**Memorandum submitted by P E Baker and Dr B Woodman of Exeter University**

**Q1. What should the Government's vision be for Britain's electricity networks, if it is to meet the EU 2020 renewables target and longer-term security of energy supply and climate change goals?**

The electricity sector is the largest producer of greenhouse gas emissions and will be required to make a significant contribution to the achievement of the UK's new renewable obligations and longer term climate change goals. In order to deliver this contribution, the Government needs to think beyond "electricity networks" and develop a vision of a "sustainable energy system" capable of accommodating the necessary renewable and low-carbon generating capacity in the timescales required, ensuring energy supply security through diversity of fuel use and maintaining appropriate levels of supply reliability. Given unprecedented uncertainties, for example the contribution of the various energy sectors to climate change mitigation, the impact of energy efficiency measures and nature of the future generation portfolio, any vision of a sustainable energy system must, of necessity, be high level. However, once a vision based around a set of commonly agreed outcomes has been established, other entities, for example Ofgem, could set about developing flexible electricity market arrangements, networks and a regulatory regime that would be consistent with the achievement of those outcomes.

**Today's electricity system**;

The electricity system we see today has been designed around large, flexible fossil-fired plant and inflexible nuclear generation. Generation plant margins over demand have historically been relatively modest at around 20 - 24%, reflecting the controllability and high-availability of conventional generation in meeting peak demands. The transmission network has essentially been designed to accommodate the output of all generation simultaneously to meet those peak demands and therefore exhibits relatively low levels of congestion. Distribution networks have evolved to be entirely passive in nature with little or no connected generation, focussing on the delivery of energy from the transmission network to individual consumers in a cost-effective and secure fashion.

Electricity trading occurs on a bilateral basis, ignoring physical transmission system limitations and with the costs of resolving any associated system congestion being "socialised", i.e. spread across all users of the transmission system. Investment requirements have been relatively predictable and are undertaken on a centrally planned basis, using long-standing deterministic security-based rules. Network regulation has historically reflected this predictability, with investment requirements determined ex-anti and with the regulatory focus very much on a very narrow view of "economic efficiency" based on the concept of customer commitment.

**A sustainable electricity system;**
A truly "sustainable" electricity system will have very different characteristics. It will need to encourage the connection of sufficient renewable and low-carbon generation to deliver the UK's renewable obligations and goals and will be as close to being "decarbonised" as possible, i.e. only using traditional conventional generation as a last resort when insufficient renewable or low-carbon resource is available. This "replacement" role implies that renewable generation should be endowed with a natural priority in terms of energy dispatch and also in accessing the electricity system, thereby ensuring the maximum contribution to decarbonisation.

The deployment of intermittent or variable-output renewable generation technologies such as wind, tidal etc and the need to retain conventional generation as "back up" implies increased margins of generation capacity over demand and the consequent need for available transmission to be "shared" between renewable and conventional plant according to the availability of renewable resource. This sharing of available transmission capacity will result in potentially significant network congestion and resolving that congestion will require efficient and cost-reflective market mechanisms.

Transmission investment required to accommodate numerous, often remotely connected, renewable generation projects with relatively short development timescales will be significant, but less predictable and more dynamic than has been the case to date. The dependence on a narrow "customer commitment" view of investment efficiency will no longer be appropriate and a more strategic approach to investment will be required, taking into account the UK's long-term sustainability objectives and goals. Operating the electricity networks will become more complex, with the need to manage shared transmission assets and volatile power flows. Future regulation will need to recognise the increasing uncertainties in operating and developing the electricity system and focus on encouraging the maximum utilisation of available network assets and objective trade-offs between investment and operational alternatives.

Distribution networks will be required to host increasing amounts of micro and smaller-scale renewable and low carbon generation and become active in nature, with the operation of distribution and generation resources being coordinated to ensure network security. “Micro” or “smart” grids will develop with aggregated generation and flexible demand providing security services to the transmission system to replace those previously provided by large centralised generation. Similarly, and in addition to its role in facilitating bulk power transfers, the transmission system will provide balancing services to these actively-managed micro or smart grids.

Demand will also have a role in accommodating variations in aggregated renewable output and in allowing additional renewable capacity to be integrated into the electricity system. Though increased exposure to real-time electricity prices via intelligent meters, the use of “smart” appliances and fuel substitution, electricity demand will have the capability to respond to fluctuations in the availability of renewable resource. Integration with the heat and transport sectors would allow electricity demand to increase in response to price signals when renewable resource is abundant and decrease when the availability of renewable resource is reduced. In addition, the introduction of locational electricity pricing would allow demand to respond to the presence of network congestion and have a role in mitigating that congestion, thereby reducing the need for transmission investment.

