Project TransmiT

Academic Review of Transmission Charging Arrangements

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Contents

1 Introduction

This report has been commissioned by the Gas and Electricity Markets Authority in support of the 'Project TransmiT' initiative, a review of transmission charging and associated connection arrangements. The terms of reference of this report are reproduced in Appendix 1.

The objectives of Project TransmiT are to ensure that we have in place charging arrangements that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers.

Past academic work has suggested high level principles that transmission charges should follow. Stanford University's Energy Modeling Forum listed six principles, in that "prices should:

1. promote the efficient day-to-day operation of the bulk power market;
2. signal locational advantages for investment in generation and demand;
3. signal the need for investment in the transmission system;
4. compensate the owners of existing transmission assets;
5. be simple and transparent; and
6. be politically implementable." (Green, 1997, p. 178)

Brunekreeft et al (2005, p. 75) suggest that "ideally the structure of network charges should encourage:

- The efficient short-run use of the network (dispatch order and congestion management;
- Efficient investment in expanding the network;
- Efficient signals to guide investment decisions by generation and load (where and at what scale to locate and with what choice of technology – base-load, peaking, etc);
- Fairness and political feasibility; and
- Cost recovery."

The present review is being undertaken in the following context.

National Grid is obliged under its licence to have in place charging methodologies that facilitate competition, result in charges that, as far as is reasonably practicable, reflect the costs incurred by transmission licensees.

The Department for Energy and Climate Change has recently made decisions on transmission access arrangements for generation in Great Britain (DECC, 2010b). These are based on the principles of "connect and manage" and "socialisation of constraint costs"; in other words, generators should be allowed to connect to the transmission system as soon as local enabling works are completed, even if they or other generators would, more often than would be the case were the transmission design criteria completely complied with, be unable to generate at full capacity because of constraints on the wider transmission system; that they should be compensated for this inability to supply their full output, and that the costs of this compensation should be recovered from all users of the transmission system.

The European Union has set out requirements in the Directives 2009/28/EC on renewable energy and 2009/72/EC on the single energy market. While in general these require transmission operators to connect users on a transparent and non-discriminatory basis, they also require renewable generators to be given priority access. While policy decisions made by the UK government are decisions that in principle could be reversed by that government, we assume that EU requirements are non-negotiable. Regulation 1228/2003 sets out requirements for access to interconnectors between countries, again requiring transparent, preferably market-based, solutions.

1.1 Structure of this report

It is has been outside the scope of the present short study to conduct detailed or quantitative analyses of the different arrangements considered. Rather, it is the intention to outline their main features in order to help inform debate on possible reforms and their industry and regulatory context, and for that debate to be made accessible to those within the industry who are neither specialist power system economists nor experienced power system engineers.

Some of the background to the development of the electricity supply industry in Britain and some of the goals that have driven it are briefly described in section 2. This is intended to help the reader understand how the present transmission charging arrangements have arisen and their relationship with other aspects of the industry.

A set of high level principles articulated by the team to help guide its review of transmission charging arrangements is set out in section 3. Arising out of these principles, a framework for assessment of different options is presented in section 4.

In section 5, we present some ways of viewing transmission charging arrangements in terms of some of the main design variables. In section 6, we describe and discuss four principal transmission charging models that have been implemented in different places around the world, including the 'investment cost related pricing' (ICRP) approach that is currently used for the GB transmission system. We also present some discussion of a potential variation on ICRP.

In section 7, a comparative discussion of the four main models is presented in the context of the assessment framework outlined in section 4. Finally, in section 8, some conclusions are presented.

It should be noted that the following are not in scope and will not be addressed except in order to note their interaction with transmission charging arrangements in pursuit of the high level principles outlined in section 3: trading arrangements, access arrangements and mechanisms for financial support of low carbon generation. Furthermore, we have not conducted a review of transmission charging arrangements in other countries and understand that this has been commissioned separately by Ofgem as part of Project TransmiT.

2 Background – how did we get here?

In order to help illustrate some of the key issues and the relationships between different functions within the electricity supply industry (ESI), this section presents some of the context of the present review of transmission charging arrangements. It begins by tracing the development of the present industry structure in Britain and goes on to show how particular aspects of that structure seek to achieve a coordination of actions of different parties in such a way that the overall cost of electricity can be minimised, standards of reliability of supply achieved and 'reasonable' costs of electricity transmission recovered by the transmission owners and the system operator. It is the effectiveness of some of these arrangements that are now under review with consideration being given to alternatives that might better achieve the overall objectives that now include facilitation of renewable generation.

2.1 Coordination of generation and network capacity in a liberalised industry

In the days of a centrally planned electricity system, transmission and generation planners within the same organisation could coordinate their activities in light of each other's proposals. The separation of ownership of generation and transmission in a liberalised ESI presents a particular challenge:

- how can the overall best balance between access to energy for conversion to electricity, the cost of that access and the cost of electricity transmission be achieved while leaving generation developers (and consumers) free to make their own investment and operation decisions?

Failure to achieve an appropriate balance would mean either that transmission capacity is over-provided relative to the location of generation or under-provided. The former means either that the transmission owner will not be permitted to fully recover the cost of the network or that network users' charges for using the network are higher than they need be.

Under-provision of transmission capacity, i.e. a relative lack of it, the absence of economic means of storing electrical energy on any large scale and the paucity of available 'demand side management' (DSM) measures (up to now, at least), mean that, at least some of the time,

- at least some generation capacity in an area with surplus power available relative to demand cannot be used;
- at least some generation capacity in an area with a deficit of power available relative to demand *must* be used if reliability of supply to electricity users is not to be compromised.

Price is not the sole determinant of the generation from which energy is bought – some generators cannot be used because of their location while others must be. As well as a facilitator of competition among generators, transmission capacity can then be seen, when there is inadequate generation available in an area to meet demand in that area, as a provider, via access to remote generation, of a reliable supply of electricity. However, minimisation of the overall cost of electricity – which includes the cost of transmission infrastructure – would suggest that some level of constraints should be accepted, albeit that the total cost of constraints depends not only on their volume, i.e. the number of MWh in a 'typical' year of operation, but also their price. Both of these are affected by the particular trading and transmission arrangements.

With generation developers' and operators' decisions being independent of those of the owner and operator of the transmission system, the challenge is to articulate some signals that facilitate additional value from construction and utilisation of generation in a particular location up to the cost of additional transmission capacity connecting that location, or the value of additional transmission up to the cost of lack of access to particular generators. (In principle, locations of demand might be similarly influenced though this might only be effective for large, industrial consumers, the majority of electricity consumption being, hitherto at least, relatively insensitive to price signals. We thus concentrate on signals to influence location of generation).

In simple terms, coordination of generation and transmission depends on answers to the following questions:

- What is transmission for? Its historic development suggests that it might be thought of as having two main purposes, and given the challenges involved in valuing each of them, this can still be a useful way of thinking. That is, transmission is for (a) 'security of supply' and (b) 'facilitation of competition', or access to 'economic' generation[1].
- How is the 'right' level of transmission capacity determined, and how does that interact with generators' decisions on where to site generation? (How can – or should – generators' decisions be influenced?)

The next section considers the above questions in more detail.

2.2 Identification of appropriate transmission capacity

At present, in many jurisdictions, the task of the transmission planner is to take a set of access rights – maximum power injections or consumptions at each location – and follow some given process to determine whether some network reinforcement is required and its extent. This might be based on some 'deterministic' rule such as to facilitate all power transfers assuming a certain number of power stations are not operating or a characterisation of the probabilistic spread of transfers, or a more direct probabilistic comparison of the cost of reinforcement with the cost of restriction of power transfers in system operational timescales or the benefit of reducing the restriction. Depending on the prevailing trading arrangements, the operational cost/benefit might be identified in terms of the actions taken by the SO in a 'balancing mechanism', constraint payments in a pool or the reduction in a locational marginal price.

Since the 1970s, the basic rule used in Britain for identifying required power transfer capability on the main interconnected transmission system (the 'MITS') has been based primarily – but not exclusively – on an annual peak demand condition. The power flows to meet that demand depend on the dispatch of generation for which generators hold access

[1] As will be presented in section 2.3, the promotion and integration of renewables now plays an important role. At present, in Britain this is largely being realised through government-mandated support to generators that falls outside the trading and transmission arrangements discussed here. For the purpose of our analysis and as discussed in section 4.1.1 below, we assume that situation to continue though we recognise that more direct support of renewables might be given through electricity trading and transmission arrangements.

rights; with a positive plant margin, there are clearly many possible dispatch patterns. What is taken as an initial reference for the transmission planner considers that there are multifarious influences – including economics and availability – that interact such that the long-term average per unit output of each generator of the same type (thermal, hydro or wind) is the same. The resulting pattern is then 'stretched' to give some margin for power transfers.

It has been argued that the above initial methodology represents a hybrid between being 'reliability based' and 'economics based', arguably being more strongly driven by the former than the latter (Bell, 2008). Although it is complemented by a probabilistic cost-benefit analysis that can drive investment in extra transmission additional to that identified by the basic rule, the starting point is, certainly, power rather than energy based. This is what the present transmission charging methodology attempts to reflect and will be discussed further in section 6.2 below.

It is worth recalling that the current transmission planning process in Britain starts from a given set of access rights. What rights are already held by generators, what new rights are being sought – and where – and what those rights entail are clearly critical in driving transmission reinforcement or constraints in operational timescales. The combination of present rights and those future rights that have been offered to and accepted by, in particular, generators, drives planning of future transmission capacity. The 'invest and connect' philosophy that was in place until recently was intended to ensure that new generation and an appropriate level of transmission capacity to accommodate that new generation (alongside existing generation) would become available at the same time. However, since liberalisation of the industry in 1990, it has become increasingly apparent that a generator accepting an offer to connect does not guarantee that it will connect (Bell, 2002)[2]. Even if a generator is connected, a right to generate does not guarantee that a generator will do so at any one time. While it may be argued that the basic rule used in Britain since the 1970s for planning of capacity on the main interconnected system is insufficiently precise in reflecting the real costs and benefits of transmission (and, in particular, does not adequately reflect the characteristics of wind power[3]), it may also be argued that an apparently more precise analysis – based on explicit quantification of costs and benefits – is subject to considerable uncertainty and that present trading arrangements provide opportunities for exploitation of transmission constraints until they are reinforced away (Bell, 2010).

Arrangements for the granting of access rights, what those access rights entail and trading arrangements are outside the scope of the present review. However, we note that they strongly influence the same issue that charging arrangements are designed to influence: an adequate coordination between generation and transmission such that the overall cost of electricity is minimised. (See section 4.1.1 below for further discussion of cost). It seems to us, and to many others, that the charging arrangements should provide a signal to influence where generators, in particular, should seek access rights and should reflect the consequences of different sets of access rights observable through the trading arrangements.

Some of the interactions between transmission charging and trading arrangements and access rights are discussed in section 7.5.

[2] In importing areas of the system, an existing generator that then withdraws or a mooted new generator that does not subsequently connect may give rise either to some other generators being constrained on or to a need for reinforcement of the network.

[3] A review of the basic rule for planning of the main interconnected transmission system was initiated in late 2004. However, at time of writing, it is still not complete.

2.3 The situation now

Various interactions between generators, the transmission owners (TOs) and the system operator (SO) are summarised pictorially in Figure 1 below. In it, the influences of one party's actions on another can be seen[4].

