Final Report

Assessment of Potential Barriers and Routes for Decentralised Energy Schemes in Rural and Urban Fringe Areas in the UK

CORNWALL INSIGHT
CREATING CLARITY

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1. Introduction

This report addresses a range of issues and the impacts that they have on decentralised energy schemes.

Decentralised energy is energy generated off the main transmission grid and includes micro-renewables, local and district heating and cooling, energy from waste plants, combined heat and power (CHP), geothermal, biomass and solar. It can be for a single building, whole community or a whole town or city. The motives behind these schemes are to take control of future energy security, cut carbon emissions, increase prosperity and resilience of local communities.

Specifically, this report provides a high level review of the GB energy markets, including the physical infrastructure and market structure. It also looks at government policy on both energy and land use.

Land is key to everything we do and need – food production, leisure, forestry, infrastructure, housing and energy and we explore these topics in detail in this report.

The report looks at how the structure of the GB energy market, changes in land use and the income derived from it will influence small scale generators in the future as well as looking at the potential implications of Brexit for the market (as far as these are known in the current climate of uncertainty).

We explore the factors affecting the routes to market and the sources of revenue open to energy projects, whether they be spatial, technological or market driven. Specifically, we analyse the routes to market and the component parts of the revenue “stack” for a range of technology types including wholesale electricity, embedded benefits and alternative revenue streams.

We also discuss seven key ownership models for decentralised energy resources, and some short case-studies where these models have been used by existing market participants. We introduce the concept of aggregation, which can allow generators and energy users to develop value from their flexibility and generation assets, where they would otherwise be too small to enter these markets.

As part of this report we have sought to analyse data from operational projects. We have utilised data gathered from Community Energy England (www.communityenergyengland.org). We reviewed the available data and excluded member organisations where no operational projects were identifiable. Where possible the identified projects have been geocoded and are referred to throughout the body of this report. A location plan of those projects identified is shown below.

Location Plan, Community Energy England

2. Summary of Opportunities and Barriers

Figure 1 summarises the potential opportunities and barriers for decentralised energy schemes. These will be analysed in more detail including land grade, population density and location, in the final report using examples of actual schemes.

Figure 1: Potential opportunities and barriers to decentralised energy schemes

Factor	Opportunities	Barriers	Main Section
ENERGY			
Market access	The Smart Export Tariff will improve market access, when introduced, for small-scale (<0.5MW) generators. Revenues are higher where connection can be made behind the customer meter. Aggregation of smaller sites to improve value is possible, but is still in its infancy.	The market access of small-scale renewables generators is currently limited due to high transaction costs and limited appetite among offtakers for very small parcels of intermittent power.	17.3
Regulation	Licence-exempt generators (<50MW) do not have to sign up to industry codes. Licence-exempt distribution networks do not have to sign up to industry codes. This saves time and money, and limits complexity.	Local energy markets and peer-to-peer trading are not supported under current regulation, and ongoing changes to network charging regimes will not introduce this capacity.	4.1.3 4.1.4
Connection cost	Areas with high connection costs could provide opportunities for private wires or smart grid projects.	The cost of the connection itself can vary considerably depending on size and technical characteristics. Connections in rural areas are likely to be further from substations and therefore more expensive.	7.2.2
Connection viability	Areas with low connection viability could provide opportunities for private wires or smart grid projects.	Many regions cannot accept any new generation being connected to the networks without exceeding limits on transformers and wires. This is particularly the case on rural networks, which tend to be “weaker” and have less spare capacity than urban networks.	7.2.1
Significant code reviews		Reviews are likely to make embedded generation less viable overall by reducing the benefits of having generation connected to the distribution networks, or behind the meter.	8.7

Factor	Opportunities	Barriers	Main Section
		May also make charges more granular, again damaging the business case for rural generation.	
Energy policy		Onshore wind, one of the most cost-effective generation technologies and one suited to rural environs, is not supported by central government.	11.1
Heat policy	Reducing carbon emissions from space and water heating will create investment opportunities in new technologies, for example heat pumps, district heating networks and energy efficiency	There is yet to emerge a unified decarbonisation policy for heating, and little financial support is available for high-cost technologies (beyond the RHI).	11.2
Electrification of heat and transport	Will create new electricity demand as fossil fuels are replaced. May also deliver new sources of flexibility, if smart technologies are deployed.	Rural areas with weak networks may struggle to roll out electric vehicle chargers and heat pumps to meet targets.	17.10
Heat networks	Rural population centres which are not connected to the gas networks will be key targets for heat networks.	With lower-density populations, connection charges may be higher than for urban networks.	9.6
The DSO transition	Drive towards efficiency for network operators is creating value in delivering local flexibility to support the grid. These values can be tapped by existing or new decentralised energy resources.	Revenue streams are not investable, being short term and uncertain.	8.6.1.5
Corporate social responsibility	Industry is increasingly aware of and looking for a way to be green and local. Decentralised renewable energy is well-placed to serve this agenda.	Companies are often reluctant to pay significantly over the odds for environmental benefits	10.1
RURAL			
Historical rural policy	Historic opportunities for energy schemes within the productivity programmes under funding for non-agricultural uses although this is very difficult to quantify.	However historical funding has been very much focussed on agriculture and the environment and the direct payments received by farmers tend to reduce innovation and investment	11.3
Future rural policy	Public money for public goods which may include energy security	Alternative income streams including food production, forestry, leisure, public access and wellbeing programmes	11.3.3
	Public money for public goods will include carbon capture which will include more trees and therefore biomass for CHP plants		11.3.4
	Eligibility for funds widened beyond active farmers with collaboration likely to be a key principle		13.3

Factor	Opportunities	Barriers	Main Section
	Collaboration is likely to be a key policy principle. Therefore, the scope of opportunities for decentralised, especially at a community level, are likely to be higher.		
	Demise of BPS income as landowners look for alternative income streams, to reduce costs and risk. This will include energy security and efficiency		14.2
Rural estates	The diversity of property assets and therefore energy consumption offers strong incentives to consider decentralised energy schemes to tenants and occupiers.	Competing uses – for example timber for construction v use CHP schemes	14.1
Land availability	There is the potential for significant change in the way land is used in the UK over the next 30 years with potentially 13 million acres of land being “released” from agricultural production. Therefore, there could be significant opportunities to increase the deployment of land intensive energy technologies including ground mounted solar and bioenergy crops for anaerobic digestion and biomass plants.	Competition for access to land not least from afforestation, housing and infrastructure. This is likely to be particularly strong in urban-fringe areas where access to land for housing, infrastructure and recreation will be at a premium.	12.4
Tenure	The structure of land occupation is likely to change as we move into the post direct payment subsidy era. We envisage that there will be more flexibility in land tenure tenancies/agreements	Inflexible land tenure agreements not allowing tenants to diversify may limit opportunities	13
Land values/prices	More flexible tenure combined with a more stable land market may make investment in and use of decentralised energy schemes more attractive	High land prices – strategic development land especially near settlements	13.1.1
Location	High population density looking for energy security	Remote areas where capital cost outweighs returns	12.4

About the Authors

Savills

Savills UK operates across 135 offices nationally and services the full spectrum of the real estate sector through our 300 different service lines. We provide a complete range of property solutions throughout the life-cycle of any real estate asset nationwide. A unique combination of sector knowledge and flair gives clients access to real estate expertise of the highest calibre. We are regarded as an innovative organisation and a number of recent market awards are a testimony to our success.

Our energy team work for a range of clients, from developers to consumers, and investors to landowners, helping them to take advantage of opportunities in creative, efficient and cost-effective ways. Traditionally, we have worked with clients to help source, fund, deliver and monetise their energy assets and infrastructure. However, as the cost and security of energy and other essential resources become acknowledged as integral to the viability and vitality of businesses and real estate, we now work increasingly with other teams within the UK and international Savills network to bring energy projects to life.

We have an independent and proactive approach to research and consultancy, which comes from a clear understanding of market dynamics in close consultation with our local market agents. Our data provides the backbone enabling us to provide analysis, commentary and forecasting that creates real value for our clients. Using our data and first-class market knowledge, we produce a number of regular reports on the regional UK markets.

Our research can also work with our analysts, producing cross sector reports – the only UK agent with the capability to do so. These look at the dynamics between the residential and commercial markets in key regional cities, uncovering potential development challenges and opportunities.

At the heart of this process lies the team's ability to generate innovative and fresh solutions, rooted in commercial reality. We are thought leaders in commercial property research and have produced several white papers that demonstrate our ability to apply our market knowledge to understand current and future market drivers. This can be provided on a bespoke consultancy basis.

Cornwall Insight

Cornwall Insight is a trusted provider of expert research, insight and intelligence to over 300 companies in the GB and Irish energy markets. Cornwall Insight works closely with clients across generation (renewables, conventional fossil fuels, flexible and peaking), storage and demand side, network companies (national and regional), suppliers (new and established, household and business), market intermediaries, local authorities, and end customers.

Providing consultancy services such a wide range of clients provides us with unrivalled insights and understanding of the links between different segments of the entire energy value chain. We are able to rapidly track how changes in each segment will play out across the whole system, and the impacts on their component companies. This is immensely important as the component sectors become more integrated.

Alongside consulting, we hold forums bringing together industry stakeholders to receive presentations from our experts on key policy, regulatory and market developments that will impact their businesses. We produce a wide range of market intelligence and cost forecasting reports across energy retail, wholesale and regulation. These rely on our experienced modelling team which has developed comprehensive forecasting and analysis models, and which develops new models as required for consultancy projects. Finally, we have a respected training business that last year trained 1,500 industry professionals.

Wholly-owned subsidiary Pixie Energy was set up in 2015 to develop innovation ideas and initiatives, focusing on decentralised energy markets and local transformation through new commercial models. Through our work with local authorities, local enterprise partnerships, distribution network operators, generators, suppliers and community energy groups, we have developed a good understanding of the developing compelling economic cases for development of low carbon energy systems at a sub-regional scale, as well as a strong understanding of current and future enablers and barriers to decentralised energy markets.

This allows us to explain how regionalised energy markets and distributed generation are likely to develop going forward and how local stakeholders can influence the underpinning economic realities to encourage this development. Our experience has been refined through work supporting local energy stakeholders, including local authorities, helping them understand market access options and energy value optimisation

3. Glossary

Term	Acronym	Definition
Active Network Management	ANM	Generation connections offered by DNOs at a lower cost and/or on a shorter timescale, in return for being able to reduce the amount of power a generator is allowed to export at times of network stress Also known as Flexible Connections, Active Connections, Managed Connections, Connect and Manage, and other names
Agricultural Holdings Act Tenancy	AHA	Farm tenancies which usually have lifetime security of tenure and those granted before 12 July 1984 also carry statutory succession rights, on death or retirement. These tenancies tend to be let below market rates.
Balancing Mechanism	BM	The primary balancing service which National Grid uses to balance electricity supply and demand close to real time
Basic Payment Scheme	BPS	The Basic Payment Scheme (BPS) is the biggest of the European Union's rural grants and payments to help the farming industry.
Balancing and Settlement Code	BSC	Code covering balancing and settlement processes by which the electricity system is kept stable and the correct parties are charged for energy use
Behind the meter	-	Location of generation or batteries on the demand-side of the customer's meter, usually an investment to minimise third party charges for power
Capacity Market	CM	The CM is designed to ensure that there is sufficient generation capacity available to the system to maintain supply
Carbon Sink	-	A carbon sink is anything that absorbs more carbon than it releases as carbon dioxide
Combined Heat and Power	CHP	A "co-generation" plant which produces electrical energy, capturing waste heat to provide hot air or water. Combining both sources of energy, this plant can be 80-90% efficient, compared to the most efficient power-only plant at 60-65%
Common Agricultural Policy	CAP	The Common Agricultural Policy is the agricultural policy of the European Union. It implements a system of agricultural subsidies and other programmes.
Committee on Climate Change	CCC	Independent advice to government on building a low-carbon economy and preparing for climate change
Common Distribution Charging Methodology	CDCM	A set of principles set by Ofgem, used by the DNOs to set distribution charges fairly amongst all user types
Competition and Markets Authority	CMA	The government department responsible for business competition and preventing and reducing anti-competitive activities
Contract for Difference	CfD	The current support scheme for large scale low carbon generation. Suppliers are required to make payments on a £/MWh of electricity supplied basis.

Term	Acronym	Definition
Connection and Use of System Code	CUSC	Code covering transmission network connection and usage charges
Department of Business, Energy, and Industrial Strategy	BEIS	The government department responsible for GB's energy policy
Department for Environment, Food and Rural Affairs	DEFRA	The government department responsible for environmental protection, food production and standards, agriculture, fisheries and rural communities in the United Kingdom of Great Britain and Northern Ireland.
Distribution Code	-	Code covering engineering principles of connections, safety and usage on the distribution network
Distribution Connection and Use of System Agreement	DCUSA	Code covering distribution network connection and usage charges
Distribution Network Operator	DNO	Own and maintain the distribution networks: regional mid- and low-voltage networks which serve most customers and growing amounts of generation. There are 14 distribution regions in GB
Distribution Use of System charge	DUoS	Recovered by DNOs to pay the costs of maintaining the distribution networks
Domestic consumer	-	A household customer
Embedded generation	-	Generators connected to the distribution, as opposed to transmission, networks. Typically, small in size and often renewable
Energy Company Obligation	ECO	This scheme obligated suppliers with over 250,000 accounts to install energy efficiency measures in domestic premises
Environmental Land Management Scheme	ELMS	New scheme within the new Agricultural Bill to allocate a greater proportion of funds to environmental enhancement
Energy Networks Association	ENA	Trade body for the GB energy networks
Electric Vehicle	EV	Car, van or truck fuelled by electricity rather than fossil fuels. Zero tailpipe emissions, offering fume and noise emissions reductions, and if charged with low-carbon electricity, carbon emissions reductions also
Extra High Voltage	EHV	The highest voltage level of the distribution network (33kV and 66kV)
Extra High Voltage Distribution Charging Methodology	EDCM	A set of principles set by Ofgem, used by the DNOs to set distribution charges fairly amongst users connected to the EHV network
Farm Business Tenancy	FBT	Farm tenancies which do not have the right of succession and are let at market rates and can be a range of lengths – usually from 1 year to 15 years.
Feed-in Tariff	FiT	The FiT scheme supports small scale (sub 5MW) generation by providing a guaranteed price for electricity generated.
Gas and Electricity Markets Authority	GEMA	See Ofgem

Term	Acronym	Definition
Generator	-	Producers of electricity, typically either thermal (coal, oil, gas, biomass etc.), nuclear, or renewable (solar, wind, hydro), though other technologies exist
Generation Distribution Use of System charge	GDUoS	Recovered by DNOs to pay the costs of maintaining the distribution networks
Grid Code	-	Code covering engineering principles of connections, safety and usage on the transmission network
Half-hourly settlement	HHS	Using actual meter reads to settle the market, rather than profiles based on assumed consumption. Currently in place for most non-domestic customers and likely to arise for small non-domestic and domestic customers in the next 3-5 years. Introduction will expose suppliers to the full underlying costs of their customers power use
Heat network	-	Supply of heat or cooling to multiple properties from a central unit. Likely to be one key route to decarbonisation of heat.
Heat Networks Investment Programme	HNIP	A £320mn government fund intended to upscale heat network adoption in the UK; aims to leverage £1bn of private funding.
High Voltage	HV	The mid-levels of the distribution network, 1kV and over
Imbalance charges	-	Charges levied on industry parties (including suppliers) for the difference between traded electricity and gas volumes and the volume delivered to customers
Imbalance Settlement	IS	The process
Industrial and Commercial	I&C	Cornwall Insight definition defines electricity I&C contracts as: NHH (>10 meters/contract), HH <1GWh (>10 meters/contract), HH >1GWh (all)
Independent Distribution Network Operator	IDNO	Small localised distribution network, typically for a campus, housing development or commercial development
Interconnectors	-	Large, high voltage connections to other national markets for the trading of electricity. Typically for GB these are undersea cables using direct current, as alternating current performs poorly in these conditions
Licence-exempt	-	Generators, distribution networks and supply businesses can all be operated outside of the usual licencing requirements, by meeting the criteria set out in the *Electricity (Class Exemptions from the Requirement for a Licence) Order 2001*
Load factor	-	The amount of power a generator produces, compared to the theoretical maximum
Low voltage	LV	The lowest level of the distribution network, under 1kV
Master Registration Agreement	MRA	Code covering metering and switching
Net Environmental Gain	-	The government's ambition is to embed the wider principle of 'environmental net gain' in development, to drive measurable

Term	Acronym	Definition
		improvements for all aspects of the environment such as air quality, flood defences and clean water
Non-domestic consume	-	A customer who uses energy supplied for business purposes
Office of Gas and Electricity Markets	Ofgem	The gas and electricity market regulator
Offshore Transmission Owner	OFTO	Owners and operators of the large high voltage connections to major offshore wind farms
Over-the-Counter	OTC	A set product for wholesale power, typically traded via a broker
Peak period	-	The time when electricity consumption is highest. This leads to wholesale prices and network charges being highest during these times, and creates addition value to generation producing power, and consumers reducing consumption, during peak periods Peaks on the GB system are winter evenings, 4-7pm
Peer-to-peer trading	P2P	Sale of power directly from a generator to a consumer, outside of the normal market structures. Usually envisaged over the local networks, but currently not economically possible under market rules
Polluter Pays	-	The 'polluter pays' principle is the commonly accepted practice that those who produce pollution should bear the costs of managing it to prevent damage to human health or the environment
Power Purchase Agreement	PPA	An agreement between a supplier and generator to buy the electricity output of the generator
Private network/ private wire	-	A network which is not part of the public, licenced networks. May connect one or more generators and customers. Often used to connect generators to nearby consumers to minimise exposure to third party charges
Renewables	-	A blanket term for “green” or “low-carbon” generation technologies. Typically include solar, wind, hydro, wave, tidal stream, biomass, and biogas. May also include hydrogen
Renewables Obligation	RO	The Renewables Obligation was the main scheme to support large scale renewable generation. Suppliers are obligated to present a certain number of Renewables Obligation Certificates (Rocs) each year for each MWh of electricity supplied.
Revenue = Innovation + Incentives + Outputs	RIIO	Price control framework for networks, operated by Ofgem
Smart Export Guarantee	SEG	A requirement introduced from 31 December 2019, requiring large energy suppliers to offer export tariffs to pay for the electricity put onto the networks by small renewable generators.
Significant Code Review	SCR	A large and wide reaching review of the operation of an area of the electricity industry. Run by Ofgem to look into perceived faults, and allowing it to introduce sweeping changes in relatively short timescales

Term	Acronym	Definition
Small and Medium Enterprise	SME	Cornwall Insight defines the following electricity contracts as SME: non-half hourly meters (up to 10 meters/contract) and half hourly meters with <1GWh demand and up to 10 meters/contract
Smart Energy Code	SEC	Code covering the smart meter rollout and data protection
Smart Export Guarantee	SEG	Proposal from BEIS to require electricity suppliers over a certain size to offer tariffs to renewables generators under 5MW for exported power, where this is metered
Supplier	-	Energy retailer
Supplier of Last Resort	SoLR	The mechanism used by Ofgem if a supplier fails to transfer its customers to another supplier
System Operator	SO	The party responsible for ensuring the safe operation of the transmission system and balancing the system where it does not deliver
Tariff	-	An energy supply contract
Third party charges	TPC	The elements of an energy bill other than wholesale costs, tax and supplier margin
Time of Use	ToU	An energy tariff where unit pricing depends on the time of day of consumption
Transmission Owner	TO	Own and maintain the transmission network, the high-voltage, long-distance energy network. There is one transmission network in GB, with three TOs
Transmission Network Use of System charges	TNUoS	Charges for using the transmission network. Location and time sensitive. Can give a benefit to embedded generation
Triad	-	See TNUoS
Utilisable Agricultural Area	UAA	Area in the UK under crops and pasture plus the area of rough grazing.
Warm Home Discount	WHD	A social scheme which requires suppliers with over 250,000 accounts to identify vulnerable customers and provide them with an annual rebate payment
Wholesale	-	The commodity price of electricity. Various prices exist, through indexes and markets. Wholesale costs make up about 35-40% of the typical electricity bill
World Trade Organisation	WTO	The only global international organisation dealing with the rules of trade between nations. At its heart are the WTO agreements, negotiated and signed by the majority of the world's trading nations and ratified in their parliaments.

4. Overview of the GB Electricity Market

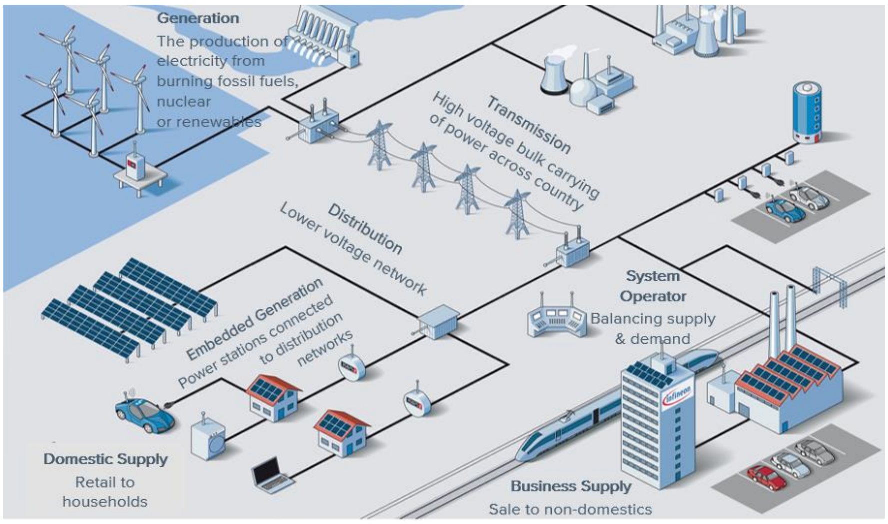
In this section, we present an introduction to the market structure in which decentralised energy projects will operate. The current market is not highly supportive of local energy markets, bringing several barriers to the trading of energy on a sub-national level, but there are several opportunities to highlight. Understanding the market and the existing roles will be crucial to market entry and operating in this complex sector.

4.1. Key Roles in the GB Electricity Market

Under most circumstances, a decentralised energy scheme will need to interact either directly or through an intermediary with at least one operator in each of the electricity system roles.

The GB electricity market is formed of a number of distinct roles and functions encompassing physical infrastructure, competitive activities, and regulatory and policy authorities. A simplified overview of the electricity market roles is shown in below in Figure 2. It is important to remember that decentralised energy schemes will operate within the single national GB electricity market, with a single structure for balancing and settlement.

Figure 2: GB electricity physical infrastructure



The physical infrastructure of the GB electricity market is made up of sources of energy input (electricity generators) and networks to transport the energy from where it is produced to where it is consumed by final users (demand). There are a range of bodies that act to maintain and regulate these systems.

The System Operator (SO) is responsible for ensuring that the electricity transmission system is operating safely in real time and accounting for any energy it procures where the market does not deliver. This activity is currently undertaken by National Grid.

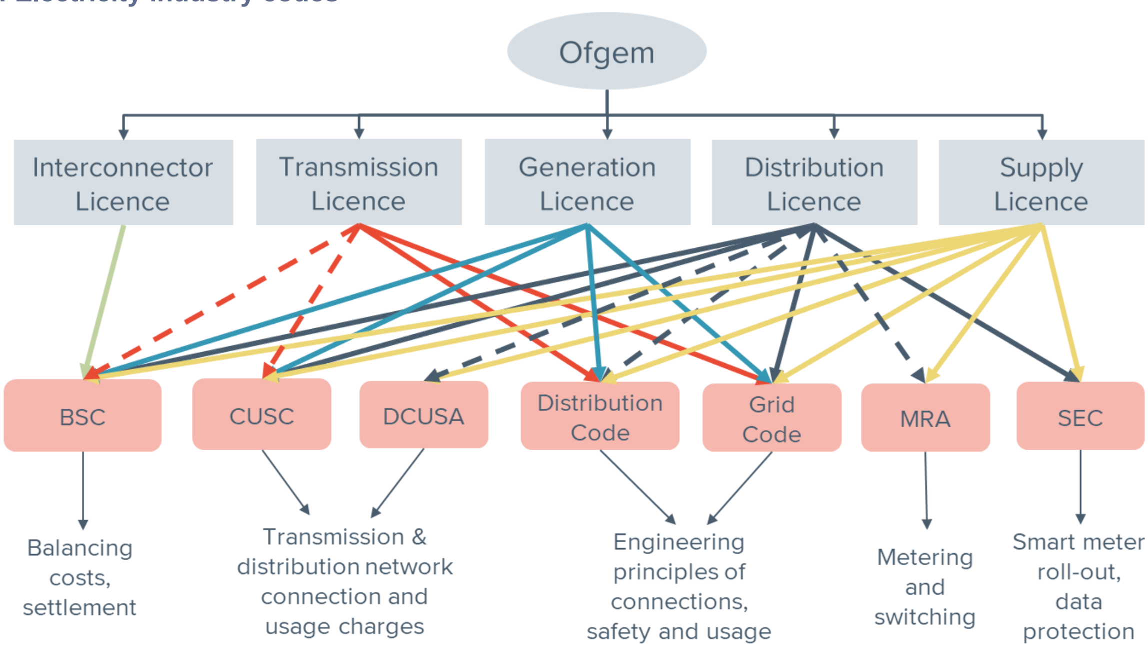
Figure 3 sets out the five key roles, which are explained in more detail below.

Figure 3: Electricity system roles

Role	Company
Generator	Numerous – competitive market. Examples of large generators include: Drax, Marchwood, EDF, Innogy, Uniper, Macquarie
Transmission Owner (TO)	Three TO's: National Grid Electricity Transmission; Scottish Power Transmission; Scottish Hydro Electric Transmission
Distribution Network Owner (DNO)	Six DNOs: UK Power Networks; Western Power Distribution; Scottish Power Energy Networks; Northern Powergrid; Scottish and Southern Energy Power Distribution; Electricity Northwest 13 independent DNOs (IDNOs)
System Operator (SO)	One System Operator: National Grid Electricity System Operator
Supplier	Over 100 licensed suppliers. Examples include: the Big Six (British Gas, E. ON, EDF, npower, Scottish Power and SSE); large non-domestic suppliers (Haven, Smartest, ENGIE, Opus) and the independent or challenger suppliers (First Utility, OVO Energy, Cooperative Energy, Octopus Energy)

There are a large number of codes which market participants may be required to sign up to. There are the Balancing and Settlement Code (BSC), the Connection and Use of System Code (CUSC), the Distribution Connection and Use of System Agreement (DCUSA), the Distribution and Grid Codes, the Master Registration Agreement (MRA) the Smart Energy Code (SEC), and the new Retail Energy Coe (REC). Figure 4 sets these out, and indicates which parties are required to accede to which codes.

Figure 4: Electricity industry codes



4.1.1. Generators

Most electrical generation plant is located in rural or urban fringe areas due to size, noise and emissions considerations. This applies equally to large-scale and decentralised plant.

Electricity generation involves the production of electricity onto the public network for onwards transport to customers. This can be either be large scale generation (several hundred megawatt (MW) or more) connected to the transmission network or smaller scale generation connected to the distribution network (known as 'embedded generation', 'distributed generation', and 'decentralised energy' interchangeably). Large generators must have a generation licence awarded by the sector regulator, Ofgem. This mandates that generators sign up to several industry codes: the Balancing and Settlement Code (BSC), Connection and Use of System Code (CUSC), Distribution Code, and Grid Code.

4.1.1.1. Licence-Exempt Generators

Small-scale decentralised generators can avoid the expense and complexity of acquiring a generation licence.

Generation is a licence-exempt activity for specified classes of generators; typically, smaller generators. This avoids many of the regulations and costs associated with obtaining a licence, for example acceding to various industry codes and central market systems. The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001 sets out the following exemption classes:

- Class A: Small generators whose generation is under 10MW at any time or under 50MW from a station with a declared net capacity of under 100MW, disregarding power supplied to customers on the same site as the generator
- Class B: Offshore generators who only generate from offshore locations
- Class C: Generators not exceeding 100MW which were connected before 30 September 2000
- Class D: Generators never subject to central despatch, i.e. those who were connected to the network before 30 September 2000 and were not on that date already required to submit to central despatch

Licence-exempt generators do not have to sign up to industry codes, avoiding significant cost and complexity. Most decentralised generation will be under 50MW in capacity and therefore will fall within the exemption regime.

4.1.2. Transmission Networks

Small-scale decentralised generators will not be connected to the transmission networks.

The national electricity transmission network provides bulk transport of power up and down the country at high voltages: 400kV, 275kV, and – in Scotland – 132kV. There are three transmission owners (TOs) across the single national transmission network. The transmission networks connect large generation assets (currently around 68GW in total capacity), interconnectors (which connect to international power markets), and some of the largest electricity consumers. The transmission networks connect the distribution networks to the generators and to one another.

Charges for the monopoly services provided by the transmission networks are regulated by Ofgem under a price control framework, known as Revenue = Incentives + Innovation + Outputs, or RIIO. This sets out how much in total networks can recover from customers over the eight-year period of the price control, and how much of this sum in each year. It also sets out how much networks are expected to invest in upgrades. The RIIO price control is currently being renegotiated, with new charges to take effect from April 2021.

Other parties own and operate the various international interconnectors, mostly under cap-and-floor arrangements, and the offshore transmission owner (OFTO) licensing regime controls connections for large-scale offshore wind farms. These operate under price controls under the "cap-and-floor" regime, which operates for the lifetime of the asset.

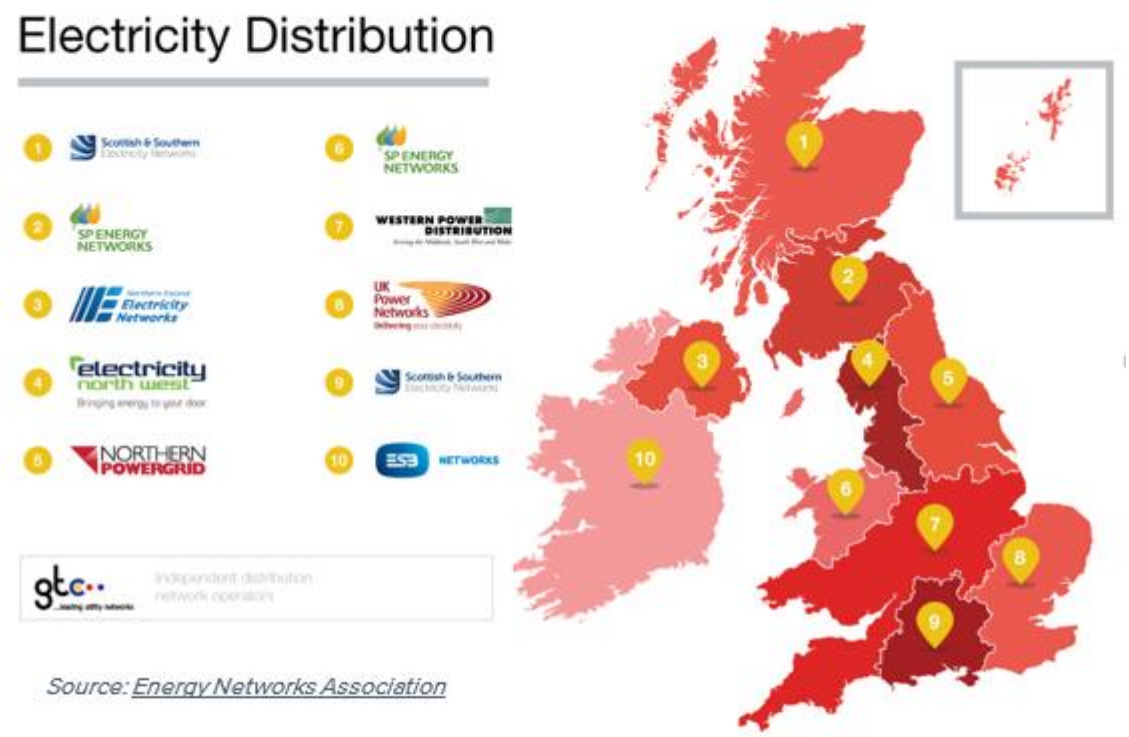
Transmission networks must sign up to several industry codes: the BSC, DCUSA, the Distribution Code and the Grid Code.

4.1.3. Distribution Networks

> Small-scale decentralised generators and electricity consuming projects will connect to one of the 14 GB distribution networks.

The lower voltage regional distribution networks step down voltage levels to safe levels for consumers: 132kV (in England and Wales) and below. There are six distribution network operators (DNOs) across the fourteen regional distribution networks, with operators managing between one and four networks each. Figure 5 shows the DNOs and their areas of operation.

Figure 5: Distribution Network Operation regions



They connect most consumers, with larger (industrial and commercial) consumers being connected at higher voltages, and smaller consumers at lower voltages. Distribution networks are also host to increasing amounts of generation. In 2018, around 45GW of distribution connected or "embedded" generation was connected to the DNOs' networks.

Like transmission networks, charges for the monopoly services provided by the DNOs are also regulated under the RIIO framework. The RIIO incentives are soon to be re-negotiated, with a new price control to commence from April 2023.

Distribution networks must sign up to the BSC, CUSC, DCUSA, Distribution Code, Grid Code, MRA, SEC and, from February 2019, the REC.

4.1.3.1. Independent Distribution Networks

Independent network operators may be able to offer lower-cost connections to the networks than the incumbent.

As well as the six main DNOs, there are a number of independent distribution network operators (IDNOs). These IDNOs are small localised networks within the main DNO areas. There are 13 licenced IDNOs in GB, with each operating multiple networks.

Like the DNO licence, the IDNO licence is also overseen by Ofgem. It is similar to the DNO licence but has fewer conditions. Prices are regulated under a relative price control mechanism, which caps charges at a level consistent with the charges of the equivalent DNO.

IDNOs are now responsible for around 50% of new connections. These providers may be able to offer faster or cheaper connections to new generation or consumption users than the main networks, though this will be dependent on local conditions. Many IDNOs look to provide services to an entire new development site, but others will connect a single premises or generator.

4.1.3.2. Licence-Exempt Distribution Networks

Small scale networks can avoid the expense and complexity of acquiring a distribution licence, but connections to consumers, particularly domestics, will be restricted.

It is possible to operate small distribution networks, often known as private networks or private wires, without a distribution license. The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001 details the situations in which it is not necessary to hold a licence. These are:

- Class A: Small distributors: Parties who do not at any time distribute more electrical power than 2.5MW to domestic consumers
- Class B: On-site distribution: Parties who do not at any time distribute from any distribution system more electrical power than 1MW to domestic consumers, provided that each domestic consumer receives the electrical power, disregarding stand-by electrical power, from a generating station embedded in the same distribution system
- Class C: Distribution to non-domestic consumers: Parties who do not at any time distribute electrical power for the purpose of giving a supply to domestic consumers or enabling a supply to be so given with that electrical power

Like licence-exempt generators, licence-exempt distribution networks do not have to sign up to industry codes. Many decentralised energy schemes make use of private wire networks to move power to customers. They will usually fall within the exemption regime. Examples of private wire arrangements range from the small, like Wadebridge's Renewables Energy Network's 100kW solar array powering the neighbouring South West Water Nanstallon sewerage treatment works, to the large commercial-industrial development site Protos near Manchester, which will host several large generating and energy storage plants.

4.1.4. Suppliers

> There is no such thing as a "local" supplier in GB; setting up a supply business is a complex, expensive and high-risk undertaking.

An energy supplier contracts to deliver electricity through a meter to a customer. Suppliers purchase energy in the wholesale markets and supply this to their customers – they buy energy directly from generators in several ways (acting as "offtakers") and also indirectly through traders and brokers. Suppliers also pay the costs of networks and government policy programmes, passing these costs on to consumers.

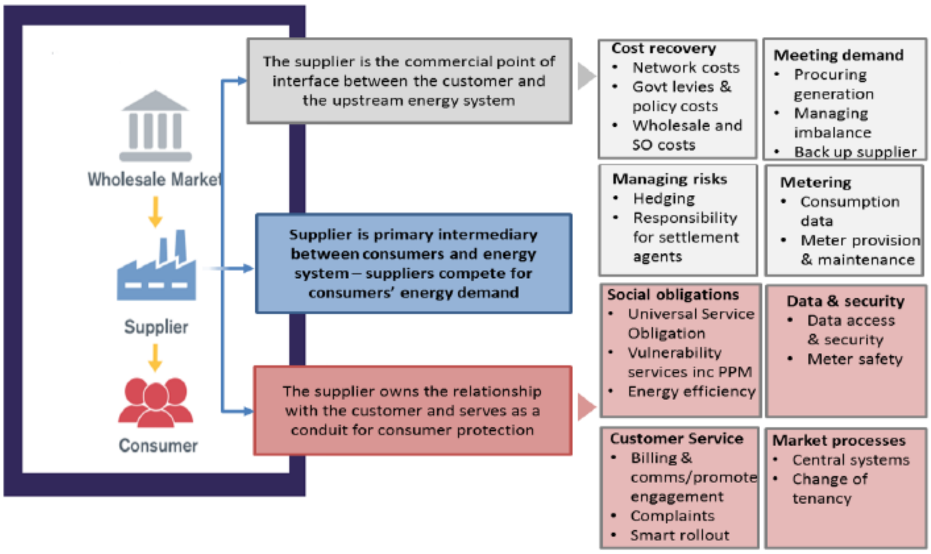
Supply contracts are known as tariffs, and there are a number of structures. Domestic customers typically have single-rate or Economy7 tariffs (two-rate) tariffs, although more complex time-of-use (ToU) tariffs are starting to appear, enabled by the smart-meter rollout. Domestic tariffs have one or more unit rates for kWh consumption, and a daily standing charge.

Non-domestic tariffs come in a variety of forms, depending on the level of consumption. Small non-domestic consumers tend to have similar tariffs to domestic consumers, while larger consumers may have various cost elements separated out as pass-through costs. The largest users may even manage their own wholesale trading, through the supplier.

Supply contracts allow customers to access products with predictable costs that match their appetite for price risk; for example, variable or fixed term tariffs for domestic customers. Once contracted, the supplier will register the customer's meter, raise bills, collect payment, and manage the customer relationship until the contract ends.

To handle consumer contracts, a supply licence is needed from Ofgem. Under a concept known as the "supplier hub", the supplier is the single point for customers to interact with the energy market and is responsible for managing nearly all energy market activities through a wide variety of commercial contracts and regulated industry codes. Suppliers are obligated to sign up to the BSC, CUSC, DCUSA, the Distribution Code, the Grid Code, MRA, SEC, and REC.

Figure 6: Supplier hub responsibilities



The supplier hub concept is illustrated in Figure 6. The core obligated activities which suppliers are responsible for are:

- Providing the commercial point of interface between the consumer and the energy system – the retail part of energy supply
- Paying for (and recovering from customers) all costs incurred from the electricity system, including network charges, wholesale costs, system operator costs and policy costs
- Metering electricity consumption, including providing of meters, and appointment of agents to install and maintain meters. Suppliers are also responsible for the smart metering programme and obligated to offer smart meters to all domestic and small non-domestic customers by the end of 2020
- Delivery of government energy policies (such as payment of the Climate Change Levy, Renewables Obligation, Feed in Tariff, Contracts-for-Difference, and Capacity Market)
- Meeting regulatory standards for customer service and interactions

In practice this means that suppliers have three key roles in the energy industry:

1. Collecting revenues to pay for the entire electricity industry value chain
2. Managing the risk arising from the differences between consumer actions and the costs incurred
3. Providing the interface for customers to the electricity industry

While suppliers are ultimately responsible for the delivery of these tasks in the market, it is up to them how they deliver these functions. This means that it is possible, and indeed common, for activities to be outsourced to specialist organisations, for example metering provision, operation and reading.

4.1.4.1. Licence-Exempt Suppliers

Small scale suppliers can avoid the expense and complexity of acquiring a supply licence, but supply to consumers, particularly domestic consumers, will be restricted.

It is possible, in defined circumstances, for supply to be made without the need for a supply licence. The primary benefit of unlicensed supply is that it avoids many of the regulatory compliance and IT infrastructure requirements associated with interfacing with market administrators. It may also be possible to avoid significant costs in government obligation levies and network charges, depending on how the supply interacts with public networks.
The details of the supply exemptions are contained in the *Electricity (Class Exemptions from the Requirement for a Licence) Order 2001*. These fall into four categories:

- Sale of self-generated electricity, up to a limit of 5MW, of which not more than 2.5MW is supplied to domestic customers
- Re-sale of electricity purchased from a licensed electricity supplier; or re-sale of power from another licence-exempt supplier provided that this from an on-site generator (with other conditions attached)
- Sale of self-generated power to consumers on the same site, and re-sale of electricity purchased from a licenced electricity supplier to the same customers. Up to 100MW can be supplied to an off-site but adjacent customer
- Power sold from and to offshore locations

Broadly, the intention of these rules is that the volumes of power supplied are to customers on the same site as the generator, and that only small amounts are supplied to domestic customers. Like other licence-exempt parties, licence-exempt suppliers are not required to sign up to industry codes. Some decentralised energy schemes will operate as suppliers, as they sell energy to end-users. They will generally take care that activities fall within the licence-exempt regime.

4.1.5. Supervisory Bodies

Energy market regulation is fluid and constantly in flux. Schemes must monitor change to ensure that impacts on activities and business cases is understood.

In addition to the infrastructure and competitive activities in the market there are a number of regulatory bodies involved in the regulation and policy setting of the energy market.

The **Department of Business, Energy and Industrial Strategy** (BEIS) is the government department responsible for ensuring that the UK has secure, clean, affordable energy supplies. BEIS sets energy policy and is responsible for energy security; making sure UK businesses and households have secure supplies of energy for light and power, heat, and transport.

The UK-wide **Competition and Markets Authority** (CMA) is also active in the energy market. The CMA is a non-ministerial government department responsible for business competition and preventing and reducing anti-competitive activities. It has a broader set of powers than Ofgem for regulating the market, including both the actions it can take and the parties it regulates. To date, the CMA's largest intervention in the energy industry has been its full market investigation into the levels of competition, conducted 2014-2016. This resulted in over 30 measures being brought forward to try and save customers money and increase competition. One of the most important of these was bringing in a price cap for customers on prepayment meters.

