PÖYRY RESPONSE TO TAR CALL FOR EVIDENCE

A note from Pöyry Energy Consulting to BERR and Ofgem

26 September 2007

1. INTRODUCTION

1.1 Background

This note is in response to the Call for Evidence issued by BERR and Ofgem on 16 August. Pöyry Energy Consulting welcomes the opportunity to contribute to the debate on the future development of the transmission access regime, which we view as one of the key issues to be addressed in the GB energy market.

The governance of transmission pricing, connection and the allocation of Transmission Entry Capacity, and compensation for transmission constraints are separate issues, and to date there has been no industry body, code or working group with the remit to consider them together. It is our view that all aspects of transmission connection, access and pricing should be covered by the Transmission Access Review, in order that the full range of options may be considered.

The transmission access arrangements in England and Wales are essentially unchanged since Vesting in 1990[1]. At that time, the key concern was to foster competition in (thermal) generation; full retail competition took almost ten years to develop. Care was taken to ensure that transmission system operation and planning should not be disturbed[2]; and material reform of those arrangements has never been undertaken.

The operation of the GB electricity market is radically different today. Generators now determine self-dispatch schedules up to one hour before physical delivery, with no obligation to offer flexibility to the system operator. However, transmission access and pricing are still based on long-term cost-based principles with little flexibility to reflect short-term value.

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1 In 2001, the introduction of NETA changed the mechanics of dispatch and compensation for transmission constraints but not the essentials. Up to 2005, as part of the BETTA programme, the key consideration was of how to apply these arrangements to Scotland, for example in dealing with the separation of transmission ownership from operation, but no fundamental changes to the original model of transmission access or pricing were made. The detail of the TNUoS pricing model has been revised, but the underlying principles have been retained.

2 To the extent that the pumped storage plants were retained by National Grid for the first few years after Vesting.

The opportunity to reform transmission access under BETTA was not taken and none of the incremental changes since then has provided the necessary clarity or flexibility.

Government renewables targets require a large-scale investment in renewable generation which has materially different characteristics to that of conventional thermal generation, and in our view the scale of this challenge merits a fundamental reform of transmission arrangements.

In particular, we note for wind generation, the value of transmission access can only be revealed in timescales close to physical delivery – e.g. within-day or day-ahead, rather than weeks or months ahead. This has strong parallels with the timing of spot electricity trading.

1.2 Existing transmission arrangements

The existing transmission access mechanism for generation encompasses the following features:

- in addition to its operational standards, the system operator applies planning standard restrictions to the connection of new generators;
  - any agreement to connect generation and the associated allocation of Transmission Entry Capacity (TEC) must follow the completion of those reinforcement works which are required by the planning standard;
  - conceptually, since the planning standard is applied in addition to the operational standards, it is an economic rather than a security standard[3];
- the holding of TEC confers (financially) firm, evergreen transmission rights to the transmission network, which entitle the bearer to access the GB market price or receive compensation:
  - therefore, generators have no incentive to alleviate transmission constraints through their own trading and self-dispatch;
- generators whose output is restricted by transmission constraints are compensated through the balancing mechanism (or other agreements with the system operator):
  - the resultant costs are smeared across all generators and suppliers (including the system operator under an incentive scheme);
- the pricing of TEC (through the payment of TNUoS charges) varies by location, based on modelling of long-term transmission investment costs (adjusted to meet revenue requirements):
  - within the modelling, transmission investment is assumed to be required predominantly to meet peak demand;
  - within the modelling, all generators are assumed to operate at near to full capacity (scaled back equally such that total capacity meets peak demand) over the system peak; and
  - the resultant TNUoS charges rely entirely on long-term pricing signals but have no provision to reflect short-run marginal costs by location;
- once TEC has been allocated and annual TNUoS charges have been paid, the operation of the decentralised market is unable to resolve short-term requirements (other than by system operator action, e.g. through the Balancing Mechanism):

3 Even if planning standards were breached or removed, any security issues could potentially be resolved in operational timescales, noting that NGET has the freedom to trade forwards.

