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Towards a Smart, Flexible Energy System - A call for evidence – Statkraft's Response

Dear Sir or Madam,

Thank you for providing the opportunity to respond to the document "Towards a Smart, Flexible Energy System - A call for evidence" published on the 10th November 2016.

Yours sincerely,
for Statkraft UK Ltd.

Knut Dyrstad
Regulatory Affairs Manager
Wind Power, Technologies and Strategy

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EXECUTIVE SUMMARY

Statkraft welcomes this call for evidence as new technologies and business models are opening up the possibility of more efficient operation and utilisation of the system. The market is already deploying many of the technologies discussed in this call for evidence. Which solutions will be the most successful are still unknown, therefore a policy of creating clarity for investors and developers is crucial to discovering the most efficient solutions. We believe firmly that the flexibility challenge can be solved by the market, ensuring it is equitable and there is information symmetry to deliver the most efficient outcome. In order to fully realise this goal, we believe a two-tiered approach is necessary where in the short-term the following is implemented;

- Clarity for investors is prioritised by ensuring a level playing field between storage and generators. DSO/DNOs and TO need to act as neutral market facilitators, which means that they shall not be allowed to own and operate assets that can also be used on the market. Interconnector capacity needs to be made available to facilitate fair cross-border competition.
- Aggregation of demand-side response by independent aggregators should be possible but not be privileged. Consumers, suppliers and independent aggregators all act in the non-regulated, contestable domain, which means that commercial terms for independent aggregation need to be negotiated freely between the involved market participants.
- Charging arrangements for non-energy charges are amended to exclude charging storage assets
- Clear guidelines are provided to the industry modifications processes so ongoing changes don't pre-empt the outcomes of this process
- Greater transparency and simplicity in ancillary services, the SO needs to progress proposals made in the power responsive workgroup to simplify and provide more information on key revenue streams
- Greater transparency in network congestion and planning at the distribution network. This enables the market participants to offer innovation and provide competition within the regulated network to manage flexibility
- Removal of price caps (£6,000/MWh) and allowing for scarcity pricing to materialise by setting imbalance prices at VoLL-levels in periods of actual physical scarcity (involuntary load shedding)

In the longer term a larger holistic assessment is needed including;

- Network charging and embedded benefits, harmonising the charging regimes at a transmission and distribution level
- Integrating planning and network operation at the distribution and transmission levels, ensuring a level playing field between all participants and favouring a market based solution to integrated constraint and energy management
- How network use of system charging interacts with constraint management and balancing services

- How best to incentivise DNO's to utilise the competitive market for new storage assets to manage constraints on their networks competitively

Introduction

The GB electricity system is becoming increasingly characterised by new low carbon renewable generation. These are intermittent forms of generation that require continued evolution in the arena of flexibility, unlocking the benefits of increased computer power and digital communication networks, and new technologies such as storage.

We believe the GB electricity network will increasingly be dominated by seasonal and intermittent power sources, solar panels, onshore wind and offshore wind. National Grids latest Future Energy Scenarios document envisions a significant build-out of interconnectors, to add increased flexibility to the system. However, we do not believe this will be a complete solution, the value of interconnectors in adding flexibility will vary based on the properties of the market on the other side of the cable. For example, interconnection with Norway will enable access to flexible hydro assets which will allow it to absorb and release power, whereas connections with continental Europe which could see close correlations in wind and solar outputs with the GB system will be able to provide less flexibility.

Energy storage is therefore a key part of the solution as it will be able to absorb solar power during the summer days, when our continental neighbours will also be experiencing high output, and wind power in periods of winter when wind speeds are highest for consumption at peak periods. In order for storage to play this role the key enabler will be investor confidence. This requires a transparent market where information is easily accessible, and network operators seek services from commercial operators in a competitive market rather than seek to own these resources themselves.

It is important to note that renewable generation not solely represents a burden in a smarter more flexible market; renewables power sources such as wind farms can make a significant contribution to the flexibility of the energy system in its own right and in addition to the potential for co-location with storage. With regulatory and market changes, renewable generation is technically able to offer numerous ancillary services; for which the industry and Government are agreed demand will grow significantly over the next few years and into the long-term. Renewable generators are in many circumstances likely to be highly competitive and able to offer extremely flexible response, in some cases outcompeting traditional flexibility service providers, it is therefore imperative that this call for evidence considers explicitly how to open these markets to renewable generation.

The section below provides responses to the individual questions contained within the call for evidence.

Enabling Storage

Battery storage has lots of potential applications and relative success in different segments will in a large part depend on the interface between declining capex costs and the competitive drivers of price discovery across the different markets that can offer revenue (ancillary services)

Question 1

Have we identified and correctly assessed the main policy and regulatory barriers to the development of storage? Are there any additional barriers faced by industry?

