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Decarbonising electricity supply: Is climate change mitigation going to be carried out at the expense of other environmental impacts?

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ABSTRACT

As nations face the need to decarbonise their energy supply, there is a risk that attention will be focused solely on carbon and climate change, potentially at the expense of other environmental impacts. To explore the trade-offs between climate change mitigation and other environmental impacts, this work focuses on electricity and considers a number of scenarios up to 2070 in a UK context with different carbon reduction targets and electricity demand to estimate the related life cycle environmental impacts. In total, 16 scenarios are discussed, incorporating fossil-fuel technologies with and without carbon capture and storage, nuclear power and a range of renewable options. A freely available model – Electricity Technologies Life Cycle Assessment (ETLCA) – developed by the authors has been used for these purposes. The results suggest that decarbonisation of electricity supply to meet carbon targets would lead to a reduction in the majority of the life cycle impacts by 2070. The exceptions to this are depletion of elements which would increase by 4–145 times and health impacts from radiation which would increase two- to four-fold if nuclear power were used. Ozone layer depletion would also go up in the short-term by between 2.5–3.7 times. If energy demand continued to grow, three other impacts would also increase while trying to meet the carbon targets: human toxicity (two times), photochemical smog (12%) and terrestrial eco-toxicity (2.3 times). These findings demonstrate the importance of considering a broader range of environmental impacts alongside climate change to avoid decarbonising the economy at the expense of other environmental impacts.

Keywords: Climate change; Decarbonisation; Electricity; Environmental impacts; Life cycle assessment; Scenario analysis

1. Introduction

Carbon reduction targets have become a common element of national policy around the globe. Currently they are disparate in ambition, ranging from The Maldives' target for carbon neutrality by 2020 to China's aim of reducing carbon intensity (per unit GDP) rather than absolute emissions (Ecofys and Climate Analytics, 2014). However, decarbonisation has become a well-established goal and the energy sector has been a popular focus owing to its contribution to greenhouse gas (GHG) emissions: in 2010, electricity and heat together constituted the largest source of CO_2 emissions globally at 41% of the total (IEA, 2012). Consequently, much debate and scenario analysis has been devoted to ways in which energy sector emissions might be reduced (see for, example, IEA (2013b) and Pehnt (2006)).

The UK provides a good example of a nation with ambitious carbon targets in need of an energy sector transforma-

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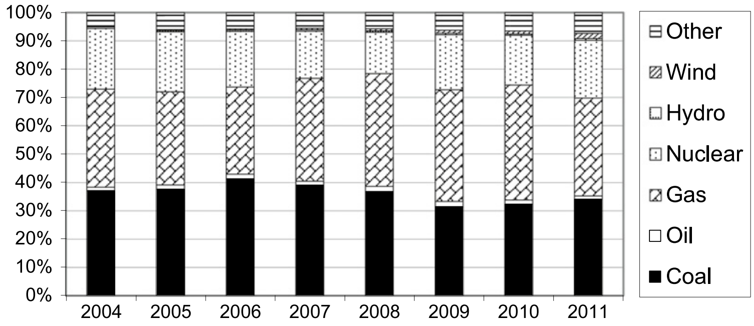

Fig. 1 – Fuel mix for UK electricity generation from 2004–2011 (based on data from DECC (2013b)).

tion. A 2050 carbon target has been set in law in the Climate Change Act (2008) requiring the nation as a whole to reduce GHG emissions by 80% relative to 1990. To meet this target, all sectors will have to increase substantially their use of low-carbon technologies. A number of studies have considered how this could potentially be achieved through scenario analysis, particularly addressing electricity supply (Tyndall Centre, 2005; DECC, 2011a; Ekins et al., 2013): the electricity sector is thought to have the greatest potential to reduce emissions and to bear reductions that would otherwise be required of sectors in which fossil fuels are harder to substitute (for example, transport and heat). As shown in Fig. 1, 65%–85% of electricity in the UK has been provided by fossil fuels in recent years (DECC, 2013b), with nuclear providing 15%–20% and renewables 5%–10%; the balance (typically 1%–3%) is imported, largely from France (DECC, 2013a).

However, while the focus remains on reducing GHG emissions, there is a risk that climate change mitigation may be carried out at the expense of other environmental impacts, such as acidification, eutrophication, ozone layer depletion and toxicity. It is therefore important that any such trade-offs be identified early on, before irreversible decisions are made. It is also essential that the impacts be considered on a life cycle basis to avoid 'leakage' from one life cycle stage – or a region – to another. Currently, global and national policies related to climate change and energy focus solely on direct carbon emissions, i.e. emissions at the point of energy generation. This omission of life cycle thinking in environmental policy has been acknowledged by several authors in the debate over consumer-oriented versus producer-oriented emissions accounting (Peters and Hertwich, 2008a,b; Hertwich and Peters, 2009; Davis and Caldeira, 2010; Davis et al., 2011; Skelton et al., 2011). In short, while policy approaches such as the Kyoto Protocol and its successors attempt to limit emissions within geographical boundaries, a globalised market compels us to consider imports and exports as well: with a producer-oriented approach, a country can decrease its national emissions by curtailing domestic industry and importing more goods from abroad, in turn stimulating foreign industrial emissions and resulting in a net zero global decrease. In many such cases, the reality is a net increase in emissions because the exporting country has a more environmentally-harmful energy system; this has been the case for many developed countries, including the UK, which have effectively exported emissions to China and other emerging markets (Davis and Caldeira, 2010). The same has been demonstrated for water consumption (Steen-Olsen et al., 2012). Life cycle assessment-based approaches avoid this problem by considering whole supply chains and accounting for impacts at both the producer and consumer sides.

In light of the above, this work sets out to explore the life cycle environmental implications of decarbonising electricity supply using scenario analysis and considering the time horizon up to 2070. In total, 16 scenarios are considered, comprising 49 technology options, from fossil-fuel with and without carbon capture and storage (CCS), to nuclear to renewables. A freely available model – Electricity Technologies Life Cycle Assessment (ETLCA) – developed by the authors has been used for these purposes (Kouloumpis et al., 2012). As an illustration of possible consequences for other environmental impacts of electricity decarbonisation, the analysis is carried out in the UK context but similar findings would hold elsewhere. A life cycle approach is applied throughout, using life cycle assessment (LCA) to estimate the environmental impacts. As far as the authors are aware, this is the first study of its kind for the UK electricity sector combining a life cycle approach and scenario analysis. Elsewhere, there have been a few such studies in the electricity sector, notably for Germany (Pehnt, 2006), South Africa (Heinrich et al., 2007) as well as Europe and Africa (Viebahn et al., 2011).

The following section details the methodology developed and applied in this work, including the description of electricity technologies and scenarios. The results are presented and discussed in Section 3 and conclusions are drawn in Section 4, together with recommendations for future work.

2. Methodology

As illustrated in Fig. 2, the methodology integral to the ETLCA model involves the following steps:

1. choice and specification of electricity technologies, both those used currently and those expected to be used in the future;
2. definition of scenarios based on different carbon targets and possible future electricity mixes;
3. estimation of direct carbon emissions for each scenario and electricity mix to ensure that the defined carbon targets are met;
4. estimation of life cycle environmental impacts for each scenario based on the chosen electricity mixes;
5. comparison of scenarios in terms of environmental impacts; and
6. identification of the trade-offs between carbon reductions and other environmental impacts.

The process begins with the selection and characterisation of technologies that are appropriate for a particular country or region. The ETLCA model comprises 12 main technology types, spanning fossil, nuclear and renewable options; each type is split further into different size, capacity, design,

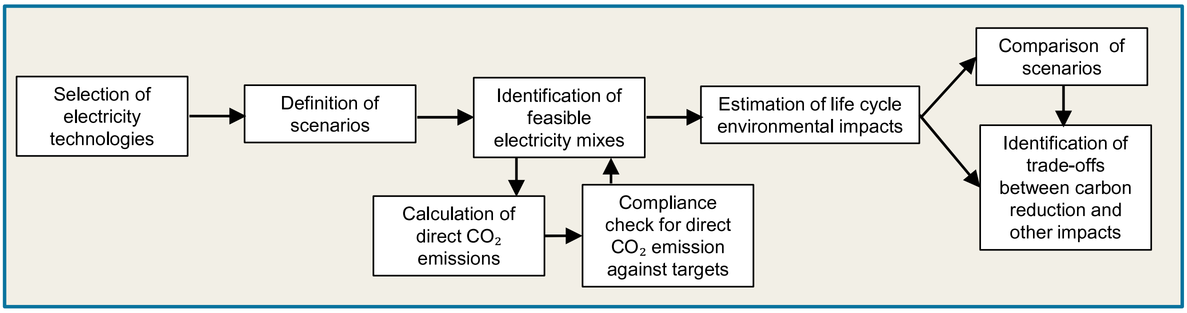

Fig. 2 – Schematic representation of the ETLCA methodology.

technology mix, etc. As mentioned earlier, there are 49 technology options to choose from, plus an electricity mix for imports. This is followed by the definition of scenarios, including the time horizon and reference years within that period, electricity demand and carbon targets. Sub-scenarios are then defined in detail by configuring the electricity mix for the reference years for which the carbon targets are specified, in this case 2020, 2035, 2050, and 2070; the related electricity generation by each technology is calculated automatically within the ETLCA model. The electricity output is then used to calculate the direct annual carbon emissions for each technology for each reference year, which are checked against the carbon targets for these years. Sub-scenario configuration is then repeated iteratively until the direct emission compliance check is passed.

Thus, in terms of user input, ETLCA requires the user to define scenarios (electricity consumption and direct carbon emissions in each reference year) and to specify a technology mix in each reference year for each sub-scenario. The technology mix may then need to be amended until the calculated carbon emissions comply with the target for that year.

Following these steps, the environmental impacts are calculated automatically for each scenario using the ETLCA database. This contains LCA data for the following 12 environmental impacts, estimated following the CML 2001 methodology (Guinée et al., 2002): global warming potential, depletion of elements and fossil fuels, acidification, eutrophication, freshwater, marine and terrestrial ecotoxicity, human toxicity, ozone layer depletion, photochemical smog and health impacts from radiation. The impacts are calculated on both an annual and per-kilowatt-hour basis for each reference year. The sub-scenarios can then be compared for the environmental impacts over time using tables and graphs which are automatically populated as the analysis progresses. The model is dynamic as it allows the user to make changes to the choice of technologies, scenario definitions and electricity mixes at any point during the analysis, with all the changes being reflected directly in the tables and the graphs. In this way, it is possible to explore in a systematic way a large number of possibilities for future electricity pathways and identify any trade-offs between mitigation of climate change and other environmental impacts. Therefore, the ETLCA model aids effective decision making by indicating how policy should be tailored to minimise environmental impacts along supply chains while attempting to meet carbon targets.

It should be noted that the ETLCA provides LCA data for technologies in a generic European context rather than a site-specific one to enable its application in different regions and countries. Site-specific considerations can be taken into account by changing parameters such as electricity demand profiles, technology mix as well as carbon constraints, all of which are fully user-controllable.

The next section describes each step in more detail using the UK as an illustrative example, starting with the description of electricity technologies and followed by the definition of scenarios and their respective carbon targets and electricity mixes. The results of the estimation of environmental impacts, including the comparison of scenarios and the trade-offs between the impacts, are discussed subsequently in Section 3.

2.1. *Electricity technologies*

A summary of the current UK generating fleet is given in Table 1, with the specific technologies detailed in Table 2, together with their contribution to the electricity mix from present to 2070. As shown in Fig. 3, the whole life cycle of technologies is considered, from extraction and processing of fuels and raw materials, to construction and operation of plants to generate electricity to their eventual decommissioning. For most technologies, future developments and improvements have been taken into account, based on projections by various sources (see Table 2). For some technologies, the ‘best’ and ‘worst’ cases have been considered, referring to their potential future development: the former takes an optimistic approach assuming high technology efficiencies and considerable technological development while the ‘worst’ case considers the opposite. This has implications for the life cycle environmental impacts of technologies, so that the ‘best’ case is denoted as ‘Min’, indicating low impacts and the ‘worst’ case as ‘Max’, denoting high impacts. The potential of different technologies to contribute to future electricity supply in the UK has also been taken into account when defining the scenarios. This is discussed below in more detail for each technology in turn.