It is against the above background that some particular current issues should be recognised:

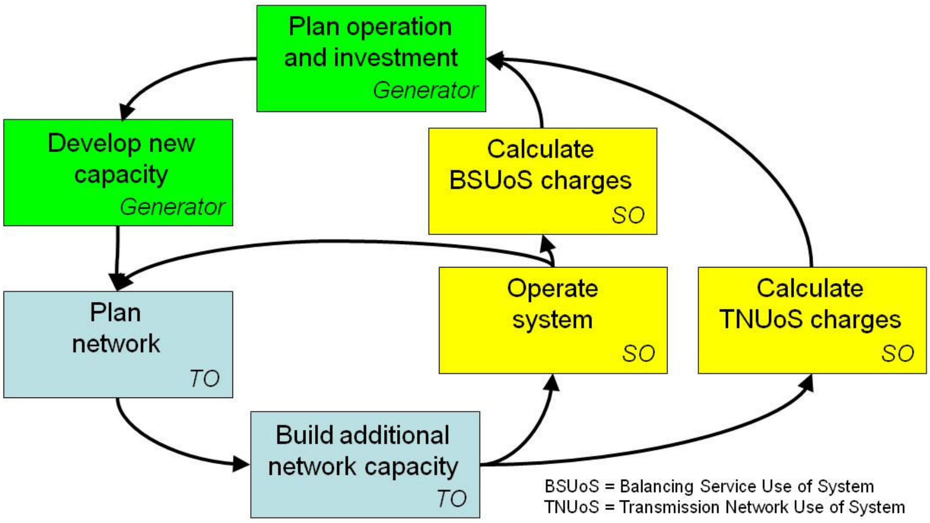

Figure 1: interactions between generators and transmission licensees affecting investment and network charges under present GB arrangements

- The UK, in common with the whole of the European Union, has legally binding targets for the proportion of energy used that comes from renewable sources; given the development of different alternatives to fossil fuels for heating, transport and electricity, meeting of the target depends largely on renewable electricity.
- At present, the most economically attractive form of renewable electricity is wind power, and, in terms of the wind resource, the best areas for this tend to be in the north of Britain or offshore. These are far from the main demand centres and would require significant investment in additional transmission capacity. Upwards of 12.5GW of onshore wind generation capacity and 9GW of offshore capacity has been forecast to be deliverable by 2020 (Pöyry, 2010), representing an investment of in excess of £43 billion[5]. The onshore transmission reinforcements to accommodate that have been estimated to cost £4.7 billion (ENSG, 2009)[6].
- Transmission access rights in the north of Britain have, arguably, already been 'over-allocated' relative to existing transmission capacity. The evidence for this is the high level of constraint costs paid by the System Operator for constraints arising within Scotland and on the boundary with England. In respect of the 'Cheviot boundary' relating to exports of power from Scotland into England, these grew from around £30 million in

[4] The intention is to show the interactions between generators and transmission licensees. To keep the image simple, interactions of both with the demand side have been omitted.
[5] Costs assumed to be £1200/kW for onshore and £3200/kW for offshore, (Mott MacDonald, 2010).
[6] The 'bootstrap' parallel HVDC connections that have been proposed are included within the onshore network costs as their purpose to directly interconnect different parts of the onshore network.

2007/8 to around £80 million in 2008/9, falling back to around £50 million in 2009/10 (when constraint costs for the whole transmission system were around £160 million). In 2010/11, the cost of Cheviot constraints was nearly £70 million. Within Scotland constraints have ranged from around £20 million in 2007/8, £50 million in 2008/9, £75 million in 2009/10 and over £85 million in 2010/11 (Winser, 2010, Smith, 2010).

- Under the previous 'invest and connect' approach to transmission planning and granting of access rights, the new wind farms seeking to connect in the north of Britain would have had to wait for appropriate network reinforcements to be carried out.[7] In July 2010, the Department for Energy and Climate Change (DECC) approved a new 'connect and manage' approach under which derogations against the transmission planning standards would be temporarily granted in order to allow generators (not only but especially wind farms) to connect ahead of completion of 'deep' reinforcements that the planning standards require (DECC, 2010c). ('Connection works' still need to be undertaken first).[8] Under this arrangement, the generators allowed to connect have firm access rights and are thus entitled to quote and be remunerated for balancing actions to reduce their output in the event of the wider network being export constrained. Ahead of reinforcement of the wider network, it would be expected that this would give rise to an increase in the total cost of constraints, perhaps significantly so.[9]

A solution to the apparent shortage of transmission capacity connecting the north to south might be a greater degree of sharing of that capacity by generators. For example, some generators north of, say, boundary B7 in the Seven Year Statement – 'Upper North' – may be regarded as 'baseload' by virtue of their short-run marginal costs being very low, at least while power is available from them, e.g. Heysham, Hartlepool, Hunterston and Torness, and while it is windy, the wind farms. However, station efficiencies and fuel prices in recent years would suggest that others – Cockenzie, Longannet and Peterhead for example – have been marginal for at least some periods. In such situations, it would seem reasonable that marginal plant and wind farms 'share' transmission capacity. In other words, marginal fossil fuelled plant uses that network capacity not being used by wind farms. In other words, wind farms use that network capacity not being used by the marginal fossil-fuelled generators. (It might be appropriate for the generators giving up firm use of system rights for some period to

[7] It may be worth noting that the 'appropriate' level of reinforcements have been defined within the 'Security and Quality of Supply Standard' (SQSS) and are not designed to deliver constraint-free transmission. (It may also be acknowledged that what is the economically optimal level of transmission for a given generation background, and how to discover it, is the subject of ongoing debate).

[8] 'Connect and manage' might be characterised as 'transmission follows generation' (Baldick, 2011). Given a set of future access rights that are sought by generators, the 'invest and connect' approach might be characterised as 'generation and transmission arrive together'. However, as has already been mentioned in section 2.2, the 'correct' amount of transmission is difficult to identify when there is uncertainty about which generators holding future access rights will exercise them, many industry stakeholders or their representatives having in the past been particularly concerned about the risk of 'stranded assets' consequential to over-building of transmission, Nonetheless, given the long lead times for investment in transmission and the 'lumpiness' of delivery of additional network capacity, many others (including Bell (2002) and Baldick (2011)) have argued that consumers' long-term interests would be best served by at least some degree of 'strategic' or 'anticipatory' investment in transmission. (This has been described in Baldick (2011) as facilitating generation to follow transmission, or a 'plan and price' approach), Some issues around future access rights are briefly discussed in section 7.5.2

[9] As part of the work leading up to DECC approving 'connect and manage', various parties, including consultancies working on behalf of DECC (Redpoint 2010) and, separately, Ofgem (Frontier Economics 2009), undertook forecasts of constraint costs under 'connect and manage'. It may be noted that Redpoint's and Frontier Economics' forecasts differed markedly.

receive some kind of compensation.[10]) However, present access and trading arrangements do not lead to that outcome. The 'deterministic' part of the present network design standard for the main interconnected system assumes only a limited amount of sharing; and transmission charges currently give no incentive to it.

A fair proportion of transmission reinforcement actions on the main interconnected system in England and Wales in the last 20 years have been driven by closure of power stations in the midlands and south east, replaced largely by combined cycle gas turbines (CCGTs) in the west and north (Hiorns, 1999). Others have involved underground cables in and around London to improve London import capability. Reinforcements could thus be seen to be necessary both for security of supply to the south-east and facilitation of access for newer, more economic power stations that made their decisions on where to locate in light of locational transmission pricing, the cost of access to gas and the gaining of planning permission. In light of the security of supply aspect, both transmission planning and locational pricing based on generation capacity and power flows at time of peak demand could be regarded as reasonable. However, the network reinforcements that are currently under consideration concern access for wind farms located towards the periphery of the system (ENSG, 2009), e.g. in Scotland or the north of England or off the east coast of England. None of them, on their own, can strongly be said to be necessary for security of supply, at least not in the short term. Partly as a consequence of the delay in a revised transmission planning standard being approved (which may, in any case, require explicit economic analysis as its basis rather than as a complement to another approach), justification for these reinforcements depends to a large extent on economic analysis, particularly constraint costs that arise at different times in the course of a year of operation. In other words, they depend on analysis of energy bought and sold. (Whether to base transmission charges on power or energy is one of the design choices that will be discussed in the next section.)

For the longer term, we return to the question of the choices that can be made by developers of new generation facilities in terms of location. Where choices do exist, our first principle would suggest that they should be, in some way, incentivised to locate in areas that minimise the overall cost of electricity. In the case of a wind farm (and all other things being equal), the developer can compare the extra revenue arising from a higher load factor in a windier area with the extra cost of using the transmission system. Similarly, the developer of a new fossil-fuelled power station with carbon capture facilities can compare the costs of access to fuel, CO_2 storage and electricity transmission in one place with those in another.

The difficulty often arises in respect of other issues. For example, can a wind farm developer be confident of gaining planning permission in a location that, from a simple economic point of view, seems ideal? If such considerations drive generation developers to locations in which the cost of electricity transmission breaks the commercial viability of their project and the consequence is a failure to satisfy renewable energy targets, to have sufficient generation capacity as to ensure a particular level of security of supply or both, then it would seem that some kind of intervention is required.

[10] Such an idea was a feature of one of the suggested models for reformed transmission access. In it, generators prepared to give up rights for some period would quote a price for that relinquishment as part of their application for access (see section 7.5.2). The price they quote may seek to compensate for the difficulty of finding a buyer for their energy on a windy day. However, the possibility of quoting a 'bid' price in the current 'balancing mechanism' arguably already represents such a possibility, though without some kind of forward contract, the system operator would have no certainty of that price.

It has been argued by some that 'cost-reflective' transmission charging as currently implemented is already deterring generation developers and putting the meeting of renewable energy targets at risk. Others point out that connection applications are still being received by the System Operator for connections in the more expensive zones, and connections are still taking place, so the deterrent does not seem to be strong. Without access to commercially sensitive information, it is difficult to verify the claim that transmission charges are making inordinate numbers of projects commercially unviable; besides, it is outside our present scope to do so.

A final, significant element of the background to the present report should be noted: DECC's consultation on 'Electricity Market Reform' published in December 2010 (DECC, 2010d). From our perspective, this opens up the following possibilities:

- a shift of financial support mechanisms away from renewables towards 'low carbon' generation complemented by greater costs on burning of fossil fuels;
- the central purchasing of generation capacity, which could be broken down into different plant types (for example in order to recognise that different types contribute differently to security of supply and CO_2 reduction) and locations;
- increased levels of financial support and certainty available to low carbon generation relative to now, levels that might be differentiated by technology and are yet to be determined.

The second and third of these, in particular, might offset any perceived risks to the meeting of climate change mitigation objectives arising from high transmission charges in particular locations. On the other hand, the purchase of generation capacity only in certain regions might make a levelling off of transmission charges redundant.

3 High-level principles

In light of the regulatory and government background outlined in the introduction, we have articulated the following high-level principles which have guided our review of transmission charging arrangements. We first list the principles, then discuss each in more detail, and then, in section 4, set out our strategy for assessing how well particular proposals perform against these principles.

3.1 Statement of principles

1. They should encourage efficient investment and operating decisions by the transmission companies, generation companies and consumers such that the overall cost of electricity is, as far as practicable, minimised.

