To: Operating.2020@uk.ngrid.com

14 August 2009

National Grid consultation on operating electricity transmission networks in 2020

EDF Energy welcomes National Grid's consultation on operating the electricity system in 2020.

Executive Summary

- The Electricity Networks Strategy Group (ENSG) Report identified the major longer-term transmission investments necessary to connect generation identified in National Grid's (NG) 'Gone Green' scenario.
- This work has formed the basis of this consultation and the GB Transmission Owners (TOs) should continue their preparatory work based on these initial assumptions as a matter of priority.
- However, we believe that NG, as GB System Operator (SO), should review and build on the assumptions in the single 'Gone Green' scenario for the following reasons:
  - More recent data is now available. Alternative scenarios should therefore be developed that are consistent with the Low Carbon Transition Plan, the Renewable Energy Strategy of July 2009, and with known planned generation projects following the implementation of the interim 'connect and manage' regime;
  - The transition to a very low carbon electricity system will take place over at least two decades, with significant progress in the 2020s. Therefore, considering only the period to 2020 is an insufficient time span over which to determine the most efficient, affordable and secure longer-term route to delivering the changes required ; and
  - Our own view, substantiated by recent work carried out for us by Pöyry Energy Consulting, is that further analysis will show that different scenarios have significantly different requirements for transmission investment over the period – with billions of pounds at stake, ultimately for customers. It is clearly critical that industry and other stakeholders understand these costs.

- The aim of the additional scenario development work by NG should be twofold.
  - Firstly, to provide valuable insight into the relative costs, benefits and risks of different scenarios for achieving the de-carbonisation of electricity generation, so that there can be a transparent and well-informed debate on the relative merits and affordability to customers of the choices we are making. NG has a vital role to play in informing and steering this debate; and
  - Secondly, to confirm (or re-confirm) those strategic investments that must go ahead now (as they are common to all scenarios), and those which are more

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dependant on future decisions and should therefore wait until the industry has greater clarity on Government's long term vision for the sector (which will hopefully be developed in the publication of DECC's 2050 Roadmap next year).

Policy background

We are entering a new phase in the development of the GB transmission system which will require a new approach. Up until recently, a relatively short term planning horizon (e.g. 7 year statement timeframe) and a policy of 'invest and connect' has served the market well in the relatively stable circumstances that have prevailed with healthy system plant margins, more than adequate grid capacity, and where market and plant changes have generally been incremental. However, that is not the case now or into the future. Plant margins are being challenged, the transmission system is in need of significant reinforcement and the predominant type of plant is going to have to fundamentally change with traditional fossil fuelled, carbon intensive thermal technologies being progressively replaced with new low carbon generation, to meet binding targets for reductions in CO_2 emissions. In this new world, much longer term planning and strategic grid investment is required to deliver the most efficient, affordable and secure route to meeting both our customers' energy needs and government policy objectives.

The roles of National Grid (NG)

As the GB SO and the TO in England and Wales, NG has a vital role to play in informing and steering the debate on the appropriate investment in the transmission system required for the different potential pathways that could be followed to meet the UK climate change targets over various timescales.

To that end, the work which NG has contributed to date, looking towards 2020, has been a necessary and valuable start. However, as government has recognised, a 2020 planning horizon is too short to determine the most efficient, affordable and secure longer-term route to delivering the major changes required to de-carbonise our energy systems. The work which has been flagged in the Low Carbon Transition Plan to produce a 'roadmap' to 2050 (to be delivered in Spring 2010), will be hugely important in determining the future strategic shape of the electricity and gas transmission systems as a whole and, thereby the best answer for current and future customers.

With its responsibility for the economic and efficient operation of the transmission network, NG has to manage a delicate balance of ensuring that new generation projects can be connected to the grid and that the necessary grid reinforcements are in place in a timely manner so the power generated can reach customers. In this context, the initial work done by the ENSG has been extremely useful in identifying some critical projects and associated issues, and also endorsing an incremental 'least regrets' approach to the necessary investment. It is important that the preparatory actions identified in the ENSG Report are carried out urgently to prepare for the longer term strategic investments that are necessary.

Additional scenario work

The ENSG work focused on the 'Gone Green' single scenario of plant mix (with some variations on location of wind generation). The initial capital expenditure set out in the ENSG Report is for £4.7bn investment by the TOs, plus an additional £7.8bn[1] for the offshore network. This total of £12.5bn in infrastructure costs by 2020 is a significant commitment. This is potentially only the first phase and the overall numbers involved could escalate significantly. It is therefore vital that the costs, benefits and risks of alternative pathways that could potentially deliver the necessary carbon outcome at lowest cost (both pre- and post-2020) are clearly understood by all stakeholders. This will allow NG and the other TOs (with Ofgem's support) to invest with confidence in the additional transmission capacity required and the industry to invest with confidence in the necessary generation projects.

In this context and in view of the assumptions made by NG in their work, the future role of distribution networks and Distribution Network Operators (DNOs) should also be explored; in particular the extent to which 'smart grid' operation in conjunction with smart meters might capitalise on the potential for demand side participation to contribute to system balancing. The output from the recently formed ENSG Smart Grids Project Working Group (due to report by the end of this year) will complement the ENSG 2020 Vision Report and should be particularly informative in this respect.

EDF Energy therefore believes that in understanding how it must operate the transmission system in 2020, and taking into account a range of potential plant mixes and locations, NG must urgently consider other scenarios apart from its single 'Gone Green' scenario. NG should build on this work and, as a matter of priority, develop and publish alternative scenarios that are consistent with, for example, the latest illustrative plant mix set out within the Low Carbon Transition Plan, the Renewable Energy Strategy of July 2009, and with all known thermal projects that are now in the pipeline. The aim of this work should be twofold.

Firstly the scenarios will inform the wider debate on the most efficient, affordable and secure longer-term route to delivering the major changes required to de-carbonise our energy systems.

Between June and August 2009, EDF Energy commissioned Pöyry Energy Consulting to develop a number of future low carbon generation mix scenarios. All of the scenarios were designed to deliver a very large reduction in carbon emissions by 2030, and maintain the level of security of supply we enjoy today. Depending on the scenario

[1] Based on a cost of £400/kW for the 19.4GW offshore wind capacity assumed

adopted, total network investment costs vary significantly. The most expensive scenario was one including high levels of intermittent generation, where many major transmission upgrades were required, including investment to accommodate almost double the current peak flows between Scotland and England. Electricity transmission investment requirements in this scenario were three times that required in a scenario with lower levels of intermittent generation.

This is why we urge NG to conduct analysis on different scenarios other than 'Gone Green' and we would be very pleased to discuss this work with you in further detail. It is vital that the 2050 roadmap considers the relative costs, benefits and risks of different scenarios for achieving the de-carbonisation of electricity generation, so that there can be a transparent and well-informed debate on the relative merits and affordability to customers of the choices we are making.

Secondly, the scenarios will confirm (or re-confirm) those strategic investments that must go ahead now (as they are common to all scenarios), and those which are more dependant on future decisions and should therefore wait until the industry has greater clarity on Government's long term vision for the sector (which will hopefully be developed in the publication of DECC's 2050 Roadmap next year).

Strategic grid investment will clearly be a vital part of the overall solution. However, we need to maintain as flexible an approach to such investment as possible to ensure that the costs to existing and future customers of making the 'wrong' decisions now are minimised.

Our response to your specific questions (see Appendix 1) is based on our own commissioned analysis as well as the recent Pöyry work that was jointly funded by the industry and other stakeholders. We hope our response to your consultation will help in establishing the next steps in the process.

