The customer-focused smart grid: Next steps for regulatory policy and commercial issues in GB

Report of Workstream Six of the Smart Grid Forum, 2015

Annex 1: Subgroup chapters

These chapters are the final output of each of the subgroups of Workstream Six (WS6), in a broadly common format. Each of the actions in the main report stemmed from the work of the subgroups. However, the final actions in the main report have been agreed by the plenary WS6 body and so the wording between the main report and the annexes main not align precisely. Annex 2, published alongside this document, contains the working documents that support the findings of these chapters.

Contents

1. Community Energy and Energy Efficiency

1.1. This section sets out what the CE & EE subgroup considers to be the key potential barriers and enablers for Community Energy projects. It should be noted that some of the issues identified below affect other stakeholders and industry participants, and that in general the members of workstream 6 support the exploration and implementation of measures that contribute to improving the energy system for all users. This section has a specific focus on community energy because of the distinctive opportunities and challenges relating to smart grid deployment for community energy projects, but this should be considered in the context of the report as a whole.

Flexibility services

1.2. Community energy groups could be well placed to provide flexibility services. They can be effective at engaging with their local community as they understand the local context and needs of the people living there. In relation to smart meters, DECC's Consumer Engagement Strategy notes that 'Third party trusted messengers, such as charities, consumer groups, community organisations, local authorities and housing associations, will also have an important role to play in delivering effective consumer engagement'.[1] This applies not only to smart meters, but also to engagement with flexibility services.

BARRIERS

1.3. Currently, there are very few mechanisms for community energy groups to benefit from flexibility services. A number of barriers are set out below. Please note that specific barriers to storage are not addressed here, as they are covered by the DG and Storage Subgroup. The Community Energy sub-group also acknowledges the recommendations made by the Distribution of Value subgroup which are particularly relevant for enabling greater value from the provision of flexibility services by community energy groups.

1.4. Under the current regulatory model, DNOs do not incentivise flexibility services. The market for both DSR and storage is not yet established. It is clear that parties such as DNOs and suppliers will require more flexibility services in the future as penetration of non-synchronous distributed generation increases. However, as there is not an established local flexibility market it is not clear how a DNO would indicate to the local network that such services are required. Flexibility services tend to be procured on the transmission system level, as opposed to locally by DNOs.

1.5. Use of system charges do not currently reflect the actual cost of transporting power in a local area when generation and demand are being actively controlled and balanced. Arguments can be made that the community should only pay for the portion of the network it uses, but:

- It is unlikely that a community will be able to be entirely self-sufficient in energy and would be likely to need to "import" energy. This import would use the extended network and the DUoS charge would need to reflect this
- Where consumers or communities go entirely "off-grid" then the cost of running the public network falls on fewer consumers and the cost may rise to those consumers remaining. This risk needs to be carefully balanced against the benefits which a partially or fully "off-grid" community project can bring, and warrants more consideration.

[1] DECC Smart Metering Implementation Programme: Government response to the consultation on the Consumer Engagement Strategy, December 2012

- DUoS charges do not just cover the use of the wire network (and all the necessary sub-stations and equipment). It also covers the cost of keeping the network stable and supporting recovery after a fault. So some proportion of these DNO-provided services would still need to be paid for by the community, if they periodically connect to the grid.

1.6. New commercial arrangements are required to allow demand customers to benefit from providing services to local generators in areas where the network is constrained. Bespoke commercial arrangements would allow the transfer of value from generators to demand customers when DSR enables generation to be connected in areas where the network is constrained

1.7. The high cost of entering domestic customers into half hourly settlement prevents both the netting off of local generation and realising the benefits of optimising the demand profile for the supplier.

1.8. Private wire networks, which enable local generation to be used and balanced locally, are expensive and may duplicate existing assets. However in some circumstances they may be the only option for a community looking to develop a generation project and supply local customers directly.

1.9. The Community Energy subgroup notes the work done by the Distribution of Value subgroup, and would like to highlight that community energy projects may act as solutions to some of the barriers listed by that group, such as – lack of customers to deliver sufficient DSR volume, and customer reluctance/trust in DSR.

ENABLERS

1.10. All of the domestic options in the Work Stream Six Interim Report would provide incentives for individual households to change their behaviour, and community groups are well placed to coordinate and educate local people to maximise the benefits locally. Community energy groups could also act as third party storage operators and could be incentivised to provide flexibility services, as set out in Appendix 2 of the Interim Report.

1.11. In addition, community energy groups could have greater ability to integrate flexibility services in their local area if they had more control over energy tariffs and the retail price of community owned generation. This could be achieved by enabling community groups to become local suppliers and/or through the setting up of private wire networks. See below for more information.

Action: Ofgem should facilitate the uptake of the DSO model to encourage DNOs to procure flexibility services. This could be done by giving DNOs the right powers and incentives. If the DNO transitioned to a DSO, which would then have a balancing role, energy services would be required and a local balancing market would need to develop to support the requirement to balance. In the interim we encourage the use of bi-lateral contracts between the DNO and the service provider. EU codes will soon require all renewable generators, above a certain size, to provide balancing and ancillary services which may further drive the need for local markets.

Action: Consideration should be given to the trialling of alternative DUoS charging methodologies for networks where there is a high percentage of local generation and local use. When carrying out this work, Ofgem should consider if a static or dynamic time of use tariff would be appropriate. Any alternative DUoS charging methodology should reflect reward reductions to DNO costs, but should be balanced against any increase in cost to the general customer.

Action: We welcome Ofgem's Consultation on Non-Traditional Business Models, which has highlighted some of the regulatory barriers to NTBMs such as Community Energy Groups. Ofgem should give full consideration as to how best to support NTBMs providing flexibility services.

Local supply

1.12. Allowing community groups to supply energy directly to customers or to partner with existing suppliers can offer specific benefits to the electricity sector and consumers[2]. Communities are ideally placed to fulfil the role of supplier in many of the options outlines in the WS6 report – particularly those that require a greater degree of interaction with customers. Equally, collaborative models involving existing suppliers are also emerging.

1.13. As of yet however, there have been few real cases to test the magnitude of these opportunities in the marketplace; and none yet at scale. Depending on the business models being proposed this can be due to unfavourable market regulation, an unsuitable policy environment, a lack of data to justify real returns, and/or simply that the technologies in metering and ICT have only recently become sophisticated enough to enable local supply.

1.14. We note that issue of the costs and burdens of setting up as supplier in the market are being explored by a range of projects, including the BIS Challenger Business project, DECC/Ofgem Independent Supplier project[3], Capacity Market Auction and Market Investigation Reference.[4]

BARRIERS

1.15. Current trading arrangements generally assume that contractual positions for supply and demand will be achieved at a national or supplier portfolio level which doesn't exclude local operators per se but puts them in a weak position, compared to national operators.

1.16. The costs associated with setting up and running a supply licence (even licence lite) are considerable.

1.17. Partnerships require a third party licensed supplier to deliver services on behalf of local suppliers. It was been reported that there is a reticence on behalf of licensed suppliers to enter into these partnerships and challenges in establishing fair partnership agreements.

1.18. The lack of replicable and tested business models is a significant barrier to local energy supply, especially for approaches including demand side response or demand reduction (such as Energy Service Companies).

1.19. There is a great deal of uncertainty over how sufficient revenue could be generated to cover these costs in small scale operations matched against local needs, which are not designed to grow. This is a particular problem for archetypes which aim to reduce demand

1.20. Uncertainty over codes, exemptions and rules is frequently cited as a major barrier to local supply. The complexity of the supply licencing regime and its focus on large

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[2] Hall and Roelich 2015
[3] https://www.gov.uk/government/publications/government-and-ofgem-action-plan-challenger-businesses-independent-energy-suppliers
[4] https://www.ofgem.gov.uk/ofgem-publications/93586/non-traditionalbusinessmodelsdiscussionpaper-pdf

suppliers makes it seem impenetrable to smaller organisations. We acknowledge the need for regulation to protect consumers but think it is important that regulations are suitable for all levels of organisations.

ENABLERS

1.21. Several of the WS6 options provide solutions to these barriers. They include:

- **Option 4:** Dynamic DUoS tariff - could enable community suppliers to support more appropriate time of use tariffs, based on real network constraints. They would be compensated (for example with cheaper DUoS charges, or through a rebate mechanism) for shifting demand to less constrained periods.
- **Option 5:** Load limiting – could provide an extra source of revenue for business models based on demand flexibility or demand reduction, although consumer protection is a key consideration which is being examined by Ofgem, suppliers and consumer representatives.
- **Option 6:** Deployment of energy efficiency measures would provide an extra source of revenue for business models based on demand reduction.
- **Option 7:** Demand reduction through information – this might help with business models based on demand reduction.

1.22. These opportunities assume that community groups can become suppliers, which as noted above can be the initial barrier for the CE project.

Action: Provide a link to the Ofgem support materials on independent suppliers on the DECC Community Energy Hub.

Action: Explore the viability of local balancing of generation and demand as part of the settlement process through the creation of a Local Balancing Unit (LBU). The concept of a LBU was developed by Elexon as a solution to the barriers to local supply and would enable local generation and consumption to be netted off before entering the national balancing settlement, therefore reducing balancing charges for the local supplier and enabling it to claim the value of embedded benefits.[5] The embedded benefits include the natural reduction in electrical losses from the generation of energy local and use of that energy locally. This reduction in carbon is not currently measured or recognised. We recommend that further work is done to investigate how to measure and reward this contribution which could be captured in the LBU

The establishment of a local balancing unit is closely linked to development of active distribution system operator which could procure local balancing responsibilities.

Action: Undertake a detailed review of the treatment of demand-reduction centred business models in regulation and policy

Action: Review regulatory issues for local suppliers, including community groups, supplying locally. Clarify the exemptions relating to license exempt supply and distribution of electricity.

Community energy connections

[5] Elexon – Encouraging local energy supply through a local balancing unit. September 2014

1.23. According to DECC's research for the Community Energy Strategy; there are now approximately 5,000 community energy groups in the UK, many of which have aspirations to generate their own energy[6]. Although many projects will be small-scale, many will need to connect to the distribution network. This issue was also explored by the Community Energy Grid Connections Working Group in January 2014.[7]

1.24. Community generation is at a disadvantage to commercial generation in relation to connecting projects to the network for two reasons: Firstly, it takes communities longer to develop projects and so can miss the chance to reserve network capacity; and secondly, they are geographically constrained and cannot move to areas where there is spare capacity. This means that smart grid solutions are particularly important for community energy. Therefore, we look at enablers before barriers in this section. The DG and Storage subgroup have developed a section on barriers and enablers of flexible connections, many of these are applicable to community energy groups, these are mentioned in more detail in the DG and Storage subgroup paper.

ENABLERS

1.25. Non-firm connections can enable community-owned generation to connect in areas where the grid is constrained.

1.26. Storage combined with export limiting technology can enable projects to connect where there is limited available network capacity.

1.27. Community groups are well placed to combine local generation with local DSR, which can increase local capacity.

1.28. Where there is limited network capacity, communities could explore options to minimise that constraint, such as a heat project, with the network operator (see section 5 for more information).

BARRIERS

1.29. Unlikely to have network connection or smart grid expertise within community energy group and are therefore not necessarily aware of the options available. Regen SW and WPD have developed a connections guide aimed at CE groups. This is a step in overcoming this barrier.

1.30. Non-firm access to a network may be the only option in areas where the network is constrained. This limits the income of a project and may make it financially unviable.

1.31. Active Network Management (ANM) requires the installation of new equipment to facilitate management of connectees and the network. As with reinforcement, the "first comer" to trigger the requirement for ANM is currently liable for the full cost. So although ANM can make connections in constrained areas possible, the cost can still be prohibitively high to the first developer. DNOs may therefore look to facilitate a consortium of developers in an area where ANM is a potential solution, in order to avoid this barrier.

1.32. When a project is not able to export its full capacity, e.g. under a non-firm connection, it can be prevented from securing Feed-in Tariff (FIT) accreditation. This is because the FIT legislation requires an applicant to show that they can export the full declared net capacity (DNC) of the installation. Where the grid connection is less than the DNC and there are no loads onsite (eg use in buildings), the installation will be viewed as not having been commissioned. As a result, it won't be eligible to receive FIT

[6] Community Energy Strategy Update, March 2015
[7] Community Energy Grid Connections Working Group Report

support, despite the installation being operational. DECC is reviewing the legislation to ensure it doesn't create unintended barriers or deter community groups from exploring flexible connection solutions

1.33. Barriers related to export limiting and storage also arose, but will be addressed by other subgroups.

Action: Ofgem to assess whether community energy applications for non-firm connections should be subject to different connection rules from commercial developers and/or different curtailment rules. We believe this is justified as CE projects are geographically fixed, they cannot spread their risk across a portfolio of projects, use governance models which means they may be slower to act than commercial actors and less likely to have upfront financing.

Action: DECC to Review FIT accreditation legislation in relation to non-firm connections as part of the 2015 FIT review.

Action: Encourage Ofgem to consider the specific needs of Community Energy projects when assessing the options outlined in its current consultation "Quicker and More Efficient Distribution Connections".[8] For example option 4.3 "Flexible Terms for the Recovery of Connection Charges" considers allowing DNOs to phase connection cost payments.

Stakeholder participation, communication and engagement

1.34. Communities have the capacity to address our energy challenges in different ways to government or the private sector, such as working through local volunteer networks or using social enterprise to deliver social returns or raise funding for non-commercial activity. Communities can mobilise and engage people effectively by tailoring their engagement to an audience they understand well, using their existing presence and networks to good effect. They could have more freedom to develop creative solutions that meet local needs and spot gaps in the markets to gain advantage. Community groups could act as innovators, catalysers and incubators for testing new approaches. Studies have found that community projects are more likely to be successful if the community has access to a significant pool of professionals or qualified people.[9]

ENABLERS

1.35. Community groups can help to accelerate smart cities and energy. Aggregated, anonymised data based on smart meter outputs could help to provide much more accurate and up to date data than has previously been available at local level, enabling more effective monitoring of impact and targeting of carbon reduction activity. There could also be opportunities for consumers to "opt in" to sharing energy use data with their peers (subject to adequate data protections being in place).

1.36. It can be difficult for government, large energy suppliers or DNOs to find vulnerable customers who qualify for support through schemes such as ECO, DNOs social obligations or government grant schemes. Community groups could be better placed to engage and target qualifying consumers in their locality, ensuring that support schemes reach the most vulnerable customers. This would also be applicable to helping DNOs identify participants for energy efficiency or demand reduction measures under options 9 and 10 of WS6 Interim Report

1.37. Community groups can help deliver the roll out of smart meters and smart trials by providing unbiased information and education on how to maximise the benefits for the

[8] https://www.ofgem.gov.uk/ofgem-publications/93479/quickerandmoreefficientdistributionconnections-final.pdf
[9] http://www.respublica.org.uk/wp-content/uploads/2013/09/yqq_Community-Renewables-Economy.pdf

local community. They can also help to increase acceptance of the technology – by showing what it can do – demonstrating that its technology that empowers people not disenfranchises them

1.38. The capacity of the community energy sector to act independently and become active in the energy market is increasing, fuelled in particular through a growing number of community renewable energy generating social enterprises. Many of these organisations are also seeking to become active in energy efficiency, demand management and energy supply. The sector's capacity for innovation and focus on delivering sustainable energy could equip it to become a significant driver of integrated approaches to energy demand management, supply and generation at local level, particularly as energy storage technology develops.

1.39. The consumer subgroup have highlighted that the complexity of DSR offers and tariffs to consumers may create a barrier. Community energy projects could be well positioned to provide trusted advice and guidance to their consumers as to which options would be most appropriate for them provided they have access to the latest information and advice themselves.

BARRIERS

1.40. Care must be taken with the use of data to ensure consumers' retain control of their energy data and community energy projects are clear with consumers regarding data access and adhere to current rules on data protection

1.41. Skills and knowledge are not evenly distributed between communities, meaning some are less able to participate in community energy. This could limit the potential of community energy to those communities which have the right balance of skills which could prevent those who could benefit most from local energy and restrict the potential growth of the sector.

Action: DECC to establish a pilot 'Smart Community' fund, which would be available for community groups to test innovative approaches at the local level, covering grid (including innovative solutions such as storage), supply, generation, demand management, and consumer behavioural elements. This fund would be separate to the existing urban and rural funds that only focus on renewable technologies. This fund should also be used to allow local supply actors to experiment, innovate and learn from each other in the local electricity supply space. The distinction with the LCNF and its successors is that communities would be able to apply to this fund directly. The success of the Local Energy Challenge Fund in Scotland indicates a high level of interest among communities in leading on innovative projects of this sort[10.] Under the fund communities should be able to team up with other parties such as aggregators, DNOs and suppliers.

Action: Ensure DECC's Community Energy Hub is fit for purpose by feeding back to DECC's Community Energy Unit on design and content when launched, and that specific links are made with other sources of information and support such as the Energy Saving Advice Service[11.] Promote the balance between community electricity and heat projects and manage expectations for community groups when it comes to grid connections and the process and cost that could potentially be involved. Provide information about smart grids and opportunities for community groups to take advantage of the opportunities (link into energy efficiency section).

10 http://www.localenergyscotland.org/funding-resources/funding/local-energy-challenge-fund/phase-one-projects/

11 http://www.energysavingtrust.org.uk/organisations/cy/content/programmes-we-deliver

Action: The potential role of third parties, such as community energy groups in the roll out of smart meters has already been acknowledged by DECC. [12] We would welcome further work on exploring the potential role of community groups in the smart meter roll-out and how groups could be resourced to provide support. The subgroup notes that Smart Energy GB has been established to assist with the roll out of smart meters in GB. The subgroup encourages Smart Energy GB to take an active role in engaging with community energy groups. This could be done as part of the Smart Energy GB consumer engagement plan update.

Action: Community Energy groups are well suited to take on a role to educate consumers of the pros and cons of sharing their data. This role should be explored further.

Other findings – Heat Projects

1.42. While the Community Energy and Energy Efficiency Subgroup of Ofgem Work Stream 6 are focusing on electrical energy in communities, heat energy is an important factor of the overall Community Energy sector, and will form an important element of a smart energy system. For example, the Smart Systems Heat led by the Environmental Technologies Institute (ETI) is a research project involving Newcastle City Council, Bridgend County Borough Council and the Greater Manchester Combined Authority. The aim is to bring various source of information (in a software) to build a cost-effective local energy systems.