2.1.1. *Fossil fuels*

As mentioned earlier, natural gas and coal still supply up to 85% of UK’s electricity demand (DECC, 2013b). The contribution from gas power has been growing since the mid-1990s, peaking in 2010 at 41%. Owing to their low capital costs and the fact that they are a proven technology, combined cycle gas turbines (CCGTs) are the main source of electricity from gas and are likely to remain a significant contributor to UK electricity supply in future: since the beginning of 2009, the government has given planning consent to 13.5 GW of new CCGT capacity (DECC, 2013e). For these reasons, CCGT is the main natural-gas technology considered in the scenarios, with the non-CCGT (advanced open cycle gas turbine) playing a negligible role (see Table 2). As indicated in the table, the LCA data have been sourced from the NEEDS database

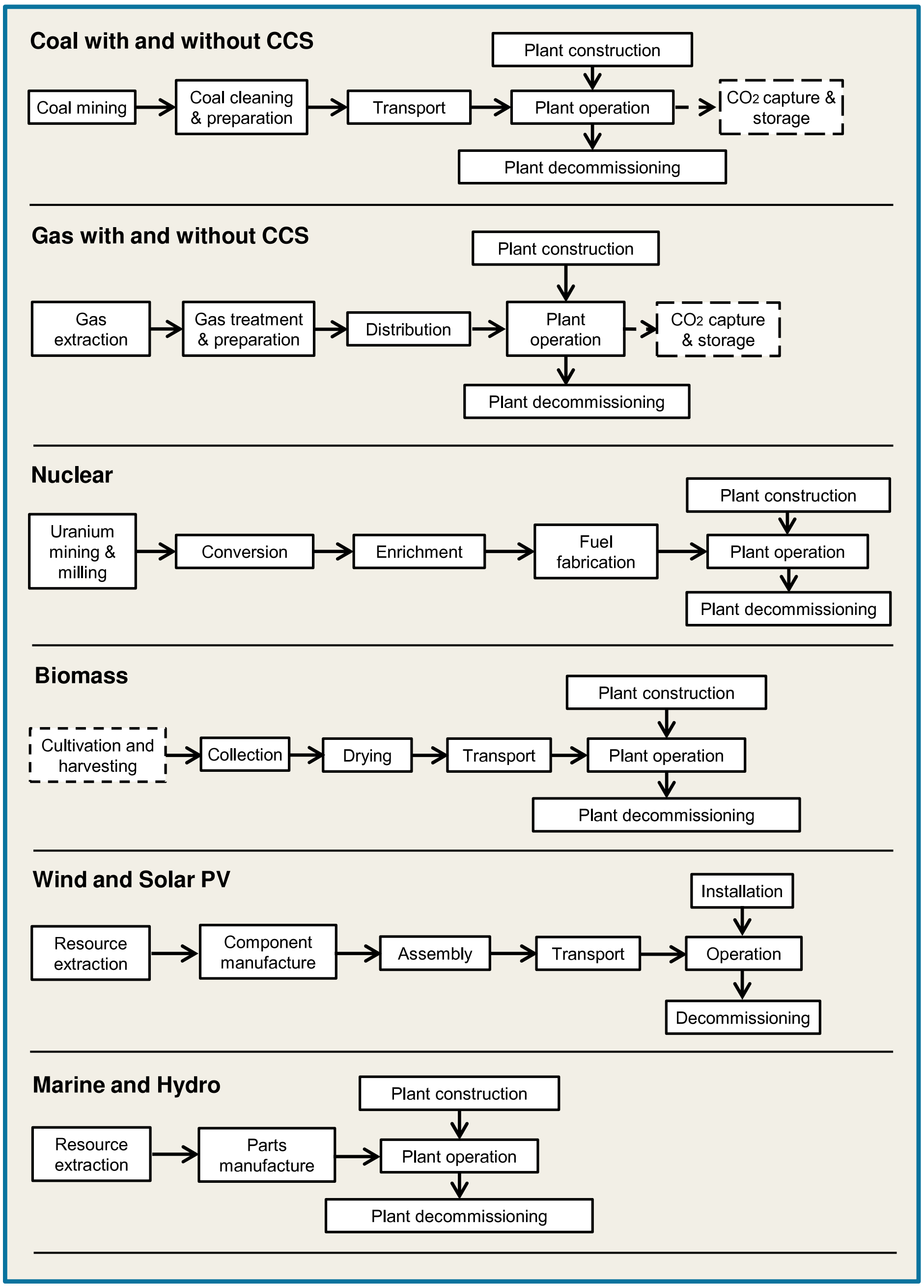

Fig. 3 – The life cycle stages for different electricity technologies considered in the scenario analysis [Dashed lines indicate optional stages, depending on the option considered.].

Table 1 – Installed capacity and number of operational power plants in the UK (in May 2013 based on data from DECC (2013a, 2014a)).

Type	Installed capacity (GW)	Number of installations
Coal	22.00	14
Natural gas	32.30	54
Oil	2.95	30
Nuclear	9.24	9
Wind	9.77	>207[a]
Hydro	1.97	82
Solar photovoltaics	1.71	402,286
Biomass/biogas	4.19	15
Other[b]	6.60	≥137[a]
Total	90.7	>402,708

[a] Actual number of installations cannot be disambiguated fully using the available statistics for the time period.
[b] Mainly comprising combined heat and power (various fuels) and pumped storage.

Table 2 – Summary of the assumptions for the technologies up to 2070.

Technology	Type	Contribution to the technology mix (%)					Technology description	Source of technology data	Source of LCA data
		2008	2020	2035	2050	2070			
Coal	UK mix (2008)	100	0	0	0	0	Current plants and supply mix of indigenous coal production and imports	Stamford and Azapagic (2012)	Ecoinvent Centre (2010)
	Coal IGCC (Min)	0	5	10	40	50	Integrated gasification combined cycle, 450 MW, 45% efficiency, low impacts	Bauer et al. (2008)	NEEDS (2010)
	Coal IGCC (Max)	0	5	10	40	50	As above, but assumes high impacts	Bauer et al. (2008)	NEEDS (2010)
	350 MW (Min)	0	15	0	0	0	Advanced ultra-supercritical pulverised coal plant, 350 MW, 45% efficiency, assumes low impacts	Bauer et al. (2008)	NEEDS (2010)
	350 MW (Max)	0	15	0	0	0	As above but assumes high impacts	Bauer et al. (2008)	NEEDS (2010)
	600 MW (Min)	0	15	20	0	0	Advanced ultra-supercritical pulverised coal plant, 600 MW, 45% efficiency, low impacts	Bauer et al. (2008)	NEEDS (2010)
	600 MW (Max)	0	15	20	0	0	As above but assumes high impacts	Bauer et al. (2008)	NEEDS (2010)
	800 MW (Min)	0	15	20	10	0	Advanced ultra-supercritical pulverised coal plant, 800 MW, 45% efficiency, low impacts	Bauer et al. (2008)	NEEDS (2010)
	800 MW (Max)	0	15	20	10	0	As above but assumes high impacts	Bauer et al. (2008)	NEEDS (2010)
Coal CCS	Coal CCS (Min)	0	0	50	50	100	Advanced oxy-fuel, 500 MW, storage 200 km away, 800 m deep aquifer, low impacts	Bauer et al. (2008)	NEEDS (2010)
	Coal CCS (Max)	0	100	50	50	0	Advanced post-combustion, 500 MW, storage 400 km away, 2500 m deep gas field, high impact	Bauer et al. (2008)	NEEDS (2010)
Natural gas	UK mix (2008)	100	0	0	0	0	New CCGT with the current mix of indigenous gas production and imports	Stamford and Azapagic (2012)	Ecoinvent Centre (2010)
	CCGT (Min)	0	48	50	50	50	Advanced CCGT, 400 MW, 57.5% efficiency, assumes low impacts	Bauer et al. (2008)	NEEDS (2010)
	CCGT (Max)	0	48	50	50	50	As above but assumes high impacts	Bauer et al. (2008)	NEEDS (2010)
	Non-CCGT (Min)	0	2	0	0	0	Advanced open cycle gas turbine, 50 MW, 38% efficiency, assumes low impacts	Bauer et al. (2008)	NEEDS (2010)
	Non-CCGT (Max)	0	2	0	0	0	As above but assumes high impacts	Bauer et al. (2008)	NEEDS (2010)
Gas CCS	Gas CCS (Min)	0	50	50	50	50	Advanced CC post-combustion, 500 MW, storage 400 km away, 2500 m deep gas field, low impact	Bauer et al. (2008)	NEEDS (2010)
	Gas CCS (Max)	0	50	50	50	50	As above but assumes high impacts	Bauer et al. (2008)	NEEDS (2010)

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Table 2 (continued)

Technology	Type	Contribution to the technology mix (%)					Technology description	Source of technology data	Source of LCA data
		2008	2020	2035	2050	2070			
Oil	500 MW	1.5	0	0	0	0	Current plants, 500 MW, 28.6% efficiency	Jungbluth et al. (2007)	Ecoinvent Centre (2010)
Nuclear	PWR	100	100	100	100	100	1000 MW, centrifuge fuel enrichment, once-through cycle, 53 GWd/tU burnup	Stamford and Azapagic (2012)	Ecoinvent Centre (2010)
Biomass	Straw	23	23	23	23	23	CHP, 6 MW, 20% el. efficiency, allocation between electricity and heat based on exergy	Gärtner (2008)	NEEDS (2010)
	Biogas (manure)	6	6	6	6	6	CHP, 50 kW, 33% el. efficiency, allocation between electricity and heat based on exergy	Jungbluth et al. (2007)	Ecoinvent Centre (2010)
	Biogas (biowaste)	51	51	51	51	51	CHP, 160 kW, 32% el. efficiency, allocation between electricity and heat based on exergy	Jungbluth et al. (2007)	Ecoinvent Centre (2010)
	Incineration (sewage)	6	6	6	6	6	CHP, sewage with 73% water, economic allocation between electricity, heat and waste disposal	Jungbluth et al. (2007)	Ecoinvent Centre (2010)
	Incineration (biowaste)	13	13	13	13	13	CHP, solid biowaste, economic allocation between electricity, heat and waste disposal	Jungbluth et al. (2007)	Ecoinvent Centre (2010)
Wind (onshore)	1.65 MW	38	30	10	0	0	Current UK farm of 1.65 MW Vestas V80 turbines, concrete foundations, 30% capacity factor	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)
	2 MW	50	50	30	20	4	As above but with 2 MW turbines	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)
	3 MW	12	20	60	80	96	As above but with 3 MW turbines	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)
Wind (offshore)	2 MW, 30%	21	10	2	0	0	Current farm of 2 MW Vestas V80 turbines, steel monopile foundations, 30% capacity factor	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)
	2 MW, 50%	0	5	3	0	0	As above but with 50% capacity factor	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)
	3 MW, 30%	78	40	15	10	0	Current farm of 3 MW turbines, steel monopile foundations, 30% capacity factor	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)
	3 MW, 40%	0	20	20	15	5	As above but with 40% capacity factor	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)
	3 MW, 50%	0	15	30	15	5	As above but with 50% capacity factor	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)
	5 MW, 30%	1	5	15	30	20	Current farm of 5 MW turbines, steel monopile foundations, 30% capacity factor	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)
	5 MW, 50%	0	5	15	30	70	As above but with 50% capacity factor	Kouloumpis et al. (2012)	Kouloumpis et al. (2012)