If you have any questions on this, or wish to discuss any of the issues raised do not hesitate to contact me.

Yours sincerely,

Denis Linford
Corporate Policy and Regulation Director

Appendix 1 - Question responses

Key Points from the Specific Responses

Understanding the potential costs and challenges associated with operating the electricity system in 2020 is crucial, and we welcome National Grid's efforts in this area.

However, we are concerned that National Grid's focus on one particular scenario ('Gone Green') is too narrow an approach, and only represents the beginning of the work that is required.

Going forward, we recommend that National Grid assess a number of different scenarios, (with varying assumptions on plant mix, the benefits of demand side management and other key variables) in order to derive a detailed understanding of how costs and risks vary in each. This will enable a proper debate about the challenges of managing the system in 2020.

National Grid makes a number of assumptions (listed below) in considering the operation of the transmission system under a 'Gone Green' scenario. Should any one of these assumptions fail to deliver then the analysis presented in this consultation will be undermined. National Grid's assumptions are:

- 'Smart' networks with more sophisticated control solutions will be available
- National Grid will invest in SO systems, ~£9m pa for next 5-10 years
- Energy suppliers tariff structures will manage energy consumption
- DNOs will control small and domestic generation (an assumed 15GW in 2020)
- Small and domestic generation will operate during network disturbances

The 'Gone Green' scenario results in a view of operating margins which may be optimistic and whilst wind generation can technically be used for both response and reserve under current market arrangements it will be very expensive (due to ROC payments). It is therefore likely that further back-up generation (with higher carbon intensity) would be required than is currently assumed.

The contribution that might be made by interconnectors to transmission system operation warrants further consideration and we urge NG to engage with interconnectors businesses to develop this possibility.

It is clear that NG need to procure long term balancing services and work is needed to provide appropriate investment signals to new potential providers. However, technical capability of a particular technology (some of which are mentioned in the consultation) does not imply that it will be economical for investors to develop such technologies.

NG should undertake detailed analysis on operating the transmission system under alternative scenarios, considering the following points in particular:

- Wind generation forecasting timescales and accuracies
- Contribution from tidal generation and managing the large variations in output over short timescales that will result from this technology
- Developments which impact electricity consumption and to what extent they will deliver expected benefits including:
    - smart metering
    - electric vehicles
    - embedded generation
    - micro CHP and heat pumps
    - customer engagement and behaviour
    - smart grid operation by DNOs
- Scope of provision of balancing services from interconnectors and other technologies
- Short Term Operating Reserve requirements should NG's assumptions (listed above) not be delivered.

Question 1: How do National Grid's observations align with your experience or modelling of wind generation?

We agree that wind generation is intermittent and difficult to forecast and that periods of high demand and low wind output will coincide. It is therefore difficult to rely on wind generation to provide firm despatchable generation. It is likely that the growth of wind capacity will have to be matched to a large extent by back up fossil plant unless major steps are made by the industry in providing the necessary framework and incentives for large amounts of dynamic demand to participate via smart networks.

In addition, occasions where high wind output and low demand coincide may mean that some low marginal cost, low carbon generation (wind, nuclear and other) is constrained off the system.

It is also possible that in response to market signals due to the intermittency of wind power, investors are likely to favour fast response technologies as backup, such as open-cycle gas generation which have high carbon emissions. This could undermine the UK's ability to deliver its 2050 emissions reduction target as well as undermine efforts to reduce dependence on non-domestic fuel sources.

We believe that assuming a relatively small reduction in the amount of electricity produced from wind generation to around 20% of the total UK generation mix by 2020 would significantly reduce the costs of accommodating wind power on the system, by:

- Avoiding some of the costs that National Grid will incur when operating the system.

- Significantly reducing the capital expenditure on new generation and the transmission network needed to support it.

Between June and August 2009, EDF Energy commissioned Poyry Energy Consulting to develop a number of future low carbon generation mix scenarios. All of the scenarios were designed to deliver a very large reduction in carbon emissions by 2030, and maintain the level of security of supply we enjoy today. Depending on the scenario adopted, total network investment costs vary significantly. The most expensive scenario was one including high levels of wind generation, where many major transmission upgrades were required, including investment to accommodate almost double the current peak flows between Scotland and England. Poyry concluded electricity transmission investment requirements were three times that required in a scenario with lower levels of wind.

Question 2: Are we correct in assuming that wind generation is controllable enough to assist in operating the networks?

We agree that wind generation (whether Distribution Network Operator (DNO) connected or transmission connected) is technically capable of controllable operation. Their output can be fairly rapidly flexed up to and down from the maximum that the wind permits at any point in time. However, it must be remembered that wind power can of course only provide balancing services when it is windy. In practise this may mean that it can only be asked to reduce production in order to provide flexibility and there will be an associated cost to the System Operator for this.

It is also worth considering how the financial incentives and subsidies for wind generators may influence their operation. Wind receives a subsidy through the renewables obligation and the climate change levy exemptions. These subsidies and the relatively low operating cost of wind generation means that the plants are likely to be dispatched at every available opportunity. National Grid should highlight to wind generators at an early stage of project development the potential enhancement of earnings that could accrue from being prepared to assist in balancing the networks. This will allow wind generators to include the appropriate control systems to run flexibly.

Question 3: Should National Grid assume that Supercritical Coal generators will provide some flexibility in operation which will assist in operating the networks?

Yes, we think that there will be commercial opportunities for flexible plant in the future and it is highly likely that new supercritical coal will be built with the option of flexible operation. However, the provision of this service will depend on whether the value of the additional revenue captured by this flexibility is sufficient to justify the additional costs.

Supercritical coal power stations can be designed to operate flexibly with relatively rapid response times and two-shifting operation. However, the combination of rapid changes in load and frequent cycles of load changes will place significant thermal stresses on the boiler materials. This can damage the integrity of the high performance materials that are used for the high temperature, high pressure operation of supercritical boilers.

To maintain sufficient margins of material safety, the boiler design will need to be upgraded at an additional cost if flexibility is to be provided on a regular basis. In addition to this increased capital cost, there will be the added operational costs of increased maintenance and monitoring that will have to be undertaken in order to inspect the physical impact of the additional flexibility on the plant.

Question 4: Should we assume that nuclear generators will continue to concentrate on base-load operation?

Yes, in general, nuclear power operators will most likely want to run on base load operation as much as possible, for regulatory, technical, economic and commercial reasons.

However, some nuclear power stations do have the technical potential to operate more flexibly. While this is not true of the existing UK AGR nuclear power stations, there is evidence that nuclear plant can be designed to vary its output if required. In France there are currently 58 Pressurised Water Reactors (PWR) operating, representing about 70% of the installed generation capacity which have to provide some flexibility.
The most recent nuclear plant in France (Flamanville 3, EPR design) has been designed to have response capability. However, although the nominal capabilities of this design are better than the AGR, it does not necessarily mean that the nuclear plant will be regularly operated in such mode as other considerations such as additional operating costs and life reduction may discourage full use of this capability. There are likely to be more economic ways in which the SO can balance the system for the majority of system conditions.

Question 5: Is it likely that Carbon Capture plant will impose material restrictions on the operation of electricity generating plant?

As the consultation notes, no commercially available CCS plant exists at the moment, so it is not possible to quantify the impact that CCS could have on generator flexibility. However, it is likely that carbon capture plant will impose some restrictions on the operation of the associated electricity generating plant.

