Future Prospects for Local Energy Markets: Lessons from the Cornwall LEM

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Abstract: The Cornwall Local Energy Market was a four year trial (2016-2020) jointly funded by the European Regional Development Fund and Centrica. The aim was to unlock network capacity through intelligent management of supply and demand in constrained areas of the distribution network in Cornwall. This was achieved by installing a range of renewable and storage devices in homes and businesses and setting up an online trading platform to allow the Distribution Network Operator to purchase flexibility services from participants.

Keywords: local energy markets, distribution networks, DSO, Ofgem, BEIS, flexibility, electricity trading, policy, renewables, net-zero

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SUMMARY

The Cornwall Local Energy Market was a four year trial (2016-2020) jointly funded by the European Regional Development Fund and Centrica. The aim was to unlock network capacity through intelligent management of supply and demand in constrained areas of the distribution network in Cornwall. This was achieved by installing a range of renewable and storage devices in homes and businesses and setting up an online trading platform to allow the Distribution Network Operator to purchase flexibility services from participants.

The University of Exeter was a project partner. A key part of our role was to provide information and recommendations on the policy and regulatory barriers to the emergence of LEMs as an option for both alleviating network congestion issues and as a means for encouraging the greater deployment of distribution connected renewables in the context of the UK's net zero commitment. This report is an update of our original report on these issues (Bray, Woodman and Connor, 2018) and is informed by Centrica's experience of delivering the Cornwall LEM.

The report finds that, although there have been changes since the original report, changes are still needed in six key areas if LEMs are to emerge as an option:

- The future role of DNOs and the characteristics of Distribution System Operators (DSOs) to enable active, flexible operation of distribution network
- Network charging regulation and the rules devised by Ofgem which can help or inhibit the deployment of renewables projects
- The rules under which renewable projects can connect to the network and the impacts these can have on the economic viability of projects
- The requirement for consumers to have a single electricity supplier – known as the Supplier Hub Model – which acts as a barrier to other ways of trading electricity such as Peer to Peer Trading
- The difficulties small, renewable projects have in accessing national electricity markets to trade wholesale power or flexibility services
- The lack of clear and transparent rules around data access, whether for electricity trading or consumption

The report sets out in detail what the issues in these areas are and provides an overview of the current state of play.

A key message coming through the report is that the current approach to distribution network governance is inadequate. Policies and regulations are dealt with in a piecemeal way, despite the fact that they are in many ways interrelated. So, for example, the future role of DNOs will be influenced – and will influence – the way in which new projects can connect to networks, but current rule making is dealing with the issues separately.

We therefore argue that if distribution networks are to play their full role in delivering our net zero commitment, there needs to be a more holistic approach to policy and regulation, with a clear vision of what needs to happen to enable more renewable generation to connect at the distribution level, and for distribution networks to be operated in a flexible way.

ACRONYMS

ANM	active network management
BEIS	Department for Business, Energy & Industrial Strategy
BM	Balancing Mechanism
BMUs	Balancing Mechanism Units
BSC	Balancing and Settlement Code
BSUoS	Balancing System use of System (charge)
BTM	behind the meter
CHP	combined heat and power
CM	Capacity Market
CUSC	Charging and Use of Services Code
DCUSA	Distribution Charging and Use of Services Agreement
DER	distributed energy resources
DNO	Distribution Network Operator
DSO	Distribution Service Operator
DSR	demand side response
DUoS	Distribution Use of Service (charges)
EB	embedded benefits
ENA	Energy Networks Association
EPG	Energy Policy Group at the University of Exeter
ESO	Electricity System Operator (National Grid)
EV	electric vehicle
FC	flexibility co-ordinator
FiT	feed-in tariff
GB	Great Britain
GSP	grid supply point – the point the transmission network meets the distribution network
GSPG	grid supply point group

I&C	industrial and commercial (businesses)
IGov	Innovation and Governance Team, Energy Policy Group, UoE
KEP	knowledge exchange partnership
kW	kilowatt
kWh	kilowatt hour
LEM	local energy market
LIFO queue	last in first out
Mod	Modification (to an industry code)
MW	megawatt
Ofgem	Office of Gas and Electricity Markets
P2P	Peer-to-Peer (trading)
PV	photovoltaic
RIIO	Regulation = Incentives + Innovation + Outputs
SCR	significant code review
SHM	supplier hub model
SME	small and medium sized enterprises
TCR	targeted charging review
TERRE	Trans European Replacement Reserves Exchange
TGR	transmission generation residual (charges)
TNUoS	Transmission Network Use of System (charges)
ToU	time of use
TPLS	third party licensed supplier
UoE	University of Exeter
UK	United Kingdom
VLP	virtual lead party
VPP	virtual power plant
WM	wholesale market
WPD	Western Power Distribution (DNO)

1. INTRODUCTION

The Cornwall Local Energy Market (LEM) programme was a four-year trial, which ran from late 2016 through to December 2020, jointly funded through the European Regional Development Fund and Centrica. The programme was led by Centrica in association with project partners Western Power Distribution (WPD), National Grid ESO, N-SIDE, the University of Exeter (UoE) and Imperial College London.

One of the main objectives of the Cornwall LEM project was to unlock network capacity through intelligent management of supply and demand in constrained areas of the distribution network in Cornwall. Cornwall currently hosts 776 MW of renewable and low-carbon generation capacity, of which 591 MW comes from solar and 140 MW from onshore wind generation (BEIS, 2020c) which is connected to the distribution network. Throughout this report we refer to renewable and low carbon generation assets connected to the distribution network as DER (short for distributed energy resources).

There are several advantages to a DER enabled energy system. Firstly it can help to address climate change and lower greenhouse gas emissions through the deployment of renewable and low-carbon technologies. A rapid shift to a low carbon, renewables-based electricity system is vital if we are to meet our net zero target. Secondly, analysis undertaken by Imperial College (Shakoor *et al.*, 2017) found that reduced system operation costs of between 25% and 40% could be achieved through the deployment of new, cheaper, DER assets rather than from conventional generation on the transmission network. These benefits come from avoided or deferred network reinforcement costs, avoided generation build, avoided curtailment of low carbon generation, and better operation of the system (BEIS and Ofgem, 2017). In addition, increase in DER penetration is a positive step forwards in GB realising a 'smart, flexible energy system' as supported by government through the Clean Growth Strategy (BEIS, 2017), the Industrial Strategy (Government, 2017) and the Smart Systems and Flexibility Plan (BEIS and Ofgem, 2017). A DER enabled system could also provide consumers with more opportunity to participate in the energy system, and allow them to access greater reward in respect to the services they could receive or provide to the system (Ofgem, 2016; IGov, 2018).

However, in Cornwall, the distribution network operator, WPD, had claimed that this abundance of DER had put the distribution network under severe strain (WPD, 2017). This had led to new DER assets facing long waits to connect to the network in constrained areas, followed by LIFO[1] arrangements undertaken through active network management[2] (ANM) once actually connected.

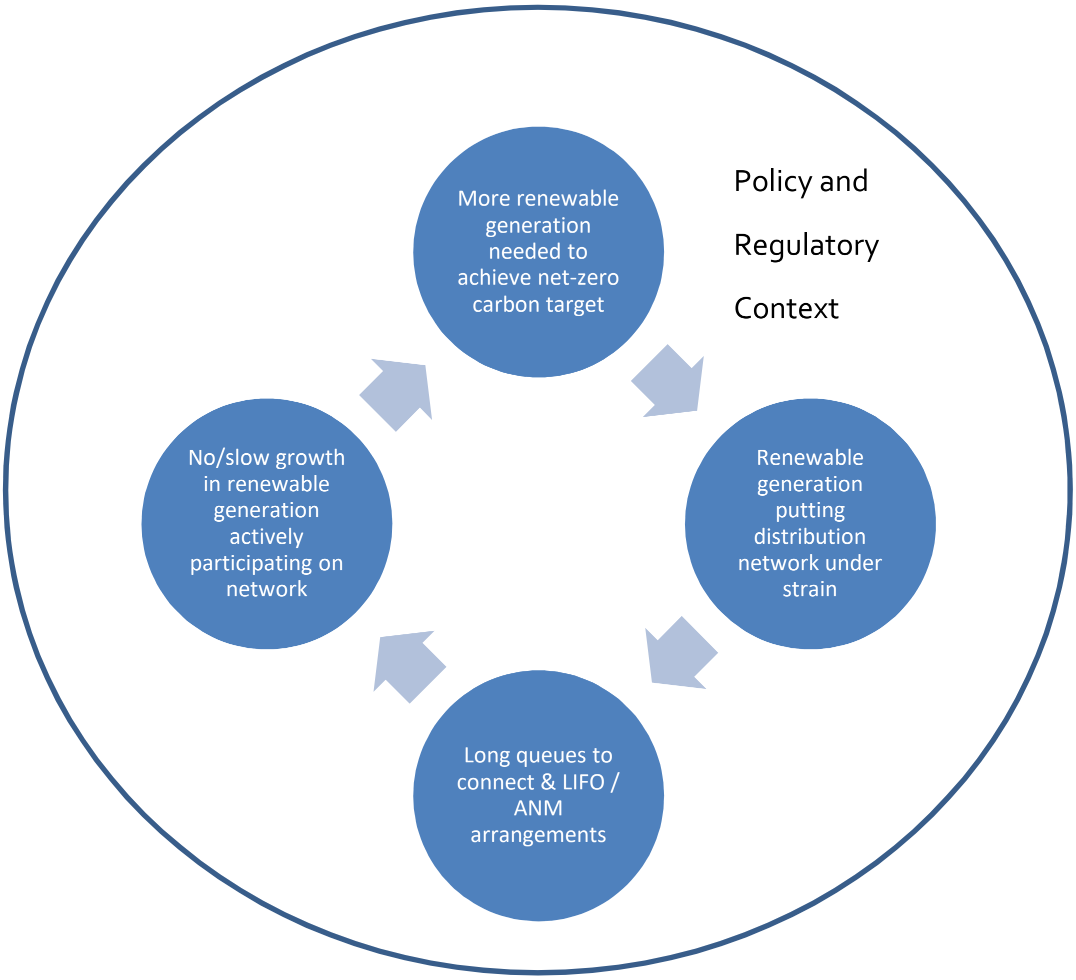
The situation was therefore posing a problem for the future of DER in Cornwall as depicted in Figure 1. This vicious circle is perpetuated by the broader institutional context in which renewables are deployed. In other words, the policies and regulations which currently govern the electricity system are largely designed to maintain the current electricity system based on large scale, transmission connected generation, rather than enabling a shift to one which can easily accommodate smaller scale, largely renewable projects connected at distribution level. However, these projects can play a vital role if we are to meet the net zero commitment. The policy and regulatory context of electricity systems

[1] LIFO – 'last in first out' meant that the last generator to connect in an area would be the first generator curtailed during system stress events. This therefore gradually undermined the financial viability of each generator which connected.

