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Review of Energy Market Frameworks in light of Climate Change Policies

Response to 1st Interim Report

Summary

1. **Do you agree that the convergence of gas and electricity markets is not a significant issue in the eastern states and therefore should not be progressed further under this Review?**

   No. Gas and electricity convergence is a key issue in many international energy markets and should be a key theme within the review, as should the ability of one market to deal with shocks in the other.

2. **Do you agree that the ability for NEMMCO to manage actual or anticipated transitory shortfalls of capacity is a significant issue that should be progressed further under this Review?**

   Yes, very much so. This is especially the case given the short-term to medium-term outlook set out in the Statement of Opportunities. More generally it is easy to understate the inherent difficulties in the market responding to investment signals even where they are strong, and there is a proven track record in several markets of a partial or belated industry response.

3. **Do you agree that the existing framework based on an energy-only market design with supporting financial contracting is capable of delivering efficient and timely new investment?**

   Broadly yes with regard to the appropriateness of the energy-only market design. However central interventions through easing the market cap and modifying the RERT framework, as well as clarifying the scope for directions by the system operator, are intimately related to this issue.

4. **Do you agree that operation of the power system with increased intermittent generation is not a significant issue and therefore should not be progressed further under this Review?**

   No. It is a very important issue from both an operational and planning perspective. Given the immense amount of consideration being given to this matter across markets by regulators and system operators, and the considerable track record already available of increasing operational difficulty, it is not easy to understand the AEMC's position here.

5. **Do you agree that the connection of new generators to energy networks is a significant issue that should be further progressed under this Review?**

   Yes. Connection of new generation is a very significant issue and warrants careful further consideration as part of the Review. This dimension is one that will probably raise many difficult issues with regard to the existing rule-book, and one which may create the need for an overhaul of existing processes and rights. This of itself has been the cause of much delay to access reform in Britain. The investment impacts and the need to "rewire the system" as a consequence will present real threats to orderly progress.

6. **Do you agree that the issue of network congestion and related costs requires further examination in this Review to determine its materiality?**

   Yes. This is key activity given the potential materiality of constraint costs locally and between pricing zones.

7. **Do you agree that the current inflexibility in the retail price regulatory arrangements is a significant issue that should be progressed further under this Review?**

   Yes. It is impossible to detach wholesale participation and retailer risk management from operation of the retail markets, and the Review of the energy markets frameworks should embrace them. Further the increases to retailers' costs from the proposed CPRS and RET (as well as the more volatile prices that are likely to arise) will complicate these relationships and increase the prudential requirements that retailers will be called on to meet, which may have important competitive effects.

8. **Do you agree that the current energy market frameworks do not impede the efficient financing of the significant increase in investment implied by CPRS and expanded national RET?**

   The current market frameworks may not directly impede investment for low-carbon generation, but there will inevitably be aspects of the rules that will need to be fine-tuned in the light of an upsurge in investment following implementation of new incentives and of any carbon prices. The timing and rate of investment is a moot point and will be determined by various factors, including:

   - political decisions on the level of incentives (RET) and the carbon price;
   - wider market weaknesses and the longevity of the credit crunch; and
   - the longevity of the current financial crisis and its impact on a sector with high-value long-lived assets.

The Foundation's and the Centre's involvement

The Foundation and the Centre are partners in a project funded by the Consumer Advocacy Panel entitled:

Attaining optimal carbon abatement rules through consumer advocacy: Learning from European Experience on the Regulation of Energy

The project is aimed at producing advocacy research papers, as well as research support for consumer group advocacy, in relation to the various current consultation processes relating to the development and implementation of climate change policies for the Australian energy markets.

While the project involves consultation with consumer groups any opinions, conclusions and recommendations in this paper and future papers are to be attributed only to the project team members and not to any organisation consulted. Moreover, project team members recognise that certain organisations have special knowledge, particularly in the field of the needs and experiences of classes of consumers in Australia, especially those on fixed incomes and otherwise disadvantaged. Such organisations may well have their own developed views on appropriate solutions for the protection and advancement of the interests of particular classes of consumers.

This paper was written for the project by Allan Asher.

Issue A1: Convergence of gas and electricity markets

A1.1 Do you agree that the convergence of gas and electricity markets is not a significant issue in the eastern states and therefore should not be progressed further under this Review? If not, what are your reasons for asking us to reconsidering this position?

No. Gas and electricity convergence is a key issue in many international energy markets especially where the proportion of gas-fired plant on the electricity system exceeds de minimis levels. At present the contribution from gas to electricity production is small, and Australia has enjoyed the benefit of abundant, low-priced fossil fuels. However its importance is set to increase and the overall importance will depend on the place of such plant in the generation merit order, the relative cost of gas to marginal generation and the extent to which a mechanism such as the CPRS "bites" on existing coal-fired plant. The impact of this growing relationship will also increase because of the tendency for commodity markets and prices to become more volatile, and the efficiency of the trading arrangements in one market will be driven over the medium term by its ability to respond to and deal effectively with exogenous shocks in the other.

