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Appendix A: Market Context and Prospects

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Getting to grips with the intricacies embedded in energy and water markets can be a daunting task. There is a wealth of information online to help you keep up-to-date with the latest developments, but finding what you are looking for and understanding the impact for your business can be tough. That's where Cornwall Insight comes in, providing independent and objective expertise. You can ensure your business stays ahead of the game by taking advantage of our:

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Contents

1 Introduction

1.1 Purpose

This assessment of market access, opportunities and risks in Scotland should be read alongside the main report, which also contains a summary of our findings. It has been developed to help us and the client understand the specific background in Scotland. It does not, however, represent a formal part of our deliverables.

All delivery models for community and local energy (CALE) schemes are impacted both directly and indirectly by the electricity market, and these influences are critical to their viability. The choice of route to market for export power and accessing sources of value will become increasingly important to scheme delivery in a largely subsidy-free world. These influences will continue to apply irrespective of emerging transformation and diversification opportunities with heat and transport sectors.

Despite a series of policy endorsements explicitly supporting community energy, the commercial environment facing developers of CALE projects is deteriorating. Indeed, shifts in central government policy are set to adversely impact on the outlook for community energy on both sides of the border. The Renewables Obligation (RO) was closed to new schemes from 1 April 2017, and the Feed in Tariff (FiT) arrangement is set for closure from 1 April 2019. There are due to be further rounds for the award of Contracts for Differences (CfDs), which could potentially include participation of remote island wind (RIW) in Scotland, but these are in practice for larger-scale projects and competition for funding is likely to be intense.

In particular, the commercial environment, which is already challenging, will be significantly more demanding than today for installations below 5MW, which have been the focus of the FiT regime. There is likely to be a bifurcation in the market in terms of options for existing and new schemes, with 1 April 2019 representing a landmark date for community developments; those schemes that have secured subsidy and those deployed after this date being subsidy free will fare very differently.

Against this, technology costs are falling and new revenue opportunities are set to merge. Local supply and balancing will also enable communities to capture the value of their power and increasingly the flexibility of their demand in a smart-enabled world.

1.2 What we cover

This market assessment considers:

- Some basic considerations underpinning the national electricity market framework that has generally worked to the detriment of local energy solutions
- The current market baseline, which is important in understanding choices made to date and the continued viability of existing schemes going forward. This is also relevant as active schemes already in the pipeline will be considered against this for a further year
- How the baseline will materially change from 1 April 2019, with no “first resort” sale option. Instead, dependency on negotiating commercial terms for sale of energy with market participants will become the norm for those with significant export power
- An overview of the various supply and intermediary models available
- Estimates of revenue streams and possible realisable power prices and other sources of value that could be available, and
- Changes in industry rules going forward that could influence options and prospects.

1.3 Appendix structure

In the rest of this appendix:

- Section 2 sets out headlines from the market assessment
- Section 3 looks at the market framework and sources of value, and explains why they vary markedly according to the route to market
- Section 4 addresses future opportunities that are likely to arise from current industry change processes, and
- Section 5 considers some risks and uncertainties arising from industry change processes.

In addition, there are a series of supporting annexes, some of which use confidential Cornwall Insight data:

- Annex A looks at supply competition and prices in Scotland.
- Annex B sets out information on FiT accredited generation (and RO accredited) in Scotland
- Annex C explores the value of private wires and on-site benefits
- Annex D sets out recent realised Power Purchase Agreement (PPA)
- Annex E explains embedded benefit values in the two Scottish settlement areas
- Annex F provides background on network charging in Scotland, and
- Annex G looks at electrical losses [and charges] in Scotland.

2 Headlines

The headlines from the market assessment are:

- The barriers to development of CALE projects in GB are significant. The market rules are national in scale and scope, and they penalise local supply
- The value of energy produced by community schemes varies dependent upon the route to market and its value to the consumer, but can range between 5-15p/kWh, depending on how the energy is transacted: that is, sold to the wholesale markets, provided to the end consumer in retail markets, or self-consumed to avoid imports from the grid
- Over the recent past community schemes have benefitted from guaranteed access to export markets under the FiT regime at reasonable rates, but more importantly the FiT regime has provided long-term certainty and underwritten investment as well as providing a guaranteed market
- Current FiT arrangements are set to continue until 31 March 2019; thereafter CALE projects will have to negotiate a route to market for power that cannot be used behind the meter
- In the absence of changes to cost recovery mechanisms for network and policy related costs, the value of power used on site is significant and set to increase. The current arrangements will increase incentives to use power behind the meter or alternatively to explore private wires options, though we note policy wishes to see current infrastructure and assets optimised
- This increase in value for such use reflects unavoidable increases in the cost of legacy government environmental programmes and the on-going costs of social programmes. Policy costs now represent 15% of the domestic dual fuel bill, and 25% of electricity costs
- We anticipate that "balancing costs" will also rise, as will charges for network use, especially at lower voltages
- In total these third-party changes could increase the avoided costs of behind the meter consumption of electricity ("on-site" benefits) by 40-55% over the next five years depending on whether it is a small (household) or larger HH metered LV business customer respectively
- Direct supply to customers across the public network is costly and complex, and not feasible under the current regulatory arrangements for community schemes even if it were possible to aggregate their output
- While there are limited exemptions, most supply is carried out under licence across the public system under a traditional model based around commodity supply of energy at scale. Even where statutory exemptions apply, any public export needs to involve an offtaker, who is usually a supplier, because of the obligation to register meters in central industry settlement
- Of recent, the market for PPAs or offtake agreements has become relatively active reflecting growing demand for green power (though less so at smaller scale), with short-term rates between £52-60/MWh. However due to a recent resurgence of wholesale power prices, values of small-scale power generation on short-term contracts have increased. FiT eligible sites received an average price of £69/MWh in the Winter 18 renewable energy auction run by the NFPA
- We expect the long-term market for PPAs in this smaller-scale segment of the market to be sluggish from April 2019 as the market adjusts to the removal of FiTs for new projects, though as noted above rising prices are attracting more offtakers to small-scale power generation and more suppliers are entering the market targeting smart, flexible developments
- Forward power prices are expected to fall over the medium term, especially winter rates, with the forward curve presently reflecting a 10% fall by winter 2020, largely as a result of the price cannibalisation we have noted as increased levels of subsidised renewables comes onto the system

- However, we expect the following factors to increasingly come into play, which should help community projects:
  - Technology costs of all mainstream renewables generation continue to fall, though forecasts for smaller-scale sites remain above utility-scale
  - Storage-based technologies are widely anticipated to become commercially viable within the next two or three years, with the expectation they will fundamentally change the options available to CALE developers both within communities and also for households behind the meter
  - Power to gas technologies are being proven and supply chains demonstrated, which should increase optionality for storage and transfer of energy, especially sites that are network constrained
  - Embedded benefit rates[1] in Scotland should continue to add up to £10/MWh, dependent on technology, location, and a number of regulatory decisions. though these values will remain below national averages[2]. In particular, increases in balancing charges could, subject to decisions on network cost recovery to be made by Ofgem in the next few years, feed through to embedded benefit payments, which should more than off-set the removal of the triad benefit, hence the steady increase in values going forward, and
  - Smart functionality will become mainstream enabling consumers and communities to understand and better control costs and consumption.
- Additionally, new sources of value should be available for CALE projects:
  - New projects without subsidy would probably be able to participate in the Capacity Market. This will require aggregation for community schemes for both generation and demand-side response to meet administered thresholds, but could add £1.50-£10/MWh (dependent on technology) to revenues if prices recover to the £25/kW forecast by some commentators during the next decade
  - New revenue opportunities will arise from sale of flexibility into balancing markets (both national and, once they evolve under DSO initiatives, regional) though these will likely require aggregation of local sites
  - Energy arbitrage opportunities and incentives to change production and consumption behaviour will exist as a result of the combination of smart meters and implementation of time of use (ToU) pricing in a world of half hourly settlement (HHS) from 2020 under current expectations
  - Energy imbalance prices are becoming more volatile, and the value of local matching will increase as a result. This will favour controllable technologies (and penalise intermittent ones) but also incentivise better forecasting and use of energy by end consumers, which local communities could be well placed to exploit, and
  - From progression of low-level rule changes that remove outmoded aspects of cost allocation within market and regulatory rules. For instance:
    - Especially around settlement rules that do not permit accurate allocation of costs at the household/individual meter level
    - Arrangements in the GB market for costing losses in the transmission and distribution of power, and then allocating these costs to physical participants, are complicated but do not seem to reflect the benefit of balancing local supply and demand

[1] These are costs avoided by a generator's counter-party from netting off local production against local consumption, and it is conventional for the greater part of this to be passed back to the generator.

[2] This is despite regulatory intervention to reduce "triad" benefits, which from April 2019 will be cut from average national values of £50/kW to less than £10/kW. Rates in Scotland, which have traditionally been lower than the national average, will quickly fall to zero A judicial review is underway to Ofgem's decision to implement these new arrangements in the form of industry code changes CMP264/265. Transmission charges for 2018-19 have already been set to start the phase in of the reduction over three years.

- Likewise, we would expect arrangements to be developed that sharpen incentives to disconnect from the public system during high demand periods and to encourage demand-turn-up when supply outstrips demand.

3 A national market

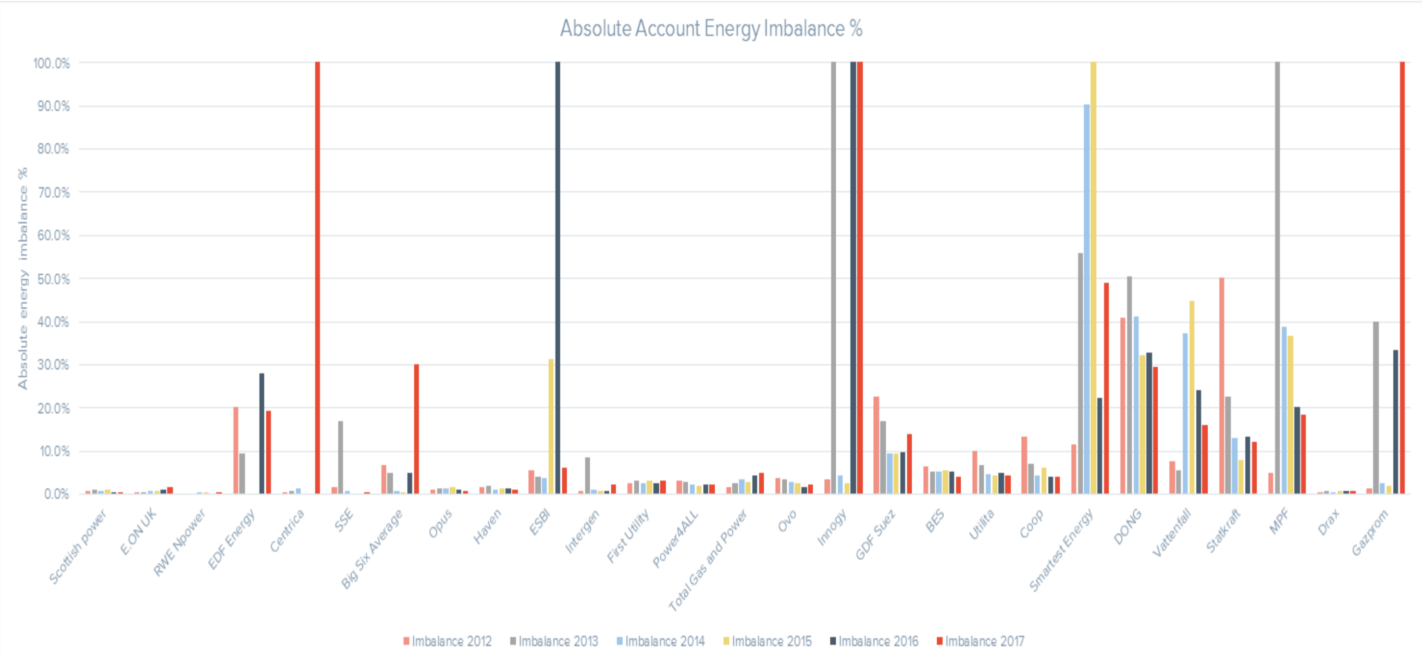
The barriers to development of local electricity markets in GB are significant. The market rules established from 2001 and implemented in full in Scotland in April 2005 are national in scale and scope, create significant costs associated with market entry and penalise regional supply and imbalances.

To illustrate, a national supplier producing energy in the north of Scotland can supply its customers in the south of England, and provided the volumes (net of thermal losses) are comparable the supplier can avoid energy imbalance charges, which can be high and volatile. In circumstances where its generation is not available, it can use its balance sheet to contract forward on wholesale markets for replacement power.

In contrast, a community generation scheme would usually have to find a supplier to move its power over the public system even if this were to social housing or community buildings across the road.[3] The supplier would usually require the generator and its "customers" to notify their production and consumption intentions in advance, and if it varied from these volumes it would face imbalance charges. Even if its production and consumption were entirely in line with its expectations, it would still see top-up and spill charges for situations where its production and consumption did not match, and the supplier would probably look to reflect its marginal imbalance costs in the price of transactions.

The advantage of a scale, and a diversified portfolio is illustrated at Figure 1. This shows that the average annual imbalance position of the main electricity trading parties over the past five years tends towards zero, while merchant players and independent suppliers carry larger imbalances. Energy imbalance rules ("cash-out") have been designed to incentivise parties to contract to minimise uncontracted energy on the system (in a system where contracts have to be notified ahead of delivery). Imbalance charges can rise to £3,000/MWh in instances of significant stress and are set to be subject to a raised cap of £6,000/MWh from 1 November 2018. In turn, exposure to imbalance prices is the primary reason used by suppliers for discounting PPA contract prices and imposing non-performance penalties.

Figure 1: Imbalance penalties in the GB electricity market



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[3] Acting as an unlicensed supplier under the exemptions regime still requires working with a supplier so meters can be settled in central industry processes. Becoming a supplier is expensive and brings with it complex compliance obligations, and is utilised usually only where a player intends to acquire scale.

The introduction of the FiT regime in April 2010 transformed this situation for community schemes. It replaced the relatively complex incentive arrangements under the Renewables Obligation (RO) – which required the producer to agree a bilateral contract for both its power generated and its Renewable Obligation Certificates (ROCs) – for low-carbon generation below 5MW. It also allowed a local producer to require any one of several obligated suppliers to offer it terms for its surplus power (the administered export rate) at posted rates set by DECC/BEIS. This low-risk, "safe harbour" is to be removed for new schemes from April 2019.

Meanwhile, the economics of commodity electricity supply at the local level have deteriorated over the recent past, and the business case for new schemes with it. The obvious examples are the removal of Levy Exemption Certificates (LECs) in July 2015, and reductions implemented since 1 April 2018 implement to the so-called "triad" benefit (and further reductions to apply in April 2019 and April 2020).

3.1 The current commercial environment

The household energy market in Scotland is characterised by:

- The fewest household energy consumers in North Scotland of any of the 14 supply regions in Great Britain. Electricity consumers number 36% of the Great British supply region average and gas consumers 23% of the Great British average
- Only 57% of electricity consumers in North Scotland can access mains gas. This is also the lowest proportion of any region in Great Britain, where access to gas averages over 80% of households. Of those that have access to gas, a similar proportion sign up to dual fuel tariffs in North Scotland as those elsewhere in Great Britain, and
- Several independent suppliers – notably OVO Energy, Robin Hood Energy and its attendant white label suppliers – operating elsewhere in Great Britain do not actively offer tariffs in South and/or North Scotland.

Three suppliers – British Gas, Scottish Power and SSE – dominate the market share for electricity customers in Scotland (North Scotland 74.5%, South Scotland 63.8%), out of a total of 19 medium-to-large suppliers. The incumbent supplier share (from when the market was opened-up) now accounts for 53.1% in North Scotland, and 34.1% in South Scotland. Although British Gas is responsible for a large take of current market share here (15.9% in North Scotland and 19.0% in South Scotland), an increasing number of small and medium-sized suppliers are encroaching into the traditional markets of the larger incumbents.

The same three suppliers – British Gas, Scottish Power and SSE – also dominate the dual fuel market share customers in Scotland (North Scotland 71.0%, South Scotland 57.0%), out of a total of 16 medium-to-large suppliers offering dual-fuel accounts. The incumbent supplier share now accounts for 36.2% in North Scotland, and 20.9% in South Scotland. British Gas is responsible for a large take of current market share here, 27.5% in North Scotland and 23.8% in South Scotland and so has been separately identified. In the south Scotland region in particular, small and medium suppliers represent a significant portion (23.8%) of the market share.

Fuel poverty numbers in Scotland are well above levels elsewhere. The England only figure (2015 data) was 11.4%, with a Scotland average (2016) of 26.5% (heavily skewed to North Scotland). This reflects [lower average incomes,] higher average bills and the high proportion of electricity only supply.

Further notes on the competitive retail landscape are at Annex A.

3.2 Routes to market

Historically, virtually all CALE projects in GB have developed outside of formal energy industry regulation and the national market context set out above. All generation developments below 50MW and all supply below 5MW are licence exempt[4].

[4] http://www.legislation.gov.uk/uksi/2001/3270/contents/made

Community schemes are typically at the very small end of this space, with the average size around 300kW for the case studies considered for the landscaping work, and this is not inconsistent with project size within the wider market. Most of these developed under the FiT regime after April 2010 or were extended after this date.

In practice, most schemes will mix elements of different commercial models, but with the focus on supply behind the meter and exports under FiT. However, there are several baseline models that need to be sketched out, as these provide the basis of our "taxonomy" used in the main report.

3.2.1 Direct and intermediary supply options

We authored a report in 2013 for Community Energy Scotland (CES) entitled *Assessment of routes to market for community energy projects.*[5] This addressed various avenues for market access, though we were asked in our terms of reference to specifically explore opportunities involving direct supply.

Our conclusion, which would be little different today, was that there were several supply models that could be considered either by a developer becoming the supplier to customers directly or by negotiating terms with a third party licensed supplier.

These included:

- Licensed supply
- Licence-lite supply
- White label supply[6]
- "Sleeving"[7]

These models are amply described in the report for CES and several other reports we have authored. However, in practice, direct supply under a full licence was - and still is - considered to be unduly costly and complex, especially given the typically small-scale of community assets even if these could be aggregated on a regional basis.

Licence lite is a regulatory innovation introduced in April 2009 that allows a customer facing supplier to contract out compliance with complex industry codes, especially with regard to registration and settlement of meters. As yet it has experienced minimal uptake, and it is seen as very complex. Participants seeking intermediary arrangements have tended to prefer to explore "sleeving" and "white label" arrangements that are underpinned contractually rather than the licence lite option.

Supply through intermediaries (notably sleeving and white label) could take several forms but would usually result in ceding too much value to the counterparty and significantly limiting the flexibility of the community project in terms of pricing and end consumer tariff innovation. In practice, few community schemes have historically attracted much interest in a supply market in which the large majority of suppliers have business models that are predicated on achieving scale.

Costs of entering the supply market have fallen in the interim, but not to the point where they fundamentally change this assessment. What has changed is that over this period a large number of diverse suppliers have entered the market increasing the number of counter-parties. A handful of these are beginning to position

[5] The report no longer seems to be posted on the CES site.

[6] A white label supply is where the local supplying entity uses an existing third-party supplier to procure, balance and settle its customers' requirements.

[7] Sleeving is where a producer flows power across the public system to its own demand sites, and a third-party supplier nets the two, buying any surplus from the generation site/s or making good any shortfall to the demand sites.

themselves as local specialists, notably through collective switches or, increasingly, local white labels. Novel forms of sleeved deals are also being piloted in a limited number of cases.

White label collaborations are presently receiving a lot of attention. They are not just about cost sharing. Working alongside an established player can help manage risks in a market-place that is unfamiliar. Sainsbury's (with Centrica) and Marks & Spencer (with SSE) have used such alliances successfully for years, although the SSE/ M&S link has recently broken. Ebico, a not for profit supplier who specialises in supply to the social housing sector, partnered with SSE for many years, showing this can be an enduring model, although it swapped supply partners in 2017.

OVO pushed the white label approach around 3-4 years ago with its community energy offering (implemented in Peterborough and Southend, among other places), but is reported to no longer be promoting its OVO Communities offering[8]. There was a spate of local authority backed white label launches in 2017, several involving Robin Hood Energy, itself promoted primarily as a municipal supply company.[9] Current white labels are shown at Figure 2.[10]

A variant on this approach are supply offers that explicitly link local low-carbon assets with local consumers. Both Good Energy and Our Power are also looking to link local production assets with local consumers. Good Energy has developed over 150MW of renewables, and it administers 137,000 FiT sites (as of Q1 2017), and Our Power has over 6MW (4.7MW hydro, 1.5MW wind). In some instances, such as the Delabole scheme in the south west of England, a local tariff is offered tied to the output of the generation scheme.

Sleeving arrangements have in the past tended to be between large corporates and certain of the Big Six suppliers (notably npower and EDF Energy), with the customer using their size and negotiating power to supply power from their own renewable assets to their sites. Marks and Spencer is possibly the best known example. The supplier facilitates this by registering the meters and paying charges associated with delivery of the power, and then providing the balance of power to the customers sites.

Some of the case studies we have examined as part of our landscaping work are in effect variants of a sleeving model. The best examples are Bethesda and MullACCESS where Cooperative Energy and Good Energy respectively provide the intermediary and balancing services. However, the former operates the arrangements under an Elexon rules dispensation, and in the latter the supplier appears to take on the risk of cost allocation rules that would otherwise distort the efficacy of the scheme.

Figure 2: Emerging intermediary supply models

White label supplier	Owner	Partner (if applicable)	Start Date	Reported number of domestic customer accounts
Angelic Energy	Islington Council	Robin Hood Energy	October 2017	None available
CitizEn Energy	Southampton City Council	Robin Hood Energy	July 2018	None available
Ebico	Certified social enterprise	Robin Hood Energy	January 2017	None available
EnergySW	Advantage SW (social housing)	OVO Communities	November 2017	None available
Fairerpower	Cheshire East Council	OVO Communities	March 2015	8,000 (30 September 2017)

[8] https://www.OVOenergy.com/binaries/content/assets/documents/pdfs/OVO-communities-brochure.pdf

[9] As does Bristol Energy Company, although as yet this has not launched any while label offerings but has indicated a willingness to do so. https://utilityweek.co.uk/bristol-energy-aims-to-be-in-profit-by-2021/ .

[10] Southampton has recently also announced a new Robin Hood Energy white label.

White label supplier	Owner	Partner (if applicable)	Start Date	Reported number of domestic customer accounts
Fosse Energy	Leicester City and Leicestershire County Councils	Robin Hood Energy	August 2018	None available
Glide	Privately-owned company	Spark	March 2018	None available
Great North Energy	Doncaster Council	Robin Hood Energy	November 2017	None available
Hebrides Energy	Community-interest company	Our Power (previously with GB Energy and Co-operative Energy)	March 2018	None available
LECCY	Liverpool City Council	Robin Hood Energy	April 2017	None available
M&S Energy	M&S	Octopus Energy	July 2018	None available
Outfox the Market and Economy7 Energy	Fischer Energy	-	September 2017	None available
Peterborough Energy	Peterborough City Council	OVO Communities	June 2015	7,000 (30 June 2017)
Powershop	npower	-	January 2017	10,000 (11 August 2017)
Qwest Energy	Cheshire West and Chester Council	ENGIE	September 2018	None available
RAM Energy	Derby City Council	Robin Hood Energy	September 2017	None available
Sainsbury's Energy	British Gas	-	February 2011	None available
Southend Energy	Southend-on-Sea Borough Council	OVO Communities	May 2015	5,300 (31 March 2017)
Split the Bills	Privately-owned company	Nabuh Energy	April 2011	None available
White Rose Energy	Leeds City Council	Robin Hood Energy	September 2016	3,000 (6 January 2017)
Wigan Warriors Energy and Wasps Energy	npower	-	April 2018	None available
Your Energy Sussex	West Sussex Council	Robin Hood Energy	February 2018	None available

Source: Cornwall Insight

In Scotland, two specific supply initiatives should be highlighted:

- Our Power launched as a specialist regional supplier in 2015. It is a social enterprise and operates not-for-profit, and is owned by social housing providers, community organisations and local authorities. It sources locally produced low-carbon generation and supplies it to largely social housing groups in Scotland. Cornwall Insight estimates that it has over 15,000 customers in the South of Scotland and 5,000 in the

North. They offer the 3rd or 4th lowest tariff in Scotland for mainstream tariffs, but it is the lowest prepayment meter supplier, and

- Hebrides Energy launched on 6 March 2018 as a local supply offering, in collaboration with Our Power.[11] Stakeholders on Lewis had primarily embarked on a white label collaboration with GB Energy Supply in 2015, but that supplier failed in November 2016 with the result that its customers were transferred to Cooperative Energy.

