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Life cycle sustainability assessment of electricity options for the UK

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SUMMARY

The UK electricity mix will change significantly in the future. This provides an opportunity to consider the full life cycle sustainability of the options currently considered as most suitable for the UK: gas, nuclear, offshore wind and photovoltaics (PV). In an attempt to identify the most sustainable options and inform policy, this paper applies a sustainability assessment framework developed previously by the authors to compare these electricity options. To put discussion in context, coal is also considered as a significant contributor to the current electricity supply. Each option is assessed and compared in terms of its economic, environmental and social implications, using a range of sustainability indicators. The results show that no one technology is superior and that certain trade-offs must be made. For example, nuclear and offshore wind power have the lowest life cycle environmental impacts, except for freshwater ecotoxicity for which gas is the best option; coal and gas are the cheapest options (£74 and 66/MWh, respectively, at 10% discount), but both have high global warming potential (1072 and 379 g CO_2 eq./kWh); PV has relatively low global warming potential (88 g CO_2 eq./kWh) but high cost (£302/MWh), as well as high ozone layer and resource depletion. Nuclear, wind and PV increase some aspects of energy security: in the case of nuclear, this is due to inherent fuel storage capabilities (energy density 290 million times that of natural gas), whereas wind and PV decrease fossil fuel import requirements by up to 0.2 toe/MWh. However, all three options require additional installed capacity for grid management. Nuclear also poses complex risk and intergenerational questions such as the creation of 10.16 m^3/TWh of nuclear waste for long-term geological storage. Copyright © 2012 John Wiley & Sons, Ltd.

KEY WORDS

coal electricity; gas electricity; nuclear electricity; wind electricity; photovoltaics (PV); sustainability assessment

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1. INTRODUCTION

The UK electricity mix is at the beginning of a significant shift away from the technologies that have dominated production for the past few decades (for the current mix see Figure 1). The European Union (EU) Large Combustion Plant Directive [1], the change from net gas exporter to importer [2], the retirement of most of the nuclear fleet by 2023 [see 3] and the legally binding Climate Change Act [4] have all forced the government to consider important questions about replacing current capacity. In many cases (such as that of nuclear power), decisions taken today will dictate the future of UK's electricity supply for 60 years or longer due to the long lifetimes of new power plants designs and their associated financial and infrastructural commitments.

It is clear, therefore, that the coming years represent an opportunity to modernise and improve UK's electricity supply, taking into account economic, environmental and social impacts that may be accrued long into the future. This is the subject of the present paper that applies the sustainability indicators framework developed by Stamford and Azapagic [5] to assess the sustainability of some of technologies that are most likely to be deployed in the UK in the near to midterm. These are offshore wind, photovoltaics (PV), nuclear and gas power. In addition, coal generation is also considered as one of the significant contributors to the current electricity mix that will still have presence in the future. As far as the authors are aware, this is the first assessment of its kind for the UK, using a life cycle approach to assess a broad range of techno-economic, environmental and social issues associated with these electricity technologies. The paper also presents several novel aspects of sustainability assessment including dispatchability, technological lock-in resistance, financial incentives,

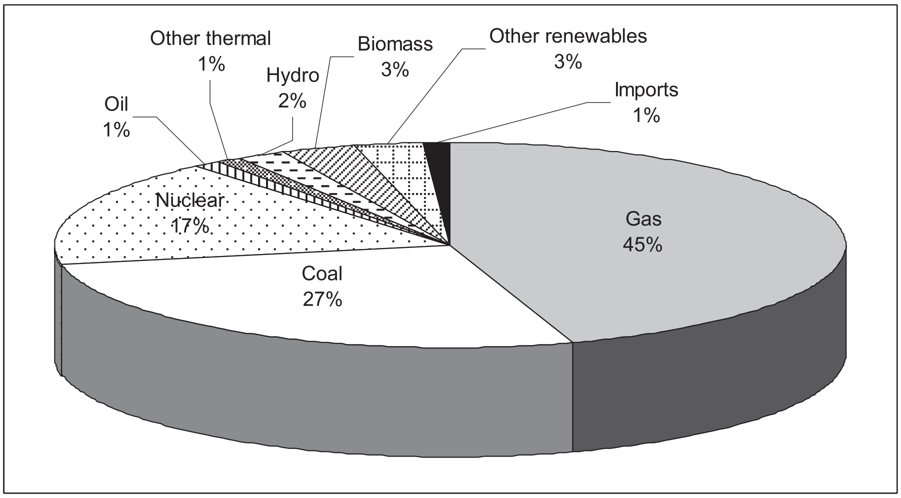

Figure 1. Current UK electricity mix (based on electricity supply in 2009 [6]).

worker injuries, diversity of fuel supply mixes, nuclear proliferation and intergenerational equity.

The prospects for these five technologies in the future UK electricity mix are discussed in brief in the succeeding text.

Current policy aims to increase substantially the installed capacity of wind power, particularly offshore installations. In December 2000, The Crown Estate began awarding sites in UK waters to potential wind farm developers and this process has continued in three ‘rounds’ of development, each successively larger than the last (although, at the time of writing, rounds two and three are yet to be completed). The three rounds total a potential installed capacity of 33 GW [7]; roughly 25 times the capacity of operational offshore wind farms in the UK in 2011 [calculated from 8]. The scale of this expansion is reflected in the emphasis given to offshore wind in the Renewables Obligation [9] that functions as the main stimulus for renewable energy technologies in the UK, whereas many renewables, such as onshore wind and hydroelectricity, receive one Renewables Obligation Certificate (ROC) per MWh produced, offshore wind receives between 1.5 and 2 in order to attract investment by offsetting its relatively high costs.

Another renewable option favoured in the UK is solar PV. Because the introduction of the Feed-in Tariff (FiT) in April 2010, large energy suppliers have been required to make payments to owners of small-scale (<5 MW) renewable installations, such as PV, based on the total amount of electricity produced as well as exported to the grid [10]. Although PV, until recently, only supplied a tiny percentage of UK electricity (approximately 0.005% in 2009 [6]), in its first full year of operation, the FiT had resulted in 28 705 PV installations, totalling 78 MW [11]; this is more than triple the total installed capacity in 2009 [calculated from 6]. It seems, therefore, that PV is set to become a significant generating technology in the UK.

The government is also trying to encourage new nuclear build, as exemplified in its recent National Policy Statement for Nuclear Power Generation [12]: “given the urgent need to decarbonise our electricity supply and enhance the UK’s energy security and diversity of supply, the Government believes that new nuclear power stations need to be developed significantly earlier than the end of 2025”. All indications are that this policy will survive the Fukushima incident as also confirmed by the recent Weightman report on the safety and security of nuclear plants in the UK [13]. Nuclear power is one of the technologies that will benefit from a carbon floor price to be introduced from 2013, starting at around £16/t CO_2 [14]. Currently, up to 19 GW of new nuclear capacity has been proposed by various utilities and consortia [3].

At the present time, electricity from natural gas and coal still dominates the UK electricity mix, providing 45% and 27% of electricity in 2009, respectively (Figure 1). However, unlike coal, gas power is still expanding, particularly combined cycle gas turbines (CCGTs). Owing primarily to their low capital costs and the fact that they are a proven technology, CCGTs are likely to remain significant contributors to UK energy supply: since the beginning of 2009, the government has given planning consent to 10.5 GW of new CCGT capacity [15]. Moreover, there is evidence that some utilities are abandoning plans to build coal plants in favour of CCGTs for various reasons [for example, 16], as discussed in the succeeding text.

UK coal power has declined greatly in the last 2–3 decades. When the UK electricity sector was privatised in 1990, coal produced 72% of electricity [17]. Following privatisation and the subsequent ‘dash for gas’, this figure declined rapidly, and in 2009, stood at 27% [6]. The contribution of coal will again decline markedly over the next few years as a result of the EU Large Combustion Plant Directive: a total of 8.5 GW of coal plants have opted out of the LCPD and are therefore operating for limited hours and will permanently shut down by 1 January 2016 [18]. Additionally, the new

Emissions Performance Standard (EPS) limits emissions of new generators to 450 g CO_2/kWh at the point of generation [19], effectively banning construction of coal plants without carbon capture and storage (CCS). Nevertheless, the existing coal plants will still have a presence, however small, in the future UK electricity grid. Therefore, in terms of the analysis in this paper, coal power serves as a useful reference technology.

The technologies considered are those most suitable for immediate deployment. For this reason, CCS, whether coal-powered, gas-powered or biomass-powered, has not been included as it will not become available on a moderate to large scale until the 2020s [20]. Other technologies have been rejected at this stage on grounds of technological diversity and related data issues (in the case of biomass), relative lack of expansion opportunities in the UK (hydro) and lower prominence in current UK energy policy than solar and offshore wind (onshore wind, geothermal, combined heat and power, imports). Assessment of these technologies to complement this study would be beneficial.

The following section outlines the methodology used for the sustainability assessment of offshore wind, solar PV, nuclear, gas and coal power, including the assumptions and data sources. The results are presented and discussed in Section 3; the conclusions of the study are drawn in Section 4.

2. SUSTAINABILITY ASSESSMENT METHODOLOGY

2.1. Life cycle sustainability indicators

The assessment follows the methodological framework developed by Stamford and Azapagic [5] that uses a life cycle approach to assess techno-economic, environmental and social sustainability of different electricity options. The framework comprises 43 sustainability indicators that are summarised in Table I. It was developed based on direct engagement with stakeholders from industry, government, academia and NGOs as well as literature review. The latter includes recent developments in sustainability assessment of electricity generation in Europe [21–24]. For a detailed description of the methodology used in this paper, see [5].

Each indicator assesses a particular sustainability issue on a life cycle basis, following electricity options from 'cradle to grave'. As shown in Figure 2, the life cycle includes extraction and processing of fuels (if relevant), generation of electricity and waste management. Construction and decommissioning of power plants are also included within the system boundary.

As also indicated in Figure 2, variations are possible within the nuclear and gas life cycles, depending on the fuel chain. In the case of nuclear power in the UK, new reactors are expected to operate on a 'once-through' fuel cycle in which spent fuel is stored for eventual disposal [25]. However, both reactor designs (AREVA EPR and Westinghouse AP1000) currently undergoing Generic Design Assessment (GDA)[1] are able to use mixed oxide fuel (MOX),[2] produced following the reprocessing of spent fuel [28,29]. Use of MOX is therefore a possibility, depending on future policy. The potential impacts of this are examined in Section 3.

Gas fuel chain variations also indicated in Figure 2 are due to increasing use of liquefied natural gas (LNG). LNG is produced by purifying and cooling natural gas. This can then be transported overseas by specially designed tankers before being regasified at its destination and fed into the gas network. The use of LNG avoids the need for gas pipeline infrastructure and improves supply diversity but it comes at an increased environmental impact, as shown in Section 3.

2.2. Data sources and assumptions

The key assumptions and data sources for the different power options for each sustainability indicator listed in Table I are given in the following text and in the Appendix **A**. Wherever possible and available, a range of values for each option has been considered to establish the lower and upper bounds. Where appropriate, average values are used as a basis for sustainability assessment in Section 3. In other cases, 'central' estimates are used instead, representing the most likely values for present and near-term new build, based on the specific technology type expected to be deployed. For instance, life cycle environmental impacts of offshore wind power are based on a central case comprising 3 MW turbines with a capacity factor of 30%, reflecting the fact that a large majority of offshore wind farms under construction or planned closely match these specifications. The lower and upper bounds attempt to account for feasible but less common situations, such as 2 or 5 MW turbines with capacity factors of 30% or 50% (see Section 2.2.1.1 for further details).

Data in this analysis have been gathered from many sources. In the calculation of results, unless stated otherwise, the following technological characteristics have been assumed:

- Offshore wind: 20-year operating life, 30% capacity factor;

[1]Generic Design Assessment is the regulatory procedure by which new reactor designs have to be approved by the Health and Safety Executive for use in the UK, pending site-specific licencing [26]. The designs currently undergoing GDA are the AREVA EPR (European Pressurised Reactor) and the Westinghouse AP1000 (an evolutionary PWR design).

[2]Mixed oxide comprises 3–10% plutonium dioxide (depending on the proportion of the Pu-239 isotope) with the remaining 90–97% being depleted uranium dioxide [27]. The resulting fuel behaves in a similar, but not identical, manner to normal, low-enriched, uranium dioxide fuel.

Table I. Summary of the indicators used for assessing the sustainability of electricity options [5].