Deployment of batteries in the Capacity Market and the Enhanced Frequency Response (EFR) tender indicate the market is keen to deploy storage in the GB market. Statkraft believes the key barrier to deployment is a stable investment environment.

Main barriers identified by the call for evidence

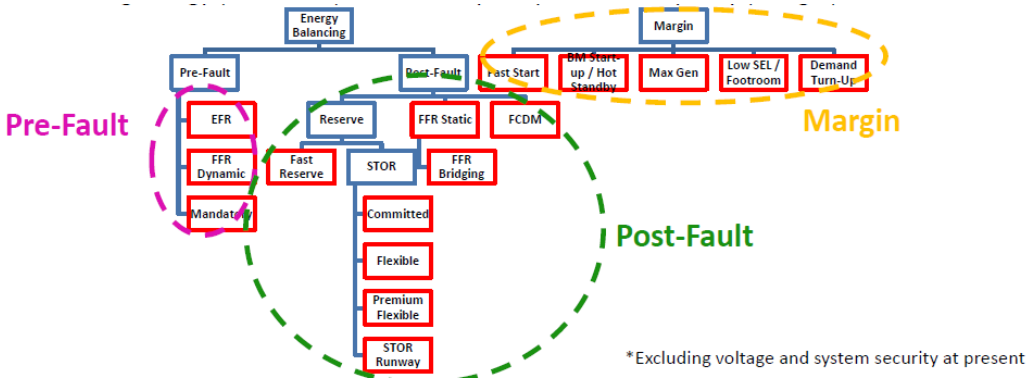
1. Network connections
2. Network charging
3. Final consumption levies
4. Planning; and
5. Regulatory clarity

The key to this will be unlocking long-term signals; to date these projects have relied on contracts with the system operator in ancillary services or through the Capacity Market. EFR, which has a limited envelope, provides four year contracts, other frequency or reserve contracts provide nothing longer than two years. There remains considerable uncertainty around EFR as it is not known whether another tender will take place. Short-term markets within a stable and predictable framework are also required for EFR and FFR to support a competitive market.

In ancillary services or balancing services, we will point to simplification of the range of products and balancing services to ensure assets can pursue long-term revenue streams in these markets This is essential, especially given long-term paybacks. We note National Grid has committed to simplifying its ancillary services as part of its Power Responsive work group[1] as illustrated in figure 1. In order for this solution to realise its full potential it needs to be accompanied by greater transparency from the SO in its procurement activities and value for money. Of key concern, here is the bilateral contracts National Grid has signed with providers without running an open and transparent procurement process, such as Firm Frequency Response, Frequency control by Demand Management (FCDM), pre-EFR or Black Start.

[1] www.powerresponsive.com/wp-content/uploads/2016/12/SWG-MasterSlideDeck.pdf

Figure 1: Simplifying Ancillary Services



Source: National Grid

Question 2

Have we identified and correctly assessed the issues regarding network connections for storage? Have we identified the correct areas where more progress is required?

Further transparency in the connection process, provision of information about spare capacity and the local requirements for reinforcement are essential and will help to unlock the value of flexibility and especially storage. We note that the current heat maps produced by the DNOs are insufficient for these purposes. We would prefer to see a standardised tool across all DNOs which would enable developers to access the DNO connectivity systems and determine the degree of spare capacity in certain locations under different system conditions. If more information is provided to the market and a system that allows market providers to offer alternative solutions to capacity than network reinforcement, this could ultimately provide savings to the end consumer.

Investor confidence can be strengthened with the appropriate queue management for storage by the distribution networks. However not all storage is the same, for example assets with EFR contracts could be importing over peak times to maintain themselves within the dead-band while projects undertaking peak-off-peak arbitrage are unlikely to be importing over these hours.

It is worth noting that a proposal for the I-SEM (Irish Single Electricity Market) is to give priority in the connection queue to assets which can provide balancing services[2]. At this stage, we do not believe this is required within the GB market and instead the focus should be on ensuring the price signals are there for providers of flexibility.

Question 3

Have we identified and correctly assessed the issues regarding storage and network charging? Do you agree that flexible connection agreements could help to address issues regarding storage and

[2] www.cer.ie/docs/001060/CER16284%20Transitional%20Arrangements%20-Decision.pdf

network charging? Please provide evidence to support your views, in particular on the impact of network charging on the competitiveness of storage compared to other providers of flexibility.

Clarity for investor confidence would best be served by defining the treatment of battery storage in relation to the p2/6 engineering requirement about the definition of intermittent and non-intermittent and importantly this needs to be treated consistently across DNOs. Currently it is up to the individual DNO to decide on the tariff treatment which is detrimental to providing investor certainty. We would argue giving consistent signals to storage is important to incentivise the right behaviour; therefore, the best solution is to define storage as non-intermittent under the current rules.