3.2.2 Self-supply and private wires

Off-market supply options such as "behind the meter"[12] or through "private wires" [13] are highly dependent on existing local circumstances (on-site demand and off-grid networks respectively).

In the case of behind the meter or "off grid" schemes, the value of a project or the commercial terms (where there are any) are usually set by reference to the avoided cost of a comparable imported supply. In this report, several of the schemes in the landscaping work have relatively significant load behind the meter.

In addition to FiT production payments or the issue of ROCs, energy consumed on site will have a value to the operator. This value is best seen as an avoided cost measured against local supplier rates (in other words, without the generation facility, the energy which the on-site consumer would have had to purchase from a supplier through the public network).

Rates for retail supply vary widely, both nationally and regionally. Average supply tariffs vary by 14 differentiated regions that mirror the 14 distribution licence zones. In these, there are unique tariffs for both transmission and distribution charges. They are based on common methodologies but reflect the different assets and topography within each area.

In Scotland there are two such zones, North of Scotland and South of Scotland. This affects not just the network charges that must be paid but also the "embedded benefits" that can be earned by a producer. Embedded benefits have historically been very important for larger distribution-connected generation, as explained below.

Within the two Scottish settlement zones supply tariffs also vary reflecting different supplier costs and strategies. Cornwall Insight's July retail tariff report has been used to derive the following tariff benchmarks, shown in Figure 3 (South Scotland) and Figure 4 (North Scotland), which can be seen as representative of the value of costs avoided from self-supply.

[11] http://www.welovestornoway.com/index.php/9638-cheaper-energy-pledge-from-local-supply-company?highlight=WyJlbGVjdHJpY2l0eSIsImVsZWN0cmljYWwiLCJlbGVjdHJpYyIsImVsZWN0cmljcyIsImVsZWN0cmljYWxzIiwidGFyaWZmIiwidGFyaWZmcyIsInRhcmlmZiciLCJ0YXJpZmYnLiIsImVsZWN0cmljaXR5IHRhcmlmZiJd

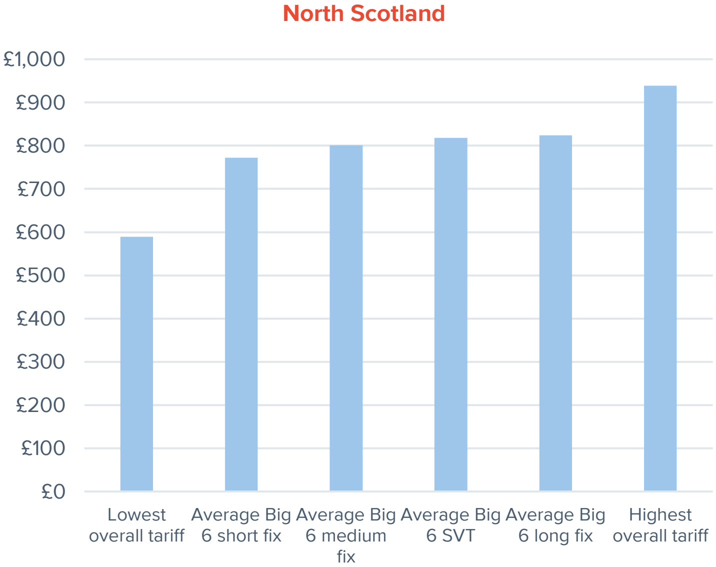
[12] Essentially where the developer or operator nets the production against its own consumption. These are sometimes termed "off-grid" schemes.

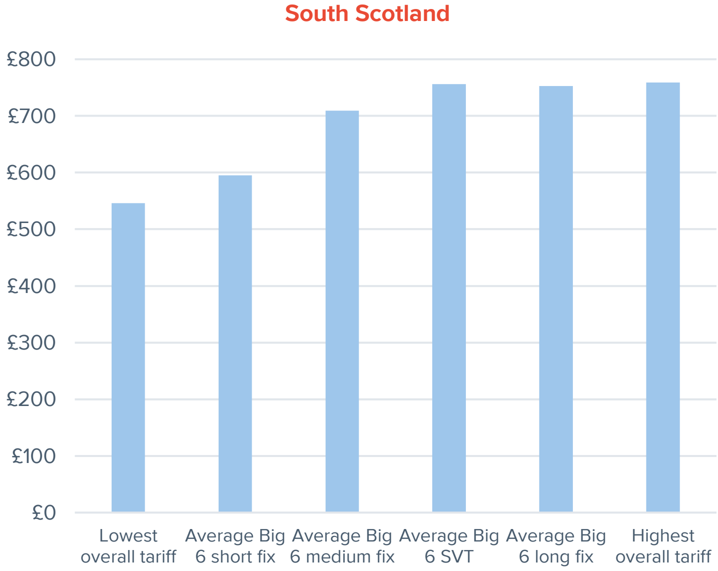
[13] This are off the public system owned by the licensed distributors but extend onto a contiguous site or sites to that of the developer/operator.

We have chosen electricity only tariffs and presented information for Economy 7 tariffs (as of October 2018) using the Ofgem Typical Domestic Consumption Value (TDCV) for a medium Economy 7 customer user (4,200kWh/yr) paying by direct debit. This has been used as a comparator to show the typical cost paid for by an off-gas grid consumer in Scotland that has electric heating.

They translate into average tariff rates (blending unit and standing charge rates) of 13.8p/kWh-20.7p/kWh in Southern Scotland and 14.0p/kWh-22.4p/kWh in Northern Scotland.

Figures 3 and Figure 4: Prevailing electricity supply tariffs in the two Scottish settlement zones[14]





Source: Cornwall Insight

We have also selected electricity only tariffs for prepayment meters (PPM) (as of October 2018) in Figure 5 (South Scotland) and Figure 6 (North Scotland). This has also been used as a comparator to show the typical cost paid for by an off-gas grid consumer which uses a PPM.

They translate into average tariff rates (blending unit and standing charge rates) of 13.7p/kWh-15.7p/kWh in Southern Scotland and 14.7/kWh-16.5/kWh in Northern Scotland. It needs to be remembered that PPM tariffs since April 2017 have been subject to an Ofgem-set price cap, which has had the effect of compressing the range of illustrative prices in a market where PPM prices have traditionally been above standard credit prices.

[14] End October 2018 data. Economy 7, annual consumption (medium user) 4,200kWh/yr.

Figure 5 and 6: Prevailing supply tariffs in the two Scottish settlement zones for PPM[15]

Source: Cornwall Insight

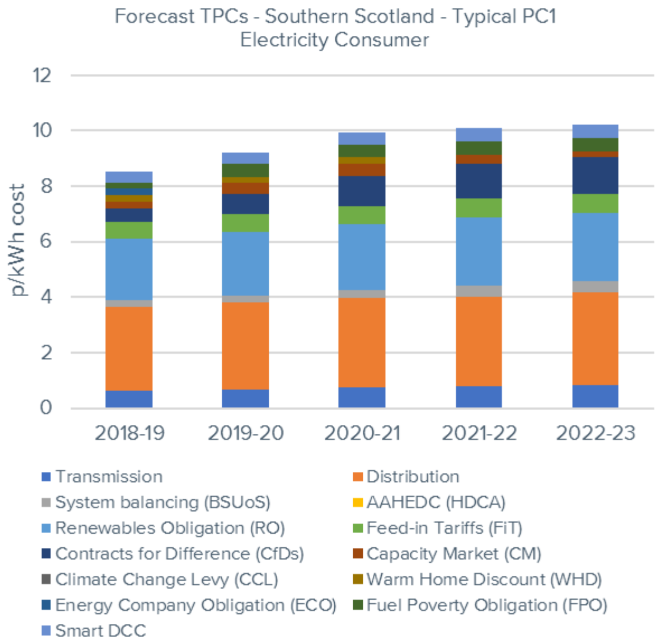
The economic case for both self-supply and private wires can be very strong for consumers. A note on the options and benefits is at Annex C. While costs of enabling physical work, including any private networks, need to be taken into account, avoidance of network and policy costs could produce savings in excess of 5p/kWh relative to current supplier tariffs. We estimate that by 2022-23 this figure could rise to 7p/kWh. In this report three of the case studies we have considered have private wires elements.

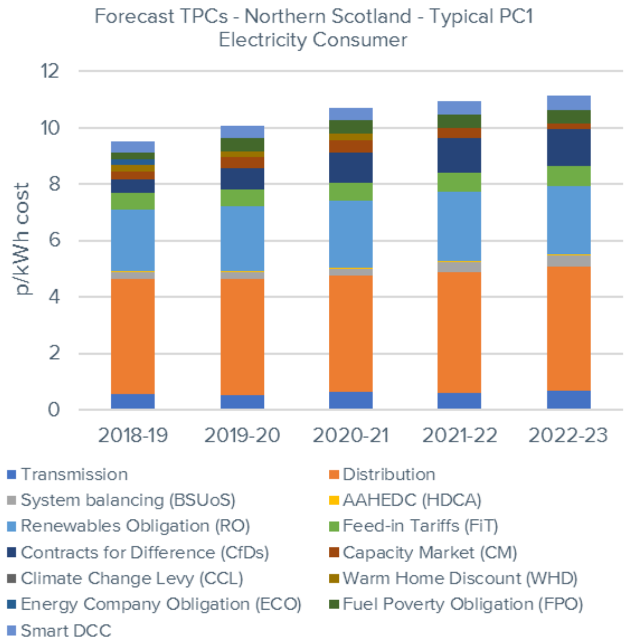
Figure 7 and 8 show Cornwall Insight's forecast of third party charges (TPCs) for a household electricity consumer in Southern and Northern regions. The individual elements include the costs levied on a supplier for use of the transmission and distribution networks, government environmental and social schemes, and the cost of the newly created smart meter communications infrastructure. In essence, these are all costs passed onto the customer except the cost of procuring the energy from the wholesale market and the supplier's own overheads (including profit margin).

In aggregate we estimate TPCs are set to rise 20% in the South of Scotland and 17% in the North of Scotland over the next five years.

[15] End October 2018.

Figures 7 and Figure 8: Breakdown of typical domestic bill, and impact of rising TPCs





Source: Cornwall Insight

3.2.3 FiT regime

In practice, the need to engage in supply to the end consumer has not been an issue, as most community projects (at least since April 2010) have been FiT accredited. As well as delivering the generation FiT “incentive” payment, developers have been able to require call down of posted terms for exports to realise value for power exported onto the public system. This removes the need to negotiate terms or a route to market from a number of counterparties and provides certainty to project backers as incentive payments will run for 20 years.

In this report, five of the case studies we have considered have been developed under the FiT regime, which in turn is a microcosm of the wider commercial environment within which most community schemes have developed in recent years.

An Annex on FiT and RO deployment in Scotland is at Annex B.

Against this, the FiT regime has been subject to high levels of government intervention since its launch with production rates generally being reduced over the life of the scheme. The central administration of generation and export rates does not provide the opportunity for generators to benefit from market movements. In practice, this latter point has not been an issue as wholesale electricity prices have tended to be depressed over the recent past and as a consequence the current FiT export rate for post November 2012 accredited installations could be regarded as attractive relative to market values. The flip side of this is that, in the absence of a rebound in power prices, new subsidy-free schemes commissioned after April 2019 will be looking at a market environment with bearish prices.

Export rates for FiT accredited plant have been posted by central government since April 2010, and these must be offered by licensed suppliers mandatorily if they are large or voluntarily for small providers. There are two rates dependent on the date of accreditation. Plant accredited prior to 13 November 2012 presently earn

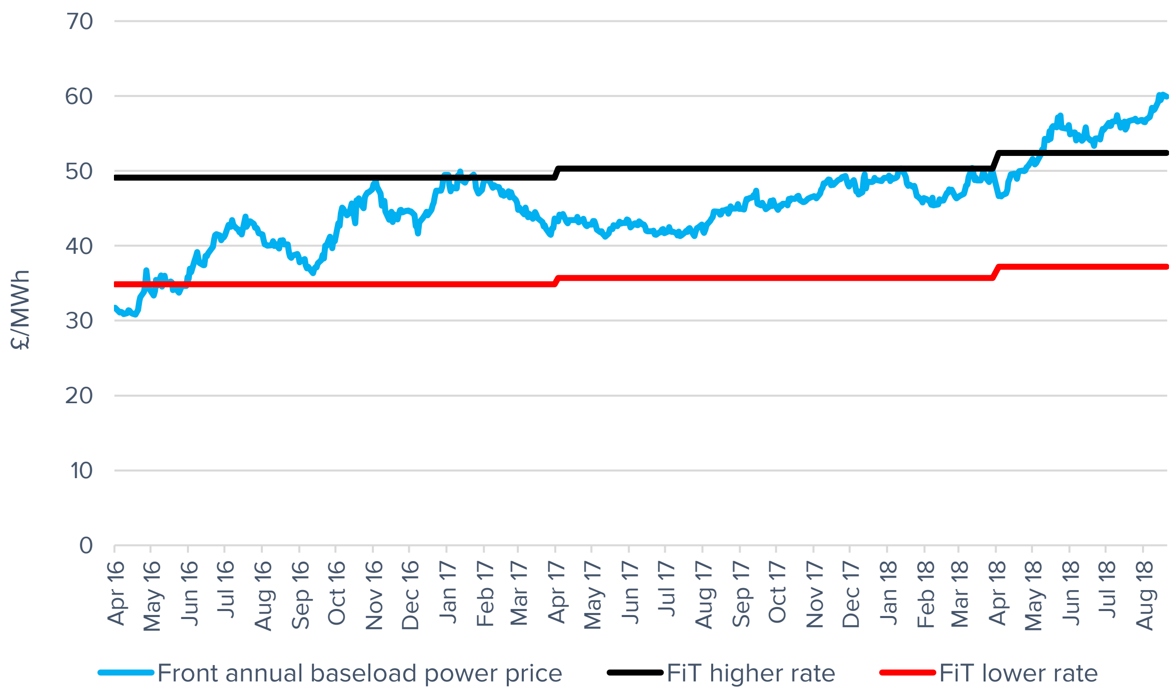
3.57p/kWh, after that 5.24p/kWh.[16] These figures are adjusted for inflation annually, with the next adjustment due in April 2019.

A licensed supplier must offer a developer FiT terms once it exceeds 250,000 domestic electricity accounts, when it becomes an "obligated FiT supplier". Other licensed suppliers can offer terms as voluntary FiT suppliers. There are now 13[17] obligated FiT suppliers, though they compete for FiT customers to different degrees. Of the other licensed suppliers, 32[18] have voluntary acceded as FiT suppliers, with some various times actively targeting FiT customers. No suppliers, as far as we are aware, offer terms above the posted export FiT rate, though payment terms can differ.

FiT generators have the right to opt-out/in of the administered export rate on an annual basis, provided they give sufficient notice to their FiT supplier.

Figure 9 shows the posted FiT export rates relative to the annual power price prevailing at the time.

Figure 9: FiT export rates vs. wholesale electricity rates



Source: Cornwall Insight

FiT suppliers active in the export market at September 2016 and September 2017 are shown at Figure 10. From this chart, it appears that:

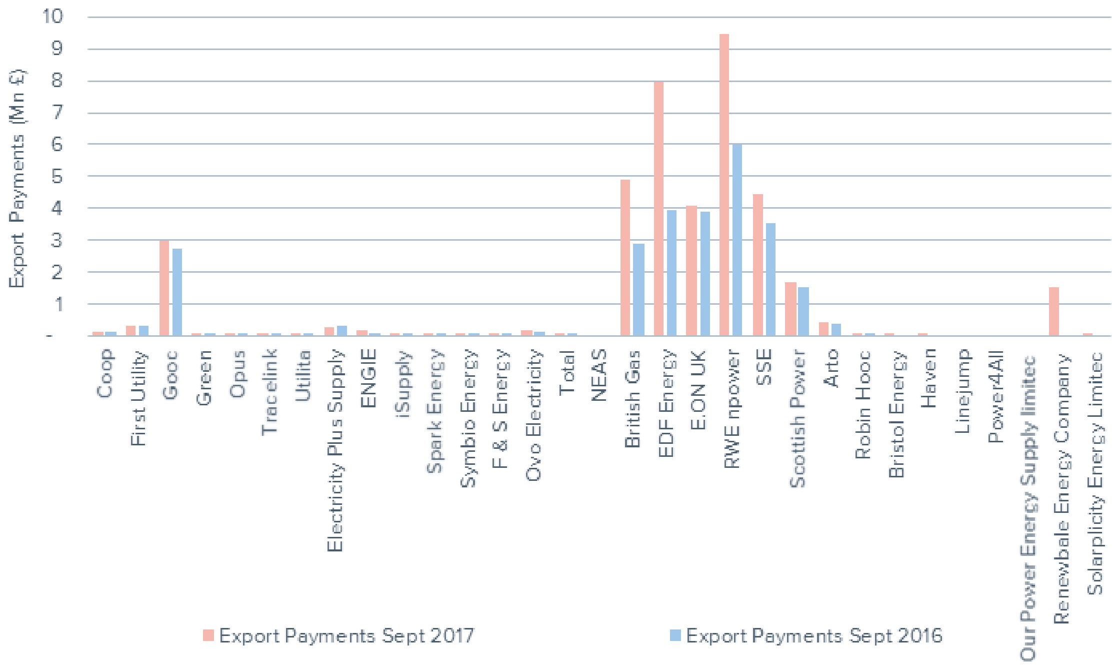
- Three of the Big Six appear to be actively targeting this part of the market, and
- Good Energy and the Renewable Energy Company (Ecotricity) are not FiT obligated suppliers but are very active, and
- Additionally, four newer entrants have recently or are poised to become FiT obligated suppliers.

[16] These rates will be adjusted by inflation from 1 April 2018.

[17] The Big Six energy suppliers, plus Economy, Hudson, OVO, Utilita, Utility Warehouse (aka Telecom Plus), First Utility and Coop

[18] The full list can be found here: https://www.ofgem.gov.uk/environmental-programmes/fit/contacts-guidance-and-resources/fit-licensee-contact-details

Figure 10: FiT suppliers and export payments



Legacy schemes that are accredited under the FiTs regime by 31 March 2019 should continue to earn the generation (production) FiT rates for the full 20-year period after their commissioning date. We would expect to see continuing and perhaps increasing competition in this space going forward as suppliers, especially new entrants, emphasise both their green offerings and/or local tariffs.

3.2.4 PPAs

The facility to earn the export FiT tariff is optional. At least nationally, some larger FiT accredited schemes have preferred instead to negotiate PPAs for their exports. The main advantage of doing this is they can often negotiate better rates for the surplus energy, largely because the counterparty supplier will usually agree to share the value of “embedded benefits”[19] with the producer[20]. Usually, however, a supplier can only be expected to seek PPAs with sites that meet defined criteria, for instance they are larger sites that offer more predictable exports or are in key locations that can support the supplier’s wider regional customer base. In this context the posted FiT export rate could be seen as a floor price.

PPAs have been particularly relevant for community schemes in the past owing to their relatively small size, but they will be the prime route to market for new developments after 1 April 2019 in a “subsidy free” world.

Good Energy, Opus, Coop, Ecotricity, OVO, F&S, Tradelink, and the Big Six are all active in the FiT PPA space. That said, we have heard anecdotally that it remains difficult in the FiT market to actively persuade customers to switch away from the export tariff. We have also been told that interest from community energy groups in developing renewable energy remains positive, but they are struggling to find a route to market for new projects. The emerging subsidy-free solar farm space consists entirely of double figure MW scale schemes. They are made viable by sophisticated financing and business models that include “revenue stacking” (e.g.

[19] Embedded benefits are cost savings that can be achieved by a supplier through electricity settlement. They do so by netting exports from distributed generation off their regional consumption, thus reducing the volume base on which certain industry charges are levied. The main ones are transmission demand charges and balancing charges. It is conventional for the generator to be awarded in excess of 90% of the benefits earned by the supplier on its exports under the PPA.

[20] Historically these values were higher because some embedded benefit values were higher, and an exported MWh could also earn a Levy Exemption Certificate (LEC). As we see below, certain embedded values are being reduced, and LECs were withdrawn from the market in [mid 2015].

from co-located storage) and sharing grid connections with other assets. These opportunities may not be available to community schemes.

Prevailing PPA rates in today's market place vary widely based on technology, location, size but also each supplier's commercial strategy and whether it wishes to compete in this market for export power. Cornwall Insight produces quarterly PPA market assessments. The most recent assessment was at October 2018, and this showed benchmark average prices for:

- Solar, wind as well as high load factor technologies such as anaerobic digestion are all assessed at a premium to traded market prices, reflecting incremental value of embedded benefits and to a lesser extent, REGOs[21], and
- The traded seasonal price is set to fall steadily based on current and future market conditions.

Further information on our current PPA price assessments is at Annex D.

One popular route to market is through the "e-power" auction platform operated by the NFPA.[22] The auction allows suppliers to offer to buy exports from low-carbon generation by site by distribution network zone for a period that is typically not less than six months and not more than 12 months. The winning supplier enters into a contract with the site registrant, which is in effect a standard, short-term PPA.

In 2017, 21 sites in Scotland entered arrangements with 8 suppliers, 3 in the South of Scotland, 18 in the North. Of these 21, 4 were FiT accredited.

Two sites in the case studies receive Rocs. The arrangements are similar in terms of production incentives/MWh, but there are no export tariffs. For Roc-accredited schemes, they must negotiate a PPA with an intermediary or a supplier. Rates for power can vary widely by location, size and technology. Rocs, however, tend to have a market benchmark price.[23] A large number of sites use the NFPA's sister e-ROC auction for this purpose, which has been operational since 2008.

The Roc regime for new build was closed April 2017.[24]

3.2.5 Collective switches

Collective switches, especially municipally led, have been popular since 2012 when DECC (now BEIS) was promoted them as part of its Cheaper Energy Together Fund.[25] A number of different type of arrangements of this type have occurred since, but with mixed and possibly diminishing success. The issues seem to flow from problems with engagement, with customers having to opt-in once to participate and then opt in again in response to the winning tender.

Ofgem recently ran a trial of an opt-out scheme involving 50,000 customers of one the Big Six suppliers. This trial, held in February to April 2018, resulted in 22.4% of customers switching, saving an average of £300 per annum. It will follow up this trial with two larger scale trials later in 2018. More details are here.

Price differential between tariffs offered through collective switches and cheapest tariff on the market are shown in the figure below. The key points are:

- Since the end of 2016, the number of collective switches has declined
- The last time a collective switch tariff was cheaper than the best offer in the market was April 2017, and

[21] Renewable Energy Guarantees of Origin (REGOs) – these guarantee the provenance of low-carbon electricity, and have a value to a supplier to validate its final disclosure reporting and green tariffs.

[22] Non-Fossil Purchasing Agency, here.

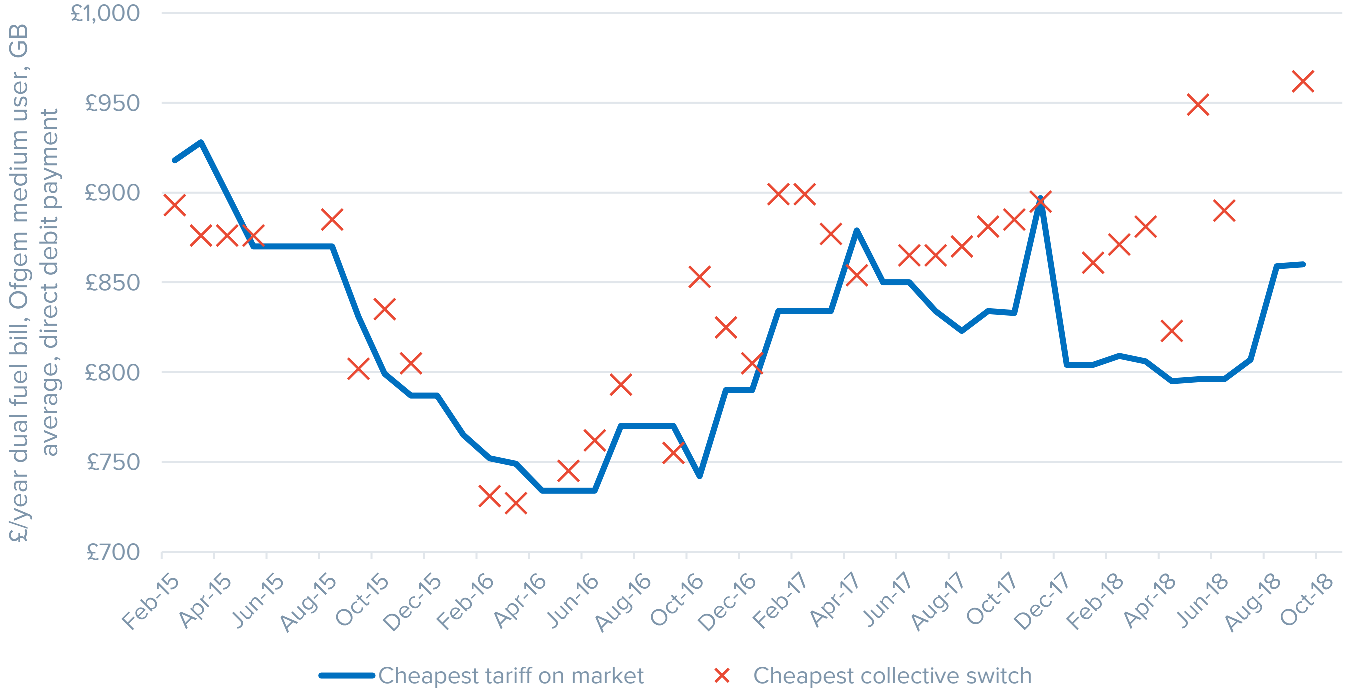
[23] This is set by reference to assessments of the total forecast number of Rocs in the market relative to the total obligation level set in advance on an annual basis by BEIS. The higher the expected shortfall between supply and demand, the higher the price will rise. The current target setting methodology employed by BEIS looks to achieve a headroom level of about 10% between the target and the assessed level of expected Rocs.

