# GE RESPONSE TO NATIONAL INFRASTRUCTURE COMMISSION CONSULTATION, 8 JANUARY 2016

1. This response focuses solely on the energy policy questions in the Commission's call for evidence.

## Context

2. In principle, GE favours a liberalised market approach, with, if necessary, time limited interventions to address clear market failures. We are also in favour of consistent policies across Europe, rather than a patchwork of conflicting national approaches, which create investment uncertainty and raise costs.

3. GE welcomes the Commission's focus on energy infrastructure. The GB electricity system is changing which presents new challenges to system security. Large, dispatchable thermal generation is being replaced by low carbon, smaller, and largely variable generation. As recent analysis by the Committee on Climate Change (CCC) has shown, the lowest-cost trajectory to the UK's legally binding carbon targets requires that the carbon intensity of power generation decreases to below 100 g/kWh in 2030, with low-carbon generation producing around 75% of generation. Managing the system will no longer be handled solely through the energy market (wholesale and balancing) and ancillary services. Flexible generation, demand side response, interconnection and storage will all be important. The CCC's analysis shows that increased flexibility is a low-regret option, with savings of at least £2.9bn p.a to 2030.

## Questions

**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?**

**a) What role can changes to the market framework play to incentivise this outcome?**
**c) Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**

4. The existing arrangements to ensure that demand is balanced with generation include:

   - **Bilateral trading or power exchanges**: generators and suppliers buy and sell power in the forward, day ahead and spot wholesale electricity markets. All transactions are notified to the System Operator. After 'gate closure' generators and suppliers use the Balancing Market to ensure that individual positions are balanced.

   - **Ancillary Services**: the System Operator (National Grid) has a number of ancillary services which can be used to balance the system.

5. We support the recent Ofgem reforms to ensure that cash-out prices respond more sharply to system imbalances. The changes should ensure that flexibility is better valued in the Balancing Market. However, it also poses risks to market participants, particularly those smaller players more at risk of being out of balance. It is therefore important that the cash-out changes are monitored closely before making any further changes.

6. We would support moving to shorter term settlement periods (e.g. 15 minutes) to reduce averaging of over and under supply by suppliers which can occur in the current 30 minute settlement period.

7. With renewables, the forecast error on a single wind turbine will be very high, on a wind farm smaller, on wind in a region even smaller, and on the whole GB wind fleet, the forecast error is very small. It is important therefore that the forecast error of the whole GB wind fleet is considered in any imbalance of wind, not the forecast error of a small part of that wind fleet.

European level

8. There are changes taking place at a European level which will affect the GB's balancing arrangements. The EU is expected to push for the alignment of national balancing markets, through the EU Electricity Balancing Network Code, which could become legally binding in the next 2-3 years. This will move Europe away from a position in which most balancing is carried out on a national level, which should bring down costs and enhance security of supply.

**b) Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?**

9. Yes. An Independent System Operator (ISO) would have merit in being clearly independent or any network asset owners. An ISO would not have any incentive to build transmission and could judge each proposed transmission and interconnector project on its merit. It could also assess the options for interconnectors to reduce transmission constraints.

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

10. Demand-side management needs strongly variable pricing to be worthwhile. This is achieved in parts of USA with locational marginal pricing (LMP) which creates large price spikes and troughs. The GB market is at the opposite end of the spectrum to LMP with one price zone for the whole market. An example of a halfway house is the NordPool market, which has a similar volume to GB, but with 14 price zones.

**2. What are the barriers to the deployment of energy storage capacity?**
**a) 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?**
**b) 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.)**

11. Energy storage systems have the potential for significant cost reductions over the coming years, growing to be a $6 billion dollar global market by 2020. GE's energy storage solutions are already present in 25 countries with over 50 megawatt hours (MWh) of grid storage installed in a variety of applications (see more at: https://renewables.gepower.com/energy-storage

12. GE specialises in bringing technologies together to configure custom solutions for a variety of applications, including:
    - **Energy management**: peak demand reduction, back-up, photo-voltaic (PV) self-consumption, power quality.
    - **Transmission and distribution**: capacity management, asset deferral, frequency regulation, harmonic suppression, voltage support, and power quality.
    - **Microgrid applications**: grid management, PV integration, and grid enhancement.
    - **Thermal and renewable power generation**: virtual spin (no emissions), ramp rate control, frequency regulation, time shifting, voltage support, curtailment avoidance.

13. Energy storage is now becoming more accepted by the market. This has been helped by reasonable size technology demonstrators and electric vehicles, amongst others. But education of developers, transmission system operators (TSOs), distribution network operators (DNOs) and investors is still very much needed to keep this market acceptance growing.

14. In the UK, there appears to be a disconnect between NGET (National Grid Electricity Transmission) and potential developers as to where best to integrate energy storage systems (ESS). This is because NGET need active power from the ESS on to the transmission grid to support frequency. However, if the ESS is connected via the distribution network, there may be additional usage fees applied to the ESS by the distribution network operator (DNO). Furthermore, there are potentially times that the distribution network may be at full capacity, meaning that the ESS is not available for the EFR (error and failure resolution) services, leaving a question of who pays for unavailability. The DS3 process in Ireland covers a huge number of similar issues, though we understand that there are no formal discussions between EirGrid and National Grid at present. Perhaps this could be initiated in order to share knowledge?

