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The economics of distributed energy generation: A literature review ☆

Grant Allan [a], Igor Eromenko [a], Michelle Gilmartin [b,*], Ivana Kockar [c], Peter McGregor [d]

[a] Fraser of Allander Institute, Department of Economics, University of Strathclyde, 130 Rottenrow, G4 0GE, UK
[b] Division of Economics, University of Stirling, Stirling FK9 4LA, UK
[c] Department of Electronic and Electrical Engineering, University of Strathclyde, 16 Richmond Street, G1 1XQ, UK
[d] Department of Economics and Strathclyde International Public Policy Institute, University of Strathclyde, 130 Rottenrow, G4 0GE, UK

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ABSTRACT

The UK electricity system is likely to face dramatic technical and institutional changes in the near future. Current UK energy policy focuses on the need for a clean, affordable and secure energy supply. Decentralisation of the electricity system is recognised as one means of achieving efficient and renewable energy provision, as well as addressing concerns over ageing electricity infrastructure and capacity constraints. In this paper we provide a critical literature review of the economics of increased penetration of distributed energy generation. We find that there exists a large volume of research considering the financial viability of individual distributed generation technologies (and we are necessarily selective in our review of these studies, given the wide variety of technologies that the definition of distributed generation encompasses). However, there are few studies that focus on the pure economics of individual or groups of distributed energy generators, and even fewer still based on the economy-wide aspects of distributed generation. In view of this gap in the literature, we provide suggestions for future research which are likely to be necessary in order adequately to inform public policy on distributed generation and its role in the future of UK energy supply.

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* Corresponding author. Tel.: +44 1786 467 478; fax: +44 1786 467 469.
E-mail address: michelle.gilmartin@stir.ac.uk (M. Gilmartin).

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1. Introduction and Overview

Driven by various technological advances, regulatory issues and emissions reduction policies, the UK electricity supply framework, and its associated transmission and distribution networks, has been undergoing significant change in recent years. The development of renewable electricity generation technologies, the growth of competition in the electricity industry, concerns over ageing infrastructure and capacity constraints have stimulated increasing interest in the potential for distributed electricity generation to address such issues. Distributed generation[1] (DG) encompasses a broad range of typically (though not always) 'low carbon' or 'efficient' technologies which are small-scale in comparison to conventional generation, and located closer to the end user. Such technologies may give rise to benefits in terms of transmission and distribution savings, as well as their potential to remove the need for costly infrastructure and capacity upgrades.

Moreover, the UK Government sets out three key priorities in its Energy Review: to reduce greenhouse gas (GHG) emissions; to secure its future energy supply; and to reduce fuel poverty [36]. Whilst some changes to the current UK energy system may lead to trade-offs among these goals (such as the potential for high-cost renewable energy installations to reduce emissions but increase fuel poverty), increased penetration of distributed energy technologies may contribute towards the achievement of all three goals simultaneously. There are potential emissions savings associated with the low carbon output (on average) of DG technologies; whilst increased diversification in the range of the type of energy supply technologies and resources associated with DG could mean reduced reliance on energy imports and increased security of supply of UK energy;[2] and the 'efficient' nature of DG technologies such as CHP, combined with possible savings relating to reduced system transmission and distribution costs, could contribute towards lower-cost energy supply than that associated with conventional centralised generation. Whilst in its report the Government acknowledges that the existing centralised system of energy production and delivery provide 'economies of scale, safety and reliability', it also states that a 'combination of new and existing technologies is making it possible to generate energy efficiently near to where we use it, potentially delivering lower emissions, increased diversity of supply and in some cases lower cost'. Thus DG has the potential to achieve a 'triple dividend' in terms of meeting energy policy objectives.[3]

In this review we acknowledge the potential for distributed energy resources fundamentally to alter the way in which UK energy requirements are met. Conventionally, the UK electricity framework is characterised by large-scale, centralised electricity generation plants. Electricity is delivered to a huge number of consumers located across a large area via a complex transmission and distribution network. In the past, this system is widely understood to have worked well, providing the advantage of economies of scale, reliable, secure and relatively low-cost electricity to consumers. In contrast, DG technologies are located close to the demand source. A greater number of smaller, modular energy generation devices are required, each producing much smaller amounts of energy. DG systems can either be stand-alone or grid-connected. In the former case the DG technology produces power independently of the grid, and the operational capacity is matched to the demand. In the latter, the main purpose is for the device to service the electricity needs in the local area. Any surplus generation is fed into the grid, whilst any shortage of electricity is drawn from the grid (see Fig. 1a and b). In such a system, both demand and generation are directly connected to the distribution network, close to the point of end use. Consequently, the electricity losses and inefficiencies, which occur as centrally-generated electricity is transported across the network, are potentially reduced, and the electricity supply system as a whole is more flexible. Such developments may avoid (or certainly delay) the need for the widely anticipated and costly investments in the existing centralised electricity network, which would otherwise be required to address capacity constraints and ageing infrastructure. Furthermore, the government's Energy Review [36] suggests that a 'community-based energy system could lead to a greater awareness of energy issues, driving a change in social attitudes and, in turn, [could lead to] more efficient use of our energy resources'.

Despite these potential theoretical benefits of distributed energy generation, there are also a number of complexities and constraints involved in its further penetration into the energy mix. The integration of distributed generation technologies within the existing network is likely to create significant issues relating to the costs of energy provision and price of electricity, power quality, infrastructure requirements, and technical performance. DG necessitates a more active distribution network than that which currently exists in the UK. In particular, there is a need for electricity to flow in two directions, both from the network to the consumer for use at home or in industry, and also from the distributed generation source to the network when exporting excess generation (Figs. 1a and b). Furthermore, there are considerable uncertainties regarding the financial viability of individual and wide-spread DG applications, as well as the social costs and benefits attached to the increased penetration of distributed generation in the UK, not to mention the macroeconomic effects of such a fundamental change in energy provision.

In this paper we provide a critical review of the literature on the economics of distributed generation. This is with a view to informing the wider energy policy community and identifying important informational and research gaps, as policy makers seek to make decisions towards developing an efficient, secure and financially and environmentally viable electricity network for future energy needs.

Evaluating the economics of the increased penetration of distributed energy generation is not straightforward. Distributed energy technologies vary widely in terms of their technological design and generation capacity, as do their capital, maintenance and fuel costs. For example, there are the potential costs of electricity infrastructure adjustments that may be required in order to make widespread use of distributed energy. These potential costs should sensibly be compared to the alternatives, such as the network upgrades that would be necessary to increase the capacity of conventional, centralised generation. Furthermore, there are uncertainties regarding the characteristics and extent of future policy support mechanisms, as well as the likely regulatory and institutional arrangements for distributed electricity generation (for example generators' obligations and costs for connecting to the grid). Data on the financial costs and benefits of distributed energy generation tend to be highly project-specific and estimates of the social costs or benefits of such generation (for example potential reduction in carbon emissions) are necessarily assumption-driven and subject to uncertainties. As such, there are no standard models or tools for analysing the economics of distributed generation. In this paper we consider the findings from a range of research that we believe to be informative about the key

[1] The term 'distributed generation' is commonly referred to in the literature, but the terms 'dispersed', 'embedded', 'decentralised' and 'on-site' are also used with reference to the same concept.

[2] Though the link between reduced energy imports and increased security of supply of domestic energy is far from clear. Stirling [82] provides a useful discussion of the factors affecting energy security of supply.

[3] The Scottish Government regards economic growth stimulated by the energy sector (with a particular emphasis on renewable technologies) as a further ambition for Scottish energy policy. If DG stimulates economic activity, there exists the potential for an additional dividend (see e.g. [4]).