**Q2. How do we ensure the regulatory framework is flexible enough to cope with uncertainty over the future generation mix?**

Whereas today’s networks of have essentially developed to allow relatively predictable demand growth to be supplied by large centralized generation, the future role and development of networks is less certain. One scenario would be that the required response to climate change would be based on bulk renewable technologies such as wind and tidal, resulting in the need for significantly more transmission capacity to handle increased and volatile power transfers to load centres. Anther plausible scenario might involved a reduced requirement for transmission, with the development of “smart grids” accommodating a growth in distributed and micro renewable technologies with intelligent metering providing a flexible demand base. The most probable outcome might lie somewhere between these two extremes, however at this point the eventual contribution that might be required from transmission and distribution is unclear.

Given these uncertainties and noting that, once committed, network assets will be with us for in excess of 40 years, there is a need develop a clear high-level vision of how the UK’s environmental and supply security goals might be achieved. As discussed above, once a common view of the potential routes to achieving these goals has been established, consistent and sufficiently flexible regulation and market arrangements could be developed. Transmission Owners (TOs) and National Grid as GB System Operator (GBSO), who are best placed to determine future network requirements, could be incentivized to embark on network developments in advance of customer commitment, thereby addressing the mismatch between network delivery timescales and the ability of individual renewable projects to provide the necessary commitments. In addition, network access arrangements could be amended to allow generation to connect in advance of transmission reinforcement where necessary and practical. In fact steps have been taken to achieve both these outcomes, with Ofgem indicating that it is "minded to" extend the BETTA transitional transmission access arrangements[1] and with all the options for access reform being considered via the Transmission Access Review (TAR) allowing generation the option of connection in advance of network reinforcement.

The role of Ofgem in setting the framework for energy investment needs to be reassessed: currently, the short term interests of consumers are prioritized, while longer term issues related to the strategic development of networks and the delivery of sustainable systems up to 2050 and beyond is given little or no consideration. Ofgem is an independent economic regulator and although the exercise of its duties is to an extent defined by Government guidance, it has considerable discretion to act within a very broad framework. The framework should be narrowed so that Ofgem can retain its independence but be required to act within clearly defined parameters designed to ensure the delivery of long term sustainable goals.

Q3**. What are the technical, commercial and regulatory barriers that need to be overcome to ensure sufficient network capacity is in place to connect a large increase in onshore renewables, particularly wind power, as well as new nuclear build in the future? For example issues may include the use of locational pricing, or the availability of skills.**

Before addressing the issue of what needs to be done to ensure that sufficient network capacity is in place to allow the connection of the required renewable and nuclear generation, some thought needs to be given to how we decide just how much transmission capacity is required. While significant network investment will clearly be necessary, the challenge of delivering that investment in the timescales available together with the potential impact on customer's electricity bills requires that we ensure all investment is fully justified and efficient in the context of the UK's long-term strategic goals. This will require not only that the process for identifying the need for additional network capacity is both objective, transparent and consistent with these goals, but also that available network assets are fully utilized.

**Maximizing the utilization of available network assets;**

There is considerable redundancy in the transmission networks and asset utilization typically around 30%. While some redundancy is necessary to ensure that demand can continue to be supplied in the event of equipment failures and faults, there appears to

---

[1] Derogations to facilitate earlier connection of generation – proposed interim approach. Ofgem, 19 March 2009.

be considerable scope to increase asset utilization. Innovation and the deployment of emerging primary and control technologies can clearly help in enhancing the capacity of the existing infrastructure, however much can also be done by improving operational procedures and techniques. An example of how a change in operational procedures could enhance the capacity of the existing transmission infrastructure would be a move to “weather-related security standards”.