1.43. Over 60% of a domestic household's energy needs are related to providing space heating and a further 15 % is related to heating water. [13] Gas dominates the production of heat energy in the home and it is important to generate heat from lower carbon sources to reduce CO_2 emissions.

1.44. **Barrier**: There is a lack of awareness amongst communities regarding projects on heat energy, compared to renewable generation projects.

1.45. Communities are enthusiastic about embracing renewable electricity generation, driven by the various incentives available. While there are some community heat projects emerging, driven by municipalities and local authorities (for example, DECC has a Heat Network Delivery Unit that provides funding to local authorities who want to investigate heat networks), the interest of communities in focusing projects on heat energy is under developed. This may be because there is a lack of awareness understanding about the Domestic and Non-Domestic Renewable Heat Incentive and domestic incentives and how this might work for a community and also because the process of building a heat network is more complex than connecting to the electricity network. In most cases the electricity network is already in place, but a new heat network would need to incorporate the development of network infrastructure, not just the heat generator.

1.46. **Enabler**: In areas where connecting new generation to the electricity network may be difficult due to constraints, certain community heat project may offer an alternative way for communities to engage with their energy use and be rewarded through incentives.

1.47. The UK's first DECC Community Energy Strategy (January 2014) focused across all 4 strands of energy activity: generation, purchasing, managing and reducing on

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[12] www.gov.uk/government/uploads/system/uploads/attachment_data/file/43042/7224-gov-resp-sm-consumer-engagement.pdf and https://www.gov.uk/government/publications/role-of-community-groups-in-smart-metering-related-energy-efficiency-activities

[13] https://www.gov.uk/government/policies/helping-households-to-cut-their-energy-bills/supporting-pages/smarter-heating-controls-research-programme

electricity, DECC has provided an update14 (March 2015) which reaffirms commitments to community heat and support is available to communities to develop a heat-related community project through the £15m Rural Community Energy Fund and £10 million Urban Community Fund. DECC hosted a community heat conference in March.15 A new Community Energy Hub is planned that will also be used to host information for those wanting to get involved in community heat. The Community Energy Hub will be an online resource for groups seeking information. This is aiming to go live later this year.

1.48. **Barrier**: Electricity pricing is regulated, but heat generation, distribution and supply is unregulated. Since consumers on a heat network are unlikely to be able to connect to a new network in any given location, protection for consumers needs to be considered.

1.49. It should be noted that a concerted move to electrify heat would increase demand constraints on some distribution networks, particularly if all heat is provided via electricity (heat pumps and boilers). By supporting the installation of hybrid heating schemes, such as solar thermal or PV assisted boilers or by including thermal storage (or electricity storage), the impact on the networks could be reduced and in addition such flexible heating systems could provide DSR services to the DNO.

Action: Community Energy groups in localities where the electricity distribution network is constrained for distributed energy connections should be encouraged to consider heat projects. A joined up approach from DNOs, local stakeholders such as Local Authorities, and national advice services cold help communities identify new opportunities where grid access is a barrier.

Action: DECC should investigate the need for regulation for heat, in particular with regards to the price of supplying heat to consumers. The Heat Trust is a voluntary, industry led consumer protection scheme for heat customers. When launched, the scheme aims to establish a common standard in the quality and level of protection given by heat supply contracts to consumers and offers heat network customers an independent process for settling disputes.16 However, there is no obligation for those managing heat networks to join the scheme and as such regulation may be required in order to ensure customers on heat networks enjoy the same level of protection as those with on-grid heat supply systems.

Other findings – Energy efficiency

1.50. Enhanced energy efficiency would bring about many benefits such as an increased GDP[17] and a reduced dependency on imported fossil fuels[18]. The Annual Energy Statement[19] recognises that poorer households are typically hit hardest by energy price rises and that providing a range of assistance to these households though energy efficiency is a priority. The main focus of this section is to highlight the potential for a range of parties to work more closely together to help improve domestic energy efficiency; primarily local authorities, housing providers, community groups; relevant national and local agencies, energy companies and network operators and energy efficiency delivery consortia. By highlighting how these parties can strengthen their

[14] https://www.gov.uk/government/publications/community-energy-strategy-update
[15] http://communityenergyengland.org/wp-content/uploads/2015/04/Community-Heat-2015-summary-event-report.pdf
[16] http://www.heatcustomerprotection.co.uk/index.php
[17] http://www.energyefficiencyconsultancy.co.uk/2014/10/tougher-energy-efficiency-targets-would-give-the-uk-economy-a-62bn-boost-2/#sthash.IHDs7Sz2.dpuf
[18] Energy Efficiency Strategy: The Energy Efficiency Opportunity in the UK, DECC, November 2012.
[19] Annual Energy Statement 2014

partnership work, it is hoped that this section can prompt enhanced co-ordination and any increase in activity can help reduce household energy bills, support the eradication of fuel poverty, drive down carbon emissions and the costs of the transition to a low carbon energy future. The working group agreed that energy efficiency measures and the customer engagement opportunities that arise from them have a key role to play in the deployment of smart grids, and particularly in relation to community participation. Care must be taken to ensure that energy system objectives are aligned, and that deployment activities and business models relating to energy efficiency and smart grids are complementary, which was the basis of the decision to include consideration of energy efficiency in this chapter.

DNOS AND ENERGY EFFICIENCY

1.51. Ofgem have stated within RIIO-ED1 strategy decision[20] that DNOs have an important role to play in supporting vulnerable customers and delivering solutions for them (either themselves or by partnering with others). Ofgem noted in the same paper that measures enabling more efficient use of energy for households might offset the need for network reinforcement (or defer it) in a given part of their distribution area.

1.52. Some appropriate alternative to reinforcing the network could include the DNO helping to replace inefficient electrically heated systems, a contribution towards connecting a household to a modern efficient district heating or gas network, helping fund extensive solid wall insulation or providing capital towards lighting improvements or other low cost energy saving measures etc. However, in order for these alternative energy efficiency projects to occur, they must be located in similar locations to those places where the DNO is planning to invest in network reinforcement, and they must also be areas with relatively high population density, high deprivation and high penetration of electrically heated housing. There must also be evidence that the energy efficiency measures in question will reduce/shift electricity demand for a reasonable period of time. As a result the opportunity to invest in these projects might only occur in a small number of planned reinforcements a DNO's may be planning on their network.

1.53. In some network areas that are off the gas grid and have a high penetration of renewable generation, additional electrical demand may be used to balance new generation as an alternative to reinforcement. In this scenario, electrical demand will increase, but consumption of fossil fuels will decrease, either through direct displacement (for example electric heating replacing oil heating) or because of the increased efficiency of the new heating system (for example a new electric boiler may be >95% efficient whereas an existing oil boiler is likely to be <90% efficient). It is important to understand that in these circumstances reductions in net energy demand can take place alongside increases in electrical demand.

1.54. Another critical challenge for alternative investments (and the key for delivering value to all energy customers not just the direct beneficiaries of these measures) is that the contribution by the DNO to the cost of these projects would always have to be lower than the cost of the business as usual network reinforcement. However, as noted later on in this section, complying with this criteria should not deter a DNO from considering these approaches and taking a longer-term view of reinforcements to their network as potential exists for leveraging national or local energy efficiency programmes funds that can defray some of the cost of the in-house measures (where these exist and are accessible to DNOs). We anticipate this model to work alongside any future lead supplier energy efficiency obligation, and any other government funded schemes. In return DNOs should also expect the support of energy suppliers or gas network operators. In this way, there is a greater potential for DNOs (along with other

[20] Strategy Decision for the RIIO-ED1 Electricity Distribution Price Control, 04 March 2013

parties) to ensure the investment in energy efficiency is more cost effective (benefiting all energy consumers) whilst also providing a direct social outcome for the recipients of the energy saving measures.

Enabler 1: Innovation Stimulus

1.55. The *Low Carbon Network Fund (LCNF)* provided results and information collected from various projects that have trialled DNO-led projects aiming at reducing peak load as an alternative to network reinforcement. These projects (and others) will give network companies a better understanding of the opportunities and challenges of pursuing this model. Brief samples of these projects are provided below.

Solent Achieving Value from Efficiency (SAVE)[21]

Led by Scottish and Southern Energy Power Distribution (SSEPD) in the Solent and surrounding area, the project aims to establish to what extent energy efficiency measures can be considered as cost effective and predictable by comparing theoretical expectations with quantitative data on actual customer responses to a range of different types of interventions. The trial will compare the effectiveness of four energy efficiency measures (LED installation, data-informed engagement campaign, DNO price-signals direct to customers plus data-informed engagement, and community coaching) and produce an investment decision tool that assesses the potential for deployment of energy efficiency measures as a solution to network constraints.

Less is More[22]

Western Power Distribution partnered with the Centre for Sustainable Energy to help communities reduce their electricity demand, especially at peak times so that less money was spent on upgrading substations, to cope with rising demand. The project encouraged ten communities, "attached to" a monitored substation to consider their electricity use and find ways to reduce it and/or shift it to off-peak times, in return for up to £5,000. The project was presented as a solution to create savings for everyone, with reduced bills and reduced upgrade costs.

energy*wise*[23]

The Vulnerable Customers and Energy Efficiency (VCEE) project also known as energywise is a partnership between ten organisations, led by UK Power Networks. The project is exploring how residential customers who may be struggling with fuel bills can better manage their household energy usage and consequently their energy bills by changing their behaviour. The project will do this by undertaking a research study with the aim to recruit 550 households who may be struggling with fuel bills in the London Borough of Tower Hamlets and carrying out two trials. The trials will test different ways of helping households better understand and control their energy spending, enabling them to make changes which may save them money on their energy bills. Firstly the project will explore if households benefit from smart metering solutions (smart meter and smart energy display) and from energy efficiency technologies such as energy efficient light bulbs, an ecoKettle and standby saver. Secondly understanding their appetite to change their behaviour by swapping to an 'off-peak' tariff. The project is rare in its scope as it involves a wide range of partners including UK Power Networks, NEA, British Gas, CAG consultants, Tower Hamlets Homes, Institute for Sustainability, Bromley by Bow Centre, Poplar HARCA, University

[21] www.smarternetworks.org/Project.aspx?ProjectID=1325
[22] www.lessismore.org.uk
[23] http://innovation.ukpowernetworks.co.uk/innovation/en/Projects/tier-2-projects/Vulnerable-Customers-and-Energy-Efficiency/

College London and Element Energy.

Power Saver Challenge[24]

The project aimed to extend the life of existing network assets by working with customers to reduce the amount of electricity they use, in return of a reward. Electricity North West Ltd worked with NEA in Stockport on a proof-of-concept, gathering 10 teams in a competition, to aim for the challenge of a 10 per cent reduction in winter peak electricity compared to the previous year, and with the help of advice and energy-saving equipment. The aim was explicitly to test the feasibility of avoiding investment in an urban primary substation and extend the life of the existing asset.

Supporting local energy efficiency as an alternative to network reinforcement[25]

The report, commissioned by Northern Powergrid in partnership National Energy Action (NEA), investigates the possibility to divert budgets allocated to load-related network upgrade schemes into local schemes that improve energy efficiency for those who need it the most. The idea could help to challenge current network planning processes and the report seeks to explore the viability of applying this concept.

1.56. Despite the insights these projects have been able to provide, a recent assessment of relevant LCNF projects by Citizens Advice[26] has highlighted the need to better capture evidence of the consumer experience and engagement from such projects to feed into future funded projects and those activities which should become business as usual for network operators.

Action: Ofgem should work with relevant stakeholders to produce detailed guidance on how DNOs could integrate the learnings of research projects from LCNF, Network Innovation Allowance and other areas of research.

Enabler 2: RIIO ED1 model

1.57. DNOs are incentivised to deliver ED1 outputs as efficiently as possible. The effect of this regulatory framework should mean that where a DNO makes a saving in the cost of their investments (by implementing this new model or more generally); they get to keep a proportion of the saving, with the remainder returned to consumers. As noted above, provided the contribution by the DNO to the cost of alternative projects is always lower than the cost of the network reinforcement, DNOs can then look to this mechanism to incentivise the installation of alternate heating technologies or in-home energy efficiency to offset the need for network reinforcement27.

1.58. In some instances, meeting the requirement to ensure the costs of an alternative project is always lower than the cost of the network reinforcement may not be feasible and therefore, justifiably, the aforementioned generic efficiency incentive would not provide a reward. This challenge may therefore result in DNOs being understandably reluctant to invest in any projects where the 'margin of feasibility' is tight. It is therefore important to understand how the regulatory regime incentivises a DNO to identify complementary energy efficiency activity that is already being planned or developed within an area. This is where the potential exists to 'piggyback' a DNO

[24] www.powersaverchallenge.co.uk
[25] www.northernpowergrid.com/news/new-research-highlights-potential-for-energy-system-win-win-win
[26] https://www.citizensadvice.org.uk/Global/Migrated_Documents/corporate/capturing-the-findings-on-consumer-impacts-from-lcnf-projects.pdf
[27] Ofgem have also set out some clear requirements to improve the quality of information DNOs (or other parties) have access to about vulnerable consumers and request that there is a clear explanation of how this information will be used

investment alongside 3rd party fund instead of making the investment entirely independently (albeit with the same intention of avoiding an unnecessary reinforcement of the network).

Enabler 3: Ofgem Stakeholder Engagement Incentive

1.59. Within RIIO-ED1 Ofgem have increased the value of the Stakeholder Engagement Incentive so that Ofgem can specifically assess and reward the steps DNOs take in response to social challenges[28]. As noted above, this provides an opportunity to develop alternative investment projects alongside other 3rd party funds (instead of the DNO making the investment entirely independently). However, in order to achieve this, there is a clear need to engage with a wide range of stakeholders such as local authorities, housing associations, obligated energy suppliers, gas distributors and potentially other utility providers. As long as the Stakeholder Engagement Incentive is large enough to cover the overheads associated with identifying and working with these 3rd parties to pursue this opportunity, this could provide a necessary reward to undertake this work. However, whilst the DNO may be directly incentivised to work with a third party, a further consideration is the willingness of a third party (or parties) to engage with a DNO and that an alternative project meets the shared objectives of all parties.

Enabler 4: Motivations to join up delivery with other partners

1.60. Gas Distribution Network (GDN) companies are incentivised to connect fuel poor households to the gas network following an economic assessment model and it is anticipated that 80,000 households will be connected to the network over the next 8 years[29]. There is therefore the potential for gas network extensions to link up to a DNO and also offsets the need for wider electricity network reinforcement. Projects that connect a property to gas network (or alternatives such as district heating) could have a greater impact on reducing the strain on the electricity network as there will be a total fuel switch and therefore less potential for 'rebound'30.

1.61. In order to fund this activity Ofgem has also recently set out its requirement for the Gas GDNs Discretionary Reward Submission (DRS) under the RIIO GD1 framework31. For the first time the regulator is asking for a collaborative approach to the submission with the four GDNs putting a joint submission as well as their own supporting evidence. These developments highlight how the current or emerging regulatory regime could help create some clear synergies between DNOs and GDNs which could help support alternative investments in energy efficiency. However, Ofgem should also ensure where a DNO and GDN are working in partnership to connect a household to the gas network, the successful gas connections must be also benefit from appropriate levels of insulation.

[28] RIIO-ED1 Stakeholder Engagement and Consumer Vulnerability (SECV) incentive consultation, Ofgem, 16th Dec 2014.

[29] On the 26th March 2015 Ofgem stated gas network companies can connect more eligible households to the gas grid than the 77,000 originally planned for delivery between 2013 and 2021. They must now resubmit their plans to Ofgem for consideration. Maxine Frerk, senior partner for distribution, said: "By encouraging gas network companies to connect more consumers to the gas grid, we're playing our part in supporting those in fuel poverty in Great Britain. We also want network companies and their partners to work more closely with suppliers and fuel poverty groups on improvement works, such as new boilers, radiators and internal pipework, to ensure consumers get the full benefit from the new connections provided by the scheme."

[30] This is a known risk that affects the performance of energy efficiency measures is "the rebound effect". This is where the reduction in energy consumption (in this case electricity consumption) caused by a new measure is wholly or partially offset by a change in behaviour because of a combination of:

- An income effect, e.g. a reduction in electricity bills from one source means that there is more to spend on other consumption which uses more electricity.
- A price effect, e.g. a reduction in electrical heating costs means that households feel able to heat their home to a higher temperature, taking the benefit as more heat rather than lower bills.

[31] Decision on arrangements for the first Gas Discretionary Reward Scheme (DRS) under RIIO-GD1, Ofgem, 12th December 2014.

Action: Ofgem should track the number and details of projects where DNOs and GDNs are engaging with existing energy EE programmes to deliver demand reduction measures to domestic customers. A first step is for Ofgem to specifically investigate how DNOs respond to the ED1 framework and rewards available under Stakeholder Engagement Incentive to build effective partnerships to use energy efficiency to offset the need for wider network reinforcement. This may prompt a need to introduce further annual reporting on what DNOs are doing to stimulate these alternatives to reinforcement and how all DNOs adopt LCNF insights in this area.

Action: In order to keep the costs to consumers down, DNOs should be able to defray the cost of in-house measures to offset or defer network reinforcement and should be able to count on the willingness of a third party (or parties) to engage on this agenda. In doing this Ofgem should continue their work with DECC to create a more deliberate policy framework for DNOs to engage local authorities, housing associations, obligated energy suppliers and gas distributors on opportunities for energy efficiency to offset the need for wider network reinforcement.

Action: A connection to the gas network should be accompanied by appropriate levels of insulation. Whilst GDNs can try and leverage ECO and other national schemes to deliver this outcome, DECC should continue to address the insufficient funding available for low income householders to fund 'in-house' energy efficiency works, especially in England.

Action: The ECO scheme administrator should track the extent to which low income households are only able to access ECO by making capital contributions towards the cost of energy saving measures.

Action: With supportive evidence from Ofgem, DECC should review the current energy efficiency schemes to see how they could be made simpler for community energy groups to access and ensure that post-2017 the next round of ECO or its successor is designed with consumer access (by both individuals and groups) in mind.

Action: There is a pressing need to reconcile national support schemes with assistance that can be provided locally. The development of service mapping either nationally or locally could reduce the risk of duplication of effort in some localities. Strengthened or additional reporting on the coverage of existing provision within an area will also enable national policy makers to monitor the national coverage and success of various policies.

