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Energy Saving Trust: New Community Energy Development Models in Scotland

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1 Executive summary

1.1 Purpose

Scotland has a vibrant community and local energy (CALE) sector. It already has more than 650MW of CALE generation capacity. The Scottish Government has a high level of policy commitment to further developing the sector and is seeking to "maintain its leadership in developing local energy systems". It is aiming to increase capacity to 1GW by 2020 and 2GW by 2030. It wishes to do so in a manner that moves from "single use" local energy projects to those that can be replicated on a strategic scale, over larger geographical areas.

This report, *New Community Energy Development Models in Scotland,* has been prepared by Cornwall Insight for the Energy Saving Trust, under the CARES programme. It sets out the process we have followed to identify good practice and outcomes from selected existing CALE schemes and available delivery models.

The report also considers how new CALE schemes can be supported and encouraged in a world that will shortly be largely subsidy-free and which is subject to a high-level of policy and regulatory change. It has been written at an important juncture in the development of the market, and because of the extent of change to incentive structures the past does not provide many indications for the future. The report then identifies some work-plans, targeted on specific areas with significant developmental potential in a post Renewables Obligation and Feed-in Tariff world, and describes the factors that influence the viability of CALE projects going forwards.

Fuller notes on the project scope are at section 2.

1.2 Approach

There are three basic building blocks to our work.

1.2.1 Setting out the market context

To inform our thinking, we conducted an **assessment of the market context in Scotland** and its interaction with policy and regulatory interventions**.** It is baselined on the position at October 2018.

The assessment is at Appendix A, and headlines points are summarised at section 3 of this report.

1.2.2 Landscaping assessment

We then conducted a detailed review of the CALE landscape. There are two parts to this work: first an assessment of existing projects in the form of case studies; and, second a review of delivery models that supported them.

A range of CALE **case studies** were referred to us by the project steering group, to which we added a number of other community developments from GB and elsewhere, to help us understand and critique the different delivery models used to date.

The GB projects considered in this report – some 17 in all – demonstrate a wide range of different innovation streams. However, these projects have all drawn support from grant aid or benefit from incentives under legacy schemes for low-carbon development. The five international examples we reference also show what can be achieved with a higher level of ambition when local conditions, policy commitment and regulatory support come together, though institutional arrangements in these jurisdictions are very different.

Overall, we found limited lessons from these projects that can be applied in the new subsidy-free environment, but we have drawn on the literature to highlight useful sources and practices elsewhere in this document and in the proposed work-plans.

This landscaping work is described more fully at section 4, with fuller notes on the case studies at Annex A to this report.

Second, based on this research, we developed **a long-list of delivery models** for potential future use focussing on how CALE projects achieve viability. These number over 20, and they are based around existing commercial and regulatory structures. The delivery models can be grouped around licensed supply, private wires, micro-grids and a range of emerging approaches that combine elements of these and others.

We then **critiqued the delivery models** against a variety of assessment criteria that included policy objectives, distributional impacts and implementation considerations (including repeatability and scale-ability), and we also considered the extent to which enabling changes would be required to enable further development.

From this critique we developed some **illustrative pathways**. A key point to make here is that, while the different models have different features and incentives, they can evolve and merge as physical features change and schemes grow.

The assessment of delivery models and thoughts on illustrative pathways is at section 5.

1.2.3 Selecting the work-plans

We produced a series of **technical summaries** that looked in more detail at costs, challenges and opportunities faced by different low-carbon technologies. We then turned the learnings from the delivery models and these technical summaries into **high-level work-plans**.

Early versions of these were discussed at the CARES 2018 conference in April 2018. These were then debated with the steering group and we evolved these into the work-plans published alongside this report. In each case the work-plan defines the possible solution, the rationale for it, how to maximise the benefits and identified the practical steps required to scope and define a project. We also consider changes underway or in process that are likely to impact on adoption, as well as factors to watch out for.

The work-plans are summarised at section 6 and published in full at Appendix C. We have developed four, focussing on the various sources of information available and the practical steps that can be taken in the light of today's largely subsidy-free circumstances.

Work-plan 1: Combined technologies
This work-plan looks at the potential to deploy solar PV arrays, storage batteries and electric vehicle (EV) chargers in combination typically at small and medium business premises. We set out how non-domestic consumers can develop investment proposals and action plans for deployment, considering a generic model based around installing or extending a 10-50kWp solar array.

We consider how value can be maximised in the brief period before but also after the closure of the FiT by rationalising on-site use through the use of batteries and charging. We also consider the likely payback periods of the combined technologies.

Work-plan 2: Wind using refurbished and life-extended turbines
In this work-plan, we look at the assessment and delivery framework for a site owner using refurbished wind turbines in a post-FiT world, after April 2019. We examine the rationale for considering a refurbished, as opposed to new, wind turbine, and identify how to develop the key parameters of a business case.

The work-plan also addresses how to locate a site and evaluate its merits, and it provides a route-map around planning and permits for construction. We recommend a structure of self-consumption of generated electricity to derive greatest economic benefit, based on an illustrative 500kW site with 4GWh consumption. However, we also explain why refurbished turbines are also approaching economic viability based around remote export-only sites without FiT payments.

Work-plan 3: Collective energy action
We address the demand-side and domestic customer engagement in work-plan 3, focusing on high density housing such as tenement and tower blocks and set out guidance for social landlords and housing associations. Switching for disengaged customers, aggregation of demand and collective purchasing, and increased deployment of energy efficiency measures are all considered.

There are significant realisable benefits by customers from switching and realising better tariffs in the current market environment. These benefits will be lesser but still significant once price caps are significantly extended later this year.

The work-plan outlines opportunities from both organised individual switching and collective switching. We address how Energy Company Obligation (ECO) funding could be targeted to increase benefits to Scottish householders.

Work-plan 4: Heat pumps
This work-plan sets out information and guidance on using heat pumps to displace conventional electrical heating and high-carbon fossil fuel heating, typically using fuel oil. We look at the costs of installing and operating heat pumps, including air, ground and water source units, and the continuing subsidies available from the renewable heat incentive (RHI) and how to go about accessing them.

We also look at comparative costs of heat pumps versus other technologies, and how a community group could go about constructing a business plan to support deployment. We then provide a costed example for a typical small building.

Supporting the work-plans
All of the work-plans could be supported and delivered by an enhanced and expanded LES portal. In each case there would also be self-help and "how to" guides, process maps, and other "route-maps" showing sources of further information.

The specific work-plans should be supplemented by awareness raising and communication, identifying and publicising good practice.

1.3 Conclusions

The headline conclusion from our work is that there are a wide range of practical steps that communities and businesses can take to develop local energy projects. However, the near-term prospects for CALE schemes have deteriorated significantly over the past few years.

This change is attributable to a number of factors but notably the withdrawal of Levy Exemption Certificates in mid-2015 that had enabled a premium to be paid for green electricity. The phase out of the "triad benefit" that began from 1 April 2018 has also had a detrimental impact. For the present build rates for generation installations below 5MW are being sustained[1] largely as a result of projects looking to achieve accreditation ahead of the closure of the FiT scheme. Withdrawal of the scheme is now confirmed from 31 March 2019, and the UK Government has also announced a provisional decision to end the guaranteed export tariff.

Without the pull-through of ROCs and FiTs, prospects for new generation schemes are set to diminish further, at least in the immediate future. Furthermore, sustained increases in wholesale power prices are not expected over the coming years, and there are no incentives under market rules for matching local production and consumption, in an electricity market that penalises imbalance between the two. However, prices paid by customers for electricity will continue to rise over the medium term, as non-energy costs increase, which will sharpen incentives to develop generation "behind the meter" and consume it on-site.[2]

CALE projects will need to find counterparties for their output among off-takers, essentially suppliers. The market for small-scale offtake power (the power purchase agreement or PPA market) is not well-developed, and community projects will struggle to find counterparties in the absence of a guaranteed route to market. While there are some suppliers competing for power below 5MW, few are offering long-term contracts. This background means communities will struggle to secure revenues and therefore underwrite new projects.

However, market opportunities and incentives will increase, which is why we have addressed these issues more fully in the *Market Context* appendix. To illustrate we expect over the near-term that:

- **Legacy schemes**, i.e. those that already exist or are enjoying support under existing grant aid or subsidy schemes, will continue to require and get support under ROC and FiT arrangements to the end of the 20-

[1] Some 40MW of capacity was accredited in the year 2017-18, though mainly hydro in the north of Scotland.

[2] We have explored self-supply behind the meter but not private wires development in any detail as "grid defection" does not align with policy priorities to maximise use of the existing network. It is likely to lead to charge redistribution to customers connected to the public network increasing the cost burden on them.

year accreditation period, and this support is essential for their continued viability. However, the reliance on subsidy means few if any of these would be replicable in the new market context

- There are **new emerging opportunities, including extending existing schemes:**
  - For deploying **refurbished onshore** wind sites that are coming to the end of their period of support and **repowering** existing sites, which can enjoy cost advantages
  - **Battery storage systems** are also being deployed behind the meter and can enhance returns on existing on-site schemes using intermittent technologies
  - **Cross-technology schemes**, including those that incorporate new storage technologies and EVs, or those that can demonstrate specific innovation or local benefit beyond the value of the energy, will continue to be eligible to apply for project support (e.g. the Low-Carbon Infrastructure Fund (LCIF)), and innovation funding will continue through network companies until into the next decade, but
- CALE projects that utilise proven technologies and avoid commercial innovation will have to look to **new, incremental revenue earning opportunities** outside of the power market to underwrite viable projects, though at present these are only just beginning to take shape.

However, looking beyond the short term, opportunities from CALE projects will increase and the outlook will improve. In particular, we identify a number of ways in the report that smarter, more flexible markets are likely to emerge, and these will help support the economics of new projects.

The opportunities will increase for a number of reasons:

- **Technology costs for proven technologies continue to fall** as deployment rates in other markets increase. Both wind and solar are expected to see further sustained reductions in levelised costs. Costs for emerging technologies such as different forms of battery storage are also expected to reduce considerably over the next few years and they become commercialised
- The **growing price differential between wholesale and retail prices** will steadily increase the value of self-supply of electricity. This is because of the growing influence on retail prices of non-energy costs, including third-party charges such as the cost of policy support. The higher the self-consumption as supplier prices increase, the greater the avoided cost benefit
- The continued **smart meter roll-out and the introduction of half hourly settlement,** combined with the development of automated control technologies, will sharpen incentives to manage load. If these are deployed at scale by suppliers, aggregators and other intermediaries, this will enable tariff innovation and the opportunity for engaged customers to benefit from reduced consumption and to change their usage patterns. The option of half hourly settlement is already possible (though complex for households), and market-wide half hourly settlement could be implemented by 2022-23
- Costs of **new conversion technologies** (power-to-gas, power-to-heat technologies and other circular economy solutions) will also reduce as they are commercialised at scale and conversion efficiencies increase. Pilot CALE schemes are already demonstrating some of these new applications, and the market is confident that these will become viable in many locations that have existing intermittent assets
- **Embedded benefits**, which reflect a supplier's avoided costs from supplying customers with local generation, will continue to be important as an additional source of value to producers. These should continue to add up to around £10/MWh in Scotland to generator revenues, dependent on technology and location. In the past these values have been greater, but they have diminished considerably following industry rule changes to the triad benefit, and average rates for other benefits in the two Scottish settlement zones are still lower than in other parts of GB. Nevertheless, a small-scale generator can negotiate a significant share of these benefits from its offtaker when it enters into a PPA
- Rules have yet to be developed that would allow intermittent generation technologies to participate in the **Capacity Market** assuming a new state aid clearance is received[3]. Aggregation opportunities were limited

[3] The UK Government announced on 15 November 2018 that the Capacity Market was suspended following a successful judicial challenge to the existing state aid clearance.

to schemes above 2MW. Different rules applied to demand-side participants, (which was the basis for the judicial challenge). We would expect new state aid approvals to be forthcoming and opportunities to arise for smaller assets, especially through aggregation, once rule changes have been brought forward possibly from 2020

- Scope exists for larger generation schemes to participate in **existing balancing service offerings** tendered by National Grid, and schemes can presently aggregate to a minimum of 1MW to access the fast frequency response service. On the demand side, sites with turn-up capability can also participate with a minimum size of 1MW (which can be aggregated from sites of at least 0.1MW). We would expect the trend towards lower thresholds and more aggregation to continue, again creating new revenue opportunities for generators and controllable load, in collaboration with equipment providers, suppliers and intermediaries. Some battery providers are also offering aggregation opportunities in combination with other demand-side response and a share of the associated revenues
- Use of **local resources to prevent generation curtailment or network reinforcement**, especially in remote areas. This practice has already been demonstrated in several of the case-studies and is likely to be commercialised further as electricity distribution network operators (DNOs) seek flexible solutions to address local operational constraints. Some rudimentary flexibility schemes are under development by DNOs, but we would expect them to further develop commercial arrangements that better incentivise local generation and demand to help avoid network reinforcement costs. The next distribution price control review settlement will come into force from April 2023, and is likely to see the introduction of new incentives to ration existing network capacity and optimise new capital investment
- On the demand side, we would expect more resources from the **revised ECO** to be directed at "affordable warmth" measures under phase 3 of the scheme, which commenced on 1 October 2018. Scotland has devolved powers in this area as well as a separate cap that requires all obligated suppliers to meet their obligation pro rata in Scotland, and
- **Electric vehicles and heat pumps** have the potential to significantly alter the economics of local generation schemes by increasing loads and demand on the local distribution system, in turn enhancing flexibility values. The ability for CALE projects to aggregate DSR increases substantially if they have the ability to control the charging of EVs and turn up/down heat pumps. EV roll-out is also likely to have a knock-on impact on the deployment of rooftop solar, especially if governments increase support to switch to an electric vehicle.[4] Again the 2023 distribution price control reset is likely to be important here.

While the pace and degree of change in many of these areas remains uncertain and details in many cases need to be worked up, the direction of change is clear. This will provide strong incentives to develop innovative local projects that help crystallise flexibility, facilitate smarter outcomes, and defer reinforcement expenditure, with the benefits being shared between generators, networks and the consumer. Customer appetite should also drive change for those who engage with the market or can be accessed by outreach programmes.

In combination these trends should reverse the recent down-turn in prospects from recent UK Government policy interventions and steadily enhance the economic and policy value of CALE projects. The important requirement at this stage is to focus on practical, targeted measures that will allow progress to continue where possible while these changes flow through the energy system.

The conclusions are expanded on in section 7.

A glossary of terms and acronyms is at Annex B to this report.

[4] The Scottish Government announced increased funding of £15mn on 3 September to accelerate EV charging deployment.

2 The Project

In this section we:

- Summarise our terms of reference
- Describe the approach we have taken, and
- Explain the report structure.

2.1 Introduction

Scotland has a vibrant emerging community energy sector, and a high level of policy interest in boosting it. The government is seeking to "maintain its leadership in developing local energy systems". It wishes to do so in a manner that moves from "single use" local energy projects to those that are more strategic, cover larger geographical areas, and are replicable.

The Energy Saving Trust (EST), in conjunction with the Scottish Government and Local Energy Scotland (LES), commissioned Cornwall Insight (CI) to carry out research into the community and local energy (CALE) sector.

2.2 Terms of reference

The objectives of the work can be summarised as follows:

- Conduct a landscaping survey of existing CALE projects to derive understanding of reasons for successful and unsuccessful methodologies and delivery models
    - Ten diverse grant-funded case studies were offered by LES as a baseline for desktop research and the landscaping work.CI added selected projects to these to provide a further diversity to broaden the landscape, seven from GB and five from overseas. The scope of projects studied includes heat and transport (where possible) as well as power. It was recognised, however, that the greatest number of projects were likely to focus around the generation of electricity
- Derive a long-list of delivery models that are representative of the CALE landscape. The reasons for success and failure, challenges and regulatory barriers should be identified. CI was also asked to identify existing market challenges and changes anticipated in the market environment affecting CALE projects
- Report on the above, and deliver an interim report with respect to the long-list of delivery models identified. In the event this interim report has evolved into this final report, and
- Select with the commissioning Steering Group a short-list of delivery models that could be developed into work packages. The detail of these work packages or work-plans should include a proposed template structure, example business cases for each model and where possible guidance on mechanisms and resource requirements to practically implement the model.

We then used this work, alongside a commentary on market conditions and changes underway, to test, establish and "future proof" possible delivery models and work-plans.

2.3 Research approach

The desktop research we have carried out is a combination of quantitative and qualitative analysis. We approached this by:

- Conducting a literature review
- Critically analysing the case studies to develop an understanding of approaches adopted to date to inform the design of the data framework for the landscaping survey and facilitate delivery of the long-list of best delivery model candidates

- Reviewing databases of a wide range of projects, including the commercial fundamentals of them, to categorise delivery models
- Evaluating each project using a common framework, including:
    - Project description
    - Project costs
    - Project financing
    - Critical assessment (e.g. carbon abatement, fuel poverty impacts, impact on related sectors), and
- Examining barriers that these projects need to overcome, e.g. regulatory, financial, community etc., the extent to which factors unique to these projects may have been an enabler or limiter (e.g. location) and the replicability of exemplar projects.

Regen has also contributed to the project, using its practical experience of supporting community energy groups to explore next-generation business models in sustainable energy to provide a critique of the proposed framework structure. This process included, as part of the project delivery team:

- Identifying key attributes used by community groups to define success
- Identifying where available data or appropriate proxies could be used to illustrate key features of projects and enable assessment
- Identifying the factors that will best enable projects to be prioritised and scored in later tasks, and
- Critiquing our emerging thinking.

2.4 Market assessment

In carrying out our research, it became clear that the policy and regulatory framework has changed materially since many of the schemes we examined were initiated, most notably with the close out of the Renewables Obligation (RO) to new schemes, but also the impending closure of the Feed-in Tariff (FiT) regime. We therefore undertook a market assessment based around the current situation and factoring in what we know about current energy industry work-streams that could impact on new projects.

The assessment also identified a range of factors that would be increasingly important going forward. Technology costs continue to fall, and commercialisation of battery storage is fast approaching. The roll-out of smart meters is also well underway, enabling a wide range of demand-side solutions to become mainstream, and the introduction of market-wide half-hourly settlement possibly from 2022-23 should bring with it widespread deployment of time of use (ToU) pricing, which could be transformative for small-scale low-carbon generation. Thus, a key theme of this report is the diminished viability of schemes in the largely subsidy free new environment we now face, but with new opportunities and business models enabled by technology coming forward in the medium term.

2.5 Stakeholder liaison

Through-out our work we liaised closely with a steering group of EST, LES, and the Scottish Government. We also presented our developing findings, recommendations and thinking on work-plans to the CARES annual conference in Glasgow 18-19 April 2018.

We also hosted workshops alongside the conference for two groups. Around 80 people attended these sessions, and there was a high degree of interest in the work-plans we presented. We have revised and updated these in the light of the discussions at the conference.

2.6 Report structure

The rest of this report is structured as follows:

- Section 3 sets out contextual information on motivations for development of community and local energy projects, the policy framework and the market background, including drivers of change currently at work

- Section 4 provides an over-view of the case studies we have considered and of our wider landscaping work
- Section 5 summarises our analysis of possible delivery models, representative pathways of how these can evolve
- Section 6 provides an overview of the work-plans
- Section 7 sets out conclusions
- Annex A to this report sets out full notes on the case studies, and
- Annex B provides a glossary of key terms and acronyms.

This main report should be read alongside the following technical appendices:

- Appendix A – Market assessment
- Appendix B – Long list of delivery models and supporting assessments, and
- Appendix C – Work-plans.