Over time as coal plant is retired in response to a carbon price signal—and use of coal is relatively high by international standards—and in part replaced by gas-fired generation, the interaction between gas supply and the associated networks and power stations and the associated transmission networks will increase.

Understanding the impact of higher gas penetration on the market framework is not a matter than can be left until some undefined point in the future or until some specific threshold is reached. The RET and CPRS, if appropriately designed, are set to be enduring features of the market landscape and will have a sustained effect on lower-carbon generation. And given the relatively high energy intensity of the Australian market, effective climate change programmes can be expected to have a pronounced impact on the composition of generation and the speed of transitioning to lower carbon technologies. In turn the interactions between climate policy and energy security can be expected to go much wider than RET and CPRS and the establishment of the AEMO will only deal with these over short-term operational timescales. At the trading level, participants can also be expected to identify inefficient arbitrage opportunities if interactions between the two related markets are not addressed.

Similarly access undertakings in the two markets should be aligned as these have the scope to distort decisions by network service operators. The guiding principle should be that the access frameworks should be aligned unless there is a clear and specific reason not to do so.

The British market has a much larger contribution from gas-fired generation than Australia and provides some insights into the problems than can be experienced, especially when domestic and small business customers for gas enjoy priority rights when there is a risk of insufficiency on the gas system. In particular there is a tendency for curtailment of larger electricity customers served to be seen as the safety valve to maintain system balance when supplies to domestic gas customers are at risk. While this may well be rationale, the rules for dealing with these interactions are ad hoc and far from integrated. In a market like Australia, in which concerns about electricity security margins in some regions over the coming years have already been raised, the impact of disruption on the gas system could be critical; changes to market (e.g. exit) rules can also cause unintended impacts.

While it is not credible that Australia will see a “dash for gas” in the same way that this was experienced in Britain during the 1990s, new gas developments will be more likely to site closer to the fuel sources. This will have a formative impact on the configuration of the electricity transmission system, the development of pricing zones, network investment and constraint management. It would also suggest some scenario planning is needed as a minimum as part of the current project.

It should also be commented that the electricity market in Australia should not be viewed as an integrated whole. Forward programmes also need to address:

- encouraging the process of integrating the regional markets, with a view to strengthening the competitive market for all customers; and
- implementation of plans for improved decision-making on inter-regional transmission investments.

Both these facets of the market frameworks have some interdependency on development of the gas market.

Sources

Country review of Australia, IEA (2005)

http://www.iea.org/textbase/nppdf/free/2005/australia2005.pdf

National Grid winter outlook 2008-09 (November 2008)

http://www.nationalgrid.com/NR/rdonlyres/1BB72E89-3B65-4DF4-9B98-0906C75C53E4/28643/Winter_Outlook_2008_final.pdf

Energy markets outlook, DECC (December 2008)

http://www.berr.gov.uk/files/file49406.pdf

Issue A2: Generation capacity in the short term

A2.2 Do you agree that the ability for NEMMCO to manage actual or anticipated transitory shortfalls of capacity is a significant issue that should be progressed further under this Review?

A2.3 Are additional mechanisms required to complement the Reliability and Emergency Reserve Trader (RERT) and NEMMCO's directions powers, and what characteristics should such mechanisms have?

A2.4 Do you have any views on the detailed design and implementation of additional mechanisms?

Yes, very much so. This is especially the case given the short-term to medium-term outlook set out in the Statement of Opportunities (SOO). In particular there is a pressing need to test whether existing mechanisms can be developed to address the situation one to two years out if there is continuing evidence that the market is not responding. This might occur, as noted later, because of interactions with external planning or inflexibilities in the current network access regime, especially in a market where the technology drivers are set to change.

The probability of a radical shift in policy settings should not distort the reality that empirically there appear to already be problems with the current market arrangements and this is reflected in the SOO as it stands. Any failure to tackle "transitory shortfalls" effectively and promptly will not only undermine the operational security of the system, but also impose additional and unavoidable costs on consumers because of the increased scope for the exercise of market power that scarcity is likely to create.

Judging by the remarks in this section, the AEMC is focussed on supply-side solutions. With regard to these options there has been considerable debate in Australia over a prolonged period that has led to evolution of the role of the RERT and defined the scope for NEMMCO's intervention and the interaction between reserve levels and reliability risks have been well-tested. In comparison to some markets these roles and responsibilities are well-defined. That said, as the 1st Interim Report notes, these arrangements were not designed to manage large or sustained capacity short-falls.

It follows that these arrangements need to be considered further as part of the review, and in this context the level and likely operation of the NEM price cap should be examined. Based on experience in other markets, including Britain, the role of the reserve trader could be extended beyond nine months with longer-term option contracts entered into with generators on a targeted basis. In this regard, the introduction of new balancing services (including the new supplemental standing reserve service which itself was replaced by a short-term operating reserve product following a review in 2005) of reserve requirements may warrant scrutiny.