Historically, the transmission system has been operated to be secure in the event of the loss of two transmission circuits strung on a single set of towers – a “double-circuit fault”. Such faults are quite rare but are more common in poor weather, in fact some 70% of all transmission faults are weather-related. Little or no account is currently taken of prevailing weather conditions in operating the transmission system and it would seem possible to relax operational security standards in fair-weather conditions by, for example, covering the loss of a single rather than a double circuit, without any appreciable increase in risk to customer supplies. A “weather-related” approach to security would significantly decrease the external costs incurred in operating the transmission system and, as transmission investment will increasingly be determined by cost-benefit analysis as renewable deployment increases, would therefore reduce the requirements for transmission investment

**Investment criteria;**

The criteria used to determine the need for transmission investment were developed in the 1950s with the aim of ensuring that the ability of conventional generation to contribute to meeting winter peak electricity demand was not unduly restricted by transmission capacity issues. The criteria are deterministic in nature but with a cost-benefit “add on” to allow additional investment to take place when economically justified. Concerns have been raised over the treatment of intermittent generation such as wind in the application of these criteria and the possibility that the need for transmission investment might be overstated. The basis of these concerns is the assumption that wind generation has 60% of the capacity value of a conventional generator with the same maximum output, whereas actual wind generation capacity factors typically lie in the range 30-45%. Work undertaken by the Centre for Sustainable Energy & Distributed Generation (SEDG)[2] confirms that capacity values of around 30-35% should be used when carrying out cost benefit analysis to determine the need for network investment.

**The Balancing Mechanism, generation fixed costs & market power.**

The divergence of view on what wind generation capacity factor should be assumed when carrying out cost benefit analysis to justify transmission investment primarily relates to the cost of resolving transmission congestion via the BETTA Balancing Mechanism. Due to the lack of any explicit reward for generation capacity, generation

[2] Transmission Investment, Access and Pricing in Systems with Wind Generation. SEDG February 2007.

displaced from the energy market will attempt to recover fixed costs via the Balancing Mechanism. This, together with possible exercise of market power[3] by generators, results in the cost of resolving transmission congestion via the Balancing Mechanism being significantly higher than was the case with the Electricity Pool which preceded BETTA, or which would be the case if Locational Marginal Pricing applied in the UK. While the costs of resolving transmission congestion via the Balancing Mechanism are often around £90/MWh or higher, fundamentals suggest that costs of around £10/MWh should apply. Clearly, much more transmission investment can be justified to avoid congestion costs of £90/MWh than would be the case if the costs of congestion were around £10/MWh and it is a real concern that more transmission investment will be required to accommodate the UK's renewable objectives with BETTA than would be the case if the old Electricity Pool was still in place or if Locational Marginal Pricing were to be introduced.

In addition to overstating the need for transmission, the unnecessarily high costs of resolving network congestion has the potential to discourage renewable generation from seeking "early" connection to the transmission system, i.e. connection in advance of any necessary network infrastructure reinforcement being completed. Early connection will inevitably increase the volume of transmission congestion and, depending on the outcome of TAR, the costs of resolving that congestion will either be smeared across all users of the transmission system ( a "connect & manage" approach) or targeted on the generation responsible for the increased congestion. In the event of connect & manage forming the basis of an enduring transmission access regime, which seems unlikely given a general lack of cost-reflectivity, the fact that the resolution of network congestion is more expensive that necessary is unlikely to have much impact of a generator's desire to connect in advance of network reinforcement being completed. However, the alternative options for access reform being considered by TAR will either target the costs of resolving congestion on the newly connecting generation or on all generation connected to the non-compliant area of the transmission network. These targeted costs could be significant and might be sufficient to make early connection uneconomic for marginal renewable projects.

As suggested previously and leaving aside any issues of market abuse, the fact the resolution of transmission congestion via the Balancing Mechanism is more expensive than with other market arrangements is linked to the recovery by generators of their fixed costs. While it is appropriate for generation displaced from the energy market to recover fixed costs when required to operate via the Balancing Mechanism, it seems fundamentally incorrect for generator fixed costs to be factored into the case for transmission investment. As transmission is incapable of producing MW, additional

---

[3] Addressing Market Power Concerns in the Electricity Wholesale Sector – Initial Policy Proposals (30/09. Ofgem, 30 March 2009.

transmission capacity cannot replace generation, it can only allow economic choices to be made as to which generation should be decommissioned.

**Incentivizing objective investment**;
Another concern in terms of ensuring objective and efficient investment is the incentives flowing from the current network regulatory regime. While developments in Transmission Price Control (TPC) methodology over time have increased incentives on TOs to undertake investment at least-cost, it is not clear that the TPC and the GBSO incentive, in combination, provide sufficient incentives to maximise the utilisation of existing transmission assets and ensure that transmission investment is truly efficient, either economically or strategically. Currently, the regulated income that TOs are allowed to recover is a function of the value of their asset base and there is therefore an incentive to grow that asset base by building as much transmission as can be justified. On the other hand, the GBSO incentive encourages NGET to outperform an operational cost baseline set for the year in question and is to all intents and purposes independent of Transmission Price Control. Taken together, there is no overall mechanism which would allow NGET or the Scottish TOs to benefit from forgoing investment opportunities and associated long-term increase in revenues if that decision resulted in a risk of an increase in system costs.

