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ICE written submission to the National Infrastructure Commission call for evidence - Electricity Interconnection and Storage

Dear Lord Adonis,

Please find the Institution of Civil Engineers' submission to the National Infrastructure Commission call for evidence on Electricity Interconnection and Storage.

The ICE is a UK-based international organisation with over 86,000 members ranging from professional civil engineers to students. It is an educational and qualifying body and has charitable status under UK law. Founded in 1818, the ICE has become recognised worldwide for its excellence as a centre of learning, as a qualifying body and as a public voice for the profession.

ICE would like to thank the National Infrastructure Commission for the chance to take part in this call for evidence. We would welcome any opportunity to provide further insight at subsequent stages.

Yours sincerely,

Gavin Miller
Policy Manager

It is noted that this section of the NIC call for evidence is titled 'Electricity Interconnection and Storage', therefore the answers given below relate specifically to electricity rather than energy as a whole.

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?**

Implementation of Electricity Market Reform (EMR) including the annual Capacity Market auctions should continue smoothly with changes kept to a minimum.

Looking at the GB electricity market as a whole, there is a need to continue to ensure the competition between generators distinguishes between cost and cost-effectiveness. That is, what is achievable for the price. This will assist the development of supporting capabilities: the efficient delivery of energy infrastructure will require a cost-effective supply chain and skilled workforce.

EMR has generally established appropriate and effective mechanisms, in the form of Contracts for Difference and the Capacity Market, to deliver a low carbon, diverse and secure energy mix at lowest cost to consumers. EMR should be more capable of bringing forward the tens of billions of pounds of investment required at a lower cost of capital than previous policy instruments.

Nevertheless, it is important to remember that EMR is relatively new; established under the Energy Act 2013 but not fully implemented until 2014. As such, any changes to its continued implementation should be considered carefully from the point of view of investor confidence. Where alterations are required, early notice of future funding availability will reduce risk, enabling investors and developers to make informed decisions, as would greater emphasis on the longer-term contracts available for new plants through Capacity Market auctions.

In the short-to-medium term, this means further changes to EMR are the minimum necessary. Nevertheless, as part the planned review of the Capacity Market system, expected in 2018-19, consideration should be given to taking a more systems-based approach, for example assessing how the mechanism relates to, and works with, other schemes such as balancing services to deliver flexibility, responsiveness and security.

- **What role can changes to the market framework play to incentivise this outcome?**

The Electricity Act 1989 (as amended) is the main legislative component of the GB electricity system introducing privatisation and unbundling, and it remains central to the GB electricity market framework. However, the licensing regime it put in place now risks working against innovation and flexibility.

There will always be a need for bulk electricity generation, transmission and distribution as encapsulated in the 1989 Act (and which EMR has sought to improve). However, an effective and vigorous market at a local and national level seems to be desirable by current common consent, with local operators, generators, communities etc., able to buy and sell power and energy to solve local constraints on networks as well as participating in national energy balancing needs. The increasingly 'local' and disaggregated supply and demand of the GB electricity market also needs a response.

Technology, in terms of small generation equipment, smart domestic appliances, and the very likely near-term evolution of affordable storage, all point to a very different dynamic arrangement than was envisaged in the 1989 Act. Therefore, it is not clear, if the basic assumptions of the Act remain capable of allowing appropriate growth in local energy services, or if it risks stifling sensible innovation and development in the sector. A thorough review of the Act and its associated licensing regime should be undertaken: it might be that the objectives of the Act remain fundamentally correct but their implementation seems to be working against the growth of new local trading and services.

- **Is there a need for an independent system operator (SO)?**

Weighing up the need for an Independent System Operator (ISO) is largely dependent on what this term would mean in the GB context.

The GB National Electricity Transmission System is owned and maintained by three regional transmission companies: National Grid Electricity Transmission (NGET) (in England and Wales)**,** Scottish Hydro Electricity Transmission (north of Scotland), and Scottish Power Transmission (central and south of Scotland). NGET alone operate **t**he GB system as a whole, the single System Operator (SO).

For the purposes of this submission, the creation of an ISO is taken to mean a separation of the ownership/maintenance and the operational functions both currently performed by NGET in England and Wales. Therefore, a newly created ISO is expected to have responsibility for controlling the access to, and use of, the transmission grid by generators and maintaining system balance across GB but would not own, nor maintain the infrastructure.

As the Scottish part of the GB system is owned/maintained - but not operated - by Scottish Hydro Electricity Transmission and Scottish Power Transmission, it follows the electricity system within Scotland effectively already functions with NGET as an ISO (albeit one that is integrated into the GB system). Therefore, we assume that the breakup of NGET would - formally - only affect England and Wales, creating a set-up similar to that currently present in Scotland.

