EDF ENERGY

National Grid
E-mail to: **energy.operations@uk.ngrid.com**

20 September 2011

Dear Sir/Madam

**Operating the Electricity Transmission Networks in 2020 – June 2011 Update**

EDF Energy is one of the UK's largest energy companies with activities throughout the energy chain. We provide 50% of the UK's low carbon generation. Our interests include nuclear, coal and gas-fired electricity generation, renewables, combined heat and power plants, and energy supply to end users. We have over five million electricity and gas customer accounts in the UK, including both residential and business users.

We thank National Grid for their work in the production and publication of this consultation, which we consider to be a detailed and comprehensive piece of analysis. We believe that the changes required to the transmission network to support low carbon generation to the level required represent a significant challenge and it is important to act now to successfully deliver them.

As with any significant change to energy markets we believe that the implementation of new mechanisms for system operation or changes to working practices need to be shown to have an overall positive cost benefit to the market.

We believe that the ongoing development of the Government's Electricity Market Reform (ERM) must be carefully monitored as it is likely to have an impact on system operation requirements in the future.

Finally, we also consider that smart technologies might offer the best route to true demand side response. The ongoing development of the role of the Data Communications Company (DCC) and Smart Energy Code (SEC) might also have a significant impact on system operation.

Our detailed responses are set out in the attachment to this letter. Should you wish to discuss any of the issues raised in our response or have any queries please contact my colleague Rob Rome on 01452 653170, or myself.

Yours sincerely,

**Denis Linford**
**Corporate Policy and Regulation Director**

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**Attachment**

**EDF Energy's response to your questions**

**Operating the Electricity Transmission Networks in 2020 – June 2020 Update**

**Q1. Do you agree that cut out will be an issue for the GB or will wind (onshore and Offshore) turbine technology compensate for the GB wind resource density?**

We have not experienced any significant issues with cut out speed, in our portfolio of primarily onshore wind generation which is managed by our sister company, EDF Energies Nouvelles. However, we are aware of the risks to system operation at times of high wind and this is something that National Grid (NG) should consider going forward. We also note that offshore wind speeds are higher than onshore.

Although we consider that this is a question for turbine manufacturers, EDF Energy believes that future offshore wind turbines might be able to withstand cut out wind speeds of around 30m/s (e.g. Repower's 6MW turbine) which might in part compensate for GB wind resource density. It is expected that turbine manufacturers will look at high rotor overspeed and stresses in their larger wind turbines (6-7MW) and we suggest that NG seek to understand these developments in the context of system operation.

**Q2. Will wind turbines within a comparatively small geographical area behave in a consistent manner?**

It is expected that weather patterns in small geographical areas will be relatively consistent, especially for offshore wind. This consistency is driven by local factors such as coasts and mountains for example.

**Q3. How do you think that controlling frequency deviations with AGC (Automatic Generation Control) would impact on the underlying costs of generating plant providing response and on rotating plant as a whole?**

To answer this question accurately, we would require further detail on the intended meaning of AGC (within the consultation document) and its implications with new or existing plant operating in an island system.

**Q4. How ready is generation on the GB system to providing AGC and**
**a) How might AGC be provided within existing services?**
**b) And the current market rules and design?**

We feel this topic needs to be further developed to gain a better understanding of the requirements and the intended meaning of AGC, as it is not a well-defined term with a single meaning. An understanding and discussion of market rules and design might be gained through a Grid Code Balancing Services Standing Group (BSSG) / Commercial Balancing Services Group (CBSG) joint working group.

**Q5 Are there any further benefits (or detriments) to managing frequency more tightly on the GB system?**

It is our understanding that frequency is managed more tightly in Continental Europe. This might assist in reducing wear and tear on synchronous generating plant, and could potentially improve system security. However, in order to manage frequency more tightly it would be necessary for more plant to be on local frequency-responsive duty (or a centrally-controlled equivalent, which may be the intended meaning of AGC in the previous questions). This would result in a larger number of plant than at present providing frequency responsive services and therefore incurring efficiency reductions. We would consider any proposed changes as significant and this would warrant a thorough cost benefit analysis.