[24] There are some exceptions under grace period rules, but these must be closed out in GB by 31 March 2019.

[25] https://www.gov.uk/guidance/collective-switching-and-purchasing

- Suppliers are using collective switches to target specific customers.

Figure 11: Collective switches compared to the lowest tariff on the market (£/year dual fuel bill, Ofgem medium user, GB average, direct debit payment)



On the supplier side several have tried this route to market, but recent instances have tended to be dominated by the Big Six looking to promote fixed allocation schemes around specific tariff offerings. Key points are:

- Collective switching was formerly a key route to market for small suppliers but has come to be dominated by large suppliers. 12 out of the last 19 switches were won by either SSE, EDF Energy or British Gas
- It has become common practice for small and medium suppliers to limit the number of places available on each collective tariff, usually under 25,000, and
- Of the small suppliers, Octopus Energy seems to be the most active in the collective switching market, winning three collective switches in the last year, most recently the IKEA Big Clean Switch.

3.2.6 Conclusion

In summary, looking across these routes to market, it is clear that the value of the power generated on site can have a value that varies from between 3.5p/kWh (the lowest FiT rate) to nearly 20p/kWh (the highest retail rate). Probably a more representative comparison is 5p/kWh (the post November 2012 FiT export rate) and 10p/kWh (which can be approximated in two ways: first, after embedded benefits and retail margin are added to the export rate; or second, using a netback calculation from a more typical retail rate but subtracting all delivery and supplier costs).

In terms of consumer savings under collective switches, these have tended to diminish but that reflects the different commercial priorities of different suppliers. For disengaged customers the savings relative to a reasonably priced fixed offer are likely to be significant.

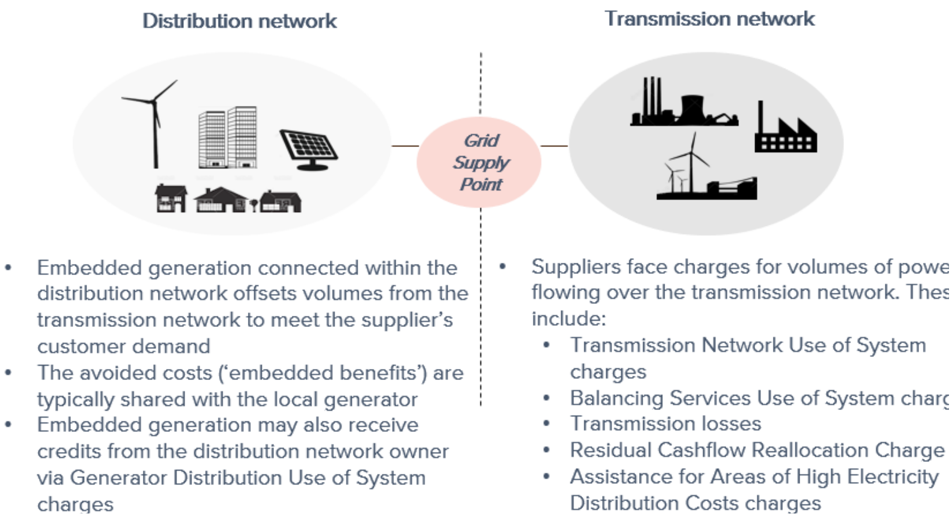
3.3 Network issues and embedded benefits

In addition to the value of the energy, the following factors need to be taken into account.

3.3.1 Embedded benefits

Embedded Benefits is the term used to describe the additional revenue that an asset that exports may earn if they connect directly to the distribution network rather than the transmission network. These embedded benefits reflect the costs avoided by not using the transmission network. In all we believe embedded benefit values could be to the order of £10/MWh in Scotland, depending on location and technology. Further detail on these values is at Annex E.

Figure 12: Embedded benefits



Concern has been raised by Ofgem that the current level of embedded benefits may be over-compensating generators for the level of the costs avoided.

Consequently, the level of embedded benefits is under review and several changes are progressing in this area. These changes are either covered under the three charging reviews that are currently underway or subject to change proposals under the relevant industry code (as described below in section 5).

There are several categories of embedded benefits[26], which are listed below:

- Transmission Network Use of System (TNUoS) (known as the **Triad benefit**)
  - Where the customer is settled half hourly the TNUoS charge is applied as a £/kW charge based on the average consumption in the three highest half hours of demand between November and February separated by 10 days. The £/kW charge changes annually and varies regionally. This is known as the Triad charge
- Balancing Services Use of System (BSUoS) charges
  - BSUoS charges recover all the costs incurred by the SO in balancing the system. They are split 50% between suppliers and transmission connected generation. The charge is a unit-based charge in £/MWh and varies by half hour. There is no locational element to the charge. It is an embedded benefit for distributed generation
- Assistance for Areas with High Electricity Distribution Costs (AAHEDC)
  - GB customers pay a subsidy to assist customers in Scotland with the high cost of distributing electricity which arises due to the spread of the population across the area. This charge is applied as a single unit-based charge that applies across the year to each supplier based on their settled consumption
- Residual Cashflow Reallocation Cashflow (RCRC)[27]
  - RCRC charges arise from balancing the residual cashflow within the balancing mechanism once all payments to or from balancing mechanism participants within a half hour have been made. The residual is allocated to all BSC parties and is charged on a unit basis which varies by half hour. The

[26] This list does not include the Capacity Market Supplier Charge or CMSC, which has been removed as an embedded benefit.

[27] Also known as the "beer fund",

charge can be positive or negative. This element switches frequently between positive and negative values and averages out at close to zero

- Network losses can be reduced at distribution and transmission and this results in a credit for embedded generation, through the scaling up of the export volume
  - Distribution losses are applied to all metered volumes, including export units within each DNOs area to create boundary equivalent volume data at the transmission network that enters settlements. A supplier can offset the generation export data from their demand or, where the supplier has insufficient demand to offset the generation, will receive a credit for the metered export after it has been increased for distribution losses. Each meter in the distribution network is assigned a Line Loss Factor (LLF) to determine the losses between the meter and the transmission system
  - Transmission losses are applied to wholesale volumes within settlement via a Transmission Loss Multiplier (TLM). This 'uplifts' the volume of power assigned to a supplier to account for the energy lost across the transmission system – in simple terms the supplier pays for the losses via the wholesale market. A supplier can offset their costs associated with transmission losses by purchasing embedded generation output which is netted off their total take from the transmission system. As of April 2018, locational and seasonal TLMs have been introduced
- Generator Distribution Use of System charges (GDUoS)
  - DNOs provide GDUoS credits to most embedded generation to reflect the reduction in their costs that result from the presence of embedded generation. Each DNO publishes an annual charging statement that sets out the unit rate charges (which if a credit is therefore negative) for Red (peak), Amber (shoulder), and Green (off-peak) time periods during the day. The 'traffic light' charging arrangement only applies to non-intermittent generation

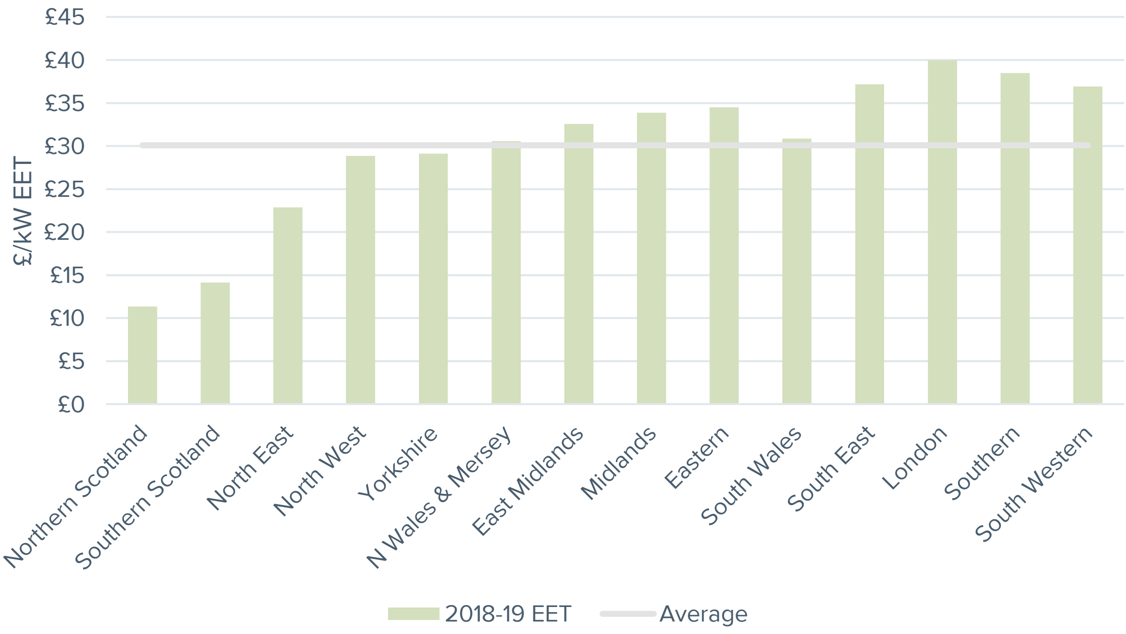
Historically, the triad benefit has been the largest of the benefits and has been steadily increasing over recent years. However, since April 2018 it has been replaced, and embedded generators have now started to receive a specific credit for generating during the triad peak, termed an embedded export tariff (EET). This benefit will fall annually to 2020-21, where it has a floor value of £0/kW for Scotland and the majority of northern England.

Non-half-hourly metered consumers (small businesses and domestic consumers) are charged based on the non-half-hourly zonal tariff. This is a p/kWh charge that is levied dependent on the consumer's average electricity demand during the early evenings throughout the year.

Costs vary on a regional basis – the EET and demand charges tend to be higher in the south and lower in the north of GB. This is because the north is generator-dominated while the south has the larger demand centres, and so an additional unit of demand in the south uses more of the network on average than an additional unit in the north.

Figure 13 shows the EET credits for the 2018-19 charging year. Northern Scotland has the lowest level of benefits (£11.36/kW) at less than half the regional average (£30.06/kW).

Figure 13: Embedded export tariffs 2018-19



Source: National Grid

Further detail on our estimates of embedded benefit values in Scotland is at Annex E.

3.3.2 Network charges

Network charges in Scotland are important for the following reasons:

- First generators and (through their supplier) consumers pay connection and capacity-based charges dependent on their voltage of connection
- Generator charges tend to be above national averages in Scotland, and demand charges tend to be lower than the national average
- Distribution connected generators in Scotland enjoy an embedded benefit based on their consumption at times of system peak, and
- Generators exporting at times of high system demand will also be paid a credit, which is again treated as an embedded benefit.

More complete notes are at Annex F.

3.3.3 Electrical losses

Arrangements in the GB market for costing losses and then allocating these costs to physical participants are complicated.

There is a strong argument that where generation and demand and are netted against each other and the volumes broadly balance that losses should be immaterial. In reality, however, losses, especially distribution losses are a significant element in the delivered price charged by suppliers through central settlement.

Further detail is at Annex G.

4 Emerging Opportunities

4.1.1 New revenue streams

Going forward, new community developments of whatever size will be subsidy free, and they will have to negotiate a route to market with limited revenue certainty. There are several direct and detrimental implications of this.

- First, achieving project funding will be more difficult as schemes will be less bankable
- Second, evaluation of projects will need to explicitly address identification and assessment of routes to market and value capture. This introduces a level of complexity and cost relative to the current baseline, and
- Third, given the limited scale of the projects we have considered[28], once the commercial evaluation has been completed and decisions taken, the scheme developers will likely be in a position of relative weakness in negotiations with large incumbents.

As the wider electricity sector is increasingly characterised by intermittent generation (especially at the distribution network level), changing demand requirements arising from electrification of heat and transport, and 'smarter' consumption solutions emerging as a consequence of smart meter deployment, the conventional approach to assessing generator revenue is rapidly changing.

Community energy developments (and indeed almost any new generation investment) will have to assess a range of revenue they may be able to access *and* how more sophisticated management of demand can realise avoided costs. It is necessary to understand what opportunities can be 'stacked' together. These are a blend of:

- Network contracted services: these are contracts whereby the generator – directly or indirectly via a third party such as a supplier or aggregator specialist – agrees to offer specific services to network operators to provide network management services. These are procured to ensure operational integrity of the networks to manage localised infrastructure constraints, voltage control, reactive power, and supply and demand balances (including the Capacity Market). The ability to provide service is very dependent on the generation technology, and usually favours more controllable assets
- Embedded benefits: as described above, these are payments an embedded generator can expect to receive from its off-taker via a PPA where its output reduces its counter-party's exposure to network charges. These are location and technology dependent, and
- Wholesale market: In addition to agreeing terms with a counterparty via a PPA to value power exported to the public network (for onward sale to end consumers over the public network), it is also possible to agree terms of uncontracted (or 'spill') power where the generator exports power to the public network that has not been contracted for purchase. This typically receives the System Imbalance Price, which is half-hourly derived value of uncontracted power on the wider system. It is difficult to predict values and can be highly volatile (in extremis -£80/MWh in low demand/ high generation scenarios, to £1,500+/MWh in high demand/ low-generation periods).

Further detail is provided below.

4.1.2 Value from flexibility services

Demand Side Response (DSR) is recognised by the government as the most available way for end users to engage with the energy system by turning up or down their demand. This implies the use of 'smart appliances' that can respond flexibly to pricing or other control signals. The appliances currently seen to be

[28] <200kW to >7.5MW

offering the greatest value to DSR include, cold and wet appliances, heating (including heat pumps, electric storage heaters and controls), ventilation, air conditioning and battery storage. The smart appliance sector is lacking in standards that would mandate greater rigour in terms of grid and cyber-security, data protection and interoperability.

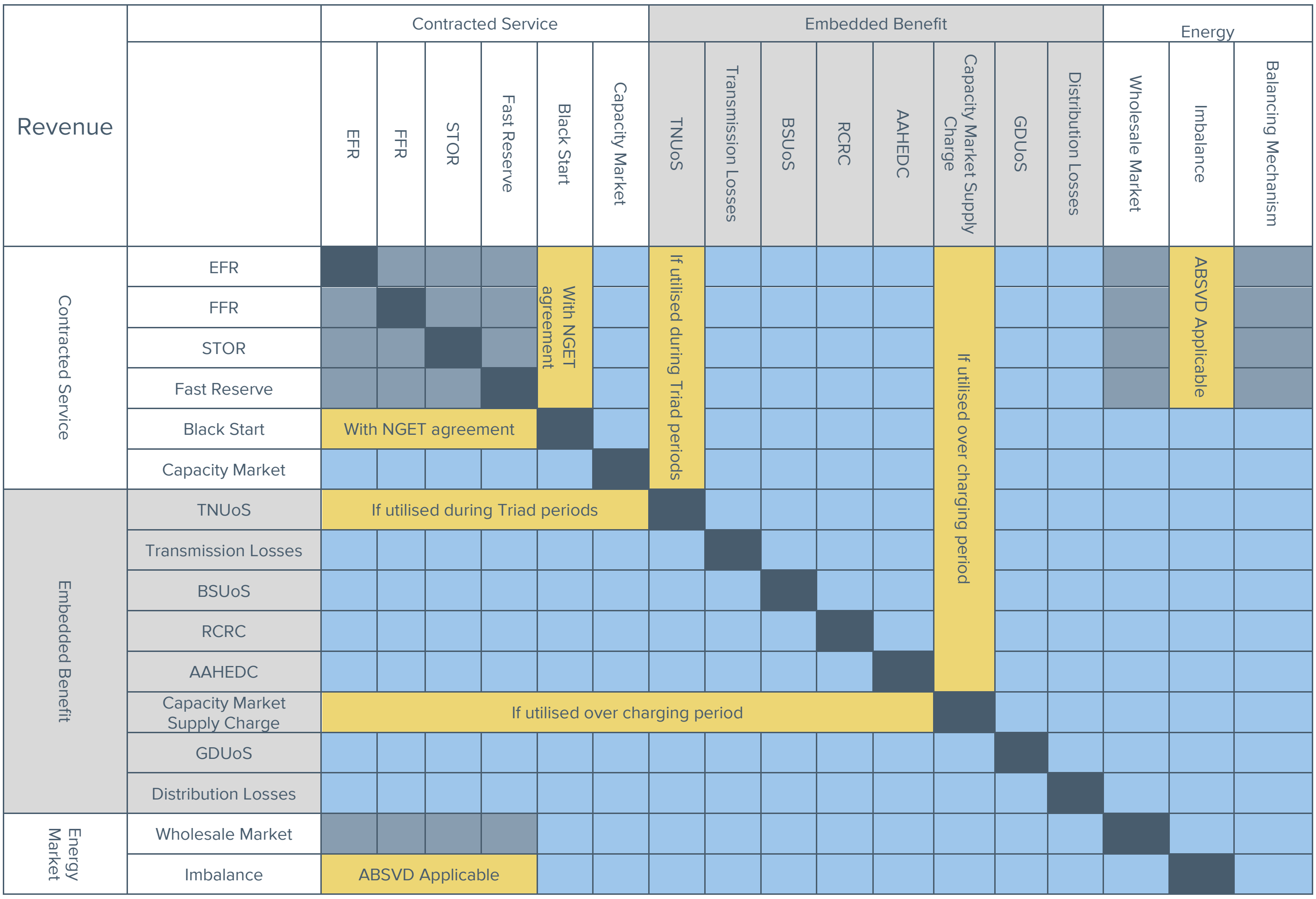
A second type, 'technical standards' is also required by which appliance compliance with principles and functionality can be assessed. Recognising these gaps, the government proposes to mandate standards upon smart appliances that will initially address:

- Those appliances offering greatest potential for DSR, and
- Appliances that can modulate their electricity consumption and are communications enabled.

In view of this, the Department for Energy and Industrial Strategy (BEIS) launched a consultation in March 2018[29] to seek stakeholders' views on whether the proposed new standards are appropriate.

DSR is already operational in the commercial and industrial sectors (where half-hour settlement exists) with 1.2GW of DSR contracted through the Capacity Market for delivery in 2021-22. In the domestic sector, non-half hourly settled small non-domestic and domestic customers cannot currently access DSR revenues, especially those which rely on peak-avoidance. But this will change when the full rollout of smart metering is completed. Smart appliance manufacturers will also require clear direction (in the form of the incoming standards) to develop devices that will interoperate, be secure and reliable in delivering the incentivised flexibility services.

Figure 14: Revenue stacking in the GB electricity market



[29] https://www.gov.uk/government/consultations/proposals-regarding-setting-standards-for-smart-appliances

	Balancing Mechanism																	

Key

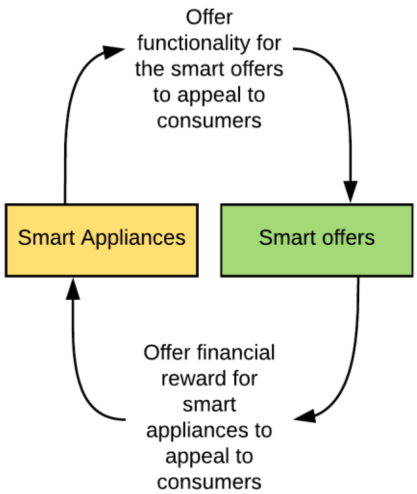
Mutually Exclusive

Compatible

Conditional

Evidence suggests that smart appliances, as key enablers of demand modulation, driven by price signals, could significantly improve on the amount of demand time-shifted, if they were automated to do so[30]. Clearly this makes interoperability a key issue, as if it is lacking, consumers could be restricted in access to flexibility benefits to a given product ecosystem. There are also risks associated with data protection and cyber-security to household users as well as grid control systems to be addressed within the forthcoming standards proposals. To create the market, the government has recognised the requirement for incentives in the form of 'smart offers' to motivate households to invest in smart appliances (Figure 15).

Figure 15: Incentive cycle for smart appliance propagation.



Source: BEIS

In Figure 16, we have presented some of the appliances under consideration for DSR and the flexibility services they can potentially offer. The matrix of appliance technology against flexibility service is supported by evidence of power usage found in a government sponsored survey of 250 homes over a 24 hour period[31] (Figure 17). Although cooking and lighting are seen to make up a large portion of the peak demand, they were considered to be less flexible in their availability. Therefore, the aforementioned wet and dry appliances, heating and battery storage systems were selected as primary targets for flexibility incentivisation payments.