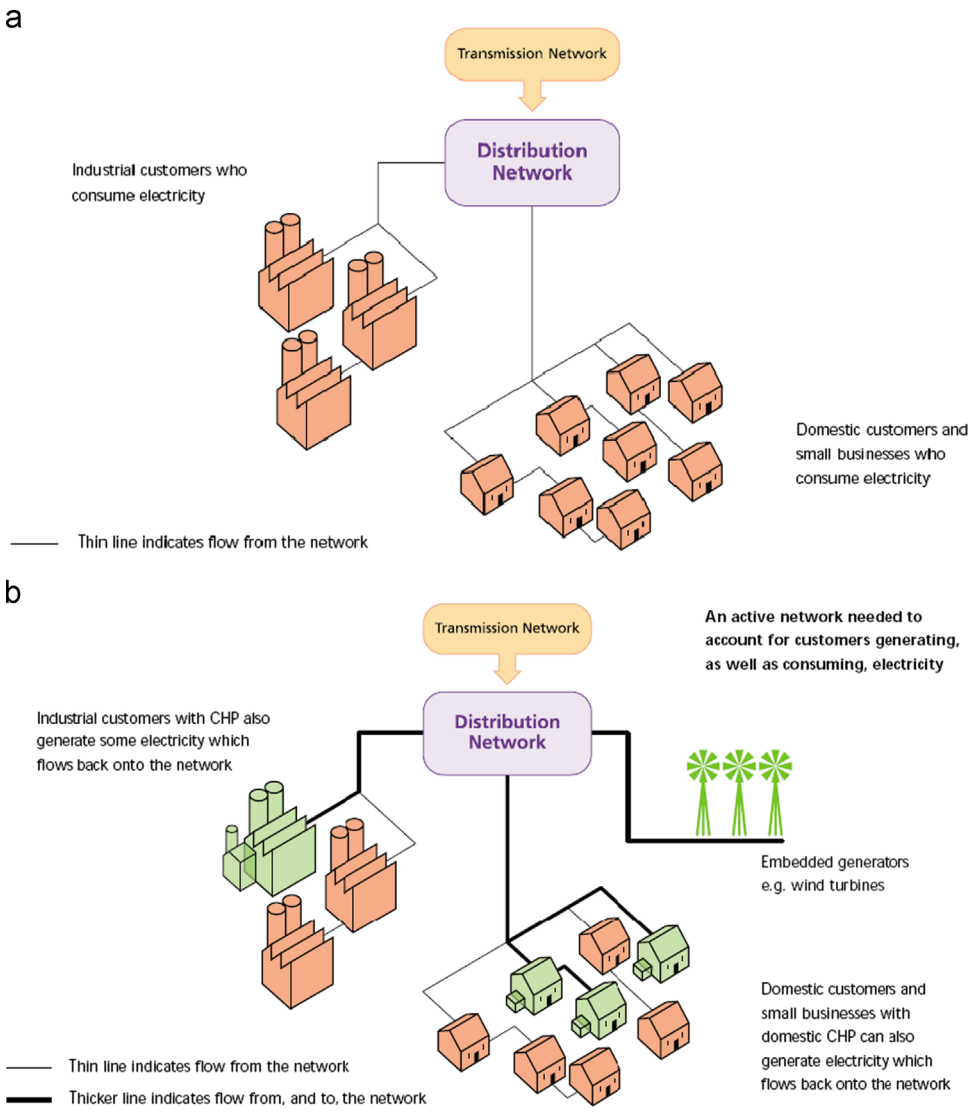

Fig. 1. (a) Conventional electricity distribution network. (b) Electricity distribution network with distributed generation.
Source: [70].

issues regarding the economics of distributed generation. These include studies of the financial viability of a number of individual distributed energy generation systems; the social costs and benefits of distributed generation, including environmental costs; and the wider macroeconomic impacts of increased penetration of distributed energy generation.

The remainder of this paper proceeds as follows. In Section 2 we discuss a suitable definition for DG, for which no precise consensus exists in the literature, and we also describe the key features of some distributed energy technologies. In Section 3 we comment on the current penetration of distributed energy in the UK and the current policy support mechanisms in the UK relevant to DG, and we briefly compare this with other countries where DG has a greater presence. In Section 4 we discuss some important aspects of estimating the cost of distributed versus centralised generation. In Section 5 we review the literature on the economics of distributed generation, focusing on both the financial and wider social costs and benefits of distributed energy systems; and the economy-wide impacts of DG in the UK. In Section 6 we provide brief conclusions and identify opportunities for further research to address the key issues raised in earlier sections.

2. Distributed generation: a definition

In general terms, DG refers to the use of stand-alone or grid-connected small, modular electric generation devices which are located close to the point of consumption [13]. The key defining characteristics of DG technologies include the size of the power production of the technology and the location and application of the device. DG systems are generally located close to the power demand, on the customer side of the metre or on the distribution network, rather than on the transmission network.[4] The systems mostly produce between 1 kW and 5 MW of power supply[5] [24]. Some systems include stand-alone rural or remote applications

[4] The electricity 'transmission network' is used for the bulk transfer of high-voltage electrical energy from generating stations (power plants) to power substations which are located close to areas of high demand. The electricity 'distribution network' is used to transfer low-voltage electrical energy from power substations to the end consumer via a local wiring system.

[5] Larger DG applications can produce between 5 and 300 MW of power, though there remains disagreement about whether such devices can truly be considered to be DG technologies [1].

(for example where there are grid access constraints); grid-connected devices for the purpose of exporting electricity to the grid; utility-owned devices (for the purposes of improving power quality and reducing power losses in certain areas); and combined heat and power (CHP) devices.

In terms of a precise definition of DG, there is no consensus in the literature. Dondi et al. [35] and Chambers [27] concur with the definition of Arthur D. Little [13] in defining DG as small-scale electric power generation that is located close to customer needs. Ofgem defines DG as 'electricity generation which is connected to the distribution network rather than the high voltage transmission network' [70]. The questionnaire-based international survey by CIRED [29] found that for respondents in some countries, the definition of DG is based on the voltage level of the system, whilst for respondents in other countries the classification was based on whether the system was stand-alone or not. Ackermann et al. [1] examine different characteristics of DG with a view to arriving at a very specific definition of distributed power generation. In that paper, the authors suggest that whether or not a system is considered to be DG depends on the location of the device (the authors suggest that a DG device should be close to the distribution network or on the customer side of the network); the type of service supplied by the system (active supply of power is required for a device to be defined as distributed generation; reactive power supply is not); and generation capacity (with micro-distributed generation assumed to be less than 5 kW; small to medium distributed generation to be greater than 5 kW and less than 50 MW; and large distributed generation to be greater than 50 MW and less than approximately 300 MW).

DG therefore encompasses a broad range of technology devices, and can include both renewable (e.g. solar photovoltaic; wind; biomass and marine) and non-renewable energy, as well as 'efficient' technologies such as CHP. Table 1 provides some examples of low carbon distributed energy technologies.

3. The penetration of distributed generation technologies in the UK energy system

The current electricity system in the UK is dominated by conventional, centralised generation, with energy supplied through a nationwide network. DG systems produced less than 10% of total electricity supply in the UK in 2006 [37]. Other European countries have a much greater share of distributed energy technologies contributing to the overall electricity supply than in the UK: in Denmark more than 50% of generating capacity is sourced from distributed energy – mostly wind and small-scale CHP technologies [61,81]; whilst in the Netherlands around 25% of electricity supply comes from DG [42]. In Sections 3.1 and 3.2 we briefly consider respectively, possible barriers to the adoption of DG in the UK, and identify key policies that have been deployed in an effort to overcome these and encourage wider deployment. The contents of Sections 3.1 and 3.2 are summarised in Table 2.

3.1. Barriers to the adoption of DG

Despite the existence of some policy support measures (see Section 3.2 below), there exist a number of institutional barriers to

Table 1
Examples of low carbon distributed energy generation technologies.
Source: adapted from [37].

Technology	Description
	Distributed Heat Technologies
Solar water heating	Uses the heat of the sun to produce hot water
Heat pumps	Uses the warmth stored in the ground or air, via a water for space heating
Biomass	Small-scale biomass installations from approx 10 kW to 2 MW that provide space and water heating by combustion of wood, energy crops or waste
Distributed Electricity Generation technologies	
Solar Photovoltaics (PV)	Panels, often roof-mounted, that generate electricity
Wind	Large wind turbines that convert wind energy directly
Micro-wind (< 100 kW)	Small wind turbines that generate electricity - can now
Micro-hydro	Devices that capture the power of flowing water and convert it to electricity
Biomass/waste	Installations range from landfill gas generation to large power-only facilities approaching 40 MW
Combined Heat & Power Technologies	
Biomass/waste	Installations range from 100 kW biomass CHP to around 85 MWth/20 MWe
Micro-CHP and CHP up to 1 MW	Small devices, usually gas-fired, that produce electricity and capture the waste heat produced as a by-product. CHP used on this scale tends to be for heat and power for a single house or on a community or commercial scale (e.g. a housing estate or office block)
CHP from 1 MWe-10 MWe	CHP on this scale tends to be large community projects or small industrial applications
CHP over 10 MWe	CHP on this scale tends to be large gas turbine industrial applications that require a substantial heat load on a continuous basis

Table 2
Summary of potential barriers to DG and policies to stimulate DG development.