**Q6 Do you agree that there has been a permanent loss of demand as a result of the recession?**

We forecast power demand based on growth and historic levels. Our forecast considers the cumulative effects of significant recessionary demand loss and efficiency gains accelerated during this period. More explicitly, we do believe that there has been a permanent loss of demand, which is likely to continue.

**Q7 How significant would a 25% increase in starts be to the operation and maintenance of a CCGT?**

In terms of cost per start (both fixed and fuel), the significance of increase will be dependent on the current operating regime of the power station. We consider that a new build plant with two daily shifts might increase its annual costs by up to 4% as a result of a 25% increase in starts.

The additional impact on plant life as a result of increased starts due to thermal and mechanical fatigue must be considered. There is evidence that cycling also leads to deterioration in heat rates of up to 20%. This is likely to increase the plant’s annual capital costs and decrease its financial life.

**Q8. Do you agree that the introduction of implicit mechanisms will remove the ability for National Grid to procure services with market participants across interconnectors?**

SO to SO assistance actions are normally short duration actions such as the provision of short-term energy or of frequency response to the SO at one end of an HVDC interconnector.

It should be possible for these SO to SO assistance actions across interconnectors to be structured so that they do not affect the integrated half-hourly energy flows. If so, this will avoid disruption to commercial arrangements as implicit auctions are in relation to half-hourly (or hourly) timeslots; flows will still be delivered as expected on an integrated half-hourly energy basis, and no party will be put out of balance or out of contract.

Even when an interconnector is already importing to the UK at maximum steady capacity, the slow thermal time constants of cables mean that it may be possible, if the power electronics are designed to allow it, to supply additional power for a short period of time. For example, the newly commissioned 1GW "Britned" cable has the capability to temporarily over-supply an additional 20 per cent of power (+ 200 MW) in just this manner.

Therefore, for such an interconnector, positive energy flow variations above the normal maximum are possible for short periods of time when flow is at nominal max cable rating. This can be counter-balanced by energy flow variations below the normal maximum for short periods of time. In this way, net flow remains in accordance with the contracted level across the half-hour; in accordance with the implicit auction results.

It is important that there be transparency around SO-SO assistance via balancing services or energy trades across interconnectors. The short entry in the monthly balancing services report on this item is not currently sufficient and should be replaced with full disclosure.

**Q9. Are you aware of any other market based mechanisms used in Europe to help manage flows on interconnectors?**

The European Target model defines the most efficient mechanisms to be used on interconnectors in order to allow each individual market to benefit from the liquidity in other European markets. One of the key components of this evolution is that the use of interconnections will increasingly be linked to market prices. This is because TSOs will be required to minimise their balancing actions and act only after the market; that is to say during the last hour before real time when continuous intraday trading will be developed. As a consequence TSOs will need to develop additional tools for managing internal congestions. Interconnectors will still play a role for balancing purposes through SO to SO balancing agreements (being developed through the EU Electricity target model) and SO to SO emergency contracts.

One of the key elements for an improved TSO control in a context of high renewable volumes will be the ability for TSOs to balance wind generation for network constraints and for wind generators to better forecast their injections into the transmission grid.

**Q10. How will shorter gate closures impact on interconnectors nominations? Will interconnector transfers become more volatile?**

There is no evidence that shorter gate closures would impact interconnector nominations. It is likely the interconnector auctions process and timings would need review to ensure compatibility with national market gate closures at either end.

**Q11. Do you think that National Grid as System Operator should take account of potential short term changes on the interconnector in reserve policy?**

We believe this should occur as a reasonable and prudent System Operator.

**Q12. How important are market liquidity and cash out arrangements on interconnector flows?**

Market liquidity and cashout arrangements are important for all users of the national electricity market.

**Q13. Which approach of those described above do you think would be most appropriate to manage uncertainty around interconnectors?**

We prefer the second approach, the carrying of additional reserve against changes in interconnector flows on high wind days only, as it appears more proportionate. Modern interconnectors can have a lower forced outage rate, when compared to many thermal generation plants.

**Q14. Do you agree that the propensity to export to Continental Europe has increased with the removal of TRIAD?**

The removal of TRIAD charges from interconnector flows has had a significant effect in removing barriers to export around the time of anticipated peak demand.

**Q15. What is your view on how the NETSO best manage the additional uncertainty in the context of system access?**

Please see our response to question 9.