	Sustainability issue	Indicator	Unit
Techno-economic	Operability	1. Capacity factor (power output as a percentage of the maximum possible output)	Percentage (%)
		2. Availability factor (percentage of time a plant is available to produce electricity)	Percentage (%)
		3. Technical dispatchability (ramp-up rate, ramp-down rate, minimum up time, minimum down time)	Summed rank
		4. Economic dispatchability (ratio of capital cost to total levelised generation cost)	Dimensionless
		5. Lifetime of global fuel reserves at current extraction rates	Years
	Technological lock-in resistance	6. Ratio of plant flexibility (ability for trigeneration, negative GWP and/or H_2 production) and operational lifetime	$Years^{-1}$
	Immediacy	7. Time to plant start-up from start of construction	Years
	Levelised cost of generation	8. Capital costs	Pence/kWh
		9. Operation and maintenance costs	Pence/kWh
		10. Fuel costs	Pence/kWh
		11. Total levelised cost	Pence/kWh
	Cost variability	12. Fuel price sensitivity (ratio of fuel cost to total levelised generation cost)	Dimensionless
	Financial incentives	13. Financial incentives and assistance (e.g. ROCs, taxpayer burdens)	Pence/kWh
Environmental	Material recyclability	14. Recyclability of input materials	Percentage (%)
	Global warming	15. Global warming potential (GHG emissions)	kg CO_2 eq./kWh
	Ozone layer depletion	16. Ozone depletion potential (CFC and halogenated HC emissions)	kg CFC-11 eq./kWh
	Acidification	17. Acidification potential (SO_2, NO_x, HCl and NH_3 emissions)	kg SO_2 eq./kWh
	Eutrophication	18. Eutrophication potential (N, NO_x, NH_4^+, PO_4^{3-} etc.)	kg PO_4^{3-} eq./kWh
	Photochemical smog	19. Photochemical oxidant creation potential (VOCs and NO_x)	kg C_2H_4 eq./kWh
	Water ecotoxicity	20. Freshwater ecotoxicity potential	kg 1,4 DCB[a] eq./kWh
		21. Marine ecotoxicity potential	kg 1,4 DCB[a] eq./kWh
	Land use and quality	22. Terrestrial ecotoxicity potential	kg 1,4 DCB[a] eq./kWh
		23. Land occupation (area occupied over time)	m^2yr/kWh
		24. Greenfield land use (proportion of new development on previously undeveloped land relative to total land occupied)	Percentage (%)
Social	Provision of employment	25. Direct employment	Person-years/GWh
		26. Total employment (direct + indirect)	Person-years/GWh
	Human health impacts	27. Worker injuries	No. of injuries/GWh
		28. Human toxicity potential (excluding radiation)	kg 1,4 DCB[a] eq./kWh
		29. Worker human health impacts from radiation	DALY[b]/GWh
		30. Total human health impacts from radiation (workers and population)	DALY[b]/GWh
	Large accident risk	31. Fatalities due to large accidents	No. of fatalities/GWh
	Local community impacts	32. Proportion of staff hired from local community relative to total direct employment	Percentage (%)
		33. Spending on local suppliers relative to total annual spending	Percentage (%)
		34. Direct investment in local community as proportion of total annual profits	Percentage (%)

(*Continues*)

Table I. (Continued)

Sustainability issue	Indicator	Unit
Human rights and corruption	35. Involvement of countries in the life cycle with known corruption problems (based on Transparency International Corruption Perceptions Index)	Score (0–10)
Energy security	36. Amount of imported fossil fuel potentially avoided	toe/kWh
	37. Diversity of fuel supply mix	Score (0–1)
	38. Fuel storage capabilities (energy density)	GJ/m^3
Nuclear proliferation	39. Use of non-enriched uranium in a reactor capable of online refuelling; use of reprocessing; requirement for enriched uranium	Score (0–3)
Intergenerational equity	40. Use of abiotic resources (elements)	kg Sb eq./kWh
	41. Use of abiotic resources (fossil fuels)	MJ/kWh
	42. Volume of radioactive waste to be stored	m^3/kWh
	43. Volume of liquid CO_2 to be stored	m^3/kWh

[a]1,4-dichlorobenzene.
[b]disability-adjusted life years.

- Solar PV: 35-year operating life, 8.6% capacity factor;
- Nuclear: 60-year operating life, 85% capacity factor, 50-GWd/tU burnup;
- Natural gas: 25-year operating life, 63% capacity factor; and
- Coal: 45-year operating life, 62% capacity factor.

The origins of these capacity factors are discussed along with the other techno-economic data and assumptions.

2.2.1. Techno-economic data and assumptions

As shown in Table I, the indicators used for the techno-economic assessment are the following:

- Operability (capacity and availability factors, technical and economic dispatchability lifetime of global fuel reserves);
- Technological lock-in;
- Immediacy;
- Levelised cost of generation (capital, operation/maintenance and fuel costs);
- Cost variability; and
- Financial incentives.

2.2.1.1. Operability

Capacity factors: for coal and gas, the capacity factors used for the assessment are based on a 5-year average figures for the UK from 2005 to 2009 [6]; the lower and higher values reported over this period have also been considered.

For wind and nuclear, a different approach has been taken because average figures do not reflect the likely performance of new power plants, for the following reasons:

- The height and capacities of installed wind turbines are increasing quickly. As height increases, so does wind speed [30]; thus newer, larger-capacity wind turbines provide higher capacity factors than the current fleet average.
- New nuclear reactors in the UK will be pressurised water reactors (PWRs), whereas the current fleet is dominated by older advanced gas-cooled reactors. The UK's only current PWR, Sizewell B, has a significantly higher average capacity factor than the UK fleet average (83.9% lifetime average [31] versus 63.2% 5-year average [6]). New reactors, being PWRs, are expected to behave similarly to Sizewell B.

As a result, industry standard figures of 30% for offshore wind and 85% for nuclear are taken as central estimates. The lower bounds for both technologies are the worst figures reported for the UK from 2005 to 2009 [6], whereas the higher bounds are the achievable values expected for new build.

Photovoltaic capacity factors have been derived from the performance range observed in a large UK study [32].

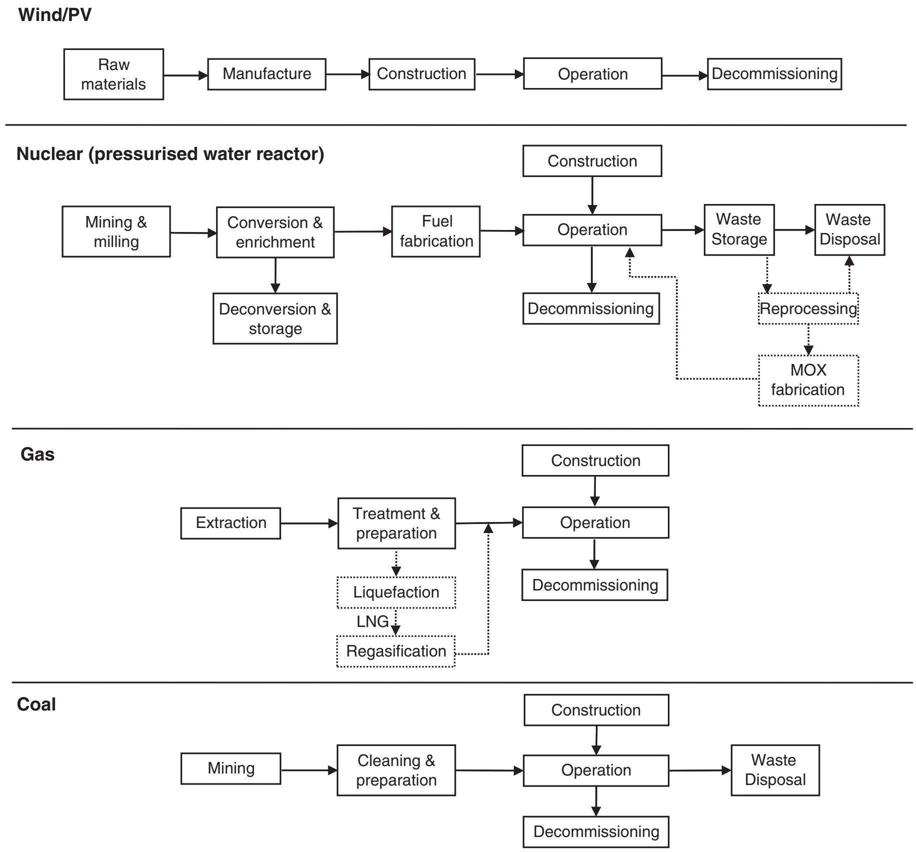

Figure 2. The life cycles of electricity from coal, gas, nuclear, wind and photovoltaics [---- optional stages, depending on the chosen fuel chain; MOX - mixed oxide fuel; LNG - liquefied natural gas].

Availability factors: these figures are based on various operational data obtained from the International Atomic Energy Agency (IAEA) [31], Scottish and Southern [33], North American Electric Reliability Corporation (NERC) [34], RenewableUK [35], International Energy Agency (IEA) [36] and Department for Business, Enterprise and Regulatory Reform (BERR) [37–46].

Technical and economic dispatchability: dispatchability is the ability of a generating unit to increase or decrease generation or to be brought on line or shut down as needed [5]. Technical dispatchability comprises four criteria: ramp-up and ramp-down rates as well as minimum up and down times (Table I). The overall technical dispatchability score for each technology is obtained by summing up its rank in each of the four criteria. Because wind and PV are not considered dispatchable as their output cannot be increased at will, they assume the worst rank for each criterion.

The data for technical dispatchability of the coal, gas and nuclear options have been obtained by observing operator-specified information [47] over a period of several months; they are summarised in Table II. It should be noted that these figures may reflect the way in which operators choose to run their plants rather than the plants' technical abilities.

The data for economic dispatchability, estimated as a ratio of capital and total levelised costs, are based on the cost estimates described further below.

Lifetime of fuel reserves: central estimates for the lifetime of fuel reserves reflect economically recoverable resources, as specified by NEA [48] and BP [49]. Lower estimates are calculated from the lifetime of current economically recoverable reserves and predicted demand increases, the latter of which are specified by WNA [50]

Table II. Summary of technical dispatchability data retrieved from balancing mechanism reporting system [47].

		Coal	Gas (CCGT)	Nuclear (PWR)
Ramp-up rate (%/min)	Worst	0.65	0.85	0.17
	Average	2.25	1.63	0.17
	Best	4.13	2.54	3.75
Ramp-down rate (%/min)	Worst	1.67	0.87	0.83
	Average	4.28	2.47	0.83
	Best	6.2	5.24	3.75
Minimum down time (min)	Worst	360	600	999
	Average	303.53	306.67	999
	Best	240	30	999
Minimum up time (min)	Worst	360	990	999
	Average	254.12	410	999
	Best	240	300	999

CCGT, combined cycle gas turbine; PWR, pressurised water reactor.

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and EIA [51]. Upper estimates reflect the total available resource [52]. For nuclear, this includes uranium from phosphates [53] and for gas, 'unconventional' resources (shale gas, coal-bed methane and 'tight' gas) [54].

2.2.1.2. Technological lock-in resistance

Ratio of plant flexibility and operational lifetime: flexibility reflects the ability of each technology for trigeneration, net negative CO_2 emissions and high temperature (800 °C) H_2 production. Ten points are accrued for each of the three criteria, with the sum being squared and divided by operational lifetime, as shown in Table III.

2.2.1.3. Immediacy

Time to plant start-up: this indicator has been estimated based on figures reported by vendors and utilities, including those incorporated into the cost estimates mentioned in the following text. As this indicator measures time taken to start up the plant from the start of construction, the figures do not include planning and preliminary studies.

2.2.1.4. Levelised cost of generation

Capital, operational, fuel and total levelised costs: cost estimates for nuclear, coal, offshore wind and gas are based on those by Mott MacDonald [55] at 10% discount rate. Because Mott MacDonald does not examine solar PV, the solar cost estimate is based on IEA data (average of OECD country estimates) [56]. Cost estimates here therefore inherit most of the assumptions made by the primary authors, such as plant lifespan and average capacity factor. However, these assumptions are broadly in line with those used in the rest of the assessment in this paper. The exception to this is capacity factor, which is universally assumed to be slightly higher than our estimates discussed earlier (see 'operability'). Nevertheless, because the capacity factors are higher for all options, their relative performance is consistent so the ranking of results is robust. Any subsidies are excluded from these costs, including the carbon price applied by the original authors and the Renewables Obligation Order [9]; subsidies are considered separately ('financial incentives').

Table III. Data used for technological lock-in resistance.