Potential barriers to DG	Selected references	Policies to stimulate DG	Selected references
Institutional (e.g. grid access, regulation, licensing and planning)	e.g. Pepermans et al. [73], DTI, [37,90].	Tariffs/subsidies for DG technologies	e.g. Bergman et al. [18], Watson et al. [90], Finney et al. [40]
Uncertainty (e.g. certainty of policy support, technology performance)	e.g. Uyterlinde et al. [85], Balcombe et al. [17].		
Consumer attitudes and social acceptance (e.g. inconvenience, value on housing asset)	e.g. Bergman et al. [18], Devine-Wright [34], Sauter and Watson [79], Balcombe et al. [17]		

the adoption of DG in electricity systems where large, centralised generators dominate. Pepermans et al. [73] note that such issues include the potential for discriminatory access to the grid, while Uyterlinde et al. [85] suggest issues relating to uncertainty over future policy support and planning and installation constraints. A joint report by the UK government and Ofgem [37] identified four key barriers considered to be important, all of which were judged to continue to apply, to varying degrees, in the more recent assessment of Balcombe et al. [17]. Firstly, DG technologies are typically less commercially attractive than alternatives since they tend to have higher capital costs; longer payback periods; and the payments for exporting excess electricity to the grid are inadequate. Balcombe et al. [17] identify that for some technologies, potential "adopters" of DG systems would accept payback periods of around 10 years, while the payback periods for current technologies combined with existing support mechanisms were often considerably longer. Secondly, potential users cannot easily access information about DG, and the incentives available are not easily understood. Thirdly, aspects of the electricity industry structure in the UK make it difficult for small generators to connect and operate within it. These could include the complex system of licensing applicable for the generation and supply of electricity to the network. Such regulations – while enforcing system stability and safety – are more costly for smaller generators.[6] Additionally, Watson et al. [90] note that the fiscal system appeared "biased towards business investments in central power stations" (p. 3100). These include the existing system of capital allowances in place for businesses, but not private actors, and the operation of the settlement system favouring centralised generation.[7] Finally, regulatory barriers exist in the form of the planning process, inhibiting community developments and initiatives associated with new housing.

A further barrier to the wider adoption of DG is consumers' apparent resistance. The potential importance of what appears to be less than entirely rational consumer behaviour has been emphasised by many, including Bergman et al. [18], Devine-Wright [34], Keirstead [56] and Rogers [78]. For example, Bergman et al. [18] argue that people generally view government or industry as being responsible for environmental change and expect them to take the initiative, whereas it may be argued that significant behavioural change requires action at the collective, social level. Attitudes towards adoption of innovations differ among heterogeneous consumers, from 'early adopters' to 'laggards', and there is some evidence to suggest that these attitudes differ systematically by age, income, class and political belief (see for example, Balcombe et al. [17] for a review and Claudy et al. [30], [55] and Claudy et al. [31] for more recent evidence). To the extent that this evidence is accepted, successful policy action would depend on more than simply addressing the financial barriers to adoption,[8] though it may be that incentives of sufficient scale can induce changes in attitudes. Balcombe et al. [17] additionally identify a potential barrier to adoption from the anticipated impact of a technology on the property to which domestic-scale technologies would be connected. They provide evidence that technologies that most closely resembled known energy technologies would be more favourably regarded by householders. While these barriers to the adoption of DG continue to exert an impact, there have recently been important policy initiatives aimed at mitigating their effects (notably in respect of reform of the planning process and the introduction of feed in tariffs (FiTs)), which we now consider.

3.2. Policies to encourage the adoption of DG

The UK government has implemented a number of policies that serve to promote the adoption of a range of DG technologies. The renewables obligation (RO) is the most important UK policy instrument directed at (larger scale) renewables initiatives. Under the RO scheme, operators of accredited renewable electricity facilities receive renewables obligation certificates (ROCs) for each MWh of electricity they produce. The introduction of 'banding' within the RO system (Renewables Obligation Order [77]; Renewables Obligation Amendment Order [92]) is intended to provide additional incentives for investment in emerging, and thus generally more expensive, renewable technologies, and this has resulted in increased support for some DG technologies (see Table 3). Technologies are presently grouped into five 'bands', with each band receiving multiples (or fractions) of ROCs for their electricity generation. Among the technologies assumed to be 'emerging' and in receipt of additional ROCs support are solar photovoltaics, some CHP applications, wave, tidal, offshore wind and biomass generation. Each of these generation types are entitled to two ROCs per MWh, compared to one ROC/MWh for onshore wind and hydro-electric generation. This effectively lowers the cost to developers of some DG facilities in the UK.[9] In the year 2006–2007, one ROC was worth £49.28 [71] to an accredited renewable electricity generator.

A number of other policies impact, at least potentially, on private sector incentives to adopt DG. These include the Climate Change Levy (CCL); the Carbon-Emissions Reduction Target (CERT); the Climate Change and Sustainable Energy Act (2006); The Low Carbon Building Programme (LCBP); VAT relief for 'energy savings' items; income tax exemption for revenue from micro-generation export; time-limited stamp duty exemptions applied to sale of zero-carbon dwellings and new building regulations. We consider each of these very briefly. The Climate Change Levy (CCL) was introduced in April 2001. It is effectively a tax on the use of energy in industry, commerce and the public sector, with revenue recycling to reduce employers' NI costs. As stated at the Department of Energy and Climate Change (DECC) website (www.decc.gov.uk), the aim of the CCL is to encourage businesses to become more energy efficient and reduce their greenhouse gas emissions. Good quality CHP systems are exempted from CCL.

The Carbon-Emissions Reduction Target (CERT) was adopted in 2008 for 3 years and replaced the Energy Efficiency Commitment (EEC), which was in operation from 2001. The CERT is an obligation for energy suppliers to reduce the CO_2 emissions of their residential customers. Hawkes and Leach [47] stress that CERT includes both energy efficiency and microgeneration measures. The Climate Change and Sustainable Energy Act (2006) aimed to promote micro-generation and required the Secretary of the State to set one or more national micro-generation targets. The Micro-generation Strategy was adopted in 2006, aiming to promote easier access to ROCs and to motivate local authorities to be more proactive in developing microgeneration through the use of planning policies. The strategy provides grant support for

[6] As DTI [37] notes, a system of exemptions does exist for those DG schemes with net capacity below a specific minimum amount.

[7] The impact of micro-DG technologies on the balancing market is specifically examined in Van der Veen and De Vries [86].

[8] Sauter and Watson [79] provide an analysis of the social acceptance of DG, which they regard as a pre-requisite for the adoption of DG, drawing on a range of surveys.

[9] These ROC 'bands' are applicable across the UK. However, the Scottish Government has indicated its intention to introduce significantly higher levels of ROC support to electricity generation from Wave and Tidal sources in Scottish waters. It is proposed that Wave and Tidal technologies might receive, in total (i.e. including the UK "banded" support) 5 ROCs and 3 ROCs for each MWh of electricity generated [80].

Table 3
Bands, technologies and level of renewables obligation support.
Source: [77,76].

Band	Technologies	Level of support ROCs/MWh
Established 1	Landfill gas	0.25
Established 2	Sewage gas, co-firing on non-energy crop (regular) biomass	0.5
Reference	Onshore wind; hydro-electric; co-firing of energy crops; energy from waste with combined heat and power; geopressure; other not-specified.	1.0
Post-demonstration	Dedicated regular biomass; co-firing of energy crops with CHP.	1.5
Emerging	Wave; tidal stream; offshore wind; fuels created using an advanced conversion technologies (anaerobic digestion; gasification and pyrolysis); dedicated biomass burning energy crops (with or without CHP); dedicated regular biomass with CHP; solar photovoltaic; geothermal; tidal impoundment (e.g. tidal lagoons and tidal barrages (<1 GW)); microgeneration.	2.0

residential adoption through the Low Carbon Building Programme (LCBP), which we now consider.

