NATIONAL INFRASTRUCTURE COMMISSION CALL FOR EVIDENCE
ELECTRICITY INTERCONNECTION AND STORAGE
Executive Summary - key points of our response

The UK faces an unprecedented challenge in meeting electricity demand in the coming years

- National Grid estimates that UK electricity capacity is at its tightest level for a decade. Coal stations are closing; the UK's nuclear fleet is ageing with only Hinkley C (earliest start-up 2025) agreed; and old gas-fired power stations are coming offline.
- Renewables have grown, but remain intermittent.
- Against this backdrop the UK can balance its electricity needs by supporting larger power stations that provide capacity; smaller peaking plants as well as other balancing services. Specifically measures would include:
    - Increasing support for gas power stations to maintain existing sites and encourage new build;
    - Facilitating interconnection with Europe, whilst recognising that interconnectors already benefit from a number of incentives and cannot be relied upon during times of system stress;
    - Supporting and growing Demand-Side Response (DSR) services and Distributed Electricity Resources (DER), which can help to manage peaks in electricity demand;
    - Support battery storage technology, which could help manage peak demand.

Gas is a more certain source of security, but currently interconnectors receive more support

- Interconnectors can play an important role in balancing the UK electricity system, but they cannot be relied upon for security of supply (as they can export as well as import) and new electricity interconnectors are already strongly incentivised as Table 1 highlights.
- Evidence suggests that interconnectors such as IFA (France-England) cannot be relied upon to flow consistently to Great Britain (GB) in cold winter periods when French electricity demand for heating may also be very high.
- We believe there is greater incentivisation for interconnection than there is for gas-fired generation in GB, which is distorting the market and there is evidence that greater encouragement of interconnection would further damage the economics of domestic gas investment. If not addressed this imbalance is likely to make the achievement of government policy objectives for gas a major challenge and could potentially threaten UK security of supply.

Table1: Incentives and Costs for Combined Cycle Gas Turbines (CCGTs) and Interconnectors showing disparity

Market conditions/rules	**Gas Generation**	**Electricity interconnectors**
Commodity market prices	Low clean spark spreads	High geographical spreads
Merchant risk	Substantial	Limited (cap/floor regime)
Transmission charges	Both TNUoS and BSUoS	Subject to neither
Carbon pricing	UK Carbon Price Floor	EUA (ETS price) only
Capacity market	Participates	Participates (from Dec 2015)
Locational incentives	Yes, via transmission charging structure (known as TNUoS)	No locational price signals apply

The Capacity Market is the correct instrument to support gas, but needs reform

- The GB Capacity Market (CM) is an essential instrument for maintaining security of supply; supporting existing power stations and incentivising new-build gas. We believe it is generally well-designed, but there are concerns it has procured too little capacity and in two years has not yet delivered any viable, new CCGTs.
- Amber Rudd's 'Energy Reset' speech in November 2015 supported a switch from coal to gas power stations by committing to the phase out of coal by 2025 and reviewing mechanisms for supporting new-build gas. We believe that coal stations are on a glide path to closure by 2025 and as more stations close, the economics for gas will improve. However, this improvement in economics for gas may not be sufficient to support new investment until 2019/2020 when significant levels of coal have been phased out, which could significantly threaten security of supply.
- The CM should be the mechanism to ensure there is sufficient gas to meet the phase out of coal. Government has rightly initiated a review of CM arrangements ahead of the forthcoming 2016 auction for 2020/21. In our view the following adjustments would ensure the CM is fit for purpose:

- review the 'de-rating' applied to certain types of capacity (e.g. wind and interconnectors);
- introduce tougher incentives (penalties) and collateral requirements for new-build plant, with a view to ensuring that contracted capacity actually gets built;
- bring forward some of the earmarked 'T-1' auction capacity in to the main CM auctions 4 years ahead to encourage new investment now; and
- procure more capacity to ensure security of supply is maintained as margins tighten.