It is therefore concluded that transmission regulation currently encourages investment over the adoption of operational alternatives and that this is reflected in the TOs and GBSO taking a cautious, low-risk, approach when making operational and investment decisions. It is proposed that, given the transmission investment challenges ahead and uncertainties over the disposition and timing of renewable deployment, more attention needs to be given to the minimisation of <u>total</u> network costs and ensuring that regulation encourages objective trade-offs between investment and operational alternatives.

**Q4. What are the issues the Government and regulator must address to establish a cost-effective offshore transmission regime?**

Offshore wind has a prominent role in the UK's proposed Renewable Energy Strategy for 2020, and in the longer term all marine renewables will presumably make a significant contribution to the UK's electricity production if we are to deliver a more sustainable system.

The current approach to devising a framework for offshore transmission investment is at best confused and offshore generators are not being treated in the same way as their onshore counterparts. For example, offshore transmission is defined as 132kV and above, while onshore transmission in England and Wales is 275kV and above.

In addition, unlike the onshore regime, the construction and operation of new lines will be open to competitive tender. Attempting to introduce elements of competition into the construction and operation of new offshore networks will not necessarily deliver substantial savings, but will ensure that the process leading to the construction the new lines will be complex and piecemeal. Current arrangements will lead to the construction of radial transmission lines from the offshore wind farm, and there is little scope for the development of offshore networks to connect different projects and technologies in the future.

Overall the development of the offshore transmission regime has been a lengthy affair with the final proposals appearing to have been driven by an ideological commitment to competition regardless of whether this would be appropriate in the circumstances. Given the strategic importance of marine generating technologies to the UK's electricity future, it would have been more appropriate to continue either the current merchant approach to offshore networks, or to give National Grid responsibility for constructing new transmission lines under defined investment criteria. This would provide offshore generators with some parity with onshore generation, while also enabling a more strategic, long term view of the development of offshore networks.

**Q5. What are the benefits and risks associated with greater interconnection with other countries, and the proposed 'supergrid'?**

Increased interconnection with adjacent electricity networks clearly has a role to play in allowing areas rich in renewable resource to be developed beyond the point that would be comfortable from a local or national perspective. An example of interconnection allowing the increased deployment of renewable capacity is West Denmark, which regularly exports surplus renewable energy to Norway, Germany and Sweden. However, there may be limits to the extent to which interconnection can be used to smooth variations in renewable energy output. Weather systems often extend beyond national boundaries and as the deployment of technologies such as wind become more widespread, interconnection may become less reliable as a means of exporting surplus renewable energy.

Denmark also provides an example of how demand flexibility and fuel substitution can be utilized to absorb fluctuations in the output of renewable energy. In December 2005, the Danish Parliament legislated to allow electricity to be used for heating in district heating schemes the large thermal storage capacity of these schemes is now used to absorb surplus renewable energy. Switching from gas to electricity during periods high renewable output has had a pronounced effect in terms of stabilising electricity prices.

Studies by SEDG[4] suggest that the need to curtail wind output during periods of low electricity demand might first arise with an installed GB wind capacity of around 16GW. As deployment increases beyond this level, combinations of high wind output and the associated need for spinning reserves to be held on conventional plant, together with inflexible nuclear output will result in increasing instances of wind curtailment. During these periods, electricity prices can be expected to collapse or even go negative as wind generation attempts to maintain access to ROC income. Clearly, low or negative prices will damage the investment case for high capital-cost technologies such as wind and nuclear.

The need for curtailment could be mitigated by developing a diverse renewables portfolio or, as discussed, by measures such as increasing interconnection with adjacent electricity systems and encouraging fuel substation. Although, unlike Denmark, the UK does not yet have a district heating infrastructure, access to domestic water and space heating thermal storage could be achieved by via smart metering and exposure to spot prices. Direct electrical storage capacity could also be increased with the development of pumped storage schemes, although potential sites are limited. New, utility scale, storage technologies, such as compressed air electrical storage (CAES) or flow-cell batteries could be developed, while electric or hybrid vehicles could also eventually form part of a distributed storage infrastructure.