3 Contexts

In the section we:

- Set out the current community energy baseline in Scotland
- Summarise the literature research we have carried out and the key CALE drivers and characteristics
- Explain the current policy framework, and
- Describe the current market background and important changes underway.

3.1 Community and local energy schemes

The EST report, *Community and Locally-owned Renewable Energy in Scotland at June 2017,*[5] highlights the extent of renewable energy-based projects throughout Scotland and the progress towards the 2020 target of 500MW of local and community renewable energy generation.

The key findings of this report were:

- An estimated minimum of 666MW[6] of community and locally owned renewable energy capacity was operational in Scotland, a 12% increase on the operational capacity since June 2016 when the operating capacity was estimated at 595MW[7]
- 666MW of total capacity was split between:
  - 403MW of electrical capacity (MWe)
  - 254MW of thermal capacity (MWth)
  - 7MW of combined heat and power (CHP) capacity, and
  - 2MW of capacity attributable to 'unspecified' technologies or energy categories[8]
- The estimated operational capacity was 33% over the Scottish Government's original target of 500MW of operational capacity in community and local ownership by 2020
- The Scottish Government has now set new targets of 1GW of community and locally owned energy by 2020 and 2GW by 2030. The estimated operating capacity of 666MW was 67% and 33%, respectively, towards these new targets
- The operating capacity resulted from a total of around 17,950 individual renewable energy installations.[9] This is a 15% increase in number of installations compared to the previous 2016 report, and
- At the end of June 2017, there was an estimated minimum of 6.77MWh of installed energy storage capacity in community or locally owned ownership in Scotland. The majority of this (4.4 MWh) is heat storage.

[5] http://www.energysavingtrust.org.uk/sites/default/files/Community%20and%20locally%20owned%20renewable%20energy%20report_2017.pdf.

[6] It is likely that some projects, particularly where planning permission is not required, were not be recorded in the database. Figures in the EST report were therefore presented as 'minimum' values.

[7] Reported capacity in June 2016 was noted as being 595MW but was actually 604MW due to 9MW of additional capacity being identified late.

[8] The unspecified energy category refers to energy generated by energy from waste projects where the energy output is unknown.

[9] This number of installations includes the total number of individual wind turbines in any multi-turbine development, rounded to the nearest 10.

3.2 Literature search

Based on our literature search and landscaping work, we identified a range of drivers for CALE projects and how they are structured.

3.2.1 CALE drivers

There are various reasons why CALE projects are initiated, and there are usually significant co-benefits outside of the value of the locally sourced, low-carbon energy delivery arising from them. The context into which a project may be situated is complex and multi-layered and frequently specific to the geographic, cultural and social contexts of a particular scheme, as well as the prevailing energy delivery system at the local level. Project COBEN[10], supported by the Scottish Government and the European Union, is currently examining issues of this nature in the Highlands and Islands Enterprise region.

Another study carried out by The British Academy in 2016[11] made a number of suggestions for supporting community energy in the UK that included:

- 'City deal' devolution settlements that addressed obstacles faced by local authorities (LAs) wishing to invest in energy projects
- Encouraging partnerships between LAs, housing associations and CALE groups
- Promoting better understanding of the benefits from CALE projects - such as jobs, revenues, skills and community 'capacity' - and pro-actively surveying potential sites for such projects
- Creating innovation spaces at a local level that could try out innovative collaborations with network operators and funded under streams such as Ofgem's Low Carbon Networks Fund (which has now transformed into the 'Network Innovation Competition'), and
- Developing community energy supply models that diversify from power into heat, energy efficiency, demand reduction (we would add derivative gases - biomethane, hydrogen, oxygen – and transport).

There is wide-ranging and diverse literature critiquing community models. Key aspects of the success of a CALE project may be qualitative and not immediately measurable, such as improving the community's resilience and social cohesion, supporting vulnerable people, diminishing fuel poverty, creating jobs and greater welfare, and promoting cleaner air from vehicle emissions. It may have the potential to create a sense of pride and purpose within communities, as well as promote more affordable low-carbon living. Local ownership, participation and benefit sharing are all motivators for investment in community-owned projects that are strongly influenced by the culture in which it is situated. However, there is no consistent or coherent way in which these benefits are usually valued.

The project idea connects with needs, objectives, desires and problems that it wishes to address. Associated with the idea is a range of considerations that are necessary to address for the idea to be delivered. They represent the 'capacity considerations' a CALE project will demand of the group - who are usually working voluntarily but often lacking in all necessary skills.

The projects we consider differ wildly in their structuring, funding and their technical specification, and they have also encountered a variety of different problems. Delays in meeting delivery milestones, changes to network capacity, gaining consumer support for schemes and the availability of skilled contractors and installers are all hazards we came across in our landscaping work. Integrating technical equipment from different manufacturers can also present difficulties. Notwithstanding the innovative and demonstrative nature of some of these funded trials, they are costly elements, and are more likely to be encountered as the complexity of projects and their ambitions rise. They demonstrate how contingencies should be prepared to manage unexpected setbacks, especially in remote regions of the country where they are likely to have greater impact.

[10] Community Benefits of Civic Energy (COBEN); https://www.localenergy.scot/media/106282/COBEN-flyer-170523.pdf

[11] British Academy 2016; Cultures of Community Energy. https://www.britac.ac.uk/sites/default/files/CoCE_Policy Report _ online.pdf

However, the spine of a CALE project and its viability is its business case. In the ensuing sections we focus our analysis upon this core element of the overall delivery model, which is each project's route to market and how it secures monetary value. In addition to any incentive payments and the energy price secured, there could be other sources of value such as embedded benefits. In addition, there are an increasing number of local community-oriented projects that are trialling novel ways in which localised approaches can assist in grid management and system support.[12]

A successful combination of the project idea and capacity to deliver will come together under the business case for the project and the (business) model supporting its viability.

3.2.2 Stakeholders

Different actors are involved in making each CALE business model work. Management of different stakeholders and navigating the complexity of shifting policy, regulations, markets and financial support, are typical challenges faced by all CALE projects. If successful, a project may then facilitate other projects, which may or may not involve the same or similar stakeholders.

With the rapid pace of change in energy markets currently taking place, understanding these fundamentals is critical to assessing the financial sustainability of new CALE projects. The withdrawal of ROCs from April 2017 and the expected closure of the FiT to new projects from April 2019 means there is no guaranteed subsidy or pull-through mechanisms for community developers. This basic shift in the market fabric places greater emphasis than before on the need to extract value from the market, and the ability to do so will determine the robustness of the business model.

3.3 Our focus

In our assessment of business models, we have focused on the following critical elements:

- The route to market that the CALE project expects to follow to sell its energy product(s), either to its participants or third parties, and whether ancillary values can be captured
- The terms, duration and stability of the contractual arrangements that provide the route to market
- The risk in delivering what it is contracted to do and the penalties for non-performance
- The attractiveness of the commercial model in a competitive environment, and
- The value to consumers and the value for money to other stakeholders.

[12] In addition to some of the CALE schemes we consider, there are larger scale innovation pilots. These include:

Scottish Power Energy Networks (SPEN) FUSION project in Fife: This aims to understand the potential for customers to operate within a local "flexibility market", the types of tradable products and services and the design of the commercial and technical arrangements to attract new flexibility providers, and

An array of projects south of the border, notably Western Power Distribution (WPD) OpenLV project: This is an open software platform that works in collaboration with sensing equipment in low voltage substations to provide local network data through a smart phone app (for example). It would be deployed to provide network data that could facilitate the operation of non-traditional business models by community groups.

3.4 Policy

Policy towards community energy in Scotland has evolved over a number of years under devolved powers, but the current baseline is derived principally from the *Scottish Energy Strategy* (December 2017) and the *Climate Change Plan* (February 2018). The recently issued *Programme for Government 2018-19* (September 2018) is also relevant. In this section we identify the main features of these documents relevant to our report and identify some important supporting documents.

3.4.1 Policies to promote local energy in Scotland

One of the core elements of the *Scottish Energy Strategy*[13] is the pursuit of a smarter local energy model as a means by which to realise the broader 2030 and 2050 targets relating to the deployment of renewable source energy, heat and transport – as well as the increased productivity of energy use.

This approach builds upon the existing development of local energy solutions, notably in island areas and rural communities that have examined issues such as network constraints and generation curtailment – through the Low Carbon Infrastructure Transition Programme (LCITP) and its successor, the Low Carbon Innovation Fund (LCIF), which has been assigned an initial £60mn. The ability to build on these will be complemented by a new framework for Local Heat and Energy Efficiency Strategies (LHEES)[14] that will promote these specific areas.

The Scottish Government's vision for 2050 is predicated on achieving key targets for 2030: sourcing 50% of final energy demand from renewable resources and ensuring that energy use delivers 30% increased productivity. It is framed around three core principles, being:

- A whole-system view
- An inclusive energy transition, and
- A smarter, local energy model.

This in turn is based around key priorities, five of which impinge to varying degrees on community and local energy:

- Consumer engagement and protection: protecting customers from excessive or avoidable costs, promoting the benefits of smarter domestic technologies and systems
- Energy efficiency: promoting more effective management of energy in the domestic and non-domestic energy sectors
- System security and flexibility: ensure securing and resilient energy supply infrastructure
- Innovation: empowering communities by supporting innovative local energy systems and networks, and
- Renewable and low-carbon solutions: supporting deployment of low-carbon energy in pursuit of emissions targets.

At the local level, Scotland is seeking to "maintain its leadership in developing local energy systems" and a smarter local energy model, but it intends to do so in a manner that moves from "single use" local energy projects to those that are more strategic, cover larger geographical areas, and are replicable. It wants to also build on the shift away from centralised generation and away from passive consumption.

Although private sector investment is seen as crucial, policy affirms it is also strongly desirable that communities or community groups take a stake in projects as well. However, to mitigate costs and improve

[13] *Scottish Energy Strategy: The Future of Energy in Scotland*, December 2017 http://www.gov.scot/Resource/0052/00529523.pdf

[14] *Consultation on Heat and Energy Efficiency Strategies, and Regulation of District Heating*, January 2017 http://www.gov.scot/Resource/0051/00513244.pdf

the efficient use of existing assets utilisation, all local projects are encouraged to use existing energy infrastructure before developing projects with new transmission or distribution requirements[15]. This steer suggests development of strategies that optimise the current system and not encourage defection from it.

Overall, the Scottish Government is seeking a “significant increase” in shared ownership of renewable energy projects with greater community involvement. Specifically, it is aiming by 2020 that at least half of newly consented renewable energy projects will have an element of shared ownership, and that there will be 1GW of community and locally-owned energy by 2020 with a total of 2GW by 2030[16].

The Scottish Government published in 2014 *Good Practice Principles* for CALE groups to consider in cases of shared ownership of onshore renewable energy developments[17], and further means by which shared ownership is being supported include:

- The net economic benefit of renewable energy developments may be considered as material from a planning perspective, given the collective national significance of such assets[18], and
- Up to 100% of business rate relief for a renewable energy project if arrangements exist that entitle community organisation(s) to at least 15% of the annual profit or as much of the annual profit as is attributable to 1MW of the project’s total installed capacity of the project[19].

Other areas of focus within the *Scottish Energy Strategy* include:

- Decarbonising heat and transport
    - Greater proportion of heat and transport demand can be met by electricity which, combined with technological developments, will add more pressure on to the electricity network, necessitating solutions to address or mitigate this
    - Decarbonisation can be complemented or mitigated by increased production of low-carbon gas (biogas) from sources such as anaerobic digestion, and from hydrogen through electrolysis – highlighting the importance of such projects, and
    - Deployment of new heat networks and associated new primary energy sources, for instance communal boreholes.
- Fuel poverty and customer engagement
    - The strategy seeks to build upon existing collaborations across public, community and private sectors, local government and other organisations, trade bodies and community groups to help address these issues.
- Smart meters and home automation
    - Presented as a catalyst to engagement, smart meters can help to provide tailored energy efficiency advice and greater awareness of energy use, provided they are accompanied by a suitable ToU tariff. The benefits can be augmented through automation, such as that proposed by Scottish Power Energy Networks in their 2017 NIC trial based upon the deployment of the Universal Smart Energy Framework (USEF[20]).
- Energy efficiency

[15] *Scottish Energy Strategy: The Future of Energy in Scotland*, December 2017; pp55-57.

[16] As at June 2017, there was an estimated minimum of 666MW of community and locally-owned renewable energy capacity in Scotland across approximately 17,950 installations (http://www.energysavingtrust.org.uk/scotland/communities/community-renewables/community-energy-reports)

[17] https://www.localenergy.scot/media/79714/Shared-Ownership-Good-Practice-Principles.pdf

[18] https://www.localenergy.scot/media/84076/letter-from-chief-planner-nov-20151-2.pdf

[19] https://www.mygov.scot/business-rates-relief/renewable-energy-generation-relief/. This project is a precursor to the Fusion project noted above.

[20] https://www.ofgem.gov.uk/ofgem-publications/115095

- The Scottish Government has designated energy efficiency as a National Infrastructure Priority, with this being achieved with the aid of the *Scotland's Energy Efficiency Programme* (SEEP[21]), itself integrated with the nation's *Climate Change Plan* and 2050 targets, and
- The goal is to transform the energy efficiency of buildings in Scotland, with a short-term (to mid-2020s) focus on reducing energy demand through switching heating to low-carbon options, particularly for those properties off the gas grid, and will be accompanied by a review of building standard and the development of a new fuel poverty strategy.

These focus areas can all impinge on CALE projects. In addition, the wide-ranging nature of interlinkage between those areas of focus and policy prioritisation suggests additional benefits that can only improve the scope for replication and commercialisation.

3.4.2 Climate Change Plan

Published on 28 February[22], the *Climate Change Plan* sets Scotland's decarbonisation targets for 2018-32. Scotland expects to see a 66% emissions reduction against 1990 levels achieved through changes in the energy system as well as non-energy sectors, including elements of the agricultural, waste, land use, land use change and forestry sectors.

The plan introduces policies aimed at increasing the level of renewable electricity generation. These include:

- Efforts to secure routes to market for a range of renewable technologies
- The development of a whole-system bioenergy action plan
- Continued support for offshore wind development, and
- Innovation and a renewed focus on developing local energy systems and models.

Of these, the first and fourth of these policies are directly relevant to this report.

The plan highlights a "crucial" role for communities in the pursuit of these targets, with the Scottish Government supporting locally-run projects through its Climate Challenge Fund (CCF). The CCF is also intended to ensure that local communities are "empowered, equipped and supported to deliver low-carbon solutions to local issues on their own terms". One of the main methods by which to do this, the plan states, is through support for innovative local energy systems and networks.

In addition to the target of having at least 1GW of renewable energy in community ownership by 2020, the Scottish Government is also looking to maximise the support that projects can obtain from the Contracts for Difference (CfD) scheme, specifically on remote Scottish islands. BEIS has confirmed that remote island wind (RIW) would be eligible for support in future auction rounds, and recently proposed changes to the scheme to give effect to this.[23] Projects would be required to be located on an island at least 10km from the GB mainland, and needing at least 50km of cabling, including 20km of undersea cabling, to connect to the transmission system. Key areas will include the Outer Hebrides, the Orkneys and the Shetlands. The threshold for participation for CfD funders is 5MW, which is considerably greater than typical CALE schemes.

3.4.3 Programme for Government 2018-19

Published by the Scottish Government on 4 September[24], the *Programme for Government 2018-19* set out measures to accelerate the transition to a high-innovation and low-carbon economy. This annual document sets out the Scottish government's plans and ambitions for the coming year.

The measures in this plan include:

[21] http://www.gov.scot/Topics/Business-Industry/Energy/Action/lowcarbon/LCITP/SEEP

[22] http://www.gov.scot/Resource/0053/00532096.pdf

[23] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/736588/Part_B_Consultation_Response.pdf

[24] https://beta.gov.scot/publications/delivering-today-investing-tomorrow-governments-programme-scotland-2018-19/

- Supporting offshore wind – a fresh £2mn of funding will be made available to support innovation and reduce costs. The coming year will also see the government consult on a new Sectoral Marine Plan, identifying future locations for large-scale offshore wind projects
- Assisting electric EV deployment – a total of £15mn is to be spent on 1,500 new electric charge points to be installed in businesses, homes and public buildings
- Assisting EV uptake – the Low Carbon Transport Loan fund will increase from £8mn to £20mn, and the coming year will see the introduction of 500 new ultra-low emission vehicles for the public sector, alongside more than 100 new green buses, and
- Creating 20 electric towns in Scotland where local communities will be supported in EV uptake, by 2025.

The Programme also announced funding for creation of a new national infrastructure bank, following the implementation plan published in February.

3.5 Market context

All delivery models for CALE projects are impacted directly and indirectly by the design of the GB electricity market; its influences are overwhelming and, we would argue, highly distortive. The value of energy consumed at the community level is set by reference to it, and any deliveries across the public system are subject to its extensive rules and complex arrangements for the recovery of network charges and other non-energy costs such as the increasing costs of policy.

To better understand the immediate market background, we have carried out a fuller market assessment to inform our thinking and substantiate our judgments. This is at Appendix A.

The market assessment considers in more depth:

- Some basic elements underpinning the national electricity market framework that has worked to the detriment of local energy solutions, and identifies market distortions that continue to exert influence
- The current market baseline for accessing the market, which is important in understanding commercial choices made to date by CALE projects, but also the continuing viability of existing schemes going forward. It is also relevant as schemes below 5MW in the pipeline will be considered against this until the end of the current financial year (2018-19), and until 2020 under certain grace periods
- How the baseline will materially change from 1 April 2019, meaning that there will potentially be no guaranteed market for export power, but community schemes will instead depend on negotiating commercial terms for sale of energy with market participants that have significant market power
- An overview of the various supply and intermediary models available for market access
- Estimates of revenue streams and possible realisable power prices and other sources of value that could be available in the electricity market, and
- Reviews and changes in industry rules going forward that could influence options and prospects for CALE sponsors, especially opportunities around smarter approaches that will incentivise use of flexibility and consumer engagement with the market.

The appendix shows how the market is characterised by six defining features:

- An increasingly complex market environment that favours scale
- Changing incentives and withdrawal of subsidies
- A sluggish traded market for PPAs especially at smaller-scale
- Gradually increasing value of power produced and consumed on-site
- Continuing reductions in technology costs, and
- Migration to a smart system that will progressively increase the value of flexibility.

3.5.1 Market complexity

The energy market environment is highly complex, and very centralised based on design assumptions that had currency 20 years ago when the power system was dominated by large, high load-factor transmission-connected power stations remote large centres of demand. Despite entry of high levels of intermittent, renewable technologies, the governance and regulation of the power system has not changed significantly, and developmental policies take limited account of the huge levels of distributed generation now on the system and pressures towards decentralised supply.

On the buy-side the market arrangements are based almost exclusively on a regulatory regime structured upon a supply licence (with some limited exceptions). At around 500 pages, the operating and compliance requirements prescribed by the licence are complex and deep, and this is now supplemented by multiple new requirements enforced by statutory orders.

While the retail market is very competitive and there are now over 70 independent suppliers, as yet very few of them are proactively seeking to provide services to CALE organisations.

3.5.2 Changing incentives

Despite a series of policy endorsements explicitly supporting community energy, the commercial environment facing CALE schemes is deteriorating because of regulatory interventions and changes in market conditions. Shifts in central government policy are also set to adversely impact on the outlook on both sides of the border. The RO was closed to new schemes from 1 April 2017 (except for some grace periods that expire on 31 March 2019), and the FiT arrangement is set for closure from 31 March 2019. There are due to be further rounds for the award of CfDs, but these are for projects above 5MW and will have to be competed for through complicated tender processes.