	Coal	Gas (CCGT)	Nuclear (PWR)	Wind (offshore)	Solar (PV)
Tri-generation	Yes	Yes	Yes	No	No
Net negative CO_2 emissions	No	No	No	No	No
Thermochemical H_2 production	Yes	Yes	No	No	No
Flexibility index, f (0–30)	20	20	10	0	0
Lifetime, l (years)	45	25	60	20	25
Technological lock-in score, f^2/l (years^{-1})	8.89	16	1.67	0	0

CCGT, combined cycle gas turbine; PWR, pressurised water reactor; PV, photovoltaics.
Italics are intended to denote the interim stages of calculation.

The cost data are summarised in the Appendix A. The values used in this study have been verified against earlier UK cost estimates [57,58] as well as data for other OECD countries published by IEA [56,59] and MIT [60]. These data are not included here as they have been found to agree broadly on the relative costs of each electricity option but not on the absolute costs. The reasons for this are twofold: firstly, the costs of electricity generation from all technologies have increased greatly in the last few years [55], making older studies obsolete, and secondly, costs (particularly capital) tend to be much lower in some OECD countries, such as South Korea, than in the UK which drags down the averages derived from studies of OECD countries. Because the solar PV estimate is based on OECD estimates, it is likely that the cost of solar has been underestimated here.

2.2.1.5. Cost variability

Fuel price sensitivity: this indicator has been estimated using the fuel cost data and total levelised generation costs discussed in the previous section.

2.2.1.6. Financial incentives

Financial incentives and assistance: this represents a 'snapshot' of the direct and indirect subsidies that could potentially be gained by owners of each electricity technology at the time of writing. The indicator includes the revenues that are available from the Renewables Obligation (using the 2011/2012 price set by Ofgem [9]) and the FiT (using 2011 bandings and assuming a 50:50 split between new and retrofitted domestic installations [10]). It should be noted that the FiT bandings are under review at the time of writing and the potential consequences of this are discussed in Section 3.1.6. Also included is an estimation of the carbon tax avoided by 'zero-carbon' (at the point of generation) technologies. This assumes that the 'zero-carbon' options—nuclear and wind—replace the equivalent capacity of gas CCGT emitting 400 g CO_2/kWh. The avoided carbon tax is not included for domestic PV, as building a CCGT would not be a valid proposition for a home owner. The resulting saving is calculated on the basis of the average carbon price in 2010/2011 of £12.69/t CO_2 [61]. No attempt is made to account for future changes in incentives. The derivation and breakdown of the results are shown in Table IV.

2.2.2. Environmental data and assumptions

As shown in Table I, the following environmental issues and related indicators are considered:

- Material recyclability;
- Global warming;
- Ozone layer depletion;
- Acidification;
- Eutrophication;

Table IV. Financial incentives for different electricity options.

	Coal (pulverised)	Gas (CCGT)	Nuclear (PWR)	Wind[a] (offshore)	Solar (PV)[b]
Number of ROCs received per MWh	n/a[c]	n/a	n/a	2.00	0
Value per ROC in 2011/12 (£)	n/a	n/a	n/a	38.69	0
Total ROC incentive (£/MWh)				*77.38*	*0*
Value of FiT for <4 kWp in 2011/12:					
New build (£/MWh)	n/a	n/a	n/a	0	378.00
Retrofit (£/MWh)	n/a	n/a	n/a	0	433.00
Total average FiT incentive (£/MWh)					*405.50*
Avoided emissions relative to CCGT (t CO_2/MWh)	0	0	0.4	0.4	n/a[d]
Total avoided carbon price[e] (£/MWh)	*0*	*0*	*5.08*	*5.08*	*0*
TOTAL (£/MWh)	0	0	5.08	82.46	405.50

CCGT, combined cycle gas turbine; PWR, pressurised water reactor; PV, photovoltaics.
[a]Wind energy does not benefit from FiT due to the large size.
[b]PV benefit from FiT only.
[c]n/a: not applicable.
[d]Replacing large-scale CCGT by a small-scale PV is not considered feasible; hence the avoided carbon price is not considered.
[e]Average carbon price from April 2010 to March 2011: £12.69/t CO_2.
Italics are intended to denote the interim stages of calculation.

- Photochemical smog;
- Water ecotoxicity (freshwater and marine); and
- Land use and quality (terrestrial ecotoxicity (TETP), land occupation and greenfield land use).

All environmental indicators, except for material recyclability and greenfield land use, have been estimated using life cycle assessment (LCA) and the CML 2001 impact assessment methodology (November 2009 update) [62,63]. The key assumptions are summarised in the following text. The CML method has been chosen because it is one of the most widely used life cycle impact assessment (LCIA) methods. Additionally, the impacts are based on either global or European data unlike, for instance, TRACI [64] which is mainly US-based. It is also a 'midpoint' LCIA method and therefore carries much less uncertainty than 'endpoint' alternatives, such as Eco-indicator 99 [65] and the endpoint components of the ReCiPe methodology [66]. Finally, it is much more transparent as the impact categories are disaggregated, unlike for example in Eco-indicator.

2.2.2.1. Material recyclability. Recyclability of input materials: material recyclability is the percentage of materials used for construction of a power plant that can potentially be recycled. For most construction materials, the potential recyclability is 100%. The exceptions to this are rock wool, which is assumed to be 97% recyclable [67], and concrete, which is calculated to be 79.4% recyclable [68]. Recyclability is calculated for each technology using the amounts of construction materials given in ecoinvent [68], as illustrated in Table V for gas CCGT (space limitation precludes showing the breakdown for other technologies).

The overall recyclability of nuclear plants is modified to reflect the fact that a percentage of materials will have been too irradiated to be recycled. This percentage is thought to be as low as 1.44% based on a Swiss study from 1985 [69], reflecting the fact that only a small volume of the total plant becomes contaminated assuming normal operation. Corroborating data are lacking in this area; however, a recent study of the AREVA EPR broadly agrees, showing that around 14 000 t of intermediate-level waste (ILW), low-level waste (LLW) and very low-level waste (VLLW) will arise from decommissioning, whereas the plant has a total mass approximating 400 000 t [70]. This would suggest that an estimate of <5% contamination is reasonable.

2.2.2.2. Other environmental issues. Environmental (LCA) impacts: all environmental impacts have been calculated using LCA as a tool. GaBi v4.4 LCA software [71] and the Ecoinvent v2.2 database [68] have been used for these purposes. The LCA models and data have been

Table V. An example of the amount of materials used for plant construction and their end-of-life recyclability for a 400 MW combined cycle gas turbine [68].

Material	Amount (t)	Recyclability (%)
Reinforcing steel	8800	100
Low density polyethylene	1300	100
Copper	440	100
Chromium	0.976	100
Chromium steel 18/8	1800	100
Aluminium	440	100
Nickel	6.3	100
Cobalt	0.720	100
Concrete	14 280	79.4
Ceramic tiles	4.2	100
Rock wool	660	97
Total materials	27 732	
Total recyclability of the plant		89% (24 771 t)

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developed anew or adapted from Ecoinvent to match UK conditions as follows:

- The current UK electricity mix is used for all relevant life cycle stages carried out it the UK;
- Fuel mixes reflect current UK conditions, including the use of LNG;
- Photovoltaic energy outputs are adjusted to UK insolation, according to data from IEA-PVPS [72] and Munzinger *et al*. [32]. An average world mix of PV technologies has been assumed [73], comprising 38.5% of mono-crystalline silicon panels and laminates, 52.3% of multi-crystalline Si panels and laminates, 4.7% of amorphous Si panels and laminates, 2.9% of ribbon Si panels and laminates and 1.6% of CdTe and CIGS (cadmium-indium-gallium-selenide) panels.
- The nuclear fuel cycle assumes burn-up of 53 GWd/tU to approximate likely new-build burn-up rates [28]. It is assumed that no MOX is used and that all spent fuel is sent to conditioning for disposal rather than reprocessing, in line with current UK policy [25]; and
- Offshore wind is based on 3 MW turbines [74].

Sensitivity analyses have been carried out to estimate the lower and upper bounds for the environmental impacts. As part of this analysis, each option has been remodelled to explore the effect of end-of-life recycling of all major components using current UK demolition recycling rates [75]. Additionally, variations in the most influential factors for each technology have been explored as follows:

- Coal: power station efficiencies have been varied from 26% to 42%, SO_2 capture by desulphurisation from 24% to 90% and NO_x removal by selective catalytic reduction from 0% to 79%. These ranges reflect operating coal plants in the UK, Germany, NORDEL (the former association of transmission system operators in Denmark, Finland, Iceland, Norway and Sweden) and various USA regions [76].
- Gas: the proportion of LNG has been varied from 0% to 100%.
- Nuclear: the proportion of MOX fuel used has been varied from 0% to 8%. The differences between enriching uranium via centrifuge and diffusion have also been assessed, with the proportion using centrifuge varying from 70% to 100%.
- Offshore wind: foundations have been assumed to be either steel monopile or concrete. In addition to 3 MW, turbine capacities of 2 and 5 MW have been assessed, with capacity factors of 30% and 50%, reflecting the average performance of offshore wind today and its potential performance in the future, respectively. The 2 MW turbine models are from Ecoinvent [68] and 3 and 5 MW models are from the SPRIng database [74].
- PV: each technology type has been assessed for a slanted roof installation. In addition, mono-crystalline and multi-crystalline Si panels and laminates have been modelled for installation on a building façade; the former two have also been modelled for a flat roof mounting.

Greenfield land use: this indicator is based on visual inspection of the land plots of accepted and proposed new build projects by large UK utilities and energy developers—including RWE npower, Scottish Power, E.On, 2CO Energy, Peel Energy and Vattenfall—as well as all the sites approved by the government for new nuclear build [77]. Table VI shows the proposed power plant sites for which data are available as well as the assumptions used.

2.2.3. Social data and assumptions

The social issues comprise (Table I) the following:

- Provision of employment (direct and indirect);

Table VI. Proposed power plant data used in estimating greenfield land use [77].

Technology	Site/proposal	Proposed capacity (MW)	Land status
Coal (pulverised)	New plants without CCS not permitted	n/a	n/a
Gas (CCGT)	Drakelow D	1320	Brownfield
	Drakelow E	1320	Brownfield
	Tilbury C	2000	Brownfield
	Willington C	2000	Brownfield
Nuclear (PWR)	Bradwell	1650	Greenfield
	Hartlepool	Grid connection not yet agreed	Brownfield
	Heysham	1650	Greenfield
	Hinkley Point	3340	Greenfield
	Oldbury	Connection agreed; capacity tba	Greenfield
	Sellafield	3200	Greenfield
	Sizewell	3300	Greenfield
	Wylfa	3600	Greenfield
Wind (offshore)			Land use negligible
Solar (PV)			No land use (rooftop installation)

CCGT, combined cycle gas turbine; PWR, pressurised water reactor; PV, photovoltaics.

- Human health impacts (worker injuries, human toxicity, worker health impacts from radiation and health impacts from radiation on workers and population);
- Large accident risk;
- Local community impacts (staff from local community, local suppliers and investment in local community);
- Human rights and corruption;
- Energy security (avoidance of fossil fuel imports, fuel supply diversity and fuel storage capability);
- Nuclear proliferation; and
- Intergenerational equity (abiotic resources, storage of radioactive waste and storage of captured CO_2).

2.2.3.1. Provision of employment. Direct and total (including indirect) employment: employment related to the extraction of ores and aggregates (for manufacture of concrete, steel and other metals) has been calculated for each option based on material requirements specified in Ecoinvent [68] and employment data from BHP Billiton [78] and the Mineral Products Association [79]. The processing of raw materials into metals is based on labour data from Corus [80]. Construction figures have been derived from estimates for new build projects produced by utility companies, except in the case of nuclear power which is based on a study by Cogent SSC [81]. The operational stage figures are again derived from utility company data, and for nuclear power, the same Cogent SSC study. Employment derived from the manufacture of replacement components during operation of technologies is not included. However, to meet this criterion, employment for the operational stage of solar PV had to be estimated by multiplying an aggregated indirect employment figure of 0.33 jobs per MWp installed capacity by 0.25 [82,83]. This is because the only data available implicitly included jobs provided by manufacturing replacement components. Because of a lack of available estimates in the literature, employment during decommissioning is assumed to be 20% of construction employment, except in the case of PV, for which decommissioning is allocated to roof replacement and therefore assumed to be zero.

With regard to indirect employment, the life cycle approach means that work normally classed as indirect (such as that due to the fuel cycle) is already included. During the operational stage, maintenance employment is included but only for inspection and installation of replacement parts; employment owing to the manufacture of parts is excluded.