**Q6. What challenges will higher levels of embedded and distributed generation create for Britain's electricity networks?**

The electricity network has evolved to transport energy from the transmission system to individual customers and has been designed on a "fit and forget" basis to be independent of any connected generation. However, a sustainable electricity system will consist of significant amounts of smaller scale, distribution connected generation, which will require distribution networks to move from their current passive configurations to become more active participants in the electricity system. At the moment, there are few incentives for distribution network operators (DNOs) to invest in technologies which would allow their networks to be more actively managed, and it is difficult within the five year price control format for them to make a business case for such investment[5]. It should, however, be possible to provide incentives for DNOs to invest in active management by, for example, allowing a greater level of cost recovery from consumers.

Specific challenges will include the need to accommodate the bi-directional power flows and increased fault levels that will arise from the connection of distributed generation,

---

4 Power and Energy Balancing in systems with nuclear and wind power. SEDG.

5 EA Technology (2006), A Technical Review and Assessment of Active Network Management Infrastructures and Practices, a report for the ENSG, URN 06/1196, http://reporting.dti.gov.uk/cgi-bin/rr.cgi/http://www.dti.gov.uk/files/file30559.pdf?nourl=www.dti.gov.uk/publications/pdflink/&pubpdfdload=06%2F1196

manage more volatile voltage profiles, more responsive demands and to generally develop the control structures require to manage active networks. As more generation connects, DNOs will be required to develop a “system operator” capability in order to effectively coordinate network and generation resources and to organize security services to replace those previously provided by displaced transmission connected generation. Furthermore, there may be a need for DNOs to become involved in the contractual arrangements between the GBSO and suppliers in order to recognize the interactions between active distribution networks and the transmission system.

While these issues will change the operational characteristics of Britain’s electricity networks, they do not pose any insuperable technical or security problems. Technologies already exist to allow active network management, although there are currently no real incentives for DNOs to invest in them.

**Q7. What are the estimated costs of upgrading our electricity networks, and how will these be met?**

An initial assessment of the cost of connecting the renewable generation capacity necessary to deliver the UK’s new renewable obligations together with new conventional generation was given as around £12.6 billion by SKM in a report to BERR[6]. More recent work carried out by the TOs for the ENSG[7], suggests that in addition to the £4 billion of investment already authorised and excluding investment required to reinforce the connections to the Western Isles, Orkney and Shetland, an additional £4.7 billion of investment will be required by 2020. In other words, the investment needed to deliver our renewable obligations and climate change goals could, in total, exceed the regulated asset valve (RAV) of the transmission networks, which currently stands at some £6.7 billion[8].

When the need to extend and reinforce the transmission networks is taken together with the need to refurbish and replace existing assets that are nearing or have reached the end of their useful life, it is clear that we have entered a period where capital investment will dominate TO revenue requirements. Investment costs will be recovered via Transmission Network Use of System (TNUoS) charges applied to all users of the transmission system (i.e. generators, suppliers and interconnector-owners) however;

---

[6] Growth Scenarios for UK Renewables Generation and Implications for Future Developments and Operation of Electricity Networks, Report to BERR. SKM 2008b.

7 Electricity Networks Strategy Group (ENSG). Our Electricity Transmission Network, a Vision for the Future. Report to DECC & Ofgem, March 2009.

8 Transmission Access Review – Initial Consultation on Enhanced Transmission Investment Incentives. Ofgem, 2008, 175/08.

ultimately, the costs of transmission investment will be borne by electricity customers. With the cost of increased investment outweighing revenue reductions accrued through efficiency savings, customers will see the costs of providing a transmission service increase, reversing the trend seen since privatisation.

It is clear that significant investment will be needed in order to deliver our renewable and climate change goals and to construct a sustainable system for the future. Furthermore, there may well be a case for enhancing capacity ahead of need, given that much of the UK's electricity infrastructure is in need of upgrading or renewal. However, in order to protect the interests of today's customers and ensure unnecessary costs are avoided, it will be necessary for regulation to focus on ensuring not only that investment is justified and efficiently carried out, but that the utilisation of available transmission capacity is fully utilised in the context of delivering those climate change and sustainability goals.

**Q9. How can the regulatory framework encourage network operators to innovate, and what is the potential of smart grid technologies?**

At the last Distribution Price Control review the negative impact of regulation on innovation was recognized with the introduction of incentives to encourage innovation and greater connection of distributed generation. These schemes - the Innovation Funding Incentive (IFI) and Registered Power Zones (RPZ) - have met with mixed success. While DNO funding for R&D under the IFI has risen, comparatively little has been spent on innovating for future active network management, rather than for extending the life or refining the performance of existing assets. Only a few RPZs have been proposed, despite early optimism about the potential for the scheme. However, the intention behind incentivising innovation and more active networks is good. The schemes need to be maintained and revised to ensure that activities geared towards more active networks and more connections of sustainable generation are rewarded to a greater extent than activities designed to maintain the current passive operation of distribution networks.

