12th January 2017

SP Energy Network's Response

A SMART, FLEXIBLE ENERGY SYSTEM

BEIS/OFGEM Call for Evidence

SP ENERGY NETWORKS

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SPEN Response-
A Smart, Flexible Energy System Call For Evidence

FOREWORD

I am pleased to see that the Government and Ofgem have released this Call for Evidence, providing stakeholders with an opportunity to inform their thinking at a critical time of change in the energy sector.

This is no longer a theoretical debate as the transition to a smart, flexible system is already underway on our SP Distribution and SP Manweb networks areas. We now have more than 3GW[1] of distributed generation connected to our networks with a further 3GW[2] contracted to connect. In many cases, we are connecting in areas with low levels of local electricity demand raising additional challenges versus high demand areas where local generation can be absorbed more easily. These challenges have led us to focus on innovative solutions that ultimately seek to maximise the existing assets that we own and operate, minimising costs to our connecting customers and supporting faster connection of low carbon renewable generation. This innovative approach has been widely supported by developers operating in our areas and they have highlighted the uniqueness of our approach in the UK.

Our innovation projects have made it possible to connect over 100MW of generation through Active Network Management that would otherwise have been unable to connect until 2023, resulting in customer and wider societal benefits of £18m. We also have a further 1.3GW of accepted flexible connection offers. To date this has been possible through innovation mechanisms, focused customer service and very limiting (De Minimis) mechanisms within the distribution price control. To fully realise a smart, flexible energy system, a more complete review of system charging will be required to ensure that network operators have a sustainable commercial framework to ensure that smart solutions become business as usual options for all GB customers and developers.

As well as the commercial and technical challenges there are some very critical practical areas that have to be recognised and agreed.

At the heart of any smart, flexible system will be a robust, reliable and more fully integrated communications network. This will inevitably lead to an increase in operating costs for network companies when compared with the communication infrastructure that they currently employ.

It is essential that we maintain our focus on providing security of supply to existing and future customers. This will be especially challenging given the closure of large scale thermal plant across the UK. We will need new and innovative approaches to ensure that the changing mix of generation can contribute to system recovery actions following a potential high impact, low probability black start event. In addition, we must consider the threat to system security from cyber security. Traditionally, electrical networks were protected through their isolation from standard communication channels. Any smart network will inherently be highly integrated and the potential risk to the economy of a successful cyber-attack should be quantified and mitigated.

The growth in de-centralised energy does not reduce the need for an interconnected transmission network. Local system balancing in many cases will still result in geographical and network areas

[1] SP Distribution 1.7GW connected, SP Manweb 1.6GW connected
[2] SP Distribution 2.1 GW contracted, SP Manweb 1.2GW contracted

of net export or net import, only by balancing these areas on a national level will we maintain a high level of system security and quality of supply. An example of this is our Dumfries and Galloway network area which we are planning to trial as a DSO enabled network area. The Dumfries and Galloway area has a local peak demand of 190MW, with 340MW of connected distributed generation and a further 660MW contracted to connect. Whilst we believe we can facilitate the majority of the contracted generation in this area through real time network monitoring and control, no smart solution will preclude the requirement for transmission interconnection.

This call for evidence highlights the potential network benefits of storage technologies, and whilst I agree that storage could resolve a range of network issues, it must be considered alongside other flexible network solutions. Where storage does indeed provide the lowest overall lifecycle cost solution, it should be employed primarily through an open market approach. There may be instances however, where there is insufficient market incentive for developers to install network storage on the network, in this instance transmission and distribution network operators should be able to own and operate storage. Where network operators own and operate storage it will be for the purpose of running a reliable network at lowest cost to customers. We will not seek to participate in energy trading markets such as arbitrage and in the event that DNO owned storage provides an opportunity to act on participate in energy trading markets we will agree commercial terms with a third party operator to do so.

The recent independent review of the Low Carbon Network Funding[3] identified £800m to £1.2bn net benefits created to date through the innovation mechanisms available to network operators. The potential for even greater benefits was highlighted in Ofgem's network innovation review consultation[4]. Now is not the time to amend an innovation mechanism that has demonstrated its value and supported the developments that have given us great insight into a smarter system.

The evolution of the energy sector towards a smarter system will be simpler, faster and cost effective if Distribution Network Operator's (DNOs) play an active coordinating role between all market participants, facilitating the markets and services in a neutral and non-discriminatory manner. This can be achieved by extending the current role of DNOs to that of Distribution System Operators (DSOs). An effective DSO model will reduce system balancing costs, whilst enabling the flexible networks necessary to facilitate customer's use of low carbon technologies. It is my view that DNOs should carry out this coordinating role as we have the infrastructure, information and experience of running a local network and as outlined we have also started to carry out local system balancing via Active Network Management. DNOs are also best placed to do so whilst maintaining their primary roles of ensuring a safe and reliable system.

However, I recognise there are different views on who should operate the DSO. It may be appropriate to revisit the responsibility for providing DSO services in the future when this model has reached a mature stage, but in the early stages of this transition DNOs are most likely to deliver a successful DSO model that facilities efficient and faster delivery of a smarter system.

[3] https://www.ofgem.gov.uk/system/files/docs/2016/11/evaluation_of_the_lcnf_0.pdf
[4] https://www.ofgem.gov.uk/system/files/docs/2016/12/innovation_review_consultation_final.pdf

In October of 2016 we published Our DSO Vision[5], which was developed collaboratively with key industry stakeholders including local government[6], National Grid and a range of industry parties at the heart of the DNO to DSO transition. Our DSO Vision seeks to facilitate an open and inclusive market for communities, aggregators, storage developers, and existing providers of network balancing services. In 2017, we will build on our vision document to develop a more detailed route map, identifying in detail the technical, commercial and regulatory actions required to realise our ambition of becoming a DSO. We will also work with customers, Government and industry to ensure that the model of a DSO for the UK is aligned, to the extent that regional and network differences allow.

In summary, the DNO to DSO transition is a key enabler for an efficient and effective low carbon network in the UK, to achieve this it is essential that we have a coordinated and supportive regulatory regime. It is also my view that the DSO model outlined in our DSO vision document best meets the current needs of our customers and wider stakeholders, whilst providing the greatest flexibility to meet the future requirements of energy users in the UK.

Frank Mitchell
Chief Executive Officer
SP Energy Networks

[5] http://www.spenergynetworks.co.uk/userfiles/file/SPEN%20DSO%20Vision%20210116.pdf
[6] Damon Hewlett - Grid, Regulation & Generation Policy, Energy Markets advisory member - SPEN DSO Steering Group

1 INTRODUCTION

SP Energy Networks is the networks business of Scottish Power and holds three electricity network licences. We own and operate the electricity distribution networks in the Central Belt and South of Scotland (SP Distribution) which serves two million customers, and Merseyside and North Wales (SP Manweb) which serves one and a half million customers. We also own and maintain the electricity transmission network in the Central Belt and South of Scotland (SP Transmission), although this is operated by National Grid, in its role as the National Electricity Transmission, System Operator of Great Britain.

The supply and generation businesses in the Scottish Power group are managerially and operationally separate to the networks business as required by the licensing regime and the EU Third Package. SP Energy Networks is therefore "ring fenced" from the other parts of the Scottish Power group.

Our functions and duties are governed by our licences and by relevant legislation. We are subject to full economic regulation unlike the competitive sectors of the energy market.

2 REMOVING POLICY AND REGULATORY BARRIERS

2.2 ENABLING STORAGE

1. Have we identified and correctly assessed the main policy and regulatory barriers to the development of storage? Are there any additional barriers faced by industry? Please provide evidence to support your views.

We believe that the majority of the main policy and regulatory barriers have been identified.

Electrical energy storage has a part to play in addressing future network challenges, however, it will need to compete on a level playing field with alternative conventional and smart technologies, with no inappropriate levy charges. Care should be taken to ensure that energy storage providers are fairly but not excessively compensated for the services that they provide. This will be a complex challenge as it is expected that most energy storage providers will only be financially viable by providing a range of ancillary services. Furthermore, storage needs to work in harmony with other Smart technologies and conventional networks to ensure that we can meet our Electricity Act/licence obligations, to provide access to and develop a safe, co-ordinated and cost-effective network.

We agree that the definition of storage within the regulatory and policy frameworks is important in order to distinguish it from generation and demand as it is our view that storage should fall into a category of its own. Any new definition should develop from existing generation or demand policy and focus on those areas where storage should be treated differently. This should minimise the amount of development work required to facilitate a fair and open energy storage market. Care should also be taken to ensure that any change to the definition for storage does not unduly disadvantage existing large scale storage facilities.

Under the current rules and processes for connecting demand or generation to the network, network reinforcement costs can be directly attributed to the connecting customer or shared with wider Use of System (UoS) customers. In instances where there are shared reinforcement costs being incurred to wider UoS customer's Government and industry must decide if this is fair or appropriate. This often occurs because DNOs/TOs are designing connection offers for the full range of scenarios and capabilities of a connecting energy storage site. Moving forward there needs to be greater focus on matching the intended use of storage (e.g. EFR), the likely times and frequency that this will be called on and the capabilities of the Distribution/Transmission network.

This issue could be alleviated through a number of activities by Industry and Government:-

- Greater locational network information provided by network operators for areas where storage will benefit the network
- Greater locational price signalling for storage applications
- Increased certainty over ancillary service contracts and the use case of connecting storage

Finally it is important to remember when comparing the costs and capabilities of storage that it can only displace energy in time and does not generate net energy. This should be a key consideration for Government in determining a future energy portfolio and associated charging regime.

2. Have we identified and correctly assessed the issues regarding network connections for storage? Have we identified the correct areas where more progress is required? Please provide evidence to support your views.

We believe that the main issues have been identified; however, we believe that there are outstanding policy issues in relation the large volume of speculative connection applications which may hinder future policy. Greater collaboration across the industry is also required to ensure a coordinated approach.

There has been a large volume of connection applications to our two distribution licences for energy storage connections, compared with the small number of acceptances as evidenced in table 1 below. The table below illustrates only 8% of applications[7] have progressed to acceptance, with a lower proportion of accepted offers expected to progress to completion.

The table demonstrates the high level of speculative activity that is currently taking place, leading to extensive abortive work by DNO design functions. This activity inevitably diverts our resources from our preferred activities of working on capacity mapping and working with a smaller number of realistic enquiries. It should be noted that the industry has been working with BEIS (formally DECC) to re-instate cost reflective connection application fees. This is our preferred method to manage such high volumes of speculative connection applications.

[7] By MW accepted

Licence Area	Connection Applications		Accepted Offers	
	Number	Capacity (MW)	Number	Capacity (MW)
SP Manweb	85	2470	5	200
SP Distribution	27	745	2	60

Table 1: Connection Applications and Acceptances for Energy Storage as of 12/12/2016

Much of this connection application activity was driven by National Grid's Enhanced Frequency Response[8] tender process and the level of response from developers far exceeded National Grid's expectations. Whilst National Grid responded quickly once the problem had been recognised, it has been agreed that a greater level of consultation between National Grid and DNOs will take place prior to any future tender of this nature. This is another illustration of the increasing need for greater co-ordination between the TSO and the DNO/DSO, which will need to be, reflected in future revisions of the Distribution Code and Grid Code.

As indicated in table 3 "Network connections for storage" of this call for evidence, network operators need to continue to innovate to provide better information to storage customers. It is our view that the connections process has been greatly improved in recent years with the provision of our network capacity heat maps and we are working to continually improve the granularity, precision and coverage of this information. We are also making improvements to the management of the "Access Queue", with a new policy recently published.[9]

Network access for storage is also a key consideration, but it is important to ensure equitable treatment between storage and generation. For example, if any scheme is to be advanced in the Access Queue, this decision has to be based on additional beneficial network attributes.

Greater understanding is also required where storage connections utilise the remaining demand capacity within a network area. Future demand connection will then lead to reinforcement costs being shared across wider UK customers, effectively subsidising the storage connection. This would not be the case for generation connections.

3. Have we identified and correctly assessed the issues regarding storage and network charging? Do you agree that flexible connection agreements could help to address issues regarding storage and network charging? Please provide evidence to support your views, in particular on the impact of network charging on the competitiveness of storage compared to other providers of flexibility.