- there is no market-based incentive for generators to behave in a way that is compatible with the constraints on operating the transmission network; and
- there is no ability in operational timescales for additional transmission access to be allocated to generators who do not hold TEC (since they are prevented under the Grid Code from exporting more than their TEC holding to the network, and therefore they are prevented from connecting until their TEC can be allocated).

1.3 Difficulties with the present regime

The most obvious issue that has triggered the need for the TAR is the perceived difficulty in connecting renewables to the network, as a significant quantity is held in a queue awaiting transmission access. This highlights a risk that Government renewables targets (which are backed by the aspirations of private project developers), with the associated environmental benefits, may not be met.

We consider that there are other inefficiencies resulting from the existing regime of transmission access and pricing, which will be exacerbated (although not caused) by a sharp increase in wind generation. Generators are prevented from responding flexibly to system needs, and instead their decisions on plant closure or mothballing have long-term consequences[4].

The radical growth in renewable capacity that is required raises questions over the entire transmission access and pricing framework set out above. For example:

- the intermittent nature of wind generation means that its expected output at system peak is lower than other types of generation, and the conventional modelling assumptions made for the purposes of long-term transmission pricing do not hold;
- if planning standards (which, we have argued, are essentially economic in nature) were relaxed and additional generation permitted to connect, then the need for efficient short-term transmission allocation mechanisms would become apparent;
- any re-allocation of transmission access in short timescales would need to be achieved with minimal risk and minimal transaction costs.

With the continued rapid growth in renewable generation, the case for consideration of radical options for the assignment, distribution and pricing of transmission access is clear. In our view, any review must encompass each of these elements.

1.4 Elements of a future regime

Contention – Additional generation under 'connect-and-manage' would not increase total generation costs

We contend that in dispatch timeframes, the connection of additional wind to the network (assuming no increase in transmission capacity) would reduce or leave constant the overall costs of dispatching generation to meet demand, but in any case would not increase total dispatch costs. (We return to constraint costs below.)

Consider the transmission system from the perspective of a centralised dispatch optimisation on a given day, which seeks to achieve a generation dispatch profile to meet demand subject to transmission (and other) operational constraints, at the lowest possible

[4] As an example, the Moyle interconnector has reserved 80MW of TEC which it virtually never uses, because it wishes to secure its future rights to import. There is no mechanism to permit other generators to use its capacity.

cost of generation. (This may be considered a variant of a centralised dispatch algorithm, enhanced to cover transmission issues.)

We may consider two cases for this example day: the status quo (with no additional wind connections) and an alternative under which ‘connect-and-manage’ has previously been applied and additional wind generation has been connected and is available to the dispatch ‘optimisation’ on the day.

Under the ‘connect-and-manage’ option for the example day, with additional wind generation, there are two cases (from the perspective of least-cost dispatch); either dispatching the additional wind generation permits a lower-cost dispatch solution, or it does not (e.g. due to reserve considerations). Even if not, there are **no** additional generation costs incurred, from the perspective of the network as a whole; and therefore the introduction of additional generation options cannot increase **total** dispatch costs in operational timescales.

This implies that any ‘costs’ associated with a ‘connect-and-manage’ approach are related to compensation for transmission users’ rights and the distribution of costs and benefits, not to the overall level of dispatch cost.

One variant of connect-and-manage, applied to the existing TNUoS regime, might be that additional generation would be permitted to connect, and given firm (financial) access rights to the network to nominate production schedules that are sub-optimal (from the perspective of dispatch ‘optimisation’, and therefore would need to be paid constraint compensation for those times when they are not permitted to generate. This would manifest itself as a payment to the generator concerned, at the expense (via the BSUoS mechanism) of all other generators and suppliers.

In mitigation of this potential cost. the additional TNUoS revenue from the additional generation (which, since NGET’s total revenue is fixed, will be passed to other transmission users through reduced TNUoS charges), may outweigh the constraint compensation costs introduced by the new wind generators. This is a transmission pricing issue rather than a transmission access issue.

A further mitigating factor is that, through increasing availability of generation at the lower end of the supply curve, wholesale market prices may reduce. From the perspective of consumers, this effect may mitigate any additional constraint costs from the perspective of the end users (although at the expense of the producer surplus to other generators).