[2] ANM enables DNOs to curtail generation assets at times of system stress without compensation, which undermines financial viability of these assets and suppresses market flexibility opportunities.

therefore need to change to allow distribution networks to accommodate renewables and to be operated in a more active way, and incentives for DNOs to deliver these more active networks.

Figure 1



However, the required changes cannot be carried out in a piecemeal way. Electricity systems are made up of interrelated technical and non-technical components, and changing one of these components in isolation will not achieve the required shift in the system overall. So, for example, making the connection regime for DER less onerous and more certain may lead to a greater level of renewables deployment, but it will not be an efficient change unless the role of DNOs has also shifted to one which is more focused on active network system management. Similarly, changing or discarding the current requirement for a single electricity supplier in order to allow some form of Peer to Peer trading to occur is unlikely to be effective unless greater data transparency and safeguarding measures are in place.

The Cornwall LEM project aimed to address one part of the vicious circle: the problem of distribution network pressure, by creating a local marketplace where WPD and the electricity system operator (National Grid ESO) could procure flexibility[3] from DER assets in order to optimise capacity on the network. The project achieved this by designing and building a bespoke online market trading platform which incentivised demand, generation and storage providers to turn up / turn down / export or import

[3] Flexibility, also known as demand side response (DSR), can be defined as the ability for consumers to change their electricity usage, or for generation and storage providers to respond in accordance with network and market requirements.

depending on anticipated network requirements. This is a vital step in enabling the emergence of LEMs but ultimately significant policy and regulatory changes will be required to allow Local Energy Markets to become a mainstream option. The aim of this report is to learn from the Cornwall LEM experience but also to highlight what future changes must be implemented.

The Cornwall Local Energy Market

The Cornwall LEM recruited participants from across Cornwall to take part in the LEM project; these included industrial & commercial customers, SMEs, and one hundred households. The households received solar panels, smart batteries and monitoring equipment through the project; enabling them to act as a 'Virtual Power Plant' (VPP), the largest of its kind in the UK (Centrica, 2020). The energy they produced was aggregated and controlled remotely to provide a single block of power in trading events. In addition, the project installed a range of devices to 87 businesses; including solar, wind, storage and CHP technologies, as well as energy monitoring devices and training opportunities (*ibid*) to enable these participants to also trade on the platform.

The Cornwall LEM programme comprised five key work packages:

WP1. Development of the LEM flexibility trading platform and trials.

WP2. Residential battery storage installation and trials.

WP3. Industrial & Commercial engagement, installations and support.

WP4. Project management, communications and compliance.

WP5. Research and reporting.

An Overview of Work Packages 1 to 3 are included in the Appendices for reference. The University of Exeter was involved in researching and evaluating participants' experiences of WPs 1-3 which we have previously published and are available to view at:
https://ore.exeter.ac.uk/repository/handle/10871/120972 for the Householder Survey Report and
https://ore.exeter.ac.uk/repository/handle/10871/123995 for the Organisations Survey Report.

The remainder of our work came under WP5 where we were responsible for analysing the GB policy, regulatory and market environment to identify the barriers to establishing local energy markets and to suggest possible solutions.

We published our first report, '*Policy and Regulatory Barriers to Local Energy Markets in GB*' in May 2018 (Bray, Woodman and Connor, 2018); which can be accessed here:
https://ore.exeter.ac.uk/repository/handle/10871/33607. In that report we highlighted that the requirement to decarbonise the GB electricity system to meet climate change targets, alongside the falling costs of renewable technologies and developments in IT capabilities, provided GB with an opportunity for systemic change.

However, we argued that the GB policy and regulatory environment regarding electricity markets, along with the accompanying market rules, could potentially act as barriers to the development of new local energy markets at the distribution network level across GB. These barriers could be in the form of existing policies and regulations, or a lack of enabling policies and regulations. The report also discussed the changes which were emerging in GB's national and regional energy markets and how these changes could impact on the creation of local energy markets, either negatively or positively.

The original report identified 71 barriers to the evolution of LEMs. From this long-list of policy and regulatory barriers we derived 6 drivers for change based on areas which we considered had the most potential for change over the course of the LEM programme. Due to ongoing BEIS and Ofgem consultations taking place over 2017 and 2018 we knew that changes would be made in these areas; but due to the stage of decision-making we couldn't foresee whether these changes would have a positive or a detrimental impact on LEM development. We therefore said that we would reconsider these drivers again at the end of the LEM project; with the hindsight of being able to analyse their impact on the LEM programme and the experiences and expectations of the LEM participants.

The 6 drivers for change as identified in 2018 were:

1. The Future Role Of The DNOs (focusing on the creation of new local markets and the services they could potentially provide)
2. Network Charges (and whether changes to existing charges could incentivise changes in user behaviour)
3. Access Rights (including curtailment of local generation by the DNOs)
4. Supplier Hub Model (the existing trading rules and the challenges these pose to more innovative trading solutions)
5. Access to National Markets (such as the Wholesale Market, the Balancing Market, the Capacity Market and Ancillary Services) which were not conducive to small scale generation.
6. Data (particularly the lack of data and access to available data).

This is our final report on the Cornwall LEM project. It sets out what we believe are the final barriers (and possible enabling solutions) to the evolution of LEMs in GB. It is based on the findings from the 2018 report; the qualitative analysis derived from the evaluation surveys; a series of interviews undertaken with the Cornwall LEM project stakeholders and an assessment of recent policy, regulatory and market changes which have occurred since 2018.

2. CURRENT STATUS OF THE MAIN POLICY, REGULATORY & MARKET BARRIERS

In 2018 we knew that policy, regulatory and market change was in progress due to ongoing consultations and discussions which were emerging from BEIS, Ofgem, the ENA and Elexon. However, as some of these anticipated changes were very early in the decision-making process, we understood that whilst they had the potential to be beneficial to the development of LEMS, there was also the possibility that the actual outcomes could create additional or unforeseen issues. That is one reason why we said that we would review policy and regulatory progress again at the end of the LEM project.

In addition, at the time of writing in 2018, the LEM hadn't commenced trading and as such their business models and market structure were unknown. We therefore also needed to assess our originally identified barriers in the light of actual trading arrangements, to be able to accurately report whether the identified barriers had posed difficulties to LEM operation in practice, and also to consider whether there were additional barriers to operation which hadn't been taken into account.

Through our work with them, the Cornwall LEM project realised that in order to work within the current policy, regulatory and market parameters they would not be able to undertake all of the trading scenarios that they originally intended to provide; unless they applied for specific derogations from these rules from Ofgem. The Cornwall LEM project therefore decided to undertake only the business models which were permissible under the current rules; but to highlight what wasn't possible to achieve, and why. We will attempt to provide clarity throughout this section and in the Conclusion on where these problems occurred and how they could be overcome in the future.

2.1 DNO to DSO transition (system coordination and market opportunities)

What was the problem?

Whilst the DNO to DSO transition was viewed in our 2018 report as one of the biggest potential enablers for LEMs in GB, we had several misgivings regarding the direction of travel.

Our main concern was that the DNOs, through their industry body the ENA, were very much at the forefront of leading the DSO transition and determining what could be achieved, and by when. We argued that a much clearer steer needed to be given by BEIS and Ofgem as to what should happen, and within a defined timeframe. At that point the DNOs were signaling that the DSO transition could be implemented by 2030, which we argued was too long and we proposed that transition should happen within the current RIIO-ED1 price control period (2015 to 2023) with an aim for all DSOs to be offering market services during the following price control period RIIO –ED2[4].

In addition, through the Open Networks project, the ENA were consulting on the future coordination scheme for the ESO and the DSOs in the procurement and dispatch of DER. This was also an integral part of the DSO transition as the chosen coordination scheme would not just determine the responsibilities of the system operators towards each other but also determine their responsibilities towards third parties such as the LEM.

The ongoing uncertainty surrounding what a DSO would be expected to deliver also provided uncertainty for the LEM, particularly in relation to what services the DSO would be procuring from the

[4] At the time of writing the 2018 report it was expected that RIIO-ED-2 would run for 8 years from 2023-2031, however this has now been reduced to 5 years, ending in 2028.

market and what they would be managing themselves as the operator through the use of active network management (ANM)[5]. Clarification was therefore needed regarding DSO activities to ensure a competitive marketplace. We also identified the need for 'value stacking' across markets in order for DER providers to realise the economic potential of their assets.

In addition, Mitchell (Mitchell, 2017) argues that Ofgem should require DSOs to conduct DER Plans to ascertain what DER are available within the network and to use this information to better inform network planning and investment. A DER plan could also help determine optimal locations for the siting and deployment of DER, thereby helping both the network operator and the economic viability of the project.

Has it been resolved?

Open Networks (Future Worlds for coordination of DER)

The ENA issued a consultation document in July 2018 entitled 'Future Worlds' (ENA, 2018) which gave an overview of five different scenarios which could be used for the future procurement and dispatch of DER services as shown in Box 1. The ENA stated that they didn't expect any one particular Future World to be chosen as the final option, but they set out what each 'world' would look like so that consultees could assess the characteristics that should be applied to the eventual model as well as identify potential barriers of implementation.

We discussed the five Future Worlds in our report '*Barriers to Independent Aggregators in Europe'* (Bray and Woodman, 2019) and include here an overview of our analysis:

Box 1 ENA's Five Future World scenarios

Future Worlds	Description	Analysis
World A DSO Coordinates	The DSO acts as the neutral facilitator for all DER and provides services on a locational basis to the ESO.	This model would entail the DSOs managing the entire GB network, which they currently have no visibility of. Systems would need to be put in place to ensure smooth transactions between the DSOs and the ESO, but the DSOs should be in a better position to understand their own areas needs and constraints and this model could achieve granularity at the local level. However, this model runs the risk of DSOs becoming 'regional aggregators' and of conflict in DER being able to access ESO markets. Worryingly, all the Future Worlds show DSOs owning and operating flexibility resources; which is a clear conflict of interest in neutral market facilitation; as well as being in conflict with the 'Smart Systems and Flexibility Plan' (Ofgem and BEIS, 2017) which states that DSOs shouldn't own and operate storage.
World B	The DSO and ESO work together to efficiently manage networks	Although complex, once the operating platform between the DSO and ESO is established, World B should enable

[5] ANM is discussed in the Access Rights section below.