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Table 2 (*continued*)

Technology	Type	Contribution to the technology mix (%)					Technology description	Source of technology data	Source of LCA data
		2008	2020	2035	2050	2070			
Solar PV	Roof, UK mix 2005	80	40	0	0	0	Roof-mounted, 3 kWp, current efficiencies and mix of panel types, UK insolation (750 kWh/kWp/yr)	Stamford and Azapagic (2012)	Ecoinvent Centre (2010)
	Roof, UK mix 2020	0	40	40	0	0	As above but improved efficiency over current technology	Stamford and Azapagic (2012)	Ecoinvent Centre (2010)
	Roof, UK mix 2030	0	0	40	40	0	As above but improved efficiency over 2020 technology	Stamford and Azapagic (2012)	Ecoinvent Centre (2010)
	Roof, UK mix 2050	0	0	0	40	80	As above but improved efficiency over 2030 technology	Stamford and Azapagic (2012)	Ecoinvent Centre (2010)
	Ground (Min)	10	10	10	10	10	Ground-mounted farm of 3.5 MW PV panels, assumes low impacts	Frankl et al. (2006)	NEEDS (2010)
	Ground (Max)	10	10	10	10	10	As above but assumes high impacts	Frankl et al. (2006)	NEEDS (2010)
Marine	Marine (Min)	0	50	50	50	50	‘Wave Dragon’, 7 MW, concrete bucket foundation, 46% capacity factor, low impacts	Sørensen and Naef (2008)	NEEDS (2010)
	Marine (Max)	0	50	50	50	50	As above but assumes high impacts	Sørensen and Naef (2008)	NEEDS (2010)
Hydro	Run-of-river	100	100	100	100	100	Current run-of-river hydropower plants	Bauer and Bolliger (2007)	Ecoinvent Centre (2010)
Imports	French mix	100	100	100	100	100	Current French electricity mix imported to the UK	Dones et al. (2007)	Ecoinvent Centre (2010)

(NEEDS, 2010); the technology specification is described in Bauer et al. (2008). An equal split is assumed between the 'best' (Min) and 'worst' (Max) cases for future technology development.

In addition to conventional gas, the UK is currently undergoing an intensive period of exploration for shale gas which might potentially lead to a boom in indigenous production. This could become significant in future gas supply. However, as LCA data for UK shale gas are still evolving (MacKay and Stone, 2013; Cooper et al., 2014; Stamford and Azapagic, 2014a), shale gas is not considered in this work.

In contrast to natural gas, UK coal power has declined greatly in the last two to three decades, going from 65% in 1990 down to 34% in 2011 (DECC, 2013b). The contribution of coal will again decline markedly over the next few years as a result of the EU Large Combustion Plant Directive (LCPD): a total of 8.5 GW of coal plants have opted out of the LCPD and will shut down permanently by the beginning of 2016 (National Grid, 2010). In addition, the new Emissions Performance Standard limits emissions from new plants to 450 g CO_2/kWh at the point of generation (DECC, 2011b), in effect making construction of coal plants without CCS impossible as the unabated emissions of new plants are around 800 g CO_2/kWh (IEA, 2013a). Therefore, while the existing coal plants will still be available in the short-term, their future potential is limited, particularly if the current carbon targets are to be met. Consequently, in future scenarios the contribution of coal power declines and the efficiency of the remaining plants improves (to 45%) under the assumption that they are upgraded by, for instance, installation of new steam turbines. A mix of plant sizes is assumed (see Table 2) using LCA data from the NEEDS database (NEEDS, 2010) based on technology specifications described in Bauer et al. (2008).

The contribution from oil power plants has been declining over the years and has been below 2% since 1998. Since oil plants are also affected by the LCPD, their contribution will continue to decline in future. Therefore, oil is not considered as part of future electricity mix in the scenario analysis.

2.1.2. *Nuclear*

At the time of writing, the UK had 16 operating reactors totalling 10 GW but this is declining as they age and are decommissioned; no reactors have been commissioned since 1995 and all but one will be retired by 2023 (World Nuclear Association, 2013). The Government has been attempting to encourage new nuclear build since 2008 (BERR, 2008), culminating recently in its agreement with EDF Energy on a strike price for the 'contract for difference' that will apply to their forthcoming Hinkley Point C nuclear plant (DECC, 2013c): this guarantees fixed, long-term income for new nuclear plants. Nuclear power will also benefit indirectly from the UK's unilateral carbon price floor which tops up the price of carbon traded through the European Union's Emission Trading Scheme (ETS). Rates for 2014–15 are £9.55/tonne CO_2, rising above £20/t by 2016 (HMRC, 2013).

Currently, up to 15.8 GW of new nuclear capacity has been proposed by various utilities and consortia (World Nuclear Association, 2013). The LCA data for nuclear power in the scenarios are taken from Stamford and Azapagic (2012) and, as described there, assume high burnup and once-through cycle (Table 2), both of which are commensurate with current policy and plant design.

2.1.3. *Carbon capture and storage*

UK policy currently supports development of CCS via a £1 billion commercialisation competition and coordinated research and development programmes (DECC, 2013d). Although the planned coal CCS demonstration plants are yet to materialise, it is still anticipated that CCS will make a considerable contribution to the UK energy mix (DECC, 2011a, 2012).

The introduction of coal and gas CCS in the scenarios follows projections of the Department of Energy and Climate Change which envisage 2020 to 2025 as the first deployment time period (DECC, 2012). LCA data on CCS are taken from the NEEDS database (NEEDS, 2010) based on technology specifications described in Bauer et al. (2008). For coal CCS, this begins with post-combustion capture technology as current plants are converted, then moves to a mix of post-combustion and oxy-fuel plants by 2035, as given in Table 2. For natural gas, only post-combustion CCS is considered, as this is the most likely technological solution for CCGTs.

2.1.4. *Biomass*

Use of biomass for energy in the UK includes landfill gas, sewage sludge digestion, municipal waste combustion, animal/plant matter combustion and co-firing with fossil fuels. In 2008, these technologies contributed 2.5% of total electricity generation, rising to 4.2% (15,198 GWh) in 2012 (DECC, 2014a). Landfill gas has traditionally been the biggest contributor with 34% of the total in 2012, but plant biomass, such as straw and energy crops, is beginning to overtake it. Projects currently under construction or in planning could lead to an approximate doubling of capacity, and this excludes proposed conversions of existing coal plants to 100% biomass (DECC, 2013f). Therefore, it is likely that biomass generation will exceed 30,000 GWh/yr by 2020, which would equate to around 8% of the electricity mix. Growth beyond this time period is currently quite speculative.

The LCA data for biomass are taken from the Ecoinvent and NEEDS databases (Ecoinvent Centre, 2010; NEEDS, 2010). As shown in Table 2, they describe combined heat and power (CHP) units of varying size including combustion of waste, sewage, biogas from waste and biogas from manure (all of which are described by Jungbluth et al., 2007) as well as a larger straw combustion plant described by Gärtner (2008). Following the common approach in LCA, biogenic carbon is not considered (ISO, 2013).

2.1.5. *Wind*

The installed capacity of wind power in the UK has been increasing substantially owing to continued political support. In 2008, 3.4 GW were operational, of which 83% was onshore (DECC, 2013a); by early 2014 this had grown to 10.5 GW, of which 65% was onshore (RenewableUK, 2014). There is currently 3.8 GW of offshore capacity under construction or consented (RenewableUK, 2014) and an identified available capacity of around 40 GW by 2030 (The Crown Estate, 2014); if achieved, offshore wind alone would then constitute 25%–30% of the electricity mix (assuming 30% capacity factor). Meanwhile, onshore installations under construction or consented total 6 GW (RenewableUK, 2014).

In total, therefore, around 20 GW may be online by 2020 (growing considerably thereafter) generating about 53,000 GWh per year. By 2050, the Government's Carbon Plan suggests a top estimate of 288,000 GWh/yr in its 'Higher renewables: more energy efficiency' scenario (DECC, 2011a): this provides 55% of electricity.

As shown in Table 2, the LCA data for wind power are based on commercially available turbines with capacities of 1.65–5 MW. Onshore installations have an assumed capacity factor of 30% – close to the UK 2008–2012 average of 26% (DECC, 2013a) – while offshore increases from 30% to 50% as technology allows the exploitation of stronger, more consistent winds at higher altitudes and in deeper waters (UK average over the period 2008–2012 = 32% DECC, 2013a).

2.1.6. *Solar PV*

In 2008, solar technology had received little support in the UK and total installed capacity was just 22.5 MW; this provided about 0.005% of electricity supply (DECC, 2013a). However, the UK introduced a Feed-in Tariff (FiT) in April 2010 obliging large energy suppliers to make payments to owners of small-scale (<5 MW) renewable installations, predominantly PV, based on the total amount of electricity produced (Energy Saving Trust, 2013). By the end of 2013 there were 497,935 installations totalling 2.65 GW (DECC, 2014a). The vast majority of this capacity comprises small-scale, building-mounted installations: large-scale (>5 MW) installations totalled only 300 MW at the time of writing.

Overall, despite its rapid growth, PV still makes a small contribution to the electricity mix, with the above capacity able to generate about 2100 GWh/yr (∼0.6% of current supply). It has been estimated that 7–20 GW of PV capacity might be online by 2020 (DECC, 2013f) – enough to provide around 5500–16,000 GWh/yr (∼1.5–4.3% of supply). It should be noted, however, that National Grid expects a total PV capacity of over 10 GW to be technically unfeasible without greatly expanded energy storage (National Grid, 2012).

LCA data for small-scale solar PV come from the authors' previous work (Stamford and Azapagic, 2012, 2014b) and are based on 3 kWp rooftop installations producing 750 kWh/kWp per year and improvements in efficiency according to the IEA's solar PV roadmap (IEA, 2010). Large scale ground-mounted installations are also included (see Table 2) using data from the NEEDS database (NEEDS, 2010) as described by Frankl et al. (2006).

2.1.7. *Marine*

Marine power in the UK remains virtually unexploited, despite considerable resources. In 2008, the total installed capacity was just 0.5 MW, rising to 7 MW by the end of 2013 with annual generation of <5 GWh (DECC, 2014a). However, these are early-stage, experimental devices; it has been estimated that up to 200 MW might be installed by 2020, by which time the technology should be more mature (RenewableUK, 2013). Ultimately, estimates suggest that the total wave energy in UK waters is as high as 840,000 GWh/yr, of which 50,000 GWh/yr might be exploitable with current technology (RenewableUK, 2013): equivalent to ∼13% of current electricity supply. Given the huge resource available to the UK, marine power is likely to expand greatly in future.

Owing to technological immaturity, LCA data for large-scale installations are currently lacking. Data in this analysis are taken from the NEEDS database (NEEDS, 2010) and describe a 7 MW bucket-type wave device as specified by Sørensen and Naef (2008); see Table 2.

