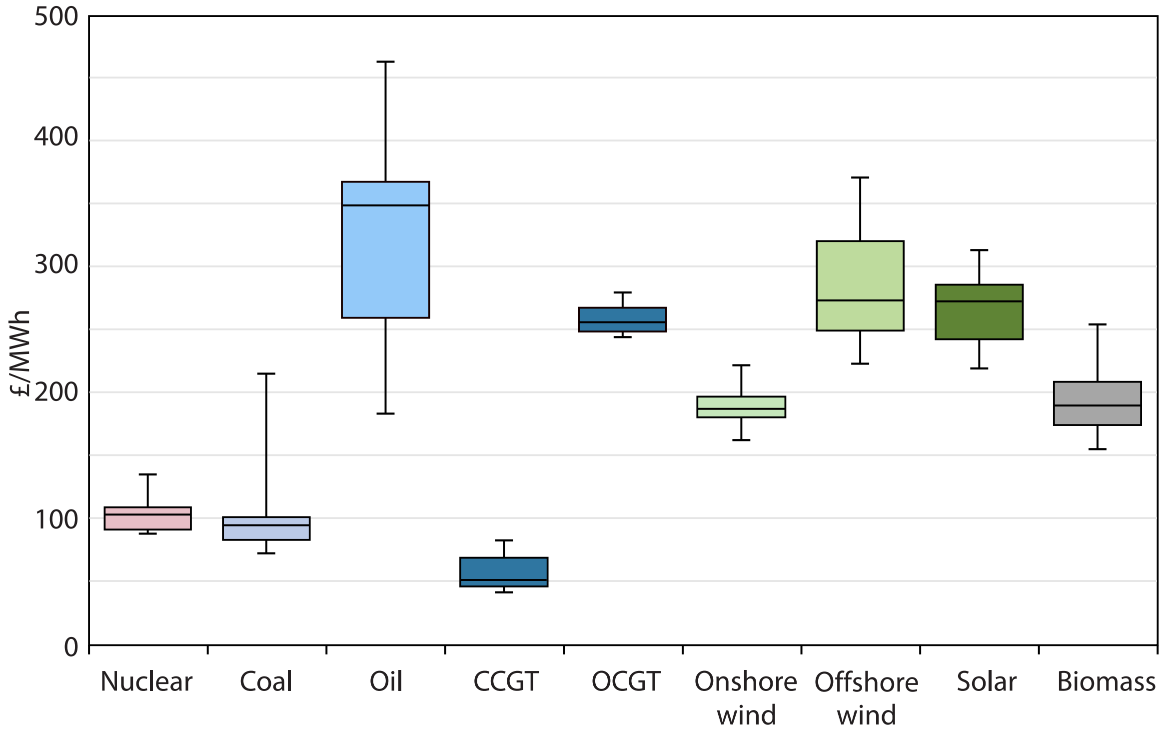


Figure 6: Study LCOE values, including system integration costs, observed 2007–2017.
The range of values shown applies only for the As-built system, operating with values of load factors and fuel prices taken from DUKES data (Figures 4 and 5) – the spike in coal costs, for example, is caused by a low load factor in 2017. The counterfactual systems have different load factors (usually higher, as noted in Section 5, and thus slightly lower costs for the fossil-fuelled plants). The inclusion of new, higher efficient CCGT plant also lowers costs. OCGT, open-cycle gas turbine.

The cost performance of CCGT plant is remarkable, but easily explained. Because of its low capital cost, low levels of staffing for operational supervision and maintenance, and its high thermal efficiency, the generation costs of CCGT are lower than all other technologies, and are thus comparatively insensitive to changes in fuel costs.

4 System performance in 1990 and 2017

4.1 Determining the production cost for a generation system from LCOE results

Using annual values for plant load factor, fuel costs, renewable capacity factors, and plant efficiency it is possible to calculate values for

- LCOE
- LCOE plus system integration cost

for each technology present in the generation mix. These are multiplied by the annual production to obtain the total cost for the system for each year. The results of these calculations are shown in Figure 7. All further plots of generation costs will include the system integration costs.

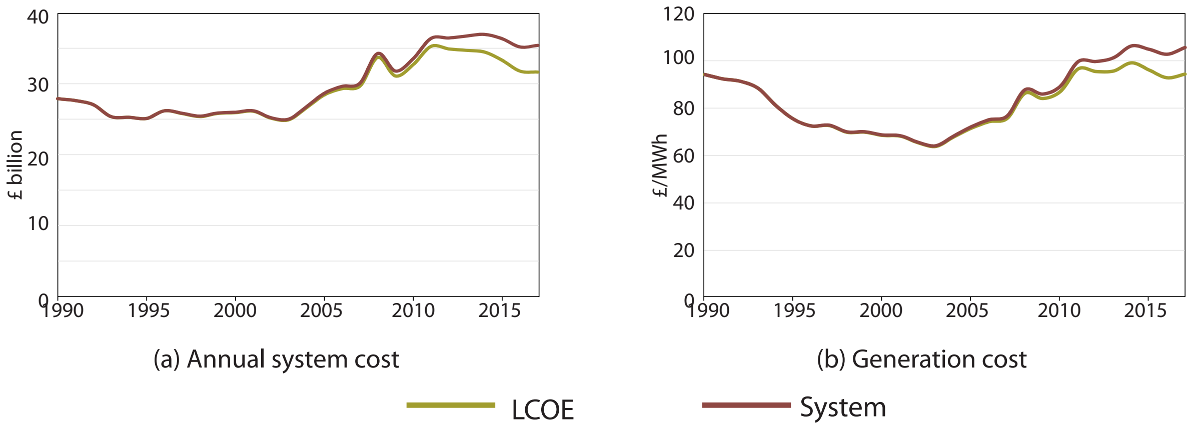


Figure 7: Financial performance of the existing UK electricity generation system.

The fall in generation costs from £94 to £64 per MWh (Figure 7b) between 1990 and 2004 results from the 'dash for gas'. The rise in costs since 2004 was driven by three factors:

- rising fossil fuel prices (Figure 5b);
- the fall in load factors assigned to fossil fuel generators (Figure 8);
- the rising proportion of renewable generation; in 2017 wind, solar and biomass generated 21% of total generation but accounted for 38% of the costs.

The full impact of the high costs of renewables is assessed in Section 6.

Household electricity bills fell during the 'dash for gas' period but have increased in recent years (see Figure 9).[3,12]

In 2017, system integration charges have added £3.4 billion to the annual system cost (Figure 7a) with an installed renewable capacity (wind, solar and biomass) of 33 GW (in a system with a total installed generation capacity of 100 GW). This would appear to be a conservative estimate: in 2012 the Committee on Climate Change estimated that:

> the combined costs of transmission upgrades and other flexibility measures related to a 30 to 64 per cent share of electricity from renewables by 2030 would be between £5 and £5.9 billion per year.[24]

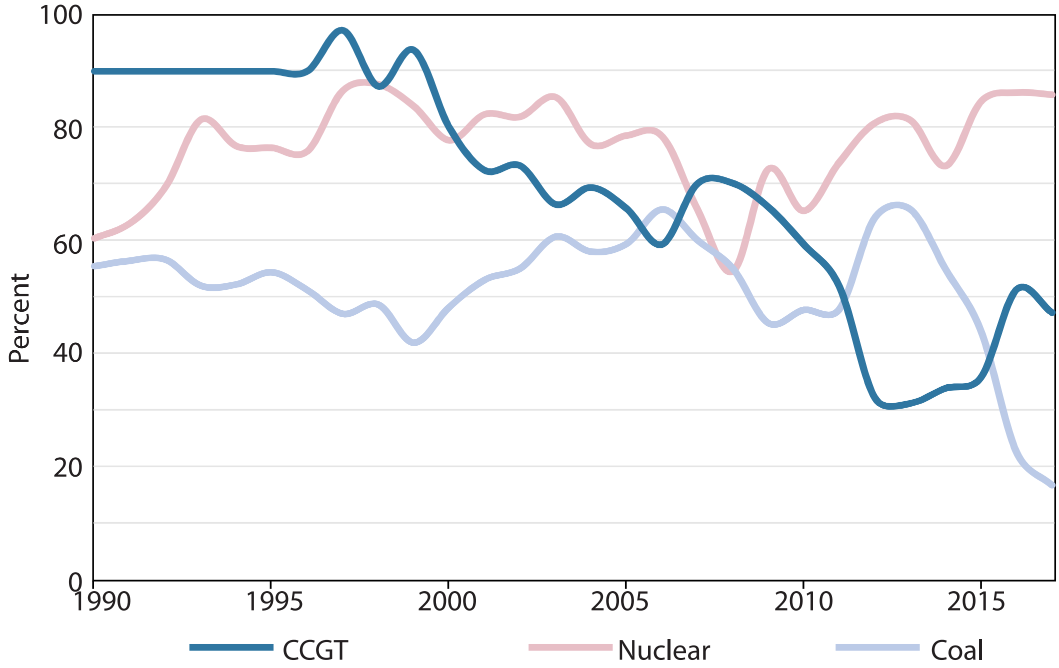


Figure 8: Non-renewable load factors 1990–2017.