Coordinated DSO-ESO	through coordinated procurement and dispatch of flexibility resources.	local assets to access multiple markets – locally and nationally. However, there needs to be transparency in decision-making as there will inevitably be conflicts of prioritisation between the DSO and the ESO.
World C Price-Driven Flexibility	Changes developed through Ofgem's reform of electricity access and forward-looking charges have improved access arrangements and forward-looking signals for customers.	*This isn't a stand-alone world but can be overlaid across any of the other 4 worlds. This 'World' was added at Ofgem's request.* The authors of this report are not in agreement with this option as we have issues with Ofgem's proposals for reforming electricity access and forward-looking charges which could financially penalise DER providers.[6]
World D ESO Coordinates	The ESO is the counterparty for DER with DSOs informing the ESO of their requirements.	This may be the most conventional model and easiest to implement in the short term due to the ESO's existing procurement, call-off and settlement processes already being in place. It also means that one organisation is procuring / dispatching on a nationwide basis, rather than 6 DSOs procuring separately for their own needs. However, it is a top down approach and may not include the granularity anticipated for full DER market availability. It is the opposite of World A and as such has the opposite issue – DER could be restricted in accessing DSO markets.
World E Flexibility Coordinators	A new national (or potentially regional) third-party acts as the neutral facilitator for DER providing efficient services to the ESO and / or DSO as required.	This is the least conventional model, requiring a new independent market actor or actors to coordinate between the ESO and the DSOs. There are issues to be addressed around whether the Flexibility Co-ordinator (FC) would become a monopoly decision maker, and therefore a very powerful new market actor. Therefore, to be a neutral actor the FC should not control assets in the same way that the ESO and DSOs should not. However, it is unclear whether the FC would fulfil an arbitrator role in managing conflicts; or whether it would be a rule-based software platform with defined processes.

Source: (ENA, 2018). Analysis includes insights from (Centrica, 2018; Elexon, 2018; Piclo, 2018) as referenced in (Bray and Woodman, 2019)

Following consultation and an independent assessment undertaken by Baringa in 2019 (Baringa, 2019) the ENA decided to work on a 'path of least regrets' until 2030. This meant adopting World B (joint ESO & DSO coordination) until such time as it may be apparent that a different direction should be taken. However, this is really only a 'wait and see' option until 2030; as BEIS have not given clear direction on

[6] See sections 2.2 and 2.3 below for an overview of this

whether the future energy system will be a decentralised one or a centralised one. It is therefore more of a holding pattern until such decisions have been made.

The Cornwall LEM platform trials were the first time that joint procurement by a DSO and the ESO had happened in practice in the UK (see Appendix 1). The LEM platform coordinated the DNO and ESO flexibility procurement whilst ensuring that conflicting resources were not simultaneously dispatched, and that contracts for national services did not increase or create congestions at the local level. All stakeholders interviewed agreed that these trials had been successful and had provided learning opportunities for all involved.

However, some aspects of trading were not trialed due to current trading rules (see Section 2.4) and in addition the DNO had no desire to procure turn-down services from the Cornwall LEM as they had no need to due to active network management arrangements (see Section 2.3). Therefore, whilst the Cornwall LEM was successful in the trading arrangements it did achieve, full market potential was stifled.

DNO to DSO transition

In July 2019 BEIS and Ofgem issued a joint letter to the ENA urging them to increase their efforts to deliver markets for flexibility (BEIS and Ofgem, 2019b). Whilst the joint letter acknowledged the work that had begun by the ENA it also stressed that further change and tangible results were urgently required in the following areas:

- Set out a clear plan with ambitious timelines for identifying and delivering least regrets actions
- Identify where current policy or regulation is a barrier, and discuss tangible recommendations with Ofgem or BEIS, as relevant, to remove these barriers.
- Set out a process for ensuring that appropriate information will be available to enable these decisions to be taken, and that actions are taken once these decisions are made.
- Take steps to ensure that new flexibility markets and products are co-ordinated with each other and with other electricity markets – including balancing and network services procured by the ESO
- Facilitate coordination between flexibility markets and national balancing/ancillary markets to enable stacking of flexibility products and services.
- Deliver more efficient and transparent processes for curtailment at distribution, including coordination and clarity on the interaction between ANM and flexibility markets.

In short, the Open Letter identified all of our previous concerns as being of importance in delivering future network operations. Ofgem continued to apply pressure to the DNOs to speed up DSO transition through their decision to ensure that the RIIO-ED2 Methodology would not pose a barrier to the part or full separation of DSO functions from DNOs should it be decided that this would be a more appropriate route (Ofgem, 2020f p.62).

Lastly, there has been some progress on the publication of DER Plans. Modification DCP350 to the Distribution Connection and Use of System Agreement (DCUSA) was brought into effect in July 2020 which requires DNOs to create and maintain a public register of all DER sites connected to their networks that are larger than 1MW (Ofgem, 2020b). During the public consultation process on DCP350 we argued that 1MW was too large and that there shouldn't be a minimum capacity applied if DNOs are to fully understand the operation of DER on their networks. Ofgem's response document (*ibid*) highlights that some DNOs are working towards including sites from 30kW upwards in the register and Ofgem encourages all parties to consider this. This could be an important step forward for the DNOs understanding of the impact of local DER to network planning and management if they so wish to do so (see also section 2.6 Data).

However, the DSO transition is still in progress and whilst many components are either in development or implementation, the end date for full implementation is still currently scheduled for January 2029 (ENA, 2020). This has a direct bearing on when and how flexibility markets (such as the LEM) will be able to fully emerge.

What needs to happen?

Both BEIS and Ofgem must continue to urge the DNOs to transition to DSO status within the RIIO ED-2 timeframe; and must take a stronger role in scrutinizing the outputs from the ENA. We agree with Ofgem's decision to include within RIIO ED-2 measures that would aid the separation of DNO and DSO roles and responsibilities within the price period should it become necessary (Ofgem, 2020f p.62). However this is a governance decision which can only be addressed by BEIS. We also welcome BEIS' commitment to 'promote greater competition and more innovation in the construction and operation of energy networks' through competitive tendering (BEIS, 2020b p.76).

However, the currently proposed World B scenario is a 'middle of the road' scenario which is unfolding due to BEIS not providing a strategic vision towards either a centralised or a decentralised energy system; leaving the ESO, the DSOs and market providers in a 'wait and see' situation. Whilst they state that this will allow time to see whether or how local markets will develop over the coming years, local markets cannot fully develop until such time as policy enables them to do so. As we will show in the Conclusion, there are several policy mechanisms which need to be aligned for the full evolution of local markets.

However, if a decentralised strategy was implemented, and policy mechanisms were put in place to enable local markets to evolve, World B would not be an adequate way to proceed. Instead there would need to be a system implemented closer to either World A or a World E which fully enabled local coordination and market opportunities. However, both of these Worlds, as detailed by the ENA, currently come with their own issues which would need to be resolve. Therefore BEIS should make the determination on the future scenario which would best lead to a net-zero energy system, rather than the ENA, through setting guiding principles of what needs to happen, by whom and by when. These principles should examine the full suite of trading opportunities at the local level, which should include energy trading markets, not just flexibility trading markets, which we discuss throughout Section 2.

2.2 Network charges

Network charges have a direct bearing on the finances and behaviours of potential LEM customers, and therefore what services a LEM could offer customers.

What was the problem?

When we reported in 2018, Ofgem were considering whether the current system of network charging was still appropriate given the higher volume of DER connected at the distribution network level; along with opportunities for prosumers[7] (potential LEM customers) to reduce their network usage (thus their network charges) through self-consumption, whilst still maintaining a connection to the distribution network for back-up electricity supplies and security.

Ofgem issued a series of consultations on reforming electricity access and charging arrangements through the Charging Futures programme (National Grid, 2018). However, as consultations were at an early stage, with a range of different options to be considered, we couldn't ascertain whether the actual options chosen would be beneficial or detrimental to the future role of LEMs. We argued that Ofgem needed to carefully consider what type of customer behaviour they would be incentivising (or disincentivising) through adopting any new methodology; and not just take an economic approach without considering the effects on decarbonisation targets and the potential future uptake of DER.

In addition, it didn't make sense to us for Ofgem to consider residual charges and forward-looking charges in two separate reviews (see Box 2 for an overview of the different charges).

Box 2 Network charges

An overview of network charges

Networks users pay for their usage of the distribution and transmission networks through four charges: Connection charge; Transmission Network Use of System charge (TNUoS); Distribution Use of System charge (DUoS) and Balancing Services Use of System charge (BSUoS). Charges are calculated according to the charging methodology in two industry codes. TNUoS, BSUoS and transmission connection charging methodology can be found in the Connection and Use of System code (CUSC). DUoS and distribution connection charging methodology can be found in the Distribution Connection Use of System Agreement (DCUSA).

System charges include 'forward-looking' charges and 'residual' charges which are additional charges set to ensure that total allowed revenues are recovered.

- **Forward-looking charges** reflect current and forward-looking costs associated with generating or consuming energy. For some users these can vary by location on the network, or by time of use. These charges reflect the marginal cost of the networks in the long run (the cost of adding each additional unit of capacity on the networks).

- **Residual charges** don't cover specific things, but are broadly used to recover sunk or fixed costs. These costs don't vary with network usage, and largely relate to costs that have already been incurred, such as past investments. Residual charges represent around 80% of revenues at transmission level and around 50% at distribution level (CMS, 2017; Ofgem, 2017d). In addition, Balancing System Use of

[7] Consumers who produce part of their own electricity demand through the use of generation technologies at their property are termed 'prosumers' as they produce as well as consume electricity

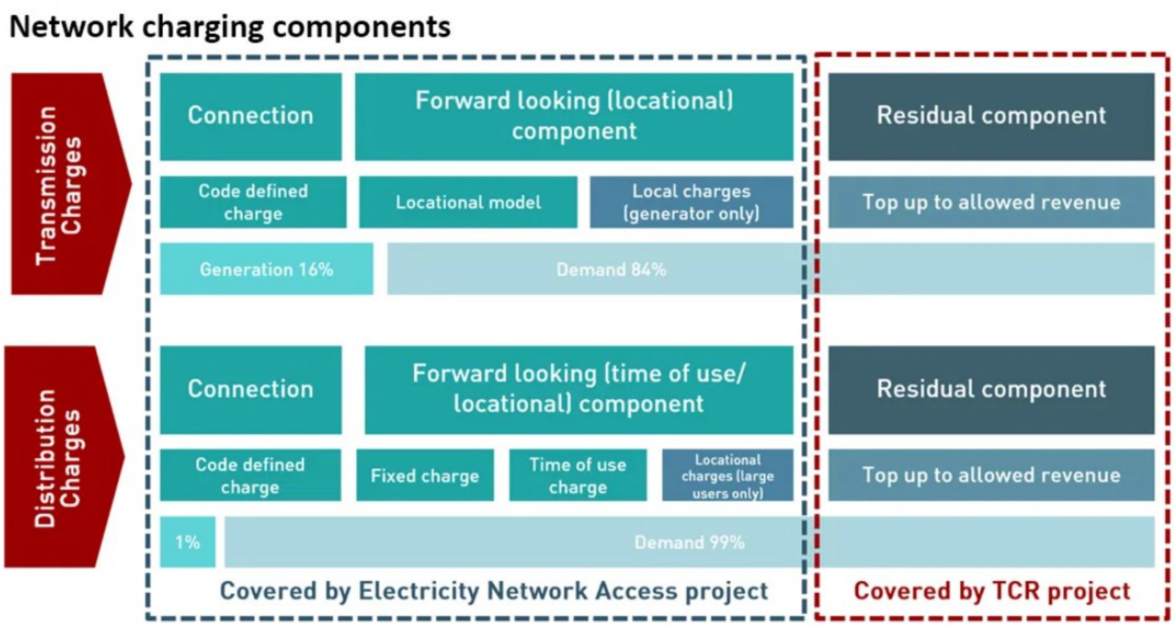
System (BSUoS) charges are currently a form of cost-recovery charge, so are similar to residual charges (Ofgem, 2017d).