2.1.8. *Hydro*

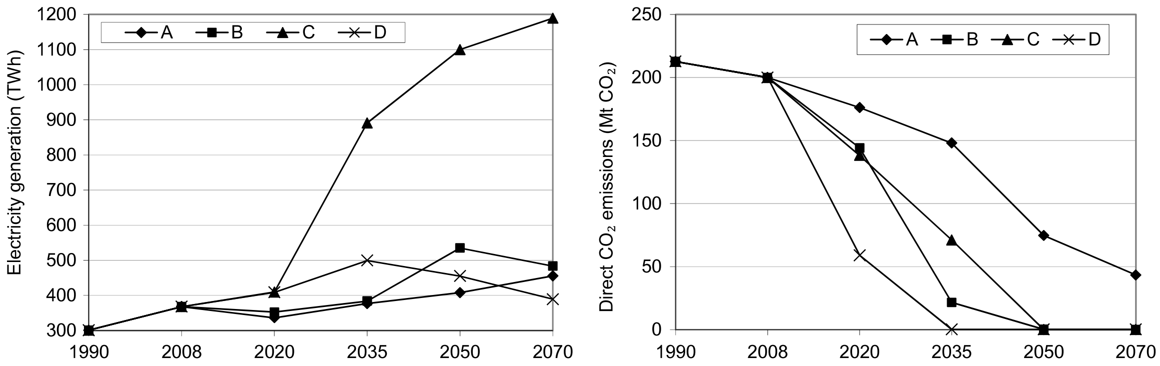
Hydropower output in the UK has been steady for at least two decades, reflecting the fact that the best sites are already thought to be exploited. Generation from run-of-river plants in 2008 was 5155 GWh from 1.6 GW capacity, providing 1.3% of electricity (DECC, 2013a). Annual generation correlates with rainfall, but these figures do not change considerably year-on-year. The UK has a greater capacity of pumped storage hydro plants (2.7 GW) – which use electricity from the generation mix to pump water uphill for later usage – and is likely to require more in future as the capacity of intermittent renewables increases. However, as pumped storage is an energy storage rather than a generation technology, it is not included in this study.

LCA data for hydropower (Table 2) are taken from the Ecoinvent database (Ecoinvent Centre, 2010) and are described in detail in Bauer and Bolliger (2007).

2.2. *Scenarios*

As with all scenario analyses, the intention here is to illustrate possible pathways and futures for electricity supply rather than to make forecasts or predictions. For these purposes, four illustrative scenarios – A, B, C and D – are considered, each with four sub-scenarios. They have been developed considering the whole energy system in the UK, based on the scenarios developed by the SPRIng project (Azapagic et al., 2011). However, for the purposes of this paper, the focus is on electricity. Unlike most other scenarios which consider the period up to 2050, the scenarios developed in this work extend the analysis up to 2070. Considering periods beyond 2050 is important not only because of the long timescales associated with climate change and sustainable development but also because some of the technologies that could help tackle climate change will have very long-term effects, particularly nuclear and carbon capture and storage. However, considering longer timescales is not without its challenges, not the least because it is difficult, if not impossible, to anticipate future technological developments. The certainty of the underlying data, therefore, diminishes as they are projected out into the future (see Fig. 6) as does the robustness of the assessment. While direct emissions scenarios may be sufficiently robust out to 2100 (as published by the IPCC, 2014, for instance), life cycle assessment data are likely not, making an earlier cut-off prudent. Nevertheless, as discussed later in the paper, we have used current knowledge and future projections from a range of sources in an attempt to estimate potential impacts of different electricity technologies up to 2070. To be consistent with the carbon targets which refer to 2050, the discussion in the paper also refers to this year as the main reference point but also shows the implications up to 2070 based on the trends established in the scenarios. The year 2008 is taken to be the base year as its electricity mix is closest to the average mix in recent years (see Fig. 1) and is therefore representative of the current situation.

All scenarios considered here are driven by the need to reduce carbon emissions as this is one of the main policy drivers in the UK (DECC, 2011b,a). As summarised in Table 3 and Fig. 4, they assume different carbon reduction targets from the electricity sector, ranging from 65% to 100%, as well as different electricity consumption and technology mixes. Scenarios B and C are based on GHG emissions trajectories in line with the current UK targets, ultimately reaching 80%



(a) Assumed electricity generation. (b) Assumed CO_2 emission targets.

Fig. 4 – SPRIng scenarios for UK electricity up to 2070.

Table 3 – Summary of scenarios and assumptions.

Scenario	Description	Ref. year	Electricity demand (TWh)	Electricity demand change relative to 2008 (%)	Direct[a] CO_2 emissions (Mt CO_2)	CO_2 reduction relative to 1990[b] (%)
Base year	Current electricity consumption and emissions	2008	372.16	–	199.94	6
A	There is limited action to reduce carbon emissions.	2020	336.38	−11	176.12	17
		2035	376.73	1	147.98	30
		2050	407.86	9	74.64	65
		2070	455.54	18	43.37	80
B	Overall carbon emissions are reduced broadly in line with UK targets. Overall energy use is reduced but electricity consumption increases moderately. The electricity sector is fully decarbonised by 2050.	2020	352.34	−6	144.14	32
		2035	383.94	3	21.56	90
		2050	535.12	30	0.21	100
		2070	483.68	23	0.11	100
C	Same as scenario B but electricity consumption increases three-fold compared to 2008.	2020	409.74	9	138.16	35
		2035	891.01	58	71.12	67
		2050	1099.82	66	0.01	100
		2070	1189.30	69	0.07	100
D	Carbon emissions are reduced at a rate that, if replicated globally, would give a high probability of limiting the global temperature increase to 2 °C. Electricity consumption increases only moderately and it is fully decarbonised by 2025.	2020	408.77	9	58.94	72
		2035	499.43	25	0.18	100
		2050	455.23	18	0.18	100
		2070	389.22	4	0.18	100

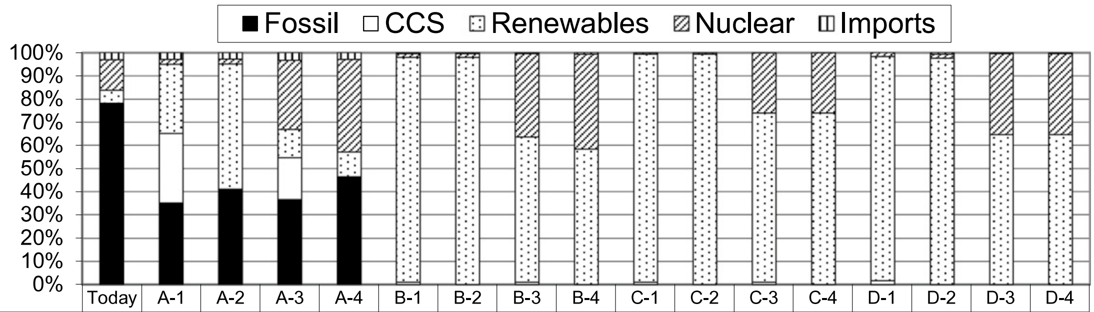
[a]Direct CO_2 emissions are those emitted from combustion of fossil fuels to generate electricity, while indirect emissions are those emitted in the rest of the life cycle, including extraction and processing of fuels, production and installation of power plant components, etc.
[b]CO_2 emissions from the electricity sector in 1990 are estimated at 212.67 Mt CO_2 based on 32 Mtoe reported by DECC (2014b). Conversion factor: 1 Mtoe = 11,630 GWh.

decarbonisation by 2050 (relative to 1990 emissions levels) across the economy as a whole; this fulfils the UK's legal obligations with respect to climate change. It is widely accepted that electricity is easier to decarbonise than other sectors such as transport or heating (Ekins et al., 2013); therefore electricity supply becomes 'zero-carbon' before 2050 in both scenarios, but Scenario C experiences much greater electrification of heat and transport along with stronger demand growth. Scenarios A and D subsequently explore more extreme futures in which decarbonisation is very modest and very aggressive, respectively. Scenario A is based on UKERC's 'Faint-heart' scenario (Ekins et al., 2013) and sees emissions from electricity supply falling much more slowly, finally reaching an 80% reduction (relative to 1990) by 2070. In contrast, scenario D assumes that electricity is fully decarbonised in the 2020s. As a result, the scenarios cover sufficiently different electricity futures to allow exploration of environmental trends within a broad 'feasibility region'. Many other scenarios can be explored through ETLCA by changing the assumptions on carbon emissions, electricity consumption and technology mixes — while the specific results will be different from those discussed here, the environmental trends will be similar.

The following provides more detail for the main scenarios; the sub-scenarios are described in Supplementary material (see Appendix A).

Scenario A assumes a moderate increase (9% by 2050) in electricity demand and relatively little effort to tackle climate change (Azapagic et al., 2011). Carbon emissions from the economy as a whole reduce by just 15% by 2050 on 1990 levels and by 2070 they are reduced only by 24% (including aviation and shipping). The majority of the emission reductions achieved in this scenario are due to the electricity sector, which reduces its emissions by 65% by 2050 and 80% by 2070. However, this means that the UK misses by a large margin its legally binding target to reduce GHG emissions from the economy as a whole by 80% by 2050 (Climate Change Act, 2008).

In contrast, Scenario B assumes that the UK broadly follows its current climate change commitment and does



	Today	A-1	A-2	A-3	A-4	B-1	B-2	B-3	B-4	C-1	C-2	C-3	C-4	D-1	D-2	D-3	D-4
Imports	3.1	3.0	2.9	3.3	3.0	0.5	0.5	0.5	0.7	0.1	0.1	0.1	0.1	0.0	0.7	0.5	0.5
Nuclear	13.2	2.1	2.1	30.0	40.0	1.6	1.6	36.0	41.0	0.6	0.6	26.0	26.0	1.8	1.8	35.0	35.0
Renewables	5.7	29.9	54.0	12.2	10.7	96.9	97.9	62.5	58.3	98.3	99.3	72.9	73.9	96.5	97.5	64.5	64.5
CCS	0.0	30.0	0.0	18.0	0.0	1.0	0.0	1.0	0.0	1.0	0.0	1.0	0.0	1.7	0.0	0.0	0.0
Fossil	78.0	35.0	41.0	36.5	46.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Fig. 5 – Summary of electricity mix for the sub-scenarios in 2050 compared to the current situation.

this with an overall reduction in energy demand of 22% by 2050 and 30% by 2070 (including aviation and shipping). This, however, requires a 90% reduction of CO_2 emissions from the electricity sector by 2035 and its complete decarbonisation by 2050. Scenario C also considers the same CO_2 emission reductions as B but with a three-fold increase in energy demand by 2050, assuming that the economy will be largely electrified, including heating and transport. Currently, electricity consumption constitutes approximately 19% of the UK's total energy consumption, with heat accounting for 44% and transport 37%; therefore, a transfer of demand for heating and transport to electricity could – in the absence of demand reduction measures – lead to a several-fold increase in electricity generation. Scenario C reflects such a possibility.

Scenario D is the most challenging with respect to climate change targets as it assumes more rapid decarbonisation in the whole economy to limit global temperature rise to 2 °C or less. This requires CO_2 emissions from the economy to drop by 53% by 2020 and 90% by 2035 (including aviation and shipping) on 1990 levels. For electricity, this means a very rapid drop from today's 200 Mt to just under 60 Mt by 2020 and to near zero (0.2 Mt) by 2025, allowing only a moderate increase in demand (18% in 2050).

The scenarios and their respective sub-scenarios are described in more detail in the Supplementary material (see Appendix A). The sub-scenarios assume different penetrations of fossil, renewable, nuclear and CCS technologies to explore how the carbon targets and electricity demand could be met as specified in the scenarios. A snapshot of the electricity mixes in all the scenarios for 2050 is given in Fig. 5 in comparison to the current situation; this is also discussed in more detail in the Supplementary material (see Appendix A).

While all the scenarios consider some penetration of renewable energy because of its availability and fast-growing uptake, new nuclear build and CCS are considered only in certain sub-scenarios to reflect the fact that they may not be available for a number of reasons (including cost, technology availability (CCS), build times and possible public opposition). Table 4 shows which sub-scenarios include new nuclear build and CCS.

Table 4 – Summary of the assumptions for new nuclear build and CCS for different sub-scenarios.

Sub-scenarios	New nuclear build	CCS
A-1, B-1, C-1, D-1	No	Yes
A-2, B-2, C-2, D-2	No	No
A-3, B-3, C-3, D-3	Yes	Yes
A-4, B-4, C-4, D-4	Yes	No

2.3. *Data quality and limitations*

The main limitations and elements of uncertainty involved in this study originate from the following:

1. the background life cycle inventory (LCI) data, i.e. inputs and outputs of materials, energy and emissions;
2. inherent uncertainty of future technological development; and
3. exclusion of certain parts of the energy system from the system boundary; for example, transmission network infrastructure and energy storage requirements will differ between scenarios but are not included.