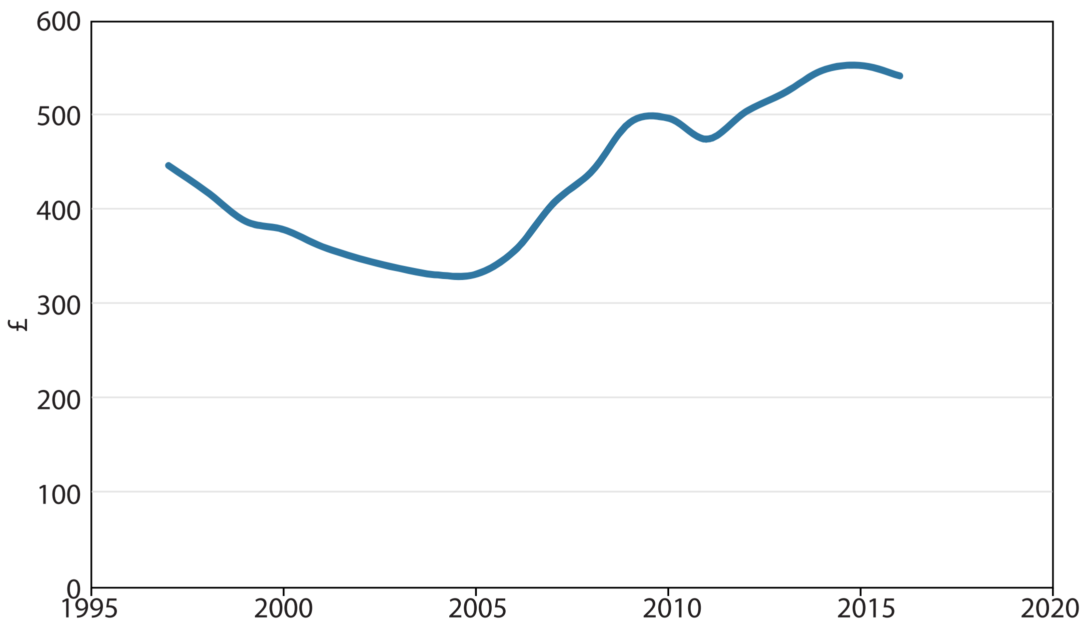
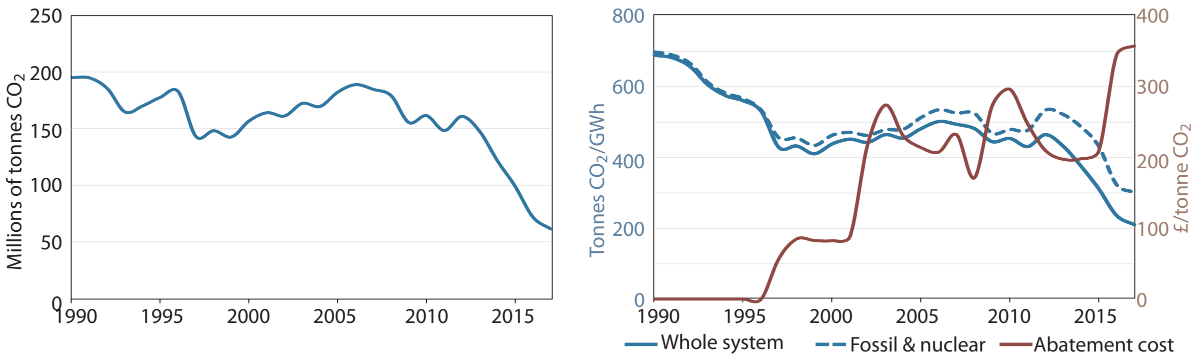


Figure 9: Annual domestic electricity bills.
2016 index, based on annual consumption of 3,800 kWh, no update for 2017 available.
Source: DECC/BEIS.[3]

All further reports of costs will include the current system integration costs calculated for the present analysis, but the possibility that they are underestimates should be borne in mind.

4.2 Reducing carbon dioxide emissions from electricity generation

Carbon-dioxide emissions rates from generation have fallen nearly continuously throughout the period 1990 to the present (Figure 10), most notably during the 'dash for gas' and the period of renewable expansion. But it should be remembered that this is not a new phenomenon, and that emissions rates have in fact been falling almost continuously since 1920, with the most dramatic fall (Figure 1) occurring in the period 1920–40, *and due entirely to efficiency improvements*. Indeed, the graph of historic emissions demonstrates that it is possible to cut generation emissions of carbon dioxide through generation-efficiency improvements, better selection of fuel type, and not just through the adoption of intrinsically low-emitting generation technologies such as nuclear, and renewables. Figure 10 shows that the large reduction in emissions seen between 2012 and 2017 has been caused mainly by switching generation from coal stations to CCGTs – and improving system efficiency. Note how Figure 10 captures the shift from coal to gas generation between 2015 and 2017. By implication, renewable generation made only a modest contribution to the recent reductions, and at considerable cost.



(a) Annual emissions

(b) Emissions rates and cost of cuts

Figure 10: Falling emissions of carbon dioxide since 1990.

In 2017 the cost of cutting each ton of carbon dioxide from power station emissions has risen to £350. As fossil-fuel generation efficiency improves and costs and emissions rates fall with the adoption of more gas/CCGT generation, the cost of carbon dioxide emissions cuts from renewable electricity generation will rise, a trend that is exacerbated by the rising costs of renewable generation as the proportion of offshore wind increases.

4.3 Security of supply

The Central Electricity Generating Board (CEGB) carried out regular assessments of security of electricity generation supply as part of their planning process, which covered the grid technology mix, generation location and maintenance planning. The main assessment tool for this work was a series of so-called 'loss of load probability' (LOLP) studies, which determined the risk of electricity generation being insufficient to meet demand.[8–10] The CEGB adopted a target of maintaining this probability at below 4%, corresponding to one failure of supply every 25 years. To our knowledge National Grid has published no LOLP data for the UK generation system since privatisation. The method assumes demand and generation probabilities have normal distributions and calculates the probability that demand will not be matched by generation. An identical method is used here to determine the current security of supply. It is reasonable to ask whether the CEGB standard of supply failure, at 4%, is sufficiently rigorous given the present, and much increased societal reliance on electricity.

Security of supply is at its lowest during periods of maximum demand, usually after dark in December and January. For planning purposes, National Grid predict demand during an 'average cold spell' (ACS) to represent the highest annual demand. In terms of the supply available to meet this demand, solar power plant can make no contribution whatsoever to meeting maximum demand, unless in combination with batteries. Wind generation output has a Weibull distribution[†] such that its generation mode is approximately 8% of generator nameplate capacity and when these generators are mixed with fossil generators the overall generation probability departs from a normal distribution towards one with a much-widened probability tail over low power outputs. In plain English, for the vast majority of the time, wind generators produce only a small fraction of their nameplate capacity, and the fraction decreases as more and more wind is added to the generation mix.

For an ACS demand of 61 GW the analyses here indicate a requirement for approximately 73 GW of dispatchable power connected to the supply grid; the capacity headroom will be reduced by planned and unplanned plant outages and inaccuracy of weather forecasts. The changes in LOLPs for the UK system between 2005 and 2017 are shown in Figure 11.