1.62. This is fundamental to the full affordability outcomes which could be realised by a new gas connection and is also critical to ensure this activity is more consistent with DECC's Heat Strategy. In addition to the potential for a DNO and GDN to work more closely to connect a household to the gas network and identify new opportunities for funding the cost of the in-house works, Ofgem will also need to continue their work with DECC to address insufficient funding available for low income householders, especially in England (given lack of recurrent grant based programme like in the rest of GB). This also prompts a consideration of the willingness of energy suppliers obligated to deliver the Energy Company Obligation to help DNOs co-fund in-house measures.

1.63. As noted in the summary of the ECO, this programme can be challenging to access and leverage due to a lack of guaranteed assistance for eligible households and a requirement to make capital contributions which may not be within the means of the low income householder. This challenge underlines the value of DNOs working with obligated energy suppliers to deliver in-house measures (and reduce the need for any household contributions) and more broadly the need for suppliers to also leverage the other national energy efficiency programmes highlighted above. Once again, this requires a complimentary regulatory regime which tracks and monitors how DNOs are helping households access these energy efficiency programmes and the need for deliberate regulatory oversight over any requirement for eligible households to contribute towards the cost of energy efficiency measures. Currently, the extent of household capital contributions towards the cost of energy efficiency measures is not subject to any oversight by the scheme administrator.

AMBIGUITY OVER THE REGULATORY FRAMEWORK AT AN EU WIDE LEVEL

1.64. Whilst the aforementioned DNO model could complement the requirements of the EU Energy Efficiency Directive[32] to identify cost-effective energy efficiency improvements in the network infrastructure, a recent consultation by the Council of European Energy Regulators investigating the Future Role of DSOs[33] questions the role of DNO's participating in this model. Whilst the paper acknowledges that a DSO's contribution to improved energy efficiency can be positive, they separately contradict this statement and imply this role should be limited to activities to improve energy efficiency of the network and there are tensions to balance in 'reaching beyond-the-meter'. This ambiguity has in part now been addressed in a recent response where CEER state their framework allows sufficient discretion for national regulators to make decisions based on the context of their country.[34]

Action: Given the flexibility CEER believe national regulatory authorities can exercise we recommend that Ofgem continues to highlight the value of this model to CEER in helping to meet the goals of the Electricity and Gas Directives[35] or wider European energy policy goals.

[32] The Energy Efficiency Directive was agreed in October 2012, please read the text here.
[33] The Future Role of DSOs - A CEER Public Consultation Paper, CEER, 16 December 2014.
[34] The Future Role of DSOs – ACEER Decision Paper
[35] The Directive can be found here.

2. Consumer Protection

Cross-cutting consumer risks

2.1. THINK's report includes a framework for considering the basic consumer risks of DSR, which the subgroup adopted. These are:

- Price risk: this is the risk from any price-signal based form of DSR that is not upside-only that the consumer ends up paying more than he or she would have done otherwise. It could also cover other costs, such as buying smart appliances, which could mean that engaging in DSR leaves the consumer out of pocket.
- Volume risk: this is the risk that the consumer's use of electricity is constrained by DSR to the consumer's inconvenience, either by an intentional aspect of the DSR contract or due to a malfunction of some kind.
- Complexity: this is the risk that DSR creates confusion for the consumers involved, or even for those who are considering it as an option. This might lead to poor decisions on consumers' part (about electricity usage and/or whether to enter into DSR in the first place), reduced effectiveness of the DSR action, or increased disengagement from the energy market.
- Autonomy/privacy loss: autonomy refers to consumers' sense of control over their usage, which DSR might affect directly through automation or indirectly through price signals. Privacy refers to the disclosure of personal information. The risk is that consumers resent the impact of DSR on either or both of these, or that further detriment is caused for example by insufficient control over private information leading to over-marketing or fraud.

2.2. Different DSR options would incur these risks to different extents. For example, offering consumers a direct payment in return for automated control of their household appliances would pose a relatively low risk in terms of complexity and cost, but might present a higher one, if not mitigated, in terms of autonomy, privacy and volume. An assessment of each option in each of these four risk categories is included in the Consumer Protections Toolkit and Risk Matrix (though it should be noted that this is only a guide and the exact details of any risk should be considered according to the details of implementation).[36]

2.3. These barriers are not all directly comparable, and may play out on different levels. Some refer simply to the risk that a participant in a given DSR scheme might face, such as paying more or not being able to use electricity when most convenient. Others might lead to a risk of consumers signing up for a DSR scheme that is not suitable for them, for example if they lack the necessary load flexibility or are medically dependent on an uninterrupted electricity supply.

2.4. Others again might be on an even broader level, to do with the electricity market as a whole including non-participating customers. Possible impacts on this level might include: consumers without flexible load paying more than those with; the relative consumer costs from different parts of the energy chain changing; or a shift in the incentives on suppliers to gain or retain certain customers.

2.5. On the system level, many changes of this type will inevitably take place in future years anyway. But some will be specific to the deployment of domestic DSR. It should be remembered that domestic DSR is only one of a number of possible sources of

[36] See Annex 2, section 3, Consumer Protections Toolkit and Risk Matrix. The document can also be found in the 'Consumer Protection subgroup supplementary material' zip folder published alongside this document.

flexibility in the electricity system, and going down the domestic DSR route will give a different outcome in terms of consumer experience than meeting the full need for flexibility from network-level storage or achieving load reductions (which would meet many of the same goals) using LED lighting, for example.

2.6. Consumer DSR risks can be loosely thought of on these three levels:

- Post sign-up: how a DSR offer works for a consumer taking part in it.
- Pre sign-up: how consumers determine if DSR is right for them.
- System: how the introduction of DSR affects the energy market overall, even for non-participating consumers, as above (barriers on this level are also considered elsewhere in this report, in particular the distribution of value chapter).

RECOMMENDATIONS FOR SOLUTIONS TO CROSS-CUTTING CONSUMER RISKS

2.7. New innovative business models may offer the opportunity to reduce or remove the need for additional consumer protection. The complexity, risks and opportunities of DSR could be managed on behalf of the consumer with simplified creative propositions in which a provider deals with various parties in the value chain and delivers a net benefit to the consumer. Creative, engaging consumer value propositions that enable DSR activity will be critical for the scale of consumer take-up needed to fully leverage value chain benefits. Aligned consumer protection will be important in achieving these.

2.8. In order to address the barriers of volume risk, cost risk, complexity and autonomy/privacy at the three levels outlined above, the subgroup has compiled a 'protections toolkit' to help enable DSR from a consumer perspective. Not every item of this toolkit will be appropriate to each DSR measure since some overlap, but it can be taken as a resource to check that every angle has been addressed. Consumers must be empowered (by measures that give consumers choice and agency) and protected (by measures that prevent vulnerable consumers, according to an agreed definition, suffering detriment from DSR), both before and after sign-up. The full toolkit is included in the Consumer Protections Toolkit and Risk Matrix.[37] It is summarised in Figure 1.

[37] See Annex 2, section 3, Consumer Protections Toolkit and Risk Matrix. The document can also be found in the 'Consumer Protection supplementary material' zip folder published alongside this document.

2.9. The colours of the measures are according to the following four categories:

- Assisting consumers' decisions about whether a given tariff is suitable
- Putting an appropriate limit on consumer's financial liability
- Ensuring sufficient and clear information on DSR offers is available.
- Enabling participating consumers to shift their load

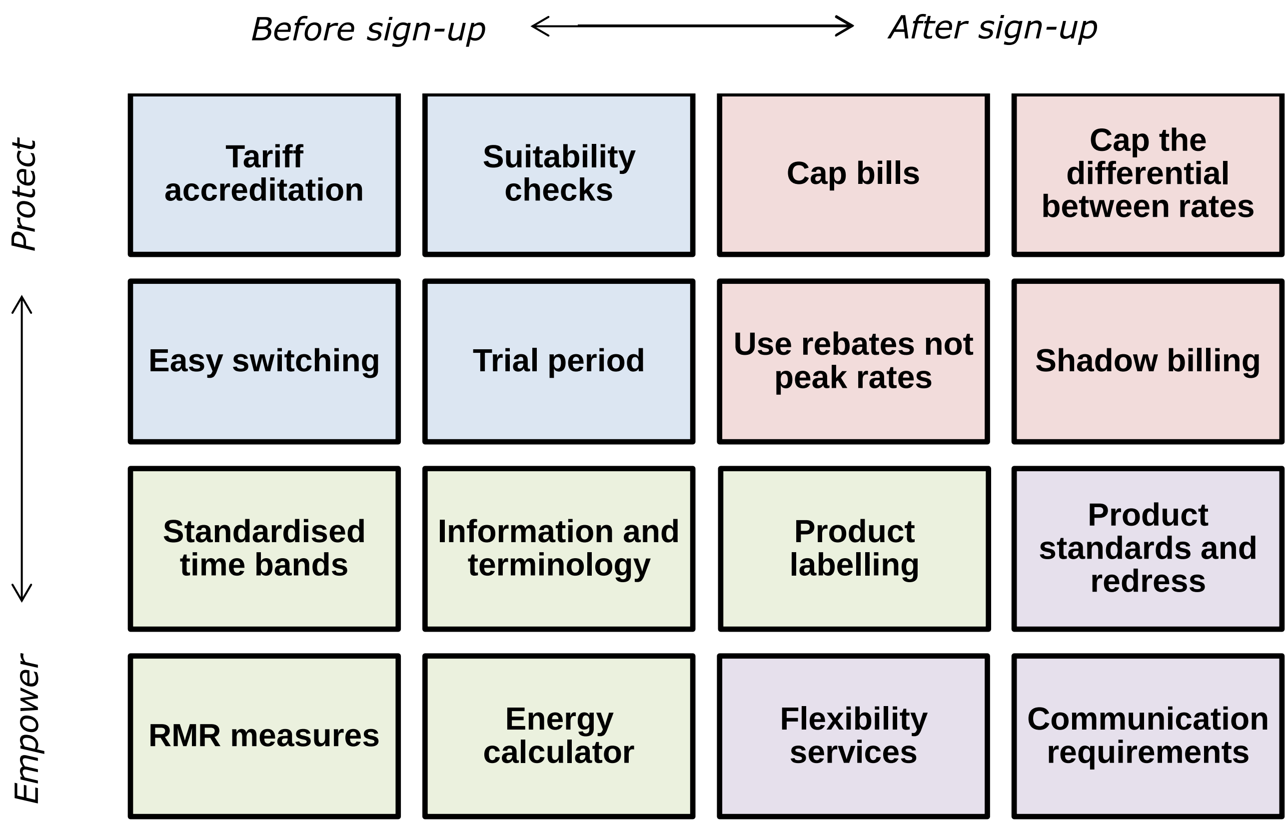

Figure 1. Summary of Consumer Protection Toolkit – see Annex 2 for full details

2.10. These measures can be divided into those that are already in place in some form, and Ofgem should review if they require new resources or regulations and ensure provisions in the following areas are 'DSR Ready'.

- Information provision requirements
- Number and design of tariffs, including safety nets
- Switching and bundled offers
- Direct or indirect involvement of third parties.

2.11. Those that are already in place in some form and so only need to be reviewed and adapted are: easy switching; information and terminology; Retail Market Review (RMR) measures; product labelling; product standards and redress; and flexibility services.

2.12. Those that would require greater changes to the current system are: energy calculator; tariff accreditation; suitability checks; trial period; standardised time bands; cap bills; cap the differential between rates; use rebates not peak rates; shadow billing; and communications requirements. For a full explanation of these, please see the Consumer Protections Toolkit and Risk Matrix.[38].

2.13. Consideration should also be given to the application of principles-based regulation to DSR. The establishment of principles along the lines of 'offers should be clear and comparable' or 'no consumer should be put on a DSR offer that is inappropriate to their situation' might help protect and empower consumers in this market, and may remove the need for more prescriptive regulation.

Conflicting signals

2.14. Given that different parties in the energy supply chain – suppliers, DNOs, the TOs and the SO, as well as aggregators serving these parties – are likely to have different uses for DSR at different times, the situation might arise where multiple parties are making competing offers to a consumer for their DSR. This could create beneficial competition, but it could also cause a problem of conflicting signals. This is considered in detail in the visibility chapter, but the consumer issue is distinct from the visibility issue. Visibility between parties might offer a partial solution to the consumer problem (see below), but on the other hand parties might still offer conflicting signals even with perfect visibility.

2.15. If a system develops where the consumer is free to accept more than one DSR offer at the same time, he or she might end up being offered an incentive from one party to turn usage up while another is trying to turn it down. At best, the conflicting signals this would be very hard to interpret and the consumer might not realise the full benefit of their flexibility, either for themselves or for the system. At worst, the consumer might end up shifting load into a period that was actually more expensive. This would be exacerbated if one or more of the parties involved had access to automation in the consumer's home, in which case they might take actions that were not in the consumer's best financial interests.

2.16. According to the work that has been carried out by the distribution of value subgroup, suppliers, SO and TO are all expected to have similar uses for DSR (at least until wind following becomes a commercial driver), so signals sent by or on behalf of those parties would be unlikely to conflict. More probable is that DNOs would have a conflicting use for DSR. On the other hand, uncoordinated signals from different parties might lead to consumer confusion even if those signals tended to be broadly aligned, so there may be an advantage in finding a way of coordinating signals even if the DNO is not involved.

2.17. Several of the following solutions could potentially form part of the framework for facilitating commercial agreements where more than one party shares access to a customer's DSR, recommended in the visibility chapter.

RECOMMENDATIONS FOR SOLUTIONS TO CONFLICTING SIGNALS

2.18. A number of approaches may be taken to overcome this barrier. One option would be to prevent consumers from signing up for more than one DSR offer. In practice, this could work by:

- The offering party being obliged to check whether the consumer was already engaged in DSR; and/or
- Only allowing a limited range of parties to contract for domestic DSR e.g. aggregators only, DNOs only or suppliers only. This group would

[38] See Annex 2, section 3, Consumer Protections Toolkit and Risk Matrix. The document can also be found in the 'Consumer Protection subgroup supplementary material' zip folder published alongside this document.

then sell the flexibility on to other parties. (In the aggregator-hub model, a solution might still need to be found to prevent a consumer signing up with more than one aggregator.)

2.19. It should be recognised that this might rule out some savings that would otherwise be available to the participating consumer and the wider system.

2.20. Multiple parties could be allowed to contract for a consumer's flexibility separately, so long as a route was found for aggregating all DSR signals – both price signals and automation – before they reached the consumer. This could take place through one party acting as the hub, all signals passing through a central aggregating system, or a device in the consumer's home performing the aggregation function. For example, a new generation of Home Energy Management systems might be able to perform this function.

2.21. Contracting parties could be required to inform other possible contractors in some form when initiating a new DSR contract (by notifying via the supplier, creating a database or similar). This would mean that at least those parties knew when conflict was likely to arise, but they might continue to send conflicting signals anyway. One way to achieve this would be to put a flag on a consumer's data records to show that they were engaged in DSR, similar to the system proposed in the visibility chapter where customers' in Load Managed Areas would receive a flag.

2.22. A rule could be established where any party contracting for DSR would be obliged to check whether the consumer was already providing it elsewhere, and if so to match or coordinate its signals with those of the earlier contract. The availability of smart meter data and centralised data within the DCC might help in determining whether a customer was already active in DSR, though this might raise new data privacy issues. The subgroup felt that in the short term this was the most promising option, as it offers an acceptable level of consumer protection without unduly constraining the market.

2.23. A separate platform for trading participating consumers' flexibility could be established, that did not discriminate between contracting parties. However this platform would need to be run by a competent, impartial and consumer-facing body, and there is no clear precedent for this in the domestic market. Due to the potential set-up costs, this option would be likely only to be viable once a mature market for domestic DSR was established.

2.24. An information-only solution could be adopted, where consumers were informed about the risks of signing up with any other DSR offers when they signed up with their first one. However, on such a confusing issue an information solution might not be sufficient.

2.25. Under any of these options it would be possible to distinguish between groups of consumers, for example giving extra protection to those designated as vulnerable using a definition to be agreed. This would, though, create a risk of shutting the vulnerable out from the savings others might realise.

Third Party Intermediaries

2.26. DSR may be associated with an increased uptake in TPI services, e.g. DSR contracts being signed with aggregators. At present there is no operational regulatory framework for this kind of TPI.

ENABLERS FOR THIRD PARTY INTERMEDIARIES

2.27. Ofgem is intending to explore further how markets for aggregators could develop and what protections may be necessary. Ofgem is currently leading a programme of work on TPIs, focused on known harm associated with energy purchase in the domestic and non-domestic sectors.

Use of capacity charge and/or load limiting for DSR

2.28. Among the options for DSR proposed in WS6's interim report, a number were based on a two-band capacity charge and/or smart meters' load limiting capability. In one way, it might make sense to combine these two, since the load limit could be used to ensure that the consumer's load never crossed over the level that would incur the higher charge. However, together or separately, a number of consumer issues specific to these options need to be considered.

2.29. It has not always been well understood that the load-limiting functionality of SMETS-compliant smart meters does not work by reducing the consumer's load and allowing them to continue their core usage, but by cutting off the connection altogether, with the consumer only able to rearm the meter once they have reduced their load in some way. While some consumers might be happy to enter into an agreement in which this functionality was used, the practicalities of such a scheme would need to be thoroughly thought through. Other technical options exist, such as the use of Auxiliary Load Control Switches (ALCS) for certain appliances. There is also a load limit counting function where each time the consumer exceeds an agreed load limit there is no immediate consequence but it is recorded, meaning that the consumer could be charged accordingly.

2.30. A two-band capacity charge might be confusing to domestic consumers, and it would be necessary to find new ways to explain this concept and ensure they were able to monitor how close to the limit they were. (A useful comparison might be to the data allowance in a mobile phone contract, although there consumers are used to paying a higher unit charge if they exceed a certain volume, rather than incurring a flat charge that does not reflect how much or how long they exceed it by. Also, the limit on a mobile phone contract is generally based on usage over a period of time, whereas a two-band charge would involve a limit on usage at any given moment.)

2.31. One option proposed in the interim report was to use automation in conjunction with a two-band capacity charge. While possible, it should be noted that automation could only work reliably in this way by imposing a cut-off load limit. Any other form of automation would still risk exceeding the capacity limit, and even if this was only momentary this would still incur the higher charge (assuming suppliers passed the capacity charge through).