2. They should be consistent with the realisation of climate change mitigation targets set by government in the UK

3. They must be compatible with EU directives and regulations

4. They should be consistent with the future integration of energy markets across Europe

5. They should not present undue barriers to the realisation of adequate security of supply

6. They should not be over-sensitive to small changes in the transmission system and its users

7. They should be as simple as possible to achieve their objectives, and no simpler

8. They should command sufficient stakeholder support to be implementable

3.2 Discussion of the principles

We now offer some comments on each principle in turn.

1. They should encourage efficient investment and operating decisions by the transmission companies, generation companies and consumers such that the overall cost of electricity is, as far as practicable, minimised

A fundamental principle of a market economy is that decisions will be most efficient if those making them have to pay for the full consequences of their actions. The implication is that a transmission user located at a node where their presence raises the system's costs should pay more than a user located at a node where they reduce costs (for example by reducing the need for investment in enhanced network capacity as a consequence of increased power flows on the system). Consider a potential system user who has the choice between two nodes on the transmission system, which may allow the same level of generation capacity but involve different direct costs to the individual user (i.e., excluding the cost of transmission charges) or may have similar direct costs but offer different levels of output (e.g. load factors for a wind farm). In the absence of a difference in transmission charges, the user should obviously prefer the node which offers it the lower direct cost or greater output. If the benefit of doing so is lower than the additional cost imposed on the transmission system from choosing this node, however, the user's choice will lead to a greater overall cost of electricity, or lower overall benefit, than the alternative. If the user faced transmission charges which fully reflected the difference in the costs imposed on the transmission system, however, the user's decision, in seeking to maximise its benefits net of transmission charges, would also maximise the benefits to the country as a whole.

The arrangements should also give the transmission companies incentives to operate efficiently; for example, they should gain if they make cost-effective investments that have benefit in meeting their licence obligations to facilitate competition and contribute to security of supply.

It is noted that failure to provide the 'right' level of transmission relative to the location of demand and the location and utilisation of generation would lead either to excessive volumes and cost of transmission constraints (and less open competition than would otherwise have been the case) or to excessive cost of transmission infrastructure. In both cases, the net consequence is higher electricity prices for consumers.

2. They should be consistent with the realisation of climate change mitigation targets set by government in the UK

The UK government has adopted policies to combat climate change, together with the devolved administrations. For our purposes, the most important is the target, agreed under the EU Climate and Energy Package, to produce 15% of the UK's final energy demand from renewable sources by 2020, a target which implies that between 30% and 40% of the UK's electricity may need to come from renewables. We note that many of the UK's best renewable resources for electricity generation are remote from consumers, and some would require significant investment in the transmission system. For a given level of support from other policies (currently the Renewables Obligation is the most important of these), the higher the transmission charges these generators have to pay to access these more remote resources, the less commercially attractive those locations will be to developers. A renewable energy scheme in one of these locations could be made more commercially attractive if it received more support or was able to pay a lower transmission charge. However, either option will have financial consequences for the overall cost of electricity and hence for consumers. Furthermore, unless the support or charge reduction is tightly targeted, it will also have financial consequences for other, non-renewable generators. If system access arrangements mean long delays before some of these generators can be connected to the grid, this could also jeopardise the 2020 targets. We note that the government has recently agreed a package of measures to reform transmission access with the intention of removing these delays.

3. They must be compatible with EU directives and regulations

This is an absolute constraint in our work; we assume it would not be possible to change the relevant EU policies on an acceptable timetable, if at all. The key principle of these policies is that transmission should be offered on the basis of regulated third party access to enable a Single European Energy Market. In general, the concept of a single market implies that there should be no discrimination between generators, but EU legislation also covers access to the grid by renewable generators and by combined heat and power stations. Member States are required to give priority access to the grid (in terms of connection) to renewable generators, and priority in dispatch, whenever this is feasible. They are allowed, but not required, to give priority to combined heat and power stations. Where there are interconnectors between electricity systems, access to these should be allocated in a transparent manner, such as via auctions.

4. They should be consistent with the future integration of energy markets across Europe

In the short-term, Great Britain is likely to remain interconnected with Continental Europe and with Ireland via a relatively small number of links with a limited total capacity, which makes this principle less of a constraint than for a market with much higher capacity for transfers to neighbouring markets. Arrangements should be consistent with EU directives for treatment of interconnectors and remuneration of the costs of transfers of power originating in another country.

The impact of transmission charges on international competition via wholesale electricity prices should be considered; broadly speaking, the charges paid by generators will have to be added to wholesale prices if those generators are to recover their costs. Inside any one country, the impact of this on total costs passed through to consumers can be offset by the relative reduction of transmission charges faced by suppliers. However, when two countries trade power and generators face different transmission charges, those in the country with higher charges will be at a competitive disadvantage.

5. They should not present undue barriers to the realisation of adequate security of supply

'Security of supply' at a GB scale at present depends on short-term actions by, in the main, generators and the system operator in the management of generation and network assets and the scheduling and dispatch of generation. In the longer-term, it depends on adequate investment in generation capacity and network capacity that facilitates its use at key times. If the effect of some particular set of transmission charging arrangements was to disincentivise the making of generation capacity available in the short-term or investment in the longer-term, security of supply would be compromised.

6. They should not be over-sensitive to small changes in the transmission system and its users

Uncertainty tends to discourage investment and can lead to inefficient outcomes. If transmission charges are very sensitive to a small change in the transmission system, or in the 'background' of generators or loads connected to it, then the impact on charges will be large and users will face an uncertain environment. The principle of sending signals to encourage efficient decisions implies that charges should change in response to conditions on the system, but users' payments (and the transmission companies' revenues) should not become too volatile.

7. They should be as simple as possible to achieve their objectives, and no simpler

If transmission charges and access arrangements are too complex, then only large companies will be able to respond to them and make efficient decisions – small users may make inappropriate decisions in response to signals that they cannot interpret in time, or may be completely blocked from entry. This would be undesirable. At the same time, the physical reality of the electric power system implies that costs will vary over space and time, and that apparently similar users in different places may require different works to be undertaken before they can be connected to the transmission system. Transmission access and charging arrangements which completely ignore these differences are unlikely to lead to efficient decisions.

8. They should command sufficient stakeholder support to be implementable

Changes to transmission charges and access arrangements are likely to create winners and losers. Stakeholders that believe they will be losers have an incentive to try to block a change. Transmission arrangements are not a zero-sum game, which means, in principle, that it should be possible to make a change and find a way of compensating the losers from the benefits that would otherwise go to the winners, at least during a transition period. Finding such arrangements in practice may be very difficult, however.

3.3 An assumption

We will assume that transmission charging arrangements will ensure adequate recovery of the costs of developing, maintaining and operating transmission assets. This assumption arises out of the following principles:

1. They should encourage efficient investment and operating decisions by the transmission companies, generation companies and consumers such that the overall cost of electricity is, as far as practicable, minimised.
   If transmission companies are not able to recover their reasonable costs, there will be a disincentive to further investment in additional network capacity where required leading to restriction of access to the network for generators, limitation of competition in generation and increased constraint costs, all of which will tend to increase the total cost of electricity.

5. They should not present undue barriers to the realisation of adequate security of supply
   If transmission companies are not able to recover their reasonable costs, there will be a disincentive to further investment, not only in additional network capacity but also in asset replacement and appropriate maintenance for the reliability of transmission assets with a consequential decrease in reliability of supply to consumers.

8. They should command sufficient stakeholder support to be implementable
   The transmission companies are among the important stakeholders in the industry. Any arrangements that do not promise that they can recover their reasonable costs will be very unlikely to attract support from them.

4 Assessing proposed arrangements

We plan to assess proposed transmission charging arrangements in a two-phase process. First, there should be a detailed assessment against a range of technical and practical criteria. Second, there should be an overall assessment against three key questions:

1. what effect would the proposed arrangements have on the overall cost of electricity?
2. what effect would the proposed arrangements have on the likelihood of meeting the UK's targets for renewable energy?
3. what effect would the proposed arrangements have on security of supply?

The context for this is that we regard the ultimate objective of a set of electricity trading and transmission arrangements as being to:

> minimise the total cost of electricity in both the short and long-term
>
> subject to
>
> - meeting the 2020 renewable energy targets;
> - achieving at least a certain minimum level of reliability of supply.

Although there are clearly interactions between various aspects of electricity trading and transmission arrangements, our focus will be on transmission charging.

4.1 Discussion of the objective function and its constraints

In this section, we discuss the objective function that we have postulated above and the constraints we have associated with its achievement.

4.1.1 What does the 'cost of electricity' comprise?

We take the cost of electricity to mean the total paid by consumers for their electrical energy. This must clearly be sufficient for the costs of 'production' and 'transport', i.e. transmission and distribution, of that electrical energy to be recovered. We assume the costs of production to include those of the physical facilities for conversion of energy and the costs of fuel. We also assume that measures to encourage investment in and efficient operation of production of electrical energy from low carbon sources should be considered as being part of the cost of production. We therefore assume the costs of production to include the costs of carbon, such as for allowances as under the EU's Emissions Trading Scheme or the future carbon tax proposed in the recent DECC consultation on Electricity Market Reform (DECC, 2010d) and confirmed in the 2011 Budget, and the value of contributions to reducing carbon emissions such as Renewables Obligation Certificates (ROCs) or Feed-In Tariffs (FITs). While this focuses on the *cost* of reducing emissions and promoting renewable energy, these policies also have *benefits* for consumers (now and in the future) – with the right mix of policies, the benefits will exceed the costs.

In this model, the role of transmission and distribution can be considered to be one of facilitating the transfer of the electrical energy produced to consumers. However, as will become evident through this report, there are interactions between decisions relating to ‘production’, ‘transport’ and the overall cost of electricity. In general, decisions made by consumers also affect this. For example, developers of electricity generation facilities whose *raison d’être* in a liberalised electricity supply industry is the making of profit from production and sale of electrical energy, have at least some freedom in deciding what kind of plant to build and where to site it. In principle, so too do consumers though, in an industrialised economy in which a reliable supply of electricity at a ‘reasonable’ price is generally assumed, the locations of domestic and commercial electrical loads are generally shaped by much wider social and economic factors than the local cost of electricity; at least until now, electricity consumption has been shown to be highly inelastic to its price. A decision by a generation developer to locate their new facility away from the main load centres (as opposed to near to them) will entail, if spare network capacity is not available, either a need for investment in additional transmission capacity or some kind of constraint on the utilisation of generation in order that network limits can be respected; while the extent depends on the electricity market arrangements, the latter normally also entails some additional cost relative to the case of the new generation facility being located near to the main load centres.

As will be discussed more fully later, one way of trying to build a bridge between highly regulated, tightly constrained world of electrical networks and the freer (though not entirely free) world of generation of electricity with the purpose of minimising the total cost of electricity is to provide signals to owners of generation regarding the different costs of network infrastructure consequential to different generation siting decisions. This is commonly done through locationally differentiated charging for access to and use of the network, locationally differentiated prices of electrical energy or some combination of the two. The same mechanism is normally also used to recover at least part of the transmission company’s costs. The subject of the present review is the choices that are available in respect of these signals and the recovery of the cost of, in particular, transmission.

4.1.2 Renewables targets and security of supply as constraints

It seems to us that there is global consensus regarding the objective of minimising the total cost to consumers of electricity supply. This includes cost of production of electrical energy and its delivery via networks. In the longer-term, costs are minimised by the undertaking of appropriate levels of investment in new generation and network capacity. This seems to us to be correct and is a principle that we have adopted in the assessment of different trading and transmission arrangements. However, there is generally also a concern with reliability, or ‘security’ of supply. If the economic penalty of failure to meet some part of demand for electricity can be quantified, the cost of unreliability of supply might be added to the cost of electricity supply and the total minimised. On the other hand, if it cannot or there is no consensus on the value of continuity of supply, some minimum level of reliability might be specified and the minimisation of cost made subject to a reliability constraint. Given the dependency a modern society has on reliable supply of electricity and that an industrial economy also has on it, and the historic recognition in GB of the important of reliability of supply, we regard the achievement of some level of reliability as also being fundamental to the design of trading and transmission arrangements.