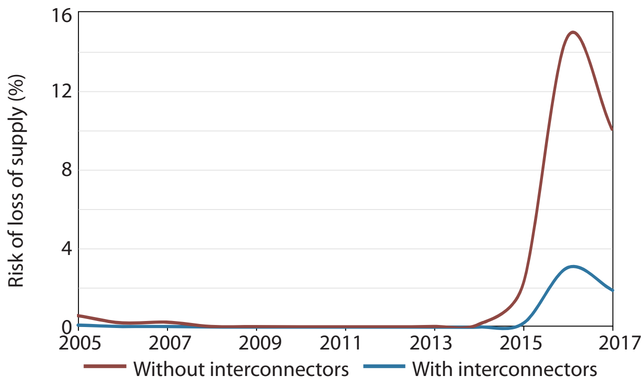


Figure 11: System security for the As-built system.

The blue line shows that the risk has been kept below 4% throughout the study period but the red line reveals that this apparent success has relied on the availability of a supply via interconnectors from continental Europe. Even a partial failure of interconnectors to deliver would significantly increase the risk of loss of supply, and this could be the case either through failure or closure to avoid stress damage of the interconnection equipment or because foreign suppliers either have insufficient surplus or have other more attractive markets.

[†] In a Weibull distribution, most of the output is skewed to low values.

The recent rise in risk is alarming, caused by a fall in the amount of dispatchable plant connected to the grid. In 2016 and 2017 only 68.4 and 69.7 GW of dispatchable plant was available; the reduction of risk shown for 2017 arises from an increase in CCGT capacity reported in DUKES 2017.

It is important to understand just how low the output of renewables plant can fall. Table 1 is drawn from the present author's study, *Solar power in Britain* (2017),[8] which analysed wind and solar generation production across the whole of northern Europe, including Ireland and the UK; the modelling was based on wind speed reports taken (with regulation anemometers sited 10 metres above ground level) from 46 airfields reporting synchronously every half hour over a period of ten years.

Table 1: Intermittent generation performance of European renewable fleets.

Percentage of nameplate capacity	5%	10%	15%	20%
Annual number of events	104	189	237	268
Duration range of incidents (hours)	6–19	6–43	6–69	6–159

Source: Aris.[8]

Figure 12 shows the predicted power duration curve for north European renewables. Weather patterns such as high-pressure regions (with low wind velocities) can prevail over the whole area so it is unsurprising that the renewable fleet output can drop below 10% of nameplate capacity every other day, and for periods lasting between 6 hours to nearly two days.

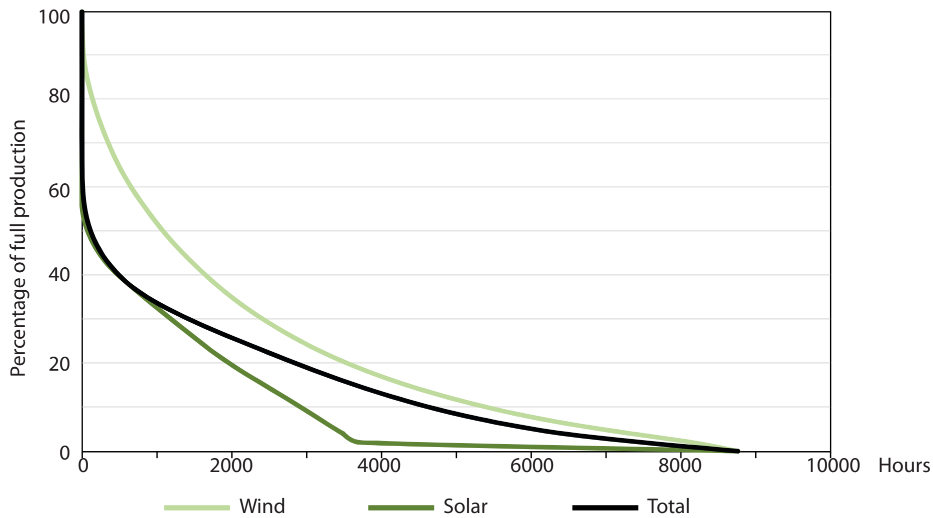


Figure 12: Annual production durations of north European renewable fleets.

5 Comparing alternative generation scenarios: 1990–2017

Rather than carrying out a detailed assessment of the performance of the existing system's costs, carbon dioxide emissions cuts and security of supply, two counterfactual scenarios have been created as performance comparisons:

- the Gas scenario
- the Coal scenario

They are designed to meet, year by year, the same maximum demand, production and ACS as the actual system. For both counterfactual scenarios, the capacity and production profiles were developed from the profiles of the actual 1990–2017 system using these first steps:

1. All renewable capacity and production values are set to zero.
2. Interconnector supply is ramped down to zero from 2002.
3. Nuclear capacity expands from 2012 onwards. Two nuclear stations totalling 3.6 GW are added between 2012 and 2017.[‡] (In variants of the gas scenario, the impacts of removing all nuclear expansion, as well as adding three or four stations of the same size from 2010, are also explored).

Then, for the Gas system:

4. Coal production is ramped down, starting in 2003, to 20 TWh by 2017.
5. The model now has a production deficit, which is cancelled by adding production to the CCGT fleet.
6. CCGT capacity is adjusted so that the load factor never exceeds 60%, considered to be a plausible average for a fleet sometimes operating as baseload, and at other times with two-shift operation.
7. The CCGT and open cycle gas turbine (OCGT) fleet capacities are then increased where required so that the security of supply is maintained; the OCGT fleet is given 25% of this duty.

Since this scenario entails commissioning new CCGT plant, it is assumed these will be of the latest high-efficiency type (60%), and so the CCGT fleet efficiency is increased from 46% in 2003 to 55% by 2017. This implies that the carbon dioxide emissions rate for this type of plant must fall accordingly.

The equivalent steps for the Coal system are:

4. From 1998 CCGT production is ramped down, dropping to 20 TWh by 2017.
5. The model now has a production deficit, which is cancelled by adding production to the coal fleet.
6. Coal capacity is adjusted so that the load factor never exceeds 60%, considered to be a plausible average for a fleet sometimes operating as baseload, and at other times with two-shift operation.
7. The coal and OCGT fleet capacities are then increased where required so that the security of supply is maintained; the OCGT fleet is given 25% of this duty.
8. Since this scenario entails commissioning new coal plant, it is assumed these will be of the latest ultra-super-critical) USC type (with a 45% thermal efficiency), and so the coal fleet efficiency is increased from 35% in 2003 to 45% by 2017. This implies that the carbon dioxide emissions rate for this type of plant must fall accordingly.

‡ Start dates are staggered by two years. Each reactor consists of three 600-MW reactors, commissioned over three years.

5.1 The performance of the Gas scenario

The capacity and production profiles for the Gas scenario, with two new nuclear power stations built between 2012 and 2017, are shown together in Figure 13.