ENABLER FOR USE OF CAPACITY CHARGE AND/OR LOAD LIMITING FOR DSR

2.32. A partial enabler is already in place, as suppliers have committed to consult with Ofgem and Citizens Advice (then Consumer Focus) before employing any load limiting functionality. This should be an opportunity to ensure consumer needs have been fully considered and develop best practice. The distribution of value subgroup has pointed out that in future more parties may be granted access to smart meters' critical commands. If this happens, it would be logical for any other parties gaining the capability to activate load limiting to make the same commitment as suppliers.

2.33. Ofgem should:

a. contact suppliers who have made the commitment already and publish details of what was agreed (the full documentation is not currently available);
b. contact all suppliers who have not made the commitment eg because they are new since it was made and ask them to sign up to it; and
c. in future, make this commitment a condition of gaining access to smart meter critical commands.

2.34. It should also be noted that under Ofgem's existing guidance load limiting is to be classed as a form of remote disconnection and treated accordingly in terms of protections.[39] This includes the requirement that suppliers check the vulnerability status of consumers before undertaking load limiting.

2.35. The problem of how to best combine a two-band capacity charge with load limiting could be partly solved in the case of EV users. If EV charging could be stopped and an alert sent when the limit was approached, this would let the consumer turn down their other usage in their own time before restarting the charging.

2.36. The smart metering subgroup has also recommended exploration of the use of targeted load limiting or load control as a substitute for emergency disconnection under some circumstances. While this could be beneficial to consumers in some ways, it could also cause new problems, particularly if it resulted in domestic and small business consumers being pushed to the front of the queue for disconnection in an emergency while larger consumers were kept on. The exploration of this possibility is ongoing, but the consumer subgroup sent a note to the smart meter subgroup in March 2015 setting out some issues which still need to be examined.[40]

Managing expectations around complex offers

2.37. Offers may start to appear on the domestic market that include new combinations of tariffs, services and appliances, which may unlock new benefits, but which may also have unforeseen consequences in practice. This has been usefully highlighted by the domestic PV and hot water heating trials in the Thames Valley Vision project. These consequences could include:

- Financial issues, such as level and timescale of savings, or hidden costs.
- Contractual issues, such as being tied in for a certain period, or unable to enter into contracts with other parties.
- Lifestyle issues, such as changes in how heating or appliances operate in the consumer's home.
- The risk of consequences of this kind being not fully explained or understood is not limited to DSR. Similar risks arise around other large consumer commitments with multiple dependencies, such as taking out a mortgage or indeed switching energy providers without DSR. In the latter case, they are already addressed to a substantial extent by RMR measures. DSR offers could, however, create particularly complicated situations which could compromise the supply of energy.

2.38. It is worth noting that this may not be the case for many customers as there are incentives on supplier to ensure propositions are clear and simple, otherwise customer take-up will be limited. The existing regulations around supplier tariff offerings may also be applicable for any product offerings from existing or new entrants.

RECOMMENDATIONS FOR MANAGING EXPECTATIONS AROUND COMPLEX OFFERS

2.39. Options for mitigating this risk should be further explored, and might include:

[39] https://www.ofgem.gov.uk/ofgem-publications/57395/remote-disconnection-and-ppm-guidance-open-letter-160810.pdf
[40] See Annex 2, section 3, Note on use of load limiting or control in emergency situations. The note can also be found in the 'Consumer Protection subgroup supplementary material' zip folder published alongside this document.

1. A coordinated phased introduction of DSR offers to allow consumer education, starting with simple offers that exploit existing opportunities such as legacy flexibility (e.g. radio teleswitched customers) and efficiency improvements.

2. A requirement that the relevant information in defined categories is provided to a certain level of clarity and detail (for licensed parties this could form a licence condition, but it should be considered that complex DSR offers could also be made by unlicensed third parties).

3. A requirement that any physical installation or sale of new equipment for DSR, or building survey for this purpose, is combined with or preceded by an in person explanation of what effects this might have on the consumer, similar to the explanation required under Smart Metering Installation Code of Practice (SMICOP). (This is the approach taken by Thames Valley Vision.)

4. A mandatory cooling-off period, though in the case of installation of large equipment this would impose a risk on the offering party. This would be covered by the 'right of withdrawal' within 14 days under the EU Consumer Rights Directive (as transposed into the Consumer Contracts, Information, Cancellation and Additional Payments Regulations 2013), but this could be interpreted in different ways. According to the Green Deal Code of Practice, for instance, installation of measures is expected not to start until after the cooling-off period where it can be 'reasonably avoided'. A similar line could be followed with smart appliances, though with the drawback that consumers would then have no chance to actually try out the new technology until the right to cool off had elapsed.

5. Careful treatment of any future bundled offers in which the cost of smart appliances are offset against DSR savings, thereby effectively tying the consumer into a particular tariff for a long period or exposing them to a high buy-out cost.

6. A prohibition on certain types of offers, e.g. those that would explicitly or effectively constrain the consumer from switching supplier tariff, though this may be allowable for any offer which includes an asset provided upfront to the customer.

7. An option for 'opt-out' contracts where consumers have the option to take up a complex or bundled offer that goes outside the normal market rules, so long as they give their consent and are sufficiently aware of any risks involved.

8. No action, if current rules plus the natural incentive on suppliers to make their offers accessible and appealing were considered sufficient to protect consumers from confusion.

Regulation of smart appliances and storage

2.40. The use of smart appliances and/or domestic level storage (of either power or heat) might substantially increase the flexibility of domestic load. However, it would also raise a new set of regulatory issues, and bring an even closer convergence between energy and other areas like labelling and product standards. To some extent this is covered in the protections toolkit above, which includes measures such as improved product labelling and product standards and redress. But if use of these technologies becomes widespread it may be necessary to consider wider issues around installation, maintenance and accountability. This would give consumers confidence in installing DSR offering appliances.

2.41. This also relates to point 4 in paragraph 2.39 above, about possibility of the consumer changing their mind about an offer that might be bundled with or depend on a particular appliance. Difficult questions could be raised by different ownership structures, similar to the problems around ownership of meter boxes, but potentially with greater materiality.

RECOMMENDATIONS FOR REGULATION OF SMART APPLIANCES AND STORAGE

2.42. These issues should be reviewed as the technologies develop, and before problems start to emerge. It would be useful to consider whether existing industry-led codes in this area, such as the Microgeneration Certification Scheme and the Renewable Energy Consumer Code could be expanded to cover domestic storage, and also whether they adequately deal with other issues such as maintenance and bundling with other offers.

Exceptions and Caveats

2.43. Throughout, we have assumed that DSR at the domestic and small business level would be voluntary and rewarded. This is in line with the work being carried out at a European level by the Smart Grid Task Force.

2.44. There is a general consensus that the possible business case for domestic DSR will look very different if and when there is wide take-up of LCTs, in particular EVs and heat pumps. This will create a large new volume of flexible electric load (and in the case of EVs, potentially of storage). In various cases it may make sense in future to treat these LCTs differently from existing appliances. This is because:

- They will be very high sustained load relative to most other electric appliances, so the value of making them flexible will be greater.
- Because their adoption will increase the load on the network, there may be cases where consumers' decision to switch to LCTs leads to a reinforcement cost or equivalent, which might be avoided if their usage was flexible. (This is supported by the Smart Grid Forum's Transform model, though findings from the Customer-Led Network Revolution and Low Carbon London suggest that the strain placed on the network by LCTs may be less than previously expected.)
- Particularly in the case of EVs, the timing of the load will be much less tied to consumers' lifestyle than is the case with most appliances, so long as the charging is complete by the next time the consumer wants to drive the EV.
- Since these are new technologies, it might be more acceptable and less confusing to consumers to introduce DSR at the same time as LCTs, rather than trying to get people to change established habits.

2.45. Insofar as distribution network savings are the main or lead driver towards DSR (and the work of the distributions of value group suggests this will usually not be very much), DSR might tend to exacerbate a postcode lottery effect. This could happen because consumers' ability to participate is affected by their location, and the network value of consumer DSR varies by location.

2.46. Consumers in Load Managed Areas (as designated by DNOs) are unable to participate in DSR without DNOs' agreement. This is not a major disadvantage at present, due to the limited volume for customers in LMAs, but might become more so as Load Managed Areas and similar schemes impact more customers in future.

2.47. Conversely, DSR will have a greater value in areas where there is constraint on the network (such as load managed areas). Consumers in areas with lots of spare capacity or ample flexibility (for example, those who live near a large flexible industrial plant) would not be able to realise so much value from their DSR.

2.48. If DNOs are procuring domestic DSR, there may be a choice between introducing a ToU element to the DUoS charge or making direct payments to customers. It should be noted that there may be a skewed incentive towards the former at present, because in the latter payments would have to be counted against the DNO's spending target. In practice, introducing a blanket ToU element to the DUoS charge would probably be highly disproportionate, but this risk should still be noted in case the DUoS charge is adapted in other ways. Introducing a blanket ToU element could be detrimental to consumers if suppliers were incentivised to pass this through regardless of whether the consumer wanted a ToU tariff or not.

2.49. When considering DSR from the consumer perspective, it is useful to keep in mind which parties they might be contracting with. This could be the supplier, perhaps the DNO or various forms of third party aggregator. From discussions in the workgroup, however, it seems very unlikely that the SO or the TO would contract with domestic consumers directly, since it would be more likely that they would go through an aggregator.

2.50. In an adjacent area to DSR, it is important to note that heat networks are currently relatively unregulated and are often monopolies. The Community Energy subgroup, in addition to considering its key remit, has looked at heat networks and has made some more detailed points in this area which have an important bearing on consumers.

3. Distribution of Value

Smart metering

3.1. Smart metering creates, enables and solves many different issues related to creating value from DSR and in enabling residential and SME customers to participate. Some of the relevant issues identified are outlined below.

HALF HOURLY SETTLEMENT

3.2. The alteration of Half Hourly settlements for Profile Class (PC) 1-4 is seen as the primary enabler needed to create a value incentive for a mass market proposition for domestic and SME customers. This would need to be implemented between 2020-2023.

3.3. Static time of use tariffs can be settled within the current settlement regime which could enable most but not all of the allocation benefits. Elective half hourly settlement is available now for suppliers to use, though it is not as complete an answer as the projected half hourly settlements change for all is expected to be. Dynamic DSR in particular needs HH settlement to work. Ofgem's Flexibility work will look at half hourly settlement benefits and issues more closely.

Action: HH settlements for all PC1-4 customers are needed to create DSR value. To be introduced between 2020-2023 by Ofgem and the industry. This will allow changing customer demand to be directly rewarded via the settlements system, whereas today the value is lost in the profile smearing process.

TRUSTED DEVICES

3.4. EVs and heat pumps are not trusted devices[41], so only one way communications from the meter to the device are possible with smart metering. Heat pumps and EVs are key drivers of the need for the smart grid development, as shown by the Transform model. As these demands are potentially flexible (Heat Pumps more so with storage attached) it seems natural that they become a core part of the GB energy infrastructure and not remote from it.

Potential solution: The current SMETS 2 specification does not stop EVs and heat pumps becoming trusted devices in future. New security standards may need to be added to EVs and heat pumps, or at least their communication devices that interface with the smart metering system. If the security standard is formalised quickly it may help the uptake of this technology and so advance DSR.

Action: Once heat pumps, and particularly EVs, take off a review should take place by DECC to see if and when they become Trusted Devices and can play a more integrated role in lowering the cost of energy to all customers. Storage and DG could also be reviewed by DECC to see if it will be beneficial for these devices also to become trusted. This should be raised in 2018 or after by Suppliers or DNOs if the lack of integration of the devices in to the energy system is causing value to be lost.

CRITICAL COMMANDS

3.5. Only suppliers are currently able to send 'critical commands' via the Data Communications Company (DCC). This means demand side response via smart

[41] 1.1. *Trusted devices can connect to the smart meter system with two way communication, enabling a greater range of functionality via the smart meter infrastructure. The trusted device becomes more integrated to the energy system than if they can only be communicated to via one way communication via the smart meter. An untrusted device could be communicated to via 2 way communications but that would have to be not via the smart meter system but via the customer's broadband or other means.

metering can only be done by the customer's supplier or with the agreement of the supplier by bilateral agreement with an industry actor.

Potential solution: The current DCC security arrangements can be reviewed when a business case is developed. At this point, new arrangements could be put in place to allow certain critical commands that may be able to be sent via more than one party. This is the recommendation within the Smart Meter Sub Group.

Action: There is a detailed working note produced as part of the Smart Meter subgroup in Annex 2 which details recommendations in relation to critical commands and load control.

EXPORT TOU REGISTERS

3.6. Currently, the value of exported energy is generally lower than that used on the property. If this changes, the current specification of smart meters does not include TOU registers for export to take advantage of this change   .

Potential solution: SMETS 3 and specifications beyond should include export TOU registers. This would not solve the issue of metering already installed using earlier versions of SMETS meters.

Action: There is no value seen currently in creating TOU registers for exported energy. No action should be taken to pursue the potential solution until a business case can be produced.

VISIBILITY OF POTENTIAL FLEXIBLE DEMAND

3.7. The lead party for DSR may not be based on value, but rather which industry player has the best visibility of / access to the customers who could provide flexible demand.

Potential solution: Whatever the solution, customer data and privacy will be an important consideration. If the market is operating effectively then the actor with the best visibility could contract with the customer and provide the DSR to the party with the highest bid. However, this creates a middleman in the chain that might add unnecessarily to industry costs and limit customer recompense compared to a direct relationship.

Action: As DSR develops it should be monitored to determine if the market is flawed, i.e. value is not being captured by the party who can provide the most back to the customer. Half hourly settlement should resolve some possible issues in this area. Ofgem should monitor this post the implementation of Half Hourly settlement.

AVAILABLE FLEXIBLE DOMESTIC DEMAND

If EVs, storage and hybrid heat pumps are excluded, the potential flexible demand for residential customers is small and may to create a little opportunity within small geographic areas. LCNF TOU tariff trials (LCL and CLNR) found most customers found domestic customers were (on average) willing to shift demand , but also indicated that most customers are unable or unwilling to change behaviour despite time of use price signals at the most important point of the year – the winter peak / cold evenings.

Action: Critical peak tariffs may show potential to make a difference; they have not been properly tested in GB so far. The critical peak tariffs should be tried in properties with and without EV, heat pumps and storage. This trialling could be done by DNOs, aggregators or suppliers.

FLEXIBLE DEMAND AVAILABILITY

3.8. Lack of customers to deliver sufficient DSR volume, especially at lower voltage levels. This is because at low voltage levels only a few customers are connected to each substation, creating only a small pool of customers able to provide DSR services.

Potential solution: Electric vehicles and hybrid heat pumps may provide DSR potential at lower voltage levels in future but there needs to be some way to find out where they are located on the network. This is being looked at by the Visibility working group.

Action: If most customers start having larger flexible loads DNOs will need to evaluate if this issue disappears.

DELIVERY RISKS AND BENEFITS

3.9. The potential impact if the DSR were not to be delivered at a critical time could exceed the benefit of success. The following example is for a DNO scenario but this issue could relate to any actor.

3.10. If the DSR action initiated for a DNO constraint does not deliver the load reduction required and customers have to be disconnected to avoid thermal overload, then the potential financial penalties could be significant. This could create barriers, especially for third parties working on DNOs behalf:

- Customer recompense (guaranteed standards payments)
- Lost financial investment in the DSR scheme
- Emergency work to get power back on supply
- Work to find another solution to tackle the lack of local capacity
- Regulated interruption incentive payments

Potential solution: The actor or aggregator contracts more capacity than they need. This reduces the value of each contracted unit of DSR to the provider but provides greater security.

3.11. This might not be possible in some cases , for instance where the number of DSR providers in a DNO's required location was limited, or the failure may not be due to one or two customers but with the aggregators or national processes (such as a DCC outage)

Action: Actors should raise the issue to Ofgem if it becomes a real barrier to creating DSR propositions. There is no easy solution to reduce the risk of failure beyond those mentioned as potential solutions to reduce the risk.

COMBINING VALUE

3.12. If the value of DSR is spread across several parties then there may be insufficient incentive for any single participant to create a DSR product.

Potential solution: Create the market opportunity where overlapping value is present to create a joint product for the customer that aggregates the value to provide sufficient incentive for participation.

Action: The workgroup can see no current barriers to stop this practice. No barriers in future should be placed against actors working together to have joint contracts providing several services in a single product or a method of multiple parties paying for the DSR proposition. Each party can of course individually contract for DSR if they have enough value by themselves. Updates to codes and licences should take this risk in to account going forward. This is a potential cross-cutting point with the visibility working group.

STAGGERED PEAKS

3.13. It is important that while we resolve the national peak we don't compound local issues of moving demand to periods where local capacity is limited. DSR which shifts demand to a later time period should not cause new issues whereby the action to resolve would negate the value of the original action. The DNOs need a means of notifying the rest of the industry about customers who have a later in the day winter peak compounded by limited head room.

Action: This recommendation is being taken forward by the Visibility Working group. It needs to be resolved by 2019 and should include examining how any notification would work for domestic winter peaks led by storage heaters overnight.

COST REFLECTIVITY AND VISIBIITY OF DSR VALUE

3.14. Costs are not reflective, but spread across the customer base or time of day / year. The full value of the DSR is not visible or available to the customer or industry.

Action: If this becomes a blocker to value then a review of how costs are allocated may be needed; however, simplification and customer protection will be factors to ensure some customers do not become overly negatively impacted. Half Hourly settlement will resolve a large part of the issue.

Action: An actor or actors should alert Ofgem and DECC if the issue continues post HH settlement implementation. Costs are smeared for a purpose, so the issue is whether the driver to smear a cost is larger or smaller than the driver for greater price reflectivity going forward.

IMPLEMENTATION COSTS FOR DSR FROM DOMESTIC CONSUMERS

3.15. One industrial and commercial customer can provide as much DSR as thousands of domestic and SME customers. This means that for domestic and SME customers it will be more expensive to set up and manage DSR than it is with industry and commercial customers

Potential solution: It is the role of aggregators to manage multiple customer contracts and form a single DSR product. It is possible that until all the easiest I&C flexible demand is used DSR products for smaller customers will be limited.

Action: This issue should be monitored. If it stops mass market DSR stepping down from industrial and commercial customers to domestic customers at a point in the future then enablers may have to be considered. However the working group do not see it likely to be a blocker to DSR development once the I&C DSR market is mature.