So, apart from the Renewables Heat Incentive (RHI), CALE projects will not be eligible for subsidy from 1 April 2019. The previous support arrangements were obviously important because of the guaranteed revenue support they provided over the longer term, making projects financeable. But they also provided secure routes to market. In the case of the RO, suppliers must buy ROCs and they are usually keen to acquire the power that accompanies them; as for FiTs, a community operator can require suppliers above a defined threshold to buy their output at posted rates that suppliers and producers have generally regarded as fair. Although these arrangements are updated annually, they are evergreen for the 20-year life of an accredited project.

The commercial environment is already challenging as wholesale electricity prices have been subdued over recent years. Even with recently rising commodity prices, this may not change over the foreseeable future as low-carbon generation that enjoys subsidies has an incentive to bid low to stay on the system to continue to maximise output, “cannibalising” prices.

We believe it is likely there will be a split in the market between existing and new schemes. After April 2019 new projects are likely to see a loss in appetite among suppliers for purchasing their output. This is because without subsidy they will probably need to seek higher prices; they are also small and the transaction costs of entering new contracts will be disproportionate in a wider market context in which many GW of new green power is also set to enter the market under CfDs.

3.5.3 Limited liquidity

The UK Government has said the current guaranteed export regime applied to FiT generators will end from 31 March 2019. As matters stand:

- Existing FiT accredited generators will continue to have the option of requiring obligated FiT suppliers to buy their exported power at administered rates, and

- New, non-FiT sites above a de minimis threshold will probably need to enter commercial offtake agreements with suppliers for sale of their power.[25]

Most new projects will therefore be reliant upon a well-functioning and liquid market for PPAs for their exports. They will likely enter this market with a significant information and skills deficit compared to their counterparties, who are most likely to be energy suppliers—addressing this asymmetry was one of the reasons for instituting the FiT scheme originally.

Cornwall Insight provides a benchmarking survey of competition in the PPA market. It is updated every six months and has tracked a generally increasing trend in competition. This trend is directly related to the growing number of suppliers becoming established in the retail energy market, many of whom actively seek deals with renewables generators so they can sell on their “green power” to consumers. However, this trend has not been uniform across the different size bandings in the PPA market.

Recent assessments from February 2018 record an all-time high 37 suppliers competing to secure PPAs with renewables generators, and 15 have a market share over 1%. However, this activity is predominantly for medium and larger generators eligible for ROCs or CfDs. Supplier participation in the small-scale generation market is markedly lower. As Figure 1 shows, the PPA market for under 30kW has just eight suppliers with a share over 1%, compared with at least 12 in the other segments. As <30kW sites are unlikely to be half-hourly (HH) metered, a large majority will receive the deemed FiT export rate from a supplier that is mandated to offer terms.[26]

Figure 1: PPA market share indicators, February 2018

	Above 10MW	500kW to 10MW	30kW to 500kW	Below 30kW	Total
>15%	2	1	1	2	6
5-15%	4	6	7	6	21
1-5%	6	6	5	0	17
All > 1%	12	13	13	8	46

Source: Cornwall Insight PPA market share survey

The 30kW to 500kW banding has a number of offtakers that are typically active in the much larger banding categories. These likely have smaller sites that have opted for the FiT export rate (over a commercially negotiated PPA) and thus the supplier has again been required to offer terms. Only around five offtakers in this banding are understood to actively offer PPAs to these sites as opposed to the mandated FiT export tariff.

These statistics and the relationships that sit behind them indicate that the sub 500kW segment of the PPA market is the most likely of all the market segments to be a buyer’s market and one, especially where there is already an information asymmetry, where sellers need the most support.[27]

3.5.4 Falling technology costs

Levelised technology costs of low-carbon generation have fallen dramatically over the past decade or so, and they should steadily fall further increasing over the coming years. All other things being equal (which they will not be), this will increase the attractiveness of future investment in distributed generation..

[25] BEIS is conducting a call for evidence on whether it should retain an obligation on suppliers to purchase surpluses and if so at what threshold this might apply. It is possible that this could apply <50kW and possibly more for community schemes.

[26] There are presently seven suppliers in addition to the Big Six, who are obligated to offer FiT payment terms.

[27] These issues around market liquidity and the case for a continuing obligation on suppliers to purchase export power are addressed more fully in an insight paper by our Pixie Energy colleagues *UnfiT for Purpose*, September 2018, https://www.cornwall-insight.com/insight-papers/unfit-for-purpose

Investment research firm Bernstein released a report in June, *Cost of Renewable Technologies – Past, Present and Future*, detailing how the levelised cost of renewable generation has fallen over time, and where future cost reduction potential lies. Bernstein expects the levelised cost of electricity of solar PV and onshore wind to decrease 65% and 34% respectively from 2017 to 2030.

We assume that:

- For solar PV today's LCOE is 12p/kWh, but could fall to 10p/kWh in 2023, and
- For onshore wind today's LCOE's are 10p/kWh for new wind and 5p/kWh for refurbished wind, but they could fall to 9p/kWh and 4.5p/kWh respectively in 2023.

Battery storage technology costs are also expected to follow a similar pathway increasing options as stand-alone investments but also in combination with generation assets.

3.5.5 Increasing the value of behind the meter generation

A growing price spread between wholesale and retail prices will steadily increase the value of self-supply and on-site consumption behind the meter. This is because of the growing influence on retail prices of third-party charges including the cost of policy support. Mid-2018 these already comprised 36%[28] of the average domestic dual fuel bill and 49% of the average domestic electricity bill. By 2023 we project these shares will rise to 38% and 52% respectively.

In Figures 2 and 3, we compare these estimates for retail prices and the levelised costs of generation today and in five years' time for solar PV and onshore wind (new and refurbished). It assumes a 5p/kWh export value and future retail prices are defined by forecast increases in non-energy charges (increasing 28%, making up half the bill, so prices increase by 14%). Import tariffs vary by region and by market segment, but we show a typical price of 14p/kWh today but rising to 16p/kWh by 2023 to capture these upward pressures.

The figures show:

- For solar PV, approximately 78% self-consumption is required today without subsidy in order to ensure the value of the energy generated is above that of the LCOE
    - By 2023 the decreased LCOE and increased tariff lower this to 46%
- For new onshore wind, 84% self-consumption today without subsidy is required to ensure the value of the energy generated is above that of the LCOE
    - By 2023 the decreased LCOE and increased tariff lower this to 64%, and
    - Refurbished wind because of the much lower costs meets its LCOE in each self-consumption scenario.

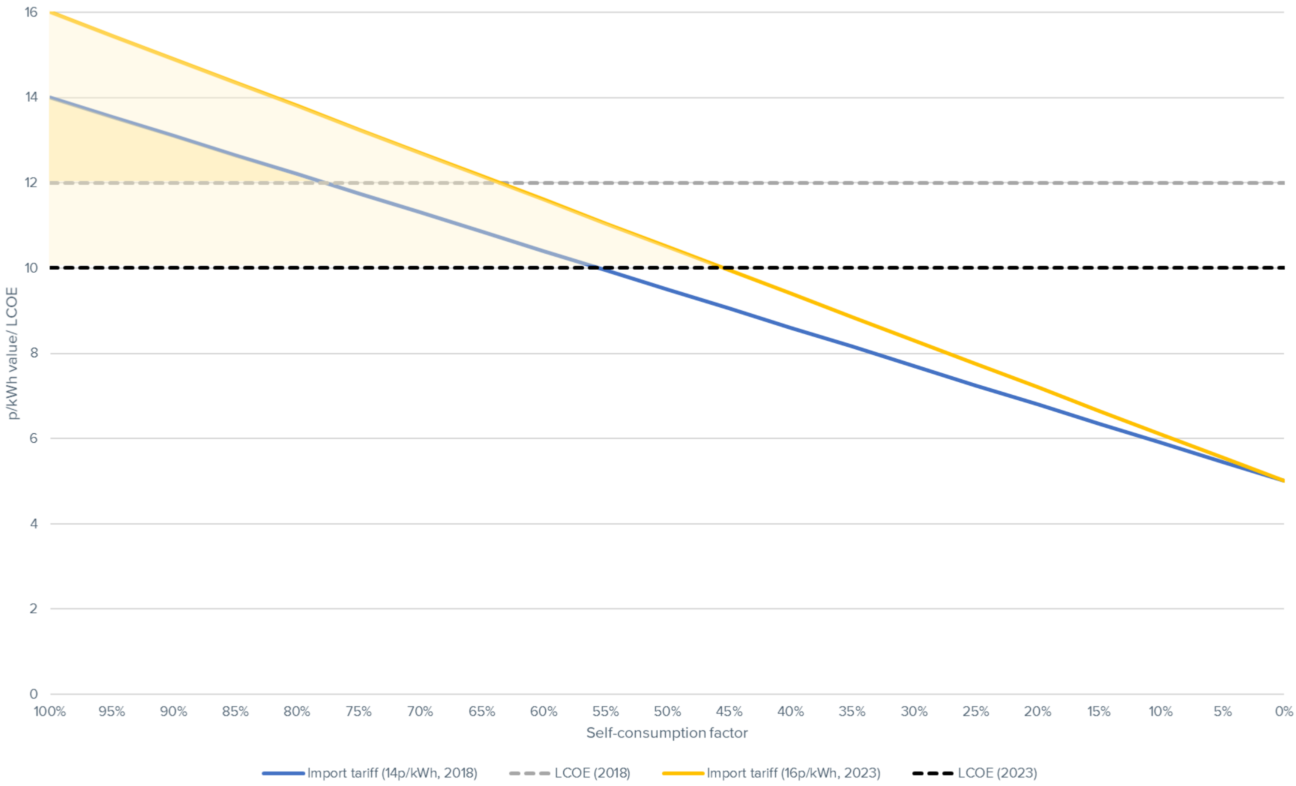
3.5.6 Better metering and control technology

Better metering and control technology, especially in combination with battery storage, will increase the potential value a generator can earn either from power sales to grid or providing services to local distribution network operators.

At this stage, however, smart meter roll-out has some way to go and commercial structures needed to facilitate this market, such as ToU pricing and half hourly settlement, are unlikely to evolve for households, communities and smaller businesses until industry reforms currently being scoped have been fully implemented. This is unlikely before the earlier part of the next decade.

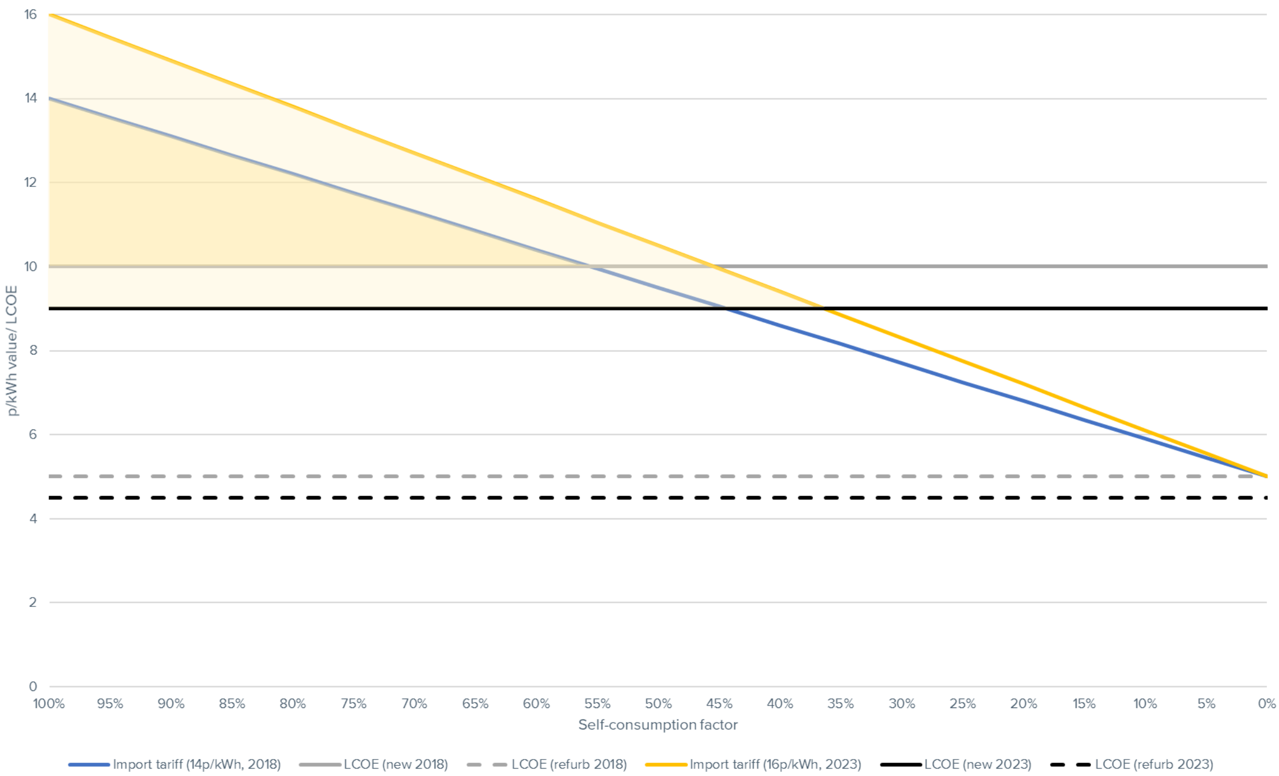
[28] Ofgem safeguard tariff: https://www.ofgem.gov.uk/data-portal/retail-market-indicators#thumbchart-c7770745751913637-n128628

Figure 2: The cost and value of on-site solar PV (2018 and 2023)



Source: Pixie Energy

Figure 3: The cost and value of refurbished vs new wind (2018 and 2023)



Source: Pixie Energy

3.5.7 Other headlines from the market assessment

The other headlines from the market assessment are:

- The value of energy produced by community schemes has various values dependent upon the route to market and its value to the consumer, but can vary between £5-15/MWh, depending on how the energy is transacted: that is, whether it is sold to the wholesale markets, or provided to the end consumer in retail markets, or self-consumed to avoid imports from the grid
- Forward power prices are also expected to fall over the near-term, especially winter rates, with the forward curve presently reflecting almost a 10% fall by winter 2019-20
- However, we expect the following factors to increasingly come into play, which should help community projects:
    - 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 as grid connected projects and also for households behind the meter
    - Power to gas technologies are being proven and supply chains that support them demonstrated, which should increase optionality for storage and transfer of energy, especially in locations that are network constrained, and
    - Embedded benefit rates[29] in Scotland should continue to add up to £10/MWh, dependent on technology and location, as increases in balancing charges are set to feed through, which will partially off-set the removal of the triad benefit, hence the steady increase in values going forward, although these values will remain below national averages.[30]
- Additionally, new sources of value should be available for CALE projects:
    - New projects will probably be able to participate in the Capacity Market, and BEIS have recently indicated it is considering implementation of this.[31] 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 (national and once they evolve under regional initiatives by the newly evolving Distribution System Operators (DSOs) expected to succeed DNOs) 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 ToU pricing in a world of half hourly settlement (HHS) from 2022-23
    - Electricity imbalance prices are becoming more volatile following structural changes to introduce more marginal pricing in November 2015 and November 2018, 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 rule changes and smarter applications that remove averaging within market and regulatory rules. For instance:

[29] 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.

[30] 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

[31] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/732546/CM_Review_call_for_evidence_final_4.pdf

  - Around settlement that do not presently permit accurate allocation of costs at the household/individual meter level
  - Arrangements for costing network losses and then allocating these costs to physical participants are complicated, but do not seem to reflect the benefit of balancing local supply and demand
  - Likewise, we would expect arrangements to be developed that sharpen incentives to produce power locally or disconnect from the public system during high demand periods and to encourage demand-turn-up when supply outstrips demand or to avoid network reinforcement.

3.5.8 Regulatory reviews and risks

The electricity sector continues to undergo unprecedented change with almost all elements of the cost chain now under some form of review. Major work programmes underway include:

- Several reviews of network charges[32], including further changes to non-triad embedded benefits
- An Ofgem-led programme to mandate that all customers are settled on a half-hourly basis (to enable introduction of ToU tariffs)
- The continued roll-out of smart meters, with all customers being offered one by 2020
- Moves to introduce 'faster and more reliable' switching to allow households to switch supplier within 48 hours
- Rationalisation of National Grid's balancing service contracts and tendering approach to better incentivise flexibility[33]
- Development of DSO structures and markets to enable local flexibility services to replace "invest and connect" DNO structures
- A review of the so-called 'supplier hub' arrangements that places the electricity supplier at the centre of the industry (and hence requires generators and developers of CALES to negotiate market access with a fully licensed supplier), and
- 'Brexit' impacts once these are known and their implementation.

These programmes are not likely to be concluded until 2020 at the earliest. In sum they present a monumental challenge for all market participants, but especially small-scale generation developers. They do suggest a clear direction of travel for market change to a smarter, flexible future. Irrespective of the pathway and pace of change, the fluid external environment presents real challenges for CALE projects in assessing opportunities and mitigating risks.

[32] The Targeted Charging Review (TCR) Significant Code Review (SCR) and the recently announced Forward Looking and Network Access SCR

[33] The so-called SNAPs process.

4 Landscaping work

In this section, we take a closer look at the headline findings from the various case studies we examined and summarise the rest of our landscaping work.

4.1 Case studies

We have tried to capture the unique features of the case study schemes but within the existing market framework and produce a taxonomy of market access options. These are summarised in Annex A.

The variety of appointed case studies we have analysed include, ten selected LES case studies, seven alternative CALE projects within the UK, and five community energy projects in other countries. The locations of the LES and alternative CALE projects within the UK are displayed in Figure 4.

Figure 4: GB-based case study locations

4.2 Selected case studies

The client provided us with ten community schemes they wanted us to examine.

They are:

- Tower Power: customer aggregation through smart meters, including behind the meter solar
- Mull ACCESS: a community-owned hydro allowing more generation onto an already constrained system, thus avoiding reinforcement costs
- Surf ‘n’ Turf: a community-owned wind power driven hydrogen production for use as a fuel. The electrolyser connected to the site consumes power during frequent periods of local grid constraint and then the fuel is moved off-site and converted back to energy
- Levenmouth Community Energy Project: a community-owned wind and solar to hydrogen fuel production scheme for 25 hydrogen powered vehicles
- Heat Smart Orkney: an Active Network Management (ANM) system to reduce wind generation curtailment, using controllable boilers and heaters
- Dalavich: another ANM system to provide local hydro power and reduce curtailment of assets
- Findhorn Eccovillage: an eco-village project with micro-grid, domestic solar and wind turbine installations
- Smart Fintry: an anaerobic digestion (AD) facility supporting a local supply tariff through smarts meters and ToU tariff, providing heating through changes from oil and CPG to electric
- The Outer Hebrides Local Energy Hub: a circular economy concept powering a hydrogen electrolyser through biogas CHP unit with associated wind turbine facility, and
- The Small Wind Cooperative / Grannell Community Energy: a dual site scheme in Wales and Scotland based around a crowd-funding model and refurbished (repowered) wind turbine installations.

In terms of the commercial elements, several of the case studies have strong on-site elements. One (Surf ‘n’ Turf) entails energy being exported through the transport of hydrogen. Another is a micro-grid (Findhorn), while another shares surplus power with neighbouring sites through private wires (Levenmouth) and surpluses when the hydrogen system is full to the public system.

Another (Tower Power) aims to incorporate solar self-generation but then aggregate unmet consumption from an existing supplier through a collective switch. The arrangement aims to be administered through a community service company, so is effectively a hybrid self-supply/ white label offering, and because it is on the public network the balancing supplier sleeves participating generation to participating demands. But at this stage it appears not to have progressed much beyond a community engagement project.