- We are also concerned that the Capacity Market may not be strongly enough incentivising reliable capacity. The future of the only new build CCGT project, Trafford, which received a contract in 2014, is uncertain and a number of the contracts awarded are short term. The Government should assess ways to ensure more reliable plant that can contribute in the longer term receives contracts, by: incentivising more new-build projects; considering lowering the investment threshold for existing 3 year refurbishment contracts; strengthening the penalties for generators that do not deliver their contractual requirements and assessing whether the current contract length and structure is providing adequately for long term security of supply.
- Electricity balancing and cash-out arrangements have recently been reformed and generally appear to be robust. There is, for example, a risk that significantly higher cash-out prices disincentivise ownership of generating assets, as opposed to buying in the market, due to an increased outage liability.

Distributed Energy and Demand-Side Response can smooth peak demand problems

- The future electricity system will need more flexibility services to manage times of the day when electricity demand peaks. Distributed Electricity Resources (DER) (generation and supply connected directly to the distributed networks) and Demand Side Response (DSR) (reductions in the amount of electricity consumers use) can achieve these aims cost effectively and should be encouraged further by the Government.
- As DER/ DSR become more important in the future system design and operations, it is essential that the national and local electricity systems are aligned and coordinated. With more electricity being generated at the distribution level there is a risk of making the balancing of the national system more challenging. It will be important for the Transmission System Operators (TSOs) and Distributed System Operators (DSOs), who manage these systems, to coordinate their work.
- We believe this work should be done before considering whether SO (System Operator) independence is sufficiently assured. But it is important that the TSOs and the DSOs act as neutral facilitators when providing connections, assessing flexibility services (e.g. DER/DSR) and communicating. They also need to be transparent and act in a non-discriminatory way - neither the TSO nor the DSOs should be active as commercial service providers.
- Policy incentives should consider the desired mix of embedded plant, making use of existing back-up diesel plant on industrial and commercial sites and flexible open-cycle gas generation to manage peak demand – without unduly incentivising new-build diesel ahead of other embedded generation types.

Battery Storage will make a major difference to the design of transmission and distribution

- Battery storage will likely bring benefits in a number of different areas. Battery storage will allow more efficient use of renewable energy and will have a significant positive impact on the grid's ability to balance and manage pressure at peak times. To help enable this product to come to market, battery storage should become eligible for Enhanced Capital Allowances.

The UK is a world-leader in balancing decarbonisation with affordable and secure supply

- There is much that the UK can learn from international experience, but in our view there is as yet no superior 'blueprint' model of international best practice and in some respects (e.g. the design of the CM and steps taken to reduce the level of unabated coal capacity on the system) the UK has been ahead of many other countries. The European Commission's updated 'Target Model' for EU electricity seeks to integrate renewable generation into the wholesale electricity market in a way which is already taken as a 'given' in the UK.
- The UK's carbon tax approach to carbon pricing is an important part of the policy framework and should be supported. Its market-based approach helps to create a simpler energy system and has the ability to create a market signal in favour of decarbonisation.

Our full consultation response

1a. 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?

Overview

The CM is an essential instrument for maintaining supply security in today's market conditions. It is generally well-designed, but it has procured too little capacity overall and deferred volume to 'T-1' which new CCGT can't access. The incentive structures do not yet support sufficient investment in new-build gas generation.

Electricity balancing and cash-out arrangements have recently been reformed and generally appear to be robust. The future electricity system will need more flexibility services to maintain security of supply.

The market needs to facilitate the growth of Distributed Electricity Resources (DER) and Demand Side Response (DSR) to deliver this cost-effectively.

Capacity margins in the GB wholesale electricity market are currently very tight and this is expected to remain the case for several more years. National Grid issued a NISM (Notification of Inadequate System Margin) on 4 November and has indicated that more NISMs should be expected in an average 2015/16 winter. This does not mean an imminent threat of 'the lights going out' but it does signal to the market an exceptional need to make additional supply available and/or manage demand.

Partly due to the growth of intermittent renewables with very low variable costs, gas generation has seen lower utilisation in recent years and clean spark spreads (a measure of operating profit margins) have also been squeezed. Gas generation has become non-viable on the basis of the traditional energy market alone and Centrica's gas fleet made a 2014 operating loss of £120m (and £133m the year before). Gas generating capacity is vital to ensure a satisfactory level of supply security, including the provision of back-up generation when wind and solar generation are low. The CM has a key role to play in supporting existing gas stations and incentivising the development of new gas stations. Existing gas and nuclear stations require significant ongoing investment, and the CM is a key revenue. The CM is an important part of the revenue available for non-subsidised technologies, providing a lower cost and less volatile capacity in comparison to some intermittent and subsidised capacity. Therefore the CM should continue to include existing plant as well as new-build.

