The attached paper forms the response of NRG Management Consultancy to the National Infrastructure Commission's call for evidence in relation to electricity interconnection and storage.

NRG Management Consultancy provides commercial advice to start ups in the energy sector and contract management advice across the energy sector.

Nic Rigby 8 January 2016

Q 1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

Q1.1 What role can changes to the market framework play to incentivise this outcome:

A number of examples where the UK electricity market is structured so as to constrain the provision of services such as storage and demand side response[1] are listed below.

Transmission/ Distribution Asset Avodiance
The nature of transmission and distribution asset ownership is such that monopoly or licensed ownership is a given. Ofgem's development of competition in asset ownership can be expected to increase transparency and reduce costs to consumers but this development will not directly address the impact of using non conventional services in place of transmission/ distribution assets. Non conventional approaches have benefited though from Ofgem's Low Carbon Network Fund. In order to ensure conventional and unconventional approaches to the provision of transmission/ distribution assets are treated equally the **Low Carbon Network Fund's role will need to increase.** The emphasis of Ofgem's treatment of the fund also needs to change to include detailed evaluation of the market benefits of non conventional approaches and **challenging those asset owners who continue to use conventional assets** in situations where non conventional arrangements have been shown to reduce costs to consumers. This approach is broadly consistent with Ofgem's proposal to develop Distribution System Operators rather than Distribution Network Owners.

Cost Reflective Charges
In a truly cost reflective and unrestrained market any non conventional service provider would expect to be able to create monetary value if their service can be provided at lower cost than existing providers.

Non conventional balancing approaches particularly location independent storage and demand side response are currently not able to monetise the value they can provide to consumers as a number of system costs are not fully imposed on the parties that cause them. Socialising some electricity market costs has the unfortunate side effect of dulling the incentive to buy alternative services. To encourage storage and demand side response users need to pay more realistic

[1] See Glossary

locational charges by **charging for time of day electrical losses**. The introduction of charges for losses should be done gradually and in a way that fits with Use of System charges.

The cost of drawing power at times of system peak also needs to fully reflect the **extreme costs associated with that extreme provision.** Ofgem have made strident efforts to ensure that both locational and system peak costs are levied on those who cause them but the lobbying for "socialisation" has been well organised and had support from more prominent politicians than the "cost reflective" case.

Demand charges being levied on parties (such as storage) that only draw demand at off peak periods is clearly not cost reflective and where this occurs (for example some DNOs levy these charges) they should be replaced by a more cost reflective mechanism.

Q1.2 Is there a need for an independent system operator (ISO)?

National Grid's approach to managing conflicts of interest is to utilise small isolated teams for sensitive roles such as the Capacity Market. Whilst this approach ensures focus and has to date generally delivered independent thought it is sub optimal as those small teams do not have the benefit of a complete management structure. For example access to lawyers and other specialist advisers are often constrained. This approach also mitigates towards the conventional. The expansion of the Capacity Market to include National Grid owned interconnectors before solving problems with storage (see 2.1 below) may or may not have been influenced by the positive impact on employee share save valuations but such perceived influences do not enhance an independent reputation. For these reasons the time has come to **adopt the Independent System Operator model** which should be established as a completely independent company with no links to National Grid/asset owners.

Q1.3 How could the incentives faced by the SO be set to minimise long-run balancing costs?
SO costs will be partly driven by the structure and location (see 4 below re crowded and windy islands) of each electricity market but as many other markets use the independent SO model comparisons will be easier once an ISO has been established in GB. As **all the employees of an ISO are dedicated** to the success of that business one would expect them to be more focused on the task of reducing costs to consumers with greater emphasis on innovative approaches that will produce long term value for the ISO and consumers.

Q1.4 Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

As set out in 1.1 additional cost reflectivity is required in all aspects of the power market and in particular the "balancing market" at times of peak demand as this ultimately reflects the cost of providing electricity or not at these times. Current Balancing Market proposals i.e. p305 are a step in the right direction. The proposal to charge VoLL at times of system stress may seem a blunt instrument but it is an essential part of charging the costs on those who cause them. Intermittent generation such as wind, solar etc are clearly a major cause of imbalance cost but imposing these imbalance charges also offers the benefit of encouraging innovative approaches to forecasting output and hence the level of imbalance. It may also be appropriate to consider **implementing an "information charge"** as well as system balance charges on those parties who incorrectly declare their imbalance in the most costly direction.[2]

