Response to Operating the Electricity Transmission Networks in 2020 (June 2011)

Prepared by the Electricity Storage Network Limited

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Introduction:

National Grid prepared "Operating the electricity Transmission Networks in 2020 – Update June 2011" as an update to the initial consultation document of June 2009. The original consultation identified a number of issues and challenges resulting from the significant change in the generation mix in the future, as related to system balancing.

Preamble:

Thank you for the opportunity to respond to this consultation. The Energy Storage Network is an alliance of industrial, commercial and academic organisations interested in the development use and application of electricity storage. We therefore have a keen interest in the topics raised in this consultation.

We will initially respond to the specific questions raised in the consultation related to storage, raise any questions for National Grid and offer any specific comments on issues related to storage in the GB system.

National Grid recognises that understanding system balancing in the future is an on-going process. They also recognise that it takes time to bring new products to the market, but as a regulated business, there is not as much flexibility to support development of new products as might be desirable. At present, National Grid uses a number of options to secure system balancing, and we agree that that future system balancing will require increased volume of balancing and an increased number of options will be required, to provide diversity in the security of response and also to be capable of acting together to support the system. We would argue that the introduction of new technologies that support the overall needs of society should be developed with financial support, and that a short term financial analysis should not be used as the technology selection process.

Questions from National Grid relating to Storage:

Q23: Do you agree that battery technology used in the context described in 14.13 could be deemed transmission?

We assume that this refers to para 14.12 (and not 11.15 as in appendix 4) where large scale batteries are described as being similar to Synchronous VAR Compensator (SVC).

SVCs are considered to be transmission assets and are therefore operated by the TSO under the terms of their transmission licence.

Battery technology, containing advanced electronics, is able to perform in a similar fashion to an SVC. The range of FACTS devices which are under development and being installed are increasingly using energy storage as a means of enhancing their performance. The boundary between an item of equipment such as an SVC and a FACTS device with storage is indistinct and therefore it seems reasonable to treat both in a similar fashion.

Q24: (i) Is large scale battery technology feasible against existing revenue streams?

(i) No.

At present, the highest value for energy storage technologies is in the provision of ancillary services. In general terms, the costs of implementing battery technology, and indeed most new energy storage technologies are high. It is not the role of this response to analyse individual maufacturers' and project developers' proposals, against the current expected income from an ancillary services contract, but the issue is not simply a cost based argument on the cost of a new technology, but also against the openness and realistic valuation of the services that can be provided by a battery (or any other storage device) and the appropriate means of recovering the value, often from a number of different income streams.

Currently some battery technologies (and other storage technologies) may be feasible on a short run marginal basis, but this is inadequate to prepare a business case. An energy storage project with a lifetime of say 15 or 20 years would need some certainty of income in order to offer a rate of return commensurate with the financial objectives of the investors. If this is not achieved the cost of capital for the battery is raised, taking the project outside the area of a satisfactory rate of return. This is highly linked to the discussions on electricity market reform, where proposals for capacity payments are seen as a means of encouraging investment.

Further contractual development work needs to be carried out, particularly to take account of the two way nature of electricity storage technologies. The ability for storage to both import and export electricity makes it a highly desirable facility on a power system. Few other technology solutions offer this degree of flexibility.

(ii) What are the limiting factors to large scale battery capacity?

(ii) Large scale battery capacity is limited primarily by commercial factors. Experience from overseas shows that battery installations in the tens of MW range are achievable, as most battery technologies are modular and scalable[1]. The control

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[1] A reference list of large scale battery and other energy storage projects is shown in Appendix I and II

interfaces to the network are similar to large SVC or AC / DC link technology where systems operating in the range 100 MW – 1 GW and above are common.

Storage technologies, such as large-scale batteries, have a short construction and installation time. However the establishment of large scale manufacturing capacity has a long lead time and therefore significant investment and development is needed well before 2019 to ensure that sufficient reliable storage is available in the system by 2019. Ensuring this investment occurs is a significant challenge. Manufacturers will only commit to investment in manufacturing capability with the backing of a contractual position. While the market for production of EV and hybrid EV batteries appears to be growing, relying on spin off manufacture from the EV market as prime source of batteries for grid deployment does not seem to make best use of industries resources, and will inevitably lead to longer lead times and higher costs.