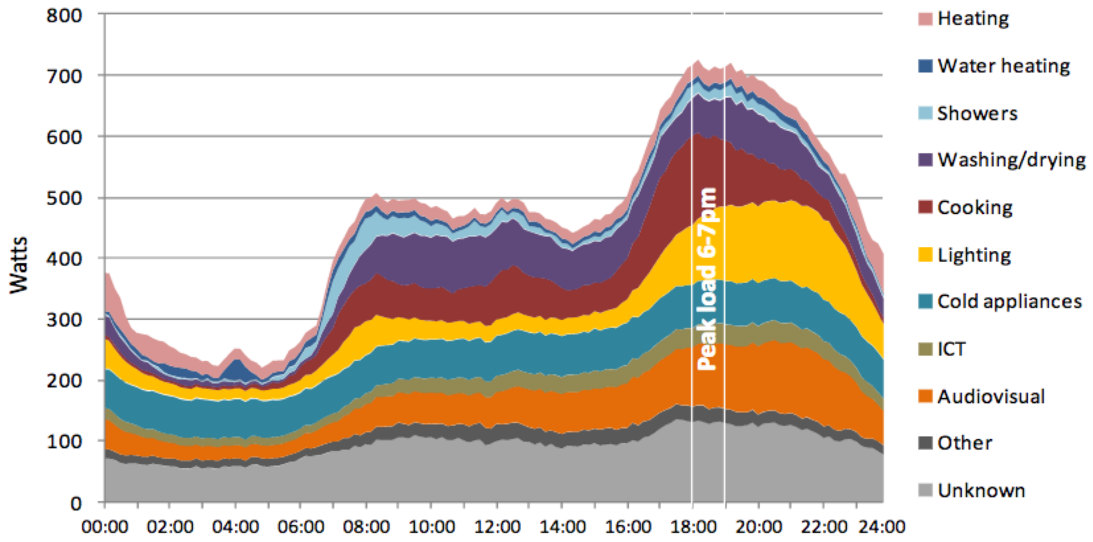
[30] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48552/5756-demand-side-response-in-the-domestic-sector-a-lit.pdf

[31] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/275484/electricity_survey_2_tuning_in_to_energy_saving.pdf

Figure 16: Appliances and flexibility

Flex tech	Dynamic/ Firm Frequency Response	Frequency control by demand management (DSR)	Enhanced Frequency response	Short Term Operating Reserve (STOR)	Fast Reserve	Demand Turn-up	Triad management	Red-zone management	Capacity Mechanism
Threshold value	**1MW**	**Vary by aggreg-ator**	**1MW**	**3MW**	**50MW**	**1MW**	-	-	**0.5MW**
Domestic customers	✓	✓	✓	✓	✓	✓			
Non-domestic customers	✓	✓	✓	✓	✓	✓	✓	✓	✓
Heating/ cooling/ Air conditioning	✓	✓				✓	✓	✓	✓
Fridges/ freezers	✓	✓	✓				✓		
Electrical appliances							✓		
Lighting		✓					✓		
Cooking									
Wet appliances						✓	✓	✓	
Hot water, electric heating/ storage heaters	✓	✓	✓						
Heat pumps		✓					✓	✓	
Electric vehicles	✓	✓							
Back-up distributed generation		✓		✓	✓		✓	✓	✓
Electricity storage	✓	✓	✓	✓	✓	✓	✓	✓	✓
Pumps/ motors/ compressors	✓	✓		✓		✓	✓	✓	✓
Industrial processes	✓	✓		✓		✓	✓	✓	✓

Figure 17: 24hr domestic demand profile



Source: Electrical appliances at home: tuning in to energy saving

4.2 Power to gas

Power to gas (P2G) refers to the use of electrical energy to produce a gas fuel, most commonly hydrogen (H_2) which can then be stored, used in vehicle propulsion (either by diluting fossil fuel or pure), or converted back into electricity and heat by a fuel cell. This is currently in evidence in the following projects covered by the main report:

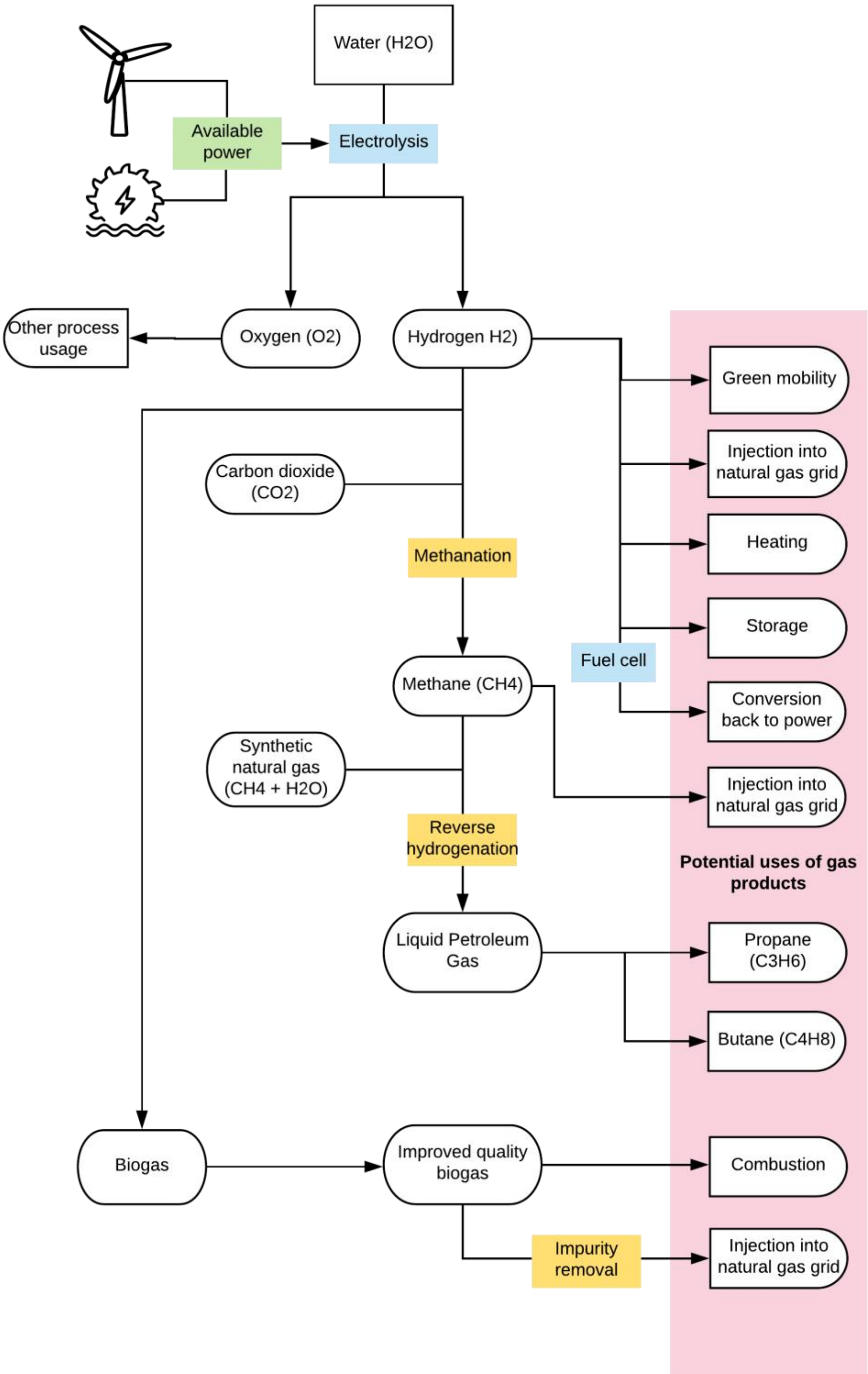
- Surf 'n' Turf – 500kW electrolyser with hydrogen converted back to power through a 90kW fuel cell
- Levenmouth – 250kW electrolyser with hydrogen used to power 25 vehicles (10 EVs with H_2 range extenders) and converted back to electricity through a 100kW fuel cell for 8 offices on a micro-grid, and
- OHLEH – 30kW electrolyser with hydrogen used to power a few municipal vehicles and supply heat and power to a local salmon hatchery through a 5kW fuel cell.

Hydrogen produced by electrolyzing water often uses surplus power from a renewable generator. It can be combined with other gases to create different fuel gases that can either be injected into the natural gas grid or used for propulsion (see Figure 18). There are other uses for pure hydrogen gas, and the oxygen which is also produced is an important industrial gas.

The market opportunity for power-to-gas developments looks increasingly positive as renewable energy capacity increases and situations arise more frequently where surplus power is available that can be directed towards hydrolysis to produce hydrogen and oxygen. This is a preferable option to costly generator curtailment[32] despite the low round trip efficiencies, affected by the processes engaged in returning hydrogen gas to power. For example, hydrogen can be used in fuel cells directly (with efficiencies up to around 80%) or processed to create methane for injection into the natural gas grid, or to make LPG. It can also be reformed by a variety of processes involving biogas (in some cases with the assistance of microbes) to make it usable in the gas grid.

[32] In Germany in 2015, 4.7TWh of electricity curtailment (93% composed of wind and PV) costing €315mn in compensation.

Figure 18: Examples of Power to gas production



Each additional stage of processing reduces the efficiency of the complete cycle.

The efficiency of hydrolysis to make hydrogen is dependent on the technology used but is reported to vary between 43-67% for alkaline electrolysers and 40-67% for proton exchange membrane (PEM) electrolysers[33].

[33] http://www.fch.europa.eu/sites/default/files/study%20electrolyser_0-Logos_0_0.pdf

The value for the round-trip efficiency will then be a fraction of these depending on the actual process endpoint and the stages of conversion in between.

The flexibility of services offered by power-to-gas, can be summarised as a carbon free energy carrier that can be deployed into the following scenarios:

- Sustainable fuel – displacing or diluting fossil fuels
- Long-term TWh-scale storage
- Heat, power and transport fuel vector
- Enabler of optimal investment in renewable generation technology (through curtailment and grid reinforcement avoidance)
- Balancing function, and
- Sustainable feedstock supporting the decarbonisation of the food and chemical processing industries.

4.3 Time of use tariffs

Just three suppliers – British Gas, Green Energy UK and Octopus Energy – have to date offered time-of-use (ToU) tariffs, whereby customers pay different amounts for electricity depending on the time of consumption.

British Gas offered free electricity for a specific day of the weekend, although it discontinued this tariff in May 2017 following its induction in July 2016, while Green Energy UK offers a true ToU tariff with peak, shoulder, and off-peak unit rates. The Octopus Agile tariff changes on a daily basis in line with wholesale market expectations.

The offer of ToU tariffs is expected to become more prevalent as the roll-out of smart meters progresses and uptake of electric vehicles increases.

Figure 19: Summary of smart-enabled ToU tariffs available to date

Supplier	Tariff	Launch	Removal	Average annual cost	Details
British Gas	HomeEnergy FreeTime (Sat/Sun) Mar 2018	July 2016	May 2017	£1,021*	Free electricity on Saturday or Sunday from 9am – 5pm. Fixed until March 2018
Green Energy UK	TIDE	January 2017	-	£1,105*	Three separate charging periods, off-peak 11pm-6am, weekday peak 4pm-7pm, all other times
Octopus Energy	Agile (electricity only)	February 2018	-	Variable^	Tariffs updated daily at 16:00 for next 24 hours with actual usage charged on smart meter data. Participants charged 21p/day “subscription” fee
Octopus Energy	Octopus Energy Go (electricity only)	February 2018		Variable	4 hours a night of super cheap electricity at 5p/kWh. Selected 4-hour period will vary

*calculated using a PC1 domestic demand profile. Cost likely to be lower if consumers shift usage as incentivised.

^ Indicative cost from Octopus website based on typical Economy 7 usage figures is £589.

Source: Cornwall Insight

Several suppliers have launched smart prepayment propositions. E.ON UK, OVO Energy (now through separate brand Boost) and Utilita were early movers in this sector of the market, but many smaller suppliers have now followed. Recent entrants Eversmart and Avid Energy (owned by Prepay Power in Ireland) have built their propositions around smart prepayment, and it is also key to small suppliers Toto Energy and E. Other suppliers that appear to offer smart prepayment are Ecotricity, Spark, First Utility, Economy Energy, Robin Hood Energy and Our Power.

Further to this, some suppliers have offered cheaper tariffs to customers willing to have a smart meter installed, to drive demand for smart meters. These tariffs do not rely on the smart metering technology – they have a simple unit rate and standing charge structure – and are thus not included in the table above. However, the terms and conditions stipulate that a smart meter must be installed for a continued discount. First Utility and EDF Energy have offered such tariffs in recent months.

'Tracker' tariffs have also become a feature of the market in recent months. The main offering is from Octopus Energy, which offers a tracker tariff with a price that changes daily based on an independent wholesale price index. Although a smart meter is not yet required, the terms of the tariff state that the supplier may require the customer to accept a smart meter in the future in order to remain on the tariff.

In the projects we studied, there was evidence of ToU, or local electricity tariffs, as well as other scheme participation financial incentives. Activities such as diverting otherwise curtailed power into renewable heating provided the incentive for the generation owners to offer benefits to their local community while offsetting the losses they would have made through continued sale of power. In the cases of the Heat Smart Orkney and Smart Fintry projects, reducing fuel poverty by heating homes with electricity during times of generator curtailment was a primary objective.

Local and ToU tariff information pertaining to the projects in this report are summarised in Figure 20.

Figure 20: Local energy tariffs

Project	Incentive/ Tariff	Details
Heat Smart Orkney	7p/kWh; £50 to sign-up and £100 at end of trial;	Local electricity price available to heat homes at times of generator curtailment
Smart Fintry	11.03p/kWh	The project claimed participants could save £100 on their electricity bill compared to to other regional tariffs
Energise Barnsley	£50/year rebate to participants in Moixa Gridshare	
Bethesda Energy Local Club	A flat rate of 7p/kWh is offered to Energy Local club members during times of hydro generation	ToU tariffs operating in the following bands when the hydro is not generating or club members have exceeded their allocations: 6am-11am, 12p/kWh; 11am-4pm, 10p/kWh; 4pm-8pm, 14p/kWh; 8pm-6am, 7.25p/kWh
Wadebridge Sunshine Tariff	5p/kWh during solar peak; 18 p/kWh at other times	
Ipswich Municipal Flexibility Market	Under development	Modelling different ToU tariffs under half hour settlement
Norwich Virtual Energy Community	Under development	Exploration of ToU tariffs possible with Supplier collaboration in future. Swapping of surpluses at fixed rate, with supplier-offered balancing tariff.

Source: Cornwall Insight

4.4 Renewable power generation costs

4.4.1 Levelised technology costs

We were asked to look at the levelised costs of the renewable energy generation technologies utilised by CALE groups. BEIS define levelised cost as "*...the average cost of the lifetime of the plant per MWh of electricity generated.*"[34]

We have reported the costs cited in the following publication but attention is drawn to the fact that this is data based on utility scale installations. As a comparable benchmark, Lazard's latest annual LCOE (LCOE 12.0)[35] that also show a continuing decline in the cost of generation, particularly at a utility scale, are presented in Figure 21 below.

Figure 21: 2017 Benchmark LCOEs for renewable energy technologies at different scales

RET	Low USD/MWh	Low £GB/MWh[36]	High USD/MWh	High £GB/MWh
Solar PV - rooftop residential	160	122.81	267	204.94
Solar PV - rooftop C&I	81	62.17	170	130.49
Solar PV - community	73	56.03	145	111.30
Wind	29	22.26	56	42.98
Fuel Cell	103	79.06	152	116.67

Source: Lazards

4.4.2 International Renewable Energy Agency (IRENA)

In its publication *Renewable Power Generation Costs in 2017,* IRENA looks at the levelised cost of electricity (LCOE) for different utility-scale renewable energy technologies in the periods 2010-2017 and also projects forward from 2010-2020 for cumulative deployment of concentrating solar power (CSP), PV, onshore and offshore wind[37]. IRENA found that there are three main cost reduction drivers affecting renewable power:

- Technology improvements: These concern on-going technical innovation in manufacturing methods, installation costs and performance of different RETs. Also increasing scale will have an impact on the LCOE, for example a larger wind turbine will harvest more energy from the bigger swept area in a single installation. New PV cell designs offer better efficiencies and capture a wider photo-sensitive bandwidth. Big data and real-time data offer better operational management and maintenance practices, including predictive interventions ahead of failure
- Competitive procurement: As RETs are now acquiring 'grid parity', or even lower in many parts of the world, their successful procurement competes with traditional generation and enables a further strengthening of the economics driving their progress. Positive regulatory and institutional frameworks will add to the competitiveness of RETs, and

[34] https://www.gov.uk/government/publications/beis-electricity-generation-costs-november-2016

[35] https://www.lazard.com/media/450773/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

[36] USD to GB rate = 0.767561 as of 9 November 2018

[37] http://www.irena.org/publications/2018/Jan/Renewable-power-generation-costs-in-2017

- A large base of experienced, internationally active developers: A proven and growing track record of RET operation now offers savings in the cost of capital with reduced project risk.

Analysing the trends in the LCOE of projects and the auction results out to 2020, IRENA suggests the average costs for **onshore** wind could fall from USD 0.06/kWh in 2017 to USD 0.05/kWh by 2020. Recent trends in auction results for **offshore** wind in Belgium, Denmark, Netherlands, Germany and the UK, suggest that for projects commissioned in 2020 and beyond costs could be in the USD0.06/kWh to USD 0.10/kWh range.

Solar PV needs to be treated some caution as the distribution of project data is concentrated in areas of the highest solar irradiance. Even so, if auction trends do accurately reflect global deployment, IRENA expect the LCOE for solar PV to fall below USD 0.06/kWh, converging to slightly above onshore wind at USD 0.05/kWh by 2019-20.

4.5 Market-wide half hourly settlement

Ofgem published[38] its current thinking on the objectives and assessment for the business case for the newly-renamed market-wide half-hourly settlement (HHS) project, in September last year. It set out the range of options that could be used to deliver the objectives of the project and the process to be used in developing the business case.

Half hourly settlement will incentivise suppliers to encourage customer behaviour that contributes to a more cost-effective electricity system, by linking suppliers' costs to their customers' actual consumption during the day. Importantly, Ofgem's objectives also include a specific customer impact measure: to minimise undesirable distributional effects on consumers.

Behavioural change on a large scale is necessary – in response to pricing signals and similar products including new small-scale generation/storage packages and smart devices – to bring about a material improvement in the cost efficiency of the energy system. Ofgem recognises that some customers may be less able to access the benefits for lifestyle or financial reasons and could be penalised for their consumption coinciding with periods of high costs of supply.

Ofgem commissioned an assessment by Cambridge Economic Policy Associates[39] to analyse the distributional impact of ToU tariffs on different socio-demographic groups and assess the potential for behavioural change amongst customers. The report concluded, on a currently sparse evidence base, that most customers would save money by adopting ToU tariffs, but there are wide variations and while a slight majority of vulnerable customers would benefit there would be bill increases for a subset of vulnerable customers. It is therefore encouraging to see an objective of the HHS programme being to minimise undesirable customer impacts.

Ofgem's assessment includes consideration of the options for access to HH data. The current arrangements require the customer to consent to suppliers gaining access to half-hourly data. It will consider three options; HH data becoming available for settlement purposes only with a customer opt-out; HH data becoming available for settlement only without an opt-out; and HH data becoming available for settlement purposes only following anonymization.

The regulator has yet to decide whether to centralise data collection and aggregation activities. It is considering whether to retain the existing competitive supplier agent arrangement, to retain the supplier agent market but with reform, or to entirely centralise data collection and aggregation. The latter would be a major change to the structure of the retail market, dismantling the long-held supplier-hub principle and severely impacting the companies operating the competitive market in metering services. Ofgem states it

[38] https://www.ofgem.gov.uk/publications-and-updates/project-objectives-and-assessment-options-market-wide-half-hourly-settlement-business-case

[39] https://www.ofgem.gov.uk/publications-and-updates/distributional-impacts-time-use-tariffs

does not have a preferred option and that all options will be evaluated. It issued a request for information[40] last Autumn to commence evidence gathering.

Ofgem's significant code review (SCR) launch statement[41] targeted the second half of 2019 for a decision on whether to implement HHS. The implementation timescale is not defined at this stage. It has, however, ruled out a big-bang approach in which all meters are simultaneously converted to HHS as being too risky, and will be taking a phased approach.

There are important lessons from the recent migration of medium-sized business customers to HHS, under BSC modification P272[42]. Migration was eventually achieved over a phased period in excess of 12 months, in a process which endeavoured to synchronise the migration to HHS with customers' contract renewal date so that customers could exercise choice of suppliers for the new HH contracts. This approach was on whole successful as it gave customers choice and suppliers time to execute the difficult, error-prone and labour-intensive migration process (termed change of measurement class under the BSC). The volumes involved are salutary: less than 200,000 business customers under P272 compared with roughly 30,000,000 in the market-wide programme.

Consideration of the options ought to lead to a more robust *systematic* process to reduce errors and operating cost in support of the programme's business case. A parallel SCR – the Switching Programme – will create a new market wide Customer Switching Service. It would be prudent to explore ways in which the new system behind this could support market-wide HHS migration.

[40] https://www.ofgem.gov.uk/publications-and-updates/request-information-supplier-agent-functions

[41] https://www.ofgem.gov.uk/publications-and-updates/electricity-settlement-reform-significant-code-review-launch-statement-revised-timetable-and-request-applications-membership-target-operating-model-design-working-group

[42] https://www.elexon.co.uk/wp-content/uploads/2016/10/02_PAB197_05a-Public-SMU-V2.pdf

5 Policy and regulatory reviews and risks

The electricity sector is undergoing unprecedented change with almost all elements of the cost chain are under review. Major work programmes include:

- The roll-out of smart meters
- An Ofgem-led programme to mandate that all customers are settled on an HHS (to enable time of use tariffs to incentivise customer response). More detailed notes on this key work stream are at Annex E
- Moves to introduce 'faster and more reliable' switching to allow households to switch within 48 hours
- Rationalisation of National Grid's balancing service contracts and tendering approach
- Development of Distribution System Operator (DSO) structures and markets to enable local flexibility services
- The end of new subsidy for low-carbon generation beyond that which has already been committed
- Several reviews of network charges, including changes to embedded benefits
- A review of the 'supplier hub' arrangements which place the electricity supplier at the centre of the industry (and hence requires generators and developers of innovative local market solutions to interact with a fully licensed supplier), and
- Other second order changes including development of the successor programme to the energy efficiency Energy Company Obligation, price cap interventions, and 'Brexit'.

These programmes are not expected to be concluded until 2020 at the earliest, with some continuing into the mid-2020s. In sum, the programmes present a monumental challenge for suppliers, but also present a clear direction of travel for the market.

At a high-level the changes are an attempt to allow for the offering of 'smarter' products and services that are based on more sophisticated price signals to value real-time/ short-term energy and network system needs. For example, moving away from the relatively crude approach of consumers facing a fixed price for units of power, enabling consumers and communities to bundle together generation, storage and 'smart' demand to optimise local needs to benefit from reduced costs (from taking power from the public network) and receive revenue (from offering services to the local and national networks to alleviate system issues).

As the supplier is at the hub of the market (responsible for contracting with the customer and paying for all network and government subsidy costs as well as managing trading and imbalance risk), the level of uncertainty regarding future costs and how they are applied to customers makes it difficult to assess exactly where the costs and benefits lie when half-hourly settled ToU tariffs are offered, particularly where the tariff is linked to onsite storage and generation.

There are many changes proposed to how network users are charged for using the transmission and distribution networks. This is being driven by concerns that current arrangements are no longer fit for purpose as the system changes to accommodate more embedded and intermittent generation.

5.1 National Grid review of transmission charging arrangements

National Grid has consistently highlighted the interaction between transmission charges and various aspects of the electricity market. It has initiated a holistic review of the transmission charging arrangements and has identified over 20 such relationships.

National Grid's review of transmission charging arrangements is wide ranging and will require a number of years to complete, although some changes are being brought forward more quickly in those areas that need to be addressed first. However, the solutions brought forward will have regard to the wider picture and take account of the interactions with other areas. The review is still at an early stage and has focussed on the identification of issues and how they interact.

5.2 Ofgem Targeted Charging Review (TCR)

On 4 August 2017, Ofgem launched its long-awaited *Targeted Charging Review (TCR) Significant Code Review (SCR)*[43]. This confirmed the regulator's intention to run an SCR[44] to examine possibilities for reform of residual charging for the transmission and distribution networks, and to keep other embedded benefits under review.

It expressed concerns that the current arrangements for residual charging may be resulting in inefficient use of the networks. Ofgem argued this may drive actions from some network users that result in adverse impacts on other network users, and hence consumers in general.

Specifically excluded from the SCR will be forward-looking use of system charges, connection charging, and charging arrangements for storage. However, Ofgem noted that it expects industry to take forward changes in the latter area independently and reserved the right to draw this area into the SCR if it did not see sufficient progress made.

Residual charges

Electricity network charges are created by charging methodologies that the regulated network companies must have in place to recover their allowed revenue. The regulator insists that users should see charges that are cost-reflective, as this is deemed fairer and gives users a price signal for using a network at various times and location.

This approach results in complex models that underpin the charging methodologies. The purpose of the models is to establish a means for ascribing charges based on actual costs (usually tied to additional investment costs) at different locations (or voltage tiers) and times (e.g. peak or off-peak).

The modelling gives the locational and temporal signal but does not result in tariffs that ensure network companies recover their allowed revenue – hence the addition of a residual (also called a scalar) element to up-lift all tariffs. This preserves locational and temporal charge differences.

Balancing Services Use of System (BSUoS) charges – which are considered to be similar to residual charges – will be considered as part of the strategy for regulating the future energy system and may be aligned with reformed transmission and distribution charging arrangements.

One of the key questions that will be addressed under the TCR is which network costs are potentially avoidable by different users and which are considered as sunk and should fall into the residual. This will require a substantive review of how existing cost elements are being recovered at present and how they should be recovered in the future.

Ofgem's initial view is that all users should make a contribution to common costs and five initial options for how residual costs could be recovered have been put forward:

- Option A: a charge linked to net (kWh) consumption
- Option B: a fixed price charge
- Option C: fixed charges set by connected capacity
- Option D: gross kWh consumption, and
- Option E: a hybrid approach.

A further issue considered within the TCR is the treatment of storage from a charging perspective. Ofgem are concerned that storage may incur network and system charges in relation to their import and export capacity, effectively resulting in double charging and placing this technology at a disadvantage compared to other industry participants.

5.3 BEIS' Smart, Flexible Energy System

BEIS and Ofgem published the *Upgrading Our Energy System: Smart Systems and Flexibility Plan* on 24 July 2017. This response document has been awaited since a call for evidence was issued in November 2016. The Plan outlines the 29 actions BEIS, government and Ofgem plan to take to remove barriers to smart

[43] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-significant-code-review-launch

[44] A Significant Code Review (SCR) is a regulatory process designed to allow Ofgem to corral industry views on an issue that has wider policy implications and introduce rule changes.

technologies – primarily storage and demand-side response (DSR) – and to improve access to the energy markets for new technologies and ways of doing business.

5.4 ENA's Open Network project

The Open Networks Project is an energy industry initiative led by the Energy Network Association (ENA). It brings together network operators, academics, NGOs, Government departments and Ofgem. The project aims to give help give consumers and networks the ability to take advantage of new energy technologies. This will allow user to take control of their energy costs, by taking a whole energy system approach to designing solutions. This takes the form of developing improved interactions between transmission and distribution network management needs around connections, planning, and shared services and operation.

6 Annex A: Supplier market share in Scotland

6.1 Market size

This Annex summarises electricity and gas usage by Scottish households with reference to Great Britain as a whole. It considers consumer numbers, access to gas, market concentration and competition measured through market shares.

6.1.1 Customer numbers

Scotland is divided in to the North Scotland and South Scotland electricity supply regions. The electricity networks in each region are owned and operated by SSE and Scottish Power respectively. Both these companies are also the incumbent electricity suppliers in their respective regions. Scotland's gas distribution network is owned and operated by Scotia Gas Networks (SGN). British Gas through Scottish Gas is the incumbent gas supplier in Scotland.

In South Scotland there were 1.92mn electricity accounts and 1.59mn gas accounts as of 31 July 2018. In North Scotland there were 0.73mn electricity accounts and 0.42mn gas accounts as can be seen in the Table below.