The DCP268 proposal facilitates a transition to half-hourly (HH) settlement for non-half hourly (NHH) customers by moving to a time band charging basis, based on the HH (profiled) data used in settlement. This will overcome this issue at the CDCM level as it proposes all generators receive the RAG time bands and reflect use of network costs; however, there is no proposal on how to treat storage at the EDCM level.

The issue of double charging for the fixed capacity element of the charging methodology needs to be resolved; we believe storage should only be charged once for the fixed capacity.

Question 4

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

Storage will be beneficial to network operators by reducing the need for reinforcement and delivering options around active network and constraint management. Network operators should be able to use storage but should procure it from third parties.

We think that network companies should not own storage as this has the potential to limit its application to the licence objectives. Storage is a flexible resource able to provide different system services and in our view private sector parties are best placed to develop storage so that it may take advantage of revenue stacking, and to ensure that the full extent of the benefits of innovation are thus realised. We agree with the European Federation of Energy Traders[3] when they state that 'should DSOs have an interest in accessing storage capacity to perform their duties of system balancing and system security, they can contract this capacity directly from market participants'.

[3] http://www.efet.org/Cms_Data/Contents/EFET/Folders/Documents/EnergyMarkets/ElectPosPapers/~contents/2882VG6WHLGKYUGL/EFET-paper_DSOs-and-storage_21102016.pdf

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Further though needs to be given as to how to properly incentivise the DNO's to contract with energy storage, under the current regime DNOs would see a reduced capital expenditure from contracting with storage instead of reinforcement as it would retain a portion of the savings, this incentive would reduce as the DNO approached the end of its price control as there would be fewer savings to access. Storage could also reduce constrains through active network management, while this would benefit constrained generators within the local region, there is no current financial incentive for the DNO, we would recommend a new incentive is placed on DNOs to reduce constraints on their network where appropriate. Storage could also potentially reduce the money spent by DNO's through the Customer Minutes Lost (CML) incentive, and some sort of insurance product against network failure could be offered to storage which can help reduce network outages.

Question 5

Do you agree with our assessment of the regulatory approaches available to provide greater clarity for storage?

We believe there are pros and cons to specific storage licenses, and would prefer a cautious approach which minimises the impact on storage business models and provides certainty to investors.

> Regulatory treatment of Storage – Option B
> Define storage as a subset of generation in a modified generation licence (no primary legislation required). Ofgem could introduce a modified generation licence specifically for storage facilities (in consultation with industry). Under this option storage could only operate under this modified licence or a licence exemption. A modified generation licence could take account of the non-generation aspects of storage.

The key benefit of storage licencing would be to provide certainty to investors by inclusion in legislation, as well as allowing charging arrangements to separate out these assets. However, there is also the concern licensing may restrict innovation through proscriptive requirements and complexities in managing code responsibilities. Storage licensing should be light touch, with minimal requirements for grid code, CUSC or BSC membership. A model similar to the one used for generation, with licence exemption for storage not connected directly to the public network. Grid scale energy storage projects would then need a storage licence while smaller scale non-domestic or domestic storage devices connected at customer sites would be exempt. We believe option B is the closest solution to our desired approach. It is also worth considering that large scale storage has the potential to manipulate the market price through its operation. Any storage licence code would need to ensure this is captured, while adhering to REMIT requirements and the regulatory authority has the ability to act quickly.

Some of the barriers identified, such as the double charging for the RO, CfD, SSFiT and Capacity Market can be dealt with within the charging arrangements themselves as storage sites could be defined with the charging guidance and specifically exempted. This could represent a quicker solution than potentially long and complicated design of a storage licence.

In the short-term we believe that a simple accreditation scheme could be implemented to track and monitor storage developments behind the meter. This will help to monitor behind the storage development and in future assist with any storage licence roll out.

Question 6

Do you agree with any of the proposed definitions of storage? If applicable, how would you amend any of these definitions?

We agree with the ESN definition of Electricity Storage.

Aggregators

Question 7

What are the impacts of the perceived barriers for aggregators and other market participants? Please provide views on balancing services, extracting value from the balancing mechanism and wholesale market, other market barriers and consumer protection. Do you have evidence of the benefits that could accrue to consumers from removing or reducing them?

We believe Balancing Mechanism (BM) revenue is incidental to the business case for DSR aggregators, which historically have relied on access to balancing services revenues. The BM is difficult to enter and does not provide a high degree of revenue certainty for prospective customers wishing to get into fixed length contracts. In addition there are the complexities around forecasting FPN requirements and how grid can have confidence in dispatching DSR in the BM. Reforming the BSC at this stage is potentially a distraction, allowing aggregators direct access to the BSC would be complicated however if this were to go ahead we believe aggregators need to compensate suppliers for any imbalance caused by the activity of the aggregator, letting these market participants decide on the level of compensation between the parties and not requiring regulatory interference. Without this compensation, the suppliers would bear the cost of DSR with the danger of seeing end-consumers' bills increasing It would be better to focus on the simplification and increased transparency of the SO's ancillary services as outlined in question 1.