The last point is problematic and unquantifiable for time spans such as that considered in this study (to 2070). This is due to a lack of knowledge of the extent to which modern electricity grids might be able to accommodate future increases in non-dispatchable generating capacity (such as wind, solar and, to an extent, nuclear) and the extent to which disruptive technologies might influence this via, for example, demand side management. In short, technologies that are outside the system boundary of this study – such as large-scale energy storage (via pumped storage, batteries, hydrogen production or other options) – may be needed in all of the examined scenarios to differing degrees, but the amount, type and impacts of these technologies are not known at present. This area would fall under the umbrella of consequential LCA, which attempts to account for environmental impacts that occur in response to decisions that might be made in a market context (Soimakallio et al., 2011). This would include the technologies discussed above as well as, for instance, the effects on the economy of energy price increases that might result from increased renewable energy penetration or fuel scarcity. Practically, this involves the integration of LCA with economic models (Earles and Halog, 2011) and, as yet, basic requirements such as the analysis of marginal electricity supply have proved difficult (Ekvall and Weidema, 2004; Lund et al., 2010). Research in this area is ongoing and examples in literature exist of future electricity analysis for the medium term. These often involve some version of the Global Trade Analysis Project (GTAP) model (Center for Global Trade Analysis, 2014) such as that by Bosello et al. (2011), Dandres et al. (2012) and Peters et al. (2011). However, this is beyond the scope of the present study and, besides, the merits of applying such an approach over such a long time scale are not certain.

The uncertainty related to future development of technologies (point 2 above) is applicable to all studies involving future scenarios owing to the stochastic nature of technological development. However, there are some uncertainties specific to this work which should be noted. Firstly, much of the LCA data for technologies in future time periods (see Table 2) is derived from the NEEDS database (NEEDS, 2010) which addresses expected variation in future characteristics by using three different scenarios: pessimistic, realistic-optimistic and very optimistic. As discussed in Section 2.1, this has been simplified in this study by using the best and worst ('Min' and 'Max') models from the selection provided by the NEEDS database. The technology mix, as shown in Table 2, typically assumes an even split between the best and worst outcomes, whereas in reality either extreme might be possible.

Secondly, the future reference points of this study (2020, 2035, 2050, 2070) do not match those of the NEEDS database (2025, 2050), therefore there is an uncertainty in their approximation. In particular, this means that there is no technological progression for any technologies using NEEDS data beyond 2050: the 2050 data are used for the 2070 time period. In reality, as discussed above, it is difficult to predict how accurate these data will be so far into the future and thus how important this assumption is. However, it should be noted that the goal of this study is to address the operating mix of power plants in each reference year and that the operating mix changes slowly: many plants operating in 2070 will likely have been commissioned decades earlier. This 'inertia' in the system should minimise the inaccuracy arising from the use of 2050 data for the year 2070.

Uncertainty in LCI data (point 1 above) is a problem inherent in LCA and, in this case, cannot be assessed statistically owing to the vast number of life cycle resource, energy, material and emission flows occurring in the datasets presented in Table 2. Furthermore, statistical data quality information, such as probability distributions, is not available with sufficient coverage to conduct a formal uncertainty analysis. However, the background data use the Ecoinvent database, which is one of the most rigorous LCI databases available. The most important weakness in the data is likely the combined use of models based on Ecoinvent v2.2 background data and models from the NEEDS database because the latter uses Ecoinvent v1.3 background data and therefore accounts for fewer environmental burdens. In particular, the number of toxic substances considered is much greater in Ecoinvent 2.2 and, as a result, human toxicity and freshwater/marine eco-toxicity are consistently underestimated for the technologies reliant upon NEEDS data: namely future coal plants (with and without CCS), future gas plants (with and without CCS), some biomass plants, large-scale solar PV installations and marine plants (see Table 2). However, these are still the best (and only) data available.

In an attempt to address the robustness of the LCI data in the study, a data quality analysis has been conducted. Each dataset within ETLCA has been scored in each reference year (2008, 2020, 2035, 2050 and 2070) according to four criteria: time period specificity, geographical specificity, completeness of inventory and quality of data source. The scoring is based on a three-point scale where 1 is worst and 3 is best; therefore, the minimum score is 4 ($= 4 \times 1$) and the maximum is 12 ($= 4 \times 3$). Thus, for example, the following datasets have lower scores: those that are based on present day technology designs and on systems installed outside the UK, those that have a less comprehensive list of burdens (e.g. NEEDS database) and less robust provenance and documentation. In the analysis, the scores assigned to each dataset in each reference year are then multiplied by the percentage contribution of each technology to the mix in a given year for each sub-scenario in order to arrive at a weighted average score for the technology mix in question. For example, if data for solar PV score 10 out of 12 in 2050 and solar PV contributes 15% to the 2050 electricity mix, its data quality score is obtained by multiplying 10 by 0.15. The same is then repeated for every other technology in the mix and the data quality scores are added up. This yields an estimate of the variance in data quality between sub-scenarios, in a potential range of 4–12 for any given year, as illustrated in Fig. 6.

As shown, the data quality in this study ranges from 7.7–11.8 with the highest quality for the present-time and lowest in future time periods. For example, the data quality in scenario B-1 for 2008 scores 11.8 but in 2070, 8.5. However, the decrease is not uniform across sub-scenarios. For instance, the D sub-scenarios maintain better quality in the future (9.3 in 2050) than the A sub-scenarios (8.5–8.9 in 2050). This is primarily due to the use of data from the NEEDS database and, in turn, its use of Ecoinvent v1.3 background data and generic EU geographical location (as discussed above). The main effect of this is that the results for sub-scenarios with a higher penetration of CCS (whose datasets all come from the NEEDS database) – such as A-1 to A-4 – are less robust than those relying more heavily on technology for which there are up-to-date, UK-specific datasets such as for wind power.

In summary, the results of the data quality analysis suggest that the data used in the study are robust, albeit more so for scenarios B, C and D than for A.

3. Results and discussion

The environmental impacts for the different scenarios, estimated using the ETLCA model, are discussed below. Owing to space restriction, only the graphs for selective impacts are shown; the graphs for the remaining impacts as well as the full results for all the 12 impacts and 16 scenarios can be found in the Supplementary material (see Appendix A). For the environmental impacts of individual technologies, see Kouloumpis et al. (2012).

3.1. *Global warming potential (GWP)*

As expected and shown in Fig. 7, the scenarios with lower direct carbon emissions, and particularly the ones in which decarbonisation happens earlier (D-1 to D-4), all have much lower GWP than today. Even in the least ambitious sub-scenarios (A-1 to A-4), the GWP is reduced by 71%–81% by 2070, with all other scenarios achieving reductions above 85% compared to today's impact. In the best case (D-3), by 2070 the electricity supply has a GWP of 8.25 Mt CO_2-eq./yr, or 21 g CO_2-eq./kWh, compared to the current 197 Mt CO_2-eq./yr or 530 g/kWh. In the worst case (A-2), life cycle emissions decline to 56.5 Mt CO_2-eq./yr, or 124 g CO_2-eq./kWh but, as discussed in Section 2.2, this is not enough for the UK to reach its carbon reduction targets.

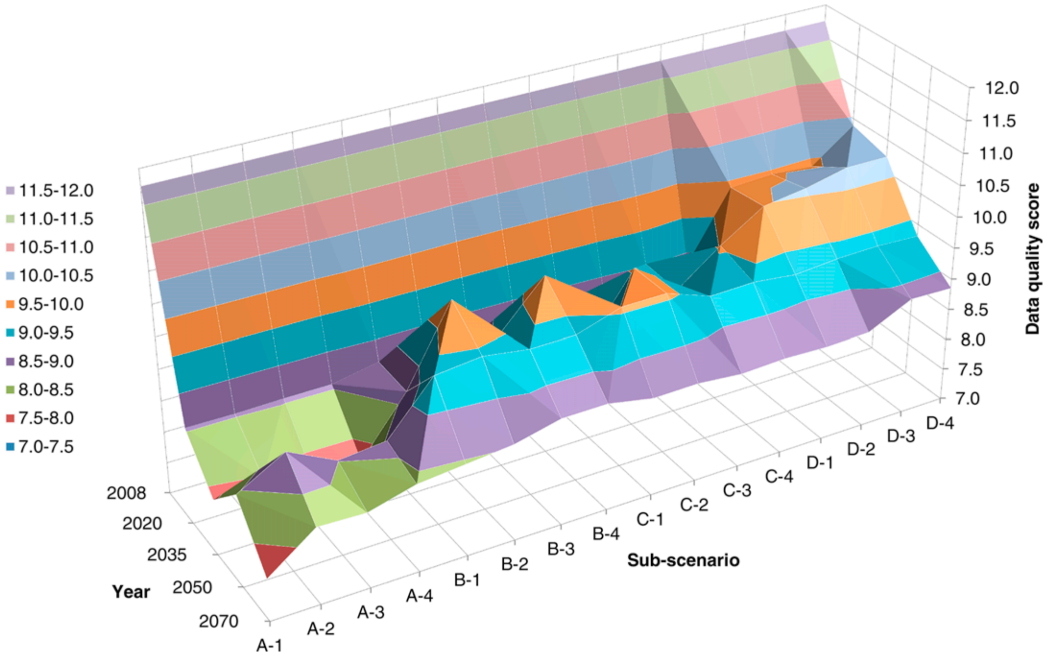


Fig. 6 – Data quality assessment for each scenario over time period considered (2008–2070). [The magnitude of the differences in data quality between sub-scenarios is accentuated because of the shortening of the *y*-axis to show only the range of scores obtained in the analysis (7–12).].

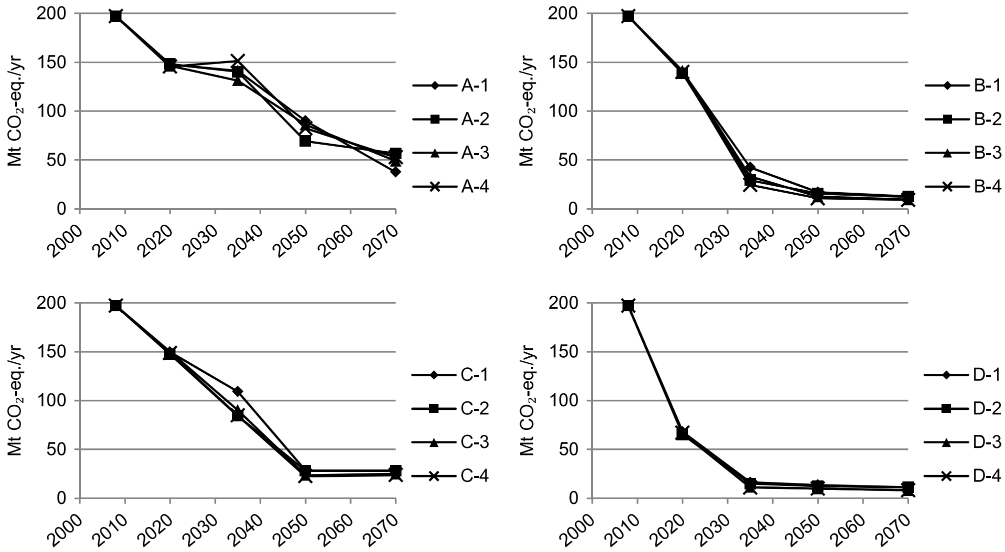


Fig. 7 – Global warming potentials for all sub-scenarios.