The **Gas and Electricity Markets Authority** (GEMA) is the governing body of the Office of Gas and Electricity Markets (Ofgem). Ofgem is responsible for regulating the gas and electricity markets. Its role is to protect the interests of consumers, particularly vulnerable consumers, regulate competition between providers, and monitor social and environmental issues within the industry. It primarily focuses on the following areas:

- Making gas and electricity markets work effectively by promoting competition in generation and supply
- Ensuring companies in the sector fulfil their legal and licence obligations
- Regulating the revenues of monopoly businesses, e.g. network companies
- Ensuring social and environmental responsibilities on energy companies are met

The regulator is tasked with assessing market power, preventing predatory pricing, assessing the effects of inter-company agreements on competition, and ensuring compliance with legal requirements. The strategic direction of the UK energy sector is to a large extent set by government policy.

There are also a number of organisations outside of government that are involved in managing and maintaining the energy sector.

National Grid has two distinct roles as both the system operator of the electricity transmission network in GB, and the owner of the electricity transmission network in England and Wales. Its primary role is to ensure system security. This requires monitoring the instantaneous generation and demand, to keep frequency stable at 50Hz, ±0.2Hz, by taking actions to balance the system by adding or subtracting generation or demand. National Grid's revenues are regulated with incentives to deliver at the least cost. National Grid also manages the CUSC and Grid Code.

Elexon is responsible for administering the Balancing Settlement Code for the electricity industry. In practice, this means that it compares how much electricity generators and suppliers say that they will produce or consume ahead of time, with the actual volumes following delivery. It then works out the imbalance price that is used to balance each party's declared position and manages the necessary transfer of funds.

Other code bodies include **Electralink**, which manages DCUSA, **Gemserv**, which manages the MRA, and the **Energy Networks Association**, which manages the Distribution Code.

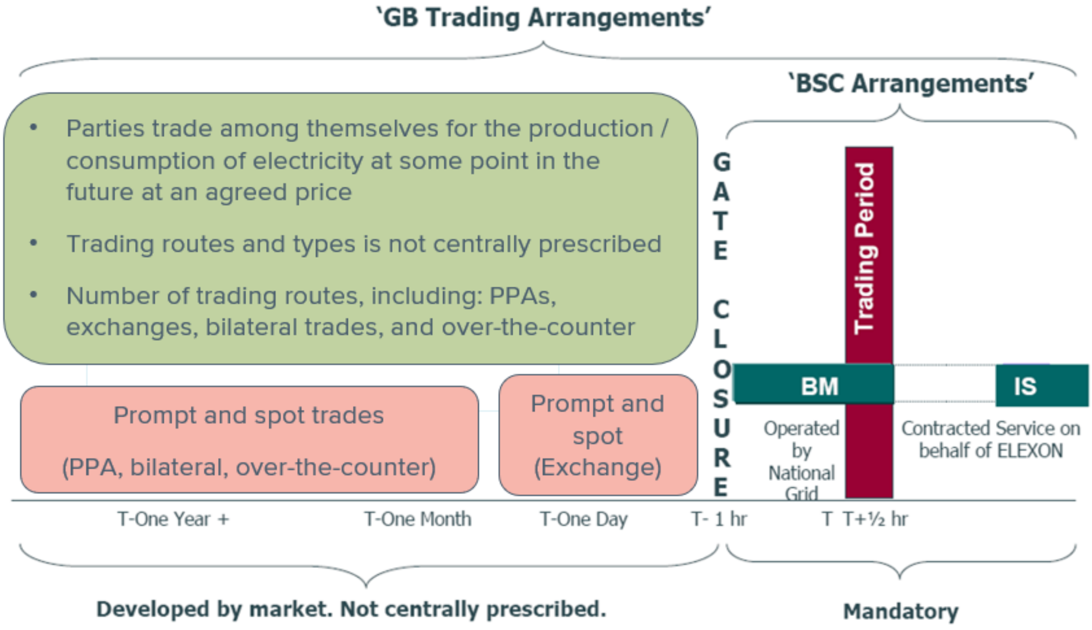
4.2. GB Wholesale Markets

There are no "local" wholesale markets in GB. Decentralised energy schemes – whether producing or consuming power – will almost certainly need to establish a relationship with an energy supplier to help them act in these markets.

Wholesale power prices can be extremely volatile and have numerous drivers, including commodity markets, renewables generation, demand, generator availability, interconnected power markets and currency exchanges. Decentralised energy generators will need to access wholesale value for their power in some way: many sell directly to consumers (being located close to or on the same site and operating behind the meter). Other will need to make arrangements to sell the power which is generated.

The operation of the GB wholesale market for the electricity sector is shown in Figure 7. The market is a bilateral market, meaning that suppliers must buy all the energy their customers use by signing deals with generators or traders in the market to match their position. Trades are bilateral (between two parties) and open to different time frames and contract lengths. The day is split into 48 half-hour trading or settlement periods – a half-hourly settled market – although products traded in the wholesale market may include power in multiple trading periods.

Figure 7: GB electricity wholesale operation



At gate closure, one hour before the start of the settlement period, the opportunity for market parties to notify physical contracts for bought or sold power closes – no more trades can be carried out. Following this, National Grid in its role as System Operator (SO) uses the Balancing Mechanism (BM) and a range of balancing service contracts to ensure the market is balanced in terms of generation and demand. Actions taken by the SO can include paying power stations to turn up or down, rewarding demand side response, or activating flexible generators through contracts for a number of services.

Following the end of the 30-minute settlement period, parties' physical positions (how much they actually produced or consumed in the period) are compared with notified positions (how much they informed the SO they would consume or produce). Where there is a difference between these positions, parties are subject to imbalance prices for the difference. Imbalance prices are linked to the costs which the SO incurred in taking actions to balance the market. This process is known as Imbalance Settlement (IS).

Prior to gate closure, the market for trading wholesale electricity is not centrally prescribed. It is up to parties to trade for power themselves. In practice, this is normally done via either a bilateral trade, a power purchase agreement (PPA), an over the counter trade (OTC), or for shorter-term trades, over exchanges. The different options for trading are explained in Figure 8 below. Parties are free to use any of these options (or most likely a combination of them) to trade power.

However, it should be noted at this point that most small generators will not trade energy directly, as there are significant fixed costs to do so – perhaps £500,000 to set up a trading team and become a member of the relevant markets and exchanges, with ongoing costs of several hundred thousand pounds a year. The minimum portfolio size we would expect to see trading directly is in excess of 100MW, or often larger. We discuss later in section 8.1 suitable routes to market for smaller generators.

Figure 8: Wholesale power trading options

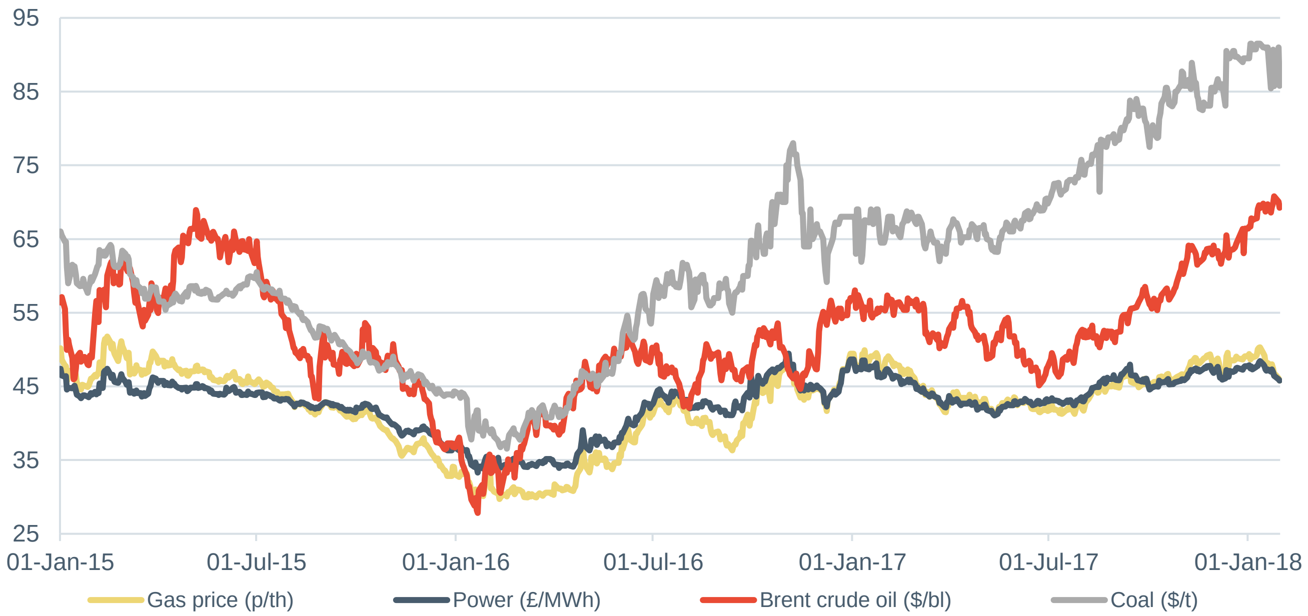
Type of Trade	Explanation	Typical Use and Fuels	Examples
Over the Counter (OTC)	Trading of set products of different maturities (e.g. contract lengths of 1 day to over 1 year) are known in the industry. These are typically traded via a broker	Prompt trading and medium to long term hedging	Baseload month ahead, peak day ahead Prebon, Marex Spectron, ICAP
Exchange	Set products for short-term spot (within-day) and prompt (next day) markets. Allows parties to refine their contracted position in response to weather, operational issues etc.	Short term position management	N2EX, EPEX, ICE
Bespoke contract	Bespoke bilateral deals with prices negotiated at a fixed level or agreed to be set against a reference. Contracts designed to meet certain consumption profiles or requirements	Specific requirement or trading need	GTMA, tolling agreement
Power Purchase Agreements (PPA)	Negotiated contracts usually between an embedded generator and “offtaker” (supplier). Maturity of 6 months to 15 years with contracts usually priced against a market reference	Purchase of green power, access to wholesale power for smaller parties	15 year PPA windfarm 1 year EfW PPA

4.2.1. Wholesale Market Trends

Wholesale prices for power, gas and other fuels are volatile and unpredictable. Most energy projects will need to insulate themselves from these effects over the long term.

Wholesale power prices are heavily influenced by oil, coal, carbon, and gas prices. As gas-fired power stations continue to make up the majority of the GB generation mix, the price of gas has the most notable influence on power prices. Furthermore, as many gas contracts are linked to the price of oil, oil prices can indirectly impact power prices through the gas market. While coal-fired power output has been declining rapidly, it still exercises some influence over the power market, while the cost of emitting carbon is also incorporated into the price of power. Figure 9 illustrates this linkage.

Figure 9: GB Wholesale market trends



This position is beginning to change. Renewables output tends to have a downwards impact on wholesale prices, mostly because the primary renewables generation types in GB – solar and wind – have low operational costs, with no fuel inputs. Despite having a downwards impact on prices, renewables tend to increase market volatility due to their intermittent nature. If there is a sudden decline in renewables output due to weather variations, wholesale prices can spike upwards as more expensive forms of generation are called on to meet demand over a relatively short time scale.

The relative differences between demand and generator availability continues to impact prices. Times of high power demand and low generator availability experience the highest prices, while periods of low demand and high availability see the lowest prices.

Finally, interconnected markets are having a rising impact on GB's wholesale power market. Interconnectors are large subsea cables that act as links between the electricity transmission systems in GB and other markets. GB currently has five electricity interconnectors (two 0.5GW interconnectors to the Irish network, one 2GW to France, one 1GW to the Netherlands, and since January 2019, one 1GW to Belgium). As the number and capacity of interconnectors with the continent is planned to increase sharply over the next decade, prices and events in Europe will more frequently impact on the GB market.

4.2.2. Wholesale Trading for Small-Scale Generators

> Direct access to wholesale markets expensive and complex; decentralised energy schemes will need to find an intermediary to act on their behalf in these markets.

The market access of small-scale renewables generators is currently limited due to high transaction costs and limited appetite among offtakers for small parcels of intermittent power. This limitation mostly applies to generators which are smaller than 0.5MW, and particularly to those smaller than 0.3MW.

The bulk of existing small-scale generation assets under 5MW are achieving value for power exported to the networks through the Feed-in Tariff (FiT) subsidy scheme. Accrediting to the FiT removes the need to contract for power offtake. Instead, power is spilled to the grid with generators paid the FiT export rate – which is 5.38p/kWh in 2019-20 – by obligated suppliers.

Requirements are even lower for generators under 30kW in capacity, which are not required to meter exports, instead being paid the export rate for an assumed or “deemed” volume of 50% of power generated.

The closure of the Feed-in Tariff to new generation in April 2019 ended this guaranteed route to market. There remain some routes to market, such as auctions for short-term PPAs with durations of 6-12 months, but supplier interest in intermittent sites under 500kW is low and value retention for generators is commensurately low. See section 8.1 for more on existing routes to market. The Smart Export Guarantee, discussed further in section 8.1.2.3, may alleviate some of these issues when it is introduced.

The lack of a guaranteed route to market is expected to limit deployment of small-scale low-carbon generation in the immediate future, though as set out in section 8.1.2.3, the government is moving towards providing a guaranteed route to market for generators of the size and technologies which would previously have been eligible for the FiT.

Mains gas is the lowest-cost heating fuel in GB and a relatively low-carbon option. Many rural areas do not have access to this fuel and so present opportunities for new routes to decarbonisation.

5. Gas and Off-Gas Networks

The gas networks provide over a third of the energy consumption in Great Britain. While historically, the UK produced the majority of its own gas from the UK Continental Shelf, we now import over half our gas. Becoming a net gas importer in 2005 exposed the GB market more heavily to international gas price fluctuations, a factor of particular significance as gas-fired generators produce over 40% of GB electricity, and gas is generally the marginal fuel for electricity price-setting. While the stereo-typical view of decentralised energy generation is of renewable technologies, small peaking gas plant is also common, and gas-fired CHPs may lead the way on heat decarbonisation in the short- to medium-term by powering heat networks.

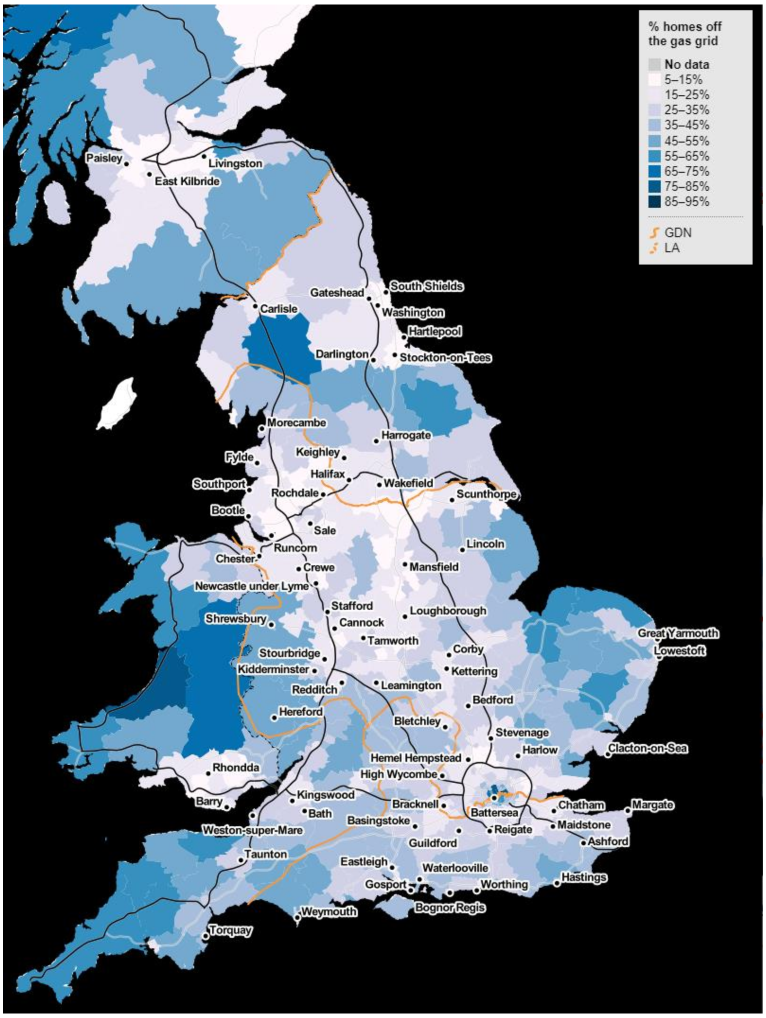
As explained in section 6.5, many policy costs have been loaded onto the electricity rather than gas bill, making gas a relatively much cheaper fuel. This is particularly important in relation to space heating, as those who do not have access to gas heating will generally have much higher heating costs. 12% of English and 19% of Welsh households are not connected to the gas networks, with these households predominantly concentrated in rural areas.

Figure 10 shows the percentage of domestic households in each region which do not have access to mains gas. The source of this map contains extensive and highly granular information about gas penetration across the country, down to the lower super output area (an area containing a population of 1,000-1,500).

These houses are likely to be heated by electricity, bottled gas, fuel oil, or biomass. All of these solutions are likely to be higher cost and more carbon intensive than modern gas-fired condensing boilers. Therefore, it will be no surprise that prevalence of fuel poverty and energy vulnerability in these areas is much higher than the national average.

Introducing lower-cost and more sustainable heating technologies such as heat pumps and heat networks to off-gas regions could be a sensible option for rural energy projects, with lower economic barriers to displace oil or conventional electrical heating than displacing gas central heating. One project looking to do this is Swaffham Prior Community Heat Scheme, albeit in a relatively affluent area. Government policy is discussed further in Section 11.2 below, and low-carbon heat provision in Section 9.

Figure 10: Non-gas map of England and Wales



Source: Non-gas map (Affordable Warmth Solutions and BEIS

GB energy markets are not set up to account for local systems, or to reflect the different characteristics of rural and urban landscapes.

6. Electricity Network Charges

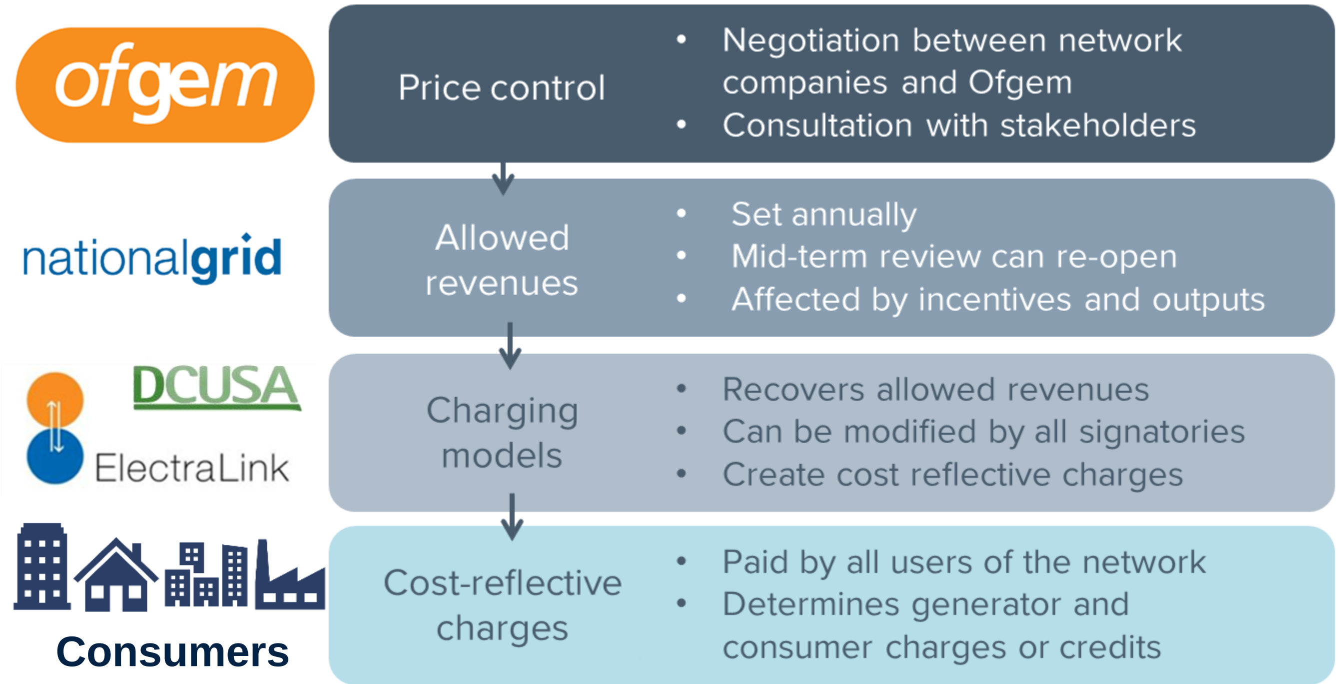
All parties using the public networks to move power from generators to consumers are required to pay towards the development and maintenance of these networks. Historically, the GB electricity system has operated "top-down", assuming that all power enters the system through the transmission network, then moving down the various voltage levels of the distribution network to end-users. This system does not support local energy markets, where a generator and consumer are connected to the same part of the distribution network and will therefore be using fewer wires to move electricity: they are required to pay the same charges unless they have established behind the meter arrangements or private wire networks. In this section, we introduce the transmission and distribution charging regimes, and explain how these impact on decentralised energy markets.

6.1. Setting Network Charges

Decentralised energy schemes will find it difficult to affect charges but may find opportunities to help consumers to minimise their charges, sharing the cost savings.

Network charges are paid by all parties which use the public networks. While some decentralised generators will be able to locate their assets behind their customers' meters, most will be exposed to network charges for either power exported, or power imported. Understanding how network charges are set will help users to understand how their exposure to charges can be minimised.

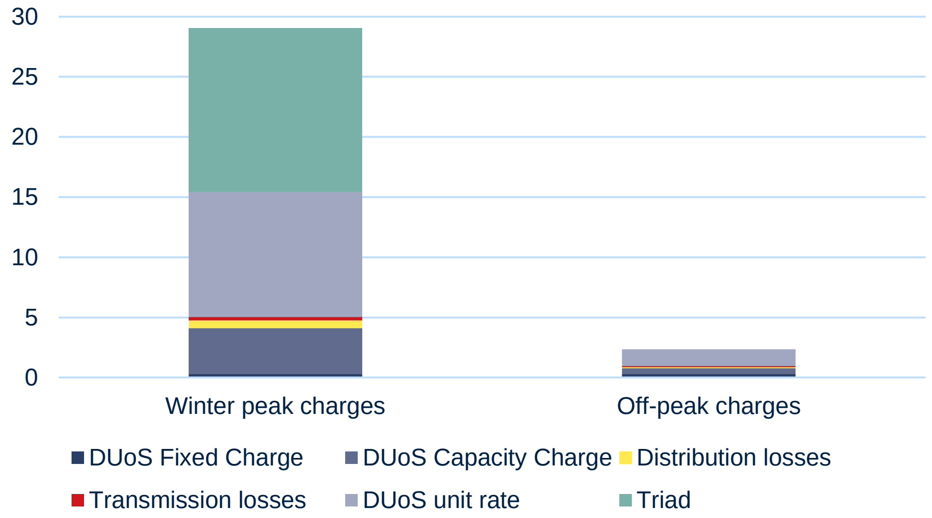
Figure 11: Charge-setting process



The charge setting process is controlled by Ofgem, which regulates network company revenues via the RIIO framework. Figure 1 sets out the process of setting cost-reflective charges for customers.

The cost-reflective principle is that those users which drive additional network costs, should pay higher charges. Therefore, typical network charges will have time-based and location-based elements. Consuming power at peak times – typically during winter weekday evenings, 16:00-19:00 – and in demand-dominated regions will incur higher charges. Figure 12 illustrates the difference in network charges between peak and off-peak times, with peak charges being around four times higher.

Figure 12: Example network charges for a Low-Voltage half-hourly metered user in the South West of England, consuming 15MWh/year, in 2019-20



Source: Cornwall Insight Third Party Charges Report

6.2. Transmission Charges

> Transmission charges for demand-side users – including all decentralised energy schemes – are affected only be the distribution region, not specific location. There is no benefit here to being rural.

There are two main transmission charges: the Transmission Network Use of System (TNUoS) charge, also known to consumers as Triad; and the Balancing Services Use of System (BSUoS) charge. While balancing charges are hard to forecast and avoid, there is a growing field of helping consumers to avoid TNUoS charges and this is a field where decentralised energy schemes can develop value. See more details in section 14 on aggregation offers.

6.2.1. TNUoS

> Decentralised schemes may find a role in helping users to avoid TNUoS charges, but beware ongoing changes to charges which will damage this business model.

TNUoS charges pay for the maintenance and operations of the transmission network. The tariffs are published annually in January, changing on 1 April, and National Grid provides forecast forward charges for several years in advance. Around £2.6bn a year is recovered by this charge. TNUoS is levied on transmission connected generators, transmission connected customers, and suppliers, with a 27:73 split between generators and demand users. Decentralised generation, which by its nature is not connected to the transmission system, is affected by these charges through its relationship with suppliers.

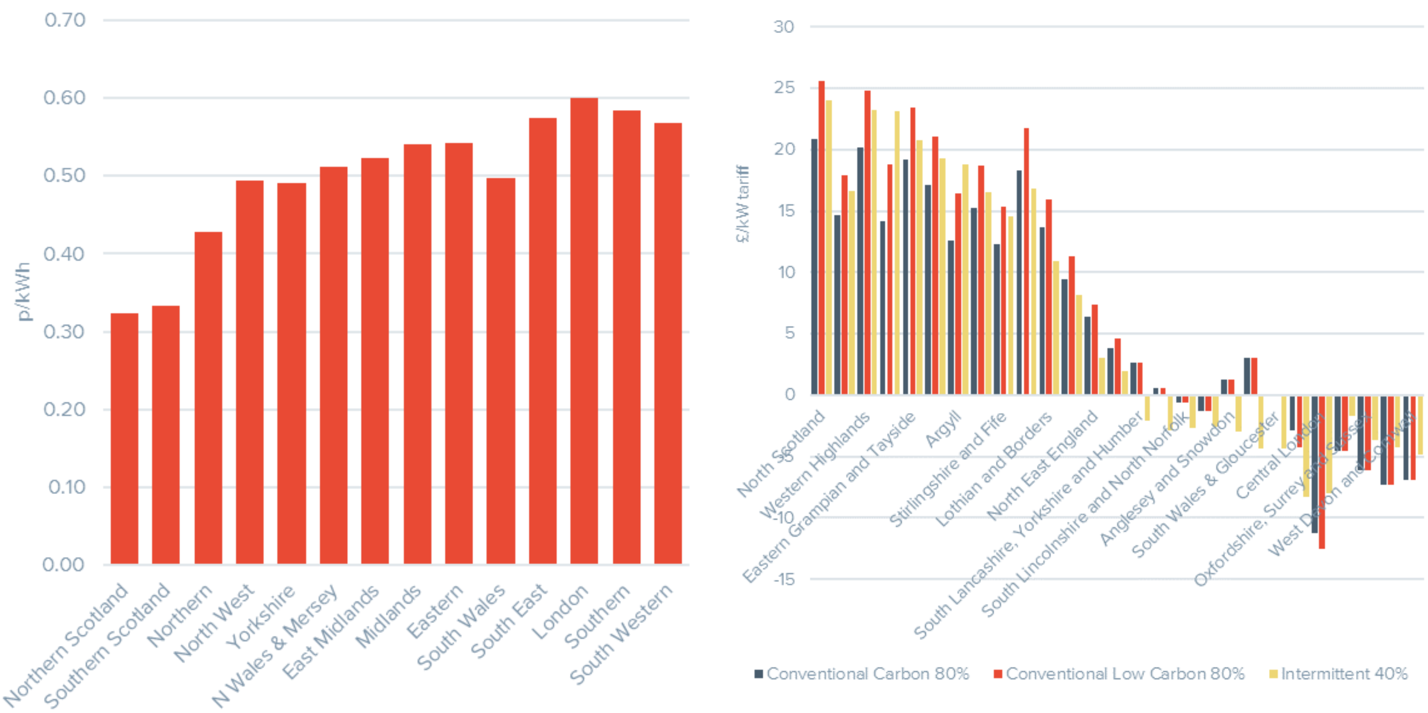
TNUoS is charged in three formats:

- Transmission connected generators and embedded generators larger than 100MW: a local charge in £/kW for assets solely used by that generator, and a wider network charge again in £/kW for use of the shared network assets based on their location in the 27 generation zones
- Embedded generators: previously counted as “negative demand”, reducing a supplier’s obligation to pay TNUoS. Now, earn the Embedded Export Tariff (EET), which is the cost of avoided grid investment
- Demand: paid in two ways, for half-hourly settled (HHS) customers and non-half hourly settled customers (NHH)
    - HHS customers pay Triad, a £/kW figure based on the customer’s average consumption in the three periods of highest transmission system demand between November and February, separated by at least 10 days
    - NHH customers pay on profiled average consumption between 4pm and 7pm all year in p/kWh

These charges change frequently, and there is a major programme of reform ongoing at the moment from the regulator. See more on how these charges are forecast to change in section 8.7.1.

TNUoS charges depend on where in the network a user is connected, with charges typically higher in the south and lower in the north for consumption users, and the opposite for generation users. This is on the basis that there is more generation in the north than the south, and therefore on average consumption in the south (and generation in the north) will use more of the transmission system to reach end-users.

Figure 13: Locational TNUoS charges for LV consumption (left) and generation (right) users



Note: Charges converted into p/kWh basis using assumed LV HH profile

6.2.2. BSUoS

Due to market structures and scale, access to BSUoS benefits for decentralised energy schemes will mostly be via aggregators.

BSUoS pays for balancing actions taken by National Grid to manage constraints on the transmission system, and also to reinforce the network to reduce these expenses in the future. BSUoS costs have risen rapidly in recent years and are forecast to continue rising in the short- to medium-term; they are currently around £1bn/year. Suppliers pay BSUoS based on consumption of their customers in each half hour, at a rate determined mostly on the actions which National Grid has taken during that half-hour to manage the system.

6.3. Distribution Charges

Distribution charges are based on the distribution region, not specific location. There is no benefit here to being rural.

Distribution costs are recovered through the DUoS charge. Like TNUoS, this is amended in April each year, but is published with 15 months' notice, with final tariffs published in December. Charges are again forecast several years in advance. Over £5.5bn/year is recovered through DUoS.

Charges are recovered differently for customers depending on whether they are connected to the Extra High Voltage network (EHV customers), the Low and High Voltage network (LV/HV customers), or are generators (GDUoS). The distribution charging methodologies area common across the 14 distribution networks, though the specific charges are different in each region. The Common Distribution Charging Methodology (CDCM) overs the 99% of meters connected to the LV/HV networks, and the Extra High Voltage Distribution Charging Methodology (EDCM) covers the remainder.

Understanding these charges will help a decentralised energy scheme understand where there are opportunities to help consumers to minimise their exposure to charges.

6.3.1. EHV Customers and the EDCM

Extra high-voltage charges are bespoke to each user and will be harder to predict in advance, but will be lower per unit.

Elements are:

- Unit charge (p/kWh) over super-red period
  - Super-red times vary between networks, but are all around 1600-1900, weekday evenings
- Fixed charge (p/meter/day)
- Capacity charge (p/kVA/day)
- Excess capacity charge

Charges are site-specific for each user, based on the assets used to connect the site to the wider network.

6.3.2. LV/HV Customers and the CDCM

99% of consumers and decentralised energy schemes will be charged under the CDCM. They depend on the voltage of connection, with higher voltage connections incurring lower per-unit costs.

Under the CDCM, users are charged differently if they are HHS or NHH. For HHS users, the following charge elements apply:

- Unit charge (p/kWh) over three periods: red, amber, and green

- Red periods are generally 1600-1900, weekday evenings. Amber periods are during weekday day-time and evenings. Green periods are overnight and weekends

- Fixed charge (p/meter/day)
- Capacity charge (p/kVA/day)
- Reactive power charge (p/kVArh)

NHH customers are charged based on either a single unit rate (p/kWh) or, for Economy7 users, two unit rates, as well as a fixed charge (p/meter/day). Figure 10 and Figure 11set out examples of charges.

Figure 10: Charges for domestic unrestricted meters in the 14 GB distribution regions

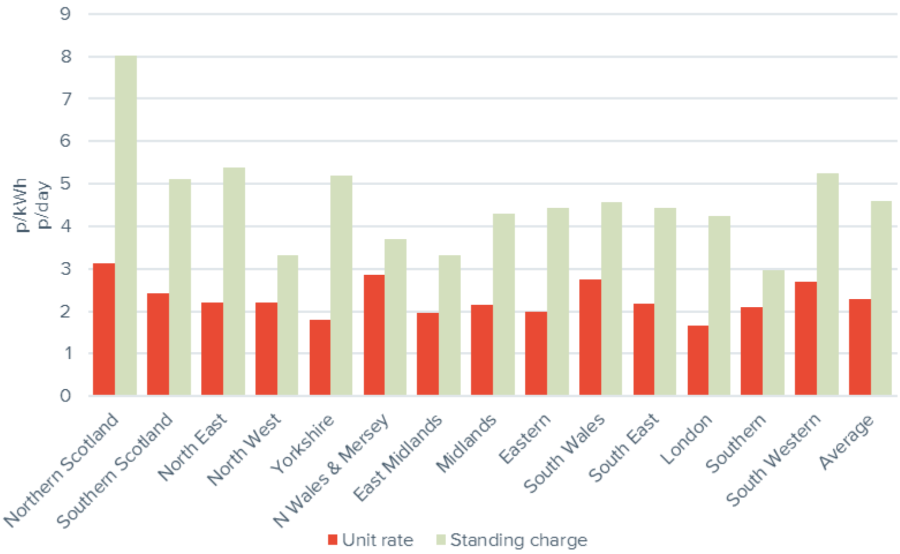


Figure 11: Example charges, Northern Powergrid North East Region, 2020-21 charging year

User type	HV HHS	LV HHS	Small non-domestic NHH single rate	Domestic NHH single rate	Domestic NHH dual rate
Unit rate 1 (p/kWh)	-	-	2.550	2.425	2.757
Unit rate 2 (p/kWh)	-	-	-	-	1.132
Red band	3.539	5.254	-	-	-
Amber band	1.325	1.575	-	-	-
Green band	1.083	1.093	-	-	-
Fixed charge (p/meter/day)	170.39	17.93	7.05	6.69	6.69
Capacity charge (p/kVA/day)	2.74	2.08	-	-	-
Exceeding capacity charge (p/kVA/day)	4.76	4.58	-	-	-
Reactive power charge (p/kVArh)	0.062	0.145	-	-	-

Source: Northern Powergrid

6.3.3. Generators and the GDUoS Charge

Decentralised generators will receive benefits from the GDUoS charge. However, values are expected to fall in many areas due to charging reform.

Since April 2005, embedded generators have been exposed to the GDUoS charge. Though presented as a charge, it is frequently a negative amount and results in payments to the generators. The methodology uses the same principles as demand tariffs, but generation is usually deemed to provide network benefits by avoiding reinforcement cost. This charge is discussed further in the next section, on embedded benefits.

6.4. Embedded Benefits

Embedded benefits currently make up a significant portion of the income of decentralised generators, but values are under review and likely to fall considerably.

Electricity network charges are levied to end users for use of the electricity networks on the principle that costs are recovered when they import electricity from the networks. Generation embedded within the distribution network appears as "negative demand" and can therefore offer to suppliers a cost reduction on some charges. These cost reductions are known as embedded benefits. Most generation-focused decentralised energy schemes will look to embedded benefits to make up at least a portion of their revenues.

Suppliers will typically pass a portion of these revenues through to generators, and embedded benefits can make up a substantial portion of the revenues of some types of generator. The terms of a PPA between a generator and supplier will specify the pass-through of benefits, usually as a percentage of the total value. Typically, 90-100% of embedded benefits are passed to generators. Figure 16 shows these benefits. Embedded benefits tend to be lower in less urbanised DNO regions. However, as they are applied on a regional basis, generation located in a region that is generally demand heavy – for example, the south east – may be able to benefit from the higher benefits while also benefiting from being located in the rural or urban fringe environment.

These values are quantified and discussed further in section 8.3.

Figure 16: Elements of the embedded benefits value-stack

Charge/ benefit	Levied by/ for	The nature of the fee/ benefit	Basis of benefit
Transmission Network Use of System (TNUoS or Triad)	National Grid System Operator recovers the cost of maintaining the transmission network	Embedded generators used to receive value paid by National Grid to the offtaker in £/kW of energy provided (half hourly metered consumers were charged on the same methodology) They now receive the EET	£/kW during system peak
Generation Distribution Use of System (**GDUoS**)	Distribution Network Operators (DNOs) recover the cost of maintaining the distribution network	Fee or benefit dependent on region and time of day, levied on suppliers Based on volume of electricity consumed or generated, which passed through the	Time and location of generation p/kWh

Charge/ benefit	Levied by/ for	The nature of the fee/ benefit	Basis of benefit
		distribution network. For generators connected at 11kV or below on the distribution networks this will result in a credit (benefit) Projects connected at 33kV or above will see a cost from the DNO	
Balancing Services Use of System (BSUoS)	The Transmission System Operator (National Grid) to recover the cost of managing the system	Costs incurred by National Grid are levied on suppliers and transmission-connected generators Distribution-connected generators currently receive this as an embedded benefit	Half hourly £/MWh
Transmission losses	National Grid System Operator accounts for electrical losses on the transmission network	Embedded generators are deemed to avoid transmission losses and these are applied as a % uplift to the volume of electricity production measured at the meter	% uplift
Distribution losses	DNOs to account for electrical losses on the distribution networks	Embedded generators are deemed to reduce distribution losses and these are applied as a % uplift to the volume of electricity production measured at the meter	Time of use % uplift

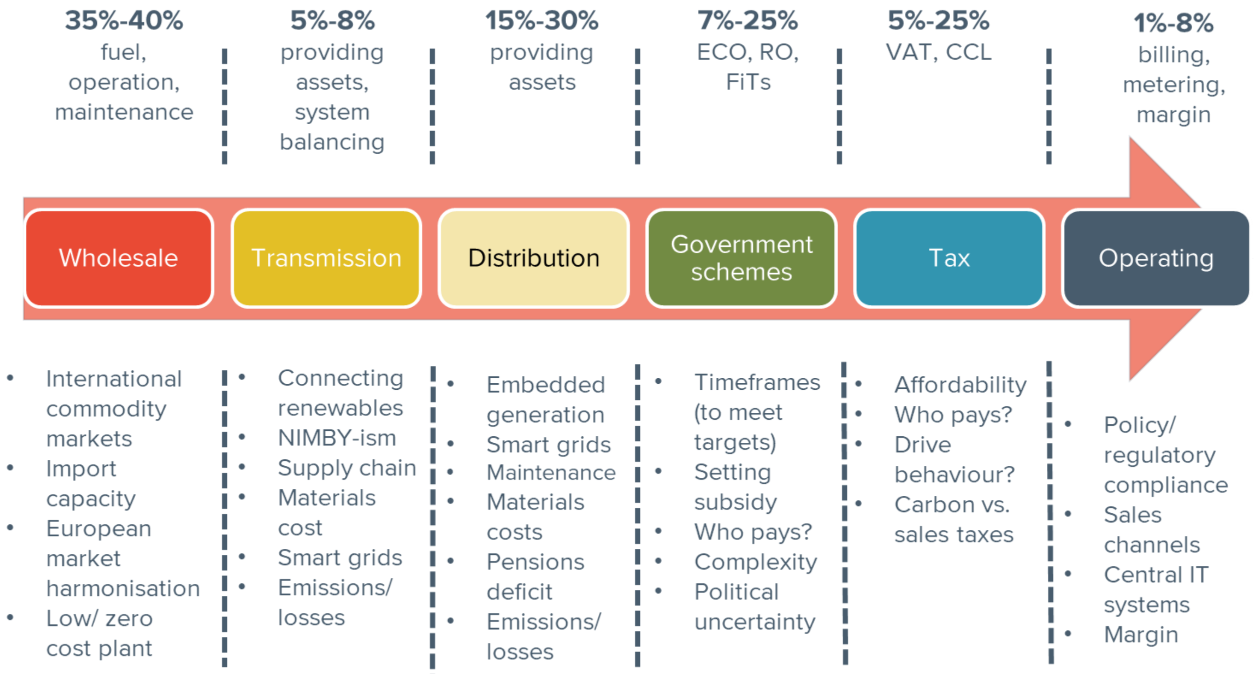
6.5. Third Party Charges and the Value Chain

> If suitable consumers can be found, connecting generation directly to consumption via private wires can be a lucrative benefit for decentralised energy.

The supplier forms the main point of contact with the customer and is therefore responsible for passing on a number of industry costs to the customer in addition to wholesale costs. These pricing elements feed into the consumer cost chain. Figure 17 below details the respective cost elements for typical electricity bills with the indicative ranges representing the differences in domestic and business bills and the volatility of some elements of pricing. The transmission, distribution, government schemes and tax elements of this cost chain are referred to as Third Party Charges.

This is important because siting generation behind a consumption meter will help a decentralised energy scheme to minimise its exposure to most elements of this value chain. This will ensure that the most value possible retains within the project. 50% or more of the cost-chain can be avoided in this manner. See more in 17.2 about the value of siting generation behind the meter.

Figure 17: Indicative cost chain



Three key points to note from this cost chain are:

1. The electricity bill contains more network and policy costs than the gas bill. Environmental policy costs are proportionately weighted more on electricity than gas. This is because policy and associated costs are mainly related to decarbonising the electricity supply. Network costs are also a greater factor in electricity than gas as electricity has to integrate renewables
2. The electricity bill has markedly increased due to the number and level of policy obligations. These obligations are used to recover the costs of various government schemes relating to decarbonisation, security of supply and consumer welfare
3. While the supplier has some control over wholesale buying/ hedging and retailing/ sales/ margin, around half of the electricity bill is “take or pay” – i.e. must be paid by the supplier, whether their customer pays the costs or not – and largely uncontrollable for suppliers

7. Connecting to the Networks

Availability and cost of network connections is highly variable based on locality. Some rural areas (eg the south west) are highly constrained for new generation. Others (eg the east midlands) are constrained for consumption. A few have little or no constraint.

In order to connect to the networks and move power from generators to consumers, decentralised energy schemes will seek a network connection. In order to connect, they will have to pay charges. These charges are highly variable, based on local network conditions, and will make up a substantial portion of the cost of building a new generator. The viability of projects may depend on locating in an area where connection charges are modest. In this section, we discuss connection charges and quantify them as much as possible.