While deployment of large scale batteries may be considered as installations of multi MW size, battery technologies may also be deployed in a distributed manner to suit a number of factors such as ownership, revenue recovery, availability of a network connection, availability of financing and the revenue stream.

We would also note that while this question is directed towards battery technology, other energy storage technologies share similar attributes of modularity and scalability.

Q25: How could investment in storage technologies be made in order that the potential benefit is shared across all parts of the value chain?

Examples from other countries show that where vertically integrated utilities own and operate electricity storage, then the benefit of overall system cost reduction is societised. Under the current arrangements for the electricity market in GB, this is unlikely. A number of investment models exist, each with their own merits and disadvantages:

a) Ownership by a transmission or distribution operator: with unused storage capacity “rented” to third party market participants, such as generators or supply companies

b) Ownership by an existing market participant, with the storage added to their plant portfolio, but with a lease or dispatch agreement with the transmission or distribution operator to use the plant as required

c) Ownership by an independent operator who contracts with the network operator and other market participants on a combination of spot, short term and long term contract arrangements

d) Ownership by a strategic body

There are no fundamental licence or regulatory constraints on any of these models, although clarification would be beneficial. The first priority is to ensure market stability so that investment can be made with a degree of confidence. Longer term contracts, both for ancillary services, as well as for network applications would encourage early deployment of battery systems

We note the concurrent consultation by DECC on Electricity Market Reform and consideration of options for a capacity mechanism. At the time of preparing this response to National Grid, the options being considered by DECC are based on either a strategic reserve or a capacity market.

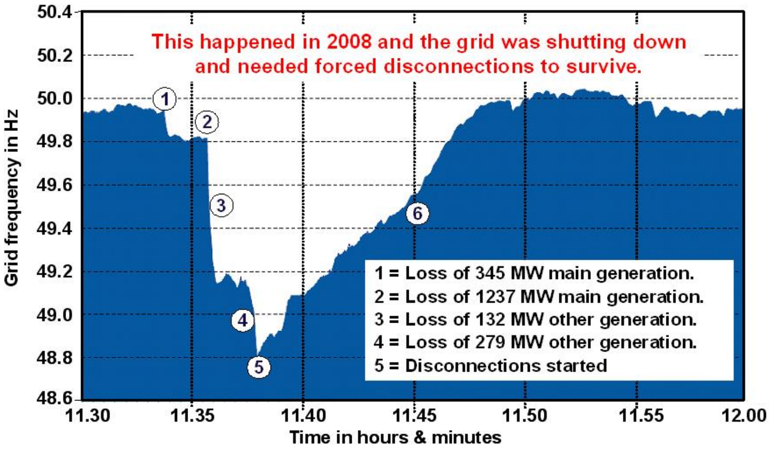
Responses to other questions:

Q1. Do you agree that cut out will be an issue for GB or will wind (onshore and offshore) turbine technology compensate for the GB wind resource density?

Cut out will remain an issue for GB, as the wind resource is likely to remain a significant issue regardless of progress in turbine technology. Gusting conditions will always pose a significant problem to turbines and therefore the system must be robust enough to cope with cut out situations.

Q5. Are there any further benefits (or detriments) to managing frequency more tightly on the GB system?

On the present AC grid the event shown on Figure 1 was made worse because in zone 4 many other small generating plants started to trip off due to either under-frequency or rate of fall of frequency.



This happened in 2008 and the grid was shutting down and needed forced disconnections to survive.

Total generation loss = 1.993 GW

Data supplied courtesy of William Hung of National Grid

Figure 1

Many smaller generating plants can have their under-frequency or rate of fall of frequency limits set too tight which increases the impact of a large transient. Due to this National Grid has reviewed the need to have a wider operating frequency and rate of change of frequency band both for existing and new plant. This could be very expensive to implement and police.

The benefit of managing frequency more tightly is that it will avoid the cascade type of trips shown on Figure 1. It will also reduce the cost of installed plant. For example all power factor correction decreases linearly with frequency as the impedance of the capacitors increases with frequency. So the smaller the frequency range the less the margin required in sizing the capacitors for a given duty. The detriment of managing frequency more tightly is that this will require fast acting power reserves that were previously unavailable.

The present method is to have large spinning inertia loads connected to the grid to provide inertia based frequency response limiting. This has expensive running costs and the present generating plant running on low load has high CO_2 emissions. As conventional rotary plant is retired from service the provision of inertia based frequency response will decrease and the grid frequency transients will increase.