We supported the introduction of a market-wide, technology-neutral CM auction which excludes only those low carbon facilities already in receipt of subsidies. Unfortunately, experience with the 'T-4' auctions held to date suggests some major flaws:

- The government has not procured sufficient capacity to encourage the development of new-build CCGTs; the auction for 2018/19 cleared at £19.40/kW/a, which is far from sufficient incentive.
- Moreover, the weak incentive structure applicable to new-build plants encouraged some projects to remain in the auction and accept a capacity price which is less than they appear to need to justify a Final Investment Decision. The large 1.6 GW CCGT at Trafford Park secured a 15 year contract but has not yet gone into construction.
- The auction for 2019/20 cleared at a slightly lower price of £18/kW/a. Contracted new-build capacity was dominated by small embedded diesel plants rather than CCGTs.
- The set-aside of 2.5GW of the required volume to the 'T-1' auction precludes new CCGT from bidding for this as the 1-year lead time is insufficient for new plant; bringing this volume forward to 'T-4' would provide a better opportunity for new plant to be successful in the CM.

The Government has stated they will review arrangements for 2020/21, but gas stations currently face major challenges and without greater support there could be risk of companies being unable to develop new stations and struggling to maintain existing sites. We believe the Government's announcement of a phase out of coal-fired power by 2025 could improve the economics for gas in the coming years, but we are concerned that this trajectory is unlikely to improve the market for gas until 2019/2020, causing capacity challenges.

We are also concerned that the Capacity Market may not be strongly enough incentivising reliable capacity. The future of the only new build CCGT project, Trafford, which received a contract in 2014, is uncertain and a number of the contracts awarded are short term. The Government should assess ways to ensure more reliable plant that can contribute in the longer term receives contracts, by: incentivising more new-build projects; considering lowering the investment threshold for existing 3 year refurbishment contracts; strengthening the penalties for generators that do not deliver their contractual requirements and assessing whether the current contract length and structure is providing adequately for long term security of supply.

The move to a low carbon economy introduces large volumes of intermittent renewable generation. These make balancing supply and demand more difficult, and also introduce operability challenges for the network, impacting its resilience to faults (i.e. reduced system inertia and resilience).

Electricity balancing and cash-out arrangements have recently been reformed and generally appear to be robust. The future electricity system will need more flexibility services to maintain security of supply. The industry has just completed a long-running Significant Code Review led to an Ofgem decision to reform these arrangements to enhance supply security. These reforms are split into two phases, the first of which took effect from 5 November 2015 and the second of which is scheduled to be implemented in 2018.

We generally supported these reforms, which should allow markets to operate more effectively to preserve supply security. They will mean ‘sharper’ (higher) cash-out prices when capacity margins are tight in order to incentivise appropriate responses from market participants, including as regards demand-side response. We still have reservations around the proposed move to ‘PAR 1’ in 2018, particularly around the risk that competition in setting very ‘marginal’ cash-out prices may not be sufficiently robust. This will need to be monitored carefully, to balance the potential gains to supply security against the increased risk and cost to market participants and consumers. There is, however, a risk that significantly higher cash-out prices disincentivise ownership of assets, as opposed to buying in the market, due to an increased liability.

Growth in DER DSR is needed to provide the GB electricity system with the flexibility it needs to evolve from a conventional centralised generation system to one that has significant contributions from intermittent sources of generation.

DER and DSR can be used in a number of ways to provide numerous benefits:

- They allow the TSO to balance electricity supply and demand both on short timescales, for frequency response services, and longer term, in Capacity Market to ensure periods of high demand can be met.
- They can reduce the demand peaks on the Transmission and Distribution networks.
- Suppliers may also use DER/DSR to reduce wholesale costs for consumers or reduce exposure to imbalance charges.
- DER/DSR can also improve choice by increasing market competition between these services.
- DER/DSR can also provide a source of value for consumers e.g. rewards changing consumption behaviour as load shifting reduces the costs of electricity.