Pressure on the grid network is projected to increase as a result of a number of factors including the shift from baseload generation (coal, nuclear and gas) to more intermittent generation (renewables) as well as a growing demand on the grid driven by the projected growth in Electric Vehicles and the proposed shift from natural gas as our primary heating fuel to more electricity demanding technologies such as heat pumps.

7.1. Transmission Connections

Connecting decentralised energy schemes to the transmission network is extremely rare, though one national operator is connecting battery and EV charging hubs to transmission substations.

The process for connection to the transmission network differs between the three TOs: National Grid Electricity Transmission (NGET), Scottish Power Transmission (SPT), and Scottish Hydro Electricity Transmission (SHET). All connections requested are processed through National Grid System Operator and logged on the various connection registers.

In England and Wales, NGET will provide a minimum of 100MW connections, which for generators are regarded as large generators. In Scotland, the southern SPT region defines a large generator as 50MW+, and in the northern SHET region, a large generator is 30MW+. This is due to the weaker networks in those areas, where smaller generators may have significant negative effects on the network and therefore must be tracked and controlled by the electricity system operator.

The process is the same for customers and the DNOs. All connecting parties must sign the Grid Code, if they have not already acceded. There is no competition in providing the point of connection, and considerable detail on the location, plant and apparatus, and technical information on capacity and type of connection must also be provided.

There is currently no competition in transmission connections to onshore sites, though the Offshore Transmission Owners (OFTO) regime competitively tenders connections to large offshore wind farms. Ofgem has been developing a similar regime for onshore transmission owners – competitively appointed transmission owners (CATO) – but this work stream has stalled.

The cost of the connection itself can vary considerably depending on size and technical characteristics. Costs can range from tens or hundreds of thousands of pounds up to hundreds of millions of pounds for offshore transmission connections.

7.2. Distribution Connections

> Availability of distribution connections is extremely variable even across a local area. Decentralised schemes should check timelines and costs at an early stage, whether generating or consuming.

New connections to the distribution networks can be provided by the DNOs and IDNOs (for simplicity, these will both be referred to as DNOs for the remainder of this section). The competition in connection rules allow for utility infrastructure providers and independent connection providers to deliver some connection activities. There are contestable and non-contestable activities:

- Non-contestable activities are undertaken by the DNO
  - Determining the point of connection
  - Reinforcement of the existing distribution system
- Contestable activities can be undertaken by third parties or the DNO:
  - Design, procurement and construction of assets for the sole use of the connecting party

Where the DNO can demonstrate that activities have been made contestable, and there is effective competition, Ofgem will lift price regulation on that activity. IDNOs can often offer substantial reductions in the cost of connections compared to DNOs, or may be able to offer a connection on a much shorter timescale. Whether a DNO or IDNO would be able to offer the cheapest and fastest delivery of contestable works is highly dependent on the project and on local conditions.

7.2.1. Obtaining a Distribution Connection

> Many distribution networks have dedicated teams to engage with community groups. They can help understand the network's process for obtaining a connection.

New distribution connections are allocated on a first-come, first-served basis. DNOs are required to offer terms and are not permitted to discriminate between parties.

A new connection request process was introduced on 27 April 2019. The Energy Networks Association (ENA) has created standard application forms for use with all DNOs and provides guides to connection.

For smaller connections, the process is known as a G98, and is essentially to connect and then notify the DNO. This process is suitable for very small generation assets up to 16 Amps per phase, which equates to 3.68kW on single-phase connections or 11.04kW on three-phase connections; this registered capacity is based on the capacity of the inverter unit. Effectively, this connect and notify process is intended for micro-generation in the domestic and very small non-domestic space.

For larger connections, the process is known as a G99, and requires DNO permission before assets are installed. There is a simplified process for generators sized under 1MW and connected at under 110kV, known as Type A generators, and a further simplification for generation under 50kW (three phase) or 17kW (single phase).

Once requests have been submitted, there are guaranteed standards for the DNO to provide a connection offer. For low-voltage generation, the quotation must be provided within 45 days. For high voltage or extra high voltage generation, DNOs have 65 days.

7.2.2. Costs of Obtaining a Distribution Connection

Cost can vary hugely over even a local area, which can make or break a project. Rural projects will often – but not always – encounter higher costs.

The Common Connection Charging Methodology (CCCM) sets out how customers are charged for connections. Each DNO publishes a CCCM, based on rules set out in the DCUSA. These require that the DNO bases charges to connect a new customer on the minimum scheme which will be required to connect that customer. The connecting customer pays for any assets which they alone will use, as well as a share of wider reinforcement costs.

Charges are broken down by activity and range from relatively modest – a few hundred pounds to connect a single new domestic property – to potentially millions or tens of millions for connecting major new development sites. The high costs of connecting some potential development sites has led to great interest in decentralised energy schemes based on these sites. Developers are considering how they could spend money on generation and storage assets, and smart technologies, rather than network assets. This could both save money and deliver revenues over time, rather than costs.

7.2.3. Example timescales and costs to connect new generation

These example costs are not averages and should not be used in business plans.

DNOs provide typical connection timescales and prices on their websites; timescales are typically longer and prices higher where reinforcement of the wider network is required. Figure 12 sets out examples provided by the DNOs, although most DNOs are reluctant to provide guide prices, as costs are so variable depending on the distance to the nearest substation and whether network reinforcement is required. Due to these factors, connections in rural areas will often be much more expensive than in urban or urban fringe areas, where the networks are denser and more cross-connected.

Figure 12: Example timescales and costs to connect generation, at various voltages

DNO	Connection size	Typical time to connect	Typical cost or cost range
Electricity North West	LV	6 weeks	£1,790-5,370
Northern Powergrid	LV generation	5 weeks	£9,800
Northern Powergrid	HV generation	19 weeks	£430,000
Northern Powergrid	EHV generation	2 years	Price on application
Scottish and Southern Electricity Networks	LV generation	2 weeks to 2-6 months	£750 to £4,450
Scottish and Southern Electricity Networks	HV generation	6-18 months to 18-36 months	£71,500 to £2,100,000

DNO	Connection size	Typical time to connect	Typical cost or cost range
Scottish and Southern Electricity Networks	HV generation	6-18 months or longer	£241,500 or more for reinforcement
Scottish Power Energy Networks	LV	6 weeks	£1,836-2,710
UKPN	LV	3-14 weeks	£1,500-7,000
Western Power Distribution	LV	5 weeks	£1,579-9,504
Western Power Distribution	HV	14 weeks	£29,088
Western Power Distribution	EHV	2 years	Price on application

Note: rows marked by the voltage level only, not including the word generation, indicate that guide prices are for demand-side; generation connections of a similar capacity should be similarly expensive

7.2.4. Active Network Management

ANM is a key route for decentralised generation to reduce costs and timelines to access the networks. There is currently no equivalent for consumers, though this may change in the next few years.

Many regions of the GB networks are now constrained for new generation connections – that is, they cannot accept any new generation being connected to the networks without exceeding voltage, fault level or thermal limits on transformers and wires, under certain conditions. This is particularly the case on rural networks, which tend to be “weaker”, having fewer cross-connections and less spare capacity than urban networks. Ofgem reported in 2017 that 40-50% of network areas were too constrained to accept a new generator connection of size 5-25MW.

If a connection customer has sought a new generation connection to a constrained network, there will be fees payable for the costs of upgrading the wider network to allow this connection. There may also be an unacceptable delay to deliver this reinforcement work, before generation is installed. There are two ways for DNOs to manage this. The original way is the G100 process, wherein peak output of generation to the network is limited.

More recently, many DNOs are introducing new ways to manage this generation. These are collectively known as active network management (ANM) solutions. Under ANM, a customer can connect a generator larger than the network would be able to sustain at times of stress. Combined with this are systems which will allow the DNO to limit or shut off export from the generator at times of system stress. This allows generation to be connected cheaper and faster than would otherwise be the case.

ANM is available over most of the GB distribution networks, and DNOs are rolling it out to further areas over time. Rules and costs vary between networks, but costs tend to be considerably lower and connection timelines faster than conventional reinforcement. The trade-off is accepting a level of constraint on the amount of power which can be exported. When locating a new generator in a location already host to considerable generation capacity of the same technology, this may result in high levels of limitation on export.

In order to undertake feasibility studies to consider the viability and terms of an ANM offer, DNOs may charge a fee. These fees are set out below in Figure :

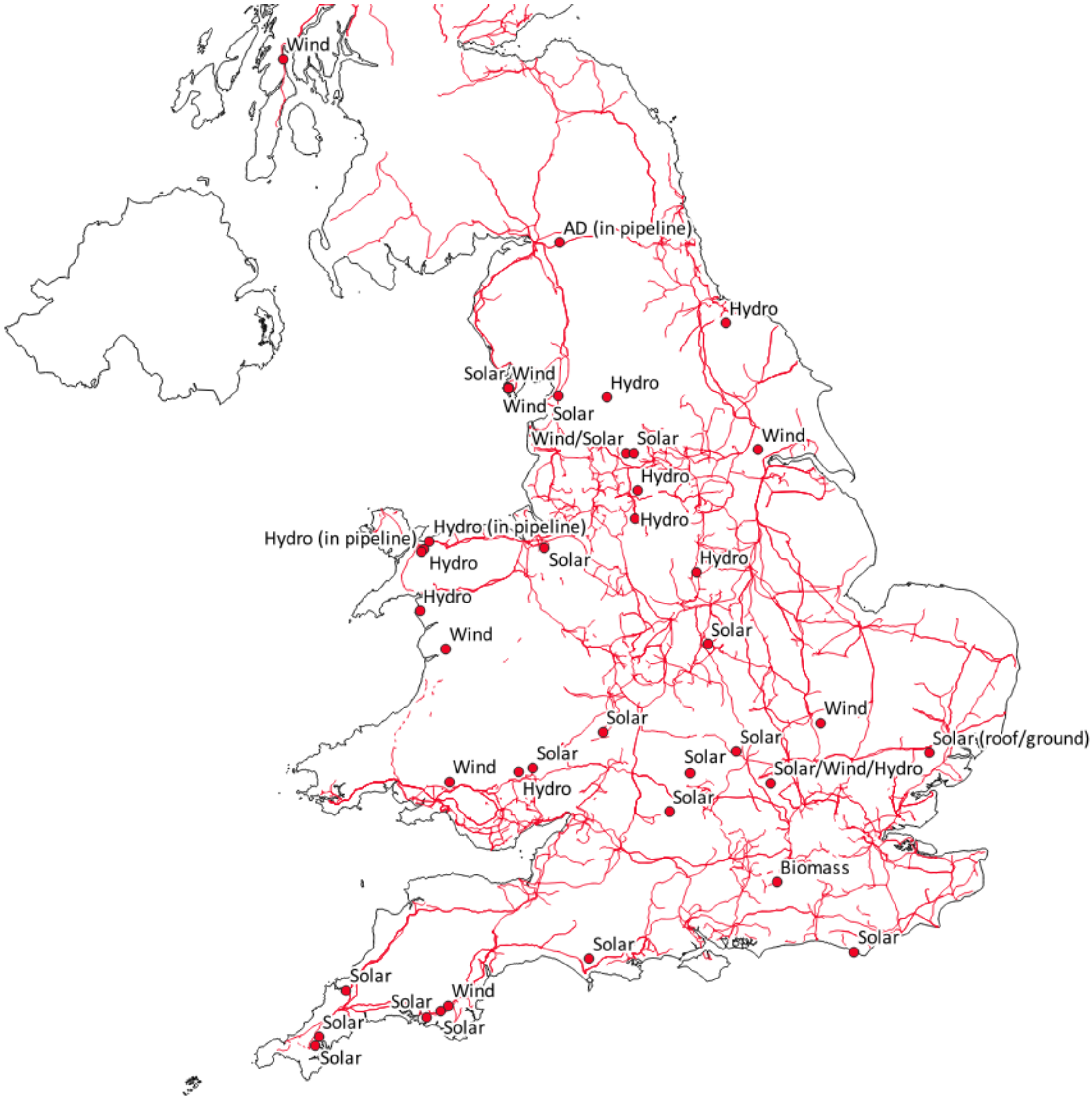
Figure 19: Up-front costs of Active Network Management feasibility studies, by DNO

DNO	Feasibility study cost (ex VAT)
Electricity North West	£1,000
Northern Powergrid	£4,000
Scottish and Southern Electricity Network	£1,364 (HV) or £2,067 (EHV)
Western Power Distribution	£2,604 to £5,075 depending on voltage and capacity of generation
UK Power Networks	£2,590

Whilst we would anticipate that most decentralised projects would connect to the grid via a distribution connection, it is notable that those projects identified through the Community Energy England data are located in close proximity to electricity transmission lines and that where there is an absence of transmission lines there are fewer projects. This will correlate with proximity to points of connection e.g. substations and wider infrastructure required to support renewable energy development e.g. roads.

ANM connections are not yet available for consumers. Ofgem is investigating the potential for introducing more flexible consumption connections through a major workstream, the Network Access and Forward Looking Charges Significant Code Review – see section 8.7.2 for more on this workstream.

Figure 20: Community Energy Schemes and Transmission Lines



8. Revenue Opportunities

Decentralised energy projects can access many sources of revenue. Locating in a rural area may give rise to more opportunities to work with the agricultural and light industrial sectors.

8.1. Routes to Market

Selling wholesale power is vital to the business case but surprisingly difficult for a decentralised generator. Direct sales may be easier in rural settings where it is more like that land will be vacant close to consumers.

The available routes to market for a generator will depend on whether or not it is licensed. Generators over 50MW are generally required to obtain a generation licence; generators under 50MW are normally able to claim an exemption from the need to hold a licence, and typically will do so as this will avoid the expense and complexity of signing up to industry codes. This means that most decentralised generation will be able to avoid the need to hold a generation licence.

In this section, we examine the routes to market for generators to obtain wholesale values for the power they produce.

8.1.1. Wholesale Trading

Direct engagement with the wholesale markets will seldom be viable for decentralised energy projects.

Generators may go directly to market with their power, selling it to offtakers via the wholesale market. This will tend to deliver the highest available wholesale revenues, as the generator is not paying a percentage to an intermediary for trading services. However, there are costs implicit in engaging in wholesale trading. This includes the costs of the trading platform (a subscription to EPEX (www.apxgroup.com/trading-clearing/apx-power-uk/), one of the primary trading hubs, costs several tens of thousands of pounds per year) as well as the costs of a trading team. Total costs for setting up trading will run to around £500,000, with significant ongoing costs.

The generator will also need to set a hedging strategy to decide when and how it will sell generated power to achieve greatest value in the market and protect revenues. This can be a complex calculation and may introduce a significant element of revenue risk to the generator's business model.

High fixed costs and complexity mean that wholesale trading is not generally a suitable route to market for small-scale decentralised generators. Any portfolio under 70MW will generally be better served by a simpler offtake arrangement, and our research indicates that most portfolios up to 100-200MW do not trade directly. This means that most decentralised generators will not want to trade their wholesale power directly.

8.1.2. Power Purchase Agreements

PPAs may offer stable income, but this will not be affected by location of the scheme in a rural region, perhaps wasting an opportunity.

Power Purchase Agreements (PPAs) are the most common route to market for small- and medium-scale generators, particularly renewables generators. PPAs are a contract between a generator and an offtaker (typically an energy supplier). The offtaker will take all of the power produced and make payments to the generator based on the wholesale value of the power, typically based on a wholesale market index. Additionally, the offtaker will pass through a large share of the embedded benefits created by the power (see section 8.3 for more details on embedded benefits).

The short-term PPA market is very liquid and there are a large number of parties – over 40 – competing for contracts. This has led to high pass-throughs of benefits, with the Cornwall Insight Green Power Forecast showing a mid-point for value retention by the generator of around 97% currently. This means that the generator receives 97% of the total value of the power and embedded benefits, with the remaining 3% being retained by the supplier to pay its costs.

The level of value retention has been rising over the past few years, with increasing levels of competition, an increasing proportion of projects re-tendering on an annual or bi-annual basis, and an increasing demand for green power from energy suppliers looking to provide this to their customer base.

Suppliers value some embedded plant more highly than others. Figure 21 presents a matrix of factors influencing this valuation, though some factors are dichotomies (for example large plant is more highly valued, but also plant connected at lower voltage levels – i.e. small plant – is also more valued).

Figure 21: Factors influencing supplier valuation of embedded plant under PPA

Characteristic	Higher value	Medium value	Lower value
Controllability	Fully dispatchable plant	Non-dispatchable, but may run over peak period	Non-dispatchable and will not run over peak (solar)
Green credentials	Unfuelled renewables (e.g. solar, wind)	Fuelled renewables (e.g. biomass)	Fossil fuelled generation
Connection level	LV-connected	HV-connected	EHV-connected
Size of plant	Large plant	Medium plant (values fall below around 500kW)	Small plant (limited routes to market)

8.1.2.1. Key PPA Considerations

While the bulk of a PPA contract is made up of standard terms and conditions, several points are to be negotiated for each contract between the generator and offtaker. These are:

- Price structuring – the price which will be paid per MWh, and how this changes over time, or alternatively the index which the price will be based on, and how much of this price will be paid to the generator
- Treatment of embedded benefits – the amount of embedded benefits which will be passed by the offtaker to the generator, usually expressed as a percentage. In long-term PPAs, how significant changes to embedded benefits are treated, whether increases or decreases, will also be need to be negotiated
- Term – the length of a PPA will influence the amount of value passed through to the generator; short-term PPAs will tend to pass through much more value per MWh than longer-term PPAs
- Treatment of ROCs and REGOs – where present, the Renewables Obligation Certificate (ROC) and Renewable Guarantee of Origins (REGOs) generated by a plant can have values around £40-48/MWh and £0.30/MWh respectively. The PPA may pass these certificates to the offtaker, or leave these with the generator

- Suppliers are obligated to surrender a certain number of ROCs per MWh of power sold to consumers (0.484 per MWh in 2019-20). Generators may include ROCs in a PPA, passing to the supplier for an additional payment, or may retain the ROCs and trade them separately
- Note that though the Renewables Obligation is closed to new entry, though accredited generators continue to produce certificates and suppliers continue to be obligated to acquire and surrender them
- Creditworthiness of offtaker – while there are around 40 suppliers competing in the market to attract PPAs, only around 10-12 are able to offer long-term contracts of up to 10-15 years, due to their creditworthiness.

8.1.2.2. Corporate PPA

The corporate PPA (CPPA) is a variant on a 'standard' PPA in which a generator signs a PPA with an end consumer as offtaker, rather than an energy supplier. CPPAs tend to be for the longer-term of 10-15 years. Unlike conventional PPAs, where wholesale prices are normally linked to an index, CPPAs are more likely to have a fixed price. Corporate PPAs are also known as sleeving deals, as the power is "sleeved" through the central markets to the consumer.

Due to creditworthiness considerations, these tend to be large and well-established corporations. For example, tech giants Google, Amazon and Microsoft have each established several gigawatts of CPPAs with generators all over the world, effectively paying for the build of new capacity in many instances. In GB, Marks & Spencer is credited with introducing the first CPPA structure with its Price Guarantee Agreement. The public sector has now also entered this field, seeking long-term stability for wholesale prices as well as carbon emissions reductions.

An electricity supplier is still required to facilitate the deal, accounting for the power in central industry systems and taking on responsibility for paying (and passing through) industry costs such as network charges and green levies. A small charge will normally be levied by the supplier for its services.

As the power is passed over the public networks, there is no saving in third party costs compared to a regular PPA. The value to participants arises in other ways:

- The fixed-price over the long term offers revenue certainty to the generator, and price certainty to the consumer. CPPAs are seen in some quarters as acting in effect as a replacement for subsidy in bringing forward new generation capacity
- Guaranteed green power from a generator which has only been built as a result of the deal is viewed as extremely beneficial from a corporate social responsibility standpoint, this "additionality" being a step up from buying existing green power in the market
- Competitiveness between companies, particularly tech companies, has also driven investment in this space, with each seeking to beat its rivals in procuring most capacity or reaching 100% renewable first. In addition, some regulated companies (like water companies) may have specific targets to deliver renewable power

The first GB corporate PPA was signed by retailer Marks & Spencer. It signed a deal with generator Energia in November 2009 to set a "Price Guarantee Agreement". Effectively, this set the wholesale price of power for the trade; in this case an initially high price but at a flat rate. This insulated both Energia and Marks & Spencer from Wholesale price fluctuations over the term of the deal.

8.1.2.3. Smart Export Guarantee

With the closure of the FiT to new generation at the end of March 2019, new small-scale generators (300-500kW in capacity) are left without a route to market for exported power. The FiT pays eligible generators (under 5MW in capacity and of renewable technologies) a p/kWh subsidy in two parts: a generation tariff, based on the size and technology of the plant, for all power produced; and an export tariff, which is the same across all sizes and technologies, for all power exported to the networks. The latter is important as it meant that eligible generators had a guaranteed route to market for power produced.

Suppliers have not demonstrated significant interest in attracting small parcels of intermittent power, and value retention in renewables PPA auctions for generators smaller than 300-500kW is typically much lower than for larger plant. For example, in the July 2018 e-POWER auction average solar value retention was 97.2%, but one small 50kW site achieved only 84.6%, with a low number of bids for the site.

To create a new market for export from these generators replacing the guaranteed route to market under the FiT, BEIS published a consultation on the Smart Export Guarantee (SEG) in January 2019. Under the proposals, suppliers over a certain size (likely to be 150,000 domestic electricity customers) will be required to offer a tariff to purchase the export of generators which would have been eligible for the FiT: under 5MW in capacity, renewable technologies. This is conditional on smart half-hourly metering of export. Prices will be set by energy suppliers, and could be fixed or based on time-of-export, and must be above 0p/kWh.

While BEIS is still considering responses to its consultation (as-of April 2019), and implementation will likely require new legislation, suppliers are starting to offer export tariffs to consumers. E.ON launched its Solar Reward scheme on 1 April, which offers the first 500 new customers for its solar panel offering 5.24p/kWh for electricity exported to the grid. The scheme assumes that 50% of generation is exported, rather than metering export, and lasts for one year only.

Subsequently, Octopus Energy launched the Outgoing Octopus tariff, which offers two tariffs for export and accepts any customers with solar or batteries and a Secure brand smart meter. The Fixed tariff pays 5.5p/kWh for exports at any time. The Agile tariff sets prices dynamically, indexed to wholesale prices and including elements of embedded benefits; Octopus said in a blog that prices would normally range from 4p/kWh to 10p/kWh, but would never go negative.

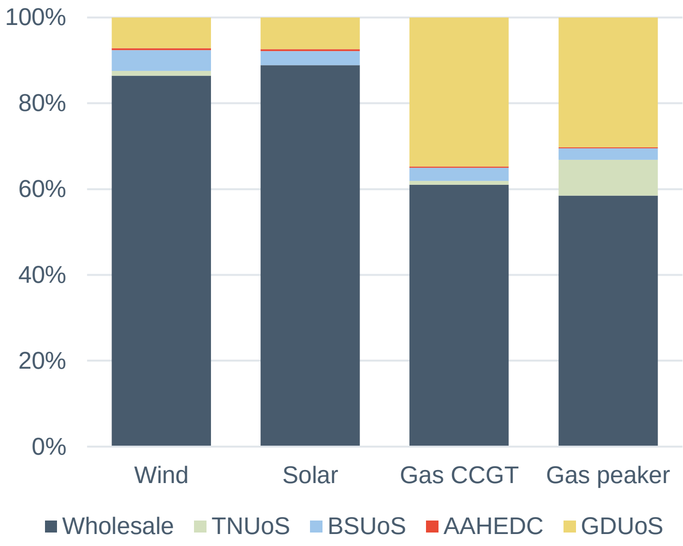
While these early offers are limited to domestic customers, they indicate the interest which suppliers have in smart-metered export and further developments are expected even if legislation is delayed.

8.2. Wholesale Power Prices

Wholesale power sales make up the largest single portion of the revenue stack for most generators – see Figure 22 for a breakdown of this. In this section, we look at the drivers of wholesale power prices, and explain how these impact on the revenues available to decentralised generation.

> Whether producing or consuming power, wholesale prices will affect the economics of an energy project. Project which consume power, however, will often be able to raise prices to compensate for higher wholesale costs, whereas generators have no way to compensate for falling wholesale profits.

Figure 22: Typical revenue make-ups of four generation types in GB



Source: Cornwall Insight Embedded Benefits modeller and wholesale pricing reports

Wholesale prices are highly volatile, and difficult to forecast accurately over the short term. With this being the case and wholesale power prices making up the bulk of plant revenue, it is understandable in the absence of subsidy or other price guarantee that investors are reluctant to develop new plant.

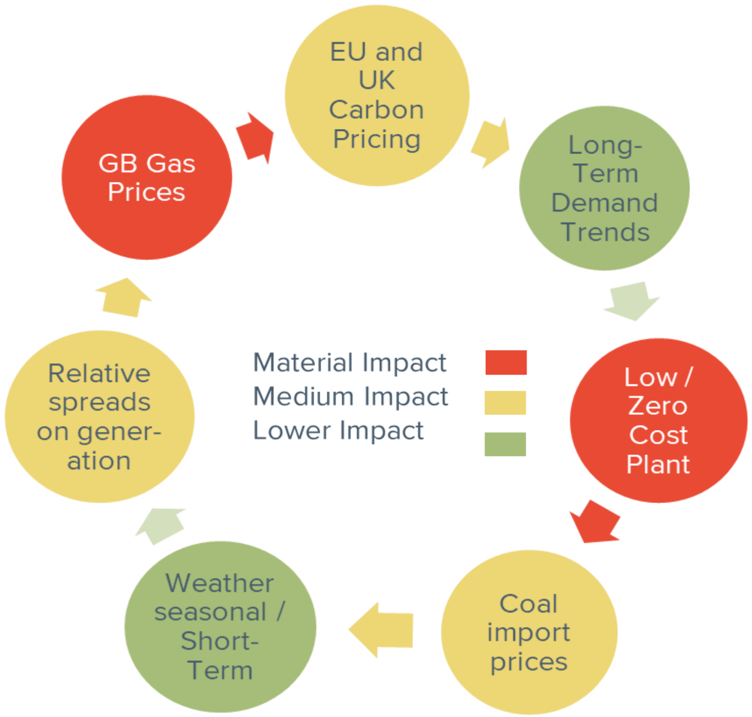
These prices are national and therefore local wholesale markets do not currently exist, although local markets are starting to emerge in respect of flexibility and other services.

8.2.1. Factors Affecting Wholesale Power Pricing

Understanding price drivers may help think about prices will do in the future, but the important thing is to prepare in advance for all circumstances.

There are a number of factors affecting GB wholesale power prices. The key drivers are set out in Figure 23 and explained in more detail below.

Figure 23: Price drivers for wholesale power in the GB market



The factors with the highest influence are GB gas prices and the level of generation from low or zero marginal cost plant. Gas generation makes up 45% of GB power generation capacity, and is typically the marginal price setter in GB. That means, where an additional MW of generation capacity is needed, this is normally provided by a gas-powered generator. Consequently, when there is too much generation on the system, it is normally a gas generator which reduces its output. The price which it will request from the system operator to take these actions will be determined, in large part, by the cost of the fuel it burns to generate power.

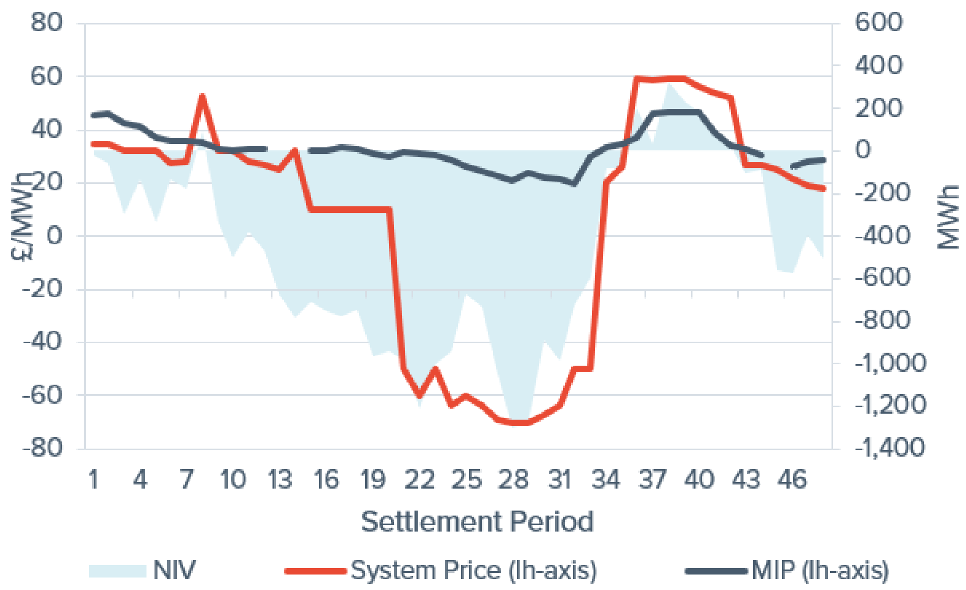
The second main influence is from low or zero-cost plant. These generators, generally renewables like solar and wind, have very low or zero marginal costs to generate power. This is because they do not have to purchase fuels, and maintenance expenses are the same regardless of how much power the plant produces. This means that they will prefer to generate power even when only earning an extremely low price per MWh.

They are commonly also in receipt of subsidies from the government, such as: the Feed-in Tariff (FIT), which pays a premium on every kWh generated; the Renewables Obligation (RO), which awards at least one Renewables Obligation Certificate (ROC) for each MWh generated which can be traded for extra income; and the Contracts for

Difference (CfD) scheme, which sets a generator's income per MWh at an agreed and fixed "strike price". Note that except for the CfD these schemes have closed, restricting the availability of subsidy for new projects.

In this case, a generator will often be willing to accept negative prices for power, relying on subsidy revenues to earn an income. The phenomenon of negative pricing in the wholesale markets was first seen in the German markets, but has become increasingly prevalent in GB markets. Figure 24 shows one recent example of negative wholesale prices over a six-hour period, believed to result in this case to high wind output coupled with low demand.

Figure 24: GB Net imbalance Volumes (NIV) System Price and Market Index Price (MIP) on 24 March



Of medium importance are coal import prices, EU and UK carbon pricing, and relative spreads on generation. These issues are closely linked. Carbon pricing adds costs to generation from carbon-emitting plant, such as gas and coal plant. Spreads on generation are the difference in prices between fuel and electricity prices, factored by the efficiency of the plant. For example, currently, though gas as a fuel is no cheaper than coal per kWh, the lower plant efficiency of coal plant coupled with the higher costs of emissions certificates to deal with the additional emissions, compared to gas, mean that overall coal generation is more expensive than gas generation. This means that coal generation is being pushed down the merit order, and is called on less frequently to run. However, if the international price of coal was to fall significantly, the gas-coal relative spreads could reverse and coal plant displace gas to an extent.

Finally, of less long-term impact are weather and demand trends. Weather will influence electricity demand, with more heating and lighting demand in the winter and more use of air conditioning in summer months. Wind speed is also becoming increasingly important as GB relies more heavily on renewables. Long-term demand trends are important because in the current situation, of falling year-on-year power demand, new generators are not guaranteed to find a market for their power. Any new generator effectively has to displace existing plant by being more efficient. Historically, when power demand was increasing over time, this was not an issue.

8.2.2. Renewable Price Cannibalisation

> Cannibalisation could be detrimental to decentralised generator's revenues. However, for a project consuming power flexibly, like a rural heat network running from heat pumps, cannibalisation could lead to much lower power costs.

Where plant output can be controlled by the operator – dispatchable plant, usually fuelled generation technologies such as gas, coal or biomass generation, of release of stored energy such as dammed hydro, batteries and hydrogen fuel cells – power can be generated whenever wholesale prices are highest. However, solar and wind plant can only generate when conditions in the environment are right: i.e. the sun is shining or the wind is blowing at sufficient speed. As GB is a relatively small country, conditions such as sunrise, sunset and wind speed are likely to be relatively similar across the entire system. This means that all solar arrays and wind farms will experience peak power generation at the same time.

This glut of power, which may or may not occur at the same time as high demand, depresses wholesale power prices and pushes higher marginal cost thermal plant out of the merit order. This issue is likely to be exacerbated as more renewables generation is rolled out, and as interconnection increases to European neighbours, which are also building large solar arrays and North Sea wind farms.

However, cheap or negatively price wholesale power creates new opportunities for energy users. In Germany, grid operators and major utilities are developing three 100MW or large power-to-gas plants, which will produce green hydrogen from excess offshore wind power. This hydrogen can be injected into the gas grid, used to decarbonise industry, or converted back into electricity using fuel cells.

8.3. Embedded Benefits

> Embedded benefits have fallen but remain a large contributor to decentralised generation income.

While wholesale power payments typically make up the bulk of generator revenues, embedded benefits are a valuable addition to the revenue stack. They arise in supplier portfolios, where suppliers offtake power generated by plant which is connected to (or embedded in) the distribution network, as a result of lower demand on the transmission system. The bulk of the value is passed on to generators under offtake contracts.

In this section, we review these value streams. Note that we have quantified revenue for different types of decentralised generation technologies in section 8.5.

8.3.1. Types of Embedded Benefit

> All embedded benefits are currently based on the distribution region a generator is located in. This means that a rural scheme will gain no additional benefits here.

8.3.1.1. GDUoS

Generation distribution use of system (GDUoS) charges/ credits are levied for use of the local network and include some costs as well as benefits for generators. The benefits are applied on a Time of Use (ToU) unit rate basis that varies from network to network and between technology types.

The introduction of national charging methodologies for all distribution networks enabled the creation of separate tariffs for embedded generation. The values vary depending on three factors:

1. The voltage at which the generator is connected, with lower voltages attracting higher benefits
2. The time of generation, with generation at times of peak demand attracting higher benefits
3. The distribution region to which the generator is connected, with south-eastern regions attracting higher benefits; generally, more urbanised regions will receive higher benefits

The new methodologies also enabled the differentiation of tariffs for intermittent generators of wind and solar PV. Non-intermittent generation now receives a ToU export tariff, which is much greater during hours of peak demand, while intermittent generation receives a flat unit rate for export throughout the day.

8.3.1.2. BSUoS

Balancing Services Use of System (BSUoS) rates are set for each half-hourly settlement period based on the actions taken by the SO to manage the system in that half-hour. This includes variable costs such as procuring balancing services through STOR, Black Start, balancing mechanism and internal costs etc. The charges are divided 50/50 between suppliers and transmission-connected generation. This charge is highly variable, depending on the actual costs incurred.

Embedded generators currently provide a benefit to the supplier offtaking their power, as the supplier treats the power as net-negative consumption. This means that the supplier's liability to BSUoS falls. The BSUoS benefit received by generators' is variable and will also be specific to each site according to the generation profile on a MWh basis.

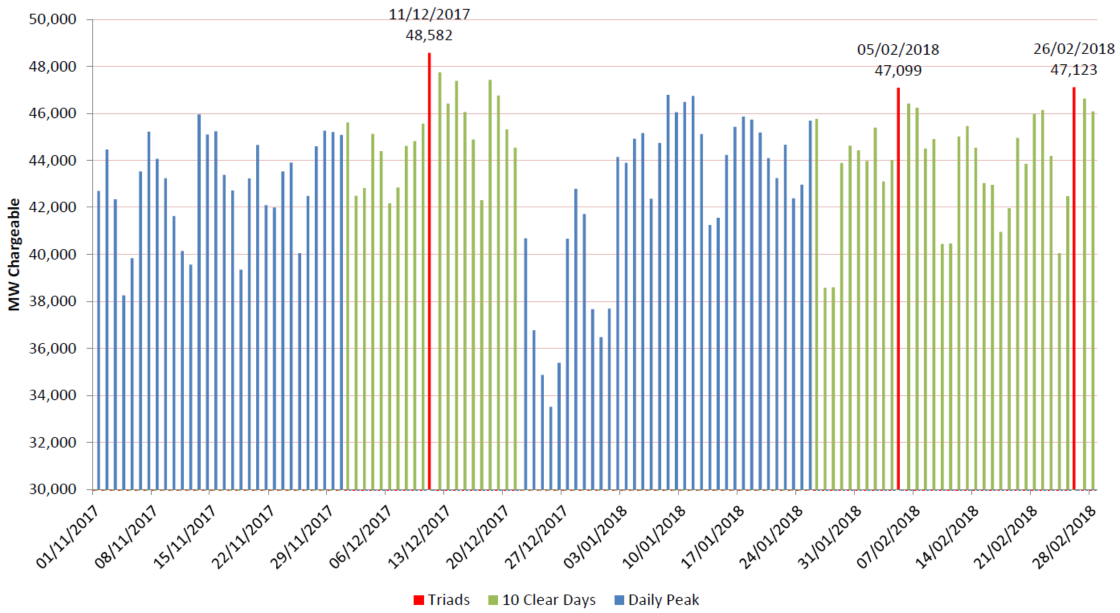
Values can range from almost zero, to a theoretical maximum of £6,000/MWh. The highest prices seen in the GB market were over £1,500MWh in May 2017. Average prices are in the region of £2.50-3.00/MWh in the current year, forecast to rise to nearly £4/MWh by 2022-23.

8.3.1.3. TNUoS

Also known as triad charges, Transmission Network Use of System (TNUoS) charges seeks to recover the regulated allowed revenue of the transmission network owners. The charges are made in two ways: on a flat-rate (based on profiled consumption) for non-half hourly metered customers, and based on the Triad methodology for half-hourly metered customers.

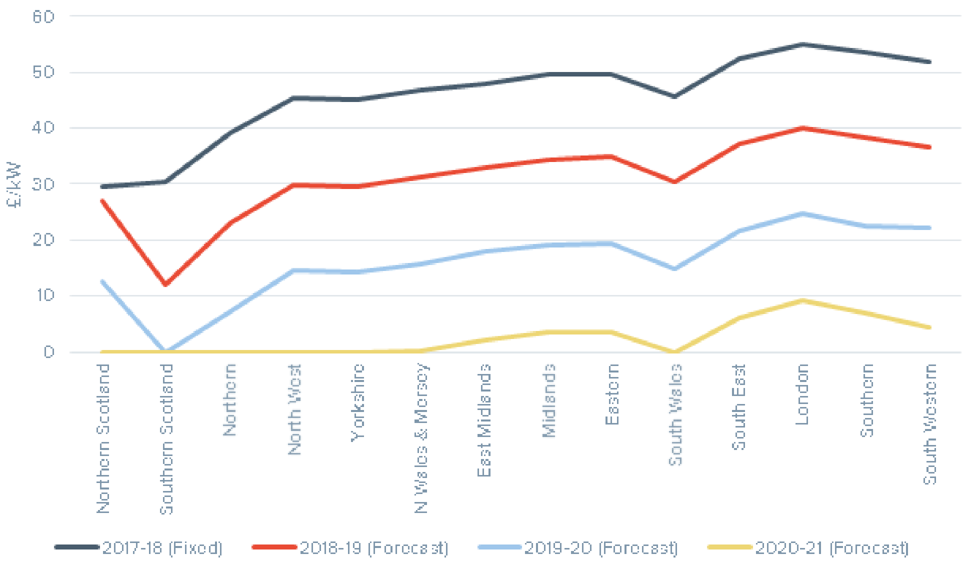
Triad charges are levied on suppliers in respect of their half-hourly customers' demand on the transmission network, assessing average peak demand over the winter period. The Triad periods are the three half-hours of highest system demand separated, by at least ten days, between November and February, on weekdays. Suppliers are charged based on their half-hourly metered consumers' usage during these periods. As embedded generation exporting during these periods lowers a supplier's effective consumption from the transmission system, it also lowers the costs that supplier is exposed to. These savings can be passed back to the embedded generator as Triad or TNUoS payments, as per the terms of the PPA.

Figure 25: Winter 2017-18 Triad Periods



Triads have been a considerable source of revenue for many generators historically but under the changes introduced in code modification CMP264/265, the value has been curtailed to the avoided grid investment cost (averaging £3.22/kW in 2018-19) plus a locational element. The locational element can be negative, although the charge as a whole may not. Revenues will step down to this value from the 2018-19 to 2020-21 charging years. 2017-18 values, and the step-down to the final benefit, are set out in Figure 26 below. The benefit will be zero for most regions by 2020-21.

Figure 26: Avoided Grid Investment Cost



It should be noted that this benefit accrues on a capacity basis (£/kW), not on according to how much power is generated. It also relies on generating across the full triad period; as triad are not known ahead of time. With many market participants are now attempting to forecast and avoid triads, it is becoming increasingly difficult to accurately forecast triad periods.

8.3.1.4. AAHEDC

Assistance for Areas with High Electricity Distribution Costs (AAHEDC) is a cost imposed on all suppliers to subsidise customers in areas with particularly high network costs, i.e. the northern Scotland distribution region. These charges are set as a flat rate across the entire system. For suppliers, embedded generation will offset demand, which means that embedded generation reduces a supplier's exposure to these charges.
The charge is updated annually and for 2019-20 it is £0.26175/MWh.

8.3.1.5. Losses

While not an embedded benefit per-se, embedded generators are credited with generating extra energy because they avoid electrical losses, which arise when power is transmitted over long distances. Around 5-10% of power produced by transmission-connected plant will be lost before it reaches a domestic consumer. As decentralised generators are located much closer to consumers, power losses will be much lower.

To compensate plant for this, meter readings for the volumes of electricity exported from the plant are factored up by the transmission and distribution loss factors.

- Transmission losses are 1-2%, and vary by:
    - Distribution region, with more southerly regions generally having higher losses and therefore higher benefit for embedded plant
    - Season, with higher power usage in the winter causing higher power losses
    - Distribution losses are 3-10%, and vary by:
- Distribution region, with more southerly regions generally having higher losses and therefore higher benefit for embedded plant
    - Season, with higher power usage in the winter causing higher power losses
    - Voltage, with plant connected at lower voltages credited with a greater uplift
    - Time of day, with generation at peak times credited with a greater uplift

8.3.2. GSP Flipping

This phenomenon occurs at GSP Group, ie distribution region. However, it is worth noting that primarily rural distribution regions tend to host more generation and therefore will tend to be more at-risk of sustaining flipping.