The provision of fast acting energy storage that can provide very fast response will achieve tighter management of frequency, significantly reducing CO_2 emissions from conventional plant running on low load to provide an inertia based frequency response.

Q17. Do you agree that wide spread demand response may be a more appropriate means of managing low probability risk?

We see demand response as one part of a range of solutions which will provide flexibility to the system. Demand response cannot guarantee complete certainty of provision of a service, but does offer a relatively low cost service. For a low probability risk which is currently managed by holding large quantities of reserve, some of this might be shifted to distributed or widespread demand response as part of the solution, but it should never be seen as the complete solution. Equally, distributed and centralised storage offers similar or improved benefits to demand side response, and with increased reliability and certainty of response, it should be considered as a viable alternative.

Q18. Do you agree that larger scale CHP such as district heating scheme developments are more probable or is there a larger role for domestic level or micro-CHP?

GB has a low proportion of CHP in comparison to a number of other countries. Large scale CHP, particularly for new build towns and large scale urban regeneration projects would be appropriate as a means of improving the overall efficiency of energy supply. CHP will have an impact, not only on demand, but also on the flexibility of the system. CHP may be fitted with contiguous energy storage, both thermal and electrical, and this may be used as a means of optimising the CHP owner's business, and have a deleterious effect on flexibility of the system, or alternatively, the additional storage may be used as a valuable means of increasing flexibility and improving the overall efficiency of the system.

New forms of electrical energy storage are under development which include a thermal cycle as well as an electrical cycle and an integrated approach is required.

Q19. Taking into account the points raised, is our assumption on CHP growth realistic in regards to (a) the investment climate and (b) the additional points raised above?

The UK has had a relatively low adoption rate for CHP, due to a number of factors, including investment certainty and rates of return. Any planning based on the assumption of adoption of new technologies needs to include flexibility, and it is important not to take actions that close the door on other alternatives.

Q20. What is a realistic view to the amount of PV installed capacity by 2020?

PV installations, particularly domestic, will only increase if there is sufficient financial incentives to do so, primarily grants towards installation costs and FiT (See DECC "Electricity Market Reform (EMR) White Paper 2011: Planning our electric future: a White Paper for secure, affordable and low-carbon electricity").

The introduction of PV has been stimulated almost entirely by grants and feed in tariffs. While encouraging the growth of PV, it is at the expense of follow on costs for flexibility and network re-enforcement. A balance between subsidy for renewable generation and cost recovery will eventually be reached, but this is more determined by government policy than by engineering estimation.

Q26. How significant will DNO network capacity be in establishing an increase of DSR service? Is a majority of the potential value more realisable by suppliers?

DNO network capacity will be a significant part of the future operating plans for the total system. With increased demand for electricity as other energy vectors are decarbonised, reinforcement and active network management will be necessary. DSR is driven by reduced network capacity – high DSR enable reduced network capacity and savings in investment, however the absence of an effective coordinated market mechanism currently limits the role of DSR for a DNO.

Q27. How much demand could be captured from the industrial and commercial sector?

The industrial and commercial sectors can offer sizable contracts for new ancillary services. Much will depend on the contract terms offered. For example, if air conditioning is to be switched on and off frequently, in effect the air conditioning may have to be oversized, so adding virtual thermal energy storage into the system. Demand response can only really be considered as time shifting of non essential energy use. The opening of the electricity market to new participants, and new technologies, including storage is an important precursor to achieving increased flexibility in the system. If market based solutions are not chosen, a strategic authority must make suitable investments at an early stage in order to be prepared to meet the future challenges.

Q28. Do you believe that the mandatory inclusion of relevant technology in domestic appliances is required as a pre-requisite to enable and capture DSR?

Mandatory inclusion of demand response technology in domestic appliances raises several regulatory and commercial issues. From a consumer perspective, to have a device that may be controlled by outside influences raises certain issues. Not everyone wishes to have their demand time shifted. The device will have an additional cost, and the consumer should therefore receive a payback in return for the additional cost. This may only be a very small amount for each consumer, and logically, should reflect the service which is provided – in other words the “as delivered” flexibility service. The costs of administering such a service would be significant. Without mandatory inclusion the viability of domestic DSR would be limited.