For the non-renewable options, fuel cycle employment was calculated using data from Areva [84], Oil and Gas UK [85] and the UK Coal Authority [86]. As most coal used in the UK is imported, the latter figures were also verified against South African data [87]. Note that although South Africa only supplies about 10% of UK steam coal imports [6], data are not available for the main supplier, Russia.

2.2.3.2. Human health impacts. Worker injuries: the worker injury results are directly linked to the employment results in that the number of person-years of employment for each life cycle stage is used to calculate the number of expected injuries using Health and Safety Executive data [88] appropriate for the respective type of labour. For instance, construction stages are based on average injury rates for the whole UK construction sector. Injuries included in the estimate are fatalities, major injuries and less serious injuries that cause an absence from work of more than three days. For stages of the life cycle occurring outside the UK, the same UK injury rates are used for reasons of consistency. It is acknowledged that rates may differ in other countries, but different national methods of injury rate estimation mean that figures from different countries are rarely comparable.

Human toxicity potential (HTP) and total human health impacts from radiation: these two impacts are estimated as part of LCA (Section 2.2.1.2.2).

Worker human health impacts from radiation: this indicator measures worker exposure to radiation but is only recorded by the nuclear industry so that comparison between the different electricity options is not possible. Therefore, this indicator is not considered here.

2.2.3.3. Large accident risk. Fatalities due to large accidents: large accident fatalities are based on data from the Paul Scherrer Institut [89] drawing on previous work using their historical Energy-Related Severe Accident Database and in the case of nuclear power, probabilistic safety assessment [90,91]. These results represent present-day estimates under Swiss conditions but have been assumed here to be suitable as an approximation of UK conditions.

2.2.3.4. Local community impacts and human rights and corruption. These impacts have not been considered, as they are company-specific and therefore cannot be assessed at the technology level.

2.2.3.5. Energy security. Avoidance of fossil fuel imports and fuel supply diversity: the amount of imported fossil fuel potentially avoided is calculated from the average efficiency of the current UK fossil fuel fleet [calculated from 6] on the basis that a unit of electricity generated by non-fossil capacity displaces a unit generated by fossil capacity. This is described further in Stamford and Azapagic [5] as is the methodology of the diversity of fuel supply indicator, which has been calculated using 2009 UK data [6]. For uranium supply, UK import data have not been available, so EU data have been used instead [92]. However, because uranium is generally imported to the UK as fuel assemblies manufactured in Europe, this is arguably equivalent.

Fuel storage capabilities: fuel storage capabilities are, for coal and gas, based on a 5-year average net calorific value data for fuel imported to the UK [6]. When quantifying fuel storage for nuclear power, it is more relevant to consider fuel assemblies than uranium itself; therefore, this indicator has been quantified using fuel assembly data from AREVA [28] on the basis of 50-GWd/tU burn-up.

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2.2.3.6. Nuclear proliferation. The use of non-enriched uranium, reprocessing and requirement for enriched uranium: neither the AREVA EPR nor the Westinghouse AP1000 is capable of refuelling whilst online, although they do both require enriched fuel. Regarding reprocessing, it is assumed that any new nuclear plants built in the UK will operate on a once-through cycle (i.e. reprocessing will not occur), as this is current policy [25]. Thus, nuclear power deployable in the near future scores one out of three on the nuclear proliferation scale (for further description see Stamford and Azapagic [5]).

2.2.3.7. Intergenerational equity. Abiotic resources (elements and fuels): these indicators have been estimated as part of LCA (Section 2.2.1.2.2).

Volume of radioactive waste and liquid CO_2 for storage: volume of radioactive waste to be stored is calculated on the basis of lifetime waste production data [93,94], assuming the standard 85% capacity factor discussed in Section 2.2.1. The results refer to the packaged volume of ILW and spent fuel. The indicator related to storage of liquid CO_2 is not applicable in this analysis as CCS technologies are not considered.

3. RESULTS AND DISCUSSION

This section presents the assessment results comparing the five options on different sustainability aspects. The summary results are shown in Figures 3–5; full results for each option and the indicators can be found in Appendix A.

However, it should be noted that this study considers the electricity options in isolation. In reality, it is likely that there will be complex interactions and related consequences that cannot be captured here. For instance, increased penetration of wind or PV (i.e. the least dispatchable technologies) has implications for the UK grid as a whole: increased system reserve may be needed to mitigate variability in output and risk of sudden large capacity loss; dispatchable generators such as coal and gas plants may need to follow load more fully, which will have maintenance and efficiency consequences; demand-side management may be needed to match supply to demand better. The implications of these impacts are highly uncertain and depend on the composition of the grid as a whole and cannot be assessed at the technology level. They have, however, been discussed where appropriate throughout this section.

3.1. Techno-economic sustainability

3.1.1. Operability

Capacity and availability factors: higher availability potentially allows higher capacity factors, effectively reducing the cost (as well as social and environmental impacts) by producing more energy from the same resources. However, the implications differ for each option. For instance, as shown in Figure 3, the central availability factors for all technologies considered range from 81% (wind) to 96% (PV), meaning that each option is able to supply electricity at least 81% of the time. Yet, only nuclear power actually does, as its capacity factor is 85%, whereas that of PV is only 8.6%. For coal and gas, the capacity factor is largely a case of operator's discretion as the power stations are used, to an extent, to follow load, thereby maximising profit and satisfying the demands of the grid. In contrast, nuclear plants run continuously because of the low marginal cost of operation. As a result, improving reliability (and thus availability) is likely to have more influence on the capacity factors of nuclear plants than fossil plants: the annual output of nuclear plants is currently

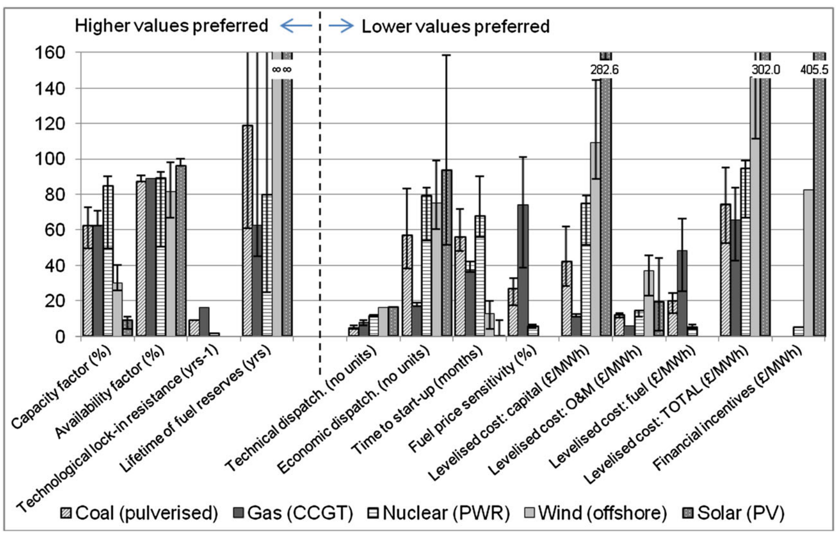

Figure 3. Techno-economic sustainability of electricity technologies.

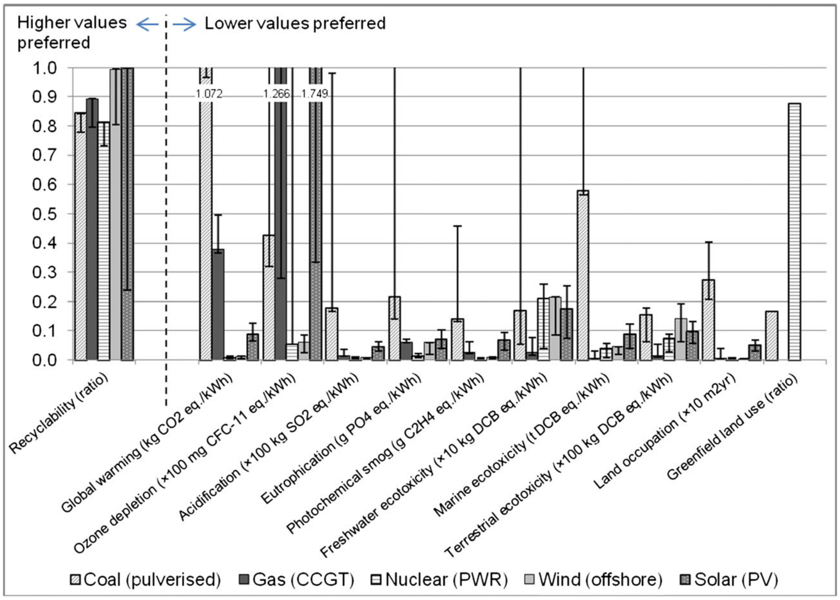

Figure 4. Environmental sustainability of electricity technologies.

limited by availability—if it was possible to produce electricity all the time, the operator would choose to do so—whereas the annual output of fossil plants is limited by the cost of fuel and the price of electricity sold to the grid.

In contrast to both of these cases, the capacity factors of renewables are dictated largely by environmental conditions (incident wind and sunlight). In the case of solar power, with its already high availability of 96%, capacity factors can only be increased by better installation and choice of site. Indeed, more than 60% of UK installations are thought to be affected by problems such as partial shading; in severe cases, this reduces output by several tens of percent [32].

Wind power, for the time being, appears to be underperforming on the actual availability, relative to that suggested by its proponents. For example, the analysis of Scroby Sands, Kentish Flats, Barrow and North Hoyle wind farms carried out in this study shows an average availability of 81.4%, compared with 98% claimed by RenewableUK [35]. However, this may improve as knowledge and expertise are gained in maintaining this relatively new technology. The current capacity factors of around 30% for wind farms will also increase as turbines grow in size, exploiting the higher wind speeds at increased altitude [30].

Technical and economic dispatchability: the dispatchability of generators has been the subject of increased scrutiny in recent years as the prospect of wider adoption of intermittent renewables has raised grid management concerns. Because offshore wind and PV are not dispatchable (Section 2.2.1.1), as shown in Figure 3, they are the worst options with respect to both technical and economic dispatchabilities. Coal and gas, on the other hand, are highly dispatchable and are therefore the preferred options for these two indicators.

However, recent studies suggest that, although the costs and complexity of balancing the grid (matching supply to demand) will increase proportionately with wind penetration, this increase is modest enough to allow wind power to expand to several times its current capacity without significant problems [see, for instance, 95,96]. National Grid, for example, estimates that an increase in wind capacity by a factor of 5 (from 5.8 to 30.6 GW) would necessitate only a 70% increase in average operating reserve capacity[3] [96].

In the case of nuclear power, although not as dispatchable as coal or gas, this is mainly an economic issue rather than a technical one, resulting from high capital costs and very low marginal cost. In the future, if the grid changes in such a way that nuclear generators are able to attain greater revenue from electricity sold at times of high demand, it is conceivable that partial load-following would become economically viable. The technical ability to achieve this has been demonstrated elsewhere in Europe, particularly France.

Lifetime of global fuel reserves: the lifetime of global fuel reserves is an important strategic indicator of energy security, as short lifetimes suggest that supply may fail to match demand in the near to medium term, causing price and/or political volatility and potentially disrupting

[3]Operating reserve requirement describes the unused capacity needed on the grid to balance out predicted short-term changes in demand or supply. Plants providing this spare capacity are required to generate the full amount at 4-hour notice. The reserve requirement in 2011/12 was 4.78 GW. National grid estimate this will increase to 8.13 GW in 2025/2026 when wind capacity is expected to reach 30.6 GW [96].