We agree with the following key principles:

1. Network charges should be cost-reflective and provide fair recovery of network costs
2. Charging principles should align with the actual operation of technology types providing clear pricing signals for network users
3. The treatment of storage as 'intermittent' or 'non-intermittent' should be clarified

[8] http://www2.nationalgrid.com/Enhanced-Frequency-Response.aspx

[9] http://www.spenergynetworks.co.uk/userfiles/file/Queue_Mgt_Policy_Communication_Dec_2016v3.pdf

4. The contribution of storage to network cost recovery should be recognised.

With these principles in mind, we believe there is opportunity for network operators to offer flexible connections which better meet the needs of storage and as a result go some way to address the issues with network charging.

It is now business as usual for distributed generation connections to have a choice of connection security i.e. whether a 'firm' connection is provided, or whether the supply can be interrupted by commercial agreement ('unfirm'). These connections are being used in conjunction with Active Network Management (ANM)[10] and are also applicable to energy storage.

Building on the ANM principles established for the management of distributed generation during constraint conditions, ANM could likewise be utilised to control time-of-use restrictions agreed for storage, for example export and no import during peak demand periods, Network charges under these circumstances could be applied in a manner akin to those levied on non-intermittent generation in recognition of the network service they are providing.

Time-limited connection agreements linked, where appropriate, to the shorter timescale during which a given storage facility is expected to be connected, may have several advantages. These can strengthen the case for a smart connection arrangement, reduce the connection charge and then free up capacity at the end of the contract for potential use by others.

As the flexibility of storage also includes its ability to respond very rapidly, this ability will need to be managed to prevent unwanted impacts to other connected customers. This will include site-specific operational limits for power swings and ramp rates.

Pricing signals at the domestic scale must also be considered. DNOs are working with the Energy Network Association (ENA) to develop more flexible domestic connections, building on the existing arrangements currently in place for domestic Photovoltaic (PV) connections.

There is a need for remuneration mechanisms for the supply of services to distribution network operators (e.g. for the deferral of investment at distribution). Energy storage business models currently focus on the existing UK balancing mechanism (e.g. EFR, FFR, Capacity Market). Clarity is required on which services can be combined. For example, many of the national network services, such as Short Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) currently contain exclusivity clauses, which then prevents the service provider from providing services to the local DNO.

If the Government seeks to promote the widespread rollout of distributed and domestic storage in the UK, storage implications to system security and current security standards e.g. P2/6[11] compliance must be considered. If an increasing proportion of system balancing activities are being provided by storage operators, then there will be an increased dependence on those operators fulfilling their contractual obligations. As highlighted in our response to question 1, we expect most grid scale storage projects will need to stack a range

[10] http://www.smarternetworks.org/Search.aspx?SearchOn=accelerating

[11] P2/6 is an engineering recommendation and is the current distribution network planning standard. DNOs have a licence obligation to plan and develop their systems in accordance with ER P2/6

of services in order to be financially viable. This suggests a need to ensure that service providers can indeed provide the full range of services which they commercially agree to.

4. Do you agree with our assessment that network operators could use storage to support their networks? Are there sufficient existing safeguards to enable the development of a competitive market for storage? Are there any circumstances in which network companies should own storage? Please provide evidence to support your views.

We agree that networks operators could use storage to support our networks, however it is important to understand when storage will provide a benefit to networks. Three key metrics drive the potential needs cases for storage facilities:-

- MW Capacity
- MWh capacity
- Responsiveness

Although we are receptive to all storage technologies, there is a current trend towards the use of lithium Ion batteries which tend to have a MWh capacity in the 1-4 hour range. In terms of network operator use, this can provide an ideal solution for short periods of excess generation or demand. Indeed this may provide a lower cost solution for network companies than conventional reinforcement or defer the decision to carry out conventional reinforcement until sufficient demand/generation connects to the network to provide a strong investment signal.

There is a requirement to develop a remuneration mechanism for the deferral of reinforcement that is consistent across the UK network operators, whilst providing price signals that truly represent lowest overall lifecycle costs for UK customers.

Storage can be of benefit to network operators, principally by the deferral of reinforcement by using peak load shifting as demonstrated in the LCNF Smarter Network Storage project[12]. We also see storage being used by network operators in conjunction with ANM to reduce network constraints associated with renewable, intermittent generation (as demonstrated by the Orkney Storage Park NIA demonstration project)[13].

Additionally, we can do more to identify where storage would provide the greatest network benefit through greater stakeholder engagement and providing information for developers, such as more detailed capacity mapping. We envisage a market-based model, with storage developers providing services to the network operator.

Engagement with our stakeholders has demonstrated that a range of ownership models are possible, illustrating the benefits of enabling ownership for all parties. It is our stakeholders' views that ownership is not seen as an issue, as long as the interests of the customer are maintained.

[12] http://www.smarternetworks.org/Project.aspx?ProjectID=416
[13] http://www.smarternetworks.org/Project.aspx?ProjectID=373

In response to the following question, *"Who should own DER resources, such as energy storage?"*

- 47% of respondents had no fixed view
- 17% had no view
- 12% were against DNO/DSO ownership; and
- 24% are actively in favour of DNO/DSO ownership

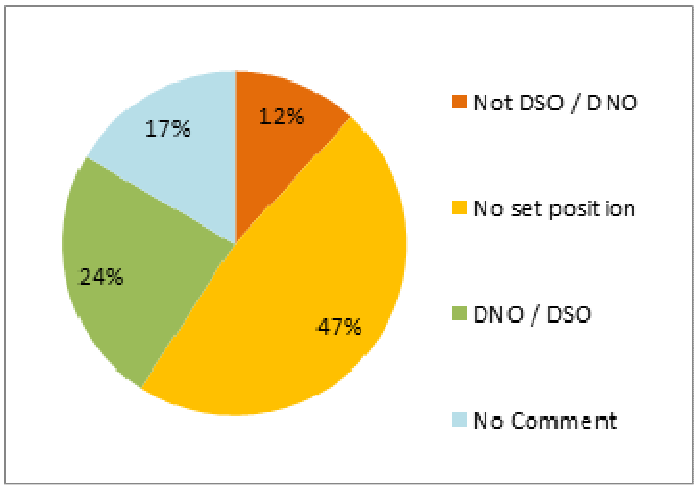


Table 2: Stakeholder views on Ownership of DERs such as energy storage[14]

A network operator may need to own and operate storage when there are insufficient market drivers to encourage independent providers to install and operate storage in such a way that it satisfies network requirements and is the most economical option for consumers. Under the majority of circumstances, this will not be the case, however, network operators require sufficient legal and regulatory powers to exercise this option, if and when, the above criteria are met.

Currently, whilst there may be strong economic drivers for the provision of multi-megawatt storage systems (6MW/10MWhr system demonstrated in the LCNF Smarter Network Storage project[15] and National Grid's Enhanced Frequency Response services), there are none for sub-MW systems of the type that might be applicable at the scale of 11kV networks and below. Multiple installations of sub-MW installations installed on the 11kV network may also mitigate 33kV network issues, but a single large multi-megawatt installation may not mitigate the local 11kV issues in the same way. This expands on the principle that if a network issue is being caused at the LV level, this has the potential to impact at all the higher voltages as well. A distributed storage solution applied at the lower voltage levels has the potential to mitigate issues at multiple voltage levels in a way that a bulk solution applied at the higher voltage levels cannot.

[14] SPEN DSO Vision
[15] http://www.smarternetworks.org/Project.aspx?ProjectID=416

Given that third-party ancillary service contracts will be short-term (typically 2-4 years), and payback periods typically more than 10 years, it is difficult to assess exactly how a market for services provided by storage might evolve in practice. We have seen that the recent National Grid Enhanced Frequency Response tender has produced highly competitive bids, providing evidence that some developers are willing to take the financial risk in order to gain "first mover" advantage. However, the real test will be in the next round of tenders, which is anticipated to increase from 200MW to >2GW, where the level of committed investment will therefore need to increase by an order of magnitude.

Network operators also require some certainty over the future use case of storage once the relatively short contract periods come to a close. In the event that storage providers sign up to fundamentally different service provision contracts after this period the storage providers network connection may no longer be suitable for their needs. This would either result in a review of their connection requirements or any additional required reinforcement costs being borne by UK customers.

5. Do you agree with our assessment of the regulatory approaches available to provide greater clarity for storage? Please provide evidence to support your views, including any alternative regulatory approaches that you believe we should consider, and your views on how the capacity of a storage installation should be assessed for planning purposes.

Regulatory and policy frameworks are vital to the development of storage.

The Call for Evidence outlines 4 key approaches for the regulatory treatment of storage:

A. Continue to treat storage as generation for licensing purposes

B. Define storage as a subset of generation in a modified generation licence

C. Define storage in primary legislation

D. Define storage in primary legislation as a new activity with separate storage licence regime

As per our response to question 1, it is our view that storage needs to be defined separately from generation, however existing generation legislation should be used as a model with the focus on defining the points of departure from the existing licence. To this end our view would most closely align with option C, however we understand that changes to primary legislation can be a lengthy and work intensive process. As such we recognise that in the interim existing legislation and distribution or transmission licence deragations can be used to ensure that the rollout of storage is not adversely impacted by the requirement for legislative change.

As Vertically Integrated companies, distribution and transmision businesses are prohibited from holding a generation licence[16] [17], care should be taken when drafting any storage defintions. We recommend that excessive ring-fencing of storage is avoided to ensure that

[16] Directive 2009/72/EC
[17] Electricity Section 6 (2) (a)

the communication of information that is necessary to optimise the system as a whole is not prohibited. If DNOs are not permitted access to storage, this may result in sub-optimal whole system solutions and will ultimately be of higher cost to the consumer.

We consider that any revisions to the regulatory framework should provide the DNO with the ability to own and operate storage in circumstances where it is both required for the wider benefit of the network and there is insufficient drive from the market to provide it. This could be achieved through the combination of changes to the distribution and generation licences.

This is particularly relevant when considering planning and consenting issues. As there is no definition of storage within the Electricity Act 1989 ("the 1989 Act"), the current approach is based on treating storage as 'generation', requiring either a consent or an exemption under the 1989 Act. Where new storage supports the operation and delivery of secure energy supply on the electricity networks, the scope of any storage installation and apparatus and the range of capacity varies significantly. The current regime under 1989 Act does not apply to every project. Therefore, the appropriate planning and consenting regimes should be available to accommodate the specifics of the apparatus, installation and capacity required.

The Energy Network Association is currently reviewing the topic of storage as part of the DG Steering Group. We believe that agreement amongst industry participants will provide clarity and be of assistance to Government, industry and developers.

6. Do you agree with any of the proposed definitions of storage? If applicable, how would you amend any of these definitions? Please provide evidence to support your views.

A definition of electrical energy storage is required both, in the regulatory framework, which can have an impact in the short term, and in primary legislation, which will ensure the long-term status of electrical energy storage. Changes in the regulatory framework will address some of the issues, such as facilitating changes to industry codes (e.g. such as connection and charging codes) and assisting town and country planners to understand how storage projects should be treated which should be sufficient to enable the creation of a market for storage. Changes to primary legislation will ensure that this market is sustainable in the longer term, since this will address the remaining residual issues, such as final consumption levies. We endorse the definition of storage as proposed by Energy Storage Network (ESN), but would like to suggest that the definition is amended by excluding traditional network assets, such as transformers, circuit and capacitors.

2.3 CLARIFYING THE ROLE OF AGGREGATORS

7. What are the impacts of the perceived barriers for aggregators and other market participants? Please provide your views on:

- **balancing services;**
- **extracting value from the balancing mechanism and wholesale market;**
- **other market barriers; and**
- **consumer protection.**

Do you have evidence of the benefits that could accrue to consumers from removing or reducing them?

Through our DSO transition, we would support the role of aggregators, however, there must be sufficient safeguards in place to ensure that in providing wider balancing services there is not a conflict with local balancing needs and network requirements.

Aggregators can sell the following services;

- SO contracts with providers who commit to being able to dispatch
- Balancing services include frequency response and reserve
- Balancing mechanism used by SO buy and sell energy in real time

Aggregators who hold supply licences can participate in this market on their own behalf. Otherwise they need to enter into an agreement with a supplier .

Through our DSO transition we are fully supportive of the role of aggregators and the part they can play in providing greater system flexibility. However the provision of services will need to be governed by a hierarchy of needs ensuring that the provision of services does not adversely affect network safety, system security or existing customer service.

Currently, there is a lack of flexibility in selling services to the SO, as the scale of the Balancing Mechanism is not open to smaller market participants. This could, in part, be resolved through the introduction of the DSO which would need to be given direct access to the balancing mechanism. Aggregators (and other DSRs) could then contract with the DSO for local balancing actions. The DSO is best placed to work with the SO to ensure optimum local balancing measures are used to deliver upon wider system requirements.