A further cautionary note on the supply side: the experience in many European Union markets, where the policy framework has already been refreshed, is that plans and consents do not necessarily translate into timely investment in generation. This is particularly true where there is limited credible threat from new scale entry from outside the established players, especially where they have significant existing assets that are set to be stranded by the policy changes. While there is undoubtedly a commercial logic for delay, there are also good reasons why market participants can take time to respond to market and investment signals. Whatever the cause, from the industry's perspective, this tendency can put additional pressure on already tight operating margins. From the Government's perspective, it usually translates into further debate about the level of incentives needed to stimulate new investment. In both cases the result for the consumer is higher bills.

More consideration is also required in particular to the potential role of the demand side. The Interim Report notes a number of artificial distortions to the amount of DSP reported to the system operator. More generally this is an area where the IEA said in its 2005 country review that Australia needed to do more and that retailers and network service providers have a role to play. Over the longer-term effective demand-side measures will more generally reduce any anticipated reserve short-fall; the rate at which new generation and transmission build might be needed may be delayed as a consequence.

Better use of existing transmission capacity could also produce benefits and help mitigate costs, to allow for plant to utilise existing transmission infrastructure should significant plant retire/require maintenance and therefore not need access to the network. This issue concerning network use will be brought into focus with the competing demands of new low carbon generation, much of which is likely to be intermittent. However, generators do not always clearly reveal their intentions and in the absence of any specific requirements will not do so. The 1st Interim Report indicates that the SOO does not constitute a credible forecast. As such, forward planning decisions by network operators and participants may be taken on the basis of erroneous information.

A further problem is that external factors such as planning and other consents can often mean that prospective generators over-subscribe for access to the system. In these instances NEMMCO should have the ability to free up access and reallocate its use, reducing the gross investment requirement and thus keeping network charges lower (and hence prices to consumers). This issue is further addressed in response to A5.

In terms of further capacity withdrawals, it is unlikely that this will be a credible risk in a well-functioning wholesale market. However, politicians and regulators should avoid the temptation to establish a carbon pricing scheme with free allocations to generators. External experience is that the marginal cost of carbon will appear in spot prices (especially with a mandatory pool such as the NEM) and will in turn be reflected in contract prices, and the generators will make windfall gains. The assistance package as provided for by the federal government should provide further safeguards, suggesting auctioning should be adopted.

Sources

Power to choose – demand response in liberalised electricity markets, IEA (2002)

http://www.iea.org/textbase/publications/free_new_Desc.asp?PUBS_ID=1201

Short-term operating reserve – principles and guidelines (December 2008)

http://www.nationalgrid.com/uk/Electricity/Balancing/services/reserveservices/STOR/

Issue A3: Investing to meet reliability standards with increased use of renewables

A3.1 Do you agree that the existing framework based on an energy-only market design with supporting financial contracting is capable of delivering efficient and timely new investment, including fast response capacity to manage fluctuations in outputs resulting from larger volumes of intermittent wind generation? If not, what are your reasons for reconsidering this position?

A3.2 Do you agree that the processes supporting the ongoing maintenance of this framework in respect of review and periodic amendment to the market settings, including the maximum market price, are robust? If not, what are your reasons for reconsidering this position?

Broadly yes with regard to the appropriateness of the energy-only market design. It is highly unlikely that the introduction of some form of capacity incentive of itself will materially influence the willingness of market participants to invest in generation. That being said, there will remain obvious uncertainties over the inter-action between the energy market price setting mechanism with the new carbon price and how that might evolve. This in turn is likely to complicate and delay decisions by investors in new low carbon generation.

With regard to generation adequacy this is a complex issue, which usually prompts diverse views, especially with regard to whether a specific capacity payment or incentive is required. Work by the IEA[1] has examined the question of the adequacy of the investment levels in seven reformed markets, including whether an energy-only market such as the NEM is better than a market incorporating capacity payments. Its main conclusions were:

- substantial investment has taken place and OECD electricity markets are generally reliable, the exception of California notwithstanding
- reserve margins have fallen generally, consistent with the improvement of allocative efficiency
- new capacity investment favoured the most economic option; natural gas where this was available but also coal where this option was less expensive
- it was too early to conclude whether electricity generation investment would mimic “boom and bust” cycles observed in other industries
- markets may increase flexibility of the demand side (e.g., through load-shifting or distributed generation) which would reduce the size of reserve capacity required
- the biggest challenges remain ahead – most markets are just beginning to approach their first major investment cycle, and
- the results of the study suggest that markets can give the right investment signals to generators and lead to timely investment. It is equally clear that adequate investment is not a given.

In short there is nothing to suggest that the existing energy-only mechanism, including the level of the price cap and its interaction with the scope of the RERT, suitably updated from time to time should not work.