The LCBP, reflecting government recognition that ROCs are insufficient to support technologies which are smaller-scale and further from market, supports microgeneration installation through direct grants and initially had £86 m of grant funding for microgeneration installations in homes, communities, public and private sector to 2009 [37]. Allen et al. [12] note that there are two phases of this programme. Phase 1 grants were available for households and for public, non-for-profit and commercial organisations. Demand from households was much higher than the programme anticipated and some adjustments had to be made. Phase 2 made funds available for the installation of microgeneration units by public sector and charitable bodies, but not for households and commercial companies. Specific technologies are supported: solar PV, solar thermal, wind, ground source heat pumps, and biomass. Also, purchase and installation of technologies is limited to a short-list of seven suppliers. This later development was criticised for excluding a large number of suppliers and installers.

Bergman et al. [18] regard VAT relief for 'energy savings' items as another important policy directed at the development of microgeneration. This policy instrument was first used in 1997 and cuts the VAT rate from the standard of 17.5–5%. Energy-efficient measures include installation of wind turbines, solar PV, water turbines, micro-CHP and some other technologies. Bergman et al. [18] also mention two other incentives for microgeneration: income tax exemption for revenue from microgeneration export and a time-limited stamp duty exemption applied to the sale of zero-carbon dwellings. The authors cast doubt that these two incentives will have any significant effect, since the costs of installing microgeneration units considerably exceed any benefits received from these measures. However, they do believe that new building regulations may have a significant impact. Currently these regulations are applied only in England and Wales and require all buildings to be built to a truly zero-carbon standard from 2016. This is potentially important since the only way to achieve the status of zero-carbon dwelling is to adopt microgeneration within the dwelling and export electricity to the grid.

Of course, broader energy policies also impact on DG. For example, the EU's Emission Trading Scheme (EU ETS), which establishes a carbon price for major covered industries in the UK (including large scale generators), serves to improve the relative cost-competitiveness of DG, though for a variety of reasons the price has fluctuated and has rarely reached levels that many regard as an appropriate long-run price of carbon. The Climate Change Bill came into effect in 2007 and set a target for reducing UK carbon dioxide emissions by at least 26–32% by 2020 and at least 60% by 2050 (subsequently increased to 80% on the recommendation of the Climate Change Committee) compared to 1990 levels. While targets are legally binding, it is not yet clear what impact these targets will have on DG, or more widely, since, for example, unlike the Monetary Policy Committee (MPC) the CCC has not been delegated any policy instrument with which to achieve the targets [63].

However, undoubtedly the most significant recent policy initiative in this area, targeted at small-scale distributed energy systems, is the Feed-in Tariff (FiT) scheme [32], which replaces the LCBP and RO for installations under 5 MW. This policy was intended to increase the installation of small-scale renewable and low carbon non-renewable generation technologies. The scheme requires licensed electricity suppliers to pay a generation tariff to small scale low-carbon generators for electricity generation,[10] and an export tariff when the electricity is exported to the grid, for the operational lifetime of the device. By obliging electricity suppliers to purchase renewable energy from suppliers at a favourable price, the FiTs policy provides emerging renewable technologies an opportunity to compete in the electricity market. The policy is intended to increase the uptake of small-scale low carbon technologies, and thus many technologies falling under the DG band, by increasing their costs effectiveness for households and communities.

The FiTs are scaled according to technology, and payments are scheduled to gradually fall over time, so as to incentivise cost-cutting and efficiency measures in renewable electricity industries. The idea behind the gradual tariff reductions is that as demand for small-scale renewables devices grows, manufacturers can take advantage of economies of scale, price reductions are passed on to the consumer and the industry becomes competitive on its own. In some European countries, however, FiT rates have recently been cut more sharply than planned due to the perceived success of the FiTs scheme. In Germany, for example, FiT rates have been cut by up to 16% for solar installations (compared with planned gradual reductions of 1–6.5%), in response to considerable growth in the solar heating sector and a steady fall in the price of solar panels ([39]). Recent empirical evidence on the success of the UK FiT scheme in encouraging significant new small-scale renewable facilities appears to be overwhelmingly positive. Bush et al. [21] describe the development of small-scale PV since FiTs were introduced in April 2010 as a "revolution" (p. 86), with under 1 MW of capacity installed prior to its introduction and 1.5 GW by the end of May 2013. However, reservations have been expressed about the inequitable impact of FiTs.[11] With the success of the policy, significant and faster reductions in the tariff levels, in particular for PV technology have been introduced ahead of

[10] Regardless of whether the electricity generated is exported to the national grid.

[11] See Jardine [53] for an ex ante analysis of the likely impact of FiTs on PV and a critique of the impact on equity, and Morri et al. [67]. We return to this in our discussion of social costs and benefits in Section 5 below.

schedule to ensure the anticipated costs of the policy were not exceeded (see for example, Cherrington et al. [28] and Muhammad-Sukki et al. [68] for reviews of changes to the PV FiT schedule). Additionally, Finney et al. [40] discuss the implications of the global economic downturn and funding for decentralised energy in the UK post-2010, and the implications for the range of FiT, RO, LCBP and CERT schemes supporting DG technologies.

4. Estimating the cost of distributed versus centralised energy generation

A sustainable future power system for the UK will likely comprise a diverse portfolio of generation techniques and plants, including both DG and conventional generation. In the UK, large-scale centralised electricity generation has been associated with economies of scale and high reliability, and the future penetration of DG systems will be determined by the costs and benefits of DG vis a vis the current centralised set-up. A distributed electricity network does have the theoretical potential to offer cost reductions. However, since the existing electricity framework has been designed to support the requirements of large-scale conventional transmission-connected generation, some aspects of the system may prevent a level playing field for the introduction of DG technologies. This could act as a barrier to entry for DG, and preclude the development of an economically efficient electricity system. However, it does seem inappropriate to assess DG simply on the basis of standalone cost estimates, since it will inevitably form part of a generation portfolio of energy resources. In this context, distributed generation may offer reduced overall risk for any given (levelised) cost, though this will vary by technology: in particular if gas generation is involved the link to fuel prices will not be entirely broken.[12]

By connecting electricity generators closer to the point of use, the extent of the infrastructure needed to transport the electricity is much reduced, as are the costs associated with transmission and distribution. Approximately 6.5% of generated electricity is lost as it is transmitted and distributed to consumers [37],[13] representing significant potential for savings with DG. In many cases, power generated from DG technologies does cost more than that from conventional electricity networks, though some authors suggest that methods for making truly cost reflective comparisons should explicitly take into account the use of the transmission and distribution systems. The cost of electricity produced by a centralised system is estimated to be around 2–3 p/kWh. This compares with a much higher value of electricity of 4–10 p/kWh for DG technologies (see, for example Strbac et al. [83] and DECC [33]). Since DG systems are located closer to the consumer than electricity from a centralised system, however, DG electricity has a much lower requirement for the transport services provided by the transmission and distribution networks, and thus avoids the costs associated with their use [90]. These 'avoided costs' however are not taken into account when comparing the p/kWh of DG versus centrally-generated electricity. Strbac et al. [83] argue that excluding such potential avoided costs results in non-cost reflective network systems, and could lead to unnecessary network reinforcement and inefficient integration of DG into the wider electricity system.

Ayres et al. [18] also suggest that centralised generation is not necessarily optimal. The authors suggest that whilst the capital cost of installing a large electricity plant is around $500–1500/kW, the 'true' capital cost can be much higher. In addition to the costs of the central plant, there needs to be investment in associated transmission and distribution capacity increases to accommodate the extra load, as well as to accommodate line losses and to provide reserve margins. The authors suggest that this could drive up the 'real' capital cost of a new central plant to over 5.5 times the assumed minimum capital costs of $500/kW, and almost 3 times the assumed maximum of $1500/kW. In contrast, installing DG systems involves no costs associated with transmission and distribution capacity or line losses, and needs relatively small costs associated with distribution. Additionally, there are potential fuel savings associated with utilising waste heat in decentralised CHP systems.

From an emissions perspective, many (though not all) DG technologies are associated with lower carbon emissions than conventional technologies. Some technologies are renewable (such as solar PV, biomass), and others bring about efficiency savings (such as CHP, via the recycling of waste heat that is produced as a by-product of electricity generation). The true benefit of the emissions savings is not represented in the market cost of DG technologies, however. Although society as whole values emissions savings, the benefits of emissions savings associated with DG technologies are not fully reflected in its price. For large electricity generators, however, the European Union Emissions Trading Scheme (ETS) does impose a cost of carbon on generators. Under the ETS, EU member states agree on national emissions caps, and then allocate emissions allowances to industrial operators. Operators may reassign or trade their allowances, treating it like a financial instrument. This results in an incentive towards low carbon distributed energy for large suppliers. However, in some cases emissions caps have been insufficiently tight to bring about a reduction in emissions [25], resulting in a carbon price that is 'too low', reflecting the difficulties inherent in estimating the true cost of carbon emissions.