15. If we look at the price for an ESS project, a large part of the cost is batteries. These costs are starting to fall; within three years, battery costs are expected to decrease by up to 30%. This means that larger systems can be considered. However, there are significant site and grid connection costs. As installations grow in size, the amount of equipment and the necessary cooling are best managed within a purpose built substation. NGET has suggested that a 50MW block is the largest they expect at any one location. But the substation and 400kV connection costs are almost the same as for a 200MW installation. This may be a problematic for developers and their business cases.

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

**a) 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?**

**b) 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?**

16. Interconnection capacity was only 6% of the UK's installed capacity in 2014 (21st out of 28 EU member states). The UK is clearly under-connected with its neighbours and greater levels of interconnection would be in the interests of consumers. The exact level of interconnection should be left to the market, but we note that the European Council agreed a target for countries to achieve 15% interconnection capacity by 2030. That would seem to be a minimum level that the UK could achieve by the end of the next decade.

17. While there is a strong pipeline of planned interconnectors, the current regime alone is unlikely to lead to an optimal level of interconnection for British consumers. There is a case for building more rapidly than the Cap & Floor (C&F) regime can deliver. C&F requires sufficient market price differences between the connected markets to provide financial certainty to investors many years ahead. It takes around 5 years to develop an interconnector and around 4 years to build it, with the investors relying on forecasts for 10-20 years after that. This high risk approach can drive interconnection where there is a severe shortage, but will otherwise result in a sub-optimal level of interconnection. Under C&F, investors will only be tempted by to take long-term, high risks against a very strong forecast revenue stream. In addition, future changes to market price zones (e.g. under CACM) could create, or destroy, value overnight. Interconnectors should have the option of being fully regulated, as is the case for onshore transmission assets.

18. Even where price zones in two markets are mostly coupled (i.e. equal) there can still be value in interconnection as the lowest cost way of overcoming transmission bottlenecks. For example we already see different percentage flows and directions on EWIC and Moyle, which connect the GB BETTA and Irish SEM markets. These flows indicate that the interconnectors are being utilised to solve transmission bottlenecks in Ireland or in GB.

19. Historically, interconnection has been much more expensive than reinforcing onshore transmission networks. However, we now see that trend reversing due to the difficulty of building new overhead power lines onshore. For example, National Grid and Scottish Power are increasing north-south GB capacity through the offshore, subsea, Western Link (West Coast Bootstrap) at a cost of over £1billion. With development of subsea cables and HVDC technology, relative costs for interconnection are falling compared to other onshore reinforcement options.

20. Reinforcements across transmission operators are facilitated by the regulatory regime with e.g. Kintyre, Beauly Denny, and Western Bootstrap. National transmission reinforcements are prioritised and treated differently to interconnectors. An independent system operator – free from any transmission or interconnector asset ownership - would help to identify and assess new assets for development and funding. Ofgem has created C&F to put risk on developers; however, developers will not be able to bring projects forward if that risk is not rewarded. A completely independent SO would help give Ofgem greater confidence in assessing new interconnector proposals and giving those projects a regulated financial regime.

21. Onshore transmission operators are paid for developing onshore transmission assets (they are reimbursed their costs from consumers) including shared assets between TOs (such as the Western Link). There is currently no such cost recovery for interconnector developers, resulting in a reducing incentive over time to develop new projects.

22. Interconnection faces specific barriers and challenges that are not faced by other balancing technologies. It is cross-border by nature, which means dealing with multiple jurisdictions and plays multiple roles in the energy system beyond system balancing alone.

23. On specific market failures/barriers, we would highlight the following points:

- The capacity mechanism should be reformed to incentivise new interconnectors. Although interconnectors were eligible to bid in the recent auction, the clearing price was too low for new build. Long term capacity payments are required over 15 years to provide the certainty to enable financing interconnector projects. Making annual payments will not provide sufficient certainty to finance new interconnector capacity.

- Interconnectors have a much longer lead time than most generation projects due to the HVDC technology and dealing with permitting regimes in at least two jurisdictions. The capacity mechanism should be able to contract years ahead for interconnectors so that new interconnectors can be financed accounting for these benefits to GB consumers.

- Interconnectors with Ireland which are often exporting or float should receive capacity payments, as they are far more valuable in addressing system emergencies and imbalances than interconnectors that are importing. Importing interconnectors cannot increase their power into GB if there is an emergency, such as a large power station trip, breakdown, fire or fault. However, exporting interconnectors can reduce exports or start importing and hence support the GB system at times of stress or crisis.

24. In any future with a greater level of interconnection, significantly less generation infrastructure will be needed to deliver a secure, balanced and low-carbon energy system. As more physical interconnectors are built, the costs to UK consumers of ignoring the opportunities to share resources

with European neighbours will become too large to ignore. It is expected that investment in onshore, offshore and cross-border transmission capacity will reach £23bn–£50bn by 2030, which is considerably greater than the entire current Regulated Asset Value of existing GB transmission assets (< £13bn). Any improvements in the network planning process therefore have the potential to deliver considerable savings in the cost of the network infrastructure, while greater integration with the power systems of neighbouring countries has the potential to deliver further savings.

## About GE

25. GE is the world's Digital Industrial Company, transforming industry with software-defined machines and solutions that are connected, responsive and predictive. GE is organised around a global exchange of knowledge, the "GE Store," through which each business shares and accesses the same technology, markets, structure and intellect. Each invention further fuels innovation and application across our industrial sectors. GE employs around 22,000 people in the UK. www.ge.com

    Contact: [email address redacted]