Although authors in the past have postulated one or more 'values of lost load' or 'customer damage functions', most – though not all – recent debate about 'security of supply' impacted by generation focuses on a particular reliability threshold[11]; although not explicitly stated in present transmission network security standards, they too are have a reliability threshold-based minimum level of transmission capacity. Based on these precedents and due to the lack of consensus on how unreliability should be costed, reliability of supply will be treated in the present assessment as a constraint, though it is recognised that its inclusion as a cost has an arguably more attractive theoretical basis.

In contrast with the development of electricity supply industries over the last 20 years, the supply of electricity is now also subject to a constraint that a certain proportion of it – achieved by whatever means – should come from renewable sources. This might be treated as an additional constraint applied to the minimisation of the cost of electricity or, if a penalty for failing to meet the target is quantified, it could be added as further term in the cost minimisation.

We are unaware of any published penalty price for Britain failing to meet its 2020 renewable energy targets. The achievement of the targets – albeit with industry responses to the setting of the targets currently incentivised through the renewables obligation and, for small scale generation, feed-in tariffs – is therefore treated as a constraint.

While different emphases might be put on short-term cost minimisation versus long-term effects, we regard the achievement of minimum costs in the long-term as being largely dependent on attracting appropriate levels of investment in generation and network capacity. The same dependency is true of achievement of renewable energy targets and adequate security of supply. If investors cannot recover the costs of past investments, future investments will be jeopardised.

While we regard security of supply and meeting the UK's renewable targets as constraints, there is a degree of freedom in the system. In this review, we do not specify the mechanism used to support renewable energy, and we note that the government is currently consulting on major changes to the mechanisms to be used in the UK. To some extent, it is possible to change the level of support provided to renewable (or other low carbon generation) to offset any changes in the arrangements for transmission charging; if the latter appear to discourage renewable generators to such an extent that achievement of the renewables targets is threatened, one option would be to provide a higher level of renewable support, with consequential costs for electricity consumers (or taxpayers). In other words, the impact of changes to transmission charging arrangements on the renewables constraint is not that they will make it possible, or impossible, to meet that constraint, but that they will change the financial and economic costs of doing so and the exact means by which it is achieved. We discuss this issue further in section 7

4.2 Technical and practical criteria

[11] DECC's recent consultation on Electricity Market Reform cited work by Redpoint and Oxera in which a value of lost load of £30/kWh was used (DECC, 2010d). It was claimed that this led to a generation plant margin – or 'capacity margin' – of 10% (including appropriate 'de-rated' contributions from variable and intermittent generation such as wind).

For our detailed assessment, we will use technical criteria – those which would apply, regardless of the country for which the proposals were made – and practical criteria, by which we mean questions that depend on the particular starting point relevant to Great Britain. We currently propose the following criteria:

Technical:
1. Economic efficiency
2. Robustness

Practical:
1. Workability by industry participants
2. Complexity of regulatory and legislative instruments
3. Prospects for gaining stakeholder support

We note that, in respect of some criteria, notably the practical ones, it will be difficult for the academic team to make a comprehensive assessment. However, we believe it to be important that such criteria are articulated and some issues raised in order to aid discussion among stakeholders.

In following subsections, we present some brief discussion around each criterion.

4.2.1 Economic efficiency

The key element here is the extent to which the proposed arrangements create incentives to decisions by transmission companies and users that deliver an efficient overall electricity system. This implies that differences in the prices paid by users of the transmission network should reflect differences in the costs that they impose on the transmission system. If price differences are too low, there will be a tendency to chose generating sites which are further from loads than would be optimal if all costs (both for generators and for the transmission system) were considered. If the price differences are too great, however, generators will tend to cluster too close to the loads.

Efficiency can normally be expected to result if

- incentives to different parties accurately reflect the effect of different actions on overall cost, in this case of electricity, and
- signals are clear and industry participants have the chance to respond to them in a timely fashion, changing their intended action where necessary.

4.2.2 Robustness

A system of transmission charges that is very sensitive to small changes in conditions will not be robust. If the presence or absence of a single generator leads to an economically significant change in the prices which other transmission users in the vicinity face, this will lead to a degree of risk which they may find unacceptable. It is possible that long-term hedging arrangements could be put in place to offset such risks, although at the cost of complexity, which we also regard as undesirable.

Another aspect of robustness is the extent to which the arrangements might be exploited by a company or companies with market power. If a transmission user has the ability, by its own independent action, to significantly change the prices it faces by changing its decisions, this may lead to inefficient outcomes and excessive costs for other users or the transmission company. Market rules cannot eliminate the possibility of exercise of market power, which comes from the fact that in some situations, there are few alternatives to buying from the company which has it. However, long-term contracts can sometimes make the short-term exploitation of market power unprofitable.

4.2.3 Workability

It is important that the signals sent by the transmission charging and access arrangements are clear and can be straightforwardly interpreted, in particular so that all market participants can successfully work with the arrangements. Excessively complex market arrangements can act as a barrier to entry, particularly to the smaller (potential) players. Given that one possible future for low-carbon energy involves a large number of small generators, this kind of barrier should be avoided, as far as possible.

4.2.4 Complexity of regulatory and legislative instruments

A different, but related question is how difficult it would be to bring about the necessary changes to the industry's Codes and regulatory context to implement any new set of arrangements. Similar issues of transition and implementation may arise in respect of extensive changes to computer systems or renegotiation of large numbers of contracts that would be required.

4.2.5 Prospects for gaining stakeholder support

Transmission charging is not a zero-sum game. The total benefit to society of an industry with efficient transmission charges and access arrangements will be greater than that of an industry with inferior arrangements. Nonetheless, any changes to the arrangements risk affecting individual market participants' profits, and it is quite possible that some participants could stand to lose significant amounts. A change which faces too much resistance from individual stakeholders or groups of them may become impractical. It is sometimes possible to sweeten the pill of an otherwise unacceptable set of changes by using a transition period to ensure that rises in charges are gradual, or by creating "grandfather rights" which provide some degree of temporary compensation to those who would benefit from continuation of an existing policy, while ensuring that all new developments face the more efficient arrangements.

5 Choices in design of transmission charging arrangements

5.1 Foundations of charging methodologies

The context of a generator's decision on where to build a new facility, the transmission planner's task in planning the system and the signals that might be sent to encourage overall economic efficiency in electricity generation and transmission can be illustrated by means of a very simple example: would it be better for the new power station or wind farm to be built at location A, which is quite remote from the main demand centre, or location B that is next door to it? (We assume that similar connection costs are incurred in both cases, but that only location A might require some additional capacity on the main interconnected transmission network).

The transmission planner's job is to decide how much additional transmission capacity would have to be built were the generator to connect at location A. If there is already enough generation on the system and enough transmission capacity to satisfy security of supply considerations, this will largely be a question of economics: what is the cost of different amounts of additional transmission capacity and, for each level, what is the impact on trading of electrical energy and on network constraints that must be managed – and, in BETTA, paid for – by the system operator? The amount of transmission capacity that the planner would seek to build would be that which would minimise the total cost of new transmission capacity and constraints, the bulk of trading of electrical energy being assumed to take place outside of the Balancing Mechanism (as it is under BETTA) and the impact of restricting physical operation of (mainly) generating plant being revealed through constraint costs.

The above total cost of additional transmission and additional constraints consequential to the connection of generation of A is what should be reflected to the generator. However, connection of the generator at location B instead of A would also affect the trading of electricity and the total constraint costs seen by the system operator. The change in constraint costs consequential to the connection at B should also be reflected to the generator. In this way, the generator, knowing all the other costs and risks of their project and the respective sites, could then include in their evaluation the cost of accessing and using the transmission system.

The challenge lies in identifying the change to constraint costs arising from a connection at A, the change to constraint costs were it to connect at B and the 'correct' amount of transmission for location A (and the cost of that additional transmission). It should go without saying that this is difficult. The economic assessment of the reinforcement were the generator to connect at A should consider a number of years of operation. (Discounting tends to mean that for assets only the first 5-10 years really make a difference.) Without firm commitment from all network users, there will be considerable uncertainty regarding which other generators will have and exercise rights to use the system. While demand for electricity might be reasonably well forecast, the operation of generation to meet that demand at different times of the year is harder to predict. For example, in the last few years in Britain, due to variations in the 'spark' and 'dark' spreads, combined cycle gas turbines have been preferred to large coal stations for some months, and at other times large coal has been. These changes give rise to very large differences in the power flows that the system operator must manage and hence to the volume of constraint actions that might be required (and to what the system operator has to pay for them) (Bell, 2010).

In theory, a large, sophisticated software tool might be used to simulate lots of different system conditions, estimate future constraint costs and inform the decision on how much transmission to build. However, as well as the practical difficulties of setting up, running and assimilating the outputs from such large simulations, this approach would depend on a very large number of assumptions, any one of which can be challenged, often giving a degree of precision in analysis that, because the uncertainty of data, is illusory. Moreover, there is often suspicion on the part of outsiders of what is going on inside large, complicated software tools.

It could be argued that what transmission charging methodologies boil down to is an approximation of the network planning and operation process so as to produce a representation of the costs that a connection at location A or location B or any other location would impose. The approximation may, in effect, short-circuit the planner's consideration of year-round constraint costs and try to represent directly the additional network capacity, perhaps itself based on one or just a few operational snapshots. That process may try to take direct account of existing capacity 'headroom', or simplify the process by assuming that all increments in power average out over time into average network upgrade costs. In any case, a charging methodology implemented by a transmission company takes on the task of estimating the costs associated with connection and operation of generation and demand at different places, and communicates them to the network users. That might be done in terms of one charge reflecting the cost of both transmission assets and network operation, or in two separate charges. Alternatively, as could be said to be the case with the locational marginal pricing (LMP) approach that will be described in section 6, it could be said to be left to each market participant to make their own forecast of the benefits (for generators, in terms of higher earnings from sale of energy) of one location compared with the costs (in terms of lower earnings) of another, a forecast that should take into account the behaviour not only of competitors but also of the system operator and transmission owner (who might reinforce some part of the network).

If the above forecasting is left to each individual network user to do, as in an LMP approach, how they do it is up to them. If it is the responsibility of the transmission owner or system operator, arguably every transmission user has a legitimate interest in how they do it.

It seems to us that a very detailed simulation of the network planning and operation process for increments of generation (or demand) at every location would be nigh on impossible (and the evidence of which we are aware is that no centrally managed transmission charging methodology has attempted it). The designer of a methodology is left with a number of choices of how to arrive at an acceptable approximation. Often, this concerns a trade-off between computational complexity, dependency on large volumes of (often uncertain) data, robustness and accuracy of reproduction of costs. In the event that no one approach seems to fit the bill, minimisation of perverse outcomes might become a priority in terms of the approximation and other considerations such as those described in section 3 will have an influential role.

Some of what seem to us to be the main dimensions in practical charging methodologies are described below.

5.2 Charging methodology design dimensions

Review of established transmission charging methods (some of which are described in section 6 below) suggests that key choices in their design can be reduced to a number of key dimensions, listed in Table 1 below. They are each discussed briefly below.