In these instances, the generator would typically be FiT accredited, receiving the relevant generation tariff. The host site would benefit from the avoided cost of supply for power consumed on-site, or from negotiated payments where the power was sold to a third party through private wires or onto the public system.

Most of the case studies are connected to the public system and flow power to consumers across it. Some of these have been designed to enable local solutions typically in remote areas to enable existing or planned generation assets not to be constraint off the system when network access limits bite. One (Outer Hebrides Local Energy Hub) centres on own use but also increasing on-site production enabling alleviation of curtailment for an associated wind turbine facility when the local power system is constrained.

Three do this through “demand turn up”. One does this through a single supplier (Mull, Coop); another does this through a smart, technology enabled solution and seems to be administered through rebates applied independently of supply tariffs (Heat Smart Orkney).

Of the others, two are conventional (i.e. generation only) FiT arrangements, with the innovation being around access sharing with a local generator to optimise an ANM solution (Dalavich). Another (the Small Wind Coop/ Grannell Community Energy) also falls in this category, with the innovation flowing from the project structure using a community energy service company and the use of reconditioned wind turbines.

Another is supported by PPAs (Smart Fintry), with the power being sleeved through a national supplier, Good Energy, though a local tariff. At this stage this has enabled development of a simple ToU tariff.

All the case studies have been subjected to a financial analysis under the prevailing industry baseline. This gives an indication, in our opinion, of their future sustainability beyond the period of support provided by grant funding and other legacy subsidies such as low-carbon incentive schemes. All the projects have benefited from pull-through schemes (for instance, FiT or RO support), and current support arrangements will be grandfathered at prevailing rates in real terms once legacy subsidy schemes are closed.

Several of the case studies include purchase arrangements for exports based on power purchase agreements (PPAs). This market has tended to become more competitive over recent years as wholesale power prices have strengthened and more suppliers have come into the market. However, the attractiveness of this market for schemes already active in it will always depend on power price fundamentals, and these can and do go down as well as up.

4.3 Other GB schemes

Additionally, we were asked to identify a selection of relevant but different examples of community schemes based on our experience of the wider GB market. We selected:

- Gateshead District Energy Project: a gas-fired CHP facility with localised heat distribution and private wire networks
- Energise Barnsley: a community scheme based around battery storage within a virtual power plant using Gridshare technology in social housing, some with solar arrays, providing an option of a ToU tariff
- Wadebridge / SouthWest Water Private Wire: a private wire linked solar farm next to a water treatment works
- Wadebridge Sunshine Tariff: a trial tariff to understand how customers respond to price signals, with lower tariffs during peak solar generation
- Bethesda Energy Local Club: a community energy project for residents in North Wales, using a hydro generator for approximately 100 households. Smart meters measure half-hourly energy use, and an Energy Dashboard forecasts the likely generation to users to change behaviour
- Ipswich: Municipal Flexibility Market: Pixie Energy is analysing available models for commercial linkage of existing and planned local low-carbon generation and demand users, including the impact of incorporating domestic battery storage predominantly in social housing in Ipswich to maximise the flexibility benefits of behind the meter production and consumption to the local community, and
- Norwich Virtual Energy Community: Pixie Energy is to install solar panels on community buildings and households to allow local residents to invest in community energy assets under a multi-supplier model.

These schemes show a range of potential business cases, as well as the importance of wider public-private engagement in developing the projects. Two of the projects (Gateshead and Wadebridge) contain private wire elements, with a further two incorporating ToU tariffs – as well as being a recommended, but not mandatory, option for a third. In the case of these projects, the issue of customer engagement is crucial, with Bethesda meeting their target for participation while Wadebridge did not. The two Pixie projects are noteworthy as they should support the development of understanding the impact of ToU and HHS on different types of consumer behaviour with on-site solar and storage.

Both the Bethesda project and the Norwich project explore innovation from a tariff perspective with the integration of dedicated generation assets and different ToU tariffs. Both are presently based on the need for a number of important code derogations and work-arounds. The Barnsley project does not mandate a ToU tariff, as participants are able to switch suppliers during the life of the trial, but it does recommend one.

4.4 International schemes

Finally, to derive a broader canvas for proposing and developing a short list of delivery models, we looked at a handful of international developments. We have considered:

- Feldheim, Germany: an energy self-sufficient village in Germany operating a 43-turbine wind farm, a biogas CHP plant from over 350 hectares of energy crops; and a woodchip furnace
- Vandebron, Netherlands: a renewable energy company allowing customers to choose which generators or technology type to purchase energy from, directly linked to local producers through online peer-to-peer marketing
- Samso, Denmark: an island community using straw-fuelled district heating systems, 11 onshore and 10 offshore wind turbines to meet 100% renewable electricity and 75% renewable heat demands
- Ecopower, Belgium: a co-operative financing renewable projects which produces energy and supplies to approximately 50,000 customers. Customers can buy into the scheme operating a Flanders based wind farm alongside solar, hydro and vegetable oil biomass facilities, and
- SOMAH, California: the California Public Utilities Commission (CPUC) regulates privately-owned public utilities in California, including the energy sector, creating the Solar on Multifamily Affordable Housing (SOMAH) to incentivise deployment of solar projects specifically targeted on the fuel poor.

The different regulatory regimes and their respective levels of support for community energy schemes are very different to GB. However, these schemes illustrate the potential routes for projects in Scotland and the wider GB market to achieve scale if the right enabling structures can be developed.

As an effectively self-sufficient community, Feldheim has conceptual similarities to the Surf ‘n’ Turf project, and both are based upon a whole system approach to energy. The apparent tourist interest in this innovative project highlights its innovative nature, and its attractiveness in terms of replicability. The high community buy-in seen in Feldheim is mirrored in the Belgian Ecopower scheme – although this is aided by legal requirements relating to wind farm developments.

As a peer-to-peer trading arrangement – wherein Vandebron facilitates the sale of energy from generators directly to consumers – it has similarities at a high level to projects such as Bethesda, but the choice of generation from multiple sources is an additional element and one which provides price signals to project developers. The integration of EV infrastructure into the scheme highlights the ability to tie-in low-carbon transport in a relatively straightforward manner.

The islanded nature of Samsø draws parallels with some of the Scottish projects. However, there is a notable difference in the underlying priorities of developments such as Heat Smart Orkney, given that the Danish project does not suffer from constrained network connections despite its high level of renewable generation deployment.

The Californian SOMAH project makes explicit provision for community benefits in the form of employment opportunities and specific rent controls. The approach to metering and the use of credits is innovative, as is the way in which the scheme is funded, which is through carbon rentals. As with the FiT regime, the degression of support rates may mean that the approach is time-limited.

4.5 CALE taxonomy

To characterise delivery model options, we have decomposed these various case studies and examples by the main characteristics. The decomposition is shown in Figure 4 and Figure 5. The first covers physical characteristics; the second the main commercial features.

Figure 5: Main features of schemes considered in CALE landscaping – EST projects

Project	Generation Size	Customer Size	Physical features	Financial features	Comment
Tower Power	Not disclosed	656 households	**VPW, MG, smart demand**	**Local tariff, customer incentive, FiT, RHI, DSR**	**As yet, well short of realising aims**
Surf'n'turf	900kW Wind, 500kW Hydrogen Electrolyser, 2MW Marine, 90kW Hydrogen Fuel Cell	150 people	**PW, MG, ANM, H_2**	**ROC**	**Interaction of activities in circular economy**
Levenmouth	750kW Wind, 160kW PV, 25 hydrogen powered vehicles	Businesses (electricity), Vehicles (local authorities), Leven swimming pool (heat)	**Mg, DH, H_2, transport**	**PPA**	**The focus is surplus energy conversion for use in transport**
Heat Smart Orkney	900kW wind	260 people	**ANM, smart demand**	**Local tariff, customer incentive, FiT, PPA, DSR**	**ANM incorporating smart demand response**
Dalavich	350kW hydro	70 people	**ANM, smart demand**	**FiT, PPA**	**A private ANM solution**
Findhorn Ecovillage	750kW wind, Domestic solar	61 buildings	**PW, MG, DH, smart demand**	**ROC, RHI, DSR**	**Local micro-grid project**
Smart Fintry	200kW anaerobic digestion, wind, solar PV	>100 households	**VPW, ANM, smart demand**	**Local tariff, PPA**	**A VPW scheme based around a local tariff**
Mull ACCESS	400kW hydro	100 homes and two small businesses	**MG, ANM, smart demand**	**Customer incentive, RHI, DSR**	**Constraint relief through demand turn up**
Outer Hebrides Local Energy Hub	150kW CHP, 300kW wind, 30kW hydrogen electrolyser	Salmon Fishery	**MG, ANM, H_2, transport**	**Local tariff**	**Circular economy solution to produce hydrogen and oxygen to increase use of generation assets**
Small Wind Co-op / Grannell Community Energy	380kW wind	Farms (Wales and Scotland)	-	**Customer incentive, FiT**	**Hybrid FiT/ crowd funded wind schemes**

Key: VPW – Virtual Private Wire PW – Private Wire MG – Micro-grid BTM – Behind the metre ANM – Active network management H2 – Hydrogen production DH – District Heating FiT – Feed in Tariff PPA – Power Purchase Agreement ROC – Renewable Obligation Certificate RHI – Renewable Heat Incentive DSR – Demand-side Response

Figure 6: Main features of schemes considered in CALE landscaping – Wider GB and international CALE projects

Project	Generation Size	Customer Size	Physical features	Financial features	Comment
Gateshead District Energy	4MW CHP, 3MW battery, 250,000-litre hot water thermal storage	1,000 planned households	**PW, DH, smart demand**	-	**Private wire DH scheme**
Project Windy: Energise Barnsley	1MW PV, 40 batteries	321 households	**VPW, smart demand**	**Local tariff, FiT**	**Flexibility aggregation with solar and batteries**
Wadebridge / South West Water private wire	100kW PV	Nanstallon Sewerage Treatment Works	**PW**	**Customer incentive, FiT, PPA**	**Private wires project backed up by long-term PPA**
Wadebridge: Sunshine tariff	Not disclosed	<50 households	**VPW, smart demand**	**Local tariff**	**Network innovation trial to boost local consumption of solar**
Local Energy Hubs: Bethesda	500kW hydro	<100 households	**VPW, smart demand**	**Local tariff**	**Local tariff structured to incentivise use of associated hydro asset**
Ipswich: Municipal Flexibility Market	Battery and storage assessment	Desk top study	**VPW, smart demand, transport**	**Local tariff, FiT**	**Desk top study of local flexibility**
Norwich Virtual Energy Community	20 PV, battery and heat pump combinations, integration of local generation	50-1,000	**VPW, smart demand, transport**	**Local tariff, customer incentive, FiT**	**Local supply community combining existing and new low-carbon assets, batteries and load using TOU**

Key: VPW – Virtual Private Wire PW – Private Wire MG – Micro-grid BTM – Behind the metre ANM – Active network management H_2 – Hydrogen production DH – District Heating FiT – Feed in Tariff PPA – Power Purchase Agreement ROC – Renewable Obligation Certificate RHI – Renewable Heat Incentive DSR – Demand-side Response

5 Delivery models and pathways

In this section we describe how we have developed a methodology for selecting, classifying and short-listing delivery models (DMs), including the criteria we have used. Elements of the short-listed DMs have then been worked up into more detailed work-plans at Appendix C.

5.1 Approach

CALE projects, like other businesses, require viable business models first to support their development and then for ensuring their financial sustainability. However, in most cases, they will be operating within complex regulated market and technical environments, which are currently subject to rapid and profound changes that are largely beyond the power of the community to influence.

In addition to this, CALE projects operate within varied physical and geographical circumstances. In terms of physical characteristics, they can be rural or urban; integrated, constrained or remote; multi-fuel or heat or electricity only. Commercial options have tended to become more diversified, but a key variable is whether a project produces more power than its host demand at any point, and if so whether it has unfettered access to the public network. Different social drivers are also evident: with different types of governance or participation; arrangements can also be socialised or targeted on the fuel poor or vulnerable.

These factors can make each project's assessment in terms of success or failure subjective, difficult to standardise and relatively dependent upon the point of view from which they are regarded. Indeed, community energy projects can have an array of primary goals, from reducing fuel poverty to improving local air quality. Through our landscaping work, we have identified a wide range of schemes with shared features and models that are either operating or under trial in the market today. While each project has unique elements, they can be grouped according to the physical fundamentals of the scheme and the commercial arrangements that have been adopted irrespective of the support they have received.

We have developed a "long list" of twenty-five DMs from the case studies and examples. Our approach has been to decompose the DMs we have identified from our research into the essential features, to identify a typology (or taxonomy). The principal relationships of elements between the wider energy system on the other side of the consumer's meter, the metering, generation and demand have all been disclosed. In some variants, we have also identified energy storage, transport and heat elements, and third parties such as aggregators, supply intermediaries and specialist technology providers are increasingly becoming involved.

The various DMs and our assessment of them are set out in further detail at Appendix C.

This long list should probably be described more accurately as types of arrangement, most of which has several variants. Six broad types of delivery model have been identified. The groupings are:

- Self-consumption
- Private wires
- Virtual private networks, enabled by an intermediary
- Micro-grids
- Generator sales to market, and
- Supply-based models.

In our descriptions of the delivery models, we have set out seven themes within each commentary:

- A diagrammatic representation and brief description of its principal commercial elements
- The overall conditions or scenario in which it is contextualised
- The revenues and associated benefits that could be derived by a CALE group operating the DM

- The variations within this model that could be possible within regulatory compliance
- Future developments of the regulatory (market and technical) environment that will impact the DM
- Critical assessment of the viability of this model moving forward under what we see as key developments in the regulated environment affecting the DM, and
- Relevance to CALE groups.

5.2 Evaluation criteria

Projects also exist on several dimensions, most notably ownership, scheme governance, market exposure and technological coverage. The DMs have been evaluated against two sets of evaluation criteria to ascertain which models and variants we should focus on to determine delivery plans. We recognise that in some cases the models we have described are unlikely to be within the capability, or interest, of a CALE group to deliver and so add our view on this as part of the individual model commentary.

Arising from these analyses, we present in Appendix B a 'traffic light' system, including two colour-coded matrices indicating our view on whether a particular DM is viable (green), possibly viable (yellow) or likely to be unviable (red).

5.2.1 Costs and benefits

In our first set of assessment criteria we have given weight to the following in order of priority:

- Consistency with the existing market framework
  - Is the project possible and does it make sense under current market and regulatory conditions?
  - Is the project possible and does it make sense under future known or expected conditions?
- Track record
  - Are similar projects in existence already, and are these economically viable?
  - Are the revenue streams the project will rely on sustainable for long enough to make the project viable? If not, are there other (existing or expected) revenue streams that could replace them?
- Ease of implementation/ practicability
  - What technical and market barriers will arise in establishing the project, and are these unique or have they been solved before for similar projects? Will a non-expert CALE group be able to solve these challenges?
  - What partner organisations will be required, and are they likely to buy in to the project, with time or financial resources? What will be the cost of accessing skills and knowledge to fill gaps in the CALE groups' abilities?
- Financial viability
  - Is the arrangement likely to be financially stable under current and likely future market conditions? Are the benefits of the new arrangement sufficient to justify the cost, in terms of money and time, of the project?
  - What are the barriers to commercialisation? Are they addressable?
- Replicability and scalability
  - How common are the conditions required to make the arrangement feasible?
  - How can the project be increased in size once implemented?
  - How repeatable is it?
  - Can the solution be scaled?

- Cost
  - What is the initial cost of setting up the arrangement, and could this be raised by the community group?
  - How will the technologies change in price and deployment in the future?
  - Will the project be able to identify and capture flexibility values? If so, how?
  - How will the arrangement be impacted by the expected shift to half-hourly metering assuming the availability of use tariffs?
- Other benefits
  - Will the arrangement build engagement?
  - Will it enhance social capital?
  - Are there other benefits? What are they?
    - This could be in terms of carbon abatement, fuel poverty alleviation and value redistribution, network resilience building etc

5.2.2 Participant objectives and impacts

In the second assessment matrix, based on participant objectives and impacts, we have also given attention to the following criteria:

- Project regulatory viability under current market rules and conditions, and potential future viability under upcoming or probable changes to conditions, for CALE groups
- Consistency with current Scottish government energy policy, in two principal areas:
  - Increasing use of existing assets and improving the efficiency and cost-benefit ratio of the whole energy system
  - Promoting social inclusion and developing increased social equity and interest in the energy sector, including the effect of uptake of the delivery model on charges and costs to other market users
- The benefits and disbenefits to stakeholders: the CALE group itself, energy suppliers, the network companies
  - This is considered in terms of finances, competition, the carbon abatement agenda, the fuel poverty agenda, and efficient system operation
- The risk of policy or regulatory interventions to change market rules and the potential effect of these changes on the delivery model, whether positive or negative

The sector has been (and will continue to be) subject to rapid change, which will impact on the relative merits of the different options going forward. With policies around decarbonisation of heat and transport firming, and smart technology and digital capability subject to constant change, we expect an increasing number of interactions and variables influencing credible development pathways and their ranking.

5.3 Summary of delivery models

Please note that the following summary is derived from the full assessment matrices presented in Annex C. The scores represent our high-level judgment of the projects' overall benefits and viability. We have scored each DM out of ten against each of the two sets of criteria described above, and ten summed them. This gives a total project score out of 20 in the final score column.

Those projects with a combined score above 14 have been bolded for emphasis in Figure 7 below.

Figure 7: Summary of delivery model evaluation

Ref	Lead concept	Differentiators	Costs & benefits	Objectives & impacts	Final score
1.A	Self-consumption model	Demand greater than generation	7	3	10
1.B	Self-consumption model	Generation greater than demand	6	4	10
2.A	Private wires model	Demand greater than generation	6	3	9
2.B	Private wires model	Generation greater than demand	5	4	9
3.A	Virtual private wires (sleeving) model	Simple sleeving	7	6	13
3.B.1	Virtual private wires (sleeving) model	Local Energy Club	7	7	14
3.B.2	**Virtual private wires (sleeving) model**	**"Smart" Local Energy Club**	**8**	**9**	**17**
3.C	**Virtual private wires (sleeving) model**	**Local Supply Community**	**7**	**8**	**15**
3.D	Virtual private wires (sleeving) model	Interposed meter	6	8	14
4.A	Generator-only model	Unconstrained connection	6	5	11
4.B	Curtailment avoidance market	Constrained connection	6	7	13
4.C.1	Generation consolidation	Aggregating generators for commercial advantage	7	7	14
4.C.2	Generation consolidation	Intermediated generation consolidation	7	7	14
4.D	Generation auction	Competitive procurement	6	7	13
4.E	**Heat & Power model**	**Heat with surplus power for export**	**8**	**8**	**16**
5.A	Microgrid model	Grid-connected	6	6	12
5.B	Microgrid model	Constrained	7	7	14
5.C	Microgrid model	Islanded	4	8	12
6.A	Energy supply company	Licensed supplier	2	2	4
6.B.1	Energy supply company	Licence Lite supplier	3	3	6
6.B.2	Energy supply company	Enhanced licence lite	7	7	14

Ref	Lead concept	Differentiators	Costs & benefits	Objectives & impacts	Final score
6.C	Energy supply company	White Label supplier	5	5	10
6.D	Energy supply company	Licence exempt supply	5	5	10
7	**Cooperative purchasing**	**Collective purchasing via CALE group**	**9**	**8**	**17**
8	Peer-to-peer	Direct contractual arrangement via public network	6	4	12

5.4 Pathways

We have then grouped these DMs to better demonstrate possible developmental pathways. We organise these below in ascending degree of complexity, with the simplest first. We have organised the DMs into pathways in order to illustrate how, with increasing experience, confidence and financial resources, a community energy group could develop from the simple to more complex models. It also highlights that some of the more advanced DMs are only suitable for established groups with considerable knowledge and dedicated staff.