Taking into consideration the perception of existing barriers when developing commercial arrangements between DSOs and aggregators/DSRs, we need to ensure that there is an appropriate balance between the minimisation of barriers and the need to ensure adequate protections are in place for consumers. 'Barriers' may exist for justifiable reasons. What is viewed as a barrier by one party may be considered a valid protection measure by another. As a minimum, light touch regulation is required to ensure that the right behaviours are incentivised by all parties, e.g. clear understanding of roles and responsibilities of all parties (including. DSO), minimised conflict between local balancing needs and network requirements, transparency of arrangements and no return to 'cold calling' practices.

As a DNO, we do not have visibility of the benefits that could accrue at this moment in time.

8. What are your views on these different approaches to dealing with the barriers set out above?

Balancing services
The SO's Power Responsive Campaign[18] seeks to bring together key stakeholders to develop a framework through which consumers are given the opportunity to be transformed into intelligent energy users making use of opportunities for DSR. We believe that the DSO model can enhance this.

Barriers to Balancing Mechanism
We do not believe that this Call for Evidence has considered what role the DSO can play in co-ordinating local balancing actions from aggregators and a wider range of DSRs. This will require changes to industry framework codes and licences.

Customer Protection
We agree that consideration needs to be given to the means via which consumers who contract with aggregators will best be protected. We consider that these protection measures are particularly relevant to the potential new consumer market segments (domestic and smaller non-domestic parties) likely to be targeted by the expanded roll out of aggregation services.

9. What are your views on the pros and cons of the options outlined in Table 5 (Page 47)? Please provide evidence for your answers.

A. Monitor

Monitoring barriers to balancing services will provide maximum potential opportunity for organisations to flourish and opens up opportunities for industry to self-police through development of SO/DSO commercial arrangements. In addition, this could be implemented quickly.

There is however a risk that Ofgem would become reactive to issues post event with a high potential of leaving new consumers exposed. There may also be an increased opportunity for aggregators to adopt aggressive tactics, for example, actions of aggregators directly controlling consumers' loads could result in them being unwittingly being left with no power.

B. Industry-led change

Industry led change can be developed following existing industry framework change control processes which would result in the effective participation of all impacted parties. This approach could also be followed alongside the implementation of the DSO and could be a single over-arching approach to formation of industry change processes.

Although industry led change provides for an opportunity to benefit from best practices, it may lack authority. The existing change control process can be cumbersome and as a result may introduce delays to implementation.

[18] http://powerresponsive.com/

C. Regulator steps in

Should the regulator step in, this would potentially maximise protection for new and existing consumers and would permit offenders to be penalised should robust regulatory and legislative changes be implemented. To be effective, the regulations and law would need to implemented robustly.

Whilst there are many merits of the regulator stepping in, this creates the possibility to stifle the potential of organisations with no guarantee of success. This option has the potential of imposing significant additional costs on the industry and will take time to implement.

Irrespective of which option is ultimately deemed to be the most viable consideration should be given to the boundaries across which aggregators operate. Currently aggregators only need to inform network operators of which Grid Supply Point (GSP) Group they are affecting and to what extent. Moving forward this would likely be of insufficient granularity to allow local balancing to be effectively managed, resulting in a conflict between local and national balancing mechanisms. It is our view that notification of aggregation activities at GSP level would be sufficient in the initial stages of the DNO to DSO transition to avoid balancing conflicts.

10. Do you agree with our assessment of the risks to system stability if aggregators' systems are not robust and secure? Do you have views on the tools outlined to mitigate this risk?

We agree with the risk assessment and the need for aggregators' systems and processes for load control to be robust and secure. At a local level, the failure of an aggregator to take an agreed action could result in system imbalance and ultimately a network failure.

3 PROVIDING PRICE SIGNALS FOR FLEXIBILITY

3.2 SYSTEM VALUE PRICING

11. What types of enablers do you think could make accessing flexibility, and seeing a benefit from offering it, easier in future?

A key enabler will be the development and introduction by the industry of a common trading platform for services that also interfaces with the SO. A key requirement will be real time visibility of what is required and what services they can offer, and provide a commercial mechanism to ensure it is driven by competition. Payment for ancillary services will need to be via a transparent and predictable charging structure to give participants confidence in the level of remuneration.

Other enablers include:

- The introduction of appropriate tariff structures that can adapt for industry changes/innovation and new products, with retail and distribution tariffs aligned to ensure price signals reflect the status of the network. Network and balancing costs combined account for approximately 25% of an annual domestic bill[19]. In Ofgem's "Retail Energy Markets in 2016 Report"[20] Distribution Use of System (DUoS) charges are, on average, £92 per annum, Transmission costs £39 and balancing costs estimated as £6 per annum. This alone provides little incentive for customers to change their behaviour as the DUoS and balancing elements are small and if not aligned with retail tariffs, do not influence behaviour.
- Current charging methodologies are also slow to change from a regulatory perspective. If Government wishes to influence behaviour and access flexibility through pricing, the rate of change of pricing regulation will need to dramatically increase.
- It is also worth drawing a distinction between system value pricing for an advanced market and system value pricing for real time network balancing. It may be possible to assist in system balancing through advance pricing signals, however, real time system balancing through charging will be difficult given the relatively small contribution of UoS and balancing to the average consumer bill.
- Aggregator services will also be required, especially in relation to domestic/small industrial customers as to enable the provision of meaningful flexibility actions.
- Providers will be encouraged if they can access several revenue streams via, for example, providing multiple flexibility services. Allowing such mechanisms will require providers to be capable of such services and the development of a means to ensure that this is monitored so that developers can only offer what they provide e.g. developer can sign up to multiple flexibility offerings gambling on the low probability that they will all be called concurrently. As referred to in Question 3, commercial clarity will be required.

19 https://www.ofgem.gov.uk/consumers/household-gas-and-electricity-guide/understand-your-gas-and-electricity-bills

20 https://www.ofgem.gov.uk/system/files/docs/2016/08/retail_energy_markets_in_2016.pdf

12. If you are a potential or existing provider of flexibility could you provide evidence on the extent to which you are currently able to access and combine different revenue streams? Where do you see the most attractive opportunities for combining revenues and what do you see as the main barriers preventing you from doing so?

ENWL's CLASS project currently provides services to the SO, however, this is captured as a 'De Minimis' activity within Directly remunerated Services. In order to provide a greater range and depth of services to the SO, DNOs/DSOs would require a mechanism out with the current De Minimis activity.[21]

To put this into the context of our own business, we are only permitted to spend upto c.£10m[22] on all combined De Minimis activities in each distribution licence.

The concept of DNOs being recompensed for ancillary services has been effectively trialled in ENWL's CLASS project. Through control of existing assets, ENWL have explored the provision of the following services:-

- DSBR (Demand Side Balancing Reserve)
- FR (Frequency Response)
- FFR (Firm Frequency Response)
- FCDM (Frequency Control by Demand Management)
- STOR (Short Term Operating Reserve), and
- Reactive Power Services.

Ofgem have provided confirmation of the regulatory treatment.[23.] The associated costs and revenues can be reported in the 'Valued Added Services' category of Directly Remunerated Services. This approach could be extended to additional services, however, this could only be achieved through working with Ofgem and the SO.

Whilst this may be a suitable interim solution for the RIIO ED1 period, a more comprehensive charging mechanism for ancillary services will be required as DNOs transition towards becoming DSOs.

In our DSO vision[24], we envisage DNOs as neutral facilitators of an ancillary services market. To achieve this goal, we require a transparent and fair mechanism to remunerate DER providers when they are called upon to provide ancillary services. Clear contractual arrangements will need to be provided to DER providers on how they will be dispatched and how they are prioritised. This will be crucial to ensure DER providers have all available information when they seek to secure finance for their projects.

[21] A De Minimis activity must not in any Regulatory Year exceed 2.5% of the total turnover of the licensee's Distribution Business plus the Equity Share of the total turnover of all of the De Minimis Business

[22] Turnover in 2015/16 for SPD was £406m and SPM £379.5m (Regulatory Accounts). £10m equates to c 2.5% of each licensees turnover http://www.scottishpower.com/pages/accounts_information.aspx

[23] https://www.ofgem.gov.uk/publications-and-updates/direction-distribution-network-voltage-control-services-nget-so-residual-balancing

[24] http://www.spenergynetworks.co.uk/userfiles/file/SPEN%20DSO%20Vision%20210116.pdf

In order to facilitate the increased volume of DERs highlighted in this Call for Evidence, we believe that the dispatch and remuneration process will need to be heavily automated through optimisation software and automated payment services. To date, ANM schemes have focused heavily on automating networks based on electrical system requirements. This technology will need to adapt to balance both system and commercial demands.

In addition to those DERs that will have direct contractual arrangements for the provision of ancillary services, there will be generation and demand resources that have no such arrangements in place that may still assist in overall network balancing e.g. domestic storage, domestic Electric Vehicle (EV) charging. The extent to which a DSO has control over these resources, either through pricing signals or other non-direct means must be determined. This must be decided in conjunction with key stakeholders, reviewing the implications on:-

- Customer behaviour
- Energy pricing
- Decarbonisation of heat and transport
- Regulatory implications of DSO/DNO powers

13. If you are a potential or existing provider of flexibility are there benefits of your technology which are not currently remunerated or are undervalued? What is preventing you from capturing the full value of these benefits?

Balancing services such as ANM are not currently remunerated. ANM creates value by providing customers with network access whilst providing Distribution network balancing and limiting the export/import onto the national grid. For DSOs, agreed export/import ranges, plus the provision of ancillary services could be provided through active management of the distribution network.

Flexibility provides significant benefits to both the customer and provider and is a key requirement to enable the future continuation of an economic, safe and reliable energy system. There are however some key issues that require to be understood in order to realise the greatest benefit from the potential of flexibility when connecting to the electricity network. Firstly, to date significant work has been undertaken in connecting renewable generation through projects such as SP Energy Networks' Low Carbon Network Funded Accelerating Renewable Connections (ARC)[25]. Both SP Energy Networks and customers have benefited from the implementation of Active Network Management across the trial area. However, one key issue that remains is the ability to levy ongoing charges against those users benefiting from the system and support costs that will be incurred by the business for systems such as Active Network Management. It should also be recognised that flexible product offerings are not only linked to generation, but also storage and demand customers.

Whilst initial funding for the equipment itself is relatively economical compared to traditional reinforcement, a fundamental review of supporting infrastructure must be undertaken in order to successfully implement a greater penetration of flexibility across our network. For example, communications upgrades and IT systems incorporating robust cyber security are required and the funding for such communications infrastructure is critical. The associated capital and

[25] http://www.spenergynetworks.co.uk/pages/arc_accelerating_renewable_connections.asp

operational costs will represent a significant cost to network companies as we transition towards the next price control.

There will be a need for the current balancing services to be expanded to meet future requirements as, for example, it does not include system Inertia. The change in generation mix creates system issues that puts the security of supply to the GB customers at risk including;

- Reduced inertia compromising the network stability and security in event of a large infeed loss and resulting in a large rate of change in system frequency.
- Low fault level results in poor power quality with higher risks of harmonics and power system imbalances. It can also result in certain protection schemes failing to operate.
- Limited voltage control in absence of immediate dynamic response as obtained from synchronous generators can result in voltages outside the statutory limits.

The lower system inertia would also require the SO to procure a higher system spinning reserve to compensate the fast frequency drop; increasing the balancing costs that make up around 1% of the GB customer's bill. Appropriate remuneration is required to ensure any increases are recovered.

14. Can you provide evidence to support changes to market and regulatory arrangements that would allow the efficient use of flexibility and what might be the Government's, Ofgem's, and System Operator's role in making these changes?

We have limited experience of consumers seeking to engage with the market to provide DSR services. Interest from our stakeholders has instead focused on opportunities for us to provide flexible connection arrangements for DG as a result of network constraints and the desire to achieve earlier connections.

We are required by our licences to annually publish Charging Statements.[26] This statement advises of opportunities for premises, whose use of system is charged under the Extra High Voltage Distribution Charging Methodology (EDCM), to benefit from entering into a Demand Side Management ("DSM") agreement. Under this agreement, all or part of the maximum import capacity will become interruptible in certain time periods in return for reduced Use of System Charges.