Has it been resolved?

Following on from earlier consultations, Ofgem published a Targeted Charging Review (TCR)[8] in November 2018 relating to **residual** charges and a Significant Code Review (SCR) in December 2018 relating to access arrangements (see section 2.3 below) and **forward-looking** charges (see Figure 2) (National Grid, 2018). In addition both reviews consider the issue of 'Embedded Benefits' (EB). The TCR deals with residual EB which are non-locational, whilst the SCR deals with forward-looking EB, which are locational embedded benefits as discussed later.

The Residual Charges review has now been largely determined, although discussions are still ongoing with the Forward Looking Charges review. The new residual charging regime is due to commence in 2021 for transmission network costs and 2022 for distribution network costs. The new forward-looking charging regime is expected to commence in 2023, which we are concerned will not be in time for DNOs to fully understand and incorporate the impacts of these changes into their RIIO ED-2 Business Plans which are also to be implemented in 2023.

Figure 2: Overview of the TCR & SCR



Source: Ofgem (as reported by http://watt-logic.com/2019/09/19/network-charging-update/)

The TCR (residual charges)

From the range of options under discussion in 2018 BEIS have since determined that residual charges will be calculated in the form of **fixed charges** for all households and businesses (Ofgem, 2019e). This was not our preferred option in 2018. We argued that whilst we could see that fixed charges would be the simplest proposal to introduce, and the one which gave DNOs the most revenue certainty, we considered that fixed charges could be unfair to domestic and commercial prosumers, which constitute

[8] The TCR is also a Significant Code Review (SCR) but denoted separately in this report to aid clarity between the two projects

all the Cornwall LEM residential participants as well as the organisational participants who have behind the meter[9] (BTM) technologies installed.

The underlying foundation of the charging review is that prosumers who use onsite generation technologies (such as solar PV) can at present reduce the amount of network charges they pay by reducing the amount of grid-supplied generation they purchase, whilst still having the advantage of the network available whenever they need. This in turn puts more of the financial burden of running the network on those who cannot avoid these costs. Ofgem have decided that this isn't fair, but by introducing a fixed charge, prosumers in future will pay the same residual charges as those who use the network all the time, which also isn't fair. As Ofgem acknowledge:

> *"Consumers who currently benefit from reduced contributions because they have onsite generation which has reduced their contribution to the existing system, without a corresponding reduction in system costs, will pay more on average. Those that haven't taken such action will on average pay less."* (Ofgem, 2019e)

Having been challenged, however, on the fairness to all customers Ofgem are now considering whether all *domestic* customers should be placed in the same charging band. This doesn't help commercial prosumers though who will generally have larger technologies than domestic prosumers, and therefore are able to produce higher volumes of their own onsite generation. These customers will also be losing some of their Embedded Benefits (such as the Triad) from 2021, which we discuss in the Embedded Benefits section below.

The SCR (forward-looking charges)

After releasing several working papers during 2018 and 2019 which contained a long-list of policy options, Ofgem published an Open Letter in March 2020 outlining their shortlisted policy options (Ofgem, 2020c). In this section we look at the potential policy changes to TNUoS and DUoS charges, whilst access arrangements are looked at separately in section 2.3.

For **distribution charges (DUoS)** we were disappointed that Ofgem stated very early in the option assessment process that they wouldn't be seeking to introduce area-based charging structures as they would be 'highly complex' (Ofgem, 2017b). Reduced DUoS charges for locally purchased generation could have provided a financial incentive for local trading across the UK.

We were also disappointed that although Ofgem had originally considered that charges could be set more dynamically, which could have included charging rebates at peak times for those users who reduced their network usage, this has now been discounted due to insufficient network monitoring and forecasting capability for this to be feasible for a 2023 implementation date (Ofgem, 2020c).

The scope of Ofgem's work on **transmission charging (TNUoS charges)** was narrower than the review of distribution charges. Again, whilst dynamic charging was originally considered (as it created the most cost-reflective signals), it was eventually discounted due to implementation challenges.

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[9] Behind the meter technologies (BTM) are technologies installed at a consumer's property such as solar PV, heat pumps, EVs and battery storage, so called BTM as they lie on the customer's side of the meter for billing and settlement purposes

Ofgem's shortlisted policy options for both DUoS and TNUoS demand charges therefore have now been reduced to 3 options: 1) tariffs based on more accurate time of use (ToU) bands, e.g. seasonal bands; 2) charges based on agreed capacity rights; or 3) a hybrid combination of the two.

In addition, through TNUoS Ofgem are considering whether distribution connected generation should pay similar or identical locational transmission charges as large generators (see Embedded Benefits below).

It should be noted, that unlike the TCR above, there is still time for Ofgem to incorporate changes to the SCR as economic modelling and final decisions haven't as yet been undertaken. In addition Ofgem are still determining whether the shortlisted options should apply to all network users, or whether there should be adaptations or specific protections for 'small users'[10] to mitigate any adverse effects. The final policy changes are currently anticipated to be introduced on 01 April 2023 (Ofgem, 2020c).

Embedded Benefits

Box 3 Embedded Benefits

Embedded benefits (EB) are payments made to generators connected at the distribution network level, as opposed to the transmission network, so called because these generators are 'embedded' further down the system closer to sources of electricity demand. EB are based on the contribution made by embedded generators to reducing demands on the transmission network, especially during the three half-hours with highest demand in the year (the Triad).

What was the problem?

Ofgem considered that the current network charging regime had distorted the playing field between generation that connects to the transmission network and generation that connects to the distribution network - with distribution level generation given a competitive advantage (Ofgem, 2017c p.52). As a result, Ofgem had taken the decision to cut the amount of embedded benefits paid to DER providers through two changes to the CUSC, Modification Proposals CMP264 and 265.

Ofgem approved a large cut in the TNUoS demand residual payment, known broadly as the Triad payment, as part of the Review on residual charging, effectively taking EB from a value of £47.30 per kW of capacity to less than £2 per kW over a three-year phase-in period from April 2018. Ofgem faced a judicial review on this decision in January 2018, which was brought jointly by eight small generating companies, which Ofgem successfully overcame (Coyne, 2017).

Has it been resolved?

When we reported in 2018 Ofgem had already taken the decisions above to cut the residual element of EB paid to DER providers, causing widespread discontent. One commentator reported that this was "*one of the worst decisions we have seen from the regulator*" (Cornwall, 2017); whilst the head of the Association for Decentralised Energy (ADE) stated that "*The consequences for industrial manufacturers, hospitals, and local authorities who generate their own power could be devastating*" (Coyne, 2017). However, Ofgem have since continued to remove EB by a combination of additional methods:

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[10] Ofgem define small users as define small users as distribution-connected users who do not have an agreed capacity requirement as the basis for their distribution network charges – this includes small business users and domestic users.

TCR decisions

Firstly, Ofgem have determined that Transmission Generation Residual (TGR) charges should be set to zero (whereas previously they were negative, thus the charge in effect became a credit). This will have a detrimental impact on both transmission-connected generation and larger distributed generators (over 100 MW). This is because these generators are liable for generator residual charges, whereas smaller distributed generators (up to 100 MW) are not. However, as the TGR had become *negative*, this had become a *benefit* to those who received the TGR credits.

Secondly, and of negative impact to smaller DER, Ofgem will remove the ability for suppliers to reduce their liability for balancing services charges[11] by purchasing from these small distributed generators located below the Grid Supply Point (GSP). This will be achieved by recovering balancing services charges for demand on a *gross* consumption basis, rather than a *net* consumption basis at the GSP.

Thirdly, smaller distributed generators (up to 100 MW) do not currently pay balancing service charges for their generation (whilst larger generators do). The TCR itself does not alter this arrangement, but Ofgem have instead launched a Balancing Services Taskforce to consider who should pay balancing charges and on what basis. The Taskforce are asked to apply the overarching TCR principles on a consistent basis in the review, which could lead to the same outcome as the first point above, in that all generators should be treated the same to level the playing field between them.

SCR considerations

Ofgem are still considering whether distribution connected generation should pay similar or identical locational transmission charges as large generators.

Whilst in theory it could make sense for all generators to be treated equally when it comes to paying network charges and balancing services charges, they are not treated equally when it comes to access arrangements (discussed in section 2.3) or in market arrangements (discussed in section 2.5). Therefore we understand that instead of developing parity between generators, Ofgem are in fact financially penalizing smaller DER by removing some of the current advantages that they have had in the past, or which they currently receive. Also attempting to create a level playing field between generators is entirely inappropriate when we need more renewable and low carbon generation feeding into the energy system and yet this has not be factored into future charging considerations.

What needs to happen?

Ofgem should primarily consider the full scope of the future net-zero electricity system they want to see delivered. The regulatory framework should then be tailored to deliver that system and charging should reflect where we want to get to and how. This cannot be achieved by taking a short-term economic viewpoint and an attempt to create a level playing field between different types of generation providers. Rather it needs long-term, holistic planning guided by a set of principles aimed at reaching net-zero. This should aim to incentivise renewable and low carbon DER take-up and incentivise DER providers to interact with local trading markets.

[11] Balancing services charges recover the costs incurred by the system operator for keeping the system balanced and the day-to-day operation of the system. Balancing services charges are currently recovered approximately 50% from demand and 50% from generation, based on net consumption at the GSP, measured each half-hour.

2.3 Access Rights (Connections)

Access rights have a direct bearing on the future potential of local flexibility and energy markets such as the Cornwall LEM.

What was the problem?

Network access rights define the nature of users' access to the networks which includes how much they can import or export, when and for how long, where to / from, and how likely their access is to be curtailed and what happens if it is (Ofgem, 2019c).

We reported in 2018 that Ofgem's review into future access rights aimed to give generators more choice in types of connections, which was supposed to speed up the connection process, rather than relying on a first come first served basis which had led to long connection queues and operational LIFO[12] queues. These new types of connections were also meant to significantly reduce connection costs. Ofgem's options under consideration in 2018 included being able to buy access for a specified length of time, or the right to be able to trade only within a specified local area, or being able to trade connection agreements between parties. Another option was to introduce auctions for access rights.