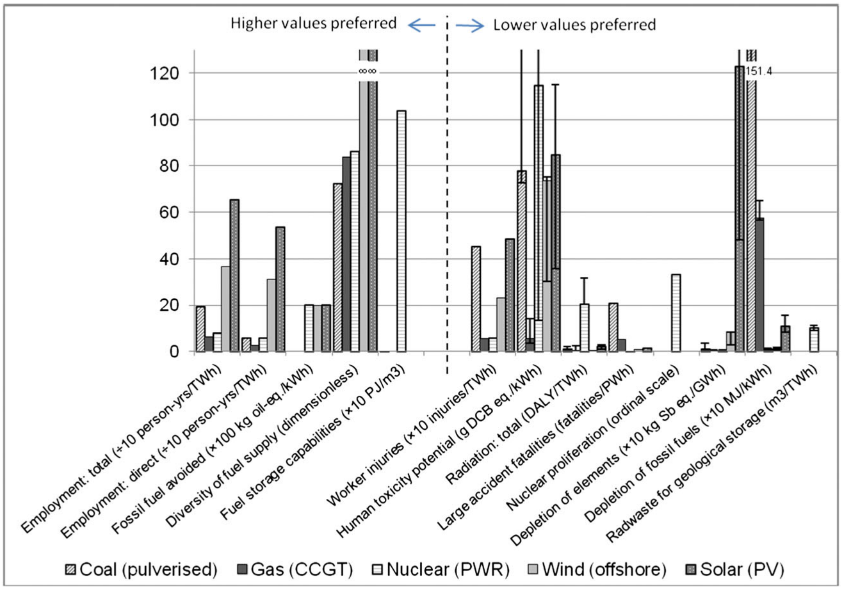

Figure 5. Social sustainability of electricity technologies.

service provision. However, estimating a reserve lifetime meaningfully is difficult because of uncertainties over future discoveries and demand trends. The central estimate given in Figure 3 is the current ratio of economically recoverable reserves to annual production. Using this measure, and excluding renewables (for which supplies are effectively infinite), values range from 63 years for natural gas to 80 years for nuclear to 119 years for coal. However, the incentive to increase exploration comes from increased fuel demand and the resulting increase in prices; therefore, it is likely that new reserves or sources will be discovered, or that uneconomic reserves will become economic. Arguably, uranium has the greatest likelihood of extending its reserve lifetime due to the relatively low level of exploration in recent decades and the increasing possibility of extraction from alternative sources such as phosphates and at higher prices, sea water. Additionally, fast breeder reactors provide the possibility of effectively increasing reserve lifetimes to around 34 000 years [53].

3.1.2. Technological lock-in resistance

Ratio of plant flexibility and operational lifetime: this indicator is an estimate of how well each option caters for potential changes in the way that energy is used nationally, accounting for whether it could be modified to tri-generate electricity, heating and cooling, to have negative global warming potential (GWP) (e.g. integrated biomass and CCS) or to produce high-temperature hydrogen. As shown in Figure 3, gas power is preferred from this perspective due to the relatively short lifespan of CCGTs together with their high temperatures which makes combined heat and power possible as well as thermo-chemical hydrogen production. In this instance, wind power is the worst option (Figure 3) because, despite its relatively short lifespan (20–25 years), it cannot provide anything other than electricity.

3.1.3. Immediacy

Time to start up: a shorter construction period is preferable from the industrial perspective because it minimises uncertainty and pay-back period. In this respect, domestic PV installations are, at first glance, preferable, with installation taking only 2–3 days (Figure 3). However, this partly reflects their small size in comparison with the other technologies (circa 3 kW compared with >100 MW for the other options). A more direct comparison may be found in larger PV installations, such as the 70 MW Rovigo plant that was completed in 9 months [97]. However, this still compares favourably to other options: the comparably sized 90 MW Barrow and Burbo Bank wind farms were built in 11 and 15 months, respectively [98]. These periods compare to around 37.5 months for gas, 56 months for coal and 68 months for nuclear (Figure 3). However, first-of-a-kind nuclear (and coal CCS) plants will take longer than this. For instance, the first EPR in Finland, Olkiluoto 3, is now expected to take over 90 months [99].

3.1.4. Levelised cost of generation

Capital, operational, fuel and total costs: the costs shown in Figure 3 represent the market cost of electricity generation excluding incentives provided by market mechanisms, which are discussed in Section 3.1.6. They are not, therefore, the net costs paid by owners. Overall, the gas option has the lowest average total annualised costs (6.5 pence/kWh) and PV by far the highest (30.2 p/kWh) despite the fact that PV costs are likely underestimated

(Section 2.2.1). The contribution of different costs to the total differs greatly between the options. For example, 80% of the cost of nuclear power is due to the capital cost, whereas fuel contributes less than 10% to the total. The converse is true for gas, where 75% of the cost is due to the fuel and less than 20% due to the cost of the power plant [56].

The levelised costs are estimated using a set discount rate, the level of which may affect the ranking of the options according to differences in the relative magnitude of cost components. There is much argument over discounting and its role in sustainability [see, for example, 100], the main premise of which is that high discount rates grossly diminish liabilities that occur far into the future (such as nuclear plant decommissioning) and that this is effectively a theft from future generations. There is a large body of literature in this area, review of which is beyond the scope of this paper. However, contrary to popular assertion, nuclear power is in fact penalised by high discount rates as a result of its large initial capital component: although discounting disguises costs in the future, it effectively magnifies costs in the present, meaning all technologies with a large capital component (nuclear, wind and PV) appear more expensive at higher discount rates. As an illustration, raising the discount rate from 5% to 10% increases the cost of nuclear power by more than 60%, whereas the corresponding increase for gas power is less than 10% [calculated from 56].

The results in Figure 3 show that offshore wind and PV are currently far from grid parity, whereas coal, gas and nuclear are broadly comparable except from the distribution of their cost components. As discussed, the fact that nuclear, wind and PV are highly capital-intensive makes them more susceptible to discount rate choice, with lower discount rates favouring them. This capital component does, however, pose a problem in an uncertain market, as it exposes owners to greater losses if plant lifetime is cut short for any reason. This is the case, for example, with German nuclear power plants that will be decommissioned earlier due to a legislative u-turn following the Fukushima incident. Another example of the importance of the capital cost is the 1.6 GW nuclear reactor under construction by EDF at Flamanville, France, which is expected to cost €5 bn (£4.4bn) [101]. In contrast, the larger 2 GW gas CCGT currently under construction by RWE npower at Willington, UK, has an estimated capital investment of £1bn [102]. To account for this differing level of risk, it is likely that a potential investor in nuclear, wind or PV technologies would assess these options at higher discount rates than, for example, gas power, increasing their apparent cost. This would be an attempt to illustrate the higher risk premium, and correspondingly, higher return on investment required to make nuclear, wind or PV profitable.

3.1.5. Cost variability

Fuel price sensitivity: fuel prices are generally volatile, particularly over periods as long as the lifetime of a power plant. As such, they are the major component of future cost uncertainty. This is a significant problem for fossil fuel power stations, particularly as fuel reserves decrease and demand increases greatly due to developing countries such as China and India. Fuel constitutes 75% of the total levelised costs for gas plants [56], exposing owners to highly uncertain operating costs in the future. Coal plants are also vulnerable to fuel price increases as fuel costs contribute around 30% to the total levelised costs. The polar opposite of these cases is fuel-free renewable energy, for which the main source of future cost uncertainty is maintenance. For nuclear power, fuel constitutes under 10% of the total cost [56], and less than half of this is the price of the uranium itself [103]. This provides a buffer to both increasing extraction costs and increasing processing costs, enabling power plant owners to tolerate a very large increase in the price of either.

3.1.6. Financial incentives

Financial incentives and assistance: two types of incentives can be distinguished: regulatory tools used by the government to drive the market in a particular direction and hidden subsidies that are not used as market tools. The former have been included here (Figure 3), namely the FiT and ROCs, which show the incentives available to power technology owners. Additionally, as an avoided cost for non-fossil technologies, the carbon price is included. From this, it is clear that PV is currently benefitting from far higher incentives than any other option as the government attempts to make PV financially viable via regulation. It is interesting to note that incentives for PV (40.6 p/kWh) exceed expected costs (30.2 p/kWh), making PV under current conditions profitable without selling any electricity back to the grid. This is because FiT payments are based on the total amount of electricity generated, regardless of how much is fed back to the grid. It is perhaps because of this that the UK Government has recently reviewed the FiT scheme and cut payments approximately in half for all installations registering FiT eligibility from March 2012 [see 104]. Under the revised scheme, the incentive for residential PV has decreased to 21 p/kWh.

It is clear that the EU Emissions Trading Scheme carbon price currently has a very limited effect on the financial viability of low carbon technologies. The government has proposed to introduce a carbon price floor from 2013, starting at £16/tCO_2 and rising to £30/tCO_2 by 2020 [19] to strengthen the scheme, which compares with the 2010/2011 average of £12.69/tCO_2 [61]. This change will have a modest effect on the incentives received by PV and wind installations, as they already receive far greater incentives from the FiT and ROCs, respectively. Nuclear power, on the other hand, does not benefit from ROCs or FiT and has costs significantly lower than wind or PV, meaning that a move to increase the carbon price will significantly strengthen its economic case: as shown in Table IV, present day nuclear power effectively avoids a carbon tax of 0.51 p/kWh compared with its total levelised cost of 9.5 p/kWh. At a carbon tax of £30/tCO_2, the avoided cost becomes 1.2 p/kWh, which is clearly a more significant incentive.

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The recently announced 'contract-for-difference'[4] will directly subsidise producers of low-carbon electricity by guaranteeing them a set sale price [19]. However, this is not included here as its potential cost is currently unclear.

The second component of this indicator, hidden subsidies, includes costs that are borne by the economy indirectly and that serve to increase the economic attractiveness of particular technologies. For instance, nuclear installations in the UK are currently only required to insure for a maximum liability in case of an accident of £140m [105] (although this is currently being amended to the equivalent of €1.2bn or ~ £1.05bn [106]). This compares with estimated losses to Belarus of $235bn (~£145bn) over 30 years as a result of the Chernobyl accident [107]. The difference arguably represents a subsidy that plant owners receive by not being required to insure their true liability (although it is also true that such large sums cannot be insured by the market). Ultimately, the amount paid by the owner in the event of a large accident would depend on many unmeasurable variables, such as the size of the company and the policies of the national government. In addition to insurance caps, hidden subsidies include the following:

- The administrative cost of technology-specific market tools (ROCs, FiT and carbon price);
- Increased maintenance costs incurred by thermal power plant owners as they are forced to run their plants more variably to compensate for intermittent renewables on the grid;
- The costs of increased system reserve due to intermittent renewables and single large capacity plants on the grid;
- Any subsidies in the production of gas and coal in the UK; and
- Subsidies to fossil fuel production in fossil fuel exporting countries (if the aim is to evaluate global hidden costs).

Unfortunately, most of the aforementioned have not been analysed thoroughly for the UK, meaning they cannot be included in the results presented here. Much further work is needed in this area, in part due to a lack of data but also due to problems of allocation and uncertainty, for example, where subsidies are applied to more than one technology simultaneously or may not be applied in certain cases.

3.2. Environmental sustainability

3.2.1. Material recyclability

Recyclability of input materials: Figure 4 shows the potential recycling rates for each option, illustrating that some technologies are more recyclable than others. For instance, 80%–90% of a typical coal, gas or nuclear plant can be recycled, with the limit largely being due to extensive use of concrete.[5] In the case of nuclear power, inevitable radioactive contamination will preclude the recycling of some materials. However, as discussed in Section 2.2.1.1, for a large plant, the mass of contaminated material is estimated to range between 5000 and 14 000 t [69,70], which constitutes less than 5% of the total plant mass. As a result, the recyclability of nuclear power plants is not as limited as might be expected, with an overall estimate of 81%.

In contrast to conventional plants, a typical large offshore wind turbine mounted on steel monopile foundations is up to 99% recyclable, as is a typical PV panel and its mounting. However, in reality, it is unlikely that such high recycling rates are achievable. Decommissioning an offshore wind farm typically involves leaving a mass of steel in the seabed to reduce cost and minimise disruption to benthic life [see, for instance, 108]. In the case of typical PV modules, solar glass coated in metal oxides makes up a large part of total mass and this may pose recycling difficulties [109]. This is less of a problem for 'thin-film' panels, such as CdTe, as the amount of glass used is lower.

To illustrate the effect of material recycling on the life cycle environmental impacts, Table VII compares the impacts of material recycling at the current UK rates to the equivalent impacts without recycling. The effect on each technology is compared using GWP and marine ecotoxicity (MAETP) as illustrative indicators. As shown, the greater benefit from recycling is achieved for PV and wind than for the other three options. This is because of the origin of their life cycle impacts: for gas and coal power, these are mainly accrued during the extraction and operational phases, making the effect of recycling construction materials almost negligible. In contrast, the majority of wind and PV life cycle impacts are due to manufacture of components; therefore, their recycling yields greater improvements. An exception to this trend is the MAETP of gas power, where significant reductions can be made by recycling. This is because the operational impact of the gas life cycle on marine toxicity is very small relative to the coal and nuclear life cycles (see the section on marine toxicity below), meaning the impacts from manufacture and construction are amplified.