The effect of ignoring the cost and reward would be damaging to other participants in the flexibility market. If a sizable part of the market was providing the service at a zero cost, (that is subsidised by mandatory requirements through legislation), other providers would suffer as the NETSO would be less willing to procure services at the full commercial rate. This would place other services, such as electricity storage at a continuing disadvantage and further slow the pace of introduction.

ToU tariffs may have more influence in determining when an appliance is run (see Q35).

Q29. Do you agree that more than 5% of domestic demand would be managed or does 5% remain a reasonable assumption?

Any estimates of domestic demand management must be made on the basis of averaging. The future domestic demand profile will include a number of devices of different power levels and tolerance to demand management. Overestimating the target for domestic demand management may leave the system operator with insufficient alternatives to control the system and respond flexibly to uncertainty. By 2020 a 5% contribution from domestic DSM is ambitious. A 2-5% contribution is probably more likely.

Q30. What are the main barriers you see in capturing demand side services, in particular those from the domestic sector?

Referring again to question 28, there are a number of issues relating to time of use tariffs, certainty of use of a device with minimum inconvenience. Customer acceptance will be dependent on trust and proven financial benefit to the customer, with minimal impact on lifestyle convenience and behaviour. Domestic DSR will be highly reliant on effective automation, IT and telecoms to enable domestic DSR. If payment has to be made in order to achieve the domestic demand side market, there may be better methods of using the money to create more effective and efficient services.

For the commercial sector there needs to be a more effective coordinated market mechanism to ensure full DSR value can be accessed.

Q31. What does this mean for NETSO services? Do you believe that the type of product described will be provided by particular sectors?

This is a complex issue. The future domestic products may include demand responsive loads such as refrigerators, heat pumps and the like, as well as the more uncertain requirements of electric vehicle charging, which may operate two way. The NETSO will require certainty and flexibility and this must be included in the analysis.

Q35. Is it likely that the demand profile will change through ToU changing tariffs? How elastic will demand from EVs be?

ToU tariffs may change domestic demand profiles, but experience suggests that many people lose interest after the initial introductory period. If fixed / published time of day tariffs are too extreme, extreme behaviour can result as people strive to take advantage of low prices and avoid the high prices. Using real time pricing would be more accurate, but if taken to the extreme, would lead to cannibalisation of prices towards a point of indifference.

If the intermittent context of generation is considered then prices become much more volatile on a day to day basis and ToU pricing will have to become very sophisticated, so unless this complexity can be hidden from the consumer in a very simple tariff scheme, the usefulness of ToU tariffs will be reduced.

The prediction of EV behaviour is still at an early stage. The expected behaviour will be towards opportunity charging in order to ensure that the EV is in a ready to go mode. Early adopters tend to be those with higher incomes and so are less sensitive to mildly varying costs arising from ToU tariffs.

The uptake of EVs has still been low. The demand of EV may be elastic but, like domestic DSR, will require effective automation, IT and telecoms to ensure EV can contribute to DSR. The importance of public recharging infrastructure in determining the demand profile from EV's needs to be researched further. Public recharging points may require a buffering arrangement, such as electricity storage, in order to reduce the need for extensive local network reinforcement. The local storage may be suitable for dual role, both to support the EV recharging as well as to provide system response.

There is a need for system modelling at the national level, looking at scenarios for the near and longer term with higher proportions of renewables, demand side, and storage.

Q36. Do you agree with the estimate for the level of aggregation across domestic premises required?

The need for control and instrumentation for the aggregation of distributed domestic demand side is substantial, and while technically achievable, we believe that use of electricity storage at a community level may be a more cost effective method to achieve the same degree of flexibility.

Q37. Do you agree with the issues raised and are they being addressed?

Ownership and use of data to deal with demand side management is a significant issue, and we agree with the issues highlighted of data security, trust, and value proposition and data ownership. We also believe that insufficient consideration has been given to the total volume of data and calculations needed in order to achieve the net result of network flexibility and when this is considered, alternative solutions, including the use of electricity storage at all scales, may prove to be more costs effective over the longer term.

Q38. What do you believe are the important factors to developing and securing demand side services?

The critical factor is customer engagement, whether directly with active support, or indirectly through soft control mechanisms. It is important to retain flexibility and not to adopt technologies or solutions which close doors on alternative solutions. The integration of storage at distributed, community and large scales with similar sized demand customers needs to be actively researched and developed. Appropriate levels of rewards and revenues for storage need to be determined at least as equitable as demand side management solutions. Many of the issues raised in the answer to Q30 are applicable here, particularly with regard to acceptance, automation and ensuring there are effective market mechanisms to coordinate all the different stakeholders.