Although we didn't have enough information at that time to make value judgements on the proposed options we did agree that the connection protocols needed to change. We were particularly discouraged by the DNOs use of active network management (ANM) which enabled DNOs to curtail generation assets at times of system stress without compensation. This incurred financial risk and uncertainty for DER and undermined market solutions for flexibility at the distribution level (such as the LEM).

Has it been resolved?

As said previously, the SCR has not been determined, although Ofgem have published their short-listed policy options. With regards to access arrangements these have been split into two distinct areas – definitions of access rights (for transmission connected generation) and the reform of connection fees (for distribution connected generation).

Definitions of access rights

Ofgem are still considering a wider choice of access rights for **large** generation to connect to the transmission network. These include:

- Options for curtailable access rights (non-firm connections)
- Option for time profiled access rights
- Ability to share access between users in the same local area
- Clarifying distribution users' access rights to the transmission network

Although Ofgem had originally looked at including **small** generation connecting to the distribution networks within this part of the review they subsequently determined that this couldn't be implemented by 2023 due to the necessary planning and security standards not being in place as yet, and the inability to develop and implement such standards within the required timeframe. Therefore

[12] LIFO – 'last in first out' meant that the last generator to connect in an area would be the first generator curtailed during system stress events. This therefore gradually undermined the financial viability of each generator which connected.

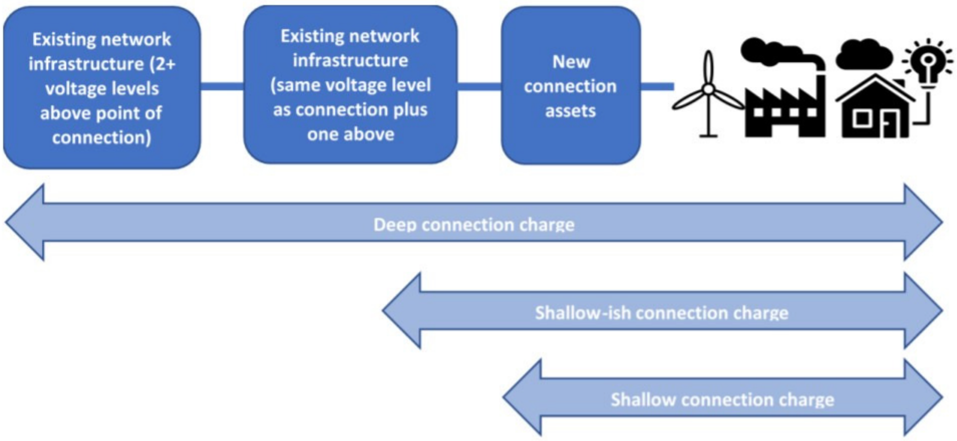
this part of the SCR does not include DER, which means that **DER will not benefit** from any of the above options which are still on the table at Ofgem.

Connection fees

However, DER are included in the review on connection fees. Although this is badged by Ofgem as being different to the definition of access rights above, it is somewhat difficult for us to differentiate this, as the connection fee paid also relates to the level of access awarded. The options for inclusion are:

- Reducing the contribution to reinforcement costs that distribution users pay through connection charges (a "*shallower*" connection charging boundary)
- Removing the contribution to reinforcement costs that distribution users pay through connection charges (a "*shallow*" connection charging boundary)
- Allowing alternative payment terms for connection charges e.g. to allow payment over time (including while maintaining the current "*shallowish*" boundary)
- Introducing liabilities and securities arrangements

Figure 3 Connection boundaries



Source: (Ofgem, 2019b page 4)

Ofgem decided not to include '*firm*'[13]access to the distribution networks within the review as it was thought that this couldn't be implemented by 2023 (Ofgem, 2020c) This is a prime example of how transmission connected generation is treated differently to distribution connected generation, despite the stripping of embedded benefits to supposedly equalize costs and charges between them.

Ofgem's explanation for this states:

> *"We have not identified clear evidence that introducing financially firm access with connect and manage at distribution would support more efficient use of the system. There are already options available for distribution-connected users that want to be compensated for a curtailment. Distribution users with a "standard connection" have a high level of firmness and are generally only curtailed due to maintenance issues.* ***Beyond this, if DNO wants to curtail one of these users, then the DNO must pay the user through a flexibility contract*** [Bold text added by

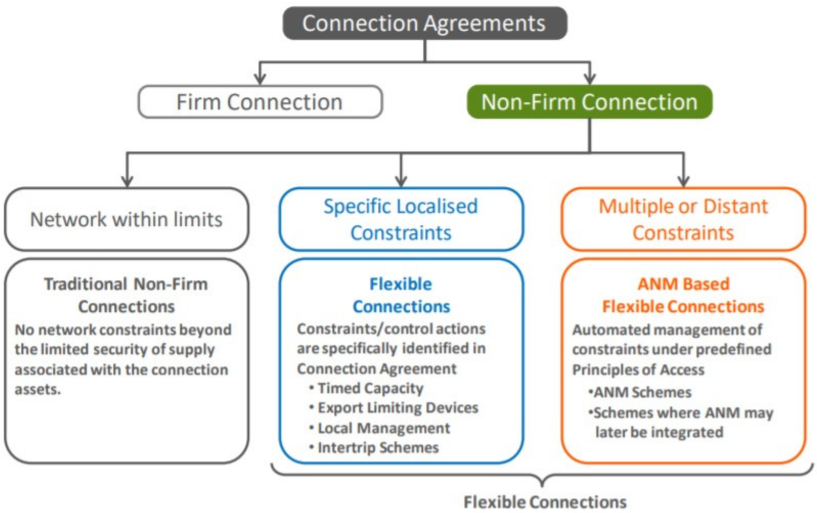
[13] Firm access is access which is non-curtailable without financial reward. Most distribution connected generation has non-firm access which means that the DNO can curtail generation through a variety of mechanisms without financial reward

report authors for emphasis]. *Users wanting a quicker or cheaper connection than available through a standard connection can choose flexible connection options."* (Ofgem, 2020c pages 7-8)

Currently DNOs do not pay DER assets to curtail except through specific contractual arrangements. The trade-off with 'flexible'[14] connections (as opposed to 'firm' connections) being that DER providers can pay a cheaper connection fee in exchange for having their assets curtailed when deemed necessary by the DNO in order to stabilize the network. Therefore DER providers have to consider the financial impact on revenue over the lifetime of the connection.

In Figure 4 below Ofgem set out 3 types of non-firm connection depending on constraint levels within the network. These range from network within limits (no network constraints), specific localized constraints and multiple or distant constraints; with cascading levels of constraint management taken for each scenario. However, as more DER connect to the network; and more electricity generation is required on the networks as low carbon technologies such as EVs and heat pumps increase overall demand; it becomes more likely that network constraints or individual bottlenecks will occur unless local energy markets can be utilized to relieve these.

Figure 4 Connection Agreements



Source: (SPEN, 2017)

What needs to happen?

Whilst BEIS and Ofgem state that they are supportive of creating flexibility markets, flexible connections will downplay the role that markets such as the LEM can play. For instance the DNOs will not award contracts for 'turn-down' services as they are simply able to curtail generation themselves without procuring a market service. This is in direct contrast to the ESO who must reward transmission generation assets (with firm connections) for their services. It also appears to be in direct contrast to Ofgem's own statement highlighted above.

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[14] The term 'flexible' connections shouldn't be confused with 'flexibility' markets, although the choice of terminology could be misleading. Flexible connections enable the DNO to manage network constraints themselves by turning down generation, without having to procure turn-down flexibility from the marketplace. Therefore flexible connections are detrimental to flexibility markets as they limit opportunities for trading.

BEIS and Ofgem should therefore set guidelines with the DNOs on what local markets should be able to provide, how they should be used in future to help with system balancing and overcoming network constraints, and allow for the cost of procuring a full suite of market services through RIIO business planning. The current state of play with flexible connections appears to defeat the object of achieving a net-carbon energy system if it is renewable and low-carbon DER assets which are turned off first whenever network constraints arise. BEIS and Ofgem therefore need to take a stronger stance in encouraging the DNOs to see local trading as a way to manage the networks more efficiently.

2.4 Supplier Hub Model

Due to the rules involved in the Supplier Hub Model (SHM) the Cornwall LEM was not able to trial peer-to-peer trading or any form of selling energy to potential purchasers other than the DNO and the ESO. If they were to have provided these services they would have had to apply to Ofgem for derogations from the current trading rules. The SHM dramatically reduced the scope of what the Cornwall LEM provided.

What was the problem?

GB policies, regulations and market rules all revolve around the Supplier Hub model. In 2018 we reported that the Supplier Hub Model (SHM) represented a major barrier to the development of LEMs due to the integral role which it awarded licenced suppliers as the core intermediary between customers and the energy system. Due to the restrictions of the SHM all transactions must be made through a licenced supplier and customers could only have one licensed supplier at any given time. It was therefore not possible for a prosumer[15] to sell any excess generation to someone else – it either had to be stored on site, or sold to the grid via the supplier. On the reverse side, it was also not possible for a customer to buy electricity from anyone other than their sole contracted supplier. This effectively blocked options for peer-to-peer (P2P) markets.

P2P energy trading can be defined as local energy trading between participants, where the excess energy, or demand reduction, from many small-scale DERs is traded amongst local individuals and organisations. Essentially, allowing households to become small energy providers. P2P trading however would appear to be one of the fundamental values of a LEM; offering the ability to trade electricity locally, within a defined area and between defined participants without the need for a third party licensed supplier. We argued therefore that a different market structure would be needed to transform the top-down electricity system to one that fully enabled distributed generation and local flexibility trading (Elexon, 2017).

In November 2017 Ofgem issued a call for evidence on the future of supply market arrangements (Ofgem, 2017a) and in July 2018 responded by stating that:

> *"current supplier hub arrangements are not going to be fit for purpose for energy consumers over the longer term. There is a strong case for considering fundamental reforms to the 'supplier hub' model, and for evaluating how alternative arrangements might operate in practice"* (Ofgem, 2018)

Ofgem considered that the SHM was not fit for purpose over the longer term as it caused barriers to innovation through inaccessibility to data, complexity of industry codes and the entrenched role of

[15] Consumers who produce part of their own electricity demand through the use of generation technologies at their property are termed 'prosumers' as they produce as well as consume electricity

traditional suppliers within the energy system. This meant that it was difficult for market participants to bring beneficial, and potentially disruptive, propositions to market (*ibid*). However, at the time of reporting in 2018 this was still unresolved.

Has it been resolved?