1b. What role can changes to the market framework play to incentivise this outcome?

Overview
We would emphasise again (as stated above) the important role gas-fired power generation will play as the country switches away from coal. It is important to ensure the sector is incentivised both to maintain the existing gas generation fleet and build new gas as soon as possible to meet the potential capacity shortfall.

As DER/ DSR become more important and services increase, it is essential we have aligned positions and processes between system operators to ensure the networks can be managed effectively.

The separate uses for DER/DSR identified above have different requirements, location may be important, the notice period to initiate the DER/DSR, the duration of the service and frequency of events will all impact availability. Whilst some DER/DSR may be better suited to certain uses, others can supply multiple uses. As a result there may be conflicts or synergies for the TSO (and/or DSOs) in managing their deployment.

TSOs have overall responsibility for system security while DSOs have responsibility for the secure operation of their distribution networks. This means TSOs will need to continue to have the leading responsibility for national balancing, frequency control and system restoration, whereas DSOs will maintain their responsibility for congestion and voltage management on their networks. As an increasing share of electricity generation connects to DSOs, one of the major operational challenges for the TSO will be maintaining overall system security. Scarcity of system services will become more acute in the future meaning new operational arrangements between TSOs and DSOs to unlock the capabilities of DER and DSR and maintain security of the distribution and transmission networks.

The TSO and the DSOs will both have a responsibility for providing information and support to market participants at their respective network levels. They must act as neutral facilitators when providing connections, assessing flexibility services (e.g. DER/DSR) and also need to be transparent and act in a non-discriminatory way. Neither the TSO nor the DSOs should be active as commercial service providers.

1c. 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?

Overview

We do not believe now is the right time to address this issue. The first priority should be to establish the right set of SO roles and responsibilities across the system so that transmission and distribution system operators can work effectively at a time when balancing the networks is becoming more challenging. There is probably a case for longer duration SO incentives (provided that these are not over-generous) and in future it will also be important to incentivise the proactive management of 'smarter' distribution systems.

The SO has recently taken on new roles as the Delivery Body for the CM and the CfD auctions and plays an increasingly important role within the GB electricity system. An independent SO, with a dedicated board focused solely on electricity system issues, could be beneficial.

However, we do not think that these are current issues, and to date business separation arrangements appear to have worked well. Hence, any decision to separate out the SO business from NGET would need to balance the costs (and risks) with the benefits it could bring. For example separation could require the division of and/or investment in new information systems, increasing costs for consumers and potential disruption to the industry.

As outlined above, the GB electricity system is undergoing fundamental change and getting this right, is more important than establishing an independent SO. We have concerns that separating out the SO at this critical time would be a distraction and could introduce uncertainty when the industry is trying to encourage more DER and DSR. The first priority should be to define an appropriate set of SO roles and responsibilities across the electricity system as a whole (including the interfaces between transmission and distribution) and then to consider how best to ensure the independence of the system operator(s).

Finally, it is important to consider how the SO or SOs can best be incentivised to carry out their roles efficiently and invest where necessary to reduce the longer term cost of system operation to consumers. In particular:

- Current TSO incentives tend to be at most two years in duration. It is for consideration (a) whether this is long enough to incentivise the right investments, in some instances and (b) whether the risk/reward balance is appropriate from a consumer point of view. Longer duration incentives could be beneficial, but care would be needed to ensure that these are not over-generous.
- In the medium-long term, as DER and DSR continue to expand, there will need to be further incentives for pro-active system management at a distribution level. This will become a major issue by the time the current electricity distribution price controls come to end in 2023, but in the meantime the interim review to take effect from 2018 may provide an opportunity to begin to address this point.

1d. Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

Overview

The Balancing Markets will need to evolve to take account of the need for more flexibility services; the number and range of balancing players; and to solve operational constraints of TSOs and DSOs which may conflict.

The TSO is currently responsible for forecasting national electricity demand and undertakes operational planning from year ahead to day ahead to match generation and demand with an appropriate level of security margin. It has to take into account generation availability, the transmission systems capability and outages.