Q1.5 To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Studies such as Element Energy and Strbac et al have demonstrated that demand side measures and storage can play a significant part in increasing the flexibility of the electricity system. Care should be taken though in promoting some forms of embedded generation. In those areas (particularly urban areas) where air quality is or could in the future be below appropriate standards **new diesel plant should not be consented nor should such plant receive Capacity Market contracts.** It is also inappropriate that money allocated to enable the transformation of the GB's energy system to reflect future environmental needs (EMR) is funding the installation of polluting diesel generators. To avoid this anomaly Capacity Market prices need to reflect the environmental credentials of each provider. A short term measure would be to **apply a price differential depending on the efficiency and environmental impact** of plant that wins Capacity Market contracts. An alternative approach is to split the Capacity Market where long term contracts are only offered to parties who can meet stricter eligibility criteria including environmental and flexibility obligations.

Q 2. What are the barriers to the deployment of energy storage capacity?

Q2.1 Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?

The issues discussed in 1.1 (Cost Reflective Charges) and 1.4 above need to be addressed to ensure that storage can access all the value that it can create. In addition the Capacity Market has been established to fit conventional providers of support rather than considering all potential providers. This is a reflection of industry understanding and insufficient motivation to be innovative. Incumbents whose assets run the risk of being stranded clearly have limited motivation in relation to certain forms of innovation. The issue for storage is that it needs to be built with an optimum MW/ MWh capability. This allows for charging and discharging in relatively short periods typically 6 hours. There are occasions when the Capacity Market expects a provider to have capacity or generate over

[2] i.e. an information charge for under delivering versus notification at peak times and for over delivering versus notification at off peak times

periods of longer than 6 hours. Storage can meet the most valuable peak period when it will be discharging and can also be available in the pre peak shoulder but would expect to be fully discharged before the post shoulder peak. Storage would want to be discharged so that it can maximise its arbitrage revenue by discharging over the peak and being ready to charge at off peak times. Clearly the **Capacity Market** needs to reflect consumer needs but the service should be **designed around those peak needs rather than conventional providers**.

Storage can manage this situation by taking penalties but this approach does not fit with the concept of matching delivery to promise and cost reflective penalties.

Q2.2 What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)

As the table in Appendix 1 sets out storage can access value from three distinct services. Some of these services are locational with optimum value when storage is located adjacent to consumers. This is because locating storage close to consumers enables the whole system from generator to storage/ consumer to run on an optimal basis. Storage located closer to the generator means that only generator to storage can be optimised leaving storage to consumer unoptimised. This suggests that the greatest value is available when **storage is located within the distribution network.** This is also supported by Strbac et al’s analysis. Storage will though need to be capable of being accumulated so as to provide ancillary services at MW levels that are of value to National Grid. In time accumulation of domestic based storage should also be feasible which would then encourage storage to become optimal at domestic scale.

It is the co-existence of storage and intermittent generation that creates the arbitrage value stream. It is also the case that to access optimum value in terms of ancillary service provision and asset avoidance the storage needs to be co-located with consumers not generators. Hence co-existence does not lead to co-location. There will though be specific occasions when storage may add significant value alongside generation for example when the generation capacity is MW constrained.

Q 3. What level of electricity interconnection is likely to be in the best interests of consumers?

Interconnection is as important as storage and demand side measures in terms of improving security of supply. It will also be particularly important in the next few years in lowering UK power prices so that they are closer to those in mainland Europe. Interconnection via under sea cable should though be subject to the same cost reflective market as all other technologies. There are a number of cost reflectivity issues in relation to environmental costs of electricity imports. The UK has taken a foresighted but lonely approach in terms of imposing a higher cost of carbon. By ensuring that the **environmental cost paid by electricity**

importers is at the same level as GB producers is unlikely to be popular and may not be possible but it does fit with the "polluter pays" principle.

Q 4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?

Deployment
UK and International studies make the case that significantly more demand side response can be utilised in the UK (see Element Energy, CEER and European Commission). Some regions in the USA appear to be leading the world in terms of MWs of demand side response. This is particularly unfortunate given that the UK was probably the world leader in this field prior to the demise of the electricity pool. In the case of storage it is probably too early to comment on UK versus world leading practice. It would be good though to see an **Office of Storage/ DSM Deployment within DECC** though, so as to give equivalent treatment to other technologies such as Nuclear.