The Grid Supply Point (GSP) is the point where the transmission network connects to each of the distribution networks. During "normal" operations, energy flows from the transmission network to the distribution network. As a result of generation being embedded on the distribution networks, energy can flow from the distribution to the transmission network. This occurrence is known as flipping.

When the GSP has flipped, energy volumes from embedded generators incur rather than offset transmission losses, so the energy accredited to a generator will be reduced. In addition, BSUoS is applied as a charge rather than an embedded benefit.

Currently the only region to experience significant flipping is Northern Scotland, but flipping is likely to be more prevalent in the future as the amount of decentralised generation increases.

8.3.3. Behind the Meter

> Rural consumers, particularly those with low-value agricultural land in the vicinity, could prove excellent partners for behind the meter decentralised generation projects.

Generation installed behind the meter alongside a consumer does not provide embedded benefits for power consumed behind that meter. However, there is a similar effect arising from the fact the consumers are not importing power from the networks. In addition to savings on network charges, the consumer would also benefit from avoiding other consumption costs: the costs of the Capacity Market; levies for renewable generation subsidies like the Feed-in Tariff, Renewables Obligation Certificates and the Contract for Difference regime; costs of the Energy Company Obligation; the Climate Change Levy; and their energy supplier’s costs of doing business and profit margin. These avoided costs add up in total to around two-thirds of the electricity bill.

The “embedded benefit” can be modelled as equivalent to the import tariff price, minus the export value which could be obtained for power. For the typical domestic or small non-domestic consumer in April 2019, with export value around 5.5p/kWh and an import tariff around 15.5p/kWh, this would deliver an effective benefit around 10p/kWh.

However, in these situations it is usually more useful to refer to the saving to the consumer of having an asset behind the meter, which is the amount that would otherwise be spent on electricity import. See section 17.2 for more on self-consumption values.

8.4. Embedded Benefits in the context of rural and urban fringe energy

Bringing together all of these benefits, the highest locational values are available for generation which is located in distribution regions further to the south and east of GB, where demand is highest. Higher value is available to generators connected to the lower voltage networks. Higher value is available to generators which can reliably produce power during times of peak demand on the system.

Contrarily, consumers will experience highest charges in the southern and eastern distribution regions, when connected to the lower levels of the distribution network, and when consuming power at peak times.

This implies that rural energy generation and flexibility schemes should either:

- Be situated in rural areas of primarily urban distribution regions, in particular the London, North Wales and Mersey, Southern, South East and Eastern regions
- Be undertaken in partnership with energy consumers, who have access to the greatest sources of value

Furthermore, larger numbers of smaller schemes are likely to derive greater value than a few larger schemes, although of course costs are also likely to be higher. This is because there are many consumers who could benefit from on-site energy generation, displacing relatively high-cost energy imports, outweighing the potential economies of scale of larger projects.

8.4.1. Behind the Meter Case Study – TNUoS

Refer to section 8.7 to learn how these revenues will change over the next few years. Charging reform will damage many behind the meter business cases substantially.

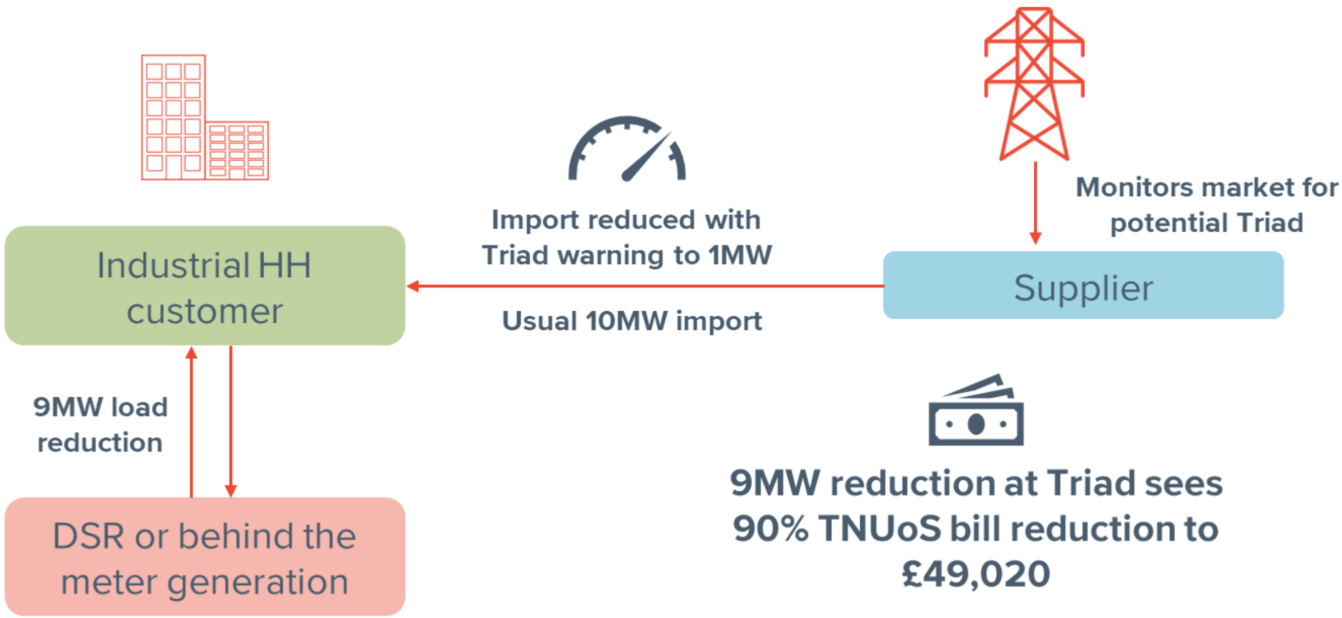
A typical industrial half-hourly metered consumer can make substantial annual savings on its electricity bill by avoiding TNUoS, the simplest cost-element to minimise. This example is of an industrial customer with a 10MW peak load located in the East Midlands region, during the current 2018-19 charging year. It is exposed to TNUoS charges of £49.02/kW. Assuming that it takes no action, its liability for TNUoS would be £490,200 for the year.

The consumer's supplier or an ESCO offers to help the company reduce this expense. By installing demand-side management and energy efficiency equipment such as remote controls to shut down industrial heating, cooling and machinery, LED lighting, EV smart chargers, battery storage, and generation equipment, the supplier creates flexibility for the company to cut energy use to 1MW for a limited period.

The supplier then monitors the energy markets for peaks during potential triad periods. When it forecasts one, it uses the flexibility to reduce the customer's consumption to 1MW this period. If successful, it will reduce the company's TNUoS bill to £49,020 for the year, saving £441,018. Depending on the commercial arrangements, this value will be shared between the supplier or ESCO and the host company.

The DSR equipment can also be used to reduce demand to a less disruptive level during DUoS red-bands, or to provide balancing or DSO services. Unlike balancing services, the TNUoS revenue is certain.

Figure 27: Case study of TNUoS avoidance



These value stacks can be applied to any generation technology imaginable. However, wholesale values are national and embedded benefits based on distribution region, so rural or urban location is largely for income at least.

8.5. Technology Value Stacks

We have modelled embedded benefits for each technology over a 5-year time horizon, and have provided a view on available embedded benefits to a distribution connected generator in the GB market based on this average.

This section stacks the value of embedded benefits with wholesale power values, to look at potential annual plant revenue which could be achieved per MW of capacity. This is also presented per MWh of energy produced, based on the expected annual load factors. Wholesale values are highly volatile, as discussed in section 4.2.1, so for clarity we have used year-ahead prices seen in April 2019 across the board: £54.50/MWh for baseload power, and £60/MWh for peak power.

The importance of this section is to highlight the comparative values achievable for embedded generation between primarily urban distribution regions (e.g. London, South East) and primarily rural regions (e.g. North West, Yorkshire). We have presented charts showing the value obtainable by plant in various technologies per MW of installed capacity. Four charts are displayed, each of which shows values available in each of the 12 English and Welsh distribution regions a rural or urban fringe energy plan could be located in. The top two charts break down total values per MW per annum, with (left) and without (right) the wholesale value of the energy. The bottom two charts breakdown the price elements of the average MWh of electricity produced, again with (left) and without (right) wholesale value.

8.5.1. Baseload Plant

Baseload plant relies most on high load factors producing lots of power from wholesale revenues while spending as little as possible on fuels.

Examples of baseload renewables plant include: **biomass and biogas thermal generation** plant, with CHP; **anaerobic digestion** with gas engines, with CHP; adva**nced conversion (gasification of waste)**, with CHP; **geothermal**, and **run-of-river hydro**. Typically, the technologies are fuelled, allowing them to operate continually whatever environmental conditions are. With similar characteristics from an energy markets perspective, we have treated generators run on these various fuels as a single technology for the purpose of modelling.

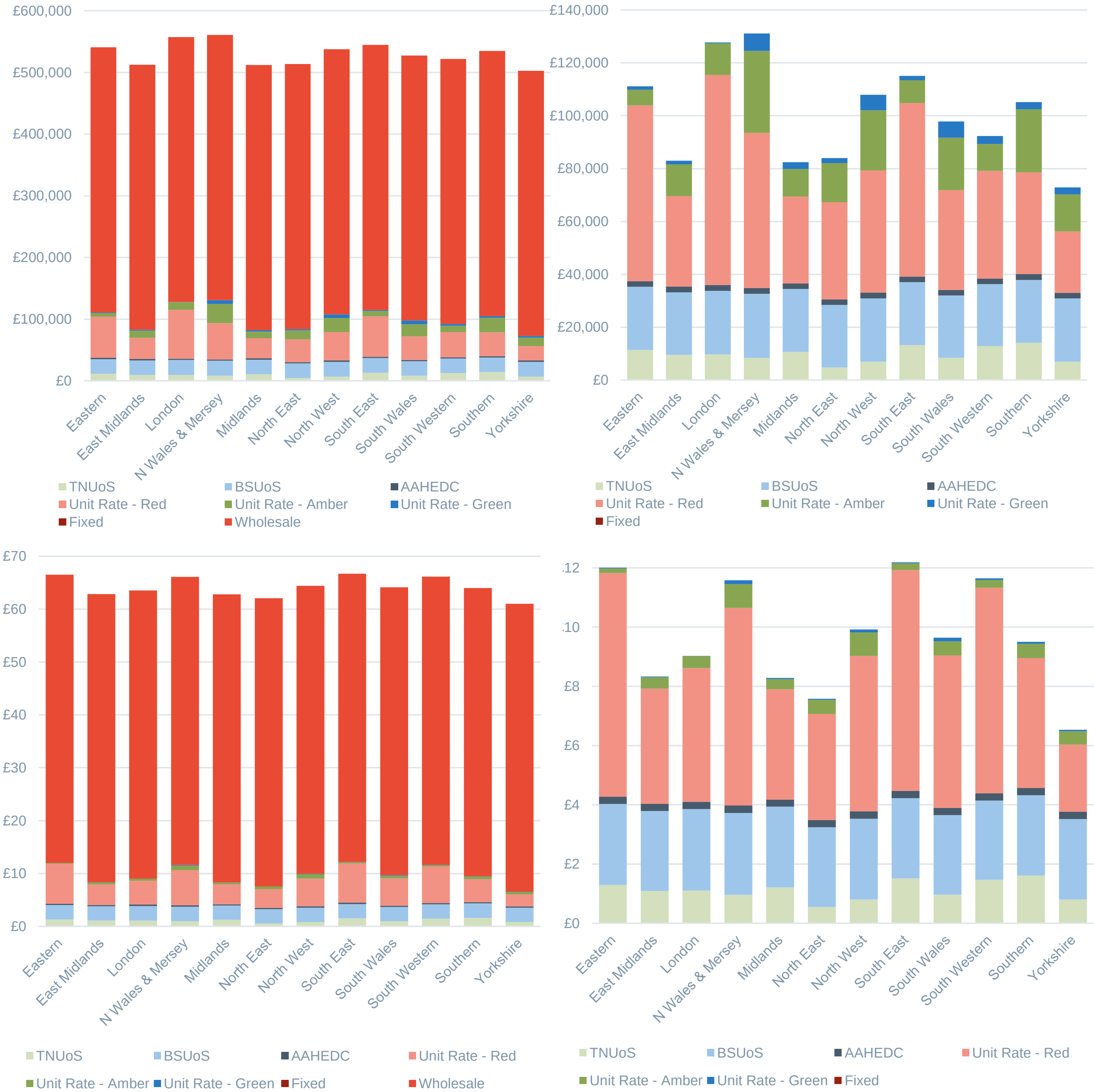
For the baseload model, output is assumed to be even across all delivery periods. The half-hourly profile is scaled uniformly across all periods to required level. Essentially, the plant is assumed to be running at a set level more or less constantly, with maintenance scheduled at times when it will cause least disruption.

In practice, most plant will run somewhere between these two extremes, seeking to maximise output – especially over the peak periods – while staying within emissions limits and minimising fuel costs.

As shown in Figure 28 below, the benefit of operating baseload plant arises mostly from wholesale revenues, or if located behind the meter, avoided electricity import. Operating baseload plant behind the meter is expensive, and accessing the greatest benefit (avoided import) is difficult where the amount of electricity needed varies across the day and the year. The most common type of baseload plant operated on the small scale are CHP (which may be renewables fuelled) and energy from waste plant (which is arguably renewables, or at least low-emissions).

Locating baseload plant in primarily rural distribution regions could result in embedded benefits being up to £50,000 a year lower per MW of capacity, around 10% of the revenue stack.

Figure 28: Baseload Generator Revenue Stack by DNO Region, per MW of capacity (top) and per MWh (bottom)



Source: Cornwall Insight Embedded Benefits Modeller, based on 1MW baseload and peaking plant connected at the LV level
Note: Baseload generation load factor 100%, triad period load factor 90%, 90% pass-through of embedded benefits

8.5.2. Peaking Plant

Peaking plant revenues include much greater access to embedded benefits than baseload; wholesale prices will also tend to be higher. This makes peaking technologies more viable for relatively high-cost renewable fuels like biomass or processes like anaerobic digestion.

Examples of peaking renewables plant include: **biomass and biogas thermal generators**, without CHP; **anaerobic digestion**, without CHP; **biodiesel gensets**; **advanced conversion (gasification of waste)**; **hydrogen fuel cells**; and **dammed hydro**. Typically, the technologies are fuelled, allowing operators to dictate when the plant runs and produces electricity.

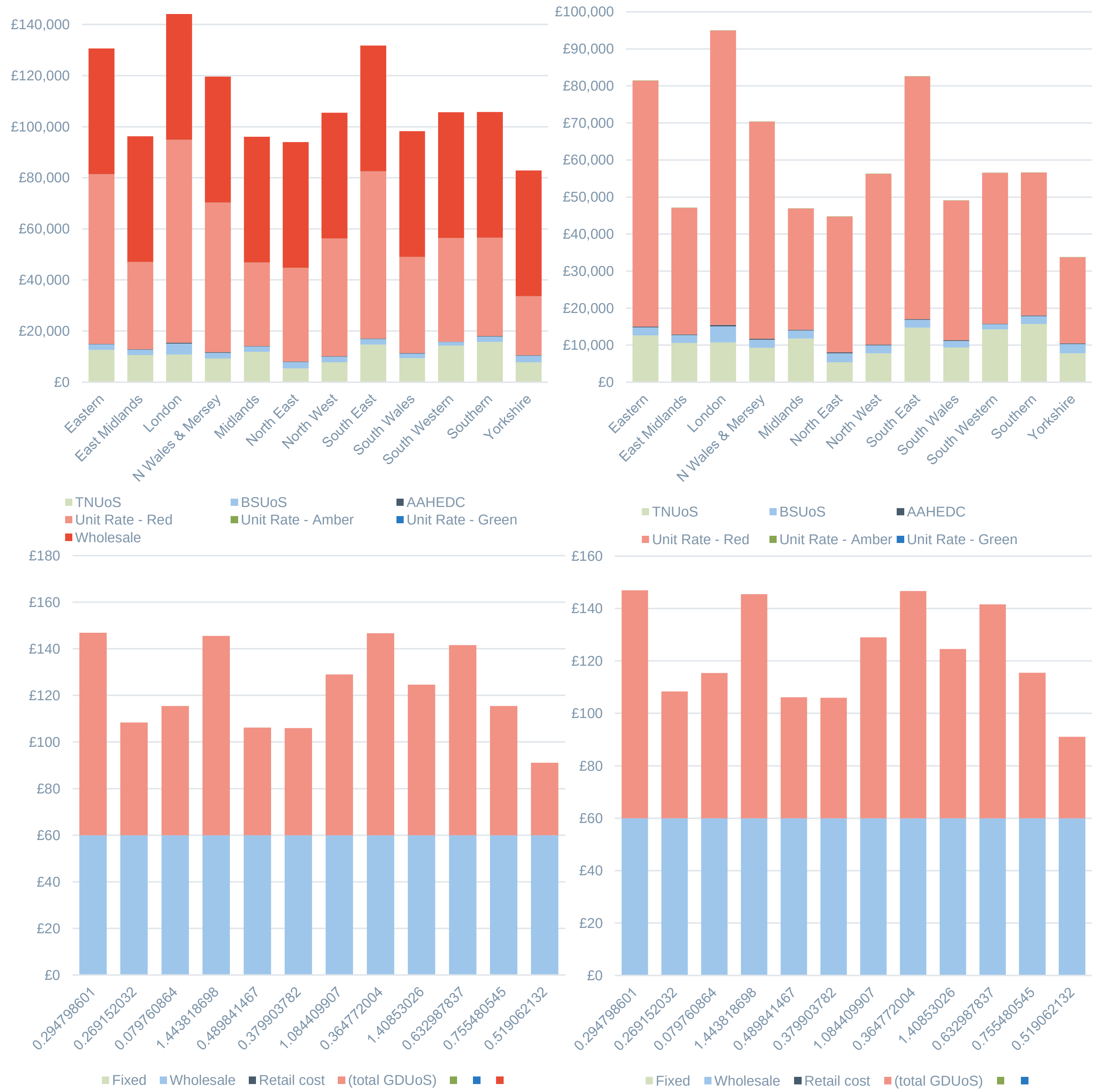
Batteries can be included in this category as peaking plant, as they can output power flexibly but not for extended periods. Demand-side technologies such as **smart heat pumps** and **smart EV charging** can also be included as peaking technologies. They can be adjusted to reduce demand, producing a similar effect in terms of embedded benefits (though these will be seen as avoided charges).

For the peaking model, output is scheduled to capture revenues from either the 'red' or 'super red' (at high voltage) DUoS embedded benefit. Dispatch is modified to capture the maximum available DUoS revenue for the specified load factor or output level, with relatively low levels of running per year.

With lower total run-time, wholesale revenues make up a much smaller part of the revenue stack for peaking plant. This means that locational aspects are much more important to total income: the embedded benefits income for a plant in a primarily rural region could be over £60,000 lower than in a primarily urban region, 55% of the revenue stack.

Common peaking plant includes Open Cycle Gas Turbine (OCGT), gas or diesel reciprocating engines, and battery storage. These technologies can be fuelled with renewable fuels (biogas, biodiesel) or charged with green power. In additional to wholesale revenues and embedded benefits, peaking plant is likely to derive part of its revenue stack from providing flexibility services.

Figure 29: Peaking Generator Revenue Stack by DNO Region, per MW of capacity (top) and per MWh (bottom)



Source: Cornwall Insight Embedded Benefits Modeller, based on 1MW baseload and peaking plant connected at the LV level
Peaking generation load factor 10.4%, triad period load factor 90%, 90% pass-through of embedded benefits

8.5.3. Intermittent Plant

Intermittent plant is closer to baseload in terms of revenues, seeking to earn wholesale revenues delivering lots of generation. Some, like solar, will earn virtually no embedded benefits; others like wind or tidal will randomly access these.

Intermittent technologies are those which generate when the conditions in the natural environment are right, irrespective of energy market conditions. These technologies include:

- **Solar**: generates when the sun is shining
- **Wind**: generates when the wind is blowing
- **Wave**: generates constantly from waves
- **Tidal-stream**: generates when the tide is going in or out
- **Tidal lagoon**: can generate "semi-flexibly" by retaining water then passing through generators, but can only produce power for around 14 of the 24 hours in the day

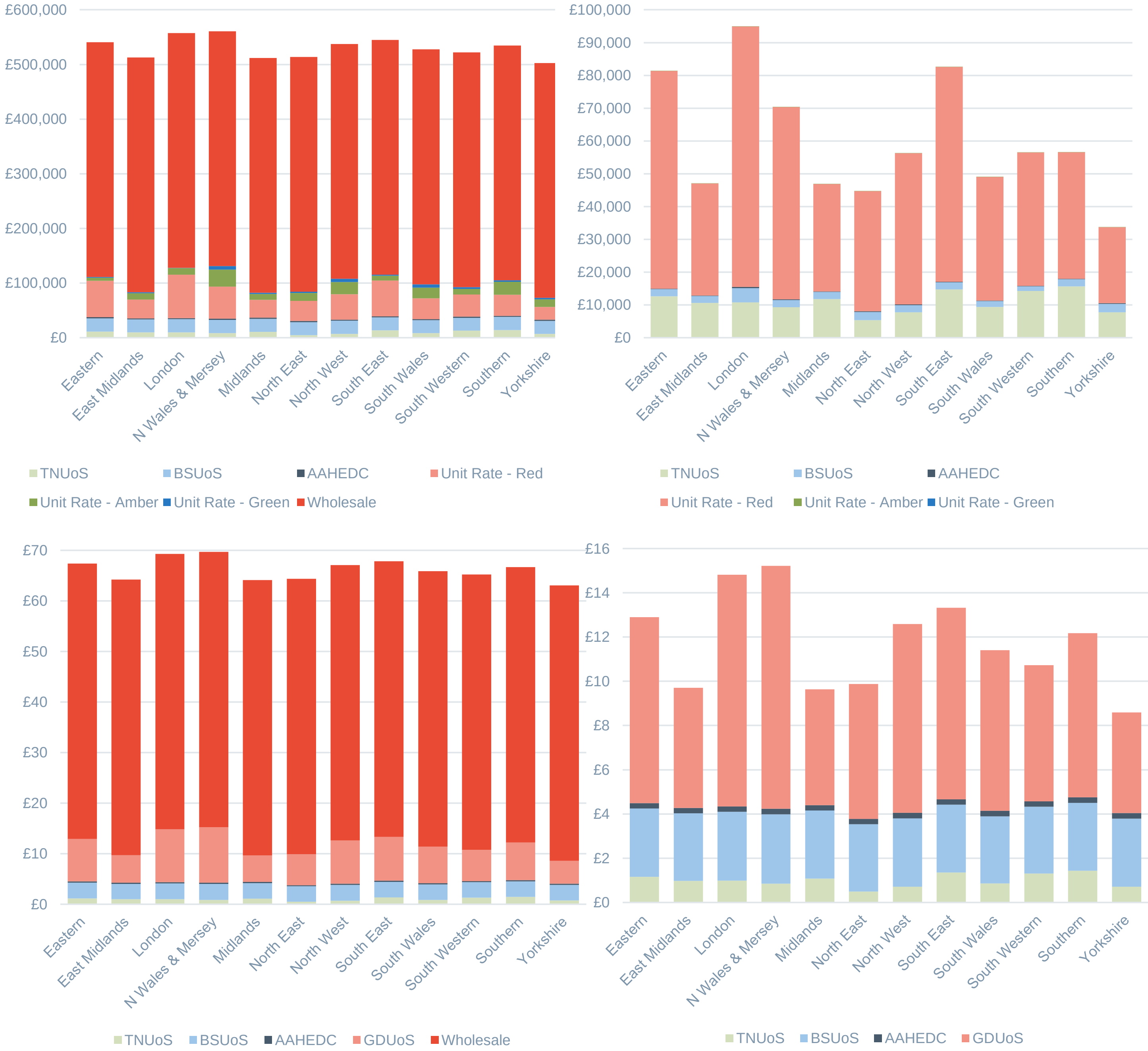
We have looked at the two widely deployed and cost-effective intermittent generation technologies, wind and solar. Wave and tidal generators remain at the prototype and early trial stages or, in the case of tidal lagoons, on the drawing boards.

8.5.3.1. Wind

Wind turbines generate more power the faster the wind blows. They also have a "cut-in" speed, below which they produce no power at all. Load factors are highly dependent on the location of individual turbines. Wind generation is highly intermittent and hard to forecast accurately, especially more than a few days out, unlike solar. However, it is generally windier during the winter months than during the summer, and also windier during the night. Wind turbines also have higher load factors than solar. This means that there is likely to be more power generated during peak periods, when embedded benefits are higher.

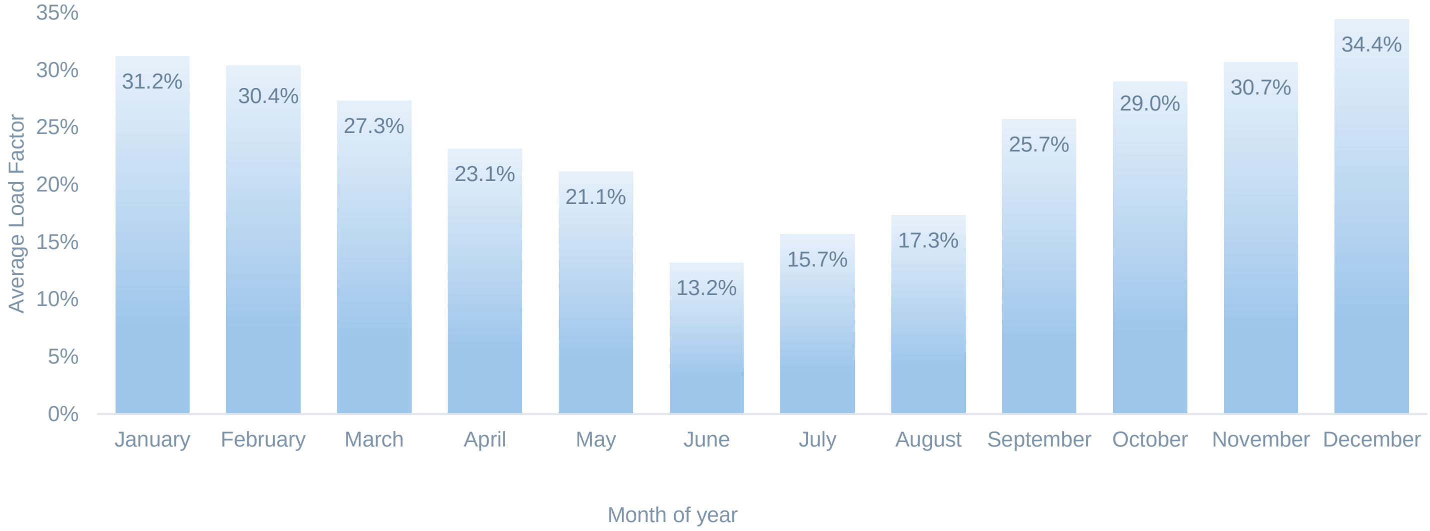
However, as with baseload technologies, the bulk of the value stack is made up of wholesale revenues. Embedded benefits vary up to £14,500/MW, or 10% of the value stack per MW, between primarily rural and primarily urban distribution regions.

Figure 30: Wind Revenue Stack by DNO Region, by MW capacity (top) and MWh (second row), and Average Load-Factors (below)



Source: Cornwall Insight Embedded Benefits Modeller, based on a 1MW wind turbine connected at the LV level

Note: Wind generation load factor 24.9%, triad period load factor 20%, 90% pass-through of embedded benefits



8.5.3.2. Solar

Solar panels generate more electricity when there is more light, known as solar irradiance. Panels are generally orientated to make the most of available light. In GB, this was originally south-facing, to capture the highest peak sunlight. Increasingly however, panels are being oriented east-west, which reduces peak generation and total generation, but produces more power during the winter and during the mornings and evenings – times when wholesale revenues and embedded benefits are highest.

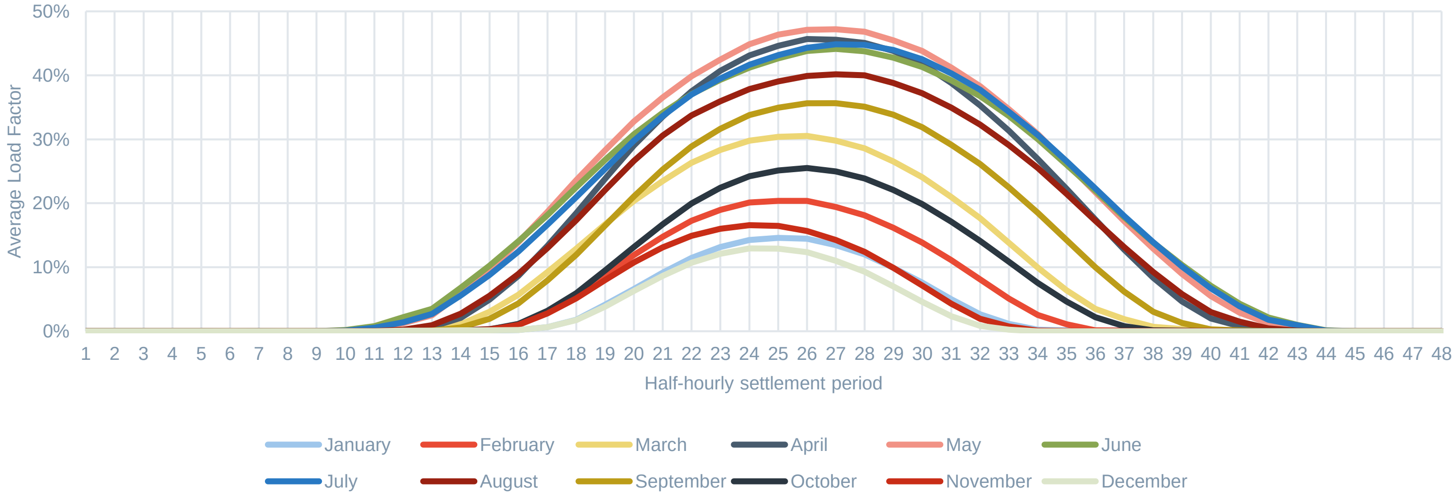
Generation from solar arrays tends to follow a sine curve, with the highest generation: during the middle hours of the day, and during the summer months of the year.

Solar delivers the lowest embedded benefits of the technologies reviewed, as it produces power during times when the network is not stressed and wholesale power is not expensive. Embedded benefits vary by around £5,500 per MW of capacity between primarily rural and primarily urban distribution regions; this is around 10% of the value stack.

Figure 31: Solar PV Revenue Stack by DNO Region, by MW capacity (top) and MWh (second row), and Average Solar Load-Factors (below)

Source: Cornwall Insight Embedded Benefits Modeller, based on a 1MW solar array connected at the LV level

Note: Solar generation load factor 9.9%, triad period load factor 0%, 90% pass-through of embedded benefits



8.6. Flexibility and Balancing Services Revenues

> Current, flexibility revenues are national, mostly from National Grid. Access to them for decentralised energy project (whether generation or consumption based) will be through aggregators.

Balancing services revenues are growing in importance for many market participants, particularly those who can control how much electricity they generate or draw from the network. There are three key streams of value: the balancing mechanism, balancing services to the system operator, and flexibility services to the emerging distribution system operators. We also include the GB Capacity Market in this section.

It should be remembered that balancing services are less certain than embedded benefits. The latter are accrued whenever the generator is producing power, while the former are only earned when the plant is called on to deliver services.

8.6.1. Value Streams

> There are several potential revenue streams. However, these revenues are variable and should not be relied upon to form the basis of a business case.

Flexibility services can return significant revenues to generators. However, accessing these services is complex and revenues are not certain. Many services are also only available to larger generators. In this section, we explain what these revenues are and what generation technologies are able to access them. However, the best way for small decentralised generators to access these revenue streams is through aggregation providers, who will take on the work of choosing the mist lucrative services and help generators to operate their asset in the optimum way to secure revenues. Aggregation is discussed in section 14.

8.6.1.1. Balancing Mechanism

The Balancing Mechanism (BM) is used by National Grid in its role as System Operator (SO) to manage the frequency of the system over each half-hour settlement period. The SO is required to maintain frequency at 50Hz, with an operational limit of ±0.2Hz and a statutory limit of ±0.5Hz.

Licensed generators and suppliers are required to register BM Units (BMUs) to participate in the BM, offering prices to the SO to turn up generation (or turn down consumption) when there is expected to be too little power expected on the system, and bidding to turn down generation (or consume more power) when there is too much power expected on the system.

Unlicensed generators and demand-side response (DSR) aggregators are not permitted to register BMUs. Recently however, changes were introduced to allow DSR and smaller generation access to the BM.

Values differ, depending on the bids and offers presented by participants. BMUs will submit “offers” to turn up the amount of power generated, or reduce the amount of power they take from the system, and “bids” to turn down generation, or increase the amount of power they take from the system. Figure 32 presents a look at prices bid and offered per MWh of power, by technology.

Figure 32: Accepted BM bids and offers in March 2019, by technology

Offers (more power)	Maximum (£/MWh)	Minimum (£/MWh)	Average (£/MWh)
Gas reciprocating engine	89.9	38.5	**81.5**
Aggregated unit	130.0	40.0	**85.6**
Open-cycle Gas Turbine	155.0	155.0	**155.0**
Battery	138.9	0.0	**95.8**
Bids (less power)	**Maximum (£/MWh)**	**Minimum (£/MWh)**	**Average (£/MWh)**
Gas reciprocating engine	-88.0	-38.5	**-54.8**
Aggregated unit	-85.0	44.3	**-30.3**
Wind turbine	51.0	188.9	**72.9**
Battery	-40.3	4.5	**-26.1**

Source: Elexon

There are several important takeaways from this chart. Firstly, values for power can be much higher than through the wholesale market, though it is important to remember than it is not guaranteed that any particular generator will be called on to deliver services and thus earn revenue.

Secondly, most types of generator will pay the SO in order to secure the right to turn down their power output. This is because generating less power will reduce operational costs, especially fuel costs for thermal generation or electricity import costs for battery storage. Note that they will retain the wholesale revenues already earned for this power. Renewables are likely to demand payments to turn down their output. This is due to their subsidies, which are earned on a MWh output basis and which are lost if power is not generated, and the fact that with no fuel costs the marginal cost of generating an extra unit of power is close to zero. They therefore require compensation for these lost revenues in order to accept a turn-down order.

Equally, intermittent renewables will not offer to turn-up generation, as they cannot guarantee to be able to offer this service.

8.6.1.2. Frequency Response

Frequency response services are used to balance system frequency in real time. The SO purchases Firm Frequency response services, topping these up with Mandatory Frequency Response which licensed generators are obliged to offer. Frequency providers are required to continuously monitor system frequency, and automatically adjust load based on the parameters of the contract agreed. These can differ for response time, response level, and duration.

There are two main types of services:

- Dynamic frequency response is a continuously provided service used to manage the normal second by second changes on the system
- Non-dynamic (or static) response is usually a discrete service triggered at a defined frequency deviation

Specific services include Firm Frequency Response, Mandatory Frequency Response (MFR), and Enhanced Frequency Response (EFR). Each has specific technical requirements for providers to be able to come online within a maximum amount of time (from half an hour down to less than one second) and provide the service for at least a minimum amount of time (from 20 seconds to indefinitely). For example, MFR is divided into three services:

1. Primary response: online within 10 seconds of an event, sustained for 20 seconds
2. Secondary response: online within 30 seconds of an event, be sustained for 30 minutes
3. High frequency response: online within 10 seconds of an event, sustained indefinitely

Values tend to be higher for services which must be provided faster, though these services will be called on for shorter durations. EFR in particular was seen as a value stream of particular value to battery providers. However, the level of interest which have been shown has cannibalised the revenues to the point at which no new developments are likely to be made.

Services are procured by auction on a monthly or weekly basis. Providers receive an availability fee in £/MW/hour, and if called on are paid a response or utilisation fee in £/MWh.

Estimated values are set out in Figure 33, but it is important to remember that frequency response contract are not long-term, and there is a high level of risk that these prices will not be sustained in the medium or long term.

Figure 33: Frequency services values in 2019-20

Service	Estimated revenue
Dynamic response	£9-11/MW/hour
Static response	£1-2.6/MW/hour
Mandatory response (primary)	£2.36/MW/hour
Mandatory response (secondary)	£1.10/MW/hour
Mandatory response (high)	£4/MW/hour

Source: National Grid SO

The amount of flexibility required varies by season and time of day, but around 600MW is needed on average.

8.6.1.3. Reactive Power

Also known as voltage support, reactive power services manage changes in voltage over network cables. There is an increasing trend towards a need for absorption rather than generation, and for a greater need for this service. There are two services in reactive power, the Obligatory Reactive Power Service (ORPS) and Enhanced Reactive Power Service (ERPS), though the latter has not been contracted since 2009, with no tenders received since 2011.

Payments for offering ORPS are limited to utilisation, with providers paid in £/MVArh. As it is a mandatory service, payments are set by the SO, averaging between £3/MVArh and £4/MVArh over the last two years.

Embedded generators are not currently permitted to deliver reactive power services, though a £9.6mn Network Innovation Competition (NIC) project is in hand to consider the potential to enable this, due to complete in 2019. The ORPS and ERPS are also under review, with the SO reportedly considering offering 10-year contracts to deliver services.

8.6.1.4. Black Start

Black Start is the service which the SO will use to re-energise the national electricity grid, if it is taken offline. It is generally provided by large, transmission-connected, fuelled generators, due to the technical characteristics of providing the service require this.

The SO is considering how embedded generators and renewables can offer Black Start in the future and a £10.3mn NIC project is in progress, led by National Grid. It is intended to complete before 1 April 2022.

8.6.1.5. DSO Flexibility Revenues

The transition of DNOs to Distribution System Operators (DSOs) is now well in hand. This transition is intended to create smart, self-balancing networks at the local level, in order to mitigate the expected costs of network reinforcement to manage the EV and electric heat transitions. By becoming more aware of how, when and where power is generated and consumed on their networks, DSOs will be able to manage the flows of power better, and only deliver reinforcement where it is truly needed.

DNO flexibility tenders are still at the trial stage. However, these are highly location specific and many regions where services are required are located in rural regions. This may present an opportunity for rural decentralised energy schemes, but note that contracts are likely to last for only 1-3 years, making it hard to underpin a business case solely on revenues from these services.

They are also looking at unconventional routes to avoid network reinforcement by creating local flexibility markets. This will be of increasing importance as EV and heat pump rollout drives increased electricity use, especially over peak periods. One route to deliver these is the Piclo Flex dashboard, which hosts competitions from all six DNOs. Areas with a need for services are identified, and local energy users can bid to provide the defined services, receiving compensation from the network operator. Figure 34 sets out the published requirements from recent competitions, though the nature of these competitions is that they are tailored to local conditions and are therefore very varied.

Figure 34: DNO requirements for flexibility tenders, through the Piclo Flex dashboard

DNO	Minimum asset size	Aggregation permitted?
UKPN	Was 100kW, now 50kW	Yes
ENW	100kW	Yes – minimum aggregated unit 250kW
NPG	100kW	Unclear – no rules yet published
WPD	50kW	Yes

Source: Piclo Dashboard

The auctions are not technology-specific, with DNO accepting both generation and demand-side assets into the tenders. Though methods vary, typically the DNO will value a participant's ability to change energy use against a baseline. Suitable technologies will need to be flexible and dispatchable to meet the requirements, and could include flexible generation, smart EV chargers, batteries, heat pumps, or changes to industrial energy use.

While in the long run the revenues will be based on auctions, the first two schemes, launched in March 2019 by SSEN and WPD, both offered payments of around £300/MWh for flexibility services.

It should be noted that these tenders provide contracts only for the short term, and against a baseline cost of network reinforcement. It is likely that each opportunity will in time be replaced by new network assets, and this should be considered when making a business case relying solely on these revenues. However, developing a capability to deliver flexibility will result in several value-creating opportunities.

8.6.1.6. Capacity Market

The Capacity Market (CM) is the government flagship program to ensure security of supply and encourage investment. It sets a target for security of supply called the Reliability Standard, which is currently three hours of expected Loss of Load per year. The CM uses a technology neutral auction to procure the cheapest kW to meet this standard. The auction is open to most types of generating technology for new build, existing and refurbishing assets, as long as plant is not receiving a separate subsidy. Intermittent renewables cannot current access the CM, although changes are ongoing and may allow access by these technologies in future.

The scheme offers an availability payment in £/kW/year. De-rating factors are used to account for the likelihood that a generator will be able to provide power over the full 4-hour CM window. These are set by technology. For intermittent technologies, these de-rating factors are likely to be high.

While existing plant will be subsidised for one year, new build plant can win a CM agreement for up to 15 years. Refurbishing plant can secure a subsidy for up to three years. T-4 auctions, for four years in advance, and T-1 “top-up” auctions for one year in advance, are held annually. Figure 35 sets out historic auctions.

Figure 35: Capacity market outturn prices

Auction	Outturn price	Capacity sought
2014 T-4	£19.40/kW	49.3GW
2015 T-4	£18.00/kW	46.4GW
2015 Transitional	£27.50/kW	0.8GW
2016 T-4	£22.50/kW	52.43GW
2017 early auction	£6.95/kW	54.43GW
2018 T-4	£8.40/kW	50.4GW

Source: Ofgem

The CM was suspended by the EU courts in November 2018, due to a challenge from a demand-side response (DSR) provider on the rules and format. It is expected to be re-introduced in due course, and BEIS issued a request to the Electricity Market Reform delivery body on 12 April 2019 to hold the postponed 2019 T-1 auction on 11-12 June.

8.6.2. Changing Value-Streams

> The forecast changes to revenues are not expected to make these charges more locational or to offer any increased benefits to smaller providers.

Though there is a rising need for balancing and flexibility services, and the SO’s total spend on services is rising year on year, values for individual services tend to be falling as technology prices fall and more players enter the market, increasing competition. This is likely to lead to falling revenue streams for providers over time.

This was seen in the Enhanced Frequency Response/ Fast Frequency Response auctions held by the SO, where battery providers caused delivered prices to fall considerably over a short period.

Figure 36 shows forecast prices for some of the main frequency services over the coming years.