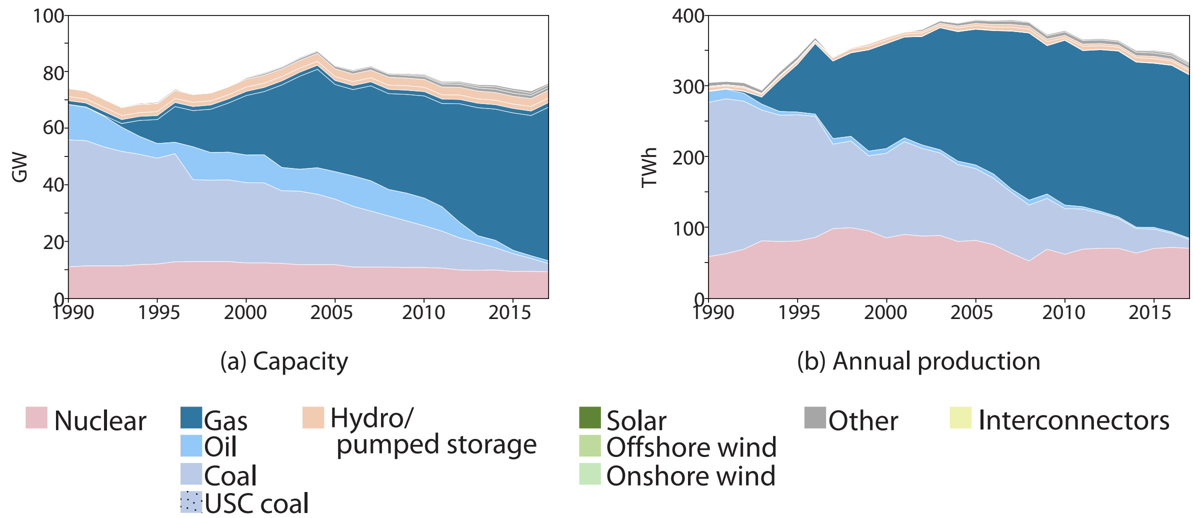


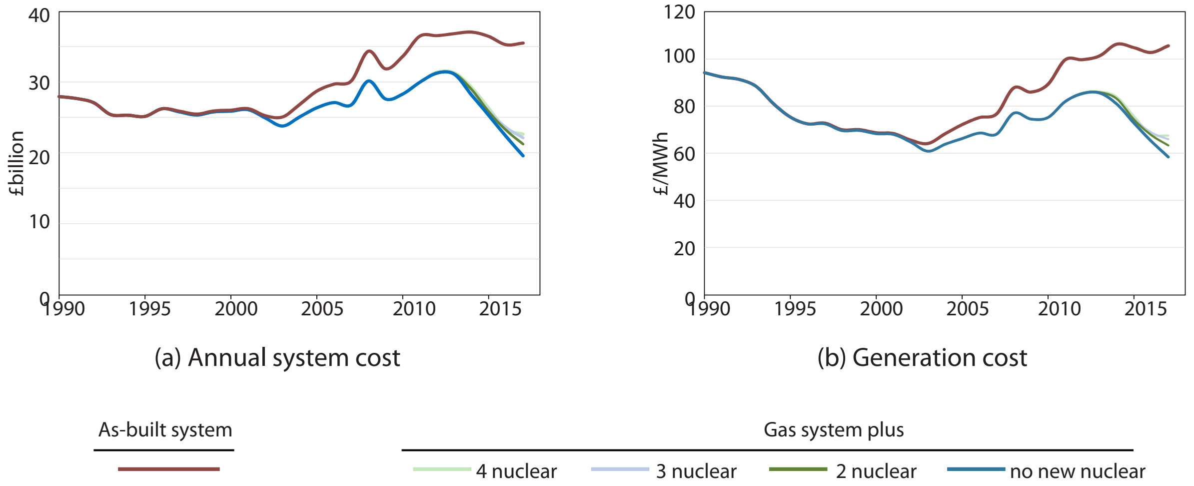
Figure 13: Capacity and production data for the Gas scenario.
With no renewables, and with two new nuclear power stations built from 2012 onwards.

Figures 14 and 15 show the cost and emissions performance of the Gas scenario (with the addition of between two and four new nuclear plants each of 1.8 GW capacity built between 2010 and 2017) compared to the As-built system. The Gas scenario is much cheaper than the As-built system (see Figure 14), and all variants of the gas scenario system deliver carbon dioxide emissions reductions that exceed those of the As-built system during most of the study period (see Figure 15). These improvements in cost and emissions reductions are partly driven by the improvement in plant efficiency of the fossil-fuelled generation fleet (see Figure 16).

The Gas scenario also delivers improved security of supply over the As-built system. This scenario tapers electricity imports to zero by 2017, but it is assumed that the interconnectors are still available for export of generation surpluses and to deliver system stabilisation if required. Including these interconnectors in the calculation of security of supply reveals very low values, generally below 0.1%. However, without these interconnectors, the LOLP still never rises above 0.6%, so they are no longer critical to the UK generation system.

The cumulative savings in cost and carbon dioxide emissions are remarkable, as shown in Figure 17. The Gas scenario out-performs the As-built system in every aspect that has been tested: costs, carbon dioxide emissions reductions and security of supply.

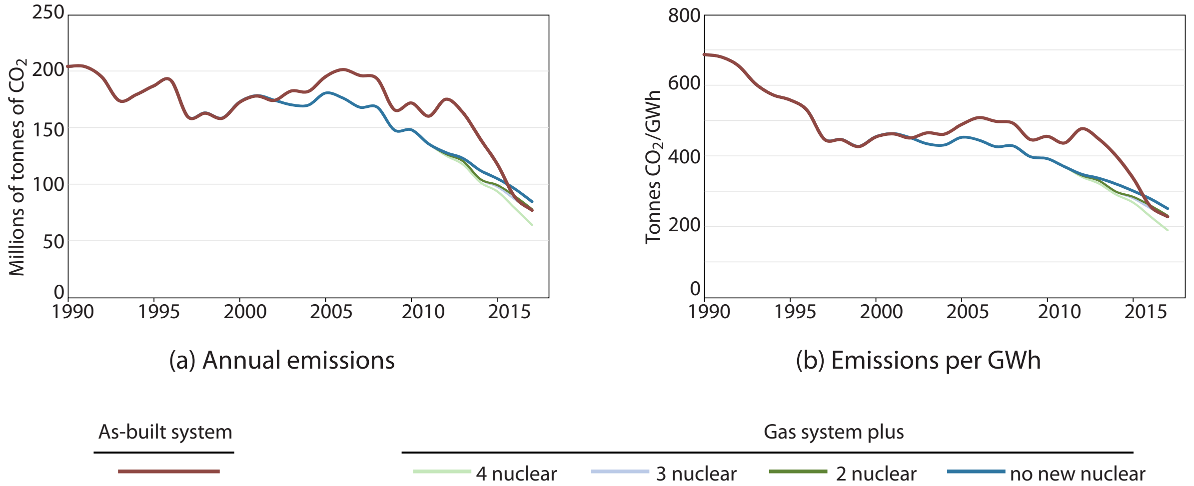
Costs per MWh are nearly 30% less, and even with an increasing nuclear component will remain below the cost of the system with renewables. This modelled fall in costs in the Gas scenario occurs during a period when fuel prices actually increased, demonstrating the fact that the main driver for recent electricity price rises is expansion of renewable generation. Historic generation data indicate that cost and emissions savings can be achieved by improving efficiency and fuel selection. There should be little surprise at this fall in costs: the Gas scenario requires 20 GW less installed capacity than the As-built system, and the plant



(a) Annual system cost

(b) Generation cost

Figure 14: Cost comparison of the variants of the Gas system against the As-built system.



(a) Annual emissions

(b) Emissions per GWh

Figure 15: Carbon dioxide emissions of the variants of the Gas system, compared to the As-built system.

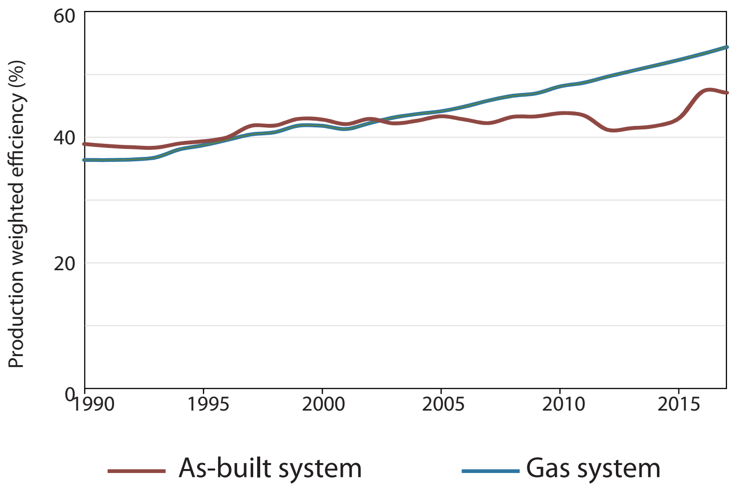
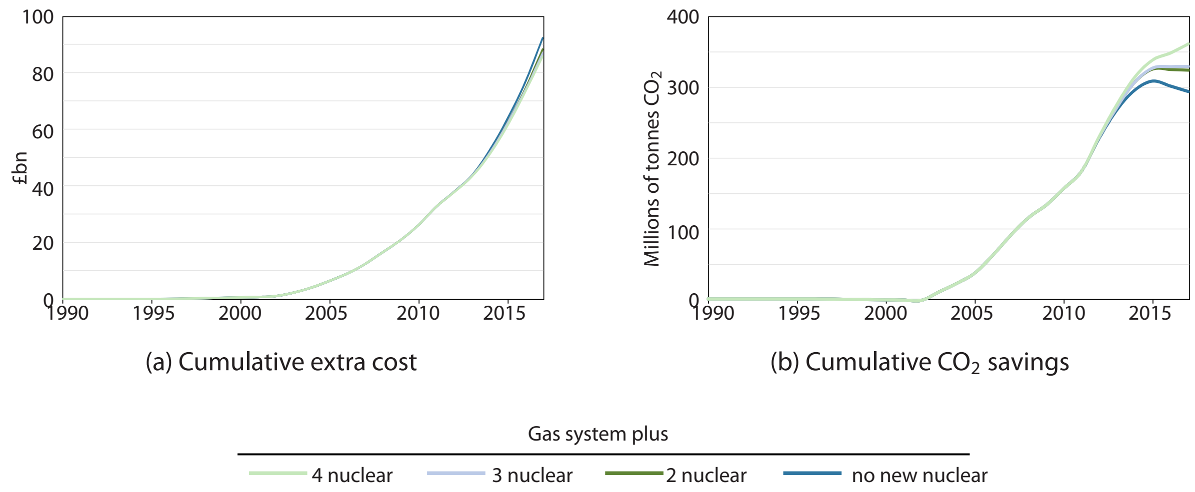


