S&C ELECTRIC COMPANY
Excellence Through Innovation

Brunel Park, Brunel Way,
Baglan Energy Park,
Neath.
United Kingdom.
SA11 2FP

Judith Ross and Andrew Self
Energy Systems
Ofgem
London
SW1P 3GE

Our Ref: 5 May 2017

Dear Judith and Andrew,

S&C Electric Company response to the Embedded Benefits Minded to Decision Consultation and the Target Charging Review Consultation

S&C Electric Company welcomes the opportunity to provide a response to the Embedded Benefits Minded to Decision and the Targeted Charging Review Consultation.

S&C Electric Company has been supporting the operation of electricity utilities in the UK for over 60 years, while S&C Electric Company in the USA has been supporting the delivery of secure electricity systems for over 100 years. S&C Electric Company not only supports "wires and poles" activities but has delivered over 8 GW wind and over 1 GW of solar globally. S&C Electric Company has been actively engaged in deploying Battery Energy Storage Systems since 2006 providing a full range of services and using a range of battery technologies and currently has 76 MW/189 MWh in operation, including the UK Power Network's 6 MW/ 10 MWh battery that provides local peak load support and frequency services to National Grid, the GB system operator.

S&C Electric Company are particularly interested in facilitating the development of markets and standards that deliver secure, low carbon and low cost networks and would be very happy to provide further input to Ofgem on the treatment and potential of these technologies.

Yours Sincerely

C. Watts

Chris Watts
Regulatory Affairs Director, EMEA

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Introduction

The UK Electricity System is in transition, moving from the traditional model of large centralised generation, percolating through the transmission and distribution networks to inflexible demand at the base of the system to a distributed model where intermittent generation is largely connected to the distribution system, resulting in power flows “up” the system and encouraging new approaches to managing energy, by operators, customers and new businesses.

Ofgem and the UK Government has sought to encourage and promote this new distributed model, incentivising rooftop solar PV generation and large-scale intermittent generation deployment and the UK has responded enthusiastically to the opportunities on offer. This has resulted in challenges in managing networks at both the transmission and distribution level and Ofgem have supported a number of critical innovation projects to allow network operators to use innovative approaches to managing these challenges. This has led to distribution Network Operators (DNOs), in particular, responding by becoming more active in their approach to their networks.

Ofgem has led a number of studies and consultations on Flexibility, Non-Traditional Business Models, participated in the Department of Energy and Climate Change (DECC, now the Department for Business, Energy and Industrial Strategy, BEIS) and Ofgem Smart Grid Forum, exploring how to deliver the smart grids of the future and is currently exploring the Smart, Flexible Energy System through a joint consultation with BEIS.

Additionally, National Grid, the Transmission System Operator (TSO) is very actively exploring demand side response, through its Power Responsive campaign (http://powerresponsive.com/), strongly supported by Ofgem. It is therefore no surprise that the charging arrangements that were designed for the traditional model are not fit for purpose in the emerging distributed model.

It should also be noted that there are many incumbents with established traditional business models who do not and will not benefit from the new distributed model. The new smart and flexible approach will not suit all participants in the system and Ofgem need to take great care, that in addressing the needs of incumbents following traditional business models, that the approaches needed to deliver the low carbon, secure and low cost electricity system of the future are not either stifled or destroyed.

We would agree that the current charging arrangements are not fit for purpose and would strongly support a Significant Code Review, which is preferable to piecemeal changes in response to individual concerns (e.g. CMP 264 and 265 and DCP 228, the latter significantly reducing the price signal to move demand, which seems contrary to a desire for an active demand side response), to ensure that we holistically achieve a charging regime that delivers national goals for our future energy system and reducing risks of unintended consequences and higher costs.

If a Significant Code Review is to be undertaken the program of work should encompass as many of the issues the new system raises as possible, to ensure that uncertainty is minimised, recognising that a balance needs to be struck between complexity and time to deliver a decision.