SOCIALISATION OF DSR VALUE

3.16. If the socialisation of DSR value does not materialise then the value of doing DSR is kept between the participating customers and the industry actor.

Enabler: For the SO, TO and DNO, the regulatory process should ensure value is provided back to the mass customer population, while effective competition should ensure suppliers and aggregators are unable to keep more than a reasonable recompense for their actions.

Action: Most actors do not see this item as a risk due to how the industry works today. However, if the risk does materialise then regulation and/or the market model which develops may need to be adjusted to ensure DSR reduces the average customer bill and not just those who take part. This is connected to issue 2 on how the market is operating.

DSR CONTRACT DURATION

3.17. As customers become more aware of the value of DSR to different parties they may want short term contracts with actors to enable them to shop around. In the LCL trial, a DNO is already seeing this happen. This creates business cases that may be only temporary, especially for DNOs with a limited pool of customers to target. If access to DSR is lost then the DNO will have to keep the DSR portfolio under constant review and potentially look at alternative solutions to maintain current security standards.

3.18. Customers shopping around would indicate that they had the knowledge to make informed decisions and would not be an issue for the industry as a whole.

Action: The combining of DSR products by 2 or more actors to one customer would mitigate this issue. The combining value recommendation within this paper would be the best enabler to reduce the risk of DSR being only a short term solution to some situations.

Other findings:

Customer reluctance / trust in DSR

3.19. DSR with energy is a new concept to many customers. It will take time and effort by the industry to sell the benefits to customers and prove any perceived negatives do not materialise.

Potential solution: The onus is on actors to work with customers to overcome these issues with their propositions. The industry, including aggregators, should work under the Ofgem trust test to always work in customers' interest. The consumer sub group is looking at ways of meeting customers concerns

Clustering of LCTs

3.20. Purchasing of Low Carbon Technologies (LCTs) can geographically cluster, instead of being spread across the country. This means demand can rise quickly and the opportunity for DSR is reduced to deal with local level issues. Less clustering or slower ramp up of LCTs would create more opportunities for DSR, however DSR could offer a rapid bridging solution before a longer term solution is put in place.

3.21. **Potential solution**: None seen. LCTs are likely to cluster and this process should not be stopped. No action is the outcome suggested by the workstream.

Customer propositions do not reflect industry needs

3.22. While flexibility at domestic level may start as a way of managing in-home factors and wider industry benefits are secondary, a DSR market model or regulation focused on this development should enable management of the winter peak via domestic DSR when it is in the customer interest. The change to half hourly settlement may see consumer DSR propositions becoming more aligned with industry needs. The DNO and Supplier / aggregator will need to ensure that the value of DSR is realised in their propositions post the implementation of Half Hourly settlements.

Action: Cost savings to be customer should drive customer propositions. Once a real industry signal is passed to consumers, either driven by capacity (generation or network) issues or process change (HH settlements) the domestic customer DSR should support industry needs more. No specific actions at this point are needed to support this outcome apart from the introduction of Half Hourly settlements.

Export value of micro generation

3.23. The value of micro generation is likely to always be of most value when used within the premises to reduce the amount of energy being exported. This limits the available export energy for other DSR uses, such as a balancing tool. This is due to the import tariff being far higher than the amount paid to customers for the exported energy.

3.24. There is no obvious solution, but it does create an opportunity for customers to maximise the value for their micro-generation by moving flexible demand to periods when otherwise the property would export. Customers limiting their exported energy will have positive system benefits at times of low demand, such as in the summer.

Action: Outside of the development of community energy the working group see this no reason to recommend any changes. The community energy working group may find reasons to explore this further and the distribution of value working group would support this work.

Caveats and exclusions

SMART METERING

3.25. Smart metering rollout will be complete by the end of 2020. Smart metering is needed to record many types of DSR action and for it to be submitted into settlements. It also provides a secure 24 hour a day (always on) messaging system into 30 million properties. Smart meter rollout is also necessary to create value in DSR through enabling HH settlements for all domestic and SME customers[42].

3.26. The distribution of value and community energy working groups have indicated a possible link between the value that community energy can create and DNOs. This is due to the localisation of both operations. This may create new opportunities for DSR which DNOs will be in the best place to take advantage of. Once the DSR opportunities of future community energy schemes are better understood this link needs more research.

3.27. The work within the workgroup will have to be revisited if suppliers primary cost drivers are no longer associated with demand but with intermittent generation instead. Should this happen then the assumption that a supplier action will be beneficial to other actors may not be true. Even if suppliers cost drivers are following intermittent generation, the winter peak is expected to remain the key time of year. Heat pumps with storage would create a DSR opportunity that could help tackle the winter peak, but would not be as helpful with issues that many forms of intermittent generation could cause, so there are scenarios where the expectation could be incorrect but it’s still unlikely.

3.28. A lack of differential between peak and off peak wholesale prices today may be a factor which stops DSR products being offered to customers, by not providing the incentive to create DSR products.

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[42] Nb. Messages are not displayed on minimum spec IHDs, but are displayed on meters. Only suppliers can send messages.

4. Smart Metering

4.1. This section sets out what the Smart Metering Sub-group (SMSG) considers to be the key potential barriers and enablers for DNOs to utilise smart meters (SMs) to deliver benefits to consumers.

SM data privacy/aggregation

4.2. Under SLC 10A (Smart Metering – Matters Relating to Obtaining and Using Consumption Data), DNOs will be able to access domestic consumers' energy consumption data from SMs, including half-hourly energy consumption data, provided that they have data privacy plans for such access approved by Ofgem.[43]

4.3. The data privacy plans must demonstrate that practices, procedures and systems can be implemented to aggregate or otherwise treat the data to ensure it can no longer be associated with individual premises.

4.4. SMSG members identified the potential risk that aggregating data as a means to protect consumer privacy may act as a barrier to attaining some of the SM benefits for DNOs/consumers.

4.5. Following discussions at the ENA SMG, on behalf of the DNOs, commissioned analysis by EATL to investigate:

- what SM benefits may require granular half-hourly consumption data
- the appropriate level of data aggregation to maximise consumer benefits.

4.6. The key findings from EATL is that:

- data aggregation alone may not be the solution to ensure compliance with licence condition SLC 10A because it does not ensure privacy
- aggregating household data to a level of more than two households may reduce DNO/consumer SM benefits from proactive HV/LV planning by a significant amount.

4.7. A more detailed summary of the EATL paper's finding and the full paper have been published alongside this report.[44] While the EATL report has not been fully reviewed and endorsed by Ofgem and wider stakeholders, it will form part of the next steps in the work programme that this report recommends.

4.8. Debate amongst the SMSG has concluded that more work is required to investigate what compliance with SLC 10A looks like. For example, investigating ways of anonymising household SM data in conjunction with data aggregation and looking at what is done in other sectors.

Action: Using EATL's analysis as background, the ENA smart meter group (SMG) is now developing a compliance framework/standard for SLC 10A which is expected to adequately protect customers whilst optimising the potential benefits of SM data. The ENA currently

[43]DNOs can also access granular data if they have consumer consent.

[44]The ENA commissioned two reports by EATL on this issue and have published them here. See 'EA Technology Smart Meter Aggregation Assessment - July 2015'.

plans to consult on this framework with the expectation that, if justified, Ofgem will then be able to approve the individual DNOs data privacy plans from Q1 2016.

Action: The ENA are also doing parallel work for gas distribution.

SM Voltage Monitoring and Voltage Anomaly Alerts

4.9. Voltage monitoring within SMs provides DNOs with an early warning of emerging power quality problems. At present there are no "standard" settings for voltage thresholds or measurement periods.

4.10. The mechanism for configuring the voltage monitoring aspects of SMETS1 meters is not clear cut. There is an aspiration for DNOs to be able to do this remotely via the DCC once the SMETS1 meters are enrolled (i.e. in the same way as for SMETS2 meters), however, it is not clear how many SMETS 1 meters will be enrolled in DCC as it is up to suppliers whether to put them forward for enrolment. DNOs would need to request Suppliers to perform this task on their behalf for SMETS1 meters that have not been enrolled in DCC.

4.11. It would be beneficial for there to be agreement on the initial configuration of voltage thresholds and periods between DNOs and suppliers. A universal standard would be beneficial so suppliers (or potentially manufacturers) can address this as part of the rollout. This would mitigate the need for each meter to be accessed separately by both parties during the rollout period.

Action: The ENA SMG is currently looking to define common settings and determine how these will be communicated to installers (or potentially the manufacturers to pre-programme). With the rollout of SMETS1 meters already under way this issue is being assessed as a priority by the ENA SMG.

Use of SM load control switches to mitigate the need for global demand control actions under ESEC and potentially Grid Code OC6

4.12. Under the Electricity Supply Emergency Code (ESEC) the System Operator (SO) may require DNOs to apply global demand reductions which are implemented via voltage reduction and then rota disconnection. [45]

4.13. Smart Meters equipped with an Auxiliary Load Control Switch (ALCS), controlling supply to a specified load with the home, which could be used to bring about a significant reduction in system demand under emergency network conditions. This may offer consumer benefits. For example, the use of ALCS to reduce related demand as a pre-cursor to actual demand disconnection could reduce the need for, frequency of and level of demand disconnection over peak load periods.

4.14. ESEC does not currently envisage such use of SM demand controls. It could be changed to provide either suppliers, the DNOs or the SO with appropriate access to utilise ALCS functionality when an emergency situation has been called. A legal review of the application of ESEC would be required as existing powers may permit such use.

[45] Rota Disconnections are used in response to a National Energy Emergency at times of a severe shortage of electricity production (generation) in the UK. Rota Disconnection is achieved by dividing all users of electricity into groups called 'blocks'. A customer's block is determined by their postcode and position on the local network. These blocks are then switched off in turn, on a 'rota', for a period of three hours. If the level of electricity shortfall increases, more blocks are switched off resulting in interruption to a larger number of customers. Once introduced, Rota Disconnections will continue for the full duration of the shortfall in electricity generation.

Action: The ENA SMG will examine the technical feasibility of this potential benefit with National Grid. If it seems feasible then ESEC will take this action forward, and consultation would then be needed on the consumer impacts of this move. This issue has been passed to the ESEC governance body - Energy Emergency Executive Committee (E3C) and the relevant working group Electricity Task Group (ETG).[46]

Action: DNOs are considering submitting proposals for a trial under Ofgem's Network Innovation Competition. This trial would test whether smart meters can be used to limit the amount of electricity households use in an emergency so that electricity can be rationed rather than disconnected. The DNO trial is being targeted for 2017 when there is a sufficient volume of smart meters installed. It is recommended that SGF seek an update from the ENA on developments in this area.

Action: As well as technical and commercial feasibility, there are some outstanding questions as to the implications this change of the emergency process might have for consumers. A note by the consumer sub-group chapter sets out some of the questions that may need to be explored.[47] This includes the possibility of domestic and small business consumers being more likely to be asked to reduce demand in an emergency situation than larger consumers.

Action: In addition, consideration would be needed of the impacts on the overall security of the smart metering system should parties other than suppliers be able to send supply sensitive commands to directly control load.

SMETS 1 and Advanced meter functionality

4.15. SMETS1 and advanced meters do not offer the same functionality as SMETS 2 meters. For example, around 400,000 SMETS 1 meters deployed to date do not have outage functionality used by DNOs. There is a risk that in the event that large numbers of SMETS1 meters are fitted, certain SM benefits may be reduced.

4.16. The impact of this could be increased if penetration of SMETS1 meters is clustered within a geographic area, limiting the benefits available until the installed meters are swapped out.

4.17. At present there is no analysis to suggest what the 'tipping point' might be for the number of SMETS1 meters that would need to be installed for there to be a material effect on certain SM benefits. DECC have recently consulted on setting an end date for the installation of SMETS1 meters.[48]

Action: As part of the existing SM programme measure DECC have consulted on setting an end date for installation of SMETS1 meters. A decision was published in July 2015 – SMETS1 end-date should be 1 August 2017 (i.e. DCC Live plus 12 Months), after which point the installation of SMETS1 meters will no longer meet the requirements of the rollout licence condition.[49] It is recommended that the SGF consider the outcomes of this decision and whether any further analysis is required.

DUoS TOU charging

[46] The latest report from the E3C can be found here: https://www.gov.uk/government/publications/energy-emergencies-executive-committee-annual-report-2014
[47] See Annex 2, section 3, Note on use of load limiting or control in emergency situations. The note can also be found in the 'Consumer Protection subgroup supplementary material' zip folder published alongside this document.
[48] https://www.gov.uk/government/consultations/smart-metering-rollout-strategy
[49] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/450167/Smart_Meters_Rollout_Strategy_Government_response_FINAL.pdf

4.18. SMs will provide DNOs with opportunities to work with suppliers to develop and deploy Distribution Use of System (DUoS) Time of Use (TOU) tariffs via smart meters. These DUoS TOU tariffs will allow prices charged to consumers to change to reflect the costs of providing high peak network capacity, and thus potentially incentivise reductions in network peak demand.

4.19. The first potential issue identified is that the relationship between the DNO's DUoS charges and domestic customers is one degree removed by the supplier and are not itemised in consumers' bills. For consumer demand behaviours to be influenced by DNO TOU signals those signals must be clearly visible to participating consumers, both prior to the tariff periods in order to inform behaviour and subsequently in the consumers' resulting cost of energy as assessed by the TOU tariff settlement configuration. As a first step to visibility, a tariff settlement configuration using half hourly (HH) settlement, or similar functionality, is required for TOU DUoS programmes to deliver the full benefits that could be available.

4.20. Settlement options for TOU tariffs could be considered without full HH settlement, such as deriving new settlement profile classes for static TOU tariffs. However, any configuration would need to be based on actual measured HH consumption, or risk not accurately rewarding and charging customers for their demand flexibility. Additionally, if the range of TOU tariff options needed to fully access TOU benefits becomes more complex, for example varying with time of year, network types and locations, or including dynamic TOU components, full HH settlement may prove to be the most cost effective option for implementing these.

4.21. The second potential issue is that DNO TOU programmes may be only one of a range of price signals incentivising customers, e.g. wholesale electricity price reflective tariffs, which may be aligned or in conflict with the DNO TOU signals. DNOs' benefits from TOU would be limited in cases where the DNO price signals was overridden by other industry price signals, or where flexible demand behaviour is not appropriately reflected in the customers' bill. Work from the Distribution of Value Subgroup suggests on particular areas of the network, the value of a DNO TOU signal may be relatively large in network critical periods and supersede that of other industry price signals.[50]

4.22. This issue depends on a number of market factors that should be considered by industry in the appropriate forums as the roll out of smart meters progresses. One possibility is for this to be considered in the forums that feed into Ofgem's work on the HH settlements for domestic and smaller non-domestic market.

SM Data Access

4.23. At present, governance arrangements don't directly allow DNOs to access some types of data for customers fed from their networks. Two potential issues have been identified:

1) The first is that some SMs are fed from IDNO or other DNO networks on cross-boundary circuits. This cross-boundary data can only be obtained by DNOs where they have obtained the DCC status of 'other user' and direct consent by the consumers affected, meaning that it may not be readily incorporated into DNO decision making.

2) The second area where data access should be considered further is for sites that are metered half-hourly for larger customers (e.g. profile classes 5-8).

[50] See the Distribution of Value section Annex 2 . 'Though this localised peak which DNOs might mitigate using DSR in a post fault management scenario will, in most cases, overlap the time period of the national system peak, the DNOs cost driver under this scenario will be stronger than that of suppliers.'

4.24. If data access issues were overcome, this could be an enabler to maximising DNO SM benefits in the following areas:

- LV/HV network planning
- active network management[51]
- the ability to measure and model losses.

4.25. While not discussed by the smart metering subgroup, WS6 also identified that National Grid should consider further the need for, and access to, smart metering data for visibility and forecasting. As embedded generation continues to increase and demand is flexed in response to new signals such as TOU tariffs, the ability to accurately estimate transmission demand becomes increasingly difficult and is likely to result in increasing system balancing costs on consumers.

Recommendations/solutions

4.26. Cross-boundary data is not regarded as a high-priority issue as the SM benefits potentially affected will only become available once a high population of smart meters have been rolled out. Further, it is not equally important across all DNO networks, affecting areas where IDNO activity is high.

Action: The group therefore considers that a solution is not required before the end of 2017. It recommends that DNOs task a DCUSA sub-group with exploring options to facilitate sharing/obtaining information of cross boundary information.

Action: This issue may also need to be referred to Smart Energy Code (SEC) panel for consideration if the solution identified by the DCUSA sub-group is direct access to the data, as opposed to data transfer between network operators.

Action: The unavailability of half-hourly metered data for some larger customers should be referred to the SGF for follow-up to understand if it is still a concern.[52]

Recommendation: If National Grid had access to aggregated Smart Metering data it may improve forecasting accuracy of both real demand and embedded generation. National Grid to discuss with DECC.

Electricity distribution losses – DNO modelling and measuring

4.27. Electricity distribution losses have a significant financial and environmental impact on consumers. SM data (particularly half hourly consumption data) may enable a step change in the way DNOs can model and potentially measure losses on network. The SMSG produced a losses options paper.[53]

4.28. The losses options paper considered and assessed:

- potential losses measuring and modelling approaches using SM data (including their relative pros and cons)
- potential barriers/enablers to measuring and modelling losses
- questions to aid design of a future losses regulatory incentive (eg ex ante/ex post funding, caps/collars, modelled or measured losses).

[51] Active Network Management is where DNOs, informed by SM data, look to optimise LV network voltage and power flows.
[52] For example, Balancing and Settlement Code (BSC) modification P272 may enable DNOs access to this form of data.
[53] See Annex 2, section 5, terms of reference (iv). The note can also be found in the 'Smart metering subgroup supplementary material' zip folder published alongside this document. See 'TORiv Losses note'.

Action: It is recommended that DNOs continue to explore the future modelling and measurement of losses and that consideration should be given to whether this should be done on a consistent basis across all DNOs. This may have advantages such as providing a common base for comparison.

4.29. Under RIIO-ED1:

- DNOs have a licence obligation[54] to manage their distribution losses to a level as low as reasonably practicable, and develop and act in accordance with their own published strategy for managing losses
- there is also a financial incentive, the losses discretionary reward (LDR). The aim of the LDR scheme is to encourage and incentivise DNOs to undertake additional actions to better understand and manage electricity losses on their networks (including actions related to measuring losses).