Additionally, distributed generation may lead to potential cost reductions in terms of the postponement of required investments and upgrades associated with the infrastructure and plants of centralised generation [50,51]. Ayers et al. [15] argue that economies of scale associated with large centralised plants are coming to an end due to capacity constraints, whilst small and renewable generators are benefiting from rapid technological advancements. Furthermore, the authors suggest that real fuel price rises are likely to continue, in line with the long-term decline in the discovery rate of fossil fuels. Additionally, it is well known that new technologies generally begin with high unit costs, which tend to fall with cumulative capacity installed. The incorporation of learning curve effects, though of course subject to uncertainty, may prove significant [42]. These factors may increase the competitiveness of distributed energy systems compared with centralised generation.[14]

5. Review of the literature on the economics of distributed generation

In this section, we review the literature on the economics of distributed energy generation. In doing so, we focus on research in a number of key areas: calculating the financial viability of

[12] See e.g. Awerbuch [3] and Allan et al. [10] for applications of portfolio theory to renewable electricity generation.

[13] However, in some cases a distributed electricity system could necessitate reinforcements to the transmission network: for example in Scotland, the output from DG may exceed local demand at times, and excess supply may be exported to the grid on large scale.

[14] Other analyses of the possible impact of DG on the electricity system include Willis (2000), Energy Saving Trust, E-Connect and Element Energy [38], Infield and Li [52], Kelly et al. [57], Pudjianto et al. [74], Alacron-Rodriguez et al. (2009) and Haesen et al. [44].

individual or groups of DG plants; estimating the social cost and benefit of DG technologies, including environmental benefits; and modelling the macroeconomic impact of an increase in the uptake of distributed generation technologies.

5.1. The financial viability of individual DG systems

The vast majority of the literature concerned with modelling the impact of DG focuses on microeconomic analyses: a wide variety of studies assess the financial feasibility of individual grid connected or stand-alone DG systems. However, because of the heterogeneity of DG schemes, there is no generalised methodology in the literature for assessing the financial or economic viability of decentralised energy systems. Further, we find a varied range of results across the literature, suggesting that the outcome of the financial calculations is highly project-, location-, and technology-specific. In assessing financial/commercial feasibility, most authors make use of standard investment appraisal methods such as Net Present Value (NPV) and Pay Back Period (PBP).[15] These analyses focus virtually exclusively on the *private* costs and benefits associated with DG, that is those cost and benefits that accrue directly to the investor, and so conventional discounted cash flow methods are appropriate. In this section we summarise a sample of financial viability studies of DG technologies; whilst in Section 5.2 we review some studies that focus on the wider economic – as opposed to purely commercial – viability of DG plants, by also incorporating the *social* costs and benefits associated with DG. These are the costs and benefits that are generated by DG but not borne by the private investors. (For example, social costs could increase by adopting DG if there are any local disamenity effects, while any reductions in CO_2 emissions would reduce social costs.)

Stand-alone DG technologies are particularly well-suited to remote or inaccessible geographic locations and developing countries, and individual assessments of the viability of DG plants in the literature reflect the impact of these characteristics. Such stand-alone DG systems are often financially viable in remote areas compared with conventional systems because of the high costs of setting up conventional systems including connectivity. Accordingly, there are many studies showing the economic efficiency of stand-alone DG systems, in particular PV systems for remote applications, and for developing countries, where the cost of other alternatives, such as extending utility power lines or transporting fuel, are very high. Kolhe et al. [59] compare the economic efficiency of a stand-alone solar PV system with a conventional diesel-powered system employing life-cycle costs comparisons using parameters for India. The authors find that the solar PV system is competitive up to an output of 68 kWh per day. Their sensitivity analysis showed that even under an unfavourable economic scenario, the solar PV system still performs better for an energy output of up to 15 kWh per day. Bernal-Augustin and Dufo-Lopez [19] conduct a financial analysis of grid connected photovoltaic (PV) systems in Spain. The authors consider the profitability of the system by assessing the NPV and PBP of the system. The results clearly suggest that the project is financially viable, but with very long pay back periods, suggesting a potentially important disincentive for investors, given that capital markets may be imperfect. Kaldellis [54] conducts a feasibility assessment of a number of widely dispersed wind energy systems at various locations across Greece, and calculates the PBP and benefit to cost ratio of all wind power installations. The author finds that, in general, the wind power programme leads to substantial financial losses, due to the low energy production of most of the wind power plants, as well as technological failures. Bakos and Tsagas [16] calculate the PBP of a hybrid solar/wind installation that is designed to provide thermal and electric power to urban residences in Greece. The authors find that the system is associated with a 12-year PBP, but note that the PBP could be reduced if the externalities of conventional power generation technologies were to be taken into account.

Audenaert et al. [14] conduct a financial evaluation of the photovoltaic grid connected system (PVGCS) for firms located in Belgium, to consider whether such investments represent a good financial decision for firms in Belgium. The authors calculate key financial criteria such as NPV and PBP, taking the tax deductions applicable to PV in Belgium into consideration. The authors also conduct sensitivity analysis to determine the key factors influencing the financial variables. The costs include those for components, O&M, financing and insurance. The revenue stream includes saved energy expenses, and tax deductions and subsidies associated with green energy installations. However, for the example studied, the investment yields a negative NPV and that the payback period is long (between 8.3 and 10.2 years). Kahn and Iqbal [58] consider potential remedies to the problems of stand-alone decentralised energy systems which sometimes make them non-viable options – such as low capacity factors and excess battery costs. The authors suggest that stand-alone systems could be used as a hybrid with other sources of energy carrier (both renewable and non-renewable) so as to increase their cost effectiveness. They use HOMER software to find the optimal combination of energy technologies in Newfoundland. The results suggest that some hybrid systems (such as a wind–diesel–battery hybrid system) are commercially feasible, but that other systems (such as an environmental friendly hydrogen-based hybrid system) are too costly to be commercially viable.[16]

Cherrington et al. [28] show how recent changes to the FiT tariff for domestic-scale PV systems in the UK have changed the private viability of such technologies. They find that even major reductions in the applicable FiT rate from 43.3 p/kWh to 21.0 p/kWh or 16.0 p/kWh delays the PBP by 2 years (12 years, rather than 10 years). While the return on investment falls, it remains "healthy" ([28], p. 421) at 7%. Muhammad-Sukki et al. [68] show how the payback period for solar PV projects differs across Europe with tariff levels, and that reductions in tariffs could have implications for the future deployment of such technologies.

5.2. The social costs and benefits of DG penetration

In practice, however, there are additional costs and benefits associated with the use of DG technologies over and above the financial costs and revenues. In particular, the potential environmental benefit of distributed generation systems is one of the main drivers of the current enthusiasm for DG. DG can play a role in helping environmental obligations be met in two key ways. Firstly, CHP applications (associated with DG technologies such as fuel cells, gas turbines and microturbines) allow for emissions savings and optimal energy consumption for firms or communities where there is a simultaneous demand for heat and electricity. Secondly, most renewable energy technologies (with the exception of large hydro stations) are decentralised because of their

[15] The NPV of a project is the discounted value of the investment's income, minus the discounted value of its outflows. An investment should have a NPV of greater than zero to be financially viable. The PBP measures the length of time taken to recover the initial investment for a project, ignoring the time value of money. NPV is therefore, in general, a more appropriate method of investment appraisal.

[16] Other relevant studies include who formulate [48,49] and apply a techno-economic modelling framework to study fuel cell micro-CHP system design and control; and Carley [24] who develops an econometric model of utilities' decisions on whether to adopt DG and, if so, how much capacity to deploy.

nature. Various studies attempt to capture such externalities (social costs and benefits) associated with DG energy systems.