Table 1: main charging methodology design dimensions

Locational	↔	Non-locational
Levied on Generation	↔	Levied on Demand
Power based (measured by MW)	↔	Energy based (measured by MWh)
Based on long-run costs	↔	Based on short-run costs
Recovery of cost of transmission assets and their maintenance	↔	Recovery of cost of operating the system
Fixed charges	↔	Variable charges
Based on typical reinforcements and their costs	↔	Based on notional or average reinforcement costs

5.2.1 Location and who pays

The meaning of the locational dimension in Table 1 is clear: either a charge (per unit) depends on exactly where that unit is connected within the network, or it does not. Some countries levy charges for use of the main interconnected system only on the demand side.[12] Others levy some part on generation and the rest on demand; it is also possible to impose all the charges on generators (even though the costs eventually find their way through to consumers of electricity, i.e. the demand side). A further variation on the theme involves either the generation (or the demand) part summing to zero even though individual generators (or demand side users) all pay some amount.

5.2.2 Power or energy

'Power based' methods generally refer to maximum power generated or consumed in the course of a year. Energy based methods take into account, at least to some extent, the variation in generation and consumption through a year. In practice, such methods might take account only of a limited number of operational snapshots[13] or might use total energy produced or consumed over the course of year. Still other approaches, such as trading based on locational marginal pricing (LMP) complemented by purchase of 'financial transmission rights' (FTRs), implicitly base net transmission access charges on energy and time and locationally dependent prices of energy. (The main features of LMP plus FTR are described in section 6.5 below.)

[12] This includes several countries that have not fully adjusted their systems to EU-mandated liberalisation. It may also be noted that at least some of these apply quite 'deep' connection charging to generation.

[13] A report by Pöyry, independently of us, presents a similar breakdown of the dimensions of a charging methodology (Poyry, 2010). In addition to MW and MWh based methodologies, they make a distinction between 'static' and 'dynamic' methods by which they mean: based on single or multiple power system conditions.

5.2.3 Short or long-run costs

The short-run marginal cost of transmission is given by the cost of losses and the opportunity cost of transmission constraints. How much does it cost to move power from one location to another at the present time, or what is the opportunity cost of the constraint that makes it impossible to do so – in other words, what is the difference in the marginal cost of electricity at various points on the network? The long-run marginal cost of transmission is the cost of building and maintaining transmission capacity in order to accommodate an increase in power flows, together with the cost of the resulting energy losses.

If it were possible to "fine tune" the size of the transmission system, the system owner would add capacity until the cost of a small additional increment was just greater than the cost of the congestion it would relieve and transmission losses it would reduce. The short-run marginal cost (congestion plus losses) would thus be equal to the long-run marginal cost (of capacity). In reality, transmission investments are lumpy. This means that there will be times when the short-run marginal cost of transmission exceeds the long-run marginal cost (i.e., congestion is quite frequent) but it is not yet worth making the investment required to ease it. Once the investment has been made, however, there will typically be spare capacity, and so the short-run marginal cost will be less than the long-run cost. If investment decisions are made to minimise the overall costs, we would expect periods when long-run marginal costs exceed short-run marginal costs to be roughly balanced by those when short-run marginal costs are higher. Short-run marginal costs will be more volatile than long-run marginal costs, but they will not necessarily be higher on average.

5.2.4 Assets or operation

A single charging methodology might be concerned with recovering the cost of transmission network assets and their maintenance, i.e. the costs associated with the 'transmission owner' (TO) role, or with the cost of operating the system (such as network losses, the scheduling and utilisation of response and reserve, reactive power, balancing actions to resolve network constraints and so on), or a combination of both. Alternatively, there might be two methodologies used in parallel, one concerned with the transmission owner's costs, the other with the system operator's.

5.2.5 Fixed or variable charges

The next dimension of a charging methodology that we highlight concerns whether the charges levied on a particular network user are set some time in advance of time of use and are fixed for some given period, or whether they are variable and depend on the network conditions that prevail through the charging period. The former might be the outcome of some auction process by which future access rights are determined. The present transmission charging methodology in Britain is an example of the latter. In it, a particular network user's charges are affected not only by their own behaviour in or at the start of the period but also by that of others.

For decisions to apply for new access rights, how much capacity is available on the network is clearly affected by the actions of others and, if the price of access is cost-reflective, by the cost of any additional network capacity needed to facilitate those rights. (If an auction approach is used to allocate access rights, the price of access would reflect both the various users' perceptions of its value and its scarcity). However, once rights have been granted (possibly accompanied by a need for reinforcement), it might be argued that the price of acquisition of such rights should be 'locked in'; anyone else seeking new rights after that would have their application assessed against the new background and would be influenced by the cost of further network capacity, if it is needed.

5.2.6 Typical or average reinforcements

Methods that are concerned not only with recovery of network costs but also with sending of locational signals and which make use of long-run costs in identifying the impact of extra generation or demand at different places might, in general, use one of two approaches: to try to identify whether the actual network would need to be reinforced to accommodate a particular change and what would be the nature and cost of that reinforcement; or to assume that the impact on transmission cost of extra generation or demand at a particular place can be represented by some notional or average reinforcement. The present 'investment cost related pricing' (ICRP) methodology used in Britain falls into the latter category (and is described in section 6.2 below). Some of the methods proposed for distribution network pricing in Britain fall into the former category (and are described in section 6.3). One of the issues around the latter arises from the 'lumpiness' of reinforcements that might typically be carried out on an actual system – they tend to provide capacity in discrete chunks and normally provide more than is immediately required. If network users are made responsible directly for the works they cause (and have their charges fixed on that basis – see above), the spare capacity might be used as a free windfall by someone else.

5.2.7 Charging in Britain as an example

The significance of the design dimensions outlined above can be readily seen in relation to some currently implemented charging methodologies. For example, in Britain, the costs associated with the role of 'transmission owner' are recovered via the 'Transmission Network Use of System' (TNUoS) charge while that of the system operator is recovered via the 'Balancing Services Use of System' (BSUoS) charge. The present TNUoS charging methodology in Britain levies locationally differentiated charges based on maximum power generated or consumed[14] over a year, and the charges are based on the long-run costs of electricity transmission infrastructure and 'notional' reinforcements. BSUoS charging to recover the costs of operating the system – payment for response, reserve, re-dispatch of generation in order to respect real-time network constraints, reactive power and so on – is based on energy and is, at present, non-locational.

Even in respect of the element concerned with transmission assets and their maintenance, the reality of a particular charging model may necessitate a hybrid whereby different proportions of the total cost of transmission are recovered via different ends of the various dimensions in Table 1. For example, in 2009-10, total income to the three GB transmission licensees via TNUoS charges came in the proportions shown in Table 2. On the other hand, some such hybrid may be a deliberate design choice.

[14] In practice, for the demand side, the power figure is averaged over the three highest demand periods in a year, each separated by at least 10 days.

We believe that the choice of design of a charging methodology, and the splits of the total charge between the different dimensions in Table 1, should comply with the principles articulated in section 3 above such that the objective and constraints outlined in section 4 are satisfied.

Table 2: proportions of total GB TNUoS charge in 2009-10

	Locational	Non-locational
Generation	7.6%	18.7%
Demand	8.2%	65.5%

Notes:

1. Total TNUoS cost-recovery in 2009-10 was £1.58 billion
2. Percentages based on total charges for 2009/10 (Hynes, 2011)
3. All TNUoS charges in 2009-10 were based on power and the long-run costs of transmission
4. Although the total TNUoS recovery via the locational is the smaller part, the differences between particular locations may be significant.
5. BSUoS cost-recovery was split roughly 50/50 between generation and demand and was based entirely on energy. However, almost all of the money spent by the system operator and recovered via BSUoS goes to generators.

6 Electricity network charging models

In this section, we present a brief review of some of the main transmission charging models that have been implemented or proposed in different parts of the world. Our intention here is not to present an exhaustive review; for one thing, there are many variations on a theme that can be seen in different places with different mixes on the design axes outlined in section 5. Moreover, a review of international practice has been commissioned separately by Ofgem as part of Project TransmiT. In addition, a plethora of charging methods has been suggested in the academic literature (e.g. Galiana, 1998; Galiana, 2003; Glachant, 2005; Lima, 1996; O'Neill, 2002; Rubio-Oderiz, 2000). We do not intend to describe them; rather, our intention here is to describe the main models that have been discussed within the electricity supply industry in relation to transmission or distribution charging in Britain and for which there is at least some practical experience somewhere in the world. We also present an initial discussion of the characteristics of each model with respect to the assessment criteria outlined in section 4, i.e. how they seems to perform in respect of economic efficiency and robustness, and how practical they are in respect of

- their workability by industry participants;
- the complexity of regulatory and legislative instruments required for their implementation; and
- the prospects for gaining stakeholder support in them.

6.1 Postage stamp pricing

Postage stamp pricing implies that all system users face the same set of transmission charges, with no geographical variation. This is the approach adopted by Sir Rowland Hill when the Post Office was reformed in 1840 – a user could send a letter anywhere in the country for the standard fee of one penny. The charges can still depend on the user's characteristics, of course, such as their maximum demand, generation capacity or output. However, access to the transmission system is seen as some kind of universal service, and the fee for this access should not depend on the user's location.

In the following sub-section, we discuss "pure" postage stamp pricing, where all of the transmission revenues come from charges that are not geographically differentiated. In sub-section 6.1.2, we consider a second application of the principle, which is as a residual in a geographically differentiated transmission tariff. Many tariffs calculated on the basis of incremental or marginal costs will only bring in part of the revenue required by the transmission owner: effectively the average cost of transmission is much higher than its marginal cost. The cost-based geographical tariff must therefore be adjusted so that it recovers the total amount of revenue required, and this adjustment is most appropriately made on a postage stamp basis, charging users the same amount, wherever they are located.

6.1.1 Pure postage stamp charging

A pure postage stamp is the simplest kind of transmission tariff – all users face the same (schedule of) charges, wherever they are located. The tariff could be based upon generation capacity and maximum demand (for consumers) or upon total energy output and consumption. Many EU countries currently have postage stamp transmission charges, frequently applying only to consumers. The Bulk Supply Tariff used before privatisation in England and Wales was based on a postage stamp approach, in that the main energy and demand charges were not regionally differentiated. We will not differentiate between capacity- and energy-based charges in our assessment:

Economic Efficiency Postage stamp charges send no signal of how the costs imposed on the transmission system by a user depend on that user's location. This means that the user has no incentive to avoid investing at locations that would impose high costs on the system, or to choose locations that would reduce the costs of the transmission system. Similarly, there is no geographical signal that relates to operating decisions. Sending this signal will not always affect the decision taken – the renewable resource in an area may be so good that it should be exploited, whatever the costs of transmitting it to consumers, but we would argue that the signal should still be sent. Otherwise, some distant resources will be exploited when it would have been cheaper, overall, to have exploited a slightly inferior resource that was much closer to the load. A pure postage stamp tariff therefore performs very badly on the criterion of economic efficiency.

Robustness Postage stamp charges are robust in the sense that they should not be affected by small changes in the industry. If a change leads to an increase or decrease in the revenue required to pay for transmission, this will be spread across all users, leading to a relatively small change in the charges. The charges may not be robust in a broader sense, however. If a system is seriously inefficient, there is always the possibility that it will be replaced by something better. If this happened, some transmission users would see large changes in their transmission charges.