Figure 16: Improvement of fossil-fuel plant efficiency in the Gas scenario plant mix.



(a) Cumulative extra cost

(b) Cumulative CO_2 savings

Figure 17: Gas system: cost and emissions savings over As-built system.

involved runs at comparatively high load factors. All the system integration costs of a renewable system are avoided: there is no intermittency problem, the system can deliver all auxiliary grid services such as response and reserve in parallel with its normal generation remit, and little change will be required to the transmission and distribution system. The illogicality of constraint payments, by which wind farm operators are paid not to generate, is avoided.

Carbon dioxide emissions reductions would outpace the As-built system throughout this continued 'dash for gas', which is no surprise given the record of gas performance during the 1990s. The asynchronous wind turbines and solar installations of the As-built system contribute little to the grid inertia or stiffness and make no contribution to grid frequency control for this island grid; these concerns are avoided with the gas scenarios. Even with the low costs of the Gas scenario, the modelled system delivers a very secure system, fit for the 21st century.

None of these observations is revelatory: all of these features of a gas-fired system were experienced and appreciated during the 'dash for gas' of the nineties.

5.2 The performance of the Coal scenario

The Coal scenario does not perform as well as the Gas scenario and only an overview is given here. Capacity and production profiles appear in Figure 18. Unsurprisingly, the Coal scenario has increased emissions compared to the As-built system, as can be seen in Figure 19.

The Coal scenario produces mixed results compared to the As-built system. Costs are lower (though not as low as the Gas scenario), but emissions are far worse than both the Gas scenario and the As-built system. The cumulative cost savings for the Coal scenario compared to the As-built system reach £40 billion by 2017, but at the expense of an additional 450 million tonnes of carbon dioxide.

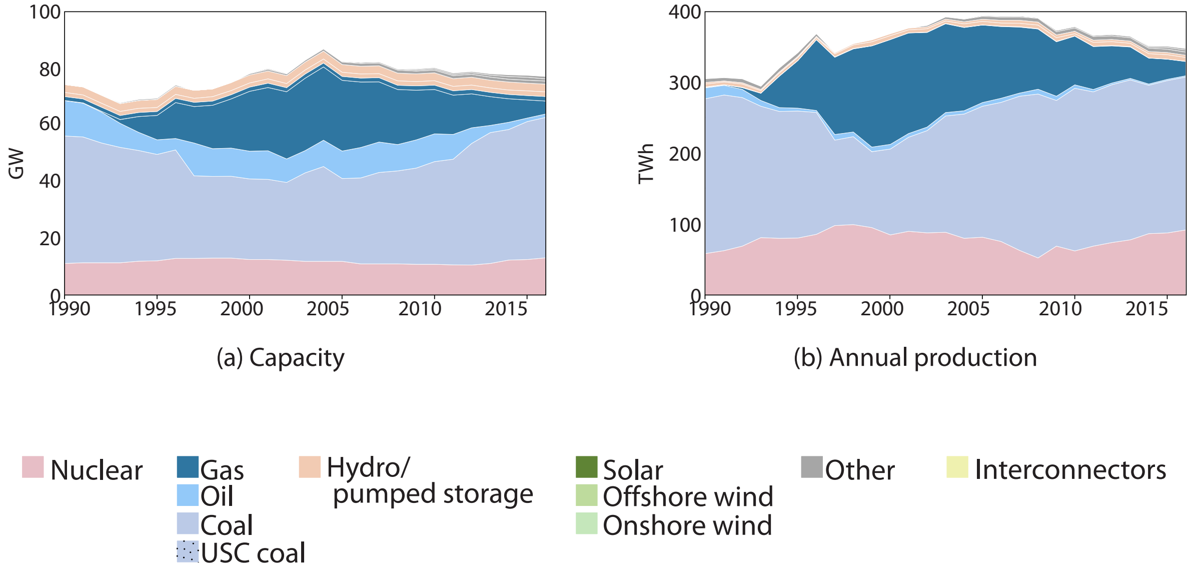


Figure 18: Capacity and production profiles for the Coal scenario.

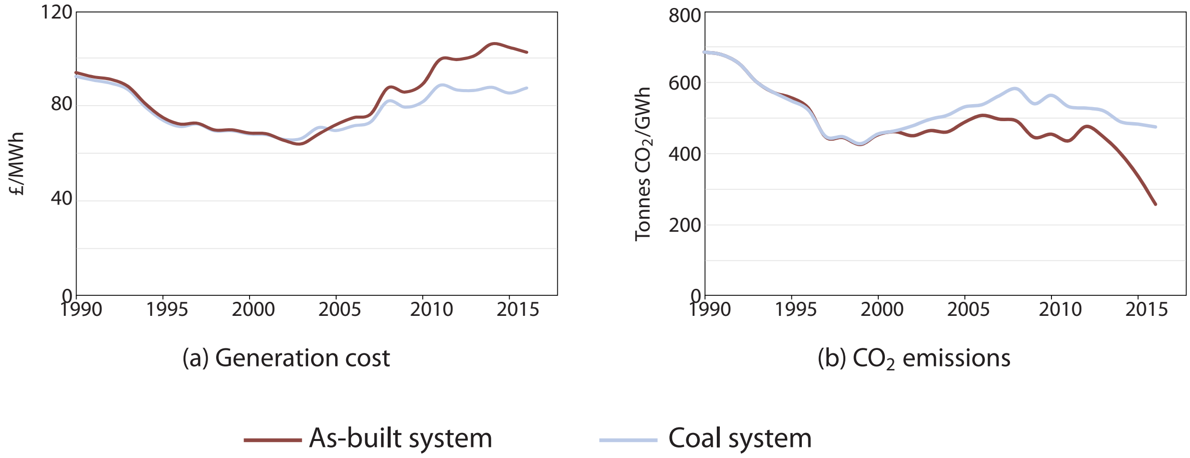


Figure 19: Cost and carbon dioxide emissions profiles for the Coal scenario.

6 Extending the generation scenarios to 2030

By 2017 the system in the Gas scenario and the As-built system are generating with the same rate of carbon dioxide emissions: 255 tonnes per GWh. If further development of renewables occurs, then emissions will clearly fall further, but given the extra cost that renewable generation entails, can further increases in electricity prices be tolerated? The rising cost of abating each ton of carbon dioxide will steepen as renewables form a greater proportion of the generation fleet, and even at current levels the abatement costs are well in excess of even higher estimates of social cost of carbon. Climate policies, such as the use of renewables to reduce emissions, that are already apparently more harmful to human welfare than the threat of climate change itself are likely to become still more harmful, raising a question over their political sustainability.