With regard to intermittency and the need for sufficient compensating plant, this is an area where the technical challenges are being better identified across markets but far from resolved. AEMC is right to identify fast response as an issue, but reserve levels more generally are a concern to system operators. In the UK the National Grid has in the past been relatively relaxed about operational assimilation of wind plant across the system, provided it has in its role as system operator the necessary flexibility to contract for additional and new balancing services. But it is now generally agreed that there is some tipping point at which the operational challenges become much more difficult.

A fundamental review of the system quality and security standards is also underway, and is due to report in December 2009; a key driver of this work-stream is the ability to support the integration of new generation technologies.

It is also now recognised that the costs for procuring such reliability services can begin to have a material impact on consumers' bills. Further if operational interactions are not properly handled, there may be real impacts on the extent to which the transmission system can become constrained in some instances and therefore—again—increasing the costs faced by consumers.

In principle the ability to vary the energy market price cap and the rules for enabling the RERT should provide a robust institutional basis for dealing with the operational challenges. In practice the investment dimension raises many questions about interaction of the market framework with planning rules, institutional arrangements for network access and charging, and final commodity and carbon prices. This is subject to the need to allow for continuity in application of these rules and the avoidance of surprises, as this can only increase perceptions of regulatory risk.

The supporting processes also need to be fashioned to explicitly take into account increasing non-economic outcomes as may be determined by the politicians. For instance:

- how should externality costs be factored into cost-benefit decisions in a consistent and transparent manner and how should the regulatory framework for allowing new investment accommodate this challenge?
- should low carbon plant be given preferential terms because of the carbon off-set benefits?
- should some technologies be given must-run status within the market framework?

Sources

Security of supply in electricity markets – Evidence and policy issues, IEA (2003)

http://www.iea.org/textbase/publications/free_new_Desc.asp?PUBS_ID=1088

Fundamental review of SQSS, National Grid (June 2008)

http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/fundamental/

Issue A4: System operation and intermittent generation

A4.1 Do you agree that operation of the power system with increased intermittent generation is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

No. It is a very important issue from both an operational and planning perspective, as the two documents referenced below bear out. Given the immense amount of consideration being given to this matter across markets and by market operators, it is difficult to understand the AEMC's position here, which is reliant on the enduring appropriateness of a couple of rule changes that have been made to date and the prospect that further rule changes could be introduced expeditiously if necessary in the future.

The role of distributed generation is also a dynamic factor, which is often neglected. The AEMC notes the experiences in Germany and the UK where there has been a lack of control over embedded plants. It is not obvious why similar issues will not arise in Australia, and we think that they will.

More generally experience elsewhere suggests that the shift from heavily centralised processes based around large, lumpy generation to a more decentralised setting incorporating a much higher level of intermittent plant impacts across the responsibilities of the system operator and how it exercises its role. There is a demonstrable trend for the need to develop different procedures and policies with regard to deal with this challenge, including:

- setting reliability standards and how they will be delivered;
- calculating operational margins and how these feed into ancillary service procurement and despatch;
- information requirements on the market participants;
- allocating network capacity and establishing priority for its use; and
- setting network charges and the associated prudential requirements.

Sources

Future Great Britain generation system reliability evaluations in the presence of intermittent renewables

http://www.esru.strath.ac.uk/Documents/MSc_2007/Hashim.pdf

One of the key elements of generation expansion planning in any electricity system, the GB system inclusive, is system reliability. Various methods and indices have been established to evaluate this particular criterion in the past for the conventional generation technologies. Nevertheless, rising concerns over exhaustible fossil fuels, increase in oil prices and the environmental impact of fossil fuel generation has led to the introduction and integration of renewable generations, especially wind generation, into the system. This report is meant to contribute to the ongoing research on the study of intermittent renewable generation, in particular wind generation, in the UK. Meanwhile, specifically, results and findings of this research is intended to be a source of reference for generation system planners in determining the most suitable generation mix in the future GB system and also other studies of similar nature.

What is the evidence on the costs and impacts of intermittent generation on the UK electricity network and how are those costs are assigned?

http://www3.imperial.ac.uk/electricalengineering/newsarchive/intermittencyreport

This report examines the evidence base (more than 200 reports, studies and articles) on how the intermittent nature of some forms of energy might impose additional costs or have other impacts on the running of an electricity system.

The key findings of the report are:

- CO_2 emission reductions from renewable energy are not significantly affected by its intermittency
- intermittency does have two types of impact – short-term fluctuations require balancing and longer-term variations require measures to maintain system reliability at times of peak demand
- both impacts can be quantified and so too can their costs
- intermittency costs in Britain are of the order of 5 to 8 £/MWh (0.5-0.8 p/kWh) of wind output.
- the ranges above assume intermittent generation is primarily wind, has reached 20% of electricity use and is geographically widespread
- these extra system costs would increase average electricity prices by around 1%
- costs rise as penetration increases; today Britain is well below 20% wind penetration and the additional system costs are much lower
- above 20%, intermittency costs would rise and/or more radical changes might be needed to electricity systems, their control and their markets. The cost implications of this requires further work
- costs will be higher if renewables are not geographically dispersed, but lower if wider range of renewables (such as wave, tidal and solar energy) are developed
- the reliability of electricity supply need not be compromised by inclusion of intermittent generation in the mix of generation used in Britain, and
- comparisons between countries require caution because there are technical, market and climatic differences between countries that alter the impact of intermittency and its associated system costs.