Figure 36: Dynamic frequency response (left), static frequency response (right), and mandatory frequency response (bottom) forecasts 2019-20.32

Source: Cornwall Insight GB Frequency Response Markets report

Balancing revenues will also be impacted by Project TERRE. This is a European project, aiming to harmonise balancing services across several areas, including GB, France, Switzerland, Spain, Portugal and Italy. It will do this by introducing a common TERRE product, consisting of 15-minute blocks of upward and/or downward energy volumes, which will be similar to current GB products such as BSC Bid-Offers or Short-Term Operating Reserve

(STOR) submissions. European generators will therefore be able to directly offer into the GB Balancing Mechanism. GB based TERRE participants will also participate in the existing BM, while the two systems run concurrently.

The modification progressing this change, P344 Project TERRE Implementation into GB Market Arrangements was implemented on 28 February 2019. The TERRE platform itself will be launched between October and December this year.

While the implementation of Project TERRE is a major reform to the GB market arrangements, it is not likely to significant implications decentralised generators. This is because it is focused on the provision of balancing service contracts, and will predominantly impact upon services such as STOR. Additionally, the competition from European generators able to compete within GB will be limited by interconnector capacity.

8.6.3. Technology Considerations

While the growth of aggregation services in the market has made it possible for decentralised schemes to access balancing service revenues, the services are often best provided by large thermal generators. That said, new technologies like battery storage and EVs will be vital in service provision in the future and decentralised schemes will find a role here.

Accessing these revenue streams will depend on the size and technology of the generator. Any generator under 1MW in capacity will not be able to access any value streams directly, though it may be able to access them through aggregation services.

Values for intermittent revenues will be very limited if available at all, as they will not be able to guarantee availability to provide services. Baseload generators, i.e. generators which expect to run at maximum load most or all of the time, will also not be able to derive high revenues from balancing and flexibility services.

Therefore, the main decentralised generation technologies which may be able to access value from these services are dammed hydro and pumped storage, fuelled thermal generators (for example gensets, CHP), and particularly battery storage. DSR, for example heat pumps and smart EV chargers, may also offer an opportunity to provide flexibility.

8.7. Forthcoming Changes to Embedded Benefits

The geographical distribution of embedded benefits will remain largely the same, but values will change substantially.

Two major work streams are currently being progressed by Ofgem, which will impact on network charges for distributed generation: the Targeted Charging Review Significant Code Review (TCR SCR) and the Forward-looking Charges Review Significant Code Review (FCR SCR). Both will have significant impact on what price signals are sent to network users concerning how and when they use the networks. This could change the investment outlook for decentralised energy schemes, and current indications are that charges will become more granular, which will on average reduce values available to rural-based schemes across all technologies, but particularly for controllable generation technologies. On the consumption side, schemes which are designed to avoid cost by minimising power consumption at peak times will see less value, and in general high-consuming domestic consumers will see lower charges while low-consuming domestic customers will see higher charges. This will benefit those who are fuel poor or vulnerable primarily by reason of using electrical heating.

Historically, Ofgem has been keen to send the correct economic signals as far as possible; if the overall arrangements do this, then there is perhaps less concern from the regulator on the effects on individual market participants. With charging a zero-sum game – whenever one user pays less, another pays more – understanding these changes will be important to customers' investment decisions in front of and behind the meter.

The SCR process allows Ofgem to carry out substantial code review and alteration in-house. This contrasts with the usual code-change process, wherein industry leads change proposals which are then reviewed and approved – or rejected – by Ofgem. The SCR allows Ofgem to lead a holistic change process across multiple codes and can circumvent usual processes to bring about far-reaching and rapid change.

The expected changes are explained below, and also we discuss how these changes may affect decentralised generators.

8.7.1. Targeted Charging Review

The TCR will cost the decentralised generation sector £150mn/year and change the business models of behind the meter operators.

The TCR SCR is looking at the way that residual charges are distributed amongst users on both the demand and generation sides, and to consider how embedded benefits may be causing distortions to the markets. Forward-looking charges give users insight into the costs of connecting to a particular location; residual charges recover the remaining monies due to a network company under its price control.

Figure 13: Forward looking and residual charges 2017-18

	Type	Transmission	Distribution
UoS	Forward-looking	£0.5bn	£4.0bn
	Residual	£2.1bn	£1.4bn

Source: Ofgem

Ofgem's initial proposals and minded-to position were issued in November 2018. Its position is that residual charges should be recovered from demand only, rather than generation and demand as it is currently. It has also taken the view that more costs should be recovered through increased fixed charges rather than consumption charges. Specific changes are as follows:

- Two alternatives are under consideration: Fixed Charges and Agreed Capacity
    - Fixed Charges: users would be segmented based on their line loss factor class, with the same charges paid by all users in each class, no matter what their consumption. For domestic and small non-domestic consumers, this has been suggested to be single rate domestic, Economy7, and single rate non-domestic
    - Agreed Capacity: users would be segmented based on the capacity of their connection to the network. Where there is no specific agreement – for example for domestic consumers – there would be an assumption of capacity made; this could be banded between lower and higher consumers, for example those with EVs or heat pumps
- The Fixed Charges option is currently preferred by Ofgem

Storage currently pays demand charges when drawing power, and generation charges when supplying power, as well as balancing charges on both. Ofgem considers that this position is incorrect. However, the treatment of storage in network charging is not being examined under the TCR.

Embedded generation is treated as negative demand for BSUoS purposes, earning embedded generators around £150mn/year when in fact, embedded generators could be said to drive higher balancing costs. Ofgem has proposed two solutions: to charge BSUoS on a gross basis, or to charge BSUoS to generators as well as demand-side users. A taskforce led by the System Operator is examining this issue, but it is minded towards charging BSUoS on a gross basis. This means that there will no longer be a BSUoS benefit available, costing the decentralised generation sector around £150mn/year.

A large consumer benefit of £0.5-1.2bn net present value from the changes is forecast to 2040, with additional system benefits of £1-3.2bn.

8.7.2. Network Access and Forward-Looking Charges Review

If the NAFLC does implement regional pricing, rural generators are likely to suffer while urban generators benefit.

The NAFLC SCR is considering network access and forward-looking charges. Forward-looking charges are paid by consumers depending on where they have connected to the system, and how and when they draw power from it. This is linked to the previous work stream as the total level of residual charges will be impacted by the total level of these charges. The charges are a key part of driving users towards behaviours which make efficient use of networks, helping avoid network reinforcement. Ofgem is looking to regulate the transmission and distribution networks as a single system, reflecting the growing importance of embedded generation.

The second part of the work stream is improving the definition and choice of access rights, and how these rights are allocated. Transmission connecting generators agree their entry capacity, paying charges on this basis and being compensated if the agreed level of access is not provided. Distribution connecting generators have less well-defined arrangements, are generally more bespoke, and include flexible connections which can be limited without compensation. By improving the choices available in connection rights to distributed generators, costs to connect new energy projects should be reduced, and ongoing charges minimised. However, this will drive additional complexity and a need for understanding how and when a project is likely to export energy.

There may also be options to share access rights between users, improving flexible connections, and considering locational network charges supporting users to match supply and demand locally. Changes are intended to improve the efficiency of the network and network reinforcement decisions.

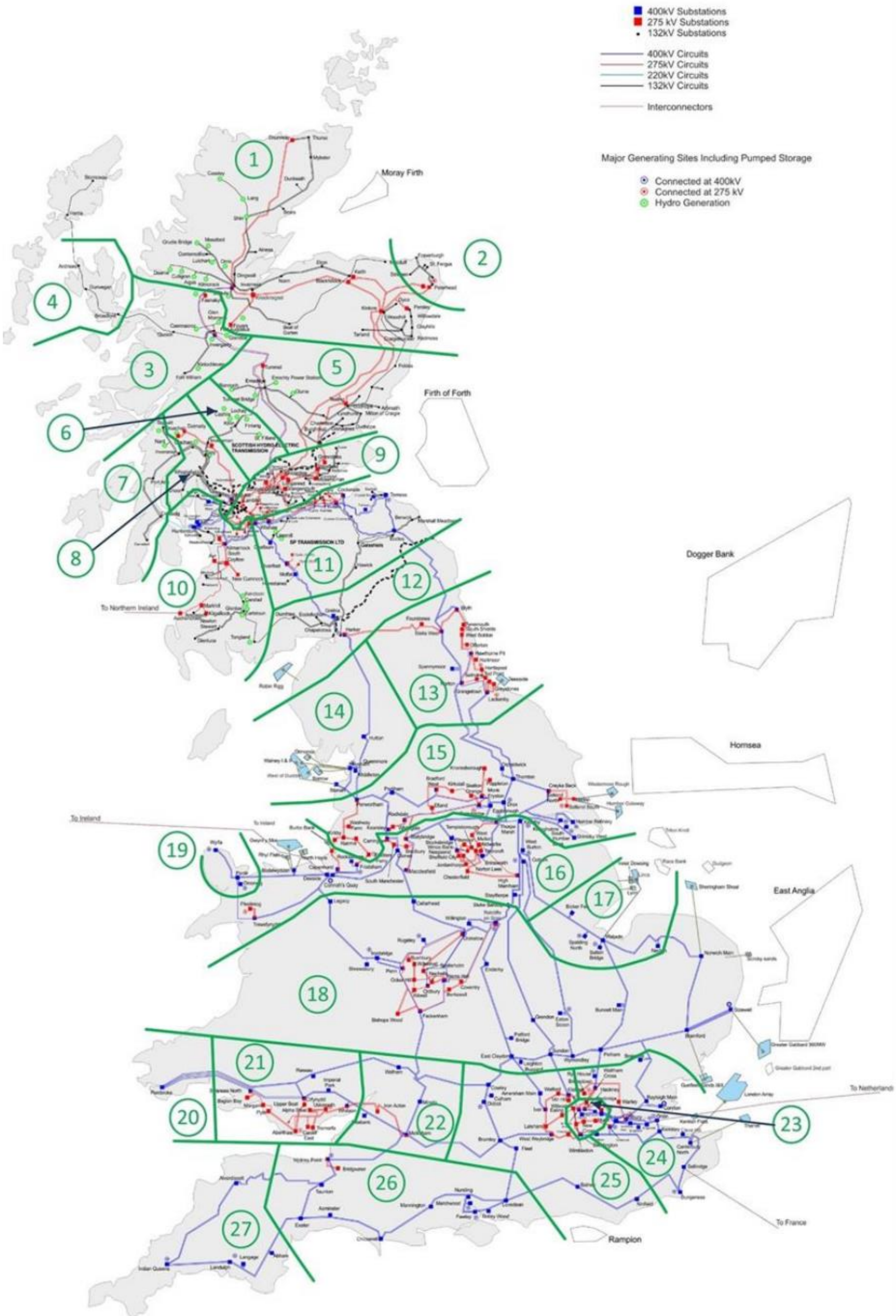
However, Ofgem is specifically not considering changes to long-term fixed capacity access rights, or rights to allow users to flow power over a specific section of the network. This latter change could enable economic local power trading, with users only paying for the sections of network they actually used to flow power. However, Ofgem considered that this would be too challenging for review and implementation.

The main specific change under consideration which will impact on embedded generation is the replacement of the demand locational charge (which generators currently see as a positive value) with the generator locational charge. Ofgem could also remove the floor on the charge – currently set at £0 – to allow negative charges (i.e. payments to generators). It may also change the charge to be based on the existing 27 generator charging zones, rather than the 14 distribution regions. It may also be converted to a fixed capacity charge.

If the charge was changed to be based on the 27 generator charging zones, this would likely reduce the value of the embedded benefits to generators located in rural regions. The smaller zones would reflect the costs and benefits distributed generation in a more granular manner, which is likely to reflect that generation in rural zones offers less system benefits than in urban zones, and so reduce the values available to, or impose costs on, rural generation. Urban fringe generators are likely to benefit from higher value. Section 8.5 sets out value-stacks for different generation technologies, but note that this is a relatively small element of the total value stack.

The 27 GB generation zones are presented in Figure 38. They are based on the fact that similar costs are caused by new generators across the zone due to similar characteristics.

Figure 38 The 27 GB generation zones



Source: National Grid

8.7.3. Impact on Decentralised Generation

Rural locales are much more likely to suffer the worst-case scenario, as they are more likely to be generation dominated than urban locales which host more demand users.

The following figures present a “worst case” scenario for generator embedded benefit values after implementation of the changes under the TCR and NAFLC SCRs. See section 8.5 for full current value-stacks for various generation technologies.

Figure 39: Worst-case value changes for a solar plant before and after TCR and NAFLC SCR

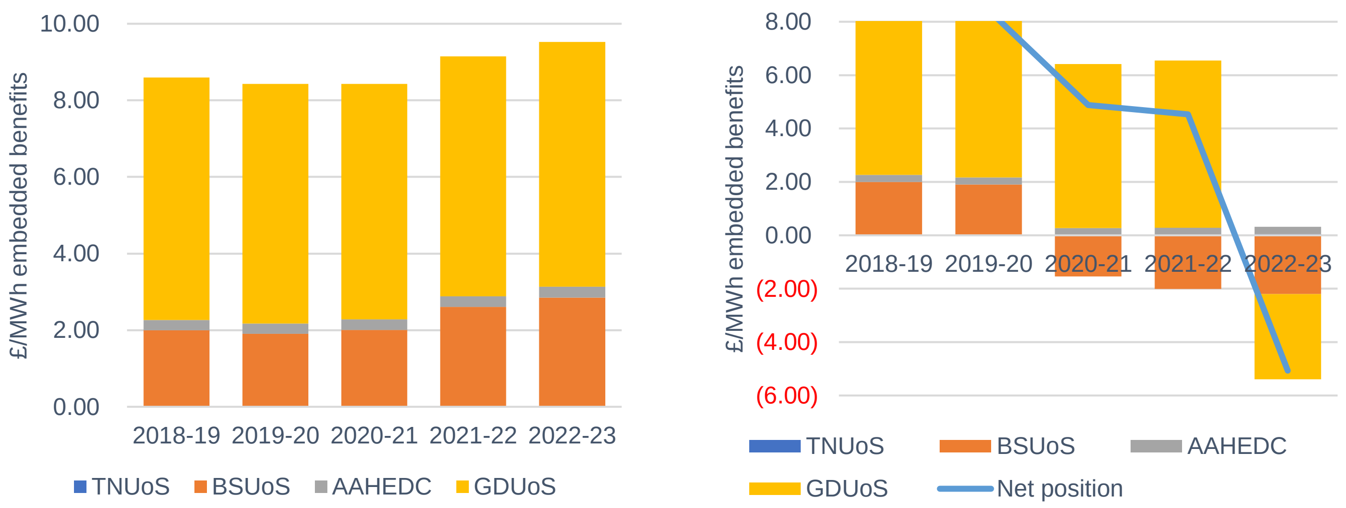
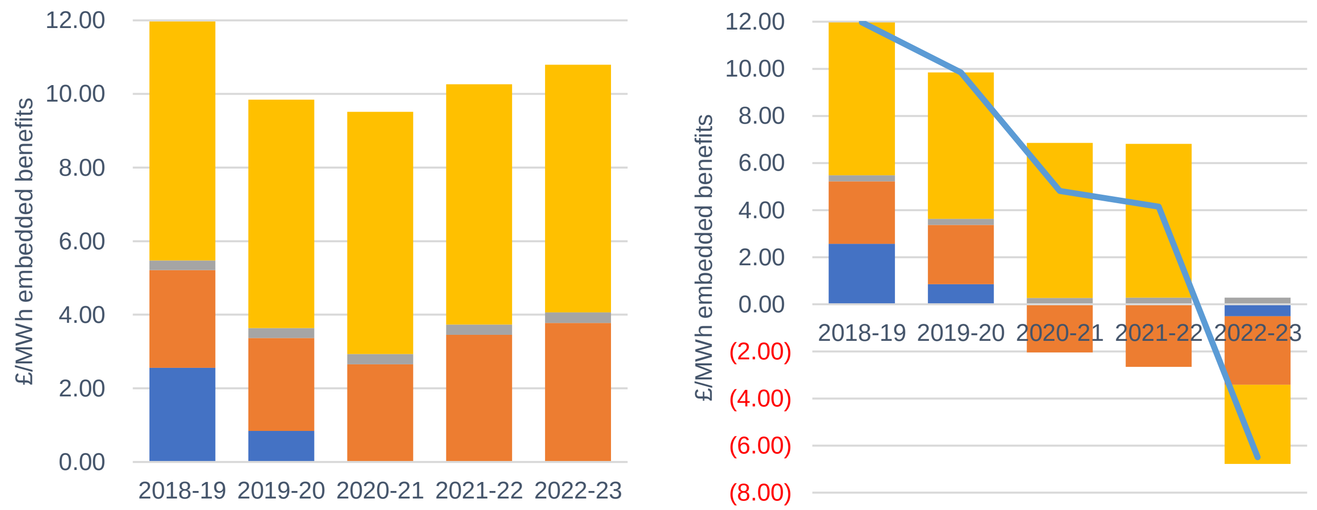


Figure 40: Worst-case value changes for a baseload plant before and after TCR and NAFLC SCR



Source: Cornwall Insight modelling

Note: Based on a plant connected in the North East region, in a generation dominated area

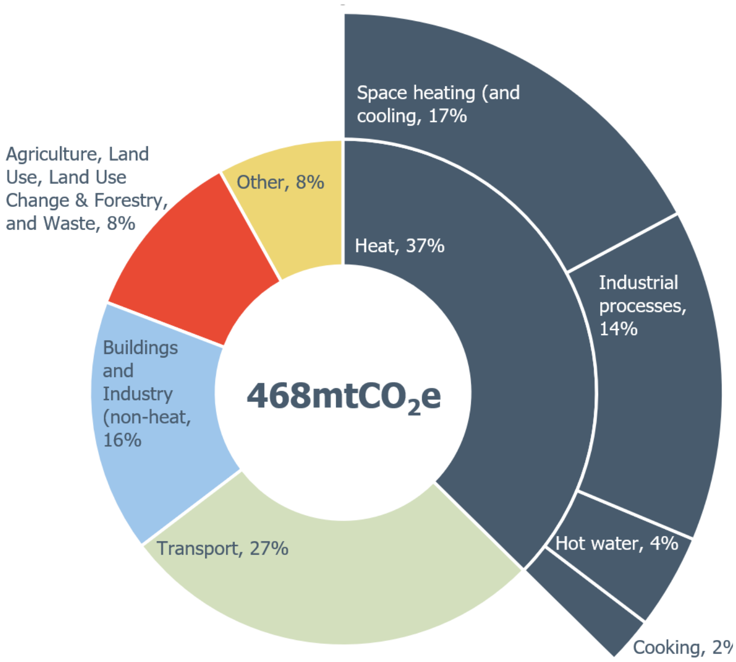
Rural properties tend to have lower energy efficiency and higher carbon emissions for heating. Decentralised energy projects could be the key to decarbonisation at reasonable cost.

9. Decarbonisation of heat

Space and water heating is the largest single source of energy demand and heat production is responsible for around a third of all UK carbon emissions. However, progress towards decarbonising heat has been slow and it has received relatively little policy attention compared to other key sectors, such as renewable electricity and low-carbon transport. This reflects the complexity of the issue as, unlike electricity generation, heat is typically produced at property level by disaggregated sources such as gas-fired boilers and electric storage heaters.
There are several routes to decarbonisation of heat and none should be regarded as a "silver bullet" – all will be needed in concert, depending on the characteristics of the property and area:

- Increasing energy efficiency with thermal insulation
- Decarbonisation of gas through green hydrogen or biogases
- Electrification of heat, with conventional equipment or heat pumps
- Connecting properties to heat networks, potentially with green heat sources

Figure 14: Estimated UK carbon emissions attributable to end use with a breakdown for heat



Increasing thermal insulation is largely beyond the scope of this paper, as is the decarbonisation of the gas network. Local energy projects are unlikely to be able to install additional insulation on an economic basis in most homes, as the annual cost of heating – and therefore consumer savings – will be much lower than the cost of upgrading insulation.

Decarbonising the gas system is similarly beyond the scope of this paper, given the national scope of the task. However, the economics of both anaerobic digestion (to produce green gas) and green hydrogen production through electrolysis are both becoming feasible. We have considered the potential for rural energy projects to deploy these technologies elsewhere in this paper.

We address renewable heat production through heat pumps and heat networks further in the following sections.

9.1. The Energy Company Obligation

Energy suppliers find it difficult to recruit customers for installations, so a project with strong community links could be key to helping consumers access much-needed support.

For vulnerable domestic consumers, home energy efficiency funding is available through the Energy Company Obligation (ECO). Many LAs and community energy groups provide valuable community benefit services in helping eligible consumers access this funding.

There remains a rural element to ECO which requires 15% of the scheme to be deployed in rural regions, and delivery to off-gas-grid homes will typically be at lower cost to suppliers, so they may be keen to work with schemes providing support to vulnerable rural domestic consumers.
BiomassThe principle of a biomass boiler is the same as that of a traditional fossil fuel boiler, in that it burns a fuel to generate heat that can be used for a central heating system in the property, as well as to produce the domestic hot water.

Where an existing wet heating system is in place with a fossil fuel boiler, then the changeover to a biomass system is fairly straightforward.

Biomass boilers are preferred over heat pumps for traditional buildings that are poorly insulated. Most boilers are specifically designed to only process one fuel type although there are some exceptions to this rule. There are principally three different biomass fuel sources; woodchip, wood pellets and logs. These options are detailed below:

9.1.1. Biomass log/batch boilers

A very traditional batch filling system whereby logs or straw bales are loaded manually and lit. The logs need to be well seasoned and many boilers can take between 0.5m to 1m long logs.

9.1.2. Biomass wood pellet boilers

The most straightforward system to manage, whereby the pellets can be bulk delivered and the whole system is automated to work without any daily interaction. Therefore this is the most comparable to a traditional fossil fuel system.

9.1.3. Biomass wood chip boilers

These boilers burn timber that has been chipped into approx. 3cm^2 particles of virgin timber, which could be from Estate grown trees. The chip is delivered into a fuel store that contains a rotating arm agitator and screw auger which feeds the boiler. The boilers are fully automated but require regular interaction.

9.1.4. Advantages & disadvantages of each technology

Technology Type	Advantages	Disadvantages
Biomass (Log)	• Cheapest wood fuel source to buy or produce • Logs are readily available • Lowest equipment capital cost of the three biomass technologies • Simple technology with few moving parts	• Daily or twice daily manual loading of logs (weekends and holidays should be considered) • Manual lighting of the logs • Logs need to be properly seasoned to approx. 20% moisture content • Challenge to meet RHI emission standards on some technology
Biomass (Wood Pellet)	• Automated fuel delivery and ignition • Fuel quality is strictly controlled by the pellet producer • Smaller fuel store required • Longer periods between fuel deliveries • Fuel can be delivered in bulk and blown into the fuel store • Lower risk of fuel blockages compared to woodchip	• Most expensive wood fuel to purchase • Availability of fuel suppliers • Fuel delivery lorries need access to within 20m of the fuel store • High capital cost compared to log boilers
Biomass (Wood Chip)	• Woodchips are cheaper than pellets • Woodchip could be produced from farm grown timber (self-sufficient) • Larger woodchip supplier list to choose from compared to wood pellet suppliers • Automated fuel delivery and ignition	• Larger fuel store required for storing the wood chips compared to wood pellets • Fuel deliveries and fuel store location need careful design • More frequent fuel deliveries compared to pellets • Higher risk of blockages from poor quality woodchip therefore more interaction than with pellets • Woodchip moisture content must match boiler manufacturer's specification otherwise efficiencies will drop • High capital cost compared to log boilers

9.2. Heat pumps

Key to electrification of heat, mass heat pump installation may overwhelm rural networks so consultation with the local DNO will be vital.

With the announcement in the Spring 2019 Budget that gas boilers would not be permitted in new-build homes from 2025, heat pumps are believed to be the ideal replacement technology. Heat pumps provide heat by concentrating it from a lower-temperature source, in the same way as a refrigerator works. They can draw heat from the air, ground or water, with different sources having different characteristics. Many heat pumps are reversable – able to provide cold air/ cooling as well as hot air/ heating.

Crucial to understanding the technology is the fact that, while heat pumps can provide a "multiplier" of energy to heat – ie 1kWh of electricity can result in several kWh of useful heat – this multiplier is dependent on the temperature of the source of heat.

This means that the multiplier – known as the Coefficient of Performance (CoP) – will be much lower in the winter when ambient temperatures are low but heating is more likely to be required. The extent to which the performance of the heat pump is affected by changes in ambient temperature is the Seasonal Performance Factor (SPF); there are also the Seasonal Energy Efficiency Ratio (SEER) and the Seasonal Coefficient of Performance (SCOP). All of these ratings attempt to provide reflection of performance of the heat pump over the year, based on assumptions of usage and seasonal ambient temperatures.

Technology considerations:

- Air-source – easiest and cheapest to install, but will suffer the worst impacts on CoP during the winter when ambient air temperatures fall. Depending on conditions, users may need a back-up source of heat in order to stay warm during cold snaps
  - Urban areas tend to have higher ambient air temperatures – several degrees in the case of large cities. This can make urban locales more suitable for air-source heat pumps
- Ground-source – the most expensive to install, requiring extensive trenchworks either horizontally or vertically. However, benefit from relatively stable temperature year-round and therefore cheapest to operate in winter
  - Rural properties are likely to have larger grounds or gardens, which increases the potential to deploy a ground-source heat pump
- Water-source – a middle-ground in terms of cost and performance variance over the year, but reliant on a local body of water or river. Trials have also been conducted on the use of sewage water for heat, as this liquid will be at above ambient temperatures and therefore offer superior CoP
  - Access to suitable water or sewage water sources will be highly locational
- Other heat sources – potentially, waste industrial heat can be linked to heat pumps, though this is more likely at scale for large users or heat networks that for individual consumers; equally geothermal sources or mine-water are available in some regions
  - Access to waste or geothermal heat, and the costs of this, is highly locational, but where low-cost access is correlated with a consumer base, it may indicate that a local heat network is viable
- X-to air – produce heat in the form of warm air, which can be ducted into rooms as required. As most UK homes are not set up for climate control through hot air, implementation may require expensive renovations
- X-to water – produce heat in the form of hot water, which can be circulated through existing hot water systems. However, this will be at lower temperature than hot water from conventional boilers and therefore larger radiators may be needed; underfloor heating is considered a preferable delivery route but again may require expensive renovations

- Fuel source – though many heat pumps are powered exclusively by electricity, some models are gas-powered. Some are "hybrid", meaning that they can use gas or electricity as fuel as required
    - A heat pump can double the power consumption of a domestic property, including at peak consumption times. Most electricity networks will be able to sustain installation of some heat pumps, but if these cluster, and particularly if consumers also have EVs charging, then weaker networks may be overwhelmed. As a consequence heat pumps are often deployed in conjunction with solar PV.
- Rural electricity networks tend to be weaker than urban examples, being designed for lower levels of power consumption. They may also be more expensive to upgrade
- Flexibility services – heat pump models have recently been released which are smart and can respond to price signals in order to deliver the most cost-effective heating depending on the time of day. Some models incorporate heat stores (for example, hot water tanks) which can increase flexibility

Though heat pumps can receive subsidy support under the RHI scheme, market penetration has been low to date with under 50,000 domestic units installed as of July 2019, and fewer than 500 non-domestic installations as of June 2019.

Many consumers are reluctant to install heat pumps as the relatively low temperature of heat (compared to gas, oil or biomass boilers) may require extensive and expensive energy efficiency renovations to buildings in order to maximise benefits.

9.3. Economics

CoP will vary by technology and time of year, but some assumptions can be made to consider the economics of operating one technology compared to others. The following table sets out comparison calculations across technology types.

Air-source heat pumps suffer most from ambient temperature changes and may be less suitable in rural settings. Older rural homes with poor insulation may also need extensive upgrades before heat pumps are suitable for use.

Fuel	Average CoP	Cost of fuel (p/kWh)	Cost of heat delivered (p/kWh)
LPG	0.9	6.5	7.3
Electricity (Economy7)	0.9	8	8.8
Heating oil	0.7	4	5.7
Gas	0.9	3.6	4
Biomass (wood)	0.9	5.5	6.1
Air source heat pump	2.5	15	6
Ground source heat pump	4	15	3.75

Source: Energy Saving Trust
Notes: - Co-efficients of performance are equal to 90% for a new condensing boiler and 70% for an non-condensing boiler. Fuel prices are rounded and set to average values for the year to March 2019

As can be seen in the chart, the economics of operating air-source heat pumps are poorer than mains gas and marginal compared to biomass and heating oil. Ground-source heat pumps do offer superior economics, and if the only fuel available is electricity then any heat pump type will often be able to provide superior performance.

As the technology matures, CoPs may rise due to more efficient models being launched. New models may also include smart technology which, in concert with a thermal store, may allow the consumer to take part in flexibility service offerings. Various trials are underway both in the operation of technology and in developing the procurement and operation of aggregation schemes, but it remains too early to judge whether this concept will be able to offer returns sufficient to justify joining schemes. Many regional flexibility offerings are based on rural regions and it may be that these increase in number in the future are rural networks become more stressed due to heat and transport electrification.

It should also be remembered that subsidies still exist for heat pumps, which can defray some of the costs. The RHI offered domestic users a subsidy of 10.71p/kWh for air-source and 20.89p/kWh for ground-source heat pumps as of December 2019. Non-domestic users could access a subsidy of 2.75-9.56p/kWh, depending on technology and scale. Subsidies last for seven years, are based on heat produced rather than energy consumed and may be capped.

9.4. Carbon Savings

Much as with EVs, depending on how calculation is done, the carbon emissions of electrically-fuelled heat pumps can vary widely. The following table sets out some assumptions, compared to other fuels.

Pairing heat pumps with onsite renewable generation could be a winning solution, though solar generation at least is unlikely to pair well, as it will not produce power during the coldest period – overnight.

Fuel	Average CoP	Emissions (gCO2e/kWh fuel consumed)	Emissions (gCO2e/kWh heat delivered)
LPG	0.9	214	237.8
Electricity (Economy7)	0.9	381	423.3
Heating oil	0.7	245	350.0
Gas	0.9	184	204.4
Biomass (wood)	0.9	0	0.0
Air source heat pump	2.5	381	152.4
Ground source heat pump	4	381	95.3

Source: Energy Saving Trust

Notes: - Co-efficients of performance are equal to 90% for a new condensing boiler and 70% for a non-condensing boiler. Carbon emissions are set to average values for the year to March 2019

If an assumption is made that the heat pump is running at off-peak times when power is relatively low-carbon, carbon intensity may fall as low as 32gCO2e/kWh for air and 20gCO2e/kWh for ground-source heat pumps respectively.

If an assumption is made that the heat pump is running at peak times when power is relatively high-carbon, carbon intensity will be much higher.

If an assumption is made that the heat pump is using 100% green power from the networks, then carbon emissions fall to zero. The same is the case for self-generated green power.
It is also worth noting that grid carbon emission intensity is forecast to fall over coming years as electricity production is decarbonised. BEIS's latest Energy and Emissions Projections, issued April 2019, show emissions of 41gCO2e/kWh in 2035 and this has fallen from the 2017 projection of 55gCO2e/kWh.

9.5. Other low carbon heating technologies

Modern smart electricity storage devices, coupled with Time of Use pricing, could offer a low-cost retrofit option for electric-heated, off-gas-grid rural homes.
While not as efficient as heat pumps, these units can be more flexible.

At various stages of development are other low-carbon heating technologies, including modern electrical storage heaters. These technologies have a CoP of one, but provide carbon and cost savings by operating on a smart/ time of use basis to consume power at times when cost and carbon intensity of electricity is low.

Typically, this will be overnight, and GB consumers on some time of use tariffs were recently (December 2019) able to benefit from the first negative prices seen in GB markets – being paid to consume additional power.
These technologies are only now coming to market so it is too early to say whether they will be cost effective – at a minimum, they are likely to be more economical than conventional electric or electric storage heating, due to their smart technologies.

9.6. Heat networks

Heat networks are hugely popular on the continent. By centralising heat production, they increase efficiency and allow relatively simple retrofit for low carbon heat production in the future.

Heat networks supply heat from a central source through a network to multiple end users for the use of space heating or hot water. They have been identified as a low-regrets option for supplying low-carbon heat in the UK. The government's Clean Growth Strategy assigns a significant role to heat networks as they could supply up to 20% of heat demand in homes by 2050, a ten-fold increase on today. Heat networks are currently mostly limited to urban high-density housing and business districts in England. However, studies have indicated that rural off-gas-grid housing clusters could also be suitable locations for heat networks.

The Heat Networks Investment Programme (HNIP) is currently the main delivery vehicle for upscaling heat networks in the UK. The government has committed £320mn of capital through the scheme in the form of gap funding to high-quality heat network projects. The aim is to leverage around £1bn of private sector support. Following a HNIP pilot, which ran from October 2016 to March 2017 and saw £24mn awarded to nine Local Authority led projects, the main scheme launched in Autumn 2019 in England and Wales.

The aim is to:
- Create a long-term, self-sustaining heat network market with a framework that is flexible to accommodate a range of new business models and innovation
- Develop a range of measures that will facilitate a heat market and upscaled heat networks, including investment, a policy framework, planning, industry regulation and consumer protection
- Deliver, through the creation of a competitive market, attractive investment opportunities, reduced costs of heating for the consumer and a contribution to decarbonisation targets

9.6.1. Heat Network economics

Higher construction costs in rural areas due to less dense populations could be offset by higher prevailing heating costs. Denmark in particular has demonstrated many successful rural district heating networks.

The economics of heat networks depend greatly on the cost of assets installed, number of users and load factors for use. A more profitable or lower cost network will be indicated by:

- A dense user-base, reducing the cost of installing heat pipes – particularly where high-rise housing or commercial space can be connected
- Differentiated heat demand, meaning that users need heat at different times of the day and therefore lower peaks and lower cost of heating sources
- Access to low-cost heat, for example waste heat from industrial processes or an Energy from Waste plant
- Access to wider revenues, for example by generating power and possibly distributing this to consumers via a private wire installed alongside the heat network

A CMA report published in July 2018 found that unit prices for heat and consumer bills varied significantly between networks and noted that average prices were close to or lower than the equivalent price of gas heating. Typically, where networks were owned by residents or not-for-profit organisations, charges were lower than private heating networks. Prices, especially for large networks, were often set according to the “avoided cost” for connected customers – set at a benchmark for individual gas boilers connected to gas networks.

This indicates that consumer benefits will be greatest where consumers are using non-mains gas heating, particularly where electrical heating is prevalent.

Rural schemes may find that population density is lower, even in towns and villages, and therefore connection costs are higher than in urbanised areas. However, given that the gas grids do not connect many rural areas, population clusters may still be suitable locales for heat networks, given the increased counterfactual cost of heating through oil, LPG or electricity.

Schemes may also find that most demand comes from a single user-type, for example from domestic users, and is therefore likely to occur during a shorter time of day with higher peaks. They should consider the impacts of this on the size and cost of equipment that is needed. Impacts may be mitigated through use of thermal stores. The total level of demand and possibilities for expanding the scheme may also be more limited than comparable urban networks, with implications for the installation of back-up heat production in case of unexpected failure or for maintenance period.

9.6.2. Heat network regulation

Sector regulation would, on balance, probably be positive for the industry, helping it gain acceptance in the UK market by ensuring consumer protections are in place.

Though various voluntary good-practice guides and codes of practice exist, along with regulation of metering and billing practices, there is currently no heat network regulator in GB. However, there are persistent rumours from government that Ofgem or another regulatory body will be granted powers over heat networks; the CMA among others has recommended this step.

This would lead to increased oversight and control, with protection for consumers to rise but a greater administrative burden and restrictions on operators.

9.6.3. Heat Networks Investment Project

This funding stream will help rural heat networks to deliver funding – though note that it is not a subsidy intended to support uneconomic projects.

Triple Point Heat Networks Investment Management has been appointed to operate the HNIP, with committed capital of £320mn. It has launched a website to manage applications for support here, and government guidance is found here. Projects can apply for grants or loans towards the development of heat networks through quarterly funding rounds. The HNIP can issue grants for up to £5mn and loans of up to £10mn to eligible projects

The eligibility criteria are as follows:

- Private and public schemes are eligible, with the project owner rather than a sponsor required to make the application
- Schemes to provide a minimum of 2GWh/year of heating or cooling
- Minimum funding of £25,000 for loans, with no minimum for grants
- Heat sources must to low-carbon, meeting one of the following requirements:
  - 75% from good-quality CHP, as defined by the CHP Quality Assurance Programme (can be non-renewably fuelled)
  - 50% from a renewable source
  - 50% recovered waste heat
  - 50% from any combination of CHP, renewable or recovered heat
- Must deliver carbon savings compare to the counterfactual of current heat provision methods
- Must deliver positive social net present value, or be a strategic network
  - Social net present value is assessed based on cost savings, carbon savings, and other elements such as measures of air quality – this will be calculated by Triple Point on the project's behalf
  - Strategic projects will demonstrate innovation, increase the capacity of the project sponsor or developer to deploy networks in the future, have potential for future expansion to deliver additional social value, or develop the supply chain with over £1mn contracts issued
- Must have potential to expand the network and the heat sources, with the aim of interconnecting networks over time
- Must comply with the Heat Networks Metering and Billing Regulations 2014
- Must use the Heat Network Code of Practice from CIBSE and the Association of Decentralised Energy and adhere to Heat Trust or equivalent standards for consumer protection
- Must not cause consumer detriment, by increasing average prices paid for heat
- Must demonstrate positive returns before the HNIP support is factored in but not be able to proceed without the HNIP support
- Support must not exceed State Aid limits and must only be used for eligible costs, which include design, costs associated with securing funding/ investment, most capital costs of construction, and the primary connection of buildings to the network – though not the works which are required inside buildings to distribute heat

BEIS announced on 8 November 2019 that four schemes were awarded £17mn in total during the first round of HNIP funding; it has not revealed the identity or location of these schemes.

All of these models are as suited to urban as rural locales, but rural-based schemes may have an easier time finding partners.

10. Ownership and Delivery Models

There are a number of different business propositions that may be used to bring forward decentralised generation assets in a rural and urban fringe setting. These propositions can be split into seven distinct offerings:

1. Full customer ownership
2. Energy performance contracting
3. Leasing of roof/ site
4. Revenue sharing
5. Provision of free power
6. Joint ownership through capital investment
7. Private wire arrangements

All of these propositions can be offered by a number of parties, singly or jointly. It should also be noted that in some cases these options may overlap. For example, a jointly owned asset could be connected via a private wire to the customer's site.

In this section, we investigate these seven ownership models and provide case studies where they have been implemented.

10.1. Full Customer Ownership

Where a company possesses sufficient up-front capital, it may elect to pay for on-site generation or energy storage measures in full. When considering this option, a company generally will undertake or commission a third party to undertake a feasibility study which compares the technical feasibility, net financial returns and payback period of several different technologies.

The advantage of this model is that, once the plant is installed, the company will benefit from 100% of the energy savings incurred through the operation of the plant, in addition to any revenue achieved through export.

The disadvantage of this approach is that there is usually a significant opportunity cost associated with committing such a large amount of upfront capital to a project. It also relies on the host company having access to suitable land on-site or nearby to deploy generation, and planning restrictions on use of land.

Pursuing this financing option is common for large organisations with a sizeable capex budget for upgrades. This includes retail and hospitality developments which are owned or managed by a large parent company and large industrial complexes where energy generation technology represents a relatively small portion of annual budget. Such organisations may also seek external financing where an investor's cost of capital is lower than the company's own cost of equity.

10.1.1. Case Study

In 2015, Anesco completed the installation of rooftop solar PV systems at 88 Premier Inn sites. As Premier Inn is a large company backed by a parent group, it was able to fully finance the projects and therefore benefit from 100% of FiT payments and energy savings directly.

The Premier Inns had sufficient onsite consumption to absorb the bulk of the power generated, resulting in significant energy bill cost savings in addition to be FiT subsidies to pay for the installations. Premier Inn is saving £160,000 annually on its energy bills, in addition to Anesco's repayment of the capital cost of the scheme and profit margin. Additionally, Premier Inn has the corporate social responsibility (CSR) benefit of saving 736 tonnes a year of carbon emissions.

10.2. Energy Performance Contracting

Where a company lacks or does not wish to commit the resources required to install on-site renewable energy generation under full customer ownership, it may seek an Energy Performance Contract (EPC) with another party, typically an Energy Services Company (ESCO). Under an EPC, the third party will finance and install energy efficiency upgrades and/or on-site renewable energy generation. In return, the ESCO receives a return on investment generated through the value of the resulting savings by the energy user (the host company). Once the party has recouped the costs of installing the project, operational expenses, and a profit margin, the energy user owns the upgrades and fully benefits from any further savings.

An investment grade energy audit is usually undertaken in advance of an EPC being signed. In addition to identifying the cost-optimal measures to install, the audit will inform a projection of the site's energy demand without the efficiency measures or on-site renewables generation being implemented. The metered demand following upgrades is then deducted from this estimate to calculate the resulting energy savings.

The advantage of this model from the energy consumer's perspective is that, if the project does not deliver the expected savings, the ESCO or third party will not receive its payments. As a result, although the business risk of the project remains with the energy user, the performance risk is transferred to the third party. The disadvantage is that the energy consumer is not able to benefit from the full electricity bill reductions until the ESCO has recouped its return on the costs of installing the system.

A range of types of companies can provide this service. Independent consultancies with sufficient capital reserves can conduct an energy audit and finance and install the recommended on-site generation. Large solar PV installers commonly offer financing to install rooftop systems, helping companies overcome the barrier of the high capital costs of the installation.

In addition, several large energy suppliers act as ESCOs, often sub-contracting the work involved in conducting the on-site energy audit and installation of the renewable energy systems. Some Local Authorities are undertaking this model as well, such as West Suffolk District Council.

10.2.1. Case Study

In 2007, London's Natural History Museum signed a 10-year EPC with Veolia, after a previous PPA between the two parties over-delivered against expectations. Under the new EPC, Veolia installed tri-generation Combined Cooling Heat and Power (CCHP) plants in two of the Natural History Museum sites, replaced lighting with energy efficient versions, replaced boilers, and installed new air conditioning equipment.

These improvements are guaranteed to deliver a minimum of £54,000 net annual savings to the client, as well as paying back Veolia's investment. The Natural History Museum has also avoided having to make capital outlay, and carbon emissions fell by 10%.

10.3. Roof or Site Leasing

Where a consumer has roof space or an area of land which might be suitable for a renewables generation or battery storage units, but lacks the financial resources to develop such a project, they might choose to lease this space to a developer.