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Additional Comments

The Role of Residual Charges

Long-run incremental costs do not fully cover the allowed revenue for DNOs or TOs under the RIIO price controls so additional top-up or residual charges are required to recover the balance of allowed revenues so that the utilities can achieve their allowed returns. This, and other supplemental charges, can potentially be distortionary. General economics would suggest that the best way to recover such costs is through a two part tariffs combining a fixed and a variable element. This would give a better outcome than a purely volumetric approach such as Ramsey pricing (giving proportionally higher charges for those with more inelastic demand). Care is needed to ensure that chopping and changing elements of the residual charge in a piecemeal way doesn't actually create something even more distortionary than we have at present.

The appropriateness of charging arrangements should to be assessed as a whole rather than treating the forward-looking charges and the top-up residual charges as separate elements. Forward looking charges are likely to change through the wider work on flexibility and this could have major implications for the amount of costs flowing through the residual element.

Embedded Benefits Minded to Decision

We understand Ofgem's rationale for its minded to decision on the proposed changes to the transmission residual charges (TDR) and embedded benefits. These charges are a top-up that recover sunk historical costs, which by their nature cannot be altered by individuals using the system differently such as calling on distributed generation to offset demand. They are not intended to create locational price signals. However, the process for the minded-to-decision and timing of the implementation of changes to embedded benefits is of concern given the scale of the change and because it is taking place when markets for flexibility, which should ultimately provide alternative revenue streams, are still at a very early stage of development.

The loss of revenue based on current embedded benefits of £45/kW (expected to rise to £72/kW) can therefore have a significant impact on the economics of electricity storage. It is of concern that there are potential impacts such as creating investment uncertainty and lengthening timescales for the penetration of grid electricity storage which don't appear to be fully recognized. Such changes would be better considered as part of a wider network charging review and as part of the development of markets for flexibility resources, that are able to fully recognise the benefits of distributed resources such as electricity storage as well as the economics underpinning the charging arrangements.

There are concerns that removing the embedded benefit outside of any holistic review (the current minded to position in response to CMP 264 and 265) that the real and beneficial impact that the TRIAD approach has secured in reducing winter peak demand may be reversed as that price signal is lost, leading to an increase in winter peak demand and increasing the costs of operating the wider system.

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TNUoS Demand Residual

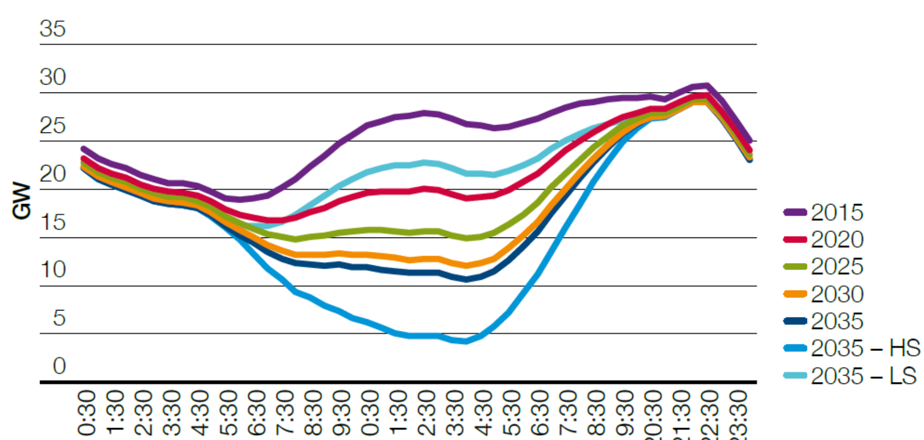
The changes to the TDR may also have unintended consequences such as favoring behind the meter electricity storage rather than utility-connected electricity storage, as the former will still earn embedded benefits through netting off and reducing demand.