However, it should be emphasised that these pathways are illustrative; embarking at the start does not mean a scheme would necessarily evolve to the end as some CALE groups will only have the ambition to, for example, generate low-carbon energy in their region.

The pathways we show below are:

- A: Living urban community
- B: Local energy hub
- C: Smarter micro-grid
- D: CHP with electricity supply to end customers, and
- E: Generation aggregation and branded supply

5.4.1 Pathway A: “Living urban community”

This is formed around DM 7 (collective net purchasing) evolving through DM 3C (local supply community) to DM 3A (a VPN). Its dominating characteristics are that it starts as consumer-led and is based around public sector housing located on the public system, incorporating increasing levels of behind the meter generation.

This is a relatively simple model, at least initially, when applied to collective purchasing of energy. There are already established networks for purchase of heating fuels in remote areas. However, collective purchase of gas and electricity delivered over the wider network based on multiple households is emerging as a new route to market. Many collective purchases have taken place over recent years, though many have presented problems with poor engagement and limited take-up for opt-in schemes. Although small in scale these problems have been well demonstrated by the Tower Power scheme.

Collective purchasing offers scope to extend to purchasing of solar panels (as evidenced by the recent “Solar Together” move by the GLA), smart thermostats and other home energy management system (HEMS) applications and energy efficiency techniques and appliances. Following reform to the ECO scheme for phase 3, there will be more activity as Local Authorities and through them Social Housing Associations will see additional opportunities to obtain supplier funding for “affordable warmth” schemes.

At some point, this type of arrangement where householders share the same supplier could evolve into a Local Supply Community structure, dependent on the amount of generation introduced. The collective supplier would be able to contract with local generation consolidating it with that owned by the community and sleeving it through to the point of consumption. The introduction of domestic (or community storage) along with HHS should greatly enhance the viability of this approach few years. Arrangements of this type are involving and can incorporate bespoke tariffs incentivising consumption at times of lower cost.

The VPN aspect of the scheme is dependent on proving of software solutions that enable production and demand to be actively balanced, with incentives to move demand to suit the generation profile and/or the supplier’s balancing position and potentially realising savings of wholesale purchasing and balancing costs. Initial trials with software and control systems have yet to be proven on multiple properties, and costs have tended to be unpredictable. However, the market is confident such approaches will become mainstream. In this circumstance, the community might wish to agree with the participating supplier an appropriate form of tariff and distribution of savings between participants.

Building on this development path, there could be scope to apply emerging peer-to-peer solutions (DM 8) where householders with small-scale generation or local producers are allowed to exchange surpluses, coordinated by the licensed supplier. Such local markets, illustrated by schemes such as Smart Fintry and Bethesda, have not as yet progressed beyond the feasibility stage and it is not clear whether they will work at scale. There are various “sandbox” trials being conducted on schemes of this type, often in self-contained buildings and estates but industry rules and structures are unlikely to accommodate them at scale.

5.4.2 Pathway B: Local energy hub

Unconstrained generator moves to local supply (DM 4.A) through a participating supplier, to peer to peer trading concept (DM 8).

Since 2010 a new low-carbon generator with surplus power has had secure market access through calling down the FiT export tariff. A more proactive, higher value route is available through negotiating terms for export under a PPA or selling exports through the e-POWER auctions for larger sites.

In the post April 2019 environment, there are real advantages from sizing new generation against minimum stable on-site demand as the differentials between wholesale and retail electricity costs grow. Similarly, incentives to supply surpluses to local sites, especially under a sleeving arrangement will also become stronger. Even under exemption limits, the generator would need to utilise a supplier to register meters in central settlement and deal with any top-up and spill services.

There are examples of this transition from the case studies and our landscaping work:

- The Bethesda scheme was initially FiT accredited in May 2017, but the export is now used in a local supply innovation scheme. This entails the supplier (Coop Energy) allocating output from the 100kW hydro scheme across the public network to 100 smart-enabled local homes, with participants being provided with information to understand when output is greatest to maximise use of the cheaper power associated with the site, using a specially constructed local tariff, and
- Mull ACCESS represents an evolution on this idea but with surpluses from the 390kW hydro scheme, FiT accredited in 2015, being converted to heat through storage heaters at attractive incentivised rates, to balance off electricity that would otherwise have been constrained off the system. In this case SSE is the supplier.

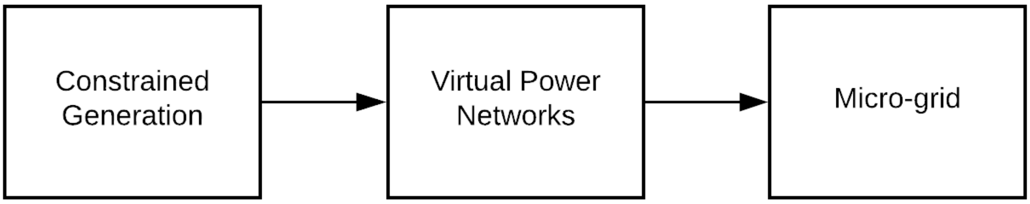
Within the typology we have developed, both of these schemes could be regarded as sleeved arrangements.

With the addition of additional generation sources, it would be possible to evolve this model into a simplified peer-to-peer model (though there are other evolutionary pathways available). An early stage example of this already in operation is the Open Utility Piclo model. Here consumers, who are usually business users, can notionally identify the low-carbon resources they buy. Again, this is sleeved by a supplier (in the case of the initial Piclo project, Good Energy), who deals with the addition of non-energy (network and policy) costs, and who also provides the balance of supplies to the customers (including top-up and spill). Under this approach generators post the energy rate they wish to realise, and the customer can nominate the generator they wish to purchase from.[34]

[34] https://www.openutility.com/piclo/

5.4.3 Pathway C: Smarter remote local network

Scotland has multiple remote and islanded networks. It also has many areas that are subject to constraints or weakness. This pathway illustrates transition from a constrained generator model (DM 4.B), through development of more responsive micro-grid (DM 5.B) to eventually a virtual private network (DM 6.D).



Even under the case studies we have examined, new renewable assets can be significantly constrained as network conditions change, and many sites are subject to ANM arrangements. This is illustrated in different ways by the schemes at HSO, Dalavich and Fintry. In each case technical solutions have been adopted to enable generation production without or with diminished curtailment. One has adopted a power to gas conversion solution, another a shared access solution pending grid reinforcement, and the other a demand turn up solution.

Several other schemes are trialling different smart control solutions, which are testing implementation of demand-side response in particular to identify scope for value creation by moving demand in response to tariff differentials, which in turn often reflect temporal supply limitations. To varying degrees, all these arrangements provide illustrations of local micro-grid development.

In circumstances where there is a physical limitation and/or geographical separation the concept of a micro-grid is easy to comprehend. Even where islanded systems are interconnected, demand growth and change in usage (as well as wider system changes) often mean usually unconstrained systems can become constrained. The value of flexibility in such circumstances, if it can be controlled, increases.

Active management of distributed energy resources on a micro-grid in the case studies remains rudimentary. However, the introduction of storage and conversion technologies will be transformative providing much more optionality, increasing local system resilience and enabling deferment of network reinforcement.[35]

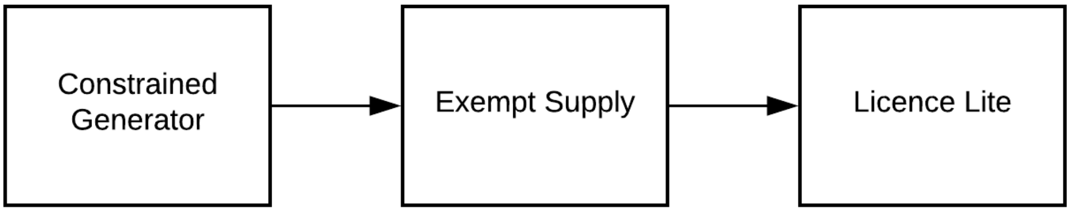
Furthermore, virtual power plant (VPP) models are being developed, which aim to balance local generation and consumption, using demand-side interventions turn demand up or down as necessary. These types of solutions are emerging in island settings (Isles of Scilly, Mull & Iona, Cumbrae possibly) whereby interconnected areas or islands can be optimised around intermittent assets and controllable demand. On the basis that policy and network costs are set to increase, incentives to remain islanded could increase if these trials prove successful.

Integration of transport is also opening up opportunities. Deployment of EV charges is being seen as a means of increasing use of local production, especially where operational constraints can come into play. Once the supply chain for hydrogen conversion is proven at scale, this could also open up the possibility of repowering existing assets and over-sizing generation through the addition of new assets. For the present, however, costs need to fall significantly before hydrogen can compete with fossil fuels for transport use.

[35] http://www.hie.co.uk/common/handlers/download-document.ashx?id=5af49f92-d359-4180-9eef-08402a186319

5.4.4 Pathway D: CHP with electricity supply to end customers

Constrained generator (DM 4.B) moves to local supply (DM 6.C) through participating supplier, to licence lite supply (DM 6.B.1 and 6.B.2).



This is similar to pathway C, but we have varied it here

- First so it embraces heat, and
- Second so that, reflecting larger scale, the generation owner ultimately becomes its own supplier but under the "licence lite" model.

In this pathway, we start with a renewable fuelled CHP plant. Usually cogen facilities are sized to deliver a defined heat (domestic) or steam (industrial) profile, producing surplus energy. They are typically sized between 500kW to 1MW, exporting surplus power to the grid. The constraint in this instance arises from limitations imposed by optimizing the heat and/or steam.

Where the site has used renewable fuel, until now the FiT export rate has been available. Henceforth, sites will need enter into a PPA or alternatively achieve supply to end consumers. Even where exempt supply can be used, the operator needs to be able to demonstrate compliance with industry codes and have its transactions settled. This means using an established licensed supplier, who among other things will register the meter and ensure network charges are applied appropriately.

We have set out in Appendix C how exempt supply status is important to community energy. In this illustrative pathway we assume that the export is sufficient (perhaps through aggregation with other local generation) to provide the basis for a wider offering to consumers across the grid.

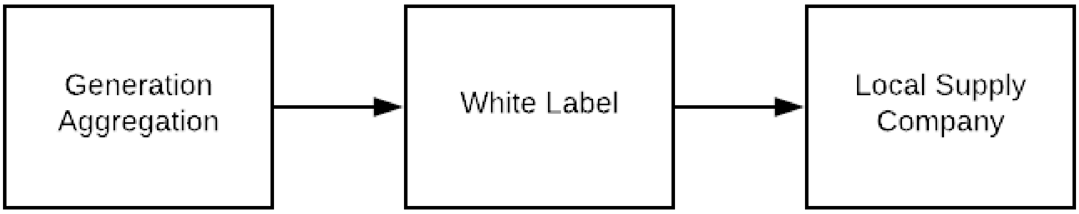
Under either approach achievement of a tariff around 10p/kWh could support or cross-subsidise heat operations.

Under licence lite (unlike under a white label), the customer from a regulatory stand-point belongs to the junior supplier, and there is much more latitude in designing and targeting local tariffs. The senior supplier delivers compliance with industry codes and provides services to the local supplier under a supplier services agreement. It would also need to provide netting and offtake services for when the local supplier was in imbalance.

Heat in this pathway is a major driver of project structure. It is possible in a network constrained area, some portion of the off-take as such projects are often over-sized in terms of electricity could be redirected towards on-site conversion from power to transport.

5.4.5 Pathway E: Generator aggregation and branded supply

Generator aggregation (DM 4C.1) is not currently a significant feature of the market, though Good Energy, Ecotricity and Smartest Energy have practised this to various degrees over a decade or more. Here it is seen as transitioning through a dedicated white label (DM 6C), potentially transposing into a local supply company (DM 3D) arrangement enabled by smart control and a bespoke tariff. As the client base expands, new generation could be added.



In certain respects, this is a variant on pathway A. However, it differs in two important respects:

- First it starts as a generator aggregator (DM 4C.1), to provide a route to market, and
- Second it moves beyond a generic market tariff to a wider community offering based on a bespoke tariff offering (DM 6C).

In a post subsidy world, establishing a route to market for new generation will be critical. Our Market shows that there are specific reasons why suppliers are presently interested in local green energy. However, most of the case studies and examples we have looked at are between 300kW to 800kW. Based on the current market process, interest in smaller parcels of power could diminish, and the appetite for writing long-term contracts could also reduce. There is a route to market through the e-POWER auction and other emerging trading platforms, but these are based on short-term PPA terms and insufficient to provide revenue security to underpin new generation investment.

The second factor is relevant because we are beginning to see the emergence of local supply specialists, but in a way that is actively looking to feed local green production to local consumers. The first example of this was OVO Communities but, while they were able to sign up several local white labels, the associated generation did not follow. Robin Hood Energy says it is seeking a similar development path.

The recently announced Hebridean Energy/ Our Power collaboration has elements of this model. First Our Power through its basic offering is looking to match local regional generation with local supply. Our Power's regional supply under its main supply brand incorporates not only its own generation but, shortly we believe third-party generation. In that sense, it could also be seen as a local supply community but with the established supplier offering a specific tariff targeted on vulnerable customers, which could be locally branded. The basic concept in this instance is being taken and applied in other areas on a white label basis.

The form of the contract between the established supplier and the client could take various forms, but usually the host/junior supplier would receive a commission for each customer who switched to the senior supplier. The customer for compliance purposes is owned by the registering, senior supplier. Subject to negotiation there could be latitude for the white label to negotiate a different tariff.[36] Under this model successful suppliers will be those that adapt their conventional supply model to become a net supplier and a seller of market services, actively supporting the sleeving of existing and new generation to the communities associated with the local generation.

We would expect regional specialists to develop under this model. This might form a template for a national, publicly owned supply company if it appears that a market in these services was not evolving by mid-2019.

[36] The two examples we are aware of are LECCY in Liverpool (a Robin Hood Energy white label) and Fairer Power (an OVO Communities white label for Cheshire East).

6 Work-plans

We have developed four, which we agreed with the project steering group, focussing on the various sources of information available and the practical steps that can be taken in the light of today's largely subsidy-free circumstances. They are summarised in this section.

6.1 Work-plan 1: Combined technologies

This work-plan looks at the potential to deploy solar PV arrays, storage batteries and electric vehicle (EV) chargers in combination typically at small and medium business premises. We set out how non-domestic consumers can develop investment proposals and action plans for deployment, considering a generic model based around installing or extending a 10-50kWp solar array.

We consider how value can be maximised before and after the closure of the FiT by rationalising on-site use through the use of batteries and charging. We also consider the likely payback periods of the combined technologies.

PV systems are already commercially mature, and until 31 March 2019 there will continue to be FiT subsidies in the 10-50kW band. Commercial sites highest usage often coincides with the main sunshine hours, making deployment attractive at offices and other business premises.

Battery prices are also falling rapidly and they can be added to increase the amount of power consumed on-site deriving greater benefits from avoided purchase costs than from selling the surplus to the market. Increasingly storage batteries are being offered with a revenue share of capacity and balancing revenue streams.

EV chargers can also use help using otherwise surplus production, and grants are available for installing chargers.

6.2 Work-plan 2: Wind using refurbished and life-extended turbines

In this work-plan, we look at the assessment and delivery framework for a site owner using refurbished wind turbines in a post-FiT world, after April 2019. We examine the rationale for considering a refurbished, as opposed to new, wind turbine, and identify how to develop the key parameters of a business case.

The work-plan also addresses how to locate a site and evaluate its merits, and it provides a route-map around how to obtain the necessary consents. We recommend a structure of self-consumption of generated electricity to derive greatest economic benefit, based on an illustrative 500kW site with 4GWh consumption. However, we also explain why refurbished turbines are also close to becoming economic based around remote export-only sites without FiT payments.

Onshore wind is already the cheapest source of new electricity generation capacity, and electricity from refurbished turbines is significantly cheaper than that from greenfield sites. Repowering is already occurring in the market (Delabole) and NFFO sites and early RO sites will begin to think about re-powering soon (not until 2020s for RO). All can offer attractive payback periods if located on good sites with suitable supporting commercial arrangements.

There are three very different circumstances where turbines can be used in CALE schemes following the removal of subsidy:

- Sitting new turbines at the point of consumption as technology costs continue to fall and as the avoided cost benefit increases
- Repowering at existing sites could yield significant cost savings to infrastructure and grid connection, and
- Deploying refurbished turbines at remote sites based on a conventional export model, perhaps using a corporate PPA.

Corporate PPAs are becoming popular between businesses and renewables developers as businesses seek green supply.

6.3 Work-plan 3: Collective energy action

We address the demand-side and domestic customer engagement in work-plan 3, focusing on high density housing such as tenement and tower blocks and set out guidance for social landlords and housing associations. Switching for disengaged customers, aggregation of demand and collective purchasing, and increased deployment of energy efficiency measures are all considered.

There are significant realisable benefits by customers from switching and realising better tariffs in the current market environment. These benefits will be lesser but still significant once default tariffs and price caps have been implemented later this year.

At the same time high levels of social housing and low costs of enabling changes means collective action offers realisable benefits, especially where critical mass can be achieved. We think more could be done to stimulate switching through use of brokerage services and also collective switching. Bulk supply arrangements could also be negotiated where tenements can be supplied through an aggregated settlement meter.

In addition, there are strong incentives and significant available funding to incorporate into community schemes access to increased ECO funding.

6.4 Work-plan 4: Heat pumps

This work-plan sets out information and guidance on using heat pumps to displace conventional electrical heating and high carbon fossil fuel heating, typically using fuel oil. We look at the costs of installing and operating heat pumps, including air, ground and water source units, and the continuing subsidies available from the RHI and how to go about accessing them.

We also look at how solar thermal, solar PV, batteries and thermal banks can support the efficiency and reduce the operational cost of heat pumps. We then expand the scope to consider options for district heat networks and shared ground loops.

Heat pumps have a low carbon intensity and are typically more efficient than traditional heating methods, when deployed in households, especially in areas not connected to the gas network. Costs of system are steadily falling

Incentives under the RHI continue to be available, and it is likely that policy focus on heat decarbonisation will increase going forward.

Increasingly this focus is likely to achieve synergies between heat pumps and PV, battery storage and solar thermal systems.

6.5 Supporting the work-plans

All of the work-plans could be supported and delivered by an enhanced and expanded LES portal. In each case there would also be self-help and “how to” guides, process maps, and other “route-maps” showing sources of further information. The specific work-plans should be supplemented by awareness raising and communication, identifying and publicising good practice.

The full work-plans are at Appendix C.

7 Conclusions

In this section we set out our conclusions on development models and areas for focus.

7.1 Learnings from existing projects

The case studies we have reviewed show the diversity of CALE schemes that is emerging. The common feature for all of them, however, is that they all enjoy support under subsidy mechanisms that are to be phased out for new schemes. The strength of the incentives has acted as a very strong pull-through mechanism for the generation assets, with other innovations supplementing the community scheme usually funded by grant aid. At the same time, network-related innovation has been largely absent outside of regulated innovation schemes, with developers largely having to navigate around defined network limitations and no guaranteed network access.

The 10 CALE projects we looked at appear to continue to be viable given the grant aid they have received and the subsidy they enjoy, as the subsidy mechanisms that sustain them will be "grandfathered". It is also difficult to evaluate the enhancing benefits they bring as they will only be clear over the life of the projects.