Issue A5: Connecting new generators to energy networks

A5.1 Do you agree that the connection of new generators to energy networks is a significant issue that should be further progressed under this Review? If not, what are your reasons for reconsidering this position?

A5.2 Would any of the models identified in this chapter ensure the more efficient delivery of network connection services? In particular, with relation to these models:

- **How should the risks of connection be most appropriately spread across new connection parties, network businesses and end use consumers?**
- **How do the connection charges change for connecting new generation plant and what benefits may arise?**
- **How do the costs for end use customers change and what benefits may arise?**

A5.3 Are there any other potential models that we should consider to address this issue?

Yes; connection of new generation is a very significant issue and warrants careful further consideration as part of the Review.

International experience illustrates that it is very easy to under-estimate the difficulties that can arise from high levels of new plant competing for finite network capacity and the associated new investment requirement. Developing enduring rules that are technology neutral (if that is the intent) and treat existing, commissioning and development sites fairly and equitably for both connection and access to the system is also not straight-forward, and reliance on the current bilateral negotiation approach as applied in Australia will not deliver the policy requirements.

There are a number of very important factors here:

- much of the new generation technology is by its very nature often location-specific, typically in remote areas close to the fuel source (i.e. exposed sites with good wind) and often intermittent (renewables). The associated investment costs are significant because of the need to reinforce systems far from the point of connection, and the term “rewiring Britain” has been adopted here and the New Zealanders refer to a “wall of wire” that needs to be funded. The scale of the necessary investment in networks also raises difficult issues about administering appropriate prudential rules and cost allocation through access charges;
- the framework also needs to allow for more traditional plant to operate profitability (for security of supply reasons) and without regulatory or pricing “shocks”;
- these imperatives invariably cause a tension between government policy objectives and industry rules that are usually premised on considerations of reflecting costs;
- the introduction of a carbon price and an expanded RET creates new incentives for investors to consider when new plant is proposed. While such mechanisms increase the cost to consumers, the associated infrastructure costs also inflate end-user prices, and require careful treatment in the regulatory price settlements;
- CPRS can be expected to accelerate the point at which older, carbon-intensive plant goes off the system highlighting the need for orderly rules for releasing connection sites and network capacity; and
- the point we have flagged previously of the need to align access undertakings in the electricity and gas markets.

To mitigate price volatility as far as possible, stable and comprehensive market rules to the extent they need to be updated and modified should be put in place quickly, and where possible remain in place without fundamental changes, over time-frames necessary for generation plant investments, i.e. at least a decade.

Two examples highlight some of the potential pitfalls.

First the EU approach adopted for the emissions trading scheme of multiple phases subject to different rules and political agreement has not, as yet, worked. Moreover, there appears to be little prospect that this position will change before 2020 at the earliest.

Second the same can be said of the access regime in Britain, which is requiring a fundamental redefinition in the light of new environmental regulations and incentives to achieve the desired outcome prescribed by the Government in the relatively short time-frames (for example GB is set to increase the penetration of renewables from ~7% to ~35% in 11 years).

In fact many issues flagged by AEMC have been crystallised in Britain through the transmission access review (TAR), a process initiated by Government following the formation of a long queue for connection to the transmission system, 16GW of which is renewables. But as yet, after five years of almost constant policy debate, the new rulebook in Britain remains a work in progress and incomplete with Government threatening to legislate if the industry cannot deliver significant early progress.

The lack of progress is not attributable to a lack of analysis. The industry is confident it can develop enduring rules but to scope the problem has required extensive information gathering. This has included:

- studies of how introducing a carbon price could impact on the despatch of plant and profitability of existing and planned plant;
- assessment of transmission network infrastructure needs, including new build, reinforcement and existing/potential constraints through to 2020;
- detailed study of planned plant, possible plant and their likely locations, including security assessments to better understand how security and quality of supply criteria might need to be varied to:
    - address intermittency,
    - provide choice to developers who may wish to share capacity or receive a lower level of security, and
    - deal with "clustering",
- development of detailed protocols for prioritising access and in some cases re-allocating rights where external conditions (e.g. planning approvals) have not been achieved;
- consideration of different approaches to network connection and use of system charges, which can be easily understood, are transparent and allow for cost forecasts to be made; and
- assessment of the performance of planning processes and how these have interacted with connection applications.

A key lesson has been that large solutions require long implementation, and there are already indications that industry participants who see the prospect of change in their access rights will challenge important elements of the proposed new regime.