Despite the B and C scenarios having the same 2050 carbon reduction target, the latter have noticeably higher GWP, particularly in the period 2020–2050. This is due to their much higher electricity demand and the resulting pressure to construct low-carbon capacity at extremely high rates. This is particularly problematic if nuclear and/or CCS do not go ahead: for instance, in C-2 (which lacks new nuclear and CCS), around 180 GW of solar PV must be installed between 2020 and 2035. This is equivalent to around 60 million residential-sized installations (at typical current sizes) — for context, in 2013 there were 26.4 million residencies in the UK (ONS, 2013). It can also be noticed from Fig. 7 that the GWP remains constant in all the C sub-scenarios after 2050: for C-1 and C-2 this is due to a slightly increased amount of electricity from offshore relative to onshore wind, with the former having a higher GWP per unit electricity generated (Kouloumpis et al., 2012); for C-3 and C-4 the increase is because of a reduced penetration of nuclear power (from 26% to 24%) as some plants come to the end of their lifetime, which is compensated by an increase in solar PV and marine energy, both of which have higher GWP than nuclear. Thus, the overall policy implications from the climate change perspective are that new nuclear and/or CCS build should go ahead and that energy demand reduction should be prioritised.

3.2. *Abiotic resource depletion potential: elements (ADPe)*

As indicated in Fig. 8, depletion of elements increases in all sub-scenarios relative to the present, but the impact varies by a factor of 53 depending on the scenario, ranging from 44–2315 t Sb-eq./yr in 2070. In the A scenarios there is a continued reliance on fossil fuels either with or without CCS (these technologies still provide 41%–65% of the mix by 2050) and fossil options tend to have lower ADPe than

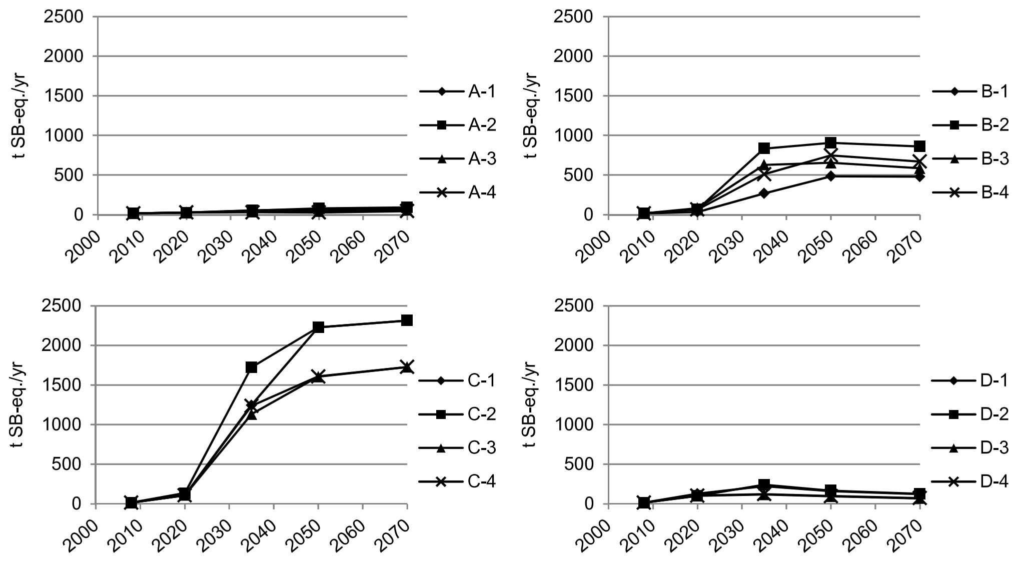


Fig. 8 – Abiotic depletion (elements) for all sub-scenarios.

low-carbon options so that ADPe in the A scenarios only increases by 3–5 times. In contrast, the C scenarios involve much more aggressive decarbonisation coupled with a high electricity demand; consequently, much greater capacities of wind and solar PV are required. The use of metals during their construction results in annual ADPe up to 145 times higher in 2070 than at the present; specifically, about 90% of this impact comes from the solar PV life cycle with tellurium and silver accounting for ~70%. The restrictive carbon targets also mean that CCS cannot be used later in the period, leaving nuclear as the major low-ADPe option. Therefore, ADPe is 25% lower in the C scenarios with nuclear power (C-3 and C-4) than in those without.

Notably, the scenarios with the lowest carbon emissions (D) cause considerably less ADPe than the B or C scenarios (see Fig. 8). This is because solar PV does not feature strongly in the D scenarios (because of the earlier mentioned assumption that end-user subsidies focus on demand reduction rather than on the FITs). Without solar PV, most demand is met by nuclear, wind and biomass, none of which causes as much element depletion as PV (for details, see Kouloumpis et al. (2012)). However, even in these scenarios the ADPe is higher in 2070 than today.

Overall, the best sub-scenario for this impact is A-4, depleting 44 t Sb-eq./yr in 2070, but in this scenario the carbon targets are not achieved. The best scenario which does achieve the carbon targets is D-3, but at the expense of a four times higher depletion of elements than today. Thus, there is a significant trade-off between mitigating climate change and depletion of non-renewable resources — both impacts have intergenerational implications because of their long-term impacts so that solutions should be sought that minimise both. It should be stressed that this is not a conclusion that could be derived or quantified without a life cycle approach.

3.3. *Abiotic resource depletion potential: fossil fuels (ADPf)*

Depletion of fossil fuels broadly reduces in line with carbon emissions, thus the overall annual depletion impact by 2070 is universally lower than today (see Figure S1 in the Supplementary material (Appendix A)). However, the use of CCS in A-1 (providing 60% of electricity) means that ADPf reduces by only 7% relative to the present. Similarly, the boom in CCS stimulated by high electricity demand in C-1 and C-3 between 2020 and 2050 produces a peak in ADPf in 2035. In the worst case (C-1 in 2035), ADPf is equivalent to 4064 PJ per year, or 73% higher than today. This not only depletes fossil resources for future generations but also has implications for energy security because of the increased reliance on imported fossil fuels.

3.4. *Acidification potential (AP)*

As shown in Figure S2 in the Supplementary material (see Appendix A), all sub-scenarios follow a downward trend for the AP, declining from today's value of 348 kt SO_2-eq./yr (0.94 g SO_2-eq./kWh) to between 83 and 277 kt SO_2-eq./yr (0.17–0.51 g SO_2-eq./kWh) by 2070. Within each scenario, the fourth sub-scenario (4) has the lowest AP because of the exclusion of CCS and considerable contribution from nuclear (which has one of the lowest APs of all the technologies considered). Coal CCS and biomass are the worst options for this impact owing to their relatively high acid emissions to air; for this reason, A-1 is one of the worst options with 232 kt SO_2-eq./yr as these two technologies contribute 38% of the mix in 2070. Nevertheless, the C scenarios still have the highest annual impact (241–277 kt SO_2-eq./yr) because of their high electricity demand. Sub-scenario C-1 is the worst option in the mid-period (2035) when the AP peaks, exceeding today's value by around 10% (see Figure S2). By the end of the period, C-2 has the highest impact of 277 kt SO_2-eq./yr. However, at 0.20–0.23 g SO_2-eq. per kWh in 2070, the impact of the C scenarios per unit generated is lower than any other scenario, except for B-1 and B-2; thus, if its electricity demand was equivalent to that in the other scenarios, C would be the best option for this impact, indicating again the importance of reducing energy consumption. It is also interesting to note that the AP for scenarios D is comparable to that of A — this is largely due to the biomass which is a significant contribution to the mix in these scenarios and has the highest AP of the technologies considered (for details, see Kouloumpis et al. (2012)).

3.5. *Eutrophication potential (EP)*

Eutrophication decreases in all sub-scenarios (Figure S3), primarily because of retirement of conventional coal plants.

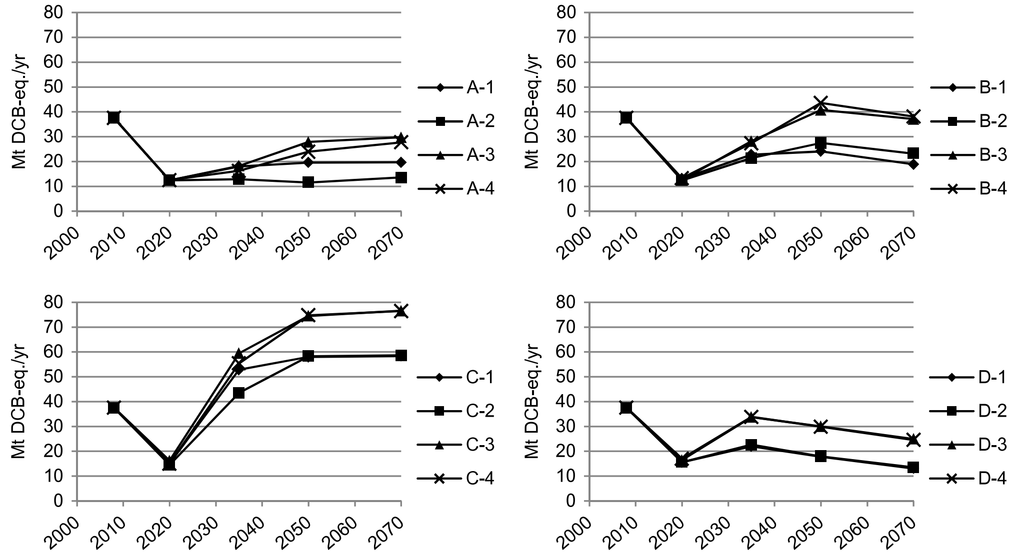


Fig. 9 – Human toxicity potential for all sub-scenarios.

Of the low-carbon technologies, biomass and solar PV have the highest EP (Kouloumpis et al., 2012); therefore C-2 has the highest overall impact owing to its installed capacities of 22 GW of biomass and around 435 GW of solar PV in 2070. Even in this case, the impact per kWh decreases from 0.65 to 0.13 g PO_4^{3-}-eq./kWh between now and 2070, with most of the reduction being counteracted by increased demand. The best sub-scenario in terms of EP is A-4 because of a strong contribution from nuclear (40% from 2050 onward) and lower carbon constraints allowing continued use of natural gas, which has relatively low EP. Thus, in A-4, the impact decreases from 242 kt PO_4^{3-}-eq./yr today to 41.8 kt by 2070 (0.092 g PO_4^{3-}-eq./kWh). The next best option, the low-carbon B-4, has an 8% higher EP at the end of the period; however, it is still five times lower than the current impact.

3.6. *Freshwater aquatic eco-toxicity potential (FAETP)*

Freshwater eco-toxicity is less affected by technology mix than most of the other impacts, other than benefitting from the retirement of conventional coal plants. Consequently, the results of the scenario analysis tend to correlate with electricity demand more than with choice of technology: the overall FAETP in 2070 ranges from 7.1 to 11.1 Mt dichlorobenzene (DCB)-eq./yr for all the scenarios except for the C scenarios which generate 24.7–25.6 Mt DCB-eq./yr. At the end of the period, the best scenario is A-4; however, the carbon targets are not achieved. The best low-carbon scenario is D-1, with 9.1 Mt DCB-eq./yr, or 20% higher than the best option, but nevertheless four times lower than today's value.

Per unit electricity, all sub-scenarios see a reduction from the current 100 g DCB-eq./kWh to 15–24 g by 2070 (see Tables S2, S4, S6 & S8 in the Supplementary material (Appendix A)).

3.7. *Human toxicity potential (HTP)*

As shown in Fig. 9, all sub-scenarios see a drop in HTP between the present and 2020 as old coal plants retire. However, from 2020 onward, the impact increases again to varying extents, with the sub-scenarios relying on nuclear power (labelled as -3 and -4) having a higher impact than those without nuclear. This is due to long-term emissions of heavy metals from uranium mill tailings in countries from which uranium is sourced.

However, as demonstrated by scenarios A, B and D, it is possible to increase nuclear generation significantly and still maintain an overall HTP similar to, or lower than, that of today. Scenario C is the exception because of its high electricity demand, stimulating up to 38 GW of new nuclear capacity (approximately four times that of the present day), in turn resulting in the HTP of 77 Mt DCB-eq./yr. Per kilowatt-hour this is, in fact, lower than the current impact (64 g c.f. 100 g DCB-eq./kWh), but the improvement is negated by a failure to improve end-user energy efficiency in the C scenario.