It is worth noting the winter package published by the European Commission in November 2016[4] contains provisions for Member States to define framework for independent aggregators and for demand response along principles that enable their full participation in the market. The package notes that derogations to fundamental market principles such as balancing responsibility act as a barrier to development of flexible solutions, as such aggregators must be responsible for any imbalance caused by their operation. We believe this is a positive step forward although there are a number of surprising omissions. Exempting

[4] https://ec.europa.eu/energy/en/news/commission-proposes-new-rules-consumer-centred-clean-energy-transition

independent aggregators from normal wholesale and retail market disciplines regarding imbalance settlement (art. 17.4) and deeming aggregators immune from claims for compensation following load shifting activation (art. 17.3 (d)) adds distortions to free price formation rather than removing them.

Project TERRE (the Trans European Replacement Reserves Exchange) has already produced proposals which will allow market access for DSR participants without being suppliers, under the P344 modification the proposal is to create virtual BM units which can participate in the TERRE platform. However, actions in the TERRE platform will adjust suppliers' imbalance positions and compensation will need to be agreed between suppliers and customers/aggregators, the preferred approach of the working group is for contractual arrangements to be defined bilaterally between suppliers/aggregators/customers.

In addition, we would identify Third Party Intermediaries (TPIs) as a barrier to greater aggregation in the non-domestic market, TPIs act as gatekeepers to many customers in the electricity market where they act on behalf of customer in their relationships with suppliers, and many offer additional services including DSR. We believe greater clarity on the role of the TPI in delivering DSR is required.

Statkraft supports the position of the European Federation of Energy Traders[5] all parties that can bring liquidity and value to the market should be allowed to participate freely and on a level-playing field and supports bilateral arrangements between parties.

Question 8

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

We believe there is some merit in exploring the concept of regulating aggregators through a licence or a General Authorisation Regime (GAR) as there is currently an un-level playing field between unlicensed and unregulated aggregators who can contract directly between customers and National Grid avoiding the energy market in-between and having knock on effects on the supplier, which can result in increased costs to consumers. If this is the case, then it is also worth considering if generation and storage should be able to aggregate units into virtual BM units for participation in the BM.

Question 9

What are your views on the pros and cons of the options outlined in Table 5?

We agree with the summarised pros and cons in table 5.

[5] http://www.efet.org/Cms_Data/Contents/EFET/Folders/Documents/EnergyMarkets/ElectPosPapers/~contents/GGH299HP5MPZQ5T5/EFET_Free-formation-of-prices-power-market.pdf

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Question 10

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

We agree there is a risk of simultaneous load switching causing voltage and frequency issues on the wider system; however, we are not concerned this is an immediate issue as now most load reduction is delivered through ancillary services where the reduction is made at the discretion of the SO and through Triad Response. There is no evidence to suggest load shedding to reduce demand over Triads has caused any system wide issues. Another potential risk we would highlight is the risk of feedback loops where actions taken by the SO can cause DSR or unlicensed generators to act in real time in response, which causes National Grid to take actions in the opposite direction, which turn signals flexible providers to reduce their response, and so on, which ultimately results in increased costs for the consumer and potential system instability.

System Value Pricing

Question 11

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

In the generation and non-domestic DSR markets Statkraft believes the key enabler would be the standardisation, simplification and open transparent procurement process to enable flexibility providers to access revenues in the most efficient manner. This should include market platforms that enable participants to see what services are being procured, in what location, so they know what the market is for their asset. In addition post-delivery reporting is essential to ensure participants can understand the value achieved and available in the market.

In the domestic market, smart metering and half-hourly settlement is going to be the key enablers, but it is proving more expensive and taking longer to achieve than originally anticipated. It may be appropriate to step back and assess the process being made and what lessons can be learned from other markets and industries, such as telecommunications.

Question 12

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

As a developer, operator and trader Statkraft can provide a range of flexibility services to the Grid and into the wholesale market on behalf of itself and assets it operate under Power Purchase Arrangements. The Figures 3, 4 & 5 in the appendix summarise which ancillary services, embedded benefits and wholesale market revenues can be stacked together and provides an illustration of business models for flexible generators and storage.

The main barrier to providing investors of flexibility with the correct signals is the lack of transparency and complexity that exists around the ancillary services market. We believe there should be a level and clear playing field within the ancillary services, offering short and long-term opportunities across all the services for the market to deliver the least cost solution.