Coupled with the introduction of the DSO, changes to the current EDCM/CDCM[27] will be required in order to present to distribution consumers more attractive options for implementing DSR. The time required to implement changes to either of these methodologies could be a significant barrier to making full use of flexibility sources. Changes to these methodologies typically take 18-24 months, which will increasingly stifle the ability for network operators and service providers to facilitate a low cost flexible network.

As the number of players in the balancing market increase as a result of the DSO transition, an IT based trading platform will be required which will allow contracts with both the SO and the DSO. The IT trading platform would be a balancing facility that can allow the DSO to provide the ancillary services from multiple providers for local and SO use. Regulatory

[26] http://www.scottishpower.com/userfiles/document_library/SPD_Final_LC14_Statement_2016.pdf
[27] Common Distribuiton Charging Methodology

changes will be required to ensure ancillary services are fully remunerated and the appropriate mechanism is in place to facilitate the transition to a DSO.

Similar to the current Transmission arrangements, the total cost of delivering ancillary services will include two components, namely:

- Internal costs (including balancing staff and systems)
- External costs (including charges from generators and/or consumers for ancillary services)

As previously discussed, trials such as ENWL's CLASS project seek remuneration through the "De Minimis Business" facility within the current Distribution Licence. Such treatment is not viable as a long term solution for the transition to a DSO. More widespread changes will be required to facilitate the market and regulatory changes implicit in the transition from DNOs to DSOs. We have considered the following options:-

Regulatory Settlement

A regulatory settlement would provide a formal process, however, it could prove onerous as a result of licensing and incentive requirements. The drafting and approval of licences etc. can take considerable time to implement, e.g. the current ongoing arrangements being developed for the DCC as part of the Smart Meter roll out.

Further issues may include the nature and level of the regulatory settlement and how it is set. It could require extensive estimates of, for example, the level of reinforcement avoided when determining the appropriate settlement level.

Considerable uncertainty surrounds the rate and potential extent of the take-up of low carbon technologies. This may require appropriate uncertainty mechanisms and/or regular reviews of the relevant incentive mechanisms, allowances and targets. Nevertheless, there is a risk that a series of short-term incentives would not be consistent fully with the desired long-term outcome, as it may unduly encourage short-term behaviours and responses.

Ring Fencing

The industry has experience of the business separation and compliance required for such an option. However, the ability of the ring-fenced entity to finance itself would need to be carefully assessed, especially where financing would not be supported by network assets.

Excessive ring-fencing may discourage or even prohibit the communication of information that is necessary to optimise the system as a whole.

Unbundling

The costs and complexities of this approach could outweigh the benefits. An unbundled entity may have different priorities, which may lead to sub-optimal decisions for the system as a whole.

With regards to the roles required:

- Policy changes should drive the correct behaviours in the market, align with overall energy strategy and ultimately work towards the lowest cost, low carbon future for all consumers.

- Ofgem will need to ensure that fair and cost reflective regulatory arrangements are in place for those entities that should be regulated and that fair market arrangements are put in place for those that should not be regulated.
- The biggest challenge for the System Operator, which is shared with the industry is developing a platform to enable real time provision and facilitation of ancillary services for existing directly contracted providers, future DSO organisations and new entrants to the ancillary services market.

3.3 HALF HOURLY SETTLEMENT

15. To what extent do you believe Government and Ofgem should play a role in promoting smart tariffs or enabling new business models in this area? Please provide a rationale for your answer, and, if you feel Government and Ofgem should play a role, examples of the sort of interventions which might be helpful.

The Government and Ofgem will need to play a role as Smart Tariffs will play a significant part in driving a coherent UK energy strategy. Incentivising the correct consumer behaviour as smart technologies are introduced will be required to ensure any impact on the network is appropriately controlled. For example, widespread uncontrolled EV rollout could lead to high levels of reinforcement. The link between retail and distribution tariffs is a key enabler in ensuring that customers receive the appropriate signals to manage their behaviour.

Individual economic agents, including firms and customers, will generally make decisions in a way they perceive best meets their interests, using the information that is available to them at a proportionate cost. However, there is no guarantee that these will deliver an overall outcome that is optimal for society and future generations. There is a potential role for the Government to influence decisions in a way which improves the overall outcome.

We are aware of the concerns of some stakeholders that the regulatory framework is not adapting fast enough to respond adequately to the development of low carbon technologies and non-traditional business models.

Smart tariffs may help to facilitate individual decentralised decision-making which is consistent with the overall preferred outcome. However, their effectiveness may be limited by customers not responding to potentially complex price signals. In the event that price signals are not sufficiently effective to deliver the optimal outcome, it may be necessary to supplement them with more direct interventions.

Increasing non-traditional business models may impact future funding. An example is the growth of local balancing through the use of virtual private wire arrangements[28] which will require changes to current settlement arrangements to ensure they continue to work for all and not just those who can access such innovation. There is no provision in the current charging methodologies to reconcile local generation with local demand and the current settlement arrangements do not facilitate this type of arrangement. Proposals to net generation from demands that are not physically connected or part of a “site” can compromise visibility of demand and generation and result in the consumer not paying correctly for using the network. Whilst such arrangements will result in consumers not using the wider network on a continuous basis, it still needs to be available for times when the local generation is not available or insufficient. Consumers will need to pay appropriate charges for top up and standby. A small number of such schemes will not impact significantly on DUoS and TNUoS recovery, however the growth of such schemes has the potential to directly impact on the distribution and transmission costs recovery, leading to distortion and discrimination of tariffs.

[28] a connection consisting of a group of customers that are to be treated as if they are physically connected but in practice are not.

Whilst we recognise the requirement for aggregators, there must be sufficient safeguards in place to ensure that there is no conflict in providing wider balancing services with local balancing needs and network requirements.

16. **If deemed appropriate, when would it be most sensible for Government/Ofgem to take any further action to drive the market (i.e. what are the relevant trigger points for determining whether to take action)? Please provide a rationale for your answer.**

The first step will be the development of a clear and coherent energy strategy and from this the role smart tariffs will play in influencing customer/parties behaviours and bringing down overall costs. New products (and technologies) will be required and adaptable industry processes will need to be encouraged whilst ensuring that such policies are as equitable as possible amongst consumers.

This should also be carried out in a measured approach from co-operating with network companies to understanding the potential impacts of tariff and incentive mechanisms as Government incentives may be put in place to encourage one specific type of behaviour, but network usage could increase which can have an impact on other incentives. It is therefore important that network implications are understood before Government policies are implemented.

For example, photovoltaic and solar uptake are overtaking the network's capability to reinforce and prepare, and as a result could be a significant risk and barrier to Electric Vehicle (EV) adoption. Overly generous EV incentives could drive a step change in adoption, which may support CO2 emissions targets but leave networks with an unmanageable level of connections and ultimately impact customer service/experience and cost.

Policy decisions need to be enforceable, for example DCP 115[29] where the authority approved changes to the National Terms of Connection to allow DNOs to write to customers who consistently under-utilised their agreed capacity and suggest a variation. However, no reductions could be implemented without the customers express permission. As a result, in areas of constraint, we are unable to connect new customers without reinforcing the network as studies have to take account of customers agreed capacities and not their usage. In 2015, we wrote to 34 large generation customers (in the SPD and SPM licence areas), 14 responses were received with 5 agreeing to release generation capacity totalling 10.4MW, the other 9 refused unless payment was received.

In addition, a vital part of our business is providing customers with new or upgraded connections. The large volume of applications received for the connection of generation developments has led to the formation of contracted queues, delays in connection dates, higher connection costs and an increasing impact on the transmission system. This situation is exacerbated by the principle of reserving capacity on a first come first served basis rather than taking into account the ability of projects to progress. During 2016, we extensively

[29] https://www.ofgem.gov.uk/publications-and-updates/distribution-connection-and-use-system-agreement-dcp114-national-terms-connection-amendments-capacity-management-overutilisation-and-dcp115-national-terms-connection-amendments-capacity-management-underutilisation

consulted on our queue management proposals. This work concluded in December 2016 with the publication of our Queue Management Policy[30]

The following governing principles form the foundations of our policy:

- Initial queue position is determined by the date of offer acceptance.
- The maintenance of queue position is dependent on contract milestones being met.
- Opportunities for queue advancement should only be given to those projects able to provide unconditional instruction to commence works.
- We will seek to recover capacity where it is not being fully utilised.
- We will terminate contracts where defined criteria not met.

17. What relevant evidence is there from other countries that we should take into account when considering how to encourage the development of smart tariffs?

The development of smart grids in other countries is at varying stages with new tariffs beginning to emerge. Examples include:

Spain

Spain's Government has introduced a near real-time electricity price-setting system for customers whose contracted power does not exceed 10kW and have not chosen a supplier (known as the PVPC and replaces the previous Last Resort Tariff)[31]. The tariff covers the cost of producing the electricity and also a fixed amount for distribution and other costs' associated with the delivery of the electricity, and is set a day ahead. At 8.15pm each day, suppliers will publish an electricity pricing schedule that will be applied to each of the 24 hours of the following day. Prices are displayed according to three types of tariffs:

A – general tariff
B – Night-time tariff or hourly discrimination
C – Super-valley tariff (electric vehicle)

Spain's smart meter rollout is due to be completed in 2018 and for those with a smart meter, the tariffs will be applied based on hourly consumptions. For those without a smart meter, the hourly price tariff will be applied via a consumption profile that suppliers constantly update (and publish).

Suppliers, such as Iberdrola, offer a wide range of time of use tariffs to give customers the choice of paying fixed or variable rates for their electricity[32]. Evolving smart networks are driving the choices, with options for electric vehicles and green energy evident.

30 http://www.spenergynetworks.co.uk/userfiles/file/Queue_Mgt_Policy_Communication_Dec_2016v3.pdf

31 Details of PVPC http://www.ree.es/en/activities/operation-of-the-electricity-systemvoluntary-price-small-consumer-pvpc

32 https://www.iberdrola.es/customers/home/electricity/power-up-10kw/iberdrola-homes-plan

USA

In May 2016, the New York State Public Service Commission adopted a framework for a ratemaking and utility revenue model under the Reforming the Energy Vision initiative, seeking to transform the utility regulatory structure by integrating greater levels of distributed energy resources (DER) and empowering customers with energy management options. The new regulatory model seeks to align utility financial incentives with customer interests. Alongside this transition, smart tariffs are being analysed prior to the adoption of time of use rates and location and time based rates to help balance the market.[33]

[33] http://breakingenergy.com/2016/06/06/new-york-adopts-new-revenue-model-for-electric-utilities-under-rev/

3.4 SMART TARIFFS

18. Do you recognise the reasons we have identified for why suppliers may not offer or why larger non-domestic consumers may not take up, smart tariffs? If so, please provide details, especially if you have experienced them. Have we missed any?

We recognise the barriers identified (cultural, regulatory, commercial and structural) and acknowledge also the work and initial findings from NATIONAL GRID's Power Responsive Programme.

Partnering with NATIONAL GRID and SSEN, we hosted a workshop on Demand Side Flexibility to Scottish I&C customers earlier this year. The need for remuneration reflective of the flexibility of the services they can provide was highlighted as well as greater understanding and transparency of pricing and data on energy consumption.

The following specific challenges were identified:

- the need for better understanding of the range of services on offer and the risks / penalties involved
- difficulties in obtaining necessary data
- change of focus as not core business
- availability of forecast information
- future energy market uncertainty
- understanding better the benefits and quantifying potential financial return
- difficulties in writing/assessing tenders
- duration of procurement timescales
- length and complexity of contracts
- need for investment in communications and IT infrastructure
- security concerns
- lack of available resources

DUoS tariff structures for particular types of customers were designed to send signals for time of use in order to encourage users to avoid the peak period and mitigate reinforcement costs. However, these signals are not always passed on, as DNOs invoice Suppliers who in turn invoice end customers. Suppliers operate in a competitive market and do not have to pass these signals on to customers. The result is that consumers will not be aware of the best time to use/avoid the use of electricity or of the impact they have on networks.

Three rate HH DUoS tariffs have been extended and are now available to domestic and small business customers should they have the correct metering installed and elect for HH billing. Educating consumers on what tariffs are available and aligning network and retail tariffs to support ToU will encourage behaviour.

The complexity of the energy tariff market is often highlighted as a barrier to customers accessing the appropriate or lowest tariff. Aligning retail and distribution tariffs should assist in encourage customer behaviour, however, will not necessarily address the complexity.