Another key issue is that market rules need to be complemented by appropriate incentives for network companies. In this context it is relevant that the British regulator has recently initiated a root-and-branch review of the current incentive-based regulatory approach, to consider among other things:

- impact of upsurge in network capex and treatment within periodically set revenue caps;
- user interaction in the regulatory determination process; and
- implications from high levels of distributed generation.

The four models highlighted by the AEMC need to be developed in much fuller detail to take on board learning points from these and related work-streams.

Sources

Transmission Access Review – Final report, Berr/Ofgem (June 2008)

http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/080626_TAR%20Final%20Report_FINAL.pdf

A review by Government and the regulator, Ofgem, on transmission grid access barriers to the deployment of new renewable (and other low carbon) generation. The measures set out in this report, when taken together are intended to remove, or significantly reduce, grid-related access barriers.

The report also includes a range of possible actions that will allow faster connection of some renewable generation to the Grid in the short-term, steps to introduce new, enduring grid access arrangements that allow faster connection and expansion of grid capacity and measures to identify the new transmission infrastructure necessary to meet the UK share of the challenging 2020 EU renewable energy targets and new financial incentives on the transmission companies to deliver that capacity.

Regulatory Policy Institute –International approaches to transmission access for renewable generation

http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Documents1/RPI%20-%20International%20approaches%20to%20transmission%20access%20for%20renewable%20generation.pdf

This paper provides a brief description of approaches that have been adopted to address the common challenge facing those who own, operate, use and regulate electricity transmission networks in many jurisdictions around the world: how can the actual and anticipated increase in renewable energy generation be reconciled with the risks, high costs and system management issues associated with the expansion and adaptation of transmission infrastructure to accommodate this form of generation?

Wind energy, in particular, provides its own set of challenges. The first is one of coordination: wind developments can be built within a short time-line, while the lead time for the development of transmission lines is long. A second follows from the nature of wind energy: transmission systems need to be adapted to accommodate the potential impact of this type of generation on system balancing and security of supply. Six jurisdictions are examined in this paper, three in Europe (Norway, Denmark and Germany) and three in North America (California, Texas and Alberta). These jurisdictions have been selected on the basis that they share a number of characteristics which allows for useful comparisons to be made, and because they include, some of the so-called “world-leaders in renewable energy generation.

Transmission Access Review—Guidance note to accompany connection and use of system code (CUSC) Working Group Consultations, National Grid (October 2008)

http://www.nationalgrid.com/NR/rdonlyres/0783B8D6-32FA-4817-9CAD-0223CA150EFF/28741/Guidance_Note.pdf

This document describes the models of transmission access reform currently being explored in the UK and how these were constructed. It provides summaries of the different options considered to increase renewables connection in the short-term and long-term.

Our electricity network – A vision for 2020, Energy Networks Strategy Group (March 2009)

http://www.ensg.gov.uk/assets/1696-01-ensg_vision2020.pdf

RPI-X@20: Principles process and issues, Ofgem (February 2009)

http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?file=Principles%20Processes%20and%20Issues%20con%20doc_final%20-%20270209.pdf&refer=Networks/rpix20/publications/CD

Issue A6: Augmenting networks and managing congestion

A6.1 Do you agree that the issue of network congestion and related costs requires further examination in this Review to determine its materiality? This includes considering whether the existing frameworks provide signals that are clear enough and strong enough in the new environment where congestion may be more material. If not, what are your reasons for reconsidering this position?

Yes. This is key activity given the potential materiality of constraint costs locally and between pricing zones.

There are three more specific problems that need to be factored into the Review:

- demand-led investment stimulated by decarbonisation programmes, relatively weak market signals (because transmission costs tend to be a relatively small element of a developers cost base) or restrictive regulation which only looks typically five years ahead can lead to a situation where network constraints grow unexpectedly and rapidly;
- new build generation especially for small, decentralised plant can often outpace reinforcement of the network also creating issues with regard to firm and non-firm access on a temporary basis; and
- there will inevitably be trade-offs between allowing access sooner thus realising environmental benefits on the one hand and creating short-run constraint costs which will be reflected in consumer prices on the other.

Allowing TNSPs to invest ahead of need is one option. In this context the British regulator Ofgem is developing detailed proposals that would allow a more strategic approach to investment (which in effect means the regulatory tests currently applied are being modified and made less prescriptive, with investments without firm customer commitments being permitted and the return determined ex post depending on whether the investment proves efficient). The regulatory treatment of capital investment also needs to be aligned to ensure the network companies have confidence they can invest and recover the associated monies when they need to.

Allowing network operators to reap the benefits (or be penalised) for risk-based investment ahead of need also requires a high degree of information regarding planned plant timescales and location. This path would also give greater confidence to investors that they could build, connect and operate plant to the timeframes they desire. All other things being equal, this should have the effect of dampening price shocks through step changes in investment programmes and maintaining future investment. It should also improve the system operator’s ability to deal with operational constraints.