All system users are then responsible for balancing their own electricity "contractual" positions with their counterparties (through Elexon). These positions are fixed at gate closure, one hour ahead of real-time. The TSO, as the "residual balancer" must then ensure that electricity generation and demand are balanced across the GB transmission system on a second by second basis in real time. It does this by procuring a wide variety of Balancing Services to balance the power flows around the electricity transmission system and is responsible for contracting short term generating provision to cover demand prediction errors and sudden failures at power stations.

Distribution networks are currently largely passive and do not have any material balancing operations. This approach is starting to be challenged by the growth of DER, smart metering and DSR. The future development of 'smarter' distribution grids which can adapt to more complex and unpredictable electricity flows will in time require both new incentives and a different organisational 'mindset'.

Looking forward the balancing market will need to be responsive to the changes identified in this paper and evolve over time. A few of the principles and features we believe will be necessary are provided below. We do not believe wholesale reform is absolutely necessary; an evolutionary approach which engages all stakeholders will be less disruptive and create less uncertainty for the market.

- The TSO will need more visibility of all the DER/DSR connected to the distribution network (and the deployment of emerging technologies such as electrical vehicles and storage). Visibility will help the TSO maintain security of supply, lessen demand forecast errors and limit increases in reserve margins driven by growing uncertainty, which will benefit consumers by increasing cost-efficiency.
- The DSOs must avoid creating exclusive, fragmented markets in their respective areas as this will impact the ability for DER/DSR resources to maximize their economic potential at scale and could ultimately impact the efficiency of the market and overall effectiveness of system operation.
- DER/DSR sources should be able to sell their services where it is the most profitable for them (e.g. balancing, system services, valuation in the energy market, congestion management, contracts with DSOs or TSOs as an alternative to grid reinforcement, etc.)
- TSO and DSOs cannot be on both sides of the market as both the market facilitator and service provider. If they are demanding or buying a system service, then this service cannot be provided by them as well.
- DER/DSR should be integrated into the market on equitable and transparent terms with those offered to generation and storage. This will require opening all markets to DER/DSR on a non-discriminatory basis and creating suitable products and services to allow markets to deliver appropriate price signals and incentives to develop DER/DSR.
- Barriers to DER/DSR aggregation should be removed so consumers can aggregate their services with third parties, regardless of their connection points. However, suppliers will need to be protected from imbalances created by third party aggregation of their consumers.
- Markets need to be left to deliver appropriate price signals and incentives to develop DER/DSR in the system. Network companies should focus on efficient grid operation and should not be playing a role as commercial intermediaries as this is better fulfilled by market participants subject to competitive commercial pressures.

2a. What are the barriers to the deployment of energy storage capacity?
2b. Are there specific market failures that prevent investment in energy storage that are not faced by other 'balancing' technologies and how might they be overcome?

Overview
The cost of battery storage needs to fall to become commercially viable, which the Government could support. There has, until now, been a 'missing market' in frequency response and other forms of flexibility within the GB electricity sector. This will be required increasingly in the future to maintain system stability and security in the face of the growth in intermittent decentralised generation.

Partly through the impact of subsidies, there has been a very rapid growth in 'embedded' intermittent generation connected to distribution networks. This includes c. 9 GW of solar plant, of which most is free-standing rather than installed on residential customers' roofs. Such developments are starting to create system stability issues for the electricity networks, which are required to keep system frequency within narrow tolerances. There has also been a sharp reduction in the costs of solar power, which is encouraging, but this now needs to be complemented by the development of cost-effective energy storage.

Battery storage is an emerging market, which has made significant steps in recent years. Battery storage will allow us to use renewable energy more efficiently and will have a significant positive impact on our ability to balance and manage pressure on the grid at peak times.

While we do not believe there are any specific market failures, the costs of battery storage mean that it is currently not a commercially viable proposition. To help enable this product to come to market, we would like to see battery storage added to the Enhanced Capital Allowances list. This would allow businesses to realise financial benefits immediately, improving the payback period. It also has the benefit of not being recovered through energy bills, so avoids a regressive impact on bills.

It is interesting to note that National Grid is launching a national tender for rapid frequency response which is expected to take place in Q1 2016. Battery storage is ideally placed to provide these services and existing 'brownfield 'generation sites with good existing grid connections will be among the most suitable locations for it. Together with partners, we intend to participate in this auction which represents a first move to create the 'missing market' in flexibility which we mentioned above.