In this context it is worth asking whether the Gas scenario can deliver further emissions cuts. Its future performance can be investigated by extending the model out to 2030, much as it is done by National Grid in its FES studies.[16]

A weakness of the Gas scenario is that it depends on two generation types when greater strategic security would be achieved if another fuel route and technology was added to the generation mix. For this reason, the desirability of retaining some coal generation is also explored out to 2030 by investigating what impact USC coal generation plant could have on emissions and cost cuts.

As seen in the previous sections, the inclusion of as much as 7.2 GW additional nuclear generator capacity (with LCOE parameters reflecting present day nuclear costs) in the Gas scenario appears to increase generation costs by a tolerable amount, but with the benefit of continued strong carbon dioxide emissions reductions. For this reason, in both of the extended scenarios, a further nuclear expansion is included, sufficient to counter the loss of production from the entire advanced gas-cooled reactor (AGR) fleet; this expansion starts in 2010 and continues out to 2030. For this reason, the two extended scenarios will be referred to as the Gas/Nuclear and Coal/Nuclear scenarios.

6.1 Development of the extended scenarios

The Gas/Nuclear scenario is developed from the As-built system as follows. Capacity, production, maximum demand, ACS, fuel prices, efficiencies, and emissions rates are held at 2016 levels, except as detailed below.

1. All renewable capacity and production values are set to zero, with the exception of biomass capacity and production which are retained.
2. Interconnector supply is ramped down to zero from 2002.
3. The reduction in coal production to 20 TWh in 2017 continues to zero by 2022.
4. The increase in nuclear capacity from 2010 is as shown in Figure 20.
5. The model now has a production deficit, which is cancelled by adding production to the CCGT fleet.
6. CCGT capacity is adjusted so that the load factor never exceeds 60%, considered to be a plausible average for a fleet sometimes operating as baseload, and at other times with two-shift operation.
7. The CCGT and OCGT fleet capacities are then increased where required so that the security of supply is maintained; the OCGT fleet is given 25% of this duty.
8. Since this scenario entails commissioning new CCGT plant, it is assumed these will be of the latest high efficiency type (60%), and so the CCGT fleet efficiency is increased from 46% in 2003 to 59% by 2024. This implies that the carbon-dioxide emissions rate for this type of plant must fall accordingly.

The capacity and production profiles for this scenario are shown in Figure 21.

For the Coal/Nuclear scenario, changes can be made to the sequence of modifications above. In step (3), coal is not ramped down to zero by 2022, but to 15% of total production in 2012 (i.e. 52 TWh), and is held at that level to 2030. From 2022 to 2030 the whole remaining coal fleet is converted to USC coal, with increased efficiency and reduced carbon dioxide emissions. It is assumed the CCGT fleet improves in thermal efficiency and carbon dioxide

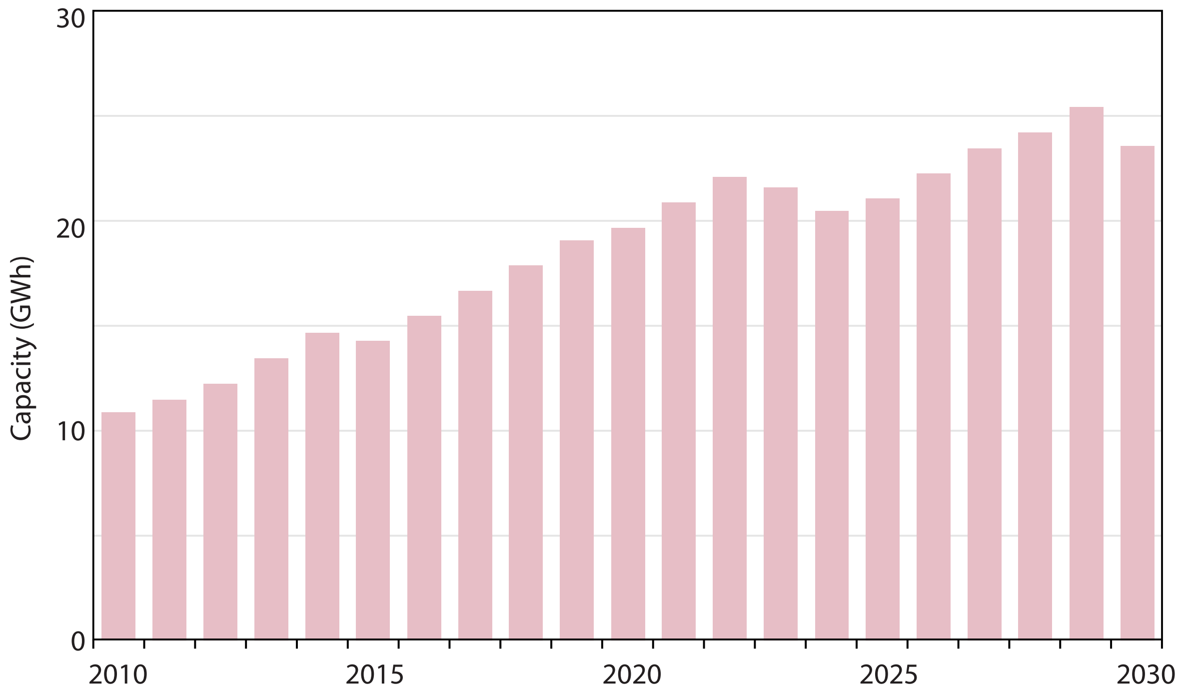


Figure 20: Modelled expansion of nuclear capacity to 2030.
New build less AGR closures.

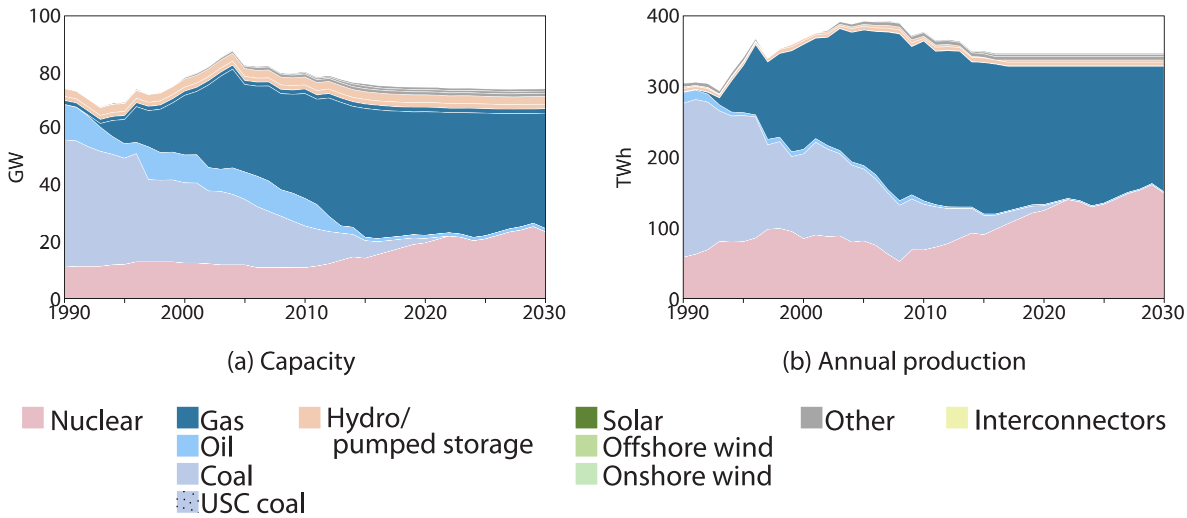


Figure 21: Capacity and production profiles for the Gas/Nuclear scenario.

emissions rate, as in the Gas/Nuclear scenario. The capacity and production profiles for this scenario are shown in Figure 22.