Looking at different parts of the electricity system, the main purported advantage of creating an ISO in England and Wales is that it should ensure – via regulatory design – that there is no inappropriate incentive for NGET to use its assets to undercut the market.

NGET does not own or operate generation or distribution assets. The licensing regime prevents it from doing so, so there are unlikely to be any conflicts of interest in these areas.

However, with the transmission network, as NGET has a dual position in England and Wales there is a potential risk it could recommend changes to the network to increase its own revenue streams (or possibly disadvantage the Scottish transmission owners and/or offshore transmission owners). Nevertheless, Ofgem have stated they know of no instances of this happening in practice[1]. As such, in terms of transmission, it appears creating an ISO would be about removing the suspicion of, rather than actual, favouritism.

Through wholly-owned subsidiaries, National Grid holds licences for interconnectors. Despite the formal separation of businesses, this twin role seems to drive criticism and suggestions that NGET should be broken up. That National Grid is both responsible for balancing the system and advising on the need for new interconnectors has been seen by some as a potentially inappropriate incentive, particularly as interconnectors can now participate in the Capacity Market[2].

If National Grid's ownership of interconnectors is the main impetus behind the creation of an ISO, then it is recommended consideration is also paid to the possibility of modifying the licensing regime to ensure transmission and interconnector licences are mutually exclusive in the same way as transmission and generator, and transmission and distribution licenses. This should have the effect of removing any potential conflict of interest.

It is further recommended that assessment is carried out of the functional relationship between Scottish Hydro Electricity Transmission **and** Scottish Power Transmission as owner/operators with NGET in its role as an 'ISO' in Scotland to ascertain if practical lessons can be learned from such a relationship within the GB context.

- **How could the incentives faced by the SO be set to minimise long-run balancing costs?**

Electricity SO incentives are designed to deliver financial benefits to the industry and consumers by reducing the cost and minimising the risks of balancing the system. Ofgem sets the incentives.

The SO incentive schemes currently establishes cost targets NGET is expected to achieve. For balancing, the key mechanism is the Balancing Services Incentive Scheme (BSIS), which covers energy, constraint and black start costs.

With BSIS, if NGET's costs come out below the level set by Ofgem, it retains a proportion of its savings (capped at £30 million) but if costs exceed the target, it faces a penalty. Since 2011, the scheme has been managed on a biennial basis with the current iteration in place until 2017.

[1] Dermot Nolan quoted in Utility Week (2015) 'Ofgem: 'Strong case' for ISO to replace National Grid'
[2] Energy and Climate Change Committee (2015) 'Implementation of Electricity Market Reform'

While the BSIS two-yearly scheme is only in its third cycle and there should be a general wariness of altering mechanisms, if the intention is to improve long-run costs, consideration should be given to increasing the cycle length from two years to three or possibly even five years. Doing so could incentivise longer-term planning, for example in line upgrades or investment in new ancillary services technologies. However, such potential benefits would need weighing up against the current short cycle arrangements that allow Ofgem a degree of flexibility to manage changing objectives.

- **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**

ICE considers the current balancing market does not fairly represent participants' roles in balancing the system, in particular the current set up unfairly penalises electricity storage.

As SO, under the terms of its electricity transmission licence NGET recovers the costs of its balancing activities through Balancing Services Use of System (BSUoS) charges. NGET applies BSUoS charges to large electricity consumers and generators to cover the costs it incurs in maintaining balance in the system, mostly through arrangements paying parties to either increase or decrease their generation/consumption.

The calculation of BSUoS charges are ex-post based on the volume of energy large users (i.e. those larger than 50 MW) takes from, or supplies to, the transmission system on a half-hourly basis. The charges are paid by the 332 parties to the Balancing and Settlement Code (BSC) and are split between generators and consumers. Ultimately, both sets of costs are passed on to business and domestic customers through their bills.

In 2013-14, more than 50% of the total cost of balancing services related to frequency response and reserve generation. Around 40% of total costs arose from instructions to generators to adjust their production because of local and regional constraints in network capacity.

Bulk storage facilities can be an effective means of balancing the network (see Question 2 for more detail). At present, the BSUoS regime works against their further deployment: storage acts as demand while charging and generation while discharging, so operators must pay BSUoS charges twice, affecting economic viability.

Therefore, ICE recommends that electricity storage's potential for helping to reduce imbalance in the transmission network should be recognised by reforming the balancing market through exempting storage operators from BSUoS charges.