While behind-the-meter electricity storage at the larger Industrial and Commercial (I&C) scale avoids the complications of utility-ownership, it may not be able to access all the benefits that utility owned and operated electricity storage can access, resulting in a higher cost system overall (e.g. WPD Solar Storage project: https://www.westernpowerinnovation.co.uk/Projects/Current-Projects/Solar-Storage.aspx, Impact Study, Annex I, where 6 out of the 9 benefits/income streams are only accessible by the DNO). However, with the correct incentives and a well-developed market for services, both at the TSO and DNO level, then I&C scale electricity storage may deliver multiple benefits to both the I&C operator and the wider system. Currently, though, the market for services, particularly at the DNO level, are under-developed and may need the full transition of DNOs to Distribution System Operators (DSOs).

One issue of behind-the-meter electricity storage at all scales is the lack of visibility to network operators. The TSO has successfully managed to develop forecasting for wind generation, which has led to lower costs for operating the system with increasing penetration of intermittent wind generation. Forecasting of solar PV generation in the UK is currently at a nascent level of development. Other countries (e.g. Australia: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting) have developed solar PV forecasting tools to help both generators and network operators.

While forecasting solar PV generation can be broadly linked to weather forecasting the addition of electricity storage behind-the-meter, in conjunction with solar PV, will negate this forecasting, because export of generation is now not dependent on the weather, but dependent on the unknown state of charge of a battery.

Figure 96
Consumer Power summer transmission demand across years



Taken from National Grid's Future Energy Scenarios 2015 (http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Documents-archive/).

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The GB TSO already has significant challenges managing minimum demand in the UK summer due to embedded solar PV generation. The addition of electricity storage, particularly at the domestic scale (without the benefit of the metering requirements that larger I&C customers have), will make the management of the GB system in mid-summer at midday exceptionally complex and challenging, further increasing the costs to run the system that this time.

The GB system is already seeing a minimum demand in summer equivalent to the minimum demand predicted for 2025 and managing the GB system in summer is becoming increasingly expensive and in the future determining the cost of running the system based on *winter-only* and on a *demand-only* basis may be inequitable.

Targeted Charging Review

We welcome Ofgem publishing its Targeted Charging Review (TCR) consultation which looks more broadly at a range of issues regarding network charging. We support the proposals in the Targeted Charging aimed at levelling the playing field for electricity storage. The imposition of double network charges for electricity that passes through an electricity storage facility is unfair. We understand the argument for incentivising an electricity storage facility to operate in a manner that alleviates congestion on the network. However, the double network charging arrangement does not do this; it disincentivises an electricity storage facility from operating at all, thereby potentially losing a proportion of the £8bn smart grid savings that it could offer to the networks, and ultimately to the end consumer.

We welcome the proposed removal of payment of demand residual at Triad for transmission and distribution connected electricity storage which is standalone or co-located with generation, given that transmission connected sites already pay generation residual and for distribution connected electricity storage, the end-user is paying the demand residual. We also welcome the proposal to rationalize BSUoS so electricity storage facilities are not charged twice.

It is important that these changes are coordinated with any changes to embedded benefits so that electricity storage does not face the double hit of having embedded benefits being removed while continuing to face double charging for network usage.

We welcome the proposed creation of a Charging Coordination Group. It is important that such a group has sufficiently wide representation including smaller distributed generators and stakeholders representing electricity storage. We would welcome a summary of how all the charging reviews link together in relation to the development of markets for flexibility tools and in particular for electricity storage and the associated timescales. Uncertainty in policy and charging start regimes are obviously unhelpful for the development of nascent markets and for securing the investment needed to deliver low carbon systems.

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Response

Question 1: Do you agree that the potential for residual charges to fall increasingly on groups of consumers who are less able to take action than others who are connected to the system, is something we should address?

Yes.

Question 2: If so, why do you think, or do not think, action is needed?

Residual charges are not the ideal vehicle to send a price signal that captures time of use of the system (both demand and generation have time related impacts on the operation of the system) or location as they are aimed at recovering historical fixed costs.

Question 3: We are proposing to look at residual charges in a Significant Code Review. Are there any elements of residual charges that you think should be addressed more urgently? Please say why.

The Significant Code Review is the correct approach, even given the likely 18-month timescale as it allows a broader range of charging issues to be addressed in a coordinated manner.