Innovation projects undertaken by 2 other DNOs, UK Power Networks[34] and Northern Power Grid[35], have offered time of use tariffs, aimed at changing consumer behaviour and potentially lowering the customers' bills. The findings of the UK Power Networks Low Carbon London project are now in the public domain and have provided an insight to the willingness of customers to accept smart tariffs and the potential benefits to the network. Customers are willing to accept smart tariffs, however, their uptake is relatively low unless engaged through aggregators or suppliers. In particular the 'Residential Demand Side Response[36]' report provides evidences on the successful uptake of customers for the trial and the financial rewards / assurances required.

19. Are distribution charges currently acting as a barrier to the development of a more flexible system? Please provide details, including experiences/case studies where relevant.

For DUoS, the tariff structure is in place to encourage a more flexible system. Three rate tariffs are available for most connections (as long as they have the correct metering in place). For example, domestic customers who have been migrated to a smart meter can elect to move to a HH three rate tariff. However, there are some inherent issues with the current methodologies, namely:

- Complexity: The current charging methodology is inherently complex with large number of network and customer specific inputs.
- Demand Side Response: Introduced as part of EDCM was the concept of demand side management capacity that offers a financial incentive to customers in that no locational charges will apply should they connect in areas of limited capacity. However, evidence to date suggests that this financial incentive is also insufficient as the number of customers with DSM capacity is very low with no new customers since the introduction of EDCM in 2012. CDCM does not offer any financial incentive.
- New Products: Current tariffs do not suit all types of technology (e.g. storage). The calculations do not allow for how new technologies may use the network. For example, a storage connection may not use the network consistently however the charging methodologies do not treat the capacity differently.
- Local Generation: Current tariffs and settlement processes do not take account of local generation, whereby a customer does not use the wider network continuously.
- Notice of Distribution charges: Licence obligations require DNOs to set DUoS charges 15 months in advance and are set using customer and network data that is two years old. The impact of this requirement (introduced in 2015) has been to reduce cost-reflectivity with the only benefit being predictability. Complexity and volatility has not changed.
- Methodology Changes: All charging methodology changes are subject to open governance under DCUSA which past experience has shown to be a very slow process. For example, DCP 228[37] which was raised by British Gas on 13th January 2015 proposed

[34] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Low-Carbon-London-(LCL)/
[35] http://www.networkrevolution.co.uk/
[36] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Low-Carbon-London-(LCL)/Project-Documents/LCL%20Learning%20Report%20-%20A1%20-%20Residential%20Demand%20Side%20Response%20for%20outage%20management%20and%20as%20an%20alternative%20to%20network%20reinforcement.pdf
[37] https://www.ofgem.gov.uk/system/files/docs/2016/09/dcp228_decison_letter.pdf

to adjust the scaling for revenue matching within the common distribution charging methodology. This change received authority approval on 8th September 2016. And once a change is agreed, revised methodology changes (including the introduction of new tariffs) require 15 months' notice from publication therefore this change won't impact customers until April 2018.

20. What are the incremental changes that could be made to distribution charges to overcome any barriers you have identified, and to better enable flexibility?

The DCMF have recently undertaken a review of both CDCM and EDCM, recognising that the evolving network with the focus on smart and flexibility requires methodologies that can adapt and reflect future consumers.

Within CDCM, five issues were identified covering:

1. types of costing model;
2. tariff structures;
3. IDNO charging arrangements;
4. new products; and
5. a combined CDCM/EDCM methodology

This formed the first stage, the second stage will involve stakeholder workshops to develop proposals and undertake impact analysis.

For EDCM a similar review was issued to Ofgem in 2015 and identified a number of recommendations including:

- Reinforcement costs to be removed
- Single methodology for locational charge setting (currently two exist LRIC and FCP)
- Allocation of costs to be more reflective
- Increase transparency of charging models possibly introducing a single EDCM/CDCM methodology.
- Consideration of options for generation credits if a single model is introduced.

Whilst incremental changes is not the preferred way forward, changes to recognise new technologies (e.g. storage) will likely be required sooner than these reviews will be completed and any subsequent changes implemented. This approach is more suited to the refinement of existing rules than the potential revolution required to realise a smart, flexible network.

21. How problematic and urgent are any disparities between the treatment of different types of distribution connected users? An example could be that that in the Common Distribution Charging Methodology generators are paid 'charges' which would suggest they add no network cost and only net demand.

Previous attempts to remove disparities between generators in relation to use of system charges (credits) have failed due to complexity and materiality (e.g. DCP 13738). However, as we move to a more flexible network, such disparities will need to be addressed.

It is important that further disparities are not introduced as more flexible technologies are utilised, for example for those accessing local generation, fixed network costs should not be subsidised by those who are unable to be part of a similar scheme.

[38] Ofgem Decision on DCP 137 https://www.ofgem.gov.uk/publications-and-updates/distribution-connection-and-use-system-agreement-dcusa-dcp137-introduction-locational-tariffs-export-hv-generators-areas-identified-generation-dominated

3.5 SMART DISTRIBTUTION TARIFFS

22. Do you anticipate that underlying network cost drivers are likely to substantively change as the use of the distribution network changes? If so, in what way and how should DUoS charges change as a result?

The discussions around the use of new technologies such as battery storage point to them being able to alleviate stress on both the distribution and transmission networks. It may therefore be more appropriate to review the charging methodologies to be more forward looking in light of where we see the networks in the future, taking account of new technologies and smarter network solutions. Changes to tariffs (and their methodologies) will develop over time. There are no set timescales. The current charging reviews will hopefully allow for more adaptable methodologies that can change as technology progresses.

Assets for review include:

- Unit / Fixed split the network needs to be there 365/24/7 days and there is an element of "sunk" costs that must be recovered from all customers who will require access. Unit costs recover between 75% and 85% of costs. Effective short term signals will impact this charge. Smoothing out the peak will reduce reinforcement costs but will have the impact of reducing the time of day price differential in the current model, which could see customers move back to a "natural" peak.
- Generation / demand split – all CDCM generators receive credits as currently they are viewed as helping the network regardless. For EDCM credits are only available during the seasonal peak period if reinforcement has been identified as being required in the future.
- Recovery of allowed revenue – changing customers behaviour will impact on the recovery of a DNOs revenue. Currently any reduction in units will reduce the revenue recovered. Moving to a capacity/fixed based charge may align better with new technologies however this could result in consumers using larger amounts of energy being subsidised by lower (and possibly poorer) users.
- Individual connection arrangements cannot be modelled in current methodologies. As an example storage does not fit the current definitions which are modelled in the charging methodologies.
- Current cost driver for reinforcement charges is increased usage during peak which is incremented to set a reinforcement charge. Incentivising customers to move from the peak will reduce such charges for some, however, the allowed revenue will then be recovered from other customers. Significant overall cost reductions will need to be realised to provide such benefits for all customers.
- One of the key drivers of the CDCM model is the 500MW model, a demand only model which takes no account of generation. This model has not been updated since the introduction of CDCM in April 2010. Each DNO has its own model. This model is no longer representative and is likely to become even less so with the evolution of smart networks.

23. Network charges can send both short term signals to support efficient operation and flexibility needs in close to real time as well as longer term signals relating to new investments, and connections to, the distribution network. Can DUoS charges send both short term and long term signals at the same time effectively? Should they do so? And if so, how?

Long term signals could be introduced however the requirement to set charges 15 months in advance will require clear policy decisions to be made within the required timescales. Current DUoS methodologies and industry settlement rules make it difficult for short term signals to be effective, due largely to the following:

- Charges are set 15 months in advance and once set can only be adjusted to reflect a "material" change.
- Settlement rules apply to tariffs based on an assigned Line Loss Factor Class (LLF). Whilst customers can move to different LLFs within a year, this would be difficult to manage in real time and if there were significant numbers at any one time. Automated settlement flows and billing systems would need to be adapted to facilitate any such change.
- Fixed /unit costs split may need to change in future to ensure network costs are recovered as customers behaviour changes in response to new technologies and smarter operation of the network.
- Charges are set to recover an allowed revenue for which there are licence thresholds [39] applied on the levels of recovery above and below this amount. Encouraging customers to change behaviour in the short term could potentially impact on the revenue recovered, causing a DNO to breach its regulatory licence obligations. In addition, the balancing nature of the charging methodologies to meet allowed revenues can dilute benefits of customer behaviour in future years.
- No evidence so far that the CDCM/EDCM have influenced customer behaviour. Locational signals were introduced as part of the EDCM, penalising customers for connecting (or utilising electricity during the peak) in areas with low spare capacity. However, in 2014 DNOs carried out an informal survey[40] on their customers which showed that no customer (either demand or generation) had responded to these locational signals, nor changed their behaviour as the price signal is not strong enough. (Only a small percentage of customers request indications of DUoS charges prior to connection, and those that do have generally progressed a connection offer and are close to energisation).
- Changes to DUoS tariffs to introduce signals, either short or long term, could only be effective if they are reflected in retail tariffs and passed on to customers and benefits realised.
- Complexity of tariffs could be a problem. Introducing costs signals via DUoS tariffs would need to be transparent. Current methodologies are complex and any changes

[39] Licence Condition CRC 2A Distribution

[40] http://www.energynetworks.org/assets/files/electricity/regulation/DCMF/EDCMReviewGroupFinalReport%2031Dec2015.pdf

can increase this. An example of this is the DCUSA change proposal DCP 137[41] which aimed to limit generation credits to those connected in a generation dominated area. The result was to introduce significantly more tariffs, with year on year estimating required and where customers may be assigned different tariffs year on year leading to increasing volatility to their charge, with no way of predicting what their DUoS would be.

[41] Ofgem Decision on DCP 137 https://www.ofgem.gov.uk/publications-and-updates/distribution-connection-and-use-system-agreement-dcusa-dcp137-introduction-locational-tariffs-export-hv-generators-areas-identified-generation-dominated

3.6 OTHER GOVERNMENT POLICIES

24. In the context of the DSO transition and the models set out in Chapter 5 we would be interested to understand your views of the interaction between potential distribution charges and this thinking.

Distribution use of system charges need to recover the cost of operating and maintaining the network efficiently. Pricing signals can be introduced to encourage consumer behaviour but any tariffs set still need to allow revenue recovery.

A fair charging mechanism is required for the DSO as it will have additional costs such as the ancillary services (e.g. balancing costs) it will provide.

Any interaction between DUoS and balancing charges would need to be on the same basis i.e. non-discriminatory and cost reflective.

25. Can you provide evidence to show how existing Government policies can help or hinder the transition to a smart energy future?

Government policies and incentive mechanisms should be considered holistically to ensure that these do not conflict one another. For example, policies to introduce new technologies may result in a higher utilisation of networks, which will increase CO2 emissions, an unintended consequence. Trade-offs need to be understood with a cohesive view of networks considered.

Further examples include:

- DCUSA[42], which covers areas including connection and use of system charging, national terms of connection and settlement requirements, and are subject to open governance. Historically changes are raised to make small incremental changes which almost exclusively require working group assessment following by authority decision. This process has proven to be subject to long delays with changes often taking more than 12 months to complete, and in the case of use of system charges, a further 15 months' notice is required for the change to take effect. The parties weighting has a big influence on the voting for such changes which takes place prior to submission to Ofgem.

- Any policy decision needs to be supported by the correct governance and monitoring to ensure industry parties can deliver what is required. For example, when HH settlement for profile class 5 – 8 customers (medium business customers) was mandated there were a number of issues with parties not providing the necessary information to ensure a smooth transition.

[42] Distribution Connection and Use of System Agreement
https://www.dcusa.co.uk/SitePages/Home.aspx

26. What changes to CM application/verification processes could reduce barriers to flexibility in the near term, and what longer term evolutions within/alongside the CM might be needed to enable newer forms of flexibility (such as storage and DSR) to contribute in light of future smart system developments?

No response

27. Do you have any evidence to support measures that would best incentivise renewable generation, but fully account for the costs and benefits of distributed generation on a smart system?

No response

28. Do you agree with the 4 principles for smart appliances set out above (interoperability, data privacy, grid security, energy consumption)?

- **Yes**
- **No (please explain)**

As a DNO we do not have any specific evidence to support this statement although we would generally agree the four principles listed would be required. Currently we have seen little growth in this area although are acutely aware that changing customer behaviour and incentives from Government has the potential to lead to a rapid rise if experience from other LCT technologies, in particular domestic PV installation, runs true. As a DNO, our experience and interaction with smart appliances to date is extremely limited as it is a beyond meter solution; however, we welcome any analysis of the potential impacts on the distribution networks.