One avenue that may be worthy of investigation within the review is that of the role of incentives on the market operator to reduce costs. Institutional arrangements in Britain incentivise National Grid in its role of system operator to share in savings achieved against pre-set targets for managing system costs including variable transmission costs (e.g. constraints), although recent experience has suggested that in a changing system the scope for exercising control is more limited than previously thought. The interactions between such schemes and TNSP regulatory controls could also be better understood. Nevertheless an incentive scheme, if properly structured, can deliver strong incentives to contain costs ultimately in the interests of consumers.

This section of the 1st Interim Report does not seek views on network planning issues and their interaction with network operations. We have noted elsewhere in this response that the scale roll-out of intermittent plant is likely to require a review of security standards.

The report also identifies as a problem the issue of benefits to market participants in adjoining regions, despite the existence of only one inter-regional TNUoS arrangement. The flip-side of this issue is the allocation of costs to causers, which is a matter that the Australian regional model would not seem well-placed to progress. In this context work by the European grid companies on inter-TSO compensation and cross-border trading could be of relevance. This area has also been a focus of the Electricity Regional Initiatives work being led by ERGEG.

Both these matters would seem to require attention within the frameworks review.

Sources

Improving incentives for investment in electricity transmission infrastructure, Frontier Economics and Consentec (2008)

http://ec.europa.eu/energy/gas_electricity/studies/doc/electricity/2008_rpt_eu_transmission_incentives.pdf

Over the next decade there is likely to be a requirement for a very significant increase in the amount of transmission investment across the EU. Given this pressing need, Frontier Economics and Consentec were appointed by the European Commission to examine the current structure of incentives for transmission investment in the EU and to suggest proposals to improve these incentives.

National Grid System Operator Incentives, National Grid (February 2009)

National Grid operates the electricity transmission system in Great Britain. It is subject to a number of financial incentive arrangements which encourage it to minimise the overall costs to consumers and to support the efficient operation of the wholesale gas and electricity markets.

http://www.nationalgrid.com/NR/rdonlyres/75839C1D-51EE-4A36-B35E-74EAC5D3AF9D/32311/NGETSystemOperatorIncentivesFinalProposalReport.pdf

Inter-TSO compensation, ETSO (various)

http://www.etso-net.org/Activities/cbt/e_default.asp

http://www.sciencedirect.com/science?_ob=ArticleURL&_udi=B6V2W-4M6SG95-2&_user=10&_rdoc=1&_fmt=&_orig=search&_sort=d&view=c&_acct=C000050221&_version=1&_urlVersion=0&_userid=10&md5=b1077253c2268f8b9b6d2c168ae68dac

The first of these links is to the mechanisms as currently applied by TSOs. The second is an academic study that considered different compensation mechanisms.

Electricity regional initiative, Ergeg (various)

http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_INITIATIVES/ERI

Issue A7: Retailing

A7.1 Do you agree that the current inflexibility in the retail price regulatory arrangements is a significant issue that should be progressed further under this Review? If not, what are your reasons for this position?

A7.2 Do you agree that the limitations with current RoLR arrangements are a significant issue that should be progressed further under this Review? If not, what are your reasons for this position?

A7.3 Are there any additional options that could supplement the processes currently under investigation to address these issues?

Yes; retail arrangements, including arrangements for dealing with retailer failure, should fall within the Review. It is impossible to detach wholesale participation and retailer risk management from operation of the retail markets, and the Review of the energy markets frameworks should embrace the retail markets and the regulation of its costs. Further the increases to retailers' costs from the proposed CPRS and RET (as well as the more volatile prices that are likely to arise) will complicate these relationships and increase the prudential requirements that retailers will be called on to meet.

Another factor that needs to be considered is the increased complexity in the retail business that will arise from implementation of climate change policies that can also create barriers to entry and hence restrict competition among existing participants. The obligations on retailers need to be carefully designed so as not to be unnecessarily complicated. This risk is compounded by the innate tendency of energy retail markets to scale—concentration and consolidation as a natural feature of these markets given fuel price volatility and which have led to aggressively cycling wholesale markets. In turn less effective competition in retail markets can mean that the benefits of even well-functioning retail markets are captured by the participants and their shareholders and not consumers.

As noted, the RoLR arrangements need to be included within the scope of this Review. The regulation of prices in the supply business can complicate this relationship, especially in the domestic market where retailers are often reluctant to adjust their prices frequently (especially in a falling market).

In GB the RoLR process (termed SoLR) has been implemented a number of times with lessons learned from each subsequent exit from the market, though it is acknowledged these do not mainly impact on the wholesale market framework. These range from:

- the case for increased monitoring by the regulator and the market operator to identify retailers in financial distress;
- the impact of overlapping credit requirements on supply and their disproportionate impact on independent retailers;
- inflexibilities arising from restrictions on the ability of retailers to adjust their prices because of the need to comply with regulatory requirements (including price controls); and
- the introduction of a mutualisation scheme in the renewable obligation to cover any shortfall in compliance certificates (Rocs) from a failed retailer.