Question 4: Are there elements of the approaches in other countries that you think could be appropriate for GB residual charges?

Since demand is increasingly being impacted by distributed generation, electricity storage and demand-side response, using either net or peak demand, to set residual charges based on volumetric measures will see a larger share of costs fall on fewer people, as those that can reduce their demand when required will see a benefit. At the same time, generation of all scales, including domestic has an impact on the costs of maintaining and managing the networks and this too needs to be factored in, particularly in the future as distribution of resources increases.

The fixed charge approach of California (standard flat fee per connection of a particular class) and the Netherlands, based on "demand connection capacity" are simple and should be straightforward to apply, but the latter is based solely on demand and takes no account of the impact of generation on the network. The combination of demand and generation on a single site is something that needs to be considered and it may not be appropriate to levy charges based on both maximum potential demand and generation, as one site may pay two charges, but this could be addressed by a specific "class".

Question 5: Are there other approaches that you know about from other jurisdictions, that you think offer relevant lessons for GB?

No.

Question 6: Do you agree that our proposed principles for assessing options for residual charges are the right ones? Please suggest any specific changes, or new principles that you think should apply.

At this stage the principles seem appropriate.

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Question 7: In future, which of these parties should pay the transmission residual charges: generators (transmission- or distribution-connected), storage (transmission- or distribution-connected), and demand, and why? What proportion of these charges should be recovered from each type of user?

Volumetric-based charges, wherever they occur in the electricity system, will encounter difficulties as demand users begin to reduce their demand, either through efficiencies or through behind-the-meter generation (and electricity storage). As the volume consumed is reduced, the costs will be shared over a smaller number of parties, some of whom may not be able to shift demand. For this reason, a residual charge that is fixed and not dependent on volume consumed, is preferable. It also allows the "forward" charges to provide price signals. This suggests that approaches B and C would be better and option C, with a capacity-based dependency, would potentially help manage the impact on some customers, but care will be needed in design to ensure the application is fair and that visibility is not compromised by driving generation and electricity storage further behind the meter.

Question 8: In future, which of these parties should pay the distribution residual charges: generators (transmission- or distribution-connected.), storage (transmission- or distribution-connected), and demand, and why? What proportion of these charges should be recovered from each type of user?

It is difficult to find an approach that is both fair and removes a locational signal. Electricity no longer flows from the top of the system (transmission) to the bottom (distribution) and as the result of distributed generation, GSPs are a prone to export (distribution to transmission). Without the transition to Distribution System Operators, it is hard to see how this export can be effectively managed by the distribution networks. At the same time, the distribution network is required to support the delivery of system services to the transmission system (e.g. the new Enhanced Frequency Response service is exclusively provided by assets that will be connected to the distribution network). The use of both networks, in either direction, for any number of services, including generation and demand, has a cost, which needs to be met.

Option A (Distribution connected parties pay the distribution residual). A fixed charge based on class seems to be a reasonable approach, but Option B (Distribution connected parties pay the residual for both the transmission and distribution system) seems to be the only way to ensure that there is no locational signal in term of connection

Question 9: Do you support any of the five options we have set out for residual charges below, and why?

Fixed options B and C. However, the benefits of either approach are likely to depend on how the classes are set up (e.g. thresholds for different storage capacity) versus a fixed charge based on capacity. As the specifics of any arrangements are likely to have an impact the charges seen, care is needed at the development stage.

Question 10: Are there other options for residual charges that you think we should consider, and why?

No.

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Question 11: Are there any options that you think we should rule out now? Please say why.

D. Gross approach as it still creates distortionary price signals and E. Hybrid – complex to enforce/enact plus there is still some element of distortionary price signals. A. is still inequitable as it enables parties to avoid residual charges if they are able to.

Question 12: Do you think we should do further work to analyse the potential effects of the charging arrangements for smaller EG (called 'embedded benefits')?