In terms of delivery models, these are many and varied and reflect the heterogenous participants involved in the schemes. In most cases they are supported by an established industry player or players. Direct supply across the public network using a full supply licence is not viable for CALE projects, on grounds of both costs and complexity.[37] However, in broad terms, there are at a high level a few ways a locally-based energy scheme can continue to survive commercially with a secure income using traditional market solutions:

- Self-supply, which is increasingly attractive given the rising costs of public network use and of the cost of legacy government policies. The avoided cost of public supply (the "on-site benefit") presently enjoys an average advantage upwards of 5p/kWh, and this is set to grow
- Associated with the above direct, unlicensed supply through "private wire" arrangements, though existing sites may be limited and additional wires costs would need to be factored in for new sites, However, it is also likely that, for both self-supply and private wires, regulation is increasingly probable to address what it might see as cost avoidance, and such developments do not sit well with policy objectives to optimise use of existing infrastructure
- Long-term negotiated PPA have increasingly featured replacing FiT arrangements for larger schemes as sites have looked to increase value, and
- We are already seeing significant new types of new activity in the PPA market:

At a more detailed level, we have found issues in several of the case studies that should provide learnings going forward that can be assimilated by developers, and which should help identification and definition of future schemes. Examples of these issues include:

For demand-inclusive schemes:

- The difficulties experienced in achieving successful engagement with local stakeholders. With demand-facing projects in particular, there is a notable shortfall in the level of participation hoped for in some of the schemes, exacerbated by the requirement to work with a single supplier and a reluctance of householders to switch
- There is anecdotal evidence around inclusion of prepayment meters into the pilot schemes, especially smart meters and deployment of new control technology, which have caused operational and communication issues

[37] The same applies to licence-lite, which also involves significant investment. White label arrangements are much lower cost, but only allow limited value capture by the local partner.

- Project sponsors have also encountered issues around use of advanced meters and compatibility with smart meters programme requirements
- In some cases, there are issues involving smarter/software with proving the customer interface, interoperability between different systems and cost overruns
- In others there have been issues around ownership of intellectual property rights.

For generation-led schemes:

- Unforeseen limitations arising from changing network conditions, and imposition of operational constraints
- Unclear requirements on use of export meters and registering offtakes in settlement (including the need for an export as well as an import register, and industry requirements for allocating charges, including the associated rationale
- Non-optimisation of revenue streams through exploration of better market options such as shifting from FiTs to PPAs, especially for generation accredited pre-November 2012[38], and
- Non-inclusion of beneficial system impacts of the schemes by relieving wider system pressure and reduction of thermal losses.

Consequently, all project objectives will not always be met. However, in part this reflects:

- Rigidities in the current market rules and regulatory rules applying to DNOs
- Wider issues around customer engagement in the energy sector, and
- Problems arising from industry change processes, rather than problems flowing directly from the projects themselves.

These issues seem to be shared by projects from the other landscaping work we have done in GB.

7.2 Future prospects

The headline conclusion from our work is that there are a wide range of practical steps that communities and businesses can take today to continue to develop local energy projects despite the significant changes in policy support.

We recognise that the near-term prospects for CALE schemes have deteriorated significantly over the recent past. This change is attributable to several factors but notably:

- The withdrawal of Levy Exemption Certificates in mid-2015 that previously enabled a specified premium to be paid for green electricity.
- The phase out of the so-called triad benefit that began from 1 April 2018 has also had a detrimental impact, and
- Sequential reduction of generation payments under FiTs and imposition of degression caps.

For the present build rates for generation installations below 5MW are being sustained but only at a very low level[39], and many industry parties are expecting these to fall away after 31 March 2019 especially if there is no guaranteed route to market.

[38] Sites accredited before this date earn a lower export rate under the administered rates.

[39] Some 40MW of capacity was accredited in the year 2017-18, though mainly hydro in the north of Scotland. In the first half of 2018-19, the figure fell again to 10MW.

Withdrawal of the FiT scheme is now confirmed from 31 March 2019, and the UK Government has also announced a provisional decision to end the guaranteed export tariff and the obligation on designated suppliers to purchase exports. It has, however, called for evidence on a safety net for microgeneration, including community schemes. [40]

With the closure of the scheme to new projects and the end of the RO grace periods in March 2019, and with the probability of no new subsidies for generation below 5MW promised by the UK Government at least before 2025, the national policy environment has set down a tough challenge to the financing and sustainability of new CALE schemes. Furthermore, wholesale power prices are not expected to increase on a sustained basis over the coming years. Multiple reviews of industry charges and rules also introduces a significant element of uncertainty.

All but the smallest CALE projects will probably need to find counterparties for their output among suppliers. The market for small-scale offtake power under PPAs is not well-developed, and community projects will struggle to find counterparties in the absence of a guaranteed route to market. While there are some suppliers competing for power below 5MW, prices are likely to be unattractive and few are offering long-term contracts. This background means communities will struggle to secure revenues and therefore underwrite new projects.

Looking further forward, however, new opportunities will arise for developers. A combination of falling technology costs, technology integration and new, smarter business processes will enable new sources of value to be created. Prices paid by customers will also continue to rise, as costs of policy and of networks increase, which will sharpen incentives to develop generation especially behind the meter. Market opportunities and incentives will increase, which is why we have addressed these issues more fully in the *Market Context* appendix.

In particular, we identify a number of ways in the report that smarter, more flexible markets are set to emerge, and these will help support the economics of new projects. The opportunities will increase for the following reasons:

- **Technology costs for proven technologies continue to fall** as deployment rates in other markets increase. Both wind and solar are expected to see further sustained reductions in levelised costs. Costs for emerging technologies such as different forms of battery storage are also expected to reduce considerably over the next few years and they become commercialised
- The **growing price differential between wholesale and retail prices** will steadily increase the value of self-supply of electricity behind the meter. This is because of the growing influence on retail prices of non-energy costs, including third-party charges such as the cost of policy support. The higher the self-consumption as supplier prices increase, the greater the avoided cost benefit
- The continued **smart meter roll-out and the introduction of half hourly settlement,** combined with the development of automated control technologies, will present new flexibility options behind the customer's meter and through aggregation. If these are deployed at scale by suppliers, aggregators and other intermediaries, this will enable tariff innovation and the opportunity for engaged customers to benefit from reduced consumption and to be rewarded for changing their usage patterns. The option of half hourly settlement is already possible (though complex for households, and few suppliers are making mainstream ToU offers), and market-wide half hourly settlement could be implemented by 2022-23
- Costs of **new conversion technologies** (power-to-gas, power-to-heat technologies and other circular economy solutions) will also reduce as they are commercialised at scale and conversion efficiencies increase. Pilot CALE schemes are demonstrating some of these new applications, and the market is confident that these will become viable in many locations that have existing low-carbon assets in the near term
- **Embedded benefits**, which reflect a supplier's avoided costs from supplying customers with local generation, will continue as an additional source of value to producers and will be shared under PPAs

[40] BEIS is consulting on maintaining an obligation to purchase at a discount to market prices for the smallest developments, including community schemes. https://www.gov.uk/government/consultations/the-future-for-small-scale-low-carbon-generation-a-call-for-evidence

(they are not available under FiT export arrangements). These could add up to around £10/MWh in Scotland to generator revenues, dependent on technology and location

- Rules have yet to be developed that would allow intermittent generation technologies to participate in the **Capacity Market, though following a successful legal challenge this is presently suspension**. We would expect opportunities to arise for smaller assets, especially through aggregation, once state aid approval has been reinstated and rule changes have been brought forward possibly from 2020
- Scope already exists for larger generation schemes to participate in **existing balancing service offerings** tendered by National Grid, and schemes can presently aggregate to a minimum of 1MW to access the fast frequency response service. On the demand side, sites with turn-up capability can also participate with a minimum size of 1MW (which can be aggregated from sites of at least 0.1MW). We would expect the trend towards lower thresholds and more aggregation to continue, again creating revenue opportunities for generators and controllable load, in collaboration with equipment providers, suppliers and intermediaries. Some battery providers are also offering aggregation opportunities in combination with other demand-side response and a share of the associated revenues
- Use of **local resources to prevent generation curtailment or network reinforcement**, especially in remote areas, as local flexibility markets are developed. This practice has already been demonstrated in several of the case-studies and is likely to be commercialised further as DNO) seek flexible solutions to address local operational constraints as the evolve into DSOs. Some rudimentary flexibility schemes are already under development by DNOs, but we would expect them to focus increasingly on commercial arrangements that better incentivise local generation and demand to help avoid network reinforcement costs. The next distribution price control review settlement will come into force from April 2023, and is likely to be a watershed in crystallising these new opportunities
- On the demand side, we would expect more resources from the **revised ECO** to be directed at “affordable warmth” measures under phase 3 of the scheme, which commenced on 1 October 2018. Scotland has devolved powers in this area as well as a separate cap that requires all obligated suppliers to meet their obligation pro rata in Scotland,[41] and
- **Electric vehicles, heat pumps and access to other forms of low-carbon local heat** have the potential to significantly alter the economics of local generation schemes and also significantly increase demand on the local distribution system, in turn enhancing flexibility values. The ability for CALE projects to aggregate DSR increases substantially if they have the ability to control the charging of EVs and turn up/down heat pumps. EV roll-out is also likely to have a knock-on impact on the deployment of rooftop solar, especially if governments increase support to switch to an electric vehicle.[42] Again the 2023 distribution price control reset is likely to be important here.

While the pace and degree of change in many of these areas remains uncertain and details in many cases need to be worked up, the direction of change towards a smart, flexible energy system is clear and unstoppable. This will provide strong incentives to develop innovative local projects that help crystallise flexibility, facilitate smarter outcomes, and defer reinforcement expenditure, with the benefits being shared between generators, suppliers, networks and the consumer. Customer appetite should also drive change for those who engage with the market or can be accessed by outreach programmes.

In combination these trends should reverse the down-turn in prospects from recent interventions and steadily enhance the economic and policy value of CALE projects. The important requirement at this stage, therefore, is to focus on practical measures that will allow progress to continue where possible while these changes flow through the energy system, which we have done in our work-plans.

Relatively few CALE schemes to date have focussed on demand-side initiatives and we have highlighted issues around customer engagement where they have. Nevertheless, there are relatively low levels of switching in Scotland despite high prices and above average levels of fuel poverty.

[41] Around 13% of measures to date deployed in Scotland

[42] The Scottish government announced increased funding of £15mn on 3 September to accelerate EV charging deployment.

Annex A: Case studies

Tower Power

- Tower Power was set out to aggregate customer demand through smart meters in high density domestic groups to reduce the overall cost of energy
- It was launched in July 2015, in Dumbiedykes in the centre of Edinburgh. This area has 656 households in two high-rises and 28 mid-rises
- The project aims to reduce energy costs by 15-20%, alleviate fuel poverty, provide community connections, educate residents to reduce energy usage through both advisory support and technology, and utilise solar PV in the area
- As well as CES and the Energy Challenge Fund, partners in the project include Our Power, Energy Local, TMA and the City of Edinburgh and City of Glasgow Councils
- It provides a relationship between energy suppliers, low-income consumers using mainly pre-payment meters and the community service company, based on aggregation and negotiating better supply arrangements
- Work to date has focussed on building the business case and building engagement and helping tenants secure better deals. A pilot proper seems not to have yet started
- The Tower Power project costs were primarily driven by public engagement with 1,344 door knocking attempts and twice weekly drop in events
- As the project was started before the roll-out of smart meters to the area, expensive pre-SMETS advanced meters were used to progress the project; the purchase and installation of these was estimated to cost £370,070
- The project received funding from the Local Energy Challenge Fund with a grant of £821,200 to cover trial costs. The project also applied for over £1mn and raised over £0.25mn in match-funding from sponsors. Solar arrays were to be financed by FiT revenues, in addition to the revenues derived from selling energy to the local residents
- Tower Power presently includes resident-based energy advice and support to switch tariff.

Comment: The basic idea here is sound, and community engagement should deliver benefits, though it is unclear to what extent this is leading to switching. The targeted model, of community switching, has merit too, but it is unlikely that a supplier would provide a sleeving deal or bespoke tariff without some long-term demand commitment. Some of the learnings from this project have informed our thinking on work-plan 3.

Mull ACCESS

- Mull ACCESS (Assisting Communities to Connect to Electric Sustainable Sources) received a 1.8mn grant from the Local Energy Challenge Fund. The total remaining matched cost was over £560,000 for the installation of controllable heating, alongside upgrades to the local distribution network
- Participants include: Mull and Iona Community Trust, SHEPD, CES, SSE Energy Services, VCharge and Element Energy.
- The initial project centred on community-owned 400kW hydro project at Garmony [FiT rate is 13.68p/kWh]. Key driver of allowing more generation onto an already constrained system through linkage with smart storage heating, thus avoiding reinforcement costs. It is expected to last 2015-18
- The target was 100 properties and two businesses
- In December 2016 there were 73 confirmed installs.[43] Of 53 private properties, 44 had new heating systems and 9 had VCharge systems by retrofit. Participants received payments of £100 at the start and £100 at the end of the trial alongside a fixed heating cost throughout the project. The initial trial occurred March 2017
- The project set out to demonstrate that change in energy efficiency standards and building regulations could allow renewable electric heating of homes, as virtual district heating with heat balancing
- VCharge's software has been proven in the pilot, and the control system could offer grid services such as demand turn-up or offer to turn-down under demand-side response. An interesting feature includes scheduling of demand turn up based on need. It is not clear what payment arrangements apply to the extra power consumed
- The aspiration is to replicate the ACCESS model nationally.

Comment: The most interesting feature here is the balancing of heat against water availability and interaction with the weather, and how these interactions are modelled. There is also "stacking" of demand based on consumer priority. The software solution now enables full access to the grid, by internalising local use when there is a surplus. Could be applied to any grid constrained areas or tenement blocks with on-site generation. Could be applied in conjunction with work-plan3.

[43] Hurding & Wight, 2016; ACCESS project progress report, prepared for Local Energy Scotland. This was the most up to date information we received about the project.

Surf 'n' Turf

- Surf 'n' Turf is a non-commercial trial based at the European Marine Energy Centre, which has a 900kW wind turbine owned by the Eday energy community on an actively managed network FiT rate is 12.08p/kWh. It was commissioned in 2012
- There is a 500kW electrolyser connected to the site, which can consume power especially during the frequent periods of local grid constraint. This is a test facility, and its primary purpose is to provide learning for the hydrogen supply chain. The electrolyser was officially opened in September 2017
- There are also eight marine electricity generators ranging in capacity up to 2MW, and it is expected conversion efficiency will increase
- Hydrogen produced by Surf'n'Turf will be transported from Eday to Kirkwall on the main island, and a 90kW fuel cell at Kirkwall Pier on the Orkney mainland will convert hydrogen back into energy. The first delivery was made in October 2017
- Revenues for the project are £66,000/year from the FiT accredited wind, £93,000/year from the RO accredited marine electricity generators, and £48,200/year from reduced energy consumption at the Kirkwell site
- A sum of £1.5mn was grant funded through the CARES programme and Local Energy Challenge Fund; £300,000 of this sum is in the form of a loan. The project is jointly fudned by the EU Horizon 2020 programme
- Participants are: EMEC, Eday Renewable Energy Community, Orkney Island Council and ITM Power
- Both the marine and wind generation units gain benefits from other sources if allowed to run more through subsidy revenue and prototype testing, thus the project energy supply is considered zero-cost. Further energy sources which could be utilised include CHP-enabled fuel cells and electrolysers to heat local buildings; improving the efficiency of the round trip of hydrogen to electricity conversion
- Electrolysers are flexible and may value-stack, offering grid services and turn-up to provide additional revenue but only on scale. Electrolysers alongside fuel cells could also work as batteries, with potential storage revenue streams available as hydrogen has higher storage capacities
- Viability of Surf'n'Turf and similar projects are dependent on the pace and extent of falling technology prices compared to rising conventional fuels and electricity and increasing the efficiency of conversion processes.

Comment: This model builds on other constraint management ideas, but uniquely embraces power-to-gas in the form of hydrogen, from production, through transport to reenergisation through a fuel cell. It potentially offers a very different storage type solution for transport as well as reconversion to electricity, and it is a key strategic project for understanding the hydrogen supply chain. There is no electricity supply dimension to this project.

Levenmouth Community Energy Project

- The Levenmouth Community Energy Project, or "Bright Green Hydrogen", aims to produce hydrogen as a viable transport fuel for 25 hydrogen powered vehicles (10 being electric-powered vans with H2 fuel cell range extenders) leased out to local businesses44
- It uses a 750kW wind turbine and 160kW solar array to provide renewable energy to do so. A fuel cell will generate electricity when outputs from wind and solar are low as part of the sister Hydrogen Office Project, which is both a demonstration and educational centre, and to maintain supply to the eight building micro-grid. Surplus energy is exported to the grid when the hydrogen storage is full
- The project has access to modular hydrogen-production and storage equipment. Some hydrogen is exported and used off-site (Glenrothes)
- Hydrogen will also be used to heat the Leven swimming pool, and will also be used to produce fertiliser and energy at the local business park through a private wire connection. This forms a smart grid-controlled network
- The project cost over £5.5mn
- Project participants are Bright Green Energy, Toshiba and Fife Council
- A £4.4mn grant was provided by Local Energy Scotland; £1.2mn from Toshiba was also received in for the smart grid system
- Revenue streams include 170MWh/year of solar energy which will be sold to local users via the project's micro-grid for 7p/kWh, deriving revenues of £11,900/year. It also expects to supply an additional 320MWh of energy to the micro-grid, at a price of 9p/kWh, deriving a further £28,800/year. Hydrogen fuel for heating and transport will be sold at a rate of £6/kg, with an expected yield of 3,700kg/year and therefore revenue of £22,200
- Hydrogen as a transport fuel, sold at £6/kg, is currently not economically competitive with costs of approximately 18p/kWh, compared to diesel or petrol at approximately 12p/kWh.[45]

Comment: This is a high-profile innovation project (Toshiba's largest outside Japan), which appears to be wholly off-grid. There are no constraint issues and no supplier involvement. It represents a different type of storage solution to the Surf 'n' Turf project.

[44] Extended recently to include nine refuse collection vehicles.
[45] https://www.all-energy.co.uk/RXUK/RXUK_All-Energy/2016/Presentations%202016%20Day%202/Local%20Energy%20Economies/Iain%20Todd.pdf?v=635996103550208987

Heat Smart Orkney

- Heat Smart Orkney (HSO) is a two- year project ending in 2018, which aims to minimise the curtailment (which is as high as 60%) of output across Orkney from wind turbines. This is achieved through ANM alongside flexible use demand
- The ANM process is a "last in, first off" stacking approach for the curtailment of generation operating on a zone structure mirroring the network location and customer base
- Demand is formed of controllable heating and boilers to alleviate high levels of fuel poverty, which is as much as two thirds of homes, with all properties off the gas grid. Smart quantum heaters are used as a secondary heating system. The heaters are linked by a smart VCharge system
- The three-island project base of HSO has a population of approximately 260 people situated in mainly isolated farming communities. 100 households were targeted, and 20 had the technology installed
- HSO pays households £50 for signing up, with additional rebates for power consumed in line with wind assets of 7p/kWh, and a £100 per household loyalty payment when the project ends
- Project partners are Rousay, Egilsay and Wyre Development Trust, Heat Smart Orkney, Community Energy Scotland, VCharge
- The 900kW Kilgary Hill wind turbine is accredited under the FiT regime and receives 11.6p/kWh generation and 3.57p/kWh export payments. However, the turbine operators have negotiated a PPA for export and may be receiving higher revenues including embedded benefits payments. Cornwall Insight's Embedded Benefits Ready Reckoner calculates that embedded benefits will average approximately £7,50/year over the next five years, assuming 90% passthrough and a 27% load factor
- The project hopes to increase the generator load from demand turn-up and turn-on by 490MWh/year, providing additional revenue of £70,000 for the site. In embedded benefits terms, this could equate to over £1,666/year of additional income
- The project costs equal £1.62mn. A £1.3mn grant was provided by the Local Energy Challenge Fund, with project partners Community Energy Scotland and V-Charge also making contributions.