Our tentative conclusion is that in the first instance, a ‘connect and manage’ approach is demonstrably capable of delivering short-term efficiency benefits and should be considered further. The focus for further work should be on the correct allocation of rights, costs and benefits.

Contention – the value of short-term transmission trading or sharing is maximised if trading occurs ex-ante but close to real time

We contend that any short-term sharing or trading of transmission access should be facilitated ex-ante (but close to real time) complemented by ex-post, and that models which bundle transmission access with spot trading of energy are worthy of consideration.

At present, the pricing of transmission access does not reflect the short-run value of transmission capacity. This value is determined by a series of factors such as transmission availability, the pattern of demand on the network and the generation supply curve at different locations, including the availability of wind generation. We note that many of these price drivers are common with those which determine short term energy prices.

We conclude that any new mechanism designed to facilitate short-term sharing or trading of capacity should be available in similar timescales to the trading of spot electricity, e.g. from 1-2 days ahead to around gate closure. If ex-ante 'short-term' trading is only available in longer timescales then it will not be capable of meeting the needs of intermittent generation and the potential efficiency gains will not be realised.

In order to minimise transaction costs, models which bundle transmission with energy trading appear to have obvious advantages, and there could be additional benefits that the existing (very low) levels of spot electricity trading could be augmented.

We anticipate that a reliance on ex-post transmission pricing would introduce commercial risks to which most generators (and their financiers) would be unwilling to expose themselves.

Contention – there are various affected parties facing different incentives who may respond to TAR; each response should be considered in its own right and no undue weight should be given to any one party.

GBSO – has a commercial interest in the outcome in terms of risks and rewards associated with SO incentives.

TAOs – receive a guaranteed rate of return on transmission assets through the transmission charging mechanism.

Existing Generators – have protected rights of access on which their business depends, but which may be threatened.

New Generators – have no access rights.

Distributed Generators - have implied rights of access which may be diminished.

DNOs – have a potential role as agents for DG access.

Consumers – although demand access is not considered, they ultimately foot the bill for any inefficiency, all investment and the costs of any proposed new access system.

Suppliers – are essentially immune from access issues.

2. QUESTIONS RAISED IN THE CALL FOR EVIDENCE

2.1 List of questions set out within the call for evidence

Chapter 3

1. Do you consider that there is a need for change to the existing transmission access arrangements?
2. Do you agree with our assessment criteria?
3. Is the concept of sharing of transmission capacity (i.e. having less transmission capacity for a given amount of connected generation) the right approach to explore?
4. Do you consider that there is an issue with the property rights associated with transmission entry capacity as set out in the CUSC?
5. Are the transmission access models set out in this document broadly appropriate in considering how to meet the Government's medium and long-term aspirations? Are there other models that should be considered?
6. Are there any issues arising from the growth in offshore generation that need to be taken into account in considering access reform for the onshore transmission network?

Chapter 4

1. What approaches to improving the delivery of infrastructure should we consider?
2. Which operational measures are likely to improve connection prospects?

Chapter 5

3. What changes to the constraint mechanism may be needed to create incentives for timely connection and disconnection from the transmission network and to sharpen investment signals?

2.2 Pöyry views

Chapter 3

1. Do you consider that there is a need for change to the existing transmission access arrangements?

We believe that there is a demonstrable need for change to the existing transmission connection, access and pricing arrangements which are currently based on long-term modelling and planning issues and are not responsive to shorter-term issues. The significant growth of intermittent renewable generation leads to an increase in the importance of these shorter-term issues in determining efficient outcomes, both within operational and investment timescales.

2. Do you agree with our assessment criteria?

The assessment criteria appear narrow. Alternative models of transmission allocation and pricing could assist with (for example):

- wholesale electricity market liquidity;

- improved integration with adjacent European markets; and
- improved calculation of energy imbalance prices, with clear separation from energy from locational and other transmission elements; and
- improved incentives for market participants to deliver ‘self-dispatch’ schedules that are consistent with transmission constraints.