Q39. Do you agree that the supplier/DNO relationship will be critical in localised constraint management? Q40. How do you see services will be developed? Q41. How does this model align with your own understanding of how operational interfaces will work?

Yes – the relationship between all parts of the electricity value chain will be critical and will be tested more than in our current experience. "Churn" of customers from suppliers will lead to mistrust, and if mishandled will lead to significantly increased costs as the requirements to bring together different operating procedures and technologies are becoming increasingly complex.

The relationships between the NETSO, DNO and supplier will need to be refined, not only for constraint management, demand side management, but also for other services, such as access to distributed storage, distributed generation and micro-generation, and reward for ancillary services and energy use reduction.

An effective coordinating mechanism needs be in place that brings all the potential DSR users and sellers into a single place, such that competing interests can be resolved efficiently. This could be on a regional or national basis. The NETSO, suppliers and DNOs may work together in the future but this will require an equal partnership and shared use of data from such devices as smart meters. Such a partnership may leverage more DSR than if the partners attempted this separately.

Questions for National Grid:

We have no questions.

Other Comments:

National Grid has a good understanding of the impact of the future generation on the system. Demand side response (DSR) is understood as it is currently used in system balancing. As system operator, National Grid has experience of the operation of the large pumped hydro plants, but the application of fast acting technologies, whether centralised or distributed has not yet been obtained in GB. The role of DSR in system balancing going forward has been well-modelled, but the potential role of storage in system balancing has not been modelled. This is likely to be the result of the wide range of storage technologies and the relative immaturity of some of these technologies. The lack of grid-scale demonstration storage, which would allow a good understanding of how the operation of such storage would impact on the system, means that the potential of storage to mitigate some of the issues and challenges of system balancing going forward is underdeveloped.

The current Department of Energy and Climate Change (DECC) consultation document “Electricity Market Reform (EMR) White Paper 2011: Planning our electric future: a White Paper for secure, affordable and low-carbon electricity” indicates a role for storage, but not until 2019 and it is not clear that the proposed electric market reforms will drive investment and development in grid-scale storage.

Storage is both a demand and supply technology and offers less complicated dispatch arrangements compared to DSR. Storage can provide both footroom and headroom, while also offering other system services, such as frequency regulation. However this ability to act as both a demand and supply technology complicates its integration into the wider system.

The Low-Carbon Network Fund has supported development within Distribution Companies, but this Fund has yet not been available to Transmission Companies. It is our understanding that this will be available in the next round, and under the development of business plans to meet the RIIO regulatory regime there should be the opportunity for Transmission Companies to develop technologies to support their future needs. **Members of the Electricity Storage Network would welcome early discussions with National Grid on the role of storage in preparing business plan proposals for consideration under the new RIIO regulatory regime.**

Appendix I: Energy Storage: Selected Projects from around the World – Batteries ≥100 kW

Location	Storage Technology	Size	Developer/Supplier
Atacama Desert, Chile	Lithium Ion Battery	20 MW	AES Energy Storage, A123 Systems
Texas, USA	Sodium Sulfur Battery	4 MW	Electric Transmission Texas
Zhangbei, China	Vanadium Redox Battery	500 kW	Prudent Energy
Rokkasho Japan	Sodium sulphur Battery	34 MW	JWD, NGK
Futamata, Japan	Sodium sulphur Battery	80 MW	Tohuko Power / NGK (under construction)
Notrees, USA	Lithium Ion Battery	36 MW	A123 Systems (under construction)
Nairn, Scotland	Zinc Bromine Battery	150 kW	SSE, Premium Power
Lerwick, Scotland	Sodium Sulfur Battery	1 MW	SSE, NGK
Hemsby, UK	Lithium Ion Battery	200 kWh	UK Power Networks / SAFT & ABB

Appendix II: Energy Storage: Selected Projects from around the World other Technologies (Non-Pumped Hydro and Compressed Air)

Location	Storage Technology	Size	Developer/Supplier
Stephentown NY, USA	Flywheel	20 MW	Beacon Power
Slough, UK	Cryogenic	500 kW	Highview Power Systems