4.30. These RIIO-ED1 measures should act as incentive for DNOs to develop thinking in terms of modelling and measuring losses. This will be monitored by Ofgem.

Action: It also recommended that the ENA regulatory managers group explore options for introducing an output based losses incentive for RIIO-ED2 (which would start in 2023). The questions set out in part b of the losses note provide a starting point for this analysis. This initial thinking can begin immediately and the SGF should follow up on its progress.

Electricity distribution losses – new DG data

4.31. The volume of distributed generation (DG) connected to the distribution network is expected to increase. This will affect the losses profile on each DNO's network and, as the penetration of DG increases, become an increasingly important variable in modelling losses.

4.32. SM data could enable suppliers to base feed in tariffs export payments on actual exported volumes. Currently this is data is estimated.[55] For an ongoing overall losses monitoring regime, the use of actual DG export volumes would enhance any monitoring regime, and will be available post SM roll out.

Action: The introduction of SM export registers to record actual DG export volumes onto DNOs' networks could be an option if SM data is used to change how FIT payments are made. In the future this may be something for suppliers and/or DECC to investigate further. A by-product of such a change will be to enable line loss factors to be calculated for all DG – this would be expected to enhance DNOs' ability to model losses. It is recommended that the SGF explore this issue with suppliers, once the roll out of SMs has progressed and the volume of associated data has increased. Any change to how FIT payments are made would ultimately be a decision for DECC to make. It is also worth noting that this is similar to proposals in DECC's recent FITs consultation.[56]

SM load control switches (1) – Visibility of ALCS load

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[54] SLC49 (Electricity Distribution Losses Management Obligation and Distribution Losses Strategy)

[55] The current FIT default position is that G83 generators are assumed to export 50% of the electricity produced. This assumption is purely for the purposes of determining payments. Actual energy exported which, for rooftop solar PV, will depend on the number and capacity of solar panels installed and the electricity consumed at the property. It follows that energy actually exported will vary significantly across seasons.

[56] https://www.gov.uk/government/consultations/consultation-on-a-review-of-the-feed-in-tariff-scheme

4.33. DNOs can obtain access, through Suppliers, to load control switches within SMs to manage consumers' load.[57] All SMs will contain a load control switch controlling all load. SMs will also have the functionality to utilise Auxiliary Load Control Switches (ALCS). Fitting, and use of, an ALCS is optional and allows control of a proportion of load, eg when an electric vehicle is charged.

4.34. The amount of load connected to, and therefore under control of, an ALCS may be visible where twin element metering within the SM is configured in some form. Twin element metering is a configuration option available in SMETS2 meters and means there are two defined registers for measuring consumption. For a household, one of these registers could be connected to an ALCS fitted to a heat pump recording its consumption, while the other register records consumption of everything else in the household.

4.35. A potential risk has been identified that such a configuration may not always be applied. For example, if a household had four ALCS with different LCT devices connected to each of them, it would not be possible to monitor the individual load of these as they would share a register. This potentially limits visibility of the ALCS controlled demand for DNOs (and other parties) because the type of device, and its associated load at times in the day, would be largely unknown. Recommendations to help enhance the visibility of the potential load under control through ALCS are seen as beneficial to reduce DNOs' (and other parties) uncertainty about the level of response (ie reduction in demand) that may be achieved through a demand side response action.

Action: DNOs have requested access (via a DCC service request) to the descriptions of the load under control by ALCS which would aid the estimation of any potential DSR action. Currently suppliers are responsible for registering a description of the device connected to an ALCS.[58]

The smart metering system includes functionality to provide a description of any ALCS. This description is stored on the electricity meter and can be written remotely. At the moment only suppliers can provide this description via the relevant DCC service request. The description is provided as free text, rather than selected from a fixed set of options. There is a potential that these descriptions may not be provided on a consistent basis (if at all) by Suppliers as they are not mandated to provide a description or a consistent description.

It is seen as useful for there to be further work to develop industry guidance on:

- how to consistently register a description of a device using an ALCS connected to a SM, and
- ALCS load estimation.

It is recommended that the SGF request an update from the ENA SMG on developments in this area.

Action: Currently the twin metering of SMETS 2 allows the consumption of a single ALCS to be monitored. A potential option that may be worth exploring in the future would be to enable individual metering of more than one ALCS into the SMETS standard, if justified

[57] Please note DNOs access, through suppliers, to load control switches are subject to appropriate mechanisms, eg IT infrastructure, being implemented to allow this.

[58] The description is held on the smart meter itself. In order to access this information a supplier would send the appropriate Service Request via the DCC.

by the benefits.[59] On an enduring basis any proposals to modify SMETS will be managed via SEC governance processes.

SM load control switches (2) - DNO/TSO/Supplier/Third parties arrangements

4.36. The SMSG's 'Load control' note[60] looks at some of the potential scenarios where SMs and SM infrastructure can assist DNOs in load control. DNOs can obtain access, through Suppliers, to load control switches within SMs. All SMs contain a load switch (controlling supply to the home). An Auxiliary Load Control Switch (controlling supply to a specified load) is optional.

4.37. The note does not seek a change in the SEC to allow DNOs direct access to load control switches. However, it identifies a number of potential barriers in current commercial arrangements. It also identifies areas of co-operation between industry parties that will need to develop in order for DNOs (and other parties) to make use of load control switches to deliver benefits consumers.

Action: Working practices between DNOs, suppliers and other parties will need to develop and this will be an important area for the SGF to monitor. This however, is not seen as an immediate priority as the development of commercial arrangements is not expected to happen until SM penetration increases. It is noted that the current work and collaboration between DNOs and suppliers to transfer Radio Teleswitch functionality to SMs may offer some lessons for future arrangements for DNOs to make use of load control functionality.

SM load control switches (3) - proactive DNO LV analysis for constraint identification

4.38. Aggregated half hourly smart meter load profile information may be used to inform DNO actions to manage the low voltage (LV) network. This may be in anticipation of (proactive) or as a result of (reactive) a localised constraint on the network.

4.39. The SM ALCS may enable DNOs to issue a command to households, via suppliers, which will reduce load. The ability to perform this would, in the future, likely form part of a contractual agreement between the Supplier and consumer. The main benefits to DNOs (and indirectly to consumers) would be avoided reinforcement.

4.40. For proactive command and control, the delay between identifying the need for action and the action taking place will be less time-critical than for a reactive command and control. As a simplistic example, proactive command and control could involve the following process:

- DNO establishes a model for LV constraint identification which is fed with SM data on an ongoing basis.
- The model is configured to automatically signal a potential constraint by issuing a command to suppliers to activate the ALCS to reduce load.
- Assuming the supplier responds to signal from the DNO, then load is reduced via the ALCS (this supplier response might be automated as part of contract with the consumer).

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[59]You could also potentially use additional single element meters with ALCS.

[60] See Annex 2, section 5, terms of reference (v). The note can also be found in the 'Smart metering subgroup supplementary material' zip folder published alongside this document. See 'TORv load control'.

4.41. Proactive DNO LV analysis for constraint identification is not common practice, but is being developed. For example, related analysis is being explored through LCNF trails eg UKPN's Low Carbon London and SPEN's Flexible Networks. In addition, as SM data becomes available DNOs will be able to develop their work in this area further.

4.42. Section 1A of the SMSG's 'Load control' note[61] provides additional information on this issue.

Action: There are no substantive barriers or enablers identified to proactive DNO LV analysis, other than SM data aggregation issues (which is being considered under a separate action). It is therefore recommended that the SGF monitor this issue and seek an update from DNOs. Commercial arrangements between suppliers and DNOs would also need to develop to formalise a mechanism for the DNO to request an ALCS control action by the supplier. Such a mechanism should be considered by industry in the appropriate forums as the roll out of smart meters progresses.

Specification and rollout of DCC User Interface and its capabilities to manage data

4.43. The DCC User Interface Specification has nearly been finalised. There is a risk that the final specification, development and roll out of related DNO infrastructure does not enable the full realisation of SM benefits.

Action: ENA SMG and DCC governance structures are in place to ensure delivery of the contracted services and are considered appropriate to manage any risk in this area. The SGF should also monitor this issue.

Demand diversity assumptions for new connections

4.44. SM data will enable more advanced data sets on residential demand patterns to be developed.[62] In particular, DNOs use diversity assessments as part of the process for assessing new connections, particularly for residential customers. This is expected to help enable the delivery of some consumer benefits (e.g. reduced time to get a connection), through more efficient access to the network for new connection customers.

4.45. More detail on this can be found in the 'Demand Diversity note'.[63]

Action: At present, there are no substantive barriers/enablers to improving and applying diversity assessments following the national rollout of smart meters and it is recommended that the SGF monitor this only as a low priority issue.

[61] See Annex 2, section 5, terms of reference (v). The note can also be found in the 'Smart metering subgroup supplementary material' zip folder published alongside this document. See 'TORv load control'.
[62] For example, those already obtained from the Low Carbon London and Customer Led Network Revolution innovation projects.
[63] See Annex 2, section 5, terms of reference (iii). The note can also be found in the 'Smart metering subgroup supplementary material' zip folder published alongside this document. See 'TORiii Demand Diversity'.

5. Storage and DG

Category 1: Storage and DG smart grid services

5.1. To date, generation on the distribution networks has been seen largely as a source of energy, sometimes in "the wrong place," while deployment of storage has been limited. However, distributed generation and distribution connected storage have the potential to play a significant role in the development and operation of a smarter energy network, through the provision of a range of "smart" grid services. The potential for these services, any commercial or regulatory barriers to these, and recommendations for next steps, are set out below.

SERVICES FROM BOTH DISTRIBUTED GENERATION AND STORAGE[64]

<u>Reactive Power Service to TSO</u>

5.2. National Grid has increasing need for reactive power support in specific locations across the country. However, reactive power is currently charged additional DUoS,[65] which acts as an obstacle to the realisation of potentially significant savings by the TSO, in particular in areas with lightly loaded circuits.

5.3. There is a mechanism currently that allows DG or storage to contract bilaterally with National Grid, on an ad hoc basis, to provide reactive power. There is currently nothing in the charging methodology that permits the provision of reactive services by DG to the TSO; and a mechanism for appropriate reward to DG for provision of that service.

5.4. In future DSOs may supply reactive power to National Grid in their own right, via service providers on their distribution network. However, there is a more immediate need for reactive services that needs to be explored.

Action: National Grid to further update on the general need for reactive power across the network, by DNO area, in the System Operability Framework (SOF) 2015.

Action: National Grid to continue discussions with the industry via the ENA ENFG, which will seek to engage with stakeholders as options emerge towards the conclusion of the groups work (September-October 2015).

<u>Reactive Power Service to DNOs</u>

5.5. DNOs also have need for reactive power support on occasion.[66] Individual DNOs may include reactive capability in a connection agreement, but mandation may not be the most economic and efficient solution. This is because different providers may be more cost-efficient than others, and mandation would not facilitate the development of a more dynamic market for reactive provision.

5.6. Reactive power services to DNOs could be enabled by the development of a mechanism, in collaboration with the off-takers of distributed generation, to enable DNOs to communicate to DG and storage, and to remunerate these connectees for

[64] This section is predicated on endurance of a connection boundary that is shallowish, but deeper than at transmission. Under the shallowish regime, network issues are addressed as part of the connection agreement, whereas the shallow transmission regime entails more locational charging and a balancing service charge. There is the prospect of conflicting signals, e.g.: the onus of mandated services vs the opportunity for commercial services in a particular location.
[65] Under CDCM only, ie for assets connected up to 11kV.
[66] The new European Network Code on Demand Connections is also expected to require DNOs to meet voltage control obligations in relation to the TSO.

additional reactive services.[67] This may be another step towards the development of a DSO, with the DNO engaging more actively with its connectees.

Action: DNOs to identify "voltage hotspots" where the provision of reactive services is a priority, as potential pilot or learning areas to feed into Workstream 6.[68]

Action: DCRP to develop mechanism for communicating reactive needs to DG, storage, and affected off-takers.

Action: Workstream 6 to contribute to development of DCP 222 charging methodology proposal and wider charging methodology changes under Distribution Charging Methodology Forum.

Constraints Management

5.7. In the DNO space, constraints management contracts are covered under Flexible Connections.

5.8. It is sometimes difficult for the transmission system to take outages for reinforcement, owing to exports from DG onto the transmission network. DG can sign bilateral BEGA contracts with the TSO, but these have costs and may be undermined by DNO activities, for example in an Active Network Management (ANM) area.

5.9. There is currently not an appropriate constraint management arrangement between the TSO, DNO and generator to enable planned transmission outages to be taken without the DG unduly losing revenue.

Action: National Grid to initiate process for managing transmission outages through appropriate mechanisms involving the DNO and relevant DG.

Balancing Services for TSO

5.10. While transmission connected generators are required to sign up to the Balancing Mechanism (BM), this is not the case for most DG. However, the BM would offer a mechanism for DG to begin to participate in wider system balancing, as well as constraints management where locally relevant. Hurdles to BM participation include a requirement for two-way communication and a 24/7 control point. To enable DG to participate in the BM more fully there is a need to minimise the cost and operational requirements of participation. In the longer term, the DNO may take on this balancing as part of an emerging DSO role.

Action: National Grid to review prerequisites for participation by smaller generation and by aggregators.[69]

Action: Service providers to consider commercial solutions (eg aggregators).

Sharing

5.11. It is not currently possible to provide services to both the TSO and the DNO with a single asset due to visibility and sharing issues, notably exclusivity and penalty clauses. This issue is being explored by the ENA Shared Services group. What is needed is

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[67] SNS is expected, through a trial, to quantify the potential for reactive power support from storage and provide recommendations for further steps. However, this work will not address reactive power from DG.
[68] Initial findings from the first reactive power trial as part of SNS showed that up to 0.09MVA/hour can be saved using 3.75MVAR (half the capability of SNS). This could reduce line loss factors.
[69] Note the need to check whether the generator is already under a flexible connection / ANM arrangement with the DNO.

exploration of a range of standard contracts that facilitate income stacking. This may be a "multi-service" contract, which allows the TSO to access the asset for a range of services that are technically appropriate.

Action: National Grid to lead an assessment of how the tender processes for various services interact and the possible impact on providing multiple services. Note that Shared Service Framework addresses how DSR services may be offered to both DNO and TSO.[70]

Action: The ENA Working Group to continue exploration of this framework to include other users of flexibility services, and including DG and storage providers.

5.12. The issues with providing TSO services are related to standard contracts and the inability to provide multiple services without a bespoke contract. Contracts incur penalties (plus a "four strikes and you're out" approach) that mean either combining services to the TSO on standard contracts or operating in both networks results in a high a probability of defaulting on a contract.

5.13. What is needed is exploration of a range of standard contracts that support multiple service provision.[71] This would include an assessment of how the tender processes for various services interact and the possible impact on providing multiple services.

Action: National Grid to explore the scope for standard contracts for multiple service provision, and opportunities for aligning tender timescales.

<u>Utilisation</u>

5.14. Technical specifications for current services do not necessarily reflect how a service is used and for electricity storage, which has a limited capacity/duration of discharge, the lack of information about actual utilisation makes it difficult to understand if the service is an option for storage. For example it is not clear how often and for how long a frequency response is required in a given day.

Action: National Grid to be as specific as possible on the commercial proposition for the technologies it expects to use for procuring services in the medium term.

SERVICES FROM STORAGE ALONE

5.15. Storage offers the distinct function of being able to absorb, hold and discharge energy when required. Storage therefore has a set of intrinsic value propositions to offer the power system. There are many technologies that can provide electricity storage, each with different technical specifications, and there are business models with multiple income streams that support deployment now.

5.16. Electricity Storage could provide a variety of services including, but not limited to, frequency response and regulation, inertia (synchronous or synthetic), balancing reserve, reactive power and voltage stabilisation. These services will be required on the system between now (frequency response and regulation, balancing reserve) and

[70] Note link to Visibility sub-group to ensure appropriate information flows among affected parties.
[71] SNS will be looking at this collaboratively with National Grid in relation to the technical aspects and design of new services. National Grid will provide guidance on the value of such new services and there will be the opportunity to trial new services within SNS.

2018 (inertia) in response to changes in the generation mix.[72] Such requirements may be met by a range of providers, including electricity storage.

Long-Term Investments

5.17. Short-term contracts favour incumbent generation, as they do not have to fund investment. If TSO and DNOs want access to new services from new providers and new technologies, including low-carbon solutions and electricity storage, then longer term contracts will be necessary to create a "level playing field" for new technologies or incentivise investment.[73]

5.18. The TSO needs to explore how best to bring onto the system in good time new, low/no carbon assets which require significant upfront investment to provide services, particularly when NG projections (FES and SOF) anticipate future needs for new services. Options include services with very specific technical requirements (e.g. speed of response, as in USA), longer term contracts or requirements to procure a proportion of services from low/no carbon assets.

5.19. What is needed is an exploration of whether the current mechanisms such as the SO incentive regime and the Capacity Mechanism will deliver the innovation required for security of the future system.

Action: Ofgem to consult on how the next SO Incentive might facilitate investment in new ancillary services technologies that promise to be of net benefit to the system and to the consumer.

Action: As part of its planned reviews of the CM (every 5 years) DECC should consider the policy's interaction with other tools in the market such as balancing services, to understand how they are affecting system flexibility, and the pipeline of new/less mature technologies such as storage. [74]

DNO/DSO: Peak load/supply management

5.20. Electricity storage can be used to defer reinforcement and contribute to management of distribution network peaks (headroom) in demand and supply (footroom). There are a number of issues with storage providing services to the distribution network.

5.21. A lack of a regulatory definition for storage makes operating various business models difficult for already licensed entities. Storage is typically treated as "generation" because there is no specific regulatory definition. For instance a DNO may not generate or supply electricity, so while a DNO could charge an electricity storage device, the discharge could be considered to be "generation", even though storage is not "making" electricity. The discharge could also be considered to be supply. There are business models that can work around this issue, but these business models do not necessarily give DNOs the security and flexibility they need to operate their networks or may necessitate very complicated commercial arrangements.