Post-combustion CCS is similar in concept to other “end of pipe” abatement techniques, such as flue gas desulphurisation (FGD) for removing sulphur dioxide and selective catalytic reduction (SCR) for removing oxides of nitrogen. In each of these techniques, flue gas is passed through a reaction vessel in which chemical reactions remove or transform the pollutant of concern. For maximum effectiveness, the chemical reactants need to be balanced as closely as possible and this requires, as far as possible, steady and stable operating conditions. To ensure that chemical equilibrium is maintained as closely as possible, any changes to the inflow of pollutant or other conditions need to be made as slowly as possible. This does not mean that there can be no change at all in plant operating levels, but it does place additional restrictions if target removal efficiencies are to be ensured. The level of restriction is likely to reduce as operators gain practical experience with the abatement system. This has generally been the case with FGD and SCR operation. However, inevitably the abated plant will not have the same degree of flexible response as an unabated plant.

An operator’s starting assumption is likely to be that CCS plant will be used as base load generation. It is therefore essential the first demonstration projects for CCS include an investigation of the range of flexibility in operation that can be delivered.

Pre-combustion CCS techniques (oxy-fuel firing, syngas firing) may not impose the same level of operating restriction. However, there may still be inherent limits to the variation in carbon removal rates that can be achieved, due to the inherent inertia of the reactions and systems and difficulty in providing buffering storage for the removed CO2 to accommodate peaks and troughs in removal rates.

Question 6: Are there other aspects of tidal or marine technologies that we should consider further at this stage?

We agree that the generation output from tidal sources is likely to be highly predictable However, tidal sources would place (and remove) a large proportion of total supply onto the transmission system over a relatively short period of time which will pose a considerable challenge for system balancing and network control, and increase the requirement for back-up generation. These challenges merit further detailed investigation.

There has been limited research to date and the preliminary findings discussed below indicate that more detailed analysis of the system impacts of tidal technologies should be carried out. In their recent report on marine technologies[2], Redpoint noted that a single 8GW Severn Barrage scheme could impose specific balancing costs and impose additional costs on the transmission system.

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[2]The benefits of marine technologies within a diversified renewables mix: A report for the British Wind Energy Association by Redpoint Energy Limited (May 2009)

According to a recent report by Pöyry[3], average annual and monthly prices are negligibly affected by large tidal generation in 2025 and 2030 in the future electricity scenarios that they examined. However, tidal was shown to increase price volatility in the GB electricity market. The scenario with the Severn barrage included has the highest volatility of all scenarios presented in the report. In addition, Pöyry also found that a large Severn barrage would substantially increase the number of periods when wind output must be curtailed due to excessive generation on the system.

Question 7: Are there other restrictions we should consider in developing a view on gas fired generator flexibility?

Yes, it is important to note that the current flexibility provided by gas plants is largely delivered by machines that are already synchronised and 'hot' and may not be as flexible under a different running profile as they are now.

One of the factors that determine the flexibility of gas fired plant is its ability to run in an open cycle mode without engaging the steam turbine. CCGT plant that is capable of running in open cycle mode could potentially provide reasonably rapid response to changing wind conditions. However there is only a limited amount of CCGT plant can run in open cycle mode as most of the recent plant that is based on a single shaft (gas and steam) turbine design. The thermal constraints imposed by the thermal inertia of the steam turbine and the metallurgical properties will limit the ability of many CCGT plant to provide short term response when it is being started from 'cold' conditions.

Question 8: What is your view of future electricity demand growth and how would you quantify any uncertainty around this?

National Grid's assumption that peak demand stays flat to 2020 may be reasonable. However, there are significant uncertainties, which would justify the modelling of a number of different demand scenarios. These include:

- Speed of economic recovery from the recession
- Impact of energy efficiency measures
- The "rebound effect" – technical improvements in energy efficiency leading to increased usage by customers.
- The extent that demand side management can minimise peak demand

[3] Implications of Intermittency: A multi-client study (1 May 2009) by Poyry Energy Consulting

In addition, in the medium term decarbonising the UK's energy mix will require a shift of demand for heat and transport purposes to decarbonised electricity, which creates significant uncertainty about future peak demand.

We have provided some analysis to illustrate the possible impacts of just one of these variables (electric transportation). The graph below demonstrate the potential impact on peak demand under three different electric vehicle penetration scenarios; Scenario 1 (1.5 million vehicles), scenario 2 (2.5 million vehicles), and scenario 3 (3 million vehicles).

It is clear that, unconstrained, electric vehicles could have a significant impact on peak electricity demand. The actual impact will be highly dependant on the impacts of demand side management actions.

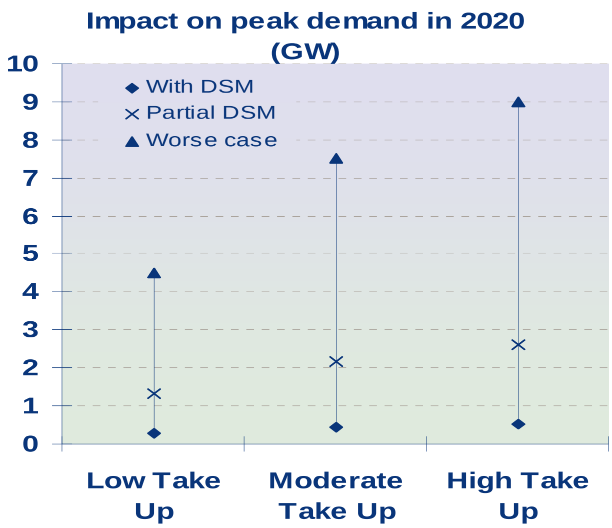

Figure 1 - Impact on peak demand depends on number of cars connected at that time
Note: The 'worst case' scenario assumes 100% of cars are connected at peak, the 'partial DSM' assumes 29%, and 'with DSM' assumes 6%. We assume that cars charge using a 3KW supply.
Source: EDF Energy analysis

Question 9: Are there other developments which will change the way that electricity will be consumed in 2020 that we should consider?

We agree that the technologies noted (smart metering, electric vehicles and embedded generation) will help in some way to flatten demand.

It is essential that industry works to make these developments a reality. However, 2020 is not far away and we should be cautious in assuming that they will provide major contributions to solving the challenges of managing the electricity system by 2020.

We have two specific concerns:
Consumer Behaviour. We agree that smart metering technology has significant potential to contribute to reductions in demand and flattening of the load shape and, more ambitiously, for active demand management. However, this potential is unproven on the scale that will be needed. Although the roll out of smart meters is planned to be completed by 2020, the delivery of benefits will be dependent not merely on installing equipment but on making real changes in customer behaviour. There is a risk of underestimating how long it will take to achieve a significant impact.

EDF Energy has reservations that that the major change in attitude of customers towards their consumption envisaged will be possible by 2020. At a time when there is concern from consumer bodies on the complexity of bills we would question the benefits of rushing a process that will need considerable customer engagement for it to take place. Many customers value the predictability of bills, preferring monthly Direct-Debit payments and fixed price tariffs, the opposite of that envisaged in some flexible Time of Use tariffs. Developing the appetite for these products effectively may take some time, and not result in universal take up.

Technical Issues. In general we would expect electric vehicles to be charged off-peak, during the night when suppliers will be able to offer lower prices.

However, there may be constraints on this, which must be considered. For example, EDF experience in France shows that at a local (residential) level, when large amounts of electric heating are present it can be possible for the largest peak to occur over-night rather than in the evening. Therefore a significant impact in demand at this time may not necessarily be always possible or desirable. Figure 2 below illustrates this effect.