It should be noted that one of the two most recent retail failures was triggered by the need to meet compliance payments under the renewables obligation. Its failure also led to a shortfall in the environmental fund undermining incentives to participants—the market framework Review should address these issues.

Sources

Supplier of Last Resort revised guidance

http://www.ofgem.gov.uk/Licensing/Work/Revoc/Documents1/5174-SolR_guidance_doc_24nov03.pdf

This document outlines the arrangements based on the current licence conditions and provides enhanced guidance on Ofgem's policies and procedures. In particular, this document provides detailed information about the process Ofgem will follow and the criteria it will use to select and appoint a SoLR. It also provides details about the information that industry parties will be required to give Ofgem as part of that selection process. This will enable them to prepare as much as possible in advance to respond to a supplier failure.

Issue A8: Financing new energy investment

A8.1 Do you agree that the current energy market frameworks do not impede the efficient financing of the significant increase in investment implied by CPRS and expanded national RET? If not, what are your reasons for this position?

The current market frameworks may not directly impede investment for low-carbon generation, but there will inevitably be aspects of the rules that will need to be fine-tuned in the light of an upsurge in investment following implementation of new incentives and of any carbon prices. The timing and rate of investment is a moot point and will be determined by various factors, including:

- political decisions on the level of incentives (RET) and the carbon price; and
- wider market weaknesses and the longevity of the credit crunch.

Investors also require certainty, and where this is not possible regulatory and policy stability is necessary to increase confidence.

In GB the Government opted that its market mechanism to support renewables (the Renewables Obligation) should be underpinned by legislation to give investor confidence, and recently indicated that it is minded to extend the arrangement from 2027 through to 2037. A recent review has introduced banded (or differential) support for different renewables technologies at different stages of commercial viability. This has been designed to maintain support for existing installations (essentially through grandfathered rights) and to encourage the development of more expensive technologies.

However, despite the stability and strength of the incentives in Britain renewables deployment has slipped in the last couple of years due to a number of unforeseen factors and which can be characterised to varying degrees as some form of regulatory risk, including:

- planning rules meaning applications for new projects are delayed for a number of years;
- access to the transmission network has not favoured renewables as the framework was designed for large thermal plant;
- investment in the network has not kept pace with demand for connection to it, creating a large queue of generation waiting to get on the system, much of which will not progress for some years, and are dependent on large investments that currently sit in the planning process; and
- the falling carbon price, primarily due to global economic downturn but also generous initial allocations, to the extent that some stakeholders are now pressing for a floor to be put under carbon prices.

Demand for hardware and specialised equipment (such as barges for offshore wind turbines) has outstripped supply pushing up costs and also lengthening delivery timescales.

The compounded effect of these factors is that—despite being a prime mover with regard to low carbon policy initiatives domestically—the UK can be seen as a laggard in terms of achievement of the targets set. As such there is much to be learnt from its mixed record of delivery.

There are a number of sources that comment in more detail on these factors and two are flagged below.

The third document evidences the problems with the queue for connection and the measures being taken by National Grid to try to expedite it.

Sources

Deploying renewables – Principles for effective policies, IEA (2007)

http://www.iea.org/Textbase/press/pressdetail.asp?PRESS_REL_ID=271

This report published by the International Energy Agency (IEA) studied 35 countries, including all major industrial nations and looked at electricity production, heating and transport. This was the first comparative analysis by the IEA of the performance of renewables promotion policies around the world. In 2005, these 35 countries accounted for 80% of total global commercial renewable electricity generation, 77% of commercial renewable heating/cooling (excluding the use of traditional biomass) and 98% of renewable transport fuel production.

Renewable energy country attractiveness indices, Ernst & Young (February 2009)

http://www.ey.com/Global/assets.nsf/International/Industry_Utilities_Renewable_energy_country_attractiveness_indices/$file/Industry_Utilities_Renewable_energy_country_attractiveness_indices.pdf

The failure of the UK Government to put wider action behind the incentives offered has led to the UK being displaced by China as one of the top five most attractive countries for renewable investment, according to the latest Ernst & Young update. Grid access and investment is one such barrier. The latest edition of the firm's quarterly Renewable energy country attractiveness indices tracked global investment in renewable energy in the first six months of 2008 and, using three indices, provided scores for 25 countries on national renewable energy markets, renewable energy infrastructures and their suitability for individual technologies.

The all renewables index is an assessment by country of the general regulatory infrastructure for renewable energy. On a weighted basis, this considers electricity market regulatory risk, planning and grid connection issues, and access to finance. A long-term index takes a long-term view of the sector, while the near-term wind index adopts the perspective of an investor looking to make a commitment within the next two years and places a greater emphasis on market growth.

Transmission networks quarterly connections update, National Grid (January 2009)

http://www.nationalgrid.com/NR/rdonlyres/22E3C271-5BDE-43A1-8B3B-F9D1B9DA686D/31412/TNQCUJanuary09v2.pdf