Smart appliances responding to market drivers may lead to changing load profiles at a domestic level with the consequence of increased network usage and localised constraints at times of peak demand. An unstructured approach, with little regard to the limitations of local networks has the potential to lead to power quality issues, which may result in the need for reinforcement or more stringent connection requirements. Network security will have to be clearly understood especially if the penetration of such devices reach a critical point where they can alter significant levels of load, therefore it would be a sensible approach to understand what the potential impacts of such devices will be for the consumer in the long run, as reduced energy usage may be offset by the requirement to reinforcement local networks to accommodate changing load profiles.

In addition to those principles set out, Government should also ensure that fuel poor customers are not inadvertently left out of this ‘smart appliances’ revolution and the energy market oppotunities that it could provide.

4 A SYSTEM FOR THE CONSUMER

4.1 SMART APPLIANCES

29. What evidence do you have in favour of or against any of the options set out to incentivise/ensure that these principles are followed? Please select below which options you would like to submit evidence for, specify if these relate to a particular sector(s), and use the text box/attachments to provide your evidence.

- **Option A: Smart appliance labelling**
- **Option B: Regulate smart appliances**
- **Option C: Require appliances to be smart**
- **Other/none of the above (please explain why)**

We have no evidence in favour for or against the options set out to incentivise that these principles are followed.

30. Do you have any evidence to support actions focused on any particular category of appliance? Please select below which category or categories of appliances you would like to submit evidence for, and use the text box/attachments to provide your evidence:

- **Wet appliances (dishwashers, washing machines, washer-dryers, tumble dryers)**
- **Cold appliances (refrigeration units, freezers)**
- **Heating, ventilation and air conditioning**
- **Battery storage systems**
- **Others (please specify)**

We do not have any evidence to support actions focused on any particular category of appliance

31. Are there any other barriers or risks to the uptake of smart appliances in addition to those already identified?

The take up and development of smart appliances will be very much driven by Government policy and market conditions. We do however see a number of potential risks which may arise from the wide scale deployment of this technology. The ability of third parties to control large sections of load based on market made decisions, may adversely impact local areas where generation and load may be more closely balanced. Our experience, especially in rural areas which are increasingly becoming net exporters onto the transmission networks, highlight the role load has on the ability to connect renewable generation onto highly constrained networks. The ability for third parties without the knowledge of network operators, or potentially the SO (or DSO in future), to turn off or on large volumes of load has the very real potential of causing local power quality issues, even if the actions are trying to address national problems.

32. Are there any other options that we should be considering with regards to mitigating potential risks, in particular with relation to vulnerable consumers?

As a DNO, whilst we do not offer smart appliances, we do actively engage with our priority services customers.

Consumers will need to have clear information available to them regarding smart appliances and how to use them, in order to build consumer confidence in this new type of product. This would be a supplier initiative or Government policy.

Stakeholder incentives could be increased for energy companies to ensure that companies are incentivised to actively engage with stakeholders or customers about a new flexible system and smart appliances. This could be a supplier initiative .

Consideration must always be given to the security of the electricity system, to ensure that smart appliances would not represent a risk to its stability.

4.2 ULTRA LOW EMISSIONS VEHICLES

33. How might Government and industry best engage electric vehicle users to promote smart charging for system benefit?

We strongly support the aspirations of Government to increase the uptake of electric vehicles in the UK. A study[43] carried out by the ENA for the Office for Low Emission Vehicles (OLEV) on behalf of the network operators estimated the network reinforcement costs to enable 8 million EVs by 2030 and 30 million EVs by 2040. The reinforcement costs were sizeable, but the cost could be significantly reduced if smart solutions, such as controlled EV charging, were introduced. We recommend that the findings of this study are considered.

There is a need to incentivise and facilitate customer behaviour to mitigate the potential LV/HV network implications on widespread uncontrolled EV rollout, as the difference in network reinforcement costs between "uncontrolled" EV charging and managed EV charging is significant, whilst the impact on customers is not expected to be significant.

There is currently a DNO working group within the Smart EV project[44] looking at this in detail. The Smart EV project is endorsed by all six GB Distribution Network Operators, with the support of the UK Government. This is a unique opportunity to help inform and direct a standard mechanism to facilitate controlled uptake of EV charging that will work with people, EVs and EV chargers.

34. What barriers are there for vehicle and electricity system participants (e.g. vehicle manufacturers, aggregators, energy suppliers, network and system operators) to develop consumer propositions for the:

- **control or shift of electricity consumption during vehicle charging; or**
- **utilisation of an electric vehicle battery for putting electricity back into homes, businesses or the network?**

Whilst the rollout of Smart Meters and consequent introduction of time of use tariffs at the domestic scale is expected to reduce the amount of increase in the peak demand for electricity, there will still be a need for network reinforcement. For example, at present, the reinforcement (i.e. upstream) cost of connecting individual domestic EV chargers is expected to be socialised. However, unfortunately, this then does not incentivise the customer to manage his EV charging with respect to the network capability, leading to greater levels of network reinforcement and subsequent higher cost to all customers, through their electricity bills.

The introduction of cost-reflective locational pricing in place of socialised cost-sharing for LV network reinforcement could in theory help to drive appropriate customer behaviour, but this is unlikely to be practical at the domestic scale. A better approach therefore is to mandate the capability of external control capability for all EV chargers through appropriate standards and regulation, which would enable automated control. To retain customer choice, an "opt-out" function could then be linked to a higher use of system charge. Low Carbon Network Fund

[43] The cost of charging infrastructure associated with uptake of electric vehicles in GB (ENA, 2016)
[44] https://www.eatechnology.com/products-and-services/create-smarter-grids/electric-vehicles/smart-ev

trials, such as Low Carbon London[45] and Customer-led Network Revolution[46] have shown that automation of load control is required to remove the burden of implementation of load control from individual customers.

35. What barriers (regulatory or otherwise) are there to the use of hydrogen water electrolysis as a renewable energy storage medium?

No response

[45] http://www.smarternetworks.org/Project.aspx?ProjectID=400
[46] http://www.smarternetworks.org/Project.aspx?ProjectID=399

4.3 CONSUMER ENGAGEMENT WITH DEMAND SIDE RESPONSE

36. Can you provide any evidence demonstrating how large non-domestic consumers currently find out about and provide DSR services?

Currently, consumers find out about DSR services through National Grid's Power Responsive Programme[47].

37. Do you recognise the barriers we have identified to large non-domestic customers providing DSR? Can you provide evidence of additional barriers that we have not identified?

Key barriers which have been recognised as part of National Grid's power responsive programme are; Initial business case development and identifying process changes that could allow participation but not increasing costs.

It has concluded that there needs to be a 'moral approach' on when there is increased demand on the network. For example, when there is excessive energy on the network from windfarms during periods of heavy wind, there needs to be a displacement of energy utilisation rather than wasted energy. It is not practical to waste this energy on unnecessary energy uses.

38. Do you think that existing initiatives are the best way to engage large non-domestic consumers with DSR? If not, what else do you think we should be doing? When does engaging/informing domestic and smaller non-domestic consumers about the transition to a smarter energy system become a top priority and why (i.e. in terms of trigger points)?

For domestic / small non-domestic consumers to partake in DSR they need to find a way to aggregate their effect with other domestic / small non-domestic consumers to make a meaningful impact to the network. This can either be achieved through the use of aggregators or by engaging with a future DSO model. (DSO will be unlikely to engage with individuals but may engage with community schemes).

The right time to engage large non-domestic consumers is through trials in the current price review period or at such a time when meaningful mechanisms are in place for customers to seamlessly engage with parties that can facilitate market access for customers.

Technology dictates that initial focus/priority for DSR is concentrated at the large non-domestic (Industrial & Commercial) market. Engagement with smaller non-domestic and domestic consumers should follow at a later stage when more cost reflective tariffs, advanced technology and scale of opportunity through aggregators is made available. Trials on domestic DSR participation have proven that the costs of large aggregation of consumers is high. The roll out of smart meters will help reduce these costs and facilitate take-up. For these reasons

[47] http://powerresponsive.com/

we consider that engagement with domestic and smaller non-domestic consumers (outwith current trials) should take place towards the end of the current price control period.

39. When does engaging/informing domestic and smaller non-domestic consumers about the transition to a smarter energy system become a top priority and why (i.e. in terms of trigger points)?

The key trigger for engaging and informing domestic and smaller non-domestic consumers about the smarter energy system is when it starts to have a material impact on their daily lives. To some extent this is already being covered by the communication of and engagement on the smart meter rollout. Additional trigger points should be identified when a critical mass of smart technologies and/or commercial arrangements become available.

Examples technologies include:-

- Electric vehicle penetration
- Aggregator services to local/national balancing mechanisms
- Electric Heating penetration
- Community Energy schemes providing services to SO/DSO.

4.4 CONSUMER PROTECTION

40. Please provide views on what interventions might be necessary to ensure consumer protection in the following areas:

- **Social impacts**
- **Data and privacy**
- **Informed consumers**
- **Preventing abuses**
- **Other**

Information security, data protection and data assurance, have become increasingly important in a world where the methods we use to share information has become more interconnected across sophisticated technological solutions.

There is a need for high levels of protection on information so that energy companies can safely collect and utilise data, bringing greater benefits to the consumer through the development of a smarter grid, while at the same time gaining public confidence in the safety of this information. In order to provide the necessary level of safeguard to the information we collect and use, it is essential that the appropriate controls, policies and procedures are embedded into the organisation and a “privacy by design” approach is adopted in the development of all major industry initiatives as seen in the smart meter rollout.

Given the scale and sensitivity of the data that will be generated by a smart flexible energy system, it is vital to ensure that this information is appropriately protected for processing, storage and transmission and an agreed period of data retention is agreed and adhered to.

Protecting data from abuse requires the implementation of data encryption accompanied by a fully implemented cryptography policy to support these processes. Encryption is aimed at safeguarding data communicated wirelessly or over networks so that information cannot be used to identify consumers or reveal sensitive consumer information.

Data protection measures such as a suite of cyber security rules encompassing the areas of HR security, access management, incident management, operations and network communication rules and third party cyber-risk management should be implemented to provide a strategic framework that is visible, clear to understand, implemented and complied with.

It is also beneficial to implement, as with smart metering an effective privacy impact assessment that ensures compliance with legislative and regulatory requirements. Such measures ensure data minimisation, data collection, data use, data disclosure and retention is proportionate and no greater than necessary.

As with Smart Metering, part of the Smart Energy Code stipulates compliance to ISO 27001 which looks at the development of an Information Security Management System. This provides the organisation with a robust method of managing information in a secure manner focusing on risk management under ISO 27005 supported by a governance model led from the top of the organisation.

41. Can you provide evidence demonstrating how smart technologies (domestic or industrial/commercial) could compromise the energy system and how likely this is?

The design of LV networks in particular is based on certain assumptions about load diversity, which is implicitly based on the independent behaviour of individual customers and is a key element in the design of cost-effective networks. Smart technologies have the potential to create synchronised customer behaviour, which removes this diversity. An example of this is the surge in electricity demand during the ad breaks of a popular TV show, or the synchronised switching of electrical storage heaters on the Economy 7 tariff. Whilst it is essential to engage with customers in order to capture any flexible behaviour, it is also necessary to include safeguard mechanisms to avoid unintended consequences, such as large-scale synchronisation of step changes of load or demand on the network which can have an adverse impact.

We will be allowing a wider range of participants to access network balancing actions which if compromised could result in risks to the UK network, locally and nationally.

4.5 CYBER SECURITY

42. What risks would you highlight in the context of securing the energy system? Please provide evidence on the current likelihood and impact.

It is conceivable that the increased levels of intermittent or inflexible generation along with the emergence of new load carbon technologies such as electric vehicles and heat pumps and the ever increasing complexity of the Smart Grid will create new risks to the system which we are less familiar with. It will therefore be necessary for us to become less risk averse and more risk aware in order to manage these risks in order to be able to make the correct balance between risk and cost to customers. Risks may include reduced system security, network frequency and as a worst case scenario, a Black Start Event.

The industry recognises the shift from traditional networks to the Smart grid and has begun the process of transitioning the network security standard (ER P2/6 – Security of Supply[48]) to take proper account of Smart technologies, such as demand-side response and energy storage. This working group[49] began with a fundamental review of network security and considered a wide spectrum of review options ranging from "do nothing" to "remove the security standard completely". This work is ongoing, but aims to provide a sound foundation for future network security beyond the current ED1 Price review period.