Figure 22 Household energy accounts in the Scottish supply regions

(mn)	*Great Britain average*	*South Scotland*	*North Scotland*
Electricity accounts	2.00	1.92	0.73
% of Great Britain average	-	96%	36%
Gas accounts	1.67	1.59	0.42
% of Great Britain average	-	95%	25%

Source: Cornwall Energy supply market share survey 31 July 2018

The South Scotland region is similar in consumer numbers to the Great Britain average electricity region with 1.92mn electricity accounts and 1.59mn gas accounts. However North Scotland has the fewest consumer numbers of any of the 14 electricity regions in Great Britain.

6.1.2 Access to gas and dual fuel coverage

Mains gas availability in South Scotland matches average Great Britain levels with household gas accounts numbering 83% of household electricity accounts. However mains gas coverage in North Scotland is the lowest of the 14 electricity supply regions in Great Britain with only 57% of household electricity accounts also connected to mains gas supply.

Of those with mains gas connection in both South and North Scotland, 87% buy both their gas and electricity from the same supplier. This proportion matches that for Great Britain as a whole where 87% of households with both fuels also buy them together.

6.1.3 Suppliers operating in Scotland

Recent years has seen the number of energy suppliers increase dramatically. At July 2018, there were 58 suppliers providing non-postcode specific direct debit dual fuel energy tariffs to customers in Great Britain. Some 54 of these companies were active in South Scotland and 51 in North Scotland.

For prepayment there were 33 active suppliers across Great Britain, of which 25 were active in North Scotland and 29 in South Scotland.

The suppliers not active in South Scotland for prepayment were:

- Robin Hood Energy and its attendant white label suppliers and GEN4U

The suppliers not active in North Scotland for prepayment were:

- OVO Energy (+Boost), Robin Hood Energy and its attendant white label suppliers, GEN4U and Toto Energy

6.1.4 Market concentration and market shares

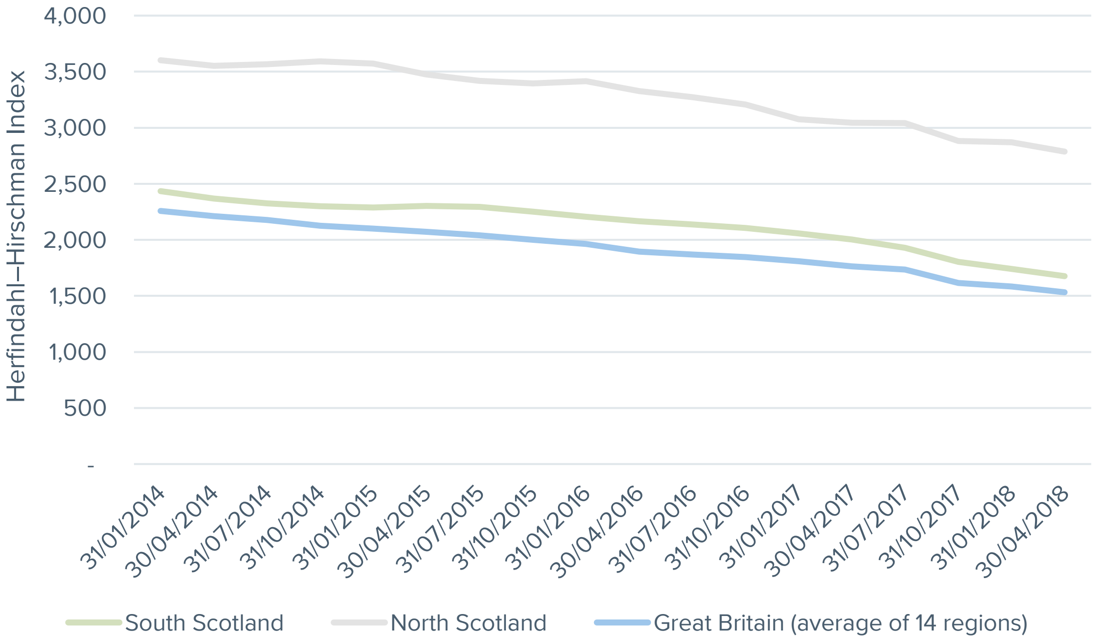
Increasing supplier numbers have been accompanied by increasing competition. Market concentration has been falling consistently as measured by the Herfindahl–Hirschman Index (HHI).

HHIs for domestic energy in Great Britain at 31 January 2018 by electricity supply region ranged from 1,092 in North East England to 2,710 in North Scotland. The HHI for South Scotland was 1,592, ranking 12th out of 14. Figure 23 illustrates the generally downward trend in HHIs.

Across Great Britain:

- Nine regions recorded HHIs below the 1,500 threshold for market concentration
- Four regions recorded HHIs between 1,500 and 2,500 including South Scotland, and
- The North Scotland region recorded an HHI over 2,500.

Figure 23 Regional energy market concentration



Energy = electricity + gas

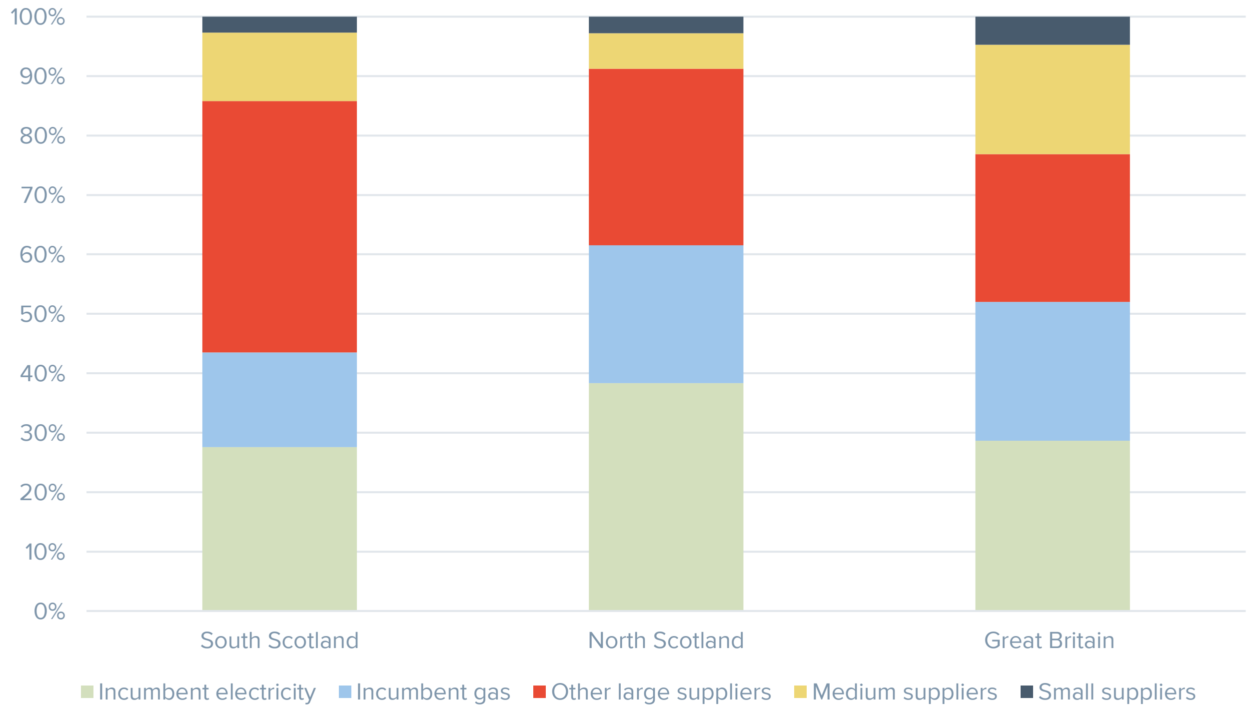
Source: Cornwall Insight

Higher than Great Britain average HHIs for energy in North Scotland and South Scotland reflect higher than market shares for the incumbent electricity suppliers as Figure 23 shows. In North Scotland at 31 July 2018 the incumbent electricity supplier (SSE) held 45.6% of domestic energy accounts, while in South Scotland the incumbent electricity supplier (Scottish Power) held 27.6%. The Great Britain average for this measure was 22.5%. In contrast the incumbent gas supplier's (British Gas) shares of 22.4% and 23.5% in North Scotland and South Scotland respectively were similar to the Great Britain average of 25%.

The shares held by other supplier groups in South Scotland were similar to those for Great Britain as a whole. The other large suppliers (EDF Energy, E.ON UK, npower in addition to Scottish Power in North Scotland and SSE in South Scotland) held 28.3% of energy accounts in South Scotland against a Great Britain average of 28.2%, while medium suppliers (entrant suppliers with more than 250,000 accounts) held 16.7% in South Scotland compared with 20.3% across Great Britain as a whole, while small suppliers (entrant suppliers with fewer than 250,000 energy accounts) held 3.8%.

In contrast all three supplier groups held markedly lower shares of domestic energy in North Scotland at 18.9% for other large suppliers, 7% for medium suppliers and 4% for small suppliers,

Figure 24: Regional energy market shares



Energy = electricity + gas

Source: Cornwall Insight

6.2 Electricity only

Three suppliers – British Gas, Scottish Power and SSE – dominate the market share for electricity customers in Scotland (North Scotland 74.5%, South Scotland 63.8%), out of a total of 19 main suppliers. The incumbent supplier share (from when the market was opened-up) now accounts for 53.1% in north Scotland, and 34.1% in south Scotland. Although British Gas is responsible for a large take of current market share here, (15.9% in North Scotland and 19.0% in South Scotland) this data indicates and increasing number of small and medium-sized suppliers are encroaching into the traditional markets of the larger incumbents (Figures 25 and 26). In Figure 27, we present the current (electricity) market share presence of the three main suppliers in Scotland by heat map.

Figure 25: Electricity market share by supplier in north and south Scotland

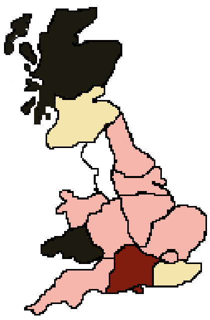
Share (%)	North Scotland	South Scotland
British Gas	15.9%	19.0%
E.ON UK	4.8%	7.3%
EDF Energy	4.1%	5.7%
npower	2.8%	3.4%
Scottish Power	5.5%	34.1%
SSE	53.1%	10.7%
Avro Energy	0.0%	0.5%
Bulb	1.4%	2.3%
Co-op Energy	0.7%	1.0%
E	0.0%	0.5%
Economy Energy	0.7%	0.8%
First Utility	0.7%	1.8%
Green Network Energy	0.7%	0.3%
Green Star Energy	0.7%	0.8%
Octopus Energy	0.7%	1.0%
Ovo Energy	0.0%	2.1%
Spark	1.4%	1.0%
Utilita	0.0%	2.9%
Utility Warehouse	0.7%	1.0%
Small suppliers	6.2%	3.6%
Total	**100.0%**	**100.0%**

Source: Cornwall Insight

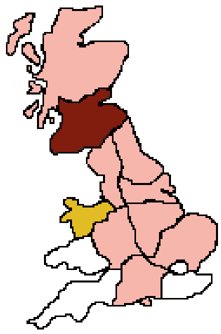
Figure 26: Electricity market share by supplier size in north and south Scotland

Share (%)	North Scotland	South Scotland
SSE	53.1%	10.7%
Scottish Power	5.5%	34.1%
British Gas	15.9%	19.0%
Other Big 6	11.7%	16.4%
Medium suppliers	7.6%	16.1%
Small suppliers	6.2%	3.6%

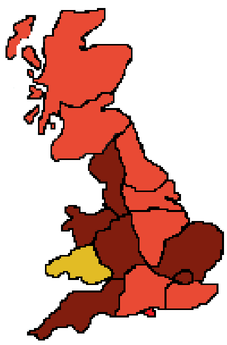
Figure 27: Main supplier energy presence in north and south Scotland



SSE presence



Scottish Power presence



BG presence

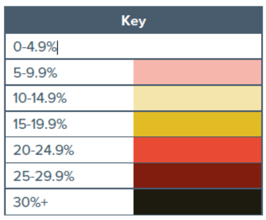
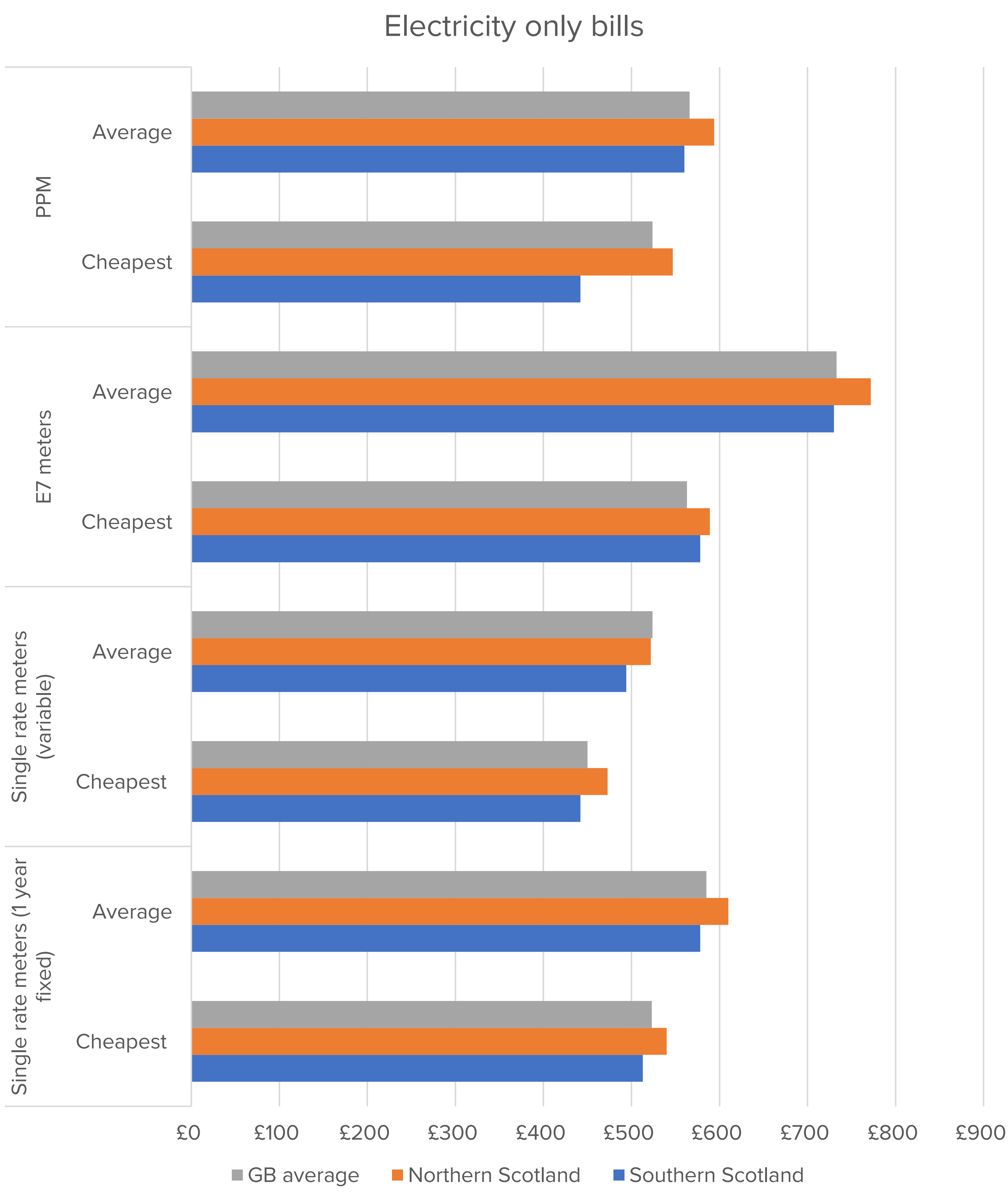


Figure 28: Electricity only prices for meters in Northern and Southern Scotland and GB.



6.3 Dual fuel

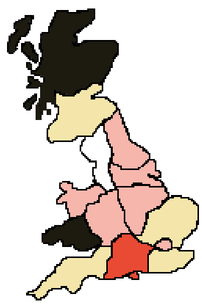
The same three suppliers – British Gas, Scottish Power and SSE – also dominate the dual fuel market share customers in Scotland (North Scotland 71%, South Scotland 57%), out of a total of 19 suppliers offering dual-fuel accounts (Figure 29). The incumbent supplier share now accounts for 36.2% in North Scotland, and 20.9% in South Scotland. British Gas is responsible for a large take of current market share here, 27.5% in North Scotland and 23.8% in South Scotland and so has been separately identified. In the south Scotland region in particular, small and medium suppliers (SaMS) represent a significant portion (23.8%) of the market share (Figure 30). In Figure 31, we present the current (dual fuel) market share presence of the three main suppliers in Scotland by heat map.

Figure 29: Dual-fuel market share by supplier in north and south Scotland

Share (%)	North Scotland	South Scotland
British Gas	27.5%	23.8%
E.ON UK	5.8%	8.3%
EDF Energy	7.2%	6.9%
npower	2.9%	4.0%
Scottish Power	7.2%	20.9%
SSE	36.2%	12.3%
Avro Energy	0.0%	0.7%
Bulb	2.9%	2.9%
Co-op Energy	0.0%	1.4%
E	0.0%	0.7%
Economy Energy	1.4%	0.7%
First Utility	1.4%	2.2%
Green Network Energy	1.4%	0.4%
Green Star Energy	0.0%	1.1%
Octopus Energy	1.4%	1.4%
Ovo Energy	0.0%	2.5%
Spark	1.4%	1.1%
Utilita	0.0%	3.2%
Utility Warehouse	1.4%	1.1%
Small suppliers	1.4%	4.3%
Total	100%	100.0%

Figure 30: Dual-fuel market share by supplier size in north and south Scotland

Share (%)	North Scotland	South Scotland
SSE	36.2%	12.3%
Scottish Power	7.2%	20.9%
British Gas	27.5%	23.8%
Other Big 6	15.9%	19.2%
Medium suppliers	11.6%	19.5%
Small suppliers	1.4%	4.3%


SSE Presence

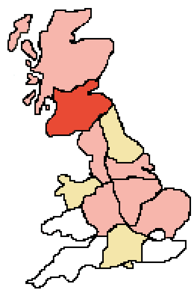
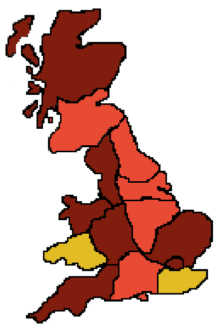

Scottish Power Presence

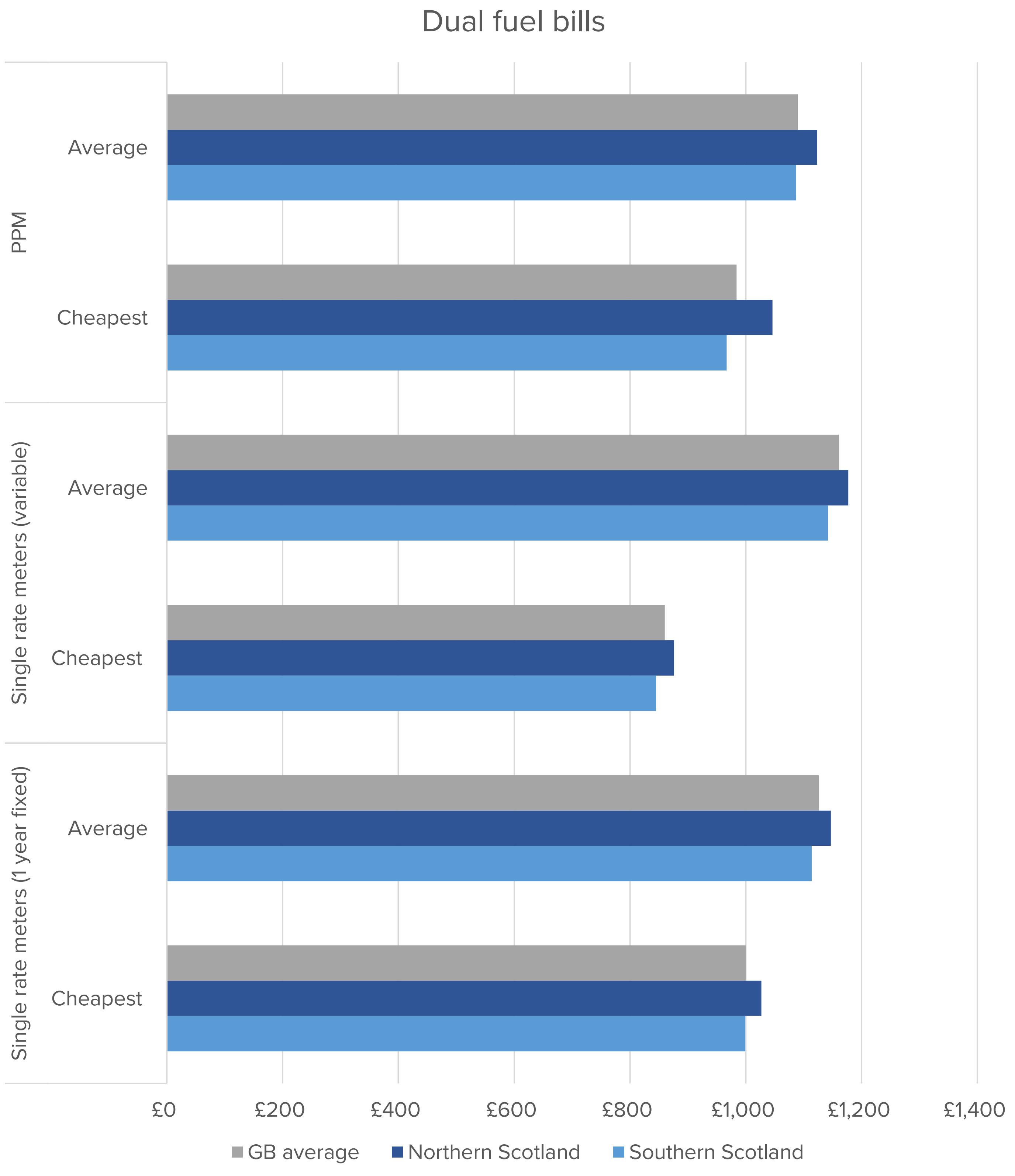
Figure 31: Main supplier presence in north and south Scotland


BG Presence

Key	
0-4.9%	
5-9.9%	
10-14.9%	
15-19.9%	
20-24.9%	
25-29.9%	
30%+	

Source: Cornwall Insight

Figure 31: Dual-fuel prices for meters in Northern and Southern Scotland and GB.