Crowded and Windy Islands
As crowded and windy Islands the UK and our neighbour Ireland have particular opportunities and challenges in terms of managing security of supply. The UK transmission system is built and operated to a very high standard[3] but alongside that getting consent for new overhead lines is particularly challenging in the UK. The traditional response to consent challenges has been to underground cables. The developing energy system in these islands deserves better than "more of the same". Other ways of optimising transmission assets and how they interface with generation and demand need to be evaluated. This suggests that the **UK should be leading rather than following in terms of best practice.**

The establishment of the National Infrastructure Commission should be a wake up call and an opportunity for the UK electricity industry to:
- establish an ISO
- structure a truly cost reflective market
- remove the barriers that prevent the implementation of storage and demand side measures
- re-establish the UK energy industry as the world leader in managing change.

References and Glossary

Reference to "demand side response" is to the shifting of load from peak to off peak or shoulder periods. Shoulder periods are those immediately before or after peak periods when demand rises or falls respectively.

Element Energy, Demand side response in the non-domestic sector, Final report for Ofgem, July 2012

[3] GB Transmission operates each cable route to N-2 meaning that even if 2 cables are unavailable the remaining N cables can carry the expected load.

Strbac et al, Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future, Energy Futures Lab, Imperial College London June 2012

CEER Advice on Ensuring Market and Regulatory Arrangements Help Deliver Demand-Side Flexibility, 26 June 2015

European Commission, Commission Staff Working Document, Incorporing demand side flexibility, in particular demand response, in electricity Markets, 5 November 2013

Appendix I Sources of Value for Storage

There are numerous ways of describing the value of storage. To focus attention on the monetisation process the table below categorises these descriptions into three capabilities.

Arbitrage or time shift which is the capability to buy power (MWh) when it is cheap and sell it later when prices have risen.

Ancillary services (now known as Balancing services in GB) which are those services (other than power) required to keep power systems operating. There are three types of ancillary services reserve, voltage support and Black start. Reserve is further divided into three types instantaneous (and automatic) provision of MWh (primary frequency response), secondary frequency response which is provided with a short delay (30 seconds) or standing reserve which typically requires plant to be started (available within 10 minutes). Voltage support is achieved by providing MVarh (reactive power) and Black start is the capability to support start up of large scale generation.

The third service is asset avoidance where storage is used in place of transmission or distribution assets. Storage running alongside assets such as lines, switchgear and transformers which are usually subject to intermittent use can significantly improve the optimal use of those assets. The ultimate form of asset avoidance is the use of storage in an off grid installation.

In the UK there are constraints on parties who provide monopoly services. The most relevant for this discussion is the constraint on owners of transmission and distribution assets in terms of their ability to also own generation assets. Two transmission/ distribution companies Scottish Power and SSE are permitted to own both but they are allocated to different companies. The potential storage owners and buyer of services are set out for each of the three capabilities of storage below.

Service/ Capability	Technical constraint	Locational constraint	Buyer of service	Owner of capability	Notes
Arbitrage/ Time shift	Typically a daily cycle so 10 years = 3000 cycles. Size of storage MWh/MW typically optimised at 6 hours approx.	None	Any BMU registered party (generator or supplier)	Owner must either be a BMU or work through an agent that is signed up to BSC	Some parties ie DNOs may be constrained in terms of being owners of a BMU.
Ancillary Services	A party providing frequency response utilisation at all times will need to accept a large number of cycles could be 100 per day. Providers of capability can constrain cycles.	Reserve is less valuable if it is the wrong side of system constraints. Reactive power is locational.	National Grid, System Operator	Could be any party except National Grid. DNOs also effectively ruled out as they cannot sell energy.	Black start needs to be co-located with conventional generation and fully available at all times so provision alongside other services is severely constrained.
Asset avoidance	If working with other conventional assets, cycles can be restrained. If off grid discharge times may need to be longer. Also cycles likely to be several per day.	Locational and greatest value is as close to customers as possible.	End Users (off grid) and DNOs or Transmission Owner	As buyers of service but feasible to consider a DNO/ Transmission Owner as a service buyer but not asset owner.	

DNO = Distribution Network Owner
BMU = Balancing Market Unit
BSC = Balancing and Settlement Code

It should be noted that revenue from the three capabilities is likely to require storage to discharge at different times. For example frequency response could require discharging at anytime, arbitrage requires discharging at time of system peak demand whereas asset avoidance requires discharging at time of local peak demand. Hence on any particular day revenue may not be possible from all three sources.

The conclusion from the table above is that DNO or Transmission Owner participation is likely to be required in order to address the asset avoidance market. Off grid application prevents access to the other markets so is not considered in detail. The approach taken to date is for DNOs to be the lead owner but other owners provide access to market for the other capabilities. In future other monetisation approaches will need to be part of the regulatory landscape. These could include DNOs requesting bids for asset avoidance services, or DNOs buying asset avoidance capability on a transportable basis.