There are a number of techniques that can be used for appraising and valuing the social costs and benefits associated with distributed energy generation. Life Cycle Assessment (LCA) is an important method of assessing the environmental impact of a technology over its entire life. In a LCA, all energy and materials use, including waste or pollutants associated with an activity or products, are quantified during the full life cycle of that activity or product. Consequently, the contribution of a product towards a predefined environmental impact over its lifetime is calculated.[17] All environmental effects associated with an activity are computed, including geographically diverse effects, such as material inputs that are imported.[18] However, a LCA, 'only' identifies the environmental impact – though this is often a huge undertaking if genuinely comprehensive. Cost Benefit Analysis (CBA) is yet more ambitious in that it seeks to assign monetary values to all of the costs and benefits of a project, even where no market price exists to facilitate valuation (which is, of course, a major challenge). CBA is the public policy counterpart to private sector investment appraisal methods. In principle, LCAs could constitute one of the inputs into an overall CBA, though a monetary value would have to be attached to the environmental impacts, and it would then be included along with all other costs and benefits into the overall welfare assessment.[19]

Chakrabati and Chakrabati [26] consider an existing stand-alone solar PV system for the electrification of a remote area in India. In addition to illustrating that diseconomies of scale are associated with conventional power generation for such a remote application, the authors also demonstrate the social viability of such a system via an observed improvement in education, trade, commerce and increased participation of women in non-household activities, though these results are based on (ex ante and ex post) frequency distributions collated from household samples, rather than by estimating the value of such social impacts via, for example, CBA.[20] The authors also note the zero emissions costs from the solar system, and quantify comparative emissions costs associated with various fossil fuel alternatives. Ravindranath et al. [75] consider the carbon abatement opportunities associated with substituting bioenergy technologies (BETs) for centralised fossil fuel energy systems in India. They compare the costs per tonne of carbon abatement of 10 BET projects with that of conventional alternatives, and find that six of the BET projects represent more cost-effective carbon mitigation opportunities compared with the conventional generation.

Walker [89] assesses the link between distributed energy systems and fuel poverty in the UK. The author notes that the wide range of potential DG technologies, as well as issues such as the operation, ownership, installation, network requirements and maintenance of the individual systems will determine the effect on fuel poverty. The author suggests that increased penetration of distributed energy systems could improve energy affordability for low income households in the UK. However, he notes that the upfront costs required to over the installation of residential distributed energy generation systems are an important barrier for low income households. Existing evidence suggests that the early adopters of microgeneration systems are higher income groups [22]. If policies designed to encourage DG are focused on households installing and paying for small-scale generation technologies (as is the case for the current FIT scheme, and the Low Carbon Buildings Programme),[21] Walker [89] argues that there is the risk of middle classes actively investing in such technologies, whilst the low-income groups rely on traditional electricity and gas supplies. If technology advances mean that investors in microgeneration benefit from falling energy costs, then the problem of fuel poverty will be exacerbated. Walker [89] instead argues that national and local governments, housing associations and/or energy providers should actively pursue the provision of microgeneration technologies in alternative ways, for example via fuel poverty programmes that provide grant funding for low-income groups.

Gulli [43] implements a social cost-benefit analysis of the decentralisation of energy supply, focusing on both residential and service sector applications (CHP installations in both a residential building and hospital). In doing so, the author calculates both the financial costs and benefits (including the price per unit consumed of energy from a centralised versus a decentralised system), as well as wider social costs and benefits (including estimates of the cost of energy-related externalities such as pollution emissions). This exercise is conducted for different hypothetical DG systems in Italy, compared with comparable conventional generation techniques. The author finds that, in terms of private costs, DG systems are, in general, uncompetitive both in the residential and service sector applications. To calculate the social costs and benefits, Gulli [43] takes into account effects such as the impact on public health, agriculture, the ecosystem in general and pollution emissions. The value of such effects are calculated in monetary terms, measured via a 'willingness to pay or accept' measure. The results suggest that even when such social externalities are taken into account, the DG project, in general, is still more costly than the conventional centralised systems (with the exception of two cases): a gas engine CHP system in Palermo (for the hospital case), and a gas turbine CHP system in Milan (also for the hospital case). The author finds that the efficiency benefits associated with CHP use and the avoidance of transmission costs are not sufficient to compensate for higher investment costs of the DG applications. However, the author notes that the methodologies used to evaluate the external costs are imperfect, and also that technological developments in the efficiency of dispersed energy systems (with specific reference to the development of fuel cells) could increase DG performance. Additionally, in this paper the author attaches a higher environmental impact coefficient to emissions that occur in urban areas than to emissions that occur in non-urban areas. The DG systems are located in urban areas, necessarily close to demand, and therefore, in relative terms, the CHP systems are associated with higher emission costs. The appropriateness of such an assumption should perhaps be considered, and sensitivity analysis around this assumption would be informative.

Hawkes and Leach [47] consider the environmental impact of energy use in the residential sector for three different types of micro-CHP installations in the UK, and five different types of residential dwelling, as well as three different electricity demand values. The authors calculate the 'equivalent annual cost' and CO_2 emissions using the CODEGen model, a generalised model of heat and power provision that minimises the present value lifetime cost of meeting a given energy demand. The authors find that the micro-CHP system can reduce CO_2 emissions by between 10% and

[17] The LCA methodology is standardised according to the Society of Environmental Toxicology and Chemistry guidelines: ISO standards 14040 and 14044.

[18] See e.g. Allen et al. [11], McManus et al. [65], Molloy [66], Hammond and Winnett [46] and Bush et al. [21] for an exposition and critique. Among the problems are the data requirements of LCA; the typical neglect of local environmental impacts and the reluctance of private companies to share environmental data that they may regard as sensitive.

[19] See Pearce [72] and Ackerman [2] for an exposition and critique.

[20] So that the *ceteris paribus* assumption is important here.

[21] A capital subsidy policy for low carbon generation installations; under this scheme households still pay a minimum of 70% of the cost of the installation costs.

20% of current CO_2 emissions for the residential sector, and generate annual cost savings of between approximately £100 and £500 per tonne of CO_2. The authors also note that the cost of the CO_2 savings is, in the majority of cases, such that micro-CHP can be an economically efficient instrument for reducing carbon emissions (given the carbon price in the EU ETS).

In Allen et al. [1] the authors use LCA to evaluate the environmental impact associated with the installation and operation of a micro-wind turbine for domestic electricity generation. The authors collect data for the manufacture of the micro-wind generator, which include materials and components; transportation of materials and components to the turbine factory; transportation of assembled turbine to the customer; and materials and production of a mounting station for the turbine.[22] During the lifetime operation of the turbine, the energy produced by the device is assumed to offset the conventional energy that would otherwise be required to be obtained from the centralised UK electricity system. The authors assume a specific 'energy mix' that is typical of the UK grid.[23] They consider a number of 'wind condition' scenarios, and find that, over the life cycle of the turbine, the device has a positive environmental impact for all scenarios except for the poorest of wind conditions. Aside from the available wind resource, the authors find that the geographical positioning of the turbine and the use of recycled materials or not for the manufacture of the device are particularly important factors in determining the environmental impact and overall environmental benefits of the device.

In Allen et al. [12] the authors conduct a more comprehensive appraisal of the environmental impacts of distributed generation technologies. The authors use both a LCA and CBA to evaluate the environmental performance of three microgenerators: a micro-wind turbine; a solar photovoltaic array; and a solar hot water system. For the LCA, the authors find that all three devices are associated with positive environmental benefits, but that the use of aluminium as an input mitigates the environmental benefits for the micro-wind turbine and the solar hot water system. For the CBA, the authors identify the financial costs and benefits associated with the devices, and also incorporate a quantification of the present value of the environmental externalities associated with the use of the devices, and determine the net benefits of the projects. The authors find that none of the devices are commercially viable and that, even when avoided environmental externalities are included, the overall cost of the devices still outweighs the benefits. The authors suggest that although the microgenerators are not currently competitive, future technological changes, operational efficiencies, and the use of, for example, recycled aluminium in the production of devices, could significantly alter the results of such studies.[24]

Bush et al. [21] undertake an LCA assessment of micro-wind and solar PV technologies in the UK. In their hybrid input–output approach, they combine technological data (i.e. a "bottom-up" assessment) with an input–output system of interactions between production sectors, to account for upstream carbon emissions in the production process. Further, they are able to then demonstrate the importance of wind speed and irradiance on the carbon payback period for both technologies.

[22] There is heating and lighting energy use associated with the assembly period in the factory; though the authors omit this factor due to a lack of data, and note that this aspect is likely to make little overall impact.

[23] Though the authors note that if the grid 'energy mix' were to change – for example via an increase in the non-fossil fuel energy share of the mix – then this could have an important impact for such analyses.

[24] Other relevant studies include Mendez et al. (2006), Pehnt (2007), Strbac et al. [83], Newborough [69] and Vogel [88].