3.2.2. Global warming

Global warming potential: as shown in Figure 4, nuclear and offshore wind have the lowest GWP, with the central estimates of 6.2 and 11.2 g CO_2 eq./kWh, respectively. By comparison, the current average GWP from

[4]The 'contract-for-difference' mechanism is essentially a long-term sale price guarantee, with the caveat that any revenue exceeding the set price (or 'strike price') is paid back to the government. For instance, a generator with an agreed strike price of 7 p/kWh is guaranteed that income—if the electricity is sold for 4 p/kWh, the government pays the generator the remaining 3 p/kWh—but if the generator sells for 8 p/kWh, the extra 1 p/kWh is paid back to the government [19].

[5]Concrete cannot be recycled in the traditional sense: it is typically crushed into aggregate, some of which is used to manufacture new concrete, but this requires the addition of new cement. A large proportion of crushed concrete is also 'downcycled' for various applications such as the back-filling of quarries and the engineering of landfill sites. Some used concrete is landfilled.

Table VII. Reduction in global warming potential and marine ecotoxicity due to end-of-life recycling at current UK rates[a].

	Reduction of impact relative to no recycling (%)	
	Global warming potential	Marine ecotoxicity potential
Coal (pulverised)	0.06	0.25
Gas (CCGT)	0.05	19.16
Nuclear (PWR)	2.14	1.66
Offshore wind (3 MW, steel monopile foundation)	28.56	59.37
PV (domestic mono-Si panel)	16.54	49.22

CCGT, combined cycle gas turbine; PWR, pressurised water reactor; PV, photovoltaics.
[a]Current UK recycling rates: construction aluminium = 95% [102]; all other construction metals = 99% [67]; plastics = 26% [67]; concrete = 71.5% (79.4% as discussed in Section 2.2.1.2.1, modified with 90% [103]); paper = 64% [104]; fibre-reinforced plastic = 10% [105]; insulation = 18% [67]; ceramics = 64% [67]; glass = 0% [101].

the UK electricity mix is 584 g CO_2 eq./kWh [68]. Solar PV is also a relatively good option with GWP of approximately 88 g CO_2 eq./kWh for the UK mix of PV technologies (see the assumptions in Section 2). Newer PV technologies tend to be preferable, with ribbon-Si laminate and cadmium-telluride having GWP of 65 and 74 g CO_2 eq./kWh, respectively.

Gas power is estimated to generate 379 g CO_2 eq./kWh using the most efficient CCGT available. However, unlike other technologies, emissions from CCGTs are likely to worsen in the future as LNG use continues to increase and indigenous production continues to decline: using 100% LNG gives a figure of 496 CO_2 eq./kWh compared with 366 CO_2 eq./kWh using only traditional North Sea and European piped gas. These figures respectively form the upper and lower bounds shown in Figure 4. Indeed, if the life cycle rather than direct emissions of greenhouse gases (GHG) were used in legislation, the upcoming EPS [19] would preclude the building of CCGTs for LNG contribution to the natural gas supply above 65%—the EPS enforces a limit of 450 g CO_2/kWh that is breached beyond this level of LNG use.

Coal power is significantly worse than any other option considered here, with a central estimate of GWP at 1072 CO_2 eq./kWh.

3.2.3. Ozone layer depletion

Ozone layer depletion potential (ODP): since the Montreal Protocol [110], signatory countries have phased out production of CFCs and halons. However, substances manufactured in non-signatory countries are still associated with global energy chains, making ozone layer depletion an extant problem. In this respect, the PV life cycle is the least preferable with OPD of 17.5 μg CFC-11 eq./kWh, 32 times that of the best option, nuclear power (Figure 4). This is because of the manufacture of tetrafluoroethylene, the polymer of which, Teflon, is often used in solar cell encapsulation. Natural gas is the second worst option with ODP of 13-μg CFC-11 eq./kWh. This is a result of halogenated gases used as fire retardants in gas pipelines. Therefore, there is a dichotomy between global warming and ozone layer depletion: to reduce the latter, using 100% LNG is preferable due to the reduced need for gas pipelines but the use of LNG increases global warming, as discussed in Section 3.2.2.

Again, nuclear and offshore wind are comparable with 0.54 and 0.6 μg CFC-11 eq./kWh, respectively. The anomalous upper bound of 73 μg CFC-11 eq./kWh for nuclear power is due to the sensitivity analysis (Section 2.2.1.1) considering the impact of enriching uranium via diffusion: the high impact is due to the use of Freon (CFC-114)[6] as coolant in the United States Enrichment Corporation (USEC) diffusion plants. However, this is of little consequence for nuclear power in the UK and is shown here only to illustrate worst-case values for ODP.

3.2.4. Acidification

Acidification potential (AP): the coal life cycle is the worst option for this indicator, with a value of 1.78 g SO_2 eq./kWh. The vast majority of this impact is from emissions of NOx and SO_2 during extraction, transport and combustion of the coal itself. The second worst option is PV with an AP of 0.44 g SO_2 eq./kWh. With a factor of 10 lower AP (0.04 g SO_2 eq./kWh), nuclear power is the most sustainable option with respect to the life cycle emissions of acid gases.

3.2.5. Eutrophication

Eutrophication potential (EP): this environmental impact shows the same trend as acidification: coal power is the outlier with 0.215 g PO_4^{3-} eq./kWh predominantly due to emission of NOx during extraction, transportation and combustion of coal. As for AP, the next worst option is PV with a value of 0.069 g PO_4^{3-} eq./kWh. However, certain PV technologies have much lower EP of which the best option is amorphous Si laminate with a value of 0.038 g PO_4^{3-} eq./kWh. By comparison, natural gas and offshore wind have EP of approximately 0.06 g PO_4^{3-} eq./kWh.

3.2.6. Photochemical smog

Photochemical oxidant creation potential (POCP): the ranking of options for this impact is the same as for acidification and eutrophication (Figure 4): with POCP of 0.140 g C_2H_4 eq./kWh, coal is the worst option, mainly due to emissions of volatile organic compounds from

[6]Although the manufacture of CFCs in the US ended in 1995 in accordance with the Montreal Protocol, there are still large stockpiles of Freon that can be used until exhausted.

mining and NO_x from combustion of coal. Nuclear is the best option for this indicator, with a factor of 28 lower POCP (0.005 g C_2H_4 eq./kWh).

3.2.7. Water ecotoxicity

Freshwater ecotoxicity (FAETP): as shown in Figure 4, the options are fairly evenly matched for this impact with the exception of gas that is by far the best option, outperforming the other technologies by a factor of 6–8. Nuclear and wind power have the highest FAETP. In the nuclear life cycle, over 70% of this impact is due to long-term emissions of metals such as vanadium, copper and beryllium from uranium mill tailings. For wind, the manufacturing chains of metals such as steel and nickel are the main contributors to FAETP.

Marine ecotoxicity : gas is also by far the best option for MAETP, outperforming the worst option, coal, by several orders of magnitude. The main reason for the high impact from coal is emission of hydrogen fluoride (HF) to air during combustion, which contributes 91.6% to the total. HF emissions also make PV the second worst option but this time from the metal manufacturing chain.

As also indicated by the ranges in Figure 4, for both marine and FAETP, coal power can be several orders of magnitude worse than the other options under worst-case assumptions (i.e. a very inefficient plant without pollution abatement technologies).

3.2.8. Land use and quality

Terrestrial ecotoxicity: TETP results in Figure 4 show that, although coal has the greatest impact for the central estimate, under the most favourable assumptions, it is comparable with nuclear power, offshore wind and PV. The latter two are disadvantaged by their relatively high metal requirements: more than 95% of the impact is due to emissions of heavy metals such as chromium, mercury and arsenic in the steel and copper production chains. As a result, this impact can be reduced by recycling the metals, decreasing TETP by 28% for wind and 37% for PV. The same processes contribute significantly to TETP from nuclear power but to a much lesser extent. More than half of the impact is due to emission of heavy metals to air from uranium mill tailings. The gas option is the best with respect to this impact.

Land occupation: over the whole life cycle, coal power occupies more land (0.027 m^2yr) than the other options, with 99.3% of that occupation being by coal mines and associated infrastructure. The second worst option is PV which occupies 0.005 m^2yr, whereas land occupation by nuclear, gas and offshore wind is negligible (Figure 4). Note that the roof space taken up by the PV panels is not included as this is not in competition with any other potential uses. Rather, approximately 95% of the total land occupation by PV is due to production of metals for the manufacture of the panel with the remaining 5% being the panel manufacturing site itself.

Greenfield land use: the greenfield land use indicator is intended to describe the percentage of new power plants likely to be built on greenfield land and as such only the operational stage is considered. Being positioned on rooftops and at sea, PV and offshore wind have a value of zero. Because no new coal plants without CCS will be built in the UK, this indicator has not been quantified for coal. Of the eight sites approved for new nuclear build, all but one (Hartlepool) is greenfield, despite all of them being adjacent to existing nuclear sites. This gives the nuclear option a score of 0.875, meaning that 87.5% of new nuclear power plants will be built on greenfield land (Figure 4 and Table VI). In contrast, no CCGTs are currently proposed on greenfield sites.

3.3. Social sustainability

3.3.1. Provision of employment

Total employment: total employment estimates in Figure 5 comprise direct and indirect employment. The former is related to the power plant erection, operation, maintenance and decommissioning, whereas the latter refers to jobs in fuel mining and production, waste management and other services to the plant over its lifetime. The results show that the gas and nuclear options employ the fewest people, 62 and 81 person-years/TWh, respectively. The coal chain employs more than double this (191 person-years/TWh), whereas offshore wind and PV provide the highest employment (368 and 653 person-years/TWh, respectively). The employment for PV increases significantly (1022 person-years/TWh) if the manufacture of replacement parts and other indirect operational activities are included. The reason that the renewables achieve such high employment is in part due to their lower capacity factors (30% for wind and 8.6% for PV): electrical output is relatively low compared with the fixed labour requirements for manufacturing, installation and maintenance, meaning that employment per unit of electricity generated is high.

However, the distribution of employment along the life cycle differs substantially between the five technologies. For example, the majority (68%) of employment for the coal option is in the mining stage. For wind, on the other hand, the majority (79%) is due to operation and maintenance, whereas most jobs in the PV life cycle (63%) are due to the installation of the panels on rooftops.

Direct employment: when indirect employment is excluded from the total, coal and nuclear power become comparable, each providing direct employment of 56 person-years/TWh. The gas option has the lowest direct employment of 27 person-years/TWh, whereas wind and PV are the best options for this indicator with 305 and 537 person-years/TWh, respectively.

3.3.2. Human health impacts

Worker injuries: life cycle worker injuries closely mirror employment as injuries occur in all professions, meaning that more employment generally causes more injuries. However, injury rates are particularly high in the construction and mining sectors, giving coal power a disproportionately high injury rate owing to the dominance of mining in the total employment (Figure 5). As a result, the coal life cycle causes approximately 4.5 injuries (fatal, major and minor) per TWh, 91% of which occur at the mining stage. However, this is exceeded by the PV life cycle that causes 4.84 injuries per TWh, primarily due to its extremely high employment rate. This injury rate is 8–9 times that of gas or nuclear power.

Human toxicity potential, excluding radiation: the ranking of the options for this social impact is very similar, with the exception of nuclear power (Figure 5). Emissions of heavy metals including arsenic and chromium are substantial in the nuclear life cycle, the bulk coming from uranium mill tailings, ultimately making nuclear power the most toxic option to humans with HTP of 115 g DCB eq./kWh. By comparison, the best option, gas, has the value of 5.4 g DCB eq./kWh, less than 5% of the impact from nuclear power.

As is the case for worker injuries, PV has a greater impact than coal on the basis of the central estimates. However, although 78% of HTP from coal power is caused in the operational stage due to coal combustion, the impact from PV is predominantly caused by emissions of heavy metals in the metal production chain and can therefore be reduced by recycling: the sensitivity analysis shows that recycling a mono-Si PV panel reduces its HTP by 54%. Similarly, although HTP for offshore wind is relatively high, this can be reduced by 51% by end-of-life recycling.

It should be noted that there is currently a disagreement between LCA impact methodologies over HTP results. As discussed, according to the CML methodology [62,63] used in this study, nuclear and solar PV have the highest HTP; this same trend is observed using the IMPACT2002+ methodology [111]. However, aerial emissions from coal combustion give coal power the highest human health impact according to the Eco-indicator 99 [65], EDIP2003 [112] and RECIPE [66] methodologies. This uncertainty suggests that further analysis is warranted in this area. Until then, the result of this particular indicator should be viewed as tentative.