2c. What is the most appropriate scales for future energy storage technologies in the UK? (i.e. Tx network scale, Dx network scale or domestic)?

Overview
We believe that battery storage will bring benefits in a number of different areas. There are a number of different types of battery storage, with different technical and operating characteristics, which we consider further in the answers to this response.

These technologies have the potential to help businesses manage their energy usage more effectively, particularly where they use on-site renewable generation, such as solar and wind. Companies with solar PV that currently export some of their generation during the day will be able to store excess generation to use later in the day such as at peak times of demand, known as network red periods. It would also allow companies to import excess during low cost HH periods such as early morning or early afternoon and then use that power in high cost Triad and red periods.

They will allow homes to do the same, shifting the power generated from solar PV to more useful times of the day such as the evening maximising consumption and minimising less valuable export. In the longer term, this could further be supported by dynamic time of use tariffs.

They will also deliver whole system benefits, by removing pressure from the grid and reducing peak demand. Battery storage also has an important role to play in National Grid's Enhanced Frequency Response.

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

Overview
The development of new electricity interconnectors is already strongly incentivised, including via a transfer of market risk and onshore transmission reinforcement costs to GB electricity consumers. We believe there is greater incentivisation for interconnection than for new gas-fired generation in GB. If not addressed, this imbalance is likely to make the achievement of government policy objectives for gas a major challenge.

The GB wholesale power market is currently characterised by a relatively low level of cross-border interconnection, at around 4 GW, equivalent to c. 5% of installed generating capacity. In part, a lower level of interconnection (by Continental European standards) is explainable by the much higher cost of constructing sub-sea cables as opposed to conventional onshore electricity transmission lines. For example, the 750 km NSN link under construction between Norway and northern England is reported to have a total capex cost of €1.5-2.0 bn, i.e. well in excess of £1 bn.

However, partly in response to the 'cap and floor' regime more projects are now going ahead: two further projects (with a combined capacity of 2.4 GW) have now begun construction and it seems likely that further Final Investment Decisions will follow in the next few years. Several factors are incentivising the development of interconnectors:

- There are currently large electricity price differentials between GB and various Continental markets. German power for 2016 is trading at €30/MWh, whilst UK power is priced at close to £40/MWh.[1] In Germany renewable generation with very low variable costs is displacing thermal generation in during off-peak periods and driving wholesale power prices at such times to very low or even negative levels.
- The EUA carbon price under the European Emissions Trading Scheme is around €8-9/tonne (c. £6), whilst UK generators are also subject to a carbon tax of £18/tonne.
- Interconnectors are exempt from National Grid's Balancing Services Use of System (BSUoS) charges which apply to GB generation and supply, the latest 2015/16 forecast being just over £1.80/MWh.
- Interconnectors are exempt from electricity transmission charges (known in GB as generation TNUoS) from which National Grid expects to recover just over £600m in total during 2015/16. Many Continental generators do not appear to face these similar charges.
- New interconnector projects are able to benefit from a supportive 'cap and floor regime'.[2] This has two particular effects:
    - First, the 'floor' on ROCE (return on capital employed) is generally set at the cost of debt – thus providing debt service assurance to providers of finance and allowing owners to take advantage of low borrowing costs by 'gearing up' the project balance sheet.
    - At the same time, since the floor applies to the whole of capital employed (and not just the debt portion), it also limits the extent of downside equity risk.
- In current market conditions, interconnector projects operating under this regime may expect to earn returns much closer to the cap than the floor, but the 'cap and floor' combination provides protection against future changes (such as a reduction in the carbon cost differential), as well as providing encouragement to any subsequent interconnectors with more marginal project economics.
- Finally, a number of interconnector projects are expected to benefit from EU subsidies, since they have been classified as 'Projects of Common Interest' (PCIs).