In this model, the generation or battery storage systems are installed by a third party. The project is usually paid for by a private investor or – for public sector organisations – a government-backed fund such as Salix, which meets the upfront capital costs of the system, in return for enjoying the majority of the financial benefits of the project.

In this model, the power provided to the end-consumer can be free or provided for a (usually below market rate) charge per unit of energy. The key advantage to the consumer of leasing roof space is that they are not required to provide any up-front capital for the project, and they incur no revenue risk. The main downside is that the benefits which they incur from the project are restricted.

Renewable energy installers offer this service to commercial and industrial energy consumers, where local consumption of the power generated can be guaranteed. Some battery providers also offer a similar model, based on network charge avoidance. Community energy groups also commonly offer roof leases for solar PV development selling green energy to hosts cheaply and providing other benefits in the community with profits.

10.3.1. Case Study

Spirit Energy recently installed a 1MW/1MWh lithium-ion battery at an industrial premise with a base load of 500kW. The investor provided £550,000 of up-front capital for the project and earned 100% of the wholesale and balancing service revenues from the project. The site owner gained 70% of the value of the network charge avoidance, with the investor earning the remaining 30%. In addition, the battery was able to replace the sites uninterruptable power supply requirement, saving them the cost of a replacement system and ensuing that they do not loss productivity due to down-time. Total benefits from the project are set out in Figure 41 and show that the assets are paid off for the investor in under 5 years, while also offering significant benefit to the host organisation.

Figure 41: Revenues for a 1MW/1MWh battery install-and-operate agreement

Item	Site owner annual cash flow	Investor annual cash flow
Battery installation	-	-£550,000 (one-off)
Grid income	-	£110,000
Triad avoidance	£37,100	£15,900
DUoS avoidance	£2,240	£960
Downtime avoidance	£6,000	-
Running costs: energy	-£8,000	-
Running costs: maintenance	-	-£1,400
Total	**£37,340**	**£120,860**

Source: Spirit Energy

10.4. Revenue Sharing

Energy suppliers and ESCOs may also provide the option for sharing both the ownership and revenue associated with the project.

Under a shared savings contract, the cost savings of the proposed project are divided between investors for a pre-determined length of time in accordance. This can be in accordance with a pre-arranged percentage split, or another sharing mechanism (such as savings over a specified level accruing to one of the parties). There is no standard or industry typical split for these arrangements, which will depend on the cost of the project, the length of the contract and the risks taken by the ESCO and the consumer.

With this model, the client takes over some performance risk but avoids assuming any credit risk. As a result, a shared savings contract is likely to be associated with a third-party source of funding or with a mixed scheme, with financing coming from the client and the ESCO. In this latter circumstance, the ESCO would take a load, which it would be responsible for repaying, taking on the credit risk. The ESCO therefore assumes both performance and the underlying customer credit risk – if the customer goes out of business, the revenue stream from the project will stop, putting the ESCO at risk.

For technologies which are not technologically or commercially mature, this seen as a good funding option, because neither the consumer nor the third party assumes the full extent of revenue or performance risk of the project. Currently, these technologies include non-lithium electricity storage, hydrogen projects, and EV chargers.

10.5. Provision of Free Power

Under this model, consumers are provided with the output of a generation asset for free, typically in return for the customer providing a site to build the generation asset. This is typically due to the good solar or wind resource within the site, and where there is access to a subsidy support scheme for the asset. A common application of this was under the Feed-in Tariff (FiT) for solar at the domestic or small business level. However, this may be the case for some energy from waste (EfW) schemes, where gate fees are paid for waste trucks bringing fuel to the site.

The main benefit of this model for the consumer is the provision of free power or heat generated by the asset for no capital outlay. For the provider, the benefit is access to sites which would potentially be inaccessible to deploy assets on. For example, householders or small businesses who may otherwise lack the capital or engagement with the market may be good hosts. The downside for consumer is that they are prevented from accessing the other sources of value associated with the generation asset, and will normally have limited to no control over its running profile.

This arrangement is often part of a leasing model. It was typically seen in the early days of the FiT scheme in relation to solar projects. The high level of the subsidy payments meant it could be economical to provide the electricity output to the consumer free of charge (particularly if the proposed asset was under the 50% deeming threshold for FiT, 30kWp, as this meant that the asset-owner would not have export revenues reduced by on-site consumption) and to generate the return on investment from the FiT generation payments.

The arrangement has become less common in recent years as subsidy payments fell; with the closure of the FiT to new entry at the end of March 2019, we do not expect that this model will continue in the short term for renewables generation. However, with increasing numbers of Local Authorities seeking to improve their processing of waste and derive additional revenues, this or similar models could be seen more in the future in the EfW field.

10.5.1. Case Study

An example of this proposition was an offering from Engensa, which in the early operation of the FiT (when subsidy payments where highest) would provide and install solar panels for domestic households for free, in return for the FiT generation and export payments. The households would benefit from free energy when the panels were generating, with Engensa receiving the generation and export FiT payments to cover the capital and operational costs. The leases lasted for the full term of the FiT subsidy.

The company also offered a solar-loan scheme, which was similar but required a deposit from the customer. The customer received free energy, with FiT revenues were set against the capital costs, plus interest, until this cost was discharged. The solar panels then passed into the ownership of the householder once the loan was repaid.

Both schemes also had arrangements for early exit, if the homeowner sold the property.

10.6. Joint Ownership, Through Capital Investment

Under the joint ownership model, ownership of the generation asset is shared between the final consumer and another party, typically an investor, an installer, or the operator/ offtaker of the asset.

This model is similar to that described for full customer ownership, except that ownership is shared with another party. This can be due to a number of reasons, including:

- The consumer lacks the full capital resources to invest in the asset itself, but has access to some capital and wants an ownership share in the asset
- On multi user sites where more than one party will be benefiting from the asset
- As a means of ensuring that the operator/offtaker has an ownership stake and therefore greater stake in asset performance, which is common where a new technology or sales model is being tested
- Where the consumer wishes to bring a party with greater knowledge of the asset into the project

The disadvantages of this development model are the more complex ownership and operational structure, and the sharing of benefits with the joint owners.

10.6.1. Case Study

An example of this proposition is the SoLa Bristol project, funded through the Low Carbon Network Fund, a support scheme for innovation in the network companies. This project installed battery storage and solar generation in 26 homes, five schools, and an office. The project used a joint ownership model for the storage device, where the costs and benefits are split between the customer and the local DNO, WPD.

10.7. Private Wire Arrangements

Due to the structure of the GB electricity market, it is possible to develop generation assets outside of the customer's site and connect these in a manner to ensure they are treated as behind the meter assets. This is achieved via a private wire arrangement, where the asset is connected via a non-public network wire directly to the customer's site.

As with any behind the meter development, private wires can allow end consumers to avoid a number of electricity charges, including: network charges (such as those for transmission and distribution: TNUoS, DUoS), other volumetric charges (BSUoS, AAHEDC, Climate Change Levy), and final consumption levies (including the RO, FiT, CfD, and CM).

This model can be combined with all the models discussed above, as it is primarily a siting and connection consideration, with the funding and benefits sharing arrangements open. Given the additional costs of private wires, compared to direct on-site connections, these assets tend to be of a larger size and be focused on larger I&C customers or business parks with a number of tenants. There is also the risk that a customer may go out of business or move during the life of the assets (which may be two decades or longer).

The benefit of this arrangement is that it enables larger assets or different technologies to be deployed than would otherwise be possible due to size or other restraints such as land use. Additionally, it can circumvent other barriers to deployment such as site requirements, noise and emissions limits, or health and safety concerns, by locating the asset at a distance from the main site.

The disadvantage is the additional cost associated with the private wire to connect to the site and the additional complexity, particularly with regards to regulatory requirements, for the asset.

10.7.1. Case Study

Given the need to be located close to the source of demand, private wire arrangements are site specific. Community energy group Wadebridge Renewable Energy Network (WREN) developed a 100kW solar array adjacent to a South West Water sewerage treatment works in 2014. The asset is connected to the neighbouring consumer by private wire, providing clean energy to offset the demand of the works. South West Water is a large company with a strong credit rating, which expects to be using roughly level amounts of power at the site over the long term, making it the ideal partner for WREN.

11. Policy

In this section, we introduce and discuss central government policy as it relates to decentralised energy. We address this in two areas: energy policy and rural and land management policy.

11.1. Energy Policy

Energy policy largely does not concern itself with rural-urban divide, but does distinguish between renewable and fossil fuel, and between large and small-scale.

The GB electricity markets have seen increasing levels of intervention from policymakers over the decades since liberalisation. The “trilemma” is used to present the inherent dichotomy in energy policy:

- Sustainability – decarbonisation – low-carbon generation is expensive and relies principally on intermittent generation, threatening system security
- System security – ensuring that the lights stay on – maintaining sufficient reserves of dispatchable generation plant is expensive, and dispatchable plant tends to be carbon-emitting
- Affordability – ensuring that customers can economically pay their bills – This would dictate purchasing only the cheapest power, but this tends to be carbon emitting and inflexible

Energy efficiency policies have been a theme throughout, as they are able – to a certain extent – to tackle all three elements of the trilemma simultaneously.

Figure 42: The energy trilemma

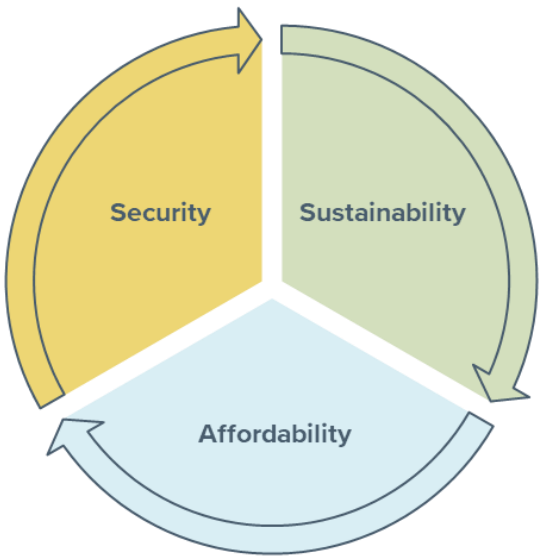


Figure 43: Policy interventions in GB energy markets

dti → Department of Energy & Climate Change → Department for Business, Energy & Industrial Strategy

Year	Policy	Objectives	
1994	EESoP, NFFO	Household energy efficiency & contracts for renewables	Sustainability focus
2001	Climate Change Levy/ CCAs	Tax carbon element of business energy, discounts for energy intensive industry	
2002	Renewables Obligation	Subsidise large scale renewables	
2002	Energy Efficiency Commitment	Household energy efficiency	
2005	EU ETS, EEC2	European carbon trading, household energy efficiency	
2008	CERT/ CESP, smart meters	Household energy efficiency	
2010	Carbon Reduction Commitment	Business energy efficiency	
2010	Small scale feed-in tariffs	Sub 5MW renewables subsidy	
2011	Warm Homes Discount	Social tariffs, rebates for vulnerable households	
2013	Green Deal, ECO	Energy efficiency (ECO household only)	Security focus
2013	EMR	Carbon tax, CfD FiTs, Capacity Market	
2015	RO, FiTs, Green Deal, CCL	Reduction of subsidy and tax relief for renewables	Affordability focus
2016	CMA, embedded benefits, coal closure	CMA whole market review and recommendations, review of network charging principles, coal closure consultation	
2018	Price cap	PPM price cap and introduction of broad SVT price cap	

Recently, government has declared the end of the trilemma, with Greg Clark, Business Secretary at BEIS, suggesting that "cheap power is now green power". The government now sees four key principles which will inform policy going forwards:

- Market – using market mechanisms to take advantage of competition and innovation
- Insurance – to protect against intrinsic uncertainty and preserve optionality
- Agility – keeping regulation flexible and responsive to read opportunities
- No free riding – all consumers should pay a fair share of system costs

Policy interventions initially focused on decarbonising the electricity supply, with relatively generous renewables subsidies delivering significant investment in new assets. These have either provided additional revenues on top of wholesale market revenues or established a guaranteed price for export of power to the grid.

More recently, the provision of reliable, dispatchable generation to secure the system at peak consumption has become an issue. This has resulted in the capacity market, a subsidy mechanism which pays generators which guarantee to be available to provide power at times of peak consumption on a £/kW basis. This has spurred new investment in large amounts of small, distribution-connected diesel or gas reciprocating plant. It is also credited with allowing existing plant to remain on the system for longer, supporting system security.

Finally, in recent years, rising energy bills have prompted politicians to introduce measures to prevent further price rises, by ending renewables subsidies earlier than planned, exempting energy intensive industries from renewables subsidy costs, and introducing caps on domestic tariffs.

11.2. Heat Policy

UK heat policy is nascent at best, but has begun to emerge in the last year or two. Rural heating is acknowledged as a priority area.

While strategy has been advanced for other key sectors of the economy, such as transport under the Road to Zero, heat represents a unique challenge as it requires both economy-wide decarbonisation as well as other factors, such as thermally insulated buildings and low-carbon fuel sources. To this extent heat strategy is behind other major emitting sectors.

There is now a growing focus on how to reduce heat emissions. The Committee on Climate Change (CCC) published recommendations for net-zero emissions on 2 May 2019. Under the "Clean Growth" Grand Challenge, long-term clean heat options are set out as an area of economic potential. Three illustrative pathways identified how the UK could achieve its 2050 target. All placed specific impetus on the role heat networks will play in the future energy system. For example, they are considered to be a low-regrets option and can help to meet carbon targets by providing 17% of heat demand in homes and 24% in public sector buildings and non-industrial businesses by 2050.

The government has so far established a twofold approach towards heat decarbonisation:

- Reduce heat demand by building a market for energy efficiency, the use of energy in business and buildings, and the reduction of industrial energy demand.
- Deliver significant growth in no or low-regrets low-carbon heating in the short term.

As part of this strategy, recent reports concerning the future of heat have been published. The Government's *Response to a Future Framework for Heat in Buildings Call for Evidence* provided initial steps for phasing out high-carbon, fossil fuel heating systems in off gas grid premises. For heat networks, *Heat Networks: Ensuring Sustained Investment and Protecting Customers* laid out priorities for regulation in the heat networks sector – one which is currently only lightly regulated – as well as initiatives to encourage investment and ensure consumer protection. It also stated that heat networks will play a critical role in decarbonising UK heat supply whilst reducing bills to tackle fuel poverty. The latter report is key to the development of heat networks in the UK as it highlights the government's thoughts on the development of a heat networks market.

Government plans to create a marketplace for heat currently centre on both the Heat Networks Delivery Unit (HNDU) and the Heat Networks Investment Programme (HNIP), which together form the main schemes working to deliver significant growth in no- or low-regrets low-carbon heating in the short term:

- HNDU – launched in 2013 to support Local Authorities (LAs) in England and Wales in developing heat network projects through the provision of £17mn in grant funding to over 200 projects in 140 LAs to stimulate an early heat market.
- HNIP – launched in 2018 to provide gap funding totalling to £320mn in heat network projects to foster increased private sector investment. It also aims to inform on a future market framework.

Other policies, such as the Energy Company Obligation (ECO) and the Renewable Heat Incentive (RHI), also offer subsidisation for heat networks. It is estimated that £16bn of capital investment is required to deliver the future heat demand supplied through heat networks, with HNIP being the main delivery vehicle for leveraging this investment and stimulating market development at present.

11.3. Rural Policy

Historically rural policy in the UK has been through the Common Agricultural Policy (CAP) as members of the European Union (EU). This is the EU's flagship policy, being its only true 'common' policy across all the Member States[i]. Founded in 1957, its original intentions remain largely intact: to increase agricultural productivity, ensure a fair standard of living for farmers, stabilise markets, ensure the availability of supplies and make products available to consumers at reasonable prices. Environmental issues have gained increasing prominence as policy drivers since the 1990s evolving to take into account new environmental and climate objectives.

There are two key areas of support – direct payments and rural development programme payments with around 90% of the funds for direct payments. Substantial reforms came in 2014 in the Basic Payment Scheme (BPS) with a view to making public money to landowners more adaptable and accountable with an enhanced level of environmental performance on which 30% of the area based payment was conditional.

Therefore, much of the historical funding has been very much focussed on agriculture and the environment. However, there may have been opportunities for energy schemes within the productivity programmes under funding for non-agricultural uses although this is very difficult to quantify.

11.3.1. Future Land Management Policy

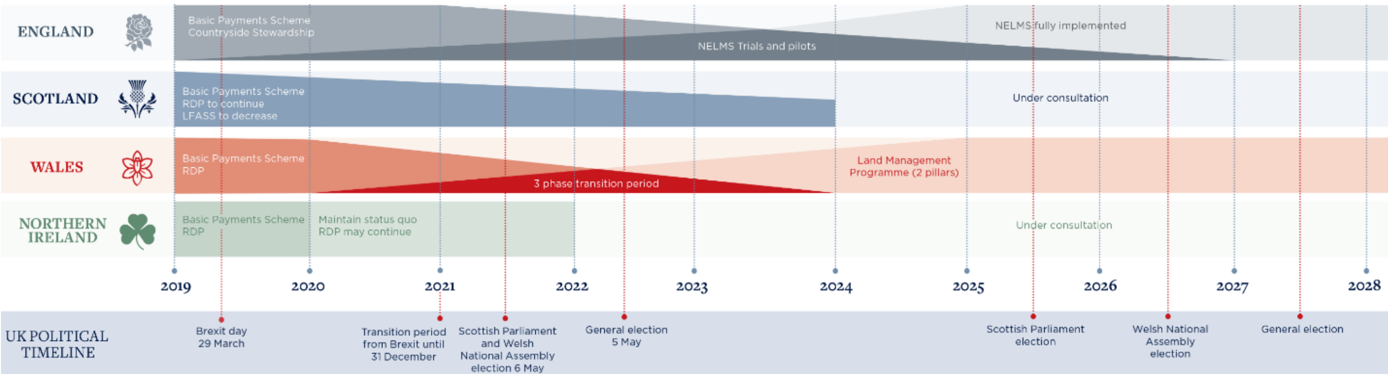
Following the referendum decision in 2016, Government published its long awaited 25 Year Environment Plan (EP) setting out three general principles for UK land management, namely: public money for public goods, more effective application of the 'polluter pays' principle, and the concept of 'net environmental gain' on all land use. Environment is a devolved matter to the UK home nations, so the EP primarily applies to England apart from reserved matters. Figure 44 gives an overview of the anticipated policy timeline.

In November 2018, Department for Environment, Food and Rural Affairs (DEFRA) published a draft Agriculture Bill for England, focussing on the 'public money for public goods' element. The Bill contains an indication of what 'public goods' are likely to be, reserving powers to provide financial assistance for a range of environmental, climate and productivity related issues, as well as wide-ranging powers to influence the operation of agricultural supply chains. The Bill also announced a transition away from the direct payments scheme from 2021 onwards (see Figure 4444), with the introduction of a new Environmental Land Management scheme (ELMS) of payments for environmental outcomes from 2025 onwards.

The Agricultural Bill for England will not be enacted in Scotland, following its publication in October the Scottish Affairs Committee launched an inquiry to investigate how any post-Brexit agricultural system, in conjunction with Land Reform, can meet the needs of Scotland's farmers and crofters. Agriculture is a devolved matter and, although the core issues will be similar there will some differences in policy and funding focus.

It should be noted that new agricultural policy is unlikely to be law and therefore implemented until after Brexit. Therefore there is significant uncertainty for farmers and land managers at present.

Figure 44: Policy timeline



The Transition Phase away from the Basic Payment Scheme (Savills Research)

11.3.2. The Purpose of English Agricultural Policy

In comparison to the CAP, the Agriculture Bill does not set out the policy intention for UK agriculture, in other words it does not make it explicit what purpose the powers contained in the Bill will seek to achieve. To understand the future shape of agricultural policy in England, it is necessary to look at other English policy and legislative frameworks.

Agricultural policy can be understood as a product of three other policy areas: trade, environment, and food security (in its true sense of quality and quantity of food availability). Relatively low barriers to trade, high environmental protection and a libertarian approach to food security creates an agricultural policy that has to prevent land abandonment or conversion to higher uses (planning) whilst incentivising environmental outcomes.
We know that leaving the EU has been pitched as an opportunity to re-engage in free trade deals around the world, and the 25 Year Environment Plan potentially creates a higher level of environmental accountability than has previously been the case.

Ideally, integration of agricultural policy with health policy is a key domestic policy synergy. For an early indication on how this might work see the National Health Service (NHS) Long Term Plan's inclusion of mental health and 'social prescribing' in enhancing access to green space and animal contact[ii]. In any event, our best interpretation of the likely combination of policies (high environment, low trade barriers, liberal food policy) suggests that a high level of public investment is needed to sustain land use in the UK and prevent it being abandoned. We do not see any indication that Government wishes land to be taken out of active management, but there are lots of indications that policy will drive different management systems.

11.3.3. The 25 Year Environment Plan

Responding to the environmental challenges facing the UK, the then Secretary of State for the Environment Caroline Spelman founded a Natural Capital Committee in 2011 to advise government on how natural capital principles (see Figure 4545) could improve environmental outcomes and help it with the creation of a 25 Year Environment Plan (EP). The Plan was finally published in 2017, with a substantial delay to take account of the new significance of the plan in post-CAP land management policy. The EP sets out three general principles for UK land management, based on natural capital principles, namely: public money for public goods, more effective application of the 'polluter pays' principle, and the concept of 'net environmental gain' on all land use. Government is also currently consulting on the metrics that will be used to evaluate the environmental performance of policy against the Plan.

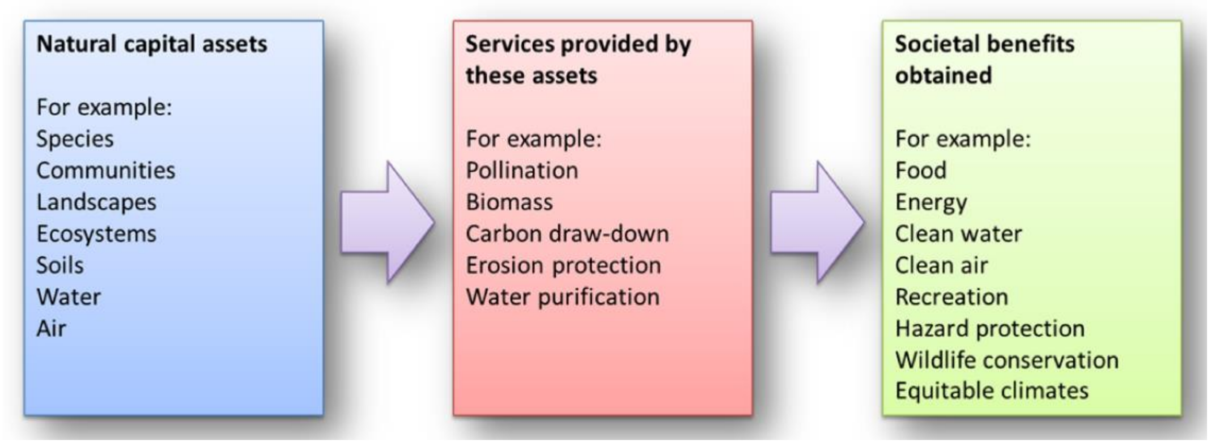
A shift in policy focus may open opportunities for environmental and energy projects.

The key opportunity in natural capital approaches is that it allows the blending of public and private sources of investment in purchasing so-called ecosystem services. Indeed, Government specified in the Health and Harmony consultation that it would be a purchaser of ecosystem services from land managers, but wanted to leave space for other buyers to interact with sellers.

Government is also consulting on 'conservation covenants', land management agreements that allow landowners to secure enduring conservation benefits on their land and binding successors and future owners of the land to abide by the same conservation standards. It is currently difficult in legal terms to bind successors in title to positive actions (as opposed to restrictive covenants, as are common in planning terms). The results of the consultation should be published later this year.

Figure 45: Natural capital

Natural capital: "…stocks of the elements of nature that have value to society, such as forests, fisheries, rivers, biodiversity, land and minerals. Natural capital includes both the living and non-living aspects of ecosystems"[1].



- Examples of natural capital assets, services and benefits (Natural Capital Workbook, Natural Capital Committee, 2017[1]).

11.3.4. The Environment Bill

It is widely expected that an Environment Bill will be published in early 2020; In December 2018, Government published a draft Environment (Principles and Assurance) Bill[iii], announcing the creation of an Office of Environmental Protection to hold the Government to account on its environmental performance, and a series of environmental principles on which the policy will be based.

a) **Polluter Pays: -** The Polluter Pays principle underpins EU law-making on environmental protection and is set out in the Treaty on the Functioning of the EU[iv]. As it is a Treaty obligation, it would not be automatically implemented via the Withdrawal Act, so requires new legislation at UK level. The principle requires that a person responsible for environmental damage pays for it to be rectified, which at EU level creates a system of penalties and enforcement regulations. At UK level, it could mean that a wide range of fiscal measures could be imposed on consumers, businesses and land users alike for the impact of their behavioural choices. The Farm Inspection and Regulation Review acknowledges the inherent difficulty of an environmental baseline based upon 'polluter pays', saying that "We do not advocate a purist application of [polluter pays]. In our view, it would not be fair or even achievable, in most circumstances"[v]. Details of how the principle may be applied to UK land use are awaited.

b) **Net Environmental Gain:** In the Chancellor's Spring Statement (14 March 2019) it was confirmed that the government will be committing to its plans to deliver net environmental gain on all new housing and infrastructure developments in the Environment Bill[vi]. This could have a notable impact on the financial dynamics of planning decisions and highlights how new sources of finance may be used to meet the government's policy objectives for land use.

It is also worth noting that Section 1(1) of the Climate Change Act 2008 commits government to achieve deep reductions in carbon emissions by 2050. Michael Gove has widely advocated productivity investments as a way of releasing land from agricultural usage to achieve environmental outcomes including climate change targets[vii].

11.3.5. The Agriculture Bill

The new Agriculture Bill takes a markedly different approach to agricultural policy than the CAP. There is no reference to income support for farmers, or the availability of produce or market prices. Instead, the Bill focusses on public money for public goods, whilst acknowledging that market and supply chain relations remain key tools to manage and allocate risk fairly amongst market actors. Three core mechanisms can be summarised from the Bill:

1. Financial Assistance for natural resource management
2. Exceptional Assistance in the event of market disturbance
3. Supply Chain Assistance to provide competition law exemption and contractual relations controls.

Compared to the CAP, this is a markedly different approach to agricultural policy, focusing on natural resource purposes and supply chain relations, with only an emergency element of market control. It has non-interventionist free market thinking at its heart and the ability of farmers to make a living from producing food is not protected. Whilst the level of future funding that may be provided is unclear, the Bill sets out the ability for the Government to utilise its World Trade Organisation (WTO) allocation of subsidy (Part 7), and we know that supporting policy measures in the farm business environment (for example a supportive taxation system) can continue to offer protection to primary producers.

Financial Assistance for Natural Resource Management
Part 1 of the Bill sets out seven stated purposes for which financial assistance may be given (part 1, Para 1(1)):

1. Managing land or water in a way that protects or improves the environment;
2. Supporting public access to and enjoyment of the countryside, farmland or woodland and better understanding of the environment;

3. Managing land or water in a way that maintains, restores or enhances cultural heritage or natural heritage;
4. Mitigating or adapting to climate change;
5. Preventing, reducing or protecting from environmental hazards;
6. Protecting or improving the health or welfare of livestock;
7. Protecting or improving the health of plants.

In addition, financial assistance may be given for the purpose of starting, or improving the productivity of, an agricultural, horticultural or forestry activity.

The first major point to note is that the potential beneficiaries of financial assistance are not defined in the Bill, only the ability to set eligibility and compliance criteria. Farmers will be used to the rigid eligibility and compliance regime of the CAP. The fact that categories of beneficiary have not been identified, means that new categories of beneficiary other than 'active farmers' will be eligible for schemes, such as forestry and smallholders.

There is also no environmental conditionality in justifying public investment in public goods in Part 1. This is not to say that a new UK environmental standard will not be enforced – details are likely to be in the Environment Bill and its subsidiary legislation. This simply breaks the relationship between complying with legislation and eligibility for financial assistance. The two will be distinct in the UK context and farmers will need to adjust to a very different compliance system.

The proposed payment structure also moves away from solely grant-based payments. Part 1 notes that financial assistance may be given in any form and may be subject to any conditions, include provisions relating to repayment with or without interest. Whilst ignoring the obvious questions about what the total budget may be, the Bill leaves open the possibility for novel financial instruments to be used in a land management context, from loan guarantees to grants to capped interest rates. This would allow any budget to go further and be more responsive to business needs, and potentially avoids the outcomes seen with area based payments that public investment is at risk of being capitalised into rents and land values.

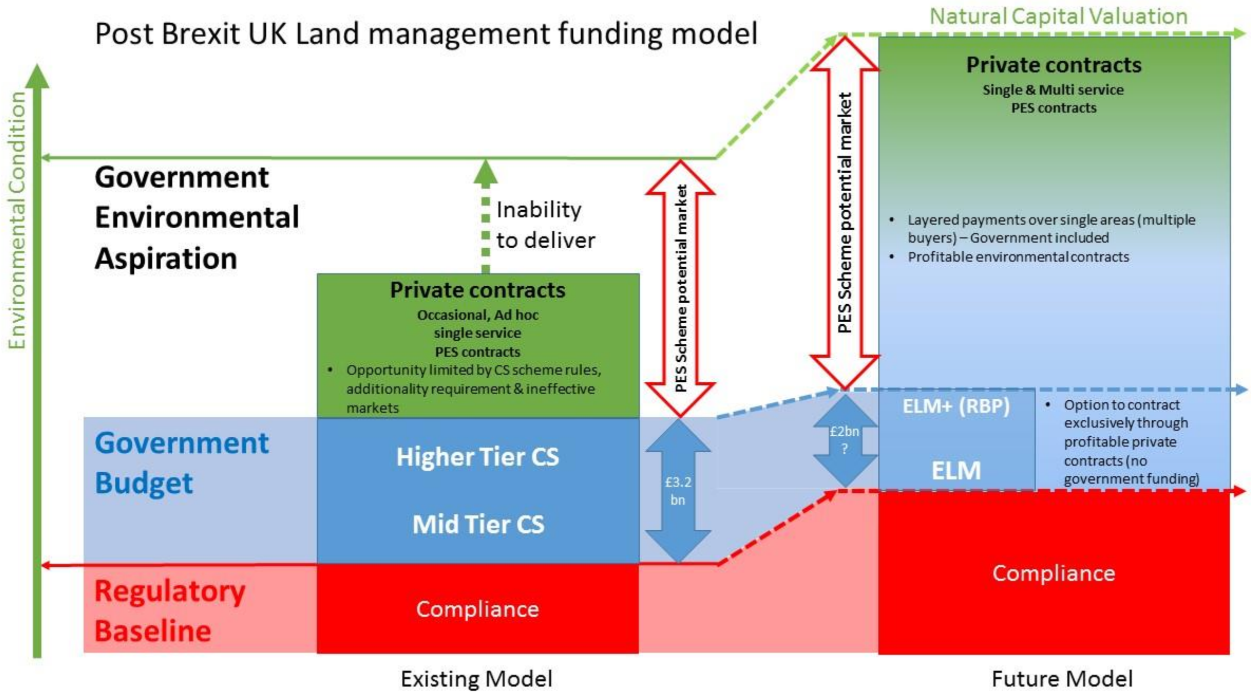
11.3.6. The New Environmental Land Management Scheme (ELMS)

Proposals for a new land management scheme were first drawn up in 2014[viii], before the Referendum, in response to a drive under the CAP to allocate a greater proportion of funds to environmental enhancement. The intention was to create locally targeted plans to improve the environment based on local priorities. Following the decision to leave the EU, DEFRA consulted on how the ELMS could be used to deliver environmental outcomes in an independent agricultural policy environment[ix]. The Health and Harmony consultation document proposed that ELMS would replace the cross-compliance, greening and Countryside Stewardship elements of the CAP, effectively rolling the direct payment and rural development (including agri-environment) subsidies into a single funding stream for land managers, and with a new environmental baseline created by the 'polluter pays' principle. It describes ELMS as follows:

New Environmental Land Management schemes: offering multi-annual agreements to support the delivery of valuable environmental improvements countrywide. These would be straightforward to understand; have a streamlined application process to lower the barriers many farmers faced to participation in past schemes; and minimise bureaucracy to encourage wide participation. Support could include schemes open to nearly all land managers who wish to enhance the natural environment; and enhanced support and continued funding for technical *advice for projects which meet national priorities and require complex, place-specific management (such as wetland and woodland creation, or peatland restoration.)*

This ambitious description - being simple to apply, based on natural capital valuations and widely taken up – has led many to question DEFRA's capability to deliver ELMS and for Natural England to enforce it. This is particularly in light of delivery concerns over the current agri-environment schemes[x]. A key point to note is the new eligibility requirements compared to CAP – the new scheme is not about 'active farming', but likely to be open to all land managers who are able to deliver public goods. The scheme expressly leaves open the possibility for private investment in ecosystem services too, which will be particularly important if the government is to achieve its ambitions in the 25 Year Environment Plan without a substantial increase in budget. Figure 46 shows a conceptual framework based on some key assumptions of what this might look like:

Figure 46: Conceptual model showing how UK land management funding might change post Brexit



Future model – key assumptions

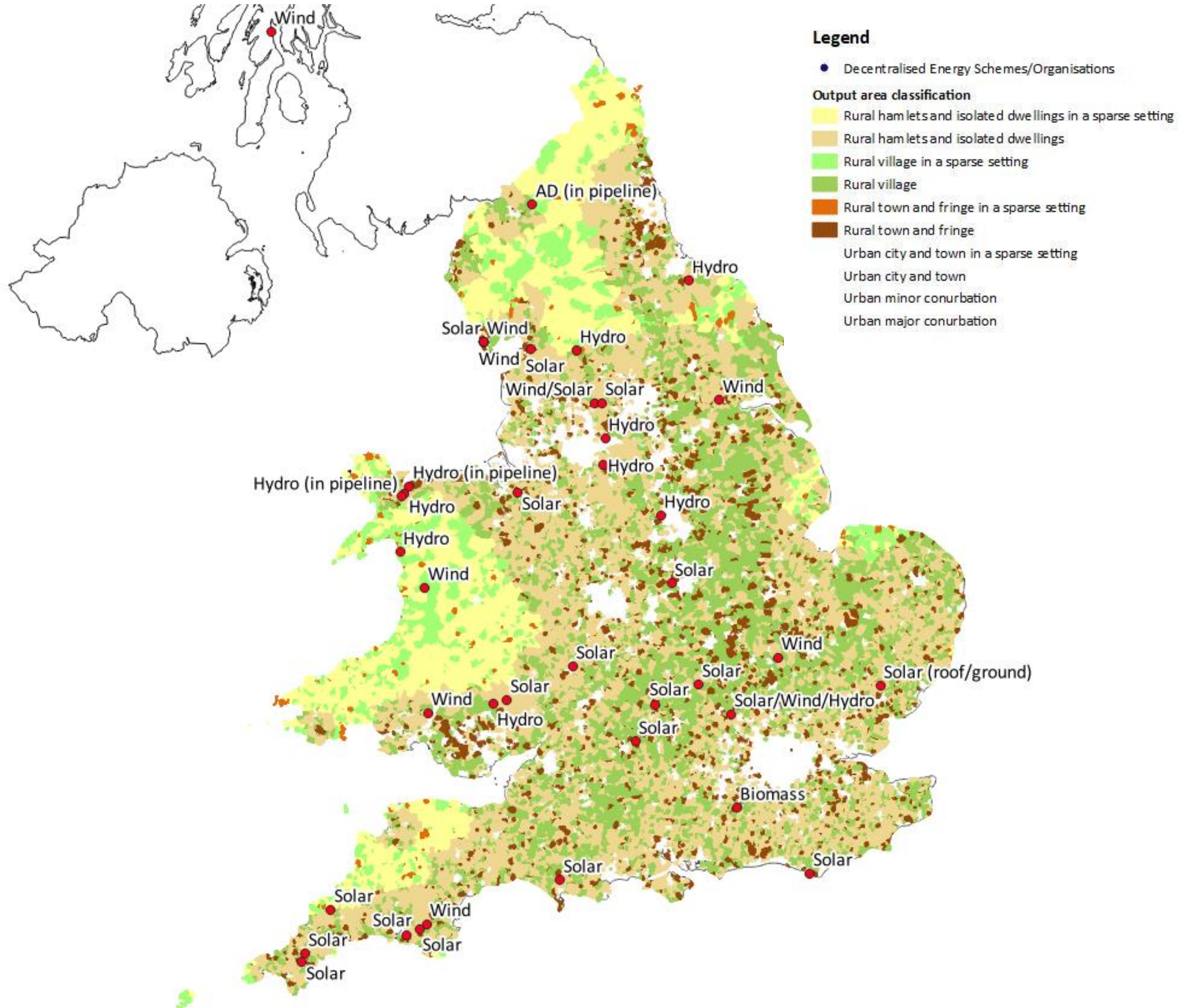
1. *Increased environmental aspiration following national Natural Capital Valuation.*
2. *Increased regulatory baseline*
3. *Reduced Government budget for agricultural support, refocussed to purchase environmental actions (and outcomes) justified by ecological surveys and regular audit (Costs borne by farmers).*
4. *Gradual migration to Results Based Payments (RBP) for public funding.*
5. *Increased market flexibility, and potential, for private environmental contracts.*

12. Land Use

Land use in the UK is diverse and includes everything from food production to forestry and leisure. In this section, we discuss current and future land use to identify potential opportunities and barriers to decentralised energy schemes.

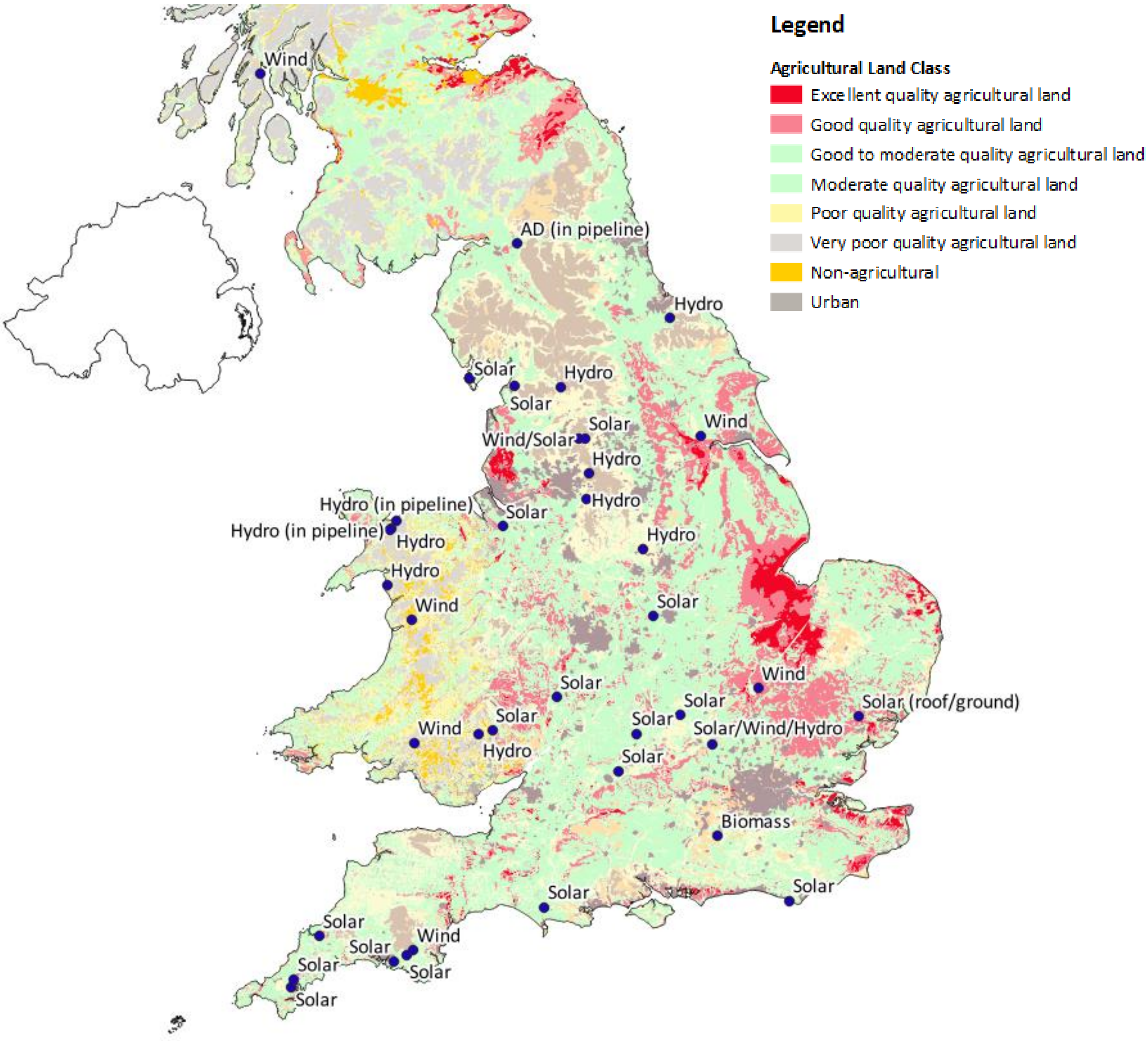
Of those schemes identified through the Community Energy England data, we have determined that 62% of projects are located in areas classed as Rural Town and Fringe and Rural Village, with nearly 90% of roof top solar schemes located in rural towns and villages. A plan showing the distribution of projects is shown below.

Figure 47: Distribution of Community Energy Projects



Of the Community Energy England projects identified as being in rural areas, we note that two thirds of projects are located in good to moderate and moderate quality agricultural land.

Figure 48: Distribution of Community Energy Projects



12.1. Agriculture

The total agricultural area in Great Britain (GB) is around 43 million acres including woodland. Of this, around 40 million acres are utilisable for agricultural (UAA). The UAA accounts for 70% of the total area of land in GB.