5.22. DNOs are required by their licences to ensure security of supply and loss of supply has serious consequences for the DNO. If only third parties may own and operate storage then the contract terms, even with penalties, may not be sufficient to ensure security of supply, since market conditions may mean that another non-DNO required

[72] National Grid SOF, 2014
[73] The emerging findings from SNS will help inform this debate.
[74] Assessments of the first capacity mechanism auction indicated a negative impact on new technologies (eg http://www.frontier-economics.com/documents/2015/01/lcp-frontier-economics-review-first-gb-capacity-auction.pdf).

service offers a better return to the third party operator. This is in contrast to the UKPN SNS model where the DNO owns the storage and operates it only to meet its primary requirement (peak management), but then releases the battery to third parties for other functions such as ancillary services and wholesale actions. This approach gives the DNO certainty that the storage will be available to ensure security of supply, but avoids any issue of the DNO "trading" energy (generation or supply).

5.23. The same generation and supply ambiguities affect the ability of the TSO/TNO to use storage.

5.24. The lack of a specific storage definition may also affect how storage is connected to networks, where it is treated as "generation" and/or "demand", rather than "storage". This affects the connection process and charges.

5.25. What is needed is the development of a specific regulatory definition for storage to clearly differentiate it from generation and supply. This may simplify the issue of DNOs and the TSO owning and operating storage, although specific amendments may subsequently be needed to licence conditions with regard to storage.

Action: DECC to review options for clarifying the definition of storage, including considering separate regulatory classification.[75]

5.26. The market for providing (multiple) services to the DNO/DSO is underdeveloped with details emerging now from LCNF projects with regard to potential services and contract terms.

5.27. As this is a new market there is limited information of the potential size of the market under different future DNO/DSO scenarios for new entrants, particularly if the move to DSOs better supports the use of storage on the distribution network. DNOs currently produce "heat maps" to show where the network is stressed or otherwise. It would be useful if the maps were accompanied by some text indicating what services might alleviate any stresses and the potential locations of such services. This would help third parties to identify potential business opportunities (less detailed, but similar to the National Grid SOF reports).

5.28. Sharing services is being examined by the ENA Shared Services group and the market for services on the distribution network will emerge in time, but it is important that no actions are taken that may limit the potential uptake of storage (or other services e.g. DSR).

Action: DNOs continue to publish heat maps and develop additional content that indicates the amount of available capacity, location and services required to facilitate the entrance of new services providers.

Action: ENA to coordinate DNO heat maps into national picture identifying constraints and possible services. DNOs to consider standardisation of heat maps to facilitate this.

<u>Storage Charging and renewables support schemes</u>

5.29. Storage providers can be thought of as being "served" by generators. The storage unit has the option of buying from the market, or to contract with a particular DG plant, or both. In the simplest scenario, the unit contracts with the generator behind the meter (i.e.: is not "seen" by the DNO). The limitation to this approach is that the storage facility may earn insufficient revenue from a single generator to warrant the

[75] Note that these issues have been raised under the UKPN Smarter Network Storage project, which will present pros and cons of different options and is due to report in September 2015.

cost of investment; and, being behind the meter of the generation plant, it is physically more limited in the services it can offer to other parties.[76] Currently there is a lack of commercial/regulatory clarity on how to handle the charging up of storage by non-renewable energy via the market, as such exports should not qualify for funding support such as ROCs.

5.30. In a more complex scenario, a storage unit may be further up the network, contracting with several DG plant and potentially others. Thus there is opportunity for a more varied revenue stream, including potential services to the networks. The downside is ineligibility for Government support if the power is re-exported via a storage unit, and there is a need to review eligibility and mechanisms for receiving renewables support. Owing to limitations on DNO trading (stored) electricity, there is also a need to explore ownership of a storage unit by a third party that can command multiple revenue streams.

Action: DECC/Ofgem to produce guidance on the applicability of various Government support mechanisms (FiTs, ROCs, CfD) to renewables generation associated with storage solutions, building on work from SNS and from the House of Lords Electricity Infrastructure report.[77]

Levies

5.31. Electricity Storage may be double-charged for both import and export in terms of levies related to sustainability. A specific exemption for a single project has been issued by HMRC so that storage is exempt from paying the Climate Change Levy, but this approach needs to be standardised for all storage projects. Likewise there is double charging of the FiT obligation to suppliers (on entering storage and on leaving storage to the end user).

5.32. What is needed is the assurance that this ruling by HMRC is applicable to all future storage projects.

Action: Further to the clarification of the regulatory definition of storage, HMRC to issue guidance on how such levies should apply in relation to storage.

Use of System Charges

5.33. Use of System charges may be applied when storage charges AND discharges (it is not "demand" or "generation").

5.34. What is needed is an assessment by DNOs (and presumably TSO for TUoS) of how the current DUoS charges impact on the viability of storage projects and whether it is appropriate to develop an UoS charge specifically for storage (a single charge).

5.35. There is charging model in the gas transmission system that does not fully-charge storage on both entry and exit, which may be relevant.[78]

Action: Subsequent to clarification of the regulatory definition of storage, Workstream 6 to take to DCMF options for how electrical charge and discharge of storage should be accounted for in Use of System charging and connections frameworks.[79]

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[76] There is arguably more scope however for this facility to be used for favourable price arbitrage, i.e.: store electricity when prices are low, release when prices are high – subject to any grid constraint.
[77] http://www.publications.parliament.uk/pa/ld201415/ldselect/ldsctech/121/121.pdf, points 210 and 213.
[78] Gas transmission charges are split into a capacity (p/kWh/day) and a commodity (p/kWh) charge. Storage users pay both charges on exit, but do not pay the commodity charge for gas entering the national transmission system.
[79] Note that SNS will present issues on Storage/DUoS and present different options or pathways to address these.

Network Development

5.36. The connection of storage to a constrained network may trigger reinforcement, even though storage may resolve or may be being used to resolve the constraint. There is a need to distinguish between storage that is contracting to offer a service to avoid reinforcement, and storage that is being used for other purposes (for example, smoothing generator output). If the former, the avoidance of peak flow would need to be at the top of the services stack. If the latter, it may still be appropriate for the storage to trigger reinforcement if it leads to additional network use. [80] SNS has looked at this.

Action: DNOs to expand flexible connection terms to address storage connections. This will likely include conditional profiles of operation within the stated maximum import and export capacities of the storage user. The DNO can use this information to evaluate the need for reinforcement.

Cost of Storage

5.37. Although battery storage is currently considered an expensive solution for many applications, the technology is following a significant cost reduction trajectory. However, the model for the RIIO-ED1 eight-year settlement, and for monitoring DNO activity (the TRANSFORM model) currently uses cost assumptions from a year or two before the settlement of 2014/15. TRANSFORM will continue to be used by the DNOs.

5.38. EA Technology has an official process and window to update the model with all the outputs from the LCNF Model. The next window for updates will include additional analysis on behalf of DECC, and findings from completed LCNF projects (LCL, CLNR, C2C) by Q1 2016. This is important because TRANSFORM is used on an ongoing basis for a variety of policy development and system modelling purposes, and over costing of storage makes its potential role in the system seem less attractive than it should be.

Action: Workstream 6 (or successor) to remind EA Technology to update storage costs, and to have the opportunity to review these.

SERVICES THAT COULD BE OFFERED BY ENERGY SHIFT

5.39. One approach to providing flexibility on a constrained network is to use “excess” electricity to create another commodity, such as heat, hydrogen or ammonia. Energy shift services using “excess” electricity can be used to provide increased demand (footroom). In certain circumstances (acting as a load), they may also be able to provide turn down (headroom).

5.40. There appears to be no particular barriers to a third party operating such a process, other than the potential to inject hydrogen into the current gas network, where gas quality regulations may block this approach.[81]

5.41. However there may be an issue if a DNO wanted to operate such a flexibility process, because it is not clear whether a DNO could trade heat, hydrogen, ammonia or other vector under current licence conditions. DNOs need to assess whether trading in a commodity is allowable under their current licence and de minimis arrangements.

5.42. What is also needed is an assessment by the Ofgem gas team to ensure that GS(M)R 1996 Gas Safety (Management) regulations are already being assessed as part of the various gas innovation projects covering injection of hydrogen in the natural gas

[80] The DG-DNO steering group is considering the level of monitoring of connectees changing equipment and the impacts of this on the network.
[81] GS(M)R 1996 Gas Safety (Management) regulations.

network. For instance, the Gas Network Innovation Competition (NIC) Opening up the Gas Market (OUGM) project is assessing the current GS(M)R gas limits. The project is injecting gas that sits at different ranges outside of GS(M)R into parts of the network and assessing whether customer appliances still work safely without any issues. The project is looking to show if the GS(M)R limits could be widened from the current limits to wider limits. This would allow gas to be injected into the network with less processing. Hydrogen is an example of a gas that would require less processing if the limits were widened.

Actions: Ofgem to confirm that GS(M)R 1996 Gas Safety (Management) regulations are being assessed. DNOs to assess licence implications of trading commodities such as heat, hydrogen and ammonia.

Category 2: Flexible connections

5.43. Flexible connection schemes have enabled more generation to connect onto the existing network.

5.44. When a distributed generator (DG) requests a connection to a constrained area of the distribution electricity network, it can lead to the need for reinforcement of the network.[82] This can cause the cost of connection to be high and the timescales to connection can be long.

5.45. As an alternative, the DNO can offer a flexible connection, whereby the DG accepts it will be subject to curtailment depending on the network's operating conditions. In return, DG customers can receive a cheaper and faster connection because the network reinforcement is avoided, or at least postponed. New sole-use assets for physically connecting the DG to the network are still required and are funded entirely by the DG (as is the case under a traditional connection agreement).

5.46. For flexible connections, estimated curtailment levels are given by the DNO to the generator using best efforts at the time of making the offer, covering more than one future scenario; however these forecasts are only estimates and different operating conditions as well as uncertain demand and generation profiles, can cause deviations.

5.47. Potential uncertainty in the level of curtailment experienced during operation of flexible connections introduces a level of risk to DG developers and may act as a barrier to financing generation projects. The next sections of this chapter look at ways to mitigate and manage that risk.

5.48. Two mitigation measures (described below) to help manage the risks associated with curtailment were assessed for barriers or enablers. Further work needs to be undertaken before any or either of the mitigation measures below could be recommended, but the likely issues with each mitigating option have been explored and recommendations for addressing these issues have been given.

Action: Further work needs to be undertaken by the WS6 (or successor) to ensure that any proposed flexible connections approach, including, but not limited to, mitigation 1 and mitigation 2, and also any reinforcement cost recovery process represents value to DUoS customers. That is the DUoS customer should never be worse off relative to an appropriate counter-factual. Such work should include an examination of the interaction between flexible connections and existing connections.

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[82] In this context, reinforcement refers to any additional network upgrades required over and above the sole-use assets.

MITIGATION MEASURE 1

5.49. Mitigation Measure 1 would involve setting a "cap" on the level of curtailment, above which a financial compensation is paid to generators.

5.50. When the cost of network reinforcement triggered by new connections is shared between DUoS customers and the connecting customer, flexible schemes potentially benefit both.

5.51. The saving for DUoS customers under flexible schemes, suggests that it may be in their interest to share some of the risk caused by uncertainty in the level of curtailment.

5.52. The existence of a compensation payment means that there would be a locational investment signal that could act as a trigger to invest to relieve the constraint.[83]

5.53. If there was a mechanism to offer a flexible connection with a cap on the level of curtailment to the generator, above which a financial compensation is paid, the purpose of the cap would be to reduce the level of uncertainty for the DG with regards to available network capacity accessible to it. This measure would be intended to provide greater certainty for the business models to take to the financers.

5.54. If this option is implemented, there are a number of considerations to take into account.

<u>Assessing the benefit of a flexible connection to DUoS customers and DG</u>

5.55. When reinforcement is avoided through a flexible connection, DUoS customers and DG each avoid the costs they would have incurred under existing cost apportionment rules. The benefit of a flexible connection to DUoS customers and the DG can be assessed by calculating these avoided reinforcement costs.

5.56. Under the emerging business as usual practices, when a DG requests a connection, it may receive both a firm connection offer and a flexible connection offer. The total cost of the connection scheme (including reinforcement and sole-use assets) proposed under the firm offer represents the base case for assessing the avoided costs of the flexible offer (which avoids the reinforcement).

5.57. Historically, DUoS customers have paid on average close to 70% of the costs of reinforcement and DG has paid 30% for those connections that require wider reinforcement.[84] For new connections in 2011 to 2013, approximately 5% of the connections that went ahead required wider reinforcement.

5.58. The potential saving to DUoS customers and DG can be calculated for any connection by comparing the traditional connection offer to the flexible connection. It is important to keep in mind that the cost of reinforcement will vary from site-to-site (as will the exact proportions covered by each party, in accordance with the connection charging principles followed by all DNOs).

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[83] Some concerns have been raised that this mitigation measure has the potential to undermine the price signal to locate generation in the appropriate place. However, such a price signal is inconsequential where the level of constraint changes owing to unforeseen circumstances. In these cases, the risk mitigation provided by this measure is needed.

[84] This refers only to the sharing of the cost of the reinforcement works, which are shared between the DG and DUoS customers according the cost apportionment rules. These rules require the DG to pay for the proportion of the new capacity it will use. DUoS customers pay for the remaining new capacity. The sole-use asset portion of the connection costs are covered entirely by the connecting customer. Likewise, the portion of connection costs exceeding £200/kW (the high-cost cap) would also be borne by the connecting customer.

5.59. The counterfactual for any particular project is whether it would have proceeded in the absence of a flexible connection, and therefore triggered reinforcements. The timing of the avoided or postponed reinforcement is also important.

Setting a cap

5.60. The methodology for determining a cap would need to be clear and transparent to all parties, and the terms and conditions of this cap would need to be specified in the connection agreement.

5.61. Factors to consider when developing mechanism for setting a cap are:

- Curtailment forecast scenarios, which may depend on load growth, load drop, micro-generation growth, profile of generation and demand modification (due to the introduction of storage for example), and known industry policy changes.
- The avoided network reinforcement cost.
- Additional ongoing costs for actively managing the network to avoid the specific constraint.
- The form of the cap itself: what form of the cap facilitates that the payment are cost-reflective of avoided costs and the benefits perceived by the customers. Options include: Average access capacity during a set period (for instance, a year), instantaneous access capacity, cumulative capacity, etc.

5.62. As a guiding principle, the cap should be set at a level that takes into account the benefit already received by the DG as a result of the lower flexible connection cost, as well as the benefits associated with receiving the connection more quickly.

Setting the level of compensation payments

5.63. Additionally, a mechanism for estimating the compensation must be defined. Any compensation scheme should not result in DNOs incurring greater costs on behalf of DUoS customers than would have been the case under a traditional, firm connection. In other words, the total available compensation would be capped at the amount of saving realised by the DNO (on behalf of DUoS customers) as a result of avoiding reinforcement.

5.64. Depending on how the cap is set, a means of measuring actual lost output will need to be put in place. One solution is for generators to provide a power available signal. Such a signal would be validated against the metered output in unconstrained conditions to verify accuracy. A similar concept is already used in Ireland, and has been agreed to be included in the GB Grid Code[85].

5.65. Under this mechanism, the DG would receive the agreed payment for any curtailment above the cap (up to a maximum total amount of compensation).

5.66. A means of ascribing a financial value to the constraint placed on the DG will need to be put in place. The financial value, as well as the maximum available compensation, should be set out in the connection agreement.

5.67. Further work is needed to understand how the compensation should be set, taking into account the risks to DG, DNOs and DUoS customers. This work will need to consider that the financial benefit from which the available 'pot' compensation is derived is linked to capacity (MW), whereas the cost of curtailment to the DG, against

[85] Grid Code Modification Proposal GC0063.

which the mechanism is to provide some mitigation, is linked to lost income (expressed in £/MWh).

5.68. Some options that could be considered are paying compensation under prevailing market conditions or an agreed up-front unit price (based on the network savings, a Contract for Difference strike price, or another agreed amount). Any future work exploring this option should note:

- A value of compensation linked to the market value of the lost energy would not reflect the avoided costs from network reinforcement due to flexible connections. Furthermore, volatility in the electricity market would make it difficult for the DNO to forecast the cost of compensation. In particular, DNOs currently have no presence in the wholesale market, and therefore, no means of hedging to minimise curtailment costs and would, as a result, be exposed to increased risk (on behalf of DUoS customers). This could change in future if DNOs develop a role in balancing the local system in a transition to "DSO" role. From a DG perspective a value that is linked to market conditions would provide greater certainty.

- A fixed (index-linked) value per MWh of lost generation set up front in the connection agreement would protect the DNO and DUoS from any price volatility in the wholesale market.

5.69. The concept needs to be reviewed against relevant codes (e.g. DCUSA and P2/6) by the relevant code panels for compliance issues, including the cash flow involved in funding reinforcements and therefore the theoretical avoided costs. If there are issues, these would need to be addressed through a change proposal.

Action: Workstream 6 (or successor) to take concept to Code Panels.

5.70. The concept should be reviewed by the DG/DNO Steering Group and the ENA ANM working group for technical/commercial feasibility, taking into account emerging learning from existing flexible connections practices.

Action: Workstream 6 (or successor) to take concept to DG/DNO Steering Group.

5.71. The detailed contractual arrangements and technical design (eg communications for the availability signal) would need to be developed by DNO connections teams in partnership with interested DG.

Action: DNO Connection Teams to develop contractual arrangements, once concept has been validated.

MITIGATION MEASURE 2

5.72. Mitigation measure 2 is designed to enable market-based mechanisms to mitigate the risks of DG curtailment and to maximise output, resolving physical constraints through bilateral contracts and load balancing.

5.73. Under this scenario, the market needs to develop to a stage that allows a balancing mechanism to take place at the distribution level. A market-based balancing entity, which could be a DSO or third parties such as aggregators or service providers, would have access to balancing funds and be able to dispatch both flexible load and flexible generation, in order to maximise the outputs and the benefits to the system as a whole. The appropriate regulatory framework needs to be put in place to allow the market to develop in this way. If the DNO is to take on a DSO role, it needs to be able to access balancing mechanisms and to dispatch users in a similar way the current TSO does.

5.74. This option has the potential to make DG projects more bankable and also reduce total system costs, as the mechanisms are geared towards allowing more renewable generation into the system when they would have otherwise been curtailed off.

5.75. One of the possible mechanisms under this option is for the connectee to manage their output in conjunction with a load user, such as storage or DSR, that is connected behind the same constraint. Such arrangements could be managed via the DNO (in a DSO role), an aggregator or any appropriate party operating in the market.

5.76. Under this approach DNOs are likely to need assurance that connectee's arrangements are failsafe. It would be preferable for this approach to be consistent across all DNOs.