Question 13

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

As a developer and operator of renewable resources we would be able to provide a number of flexibility services which are currently unvalued. This includes voltage support through the reactive power equipment which is required to install on site, however at present DNOs do not value reactive power provision and the SO only makes use of the mandatory reactive power service. It is also possible for the power system electronics of wind farms to provide synthetic inertia. A study of the Swedish system showed wind farms were able to increase the minimum frequency during a loss of production and prevent load shedding[6]. Although there were some concerns that use of synthetic inertia put higher demand on primary reserves, we believe synthetic inertia could reduce costs to consumers of reducing conventional inertia.

Question 14

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

We believe the DNO should be tendering for flexibility services, this would be a vital part of opening up the market and achieving efficient outcomes, however this is linked closely to the outcome of the DNO-DSO transition.

Smart Tariffs

[6] www.elforsk.se/Rapporter/?download=report&rid=13_02_

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Question 15

To what extent do you believe Government and Ofgem should play a role in promoting smart tariffs or enabling new business models in this area?

Benefits from smart tariffs are being hindered by the limited smart meter roll out and half hourly settlement migration. Ofgem and government should consider other options to speed up the roll out, such as prioritising certain areas. Ofgem also need to focus on the supply chains and financing issues that are delaying roll out.

Question 18

Do you recognise the reasons we have identified for why suppliers may not offer or why larger non-domestic consumers may not take up, smart tariffs?

No, Large non-domestic consumers are effectively on smart tariffs already, in their contracts many of the Time of Use specific charges are “passed through” straight to the consumer and the supplier usually acts as a billing engine providing access to wholesale power. These consumers already see price signals and respond as can be witnessed by the GW’s of response Grid estimates it receives from Half Hourly billed consumers under the Triad charging methodology.

Smart Distribution Tariffs

Question 19

Are distribution charges currently acting as a barrier to the development of a more flexible system?

Uncertainty around the future of the embedded benefits regime is a significant barrier to investors looking to develop assets in the flexibility space.

We think ultimately that an alignment of network charging models between transmission and distribution networks would be helpful. Distribution charging models should be the exemplar, with genuine, locational and site specific charging being adopted as the key plank of new network charging arrangements. Whilst this may see the loss of Triad benefits (for example) this may be compensated for through locationally reflective pricing, even if this does not imply we see it as justified to remove triad benefits or wider embedded benefits in isolation. A revised network charging model should address the disparity between connection charges on the transmission and distribution systems. Distributed generators face “deeper” connection charges which means higher up-front costs compared to connections at the transmission system; this should be reviewed as part of Ofgem’s embedded benefits work stream.

Question 20

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

A holistic review of the embedded benefits regime should be undertaken as soon as possible; in addition to this the regulator and government should publish some guidelines for any code modifications which are proposed in the mean-time in order to avoid making any changes which then have to be reversed.

Question 21

How problematic and urgent are any disparities between the treatment of different types of distribution connected users?

We are not concerned that embedded generators receive payments for their exports onto the network through the distribution charging methodologies, because embedded generators offset required investment in the network over the long-term and should be rewarded.

Question 22

Do you anticipate that underlying network cost drivers are likely to substantively change as the use of the distribution network changes?

No response provided

Question 23

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

Statkraft believes, that in the absence of a DSO actively managing its network a mix of short-term and long-term signals through volumetric and capacity charges are an appropriate way to signal the correct investment decisions, as network reinforcement deferral is best signalled through long-term capacity charges whereas short-term issues such as constraints and peak demand are best signalled through volumetric charges.

Where the DNO is undertaking a local balancing function through active network management it would not be appropriate to use the distribution charging methodology to recover those costs, as under current regulations costs have to be fixed 15 months in advance, therefore this could lead to increased costs to

consumers. In this case it may be appropriate to adopt a methodology closer to the Balancing Services Use of System (BSUoS) charging method where an incentive is set and recovered by the DNO from all users. In addition, care needs to be taken to ensure that any volumetric charges do not result in undue burden on participants unable to provide a flexible response.

Question 24

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

In terms of the market frameworks for DSO/SO and market interaction outlined on page 80 of the call for evidence we would prefer a market led approach. So, the model where DSO and TSO compete for the same resources would be preferable. This necessitates in our view a common platform for service procurement across the whole market, removing the distinction between transmission and distribution connected participants.

Other government policies

Question 25

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

A major obstacle in the deployment of flexible power solutions is the approval of CUSC modification proposals 264 and 265, these modifications would remove and/or reduce the Triad benefit from distribution connected projects. In addition modifications 271 and 274 would affect behind the meter and DSR operators by changing the way the TNUoS residual is recovered. These modifications have caused significant uncertainty during their progression ahead of the Capacity Market auctions, and are significant stumbling blocks to providing investor certainty in this market.