**Q16. How should consideration be given to the trade off between unrestricted trading on interconnectors and cost of risk mitigation?**

Trading on interconnectors should be unrestricted as much as possible to let the market decide the most efficient and economical flows. However, a balance needs to be struck between allowing price signals between interconnected markets to determine where the flow of power should go (unrestricted trading) and accounting for when system constraints or distressed periods could result in threats to system balancing and security of supply (risk mitigation). The latter may mean some intervention in the markets by the SO to secure sufficient reserve margin from the interconnectors. We ultimately believe that the SO should have a residual balancing role and only be active to manage the supply/demand imbalance between countries where necessary. Such actions should be made transparent.

**Q17. Do you agree that wide spread demand response may be a more appropriate means of managing a low probability risk?**

Increased demand side response will be a necessary part of system operation in 2020. Without it there will likely be a need for more low voltage system reinforcement and for new additional peaking generation capacity. This may not be the most cost-effective solution.

Demand side response is one of the balancing options that might assist in accommodating wind generation intermittency alongside new energy storage, interconnector capacity, or new additional peaking generation capacity. Given wind penetration estimates, existing storage capability in GB is likely to be a small proportion of the energy shortfall that can occur during a wind "lull". It is unclear whether interconnectors will always be able to assist during such a lull, as the size of anticyclonic weather systems means that larger parts of Europe may be affected at the same time.

Therefore, demand side response will have a part to play. The demand side response must be available to system operators, particularly in relation to low voltage network constraints. Wholesale market price signals alone would not always be able to create demand side response at the right time of day, or in the right location. It is likely that NG will need to liaise more closely with Distribution System Operators (DSOs) by 2020.

**Q18. Do you agree that larger scale CHP such as district heating scheme developments are more probable or is there a larger role for domestic level or micro CHP?**

We predict a 10 to 40% growth in current levels of embedded Combined Heat and Power (CHP) by 2020, with less than 100,000 households installing micro CHP by 2020. This is consistent with DEFRA's MTP Reference Scenario which assumes the bulk of the increase will be from district heating schemes. The quoted 7GW of embedded CHP by 2020 is at the high end of our planning range.

**Q19. Taking into account the points raised, is our assumption on CHP growth realistic in regards to:**

**a) the investment climate?**
**b) the additional points raised above?**
**c) Increased embedded generation**

Please see our response to the previous question

**Q20. What is a realistic view to the amount of PV installed capacity by 2020?**

In a "business as usual" scenario, we expect the level of embedded Photo Voltaic (PV) capacity to be in the region of 1GW by 2020. However, this could rise significantly in the event of a breakthrough in the cost of PVs.

**Q21. As the size of the CHP generation going forward is likely to be lower capacity, will inclusion into the FITS make flexible operation of CHP less likely?**

This will depend on the relative size of incentive between FiTs for output, and revenues from providing ancillary services. Currently FiTs appear to offer higher returns (to incentivise higher energy efficiency) than those expected to be earned through reserve or response services. Flexible generation capacity would need to be significantly scarcer before premiums for this type of service would rise to FiT-type levels. We believe it is likely that flexible operation of CHP will be reduced.

**Q22. Are there any existing or proposed district heating systems in GB that use these methods?**

We are not aware of any such scheme.

**Q23. Do you agree that battery technology used in the context described in the context 11.15 could be deemed as transmission?**

As an ancillary service provider, it is our view that this type of asset would not be deemed as transmission, in a similar way to other storage, and would need to be ring-fenced from regulated activities.

**Q24. Is large scale battery technology economically feasible against existing revenue streams? What are the limiting factors to large scale battery storage capacity?**

Large scale battery technology is economical in the UK for certain specialist services to the market. Having considered such projects it is unlikely that an application will be economically feasible for simple energy storage. Limiting factors can include issues such as network connection and building availability.

**Q25. How could investment in storage technologies be made in order that the potential benefit is shared across all parts of the value chain?**

The most efficient way to implement these projects would be for NG to offer contracts as a form of ancillary service. In this way, NG can monitor the market and dispatch the technology as needed for the benefit of the network. Should NG wish to invest in storage technologies then there would, of course, be many legal, competition and regulatory issues to overcome.