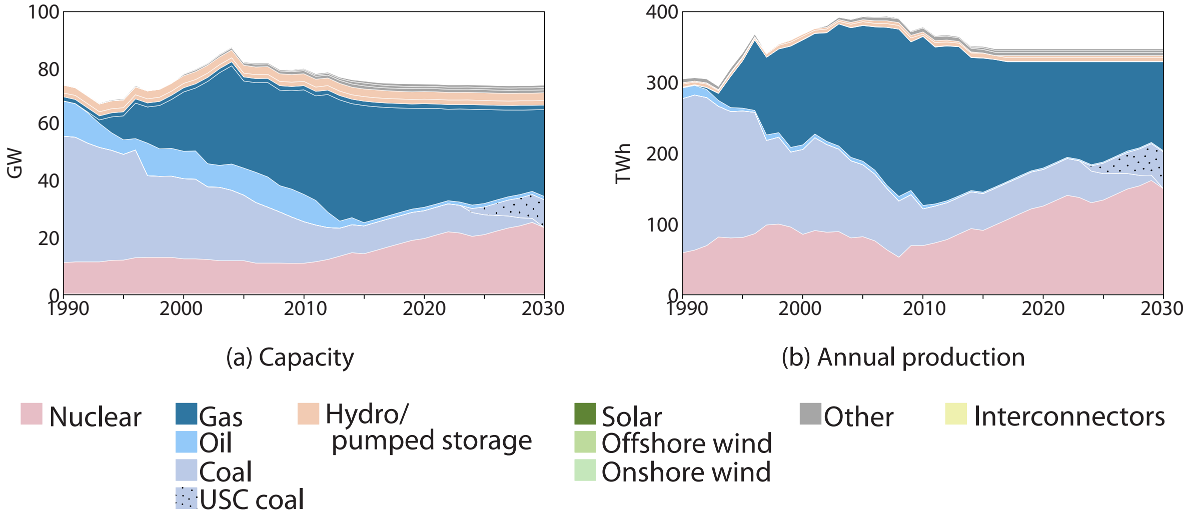


Figure 22: Capacity and production profiles for Coal/Nuclear scenario.

6.2 The performance of the extended scenarios

The cost performance and carbon dioxide emissions reductions for these two future projections are shown in Figures 23 and 24.

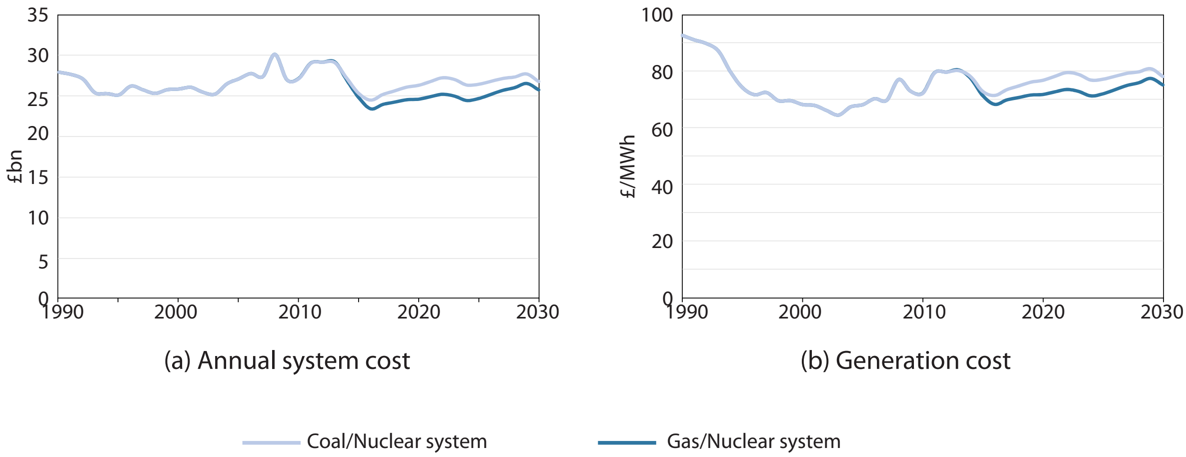


Figure 23: Cost performance to 2030 of the two scenarios.

The system in the Gas/Nuclear scenario maintains costs below 80% of those of the As-built system, and continues to cut emissions; by 2030 emissions have fallen to 25% of 1990 levels. The inclusion of coal (even if of USC type, with increased efficiency, reduced emissions, and reduced capital cost compared to coal) raises costs and diminishes the carbon dioxide emissions cuts compared to the Gas/Nuclear system. It may be that the degradation in performance through adding this coal generation can be tolerated for the benefit it delivers in terms of fuel-route security. Serious consideration should be given to the possibility that the security of a third fuel route could be delivered through the gasification of coal,[25] which would avoid the associated emissions.

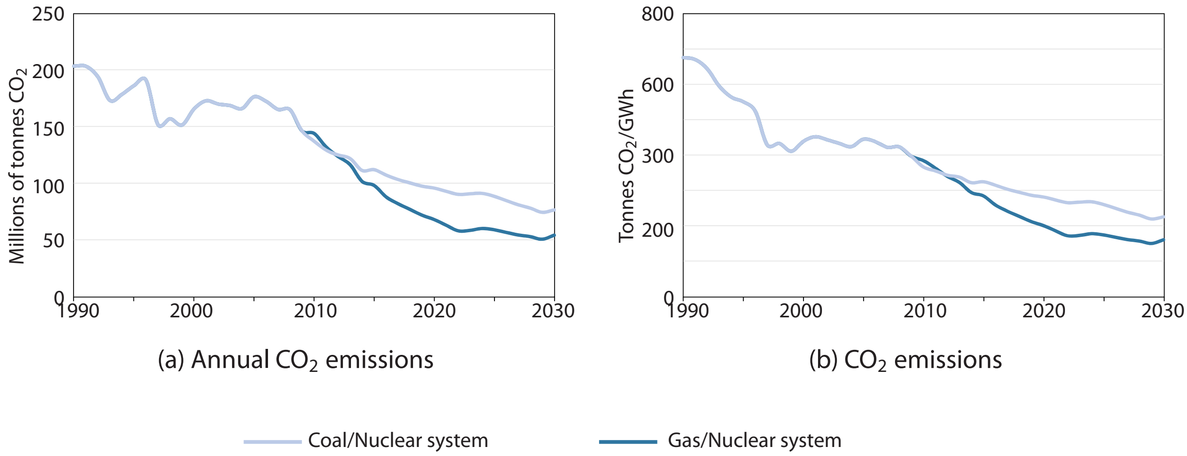


Figure 24: Carbon dioxide emissions cuts of the two scenarios to 2030.

7 Modelling of future generation scenarios by National Grid

Each year National Grid publishes its *Future Energy Scenarios* (FES), as a way of exploring the possibilities for future energy generation. However, the scenarios do not deal with costs or with security of supply. Therefore, in this section, the scenarios are compared using the tools described above.

The National Grid scenarios are:

- 'Gone Green or Two Degrees'
- 'Consumer Power'
- 'Slow Progress'
- 'No Progress'.

The first two involve large expansions of renewable capacity. For reasons of brevity the capacity and production profiles for only the Two Degrees scenario are shown (Figure 25). The FES reports show all four profiles.[16,26,27] The costings and emissions results for all of the scenarios are shown in Figure 26.

Three of National Grid's scenarios raise consumer costs by 75% and one by 30% compared to the Gas/Nuclear scenario proposed above. Only two of the National Grid scenarios reduce carbon dioxide emissions more than the Gas/Nuclear scenario. All four National Grid scenarios seem to have neglected any consideration of security of supply.[27]

8 Conclusions

The counterfactual generation system based on the expansion of gas generation – the Gas scenario – has demonstrated that large reductions in both cost and carbon dioxide emissions are possible compared to the current system. These reductions are nationally significant: they indicate cumulative cost reductions of £80–90 billion by 2017, and carbon dioxide emissions cuts of 300–370 million tonnes over a period of only fifteen years. It should be noted that this comparison is made against the As-built system which, in 2017, included 33 GW of new renewable capacity.