In July 2019 BEIS and Ofgem launched a consultation on 'Flexible and Responsive Energy Retail Markets' (BEIS and Ofgem, 2019a) which stated that:

> "*We recognise that in order to meet our* [net zero] *goals, fundamental change needs to take place and happen quickly…….The retail market design, including the 'one size fits all' supply licence, which has for so long defined the energy system for consumers, is starting to hold back progress by preventing consumers from benefitting from innovation, and is slowing down decarbonisation."* (BEIS and Ofgem, 2019a p.10-11)

The consultation proposed a 'flexible, modular approach to regulation' which would help to remove regulatory complexities, making it easier for new entrants to understand the rules and provide investor confidence. The changes were also hoped to help accommodate demand-side response services and flexibility opportunities.

Overall, we welcomed this consultation and BEIS and Ofgem's acknowledgement that regulation needed to be redesigned with consumers in mind. However we also thought that the consultation concentrated too heavily on retail price, whilst failing to adequately consider the full remit of what drives that price, such as the relationships between network regulation, network charging, market design etc. (Mitchell *et al.*, 2019) which are all factors discussed in this report.

We delayed publication of this report in anticipation that the long awaited 'Energy White Paper' would address retail market issues. However, despite Ofgem's recognition in 2018 that the SHM is 'not fit for purpose' and both BEIS and Ofgem's recognition that 'fundamental change needs to take place and happen quickly', the Energy White Paper published in December 2020 (BEIS, 2020b) has not made any determination on the SHM's future; instead pushing decision-making further down the road through "*engaging with industry and consumer groups throughout 2021 before a formal consultation*." The paper also states that government will:

> *"assess whether incremental changes, alongside wider sectoral initiatives, are sufficient or whether more fundamental changes are required."* (BEIS, 2020b p.35)

This is disappointing given both BEIS and Ofgem's earlier recognition that fundamental reform was necessary.

In the meantime *some* incremental changes have occurred or are in progress. For instance, following the government's demise of the Feed in Tariff as of April 2019, Ofgem introduced the Smart Export Guarantee in January 2020 (Ofgem, 2020a) for licensed electricity suppliers to make payment to small-scale low-carbon generators for electricity exported to the grid. In addition, the proposed Local Electricity Bill (Parliament, 2020) would enable suppliers to trade only at a local level, without having to incur the costs and responsibilities of national suppliers. However, neither of these actually overcome our previously reported barriers as they still rely on suppliers' undertakings.

More encouragingly, proposed modifications to the Balancing and Settlement Code (BSC) would help overcome **some** of the trading difficulties posed by the SHM. Modifications currently being explored include:

P375 'Metering behind the Boundary Point'

Modification P375[16] would offer balancing using metering equipment 'behind the meter' (BTM). By determining settlement BTM, instead of at the meter boundary point, this would open up customers' access to the Balancing Mechanism in line with Project TERRE directives (see Section 2.5 below). In short, this would mean that both industrial and domestic customers could engage in flexibility trading through a third-party such as a LEM or an aggregator, without affecting their main supplier's imbalance position, thus negating the need for any financial compensation to the main supplier or for a contractual agreement made with them before trading occurred. However, it still wouldn't be possible for customers to engage in direct P2P arrangements as the Modification doesn't enable the direct trading of electricity (e.g. from household to household) as transactions would still have to go through a registered third party who would deal with metering and settlement.

P379 'Multiple Suppliers through Meter Splitting'

Modification P379[17] would enable customers to buy electricity from multiple suppliers thus widening customers' choices for supply. Recent research (Watson *et al.*, 2020) points to multiple supplier models being a promising avenue for driving the growth of local energy. Whilst it is envisaged that customers would still have one dedicated licenced supplier, they could also, for example, purchase locally generated electricity from a community energy scheme and / or take out a contract on an EV which gave a dedicated amount of free or reduced cost charging. This could open up options for a LEM to act as a secondary supplier to both industrial and domestic customers.

Whilst these Modifications would be extremely welcome if they were passed there is no target date as yet for their implementation. They are both undergoing lengthy assessment processes (P375 was first presented in December 2018' and is after various assessments and consultations will next be reported on again on 10 December 2020. Meanwhile P379 was first presented in January 2019 and is currently awaiting a cost/benefit analysis which has been stalled through to Covid-19 restrictions).

However, both Modifications only constitute tweaks to the current market arrangements, rather than provide an overhaul of the SHM. This is a recurring theme in energy policy, with BEIS and Ofgem relying on minor adaptations to the existing structure (brought by external parties at their own expense) rather than replacing the structure with fit for purpose measures. As can be shown by these two examples, and the response of the Energy White Paper to the SHM, it remains very uncertain that real change ca and will happen in a timely manner. This creates uncertainty for LEMs markets and for similar innovative business models in the meantime.

[16] More info here: https://www.elexon.co.uk/mod-proposal/p375/

[17] More info here: https://www.elexon.co.uk/mod-proposal/p379/

What needs to happen?

We urge BEIS to immediately consider change to the SHM, building on the Call for Evidence raised by Ofgem in 2017 which aimed to address this issue. Concentration should be given to the future role of energy suppliers and whether their remit will be extended to other market actors. We hope that by removing trading barriers this will widen the scope for local energy markets and offer LEM participants the opportunity to buy and sell electricity from local participants, as well as being able to buy from and sell to external/national markets. In the meantime the adoption of Modifications P375 and P379 should be speeded up.

If the need to transact via a licensed supplier remains, this will drive P2P trading in a certain way and consideration should be given to whether this would be optimal. However, we are not convinced that a direct P2P market (without any third-party involvement) is feasible until proper safeguards are in place regarding dispute resolution. In this respect we recognise the role that suppliers currently undertake in providing settlement, balancing, metering and billing, as well as guaranteeing a continuous supply of service and acting as a point of dispute resolution. We do think however that barriers should be removed to enable other providers, such as LEMs, to take on this role for meeting safe and secure standards of operation on behalf of customers. This would further enable local trading of not just flexibility provision, but also energy provision, which could help to self-manage the networks, thus reducing network constraints.

2.5 Access to national markets

The Cornwall LEM project did not attempt to access any national markets, although it did trade with the ESO for the purposes of trialing how DNOs and the ESO could procure flexibility simultaneously, ensuring that contracts at the national level did not adversely impact the local network.

What was the problem?

The wholesale electricity market was seen as particularly difficult for DER to enter *directly* due to the costs involved with registering, licensing and trading in this market. Although Ofgem had introduced new rules to accessing the wholesale market in 2014 to create a 'more level playing field' for independent suppliers and generators (Ofgem, 2013) this had little impact on the volumes entering the wholesale market from these actors due to several other inhibiting factors (as reported in more detail in both our 2018 report '*Policy and Regulatory Barriers to Local Energy Markets in GB*' (Bray, Woodman and Connor, 2018) and our 2019 report '*Barriers to Independent Aggregators in Europe*' (Bray and Woodman, 2019).

In addition, small generators and independent aggregators[18] were unable to access the Balancing Mechanism (BM) as it wasn't possible to aggregate generation from multiple sites into a single Balancing Mechanism Unit (BMU), making it difficult for them to compete with larger power stations.

[18] Aggregators bundle together generation and flexibility from multiple sites to act as one combined unit in electricity markets; thus enabling participants to engage in markets which they could not have accessed individually, either due to volume restrictions or licensing restrictions (Bray and Woodman, 2019).

Has it been resolved?

We do not address the design and operation of the wholesale market, the Capacity Market or the ancillary services market again in this report, as we have already covered these in our two reports referenced above. However, there have been positive changes to access to the BM which we update on here.

European balancing project TERRE[19] (AAMHE *et al.*, 2016) has indirectly eased access to the BM for independent aggregators and smaller generators, by requiring modifications to the Balancing and Settlement Code (BSC), Connection and Use of System Code (CUSC) and the Grid Code in order for GB to align with European Project TERRE requirements which state that "*DSR must be allowed to compete on a level playing field with traditional flexibility providers*". We outline these changes in Table 1.

Although the TERRE platform went live in some EU countries in January 2020, the UK's admission to the platform has been delayed, perhaps permanently. This is due to the UK's Transitional Arrangements for leaving the EU ending as of 31 December 2020 and the ratification of a free trade agreement on energy by the EU and parliament not (as yet) achieved (National Grid, 2020). Nevertheless, the Modifications shown in Table 1 that have been implemented, in anticipation of entry to TERRE, will remain in place.

Table 1

Mod no / Code	Description	Status
P344 / BSC	Creates a new type of BSC participant, a 'Virtual Lead Party' (VLP) which can register Secondary BM Units (minimum size 1 MW) and hold a Virtual Balancing Account. Under this model VLPs do not become full Balance Responsible Parties (BRPs) and as such this role can be fulfilled by independent aggregators or others parties which can aggregate flexibility provision. This therefore enables these parties to access the BM for the first time. In addition, whilst Secondary BMUs can be individual units (1 MW+) they can also be aggregated across a Grid Supply Point Group (GSPG) level rather than at the Grid Supply Point (GSP) level which therefore enables smaller generators and flexibility providers (below 1 MW) to access the BM by aggregating their flexibility into one BMU package. However, the responsibility for ensuring units within a Secondary BMU are balanced currently remain with the registered supplier of each site at which a unit is located (although implementation of P375 (see section 2.4 above) would remove this restriction). This could therefore cause contractual issues between suppliers and flexibility providers until P375 is resolved.	Technically implemented in Feb 2019[20] with a partial go-live achieved in Dec 2019. The remainder of the Mod will be implemented when /if Project TERRE goes live in the UK.

[19] More info here: https://www.entsoe.eu/network_codes/eb/terre/ and here: https://www.elexon.co.uk/mod-proposal/p344/

[20] At which time interested parties were able to register their interest.

CMP295 / CUSC	Seeks to create a contract under the CUSC for VLPs which will tie them into the relevant parts of the CUSC and the Grid Code relevant to BM participation. CMP295 is currently still in proposal.	Still in proposal
GC0097 / Grid Code	Aligns the Grid Code with the BSC which allows Secondary BMUs to be aggregated at a GSGP (a wider geographical area than the original GSP level).	Approved Sept 2018

Aggregator firm Limejump (who hold a supplier's licence) became the first company to trade an aggregated unit in the BM in August 2018 and the first to trade batteries in the BM. Limejump's 168 MW virtual power plant (VPP) was also the first BMU to be aggregated across multiple GSPs. The VPP was able to enter the BM after Ofgem granted a derogation from Grid Code requirements, enabling BMU data to be aggregated at the GSPG level. That derogation was specific to Limejump, however once Ofgem approved Mod GC0097 in September 2018, this allowed other licensed suppliers to do likewise; although independent aggregators and flexibility providers without a supply licence had to wait until Mod P344 was implemented.

2.6 Data

What was the problem?