5.3. The overall economic, environmental and social impacts of DG penetration

We next consider the overall/system-wide/macro-economic, environmental and social impacts of DG penetration. Here our concern is with the likely system-wide[25] consequences of significant penetrations of DG. Clearly the intention of policy-makers in introducing measures to encourage the adoption of DG is that this will assist in the achievement of some or all of their energy policy goals. To determine whether this is so we need to assess the likely impact of significant DG penetration on economic activity as a whole. This is likely to be of interest in its own right (since economic activity is typically one of the wider goals of government policy, and in Scotland – for example – is one of the goals of energy policy per se), but also because this is a key determinant of the level of GHG emissions. Furthermore, we are also likely to be concerned with the sectoral composition of any changes in economic activity because we know that energy demands (and the emissions intensity of output) vary significantly across sectors. To assess the system-wide environmental impacts of significant DG penetration we have to understand its effect on sectoral and aggregate economic activity. In addition, such changes invariably have uneven impacts across household groups, and if we wish to track effects on fuel poverty, for example, we again need to adopt a system-wide perspective. We consider the system-wide economic, environmental and social impacts of significant DG penetration in turn.

5.3.1. The system-wide impacts on aggregate and sectoral economic activity

Macroeconomic analyses of DG are few, possibly reflecting a number of difficulties and uncertainties associated with modelling the economy-wide impacts of increasing penetration of DG technologies. DG encompasses a wide variety of generation technologies, and the costs associated with DG differ widely according to technology type, geographic location, infrastructure requirements and so forth. Additionally, there are many unknowns regarding feasible penetration scenarios for DG; policy support mechanisms, and potential cost requirements for network adjustments, which could be important factors to consider in a macroeconomic analysis of DG.

There have been some attempts to quantify the costs (including the social cost of emissions) associated with the UK moving towards an electricity system that is based on DG as an alternative to centralised generation, so these studies go well beyond cost benefit analyses of individual distributed energy plants. BERR and WADE [20] quantify the costs and benefits (including the social cost of carbon emissions) of using a decentralised electricity generation system (that encompasses a range of different technologies) to meet electricity demand needs for the whole of the UK for the next 20 years, and compare this with the relative costs and benefits of equivalent centralised generation. They compare alternative 'scenarios' (exogenously determined "bundles" of electricity generating technologies) and a wide range of model input assumptions by the user for a DG compared with a CG system (regarding, for example: transmission and distribution infrastructure costs; electricity output losses associated with transmission and distribution; fuel use; electricity demand growth over time). Given the complexities of modelling DG, the exercise is necessarily rather assumption-driven. As a result, there are significant uncertainties associated with the 'rule of thumb'-type assumptions

[25] Here 'system-wide' refers to the economy as a whole, not the electricity system. (However, for the latter see, for example, Viral and Khatod [87] and Tan et al. [84]).

made in the study. For example, the authors note that the WADE framework incorporates a single cost to reflect the cost of infrastructure updates required for transmission and distribution under each of the DG and CG scenarios. In practice, however, such costs vary significantly from project to project. Furthermore, the model adopts a very simplistic treatment of CHP: although the generation sector is explicitly modelled in WADE, heat is not explicitly identified and so instead the authors attempt to quantify the benefits of better fuel efficiency associated with CHP simplistically.

The WADE model is used to calculate the costs associated with generating a given quantity of electrical output for different technologies. For CHP, the costs are associated not only with the production of electricity, but also heat generation – an efficiency benefit associated with CHP. Appropriate measurement of the efficiency benefit of CHP requires a comparison of the costs of CHP generation with that of the separate centralised generation of (power station) electricity and (gas boiler) heat. However, since heat is not explicitly modelled in WADE, this is not possible. In order to capture the efficiency benefit of CHP in the WADE model, the input electrical efficiency data is increased as an approximation for the heat benefit associated with CHP, taking account of different sizes of CHP plant and their associated efficiencies. This is an important limitation of the WADE model (and is explicitly recognised by the modellers): CHP is likely to play a crucial role in a future DG scenario (in this case the modellers assume over 50% of new capacity is accounted for by CHP technologies), so the simplified treatment of CHP may well have important implications for model results.

In a study commissioned by the DTI, Cambridge Econometrics [23], the authors use an energy–economy–environment framework that is designed to model the growth of CHP capacity in the UK to 2010, and the resulting impacts on energy demand and environmental emissions. They use a macro-econometric model that is based on a set of input–output (IO) coefficients which are updated with a series of econometric time series relationships. Embedded within the main model is a series of sub-models (energy, electricity supply and environmental emissions model). These sub-models update specific prices and demands, which then feed back into the main model and are used to update the IO data. Further, the electricity supply and energy sub-models are integrated with a CHP sub-model, designed to allow examination of the factors that are important in influencing CHP installation decisions. Operation of the model requires a large number of assumptions concerning the future energy and economic environment. These assumptions relate to macroeconomic conditions over time (including forecasts of the economic growth rate, domestic and trading partners' inflation rates, exchange rates, interest rates, domestic tax rates, and government expenditures); energy prices (including forecast of electricity and gas prices); and the extent and characteristics of policy support mechanisms for the energy industry. For the CHP sub-model, the authors also input statistics on the use of CHP in the UK (using historical data on the uptake of CHP); cost estimates of CHP installations; and the avoided costs of alternative energy sources. The simulation methodology of estimating the uptake of CHP involves inputting the exogenous assumptions and data sources described above to the main and sub-models, with the model then calculating the altered investment decisions. The historical data on the uptake of CHP is used to estimate how the share of the associated CHP will change. This is done by separating the individual demand for CHP into sub-sectors, calculating a NPV for each scheme, and then allowing the model to select a proportion of the plants which are financially feasible according to their NPV. The main output of the MDM-E3 model is the technological capacity, rather than the impact on wider economic variables.

In their simulations, the authors consider the contribution of selected policy support mechanisms in affecting the growth rate of CHP uptake in the UK, and, given the significant degree of uncertainty surrounding the input data and assumptions, the authors conduct significant sensitivity analysis around fuel price and other modelling assumptions. The extent of the sensitivity analysis means that there are a wide range of possible CHP capacity outcomes. The authors find that fuel price assumptions, in particular, have substantial effects on results, in line with intuition: for example, the results suggest that under a 'more favourable' price scenario for CHP (where electricity prices are assumed to be 40% higher and gas prices 40% lower than baseline assumptions), a higher CHP capacity is installed (13.6 GWe by 2010), whilst for a 'less favourable' price scenario for CHP (where electricity prices are lower and gas prices are higher than in the baseline), there is downward pressure on installed CHP capacity, with build estimates of 7.3 GWe by 2010. The authors also estimate the importance of key support mechanisms in influencing the installation of CHP capacity, and find that exemption from the Climate Change Levy (CCL) for certain CHP power exports has a particularly strong impact on CHP capacity installed by 2010. The authors also find that CO_2 emissions fall as a result of the CHP installations, due to CHP being more efficient and using fuels with a much lower carbon content, on average, compared with conventional generation. While the analysis is indicative, the results are, of course, heavily dependent upon the specific assumptions made, although the sensitivity analysis is a recognition of this.

There are demanding informational requirements related to the DG sector associated with carrying out detailed macroeconomic analyses of its impact. One important requirement in estimating the macroeconomic impacts of DG is reliable and realistic estimates of the extent of DG generation. Government targets for the uptake of renewable energy provide some indication of the potential penetration of DG. Furthermore, there are government and other organisations' forecasts/projections at a national level of the likely system-wide uptake of DG technologies. However, in practice, it is likely that one or two DG technologies become dominant, and such projections do not provide information on how the overall level of penetration is shared across technologies. Due to the heterogeneous nature of distributed energy technologies – each technology differs greatly in terms of their financial costs (thereby influencing overall expenditures, for example, and corresponding macroeconomic impacts), as well as their emissions performance, for example – more detail is required not only on the likely overall DG capacity, but also on its likely composition.