<u>Local Demand Profile</u> <u>National Demand Profile</u>

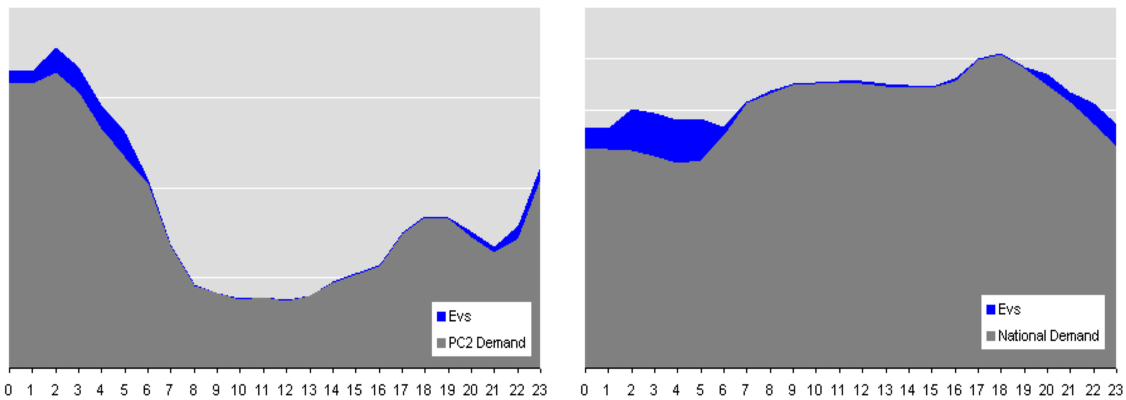

Figure 2 - Example demand profiles from an EDF France study Electric vehicle charging

Question 10: Do you share our view that distribution companies, suppliers, aggregators and ourselves will all value and compete for demand side services?

Alongside the 'Gone Green' scenario National Grid have assumed that there will be smart networks with more sophisticated control solutions, this would require a full roll-out of smart metering by 2020. This is indeed a challenging target however if this is the case we believe that distribution companies, suppliers, aggregators will all be able to play a role in providing future demand-side services. These services could include balancing and reserve services, the latter in the form of short term operating and regulating reserve. These services could be useful, cost-effective and reduce carbon emissions by displacing fossil fuelled generation and reducing curtailments of surplus wind generation output during periods of minimum demand. A key part of this assumption is the expected behavioural change in response to price signals from well informed consumers.

Given the prolific volume and inherent flexible nature of certain categories of 'residential' demand the scope for shaping electricity demand profiles over timescales of up to 4 hours is considerable. However, speed of response will be dependant on the extent to which such appliances are controlled by 'smart' technology and ultimately could provide a very rapid response consistent with short term operating and even regulating reserve. Further research will be necessary to understand the extent to which residential customers might be prepared to provide such services. Energy has traditionally been a 'low interest' consumer category, and significant advances in behavioural change will be needed to get widespread engagement and participation.

Another assumption of National Grid is that energy suppliers are expected to use tariffs in order to manage energy consumption. Ultimately, the scope for demand side services will depend on the extent to which customers feel incentivised by the range of tariff prices available and take-up of smart appliances. However, depending on the actual generation mix at 2020, initial studies undertaken by SEDG have estimated that the capitalised value of such flexible demand could range from £3 to £15 per kW for a highly flexible generation portfolio, rising to between £50 and £75 per kW under an inflexible generation scenario. Even at the lowest end of this overall scale, the incremental cost of the 'smart enabling' technology is attractive. The estimated range of potential CO_2 emission savings is between 50 and 250 kg per kW p.a. National Grid should compare these figures and the assumptions behind them with their 'Gone Green' scenario.

With the correct incentives distribution companies may also incentivise consumer demand and assist the SO in managing the system. However, for DNOs to make the contribution that NG have assumed it is essential that NG work closely with DNOs, suppliers, generators and the Regulator to develop the appropriate incentives and market framework that would be required to make this a reality. These possibilities are outlined below.

DNOs may be able to act as distribution 'system' operators (sometimes referred to as 'technical aggregators') optimising distribution power flows (with regard to capacity provision, losses, network constraints, security of supply etc.) and also providing GSP-specific balancing services to National Grid which might, inter alia, release upstream transmission capacity to facilitate the connection of renewable generation to the transmission system.

Rather than simply 'competing' for demand side services distribution companies could in future facilitate a balancing market. Allowing suppliers and aggregators (including operators of virtual power plants) to not only incentivise customer self-dispatch of generation and demand through time-of-day or real-time energy prices, but to actively control distributed generation, storage and flexible demand they could not only balance their own positions but provide additional balancing services to the GBSO.

NG should not underestimate the scale of the work that would be required in order for demand side services to become a reality, as well as a successful roll out of smart metering, there will need to be changes to the regulatory framework and a recognition by the regulatory authorities that roles of existing market players will need to be extended (for example DNOs owning (and despatching) distributed storage or contracting directly for demand side services will challenge the traditional 'DNO' role and the 'Supplier Hub' principle respectively). Amendments to (or new) licence conditions, the Grid and Distribution Code and the CUSC would seem to be inevitable. These are important matters for Ofgem to consider as part of the RPI-X@20 project.

Question 11: Are our assumptions around the number of electric vehicles in 2020 reasonable?

The assumption of 1.5m electric vehicles by 2020 is a reasonable suggestion. The majority of these will be plug in hybrid vehicles, rather than pure electric vehicles.

We expect the uptake to increase dramatically post 2030.

Question 12: Is it valid to assume that electric vehicle charging will be co-ordinated via a smart grid or something similar and will react to price signals?

There is potential for electric vehicles to provide demand side management services – primarily by controlling when and how quickly the vehicle is charged. And we would expect that well informed customers will react to price signals. Our comments on consumer reaction to smart metering and prices in response to question 9 are also relevant here.

This is an area that will examined as part of the trials by EDF Energy in partnership with Toyota and Daimler as part of the Technology Strategy Board low carbon demonstrator.

Question 13: Do you foresee a greater or lesser role from embedded and distributed generation than we have assumed?

The assumptions on penetration of embedded and distributed generation are very ambitious, considering the immature nature, and current low penetration levels of many of the technologies.

We believe that National Grid should consider some alternative scenarios of the contribution from embedded generation other than that which is assumed for the 'Gone Green' scenario.

Question 14: Is our anticipated improvement in wind forecasting performance at 4 hours ahead achievable?

Yes, however we believe that there are four possible areas where demand forecasting accuracy of wind generator output could improve over the four hour horizon. The descriptions below highlight the additional research and other information that will be required to quantify the improvement.

1. Improved (real time) data

Many smaller wind generators (currently connected to the distribution network) have poor communication channels with the company responsible for their off-take. Real time data is often not available. Although the proportion of wind generation connected to the distribution network may be lower in the future, improved real time data could reduce the forecast error of an individual small wind generator by two or three percentage points.

2. Improved meteorological forecasts

There is potential for a significant improvement in weather forecast accuracy. The UK Met Office (UKMO) and European Centre for Medium Range Weather Forecasts (ECMWF) are both planning improvements to their models. Some examples from the UKMO include:

- The current deterministic model has a horizontal resolution of 4 km over the UK. This is soon to be reduced to 1.5 km, which will enable local terrain to be better modelled, important especially for on-shore wind.
- Ensemble forecasts resolution (which provides probabilistic information) is currently 18km; The Met office has an aspiration towards a resolution

comparable with their deterministic forecast which would provide a significant improvement. Subject to funding, this could be in place by 2020.