[48] http://www.dcode.org.uk/dcrp-er-p2-working-group.html
[49] http://www.smarternetworks.org/Project.aspx?ProjectID=1723

5 THE ROLES OF DIFFERENT PARTIES IN SYSTEM AND NETWORK OPERATION

43. Do you agree with the emerging system requirements we have identified (set out in Figure 1)? Are any missing?

We broadly agree with the emerging requirements identified in the Call for Evidence, however, we believe it is work considering the following points:-

- The emerging system requirements should seek to acheive the lowest overall cost to the UK customer.
- In addition to the visibility of networks, all parties should have visibility of system balancing actions undertaken by system operators and the services provided to meet said actions. This will be essential to avoid conflicts between local balancing actions and wider system balancing actions. Transparency will also be key to fostering an open and inclusive balancing market.
- Although identified as a driver for change the system requirements associated with the 'rapid/unpredictable pace of change' can in part be mitigated through a more coherent UK energy strategy developed through Government co-ordination with network and system operators. As an example the uptake of EVs could be heavily influenced by direct or indirect incentivisation of EVs.

44. Do you have any data which illustrates:
a) the current scale and cost of the system impacts described in table 7, and how these might change in the future?
b) the potential efficiency savings which could be achieved, now and in the future, through a more co-ordinated approach to managing these impacts?

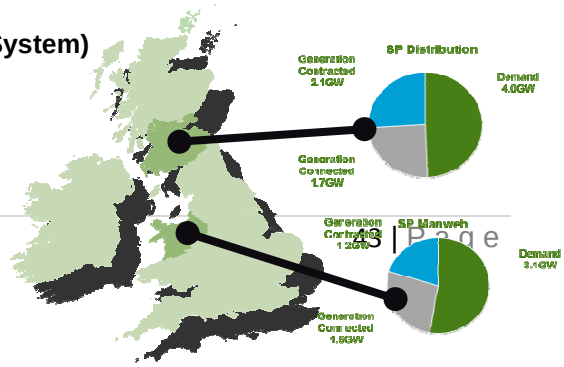
We already have considerable experience with exporting GSPs across our two licence areas due to the proliferation of onshore wind generation. In our SP Distribution network area 33 of 85 GSPs currently net export and in our SP Manweb network area 4 of 15 GSPs currently net export. This has resulted in network constraints, creating barriers for connecting generation customers at both Distribution and Transmission voltages. A summary of the connected distributed generation and distributed generation contracted to connect to our networks is shown below:-

SP Energy Networks Statistics (>1MW)

- Demand **7.1GW**
- Distribution DG Connected **3.3GW**
- SPT Renewables **2.7 GW**
- DG Contracted **3.3GW**

SPM Stats

- SPM System Maximum Demand (Total) - **3.1GW (System)**
- DG connected (>1MW) **1.6GW**
- Feed-In-Tariff (<1MW) – PV Connected **148MW**
- *DG Contracted 1.2GW*



SPD Stats

- SPM System Maximum Demand (Total) – **4.0GW**
- DG connected (>1MW) **1.7GW**
- Feed-In-Tariff – PV Connected **166MW**
- DG contracted to connect to the Distribution network **2.1GW**

These network challenges have driven SP Energy Networks to pursue alternative methods of connecting customers which was the focus of both our Flexible Networks[50] and Accelerating Renewable Connections[51] (ARC) innovation projects. The ARC project alone accelerated the connection by over 100MW and saved £18m[52] accruing to connecting customers and through wider societal benefits. Alongside the other UK DNOs we are in the process of adopting the learnings of flexible connections options into business as usual activity. These options focus on maximising the utilisation of our existing assets through enhanced monitoring and control with the goal of minimising the high capital costs associated with traditional reinforcement. It should be noted however that traditional reinforcement options may still represent the lowest overall cost for UK customers.

We currently have significant volumes[53] of flexible connection offers that have been accepted by our connecting customers. Further detail and evidence on our approach to flexible connections has been submitted to Ofgem throughout 2016 as part of the Quicker More Efficient Connections initiative[54].

Current ANM solutions create capacity by monitoring the real time energy flows on the electrical Distribution networks and comparing that with the real time capabilities of the Distribution network assets. This may circumvent Transmission SO actions that are issued to Distribution connected (Transmission contracted) Balancing Mechanism (BM) resources. As ANM is more widely adopted across the UK the potential for these conflicts to arise and impact the Transmission network will increase. This issue can be resolved however through greater coordination and communication between the SO and DNOs/DSOs, ultimately a communication and trading platform between the SO/DSO and service providers can solve potential conflicts.

The current scale of adoption of EV's[55] and heat pumps[56] has been negligible in terms of network impact, due to both scale and a lack of significant clustering. However, recent

[50] http://www.spenergynetworks.co.uk/pages/flexible_networks_for_a_low_carbon_future.asp
[51] http://www.spenergynetworks.co.uk/pages/arc_accelerating_renewable_connections.asp
[52] Identified in 2015/16 Regulatory Reporting Pack return to Ofgem submitted 29th July 2016
[53] 31 accepted offers SP Distribution representing 450MW, 24 accepted offers SP Manweb representing 866MW
[54] https://www.ofgem.gov.uk/publications-and-updates/quicker-and-more-efficient-connections-update-industry-progress
[55] SP Distribution 884 charger installations, SP Manweb 753 charger installations as of 31st March 2016
[56] SP Distribution 43 heat pump installations, SP Manweb 61 heat pump installations as of 31st March 2016

studies[57] have shown that the uptake of EVs is starting to increase, in addition OLEV's ambition is that nearly all new cars and vans will be emission free by 2040[58]. It is our view that as the rollout of EVs and heat pumps accelerates, the distribution network will experience localised thermal and voltage issues particularly in areas with high clustering of these technologies. As the rollout reaches saturation point on the low voltage (LV) networks, greater coordination and control will be required and ultimately Vehicle to Grid applications may start to provide network benefits rather than network challenges. There is a great deal of uncertainty over these levels of penetration over the next 20-30 years as it will be dependent on a range of factors including technology costs, available charging infrastructure and Government incentivisation to meet CO^2 emission targets.

45. With regard to the need for immediate action:
a) Do you agree with the proposed roles of DSOs and the need for increased coordination between DSOs, the SO and TOs in delivering efficient network planning and local/system-wide use of resources?
b) How could industry best carry these activities forward? Do you agree the further progress we describe is both necessary and possible over the coming year?
c) Are there any legal or regulatory barriers (e.g. including appropriate incentives), to the immediate actions we identify as necessary? If so, please state and prioritise them.

We strongly agree with the requirement for DNOs to transition to DSOs and published a consultation document on the 21st October 2016 outlining our DSO Vision[59]. The consultation is now closed and a summary of the stakeholder feedback has been published on our website[60]. This vision was developed in conjunction with a number of key industry stakeholders and includes five overarching principles that we believe are at the heart of the DSO transition.

- Our Vision is that SP Energy Networks will transition towards becoming a full DSO which will facilitate an open and inclusive balancing services market at the Transmission/Distribution interface. The DSO will also carry out local system balancing, efficiently utilising the Distribution network;
- We will continue to improve the level of customer service and manage system security in line with our current role as a DNO. We will ensure that the expansion of our role as a DSO continues to deliver value for money to our customers;
- Our DSO model will be capable of enacting system balancing actions from the SO within timescales that best meet the needs of the SO and the capabilities of the DERs connected to our network areas;
- Our transition to a DSO will be both modular and proportionate;
- We will work with BEIS, Ofgem, UK Network companies, DER providers and key stakeholders to develop and implement a fair and cost effective remuneration mechanism for all DSO services and DER providers.

[57] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/464763/uptake-of-ulev-uk.pdf
[58] https://www.gov.uk/government/news/government-gears-up-for-zero-emission-future-with-plans-for-uk-charging-infrastructure
[59] http://www.spenergynetworks.co.uk/userfiles/file/SPEN%20DSO%20Vision%20210116.pdf
[60] http://www.spenergynetworks.co.uk/pages/dso_vision_consultation.asp

Further detail on the technical, commercial and regulatory challenges associated with the transition to a DSO can be found in our vision document.

It is our intention to now develop our vision into a more detailed route map, outlining the detailed steps we plan to make to develop towards a DSO. Key to this route map, will be identifying programmes of work that can be progressed under current licence conditions and are least regrets solutions. The route map will also identify those programmes of work that require industry and Government co-ordination to advance.

The route map will be created in conjunction with the Energy Networks Association (ENA). The ENA Transmission Distribution Interface (TDI) steering group will take responsibility for developing industry proposals for this transition focusing on three key areas of work:-

- Existing Transmission–Distribution interface issues
- Customer experience
- The DNO to DSO transition

We also believe that progress needs to be made towards defining, understanding and realising the DSO transition in the next year. In addition to the drivers outlined within this Call for Evidence, there are current network challenges that need to be met through flexible and ultimately DSO enabled solutions.

The regulatory settlement periods further reinforce the need for progress in defining the roles and responsibilities of future DSO's. The RIIO-ET1 and RIIO-ED1 price controls conclude in 2021 and 2023 respectively, and the negotiation process will typically begin 2-3 years prior to commencement of the next regulatory period. Given that DSO services and capabilities are likely to feature heavily in future price reviews, the maturity of thinking in terms of technical, commercial and licencing of a DSO model needs to be significantly advanced in a relatively short period of time.

Under the current price control settlements we believe that there is sufficient scope within the Directly Remunerated Services (DRS) mechanism to trial and explore DSO services to the extent that it will be possible to develop technical capability and commercial agreements to do so. We would welcome further instruction from Ofgem on the provision of DSO services, similar to that provided to cover the commercial elements of ENWL's CLASS project[61].

The limitation on this mechanism is that the DSR activity is limited to De Minimis activity which will ultimately limit the extent to which DSO's can operate. As outlined above, this approach will need to be reviewed as part of the RIIO-ED2 Price control settlement.

If BEIS and Ofgem seek to accelerate the evolution towards both a smart grid and ultimately to a DSO model, they could investigate the potential to connect customers through flexible or innovative techniques. Currently the main drivers to offer flexible connections are; improved customers service through quicker connections to the network, and network operators aspirations to advance their understanding of alternative solutions to traditional reinforcement.

[61] https://www.ofgem.gov.uk/publications-and-updates/direction-distribution-network-voltage-control-services-nget-so-residual-balancing

46. With regard to further future changes to arrangements:
a) Do you consider that further changes to roles and arrangements are likely to be necessary? Please provide reasons. If so, when do you consider they would be needed? Why?
b) What are your views on the different models, including:
i. whether the models presented illustrate the right range of potential arrangements to act as a basis for further thinking and analysis? Are there any other models/trials we should be aware of?
ii. which other changes or arrangements might be needed to support the adoption of different models?
iii. do you have any initial thoughts on the potential benefits, costs and risks of the models?

The requirements for a need to change the roles and arrangements are well established within: the Call for Evidence; DECC/BEIS publications;[62] Our DSO Vision document,[63] and a range of international publications.

As outlined above, it is our view that fundamental regulatory/licence arrangements will need to be in place for the next price control settlement periods, particularly the next Distribution price control.

We believe that the range of models identified in the Call for Evidence represent the right range of potential arrangements as a basis for further thinking and analysis. We would like to add however, that the correct solution may be a hybrid of the models identified, for example, the 'DSO/SO procurement mechanism' is likely to be supported by a 'market signals and arrangements' approach, particularly for domestic customers.

We do have concerns that the 'market signals and arrangements' model may ultimately be unsuccessful in achieving the required balancing services required in order to ensure local and national system stability. This approach is more well suited to a utility network with low cost, large capacity storage e.g. gas networks. With market signals, only the SO and DSOs would struggle with either over or under subscription of ancillary services leading to a continued balancing issue.

Our DSO Vision document outlines a range of technical, commercial and regulatory changes that will be required in order to facilitate the transition from a DNO to a DSO. These changes are identified on the assumption that the DSO model implemented is closely aligned with the 'DSO/SO procurement mechanism' model, however the majority of the technical developments required will be required under the full range of DSO models.

Our planned DSO transition routemap (outlined above) and the ENA TDI work stream will provide additional detail on the prospective costs associated with the change of roles. These sources will also account for a range of scenarios on the scale and duration of the transition to

62 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/285417/Smart_Grid_Vision_and_RoutemapFINAL.pdf

63 http://www.spenergynetworks.co.uk/userfiles/file/SPEN%20DSO%20Vision%20210116.pdf

smart grid enabled DSOs. Both work streams will provide outputs during 2017 answering or partly answering the questions in the Call for Evidence.