In Foote et al. [41], the authors develop penetration scenarios for low-voltage DG that provide an indication of not only the overall system-wide potential of (low-voltage) DG uptake in selected European countries (including the UK), but also an indication of the technologies that are most likely to be prevalent. The authors collate government and other organisations' forecasts of the uptake of DG for each country, and also collect survey data from industry experts to indicate which of the DG technologies are likely to be most prevalent, ranking the DG technologies with respect to which are most likely to be installed in 2010 and 2020. For the UK, the authors suggest a DG capacity of 8.24–17.30% as a percentage of total capacity in 2010, with photovoltaics, micro-gas turbines and reciprocating engines amongst those technologies expected to be the most prevalent by 2020. This provides a starting point for more macro-based analysis. For example, macroeconomic analysis could be conducted by assuming an overall capacity of DG penetration, assigning generic (and necessarily uncertain) costs associated with this capacity installation, and assigning these expenditures to the top three (for example) dominant technologies. Scenario analysis around benchmark values could yield significant insight into understanding the significance of key assumptions. Such work provides insight into the expected level of DG penetration, and informs the modelling, simulation and analysis of its impact.

Although it is difficult to do so, estimating the macroeconomic impacts of DG has clear benefits. DG is becoming increasingly widespread and its uptake is fundamentally changing the structure and operation of electricity networks, and increased expenditures on renewable energy installations, for example, is likely to have wider economic interactions and feedback effects. A number of multi-sectoral modelling approaches allow an analysis of the likely aggregate and sectoral economic impacts (which in turn can be linked to environmental and social impacts – see below). First, input–output (IO) analysis can be usefully employed to assess regional (and if data permit) local economic and employment effects of, for example, the introduction of significant DG penetration.[26] Such analyses can be employed, for example, to assess the importance of supply-chain development in governing the scale of economic impacts: the greater the degree of local embeddedness, the greater the impact on the host economy.[27]

Although undoubtedly useful, IO studies have limitations. For example, while onshore wind developments currently typically have little in the way of backward linkage into the host region (since the technology is imported), they are often associated with significant income flows in the form of community benefits and, increasingly, returns to local ownership. These income flows are not captured appropriately in IO systems, but are in social accounting matrices (SAMs), which can identify the potentially significant impacts of such income flows on the local economy.[28] Such models are capable of exploring the impacts of different levels and forms of community benefit payments and of alternative ownership models and so could be applied to a range of DG initiatives.

Another limitation of IO models (shared by SAM models) is that they are predicated upon an assumption of entirely passive supply: they are completely demand-driven. In circumstances where there are important supply constraints in the host region, the supply side of the economy has to be modelled explicitly. In principle, computable general equilibrium models (CGEs) permit a complete, theory-consistent model of the demand and supply sides of all markets. In CGEs prices are endogenous, and typically adjust to equate demand and supply in each market. However, for demand-side disturbances they replicate the comparable IO systems where supply is passive (e.g. where there is significant unemployment and spare capacity). These studies have modelled, for example, the macroeconomic impact of increased demand connected with marine expenditures, the potential legacy effects of such expenditures, and the creation of new export opportunities [4,6,8].

5.3.2. Economy-wide environmental impacts

Given the existence of fuel emission coefficients and knowledge of the fuel-use of industries, it is possible to construct integrated IO and SAM accounting systems that include energy demands and emissions. These integrated databases can be used to calibrate energy–economy–environment IO, SAM and CGE models, which can be used to track the impact of disturbances on GHGs for example. The resultant databases can be used to compute carbon footprints in a rigorous and transparent way that reflects system-wide impacts on emissions (including those that arise indirectly through intermediate purchases and those that are induced by consumers' expenditure responding to changes in income). In the context of DG, this would allow an assessment of its impact on a particular region's carbon footprint. However, in the context of 'open' regions or localities (where trade flows are relatively large), it would be important to distinguish between production-oriented measures of emissions (as emphasised by Kyoto) and consumption-oriented measures. In two (or more) region context it would be possible to identify the CO_2 'trade balance' between regions, and the impact of DG on this.[29] Clearly, small, open regions may initially import electricity from beyond its geographic boundaries, whereas CHP development may bring generation within those boundaries but result in a cut in imports (and possible electricity generation) elsewhere. Production-oriented measures would clearly indicate an increase in emissions, whereas consumption-oriented measures may indicate the reverse.

CGEs can and have been used to identify the environmental impacts of various policy and other disturbances. This approach is essential if relative price changes are a key element of any disturbance, as is the case, for example if a carbon tax is imposed (e.g. [9]) or energy efficiency is improved. In the latter case CGEs can be used to analyse the 'rebound' and 'backfire' effects associated with energy efficiency improvements (e.g. [7,60,45]). The approach may similarly be applied to explore the economic and environmental impact of significant penetration of DG.

5.3.3. Economy-wide social impacts

In principle, the energy–economy–environment IO and SAM databases can be augmented to include a degree of household disaggregation by income group. Again these databases can be calibrated to yield corresponding models in which impacts on households by broad income group are automatically tracked. Clearly this is of interest given concerns about fuel poverty, and indeed about income distribution in general. Again such models can be usefully applied to DG.[30]

6. Conclusions

In recent years, there have been significant changes to the institutional, technical, and policy environment within which the UK energy supply system operates. The current energy resource mix has expanded, with the increased operation of 'clean' and 'efficient' supply sources, and a shift towards distributed energy technologies. In this paper we consider the economics of distributed generation, and review the literature on the financial viability, social costs and benefits, and macroeconomics of DG. This is with a view to contributing to the knowledge base on DG, and to identifying any gaps in the literature that future research might address to improve the evidence base for policy formulation.

Distributed energy encompasses a wide variety of technologies, and we find that the economics of DG tends to be highly sensitive to the type of technology and deployment context. The results of financial viability studies are mixed, although stand-alone projects in isolated areas in developing countries seem currently to be the most attractive. As is the case for most emerging technologies, DG technologies are typically not yet commercially viable without support, and tend to have greater costs than conventional technologies, though many authors acknowledge the potential for future cost reductions through technological advancements. We believe there is scope for wider application here of the 'learning curve' analyses that have been applied to other emerging technologies. Furthermore, recognition that DG will inevitably form only part of a portfolio of generating technologies suggests that

[26] See Miller and Blair [64] for an exposition of IO and SAM models.

[27] See Allan et al. [7] for a study of the impact of alternative electricity generating technologies.

[28] Allan et al. [10] adopt a SAM approach to illustrate the potential impacts of the Viking windfarm proposal in the Shetland Islands.

[29] See e.g. McGregor et al. [62]. Allan et al. [5] is an illustrative application to the introduction of CHP to Glasgow.

[30] The illustrative application of Allan et al. [5] includes a degree of household disaggregation.

levelised cost comparisons reflect a limited perspective (even if these do incorporate wider electricity system impacts), since DG may reduce risks for any given cost level because it is likely to reduce correlations with fuel prices, and to enhance security of supply.[31] This perspective also suggests that there is scope for the application of portfolio theory to incorporate DG. At the aggregate level this would focus on the benefits of diversified technologies; at the spatially disaggregated level account should be taken of the benefits of geographic diversification.

In terms of social costs and benefits, the limited attempts at comprehensive analysis exhibit considerable variation in results, with DG proving less attractive than some alternatives. However, whether that will continue to be so if learning is explicitly incorporated and portfolio and other benefits fully valued, remains to be seen. Certainly, difficult though it undoubtedly is, we judge that further cost benefit analysis (CBA) of DG is likely to prove productive, with some of the uncertainties diminishing with time. CBA continues to provide, in our view, the most comprehensive and systematic framework for evaluating individual projects, or groups of projects, from the perspective of society as a whole. However, the approach can, and should, be extended to accommodate general equilibrium impacts/macroeconomic effects.

We find very few examples of macroeconomic analyses of DG. Of course, the very heterogeneous nature of DG renders such analyses especially difficult. The appropriate numerical representation of DG is clearly complex. Nevertheless, in order to assess the contribution of DG to energy (and other) policy goals, we need to understand the system-wide economic, environmental and social impacts of increased penetration of DG. Increased decentralisation of the UK energy system via DG technologies would likely have substantial impacts through construction expenditures, infrastructure adaptations, employment changes in 'green' industries and environmental impacts. Such effects could have important implications for economies at all spatial scales, and are of interest to local, regional and national governments. There are also potentially important impacts of DG policy on fuel poverty in particular and equity in general, as well as issues relating to the potential displacement of emissions across local areas, from centralised 'out of town' plants to urban locations. This highlights the complexity of, but also the need for, emissions attribution analyses that recognise geographic boundaries (and accommodate trade flows) appropriately. System-wide economic-energy-environment modelling can, we believe, enhance the evidence base for DG policy formation and implementation.

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