It will be critical to investigate the system-wide impact of the proposed changes in Embedded Benefits (related to CMP 264 and 265) on system peak demand.

Question 13: Do you think changes are needed to the current charging arrangements for smaller EG, and when should any such changes be implemented?

Other elements of Embedded Benefits should be looked in a holistic way with changes to residual charges.

Question 14: Of the embedded benefits listed in our table, do you think that any should be a higher or lower priority?

Currently, the transmission generation residual is a relatively small element of the wider charging process. It will be more important to explore the locational element of embedded benefits as the work on flexibility progresses.

Question 15: Do you think there are other aspects of transmission or distribution network charging which put smaller EG, or any other forms of generation or demand, at a material disadvantage?

No Comment.

Question 16: Do you agree with our view that storage should not pay the current demand residual charge, at either transmission or distribution level?

The removal of the current demand residual charge for storage and both the transmission and distribution level is a welcome recognition of both the differences between electricity storage and other connectees and the inequities in current arrangements. However, exempting electricity storage from demand charges seems like a "quick and dirty" solution to a very complex problem, welcome though it is in leveling the playing field for electricity storage in the short-term. While this approach may be appropriate now, it may not be appropriate in the future and care is needed to ensure that any new approach supports long-term aims for electricity storage and the wider energy system. For instance, there is no generation residual on the distribution network, but if generation is subsequently captured in charging regimes (particularly on the DN), is it appropriate for electricity storage then to be locked in to paying those charges?

It is inappropriate for electricity storage to simply be treated as generation as recognition of the different roles and impacts that electricity storage has, as both a demand and export, is required.

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While energy storage should not pay “double” charges, a solution that simply exempts electricity storage from specific network charges, while not reflecting its ability to both import and export, seems inappropriate. A durable approach is needed.

Question 17: Do you agree with our view that storage should not pay BSUoS on both demand and generation?

Yes, since electricity storage is not an end user demand and the majority of the stored electricity is subsequently exported, it is appropriate to adjust the application of BSUoS to electricity storage to it does not have to pay on both demand and generation. A solution that is closer to the first proposed option would preferable:

“Balancing Mechanism Unit (BMU) Definition: define storage BMUs as either importing or exporting, irrespective of their actions in any particular settlement period. Storage would then earn import/export credits to off-set its actions in instances in which power flows in the opposite direction. For example, if storage was defined as an importing BMU, it would earn credits when exporting which would 'net off' the charges it receives when importing.”

We would rather see electricity storage treated on a “net” basis of import against export for BSUoS. Since no form of electricity storage is 100% efficient, demand will always be greater than export. This approach would favour more efficient forms of electricity storage, so care would be needed to ensure that if lower efficiency electricity storage offered other benefits that were required by the system (e.g. duration) that any new BSUoS arrangements have no wider system implications.

Question 18: Which of the BSUoS approaches describe is more likely to achieve a level playing field for storage?

See above response to Question 17.

Question 19: Do you think the changes in this chapter should be made ahead of any wider changes to residual charging that may happen in future? Do you agree with our view that these changes should be implemented by industry through the standard code change process?

As long as those in the electricity storage industry that are currently not parties to CUSC, DCUSA and the BSC can implement a code change process, then this seems to be a reasonable approach.

Question 20: We would welcome your thoughts on the potential make-up of a CCG. Please refer to the potential role, structure, prioritisation criteria and assessment criteria.

Distribution-connected Low Carbon Generator, Distribution-connected electricity storage operator (third party), Electricity Supplier (or representative from Energy UK), Transmission-connected conventional generator (large thermal), Transmission-connected electricity storage (Accepting that this is likely to be incumbent pumped storage operators, but this representative should be separate from the conventional generator), Transmission-connected low carbon generator, Aggregator, DNO, TSO, ENA, Consumer representative and representative from BEIS.

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Question 21: Do you agree with our proposed delivery model, including its scope?

Yes.

Question 22: Do you agree that our proposed SCR process is most appropriate for taking forward the residual charging and other arrangements for smaller EG discussed in this document?

Yes.