Total human health impacts from radiation: All five technologies have health impacts related to radiation because of the background processes in their respective life cycles. This is typically as a result of emissions of radon and thorium during mining and milling processes. However, the impact of nuclear power is an order of magnitude greater than that of any other option with a value of 20.3 disability-adjusted life years (DALYs) per TWh (Figure 5). Approximately 90% of this impact is caused by emissions to air of radon-222 from uranium mine tailings over a period of thousands of years, with the remainder being emissions of isotopes like carbon-14 during power plant operation (although this will vary with reactor type).

To put the radiation health impacts from nuclear power in context, the health impact from global nuclear electricity generation of 2600 TWh/yr [113] is roughly 53 000 DALYs/yr. In comparison, COMEAP [114] estimates that, as a result of anthropogenic air pollution, up to 597 000 life-years were lost in 2008 in the UK alone—this refers to premature deaths only and excludes disability induced by the pollution.

3.3.3. Large accident risk

Fatalities due to large accidents: the risk of large accidents is a particularly important issue for nuclear power. Using probabilistic safety assessment, the Paul Scherrer Institut estimates that a new nuclear power station such as the EPR would cause 1.22×10^{-3} fatalities/PWh [89]. In other words, if global nuclear capacity was replaced with EPRs and electricity production levels remained the same as the present, one fatality would be expected every 315 years as a result of large accidents [calculated from 113]. This represents by far the lowest fatality rate of the technologies assessed here and is due to a low probability of occurrence. However, a single large accident at an EPR in Europe, if it were to happen, could cause up to 49 000 fatalities [89]. The difference in these two results illustrates the fact that this issue is as much about risk perception as objective estimates: most people are more willing to accept a situation with a high probability of minor detriment than one with a low probability of great detriment, even if the total detriment caused by the former is higher.

In contrast to nuclear power, coal power is associated with high-frequency, moderate-impact accidents, the vast majority of which occur during extraction, processing and transportation of the coal itself. As a result, it has the highest life cycle fatality rate of the options considered, causing an estimated 20.7 fatalities/PWh (Figure 5). Gas power is significantly better at 5.08 fatalities/PWh. However, the renewable technologies have relatively low fatality rates (0.77 and 1.14 fatalities/PWh for offshore wind and PV, respectively) with very low possible fatalities, thereby avoiding the negative risk perception often associated with nuclear power [115].

3.3.4. Local community impacts and human rights and corruption

As mentioned in Section 2, these impacts have not been considered because they are company-specific and therefore not applicable for technology assessment. For further discussion, see Stamford and Azapagic [5].

3.3.5. Energy security

Alongside climate change, energy security is the key driver of UK energy policy [19]. There are several facets to energy security and the indicators discussed here address primarily fuel supply diversity and resilience to fuel supply disruptions. The other element of energy security is the delivery of electricity to consumers, which depends on the stability of grid infrastructure and the ability of generators to match supply to demand. This is addressed, to the extent that it falls within the bounds of this study, by the dispatchability indicators discussed in Section 3.1.1.

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Avoidance of fossil fuel imports: the fossil fuel plants that currently provide around 75% of UK electricity are estimated here to use, on average, 200 t of oil-equivalent (toe) per GWh (Figure 5). The avoidance of this by non-fossil capacity (nuclear, wind and PV) represents a national increase in resilience to fossil fuel price volatility. However, it should be noted that an increase in nuclear, wind and PV capacity, which are less dispatchable, may force the remaining fossil plants to operate less efficiently as they are increasingly needed to follow load. As mentioned previously, extra system reserve capacity may also be required. Therefore, it may not be realistic to suggest that a GWh of non-fossil electricity displaces 200 toe as this is likely to be lower.

Diversity of fuel supply mix: this indicator reflects the resilience of national electricity production to fuel supply disruptions, whether they are economic, technical or political. Because of the incorporation of the Simpson Index into this indicator, as detailed in [5], performance is improved by producing more fuel indigenously, importing from more countries or reducing dependence on one or two major suppliers. By this definition, wind and PV have infinite supply diversity. Uranium, being an energy-dense fuel traded on the world market, is not specifically imported to the UK. Rather, large electric utilities normally buy prefabricated fuel assemblies on the European market. For this reason, EU uranium import figures are more appropriate and have been used here, giving the nuclear option a score of 0.86 (Figure 5). This is similar to the supply diversity for natural gas (0.84). Coal has the lowest score at 0.72 as a result of low indigenous production and high reliance on Russia, which in 2009 supplied 47% of the total UK demand and represented 56% of coal imports. As shown in Figure 6, the diversity score of coal is gradually declining toward the value for natural gas in Ukraine during the 2005/2006 gas crisis that had dramatic social and economic consequences for Ukraine and much of Europe.

Natural gas supply to the UK decreased in diversity following the country's change in status from net producer to importer in 2004. However, rapid introduction of LNG imports is reversing this trend (although the UK's gas supply diversity is still below that of the USA). However, as discussed in Section 3.2.2, increased use of LNG also leads to higher environmental impacts such as GWP.

Fuel storage capabilities: this indicator shows inherent resilience: energy dense fuels are physically easier to transport and store to be used when supply is problematic. In this respect, nuclear power is by far the best option. Assuming a burn-up of 50 GWd/tU, conservative for new reactors [see, for example 28], a nuclear fuel assembly has an energy density of 10 367 000 GJ/m^3 (Figure 5). This compares with an average value of 21.2 GJ/m^3 for coal imported to the UK. Compared with gas, at 0.036 GJ/m^3, the difference is even more pronounced. Wind and PV have zero fuel storage capabilities because, despite wind and sunlight having a derivable energy density, they cannot be stored and therefore do not contribute to the same goal. Note that fuel storage should not be confused with electricity storage.

3.3.6. Nuclear proliferation

The use of non-enriched uranium, reprocessing and requirement for enriched uranium: nuclear proliferation clearly only applies to the nuclear option and as such is considered in a relatively simple form here. However, different combinations of reactor type and fuel cycle present unique proliferation problems, as discussed in [5]. New nuclear build in the UK is likely to involve PWRs on a once-through cycle with no reprocessing of spent fuel. The only proliferation problem this presents is its requirement for enriched uranium, which arguably contributes to

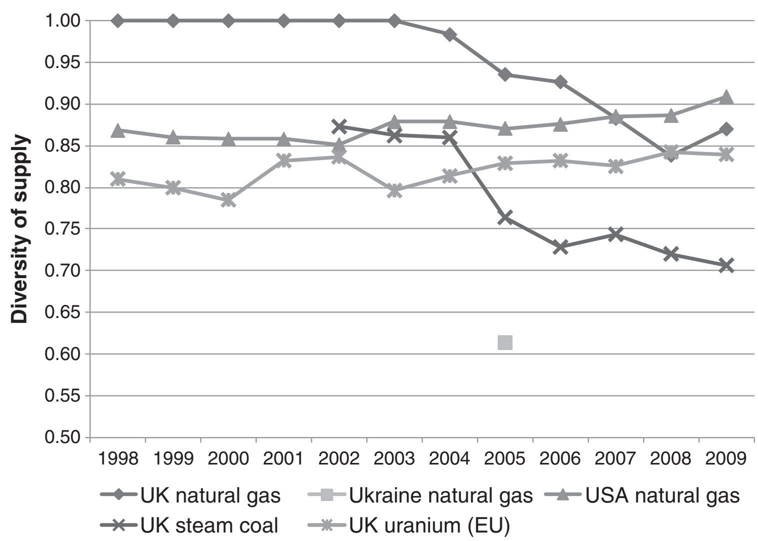

Figure 6. Historical diversity of fuel supply index for fuels used for electricity generation.

the spread of enrichment technology worldwide. On the scale used in this assessment, this gives a score of one out of three (given the aforementioned three components of this indicator). If reprocessing of spent fuel occurs at some point in the future, this increases proliferation risk by separating uranium and/or plutonium, stores of which might then become targets of theft or terrorist attack. This would raise the score to two out of three. The worst case would involve the use of reprocessing and enrichment in a fuel cycle involving a Magnox or CANDU reactor, from which high quality plutonium can be extracted relatively easily. Nothing of this sort has been proposed for the UK at the time of writing.

3.3.7. Intergenerational equity

The use of abiotic resources (elements): as indicated in Figure 5, the use of abiotic elements is highest in the PV life cycle, giving a central estimate of 12.3 mg Sb eq./kWh. This is around 435 times that of gas power, the best option for this impact. PV is also 260 times worse than nuclear, 125 times higher than coal power and 15 times worse than offshore wind for this impact. This is primarily due to extensive use of metals and metalloids in the manufacture of electronic components and the PV cell itself. Although offshore wind also has a relatively high impact, this is mainly because of the elements contained in steel alloys such as molybdenum. However, as these steel alloy components tend to be large structural pieces, they are arguably much easier to recycle after decommissioning than the smaller scale electronic components that dominate the impact from PV.

The use of abiotic resources (fossil): the depletion of fossil resources is obviously greatest in the coal and gas life cycles, with coal power using 15.1 MJ/kWh of fossil fuel (Figure 5). The 36% efficient power plant used in the central case consumes 10 MJ/kWh, with the remaining 5.1 MJ/kWh being due to losses during coal mining and processing as well as fossil fuel used in transportation. The gas option depletes 2–5 times less fossil resources than coal, with a central estimate of 5.75 MJ/kWh. By comparison, PV consumes 1.1 MJ/kWh and wind and nuclear 0.14 and 0.08 MJ/kWh, respectively.

Volume of radioactive waste and liquid CO_2 to be stored: production of radioactive waste and CO_2 from CCS represents a burden of storage and monitoring being passed to future generations. They also represent a burden of risk, but at the present time, this cannot be quantified due to the lack of operating experience with geological repositories of nuclear waste and supercritical CO_2. The volume of CO_2 for sequestration is irrelevant here as CCS options have not been assessed. However, average lifetime waste production by the two nuclear reactors currently proposed for new build in the UK is estimated at 10.16 m^3/TWh. This is the packaged volume and includes spent fuel as well as all intermediate level waste from decommissioning, such as reactor components, filters and resins. The value represents a total lifetime waste volume of 5581 m^3 for a single AP1000 and, due to its greater rated capacity, 6647 m^3 for an EPR. By comparison, the UK's current and future HLW and ILW arising from past and current commitments, but not including new build, is 489 330 m^3 [116]. It should be noted that this does not include low-level waste, most of which is now recycled or disposed of in near-surface facilities. The nuclear option, therefore, poses complex intergenerational dilemmas: although it passes the burden of radioactive waste management onto future generations, it could also play a significant role in preventing climate change—for the benefits of future generations as well as of our own [117].

4. CONCLUSIONS

This study has used sustainability indicators to compare the economic, environmental and social impacts of five major potential electricity options for the UK. The results suggest that no one option is the 'most sustainable', meaning that trade-offs and compromises are inevitable. Therefore, there is no overall 'winner' among the five options. Their overall attributes can, however, be summarised as follows.

Traditional coal power is the second cheapest option (gas being first), excluding incentives. It also benefits from significantly lower vulnerability to fuel price fluctuations than gas, with fuel accounting for roughly 30% of the total levelised cost (versus 75% in the case of gas). However, imminent regulations requiring all new power plants to emit less than 450 g CO_2/kWh means that new coal would require CCS, significantly increasing costs. Other benefits of coal power include high economic and technical dispatchability and, at 119 years, the longest lasting conventional fuel reserves of the non-renewable technologies considered. However, coal is also the worst performer in seven of 11 life cycle environmental indicators, including GWP. Additionally, although it provides the second highest employment, most of this is in mining and consequently, worker injury rates are high. Moreover, large accident fatalities are the highest of all options considered at 20.7 per TWh. Coal is also by far the worst option in terms of fossil fuel depletion and diversity of fuel supply, the latter mainly due to over-reliance on imports from Russia.

Gas (CCGT) is the cheapest option but has the highest cost variability due to its high fuel component. This is especially relevant given the continuing decline of UK gas production and increasing reliance on LNG from the international market. It is, however, highly dispatchable, quick to build and resistant to technological lock-in due to its relatively short lifetime and high temperature heat production. However, estimated at 63 years, natural gas has the lowest reserve lifetime of the technologies considered. Furthermore, its energy security contribution increasingly depends on LNG, the use of which could increase GWP from gas by 36% to 496 g CO_2 eq./kWh. Additionally, it provides the lowest employment and causes

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relatively high fossil fuel depletion. For other sustainability aspects, however, gas performs extremely well, having the lowest human and ecotoxicity, worker injuries and depletion of elements.