- Numerical weather forecast models are currently run every six hours. By 2020, the temporal resolution is expected to be reduced to hourly; this could have a big impact at the four hour horizon for wind generation forecasts.
- Vertical resolution (the number of vertical layers in the modelled atmosphere) is also expected to be increased. This would have a favourable impact on the accuracy of wind forecasts at turbine height.
- Improved coupling of the ocean and atmosphere models should improve the accuracy of lower level wind forecasts over the sea.

3. Improved demand models

Statistical models to translate meteorological data and turbine dynamics into demand output are reasonably mature. There is some scope for improvement as additional second order variables are included in the specification (for example site specific wind direction impacts and by ensuring air density is included). The main difficulty in modelling the output of individual wind generators is the combination of non-linearity of wind speed to demand output and the steep 'cliff face' reduction in output at a critical high wind speed. Our view is therefore that further improvements from methodological development will be small.

4. Diversity

Increased diversity in the geographical distribution of wind generators will almost certainly result in an improvement in the overall forecasting accuracy of the national wind fleet. Additionally, modelling total wind generated power output directly might be expected to yield improved accuracy over a forecast based on aggregated individual site forecasts when the fleet is geographically diverse. However before such models are developed (and the extent of future diversity is known) the extent of any improvement is difficult to quantify; experience from other European countries may not be directly applicable to Great Britain. Overall accuracy will be heavily dependent on the degree of diversity and ultimately limited by concentration of geographical areas that contain relatively large proportions of capacity (for example offshore North Sea). This area has the potential to deliver (possibly significant) improved forecast accuracy but it is very difficult to quantify without a detailed understanding of the regional diversity expected by 2020.

Question 15: Do you have any views on our projected Short Term Operating Reserve requirement under 'Gone Green'?

We note that National Grid's estimate of the physical requirement for STOR is based on a number of assumptions.

There would be value in considering in more detail the sensitivity of these estimates to the many different assumptions made – demand growth, generation plant mix in 2020, performance of the wind generation fleet, improvements in wind forecasting capability. In particular, as we move towards 2020, many of the assumptions about wind generation based on modelling and extrapolation will be updated based on more extensive operational experience; at present, we are still making assumptions even about where the wind generation will be located.

The possible impact on carbon dioxide emissions should also be considered as well as the technical capability of plant. Even where a generator is capable of operating in a flexible manner, there are potential additional carbon emissions likely as a result from operating that way. Larger reserve requirements, whether spinning or balancing reserve, may lead to increased emissions – particularly if a CCGT is forced to operate as an OCGT – from the outcome as a whole compared to scenarios where lower flexibility is required.

Question 16: Do you have any views on our projected volumes, prices and costs for STORR under 'Gone Green'?

We have reservations about National Grid's cost estimate for STORR which seems to assume that it will be possible to procure reserve in 2020/21 at broadly similar or lower prices than those currently prevailing. The detailed calculation in Table 5 concludes that moving from 3.1TWh of STORR in 2010/11 to 7.4TWh in 2021 will lead to a cost increase from £311m (average cost £99/MWh)to just £566m (average cost £77/MWh). Putting aside the details of the calculation, and assuming that the overall average cost of STORR remained unchanged between 2010/11 and 2020/21, then the cost in 2020/21 would not be £566m but £732m. Furthermore we believe that there are two reasons why it may be more realistic to assume that the average cost per MWh of STORR will increase over the period to 2020/21:

- Firstly, if we assume that National Grid currently procures STORR as efficiently as possible, then, if there were no other changes in the electricity system, it would appear likely that, in order to procure more than twice as much STORR by 2020/21, it would need to procure some STORR from more expensive sources than it currently uses. (This requirement for new sources of STORR is illustrated clearly in Figure 21.) As a result, the average cost per MWh may be expected to increase.
- Secondly, there will be many other changes in the electricity system over this period. There is a need for major investment in new power generation over the next decade. Many of the plants currently providing STORR will close and will need to be replaced. However, the fossil fuel plant that is built in this period will face the prospect of operating at lower load factors with potentially lower returns on investment and greater uncertainty than has been the case in the

past. This risk was highlighted by the recent Pöyry study on wind intermittency. A part of the solution to making it economic to build the necessary plant to provide STORR may need to be higher prices for STORR.

For these reasons, we believe that there is a real risk that the cost of providing STORR will be substantially more expensive than National Grid estimates. We are also concerned that, although National Grid operates under incentive schemes in the short to medium term, the long term risk of increases in these costs lies with our customers and there is currently no effective mechanism to encourage the right decisions to manage these costs effectively.

Question 17: Is National Grid's current view that 'low wind' events across Great Britain need to be considered when evaluating electricity operating margins reasonable?

We agree that "low wind" events need to be considered when evaluating electricity operating margins.

We note National Grid's view that at this stage it is reasonable to assume a 15% capacity credit for wind. Our view is that the analysis that has been provided by National Grid and by other sources is not yet sufficiently well advanced to establish the appropriate capacity credit for wind with any degree of certainty.

This is a complex topic and can only be resolved by comprehensive modelling of the electricity system, taking account of the risks associated with demand, thermal generation and wind generation and the relationships between them. With the development of large volumes of wind generation, there is clearly a risk that the "capacity credit" will be overestimated, which may result in inadequate operating margins in future, and power interruptions. However, there is also a risk that it will be underestimated, resulting in an increased cost to consumers arising from the development of excessive back-up capacity.

Therefore, while it may be reasonable in the short term to use a working assumption of 15% capacity credit for wind at this stage, it is important that National Grid leads the industry in developing a better understanding of this topic, including the frequency and duration of "low wind" events.

Question 18: Are our generator availability assumptions reasonable for application to analysis of future operating margins?

We agree that it is sensible to distinguish between onshore and offshore wind and to assume that offshore wind may have a lower availability due to physical restrictions on repairs and maintenance in adverse weather conditions. Managing this issue effectively will clearly be a major challenge for offshore wind operators. At this stage, as National Grid acknowledges, we lack evidence with which to validate these assumptions; in the fullness of time, they may prove to be either too pessimistic or too optimistic.

However, given that much of the fossil fuel plant on the system will be required to operate at much lower load factors than it has historically done, this would be expected to increase some of the operational risks and may lead to a lower level of availability from this plant than National Grid's assumptions based on historical data.

Question 19: We would welcome comments from market participants on how they expect to manage periods of low wind generation output and whether this is an important consideration for them.

We are at the very early stages of evaluating the impact that periods of low wind generation may have on our ability to effectively meet our supply commitments and are actively engaged in external and internal assessments of the possible future plant mix to gain a better understanding of the issues. We believe it is important that National Grid maintains a close dialogue with industry to highlight any specific concerns that it has and consider using the seven year statement and other means to provide feedback to market participants if it believes that identified risks are not being addressed.

Question 20: Are we correct to highlight the importance of wider European issues in electricity operating margin analysis?

Yes, we agree that it is important to consider the interaction with wider European issues, for example the correlation of weather events and the availability of reserve power from Europe.

The analysis of 'weather regimes' is increasingly used by meteorologists in analysing future and historical weather patterns. In devising weather regimes, many years of historical data are used to identify synoptic patterns of weather. One such, the Grosswetterlagen[4] (GWL), is in common use. The GWL had objectively categorised many decades of historical weather into 29 "regimes". Each day in the historical record is thus categorised as being represented by one of these 29 regimes. It is possible to analyse the regimes in terms of how often each occurs and to analyse the weather associated with a particular regime, for any given time of year (for example mid-winter).