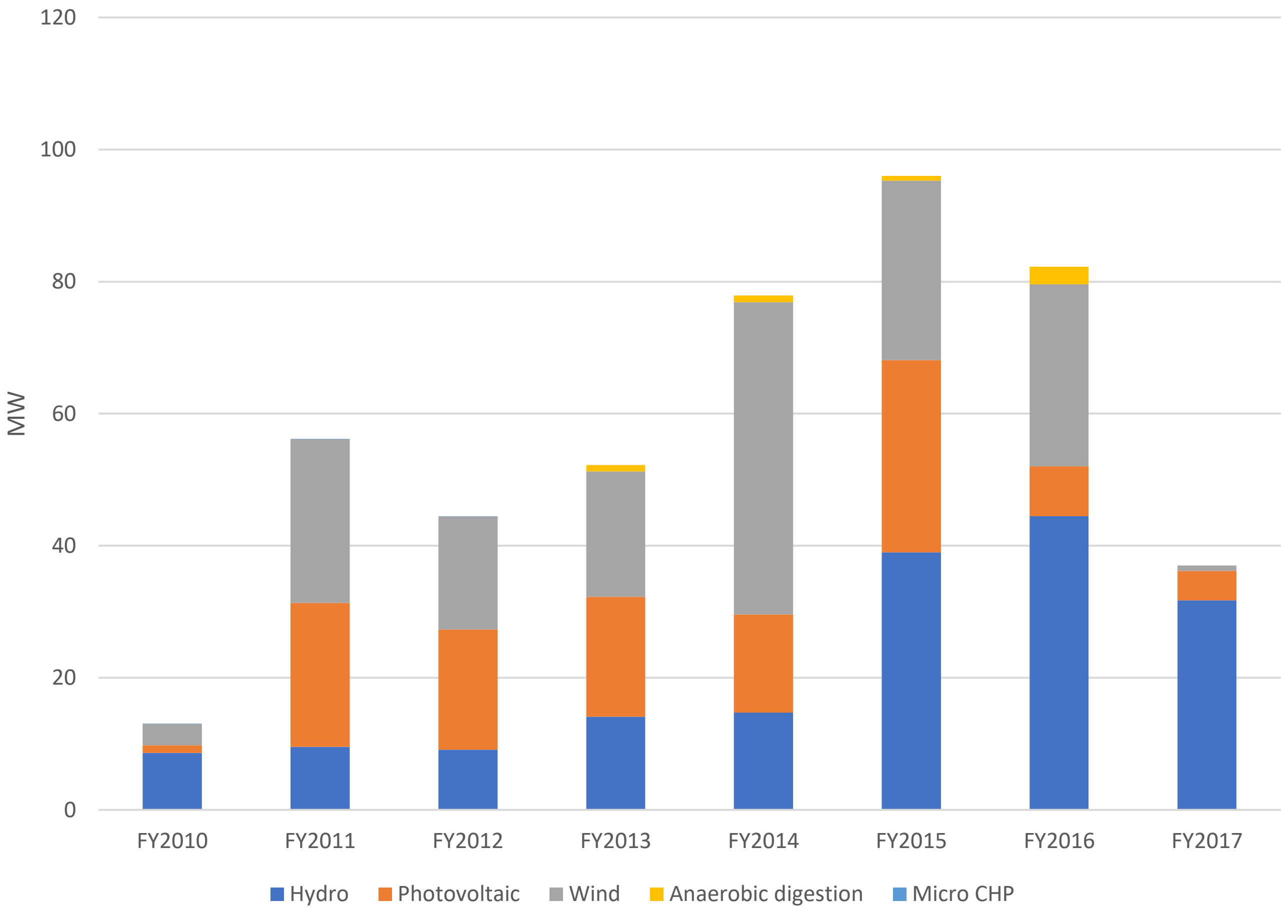


7 Annex B: Scotland, FiT RO and community energy

Figure 32 and 33: North Scotland installation capacity (MW) per accreditation year (financial year)

North	Accreditation Year Capacity								
Technology	**FY2010**	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**	**FY2016**	**FY2017**	**Total**
Hydro	8.5987	9.5483	9.0993	14.0865	14.7479	38.9847	44.4782	31.7283	171.2719
Photovoltaic	1.1760	21.8083	18.2302	18.1971	14.8332	29.1427	7.5361	4.4532	115.3768
Wind	3.2615	24.7895	17.0741	18.9541	47.3138	27.1666	27.5740	0.8100	166.9436
Anaerobic digestion	0.0000	0.0000	0.0000	0.9990	0.9970	0.6990	2.6450	0.0000	5.3400
Micro CHP	0.0040	0.0070	0.0030	0.0000	0.0000	0.0000	0.0000	0.0000	0.0139
Total	13.0402	56.1531	44.4066	52.2367	77.8919	95.9930	82.2333	36.9915	458.9462

North Scotland FiT installation commissions by financial year

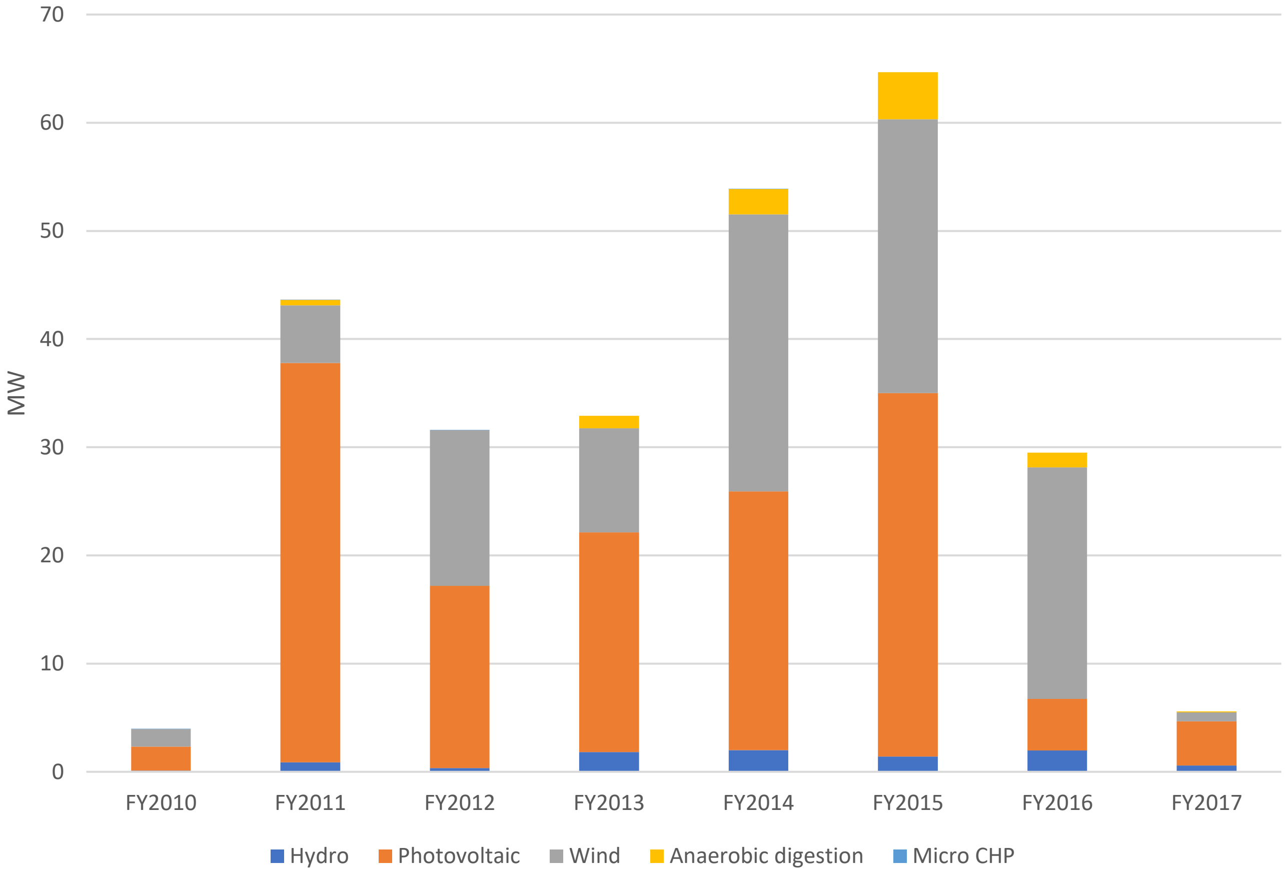


Source: Ofgem Feed-in Tariff Installation Report 31 March 2018

Figure 34 and 35: South Scotland installation capacity (MW) per accreditation year (financial year)

South	Accreditation Year Capacity								
Technology	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015	FY2016	FY2017	Total
Hydro	0.0989	0.8784	0.3366	1.8299	1.9996	1.4115	1.9799	0.5950	9.1298
PhotOVOltaic	2.2174	36.9165	16.8457	20.2893	23.9343	33.5997	4.7490	4.0779	142.6298
Wind	1.6254	5.3284	14.4026	9.6219	25.6072	25.2973	21.4150	0.8210	104.1188
Anaerobic digestion	0.0000	0.4990	0.0000	1.1600	2.3190	4.3550	1.3480	0.1000	9.7810
Micro CHP	0.0069	0.0060	0.0010	0.0000	0.0020	0.0000	0.0000	0.0000	0.0159
Total	3.9486	43.6282	31.5859	32.9011	53.8621	64.6635	29.4919	5.5939	265.6752

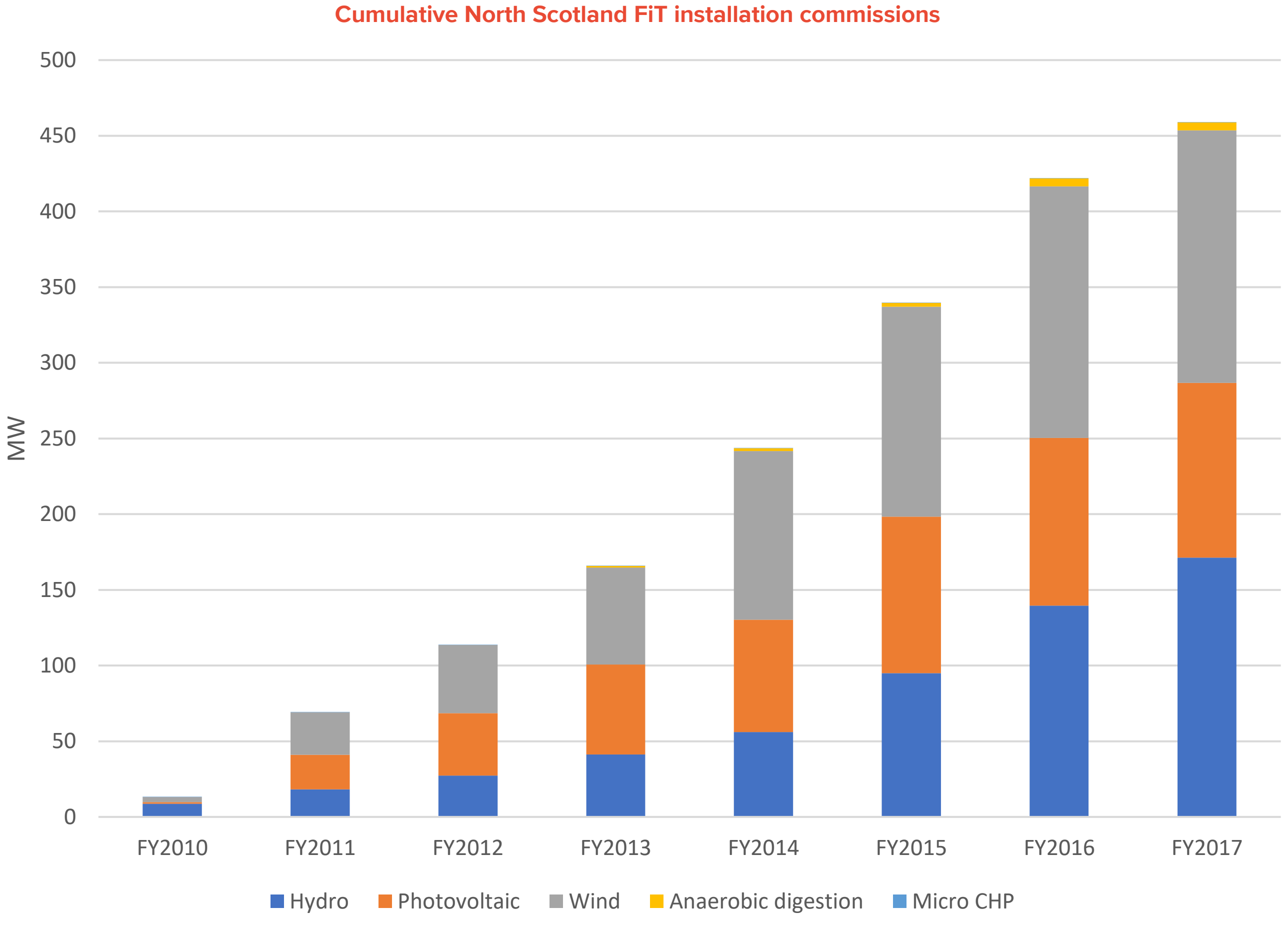
South Scotland FiT installation commissions by financial year



Source: Ofgem Feed-in Tariff Installation Report 31 March 2018

Figure 36 and 37: North Scotland cumulative installation capacity (MW) per accreditation year (financial year)

North Running Total	Accreditation Year Capacity							
Technology	**FY2010**	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**	**FY2016**	**FY2017**
Hydro	8.5987	18.1470	27.2463	41.3328	56.0807	95.0654	139.5436	171.2719
PhotOVOltaic	1.1760	22.9844	41.2146	59.4117	74.2449	103.3875	110.9236	115.3768
Wind	3.2615	28.0510	45.1251	64.0792	111.3930	138.5596	166.1336	166.9436
Anaerobic digestion	0.0000	0.0000	0.0000	0.9990	1.9960	2.6950	5.3400	5.3400
Micro CHP	0.0040	0.0109	0.0139	0.0139	0.0139	0.0139	0.0139	0.0139

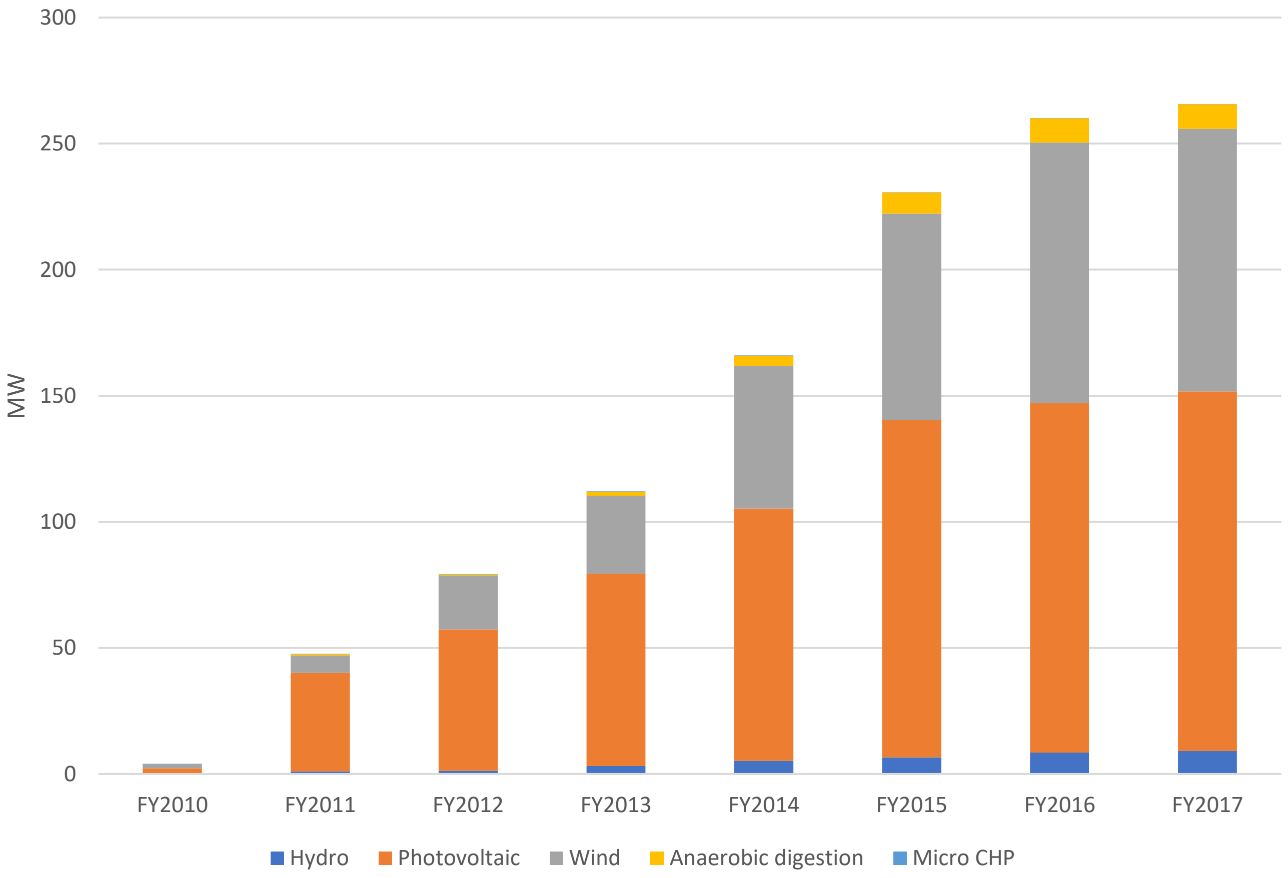


Source: Ofgem Feed-in Tariff Installation Report 31 March 2018

Figure 38 and 39: South Scotland cumulative installation capacity (MW) per accreditation year (financial year)

South Running Total	Accreditation Year Capacity							
Technology	**FY2010**	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**	**FY2016**	**FY2017**
Hydro	0.0989	0.9773	1.3139	3.1438	5.1434	6.5549	8.5348	9.1298
PhotOVOltaic	2.2174	39.1339	55.9795	76.2688	100.2031	133.8029	138.5519	142.6298
Wind	1.6254	6.9538	21.3564	30.9783	56.5855	81.8828	103.2978	104.1188
Anaerobic digestion	0.0000	0.4990	0.4990	1.6590	3.9780	8.3330	9.6810	9.7810
Micro CHP	0.0069	0.0129	0.0139	0.0139	0.0159	0.0159	0.0159	0.0159

Cumulative South Scotland FiT installation commissions

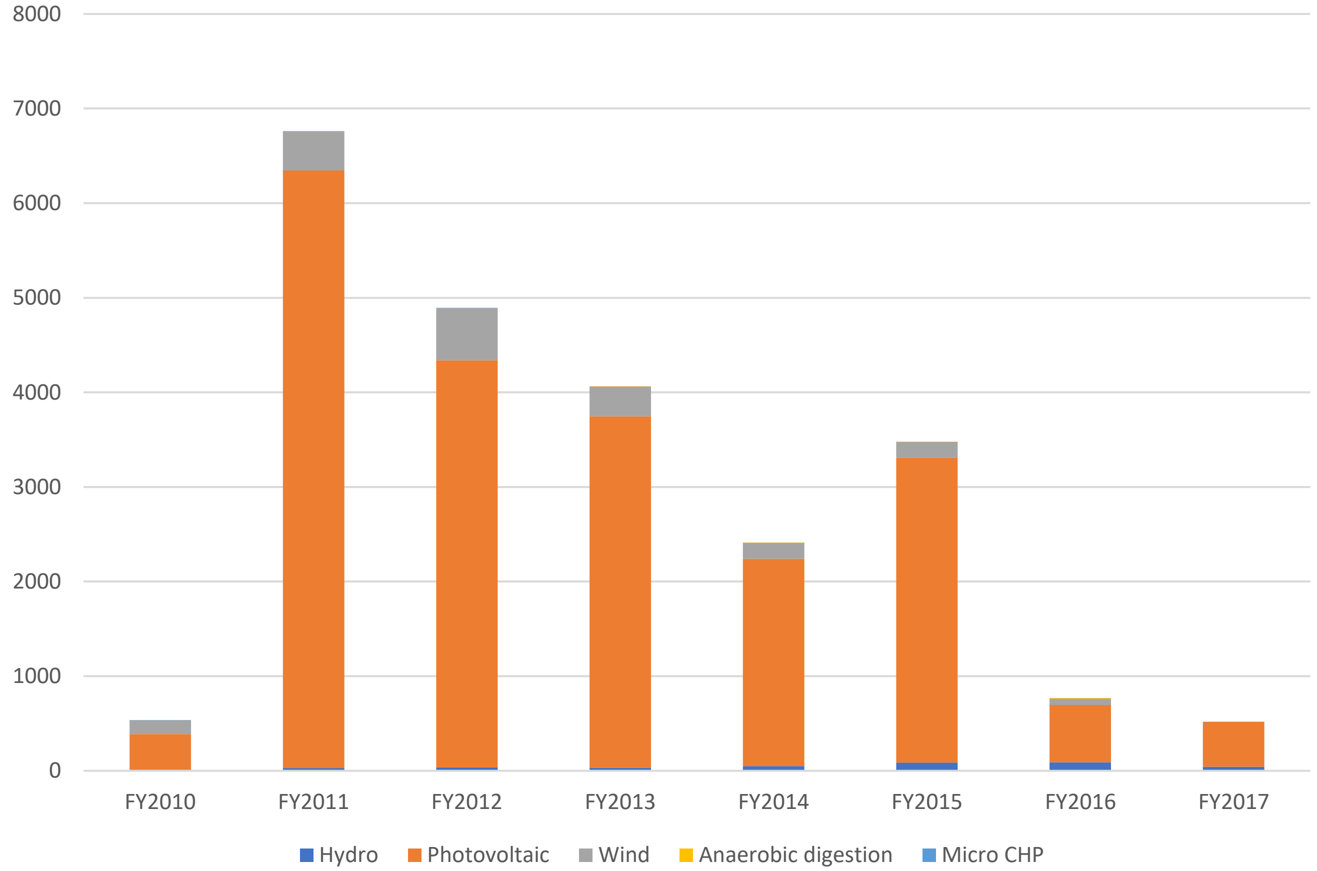


Source: Ofgem Feed-in Tariff Installation Report 31 March 2018

Figure 40 and 41: North Scotland installations (count) per accreditation year (financial year)

North	Accreditation Year Installations								
Technology	**FY2010**	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**	**FY2016**	**FY2017**	**Total**
Hydro	10	28	37	34	49	85	89	44	376
Photovoltaic	379	6318	4301	3712	2193	3221	608	472	21204
Wind	145	407	554	317	170	172	67	1	1833
Anaerobic digestion	0	0	0	2	3	2	5	0	12
Micro CHP	4	7	3	0	0	0	0	0	14
Total	538	6760	4895	4065	2415	3480	769	517	23439

North Scotland number of FiT installations commissioned by financial year

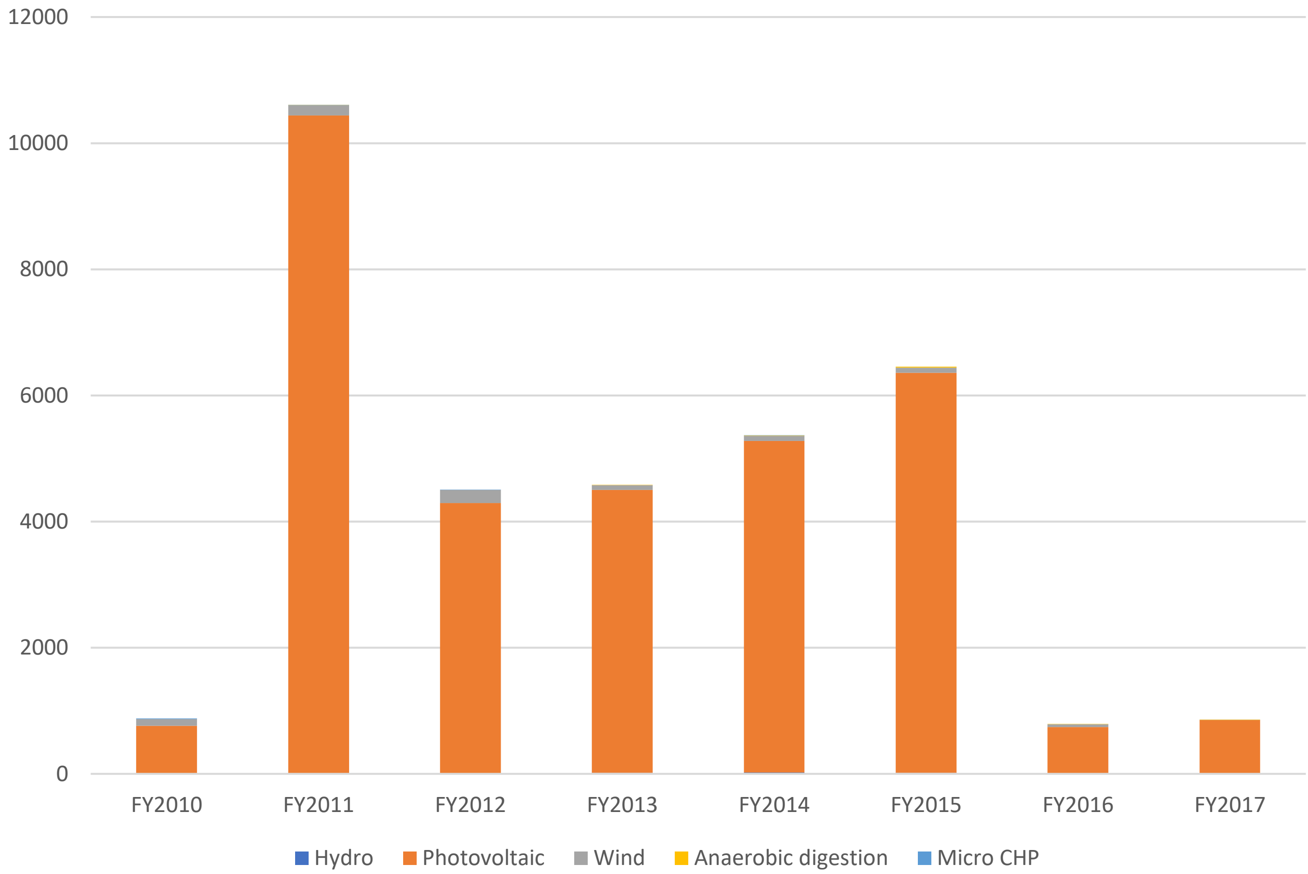


Source: Ofgem Feed-in Tariff Installation Report 31 March 2018

Figure 42 and 43: South Scotland installations (count) per accreditation year (financial year)

South	Accreditation Year Installations								
Technology	**FY2010**	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**	**FY2016**	**FY2017**	**Total**
Hydro	7	13	10	18	22	17	7	5	99
PhotOVOltaic	756	10429	4285	4482	5256	6340	736	848	33132
Wind	107	158	209	76	81	86	44	2	763
Anaerobic digestion	0	1	0	1	6	11	3	1	23
Micro CHP	7	6	1	0	1	0	0	0	15
Total	877	10607	4505	4577	5366	6454	790	856	34032