We believe that these potential benefits should be included within the decision framework, if only by inclusion of an ‘other’ category.

3. Is the concept of sharing of transmission capacity (i.e. having less transmission capacity for a given amount of connected generation) the right approach to explore?

In our view, the existing allocation mechanisms are rigid and do not meet the needs of intermittent generation on the scale that is anticipated. Any effective solution is likely to use shorter-term allocation mechanisms which may generically be termed ‘access sharing’, although there are many variants that could deliver more or less successful outcomes.

4. Do you consider that there is an issue with the property rights associated with transmission entry capacity as set out in the CUSC?

This is an important issue. The operation of the electricity system as a market rather than a centrally-planned system relies on investors having confidence in the regulatory regime. Historically, transmission access has been seen as an evergreen right, at prices whose calculation methodology is stable. The monopoly provision of this essential product suggests that any regime change needs to be proportionate, and (for example) that any move to more market-based pricing should be accompanied with options that permit generators to hedge transmission prices.

5. Are the transmission access models set out in this document broadly appropriate in considering how to meet the Government's medium and long-term aspirations? Are there other models that should be considered?

In our view the models set out do not encompass the full range of options that should be considered. Increasingly, the need is for shorter-term mechanisms for pricing and re-allocation of transmission access between participants, compared with the existing long-term regime.

An accepted solution to these issues in other countries includes locational energy pricing, either nodal (as in the PJM markets in the US) or zonal (as in the Nord Pool market and the forthcoming ‘pentelateral’ spot markets of France, Belgium, Netherlands, Luxembourg and Germany). These solutions encourage market participants to trade in ways which resolve rather than exacerbate transmission constraints, and are capable of delivering both short- and long-term incentives which align the needs of providers and users of the transmission network.

With regard to the models proposed, we have the following brief comments:

Incremental approach

The existing governance framework for connection, allocation and pricing of TEC, permissible generation nominations[5] and constraint compensation does not permit all relevant aspects of transmission (allocation, distribution and pricing) to be considered as a whole. The governance of these issues is split between a set of industry codes and licenses:

- transmission pricing is covered by the transmission system operator licence, and NGET is responsible for proposing methodology which Ofgem may veto;
- Transmission Entry Capacity (TEC) is governed by the CUSC;
- the submission of Final Physical Notifications is covered by the Grid Code; and
- pricing and settlement for Balancing Mechanism actions is covered by the BSC.

There has been a series of attempts to introduce shorter-term transmission access products over recent years, including short-term TEC (access for a limited period, with a number of weeks' notice) and limited duration TEC (access for the remainder of the charging year). These have retained the long-term nature of the charging regime, and the take-up of the products has been near-zero. In particular, the timescales of the short-term TEC product are not aligned with the needs of intermittent generators.

We suggest that a more holistic approach is required to deliver a transmission access and pricing regime that will meet the needs of the future, and that the existing governance arrangements cannot deliver the range of reforms that we anticipate is required.

Connect-and-manage

At a high-level, this appears to be an essential component of any future approach which meets the needs of additional intermittent generation. Depending on the model chosen, it can facilitate close-to-real-time sharing of transmission access, which in turn allows short-term efficiency to be maximised.

The potential benefits would be:

- to facilitate additional generation (especially, but not only, renewables); and
- to permit more efficient (lower-cost) dispatch patterns in real-time, ultimately lowering costs to consumers.

However, the full regime of transmission pricing and the meaning of transmission access 'rights' would need to be reviewed in order to secure the potential efficiency benefits.

Over-run

If 'over-run' implies 'determining cost-reflective transmission prices by location' then it appears to be an essential component of a future approach.

However, in a simplistic application, using ex-post pricing, the risks to new generators appear extremely high, not least because of the non-transparent and ex-post way in which NGET proposes to calculate the prices. If this type of ex-post pricing is the only form of short-term transmission access that is available, we consider that it is unlikely that any wind generator will be prepared to connect or generate on this basis

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[5] These take the form of Final Physical Notifications for generation.