The most appropriate way forward would be to include changes to Triad embedded benefits as part of Ofgem wider review into embedded benefits in 2017, ideally this should be result in a Significant Code Review, because of the scale of inter-dependencies involved in the connection charging methodologies. Special consideration should be given to renewable projects which co-locate with storage or can provide flexibility above the current generation of assets in the proposed emissions reduction plan slated for early 2017.

Further uncertainty is being introduced into the Capacity Market by rules change proposals which seek to amend the testing regime for all Capacity Market Units (CMUs). There are nine rules change proposal which will affect the satisfactory performance test all CMUs have to perform in order to receive their CM payments.

Now, the CMU has to demonstrate it can meet its de-rated capacity obligation over three separate half hourly periods during the delivery year. The proposals include changes to increase the satisfactory performance test up to eight settlement periods; this is of considerable concern to developers of batteries which have been designed with half hour delivery periods in line with FFR and EFR. Another proposal (CP176 from EDF) would create a new definition within the rules which would scale the availability factor of storage based on the duration of the asset and the already committed storage capacity of that duration. This could introduce considerable uncertainty into forecasting outturn capacity market prices because of the increase in variables and become a barrier to entry.

Question 26

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

We would argue that the Capacity Market is currently bringing forward new flexible resources such as DSR and Battery storage. Consideration needs to be given to how storage is treated within the Capacity Market as duration of response needs to be aligned with the requirements of the system and there are a number of proposals being made to change the rules which could act as a barrier to the current generation of small scale storage solutions in the Capacity Market.

Question 27

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

The Emissions Reduction plan slated for early 2017 needs to account for the ability of renewable generation to provide synthetic inertia and voltage reduction, these schemes should be encouraged to provide flexibility services to the system and any changes to the support schemes should recognise it. Any barriers to the co-location of storage with renewable generation should be addressed, it is essential that renewables and storage together can access revenues such as the Capacity Market and the CfD without interference from the other. Clear guidance like that given by BEIS for storage within the CfD would be useful for all schemes such as the Capacity Market, RO and SSFiT.

Network Operation – roles and responsibilities

Question 43

Do you agree with the emerging system requirements we have identified?

We agree with the merging system requirements identified in the call for evidence.

Question 45

In regards to the need for immediate action;

a. Do you agree with the proposed roles of DSOs and the need for increased coordination between DSOs, the SO and TOs in delivering efficient network planning and local/system-wide use of resources?

b. How could industry best carry these activities forward?

c. Are there any legal or regulatory barriers (e.g. including appropriate incentives), to the immediate actions we identify as necessary?

Statkraft agrees what DNOs/DSO should take more active approaches in managing and planning the wider network. In the short-term more transparency needs to be delivered at all levels of the network on congestion and connections so that market participants are receiving the correct signals about where to invest.

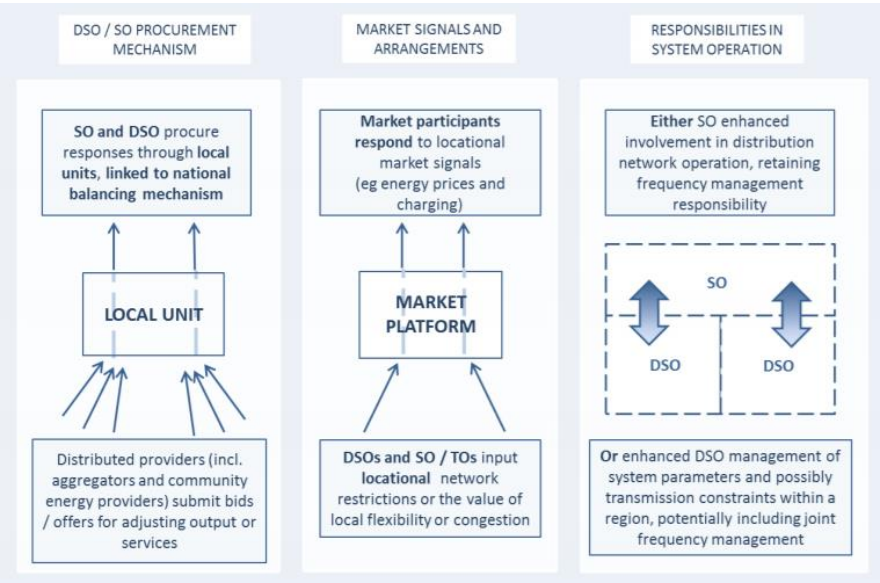
Question 46

With regard to further future changes to arrangements:

a. **Do you consider that further changes to roles and arrangements are likely to be necessary?**
b. **What are your views on the different models?**

Statkraft agrees with the proposed role for DSO actively managing network – it is key that they procure services through open and transparent tender or auctions which allow greatest access for all market participants to achieve the most efficient outcomes. However, this will not be a short process will require detailed government intervention to achieve this goal and cannot be left solely to industry to move forward.