South Scotland number of FiT installations commissioned by financial year



Source: Ofgem Feed-in Tariff Installation Report 31 March 2018

Figure 44 and 45: Comparison of North and South Scotland installations capacity (MW) for the last two accreditation years

North	Accreditation Year Capacity		
Technology	**FY2016**	**FY2017**	**Total**
Hydro	44.48	31.73	76.21
PhotOVOltaic	7.54	4.45	11.99
Wind	27.57	0.81	28.38
Anaerobic digestion	2.65	0.00	2.65
Micro CHP	0.00	0.00	0.00
Total	82.23	36.99	119.22
South	**Accreditation Year Capacity**		
Technology	**FY2016**	**FY2017**	**Total**
Hydro	1.98	0.60	2.57
PhotOVOltaic	4.75	4.08	8.83
Wind	21.42	0.82	22.24
Anaerobic digestion	1.35	0.10	1.45
Micro CHP	0.00	0.00	0.00
Total	29.49	5.59	35.09

Source: Ofgem Feed-in Tariff Installation Report 31 March 2018

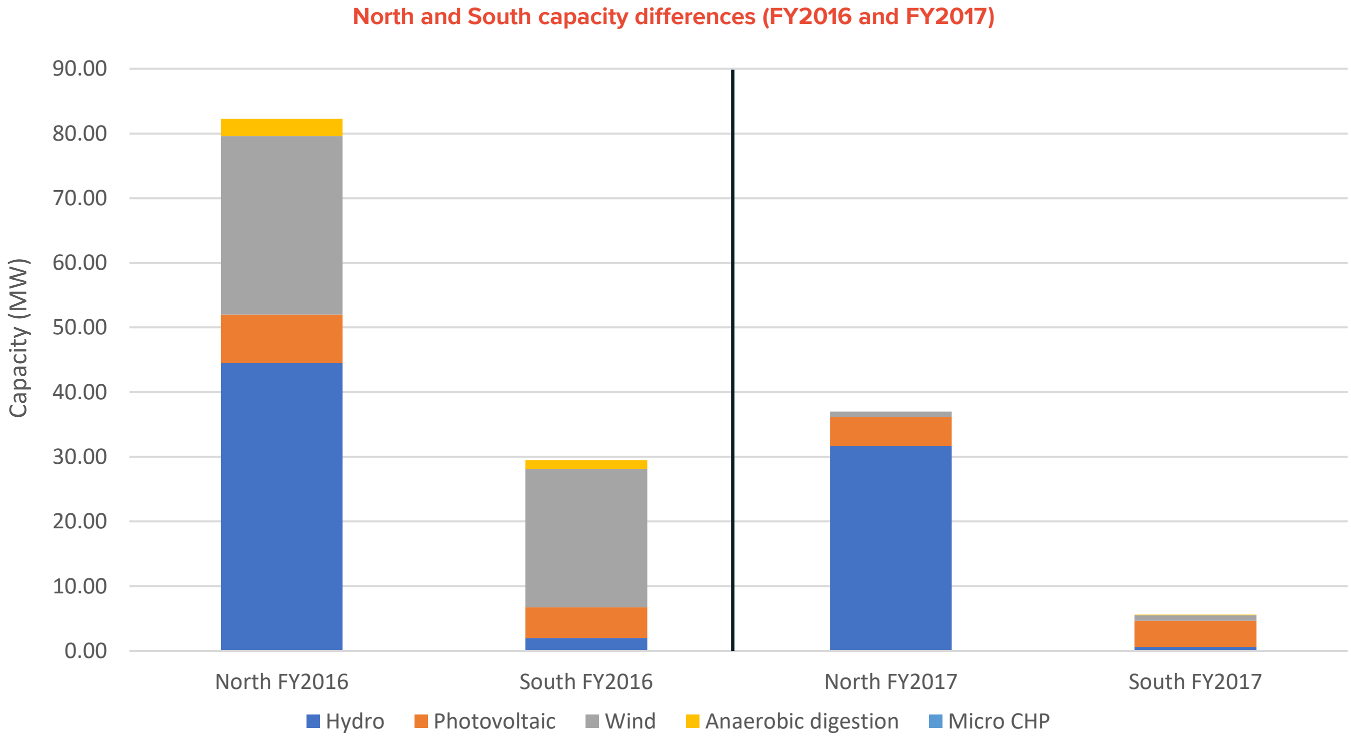
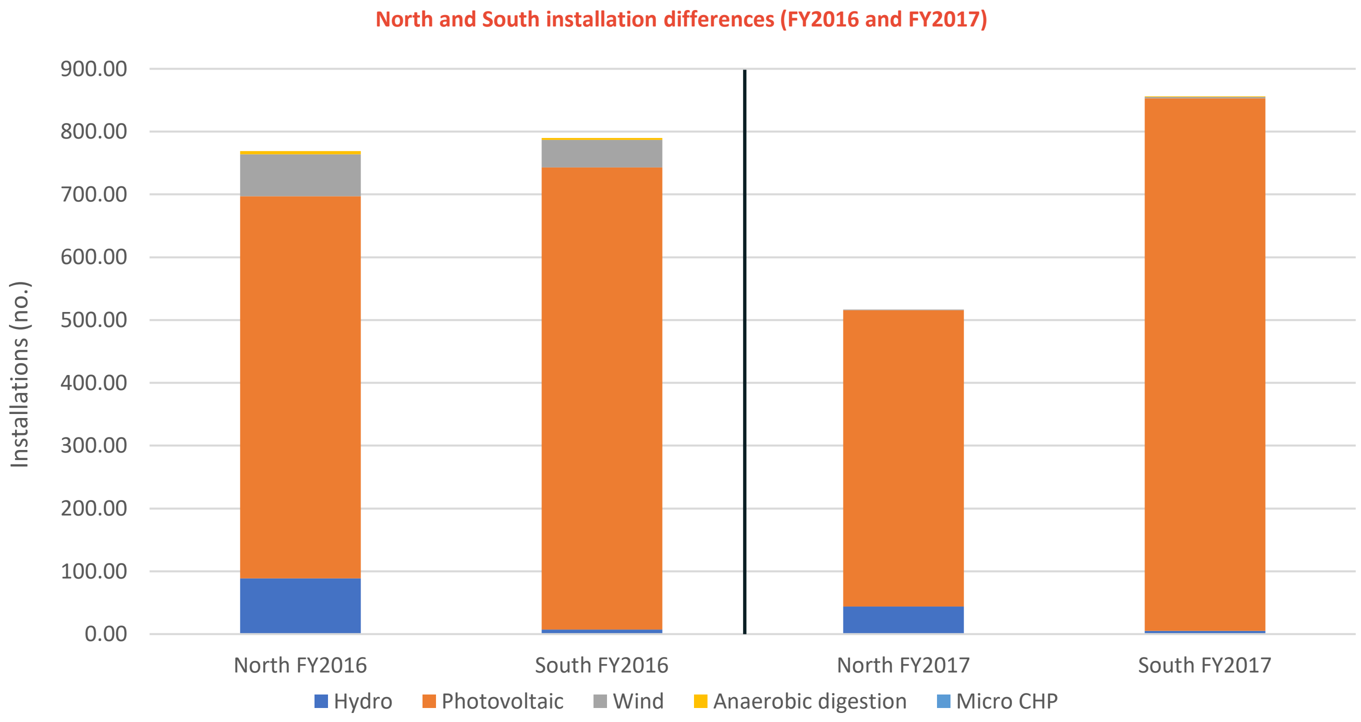


Figure 46 and 47: Comparison of North and South Scotland installations (count) for the last two accreditation years

North	Accreditation Year		
Technology	**FY2016**	**FY2017**	**Total**
Hydro	7	5	12
PhotOVOltaic	736	848	1584
Wind	44	2	46
Anaerobic digestion	3	1	4
Micro CHP	0	0	0
Total	790	856	1646
South	**Accreditation Year**		
Technology	**FY2016**	**FY2017**	**Total**
Hydro	89	44	133
PhotOVOltaic	608	472	1080
Wind	67	1	68
Anaerobic digestion	5	0	5
Micro CHP	0	0	0
Total	769	517	1286

Source: Ofgem Feed-in Tariff Installation Report 31 March 2018



8 Annex C: The economic case for private wires

8.1 Overview

An increasing number of market participants are choosing to locate behind the meter due to financial benefits of doing so. Any electricity generated and consumed either on site or via a private wire (an electrical network or wire not owned or operated by a licensed distribution network) is currently exempt from a number of costs associated with the electricity retail bill.

8.2 Retail savings for private wire arrangements

The economic case for private wires is very strong for consumers. Figure 48 below outlines the savings that can be made for switching to a private wire arrangement for a HVHH customer[45] on a regional average basis. An underlying assumption for the analysis is that there is no saving from wholesale costs between a generator that connects directly to the distribution network or to one that connects to a private network. This is because the fuel costs and plant efficiency is assumed to be the same. The analysis also ignores the implicit losses through using a private wire arrangement, and savings that accrue due to reductions in VAT and supplier costs, as some elements of these costs will likely need to be paid in the private wire cost chain.

Figure 48: Retail savings for a HVHH customer combined with a generator on a private network in 2018-19

Cost component	Current Costs for a HV HH customer (p/kWh)	Private Wire Saving
Wholesale	5.80	-
Transmission	0.18	0.18
Distribution	1.31	1.31
Balancing services	0.27	0.27
AAHEDC	0.03	0.03
Losses	0.58	0.58
Renewables Obligation	2.21	2.21
Feed-in Tariffs	0.56	0.56
Contracts for Difference	0.37	0.37
Capacity Market	0.26	0.26
Supplier costs	0.80	-
VAT @ 20%	2.474	0.90
Climate Change Levy	0.58	0.58
Total	**15.42**	**7.25**

Data correct for HVHH connected customer on a regional average basis in 2018-19

[45] Any customer connected at above 1kV.

The total savings to be made through private wire supply are 7.25p/kWh, or 47% of the total retail bill. If we were to remove the majority of supplier costs (based on the assumption that a private wire does not incur the same overheads as electricity supply) this figure can be in excess of 50% of the retail bill.

The renewable and low carbon levies (the Renewables Obligation (RO), Feed-in Tariffs (FiTs), Contracts-for-Difference (CfDs), Climate Change Levy (CCL)) are all effectively fixed costs levied on a volumetric basis. A number of the cost components have a time of use element to them (network charges and losses, wholesale costs, Capacity Market, and balancing services costs) and so will depend upon an individual customer's consumption profile. Therefore, customers may face different charges to those outlined here, however for comparative purposes we have used our standard profiles.

The economic case of using private wires is sufficiently strong in many instances that this is likely to form the overriding factor in making the decision to adopt a private wire approach.

8.3 The future

The non-energy component of the bill is forecast to increase in the future. For example, CfD charges are forecast to increase 196% from an average GB-wide value of 0.369p/kWh in 2018-19 to 1.092p/kWh in 2022-23 due to rapid increases in capacity subsidised under the scheme. The introduction of a completely new cost item on the bill (the Capacity Market) further adds to these increases. Given this background of rising non-energy costs, we expect the economic incentive for consumers to move private wires is going to increase in the future.

The same is true for generators. There are a number of factors forcing generators to look at maximising value for their generation:

- Increasing cannibalisation of wholesale prices for intermittent renewables during windy and sunny periods, leading to lower realised value for these plant. This will only increase as more intermittent capacity is installed
- Subsidy regimes are being scaled back – the RO is shortly closing to new generation, the FiT rates have been scaled back and support is subject to a cap, and the CfD auctions require generators to bid in order to win subsidy arrangements, and
- Small-scale and distributed generators are also facing the uncertainty of sweeping changes to network charges and embedded benefits, driven by code governance, the Targeted Charging Review (TCR) and Charging Futures work.

The case for installing private wires is site specific and varies based on the amount of infrastructure that is required and the savings that will accrue at each site. This means the economic case needs to be assessed individually on a site by site basis. However, our analysis suggests that the significant economic benefits of a private wire arrangement will prove attractive for both demand customers and generators in most cases. Without regulatory reform, reductions to embedded benefits are likely to drive more and more capacity behind the meter and onto private wire agreements.

9 Annex D: PPA price benchmarks

Subsidy free

Solar										
Market Benchmark Price	**Solar (£/MWh)**	**Win-18**	**Sum-19**	**Win-19**	**Sum-20**	**Win-20**	**Sum-21**	**Win-21**	**Sum-22**	**Win-22**
	Power	68.45	59.96	61.79	51.88	55.65	47.90	51.36	46.34	50.35
	Embedded benefits	9.28	8.81	8.89	8.60	8.77	8.80	8.96	9.25	7.19
	Rego	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	Total	77.92	68.97	70.88	60.68	64.62	56.90	60.52	55.79	57.74
Routes to market	**Solar (£/MWh)**	**Win-18**	**Sum-19**	**Win-19**	**Sum-20**	**Win-20**	**Sum-21**	**Win-21**	**Sum-22**	**Win-22**
	e-POWER/ <1 year	75.59	66.90	68.75	58.86	62.68	55.20	58.70	54.11	56.01
	Fixed Price PPA (1-3 years)	74.81	66.21	68.04	58.25	62.03	54.63	58.10	53.55	55.43
	Flex PPA (1-3 years)	74.81	66.21	68.04	58.25	62.03	54.63	58.10	53.55	55.43
	Long-Term PPA (10-15 years)	74.03	65.52	67.33	57.65	61.39	54.06	57.49	53.00	54.85
Wind										
Market Benchmark Price	**Wind (£/MWh)**	**Win-18**	**Sum-19**	**Win-19**	**Sum-20**	**Win-20**	**Sum-21**	**Win-21**	**Sum-22**	**Win-22**
	Power	69.52	57.26	62.75	49.55	56.52	45.74	52.16	44.25	51.14
	Embedded benefits	12.38	9.37	10.80	9.23	9.80	10.08	10.64	10.27	8.65
	Rego	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	Total	82.09	66.83	73.75	58.98	66.52	56.03	63.01	54.72	59.99
Routes to market	**Wind (£/MWh)**	**Win-18**	**Sum-19**	**Win-19**	**Sum-20**	**Win-20**	**Sum-21**	**Win-21**	**Sum-22**	**Win-22**
	e-POWER/ <1 year	79.63	64.83	71.54	57.21	64.53	54.35	61.12	53.08	58.19
	Fixed Price PPA (1-3 years)	78.81	64.16	70.80	56.62	63.86	53.79	60.49	52.53	57.59
	Flex PPA (1-3 years)	78.81	64.16	70.80	56.62	63.86	53.79	60.49	52.53	57.59
	Long-Term PPA (10-15 years)	77.99	63.49	70.07	56.03	63.19	53.23	59.86	51.99	56.99
Baseload										
Market Benchmark Price	**Baseload (£/MWh)**	**Win-18**	**Sum-19**	**Win-19**	**Sum-20**	**Win-20**	**Sum-21**	**Win-21**	**Sum-22**	**Win-22**
	Power	71.30	59.96	64.36	51.88	57.97	47.90	53.50	46.34	52.45
	Embedded benefits	15.49	9.26	12.78	11.90	10.15	9.84	10.89	10.00	11.11
	Rego	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	Total	86.89	69.32	77.24	63.88	68.22	57.84	64.49	56.44	63.66
Routes to market	**Baseload (£/MWh)**	**Win-18**	**Sum-19**	**Win-19**	**Sum-20**	**Win-20**	**Sum-21**	**Win-21**	**Sum-22**	**Win-22**
	e-POWER/ <1 year	84.28	67.24	74.92	61.97	66.17	56.10	62.56	54.75	61.75
	Fixed Price PPA (1-3 years)	83.42	66.55	74.15	61.33	65.49	55.52	61.91	54.18	61.11
	Flex PPA (1-3 years)	83.42	66.55	74.15	61.33	65.49	55.52	61.91	54.18	61.11
	Long-Term PPA (10-15 years)	82.55	65.86	73.38	60.69	64.81	54.95	61.27	53.62	60.48

10 Annex E: Embedded benefits in Scotland

HV connected 0.5MW wind farm, North Scotland

£/MWh	Embedded Benefit	2018-19	2019-20	2020-21	2021-22	2022-23
	TNUoS	4.05	0.00	0.00	0.00	0.00
Transmission- related	BSUoS	-0.78	-0.74	-0.79	-1.02	-1.12
	AAHEDC	2.53	2.58	2.63	2.68	2.74
	Transmission subtotal	5.80	1.84	1.85	1.66	1.62
Distribution-related	GDUoS					
	Unit Rate - Super Red	0.00	0.00	0.00	0.00	0.00
	Unit Rate - Red	5.49	3.98	3.89	4.03	4.14
	Unit Rate - Amber	5.49	3.98	3.89	4.03	4.14
	Unit Rate - Green	5.49	3.98	3.89	4.03	4.14
	Fixed	-3.49	-1.13	-1.11	-1.15	-1.18
	Distribution subtotal	1.97	2.80	2.74	2.84	2.92
	Total	7.78	4.64	4.59	4.50	4.54

HV connected 0.5MW baseload, North Scotland

£/MWh	Embedded Benefit	2018-19	2019-20	2020-21	2021-22	2022-23
	TNUoS	1.21	0.00	0.00	0.00	0.00
Transmission- related	BSUoS	-0.10	-0.10	-0.10	-0.14	-0.15
	AAHEDC	2.53	2.58	2.63	2.68	2.74
	Transmission subtotal	3.64	2.48	2.53	2.55	2.59
Distribution-related	GDUoS					
	Unit Rate - Super Red	0.00	0.00	0.00	0.00	0.00
	Unit Rate - Red	21.56	32.47	31.76	32.90	33.79
	Unit Rate - Amber	6.35	2.62	2.56	2.65	2.73
	Unit Rate - Green	1.82	0.09	0.09	0.09	0.09
	Fixed	-0.23	-0.08	-0.07	-0.08	-0.08
	Distribution subtotal	5.02	3.91	3.82	3.96	4.07
	Total	8.66	6.39	6.35	6.51	6.66

HV connected 0.5MW wind farm, South Scotland

£/MWh	Embedded Benefit	2018-19	2019-20	2020-21	2021-22	2022-23
	TNUoS	5.01	0.00	0.00	0.00	0.00
Transmission- related	BSUoS	2.84	2.70	2.85	3.70	4.05
	AAHEDC	2.52	2.56	2.61	2.67	2.72
	Transmission subtotal	10.37	5.26	5.46	6.37	6.77
Distribution-related	GDUoS					
	Unit Rate - Super Red	0.00	0.00	0.00	0.00	0.00
	Unit Rate - Red	4.07	3.98	4.08	4.07	4.17
	Unit Rate - Amber	4.07	3.98	4.08	4.07	4.17
	Unit Rate - Green	4.07	3.98	4.08	4.07	4.17
	Fixed	-1.25	-1.13	-1.16	-1.16	-1.19
	Distribution subtotal	2.75	2.78	2.84	2.84	2.91
	Total	13.12	8.04	8.30	9.21	9.68

HV connected 0.5MW baseload, South Scotland

£/MWh	Embedded Benefit	2018-19	2019-20	2020-21	2021-22	2022-23
	TNUoS	1.50	0.00	0.00	0.00	0.00
Transmission- related	BSUoS	2.51	2.39	2.52	3.27	3.58
	AAHEDC	2.52	2.56	2.61	2.66	2.72
	Transmission subtotal	6.52	4.95	5.13	5.94	6.30
Distribution-related	GDUoS					
	Unit Rate - Super Red	0.00	0.00	0.00	0.00	0.00
	Unit Rate - Red	33.33	32.47	33.25	33.22	34.01
	Unit Rate - Amber	2.66	2.62	2.68	2.68	2.74
	Unit Rate - Green	0.13	0.09	0.09	0.09	0.09
	Fixed	-0.08	-0.08	-0.08	-0.08	-0.08
	Distribution subtotal	3.90	3.81	3.90	3.89	3.99
	Total	10.42	8.76	9.03	9.83	10.29

LV connected 0.3MW wind farm, North Scotland

£/MWh	Embedded Benefit	2018-19	2019-20	2020-21	2021-22	2022-23
	TNUoS	4.28	0.00	0.00	0.00	0.00
Transmission- related	BSUoS	-0.83	-0.79	-0.83	-1.08	-1.18
	AAHEDC	2.68	2.73	2.78	2.84	2.90
	Transmission subtotal	6.14	1.94	1.95	1.76	1.72
Distribution-related	GDUoS					
	Unit Rate - Super Red	0.00	0.00	0.00	0.00	0.00
	Unit Rate - Red	12.15	7.53	7.36	7.63	7.84
	Unit Rate - Amber	12.15	7.53	7.36	7.63	7.84
	Unit Rate - Green	12.15	7.53	7.36	7.63	7.84
	Fixed	0.00	0.00	0.00	0.00	0.00
	Distribution subtotal	11.31	7.01	6.86	7.10	7.30
	Total	17.45	8.95	8.81	8.87	9.01

LV connected 0.3MW baseload, North Scotland

£/MWh	Embedded Benefit	2018-19	2019-20	2020-21	2021-22	2022-23
	TNUoS	1.28	0.00	0.00	0.00	0.00
Transmission- related	BSUoS	-0.11	-0.10	-0.11	-0.14	-0.16
	AAHEDC	2.68	2.73	2.78	2.84	2.90
	Transmission subtotal	3.85	2.62	2.67	2.70	2.74
Distribution-related	GDUoS					
	Unit Rate - Super Red	0.00	0.00	0.00	0.00	0.00
	Unit Rate - Red	46.68	57.34	56.08	58.10	59.67
	Unit Rate - Amber	14.24	5.74	5.61	5.82	5.97
	Unit Rate - Green	4.05	0.32	0.31	0.32	0.33
	Fixed	0.00	0.00	0.00	0.00	0.00
	Distribution subtotal	10.97	7.17	7.00	7.25	7.45
	Total	14.82	9.79	9.68	9.95	10.19

LV connected 0.3MW wind farm, South Scotland

£/MWh	Embedded Benefit	2018-19	2019-20	2020-21	2021-22	2022-23
	TNUoS	5.46	0.00	0.00	0.00	0.00
Transmission- related	BSUoS	3.04	2.89	3.05	3.96	4.33
	AAHEDC	2.69	2.74	2.79	2.85	2.91
	Transmission subtotal	11.19	5.63	5.84	6.81	7.24
Distribution-related	GDUoS					
	Unit Rate - Super Red	0.00	0.00	0.00	0.00	0.00
	Unit Rate - Red	7.62	7.53	7.71	7.70	7.89
	Unit Rate - Amber	7.62	7.53	7.71	7.70	7.89
	Unit Rate - Green	7.62	7.53	7.71	7.70	7.89
	Fixed	0.00	0.00	0.00	0.00	0.00
	Distribution subtotal	6.96	6.87	7.04	7.03	7.20
	Total	18.15	12.50	12.88	13.84	14.44

LV connected 0.3MW baseload, South Scotland

£/MWh	Embedded Benefit	2018-19	2019-20	2020-21	2021-22	2022-23
	TNUoS	1.63	0.00	0.00	0.00	0.00
Transmission- related	BSUoS	2.68	2.55	2.69	3.50	3.83
	AAHEDC	2.69	2.74	2.79	2.85	2.90
	Transmission subtotal	7.00	5.29	5.48	6.34	6.73
Distribution-related	GDUoS					
	Unit Rate - Super Red	0.00	0.00	0.00	0.00	0.00
	Unit Rate - Red	56.17	57.34	58.72	58.66	60.07
	Unit Rate - Amber	6.13	5.74	5.88	5.87	6.01
	Unit Rate - Green	0.45	0.32	0.33	0.33	0.34
	Fixed	0.00	0.00	0.00	0.00	0.00
	Distribution subtotal	6.97	6.89	7.05	7.04	7.21
	Total	13.97	12.18	12.53	13.39	13.94

11 Annex F: Networks

The electricity industry distinguishes between wholesale energy production, delivery through the transmission and distribution networks and supply to customers. Energy production and supply are competitive, while delivery is a regulated monopoly. Delivery gives rise to third party use of system charges covering the functions of:

- Electricity transmission – defined as the assets at voltages of 275kV and over in England and Wales and 132kV and over in Scotland. National Grid levies charges for using the transmission system in Great Britain, although it does not own the networks in Scotland;
- Electricity distribution – defined as voltages up to 275kV in England and Wales and 132kV in Scotland. There are 14 licensed distribution network operators (DNOs) in Great Britain each responsible for a distribution services area. The 14 DNOs are owned by six different companies. There are also a small number of independent network operators (IDNOs) that own and run smaller networks embedded in the DNO networks

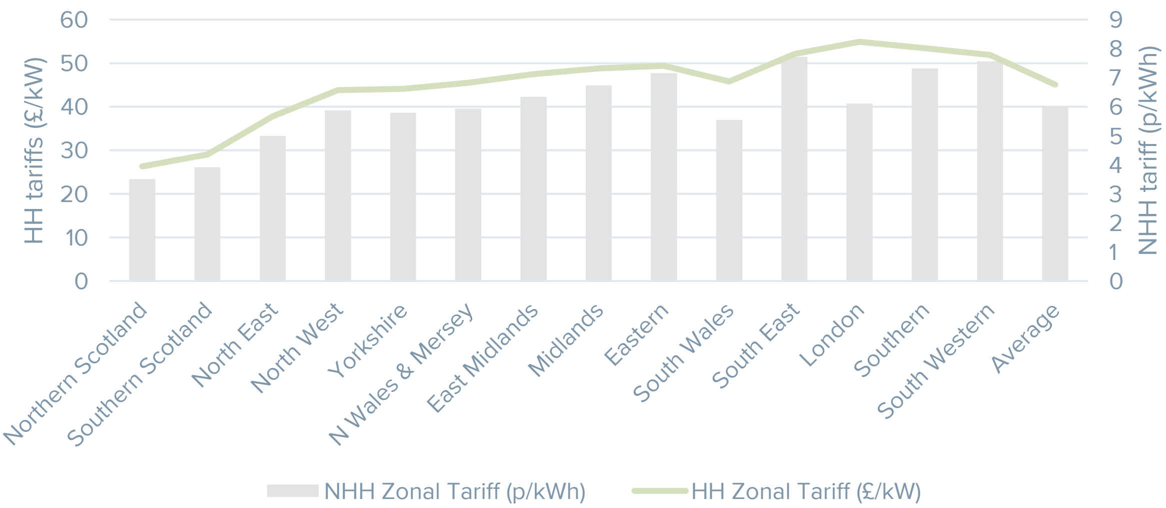
11.1 Electricity transmission

Electricity transmission charges, termed Transmission Network Use of System charges (TNUoS), are levied on generators connected to the transmission system and consumers. They recover the costs of maintaining and enhancing the transmission network, owned by National Grid (NGET), Scottish Power Transmission (SPTL), Scottish Hydro-Electric Transmission (SHETL) and a number of offshore transmission owners (OFTOs).