Workability We expect that industry participants would find it easy to adapt to postage stamp charges, due to their simplicity. If a tariff was based on maximum demand and generating capacity, existing administrative systems could be used, simply placing each location in the same zone, or inputting an identical tariff for each zone. If the transmission tariff was based on output and consumption, systems used for the Balancing Service Use of System charges would record the information required.

Complexity of regulatory and legislative instruments Similarly, it would not be difficult to regulate a geographically undifferentiated transmission tariff. EU policy requires transmission tariffs to be 'non-discriminatory', and it is possible to argue that a tariff that charges all users the same amounts does not discriminate against any of them. (To anticipate a later argument, it is our view that a tariff that accurately reflects differences in costs between users is also non-discriminatory. Indeed, if there are differences in costs, most economists would argue that it would actually be discriminatory to charge the same amount.)

Stakeholder support This change would be welcomed by some stakeholders and opposed by others. We expect that it would be welcomed by companies which own (or are developing) generation in areas that are quite remote from the main demand centres. We would expect it to be opposed by politicians who are interested in the price paid for electricity in those areas. Generators in the south of England, who currently benefit from low or negative transmission charges, would be most likely oppose the change. Except insofar as the removal of cost-reflectivity from transmission pricing might lead to an increased overall cost of electrical energy that offsets the benefit, consumers in southern England may be expected to gain slightly from a move to postage stamp transmission pricing.

6.1.2 Residual Postage Stamp Pricing

Most cost-based methods of transmission charging initially fail to recover the required amount of revenue. That is, when an initial set of tariffs is calculated, which reflects the incremental (short- or long-run) costs that users impose on the transmission system, the revenue which would be collected by these tariffs falls well short of the total cost of the transmission system. This has been noted for the system currently used in Great Britain, and for the locational marginal pricing used in parts of the United States. Effectively, the average cost of transmission is well above its marginal cost (Pérez Arriaga, 1995).

We would argue that a postage stamp charge is the best way to recover the residual. The charges should be raised by the same (absolute) amount at each point in the country, maintaining the geographic differentials established in the cost-based transmission tariff. This ensures that the locational signals from that tariff are maintained at the correct level. Any alternative that simply scaled up the initial tariff to a level that recovered the total revenue required would impose geographical differentials that far exceeded the cost differences imposed by transmission users. This would send perverse signals, and would be discriminatory.

Should the postage stamp be imposed on generators or on suppliers, and should it be based on capacity and peak demand, or on output and consumption? Eventually, all transmission charges are paid by customers – generators have to cover their costs, and do so from the prices which are ultimately paid by electricity consumers. If consumers end up paying the bill, would it not be simpler just to charge their suppliers? This also has an advantage in an interconnected system in which neighbouring countries levy most or all of their transmission charges on consumers, in that British generators would then face a more level playing field. The main reason for imposing the residual charge on both generators and suppliers is one of meeting past expectations enshrined in contracts. Ever since privatisation, National Grid has calculated a transmission tariff so that generators provide 27% of its 'transmission owner' revenue, and suppliers 73%. Our understanding is that this split was arbitrary, but since long-run contracts for the sale of electricity have been written in the expectation that generators would provide this proportion of transmission revenues, National Grid and Ofgem have been reluctant to change it. To reduce generators' transmission charges would give them a windfall gain, unless their power sales contracts were renegotiated to pass through the benefits of the lower transmission charges to suppliers – who would find themselves facing higher charges. In the ordinary course of business, such renegotiations would be unlikely. It is possible that they might be contemplated as part of a sufficiently wide-ranging reform of transmission charging.

The choice between a capacity/peak demand residual charge and one levied on output/consumption should be viewed mainly in terms of its effect on consumers' decisions. With any charge designed to raise revenue, rather than to send a signal of costs, the aim should normally be to minimise the impact of the charge, in terms of the risk that it will change people's choices. In terms of taxation, one reason for taxing petrol has been that its consumption is not very responsive to its price, and so large amounts of revenue can be raised without too much distortion. Economists have a well-developed theory of so-called Ramsey pricing which would raise prices the most for those customers or products that would minimise the change in sales. Much of this theory is irrelevant for setting transmission charges, however, because National Grid has to charge electricity suppliers, not final customers. It would be impractical to have a transmission tariff that attempted to discriminate between electricity suppliers on the basis of the customers that they were serving. The current tariff does have separate charges for half-hourly and non half-hourly metered customers, but a transmission tariff that had separate charges for domestic and non-domestic customers, for example, would likely be unworkable.

The pattern of transmission charges will be reflected in customers' prices, except where charges levied on generators fail to feed through to wholesale prices – which would not be a feature of a competitive market in the long run. This means that if the residual transmission charge is levied on consumption (and output), we would expect energy prices to rise across the year by the amount of the charge. If the charge is levied on peak demand, customers will face higher peak demand charges. If a charge is levied on generating capacity, this will raise the amount that generators have to recover from the wholesale market. Given the current British market design, this implies higher peak wholesale prices, since the peak is the only time that some generators are able to earn any money. Once again, these peak prices will be passed through to consumer prices.

Customers with half-hourly meters can receive signals of the price of power at different times. Residual transmission charges that are based on the peak demand will give them a sharp incentive to reduce demand at these times. If wholesale prices are an accurate signal of the cost of power, and are passed through to these consumers, then the combined signal from cost-reflective transmission charges, wholesale prices and the residual transmission charge may be too strong, encouraging the customers to take unnecessarily disruptive steps to reduce their consumption. This is because the transmission charges are focused on a few periods, and are at a level that can capture the attention of energy managers. If the same amount of residual revenue was recovered over the year as a whole (via charges on energy consumption), the cost in each half-hour would be far lower, and there would be no artificial incentive to switch consumption between periods.

For customers without half-hourly meters (or with such a meter, but with a supply tariff that does not take advantage of its features) even a charge based on their estimated peak demand will actually be smeared across their consumption. For these customers, the main question is how the choice of residual charge affects their overall bill. Customers with a relatively peaky demand would be better off with residual charges that are based on kWh of consumption, whereas those with above average load factors would gain from a transmission residual charge based on kW of peak demand. This consideration also applies to customers with half-hourly meters, of course. However, it should be pointed out that the amounts at stake for customers are typically less important than for generators, since transmission is a small part of the average customer's bill.

Since a residual postage stamp charge is something used as part of a transmission tariff, rather than a system in its own right, we do not formally analyse it against our criteria here. However, we note that a postage stamp design is the most economically efficient way of recovering the revenue remaining after cost-reflective prices have been imposed, and that it can be robust, workable and does not require complex regulation. If the residual postage stamp used in Great Britain were to change, stakeholders would likely support or oppose the change based on their own perceived interests: much would depend on whether long-term contracts could be renegotiated to reflect any change in the proportion of transmission revenue coming from generators.

6.2 Simple long-run network pricing: investment cost related pricing

6.2.1 Basis of the method

The method on which the setting of transmission network use of system (TNUoS) charging in Britain is based at present is known as 'investment cost related pricing' (ICRP) (NGC, 1992). It is intended to allow the setting of different tariffs for different locations across the transmission network in Britain in a manner that reflects the cost of transmission infrastructure associated with connecting there.

The method proceeds via a determination of how far how much power flows around the network – the product of MW on each branch and the length of each branch, i.e. the number of MWkm – and how that changes as additional power injections are added at each location in turn (National Grid, 2010a). Fundamental to the method is the assumption that the total cost of additional transmission infrastructure associated with additional power generated at each node (or demand consumed) is closely related to the change in total system MWkm. Although some of the details in its implementation are quite involved (such as the way incremental MWkm costs are calculated or the setting of the residual to ensure a particular split of the total income from generation and demand), as will hopefully become clear from the description below, the basic method is relatively simple.

In the course of a year of operation of a power system, there is no single pattern of power flows. This is due to the variation in demand through the year between its minimum and maximum levels, and the fact that, with a positive plant margin, the available generation almost always exceeds the total demand and yet a power flow solution is only valid if total generation output matches total demand (plus network losses). For each demand condition, there are therefore many possible dispatches of generation that would allow the totals to balance.

Behind the current methodology is an implicit assumption that transmission capacity expansion is driven by conditions around peak demand. (Some of the background to this is described in section 2.2 above). Furthermore, while a large number of combinations of generation outputs are possible under that condition[15], the present TNUoS methodology uses only one, based on a uniform scaling of generation outputs (relative to each generator's network access rights, i.e. 'transmission entry capacity' (TEC)). Thus, for the purpose of application of the methodology for a particular year's charges, to find an amount of power flowing on branch of the network, and the distance that it travels, the inputs are the full set of generator TECs at each location, the demands at each location under a single, weather-corrected ('average cold spell') annual peak demand condition and the planned network characteristics including the impedances and lengths of each branch.

The power flow solution yields the MW figure for power flowing on each branch of the network which, for each branch, can be multiplied by the length of the branch to obtain a

[15] To be more precise, a system peak demand condition is modelled under an 'average cold spell', which has the effect of smoothing out the year-by-year variations in weather that affect the exact level of peak demand.

MWkm figure. Generation is increased by 1 MW (and balanced by an increase in demand at a single 'balancing node') at each node on the network (i.e. each location at which generation or demand might connect) in turn and the change in total system MWkm is found.

On its own, this set of increments might be used as the basis for a split of total infrastructure costs. However, an acknowledgement is made that additional transmission capacity might be provided by different means. For example, the cost per MW of capacity is less on a 400kV overhead line (OHL) than on a 275kV overhead line. Furthermore, the cost of per MW of capacity is much less for OHLs than for underground cables (and the cost per unit capacity is less for 400kV cables than for those at 275kV). Thus, the MWkm on each branch is multiplied by a cost per MW per km for that particular branch depending on its construction[16]. Finally, the cost of the MWkm on a network branch is multiplied by a 'security factor'. This is intended to represent the fact that the actual increase in network capacity required for an increased power injection depends not on the power flow in the intact network, but on that on the network following a 'secured outage'[17].

The result of a change in power generated at a node (and demand at the 'balancing node') is a set of cost changes, which can be summed to find a total change in cost associated with the extra MW injected at that node. When this is done for each node in turn, there is a set of cost increments. It is this that is actually used in determining the relative prices at each location. However, there is a further step in which nodes are clustered together into zones, the intention being to group nodes that have similar cost increments and to use a single, average cost increment for every node within the zone.

It can be seen that the whole methodology starts from power capacity figures. The zonal cost increments obtained are multiplied by the MW TEC figure for generation[18] and by 'triad' demands[19] for consumption to find the respective total charges. However, that is not the end

[16] This is the product of the 'expansion constant' and the 'expansion factor'. The former is the 'typical' cost, per MW per km, of a 400kV overhead line. The 'expansion factor' is the cost of the particular technology – 400kV OHL, 275kV OHL, 400kV underground cable and so on – relative to the 'expansion constant'. In practice, the costs of network branches constructed with the different technologies vary from branch to branch depending on, for example, the tower type and the conductor type. For the purposes of the charging methodology, costs for each tower and conductor type are based on historic costs (documented internally within National Grid) and tender valuations. A weighted average is taken based on recent usage of different overhead line and cable types and installation methods. For underground cables, one variation arises from whether the cable is in an urban or rural area. The 'typical' costs for TNUoS purposes assume a 50/50 split between these types. However, in a final adjustment to the applied costs, account is taken of each transmission licensee's plans for uprating of circuits, e.g. from 132kV to 275kV or 400kV. With the latter being cheaper than the former, a discount is applied to MWkm on 132kV network branches, the value of the discount being dependent on licensee area.