Data, communications networks and information flows are increasingly viewed as integral parts of a modern, digitalized energy system (Ofgem and BEIS, 2017; Sandys *et al.*, 2019). As the energy market transition unfolds data can help improve distribution system planning and operation, integration of distributed energy resources (DER), and enabling the provision of flexibility services. Good quality data also substantially strengthens the planning and operation of LEMs. For example, network performance and management data can help identify trading opportunities in areas where flexibility could ease constraints. More granular consumption and export data is also necessary to facilitate forms of localized trading, such as P2P, while ensuring the grid remains balanced. Furthermore, improved market data supports accurate and transparent monitoring of LEM trades and function, improving participant trust in the market and highlighting potential governance issues such as gaming. However, issues concerning data visibility, sharing, privacy, and quality were identified as barriers to the positive potential for data to support LEM development.

Has it been resolved?

Data governance represents an area of significant policy growth in the energy sector. At the level of central government the Modernising Energy Data (MED) collaboration, co-led by BEIS, Ofgem, and Innovate UK, is ongoing. Within Innovate UK, the Energy Systems Catapult (ESC) and its Energy Data Taskforce (EDTF), are additional key players in research and policy development. Expanding from the energy sector, the recently established BEIS Smart Data Taskforce aims to coordinate smart data infrastructure and standards development across regulated sectors such as energy, water and finance (BEIS, 2020d). Key policy developments are discussed below.

Data and Asset Visibility

In response to opacity regarding what datasets exist in the energy system, who holds these, and how they are described, the EDTF have recommended the establishment of a sector 'Data Catalogue' (Sandys *et al*, 2019). The catalogue will list datasets using the Dublin Core 'Core Elements' metadata standard ISO 15836-1:2017 (ISO, 2017), which is now also recommended for use across the sector (Modernising Energy Data, 2020). The Data Catalogue prototype is expected to be available by summer 2021 (BEIS, 2020b p.82) and represents a significant policy shift towards more data transparency in the sector.

In addition to improving dataset visibility, recommendations for a national asset register and digital systems map have been made (Sandys *et al.*, 2019). These initiatives could help LEMs by increasing system transparency and supporting strategic analysis of flexibility service potential. Both items above remain under development at present and their granularity remains unclear. In order to maximize their value in a more distributed energy system, including for LEM function, it will be vital for these initiatives to include assets below the 1MW clip size and behind the meter (Judson, Soutar and Mitchell, 2020).

Data Sharing

The 2019 EDTF report recommended adoption of the new 'Presumed Open' principle, whereby data should be made as open as possible by default (Sandys *et al.*, 2019). Open data is defined as data 'made available for all to use, modify and distribute with no restrictions' (Modernising Energy Data, 2020). The Presumed Open principle concerns all data relating to common assets defined as 'a resource (physical or digital) that is essential to or forms part of common shared infrastructure' (Modernising Energy Data, 2020). A triage process was also proposed in order to decide which datasets are safe to be made open (Modernising Energy Data, 2020). Where data cannot be opened, justification for this decision must be provided; for example grounds of privacy, security or commercial interest may be considered legitimate for retaining data closure.

While this principle currently invites voluntary compliance, in June 2020 Ofgem proposed a new license obligation requiring network companies' adherence to Presumed Open and broader MED data best practice guidance (Ofgem, 2020e). The new obligation is expected to come into force in 2021 for RIIO2 and 2023 for RIIO-ED2. It will accompany another new regulatory requirement for network companies to publish their digitalisation strategies on an annual basis and to report regularly against their plans (Ofgem, 2019a, 2019d, 2020e). Ofgem has elaborated on expectations for distribution network data openness in particular, stating that they wish networks to make four types of operational data available: configuration data, outage data, constraint data, and utilisation/historian data (Ofgem, 2020d). Open access to these datasets will be highly valuable to LEMs so long as sufficient granularity is provided and regular update schedules are adhered to.

Privacy and security

Two main frameworks govern access to smart meter data in the UK: General Data Protection Regulation (GDPR) and the Data Access and Privacy Framework (DAPF). The Data Protection Act (DPA) 2018 is the UK's implementation of the General Data Protection Regulation (GDPR) and contains provision for establishing the Information Commissioner's Office (ICO) as an independent regulatory body for data protection.

GDPR governs the processing of personal data, defined as '... information relating to natural persons who: can be identified or who are identifiable, directly from the information in question; or who can be indirectly identified from that information in combination with other information.' (ICO, no date). Smart meter data is classified as personal data and is thus subject to GDPR. A key consequence of this is that individuals or organizations wishing to process smart meter data must acquire opt-in consent from the data subject (household) to do so.

The DAPF is a framework that works in parallel with the GDPR and was originally created to set out enhanced privacy provisions built into the smart meter rollout. The DAPF was upheld by BEIS under review in 2018 and thus continues to control access to smart meter data related to domestic properties and microbusinesses. The DAPF contains more detailed provisions for smart meter data access than the GDPR, specifying separate conditions for suppliers, distribution network operators, and third parties' access. Classified as third parties, LEM access to household-level smart meter data at any granularity would be contingent on becoming a signatory to the Smart Energy Code and meeting associated requirements regarding (cyber)security, opt-in consent, and regular consent reminders, among others (Smart Energy Code Administrator, 2020). While this may add an additional level of complexity to LEM operation, it would not present an unsurmountable barrier to smart meter data access if appropriate consents are given by market participants. However, consents being denied or rescinded presents an operational risk for LEMs.

Gaining access to smart meter data for other purposes, such as planning, may require a different approach based on aggregated and/or otherwise anonymized data. Access to this type of data is permitted by GDPR without consent so long as data is sufficiently aggregated or otherwise anonymized as to ensure individuals cannot be re-identified. In this circumstance while the data itself does not pose a privacy concern, 'The challenge comes in how the input [non-aggregated] data might be collected and how privacy plays into that process' in the absence of a central access point for the data or 'trusted processor' responsible for anonymization (Frerk *et al.*, 2019).

Limitations

Despite several positive developments outlined above, there are still significant gaps in the technical and policy infrastructures required to facilitate effective use of data in the energy sector. Two of these gaps are particularly pertinent to data issues encountered by LEMs.

Firstly, issues surrounding data quality, format, granularity and update schedules remain unresolved in many parts of the sector in absence of definitive standards. These issues are likely to become more complex as more and more varied devices become part of energy systems (IET, 2016). As such, even where data can technically be opened or shared without friction, its usability may be compromised. For example, data made available in non-machine readable formats may require investment in cleaning and processing before use. Furthermore, poor data quality can lead to risk and liability issues for downstream use. For example, if inaccurate data is used to inform flexibility procurement, this could lead to price distortions within a LEM or failure to balance supply and demand.

Secondly, the push for Presumed Open does not address barriers to sharing data that is not openly licensed[21], but could be productively used by trusted parties under specified conditions. Development of policy and standards in this area is likely to be more complex than addressing open data, however it would help to increase fluidity across the full data ecosystem. For LEMs, improved data sharing policy

[21] Either due to restrictions to making data open, or where datasets are controlled by non-regulated actors not obliged to comply with the Presumed Open principle.

could potentially support access to more granular or sensitive data required to improve market planning and operation. It could also streamline data access processes, reducing time and costs associated with negotiating multiple bespoke access contracts.

What needs to happen?

Despite present gaps, recent expansion of data governance work across the energy sector suggests that these issues are entering the mainstream policy agenda. The upcoming Energy Data Strategy expected from BEIS and Ofgem in 2021 offers a chance to cement this (BEIS, 2020b). There is also evidence that similar issues are being faced across other sectors, prompting initiatives for cross-sector policy coordination in this space (BEIS, 2020a). To ensure that that these developments enable rather than constrain activity, LEMs may be compelled to take a more active role in future data policy discussions.

3. CONCLUSION: FUTURE PROSPECTS FOR LEMS

The renewables sector needs to expand rapidly if we are to meet our net-zero commitments for 2050. This includes renewable generation connected at both the transmission and distribution level, and this will in turn demand new thinking about how we construct, operate and regulate our electricity networks if we are to do it efficiently.

In this context, the Cornwall LEM project is a proof of concept which has shown that distribution connected renewable and storage capacity can provide system services to provide flexibility and enhance distribution network management. It has also shown that there is demand for such a trading service with both the DNO and those at business or domestic level with renewables and storage capacity. Finally, it has demonstrated that local energy markets may be novel, but they are both feasible and viable, and will provide new ways of ensuring the economic viability of renewables and storage while providing tangible services to the distribution network operator. Both of these are vital if we are to achieve the net zero commitment.

As described in Section 2, there are an abundance of policy, regulatory and market reform initiatives in progress, or under consultation, which can either aid or hinder the evolution of LEMs. For instance, we have described how the DNOs are on a (long) journey to becoming DSOs and taking on a wider remit with regard to purchasing flexibility products and balancing demand and supply flows across their networks. We have also outlined changes to the network charging structures and connection procedures, which will determine how the DNOs are paid in future for their services and by whom. We also outlined how trading limitations and access to markets can hamper future LEM opportunities and the need for robust and open data to underpin decision-making by all actors involved.

Although BEIS and Ofgem have oversight of all of these initiatives, they each appear to be progressing to some extent within individual silos. However there are increasingly complex interdependencies between them, particularly at the distribution network level, which need to be clearly understood if they are to be considered as complementary to achieving a net-zero outcome. At present some of these initiatives not only seem to be divorced from one another, they also seem divorced from achieving a 'smart and flexible energy system' as directed through BEIS and Ofgem's '*Smart Systems and Flexibility Plan*' (BEIS and Ofgem, 2017)[22].

This is because how the networks are operated, managed, regulated, costed and used is an interlinked and iterative process; one which will dynamically change over time (Bray and Mitchell, 2018; Mitchell *et al.*, 2019). To reduce carbon emissions to net-zero by 2050, both heat and mobility will need to face much higher levels of electrification over the next few years, which will place a higher burden on the distribution networks. However, DER can help to offset network usage; whilst local trading and complementary mechanisms such as ToU tariffs and smart charging of EVs could help to smooth out demand peaks and seek to self-manage network constraints. Additionally, if new localised market arrangements evolve, then generation will be travelling shorter distances across the networks. All of these factors have implications for how transmission and distribution networks are coordinated and the way in which network charges and use of system charges are calculated. A traditional economic approach to regulating networks will therefore not be workable in a dynamic, smart, flexible, net-zero energy system (Bray and Mitchell, 2018).