Comment: The novel feature of this project is demand turn up and its use to address local fuel poverty in an islanded community, but its limited scale and take-up is clearly an issue. The smart application appears similar to that being applied by Mull ACCESS, and the project notes say it improves on the Mull approach but it is not clear how. The application is clearly of use in areas where generation is over-sized owing to growing network constraints or islanded or remote locations.

Dalavich

- The Dalavich project involves a 350kW run of river hydro generator situated on the River Avich in Argyll and Bute commissioned in January 2018, maintaining the generation FiT rate of 12.67p/kWh and export rate of 5.03p/kWh. This provides a total revenue of 17.7p/kWh, four times recent average wholesale prices
- Through work with another hydro generator, a private ANM solution using monitoring and control equipment allows flexible export by using the grid connection when the other scheme is not operating. Without the scheme the new connection would have been restricted to 50kW until 2021 when reinforcement work on the local network will be completed
- The partner generator released 220kW of firm capacity, giving Dalavich 270kW firm capacity, and ANM will allow the full 350kW export when available
- The cost of the project was £1.45mn. The original solution was projected to cost around £784,000, about half as much as the final total, however large sum was spent on feasibility studies and working with the DNO towards the ANM solution
- Grants for this project totalled approximately £133,500, with loans around £250,000. £1.1mn of Social Investment Scotland loans have been received; £200,000 raised by share offers. Further share offers will be undertaken to repay the CARES loan of £250,000
- An income of £202,000 is expected in the first year of generation, largely based on FiT revenues. Embedded benefits also average around £21,000/year for the next five years assuming 35% load factor and 90% embedded benefits passthrough
- Profits from the scheme are given to the Dalavich Improvement Group, set up to manage community land and associated assets for community benefit.

Comment: This is an example of collaboration to achieve increased physical access, with an existing connected party trading access with a new connecting party. ANM schemes have become mainstream among DNOs (accommodating more local generation without reinforcement). Development of demand-side options behind the constraint is likely to increase flexibility and resilience.

Findhorn Ecovillage

- The Findhorn Ecovillage project in Moray started in 2005, and it involves a local micro-grid (the main campus developed from a private wire on a caravan park), domestic solar and four wind turbine installations (all second hand) totalling 750kW targeted on self-supply but grid connected for export. District heating involves a ground source heat pump, an air source heat pump, and biomass alongside heat exchangers
- Recent applied funding was related to the Renewable Energy Roadmap for district heating, undertaken alongside the University of Strathclyde and Heriot-Watt University. The Renewable Energy Roadmap was funded through a CARES grant equalling £30,000. As well as state-backed funding, Renewable Heat Incentive (RHI) and Domestic Heating Loan Fund (DHLF) funding has been obtained proposed
- The costs of the project depend on the scale and type of technology used, with proposals for a biomass-fuelled installation cited as having a net cost of £88,606 after deduction of customer buy-in of ten connections to the network at £3,000 each. Pending a decision on the technology chosen, a more specific overview cannot be made
- The site is an isolated net electricity exporter. Just over half of the generation is exported, and the balance consumed within the micro-grid
- If the full amount of power produced was to be exported to gird, embedded benefits would average around £5,333/year over the next five years, assuming 90% passthrough and 27% load factors

Comment: This is a micro-grid project combining three energy sources. It combines many elements of a local supply community, though demand-side elements appear relatively immature.

Smart Fintry

- The Smart Fintry project, now in its third year of operation and having two rounds of customer sign up, utilises a 200kW AD facility to create a local supply tariff for Fintry residents, designed to alleviate fuel poverty. The scheme is also designed to address generation constraints, using smart meters from Good Energy. Two wind turbines supplement the AD facility, and there is a small amount of solar PV on the community sports centre
- Electrified heating systems will replacement the existing LPG and oil boilers in 144 homes, potentially reaching a total customer base of approximately 700 residents
- The basis for the project financing is through PPA agreements with Good Energy, with a duration of ten years primarily.
- The project costs were £2.1mn. The project was awarded £840,000 from the Local Energy Challenge Fund for heat pumps, with supplemental grants of £268,000, a bank loan of £500,000 and an in-kind contribution of approximately £400,000
- Project partners are: Good Energy, Veitch Cooper, Energy Assets, Heriot-Watt University, Fintry Development Trust, as well as Local Energy Scotland
- The Fintry tariff is 100% renewable, with a single unit rate of 11.03p/kWh[46] for flat rate customers, with comparable rates for Economy 7 and Economy 10 customers, alongside metering and energy efficiency measures.
- 84 households were signed up in April 2017 and a second round of sign ups has taken the total to over 100 households
- The community website has an energy dashboard showing amount of energy produced/ imported the previous day, plus weather, generation and demand forecasts (but no pricing information), including when the local balance is most likely to be in surplus or shortfall
- The project underwent some issues, including communications infrastructure, demand profile variability, and local engagement challenges
- Ofgem announced in early 2018 that the Smart Fintry project is now being considered for participation in the second round of its regulatory sandbox initiative[47]

Comment: Great portal but the project is diminished by low sign-up and a flat tariff, though discussions on a simplified ToU tariff are underway. Good savings can be achieved against SP/SSE comparator tariffs, as well as Good Energy alternative offerings in the region. It is unclear how the constraint element works, but there appears to be no incentive for demand turn up or down.

[46] Standing charge of 26.51p/day giving TCR rate of 14.15p/kWh
[47] The purpose of this initiative, introduced by Ofgem in early 2017, was to enable market participants to trial products and business models that were incompatible with their prevailing licence conditions and less in line with traditional business models.

The Outer Hebrides Local Energy Hub

- The Outer Hebrides Local Energy Hub (OHLEH) is based around a circular economy concept, using fish waste for an anaerobic digestion (AD) facility from a food processing plant and salmon hatchery. The primary rationale was to provide a local circular economy owing to constraints on grid access
- Biogas produced fuels a 150kW CHP unit in conjunction with a 300kW wind turbine facility. Resultant electricity then powers a 30kW hydrogen electrolyser. The oxygen produced from this facility is supplied to the fish hatchery, alongside hydrogen, which is used to power a fuel cell for the benefit of the nearby salmon hatchery, with some hydrogen also being used in refuse vehicles
- The project is based around adding missing assets alongside those already present
- The project received a £600,000 grant from Local Energy Scotland, with commercial borrowing making the balance
- The total project costs equal £1.15mn, 75% of which was spent on the fish treatment processes and the hydrogen and oxygen production equipment. Most of the generating equipment and the AD plant were already present onsite
- Revenues are based primarily on the cycling assets, with hydrogen and oxygen sales and gate fees contributing. Increased generation and reduced import also deliver revenues
- Specific assets included in this project make it difficult to replicate
- The project is looking for further growth by utilising hydrogen to produce ammonia-based fertilisers.

Comment: Faced with grid constraints, the scheme has enabled deployment of renewable assets. Circular waste to energy conversion reduces costs and keeps money within the local economy, promoting job creation as an added benefit.

The Small Wind Co-op / Grannell Community Energy

- The Small Wind Co-op and Grannell Community Energy runs a 180kW turbine at Troed y Bryn in North Wales, and two 100kW turbines in southern Scotland, all commissioned in 2017 for a total of 380kW generation capacity
- Troed y Bryn has projected generation of 305,000kWh/year, a 20% capacity factor
- The two Scottish turbines are projected to generate 320,000kWh/year each, an approximate 37% capacity factor
- This puts total generation just under 1GWh/year
- The project was financed by share offers and bond issues, raising £1.4mn in total. Shares will return 6.5% on average over 20 years, and bonds were issued for a 6-year term with 4.5% annual returns. The capital of shares will be repaid at the end of the project timeline
- All wind turbines were pre-accredited for FiT rates of 12.49p/kWh, and embedded benefits are expected to average just over £8,000/year over the next five years
- Total costs for the project were £1.4mn. Around £900,000 was paid for the three turbines, with further £2,800/year insurance costs, to ensure 95% turbine uptime. The project also made use of a delivery partner in the form of community energy service company Sharenergy. The project will pay Sharenergy £10,000/year for its services, rising with RPI and fixed for five years
- Total revenue is estimated by the Small Wind Co-operative at £170,000/year

Comment: The interesting feature here is the funding mechanism, a mix of FiTs and crowdfunding.

Gateshead District Energy Scheme

- Gateshead District Energy Scheme involves a 4MW gas-fired CHP facility with localised heat distribution and private wire networks, providing low cost heat and power
- The private wire network has been extended to include a 3MW battery storage facility, and there is a 250,000-litre hot water thermal storage facility at the main energy centre
- The project is operated and owned by the council with a second 1.5km extension receiving £0.9mn of ERDF funding
- The 3MW battery array has a frequency response contract with National Grid
- The site was also awarded a 15-year Capacity Market contract at a clearing price of £18/kW in the 2015 t-4 auction. This was brokered through aggregator Flexitricity, yielding £60,000 per year
- The initial costs of the project were £1.8mn
- Gateshead District Energy Scheme is intended to accommodate future demand growth with rolling extensions, with a second 1.5-kilometre extension will be in receipt of £0.9mn of ERDF funding as the council is testing a new type of plastic piping for the heat network
- The project is intended to be heat-led for most of the time, with the ability to run as power-led during winter peak periods.

Comment: We selected this project because of its district heating and private wires elements. It is ambitious both in terms of its scale, plus the ambition to add battery storage and thermal storage at scale. It is also an early example of accessing new revenue streams ("revenue stacking"), in this case through the CM but also through frequency response. The project also has a strong element of urban redevelopment associated with it.

Project Windy: Energise Barnsley

- Project Windy: Energise Barnsley is a two-year project installing 40 Moixa batteries within a virtual power plant using Moixa Gridshare technology in social housing owned by operator Berneslai Homes. 30 of these properties have also been fitted with rooftop solar arrays
- The homes are 70% occupied by retired consumers, around half of whom are living alone
- Northern Powergrid monitors the voltage and generation at the local substation. Residents are free to select their own energy supplier
- Total costs of the project equal £250,000, funded by Northern Powergrid under a Network Innovation Competition award
- Trial participants are expected to see energy bills decrease 30% due to reduced imports from installation of solar panels and 20% more because of batteries enabling reduced exports
- Moixa currently offers £50/year payment for using the batteries as part of the its Gridshare VPP platform. The value and flexibility of the VPP is expected to increase
- The batteries used in this trial project cost approximately £6,250/unit, at the time of installation in January-March 2017. These costs have already fallen considerably to £2,500 plus VAT and installation. Domestic battery prices will continue to decrease with time, improving the economics of this sort of project
- Ofgem announced in early 2018 that the Energise Barnsley project is now being considered for participation in the second round of its regulatory sandbox initiative.

Comment: This is a novel solar/storage combination scheme, which is aiming to reduce overall fuel bills by 50%. The VPP Gridshare approach adds an additional feature opening-up the sale of frequency response services to National Grid through aggregation.

Wadebridge/ SouthWest Water Private Wire

- Wadebridge Renewable Energy Network (WREN) installed a private wire linked 100kW solar farm next to South West Water's Nanstallon Sewerage Treatment Works in September 2015
- The solar farm and private wire to the neighbouring site cost £101,000 to install
- Energy sales to South West Water will recoup costs alongside FiT subsidies, with solar pre-accredited to a rate of 10.40p/kWh. South West Water have also signed a 20-year PPA for the site
- A Low Carbon Society loan was also used to fund the project but the rate has not been disclosed; it is assumed to be at or below commercial rates with a 20-year term. WREN plans to pay back the loan in the short term with community shares. This includes 10%/year repayment of capital and interest, for a 6% overall return over 16 years. 3% of gross income goes to a community fund for Nanstallon
- The agreement is mutually beneficial; WREN derive a greater than wholesale price for energy, and South West Water pay less for consumption. Similar FiT subsidised solar arrays have 8-10%/per annum rates of return
- This arrangement is sustainable without subsidies if the solar array was sized to deliver at most the amount of power the consumption partner would need. However, the demand-side partner needs to be stable and provide "security of demand".

Comment: This simple bilateral model shows the benefits of co-locating new renewables assets next to business load, then bypassing the public system. The two counter-parties then share the value realised through avoiding market-based retail rates. Dependent on the size of the wires and prevailing local retail rates, we estimate such arrangements are already close to being viable without subsidy, but they risk stranding the local public networks and shifting costs onto other consumers.

Wadebridge Sunshine Tariff

- Wadebridge Renewable Energy Network (WREN) was also responsible for a trial sunshine tariff to understand how customers respond to price signals. Working with Regen, Western Power Distribution (WPD) and Tempus Energy, the project financially incentivised consumption in a 10am to 4pm summer period, following peak solar generation. Four test groups of consumer were set to test behavioural responses
- A standard winter flat-rate of 13.4p/kWh was charged; during summer, however, there was a 5p/kWh tariff during solar peak and 18p/kWh at other times
- The full cost of £273,856 was financed by WPD, through a Network Innovation Allowance (NIA) award. Most of these costs were incurred by Regen and WREN, which spent nearly £120,000 each, however, the project came considerably under the budget of £305,000
- 89 of 240 households were persuaded to sign up; only 46 got onto the Sunshine Tariff, plus a control group of 15. This response was far lower than expected; extra time might have allowed more customers to sign up, but also brought to question whether the tariff was lucrative enough
- The average household shifted just under 150kWh into the Sunshine period, or around 10% of their load. Groups with automation (2-4) shifted 13% of consumption, compared to 5% for those without
- Approximately 650 non-automated or 360 automated households are required to offset 250kW solar farm generation
- WPD and Regen concluded that an offset connection tariff would not be viable. The number of customers required to offset a new generator is too challenging for feasibility on a broader scale.

Comment: The objective appears to have been to offset the impact of new solar generation on demand within the same WPD area by increasing demand in the sunshine hours. While the pilot scheme was acknowledged to have failed by its backers, it provides useful learnings for other ToU arrangements once half-hourly settlement becomes mainstream (although the incentives offered here look weak). The scheme shows the importance of wider engagement and also the added value of automation.

Energy Local Club: Bethesda

- The Bethesda scheme is a community energy project for residents, using a 100kW hydro generator providing about 500MWh/year, to approximately 100 households locally, managed (and sleeved) by Cooperative Energy. Smart meters measure half-hourly energy use, and an anergy dashboard forecasts the likely generation so that users can adjust their demand to periods when hydro production is high
- Generation output is equally divided between households, according to their energy usage in the same half hourly period. Customers who more closely align consumption with peak generation of the hydro facility will therefore gain the most benefit
- Balancing energy is provided under a relatively complex ToU tariff, under four bands: 6am-11am, 12p/kWh; 11am-4pm, 10p/kWh; 4pm-8pm, 14p/kWh; 8pm-6am, 7.25p/kWh.[48] The project initial report noted 19-29% savings on electricity bills, with 52% of customers' energy usage matched to hydro generation
- The generator receives 7p/kWh, while consumers pay 7p/kWh for the units allocated to them from the scheme. The aim was to achieve a 32% improvement in generator revenues of £6,400
- According to a feasibility report, assuming 150 domestic customers, there should be savings of around 24% or £128 per household
- Principal costs are smart meters, provided by Cooperative Energy, and a half-hourly settlement/ billing system. The involvement of the National Trust and Cooperative Energy helped engagement (gaining 100 households) alongside the proximity of the project to local participants
- ToU tariff offered by Cooperative Energy for the top-up energy appears attractive
- This project is likely to be replicated in two other locations in Wales, indicating appeal to customers.

Comment: This is a sleeved model connecting a hydro station and domestic dwellings on the public system, with Coop providing the top-up power but its viability presently relies on settlement derogations. It provides a reduced rate for the hydro output and a "normal" rate based on a relatively complex ToU structure for remaining consumption. The dashboard, which has a forecasting algorithm associated with it, allows households to know when the hydro output will be greatest and move consumption accordingly to maximise benefits.

[48] This compares with an average TCR electricity only rate of 18.13p/kWh in the MANWEB area.

Ipswich: Municipal Flexibility Market

- Through a desktop study at this stage. Pixie Energy will test available models for the commercial linkage of existing and planned local low-carbon generation and demand users in Ipswich and its environs to maximise the benefits of low-carbon energy to the local community, especially social housing tenants. This is a three-year study which will run from 2018 to 2020 inclusive. Stage 1 is being funded by a BEIS grant under its Flexibility Feasibility budget
- It will seek to create better incentives for the management of on-site solar use in conjunction with battery storage and grid-spilled solar, and to develop a route to achieve better value for this energy while retaining more of the value in the local community
- In addition, it will investigate the commercial basis for using batteries and other demand-side interventions behind the customer's meter in the locality, TOU tariffs and HHS
- Working with a local supplier, it will explore the different ways that flexibility can be valued and shared
- It will assess the comparative value of storage and solar behind the meter under a traditional single rate tariff, a multi-rate tariff comprising three or five separate unit rates for consumption during different times of the day/ seasons, and using direct half-hourly costs incurred by the supplier for each period
- The objective is to enable the supplier eventually to establish a local innovation tariff that can be offered to social housing tenants, local businesses, schools or other participants at managed, and potentially overall, reduced rates
- This will be complemented by analysis of using different demand-side technologies, including smart meters, home energy management systems (HEMS) and batteries to time-shift energy generation and consumption under HHS conditions
- The study also includes analysis of the variability inherent within different consumers' supply, and how the payback period of different combinations of technologies is affected by different usage patters
- As a desktop study, there was no proposed investment in physical assets
- The study cost approximately £80,000, with approximately 60% of this funded through a grant from the BEIS Flexibility Markets Feasibility Study
- The study hopes to demonstrate multiple benefits, including cost reductions to the energy system, improved revenues for generators and lower prices for consumers
- Although the local market area is based around a specific part of East Anglia, the intention is to create a broad structure and evaluation approach that could be applied across the region, and potentially beyond to the rest of the GB electricity market.

Comment: The project is designed to model and match local generation with local demand, focusing on the social housing sector and existing generation assets. Initially it will look to assess the value of different combinations of solar and storage assets, backed up by analysis of opportunities and risks of moving to half hourly settlement. The study will identify savings based on simulating HHS, first based on existing demand for various consumption archetypes but then with volumetric interventions to show the impact of a range of smart technologies, including battery storage.

Norwich Virtual Energy Community

- Pixie Energy is also working with local stakeholders to test a multi-supplier model
- A local participant New Anglia Energy will seed fund solar panels and batteries at households and community buildings around the city, and is also developing a crowdfunding tool to allow people to invest in community energy assets, and will be one exempt supplier operating behind the meter
- Initial thinking is that the solar tariff will be priced at a 20% discount to competitive local tariffs, with surpluses sold top other scheme participants
- Under the Norwich Virtual Energy Community, the project's energy supply partner will work with Pixie Energy, who will manage the project, to create an innovative "balancing" tariff for the local community
- Third party suppliers will also be included to provide dedicated supply to batteries and EV charge points behind the meter
- This will be enabled by seeking sandbox treatment under new arrangements recently implemented under the BSC
- A customer notification agent will also be established to manage billing and reconciliation and to ensure compliance with BSC rules
- Although dependent on the number and scale of the projects, as well as the extent of participation, this approach is both scalable and replicable
- Project costs will depend upon the developments proposed through the crowdfunding platform, but the funding will be provided by the participants.