Overall, the best sub-scenarios for the HTP in 2070 are A-2, D-1 and D-2, emitting 13.1–13.5 Mt DCB-eq./yr — all three exclude nuclear power but A-2 misses the carbon targets while D-1 and D-2 achieve the early decarbonisation needed to stabilise the global temperature rise to 2 °C. Therefore, these results would suggest that an electricity mix dominated by renewables (biomass, wind and marine) would be preferred over that relying on nuclear power as that would meet the very ambitious carbon targets while minimising the human toxicity potential from electricity generation.

3.8. *Marine aquatic eco-toxicity potential (MAETP)*

Nearly 95% of the MAETP from current electricity generation is due to coal power (primarily from emission to air of hydrogen fluoride during coal combustion and beryllium to water during mining). As a result, elimination of conventional coal from the mix reduces the current MAETP from 146 Gt DCB-eq./yr (391 kg/kWh) to 11–57 Gt/yr by 2070 (27–122 kg/kWh). The best options for the MAETP are the D scenarios: they are the only ones for which this impact is consistently below 20 Gt/yr for the entire 2020–2070 period (Figure S5). This is due primarily to the absence of coal CCS in the D scenarios as a result of very early, aggressive decarbonisation. In later time periods, solar PV tends to dominate the MAETP in all the D scenarios because of high installed capacities and emissions of metals to water and hydrogen fluoride to air (both associated with metal processing during component manufacture).

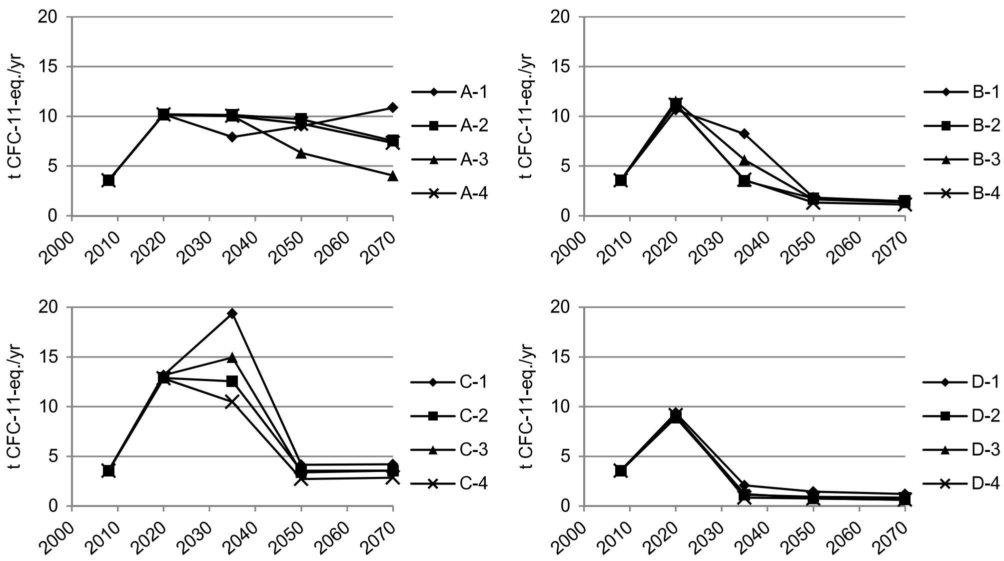


Fig. 10 – Ozone layer depletion potential for all sub-scenarios.

3.9. *Ozone layer depletion potential (ODP)*

All scenarios see an increase in the ODP in the short term owing to increased reliance on natural gas and the subsequent increased leakage of halons during gas distribution and its associated supply chain. However, as shown in Fig. 10, after 2020 there is considerable variation between the scenarios. All the A scenarios stay above the current ODP value of 3.54 t CFC-11-eq./yr throughout the time period because of a reliance on gas (with or without CCS). Scenarios B and D both have a similar ODP which reduces to below 2 t CFC-11-eq./yr by 2050. This reduction is brought about by a greater penetration of renewables and nuclear power. Sub-scenarios C-1 to C-4 cause similar impacts per kWh to B-1 to B-4, peaking at around 32 μg CFC-11-eq./kWh in 2020 and declining thereafter (see Tables S2, S4, S6 & S6 in the Supplementary material (Appendix A)), but the high electricity demand in the C scenarios increases annual ODP significantly: in 2035, C-1 has a 5.5 times higher impact than today.

3.10. *Photochemical oxidant creation potential (POCP)*

Also known as photochemical smog, this impact is lowest in B-4 over the entire time period, owing to its sizeable contribution from nuclear and wind power which have the lowest POCP of all the technologies considered (Kouloumpis et al., 2012). By 2035, POCP decreases from 28 kt C_2H_4-eq./yr (76 mg C_2H_4-eq./kWh) to 10 kt/yr (27 mg/kWh) and stays steady around this level until 2070 (Table S6). In all cases, the sub-scenarios that lack nuclear power have the worst POCP because they are forced to rely more heavily on CCS, biomass and/or solar, none of which has as low an impact as nuclear or wind. As for most other impacts, scenario C is the worst option, with the POCP peaking in 2035 at 48.8 kt (for C-1), 40% higher than today. As before, this is mainly due to the high electricity demand. After that, the impact gradually reduces to levels slightly above the current value.

3.11. *Terrestrial eco-toxicity potential (TETP)*

The best scenarios for this impact are A-2 and D-1 with around 228 kt DCB-eq./yr in 2070 (see Figure S7). This represents a reduction of around 30% compared to the current TETP. In both cases, the reductions are due to the initial phasing out of coal power and a lack of coal CCS.

As is the case for most other impacts, the C sub-scenarios are the worst overall owing to their high electricity demand: while TETP per kWh is similar to that of the other scenarios, higher demand results in a 2.3-fold increase over today's levels on an annual basis.

3.12. *Health impact potential from radiation (RAD)*

As indicated in Fig. 11, there is clear divergence in future RAD impact between sub-scenarios with and without new nuclear build. In the best case (D-1) the annual impact declines from today's 1300 disability-adjusted life years (DALYs) per year to 28 DALYs/yr by 2070 owing to a lack of nuclear power and the low overall electricity demand that results from aggressive energy-efficiency measures. In the worst cases (C-3 and C-4) the impact rises to 5900 DALYs/yr, to which nuclear power contributes 98%. In this case, around 38 GW of nuclear capacity is installed; however, the majority of the impact is from very long term (thousands of years) emissions of radon from uranium milling facilities rather than from the plants themselves.

3.13. *Summary comparison of scenarios*

The results for each sub-scenario are summarised on a 'heat map' in Fig. 12 by normalising the annual impacts in the baseline year (2008) to 100, allowing each environmental impact in subsequent years for every sub-scenario to be expressed relative to the baseline. Therefore, lighter shades in the figure represent an improvement over 2008, while darker shades represent an increased environmental impact.

As can be seen from the figure, the A sub-scenarios are typically characterised by the fastest and greatest reduction in EP, FAETP and HTP, but do not meet the carbon targets. Moreover, it should be borne in mind that the results of the A sub-scenarios are the least robust because of the less comprehensive list of burdens considered in NEEDS, as discussed in Section 2.3 (see Fig. 6), therefore the aforementioned reduction in certain impacts may be overestimated. The D sub-scenarios tend to have the lowest

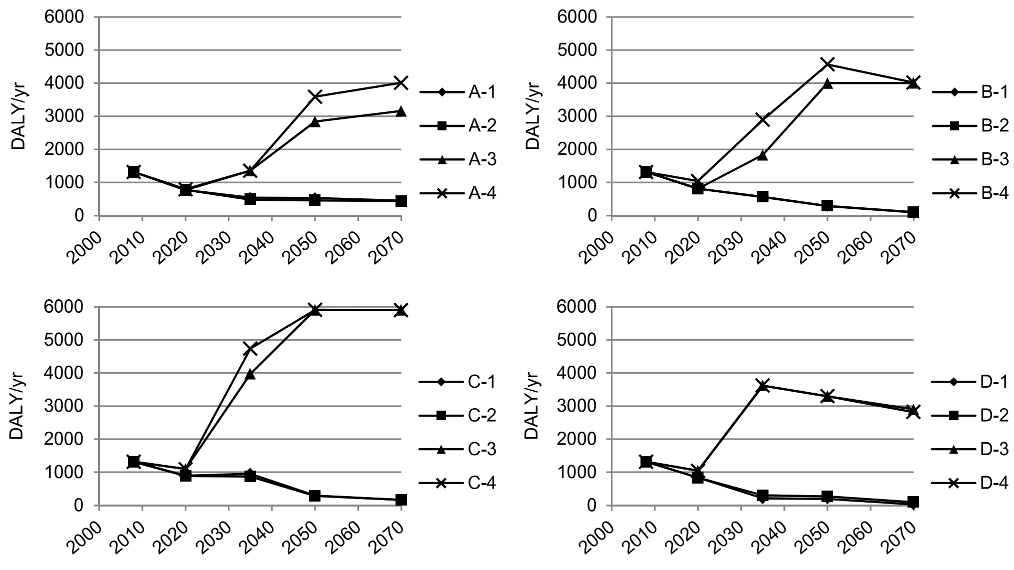


Fig. 11 – Health impact potential from radiation for all sub-scenarios.

impacts, particularly in the long term (beyond 2035), while the C sub-scenarios are the worst options overall throughout the time period. B-1 to B-4 successfully reach the carbon targets with impacts that are generally lower than their A and C alternatives while requiring a less extreme energy mix than D-1 to D-4.

It is also useful to compare the impacts of individual technologies to gain insight into their effect on the impacts in different scenarios and identify possible mitigation strategies. Fig. 13 shows the 'heat map' for the impacts of each technology in the year 2050. As can be seen, hydropower and onshore wind have the lowest impacts overall, while oil and coal CCS have the highest. Since the share of oil in the electricity mix is already decreasing and will be phased out in the future, this leaves coal CCS as the worst overall performer. As a result, coal CCS tends to make a major contribution to the overall medium-term environmental impacts in all future scenarios in which it features (although beyond 2035 it is a minor component of the mix due to its relatively high global warming potential). In scenarios without coal CCS (those ending in '−2' and '−4'), impacts tend to be dominated by biomass and solar PV.

It is of note that offshore wind, solar power and marine are the worst options in terms of depletion of elements owing to their high metal consumption per unit output. This emphasises the need to ensure end-of-life recycling to recover as much material as possible, and to improve design by using less scarce materials and through 'lightweighting'. Biomass – another prominent low-carbon option – performs badly in terms of AP, EP, FAETP and POCP. Some of this can be attributed to the transportation of biomass (POCP), the use of fertilisers and treatment of waste streams with a high organic content (EP) and emissions from power plants (NOx and SOx in the case of AP; heavy metal emissions from combustion in the case of FAETP). Therefore these impacts might be reduced by measures such as (a) ensuring that energy crops are high yielding and fertiliser-free where possible (e.g. miscanthus) and (b) implementing pollution control measures such as those used for coal power plants to minimise emissions of SOx, NOx and heavy metals.