DECC's Smart Grid and Vision Routemap[64] identifies significant benefits associated with the transition to a Smart Grid in the UK. We suggest that further work is required in order to demonstrate the specific benefits of transitioning UK DNOs towards DSOs and ensuring that it is indeed the lowest overall cost solution for UK customers.

64 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/285417/Smart_Grid_Vision_and_RoutemapFINAL.pdf

6 INNOVATION

47. Can you give specific examples of types of support that would be most effective in bringing forward innovation in these areas?

Innovation Stimulus

The UK is currently at the forefront of developing network centric smart solutions that look to facilitate low carbon technology and provide greater value to customers and this position is largely down to the innovation stimulus made available. Through the Network Innovation Competition (NIC), Network Innovation Allowance (NIA) and the previous Low Carbon Network Fund (LCNF) and Innovation Funding Incentive (IFI), DNOs have been able to support the inception, development, trialling and adoption of several new technologies and commercial arrangements that are now becoming commonplace in the UK. Most importantly these solutions have started to deliver clear benefits to customers, as highlight by the recent Poyry report[65] which forecasts the benefit of the £250m LCNF portfolio of projects could be £800m-£1.2Bn and potentially several times greater if the benefits are also realised by the non-trialling DNOs.

The challenges faced by the networks are going to continually change as UK customers adopt low carbon technology en masse, and greater network visibility is provided from smart metering. Without access to innovation funding it is unlikely that there will be substantial DNO activity to rectify these emerging network issues until they are appearing which is obviously too late. We believe it is therefore imperative that the DNOs continue to have access to innovation funding to ensure solutions to future problems can be trialled ahead of our customers needing them in place. In particular, we see there being a strong requirement to utilise innovation funding to facilitate the transition from DNO to DSO in ED1 and we would encourage ongoing support in this area from both BEIS and Ofgem. At the same time we recognise the need for stronger collaboration in this area by UK DNOs.

We do however believe that there is an opportunity to make small changes to the existing funding mechanisms that can result in some beneficial outcomes for UK customers.

One such change would be to provide non-DNO parties with access to the existing or new innovation funding mechanisms. With bidding parties requiring DNO sponsorship / buy in to ensure that customer benefits are realised through the mechanism. With this in mind, we welcome the introduction of both the 'Innovation Link' and the 'Innovation Space for Experimentation'. If our understanding from the limited details provided at this time are correct, then both of these mechanisms would assist in preparing these parties for entry into the UK energy market and foster low Technical Readiness Level (TRL) solutions that DNOs would be unable to justify funding under existing mechanisms. In particular, the Innovation Link has the potential to benefit DNOs through the education of new entrants to nuances of the UK market. This process would streamline the vendors approaching DNOs to only those that are viable to the UK.

[65] Poyry 'An Independent Evaluation of the LCNF' October 2016
https://www.ofgem.gov.uk/system/files/docs/2016/11/evaluation_of_the_lcnf_0.pdf

It would also be beneficial for the Innovation Link to raise awareness of the regulatory funding received by DNOs and how successful innovation delivery cannot necessarily turned into high volume orders if not built into the existing ED1 plan. This so called SME 'Valley of Death' is often not considered by prospective partners.

BEIS Funding

We welcome the introduction of further BEIS funding of technology that we are presently not in a position through existing mechanisms, be it to the low TRL or the vendors reluctance to accept the default IPR position. We welcome the opportunity to be involved in this mechanism in whatever capacity is appropriate. We would be particularly keen to assist in the assessment of the potential network benefits of the smart technologies being proposed for funding.

48. Do you think these are the right areas for innovation funding support? Please state reasons or, if possible, provide evidence to support your answer.

Commercial and residential automated Demand Side Response

Over the next few years, we expect the development and residential customer uptake of home automation which combined with smart meters will serve as the enabler for this technology. This will be driven by the growing number of automated home technology providers and energy retailers offering products and services to retain customers. As a DNO, our experience and interaction with this technology to date is extremely limited as it is a beyond meter solution. As such we welcome any analysis of the benefit this solution can have, however, for any trials to truly assess the impact, this solution might have on local networks then we believe a number of things will need to be considered.

To assess the impact and potential benefit to localised LV networks and secondary substations, there will need to be a substantial DSR uptake from residents in the trial area. These customers will also have to have a significantly high up take of low carbon technology. Only with these conditions will it be possible to ascertain the impact and benefits of automated residential DSR on local networks. We would also welcome the analysis of the potential conflict between national and localised DSR service requirements. The national requirement for DSR is less dependent on geographical clustering of customers, and as such will likely be the first commercial service established with customers. These national trials will help to identify customer willingness and the remuneration required to facilitate DSR.

We have recently completed a Tier 1 LCNF / NIA funded project 'NIA_SPEN_0001 Smart Building Potential Within Heavily Utilised Networks' looking into the potential localised network benefits of automated DSR in commercial properties in Glasgow. The project closedown report will shortly be available on the ENA Portal[66]. This project has highlighted a number of key findings which provide evidence to support further investigation into this technology / commercial offering.

The project identified that automated DSR through the control of commercial building management systems is capable of providing DNOs with worthwhile local network demand flexibility. To do so at a primary substation level requires a considerably lower customer

[66] NIA_SPEN_0001 ENA Portal Link http://www.smarternetworks.org/Project.aspx?ProjectID=1678

uptake required, typically 50-100 commercial customers per primary. The project also identified that the solution is most effective where it is used in conjunction with older less efficient buildings. One of the projects main conclusions was that it is unlikely that this type of DSR is unlikely to be commercially viable to customers if they are only providing flexibility services to just DNOs. This conclusion further warrants investigation into the ability of flexibility providers to serve both national and local network requirements without causing conflict.

Flexibility Providers

As previously mentioned, we recently published our 'DSO Vision'.[67] In this, we outline the importance of network flexibility provide Distributed Energy Resources (DER) as we migrate to a DSO model. As such we fully support the ongoing support of Ofgem and BEIS to bring an open market to flexibility providers.

The DSO model proposed by us provides a commercial and technical framework allowing DERs to participate in the UK balancing services market. This will be achieved by understanding the real time requirements of the UK SO and the real time capabilities of DERs within the DSO enabled network areas and agreeing commercial terms act on that market. Ultimately we believe this will be achieved through a real time service tender process facilitated by communications, automated services and commercial terms. Our goal is to facilitate an open market where participants can choose to contract directly with national grid, utilise the service of aggregators and other third parties or contract with the DSO.

The DSO would be able to draw on a range of flexibility services, including:

- Controllable generation
- Storage
- Demand Side Response (DSR)

The DSO is then able to use these to:

- reduce network reinforcement
- provide flexibility
- offer balancing services
- provide ancillary services
- encourage demand to match generation

In the last two years we have submitted NIC bids focusing on the transition from a DNO to a DSO including our Evolution[68] and Inspire[69] bids. These bids were unsuccesful and in the case of Inspire a prime reason for this was a view that we should be doing carrying out these activities as 'business as usual'[70]. There is still considerable innovation, both commercial and technical that will be required to facilitate the DNO to DSO transition, this should be a consideration for Ofgem going forward in supporting the RIIO Innovation strategy of the UK network companies.

[67] DSO Vision http://www.spenergynetworks.co.uk/pages/dso_vision_consultation.asp
[68] https://www.ofgem.gov.uk/sites/default/files/docs/evol_resubmission.pdf
[69] https://www.ofgem.gov.uk/publications-and-updates/electricity-nic-submission-sp-distribution-inspire
[70] https://www.ofgem.gov.uk/publications-and-updates/electricity-network-innovation-competition-2016-funding-decision

Storage

It is our view that storage will be owned and operated by third party flexibility service providers and as a DNO it will be a service that we call upon. As such, we are agnostic to the technology used to provide this service as long as it is proven to be safe and is at a cost point that provides value to our customers.

If there is evidence to show that these low TRL storage solutions have the potential to be more cost effective than existing storage solutions then we support the innovation support to catalyse the development of the technology.

We would welcome the opportunity to facilitate the connection of a third party storage DER solution on our network and utilise NIA funding assess its network benefits.

Vehicle to Grid

We are in agreement that to date there has been very little exploration of this concept in the UK. Our involvement has been limited to a single collaborative Innovation Funding Incentive (IFI) project[71] that resulted in a very small 1-2 vehicle trial, with no major assessment of the potential network impact.

It is however unlikely that we would look to undertake such a project using the existing innovation funding until such time as there is clear acceptance and support of the concept from both the EV manufacturers and their end users. In this regard it will be very interesting to hear from the experiences of the trials in Denmark and Japan and to understand the present position of EV manufacturers. The last time we were engaged in this area the EV manufacturers appeared to be reluctant to the concept on the basis that it might have a detrimental impact on the life of the battery, and whilst the uptake of EVs was in its infancy this would be a risk they would be unwilling to take.

As the penetration of EVs increase, we will look to understand the benefit of Smart Charging for EVs that responds to national / localised price signals to absorb generation peaks or remove network constraints. The projects to do so would most likely look to develop the charging technology required to also provide vehicle to grid. So we would encourage DNO development of projects in this area.

[71] IFI 1312 Vehicle to Grid – Collaboration between SPEN, SSE, WPD and UKPN

7 GLOSSARY

Acroynmns

BEIS: Department for Business, Energy and Industrial Strategy

BSC: Balancing and Settlement Code

BSUoS: Balancing Services Use of System charges

CDCM: Common Distribution Charging Methodology

CLASS: Customer Load Active System Services

CM: Capacity Market

DNO: Distribution Network Operator.

DSO: Distribution System Operator

DSR: Demand Side Response

DUoS: Distribution Use of System charges. These are the costs that customers pay to DNOs via their energy suppliers. The amount of DUoS charged is determined with Ofgem at each price control review.

EFR: Enhanced Frequency Response

ENA: Energy Networks Association

ESN: Electricity Storage Network

EV: Electric Vehicle

LCNF: Low Carbon Networks Fund

NIA: Network Innovation Allowance

NIC: Network Innovation Competition

OFGEM: Office of Gas and Electricity Markets

OLEV: Office for Low Emission Vehicles

PV: Photovoltaic

RIIO: Revenue = Incentives + Innovation + Outputs

SO: System Operator

STOR: Short Term Operating Reserve

TNUoS: Transmission Network Use of System charges

TO: Transmission Owner

ToU: Time of Use (tariffs)

SME: Small and Medium Enterprise

Definitions

Access Queue: The queue of customers waiting to connect to our network within a constrained network area, where network access is limited by the physical constraints of the network.

Distribution Code: The distirbituion code covers the technical aspects relating to the connection and use of electricity distribution licensees' distribution networks.

Distribution Network Operator (DNO): DNOs are the organisations that look after the networks transporting electricity to end users such as homes and businesses. In England and Wales, DNOs manage the network from 132,000 down to 230 volts. In Scotland, DNOs manage the network from 33,000 volts to 230 volts. The UK distribution network is divided into 14 distribution areas and these are managed by 6 companies.

Enhanced Frequency Response (EFR): Enhanced frequency response a service offerred by National Grid that achieves 100% active power output at 1 second (or less) of registering a frequency deviation. This is in contrast with existing frequency response services of Primary and High which have timescales of 10 seconds, and Secondary which has timescales of 30 seconds.

EU Third Package: (Directive 2009/72/EC) EU energy market legislation, known as the third package, was enacted to improve the functioning of the internal energy market and resolve structural problems.

Grid Code: The Grid Code covers all material technical aspects relating to connections to, and the operation and use of, the national electricity transmission system.

Grid Supply Point: means a Systems Connection Point at which the Transmission System is connected to a Distribution System

P2/6: is an engineering recommendation and is the current distribution network planning standard. DNOs have a licence obligation to plan and develop their systems in accordance with ER P2/6

Queue Management Policy: The management of contracted capacity and treatment of stalled projects is a significant issue. As a consequence, opportunities for consented sites to progress can be delayed and, in some cases, increased connection costs through additional network reinforcements can occur. Our Queue Management Policy helps to address this issue and can be found on our website. http://www.spenergynetworks.co.uk/userfiles/file/Queue_Mgt_Policy_Communication_Dec_2016v3.pdf

Smart Grid: A generic term for a range of measures that are used to operate electricity networks allowing more generation or demand (load) to be connected to a given electricity circuit without the need for traditional reinforcement (or upgrade) of that equipment.

Short Term Operating Reserve (STOR): is a service offered by National Grid for the provision of additional active power from generation and/or demand reduction