[17] A 'secured outage' is an unplanned loss from service of some system element that the Security and Quality of Supply Standard (SQSS) stipulates must be 'secured against', i.e. it should not cause any breach of system operation limits. Such security rules are commonplace in the electricity supply industry worldwide, especially on transmission systems, and have provided the main guarantee of some level of reliable supply of electricity. The 'security factor' varies from place to place and depends on demand and generation dispatch. However, a single factor – 1.8 – is currently used in the TNUoS methodology for every location though may be modified to 1.0 for generation connections via single circuits.

[18] More precisely, a simple multiplication by TEC is used for generation in zones that have positive cost-reflective tariffs. Because additional generation (or demand) at some locations can give rise to *decreases* in total MWkm, additional generation (or demand) at some locations has a negative transmission cost. For these locations, a function of out-turn generation is normally used to set the final tariff.

[19] This is the average of the peak demands on the three highest demand days of a year, those days each being separated by at least 10 days.

of the process as the total of those charges is insufficient to recover the total cost of developing and maintaining the transmission network infrastructure. The difference is known as the 'residual' and recovered by adding a non-locational additional element to the charge at each location, proportional to the TEC or triad demand as appropriate. The total figure to be added to the generation or demand side is determined by the need for the total income to be recovered 27% from generation and 73% from demand. (This split is quite arbitrary and was set at privatisation).

6.2.2 Some points of note

A number of observations can be made about the above approach.

1. It is 'capacity', i.e. MW, based.
2. The costs it uses are long-run costs.
3. While there is a difference in per MW tariffs in different zones, i.e. it is a locational charge, there is also a non-locational element to ensure adequate recovery of costs by the transmission owners.
4. The charges are based on notional small increments of power of each node.
5. While the charge is capacity based and, in indexing of charges, it makes use of measures of changes of power flows resulting from changes to generation (or demand), it makes no reference to actual network limits. That is, it does not recognise the existence of spare capacity.

As is noted in Russell (2010), the fifth point might make it appear as if there is no spare capacity anywhere on the network and each additional MW connecting causes a need for reinforcement of the network. Moreover, the effect of the methodology is to assume that the capacity of a line will be increased at the same voltage whereas, in reality, it might be uprated or a new line built[20].

By neglecting line ratings, smearing notional capacity changes across the network and using notional small, i.e. incremental, changes to generation or demand at each node, the methodology does not take account of exactly when actual reinforcements would be triggered.[21] However, in comparison with the more 'refined' long-run methods described in section 6.3, this makes ICRP less volatile; in these other methods, once a trigger point is hit, if a particular generator (or group of generators) is held liable for the cost (or some part of it) of a particular reinforcement, their charges will see a significant step change. ICRP has the effect of smoothing out all such effects. As suggested in Russell (2010), this means that ICRP might be described as 'ultra long-run'.

[20] In practice and as noted earlier in this section, some account is taken of planned uprating from 132kV to higher voltages in setting the 'expansion factor' for 132kV and 275kV lines.

[21] Actually, an additional MW of generation (or, in theory, demand), may cause 'negative reinforcement' as a consequence of the total MWkm reducing. The locational element of the tariff would therefore be negative, and this has, at times, been the case for some zones. Engineers might also note that changes to the generation or demand background might drive a need for reactive compensation, and this is not modeled at all in the 'DC power flow' that is used in the charging methodology. On the other hand, the total asset value of reactive compensation on the GB network is very small in comparison with that of overhead lines, underground cables, transformers, substations and switchgear, and only overhead lines and underground cables are directly accounted for in the ICRP approach.

It might also be noted that any change in connected generation capacity or demand at any node will change the set of nodal MWkm increments, even if only by a small amount. Thus, a particular generator, even if it has been connected for some years and would seem to no longer drive, by itself, reinforcements, pays charges as if it was increasing output; it will find its charges affected by the existence of other generators. It might be argued that an established generator should not pay incremental costs if it is not seeking an increase in access rights; however, its continued use of the system adds to the overall requirement for capacity. A particular generator might choose to give up its rights and would then (in an exporting area) reduce the need for transmission; moreover, in an export limited area, under present trading arrangements, a generator with access rights has the opportunity to take advantage of the constraint by having 'bids' to reduce output accepted by the system operator[22].

The influence of one generator's actions on another's charges is somewhat smoothed by the levying of average tariffs across a zone. The main problem that arises from the zonal approach is when a zonal boundary moves – boundaries are based on clusters of nodes that have similar locational tariffs, i.e. similar MWkm cost increments; for a variety of possible reasons, one particular node may, one year, have a tariff that is nearer to those at nodes in a different zone than in the existing zone and so the zonal boundary would be changed. The basing of boundaries on clustering of similar tariffs also means that some network spurs at the periphery of the system may have their own zone and very different charges from the next node or zone. This can be a particular issue for island connections.

A counter-intuitive effect of the methodology was noted in Russell (2010). As described above, one of the inputs to the ICRP model is the network for the particular year for which charges are to be set. This will include the net result of any planned reinforcements. One such reinforcement might be the reconstruction of a particular route from, say, 132kV to 400kV, an investment triggered (on the actual network) by the connection of new generation and the need to comply with planning standards. Because the cost per MWkm of a 400kV overhead line is less than that of a 132kV overhead line, the difference in cost per MW of connected generation between one end of the line and the other would be less than it was before the reinforcement, in spite of the generator at the sending end sending its power along a route that has just had quite a lot of money spent on it, perhaps because of that generator. Russell (2010) suggests that this might send a wrong signal: rather than build a new generation facility of size x that would not trigger a major reinforcement, build one of size $2x$ that would since the locational tariff (per MW of TEC) would be less even though, by virtue of a network reinforcement having just been triggered, the total cost per MW of additional generation capacity for the actual development of generation of size $2x$ and the associated extra transmission may be more than for a generation development of size x.[23] However, it might also be noted that the total revenue to be recovered by the transmission owner would have gone up as a result of the new assets being added to the asset base. Although the locational element of the TNUoS charge might have come down as a result of use of a

[22] In practice, this opportunity will be more easily exploited by fossil fuelled generation than by wind farms or the present generation of nuclear power stations. In addition, it provides an opportunity for generators on the other side of the constraint to have offers of increased output accepted. (In monetary terms, the latter are normally more expensive).

[23] The total TNUoS charge paid by the second project would, of course, be much more than that of the first so whether the signal would have any effect is open to question. However, if the most economic outcome would be for a bigger generation development to be undertaken along with the network reinforcement, perhaps the signal given would have been correct.

smaller expansion constant, the non-locational element would have increased, although this will be spread among all transmission users. (A change to the network's characteristics as a result of reinforcements can be summarised as having, in general, three effects: to change the pattern of MW flows and hence MWkm; to change the cost applying to a particular branch of the network; and to change the total revenue to be recovered.[24])

There is another possible way of viewing the above anomaly, noted by SSE (SSE, 2010). The very large difference in 'expansion factors' that represent the relative costs of reinforcements of branches of the network at 132kV and 400kV would seem to suggest that connection of a new generator at 400kV is always the right answer, however small the generator is.[25] In reality, for a particular generator location, the transmission planner will design the connection that is most cost-effective for the industry as a whole, and this may be at 132kV.[26]

Particular further points of detail that might be highlighted in respect of the method and its applicability to the present day network situation include the following.

- Network reinforcement in many parts of the GB network is currently being driven not by capacity (MW) but by constraints, the latter measured in terms of energy curtailed and replaced (MWh) and the prices paid for increments or decrements of energy.
- The costs used in the costing of MWkm on each branch are based on at least partly on historic costs and could be argued to reflect inadequately the actual reinforcement costs (which, in recent years, have tended to be higher), and so provide insufficiently strong locational signals. (Use of lower branch costs will tend to reduce the MWkm cost differences between nodes).
- There is a proposal to build an 'embedded' HVDC link in parallel with the main AC system and directly connecting the south west of Scotland to somewhere near Deeside (ENSG, 2009). The cost of this is likely to be in the region of £0.8 billion to £1 billion. There is currently no representation of HVDC in the ICRP power flow model and no cost defined for it in the TNUoS methodology.

One final question we would raise is whether the present methodology is consistent in its treatment of offshore and onshore networks (are 'local circuit' assets including substations, transformers and switchgear treated consistently?), and of offshore networks (which connect artificial islands on which generation is located back to the main system) and connections between the main system and islands. In the latter case, our understanding of the present methodology is that, assuming an 'expansion factor' for the connection has been defined, a connection from an island to the onshore network would be treated as part of the main interconnected transmission system (MITS) due to the presence of demand on the island. It

[24] In practice, this last effect would already have been taken account of in the setting of total revenues in a price control based on forecast expenditure, or would be taken account of following the next price control.

[25] It might argued that this effect is somewhat offset by the qualifying of the 132kV 'expansion factor' to take account of planned upratings to 400kV.

[26] The question arises here of what the transmission planner anticipates might happen after: if further generation is expected, it may be better to build at 400kV to provide, in the short-term, spare capacity that can be used in the longer-term more cost-effectively than to undertake a 132kV transmission development and then some additional development afterwards. While such 'strategic' or 'anticipatory' transmission development would seem sensible (see, for example, Bell, 2002), it has, to date, often proved difficult to justify whenever there is uncertainty about the later generation connections.

would therefore have a 'security factor' of 1.8 applied, even if there was only a single cable in contrast to use of a 'security factor' of 1.0 for offshore connections.[27]

6.2.3 Assessment of the method

Economic efficiency We feel that a cost-reflective signal is important to the satisfaction of our first principle regarding the overall cost of electricity, and we feel that the signal arising from ICRP is broadly in the right direction in that, in general, locations that 'need more transmission' are charged at higher rates than those that 'need less'. However, we note that, under some circumstances, the signals provided might be incorrect (discussed in section 6.2.2 above) and that some would argue that the locational tariff differences, rather than being too strong, are actually too weak relative to the costs of future reinforcements and so provide weakened signals.

A final point on economic efficiency concerns possible differences in the treatment of offshore networks, onshore networks and connections between islands and the main onshore network. We believe that it is important that there is consistency between them in terms of signals towards economic efficiency.

Robustness Notwithstanding some complaints levied by some generation companies, we would regard it as being quite robust, i.e. it is not 'over-sensitive' to small changes in inputs; at least, that is the case relative to the models described below. The smoothing out of the 'lumpiness' of real-world network reinforcements helps in this regard, as does the averaging over zones. Some generation companies have complained that charges levied at the end of a year do not match those forecast before the start of it, but the differences are generally small and reflect changes in the level of TEC bought by generation companies. Where significant step changes in charges do occur between one year and the next, it tends to because zonal boundaries have changed. We understand that, hitherto, this has occurred only rarely. However, one significant uncertainty going forward that will particularly affect network users in the north is how the planned 'embedded' HVDC links would be treated in the methodology.

Workability and Complexity of regulatory and legislative instruments The fact of ICRP being the methodology that is currently applied reveals it to be workable. Moreover, for it to continue to be applied would not require any regulatory or legislative changes.

Stakeholder support Although this is the approach currently in use, it is clear from the run-up to Project TransmiT that it does not attract uniform support among stakeholders.