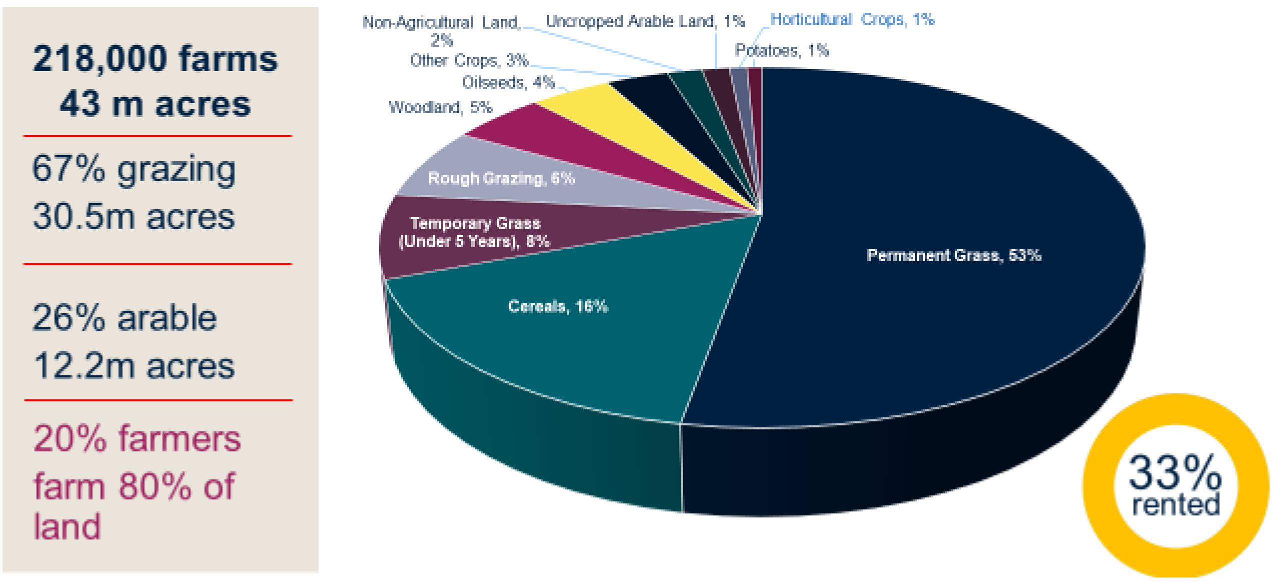
The UAA has declined by around 65,000 acres per year over the past 20 years. Reasons include transport infrastructure, building, woodland expansion (which has more than doubled over the past 20 years), non-agricultural use (golf courses, minerals, etc.) and some has been lost to the sea.

Figure 4949 shows how GB agricultural land is used. There are around 192,000 farms in the UK.

Soil type, topography, and climate determine the type of enterprise that is suitable for a particular farm. In general, the climate and topography of GB are most suited to two distinct types of farming:

- Grassland farming (dairy, sheep and beef) is found in areas of higher rainfall and among the hills, predominantly to the north and west of GB.
- Arable (cropping) farming (land that can be ploughed to grow crops) is concentrated in the south and east of GB where the climate is drier and soils are deeper.

Figure 49: GB land use



12.2. Forestry/Woodland

Currently UK forests and woodlands cover 13% (3.2 million hectares) of the UK total area and, as UK forestry is a net carbon sink, they contain around 150 million tonnes of carbon in the trees (biomass) and a further 640 million tonnes in the soil.

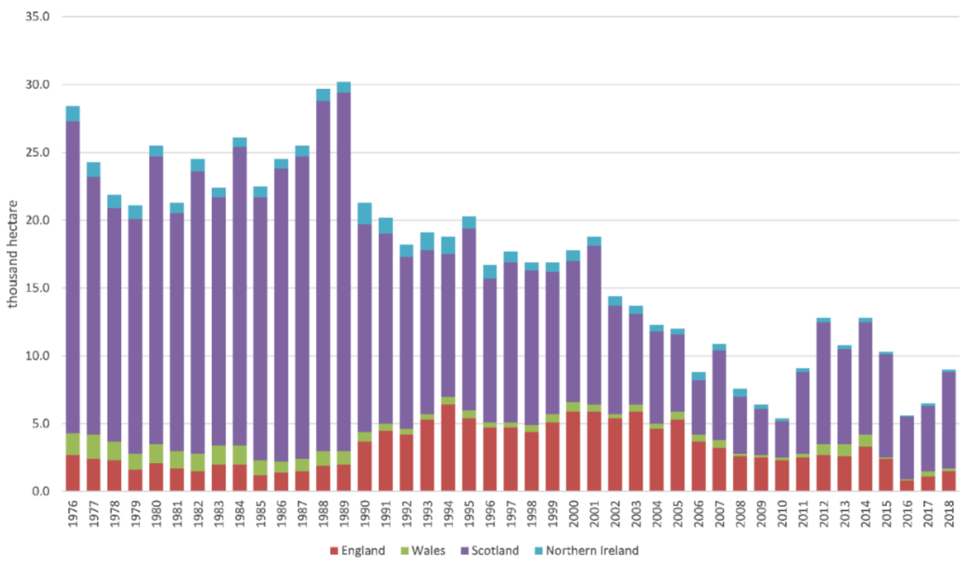
The forests / woodland in the UK are evenly distributed between conifers and broadleaves. On a country basis, Scotland is the most forested country (18.5% of its land area), followed by Wales (15%), England (10%) and Northern Ireland (8%).

The area of woodland increased during the latter half of the 20th century (from 6% in 1947) as a result of a steady programme of afforestation throughout the UK. Planting rates reached a high of 30,000 hectares annually in the late 1980s, but have declined dramatically in recent years, averaging 9,000 hectares annually since 2010. In the past three decades, and especially in the past decade new tree planting has fallen, see Figure 50. According to the

Committee on Climate Change (CCC) at current levels (3.2 million hectares) the carbon sink from forests and woodlands will be half of what it is now by 2050 due to ageing forest and lack of planting, as trees are unable to sequester more carbon on reaching an equilibrium.

As well as reducing the future net carbon sink the reduced rates of tree planting will also restrict the opportunities to harvest timber. According to the CCC, in order to meet UK binding greenhouse gas capture targets, up to 1.5 million hectares of new woodland would be needed to store carbon by 2050. This would increase tree cover to 18% of the UK and would require around 40,000 hectares of tree planting per year to 2050. That is significantly more than twice the average number planted per year since 1976 and almost four times more than the average planting over the past 20 years.

Figure 50: New planting in the UK: 1976 – 2018



Source: Forestry Commission, Natural Resources Wales, Forest Service, grant schemes

12.3. Rural Estates

Rural estates, excluding those in public ownership such as utilities, are essentially a diverse portfolio of property, agricultural, forestry, residential, commercial and often energy, within a property. There have been significant changes in both the structure and occupancy of rural estates since Savills launched its Estate Benchmarking Survey in 1996. Back then, the average area of an estate was 6,600 acres. Today, it's down one-third to 4,700 acres. These changes are the result of changes in policy and proactive asset management. The diversity of property assets and therefore energy consumption offers strong incentives to consider decentralised energy schemes to tenants and occupiers.

Figure 51: Core estate structure by region (five year average)

	East of England	East Midlands	North of England	SE England	SW England	West Midlands	Scotland
Land (acres)	3,200	5,200	5,300	3,000	4,800	5,000	4,200
Number of houses	41	28	79	53	52	45	50
Commercial workspace (sq. ft.)	8,900	2,500	18,200	15,300	9,800	7,000	19,000

12.4. Land Use Changes

Could a third of UK land area change use by 2050? The diagram below illustrates the potential area of land needed for agricultural production (grey dots) in 2050 and the areas that might be 'released' from current land uses and available for alternative uses including boosting food production.

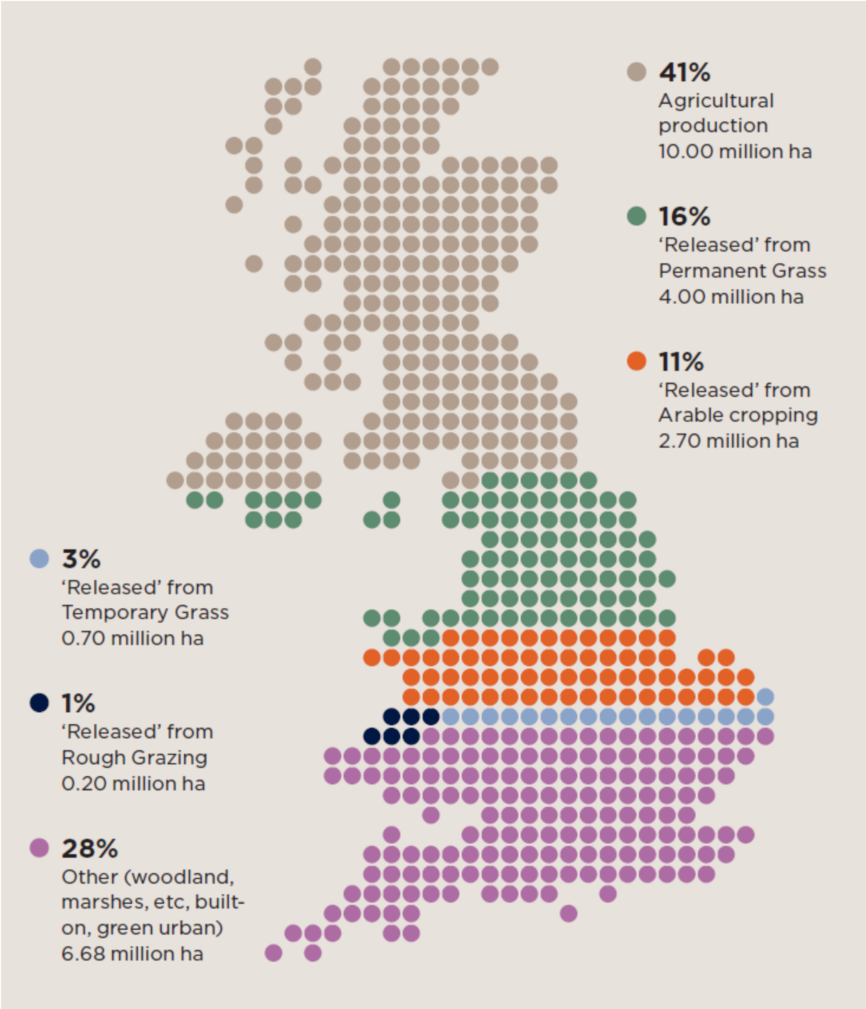
Significant land use change over the next 30 years will free up land for alternative uses including energy.

The next 30 years are likely to see some significant changes in land use across the UK that will no doubt impact on the tenure of farmland and its capital and rental values. The key policy driver of land use change over the next 30 years is likely to be the mitigation of Green House Gas (GHG) emissions.

Agriculture production area – according to the CCC this could shrink by 30% by 2050. This scenario would make the maximum use of innovation and technology, need high levels of change in behaviour towards healthy eating guidelines, the willingness to try novel food sources and significantly reduce waste.

The area 'released' could be used for more trees, environmental adaption, and renewable energy or indeed to increase agricultural production. Opportunities will emerge through technological improvements for land to be put to multiple uses e.g. tree planting and wind turbines or rooftop solar PV.

Figure 52: Possible land use in 2050



- **Trees:** including commercial forestry, hedgerows and agroforestry. To meet GHG capture targets up to 1.5 million hectares of new woodland would be needed to store carbon by 2050. In addition, to help mitigate GHG emissions and increase biodiversity while maintaining food production there is likely to be an increased area of agroforestry and hedgerows.

- **Environmental adaption including reclaiming peatland:** In 2017, 6.8 million hectares or 27% of the UK land area were under environmental designations. These include National Parks and Areas of Outstanding Natural Beauty. These are under review and are likely to expand. Peatlands account for around 12% of the UK land area, but only around a quarter is in a near-natural or re-wetted state. Restoration and rewetting of degraded peatland currently under agricultural and forest land use will make a significant contribution towards the 2050 emission targets.

- **Energy:** Significant planting of second generation biomass energy crops such as short rotation coppice and forestry – up to 1.2 million hectares for bioenergy crops by 2050. The area occupied by renewable energy infrastructure – especially ground mounted solar and feedstock for Anaerobic Digestion (AD) plants – is likely to increase.

Renewable energy projects can have ecosystem co-benefits.

The Universities of Lancaster and York have produced a report on the impact of solar farms on ecosystem services, which can be found at www.lancaster.ac.uk/spies. An extract provided by Lancaster University is provided below;

Solar parks offer an opportunity to deliver ecosystem co-benefits but there is also a risk that their development and operation may be detrimental. Consequently, we created the Solar Park Impacts on Ecosystem Services (SPIES) decision-support tool (DST) to provide evidence-based insight on the impacts of different solar park management practices on ecosystem services. Application to two operational solar parks evidences the commercial relevance of the SPIES DST and its potential to enable those responsible for designing and managing solar parks to maximise the ecosystem co-benefits and minimise detrimental effects. With the increasing land take for renewable energy infrastructure, such DSTs that promote the co-delivery of other ecosystem benefits can help to ensure that the energy transition does not swap climate change for local scale ecosystem degradation, and potentially prompts improvements in ecosystem health.
The SPIES DST summarises the effects of solar park management practices on ecosystem services, applied both individually and in combination, and displays links between these impacts and the underlying scientific evidence in a form accessible to the public.

Balancing Agricultural Productivity with Ground-Based Solar Photovoltaic (PV) Development (August 2017) was produced by NC Clean Energy Technology Centre and looked at solar development in North Carolina (https://nccleantech.ncsu.edu/wp-content/uploads/2018/10/Balancing-Ag-and-Solar-final-version-update.pdf). The report noted that these often compete with one converting sunlight and fertiliser into food and fibre, while the other converts sunlight into electricity. Rather than make specific conclusions the report discussed some of the issues which included:

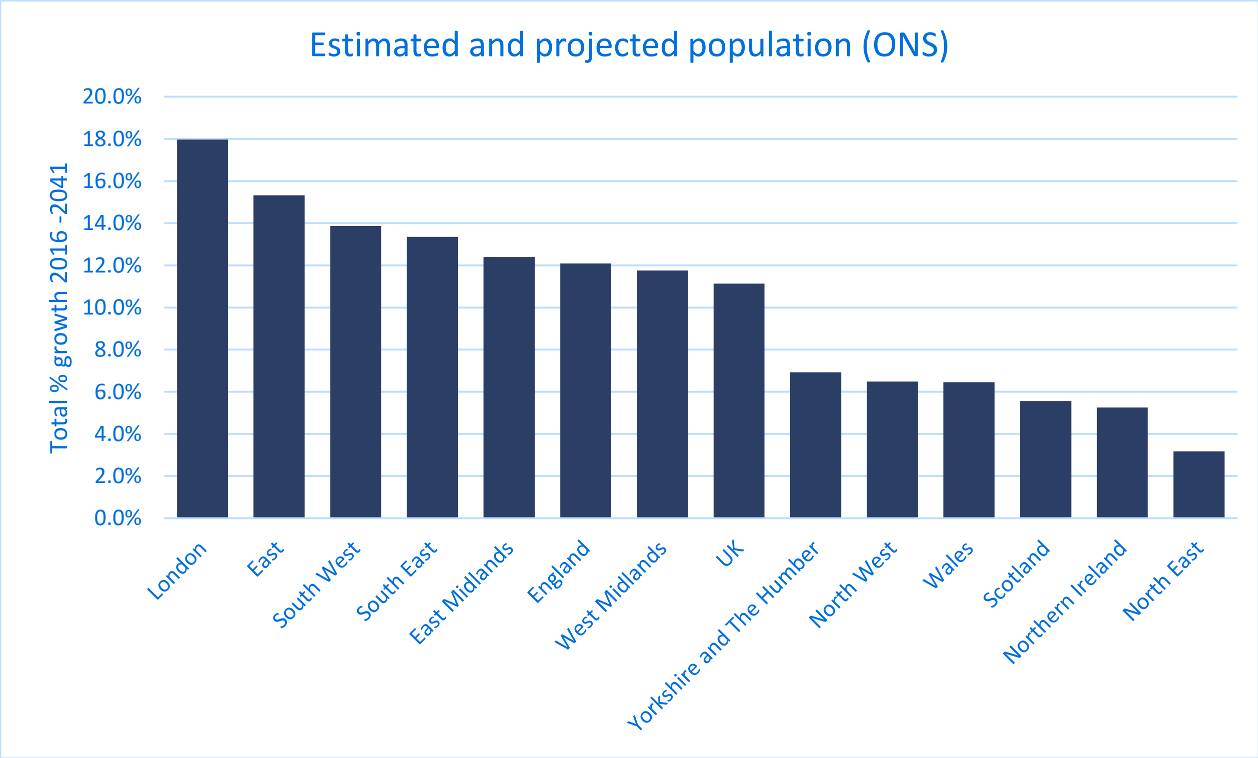
- There is no significant cause for concern about leaking and leaching of toxic materials from solar site infrastructure
- Once permanent vegetation is established it will be necessary to maintain soil pH and fertility as mentioned above in order to ensure sufficient, healthy, and continuous ground cover for erosion control
- Soil compaction can negatively impact soil productivity and will occur to some degree on every solar site
- Solar facilities maintain vegetative ground covers that can help build soil quality over time. When the vegetation is cut, the organic matter is left in place to decompose which adds valuable organic matter to the soil.
- Appropriate vegetation can provide habitat for pollinators
- Maintenance of vegetation on site can be accomplished using several options, including but not limited to the following: mowing, weed eaters, herbicides, and sheep.

- **Housing and Infrastructure:** by 2050, 0.3 million hectares might be required for housing and infrastructure. This equates to 2.7% of UK land use and increases the current ‘built–on’ area by 21%.

The most significant growth in land required for housing and infrastructure will be closely linked to areas with high projected population growth, principally the Midlands, South and East. In these locations we will expect the number of decentralised energy schemes to increase as new developments seek to incorporate energy generation, both electricity and heat, into their designs. Conversely however, those areas of low projected growth namely the North and the devolved regions will continue to be reliant on the distributed energy market currently in operation in the UK.

> We expect decentralised energy schemes to grow in the Midlands, South and East.

Figure 53: Estimated and Projected Population graph



13. Land Tenure

Land tenure, the status and motives of the occupier, and the value, both capital and rental, of rural assets will be a consideration in rural land based business energy planning. In this section we look at these markets drawing out the issues that might have affected the business case for or against decentralised energy schemes and whether these will continue in the future.

13.1. Owner Occupier – Capital Asset

13.1.1. Farmland Market

Over the past 100 years, the value of GB farmland has, on average, increased by 6% per annum. Yet, when adjusted for inflation, real-term growth equates to just over 1% (compound annual growth). While the lion's share of nominal growth has occurred over the past 15 years, real-term values indicate higher volatility.

Despite the sector-specific and macro-economic factors which influenced values, we also note that the fundamental shape of land ownership has shifted. At the turn of the 20th century, the bulk of farmland was held by a comparatively small number of owners, with more than 90% of land let. Over the period of our research, this has fallen to around 35%. Today, annual supply equates to around 0.5% of total GB farmland.

Following the Second World War, growth was largely driven by a combination of market intervention by the British Government and inflationary pressures. The uptick in protectionism and initiatives to encourage domestic output bolstered the earning potential from agriculture while also reducing downside price risk. This, in turn, prompted increased interest from both domestic and foreign investors, who entered the market in search of stable and relatively low-risk cash flow.

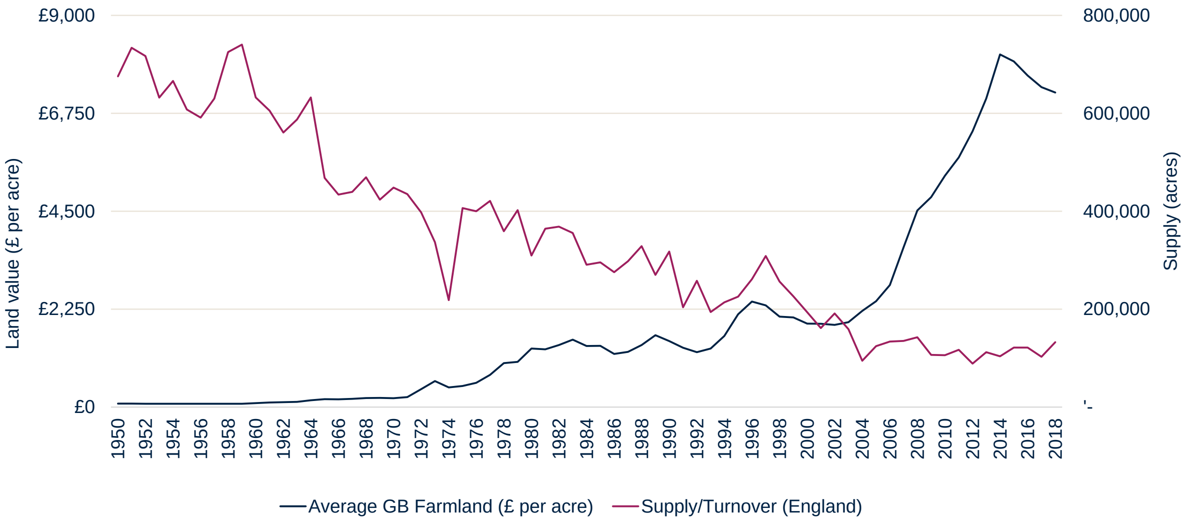
The UK's entry into the European single market in the early 1970s, and, subsequently, the Common Agricultural Policy, further spurred demand-led growth, amplified by strength in commodity prices.

While the correlation between farm profitability and land values has become somewhat diluted with the emergence of non-farming lifestyle buyers, any reduction in farm subsidies and/or weakened trade position would likely exert downward pressure on the value of commercial holdings. Yet, we see no reason why farmland will not retain its status for long-term wealth preservation.

2018

Farmland value growth continued to be muted during 2018, with significant price differences for both land types and regions. Our Farmland Value Survey shows that during 2018 the average value of all types of farmland in Great Britain fell by -1.8% to £6,700 per acre. The average value of prime arable land fell by -2.0% to £8,760 per acre. Average values for all land types in Scotland remained unchanged, whereas average values in England and Wales fell -1.8% and -3.9% respectively.

Figure 54: Historical supply and values



Additional value gains

Purchasers and owners of farmland and rural estates often have the opportunity to add value to these assets by:

- unlocking latent value through conversions and upgrading
- reversionary gain on lifetime tenancies and
- long term development gain

Farmland values forecasts – a mixed message - diversity and quality will underpin performance

Economic change and uncertainty continue to have an impact on the farmland market in Great Britain. Alongside the traditional core drivers of this market some new influences are on the horizon including regulatory change, a shift towards public money for public goods, enforcement of the polluter pays principle and an increased scrutiny on land value capture. All these will amplify the importance of rural businesses nurturing natural capital, non-farm income streams such as energy, economic AgTech and innovation take up.

Our forecasts in the graph below are average scenarios in a market where there are a variety of influences and demand profiles. There will continue to be a wide range of prices achieved either side of the averages with factors including location, quality and size of holding, as well as neighbouring interest often coming into play.

The regulatory reform position has announced the end of the Basic Payment Scheme (BPS) by 2027 in England and we know, in the light of this, that many rural businesses are already evaluating their business strategy and succession plans.

Amenity farms (those desirable for lifestyle buyers) and those with, or the potential for, a variety of income streams will continue to be in demand. In contrast, demand for commercial units in need of investment, without the scope to diversify, is more likely to weaken, unless there are neighbouring farmers looking to expand.

In the longer term, there are likely to be some very significant changes in land use, as noted in 12.4, driven by environmental and climate change targets. We do not anticipate a repeat of the significant price increase recorded in the decade to 2014, but we do expect the market to return to its long term historical real-term growth of around 1% per annum (i.e. 1% above inflation).

Many factors contribute to the performance of farmland values and it is the balance between them that determines the outcome for each sector of the market.

Figure 55: Land value drivers

13.1.2. Development Land

As noted above it is anticipated that up to 0.3m hectares of land maybe required for housing and infrastructure and we expect competition for land to characterise the future land use in the UK. This will be driven by a range of factors in different regions around the UK including the local housing markets both demand and prices. Different regions are at different stages of the housing market cycle with some regions slowing (London and South East) and others growing (Midlands and North). Frustratingly spatial data on DUN land is sparse and only easily available for a limited number of local authorities.

> Land for housing and infrastructure will be a significant competing land use in the future.

13.1.3. Brownfield Land

It is estimated that there is in excess of 30,000 hectares of Brownfield Land in England (source: National Housing Federation) across approximately 17,000 sites, with approximately 15% being in rural areas. Brownfield Land offers significant opportunity for redevelopment with proposals to bring Brownfield Land back in to use often being favoured by planning authorities. Sites will also often benefit from low infrastructure costs typically being sited near to existing infrastructure e.g. road and grid networks. However, depending on a sites historic use, the cost of remediation may be prohibitively high to re-develop that meaning that sites often remain vacant for long periods. Given the pressures to meet housing targets alongside other potential uses, there is likely to be increased competition where Brownfield sites become available. Standalone energy projects may struggle to compete with other forms of development, however, could form part of wider development strategy to deliver energy to a wider site or nearby consumers.

Figure 56: Brownfield Land

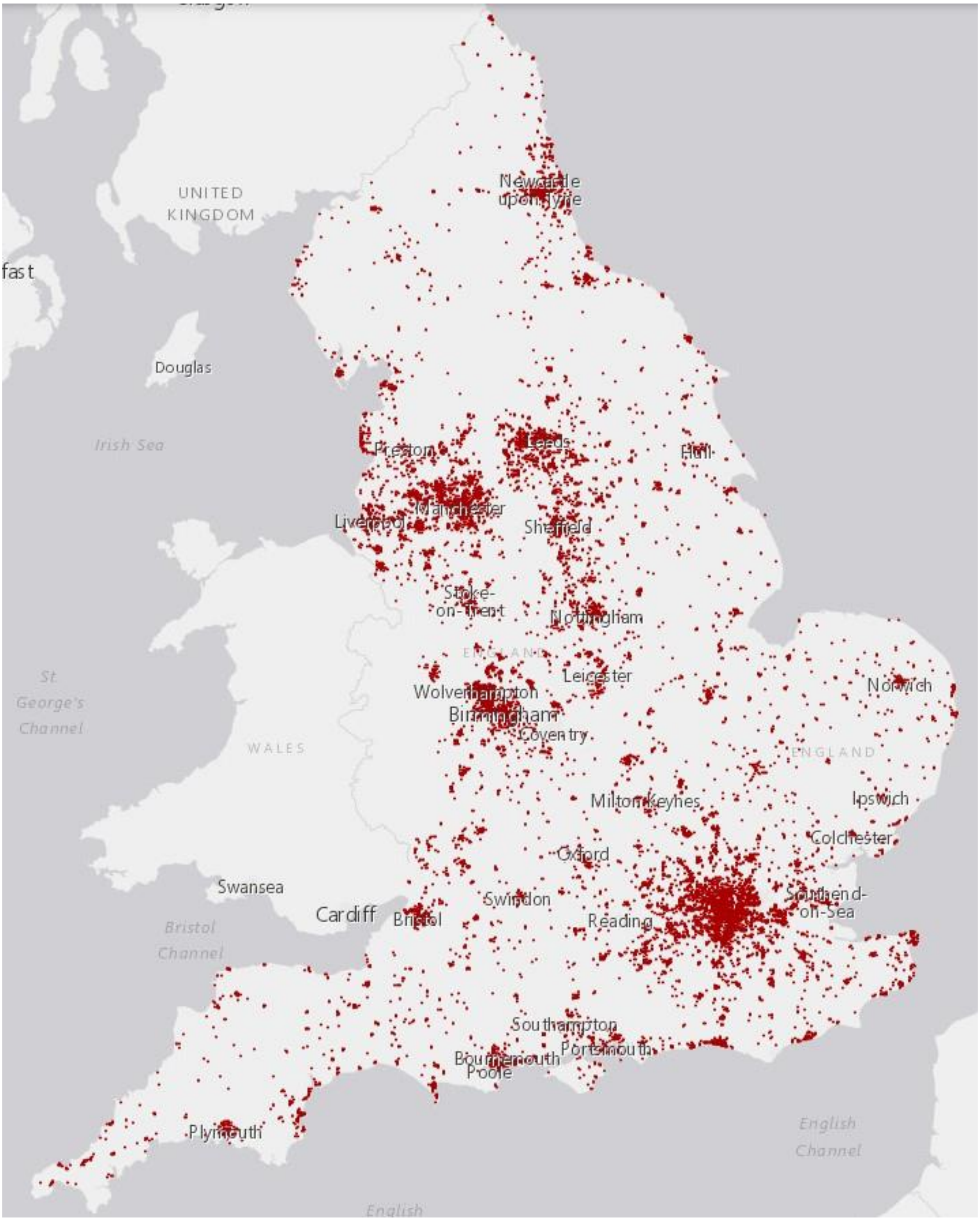


Figure 57: Five Year Forecasts

Five year forecasts (first published November 2018)

	2019	2020	2021	2022	2023	5-year
UK	1.5%	4.0%	3.0%	2.5%	3.0%	14.8%
London	-2.0%	0.0%	2.5%	1.5%	2.5%	4.5%
South East	0.0%	2.0%	2.5%	2.0%	2.5%	9.3%
East of England	0.0%	2.0%	2.5%	2.0%	2.5%	9.3%
South West	0.5%	3.5%	2.5%	2.5%	3.0%	12.6%
East Midlands	3.0%	5.0%	3.5%	3.0%	3.5%	19.3%
West Midlands	3.0%	5.0%	3.5%	3.0%	3.5%	19.3%
North East	2.0%	5.0%	3.5%	2.5%	3.5%	17.6%
Yorks & Humber	2.5%	5.5%	4.0%	3.0%	4.0%	20.5%
North West	3.0%	6.0%	4.0%	3.0%	4.0%	21.6%
Wales	2.0%	5.5%	4.0%	3.0%	3.5%	19.3%
Scotland	2.5%	5.0%	3.5%	2.5%	3.5%	18.2%

Source: Savills

13.1.4. Ownership Motives

There are strong reasons to own and/or invest in farmland in GB; these include:

- Investment performance – driven by capital growth (over the past 10 years, the value of GB farmland has, on average, increased by just over 50%).
- Opportunity to diversify an investment portfolio. Farmland is inversely correlated to many other assets and therefore tends to perform when other assets are under pressure and is relatively recession proof.
- Low-risk investment in a very transparent market place and in a benign political, economic (albeit with a degree of uncertainty in the short term) and cultural environment. Entry and exit from the market is easily achieved.
- Income generation – land-based opportunities extend beyond food production, and diversified income sources mitigate exposure to commodity price volatility and include:
  - Energy
  - Forestry
  - Diversification and non-farming opportunities including leisure and tourism enterprises
  - Support and environmental payments and grants
  - Property rental from residential and commercial assets
- Lifestyle – ownership provides somewhere to live, work and play and fulfils an aspiration ‘to own a piece of the countryside’.

- Taxation advantages – although these tend to be a secondary reason for holding land. 100% relief from Inheritance Tax after a qualifying period of ownership, which can be two years, is a valuable means of passing wealth to the next generation. Capital gains can be rolled over into farmland, thus deferring Capital Gains Tax, although the benefit is less than it was before the introduction of entrepreneurs' relief.
- Strategic development potential, especially where land borders settlements, offering windfall capital growth.
- Capital availability – assets, such as minerals, residential properties, off-lying land, can be used to release capital.

These attributes outweigh the constraints which include:

- Limited opportunities to achieve scale in farm businesses.
- Relatively low income yields – long term capital appreciation is the prime attraction for holding agricultural land as an investment.
- Generally, a lack of product in a constrained market place.

13.2. Land Rental

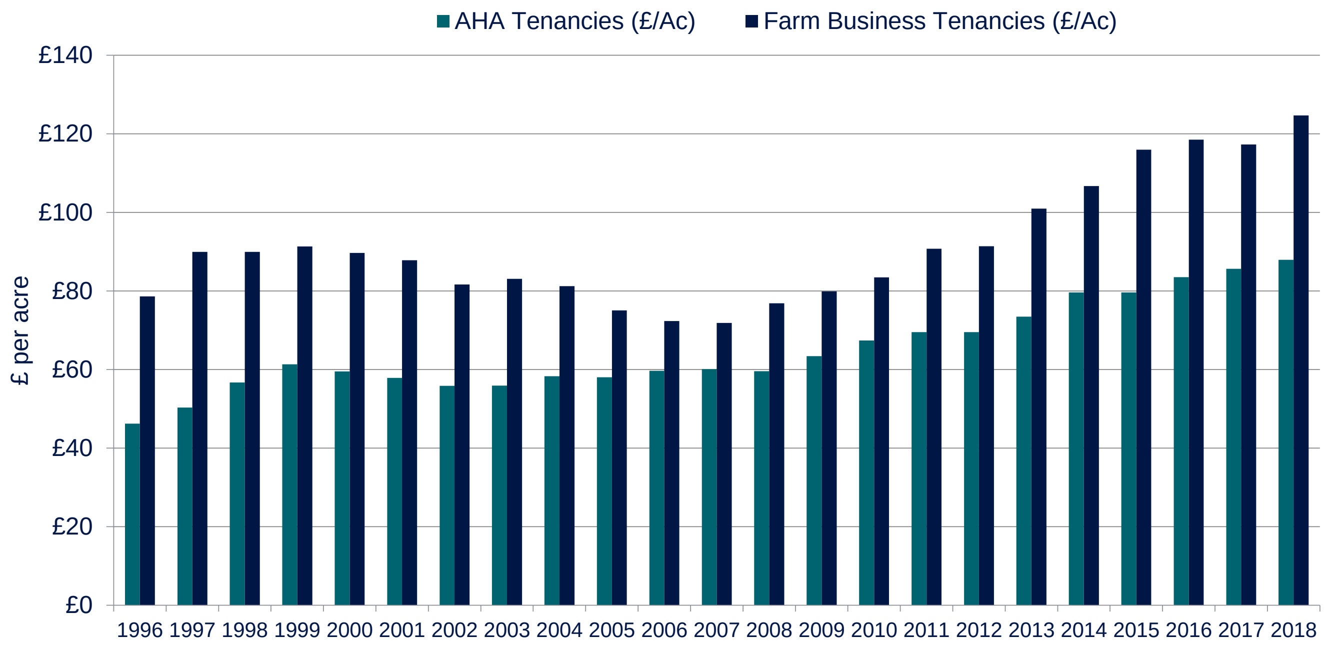
13.2.1. Agricultural Rents

Agricultural tenancies agreed before 1 September 1995 are known as 1986 Act Tenancies. They're also sometimes referred to as Full Agricultural Tenancies (FATs) or Agricultural Holdings Act tenancies (AHAs). These tenancies usually have lifetime security of tenure and those granted before 12 July 1984 also carry statutory succession rights, on death or retirement. These tenancies tend to be let below market rates.

Since 1995 we have had the Farm Business Tenancy (FBT). These tenancies do not have the right of succession and are let at market rates.

Figure 58 shows average rents across England. It should be noted there are a wide range of values depending on farm/enterprise type, soil type, region and individual circumstances.

Figure 58: Average rents across England



Source: Savills research and Defra

Outlook

Moving forwards prospects look better for arable rents. On the other hand, livestock farmers are currently farming in more challenging circumstances. Whilst businesses are preparing for the impact of Brexit, crucial aspects such as our future trading arrangements with the EU remain uncertain. If a deal is not struck the UK will default to WTO rules. It is the 'no deal' scenario which poses the biggest short-term challenges to the UK economy, in agriculture lamb producers are particularly vulnerable.

For agricultural policy we do at least know the direction of travel. Future policy and support schemes will have an increased focus on public money for public goods, especially environmental enhancements. Work developing the Government's new environmental land management scheme continues, it will provide an opportunity for farmers to recoup some of their lost support income.

Defra has extended its environmental scheme pilot projects in Wensleydale, Norfolk and Suffolk which pay farmers according to the environmental results they achieve. Other elements of the proposals would affect land availability and rents, such as the intention that direct payments during the transition period will be detached from land occupation to encourage retirement. This would be based upon a reference period and could include a lump sum payment rather than annual payments; at this stage we do not have any further detail on how this concept would be implemented.

Regardless, Brexit has already encouraged many to be more analytical about their business. Some farmers are choosing to retire or restructure how they farm, whilst others are expanding, resulting in strong competition when FBTs are tendered on the open market. For both landlords and tenants, the best course of action is to review their business interests and work towards ensuring they are resilient under any trade or support scenario. This business review could open new opportunities for energy generation especially where agricultural rents are under pressure and at levels which make a land based energy scheme, such as solar, economic. However each scheme will need to be evaluated on its economic merits taking into account land cost whether capital or rental.

13.2.2. Renewable Energy Rents

Where, in order to secure necessary land rights to site a project, a lease is to be entered into, the rent payable is likely to be driven by three principle factors.

1) Project Economics – What can the project afford to pay?
2) Market Comparables – What rents are being paid for similar projects in the area?
3) Opportunity Costs – What alternative income is available to the owner of the land from the land in question?

Given the variability of annual income from energy projects, rents are often linked to a projects performance and linked to a project either to a turnover or another identifiable metric, e.g. annual generation.

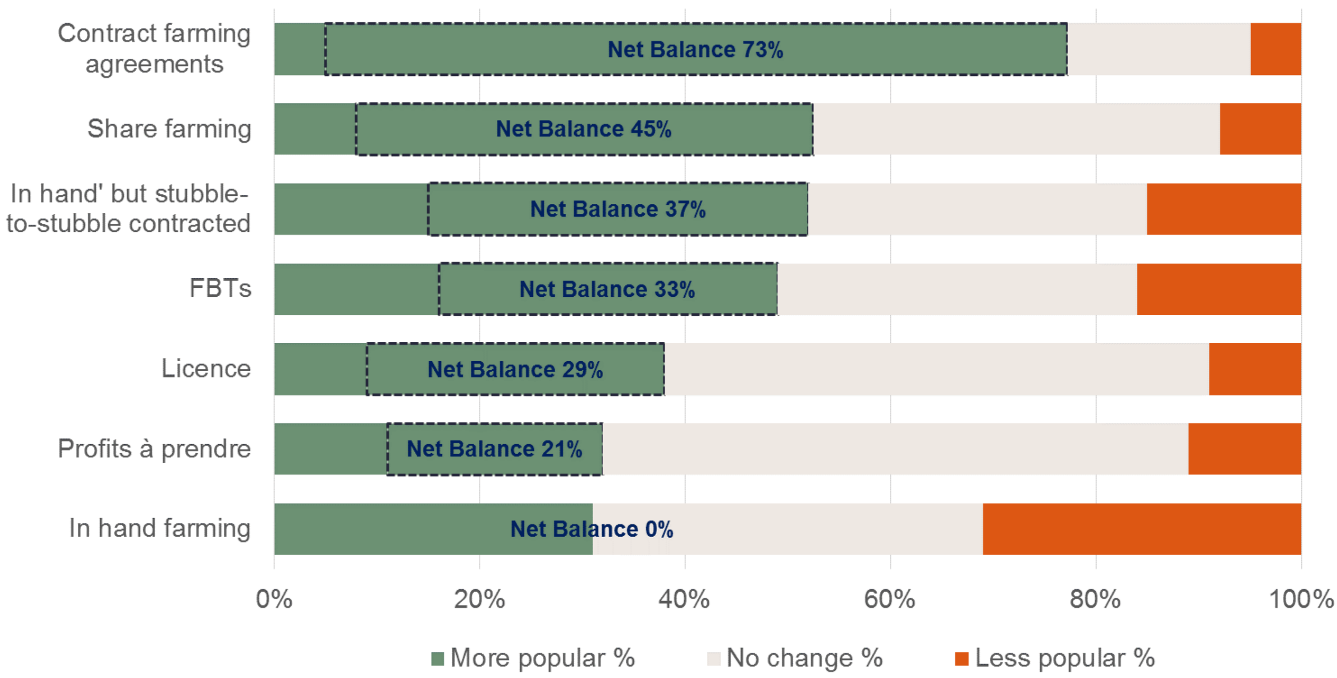
13.3. Other Tenure Options/Agreements – Looking Forward

To investigate the impact of the Agriculture Bill's policies we surveyed surveyors and food and farming consultants within Savills Rural Energy and Projects division. Collectively the respondents advise upon 2 million acres of land, of which 1.1 million acres are occupied by nearly 3,500 tenants.

On tenure change the responses (see Figure 59) suggest that contract farming agreements are viewed as the tenure most likely to increase in use, followed by share farming and stubble-to-stubble contracting. Overall, against the background of a likely reduction in AHA area, this tends to suggest a trend towards landowners being in occupation but working in collaboration with others to farm their land. This suggests an increase in demand for contract farming operations in the future. That said, FBTs are expected to continue to play an important role in the English tenure mix, a net balance of 33% expect them to become more popular, whilst 35% expect their usage to remain stable.

We anticipate that there will be more flexibility in tenure and the types of agreements in the new agricultural policy regime and therefore a potential opportunity for energy to enter the mix.

Figure 59: Expectations for the nature of future land occupation



14. Rural Business Economics

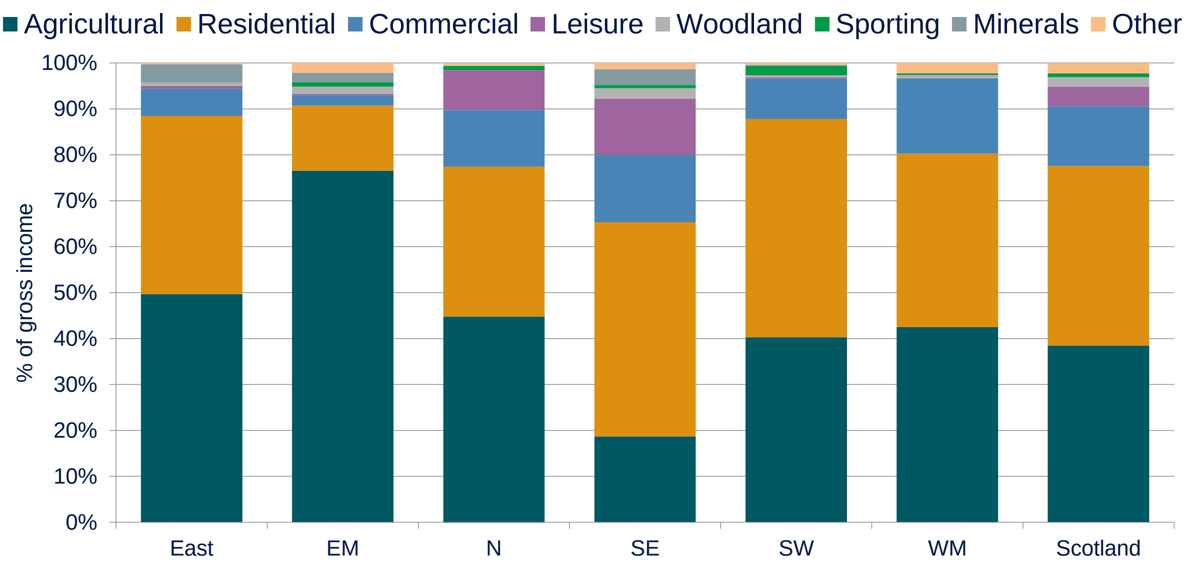
The relative economic returns of rural businesses to decentralised energy schemes are clearly a relevant factor to the uptake of energy schemes. This section discusses historical and future performance of rural businesses.