**Q26. How significant will DNO network capacity be in establishing an increase of DSR services? Is a majority of the potential value more realisable by suppliers?**

It is likely that we will see significant growth in load on DNO networks due to electric vehicles and possibly heat pumps (50% growth by 2030 estimated by NG).

This will prompt infrastructure investment where load factors are high now, but some infrastructure will have sufficient capacity already installed to cope with the demand growth. Overall though, this is likely to have a significant impact on required future capex levels and therefore demand-side management (DSM) is an attractive option to contain tariff increases for customers as far as possible. Some networks e.g. in New Zealand, have used DSM operated by the DNO for many years to improve load factors. Incentives may be required to encourage DSM rather than traditional infrastructure solutions by the DNO, assuming that cost of capital remains attractive to stimulate investment.

**Q27. How much demand could be captured from the industrial and commercial sector?**

Based on high-level analysis, we believe that up to 10% of I&C demand might be accessed to provide demand side response.

**Q28. Do you believe that a mandatory inclusion of relevant technology in domestic appliances is required as a pre-requisite to enable and capture DSR?**

Mandatory inclusion of such technology in all domestic wet appliances would allow optimum capture of DSR potential. However, certain appliances (such as refrigerators, dehumidifiers and air conditioning) have higher potential for providing these services; enabling technology to be targeted at certain categories. Furthermore, if economic incentives are sufficient, consumers could choose to purchase "DSR-enabled" products which would allow them to benefit from DSR tariffs or revenues, without requiring inclusion of technology in all new items. This latter scenario would perhaps allow a smoother transition to a fully-enabled system. Certainly smart appliance standards should be mandated for wet appliances and EV chargers to ensure a compatible and efficient roll-out.

**Q29. Do you agree that more than 5% of domestic demand could be managed or does 5% remain a reasonable assumption?**

By 2020, the level of demand that can be managed is likely to be above 5% based on the current teleswitch load during the times the equipment is used. At other periods, the amount of demand which can be controlled will be subject to customer acceptance and the necessary hardware to enable this.

**Q30. What are the main barriers you see in capturing demand side services in particular, those from the domestic sector?**

Customers need to accept and trust demand-side services. Customers may not be sufficiently engaged with energy efficiency or be comfortable passing control of their appliances to third parties. We believe there is some way to go to allow such control; for example, the UK has not yet experienced the power cuts or price drivers seen in California that prompted customer acceptance. As the consultation document states, propositions will have to make participation easy, with limited inconvenience and appropriate financial rewards if they are to be a success.

Wet appliances are currently not smart-ready (see answer to question 28) and the lack of consideration of heat storage in building standards for new premises means they might not have inherent demand-side response capability from any heat pump fitted.

If the DCC lacks the ability to send broadcast messages in a timely and cost effective manner, this will be a major barrier to smart metering development in the domestic and SME arena. The main constraint of this will be the DCC technology chosen. The DCC and

Smart Meter System security requirements are still in their infancy and it is unknown if any restrictive practices or software will be put in place to reduce the impact of any security beaches on the system

The DCC and Smart Meter System should provide the framework to allow demand side services but additional hardware will still need to be fitted to control devices (e.g. smart thermostats) or the devices that can talk to the DCC (e.g. smart appliances) have to be purchased. These costs will have to be factored in to the business case for demand response.

There will be a reliance on the DCC for these services; if this service is unreliable, this may hinder demand response services. Aggregators would need to have a mechanism for passing on risk to the DCC for failure of service. If this is not the case, aggregators (be they suppliers or not) may feel it is too risky to run the service.

**Q31. What does this mean for NETSO services? Do you believe that the type of product described will be provided by particular sectors?**

The high value of this type of service should be reflected in the price signals given by the NETSO perhaps by making prices achieved for response more visible to the market (similar to STOR tender reports). This would allow suppliers to adjust their behaviour accordingly. In the short term, we believe that response services might best be suited to refrigeration, heating and ventilation carried out in the I&C sectors, but as residential aggregation increases (probably post-2020) this sector could also provide this service.

**Q32. Do you agree that the heat pump penetration described above is realistic?**

While this is a reasonable high case, this is at the top end of our expected range. Notwithstanding this, in order to meet CCC emissions targets we expect close to three times the suggested level to be required by 2020.