Action: ENA DNO/DG steering group to develop consistent approach for mitigation measure 2 across DNOs and consider role of flexibility in supporting flexible connections..

5.77. Alternatively, the DNO/DSO may decide to invest in storage (or DSR) to manage a constrained network, either directly or through procurement via a third party. Potential commercial and regulatory barriers to this were addressed under the services section of this paper.

5.78. While it was not within the original scope of the subgroup to develop recommendations for such a market-based mechanism, the subgroup nevertheless considers that such a mechanism could also effectively address curtailment risk**.**

5.79. There are a number of groups independently investigating flexibility options, such as Ofgem's Flexibility Project and DECC's Smart Energy Team, but not specifically looking at the role flexibility could have in addressing connections on a constrained distribution network.

Action: Groups that are working on system flexibility services, such as Ofgem's Flexibility Project and DECC's Smart Energy Team need to not only consider facilitating the development of flexible services, but also the role of flexibility in supporting flexible connections.

CONCERNS FOR TRIGGERING REINFORCEMENT UNDER FLEXIBLE CONNECTIONS

5.80. Flexible DG connections should not be considered a long term solution for every connection in the network. Currently there is no operational cost signal to inform DNOs where best to invest for facilitating DG connections, whereas the constraint applied to flexible connections could potentially become a proxy for such a signal. Furthermore, the present charging framework (apportionment and high-cost cap rules) typically anticipates a single pre-connection user[86] as the trigger for reinforcement, requiring up-front capital contributions which can represent a very high proportion of the total connection cost. This itself can be a significant hurdle for progression. Flexible connections for multiple users behind a constraint could, with an appropriate contractual framework, form part of a needs case to justify a reinforcement. Such an approach may also spread the cost between a number of users, including those with flexible connection contracts.

5.81. For reinforcement to follow after a flexible connection there needs to be consideration of how and when to trigger and recover the costs of reinforcement. This should be done in such a manner which permits network development and facilitates new connections without adding undue increased cost to existing customers. Specific considerations include:

[86] Or concurrent users, in the case of consortia.

- How to determine when the network has reached a certain level of curtailment which makes it optimal to reinforce instead of continuing to curtail generation.
- Cost recovery, or cost apportionment, from converting flexible customers to firm customers, for example when a subsequent new user triggers a reinforcement which relieves a constraint, or if the existing user specifically requests an upgrade to an unconstrained connection.
- When precisely the trigger for reinforcement is.
- How constraint costs can be linked to reinforcement costs (e.g. annualised and charged post-connection).
- How existing customers behind a constraint can contribute towards a subsequent reinforcement which relieves (or partially relieves) the constraint.
- What the appropriate reinforcement is, e.g. balancing a short-term solution versus a long-term reinforcement rather than performing both.

5.82. Taking into account the above considerations, flexible connection contracts could include a mechanism to set out when and how to trigger and recover the costs of reinforcement. Such a mechanism should permit network development and facilitate new connections.

5.83. The mechanism should avoid adding undue increased costs to existing flexible connections customers. In other words, it should avoid simply moving the 'cliff-edge' of reinforcement costs at some unknown time in the future.

<u>Example of a possible mechanism[87]</u>

5.84. In this example solution, a specific reinforcement is triggered when the value of constrained energy reaches the (annualised) cost of the reinforcement. Constrained energy is measured and valued as set out in the paragraphs above, totalled for all the relevant flexible connection customers, and compared with an annualised equivalent cost for the reinforcement. Once complete, the reinforcement removes the constraint for these generators, who instead pay an apportioned annual charge towards the cost of the reinforcement, which thereafter remains fixed.

5.85. For the generator, the result has a similar effect to 'capping' the constraint. For the DNO, it may be seen to facilitate both flexible connections and efficient longer-term connection solutions.

5.86. The terms of the flexible connection contract could set out the triggering methodology for the avoidance of doubt, and oblige payment of the relevant share of annualised reinforcement charge as a condition for remaining energised.

<u>Next steps for development – Reinforcement cost recovery</u>

Action: Workstream 6 (or successor) to explore how significant reinforcement work is identified. This should include answering the questions:
- How would the most appropriate reinforcement for all parties be identified?
- How specific would the flexible contracts need to be on the reinforcement scheme?

5.87. A clear and transparent methodology is needed for constraint modelling used to trigger reinforcement.

Action: DNO Connection Teams to develop methodology for constraint modelling.

[87] This example is considered in greater detail in the 'Flexible connections paper' annex.

Action: Ofgem to consider how to value constrained energy under flexible connections and use this as an investment signal. This consideration should include: would existing flexible generation, behind a constraint with appropriate contractual obligations in place, sufficiently de-risk a reinforcement investment from the DNO's perspective (for example, if a generator goes out of business)?

5.88. It will be important to monitor the rollout of flexible connection agreements by the DNOs. These are a relatively new form of arrangement and there are still operational and commercial lessons to be learned.

Recommendation: DNOs to ensure that MWh constrained is being recorded in order that this value can be captured. Recording should include when the constraints occur and identify contributory factors.

6. Visibility

Notifying relevant actors

6.1. If a significant[88] volume of actions is taken and DNOs and SO aren't notified, then this could result in networks having to take expensive or radical actions to balance the network. It will also impact a supplier's imbalance and impact them financially.

6.2. The granularity of this technical and consumption data will vary between parties, for example, DNOs may need this data by substation level while suppliers would want to know by grid supply point (geographical area). But both of these would need to be further split by measurement class – suppliers require this distinction for settlement and DNOs for allocation of network charges.

6.3. The data will also vary based on timings, before gate closure this data will be at a high level, i.e. volume and location. But post-event more detail may be needed for settlement and potentially customer billing.

6.4. The exact requirements for data have not been set out in this workgroup but it is clear that changes will be needed to the existing flow structures. The level and type of information exchange will vary between the parties communicating – e.g. the supplier may need to send the DNO metering data and only aggregated read data.

6.5. The exchange of data between the system operators and DNOs will be picked up within the ENA shared services work.

6.6. It is assumed that the DSR provider will receive half-hourly data and will then need to agree with other affected parties on how this data is aggregated when it is passed on to them.

6.7. Current market actors are used to managing multiple data flows between different parties and it is assumed that the current industry and industry party systems will remain capable of processing a similar or slightly large amount of data. If the DSR market grows in size with many third parties involved, managing all of this notification data may become onerous and may trigger the need for an industry intermediary to manage the data flows. This is only likely to be needed if there are greater than circa 20 third parties operating in the DSR market.

6.8. If a customer is unable to deliver the demand response, then this must be measurable so that they are only rewarded for the delivery of a response.

METHODS OF NOTIFICATION

6.9. To prevent negative impacts in terms of system stress or imbalance it is important that there is a network for notifying relevant market participants of DSR actions. Existing and future data networks (such as the DTS and DCC) may be used, as both suppliers and DNOs will already use them.

6.10. It is important that the cost to access these networks is not prohibitively expensive as it may act as a barrier to new entrants, and result in parties potentially bypassing these networks. I.e. broadband could be used for communication, this could reduce the benefits of having a centralised DCC.

[88] See thresholds section for what amount of energy is considered significant

6.11. Where possible, existing methods of communication, including those used for National Grid's balancing services, should be used so as to minimise costs to consumers.

COMPENSATORY PAYMENTS

6.12. A Eurelectric paper[89] considers a process whereby a DSR provider must compensate an affected party (e.g. a supplier placed into imbalance) with either a regulated or a cost-reflective payment. This may act as a barrier to entry and could arguably be managed by the supplier largely through portfolio management and hedging. The view of the visibility group is that this should not be needed as appropriate visibility will negate the need for compensatory payments.

NOTIFICATION THRESHOLDS

6.13. Below are the thresholds for the level of demand reduction or shifting that would need to be notified to the relevant parties – i.e. how much DSR would need to occur to have an impact on their operations. This is caveated as being based on thresholds applied today or a forecast of future thresholds:

- **System operator –** 12MW in England and Wales, 5MW in Scotland[90]
- **Distribution Network Operator –** This will vary between geographical locality and the impacted substations and thus a set notification threshold may not be able to be set. One alternative option might be to utilise the data flows from the smart meters when related to time of use tariffs, generally for domestic and small business customers. This would limit large volumes of new data requirements. However, for the larger customers such as industrial and commercial DSR, a separate notification process would only be needed. One example of a threshold could be around 1MVA for extra high voltage (EHV) connected customers or 200kW for high voltage (HV) connected customers. However, these values are variable and dependent on the configuration and load of the specific site, thus for visibility requirements the DNO threshold will be variable
- **Supplier –** A supplier would need to know any customer actions to ensure the customer is correctly billed and on the right tariff. In terms of impact on imbalance, any shift of circa 1.5% of total volume for a particular settlement period across its entire portfolio would have an adverse impact on a supplier's contracted position. This percentage will show some variation between suppliers.

6.14. These thresholds are important as they mark the point at which DSR can become problematic for the relevant actors. For example, the notification requirements for aggregators may be light touch at first to ensure the market is established, both for incumbent and new entrants. However, after it exceeds the system operator threshold then the notification requirements would increase as its aggregated load becomes more of a threat to network stability and supplier imbalance.

6.15. The difficulty lies in that these thresholds refer to total DSR that will impact the relevant actors. If this is caused by one party then it will be notified if the relevant processes are in place. However, if it is caused by a combination of two or more third parties, then this may go unnoticed. This is an issue only likely to cause a problem

[89] http://www.eurelectric.org/media/169872/0310_missing_links_paper_final_ml-2015-030-0155-01-e.pdf
[90] These figures are in line with notification requirements in the Grid Code

once a large volume of DSR is present, as before this point the low volumes will mean that the potential impact on DNOs and suppliers is likely to be minimal.

Action: In the short term (to 2016), a quick and simple method should be designed for notifying relevant actors when there is a DSR action, both before and post-event. Ofgem should be responsible for delivering this mechanism. Several options exist using existing or **new** mechanisms and these will need to be explored in more detail, so we can design and implement a cost-effective solution. The issue of compensatory payments and whether they should be used can also be considered within this work. This will need to include: in what circumstances would post event notification be required and what additional post event information would need to be shared. In the medium term (by 2020), a wider industry mechanism should be designed for when DSR becomes more common. It is still unknown as to whether and when it will be needed. It would be presumptuous to implement a solution but a specification could be designed in the interim. The responsibility for designing this mechanism should sit with Ofgem.

6.16. This issue and these recommendations apply to Workstream 6 options 2, 4, 5 and 9.

Facilitating commercial agreements

6.17. As part of this work, we have looked at the question of priority between relevant actors where more than one party shares access to a customer's DSR.

6.18. Within this work group an understanding has been established between the SO and DNOs, that the DNO has priority for DSR as their requirements are likely to be location specific and the SO may have other options available. This is caveated up to a certain level of DSR (see thresholds), over which the SO may need some degree of control. This work has commenced under the Energy Networks Association DSR shared services framework.

Action: The ENA shared services framework could be used as a starting point and expanded to include all relevant actors. This is purely a commercial issue with no regulatory implications. Solutions need to be developed to this issue in the short term (by 2016) and industry should take the lead on developing the necessary arrangements.

6.19. This issue and recommendation apply to any solution where different market actors are utilising DSR. It will not be the case where one party manages the DSR interaction with the customer and all other actors are required to work through this lead party.

Load management for network stability

6.20. Aggregators should face as few barriers to entry as possible in entering the DSR market, but the group has considered whether any restrictions to aggregator activities may be required to prevent conflicts, potentially involving licensing aggregators or establishing an aggregator code of practice.

6.21. Ofgem has explored the role of third party intermediaries, including aggregators, and this could be an issue picked up by Ofgem's workstream looking at third party intermediaries. One issue considered was that suppliers cannot offer time of use tariffs in certain load managed areas, without the consent of the DNO. It is important for network stability and to ensure a level playing field that aggregators are held to the same requirements. The DNOs will also be required to notify this data to aggregators in an easily digestible format, possibly via an online database or spreadsheet.

6.22. A method for notifying suppliers of load managed areas may be through a flag in the registration systems for relevant customers. This may be insufficient for customers whose load management varies dynamically, in which case the flag may be the trigger for a supplier to access another system which holds further customer details.

6.23. Another issue considered is when DNOs face a secondary risk where the networks still retain heat after a peak period or have a slightly later peak than the national peak. In these areas delaying peak usage by a few hours could be very problematic. These areas would need to be highlighted to suppliers and aggregators, potentially using flags much like has been suggested for load managed areas above.

6.24. A risk has been identified that DNOs could choose to mark many areas as 'load managed' to avoid reinforcement. This has been deemed a very low risk as DNOs only use this method for small loads and will reinforce over a certain threshold. If a DNO chose to abuse this system it would quickly become evident to suppliers and reported to Ofgem.

6.25. We note that there is a wider issue about licensing aggregators that extends to marketing and selling DSR products, particularly to domestic customers. However, this is outside the scope of this sub-group and falls within the consumer sub-group's remit.

6.26. Importantly, the group noted that licencing aggregators is likely to damage the potential of the growing market which would significantly impact the benefits able to be achieved by DSR.

6.27. This option only applies to a market where significant DSR is contracted for by third parties and aggregators.

Action: Managing DSR in load managed areas for both aggregators and suppliers. The risk of aggregators shifting load in load managed areas will be passed on to Ofgem's working group looking at TPIs. Responsibility for this area sits with Ofgem and should be addressed by 2018.

Action: Additionally, introducing a flag in registration systems so networks can identify customers in areas where the peak happens later, so no aggregator or supplier offers a tariff to that customer that delays peak usage. The registration system(s) could have new 'flags' added to them to highlight the relevant meter points within load managed areas. But a simpler online solution may be required for aggregators. It is proposed that this will be a recommendation from WS6 to be picked up in Ofgem's Target Operating Model work. Responsibility for this area sits with Ofgem and should be addressed by 2019.

6.28. These issues and recommendations relate to options where there is a significant amount of DSR being offered to customers by third parties.

Notification of flexible load installation

6.29. To manage network stress, it is important that when large flexible loads are connected to the network (e.g. EVs, heat pumps etc) that networks are notified. Currently these are only notified to DNOs and not in a consistent or accurate manner, circa 50% of the photovoltaic installation reported to Ofgem are also notified to DNOs[91].

6.30. The DNO will need to know the capacity of the load and its operating window to ensure it can manage this extra load on its network. This process will need to be improved and legislative / regulatory intervention may be needed to achieve this.

[91] One indication is found in UKPN's PV assessment tool reports which analysed UKPN's networks and found this estimated value - see Figure 12: https://www.ofgem.gov.uk/ofgem-publications/93938/pvtoolcdrfinal-pdf

Action: The issue of introducing a way for relevant installation and their capacities to be notified to DNOs affects Ofgem, DNOs and DG. It should be taken forward by Ofgem and DNOs working together. This could involve placing more robust requirements upon installers, possibly by expanding or conglomerating existing notification processes.

6.31. This option, and the one above, are applicable in any world where there are appliances being installed, which are capable for providing DSR.

Risk of information asymmetry resulting in competitive advantage in contracting for DSR

6.32. As set out above, it may be important for suppliers and DNOs to have visibility of customers who are able to provide DSR, for billing purposes and network management respectively.

6.33. It is important to have visibility as it enables each market actor to take the most efficient course of action, such as DNOs using DSR instead of reinforcing and suppliers providing services to customers that can help with their hedging and imbalance management.

6.34. The above point raises a risk of competitive advantage over those market actors who do not have access to this information such as other suppliers and aggregators looking to offer services to DNOs and suppliers. While this may be a regulated DNO activity, there is still competition between different parties who may want DSR availability for different purposes, i.e. network stability versus imbalance management and hedging.

6.35. There may need to be a process to ensure that all parties have access to the same data to ensure a level playing field, otherwise parties with access to a list of a customer's smart appliances and on-site storage / generation will be able to better target customers with DSR offerings. One solution may be that this data is kept in one part of a DNO business for network management purposes but cannot be used when targeting customers for DSR. This is only an issue if the DNO starts contracting directly with domestic customers. though we note that there is nothing preventing DNOs from contracting with domestic consumers now. The view of the group is that this is unlikely as they would most likely to utilise domestic DSR via an aggregator or supplier, though may retain the ability to pay customers for DSR directly.

6.36. This risk could be addressed by requiring information on all 'DSR capable' customers to be made available across all interested parties. However, this would raise a data privacy risk and customers may not want their details available as this may lead to unwanted targeted sales activities.

Action: The aim of this recommendation is to ensure that any DNO information asymmetry does not adversely impact domestic customers. All DNOs could agree to notify and seek input from Ofgem and Citizens Advice before they contract directly with domestic and microbusiness customers. Responsibility for reviewing and approving this action lies with Ofgem / Citizens Advice and is envisaged to be relevant before 2018.

6.37. This issue and recommendation apply to any solution where different market actors are utilising DSR. It will not be the case where one party manages the DSR interaction with the customer and all other actors are required to work through this lead party.

Other finding: Processing of DSR payments to customers

6.38. Payments for DSR services may come in different forms, in that it could be an availability payment, a payment per DSR action or at pence per kWh level – these are some of the options considered within the previous workstream 6 report looking at different types of DSR. These are the views of the subgroup on how these payments could be passed on to the consumer.

6.39. **DNO** - the logical solution for regular payments to residential and small business customers is to go through the supplier bill as suppliers have an existing customer relationship and billing infrastructure. However, we note that the finding of this group is that this shouldn't prevent other billing methods from being used as long as they are easy for the customer to understand.

6.40. It is important that information on bills and payments is transparent and it is clearly visible to the customer how much they are being rewarded for DSR actions. For one-off payments a 'cheque in the post' process may be best, akin to current DNO guaranteed standards of performance payments.

6.41. For industrial and commercial customers DNOs may either have a direct relationship with the customer or choose to go through the supplier or an aggregator.

6.42. **Supplier** – this will need to be included in the customer bill as a separate and easily identifiable line item. The bill will also need to recognise the different types of payments set out in the first paragraph of this section.

6.43. **Aggregator** – the aggregator is likely to be functioning on behalf of, or operating ancillary services, for the DNO, supplier or SO. It will establish a separate relationship with the customer and bill / incentivise them accordingly. In this instance, the presence of two bills carries a risk of customer confusion but billing via the supplier also raises competition concerns as an aggregator would not want a competitor to have access to their data, so for this reason aggregators are likely to bill customers directly.