Three of the regimes, HB, NEA & NEZ are generally associated with cold winter weather (and thus high electricity demand) in the UK. Historically, these regimes are proven to be associated with low wind speed across most of Great Britain – indeed for the last 24

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[4] An objective classification method for Hess and Brezowsky Grosswetterlagen over Europe, P. M. James, Theor. Appl. Climatology. 88, 17-42, (2007)

years, all 1st – 5th annual peaks (bar two) have occurred coincident with wind capability of less than 50% and around 75% with less than 10%. Perhaps more significantly, they also demonstrate a high correlation with northern Europe (Germany and France) where cold temperatures and low wind speeds are also expected. This potential for UK low wind and cold temperature to be highly correlated with Europe needs to be factored in to any reliance on interconnectors in providing a guaranteed source of energy for the UK under such conditions.

Electricity Operating Margin support by interconnection from the Continent is obviously dependent on sufficient Continental reserves being made available and not already being needed more strongly elsewhere. Availability will require a robustly coordinated response mechanism to be agreed between relevant adjacent Transmission System Operators and generators. This agreement could be facilitated by the new ENTSO-E and ACER agencies created by the 2009 3rd Package of Energy Liberalisation Regulations.

Question 21: Are there further technical solutions for maintaining operating margins which we have not mentioned here?

We believe that contribution to managing operating margins might be made by HVDC interconnectors and that further analysis should be made on the potential contribution to STOR from other technologies.

At present the HVDC cross-Channel interconnector does not contribute to STOR however it may be possible to make HVDC interconnectors respond to the system frequency if the monitoring and control systems were modified. In order to contribute to STOR, it would require spare capacity to be held back on the interconnector and will have an impact on its operational economics.

Question 22: Do you think National Grid's view of future operating margins is useful and do you have views on how this should be presented?

National Grid's view of future operating margins is based on their 'Gone Green' scenario (which was used by the ENSG). This scenario has a higher proportion of fossil fuelled thermal generation, than equivalent relevant scenarios, such as those produced by Poyry[5] and McKinsey[6]. This leads to an assumed healthier operating margin,

However, in this scenario, if thermal plant operates at more economic load factors it could lead to higher carbon emissions and failure to deliver carbon targets. National Grid should consider alternative scenarios. In particular National Grid should model the latest scenarios in the governments July 2009 Renewable Energy Strategy.

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[5] Impact of intermittency: How wind variability could change the shape of the British and Irish electricity markets. Poyry July 2009

[6] Mckinsey July 2009, sourced from Decision Time. CBI, July 2009

It is useful to have a view of future operating margins as maintaining a suitable operating margin is important to maintain security of supply. However, National Grid should also consider alternative scenarios. The impact of wind generation on operating margins system operation and total transmission costs have not been fully demonstrated, and we are concerned that figure 12 in using an average wind scenario showing a normal operating condition does not adequately demonstrate the risk of wind. The picture shown in Figure 13 is more helpful to demonstrate the risks under low wind conditions.

Average and maximum load factors for wind are unhelpful when calculating peak capacity, as there is a much larger deviation from the mean than there is for conventional thermal plant. There is a need for an industry agreed capacity credit of wind generation, to enable margins at extreme peak conditions to be calculated.

Question 23: Are our assumptions regarding the level of electricity demand during the minimum demand periods reasonable?

The assumptions are reasonable for the 'Gone Green' scenario discussed by National Grid in this document. However additional scenarios should be explored particularly in the context of the issues we discuss in our response to question 8 where we believe there are uncertainties in the way in which both heat and transport sectors may decarbonise. And this variation in the UK energy mix will lead to alternative minimum demand levels.

Question 24: Are our generation availability assumptions for minimum demand periods reasonable?

National Grid's assumptions are not sufficient for the following reasons:

The assumption that CCS plant will be shut down at such periods is, as yet, unproven. Although the economic operation of the electricity system will require that CCS plant operates flexibly, the technical limitations of the CCS technology may make this difficult. Otherwise, the generator availability assumptions for minimum demand periods, taken in isolation, are reasonable.

Figure 21 of the consultation document demonstrates that 75% wind availability plus "must-run" plant could exceed minimum demand by a significant margin from 2020/21 onwards. This also means that, increasingly, the impact of high wind may not only be at the times of minimum demand. There will be increasing periods where the amount of wind generation and 'must-run' plant will exceed demand and we believe that National Grid should consider alternative generator availability assumptions for such times. The physical problem this creates could be solved by constraining some plant but the economic impacts of this situation, leading to increased incidence of very low or negative prices, will be significant. This has a much wider impact than National Grid's narrow estimation of balancing costs for such events.

Question 25: Is our central assumption regarding wind generation bid prices related to ROCs reasonable?

This assumption is reasonable if based on existing market rules. A wind operator bidding rationally will not curtail output unless compensated for the loss of ROC income. This is likely to result in negative bid prices. There is a risk however that wind generators may not actively participate in the balancing mechanism. As wind becomes an increasingly important part of the generation mix it may be necessary for the SO to curtail wind in order to balance the system. It should be recognised that this is likely to increase the cost of meeting the UK's renewable electricity targets.

Question 26: Is it reasonable to assume that minimum demand periods will be managed using Interconnectors and Wind Generation in preference to the curtailment of Nuclear Generation?

The response to this question should be read in conjunction with our response to Q24.

In the wider national context, there will be a strong temptation to favour the running of wind generation over other generation sources to maximise delivery of EU renewable targets. However we believe it is important that the market rules are designed to deliver the economic and secure operation of the electricity system to meet the CO_2 reduction targets.

This means that the provision of balancing services, including curtailment of production when required, must be provided in the most economic and secure manner consistent with delivery of CO_2 reduction targets. To achieve this, operators of all generation plant should be prepared to bid to reduce output within the technical capabilities of their plant but they should be free to price these services to reflect their costs. The result would be that generation output would be curtailed in the most cost-effective way.

However, because of the Renewables Obligation, it is likely that un-subsidised plant would be curtailed rather than wind generation and this could result in higher costs for the consumer.

We therefore broadly agree with National Grid's observations that technically minimum demand periods could be managed using Interconnectors and Wind Generation. It is reasonable to assume that the System Operator would utilise Interconnector and Wind Generation technology's short response times in managing such periods. This could enable the system operator to manage unexpected increases in wind output or reverse a decision to constrain down a generator. Wind generation of course does not have the opportunity to regulate its output when the wind is not blowing and our response to Q2 provides our views on the ability to control the output from wind generation.

Question 27: Do you agree with National Grid's view of increased balancing activity in the future due to variation in market length?

We note National Grid's forecast of a large increase in the number of Bid Offer Acceptances (BOAs) it would have to issue each year under the 'Gone Green' scenario. Whilst this may be a reasonable projection it is not obvious why it should map onto an increase in market length (NIV). An increase in market length (NIV) would only be likely if there was an increase in volatility, degree of asymmetry (in particular) and spread of imbalance cash out prices; there is no particular reason to believe that this might be so.

National Grid thinks it likely that the SO would need to be able to issue BOAs or take equivalent action without the level of manual intervention required at the present time. This statement does not easily reconcile itself with the broader assertion in the consultation on the general ability to manage large volumes of intermittent wind generation connected to the system. A 50% change in output of a large wind fleet would be onerous. We are not clear how much manual intervention is in fact required in planning and issuing BOAs, and are therefore ill-placed to judge how this might vary. If there is a high level of manual tasking and judging in these processes at present, as the consultation text would seem to imply, it does seem likely that there would be a need to move to more automation under the 'Gone Green' scenario which has a very high degree of wind penetration.