14.1. Rural Estates

Rural estates across England and Scotland continue to record positive gross income growth with average gross income rising by 1.2% to £242 per acre. Agricultural and residential assets, on average, continue to provide the majority of income although, depending on location and the mix of assets of individual estates, there are significant differences in the relative contributions of the asset classes. The key performance figures from our 2018 survey are highlighted below.

There is a wide variation of income streams between regions (see Figure 6060). Location is clearly key to the opportunities presented to an estate or rural business both in terms of population density, proximity to centres of population and the rental and asset values in the local markets.

Figure 60: Proportion gross income on rural estates by region



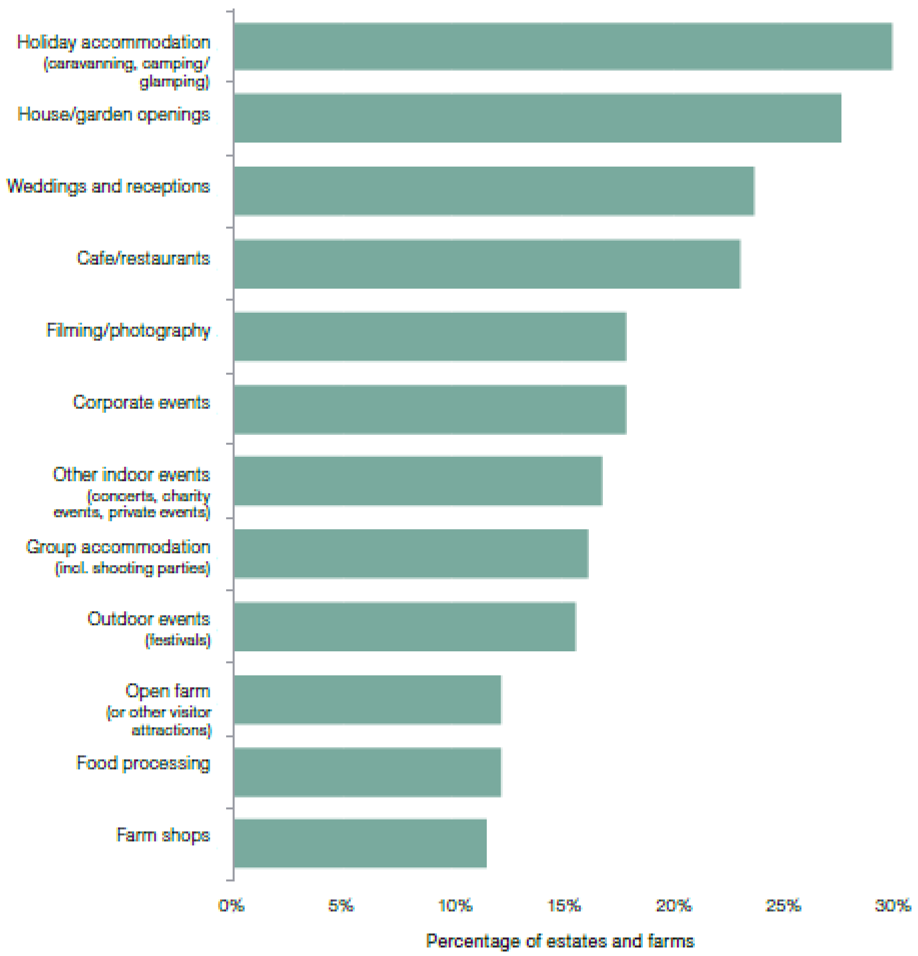
14.2. Alternative Income Streams – Diversification

There has been a trend for farms and estates to focus on the development of income from other assets alongside and complementing their core business including woodland and minerals. This is being driven by economic pressure, markets and the need to spread risk, especially with the uncertainties surrounding the outcomes of Brexit. With question marks over both the future of farm support and world-trade arrangements, income streams other than the traditional agricultural ones will be vitally important.

Our Estate Benchmarking Survey shows that, on average over the past five years, trading enterprises (including in-hand farms) contributed just 8% of gross income on all estates across England. This is in stark contrast to the situation in Scotland, where trading income represented 18% of gross income over the same period. This suggests that political interference in land ownership has made landowners north of the border more reluctant to let their holdings.

Our research shows that almost one-third of farms and estates have holiday accommodation (including caravans, camping and glamping). A similar proportion open their house or garden, a quarter host weddings and receptions, and more than 10% operate a farm shop (see Figure 61). Other popular choices include cafes and restaurants, filming and photography, and corporate events.

Figure 61: Diversified enterprises on farms and estates by proportion of total



14.3. Natural Capital/Ecosystem Services

Payments, capital and/or an annuity for ecosystem services are made to the “manager” of the natural capital to provide the ecosystem service. Many services are currently provided without charge or under local initiatives, but as the new environmental policy landscape becomes more established so does the potential for offering offsetting services and the development of associated markets. These might include:

- Markets in avoided costs such as reducing nitrates in water, paid for by savings on water purification costs
- Compulsory offsetting such as carbon trading through the Emissions Trading Scheme
- Voluntary offsetting and links with CSR initiatives
- Social prescribing and paid-for access to green space through NHS budgets
- Green finance from corporate investors looking for long-term environmentally beneficial commercial projects.

14.4. Renewable Energy

Renewable energy, according to Savills Estate Benchmarking Survey, contributed an average of £5.57 per acre to rural estate incomes representing 2.3% of gross incomes in 2018.

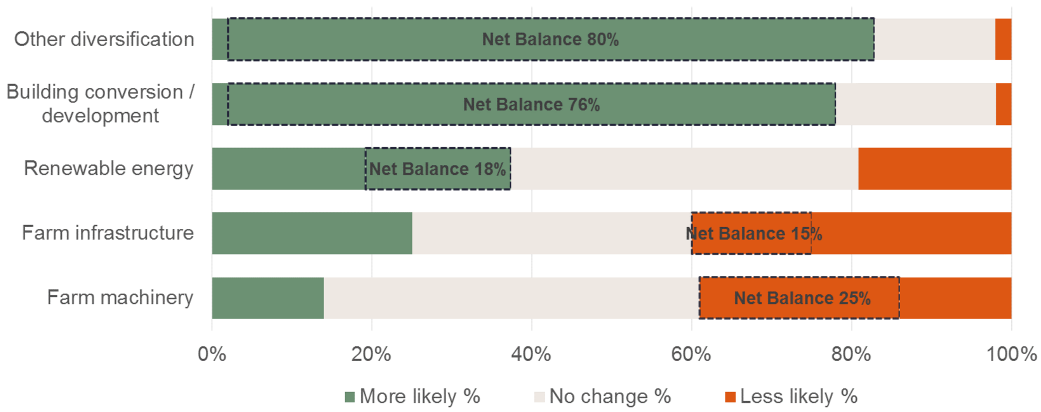
Renewable energy contributed 2.3% to gross incomes of to the gross income of rural estates in 2018, a significant increase over the preceding five years.

Figure 62: Renewable energy: gross income (£ per acre)

2014	2015	2016	2017	2018
£1.16	£2.07	£2.65	£4.25	£5.57

Our survey on the impact of the Agriculture Bill’s policies showed that reduced investment in farm infrastructure and machinery is expected as farmers focus their investment on diversification including energy. Our professionals see renewable energy, building conversion / development and other diversification as areas where increased investment will be made (see Figure 63). We would expect an increased focus on bringing forward sites and buildings for planning permission in order to diversify income streams.

Figure 63: Expected impact of subsidy withdrawal on these investment types



15. Aggregation

Flexibility providers are parties who look to optimise the use and revenue potential of flexible assets in the GB market. This includes both grid-connected and behind the meter assets. Flexibility providers can be involved in the development, ownership and operation of assets. They are and increasingly are taking steps such as obtaining supply licenses to access certain flexibility opportunities.

> Aggregators allow decentralised energy schemes access to national energy market revenues. There is little benefit to an aggregator to focus on a single locale, but may be some benefit in specialising on a rural economic sector.

Flexibility providers are also commonly referred to as aggregators, as they typically work with smaller assets and demand side response offerings, though most are also happy to work with larger asset owners to help optimise revenues.

Due to their position in the market, flexibility providers typically provide offerings designed to offset consumption at peak times and provide access to balancing service revenues. They may also support their customer in understanding and optimising their load management.

Being part of an aggregated unit has the benefit of allowing owners of smaller sites to access additional revenue streams which they otherwise wouldn't be able to. The downside to this approach is that there is an additional expense of paying an aggregator to operate the site and so the consumer will lose a proportion of revenues.

15.1. Using Aggregation to Offer Balancing Services

> Aggregation revenues can offer a useful extra income to decentralised energy project whether a consumer or a producer or power – but will not underpin a business case alone.

The exact technical requirements for participating in each balancing service varies. Broadly speaking, the services that a participant can offer depend on how quickly they can respond to a signal to change generation output or consumption. A summary of the requirements to participate in different balancing services is provided in Figure 64.

Offering these services can provide additional sources of revenue for consumers with flexible behind-the-meter generation, although in some cases the owner of the generation may not be aware of all the necessary requirements to offer these services. This has led to numerous parties offering to use consumers' existing assets to participate in balancing services on their behalf.

Figure 64: Balancing services scheme aggregation eligibility overview

Scheme	Volume Threshold	Aggregation Available?	Reaction Time
Firm Frequency Response (FFR)	1MW	Yes	10 sec
Short term operating reserve (STOR)	3MW	Yes	20 mins
Fast Reserve	50MW	Yes	2 mins
Demand Turn-up	1MW	Yes	Tendered
Capacity Market	2MW	Yes	4 hours
DUOS Avoidance	N/A	Yes	N/A
Triad Avoidance	N/A	Yes	N/A
CM Avoidance	N/A	Yes	N/A
DNO/Supplier schemes	Varied – still in trial phases	Varied – still in trial phases	Varied – still in trial phases

Source: Cornwall Insight and National Grid

15.2. Providers

Some service providers offer services more relevant to small-scale rural enterprises than others. Services also evolve rapidly, so decentralised projects should review their options regularly.

This is a rapidly growing field and one in which new offering are frequent. Currently, key flexibility providers in the market include:

- Kiwi Power – specialises in the creation and management of demand-side response opportunities. Its focus aggregating small-scale grid and behind-the-meter assets, but it also markets its services towards network operators to monitor and manage load. It claims to be able to achieve a return of up to £100,000/MW/year for customers' assets. It is active in the Capacity Market, FFR, network charge avoidance, and STOR services
- Limejump – a significant flexibility provider in GB. Its service includes the Capacity Market, offtaker PPAs, Balancing Mechanism access, and frequency response markets. It works with over 250 customers through its VPP offering

- Flexitricity – specialises in DSR and small generator opportunities in GB. It is active in markets including frequency response, turn-up, STOR, triad management, Capacity Market, the Balancing Mechanism and the DSO trial services. It has an electricity supply licence for Balancing Mechanism access and with this offers large consumers pass-through access to the major wholesale markets to fix energy costs and revenues at timescales that suit their businesses
- Open Energi – manages a range of distributed energy resources across the UK. For large consumers, its services focus on balancing services, peak price management, constraint management, the Capacity Market, and energy efficiency offerings
- Origami Energy – offerings include access to balancing service contracts. Markets services to both energy suppliers looking support their customers and minimise exposure, and asset owners looking to maximise value through value stacking. The Origami Control product optimises returns through access to balancing services, the Capacity Market, and wholesale energy prices

Emerging players are often based on battery installation. They include companies looking to introduce batteries to the home and provide services on an aggregated basis through various branded platforms. Others are implementing the first real-world versions of vehicle-to-grid systems.

- Connected Energy – provide commercial-scale battery storage units built from second-life EV batteries. Their E-STOR platform offers peak reductions, can integrate onsite renewables and EV chargers, and accesses revenues from several balancing services
- Powervault – domestic-scale batteries second-life EV batteries, with a built-in inverter, allowing charging directly from solar panels for efficiency gains. Paired with the GridFlex platform and a smart tariff control system to support time-of-use charging and discharging; marketing material promised new customers £20/month from GridFlex on launch last year
- Nissan – looking to aggregate the capacity of EV batteries through vehicle-to-grid schemes to provide services. It has said that it hopes to deliver £350/year to participants, or free EV charging
- Sonnenbatterie – a German company which entered the GB market in 2018; since bought by Shell. The sonnenCommunity in Germany, Austria, Switzerland and Italy shares energy between householders in a peer-to-peer market. The batteries also form a VPP to deliver balancing services
- Moixa – domestic-scale batteries with GridShare software. Moixa are working to introduce vehicle-to-grid and vehicle-to-home services access new revenues
- OVO VCharge – provide a smart heating solution through Dynamo devices which control storage heaters. This also provides balancing services including turn-up. It is also offering domestic storage batteries and investigating smart and V2G charging

Many of these services offer a share of revenues earned by allowing the aggregator to operate assets. These offerings differ from the existing aggregators, however. Some providers offer fixed revenues in place of a share of earnings. Another business model is to offer a lower cost of acquisition in return for rights to deliver services using the asset or provide another benefit such as an interest-free loan to cover acquisition. An emerging model is to offer free or reduced cost EV charging in return for providing services from the EV battery.

15.3. The Future of Aggregation

> As more aggregators enter the market and more look to work with large numbers of smaller actors, the opportunity for rural businesses and eventually domestic consumers will grow.

Early aggregators worked with large industrial and commercial customers with significant levels of consumption, the potential to shift large amounts of load, and frequently on-site generation. More recently, the Virtual Power Plant (VPP) concept has been introduced. Rather than a few large sites, the VPP incorporates many thousands or even hundreds of thousands of small amounts of flexibility, controlled automatically by a central player within pre-agreed parameters.

VPPs are believed to be less reliable in terms of delivering usage reductions, but as smart technology and the internet of things develops the breadth of these services could be much greater, reaching into small business and even domestic properties.

16. Funding Sources

Most of these funding streams are available nationally irrespective of location – but there are exceptions.

As noted above, policy interventions from UK government have historically focussed on introducing subsidies aimed at delivering investment in new assets. These either provide additional revenues on top of whole sale market revenues or establish a guaranteed price for the export of power to the grid. Of those introduced since 2002 the Renewable Obligation and Feed in Tariff have now closed with only the Contracts for Difference and Renewable Heat Incentive remaining as the main subsidy mechanisms available to projects.

16.1. Contracts for Difference

Generally not suitable for rural projects.

Contracts for Difference (CFD) were introduced as part of electricity market reform under the Electricity Act 2013 and are the successors to the renewable obligation regime. They are designed to stimulate investment in the large scale low carbon technologies including renewables, nuclear and carbon capture and storage. The approach is aimed at reducing exposure to wholesale price volatility and providing a long-term legally enforceable contract for the government. CFD's provide a variable "top up" to generators by paying the difference between a strike price and a wholesale price of electricity. Technologies are grouped and a competitive auction process run periodically. At the time of writing, on shore wind and solar PV are excluded from participation in the auction process.

16.2. Renewable Heat Incentive (RHI)

May be key to support the installation of heat pumps and the energy centres of heat networks.

The RHI was brought in under the Energy Act 2008 and is a payment system for the generation of heat from renewable sources. The RHI was introduced in two phases. Phase 1 for non-domestic installations was introduced in 2011, and Phase 2 for domestic installations was introduced in 2014. The RHI provides a tariff payment per unit of heat output from an eligible installation e.g. heat pumps or biomass boilers. Tariffs last 20 years and are index linked. The RHI is subject to periodic review, through which the government introduced digression. The RHI is to remain open until 2021.

16.3. Alternative Sources

There is a wide range of funding sources available for renewable energy projects however eligibility criteria varies depending on the ownership of an entity proposing the project, the location of the project and the technology proposed. Community Energy England provide a list of potential funding sources on their website: www.communityenergyengland.org. Examples include;

16.3.1. Smart Energy Systems

Suitable for innovative rural models.

The Industrial Challenge Fund programme is offering UK organisations a share of up to £30 million to develop smart energy system designs for innovative renewable technologies. Community groups who wish to apply for funding will need to form a consortium, with a private or public organisation as lead partner

16.3.2. Community Shares Booster Scheme

Ideal for maximising the local sharing holding of rural projects, but not a specifically rural fund.

Community Businesses can access up to £10,000 to help launch community share offers, and up to £100,000 match funding when the share offer goes live.

16.3.3. South Cambridgeshire Community Energy Fund

Based in a largely rural region.

Grants of up to £3,000 are available to voluntary and community sector groups and parish councils to support the delivery of local energy saving and green initiatives. Applications are accepted at any time, until funding runs out, and can completely or partially cover the costs of a project, equipment or work.

16.3.4. Rural Energy Community Fund

Only for rural groups.

The Rural Community Energy Fund (RCEF) is a £10 million programme, jointly funded by the Department for Environment, Food and Rural Affairs (Defra) and the Department for Business, Energy & Industrial Strategy (BEIS). It supports rural communities in England to develop renewable energy projects which provide economic and social benefits to the community. Project specific grants are provided, to pay the costs of feasibility and pre-planning work and get projects to an investment ready position. Stage 1 provides a grant of up to £40,000 for investigating viability, and Stage 2 offers a further development grant of up to £100,000 to develop a business case and planning application.

Community groups seeking funding must represent a rural population of fewer than 10,000 residents. Groups must also be able to demonstrate a legal entity and the support of the wider community. Projects which are eligible include a mainstream renewable generation technology, CHP, and low-carbon district heating. Projects must also demonstrate scale, which is assessed as providing power to more than one building.

This grant funding is managed by the Local Energy Hubs.

16.4. Crowd Funding

Crowdfunding has supported many rural projects. Local investors may not be enough to underpin full investment costs, particularly in sparsely populated rural regions.

Crowd funding has increased in popularity in recent years, utilising a number of web-based platforms. Businesses look to raise finance by asking for a large number of people for a small amount of money. Funding can be in a number of forms including reward crowd funding, debt crowd funding and equity crown funding.

16.5. Bank Funding

Requires a solid long-term business case.

Bank funding is widely available for the development of renewable energy projects that meet a lending institutions criteria.

17. Implications for Rural and Urban Fringe Generators

In this section, we discuss the implications which the themes and topics explored above have for rural and urban fringe energy schemes, relating the general issues to decentralised energy.

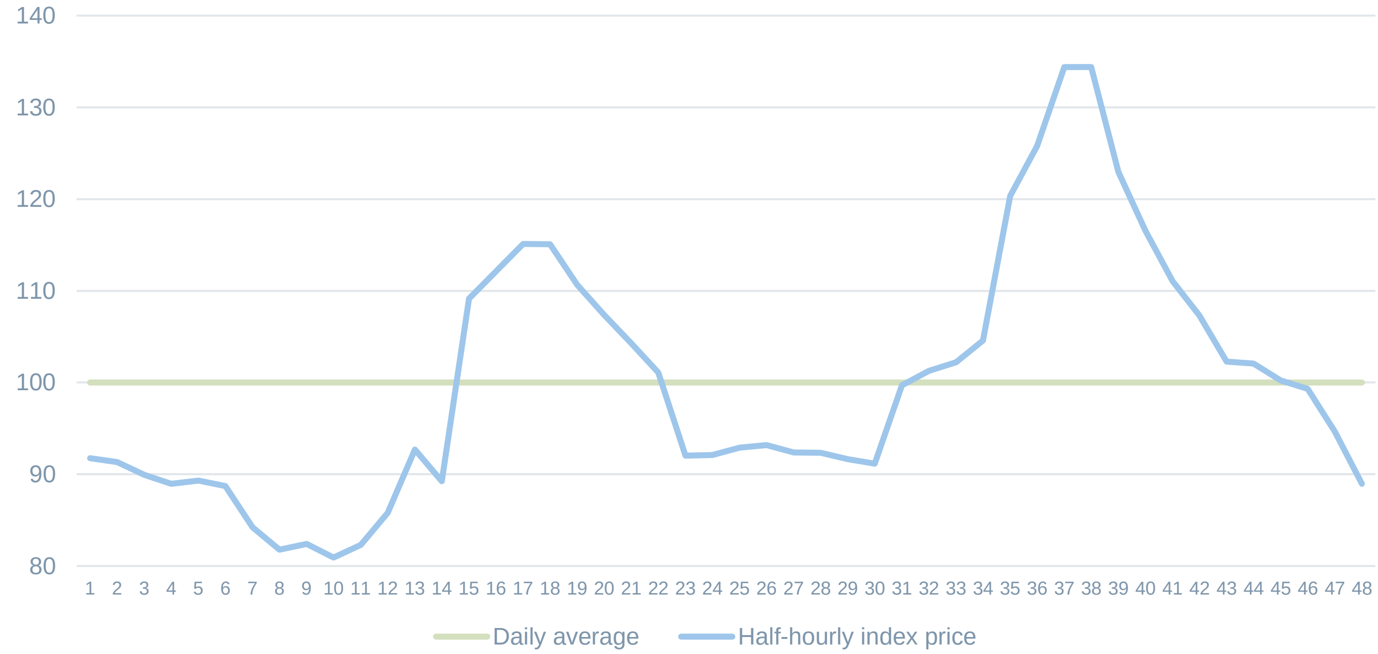
17.1. Time-value of Power

This conclusion indicates a greater need for flexibility in generation and consumption.

The wholesale price of power varies across the day, with prices much higher in the peak periods that at other times. Currently, export from small-scale generation was previously remunerated under the FiT, which sets a flat price for power at any time. This does not reflect the actual value of this electricity in the market. Figure 65 sets out relative pricing across a typical day in the GB wholesale EPEX spot market.

Source: Cornwall Insight, from EPEX data. Based on sample of 10 consecutive days in March 2019

Figure 65: Typical wholesale power prices in GB (relative values)



Introducing time-of-export remuneration for generators would expose decentralised energy generators to this effect. For generators which can control the time when they produce and export power – either by direct control of the generating asset or by using energy storage – this could increase the value of export; for generators which cannot control the time of export, time-of-export pricing could reduce the value of power.

17.2. Self-consumption

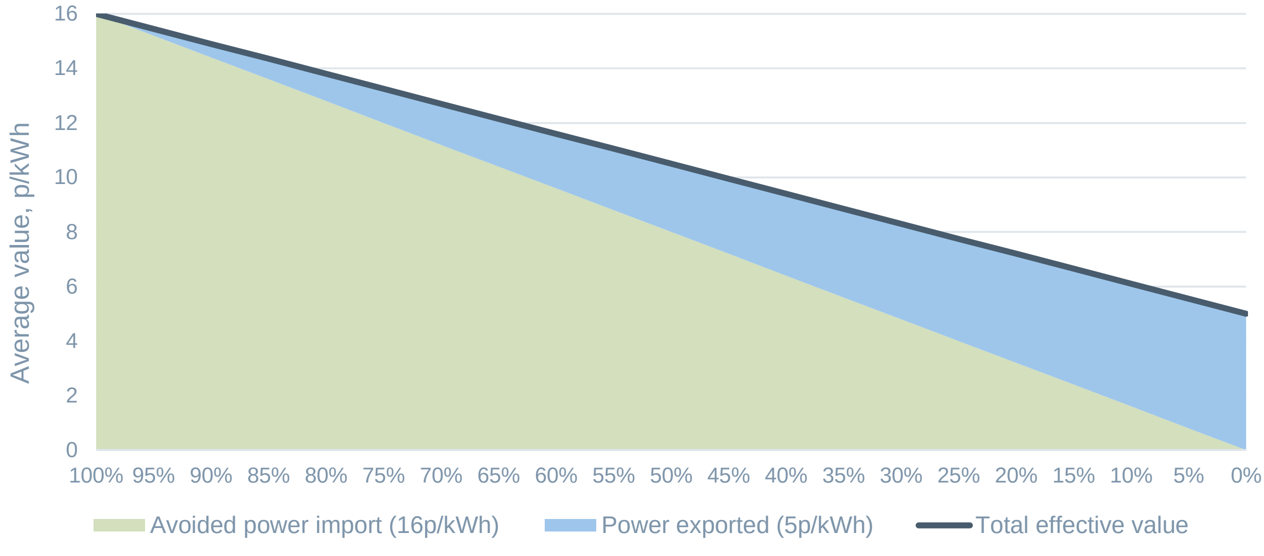
This conclusion also indicates a greater need for flexibility in generation and consumption.

As set out in section 8.2, the value of wholesale power is only a fraction of the total retail price of electricity. Net metering is a concept implemented in several international markets, where power exports effectively wind a meter backwards. This means that the value of exporting power generated behind a consumption meter is exactly the opposite of imported power. This is practice is often used as a form of subsidy for small, especially low-carbon domestic, generators. However, there are no net metering rules in the GB market.

This means that the value of exporting power to the grid is much lower than the cost of importing power. This is important for those operating power generation assets behind the meter, as the value of displaced import is much higher than the value of exporting power. This encourages users to take steps to ensure that they self-consume as much of the energy generated as possible, rather than exporting it.

Figure 66 sets out the relative value of power from a behind the meter generator, based on how much is self-consumed and how much exported. We have assumed that imports cost 16p/kWh, while exports are worth 5p/kWh.

Figure 66: Overall value of power at various levels of self-consumption



Where customers are exposed to time-of-use pricing, rather than single-rate prices, this will change the value of self-consumption. If self-generated power is available at the times when tariff prices are highest, this will increase the value of the power as it will offset more expensive consumption. However, if power is available only intermittently and unpredictably, this may introduce a role for energy storage. With time-of-use pricing expected to increase with the rollout of smart meters to domestic and small business consumers, the benefits of storage be available to more customers in the future.

17.3. Market Access for Small-Scale Generation

Market access is improving for decentralised schemes, but local markets are not on the horizon.

As discussed above, currently the main route for remuneration of small-scale low-carbon generation was the FiT scheme. However, the closure of the FiT has left generators under approximately 500kW capacity without a route to sell their generation to the markets. These generators will not produce sufficient power per annum to make directly trading financially viable and are too small to interest suppliers in negotiating a PPA for offtake.

Short-term PPAs can be secured through brokers or mechanisms such as the Renewable Exchange or NFPA's e-POWER auctions, but value retention for generators smaller than 500kW tends to be low. Furthermore, these contracts are typically for 6-12 months, not the 15-20 years of previous subsidy mechanisms. This makes securing long-term revenues to enable an investment decision problematic.

BEIS issued a consultation for views on a replacement to the FiT scheme in early 2019. This consultation for a smart export guarantee (SEG) may establish a guaranteed route to market for small scale generators, with large and medium suppliers likely to be required to offer contracts to low-carbon generators under 5MW in capacity when the scheme is implemented.

However, under the proposal, while a tariff must be offered by each supplier, there is no mandatory minimum price, and it is not clear what level of pricing will be offered by suppliers. Initial indications from domestic tariffs offered by suppliers E.ON and Octopus Energy in April indicate that rates will be in line with FiT export prices, with 5.24p/kWh and 5.5p/kWh offered respectively.

17.3.1. Peer-to-Peer Supply

Peer-to-peer is perhaps the holy grail for decentralised energy. But in GB, it is not expected to become a reality I the short-medium-term.

Selling electricity between producers and consumers across the distribution network is not currently economically feasible. GB has a national electricity market, and there are currently no advantages to generating power close to the point of consumption, unless this power is being supplied directly to the consumer over a private network or from a location behind the same meter. Any power passed across the public network, even the local network, will incur full Third Party Charges.

Various trials are ongoing to examine whether there could be ways to enable this. Some of the projects are:

- Verv and Centrica's Community Energy Blockchain trial. Solar panels have been installed on 13 blocks of social housing flats in Hackney, London, to supply power to communal areas. The project is examining how customers could be billed for energy if this was sold to residents, instead of to the grid, using a blockchain platform for settlement. Derogations from Ofgem's innovation sandbox enable the trial
- Centrica's Cornwall Local Energy Market is a £19mn project operating in the county, also using blockchain. The project is examining creation of local wholesale and flexibility markets, including peer-to-peer trading again using blockchain settlement tools
- Sero Homes has recently been funded by BEIS to implement a trial of its FLATLINE system, which will put 58 new build energy-efficient homes behind a "virtual meter". The virtual meter will be used for central

industry purposes, allowing SERO to share local generation between homes, manage heat pumps and battery storage across the pilot homes, while offering balancing services to National Grid

If implemented, peer-to-peer trading would allow local energy markets supporting decentralised energy generation and consumption to develop. These markets would reflect regional value for power and encourage additional generation to develop in areas of high consumption, and additional consumption in areas of high generation. However, despite these developing projects, open access peer-to-peer trading across the public networks remains at least several years away.

17.4. Technology Choice

> Most decentralised energy projects are, and will continue to be, solar or wind generation. However, batteries and anaerobic digestion plant will have an increasing role to play and in the case of the latter will have significant interactions with the rural agricultural economy.

Figure 67 and Figure 68 show the growth in renewable energy across the UK by tracking the status of planning applications submitted to Planning Authorities since 1991. It shows how the policy interventions set out in Figure 43 have influenced the rate of deployment in the renewable energy market and the growth of certain technologies. For example, the rapid growth of solar PV following the introduction of the FIT in 2009. Technology choice in the future will be less driven by policy intervention and increasingly by an opportunity to integrate them into existing or proposed businesses to deliver cheap, reliable and green power.

Figure 6715: Renewable energy planning applications since 1991

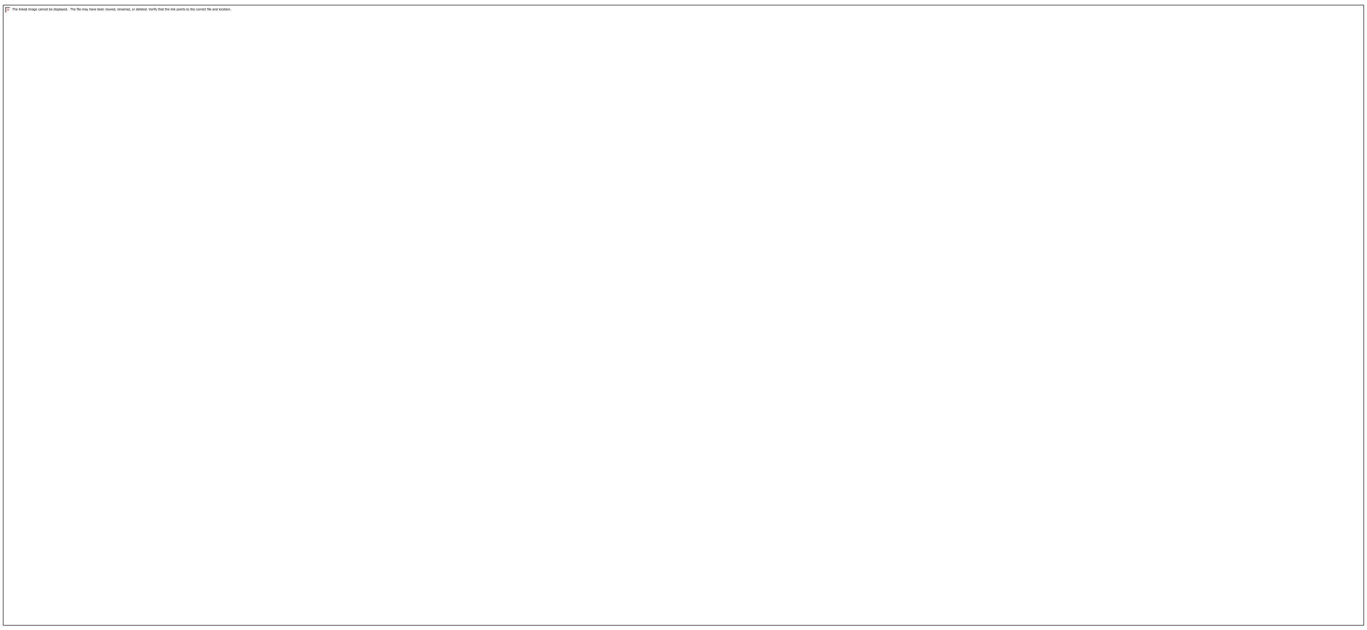


Figure 68: Renewable energy planning applications by technology

17.5. Grid

Rural networks tend to be weaker than urban ones and this may cause issues with heat and transport electrification.

As discussed above, the changing ways in which we generate and consume electricity will increase pressure on the grid network. The availability and cost of securing a connection to the grid will vary based on local and regional factors and will act as a potential barrier to the future deployment of decentralised energy schemes. However, it may open up opportunities for alternative route for markets such as private wire schemes. The district network operators provide high level information on the availability of grid capacity on their websites, which should be viewed prior to submitting budget or full grid applications.

17.6. Co-Location

Battery parks take up a lot of room, so are likely to be best situated in rural regions.

Technological advancements and a desire from developers looking to optimise output from projects has opened opportunities for hybrid projects to develop combining different technologies such as solar and wind or batteries with solar/wind. Such projects would deliver the following key benefits:

- Maximise use of grid capacity and project infrastructure
- Potentially increased ability to compete in subsidy-free market
- Levelling peaks and troughs in output

Technologies could either be deployed in tandem or sequentially depending on circumstances

17.7. Land Use Changes

There is the potential for significant change in the way land is used in the UK over the next 30 years with potentially 13 million acres of land being “released” from agricultural production. Therefore, there will be significant opportunities to increase the deployment of land intensive energy technologies including ground mounted solar and bioenergy crops for anaerobic digestion and biomass plants. However, there will be significant competition for access to land not least from afforestation, housing and infrastructure. This is likely to be particularly strong in urban-fringe areas where access to land for housing, infrastructure and recreation will be at a premium, driven by projected population growth.

17.8. Diversification

We expect the trend for rural businesses to develop sources of income from diversified sources to increase, particularly as they adjust to operating without income support that has previously been delivered through the CAP. Whilst the growth in renewable energy deployment has primarily been driven by historic subsidy incentives the opportunities to establish a diversified income stream and integrate technologies into existing business activities to deliver cheap green energy, reduce reliance on imported energy and reduce costs will be a key driver in the future.

17.9. Planning

It is beyond the scope of this report to assess national and local planning policy. This would be a key element in the growth, or otherwise, of decentralised energy projects. With very few exceptions all renewable energy technologies require planning consent. Micro generation technology such as Solar PV. Solar Thermal and heating technologies e.g. Heat pumps maybe classed as permitted development effectively removing the need to secure planning consent from a planning authority. As part of any proposed project the developer should seek to engage with the planning authority at an early stage.

17.10. Future Sectoral Change

Most of the changes forecast are either neutral on location or benefit urban sites over rural. However, the lack of granularity in GB network regions at various levels could allow projects to take advantage of cheaper rural locations as well as higher urban revenue streams.

The energy retail markets are currently subject to high levels of regulatory uncertainty and technological change. Although retail markets have always been heavily politicised, the attention that the sector is receiving from national, regional, and local politics and the media is unprecedented. Ofgem and BEIS are undertaking a number of work streams which could lead to fundamental changes in the GB retail market. In general, these are looking to take advantage of technologic improvements to increase the timeliness of industry processes and improve data quality, reduce prescription to permit greater freedom for suppliers, and ensuring the market and its regulations are fit for purpose moving forwards and to permit innovation in the market.

- Supplier hub review – as discussed within this report, the energy market operates on the supplier hub principle which places the supplier at the heart of the market. Ofgem is currently considering if this concept is still fit for purpose moving forwards, with new actors and technology in the market. Following a call for

evidence, the regulator has determined that the principle needs consideration. It is assessing and will, where necessary, redesign the retail energy market to ensure the best consumer outcomes
    - This may change or expand the range of counterparties seeking to contract for power
    - It may, in the longer term, allow for community or local energy groups to directly supply some power directly to customers, or enable peer-to-peer trading between users, leading to increased revenues
- Triad changes under CUSC modification CMP264/265 – the Triad benefit to embedded generators was restricted in 2017 to the value of avoided network reinforcement; effectively cutting it to between £1 and £6/kW, or to zero in many regions. This was down from a previous average value of around £47/kW, which had been forecast to rise to £70/kW by 2022
- Targeted Charging Review Significant Code Review (SCR)
    - A move to more capacity rather than unit-based charges will reduce the benefit of generation behind the meter. Depending on implementation, it may also reduce the benefit of energy storage behind the meter. This will change the revenue streams available to decentralised energy schemes
    - Domestic consumers are likely to see charges fall, unless using low-carbon technologies like EVs and heat pumps, in which case they are likely to see charges rise: potentially by 20-30%
    - Changes are likely to come into charges from April 2020 or 2021
- Forward Looking and Network Access SCR – this wide-reaching work stream will impact on network access rights and charging methodologies
    - The main impact on embedded generation will be to align locational charges with transmission-connected plant. This will increase costs for embedded generators located in more northerly locations and decrease costs or add benefits for southerly generators. However, it is likely to have limited impact on intermittent renewables generators
- Smart metering –the smart metering roll-out has been subject to considerable delay and suppliers are forecast to miss the end-2020 target. However, when smart metering is complete, or even at an advanced stage, there is an opportunity to develop considerable value from the data generated. This value will arise from disparate streams such as:
    - Shortened settlement timescales, from the current length of up to 30 months. This could reduce the cost of credit, as parties will know their exposure to charges earlier
    - Market-wide half-hourly settlement, which will expose suppliers to the true underlying costs of their customers' electricity consumption, and drive the case for ToU tariffs
    - Faster and more reliable switching, bringing the timescale down from the planned five days to as little as 24 hours
- DNO/ DSO transition and flexibility procurement – the distribution networks are running projects to investigate and procure flexibility services to help them better manage their networks. They intend to reduce costs to consumers during the ongoing transformation of the networks by paying generators, consumers and storage providers to change the ways in which they use and produce energy
    - This will introduce new potential revenue streams for decentralised energy schemes; however, these revenues are not guaranteed to be available for the long-term and are not investable
    - One key work stream for this is the Piclo Flex dashboard
- Electric vehicles – enabling the connection and charging of large numbers of electric vehicles (EVs) will be a growing challenge to the distribution networks, especially where EVs cluster in proximity on the network, for example a fleet depot. Various work is looking to tackle these issues, from smart charging (which could be managed by charging providers, by suppliers, by aggregators, or by the DNOs), vehicle-to-grid system (where EV batteries are aggregated to provide balancing services)

    - This could offer opportunities for decentralised energy schemes to offer support to EV charging hubs, particularly in rural regions with weak networks
- The electrification of heat – decarbonising the economy well require the replacement of natural gas heating with other fuels. These are likely to include biogas and hydrogen, but also electricity. Electric heating could double the peak demand of a typical house, so being able to manage this demand will be important to avoid expensive network reinforcement
    - This could offer opportunities for decentralised energy schemes to offer support to congregations of heat pumps, or district heating systems, particularly in rural regions with weak networks
- Code governance review – Ofgem is running a review on the process for managing and making amendments to the energy codes. Codes are managed in a number of different ways and it can be hard for market participants to keep track of code change and modifications, especially for smaller parties with limited resources. This can result in poor outcome for these parties, as their views and the interests of their customers are not represented. The code governance review aims to introduce reforms to standardise how codes operate and create oversight to help drive all codes in the same strategic direction

18. Technology Review

This section provides a brief overview of each of the technologies considered in this report. For each technology we have provided a basic summary, the market and land issues that mu
and opportunities for co-location with other technologies. We have a
Red indicates an unsuitable landscape for a technology, amber indica
number of factors and green indicates clear suitability.

> The primary impact of Brexit may be to make investing in foreign equipment more expensive and therefore result in only the most profitable schemes being delivered. This is a key risk to rural decentralised energy schemes looking for investors, particularly where led by the community.

19. Brexit Implications for Electricity

The precise implications of Brexit for the energy industry will ultimately depend what deal, if any, is secured with the EU for the UK's exit. Some key areas where changes will be seen and possible impacts on decentralised energy schemes are outlined below:

- The weighted average cost of capital (WACC) in the UK could increase, raising the cost of borrowing for new projects and thereby increasing development costs. Many of the most significant renewables developers in GB are European companies. A final decision on Brexit – whatever that may be – will reduce uncertainty, allowing final investment decisions on projects, though the decision may be to reject them
- Cross-border flows of power will no longer be governed by EU codes, and the GB market will no longer be coupled to the Single Electricity Market. BEIS and Ofgem are developing new access rules for interconnectors, which will likely require registration with ACER's REMIT system for cross-border trades. Tariffs imposed on electricity trade could raise prices during peak periods
    - This will increase commodity prices and reduce gains from trades, and reduce the incentive for future interconnectors to be built
    - In the long run, fewer interconnectors may require more batteries and flexible resources in GB to stabilise intermittent generation

- Depreciation against international currencies could increase import prices for gas and other fuels; as electricity prices are generally cost-reflective of gas prices, these increases will flow through to the electricity price. A weakened pound would also increase the cost of importing equipment for building new generation, storage, and expanding the electricity networks
  - Annual domestic bills in the UK rose £75 following the June 2016 vote (around 18%), and are expected to rise a further £63 (15%) in the event of a hard Brexit
  - However, increased wholesale prices may benefit generators, especially renewables generators which do not pay for fuel
- The UK will be excluded from EU solidarity rules, which will increase required gas storage volumes and prices in order to preserve security of supply against gas shortfalls; this will increase gas and electricity prices during periods of high consumption. This may make unfuelled renewable generation more investable, especially where combined with an element of storage to make power dispatchable
- EU ETS already no longer applies in the UK; emissions from 1 January 2019 are not required to surrender allowances, and the UK government did not issue certificates for the 2019 year. The EU ETS will be replaced by the Carbon Emissions Tax on 1 April 2019, which is expected to be set at £16/t, higher than the average EU ETS price but lower than prices seen in early March 2019 (around £20/t)
- The £18/t carbon floor price tax in GB will continue

With the deadline for the UK's withdrawal from the EU put back until 31 October, this uncertainty is unlikely to be resolved in the short term.

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