The cost of nuclear power is roughly comparable with that of coal and gas but with a much bigger capital component, meaning that it becomes less attractive at higher discount rates. Total cost is virtually insensitive to fuel price changes, and although conventional uranium reserves have a relatively short expected lifetime of around 80 years, this could increase to 675 years with phosphate resources and over 34 000 years if fast reactors become widespread. Nuclear power is quite non-dispatchable, but this is mainly an economic issue rather than a technical one, meaning partial load-following is achievable depending on peak electricity prices. Environmentally, nuclear is one of the best two options (the other one being wind) according to eight of the 11 indicators. In addition, it scores high for the energy security indicators. It does, however, have the second lowest life cycle employment, the highest health impact from radiation and arguably the greatest intergenerational impact, producing ~6000 m^3 of waste requiring geological storage per reactor lifetime. However, this should be weighed against the intergenerational impact of climate change, for which nuclear is the best option. Nuclear power also has the potential to cause the highest number of fatalities in a single incident, although in terms of the rate of large accident fatalities, it is the best option, causing nearly 17 000 times fewer fatalities than the coal life cycle.

Wind power has significantly lower costs than PV, although still much higher than the other options. This is in part due to the high operation and maintenance costs incurred as owners attempt to improve availability factors. The incentives currently available to offshore wind total 8.2 p/kWh and compare with the 40.6 p/kWh recently available to PV, which illustrates the fact that the indirect cost to consumers of making offshore wind competitive is 32.4 p/kWh lower than that of PV. Even with the new, decreased residential PV incentive of 21 p/kWh, offshore wind is still 12.8 p/kWh cheaper. As wind is non-dispatchable, costs depend heavily on capacity factors which should improve as newer, larger turbines become widespread. Wind is one of the best environmental options and broadly comparable with nuclear power. It only performs badly in freshwater and terrestrial eco-toxicity due to its high metal requirements. Provision of employment is second highest at 368 person-years/TWh, whereas it is a middle-ranking option in terms of worker injuries and HTP. Being fuelless in the conventional sense, in some respects, it increases energy security, although its non-dispatchability potentially necessitates increased grid-level reserve capacity. Offshore wind has few intergenerational equity issues, apart from non-fossil resource depletion, although even this is an order of magnitude lower than that of PV.

Solar PV performs poorly according to many indicators, mainly due to the relatively low insolation in the UK compared with countries such as Spain and the USA. The effect of this is high resource requirement being badly balanced against low electrical output. It has extremely high costs, recently necessitating incentives of 40.6 p/kWh—a cost that is ultimately passed on to consumers (although, as previously mentioned, this has recently decreased to 21 p/kWh). Environmental performance is relatively poor, with the highest ODP as well as the second worst result in five of the remaining 10 indicators. Many of these results can be improved significantly by recycling, as most impacts are accrued during resource extraction and processing. However, even then the impacts tend to be higher than those of nuclear, gas and in several cases, offshore wind. In terms of social impacts, PV provides the highest employment of the five options but consequently, the highest worker injuries. It also has the second highest HTP and the highest depletion of abiotic elements, exceeding the next worst option by a factor of 15.

Ultimately, decisions on future technologies and electricity mix in the UK will depend on many different factors, some of which have been discussed in this paper. It is obvious that compromises will have to be made and these will be determined by the priorities and preferences of different stakeholders. A forthcoming paper explores how these priorities and preferences, expressed by a range of stakeholders consulted in the course of this research, influence the outcomes of the sustainability assessment of electricity options examined in this paper.

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APPENDIX A

Sustainability indicators for different electricity options

Table VIII. Techno-economic sustainability indicators.

	Coal (pulverised)			Gas (CCGT)			Nuclear (PWR)			Wind (offshore)			Solar (PV)		
	Min.	Central	Max.	Min.	Central	Max.	Min.	Central	Max.	Min.	Central	Max.	Min.	Central	Max.
1. Capacity factor (%)	49.76	62.32	72.90	62.50	62.80	71.00	49.40	85.00	90.00	25.60	30.00	40.00	4.00	8.60	10.84
2. Availability factor (%)		87.10	90.70		88.70		50.67	89.21	92.70	67.00	81.40	98.00		95.90	100.00
3. Technological lock-in resistance (years^{-1})		8.89			16.00			1.67			0.00			0.00	
4. Lifetime of fuel reserves (years)	61.00	119.00	2184.00	45.00	62.80	250.00	25.00	80.00	675.00	∞	∞	∞	∞	∞	∞
5. Technical dispatch. (no units)	4.00	4.67	6.00	6.00	7.67	9.00	11.00	11.67	12.00		16.00			16.00	
6. Economic dispatch. (no units)	38.20	56.89	82.99	16.89	17.05	18.87	54.23	79.28	83.93	60.57	74.88	98.97	51.69	93.59	158.67
7. Time to start-up (months)	48.00	56.00	72.00	36.00	37.50	42.00	56.00	68.00	90.00	4.00	12.80	20.00		0.10	9.00
8. Fuel price sensitivity (%)	17.48	27.03	32.82	38.66	73.82	101.07	4.44	5.60	6.66	0.00	0.00	0.00	0.00	0.00	0.00
9. Levelised cost: capital (£/MWh)	28.40	42.30	61.70	11.10	11.20	12.40	51.30	75.00	79.40	88.50	109.40	144.60	156.10	282.62	479.12
10. Levelised cost: O and M (£/MWh)	10.70	11.95	13.10	6.00	6.00	6.00	10.90	14.30	14.30	23.00	36.70	45.80	3.12	19.35	44.21
11. Levelised cost: fuel (£/MWh)	13.00	20.10	24.40	25.40	48.50	66.40	4.20	5.30	6.30	0.00	0.00	0.00	0.00	0.00	0.00
12. Levelised cost: TOTAL (£/MWh)	52.60	74.35	95.00	42.50	65.70	83.60	66.80	94.60	99.00	111.50	146.10	190.50	181.70	301.96	510.31
13. Financial incentives (£/MWh)		0.00			0.00			5.08			82.46			405.50	

CCGT, combined cycle gas turbine; PWR, pressurised water reactor; PV, photovoltaics.

Table IX. Environmental sustainability indicators.

	Coal (pulverised)			Gas (CCGT)			Nuclear (PWR)			Wind (offshore)			Solar (PV)		
	Min.	Central	Max.	Min.	Central	Max.	Min.	Central	Max.	Min.	Central	Max.	Min.	Central	Max.
14. Recyclability (ratio)	7.77E-01	8.43E-01	8.43E-01	7.94E-01	8.93E-01	8.93E-01	7.33E-01	8.12E-01	8.12E-01	8.03E-01	9.94E-01	9.94E-01	2.38E-01	9.98E-01	9.98E-01
15. Global warming (kg CO_2 eq./kWh)	9.65E-01	1.07E + 00	1.48E + 00	3.66E-01	3.79E-01	4.96E-01	5.13E-03	6.24E-03	1.31E-02	4.73E-03	1.12E-02	1.42E-02	6.48E-02	8.78E-02	1.26E-01
16. Ozone depletion (kg CFC-11 eq./kWh)	3.20E-09	4.25E-09	1.05E-08	2.80E-09	1.27E-08	1.38E-08	5.26E-10	5.41E-10	7.28E-08	2.55E-10	5.96E-10	8.52E-10	3.34E-09	1.75E-08	2.52E-08
17. Acidification (kg SO_2 eq./kWh)	1.66E-03	1.78E-03	9.80E-03	1.22E-04	1.48E-04	3.70E-04	3.76E-05	4.40E-05	9.34E-05	3.35E-05	8.29E-05	8.41E-05	3.16E-04	4.36E-04	6.18E-04
18. Eutrophication (kg PO_4^{3-} eq./kWh)	1.41E-04	2.15E-04	2.24E-03	6.00E-05	6.23E-05	7.11E-05	6.42E-06	1.32E-05	2.23E-05	2.05E-05	6.01E-05	6.01E-05	3.81E-05	6.87E-05	1.04E-04
19. Photochemical smog (kg C_2H_4 eq./kWh)	1.33E-04	1.40E-04	4.57E-04	2.31E-05	2.73E-05	6.30E-05	4.50E-06	4.96E-06	8.08E-06	3.47E-06	8.49E-06	9.81E-06	3.39E-05	6.72E-05	9.27E-05
20. Freshwater ecotoxicity (kg DCB eq./kWh)	5.27E-03	1.67E-02	3.99E-01	1.72E-03	2.57E-03	7.73E-03	3.83E-03	2.11E-02	2.58E-02	8.68E-03	2.14E-02	2.14E-02	7.32E-03	1.74E-02	2.52E-02
21. Marine ecotoxicity (kg DCB eq./kWh)	5.66E + 02	5.78E + 02	2.24E + 03	3.60E + 00	7.08E + 00	3.07E + 01	6.68E + 00	4.02E + 01	5.61E + 01	1.83E + 01	4.64E + 01	4.64E + 01	4.04E + 01	8.76E + 01	1.22E + 02
22. Terrestrial ecotoxicity (kg DCB eq./kWh)	6.13E-04	1.53E-03	1.78E-03	1.16E-04	1.58E-04	5.31E-04	2.84E-04	7.40E-04	8.77E-04	6.33E-04	1.43E-03	1.93E-03	5.60E-04	9.44E-04	1.33E-03
23. Land occupation (m^2yr)	2.07E-02	2.73E-02	4.04E-02	2.76E-04	6.33E-04	3.79E-03	5.28E-04	5.49E-04	7.71E-04	1.56E-04	3.74E-04	4.61E-04	3.14E-03	4.97E-03	6.82E-03
24. Greenfield land use (ratio)		1.67E-01			0.00E + 00			8.75E-01			0.00E + 00			0.00E + 00	

CCGT, combined cycle gas turbine; PWR, pressurised water reactor; PV, photovoltaics.

Table X. Social sustainability indicators.

	Coal (pulverised)			Gas (CCGT)			Nuclear (PWR)			Wind (offshore)			Solar (PV)		
	Min.	Central	Max.	Min.	Central	Max.	Min.	Central	Max.	Min.	Central	Max.	Min.	Central	Max.
25. Employment: direct (person-years/TWh)		5.56E + 01			2.66E + 01			5.59E + 01			3.11E + 02			5.37E + 02	
26. Employment: total (person-years/TWh)		1.91E + 02			6.24E + 01			8.08E + 01			3.68E + 02			6.53E + 02	
27. Worker injuries (injuries/TWh)		4.50E + 00			5.41E-01			5.91E-01			2.30E + 00			4.84E + 00	
28. Human toxicity potential (kg DCB eq./kWh)	7.28E-02	7.77E-02	4.58E-01	3.68E-03	5.44E-03	1.41E-02	1.35E-02	1.15E-01	1.35E-01	3.03E-02	7.36E-02	7.52E-02	3.57E-02	8.44E-02	1.15E-01
30. Total health impacts from radiation (DALY/kWh)	2.15E-10	7.10E-10	2.21E-09	1.16E-11	2.63E-10	2.53E-09	2.03E-08	2.03E-08	3.19E-08	1.86E-11	4.31E-11	6.66E-11	1.13E-09	1.99E-09	2.88E-09
31. Large accident fatalities (fatalities/PWh)		2.07E + 01			5.08E + 00			1.22E-03			7.72E-01			1.14E + 00	
36. Fossil fuel avoided (toe/kWh)		0.00E + 00			0.00E + 00			2.00E-04			2.00E-04			2.00E-04	
37. Diversity of fuel supply (–)		7.20E-01			8.38E-01			8.61E-01			∞			∞	
38. Fuel storage capabilities (GJ/m^3)		2.12E + 01			3.58E-02			1.04E + 07			0.00E + 00			0.00E + 00	
39. Nuclear proliferation (ordinal scale)		0.00E + 00			0.00E + 00			3.30E + 01			0.00E + 00			0.00E + 00	
40. Depletion of elements (kg Sb eq./kWh)	8.11E-08	9.72E-08	3.50E-07	1.82E-08	2.83E-08	8.06E-08	4.34E-08	4.74E-08	6.21E-08	2.96E-07	8.39E-07	8.39E-07	4.80E-06	1.23E-05	7.51E-05
41. Depletion of fossil fuels (MJ/kWh)	1.18E + 01	1.51E + 01	2.47E + 01	5.66E + 00	5.75E + 00	6.51E + 00	6.62E-02	8.07E-02	1.51E-01	5.74E-02	1.37E-01	1.74E-01	8.15E-01	1.09E + 00	1.58E + 00
42. Radwaste for geological storage (m^3/TWh)		0.00E + 00			0.00E + 00		9.13E + 00	1.02E + 01	1.12E + 01		0.00E + 00			0.00E + 00	

CCGT, combined cycle gas turbine; PWR, pressurised water reactor; PV, photovoltaics.

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