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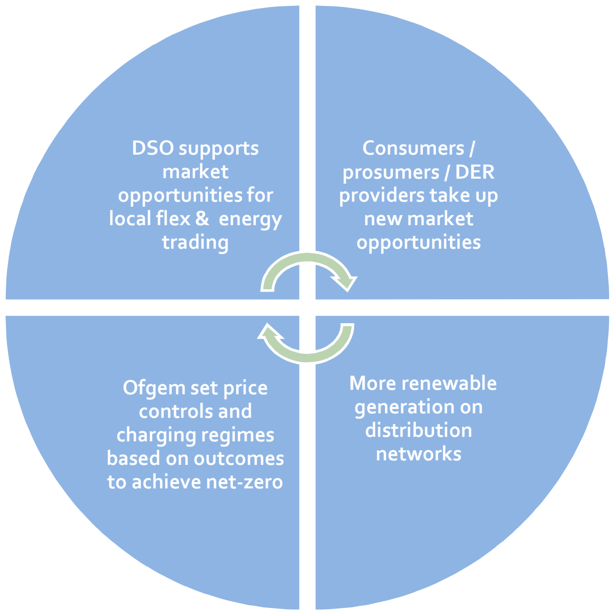
[22] BEIS and Ofgem are due to publish a new Smart Systems Plan in spring 2021 (BEIS, 2020b)

In this dynamic interlinked future the way in which the networks are operated and coordinated will shape how and when future local market opportunities emerge; whilst the consumer take-up of these local markets will shape future network usage and associative costs as shown in Figure 5. This then becomes a virtuous circle, as opposed to the vicious circle depicted earlier in Figure 1. Underpinning this our other key themes of the Supplier Hub Model reform (the trading rules), the ease in which DER can access trading markets, whether that access will be curtailed by the network, and access to the data necessary for decision-making, are all necessary and interlinked components.

Figure 5 The interlinked and iterative process of network coordination, market access and regulation



Given the interrelated issues that we have identified as vital to enabling the emergence of LEMs, the current silo thinking of BEIS and Ofgem is not fit for purpose, and a more holistic, strategic approach is needed. Instead of thinking about how to address individual problems as they are identified, there needs to be a clear vision about how to deliver networks which will allow the electricity system to deliver net-zero generation as rapidly as possible. As a first step then, BEIS needs to urgently produce a strategic roadmap concentrating in particular on the future role of DNOs as active system operators, and present a framework for Ofgem's regulation of the distribution networks which will address the charging and connection shortcomings identified in this report. The driving force behind this strategy and framework should be 'where do we need to be' rather than the current approach of 'where are we starting from'.

Overriding change can only happen through BEIS developing a new market structure. In addition, Ofgem need to take more control over what happens at the distribution network level. This should include an overhaul of the RIIO programme to ensure that network operations are properly incentivised to act in accordance with guidance, and in a timely manner.

What would this mean for LEMs?

The Cornwall LEM as trialled was developed to enable it to work within the current regulatory framework, as well as to draw attention to the changes required to maximise the value that local flexibility markets can offer over the short to medium term. The Cornwall LEM could have taken a different route, but they wanted to trial a version that could be made to work commercially in the near term and which helped to move the regulatory and industry agenda forward.

For example, the Cornwall LEM designed their online market platform such that non-network or system operators (i.e. peers) could act as buyers as well as sellers. However, they did not include that functionality within their trials due to the regulatory barriers to trading (the Supplier Hub Model rules). In addition, the current ANM and LIFO system would have acted as a barrier to the effective use of DER trading at the local level. The Cornwall LEM to some extent was ahead of its time – the top-down hierarchical electricity system was not yet equipped to cater for a locally driven, consumer-focused, market design and in this respect could not take advantage of the benefits that such a system should be expected to achieve (e.g. local tariffs, local trading opportunities, locally retained energy spend, reduced DUoS charges etc.). Despite this, the Cornwall LEM was very successful in what it *did* achieve, working within the current policy, regulatory and market parameters and therefore provided a useful proof of concept.

The Cornwall LEM can also be seen as a forerunner to other emergent projects currently in development across the UK under the government funded Prospering for the Energy Revolution (PFER) Programme.[23] However without addressing the issues highlighted within this report, future projects will face the same policy, regulatory and market barriers. Therefore, if we are to make local energy markets a mainstream option, additional reform will be urgently required. We hope that the lessons learnt from the Cornwall LEM will help future projects unlock these barriers.

[23] More information can be found here: https://www.gov.uk/government/news/prospering-from-the-energy-revolution-full-programme-details

4. APPENDICES

Appendix 1 Overview of the LEM flexibility trading platform and trials (WP1)

The LEM online market trading platform enabled the buyers (WPD and National Grid ESO) to place bids for flexibility[24], which the platform then matched with seller offers (the LEM participants) through auctions that ran from months ahead, through to week ahead, day ahead and intraday, with a gate closure two hours ahead of dispatch time.

The market trials occurred in 2 phases (see Box 4). Phase 1 trials commenced in May 2019 and ran until August 2019 and were conducted with WPD under a Quote and Tender arrangement (whereby WPD quoted their flexibility requirement and sellers tendered for the service). Thirteen events were scheduled during Phase 1 with WPD paying in the region of £300 p/MWh for a total combined capacity of 18MWh (WPD, 2020). Events were either for demand turn-down / generation output (to increase volume on the network) or demand turn-up (to decrease volume on the network).

Box 4 Market Trials

Feature	Phase 1	Phase 2
Purchasing method	Quote and Tender	Spot Market
Trial duration	May 2019 to August 2019 – with WPD only	September 2019 to December 2019 both WPD and National Grid December 2019 – March 2020 National Grid only
Conflict resolution[25]	None	Included in the market clearing algorithm and Transmission / Distribution coordination was supported via the dashboard providing visibility of services purchased by each party
National Grid participation	No	Yes

Source: Adapted from 'Visibility Plugs and Sockets Closedown Report' (WPD, 2020)

Phase 2 trials commenced in September 2019 and ran to December 2019 with WPD and National Grid ESO both procuring services; and then from December 2019 to March 2020 with just National Grid ESO. Phase 2 ran as an auction-based spot market for flexibility services, as a contrast to the tender model in Phase 1. The spot market was designed to allow for joint procurement by both WPD and National Grid ESO concurrently to test how such an arrangement would operate as this joint procurement arrangement had never happened in practice prior to these trials. The LEM platform

[24] Demand turn up / turn down, generation export / turn off, or storage export / import.

[25] Conflict resolution was needed when the two parties were purchasing in the same time frames as this could potentially lead to actions taken by one party (e.g. National Grid) causing negative impacts to the other party (e.g. WPD). Therefore any conflict had to be managed through coordination and the clearing algorithm of the platform. This was the first time in GB that joint purchasing by both the ESO and a DNO had occurred and so it was a 'learning by doing' opportunity for both parties.

coordinated DNO and ESO flexibility procurement ensuring conflicting resources were not simultaneously dispatched, and that contracts for national services did not increase or create congestions at the local level.

In Phase 2 there were 77 reserve contracts (flexibility which was reserved by WPD or National Grid to be dispatched if called upon), and 49 utilisation contracts (flexibility which was actually called upon) cleared by the platform. The total contracted volume was 218MWh of reserve capacity of which 99MWh was actually utilised.

Although the Cornwall LEM project funded installations that would enable both I&C and domestic customers to provide flexibility services, fewer flexibility customers were recruited than were originally expected, which can be attributed in part to location, the lack of available appropriate network connection capacity and the lack of industrial and commercial loads that may be attracted to flexibility offerings. The customers that were recruited, however, provided significant combined capacity (18MWh in Phase 1 and 218 MWh in Phase 2) (WPD, 2020).

Appendix 2 Overview of the residential battery storage installation and trials (WP2)

One hundred households were recruited to take part in the residential trials. All 100 households had an independent monitoring system and a Sonnen home battery installed free of charge (paid for by the LEM project) in order to take part in the project. In addition, 54 of the households had solar PV installed at their property free of charge; whilst the remaining 46 households already had PV installed. The householders were also encouraged to use a Sonnen App to monitor their daily electricity usage.

Three different capacities of batteries were installed across the households, depending on the household's estimated energy, the capacity of any previously installed PV array, whether the participants also charged an EV, or had any other large load appliance installed. The batteries supplied were either 5kWh (61 batteries); 7.5kWh (24 batteries) or 10kWh (15 batteries).

As part of the domestic trial, Centrica remotely discharged the home batteries simultaneously, at previously determined times and dates. This was to test the feasibility of trading the aggregated battery output into the LEM platform trials which were being undertaken with WPD and National Grid ESO. The householders were given written notification of when these trials would be occurring. As the trials were undertaken remotely by Centrica, the householders were not actively engaged in using the trading platform themselves; although they were aware of the purpose of the trials in proving the feasibility of the LEM concept.

Appendix 3 Overview of the I&C workstream (WP3)

In total, 252 Cornish businesses and organisations had some form of contact with the Cornwall LEM project through the I&C workstream offerings. The workstream comprised 3 dedicated services which could be awarded to these organisations:

1) Installation of significant capital equipment at client sites.

2) Grant award of £1000 or more towards the cost of an advanced electricity sub metering system.

3) Non-financial assistance in the form of a minimum of 12 hours energy related expertise.

Once contact was made with an organisation, typically an arrangement was made to visit the site by one of the LEM project's energy engineers, who would conduct an initial walk-through survey and discuss the site's energy situation and forward strategy. The initial visit and discussions might then be followed by more targeted discussions and meetings if a potential solution for inclusion in the LEM project was identified (Parish, 2020).

Inevitably not all sites / participants progressed through to receiving one of the three service offerings, either through the organisation withdrawing from the project or through the Centrica LEM team being unable to support a request. For instance, in several cases, the availability and cost of a new network connection; the upgrading of an existing connection; or the addition of export capacity to an existing connection, became a defining factor in project viability (Parish, 2020). Consequently, although 14 organisations engaged in detailed discussions, designs and negotiations with respect to major asset installations; of these, only 6 organisations progressed through to receiving grant funding to build out smart energy infrastructure.

Assets installed included battery storage systems, combined heat and power plant (CHP) and utility scale wind and solar power generation equipment. The total renewable energy capacity installed under the project exceeded 4.8 MW with a further 2.6 MW of battery capacity.

In addition to the 3 service offerings shown above, the Cornwall LEM team, in association with the project's research partners the UoE and Imperial College London, created a Knowledge Exchange Partnership (KEP) which any organisation in Cornwall was able to join. The KEP held a series of bi-annual seminars throughout the project period aimed at providing organisations with up-to-date advice on emerging flexibility markets, including guest speakers from industry. Speakers included representatives from BEIS, WPD (the local distribution network operator) and aggregators[26] working within Cornwall as well as presentations from the research partners.

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- Western Power Distribution
- National Grid
- Centrica's Cornwall LEM team

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We also thank Emily Judson for writing Section 2.6. and Dr. Jeffrey Hardy for reviewing the policy context.

[26] Aggregators bundle together generation and flexibility from multiple sites to act as one combined unit in electricity markets; thus enabling participants to engage in markets which they could not have accessed individually, either due to volume restrictions or licensing restrictions (Bray and Woodman, 2019)

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