**Q11. What can the UK learn from the experience of other countries' management of their electricity networks?**

The challenges associated with integrating renewables generation into the electricity system are mostly generic in nature and it should therefore be instructive to consider the policy responses of other jurisdictions to those challenges, particularly of those jurisdictions that have been rather more successful than the UK in developing renewable capacity.

The principal challenges to integration relate to the mismatch in the development timescales of renewable generation and transmission infrastructure projects and the associated issues of allowing early access to the electricity networks and managing the resulting network congestion.  As the deployment of renewable technologies such as wind progresses, issues of managing intermittency will also arise, as will the issue of dealing with surpluses in renewable output and avoiding the need for curtailment.

**Investment, early access and congestion;**
In terms of the mismatch between renewable project and transmission infrastructure development timescales, it is pertinent that both Germany and Denmark have adopted a rather more strategic approach transmission infrastructure development, encouraging pre-investment in order to open up areas of high renewable resource.  The German Energy Agency (DENA) for example has been proactive in producing strategic electricity network studies linked to the development of renewables, while legislation has been enacted ( the Infrastructure Acceleration Planning Law)  which requires utilities to provide anticipatory offshore transmission investment.  This strategic approach to infrastructure development is mirrored in Denmark with the production of long-term infrastructure plans linked to the delivery of energy policy objectives, resulting in initiatives such as the interconnection of the Danish eastern and western electricity networks.

These measures designed to ensure the timely delivery of electricity infrastructure are complimented by, and are partly as a result of, measures to allow the early access of renewable energy to electricity markets and to manage resulting network congestion. Both Germany and Denmark, in common with other jurisdictions, have applied a "connect & manage" approach to connecting renewable generation, which requires utilities to connect renewable projects in advance of transmission infrastructure being delivered, with renewable energy being guaranteed access to electricity markets via "feed-in" tariffs.  This approach has been successful in delivering renewable capacity but, particularly in Germany, has resulted in significant levels of network congestion. This has been managed by restricting the output of conventional generation (the whole point of deploying renewables) and also by curtailing the output of wind when necessary.

With the Transmission Investment for Renewable Generation (TIRG) report in 2004 and the more recent ENSG report into the transmission development necessary to deliver our 2020 renewable obligations, the UK appears to be tentatively edging towards a more strategic approach to infrastructure provision.  The outcome of the TIRG process allowed TO's to proceed with authorized reinforcements safe in the knowledge that costs would be recovered.  However, Ofgem appear to be suggesting a different approach to the work identified by the ENSG, with TO's being incentivized to invest ahead of customer commitment by the prospect of an enhanced rate of return on investments that ultimately become fully utilized.

**Investment versus alternative means of increasing network capacity**
There may be sessions to be learnt from Norway in terms of its approach to transmission infrastructure development. Whereas countries such as Germany and Denmark have generally looked to build new transmission assets in response to increasing network congestion associated with the connection of renewables, Norway has arguably taken a more objective approach to investment. For example, Norway will always look to increasing the capability of existing assets by thermal or voltage upgrades, or by other means such as the use of interruptible transmission contracts as a means of avoiding the need for new infrastructure. Whereas it is clear that new transmission infrastructure will be required in the UK to accommodate renewable generation, maximizing the utilization of existing assets would seem to be a pre-requisite for efficient investment.

**Intermittency and curtailment**
The fact that Germany and Denmark have installed far more wind generation both in absolute terms and in relation to the size of their electricity system(18% and 15% respectively) than has the UK and have encountered few problems in terms of intermittency, is reassuring. In fact there seems to be an almost generally held view that the acceptable limit of installed intermittent renewable generation is likely to be defined by economic rather than technical factors.

One of these factors may well be the potential need to curtail the output wind generation output during low demand. This is an issue that been faced by Denmark in particular and addressed primarily by exporting surplus output to Norway and Germany. However, as renewable capacity builds in those countries, relying on interconnection to manage energy surpluses will become a less-viable option and Denmark has exploited fuel substitution driven by exposure to real-time electricity prices to as a means of mitigation. Denmark's experience holds valuable lessons for the UK both in terms of the value of fuel substitution and the fact that there is a limit to the extent to which national electricity systems can rely on interconnection as a means of exporting energy surpluses.