Figure 2: Illustrative range of potential models for further changes to arrangements to support efficient use of local/system-wide resources



Source: Smart, Flexible Energy System – Call for Evidence

Comparing the models in figure 2, the preferred option would be to use the Market Signals and Arrangements model where market participants signal their ability to provide flexibility to a market (DNO/ DSO and SO/TO) or their requirements for services on a locational or national level.

Though needs to be devoted to how this approach dovetails with the existing and proposed charging regimes for losses, use of system charges for network use, capacity market and other third party charges as they could be sending conflicting signals to participants and resulting in increased costs.

Appropriate incentives and cost recovery schemes will need to be designed, the Balancing Services Incentive Scheme provides National Grid's SO function with the incentive to manage the system efficiently however it is difficult to forecast and provide poor signals to market participants about future costs. It is worth noting that uncertainty and volatility in the distribution charging models have increased consumer costs as suppliers over recover to mitigate the risk of unforeseen changes in charges.

Other issues not addressed in flexibility call for evidence

Emissions

Thought needs to be given to the carbon intensity of projects which can provide flexibility, government schemes such as the capacity market has encouraged diesel reciprocating engines to become the de-facto providers of flexibility while black start and BM-Start up payments have kept coal online to provide margin on the system. Correct pricing of carbon needs to be maintained and low-carbon sources of flexibility such as electricity storage and interconnectors that can offer green options should then be encouraged.

Interconnector issues

Statkraft is concerned that interconnectors only receive only two mentions in the consultation, as National Grid considers them to be a key linchpin for future electricity supplies according to the latest Future Energy Scenarios. Interconnectors will be able to provide flexibility, based on the correlation between the neighbouring market and conditions in GB, and connections with markets that have abundant and renewable flexibility, such as Norway should be prioritised. Interconnectors are also able to provide other important system services such as frequency control, black start and reactive power[7] and these services need to ensure there are no barriers to their entry.

It is also worth noting that Brexit and a lack of clarity on the future role of the UK in the European Energy System poses a risk of damaging the equitable basis approach to energy market integration and could potentially focus the UK market on self-reliance resulting in an increase in consumer costs. ICIS reported on 5 January[8] that developers of interconnectors are pushing back investment decisions, with investors adding risk premiums to investments because of Brexit. This pushes back the date at which interconnectors will be connecting to the system and increasing costs through provisions of more expensive forms of flexibility.

[7] https://www.ofgem.gov.uk/ofgem-publications/93802/ngetreporttoofgem-qualitativeinterconnectorbenefits-pdf.
[8] http://www.icis.com/resources/news/2017/01/05/10067884/uk-interconnector-focus-brexit-risks-stalling-cable-blitz/?cmpid=SOC%7CRSS%7Cjamie%7Cstewart