**Q33. Do you believe that table 13 reflects a realistic profile of potential demand from heat pumps? Will time of use tariffs (ToU) shift some demand away from the peak?**

Two sets of smart meter trials have recently been completed on time of use tariffs (TOU) impacts. Although the trials did not specifically relate to heat pumps, a trial in Ireland recorded a 9% shift of electricity use at peak for customers with smart meters and a three rate, four time period tariff (night, day, peak, day and back in to night). The Ireland trial considered findings over one year, in Ofgem's UK Energy Demand Research Project (EDRP), two Suppliers including EDF Energy, trialled TOU with smart meters over two years. In EDRP, the TOU customers shifted peak demand by 7% in the beginning but after the two years the savings had reduced significantly. This suggests that customers understand TOU tariffs and react to them but suppliers need to understand how to maintain customer behaviour after the first year.

Customers have to reach their own acceptance of the value of TOU tariffs; EDF Energy does not expect customers with heat pumps or Electric Vehicles (EVs) to be forced onto TOU tariffs. Suppliers are likely to encourage customers with these devices to take TOU tariffs through price signals but the likely take up is unknown at present.

Barriers exist to the enablement of demand side response in relation to heat pumps. GB experience from the Energy Savings Trust trials is that the scope of heat pump (HP) users for DSR is very limited on cold days in the absence of a heat store. It would add very little to the cost of a new home to mandate the inclusion of plastic heat piping in the concrete floor, making it “HP ready”. In addition, mandating radiators in new homes at 60 degree heat rather than the present, 80 degree heat would be beneficial.

Boilers provide water at 80 degrees, but heat pumps achieve only 60 degrees at best. A retro-fit HP, driving smaller radiators originally sized for 80 degree heat, would only just able to keep the building warm on cold days. The need to upsize the radiator in each room comprises a barrier to the adoption of heat pumps.

**Q34. Does the demand profile described in table 7 for electric vehicles by time of day look realistic?**

We believe the profile reflects a reasonable shape for fixed demand from EVs, however, we also expect there to be significant overnight demand (i.e. 60% of total demand) across EFAs 1, 2 & 6. We therefore expect TOU tariffs to have made an impact on shape by 2020. We note that, if set too high, minimum charge power settings for EVs may lead to overloading of distribution networks at times of minimum wholesale prices (currently, minimum charge power settings are at least 3kW).

EVs exhibit daily average charging energy requirements of about 8 to 9 kWh so if taken steadily at 1 kW, the night power requirement per home is well within local DNO constraints. However, if taken at 3 kW or more for the same 3 hours per day of minimum wholesale price, then in areas of high take-up, some significant local network issues could result.

**Q35. Is it likely that the demand profile will change through ToU charging tariffs? How elastic will demand from EVs be?**

Please see our answer to question thirty three above. Suppliers are likely to encourage customers with compatible devices to take TOU tariffs through price signals but the likely take up is unknown at present.

**Q36. Do you agree with the estimate for the level of aggregation required across domestic premises?**

The estimate for the level of aggregation across domestic premises required, is a little circular, since an assumption is stated that NG will not, in future, accept tenders for demand side response of less than 3 MW. The question then is, does the calculation of the number of homes that could provide 3 MW at time of peak domestic demand, i.e.

1500 homes, seem correct. This is further put in the context of a statement that 1.5 to 2 kW is the assumed After Diversity Maximum Demand (ADMD) figure.

We are not in a position to consider to what level NG's systems might develop such that it could accept DSR tenders of less than 3 MW, but would agree that below that level, it would seem to add a heavy burden in terms of verification and monitoring, even with only a light-touch/occasional check approach, given the sheer number of service providers involved.

The ADMD figure stated seems to be a weighted average. In areas with a mains gas supply, we are aware of DNOs with ADMDs of 1 kW on average, and in areas without a mains gas supply, we are aware of DNOs with ADMDs of 2.5 kW on average. Given the level of gasification overall, it would seem that 1.5 kW to 2 kW might be a little high as a weighted average.

We would certainly question an assumption that demand-side response from domestic premises has to come by way of aggregation services. There is a good deal of international evidence that DSR can come by exposure to time of day pricing. Our experience with "red" (the most expensive) days in relation to the French "TEMPO" domestic critical peak pricing tariff, is that domestic customers reduce their electricity demand by 45% on such days.