Cost neutrality can be maintained by removing extraneous costs instead of providing a direct subsidy. Exempting *new* storage from BSUoS charges when they are acting to help balance the system would not result in National Grid losing money, nor would it add costs onto other electricity generators or customers[3].

Looking at balancing the system in a wider sense, consideration should be given how to manage smaller operators outwith the market. This will become of increasing importance as the prevalence of distributed, often intermittent, generation on the grid.

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

More work needs to be done to ensure that active demand side management (DSM) develops in GB. All decarbonisation trajectories assume increases to near total electrification of heating and transport. With this comes the likelihood of creating a much larger peak electricity demand for which networks and generation will need to be sized to match.

However, improvements can also be made on the demand side through storage to allow time-shifting of consumption to more closely match the capacities of the electricity system[4]. The use of storage should also help to reduce the use of high emission diesel generators currently commonly used in DSM.

Embedded generation on the distribution network has grown dramatically over the past few years with around 11 GW connected since 2010. On the face of it, the shift to disaggregated generation would seem to increase the electricity grid's overall flexibility – rather than relying on a few, large generators with limited variability of output on the high-voltage network, the country is moving to many, smaller, more responsive facilities on the low-voltage system.

However, existing distribution networks and their regulation were not designed with embedded generation in mind. Rather, they were configured to manage one-way flow from the transmission grid to consumers with relatively passive controls. As such, the GB electricity system is getting to the point where the low voltage networks, DNOs and their regulation can hinder rather than enable increased flexibility.

Embedded generation has the potential to play an important role in smart energy networks. Here, real-time information on network operation and energy consumption are used to manage demand with new monitoring and control technologies making the network more flexible and reliable. However, for this to be fully realised it seems there is a need to shift from a DNO to a Distribution System Operator (DSO) model, where the low-voltage system as a whole, including generation,

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[3] It is noted that extending such an exemption to *existing* bulk storage operators would result in the storage operators BSUoS charges being picked up by the other BSC parties, marginally increasing their costs. However, as bringing new storage onto the system should improve system balance the storage exemption is also expected to result in overall BSUoS charges decreasing, therefore all BSC parties' costs.

[4] There is a significant work looking at these issues, in particular see Smart Grid Forum and Future Power System Architecture Project

demand and the technical and commercial interaction between them, is managed and operated on a regional basis.

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

ICE considers electricity storage to be a key technology for the development of electricity networks to manage the transition to a low carbon economy. Markets and regulation do not currently recognise the potential of electricity storage and need to adapt if Britain is to take full advantage of the technologies on offer.

We have built a national electricity grid to deliver electricity from *where* it is generated to *where* it is needed. Electricity storage can help us in much the same way by moving electricity from *when* it is generated to *when* it is needed. With more and cheaper renewables, storage will become a crucial part of efficient future energy systems.

Storage's important role should be recognised and enabled through removing the red tape and regulatory barriers to its further deployment. We encourage the Commission to consider our recent report, 'Electricity Storage: Realising the Potential' in order to explore this further.

- **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?**

ICE considers there are three key policy/regulatory barriers, the removal of which will facilitate further development and deployment of electricity storage:

1. *Exempt storage operators from Balancing Services Use of System (BSUoS) charges.*
   Storage's role in balancing the network should be recognised by exempting it from BSUoS charges. Currently the BSUoS regime works against the further deployment of storage as operators are 'double-charged'. This is because storage draws electricity from the grid when charging up and exports electricity to the grid when discharging. If these charges were to be removed, this would act as an economic incentive for operators to deploy new storage. Exempting new storage from BSUoS would not result in National Grid losing any money, nor would it add costs on to other electricity generators or customers.

2. *Clarify storage's position through establishing a separate regulatory classification.*
   Electricity storage does not have a licencing classification and is consequently often treated as a form of generation. DNOs' (and others') licences prevent them from operating generation and therefore, cannot control storage facilities. Classifying storage as a specific activity - one that all licence holders can participate in - would free up DNOs to improve their networks. Such cutting of red tape will effectively be cost neutral, as it would only involve minimal administration costs.

3. *Enable renewable electricity generation to match demand through encouraging storage.* Renewables operating with storage should be eligible for a feed in tariff (FiT) that tops-up wholesale electricity prices. The percentage premium FiT is designed to use market signals – tracking the wholesale price – to encourage renewable operators to use storage so as to export electricity at times of high demand. Under this system, decisions on whether, when and how much storage to build are guided by the market, enabling new storage to be built when there is a need and when it is economic to do so.