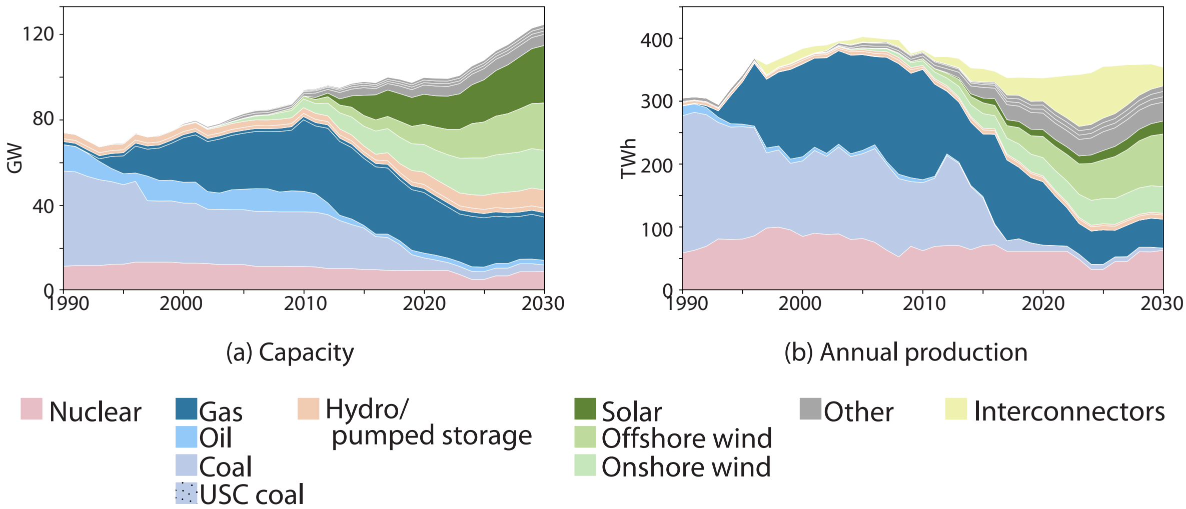


Figure 25: Capacity and production data for the 'Two Degrees' scenario.
This scenario has a high proportion of renewable energy.

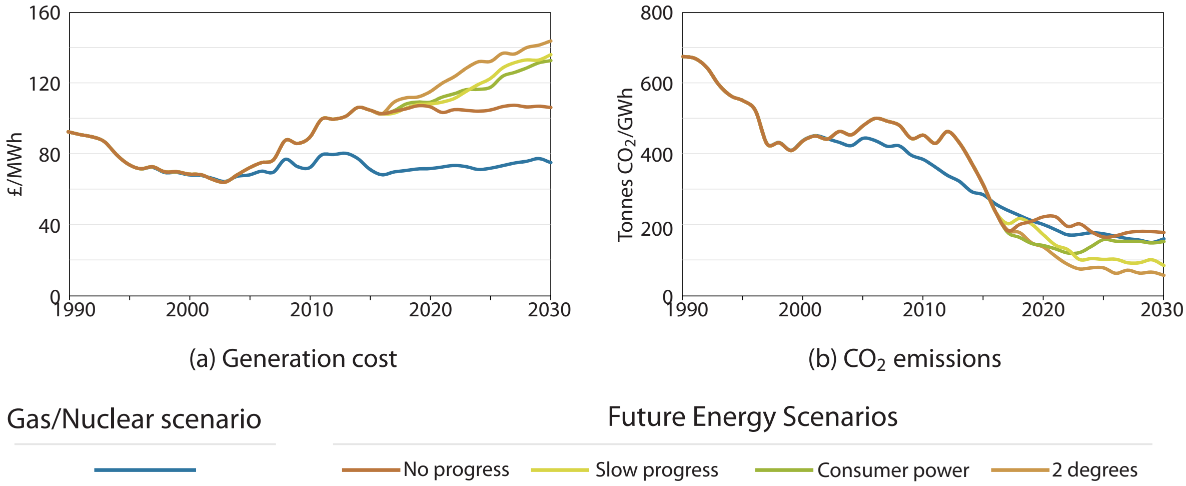


Figure 26: Comparison of Future Energy Scenarios and Gas/Nuclear scenario.

The design of this counterfactual system is not complex; it simply continues the success of the 'dash for gas' of the 1990s, which in turn was founded on the experience gained from half a century of generation efficiency improvements. Nor would the counterfactual system have been difficult or expensive to build. It requires simply a planned closure of coal-fired stations, the majority over forty years old, and replacement with modern CCGT plant with higher efficiency than the older CCGTs. In the majority of cases, this replacement could have been accomplished with no requirement for new power station sites and much of the generation infrastructure (especially the grid connections) could have been retained. In some cases, the expenditure incurred in fitting flue gas desulphurisation equipment to old coal generation plant, in order to comply with the European Union's Large Combustion Plant Directive, could have been better placed in CCGT procurement. It is to be suspected that this is not the only instance where the opportunity cost of one environmental policy is the successful delivery of another environmental policy.

The gas system could have been delivered with none of the concerns that burden our present system and its 33 GW of renewables. There would be no problems associated with the variability and intermittency of wind and solar generation, no additional system costs, no subsidies, and no capacity mechanism, since there would be no market distortions destroying price signals and rendering uneconomic otherwise viable projects. All the ancillary service requirements could be served by the operation of the Dinorwig, Ffestiniog, Cruachan and Foyers pumped-storage stations at very low cost, and with no further impact upon the environment. Expensive 'smart' metering (now approaching an installation cost of £15 billion for 27 million households) configured to reduce demand during periods of low renewable generation would be superfluous. There would be no need to pay for industrial production to deliver expensive demand reductions during lulls in renewable production. In brief, there would be much less capital equipment and complex ancillary activity in the Gas scenario, thus preserving and even increasing its productivity, an obviously desirable outcome from both economic and environmental perspectives.

The As-built system has reached a position in which the problem associated with renewable generation can no longer be overlooked. The cost of generating electricity has nearly doubled as a result of adding renewable generation to the grid. The gradual shift of fossil-fuelled generation from coal towards CCGTs improves fossil efficiency, and reduces costs and carbon dioxide emissions; consequently, the rate at which renewable generation can cut emissions for each new megawatt of capacity is decreasing, and the cost of cutting emissions will rise – see Figure 10. In 2017 the cost of cutting each ton of carbon dioxide has reached £350, well in excess of most estimates of the social cost of carbon.

There is now an increasing risk of loss-of-load caused by intermittent renewable generation across the whole of northern Europe [8,9] (see Figure 11 and Table 1). Interconnection of electricity grids across Europe will partially solve this problem, at a cost, but even so there remains a significant probability of loss of renewable supply over this whole area. The renewable grid now needs to deploy energy storage to combat the problem of intermittency, and this will raise costs still further. By comparison, the modelled Gas system would of course have had no requirement for any mitigation of intermittency and would have delivered similar carbon dioxide cuts as the system we have built.

It has been shown that the Gas scenario can continue to deliver cost and emissions cuts towards 2030. This system requires replacement of old CCGT plant (at planned generation life) with higher efficiency CCGTs, replacement of the AGR nuclear fleet, and modest expansion of the nuclear fleet. The Gas/Nuclear scenario also outperforms all of the National Grid's Future Energy Scenarios (using the same costing method throughout) and produces comparable emissions cuts while ensuring that the risk of loss of supply is maintained at the levels of safety that applied before privatisation. (Some of National Grid's scenarios postulate generation fleets of great size: the 'Gone Green' scenario envisages a grid of 168 GW capacity, with 29 GW of offshore wind, 18 GW onshore wind, 31 GW solar, and 8 GW of storage. Interestingly, National Grid provides no costing of this scenario.)

Increasing coal-fired generation, and the future introduction of advanced USC coal generators have also been examined. These scenarios demonstrated cost reductions, secure supply status, but poor carbon dioxide emissions performance. However, the use of coal should not be dismissed too quickly. Gasification of coal to produce syngas is not a new technology, and is undergoing development at several sites in the United States. [25] General

Electric has produced CCGTs capable of burning syngas at high efficiency.[28] Burning syngas for generation lends itself to a much simpler process of carbon capture since it avoids the dilution of the flue gas with nitrogen involved in conventional coal combustion. The introduction of coal burning in this manner, using within-territory reserves of coal, would provide a valuable third fuel route to national security of electricity generation.

In summary, practically every alternative scenario considered is superior to the current situation, the As-built reality, in at least one respect, and the Gas scenarios are overwhelmingly superior on every measure, including the reduction of emissions in the longer term.

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Our main focus is to analyse global warming policies and their economic and other implications. Our aim is to provide the most robust and reliable economic analysis and advice. Above all we seek to inform the media, politicians and the public, in a newsworthy way, on the subject in general and on the misinformation to which they are all too frequently being subjected at the present time.

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