Certainly the time of day pricing offered by the Supplier to secure DSR for the purpose of local or even wider networks, cannot be driven solely from wholesale price tracks. DNOs must have a means of accessing DSR independently of wholesale price tracks. One way of achieving this is by time of day varying, localised DNUoS, but there are other ways. Ofgem has allocated monies to the Low Carbon Network Fund trials, some of which are aimed exactly at this issue, i.e. at discovering ways and means for DNOs to access DSR independently of wholesale prices. In New Zealand, local network firms have been able to access DSR for many years, as the cost of local network reinforcement is simply too expensive. The cost of local network reinforcement in GB is also un-budgeted at this time.

We do agree that from the TSO's point of view, it is most likely to access DSR by way of aggregated services that it reimburses in a traditional manner. So far the aggregators are generally seeking value only from NG and not seeking value from DSOs or Suppliers, so the value of the information to DSOs and Suppliers is lost, as is the value that DSOs and Suppliers might have given to influencing consumption actively via the aggregator.

We do not believe that National Grid should entirely rule out the possibility of accessing or influencing DSR through other means than via an agent tendering into something like STOR. It should consider other possibilities and observe closely the innovations that come out of the DSO's participation in the low carbon network fund trials, as some of the new approaches may be adaptable for TSO use.

**Q37. Do you agree with the issues raised and are they being addressed?**

We agree with the issues raised, many of which are addressed, in principle, in the Smart Metering Implementation Prospectus Consultation. It is not yet clear if the principles and recommendations contained within the consultation are accurately reflected in the terms of reference for the DCC.

**Q38. What do you believe are the important factors to developing and securing demand side services?**

Smart appliance standards are vital so that new wet appliances are sold "smart-ready". Early agreement of the home area network protocol is a precursor to this. Appliance manufacturers might see little value in smart functionality at present as there is little customer awareness or demand for it. Inclusion of smart-readiness in the EU Eco-Appliance Standards for wet appliances would be highly beneficial, although this may require a European home area network standard. The changes to building standards outlined in our reply to question 33 would enable heat pumps to deliver demand side response at time of peak demand.

For the domestic and SME markets, the key factors are:

- Customer trust and understanding
- DCC services and capabilities
- The reduction of controllable demand (EV, smart appliances etc).
- The ability of aggregators to engage and gain customers' trust with clear and acceptable propositions that suit their lifestyles and reward them for taking part
- The development of a meaningful business case for the aggregator

For larger, I&C customers, a clear and sustained price signal will be a key driver for those customers able to participate in demand side response.

**Q39. Do you agree that the TSO and DNO relationship will principally revolve around better co-ordination of generation patterns from embedded generators?**

With regards to the TSO – DNO relationship, we agree that this relationship will principally revolve around load forecasts and embedded generation profiles for the foreseeable future. Even if demand side response services were made by a DNO responsibility, load forecasts and embedded generation profiles would remain central to the relationship, although there would be an increasing emphasis on real-time demand.

**Q40. Do you agree that the supplier / DNO relationship will be crucial in localised constraint management? How do you see services will be developed?**

The relationship with the DNO and supplier will be vital. Suppliers and network companies are working through the Energy Retail Association (ERA) and Electricity Networks Association (ENA) to identify workable models of demand side response which will allow the network and generation needs to be met. The outcome of this work will be known at the beginning of 2012. DECC and Ofgem are working on this issue and we expect possible frameworks to be much clearer by the summer of 2012.

DNOs have put in place the functionality to allow variable, localised price messages to be sent by the supplier to the customer with smart metering. It is not yet clear when this functionality will be used by suppliers on a wide scale.

**Q41. How does this model align with your own understanding of how operational interfaces may work?**

The key feature is the ability for networks, particularly a local network operator, to influence or access local demand management independently of wholesale market prices. There will be days when the local network infrastructure (i.e. the last transformer, its upstream feed, and the street cables to the consumer) are at risk of overloading at a time of peak demand when wind generation is high. At such times, wholesale prices might not provide signals for demand side response. Street cables fail badly as they are not protected against sustained overload, only against a short circuit. The ability for at least local networks operators to influence or access local demand management will enhance security of supply.

**EDF Energy**
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