4. Conclusions

This paper has presented an application of a novel model combining a life cycle approach with scenario analysis to explore what implications the anticipated decarbonisation of electricity supply may have for other environmental impacts. For these purposes, 12 life cycle environmental impacts have been estimated for 16 electricity scenarios up to 2070, to identify any trade-offs between mitigation of climate change and other impacts. The UK has been used as an illustrative example to demonstrate the scale of transformation needed and the resulting impacts on the environment as a whole. The main conclusions are as follows:

- As demonstrated by scenario A, unprecedented deployment of low-carbon technologies (up to 40 GW of CCS capacity, 24 GW nuclear, 65 GW wind, 19 GW biomass) may still be insufficient to meet carbon targets and limit global average temperature rise to 2 °C if any significant conventional fossil-fuelled capacity is retained beyond 2035 (without CCS). The sub-scenarios in which the least decarbonisation is attempted also have the worst depletion of fossil fuels and, beyond 2035, ozone layer depletion.
- While conventional coal power must be phased out by the mid-2020s to meet carbon targets, natural gas (without CCS) may persist for longer at a reduced contribution – typically less than 14% of the mix by 2035 – but deployment of low-carbon options must be pursued rapidly.
- When demand reduction is not prioritised alongside decarbonisation (as in scenario C) several impacts increase by 2070: annual depletion of elements (by 110–145 times), human toxicity (by 1.5–2 times) and terrestrial eco-toxicity (by 2.3 times). Additionally, depletion of fossil fuels, ozone layer depletion and photochemical smog all increase between 2020 and 2050 (owing to extensive use of gas CCS, coal CCS and biomass) before falling back to lower levels by 2070.
- Another consequence of high demand is extremely high installed capacities including up to 160 GW of wind capacity by 2070, 440 GW of solar PV, 38 GW of nuclear and 60 GW of biomass and marine. These capacities eclipse the entire current UK generating fleet of ~90 GW and may not be feasible or socially acceptable. In short, if demand

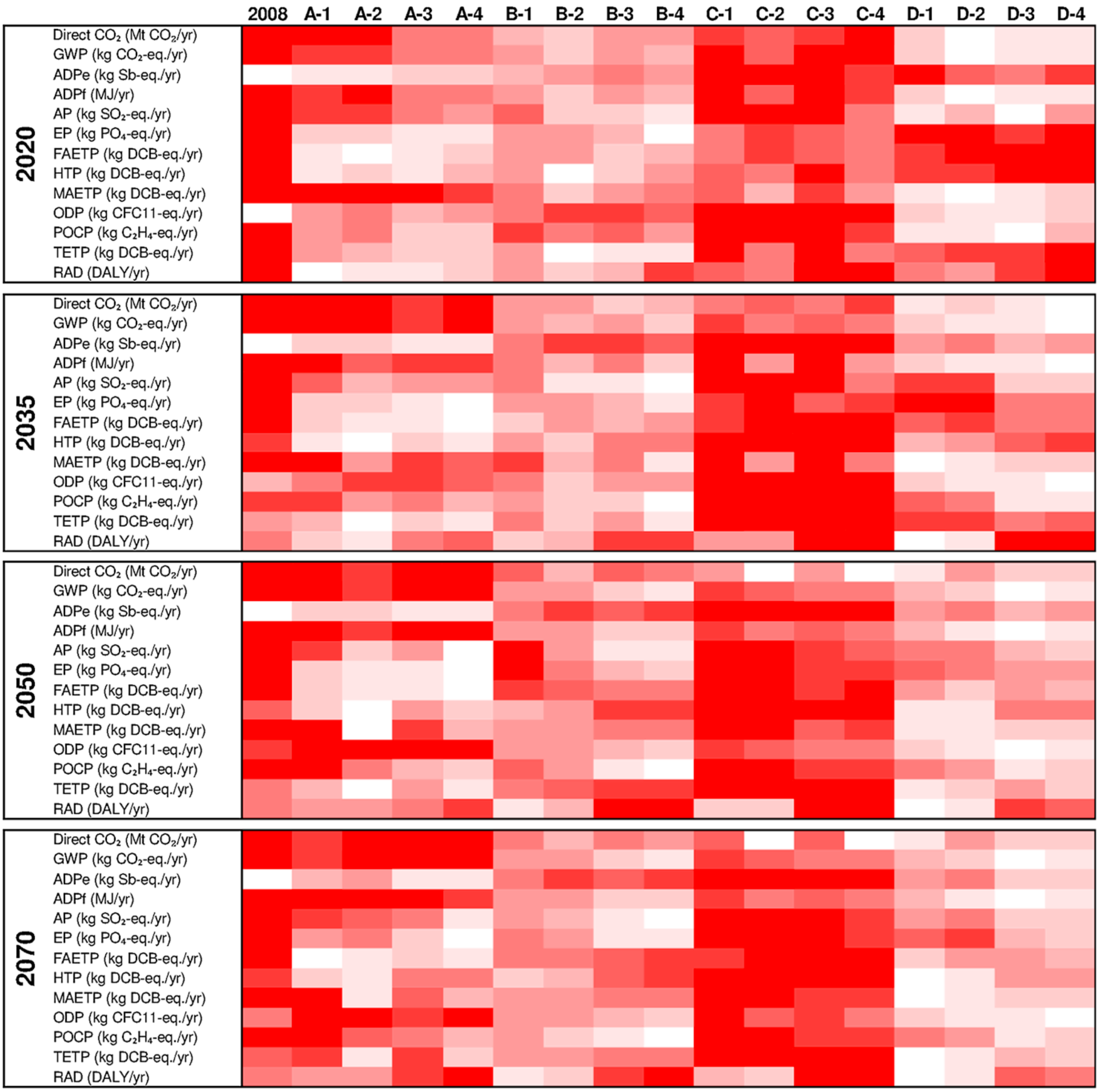


Fig. 12 – 'Heat map' of the environmental impacts of the sub-scenarios A-1 through to D-4. [White signifies the lowest and dark red the highest environmental impact. Direct CO_2: direct emissions of CO_2 from power plants, GWP: global warming potential, ADPe: abiotic depletion potential of elements, ADPf: abiotic depletion potential of fossil fuels, AP: acidification potential, EP: eutrophication potential, FAETP: freshwater aquatic eco-toxicity potential, HTP: human toxicity potential, MAETP: marine aquatic eco-toxicity potential, ODP: ozone layer depletion potential, POCP: photochemical oxidants creation potential, TETP: terrestrial eco-toxicity potential, RAD: health impacts from radiation.].

rises considerably it is difficult to meet carbon targets and impossible to avoid increases in other environmental impacts.

- Decarbonisation is likely to increase depletion of elements: in the carbon target-compliant scenarios examined, ADPe in 2070 is 4–145 times higher than in the present. Therefore, end-of-life recycling and a circular economy are important and must be pursued alongside carbon reduction.
- It is possible to decarbonise while simultaneously reducing other life cycle environmental impacts (apart from depletion of elements) by following one of the scenario B options and avoiding CCS deployment. Sub-scenario B-4 requires 29 GW of new nuclear build by 2050, 36 GW of wind, 136 GW of solar PV and 16 GW of biomass and marine. In fact, by making use of nuclear power, B-4 has lower global warming potential than some of the more aggressive scenarios (D-1 and D-2).
- The lowest overall impacts are achieved in scenario D, but this requires deployment of renewables at a magnitude (e.g., 75 GW of wind by 2035) that raises questions surrounding technical ability to match supply and demand owing to the intermittency issues. Moreover, the climate change benefits are negligible compared to scenario B.

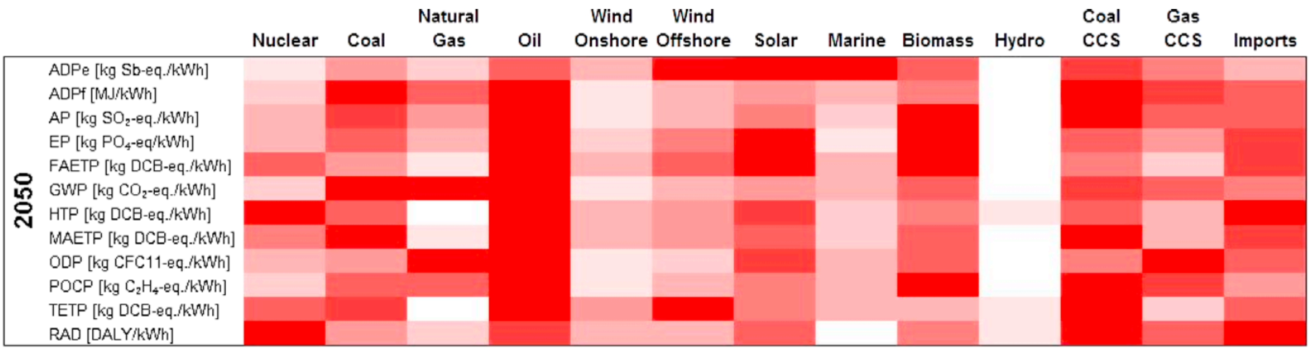


Fig. 13 – 'Heat map' of the environmental impacts of individual technologies in 2050. [White signifies the lowest and dark red the highest environmental impact. For impacts nomenclature, see Fig. 12.].

- With respect to the individual technologies, those with the lowest impacts overall are hydro and onshore wind. However, the potential for the future expansion of the former is limited and the latter is constrained by land availability as well as opposition by the public. Marine, nuclear and gas power are the next best options, assuming all the impacts are of equal importance. If, on the other hand, climate change is considered a priority for the UK, then deployment of low-carbon technologies such as marine, nuclear, wind and solar PV should be pursued. Coal CCS should be avoided as it has high impacts across all the categories, including greenhouse gas emissions.

In summary, the results from this work suggest that decarbonisation of electricity supply to meet the 2050 carbon targets would lead to a reduction in the majority of the life cycle impacts by 2070. There are two exceptions to this. First is depletion of elements which would increase by 4–145 times on today's value. The second exception is health impact from radiation which would increase four-fold if nuclear power is used and electricity demand grows strongly; even if growth in demand is reduced, it would still rise two-fold. Furthermore, ozone layer depletion would also increase beyond the current value in the short-term (2020) across all the scenarios, by between 2.5–3.7 times. The results also reveal that, if energy demand continued to grow (as in C), three other impacts would also increase over their current values by 2070 while trying to meet the carbon targets: human toxicity (up to two times), photochemical smog (by 12%) and terrestrial eco-toxicity (2.3 times). These findings illustrate yet again the importance of prioritising measures for demand reduction to avoid meeting climate change targets at the expense of other environmental impacts.

The problems associated with high demand also have serious repercussions for the oft-recurring suggestion to electrify heating and transport, which would inevitably lead to a great increase in electricity demand. The whole-system effects of such a shift need to be considered and, therefore, future work would need to compare a complete provision of services under different paradigms: i.e. the entire current system (electricity, heating and transport) must be compared to a fully electrified system in order to investigate the trade-offs fairly. There may be benefits, for instance, in reduced urban air pollution owing to electrified transport; conversely, the use of electricity for heating is likely to result in much higher system-wide depletion of resources than the current gas-dominated heating system. These and other complex causal sequences should be taken into account.

Similarly, infrastructure and energy storage are examples of other system-level parameters requiring consideration. Scenarios with higher penetration of inflexible technologies such as wind, PV and nuclear will require energy storage technologies and this will increase the impacts of the system as a whole. Scenarios that will be most affected by this include B-3, B-4 and all the C scenarios. As discussed in Section 2.3, this is beyond the remit of this paper and requires further study.

The results also beg the question of how important each impact is in absolute terms: for instance, would a doubling of terrestrial eco-toxicity breach some ecological limit or is it of little importance? This could be quantified by normalising the results to the world or regional impacts. However, this is problematic because of the many assumptions that would be required for normalisation of impacts so far out in the future when it is not known what they will be either globally or regionally. Further work in this area may prove useful to fully contextualise findings from this and other similar studies.

Future work should also include the economic and social implications of the scenarios as well as development of more robust LCA databases for future energy technologies. Moreover, further research is needed into the ability of electricity grid systems to incorporate less dispatchable generation capacity (such as wind, solar and nuclear) simultaneously. The latter is critical to ensuring that impacts are captured at the systems level, commensurate with the systems approach that is so fundamental to LCA.

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at http://dx.doi.org/10.1016/j.spc.2015.04.001.

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