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APPENDIX

Figure 3: Example business model for a peaking plant

Figure 4: Example business model for energy storage

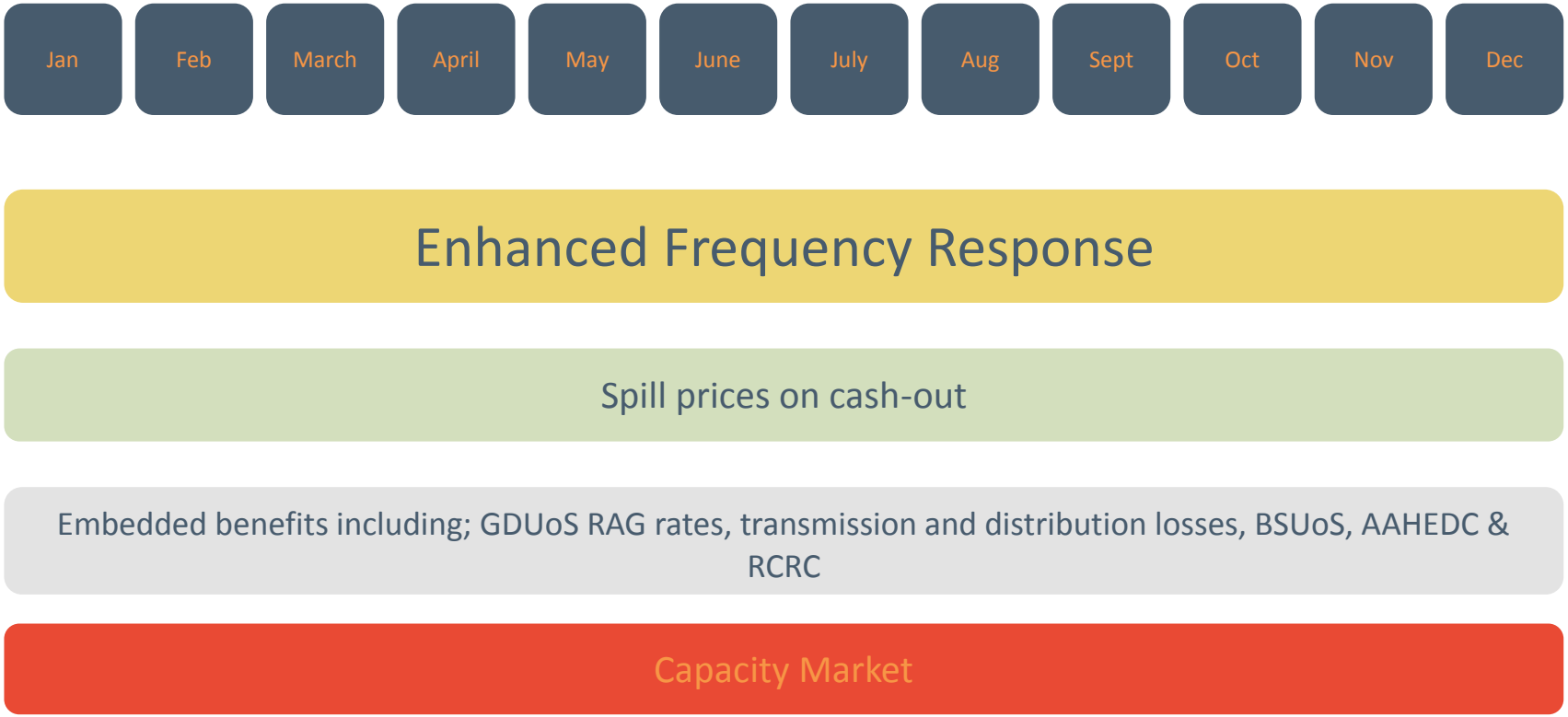

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Figure: 5 Revenue stacking

Scheme	EFR	FFR	STOR	Fast Reserve	Black Start	Capacity Market	TNUoS	Transmission Losses	BSUoS	RCRC	AAHEDC	Capacity Market supply charge	GDUoS	Distribution Losses
EFR	N/A	Not during same hours	Not during same hours	Not during same hours	Not during same hours	Not a schedule 4 balancing service.	Yes if utilised over Triads	Yes (locational & season specific)	Yes	Yes	Yes	Yes if utilised over charging period	Yes	Yes
FFR	Not during same hours	N/A	Not during same hours	Not during same hours	Not during same hours	Yes	Yes if utilised over Triads	Yes (locational & season specific)	Yes	Yes	Yes	Yes if utilised over charging period	Yes	Yes
STOR	Not during same hours	Not during same hours	N/A	Not during same hours	Not during same hours	Yes	Yes if utilised over Triads	Yes (locational & season specific)	Yes	Yes	Yes	Yes if utilised over charging period	Yes	Yes
Fast Reserve	Not during same hours	Not during same hours	Not during same hours	N/A	Not during same hours	Yes	Yes if utilised over Triads	Yes (locational & season specific)	Yes	Yes	Yes	Yes if utilised over charging period	Yes	Yes
Black Start	Not during same hours	Not during same hours	Not during same hours	Not during same hours	N/A	Yes	Yes if utilised over Triads	Yes (locational & season specific)	Yes	Yes	Yes	Yes if utilised over charging period	Yes	Yes
Capacity Market	Not a schedule 4 balancing service.	Yes	Yes	Yes	Yes	N/A	Yes	Yes (locational & season specific)	Yes	Yes	Yes	Yes if utilised over charging period	Yes	Yes
TNUoS	Yes if utilised over Triads	Yes if utilised over Triads	Yes if utilised over Triads	Yes if utilised over Triads	Yes if utilised over Triads	Yes	N/A	Yes (locational & season specific)	Yes	Yes	Yes	Yes if utilised over charging period	Yes	Yes
Transmission Losses	Yes (locational & season specific)	Yes (locational & season specific)	Yes (locational & season specific)	Yes (locational & season specific)	Yes (locational & season specific)	Yes (locational & season specific)	Yes (locational & season specific)	N/A	Yes	Yes	Yes	Yes if utilised over charging period	Yes	Yes
BSUoS	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	N/A	Yes	Yes	Yes if utilised over charging period	Yes	Yes
RCRC	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	N/A	Yes	Yes if utilised over charging	Yes	Yes

AAHEDC	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	N/A	period Yes if utilised over charging period	Yes	Yes
Capacity Market supply charge	Yes if utilised over charging period	Yes if utilised over charging period	Yes if utilised over charging period	Yes if utilised over charging period	Yes if utilised over charging period	Yes if utilised over charging period	Yes if utilised over charging period	Yes if utilised over charging period	Yes if utilised over charging period	Yes if utilised over charging period	Yes if utilised over charging period	N/A	Yes	Yes
GDUoS	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	N/A	Yes
Distribution Losses	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	N/A