The Secretary of State set out in her November energy speech that building new gas-fired power stations would be a key priority. However, providing support for interconnection and gas-fired power stations could create challenges. The impact of more interconnection on the economics of gas-fired power is three-fold:

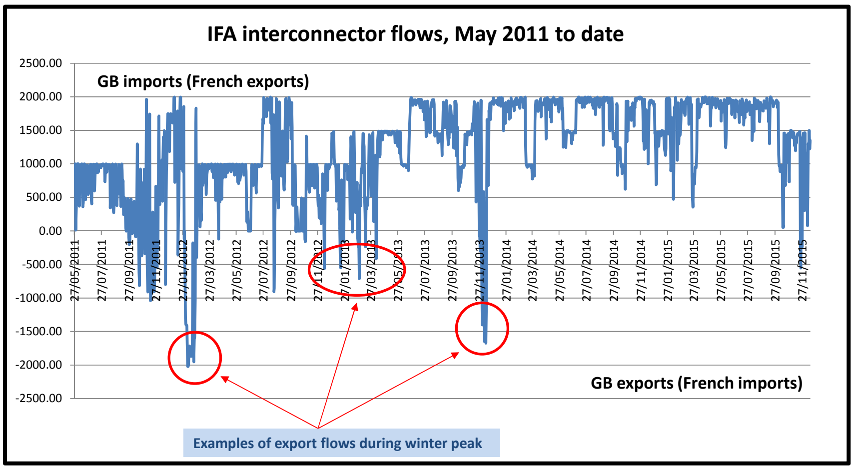
1. By driving marginal GB (gas) generation out of merit, it will tend to reduce the average level of wholesale power prices in GB. There is likely to be a similar impact on clean spark spreads, which are a key indicator of viability for gas-fired power stations.
2. Increased interconnection capacity operating at reasonably high load factors and mainly in the GB import direction will also reduce the average utilisation of GB gas-fired generating plant, perhaps by c.2.5% for each additional GW of interconnection.
3. Finally, interconnection bidding into the Capacity Market will tend to push back demand for GB generating capacity and thus reduce the amount of GB gas plant which secures Capacity Market contracts. It may also reduce the level of Capacity Market exit prices, at least in some periods.

[1] This does not mean that retail energy prices are lower in Germany; in fact they are significantly higher than in the UK, in large part because the rising cost of renewable generation subsidies more than outweighs the lower wholesale electricity price.

[2] Exceptionally, the proposed 1 GW Eleclink project from France to GB via the Channel Tunnel is planning to operate on a merchant basis, exempt from regulated third party access rules.

In reality, therefore, any artificial 'over-promotion' of electricity interconnector investment is likely to damage the incentives for investment in GB gas-fired generation which the government wishes to see. Although GB interconnectors with the Continent will tend to flow in the UK import direction during most hours under current market conditions, it cannot be assumed that they will always do so and the benefits to GB supply security may thus be lower than is sometimes portrayed. This was noted in the European Commission's state aid report on the GB capacity market (para 119), which stated "*…for the hours of highest GB system stress (i.e. where capacity margins are below 10%) interconnection flows have not consistently helped and have sometimes worsened capacity margins in GB.* "

To illustrate this point, we show in the chart below the daily electricity flows on the 2 GW IFA (France-England) interconnector in the period from 2011 to 2015. Flows have mainly been in the GB import direction, but there have been peak winter periods (in 2011/12, 2012/13 and again in 2013/14) during which the IFA was exporting. In a number of instances, this took place even though wholesale electricity prices in GB were above those in France. When the weather is cold, French heating demand can increase sharply and electricity which would otherwise have been exported to GB is retained within France itself.



For these reasons, interconnector capacity is typically 'de-rated' (reduced) for the purposes of GB capacity market participation. This suggests that around half the nameplate interconnection capacity can be relied up to contribute to GB supply security in peak hours. However, we suggest that the extent of de-rating should be reviewed ahead of the next 'T-4' CM auction, in the light of the above flow patterns and other relevant evidence.

The development of further interconnection at the expense of new GB gas generation is likely to erode the level of government tax receipts from the UK carbon price floor and other sources. The Carbon Floor is an important element of the UK's decarbonisation policy and is a sensible market-oriented approach to this policy aim. Therefore any move to harmonise UK carbon pricing with its neighbours should be by raising the latter's (most likely through reform of the EU ETS), not by eroding the UK's Carbon Floor. However, as it relates to interconnection, there is a disparity that distorts the cross-border economics.