Consumers that are metered on a half-hourly basis are charged the half-hourly zonal tariff, sometimes referred to as the "triad charge". This charge is based on the average kW demand during the triad periods (the three periods of highest system demand, usually three winter early evenings, separated by at least 10 days).

Non-half-hourly metered consumers (small businesses and domestic consumers) are charged based on the non-half-hourly zonal tariff. This is a p/kWh charge that is levied dependent on the consumer's average electricity demand during the early evenings throughout the year.

Figure 49: Demand tariffs 2018-19



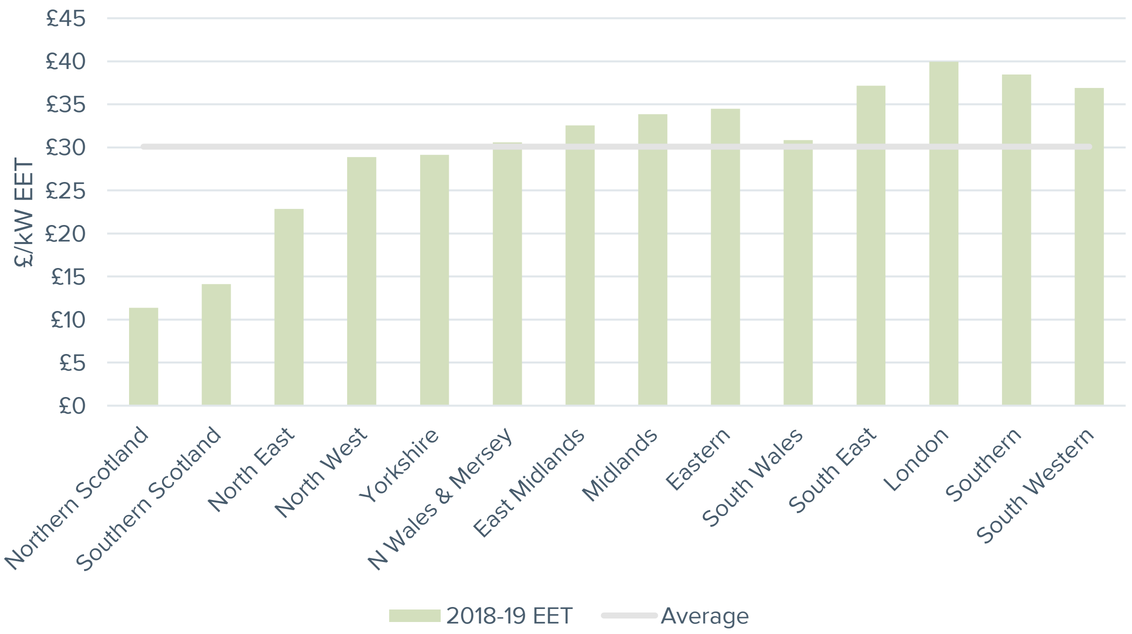
Source: National Grid

From April 2018 embedded generators also receive a specific credit for generating during the triad peak, termed an embedded export tariff (EET). This benefit will fall annually to 2020-21, where it has a floor value of £0/kW for Scotland and the majority of northern England.

Costs vary on a regional basis – the EET and demand charges tend to be higher in the south and lower in the north of GB. This is because the north is generator-dominated while the south has the larger demand centres, and so an additional unit of demand in the south uses more of the network on average than an additional unit in the north.

Figure 50 shows the EET credits for the 2018-19 charging year. Northern Scotland has the lowest level of benefits (£11.36/kW) at less than half the regional average (£30.06/kW).

Figure 50: Embedded export tariffs 2018-19



Source: National Grid

11.1.1 Transmission connected generation

Generation connected directly to the transmission system must also pay transmission network charges. These comprise of any local charges for connecting to the transmission system and the costs of the wider transmission system. Local costs vary by generator and depend on the cost associated with the transmission substation they connect to and the cost of any local circuits.

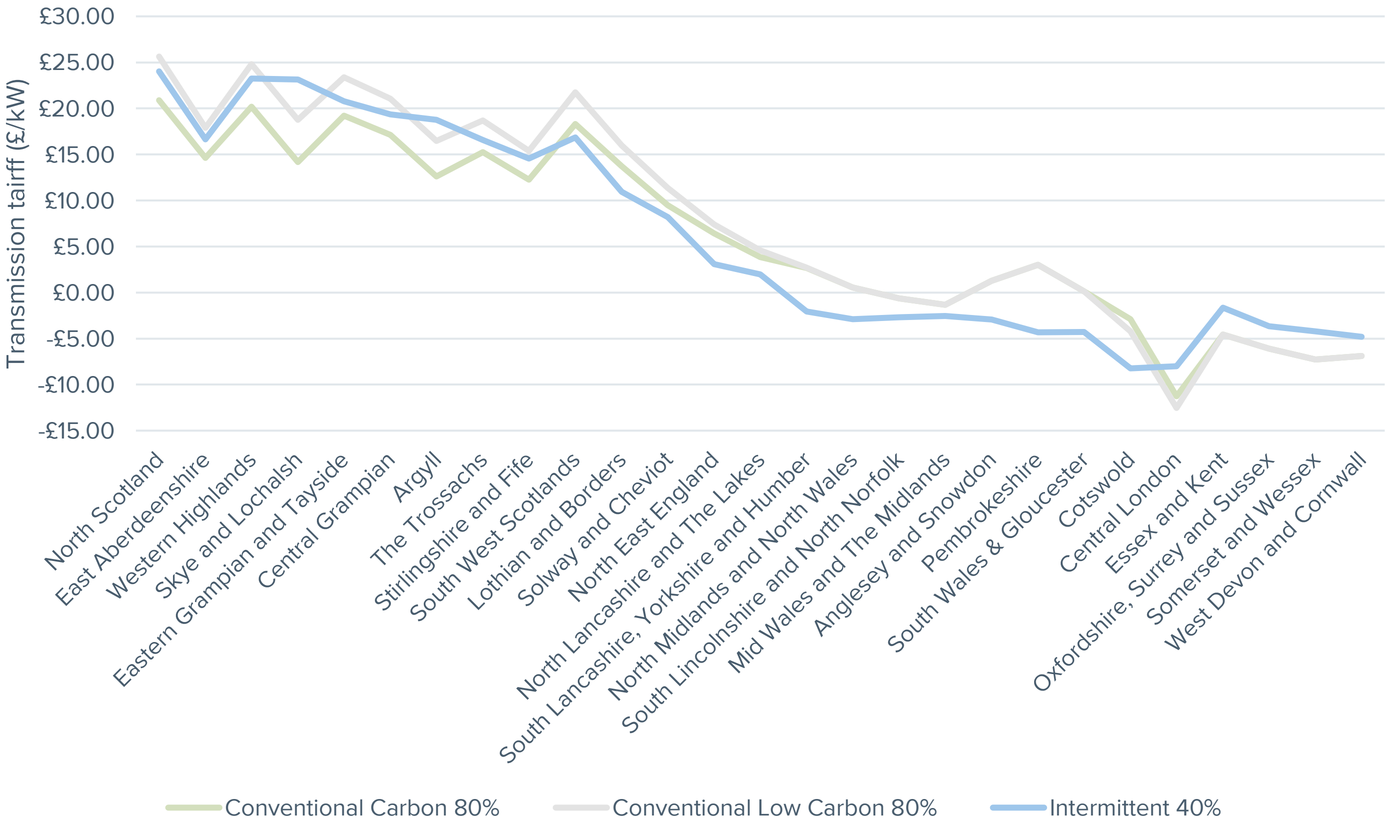
Wider generation tariffs are comprised of a range of different elements:

- A peak element – paid by conventional generators
- A year round shared element – paid by all generators
- A year round not shared element – paid by all generators
- A residual element – paid by all generators

Wider generation tariffs follow a GB-wide trend of highest costs in the north and lower costs (and in some cases payment for connecting to the transmission network) in the south. This is because the north is generation-dominated and so any generation in the region flows power over a longer distance than any power generated in the south, using more of the transmission network. There are 27 different generation charging zones that can vary at the start of each price control.

National Grid calculates representative tariffs for an assumed conventional carbon generator, a conventional low-carbon generator, and an intermittent generator. The regional differentiation in the wider tariffs is outlined in Figure 51.

Figure 51: Transmission generation tariffs



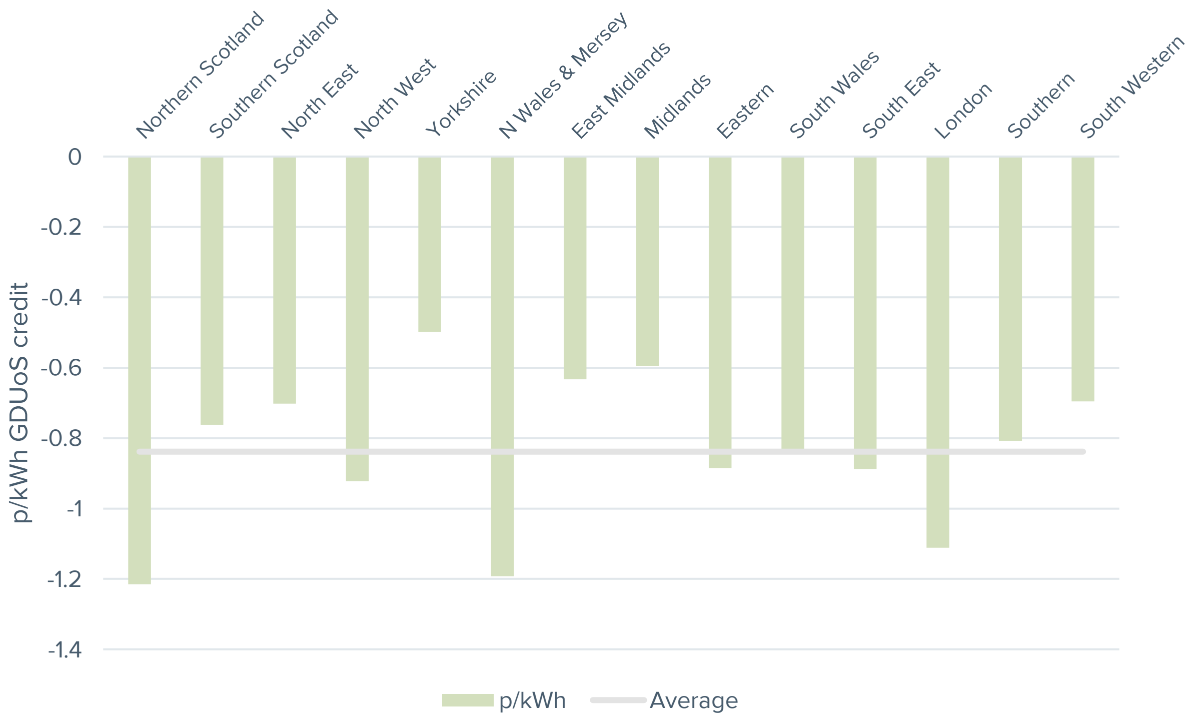
11.1.2 Electricity distribution

Electricity distribution use of system (DUoS) charges recover the costs of maintaining and upgrading the local distribution networks across GB. Charges are levied on (or credits are paid to) generators and consumers and are differentiated by location and user type:

- Extra-high voltage (EHV) users have site-specific charges broken down into fixed, capacity, and super peak (generally winter evening) charges
- Low (LV) and high voltage (HV) connected users face charges aggregated across their user type rather than on a site-specific basis. The format of these charges varies depending on whether a generator is intermittent or not (non-intermittent generators can receive greater credits for exporting during peak periods) and whether a demand user is half-hourly settled or not (half hourly settled consumers face higher charges during peak periods)
    - Charges or credits tend to be unit rates (that can be differentiated on a three tier basis over peak, shoulder and off-peak periods), fixed charges and capacity charges
    - Customers are also charged for any reactive power effects that they have on the system

As can be seen in Figure 53, Northern Scotland has the highest GDUoS credits in the country for an LV connected intermittent generator.

Figure 52: GDUoS distribution credits – 2018-19 for an LV HH intermittent generator



Source: DNO LC14 charging statements

12 Annex G: Electrical losses – Scotland

12.1 Transmission losses

Transmission losses are energy that is lost as electricity travels from transmission-connected generator to a directly connected customer or a grid supply point. The greater the distance travelled, the higher the losses, which typically account for around 2% of electricity transmitted.

Transmission losses are allocated by scaling up or down metered volumes of each non-interconnector BMU. Losses are applied using Transmission Loss Multipliers (TLM). The values of TLM can change in each Settlement Period to reflect the proportion of transmission losses being allocated to BM Units in either delivering or offtaking Trading Units (other than Interconnector BM Units) spread over the aggregate quantities of imports and exports of BM Units (other than Interconnector BM Units) in those delivering or offtaking Trading Units.

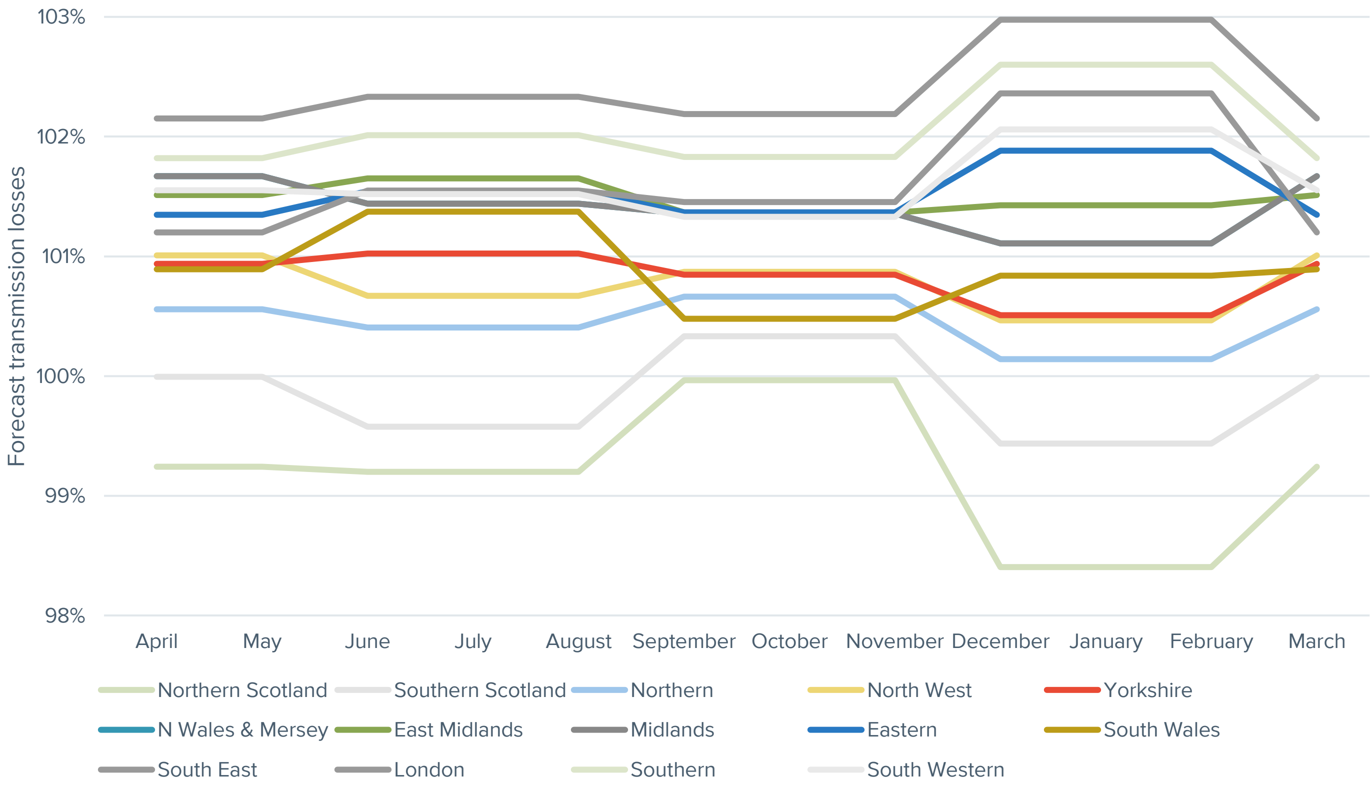
45% of losses are applied to delivering BMUs (generators) and 55% of losses are applied to off taking BMUs (suppliers). This segmentation takes account of the fact that generators are metered on the HV side of the transformer and losses in the transformer are allocated to the generator. For volumes transferred from the transmission system to the distribution system the metering takes place on the LV side of a grid supply transformer so the losses in the transformer are included in the overall transmission losses.

The TLM calculation includes Transmission Loss Factors which vary the weight of TLMs applied to individual BMUs; this allows the allocation of losses depending on geographical location.

From April 2018, transmission losses will be attributed on a seasonal and locational basis. This follows the Competition and Markets Authority's (CMA's) investigation into the energy market, which found that non-locational transmission losses were having an adverse effect on competition. The net effect of this change is to modify transmission loss factors (TLFs, previously set at zero) to be positive or negative depending on the network and time of year. For a consumer or embedded generator, this is then added to the transmission loss modifier adjustment for offtaking units (TLMOj-), which varies on a half-hourly basis, to calculate total transmission losses.

Figure 53 outlines the total transmission losses applied to each region in each month for 2018-19, using the forecast TLMOj- provided by Elexon and finalised TLFs. Offtaking losses are lowest in North Scotland and highest in London and the south of England.

Figure 53: Forecast off-taking transmission losses by region and season 2018-19



This change in attribution means that embedded generation located in Scotland will generally be at a disadvantage compared to embedded plant located further south. This is because distributed plant in London for example will be offsetting up to 3% of additional demand attributed to transmission losses, whereas an embedded generator in Northern Scotland will see no benefit or costs for much of the year.

12.2 Distribution losses

Distribution losses are the flows of power on the distribution network lost as heat or stolen from the network. They can be divided into:

- Technical losses – these losses are inherent to the running of the distribution network and include electricity lost as heat during transportation, and
- Non-technical or commercial losses – these are losses from theft (either from a site supplied by a supplier or sites without a supplier appointed) or under-declaration of consumption from unmetered supply points (UMS).

Technical losses can be further subdivided into variable and fixed losses. Variable losses are associated with the electrical resistance of conducting wires, and therefore vary depending on the load they are carrying. Fixed losses are those associated with the transformation of electricity and, unlike variable losses, these are not a function of the load passing through the wires. Fixed losses are present and virtually constant as long as the transformer in energised. For a distribution network, typically around 30% of technical losses are due to fixed losses, with the remaining 70% due to variable losses.

12.3 Application

Losses are allocated to different voltage levels of the network. Extra-high voltage (EHV) users (generators and consumers) have a site-specific line loss factor (LLF) applied to their volumes, which will vary depending on their location on the network and its relative load. All other customers (over 99% of customers) are located at the high or low voltage level, and these have a socialised LLF applied based on the customers' voltage level.

These are calculated by metering intake from a higher voltage tier, offtake from a lower voltage tier, and generation and demand at the relevant voltage level. Any difference between input volumes and output volumes is due to losses.

Losses vary throughout the day and across the year. Peak losses occur in the winter periods of peak demand, with the lowest periods during weekends and nights.

12.4 Derivation

There are two key stages to LLF derivation:

- Submission, review and approval of an LLF methodology, if new or altered, and
- Submission, audit and approval of LLFs, and subsequent notification of LLFs to supplier agents and other parties.

Distribution Network Operators (DNOs) are required to provide their methodologies (if new or altered) for calculating LLFs to Elexon for approval. Elexon will review the methodologies against the underlying principles all DNOs mush adhere to when developing a methodology, before submitting a recommendation to the Balancing and Settlement Code (BSC) Panel. The BSC Panel then either approves or rejects the methodology.

Following approval of a methodology, each host DNO and embedded DNO that does not mirror its host DNO's loss factors, must calculate the LLFs in accordance with the approved methodology. This is then submitted to Elexon for audit – if the losses do not pass the audit, Elexon recommends default values be approved by the Panel. DNOs are then required to correct any non-compliance, after which the Panel may approve the revised LLFs for the remainder of the year. All approved LLFs are provided to supplier and settlement agents and published on the Elexon Portal.

12.5 Quantum

Losses in the Southern Scotland region are representative of those found more broadly across GB in that there is significant diurnal and seasonal variation. They rise from 7.6% in the overnight period to 11.3% in the winter peak period for the LV network. At the HV level they approximate 2%-3% and at 33kV (EHV) they are closer to 0.3%-0.5%.

Losses in the Northern Scotland region have much less variation than typically expected, ranging from 9.1% in the early night to 9.6% in the winter peak. Losses between 12:30am and 7:30am remain significant at 9.5%, where they would typically fall by 3%-4% compared to the winter peak in other regions. This is in part due to the high consumption of electricity for heating in overnight periods, due to the relative lack of access to the gas grid in the region. Losses on the HV network range from 3.2% to 3.6% and 33kV losses are 1.1%-1.6% and so are much greater than losses in Southern Scotland.

This loss is applied to embedded generation in reverse – its export onto the system is lossed upwards by the relevant LLF. As such it is one of the so-called embedded benefits available to a generator, and these are captured either by the generator or offtaker depending on the terms of a power purchase agreement (PPA).

12.6 2018-19 LLFs for Northern Scotland

Metered voltage	Period 1	Period 2	Period 3	Period 4
LV	1.096	1.095	1.091	1.095
LV substation	1.059	1.060	1.064	1.069
HV	1.036	1.036	1.032	1.033
HV substation	1.026	1.026	1.024	1.026

Metered voltage	Period 1	Period 2	Period 3	Period 4
33kV generic	1.016	1.016	1.011	1.012

All losses are reported on a 2018-19 basis.

Time periods	Period 1	Period 2	Period 3	Period 4
	Winter weekday peak	Winter weekday	Other	Night
Monday to Friday Nov to Feb	16:00-19:00	07:30-16:00 19:00-20:00	20:00-00:30	00:30-07:30
Saturday to Sunday all year and Monday to Friday Mar to Oct	-	-	07:30-00:30	00:30-07:30

UK Clock time

12.7 2018-19 LLFs for Southern Scotland

Metered voltage	Period 1	Period 2	Period 3	Period 4
LV	1.076	1.088	1.100	1.113
LV substation	1.044	1.044	1.046	1.049
HV	1.023	1.026	1.029	1.031
HV substation	1.013	1.012	1.012	1.013
33kV generic (demand)	1.003	1.004	1.005	1.005
33kV generic (generation)	1.000	1.000	1.000	1.000

Time periods	Period 1	Period 2	Period 3	Period 4
Monday to Friday Mar to Oct	23:30-07:30	07:30-23:30	-	-
Monday to Friday Nov to Feb	23:30-07:30	20:00-23:30	07:30-16:00 19:00-20:00	16:00-19:00
Saturday to Sunday all year	23:30-07:30	07:30-23:30	-	-

UK Clock time