There is a specific conundrum introduced by the addition of short-term over-run pricing to the longer-term TNUoS regime. In most locations and for most of the time there are no binding transmission constraints. Even in an alternative 'connect-and-manage' future, in which new generation is connected without completion of deep reinforcements, there would be many times at many locations where the 'over-run' prices would be zero. NGET's continual concern is that the core TEC product is not undermined.

We advocate consideration of models in which a short-term transmission price should be applicable to all generators. There could perhaps be contracts available that permit generators to hedge transmission prices in advance, but the drivers for their pricing should be from short-run rather than long-run models.

Auctioning of transmission access

Models which include the auctioning of transmission access have previously been considered. Our concern is that any trading of transmission capacity needs to be within timescales that is of value to intermittent generation, and it is unlikely that auctions would serve this need.

6. Are there any issues arising from the growth in offshore generation that need to be taken into account in considering access reform for the onshore transmission network?

The advent of offshore generation in licensed locations offers an opportunity for the system operator to make plans for additional transmission capacity in advance of specific connection applications. This in turn highlights a gap in the existing incentives for the system operator to accelerate the connection of new generation. At present, the transmission price control provides incentives for the early connection of generation once a connection date has been agreed, but limited incentive to offer an early connection date in the first place.

Chapter 4

1. What approaches to improving the delivery of infrastructure should we consider?

Within the existing regime, any derogations granted to defer compliance with planning standards need to be time-limited and strictly enforced. The transmission system should be planned on the basis that constraints are temporary and manageable rather than enduring and limiting to the connection of new generation.

Considered from another angle, we suggest that options should be considered which include the abolition of the planning standards (which, it may be argued, are economic rather than technical in nature) and instead rely on operational standards and economic signals.

2. Which operational measures are likely to improve connection prospects?

In our view, a change to an energy market that recognises location would improve the incentives on generators to trade and dispatch their plant in a way that is consistent with transmission requirements. By aligning incentives of generators and the system operator in this way could increase the ability of the system operator to manage the network within tighter tolerances.

Chapter 5

1. What changes to the constraint mechanism may be needed to create incentives for timely connection and disconnection from the transmission network and to sharpen investment signals?

In our view, the existing separation of energy pricing (which considers short-term value but not location) from transmission pricing (which considers long-term cost but not value) is artificial and unnecessary. Since transmission access and pricing is currently dealt with from a long-term rather than a short-term perspective, short-term efficiencies are not realisable. In markets for most products, the spot price determines expectations of the forward (long-term) price and not vice versa, and we believe that the justification for making an exception for transmission access is becoming weak.

We would advocate – as least as a comparator – the inclusion of locational energy pricing (e.g. nodal and/or zonal pricing) within the set of the models for consideration. A more complete model would include the following features:

- allocation of connection rights to generators on completion of shallow reinforcements;
- locational energy pricing, e.g. on a zonal basis, to reflect the major transmission constraints;
  - under these arrangements, transmission constraints would be manifested through lower market prices in certain areas, which would (through bilateral trading) cause participants to trade bilaterally in order to achieve a set of 'self-dispatch' schedules which broadly satisfy transmission requirements;
  - the implication is that generators would not be entitled to compensation at times when transmission constraints curtail their output;
- there would be opportunities for generators to acquire long-term (financial) transmission access rights (which could take the form of financial contracts based on price differentials between regions), which permit them to limit their exposure to locational price variation;
- there would be some requirement for the system operator to offer for sale long-term (financial) transmission access rights[6].

6 We note that although the Nord Pool system permits bilateral trading of contracts to hedge locational price differences, the system operators (who, it may be argued, are the natural sellers of these products) do not offer these contracts as a matter of course.

Contact details

Name	Email	Telephone
Stephen Woodhouse	stephen.woodhouse@poyry.com	01865 812222

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Pöyry Energy Consulting
King Charles House
Park End Street
Oxford, OX1 1JD
UK

Tel: +44 (0)1865 722660
Fax: +44 (0)1865 722988
www.ilexenergy.com
E-mail: consulting.energy.uk@poyry.com

www.poyry.com

Pöyry Energy (Oxford) Ltd, Registered in England No. 2573801
King Charles House, Park End Street, Oxford OX1 1JD, UK