Comment: The primary aim will be to test the multi-supplier model and to allow volume splitting behind the meter.

Feldheim, Germany

- Feldheim is an energy self-sufficient village in Germany operating a 43-turbine, 74.1MW capacity wind farm, generating 129GWh/year; a 500kW biogas CHP plant from over 350 hectares of energy crops; and a 400kW woodchip furnace
- Initial costs were paid by homeowners in Feldheim. The village received €850,000 from European and Geman government subsidies for the new pipelines. A new electrical grid was funded by Energiequelle, European subsidies, capital loans and contributions from Feldheim homeowners. Government subsidies also paid for the biogas facility. A battery facility was funded via a grant shared by Brandenburg and the European Regional Development Fund
- The local electricity distribution grid and heat network cost €2.2mn with new power and heat lines connections at €3,000 per household. The biogas facility cost nearly €1.75mn. A 10MW/ 10.7MWh energy storage facility, commissioned in 2015, cost €12.8mn
- E.ON, the local DNO, refused to sell or lease its electrical grid to the village. Feldheim built its own parallel electrical grid and heating network. However only homeowners can buy into cooperative networks, so businesses in the area and renters continue to take supply from the old grid. This demonstrates the case that network ownership issues should be assessed for any GB projects of a similar nature
- Feldheim energy costs of €0.166/kWh were just under half the €0.27-0.30 average German electricity prices in 2013. Costs subsequently rose to around two-thirds of national averages, but still remained below national averages
- The village wind farm sells 99% of generation to the energy market. This, paired with the leasing of areas for new turbine builds, has created revenue streams into the project.

Comment: The interesting feature here is the cooperatively owned local network that has allowed a self-sufficient energy economy. The project was not without its issues, and highlights problems around ownership of shared networks.

Vandebron, the Netherlands

- Vandebron is a renewable energy company that allows customers to choose which generators or technology type to purchase energy from, directly linked to local producers through online peer-to-peer marketing. Vandebron reported that contracting directly between parties results in lower prices for consumers and higher profits for generators as utility margins are cut
- The company has also started an EV charging network, with access to public charging points for a flat monthly fee and a ToU tariff. A home charger system launched in February 2018, with smart charging pilots aiming to pay an average of €250/year to users when running
- The cost of the project equals €1.9mn to build the platform
- Vandebron received a €2mn investment from the climate fund Amsterdam's Klimaat en Energiefonds (Akef) as well as start-up funding from the Tridos Bank and the Dutch Greentech Fund
- Vandebron charges generators and consumers a small fee (€6.25/month for domestic customers) for services. The EV charging service is charged at €3.50/month, or €1.50/month for domestic users
- As generators are competing both with regular energy suppliers and each other to sell their energy, price pressure is high. Prices for electricity at average consumption (2,850kWh/year) run between €43.67 and €51.80 per month at time of review of information on the Vandebron website
- Vandebron now connects over 120 generators, and 100,000 households, about 1.4% of the Dutch market, achieved within three years due to its commercial model and public interest.

Comment: There are some significant institutional differences that have facilitated this peer to peer arrangement. In the GB market, it is not possible to contract directly peer-to-peer for energy due to market rules. In the Netherlands network charges and costs are billed separately by the DNO, unlike in GB. Furthermore, policy costs such as renewable subsidies are funded through taxation rather than energy bills. This simplifies payment processing to generators.

Samsø, Denmark

- The island of Samsø uses straw-fuelled district heating systems, 11 onshore 1MW and 10 offshore 2.3MW wind turbines to meet 100% renewable electricity and 75% of heat demand by renewable sources
- Assets include municipally and privately-owned wind turbines alongside commercially and co-operatively run district heating systems in Ballen/ Brundby. In Onsbjerg, the heating system is organised as a limited company owned by a local contractor
- The project is financed by municipal authorities. The Department of Energy in Denmark provides funding to alleviate initial costs, for example 7.5mn DKK (€1mn) towards preliminary studies
- Wind turbines were also financed locally, with farmers in particular keen to invest in their own turbines. All local citizens were given a chance to invest, with a central organisation “Samsø Wind Energy” set up to manage the turbines and investments
- A total of 316mn DKK (over €42mn) was spent on wind turbines, with onshore turbines costing approximately 6mn DKK (€0.8mn) and the offshore costing 10.4mn DKK (€1.4mn) each. 45mn DKK (€6mn) was spent on district heating systems
- The environmental benefits as well as community support make the project attractive, with Samsø’s inhabitants having access to energy consultants offering free advice on insulation improvements and renewable energy alternatives
- Samsø Energy and Environment Office works with tradesmen, arranging training courses about available technology
- Generation prices are fixed by the Danish central government for 10 years, at €0.08/kWh for 12MWh, then €0.06/kWh. Investments are expected to pay off in approximately 11 years
- Annual fixed rates for consumers for the district heating installations range 2,500 DKK (336 EUR) to 2,695 DKK (362 EUR). The price per MWh ranges from 665 DKK (89 EUR) to 772 DKK (104 EUR). These are comparative to traditional fuel or electric heating.

Comment: Samsø is multi-participant and has achieved high levels of community engagement. Its governance through municipal authorities is also of interest.

Ecopower, Belgium

- Ecopower is a Belgian co-operative founded in 1991 financing renewable projects that produces energy and supply to approximately 50,000 customers, or 1.5% of the Belgian market. Customers can buy in to the scheme with a minimum of €250, and a maximum of €5,000
- The cooperative operates in Flanders with 35MW wind capacity, 5.4MW of solar, 100kW of hydro and 250MW of vegetable oil biomass plant. It can supply half of its customers' 100GWh/year demand and additionally produces around 40,000t/year of biomass fuels
- Renewable energy projects are financed by co-operative members, who together own all renewable energy installations. Belgian law requires that wind farms under development are part-offered to citizen-ownership. In Walloon, 25% must be offered to citizens and 25% to the local municipality; in Eastern Flanders, this is 10% to each
- By the end of 2016, €61mn had been invested with no long-term debt. The growth and investments of Ecopower demonstrate a successful business model, and annual reports show substantial assets for further expansion totalling nearly €50mn
- Policy costs are paid through taxation, with a top-up from the "Contribution Energy Fund", billed at a flat rate; €5.04/year for domestic customers, €94.44 for vacant properties or companies, or €1,800 for medium-voltage and €10,500 for high-voltage connected customers annually
- Ecopower also run an "Ecotraject" scheme, costing €599, or €499 for co-operatives, providing professional guidance on energy efficiency
- Ecopower's members have reduced electricity consumption by roughly 50% over the last 10 years
- Ecopower forms direct partnerships with local municipalities, reinvesting profits into the local community.

Comment: The partnership approach with Ecopower working with municipalities is of interest. It provides a "one-stop" shop of support and advice, including usage and demand-side advice.

California Public Utilities Commission, USA

- California Public Utilities Commission (CPUC) is a regulatory agency that regulates privately-owned public utilities in California, including the energy sector
- CPUC created the Solar on Multifamily Affordable Housing (SOMAH) programme in December 2017, to incentivise solar projects for multifamily social housing as well and contribute towards a solar deployment ambition of 300MW by 2030
- Funding for the project goes through the greenhouse gas allowance auction proceeds of electric utility companies, including Pacific Gas and Electric, San Diego Gas & Electric, Sothern California Edison, Liberty Utilities and PacifiCorp. Of these auctions, the lesser of $100mn or two-thirds of these revenues will be available to the project
- Solar installations gain an incentive rate of $3.20/watt, or $3,200/kW of AC generation supplied to tenants
- The total project costs are limited to $1bn ($100mn a year for 10 years)
- Apartment building owners and tenants will be awarded credits through virtual net metering (VNEM), providing a mechanism for allocating bill credits from system generation among the property occupants
- Tenants will receive at least 51% of the VNEM, but 49% will flow to common areas of the buildings for integrated facilities and utilities
- Only existing buildings containing at least five homes and classified as affordable housing for at least the next 10 years are eligible. A minimum of 80% of the unit households require incomes below 60% of the area median income
- However, the system transfers market risk from the asset operator onto CPUC, as there is less incentive to keep the asset running once it is installed and subsidy paid out.

Comment: Subsidising the up-front installation costs of the solar panels, rather than ongoing kWh generation, allows control of the scheme costs, keeping CPUC within budget.

Annex B: Glossary

Term	Definition
Active Network Management (ANM)	Connects separate components of a smart grid such as smaller energy generators by implementing software to monitor and control the operation of these devices.
Assistance for areas with high electricity distribution costs (AAHEDC)	A scheme that aims to reduce the costs to consumers of the distribution of electricity in certain areas. GB customers pay a subsidy to assist customers in north Scotland where the high cost of distributing electricity arises due to the spread of the small population across the area. AAHEDC is charged at GSP so output from embedded generation at the meter is uplifted according to the distribution loss factors. This enables distribution charges to be reduced.
Balancing and Settlement Code (BSC)	Contains the governance arrangements for electricity balancing and settlement in GB. The energy balancing aspect allows parties to make submissions to NG to either buy or sell electricity into/out of the market at close to real time in order to keep the system from moving too far out of phase. The settlement aspect relates to monitoring and metering the actual positions of generators and suppliers against their contracted positions and settling imbalances when actual delivery or offtake does not match contractual obligations.
Balancing System Use of System (BSUoS)	Charges that are paid by electricity suppliers and generators based on the energy taken from or supplied to the National Grid system in each half-hour settlement period. It varies for each settlement period
Cannibalisation (prices)	A phenomenon observed particularly in German, but seen during Summer 2018 in GB for the first time, where large amount of renewables cause low wholesale electricity prices – including negative prices – when conditions for operation are particularly favourable. A typically low wholesale price at times of peak generation may prevent new, unsubsidised, generation from being investable.
Capacity Market	Designed to ensure sufficient reliable capacity is available by providing payments to encourage investment in new capacity or for existing capacity to remain open.
Climate Change Levy (CCL)	An environmental tax charged on the energy used by businesses. It's designed to encourage businesses to be more energy efficient in how they operate, helping to reduce their overall greenhouse emissions.
Community and Local Energy (CALE)	Local projects owned by community groups, local authorities, housing associations, other Scottish public bodies, charities (including faith organisations), further and higher education establishments, local businesses, and Scottish farms and estates.
Commodity prices	The wholesale price of gas or electricity on the markets. This forms about a third of the retail price paid by consumers, along with the Third Party Charges and supplier's operational and profit margin. This is also the wholesale price of other fuels such as coal, oil, and biomass.
Consumer Access Devices (CADs)	Devices connected to smart meters, which can be owned by consumers to identify their energy usage, energy costs, and other information.
Contract Forward	A non-standardized contract between two parties to buy or to sell an asset at a specified future time at a price agreed upon today, making it a type of derivative instrument. It is a trade that is agreed to at one point in time but will take place at some later time.

Term	Definition
Contracts for Difference	A generator party to a CFD is paid the difference between the 'strike price' – a price for electricity reflecting the cost of investing in a particular low carbon technology – and the 'reference price'– a measure of the average market price for electricity in the GB market.
Demand Side Response (DSR)	Allows businesses and consumers to turn up, turn down, or shift demand etc. in response to signals from the wider system.
Distribution Losses	The difference between electricity entering the distribution network and that leaving it.
Distribution Network Operator (DNO)	The operator of an electricity distribution network.
Distribution Use of System (DUoS)	Charges made by DNOs to recover their maintenance and asset reinforcement costs from energy suppliers and smaller, independent distribution network operators that use part of their network. Charges are then passed on by energy suppliers to their customers - the end-users - and are based on actual use
District Heating Loan Fund (DHLF)	The District Heating Loan Fund provides loans for both low carbon and renewable energy technologies to help organisations implement district heating projects that benefit local communities.
Energy Company Obligation (ECO)	A government energy efficiency scheme in Great Britain to help reduce carbon emissions and tackle fuel poverty.
Energy Imbalance Prices	The imbalance process settles discrepancies, for each half hour trading period, between the amount of electricity that a company has contracted to generate or consume and the amount of electricity which the company generated or consumed. This difference costs a certain price dependent on the difference
Energy Service Company (ESCo)	A commercial or non-profit business providing a broad range of energy solutions including designs and implementation of energy saving projects, retrofitting, energy conservation, energy infrastructure outsourcing, power generation and energy supply, and risk management.
European Regional Development Fund (ERDF)	A fund allocated by the EU. Its purpose is to transfer money from richer regions and invest it in the infrastructure and services of underdeveloped regions.
Feed in Tariffs (FiTs)	A payment made to generations of small-scale renewable electricity generation (total installed capacity ≤ 5MW for hydro, wind, PV and AD; ≤ 2kW for CHP) for electricity produced.
Generator Distribution Use of System (GDUoS)	Charges that are levied by host distribution companies to electricity supply companies to cover the cost of distributing electricity to their customers. Half hourly DUoS systems calculate site specific bills for large organisations where their energy consumption is significant on a half-hourly basis.
Good Quality Combined Heat and Power (GQCHP)	A government quality mark for a CHP facility that has a minimum efficiency which will allow access to government subsidy streams.
Grid Supply Point (GSP)	The point at which energy is taken from the National Grid transmission system into a local distribution system.
Half-hourly settlement (HHS)	A method by which electricity usage is read every half hour. Meters read electricity usage every half hour, this information is sent to suppliers to settle a more reliable price of energy used by a business or homeowner.
Local Enterprise Partnerships (LEPs)	Partnerships between local authorities and businesses. They decide what the priorities should be for investment in roads, buildings and facilities in the area.
Low Carbon Infrastructure Transition Programme (LCITP)	A working partnership between the Scottish Government, Scottish Enterprise, Highlands & Islands Enterprise, Scottish Futures Trust and sector specialists. Based on the transition to low carbon infrastructure and technology.

Term	Definition
Low Carbon Innovation Fund (LCIF)	A Scottish government initiative co-funded by the ERDF as part of the Low Carbon Infrastructure Transition Program (LCITP), which will help large scale projects supporting the ambitions of Scotland's Energy Strategy.
Microgrid	Microgrid - A system that integrates (aggregates and optimises) in the cloud several types of energy assets, for the purpose of enhancing capacity and trading power but is limited in geographic scope often to resolve a localised requirement. In some circumstances microgrids are designed to be able to disconnect or are permanently disconnected (islanded) from the national network.
National Transmission System (NTS)	The network of gas pipelines that supply gas to about forty power stations and large industrial users from natural gas terminals situated on the coast and to gas distribution companies that supply commercial and domestic users.
Netting Off	Billing for energy consumption subtracting the result of subtracting generation from consumption. For example, the use of local energy resources to reduce the requirement for import.
Network Innovation Competition (NIC)	An annual Ofgem competition to fund flagship innovative projects which could deliver carbon or environmental benefits for gas customers, and that would not otherwise be funded without this additional funding.
Network Replicating Private Wires (NRPW)	NRPWs are a subset of private wires that replicate existing assets owned and maintained by the local DNOs. The arrangement involves a single generator supplying electricity under contract to at least one independent customer using wires that are owned and maintained by one or both parties and are not part of the regional DNO's network.
Peer-to-peer Trading	The sale of energy directly between generators and consumers, over the public networks but without going through central settlement. Currently impossible in the GB market structure, but the area for several trials.
Power Purchase Arrangement (PPA)	A contract between two parties, one who generates electricity for the purpose (the seller) and one who is looking to purchase electricity (the buyer).
Private Wire	In a standard private wire arrangement, a generator supplies electricity directly to the consumer via a privately-owned wire. Participants are then exempt from paying certain environmental, supply and network charges, such as Climate Change levy and DUoS, on the electricity supplied under the arrangement. The concept of private wires covers a wide range of practical arrangements, including self-supply and same-site installations, and is the only existing pricing model that provides a price incentive for local matching.
Renewable Heat Incentive (RHI)	A UK Government scheme set up to encourage uptake of renewable heat technologies amongst householders, communities and businesses through financial incentives.
Renewable Obligation Certificate (ROC)	Certificate issued by the regulator to generators who demonstrate that they have issued one MWh of renewable electricity.
Renewables Obligation (RO)	The government's main policy measure to encourage the development of electricity generating capacity using renewable generation technologies.
Residual Cashflow Reallocation Cashflow (RCRC)	These 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 Balancing and Settlement Code (BSC) parties and is charged on a unit basis which varies by half hour. There is no locational element to the charges. This charge is less than BSUoS but can also be positive or negative per half hour.

Term	Definition
Revenue Stacking	Where revenues are earned for multiple uses of the same energy asset. This may occur sequentially or at the same time.
Revenue Swapping	The action of deriving one form of revenue stream for another which offers better income, such as deciding to change from regulated services to non-regulated. An example could be changing from tendering for TRIAD avoidance revenues to flexibility service payments.
Scotland's Energy Efficiency Programme (SEEP)	An energy efficiency strategy to help local authorities pilot new and innovative approaches to energy efficiency with community groups and businesses, helping reduce costs and improving warmth in homes, schools, hospitals and businesses.
Short term operating reserve (STOR)	A quick reacting service that provides additional active power from generation or demand reduction.
Significant Code Review (SCR)	An Ofgem led initiative to examine the residual charges which recover the sunk costs of distribution and transmission networks. As a result of changes in technology and other factors, some network users are increasingly able to adjust the timing and volume of their production and/or consumption of electricity, reducing their exposure to charges. Therefore, current residual charges will increasingly fall on those network users who are not able to do this. They are likely to include residential and small business consumers in general, and more vulnerable consumers in particular. Residual charges currently account for about four fifths of transmission charges and half of distribution charges.
Standard Variable Tariffs (SVTs)	A supply contract with an indefinite length that does not have a fixed-term applying to the terms and conditions. It's an energy supplier's basic offer.
System Needs and Product Strategy (SNAPS)	A National Grid led consultation based on the future system needs that seeks to consult on how we can best facilitate the evolution of balancing services markets.
Targeted Charging Review (TCR)	A targeted review looking at a number of electricity network charging issues that are leading to "inefficient investment decisions".
Third Party Charges (TPC)	The non-energy elements of a consumer's retail bill. Includes elements such as transmission and distribution charges, government levies, and taxation.
Time of Use (ToU) tariffs	A variable tariff based on the use of electricity at different times of the day, which can be charged by an energy company.
Top up and Spill (TUAS)	A market that allows members to purchase top-up energy when their production is below the level of their customer demand, and to sell spill energy when their production exceeds demand.
Transmission Losses	The difference between electricity entering the transmission system and that leaving it.
Transmission Network Use of System (TNUoS) charges	Also known as a TRIAD; charges that are paid to the National Grid by those generators and suppliers who are considered to have used the electricity transmission system to transport energy. A triad is the three half-hours of highest demand between November and February each year that identifies the points of peak electricity demand on the GB electricity transmission system. The charges vary for both generators and suppliers according to their geographic locations and the demand for grid usage at that location and are designed to incentivise minimal use of the system at peak times.
Typical Domestic Consumption Values (TDCVs)	Industry standard values for the annual gas and electricity usage of a typical domestic consumer.
Universal Smart Energy Framework (USEF)	Developed by the USEF Foundation, it provides non-discriminatory access to smart energy systems at acceptable cost-to-connect and cost-to-serve levels. It offers a standardised flexibility framework of use to Distribution System Operators.

Term	Definition
Virtual Power Plant (VPP)	A system that virtually integrates in the cloud several types of energy, such as distributed energy resources for the purpose of enhancing capacity and trading power.
Virtual Private Wire (VPW)	A theoretical alternative pricing option that instead of requiring the use of new wires would utilise an allocation of the DNO's spare capacity over existing, licensed distribution network assets through some kind of private leasing arrangement.