Question 28: Do you agree with National Grid's view that ramping effects will impact on operation of the networks?

Yes, and the for plant mix assumed in the 'Gone Green' scenario the effect may be greater than that assumed by National Grid.

EDF Energy would expect Supplier participants to balance their half-hourly physical demand positions with half-hourly contractual arrangements. Therefore we would expect contracted generation output to be correlated to anticipated demand ramping at the half-hourly level. We acknowledge that the additional effect of a large volume of wind plant output variation will be much more difficult for National Grid to manage than at present. This would involve much larger volumes of balancing actions and often this may involve constraining wind generation down. As previously discussed it is unlikely that this would be cost-efficient, or effective in CO_2 terms.

Question 29: Do you believe that a new approach is required in the development of System Operator to generation or demand control point interfaces for 2020?

We agree that in with the plant mix in the 'Gone Green' scenario the need to deal with increased ramp rates suggests a need to reduce the time between issue of instruction and delivery of the required response. Faster automated generator control facilities to automatically issue bid offer acceptances may therefore be required to balance a system with the high degree of wind penetration assumed under the 'Gone Green' scenario.

Question 30: Are there any specific factors which suggest that adequate flexibility will not be available to National Grid for use in operating the networks in 2020?

Yes, we believe there is a risk that the flexibility that National Grid requires will no longer be available. National Grid's assumed requirement for flexibility is based on the assumptions that energy suppliers will manage consumption using tariffs, that smart networks will be available to them and that the distribution network operators will have control of small and embedded generation.

More specifically, as the size of the fossil fleet falls:

- From 2016, there will be no oil fired plant on the system and 9GW less coal fired plant than at present;
- CCGT plants will be required to contribute more flexibility to the system; it is unproven whether they will be able to do this. They are likely to be called on to run at lower load factors with significantly more starts during the year, which may well have an impact on reliability.
- We believe there will be a physical need for new peaking capacity, probably in the form of OCGTs. It is less clear whether there will be adequate financial incentive to ensure that they will be built.
- There are significant barriers to the sizeable demand side capability envisaged as noted earlier

Question 31: The combined challenge of:

a) ensuring the networks are operated safely and securely against a background of generation variability; whilst

b) getting more from existing infrastructure; suggests to us that control, communication and information systems have a greater part to play in controlling flows across the transmission networks.

Are there alternative approaches which should be considered?

The 'Gone Green' scenario has the potential for more generation variability than other similar scenarios[7] and the plant mix available on the system will play a large role in affecting what level of other measures need to be taken and the likely costs.

We agree that under a 'Gone Green' scenario it will become more difficult to reliably forecast power flows due to limitations in predicting wind patterns, and hence wind generators output. It follows that in order to avoid excessive costs of balancing provision (and/or costs of constraints) there will be a need for greater active management of the transmission system in order to maximise network capacity under both intact and post-fault conditions. The increased complexity of the transmission system and greater number of 'active' devices may result in the need for autonomous automated control systems. However, possible alternative approaches which National Grid should explore further are STOR and the benefits of changing the load shape of demand if possible. Examples of this include the promotion of heat pumps (combined with hot water storage), electric vehicles (through subsidised purchase and tax concessions).

To get most out of the existing infrastructure, prevent overuse of constrained transmission capacity and optimise the utilisation of redundant transmission capacity demand would not only need to be flexible but be incentivised to grow in different parts of the UK. The Scotland –England transmission boundary is an example of a constrained boundary and with the connection of more generation in Scotland will become further constrained, initial studies undertaken by SEDG have estimated that, used in this context, the current capitalised value of flexible demand (depending on degree of flexibility) is in the range of £10 to £30 per kW. This value should increase significantly under a 'Gone Green' scenario with up to 11.4GW of wind generator capacity in Scotland by 2020.

In order for demand side services to become a reality (in line with NG's assumptions) the incentives and market framework need to be developed and this should be a combined approach from TOs, DNOs, suppliers, generators and the Regulator. NG should not underestimate the scale of the work that would be required. However in terms of possible alternative (or complementary) approaches, the scope for exploiting new opportunities for securing balancing services (including short term operating and regulating reserve) should be fully explored. National Grid is correct that the most onerous operating conditions might not coincide with times of peak demand and hence could be less predictable. However, measures to decarbonise energy consumption, as well as local energy production, is likely to continue; examples including the promotion of heat pumps (combined with hot water storage), electric vehicles (through subsidised purchase and tax concessions), and (generous) feed-in tariffs (to encourage low carbon distributed generation).

[7] Pöyry 2009, Mckinsey 2009 ibid

Taken together these new developments could give rise to the concept of flexible demand and provide new opportunities for manipulating demand profiles over the sort of timescales typically associated with short term operating reserve (up to 4 hours). Moreover, given the necessary development of 'smart' distribution networks and smart metering systems (the latter due to be fully rolled out by 2020) such flexible demand could be 'despatchable' in very fast timescales (less than two minutes) thereby providing a potential alternative source of both short term operating and regulating reserve.

Question 32: What criteria should National Grid use in developing any requirements for information regarding embedded generators? Are there other ways of obtaining this information?

While National Grid perceive a need for greater visibility of embedded generation, it is also true that distribution network operators have a need to understand the capacity and operating characteristics of such generation connected to their networks i.e. be able to quantify 'latent' demand. Latent demand is that which is effectively hidden by embedded generation which would be presented to the network immediately following re-energisation of a network following an outage, or disturbance.

Distribution network operators would increasingly need to capture this if active management of distribution networks were incentivised through the development of smart grid technologies and the wide-scale deployment of smart metering. It would seem feasible for network operators to also provide ancillary balancing services to National Grid, for example by managing agreed net import (or export) limits at Grid Supply Points (GSPs) on a near to real time basis. This might even extend to distribution network operators installing distribution network-scale electrical storage (subject to the necessary technological development of battery systems and power electronics in order to make such systems economically viable). In summary, provided distribution network operators are taking full account of the level of penetration of embedded generation in actively managing their networks in both planning and operational timescales, and as a result are able to exercise control over net power flows as experienced at GSPs, then this should reduce National Grid's requirement for granularity of information concerning embedded generation.

National Grid also raises a concern over the performance of embedded generation during sudden changes in frequency. The frequency collapse following the sudden loss of centrally dispatched generation on 27 May 2008 is believed to have given rise to a significant loss of embedded generation due to the operation of 'G59' protection (particularly generation that might have been installed prior to publication of the updated guidance on protection settings provided in the revised G59/1). Closer attention to the correct application of G59/1 settings (and potential revisions to such settings, depending on the recommendations of the Grid and Distribution Code (small embedded generation frequency obligations) working groups) might alleviate the risk of wide-scale loss of embedded generation under such circumstances in future. However, a more reliable, or at least complementary, approach might be to exploit the potential for certain electrical appliances to provide low frequency triggered (dynamic) demand reduction which would beneficially reduce or, depending on the severity of the event, even avoid the need for operation of low frequency demand disconnection (LFDD) relays.

For example it has been calculated that by equipping all refrigerators with an inexpensive frequency (and internal case temperature) sensing device the aggregate capacity of frequency response would be broadly equivalent to a large CCGT station[8]. The speed of response would of course be instantaneous which would be particularly beneficial given the inherent sensitivity of embedded generation to a sudden frequency collapse of the type experienced on 27 May 2008. Initial studies undertaken by SEDG have estimated that the value of such response would range from £10 - £30 per refrigerator under a low wind penetration scenario, up to £40 - £90 per refrigerator under a high ('Gone Green') wind penetration scenario.