If the potential benefits of electricity storage in future systems are to be realised for GB, the Government, working with the regulator and industry should act to provide a clear statement on the future of electricity storage in the energy system setting out steps towards making the recommended policy changes.

Doing so will encourage investment in a sector with huge potential not just to improve energy efficiency and security but also position the country as a leading technology innovator. With the confidence provided by the certainty of direction on electricity storage, new technologies would develop to market and existing ones will improve their application and efficiency.

- **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.)**

There is no "most appropriate scale" for electricity storage. Rather, because the term 'electricity storage' encompasses a wide range of technologies with diverse capabilities suitable for application at different points on the network for different purposes, electricity storage can be deployed at a variety of scales, situations and sizes.

Storage is unique in the electricity system in that it cannot only supply, it can also absorb energy to export as-and-when required. This can be for frequency response to maintain the second-to-second balance between level of supply and demand (either through absorption or through discharge), providing reserve power or inertia, network congestion management and reducing the need for investment in system reinforcement.

Economies of scale will apply to storage just as they do to generation. However, it is the use of storage that will determine the scale: the MW by the local needs, and MWh by the owner's view of the appropriate capacity / cycle.

Transmission-level or 'bulk' storage can reduce generation investment costs and help ensure security of supply against unplanned outages and mitigate the need for inefficient ramping up and down of low load factor backup generation with low efficiencies and high emissions. In addition, they can 'firm–up' intermittent renewables generation by effectively shifting supply profiles to meet demand. If planned from a systems point of view such storage can complement or potentially offset the need for interconnection and transmission investment.

Currently there is a capacity of around 2.8 GW (or up to 25.5 GWh) of electricity storage capacity in GB. All of this bulk storage is currently from pumped hydro storage (PHS). In the main, PHS is expected to continue to be the main technology for bulk storage in the near future, however, there is also potential for newer systems such as liquid air and compressed air. There are at least five planned new bulk storage facilities in GB, all PHS three new plants in Scotland plus Glyn Rhonwy in Wales, and the proposed upgrade of Cruachan PHS. If all were developed to their planned capacity they could provide a further 1.8 GW (up to 69.6 GWh) of new storage**.**

For Distribution Network Operators (DNOs), managing the connection of an ever-increasing share of distributed generation combined with the electrification of heat and transport, and multiple, intermittent generation sources in the market will be a challenge. Networks will no longer be just from transmission to customers, but rather multifaceted networks with two-way flows. Here electricity storage will be particularly useful in avoiding local network constraints and reducing / deferring the need for line reinforcement. They will, therefore, be sized to match the local requirements, generally in MW/MWh but also including quite small installations possibly of only a few kW/kWh. Such installations can of course contribute to local, regional and national balancing opportunities.

There are two main reasons why co-location with renewable power - as opposed to network connected - generators is important, or at least valuable. The first is to avoid flows of energy that are too large for the local network, diverting the excess into storage, to be released later. This can also avoid the need to make constraint payments. Secondly, co-location allows the losses incurred from storage to be kept 'on the same side of the meter' - in other words, they are picked up by the storage operator unlike the cost of network loss costs that are spread across electricity suppliers.

If storage is working in concert with renewable generation, it operates as a form of pre-network helping to flatten the load curve and potentially facilitating predetermined generation profiles improving dispatchability and integration with the network. By releasing energy at a steady rate when most needed, storage co-located with renewable generation can smooth supply fluctuations and, as such, is expected to play a significant role for further integration of renewables onto the grid. It follows that this would also lead to less network constraint problems and assist in reaching renewable energy targets.

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

If interconnection is displacing synchronous generation, the behaviour of interconnectors needs to compensate for the loss of the system inertia. It is also worth pointing out that alongside the benefits of interconnection in balancing the system, there is also increased risk to the GB system from transferring a serious problem on the continent by interconnection to the GB system. A simultaneous loss of more than one interconnector because of a widespread blackout (such as that which happened in 2006 on the continental system), could lead to serious system stress and frequency exertion on the GB system, possibly resulting in the tripping of demand in GB.

- **Is there a case for building interconnection out to a greater capacity or more rapidly than the current 'cap and floor' regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?**

No response.

- **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

Under the EC's Third Package's Electricity Regulation, interconnectors are defined as a transmission line. Consequently, interconnector flows are neither classed as production (generation) nor consumption (demand) but part of the overall transmission infrastructure facilitating the wider market and are therefore not liable for BSUoS. As such, it could be argued that interconnectors have an advantage over other 'balancing' technologies, most notably storage, which as noted above pay BSUoS twice.

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?**

No response.

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