Finally, we note that GB gas generation is incentivised under transmission charging arrangements to locate in 'deficit' regions which need the additional supply; this also allows the best use to be made of existing transmission infrastructure – thus helping to defer the need for additional capacity investment. By contract, there are no such locational investment signals applicable to interconnectors and as a result interconnectors may trigger material transmission grid reinforcement which will fall as an additional cost on GB electricity consumers. We believe interconnectors can play an important role, but we do not believe there is a need for further incentives, or a removal of existing barriers. We believe developing gas-fired generation should be the priority.

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?

Overview

There is much that the UK can learn from international experience, but in our view there is as yet no superior 'blueprint' model of international best practice and in some respects (e.g. the design of the Capacity Market and steps taken to reduce the level of unabated coal capacity on the system) the UK has been ahead of many other countries.

Gas-fired power generation has recently been struggling for viability right across much of the EU. Gas plant utilisation has typically been lower in recent years than it was in the period to around 2010, in part due to reduced demand and (even more so) the rise of renewables. In some Continental markets, such as the Netherlands and Germany, there has also been construction of new, unabated coal or lignite capacities. Nevertheless, gas generating <u>capacity</u> is often vital to maintaining supply security at those times when intermittent renewable generation (whether wind or solar) is significantly lower than average.

Several other EU Member States (e.g. France) which are facing similar challenges to the UK already have their own capacity markets. A number of others have capacity payment mechanisms, of which some (including Italy and Ireland) have plans to move from capacity payments to a proper capacity market. As mentioned above, the UK has been ahead of many European states in this respect, but there is longer-running experience of capacity markets in several US jurisdictions.

The UK could learn the lessons of countries like Germany and Ireland in terms of integrating high volumes of intermittent renewables, which will be a key challenge for the networks in the coming years:

- In Germany, most wind capacity is in the north of the country whilst the early shutdown of existing nuclear stations has particularly affected the south. There are severe north-south transmission constraints which require (otherwise economically non-viable) thermal plants in the south to remain open. At a local level, there are also capacity issues on the local electricity distribution system in areas (such as Bavaria) where there are very high amounts of installed solar PV, with output typically concentrated in a relatively few hours per day and annual load factors of the order 10%.
- In Ireland, the rapid growth in onshore wind on a relative small power system has led to a very considerable escalation in transmission constraints and constraint costs. Partly in order to comply with EU legislation, a decision has also been made to replace the existing Single Electricity Market based on a mandatory Power Pool with a revised market design (I-SEM) which will provide for a balancing market and support intra-day trading across the electricity interconnectors. (These features are already provided for in the GB wholesale market design.)

It will be important for the UK to be prepared to handle growing issues of intermittency and regional imbalance. The very rapid recent growth in UK solar capacity to around 9 GW is already giving rise to distribution network constraints (e.g. in SW England) and issues around controlling frequency (system stability) in some parts of the electricity network. (See our answer to qu. 2 above re the role which energy storage can potentially play in helping to provide frequency response to the grid.)

In the USA, there is a somewhat different set of issues there are also significant differences between the different US regions. Given low wholesale gas prices, gas generation is more competitive in North America that it is in Europe.

North America is also the world leader in carbon capture and storage (CCS) applied to power generation. One Canadian CCS/coal plant is already in operation, with a pre-combustion coal facility in Mississippi and a post-combustion coal plant in Texas under construction; these two plants are expected to be on-stream at some point in 2016. In North America, CCS economics are somewhat enhanced by the scope to use CO_2 for enhanced hydrocarbons recovery in onshore oil and gas fields, which is not yet envisaged in either of the first two candidate UK CCS projects. However, the capital costs of these “first of a kind” projects are extremely high. In our view, these costs would have to come down very dramatically before CCS could play a material role.

Centrica’s downstream business in North America, Direct Energy, has seen considerable growth in energy technology in recent years. One key area has been battery storage, which is increasingly used to manage pressure on the grid. Battery storage in North America is further along the commercialisation curve than the UK. Market conditions, such as volatile demand and an increased amount of renewable generation have contributed to this, but incentives have also been put in place to speed up commercialisation. Government may want to consider this when looking at the role battery storage can play in the UK.