Taken together, it follows from all the above that National Grid might in future be able to relax their requirements for information regarding embedded generation on the understanding that distribution network operators might in future take a more active role in managing their networks (necessitated by the emergence of new market players but also enabled by the development of smart grid technologies and smart metering) and by the capability of refrigerators to provide effective dynamic frequency response.

However we must recognise that we cannot take such solutions for granted in their ability to provide frequency response or demand side management. For example, refrigerators can provide a very fast response but the level will gradually fall off as cabinet temperatures rise and the fridges begin to restart. Once frequency recovers after any significant delay the refrigerators will restart en-masse unless this is phased by randomly set time delays built into the device (cabinet temperature always taking priority). Post recovery, there will also be a delay before the refrigerators settle down to 'normal' cabin temperatures - during which time their aggregate demand will initially be higher than before the low frequency event. It will then take some considerable time before natural diversity is restored, and during this time, the refrigerators will be able to offer a lower level and duration of frequency response.

Question 33: Are there additional options that National Grid should consider to maintain a Black Start capability?
We agree that National Grid should explore a wide range of possible sources of Black Start capability, including the assistance which new nuclear plants can offer, as well as those listed. National Grid should also consider options and incentives to maintain

[8] We note National Grid's more conservative estimate under paragraph 8.17 of 500MW

black start capabilities at sites where the main generation plant will be closing in the medium term, as these sites comprise a significant proportion of current capacity.

Question 34: Are we correct in assuming that new interconnectors will be able to meet some of our Balancing Services requirement?

Yes, we believe that this is a possibility that should be explored and should be used to the extent that it is technically feasible and economic to do so. The manufacturers of modern technology interconnectors claim their equipment can reverse flow direction in microseconds, limited by the speed in which the connected Transmission Network Operator networks can coordinate changes in power or demand. This is a much faster response than any other form of reserve to protect generation operating margin.

The size of current and proposed interconnectors is at least as big as any of the current dedicated Balancing Services plant. Availability will require a robustly coordinated response mechanism to be agreed between relevant adjacent TSOs and generators. This agreement could be facilitated by the new ENTSO-E and ACER agencies created by the 2009 3rd Package of Energy Liberalisation Regulations.

However this needs to set in the context of current EC regulatory and national legislation that has created restrictions and uncertainty in the view of TSO and merchant developers, which in turn has discouraged them from building new interconnectors. The EC's Barcelona 2002 goal of interconnection equivalent to "10% of installed generation" by 2010 is still a long way from being achieved.

National Grid should also be cautious in assuming that interconnectors will always be able to provide solutions to our balancing needs; on many occasions, the needs of the other Transmission System Operator will conflict with the needs on the GB system. This should be taken account of in assessing the scope for using interconnectors as well as some of the points made in our response to Q20 on meteorological correlations.

Question 35: What is your view on the potential of electric vehicles to provide balancing and other energy services?

EDF Energy believe that there is the potential for technology to be available that would enable fast response demand shedding from the charging of electric vehicles. However we have reservations about the level of capacity that would be available.

We are also concerned that the concept of using electric vehicle batteries as additional grid storage capacity has impacts that have yet to be considered, not least the potential perception to the owners, and the potential for reduced life-span of the in-car battery.

Question 36: How much of the electricity demand in Great Britain do you think could be regarded as discretionary or deferrable and hence available for use as a Balancing Service or other energy service?

It is clear that current demand side participation in the balancing services market is low however for NG to operate the system under the Gone Green scenario an increase in the participation of such parties is assumed. NG should consider a number of different scenarios of demand side participation in order to model the potential value of these services properly. This analysis will make an important contribution to facilitating demand side participation (see next question for further comments).

Question 37: What specific actions should National Grid take to facilitate Balancing Services from demand-side providers while maintaining the required quality and volume of service?

It is essential for NG to work with industry (including suppliers, DNOs and potential providers) on ensuring that the opportunities for demand side providers to participate in balancing services are transparent to all parties. The existing opportunities might be developed in conjunction with industry to ensure that appropriate market signals exist and that the right balance of risk and incentives (for both NG and services providers) can be reached.

Question 38: Are there further aspects of storage or other storage technologies we should consider when looking forward to 2020?

Table 13 in the consultation document appears to provide a comprehensive list of potential storage solutions. However, our main comment here is to stress the significant risks with assuming that the development of electricity storage technologies will make a contribution to balancing the system in 2020. While some contribution is likely, many uncertainties about cost and reliability remain.

In particular, in the case of electric vehicles, the prospects for storage (vehicle-to-grid) are highly uncertain, and at present the associated costs, such as the potential for reduced battery lifetime, would appear to far outweigh the benefits. We would be concerned if National Grid were to assume that electric vehicle battery storage was making a measureable contribution to balancing requirements in 2020.

Question 39: What are the prospects for the provision of Balancing Services from new OCGTs or other 'Back-Up' generation?

EDF Energy notes the existing requirement on OCGTs to provide mandatory services (frequency response and reactive power) and consider that as a need for Balancing Services develops in this 'Gone Green' scenario clear, firm signals will need to be created to ensure that the demand for services will be met. As we have previously discussed we believe that with the large penetration of wind generation in the 'Gone Green' scenario there will be a strong need for back up fossil plant or large amounts of dynamic demand. National Grid should consider further analysis on the feasibility and cost effectiveness of Balancing Services from such providers.

Question 40: Is our mapping of technology to Balancing Services reasonable?

We would consider that the mapping shown in table 14 appears to be technologically feasible. However further analysis is required to determine whether this mapping is economically feasible and how appropriate incentives to deliver these services can be developed.

Question 41: Is a statement of National Grid's view of its long term Balancing Services requirement useful to industry stakeholders?

EDF Energy is of the view that such a statement is not only useful but necessary if National Grid wish to encourage additional balancing service providers. New investment requires as much certainty of opportunity/need as possible, as far ahead as possible. This statement should provide an element of certainty to energy firms that a service is required. In turn this should lead to investment decisions being taken to satisfy this need (as we discuss in our response to question two). National Grid would also have to consider how the procurement of these services is optimised.

Question 42: What period should a long term Balancing Services Requirement statement cover?

Any new investment will require an extended period of service requirement before being progressed. We would suggest a forecast requirement of at least 10 years should provide the information necessary for investment decisions to be taken. This period should also consider the lead times that may apply to developing new plant to provide these services.

Question 43: What changes to the current reserve products would better encourage the provision of reserve services?

National Grid should recognise that balancing service providers will not provide reserve products at a discount to income achievable in the wholesale market. We note that this is the main reason why firm frequency response has not delivered to National Grid's expectations.

EDF Energy notes National Grid's current arrangements for ongoing review of tender processes e.g. the recent review of Reactive Power and the development of a longer term STOR contract. We believe that methods of consultation with industry on amending procurement and contract terms should be continued. This will ensure that as the need for reserve services increases the appropriate incentives are developed to allow them to be delivered.

Question 44: What actions would ensure that procurement of reserve services does not impact adversely on the efficient operation of the wholesale energy markets?

In moving towards a 'Gone Green' scenario National Grid is likely to need to contract for balancing services over longer time periods than is currently the case (i.e. greater than one year) and the incentives for the system operator may need to be changed to allow for this. National Grid should continue to review the procurement of balancing services to ensure that contracting with an excess of providers for a number of years does not effectively withdraw plants from the wholesale market as this is likely to put upward pressure on prices until the equilibrium is re-established.

EDF Energy
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