[27] The 'security factor' is meant to represent the fact that unplanned outages of circuits due to, for example, faults, are normally 'secured', i.e. they should not cause overloads of other circuits or voltage or system stability problems. It often means that the pre-fault power flow on a circuit should be some way below its rating to provide some headroom for the re-distribution of power following the outage of another circuit. However, for single circuit connections of generation or demand, there is no re-distribution of power flow between the generation or demand and the rest of the system, only, in the immediate aftermath of a fault outage, a simple disconnection.

6.3 Forecast based long-run network pricing: long run incremental costing

In this model there are actually a number of variations on a theme, all based around charging in accordance with long-run costs of the network but intended to reflect actual network limits (and spare capacity) better than the simple approach described above. The variations on the theme concern the extent to which the ‘lumpiness’ of network investment (the fact that discrete physical works are actually carried out), the timing of investments, the level of additional capacity that the charging methodology assumes them to achieve, the period over which those new investment costs are to be recovered and the parties on whom those costs are levied. By way of example, the following sections will focus on the ‘Long Run Incremental Cost’ (LRIC) method that has been adopted for distribution use of system pricing in Britain.

6.3.1 Basis of the Method

In microeconomics, setting prices according to marginal costs is considered to send the most efficient signals regarding the resource utilization. However, these costs are based on short-term costs, and in electricity markets reflect the cost of energy without always adequately reflecting necessary infrastructure investments. The latter are better reflected under a Long Run Incremental Cost method that considers new investments and allocates them to users that cause these reinforcements.

The Long-Run Incremental Cost (LRIC) method has been discussed for water charges in Britain, and in the electricity sector it has been considered for cost-reflective use-of-system charges for the extra high-voltage (EHV) distribution networks. (See, for example, ENA, 2010).

The LRIC method calculates how new customers, or an increase in a demand or generation of existing customers, affects network capacity and thus causes network reinforcement. Unlike for a simple long-run method such as that discussed in section 6.2, the calculations take into consideration the lumpiness of network investments as well as the time at which increased network utilisation would cause the investment to have to be made. The resulting charges are calculated based on the annualized cost of the network reinforcement decisions, and the process is shown in Figure 2 (Levi, 2009).

As indicated in Figure 2, a forecast of customer behaviour is initially used to evaluate future network expansion needs. These plans are then applied when calculating a cost associated with the required expansion, as well as when this reinforcement is needed. As discussed in (Levi, 2009), charging models based on LRIC produce nodal charges for each network node.

In the original LRIC approach (Li, 2007), each branch in considered in isolation from the rest of the network and its reinforcement is calculated without limitations on how far in the future it would need to be reinforced. The LRIC approach requires two sets of, typically, three load flow calculations representing winter peak demand, summer peak and summer minimum. In the first set, the original network is considered. The most critical of these three conditions is then used to determine the time that it will take for each component to reach its capacity, assuming a particular forecasted load growth,

$$P_l^{\max} = (1+r)^t \cdot P_l \tag{1}$$

where $P_l^{\max}$ is the maximum line capacity, P_l is the calculated line flow for the current condition, r is the estimated load growth rate, while t is the time it would take to reach its limit, i.e. the number of years before reinforcement would be required. The rearrangement of (1) to express time t in terms of known line capacity, $P_l^{\max}$, current line flow, P_l, and rate of growth of total network load, r, yields,

$$t = \frac{\log P_l^{\max} - \log P_l}{\log(1+r)} \tag{2}$$

Thus, reinforcement of the considered line, l, would be necessary after t years. If the value of t is larger than the asset's remaining life (which in the UK is typically set to 40 years), then its replacement would not be brought forward. Note that the same growth rate, *r,* in (2) is used for the total power injection at each node. In general, it can have either a positive or a negative value, indicating load growth or load reduction.

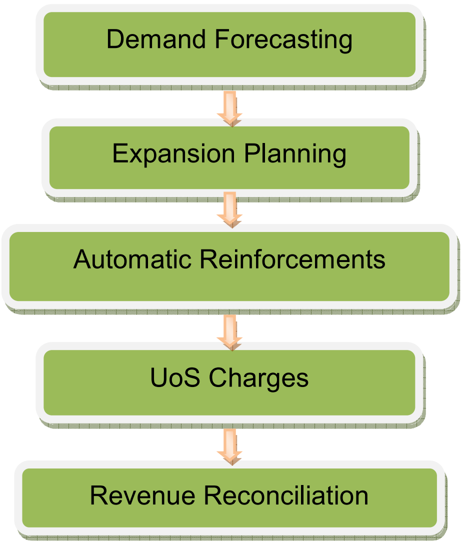

Figure 2. LRIC calculation for EHV distribution networks (Levi, 2009)

Given these timings and the future reinforcement costs of this line, $Asset_l$, a net present value of the future reinforcement cost, PV_l, for the network is calculated using a discount rate, d, equal to the cost of capital (assessed by Ofgem),

$$PV_l = \frac{Asset_l}{(1+d)^t} \tag{3}$$

If there is a particular known or forecast change in the load or generation at a specific node in the network, it would affect the above calculated time to reinforcement, t.

The second set of load flows is used to identify the change in line flow of ΔP_l caused by a change of injection ΔP_N^{inj} at node N. The relationship between a new time to reinforcement,

t_{new}, the change in line flow of ΔP_l, the maximum line capacity $P_l^{\max}$, the whole network load growth *r* and the calculated line flow for the original condition, P_l, is

$$P_l^{\max} = (1+r)^{t_{new}} \cdot (P_l + \Delta P_l) \tag{4}$$

Therefore, the new time to reinforcement, t_{new} consequential to the change of injection ΔP_N^{inj} at node N, and therefore due to the increase in line flow ΔP_l, is,

$$t_{new} = \log P_l^{\max} - \frac{\log(P_l + \Delta P_l)}{\log(1+r)} \tag{5}$$

This change of the time to reinforcement, t_{new}, will also influence the net present value of the future reinforcement cost, which now becomes PV_l^{new},

$$PV_l^{new} = \frac{Asset_l}{(1+d)^{t_{new}}} \tag{6}$$

Furthermore, a change in injection at node N, ΔP_N^{inj}, will cause a change in the net present value, i.e.,

$$\Delta PV = PV_l^{new} - PV_l = \frac{Asset_l}{(1+d)^{t_{new}}} - \frac{Asset_l}{(1+d)^t} = Asset_l \left(\frac{1}{(1+d)^{t_{new}}} - \frac{1}{(1+d)^t} \right) \tag{7}$$

For the considered line l, the annualized incremental cost, IC_l, is the difference in the present value of the future investment as a result of a change of injection, ΔP_N^{inj}, at node N multiplied by an annuity factor,

$$IC_l = \Delta PV_l \cdot annuity\,factor \tag{8}$$

The above annuity factor reflects the rate of return on investment and an allowance for operation, repairs and maintenance. .

Since the change in power injection, ΔP_N^{inj}, at node *N*, affects a number of lines (or other devices) in the network, the total charges attributed to this node will equal to the sum of incremental costs for all of the lines affected by the change,

$$LRIC_N = \frac{\sum_l IC_l}{\Delta P_N^{inj}} \tag{9}$$

In the above network planning process, a number of considerations could be included when deciding which line, and when, needs to be reinforced. These criteria, such as security levels, will affect network charges, but will not be addressed further here.

6.3.2 Some points to note

A number of observations can be made about the above approach.

1. It is 'capacity', i.e. MW, based.
2. It is based on Long-Run costs.
3. It is a locational charge, but the revenue reconciliation could be done either by adding a surplus charge, or using a multiplier[28].

The ICRP method described in section 6.2 could be modified to take into account network capacity, and calculate time before a reinforcement would be required. This improved ICRP, i.e. IICRP (Levi, 2009), is similar to the original ICRP model, except that includes maximum line capacities which are used to calculate time to reinforcement which is a function of the loads and generation as in the case of the LRIC model. In this case there are two functions in the cost equation, so the locational marginal charges have two terms.

By virtue of being directly concerned with the remaining capacity of the network and timing of the investment than ICRP and being locational, the approach may be thought of as approximating 'deep' connection charging. A concern of the latter has commonly been the imposition of the full cost of an enhancement of transmission capacity on a single user. Specific investments tend generally to be 'lumpy' and may well leave some spare capacity, with the possibility that another user would then have much easier and cheaper access than the first one.[29] This would seem inequitable, but that effect might be reduced by a sharing of transmission charges between the two users once the second one connects, in the ratio of their relative capacities.

6.3.3 Assessment of the method

Economic Efficiency LRIC indicates when changes to nodal injections would cause power flows to exceed the limits of the existing or planned network and reflects the cost of network upgrades to accommodate the changes at each location. However, in its basic form and in common with ICRP, the approach neglects alternatives to reinforcement such as constraint actions in operational timescales. Nonetheless, it has good characteristics to promote economic efficiency.

Robustness The focus on when reinforcements would actually be triggered by breach of branch capacity limits makes the method very sensitive to small changes when that limit is approached. However, it would be possible for this effect to be reduced by the averaging of nodal charges across pre-specified zones. Furthermore, the power flows, and hence the time at which a reinforcement is needed on any one branch, are heavily dependent on the assumptions made not only for demand growth but also for which generators have access to the system in future and how their power will be dispatched. On a distribution network with a radial structure and, to date, relatively little embedded generation,[30] this is much less of a problem than on a transmission network

[28] See the discussion of 'residuals' in section 6.1.2

[29] The same effect of the making available of spare network capacity may result not only from discrete reinforcements but also from changes to load or generation at other locations on the network.

[30] Small scale embedded generation is currently experiencing significant growth following the introduction of feed-in tariffs.

in which there are many degrees of freedom, all of which are uncertain. (This problem of what to assume about a future dispatch of generation is shared by ICRP, but is arguably worse here as it goes further into the future).

Workability and Complexity of regulatory and legislative instruments As mentioned, the LRIC method has been developed for the distribution network in Britain, and has not been applied to transmission. While similar principles of recovering network reinforcement costs could be considered for a transmission level, there are a number of specific details that would need to be taken into consideration., e.g. the process by which some forecast of the future generation and demand 'background' would need to be developed and agreed, and the manner in which the planned HVDC 'bootstraps' would be treated. However, it is not expected to need significant regulatory or legislative changes; it would require a change to the approved TNUoS methodology and otherwise would fit with existing transmission licence conditions.

Stakeholder support One criticism made of ICRP by a number of stakeholders is that they regard it as excessively complex. Although LRIC is somewhat familiar to GB industry stakeholders through its application to distribution charging, it is significantly more complex than ICRP, especially when applied to transmission. On the other hand, for a particular forecast of generation and demand 'background', it ought to provide a more accurate reflection of the cost of additional generation or demand at different locations and might therefore be welcomed by at least some stakeholders.

6.4 ICRP-based charges with an energy component

6.4.1 The basis of the approach

The Investment Cost Related Pricing system has the advantage of relative simplicity, and sends signals to transmission users on the relative cost of different locations. It can therefore affect their investment decisions, helping to minimise the overall cost of generation and transmission together. What it does not do, however, is to affect operational decisions by generators (except for those with negative charges, who have an additional incentive to generate at the system peak to ensure their eligibility for those charges). This is unfortunate, since there are operational costs to transmission, as well as investment costs. Indeed, as argued in section 5.2.3 above, in an optimal system, the short-run marginal cost (linked to operational costs) will equal the long-run marginal cost (linked to investment decisions), at least on average.

The ICRP methodology might be amended to send signals of the operating cost of transmission. We call this Investment Cost Related Energy Pricing – ICREP. A number of options might be thought of for precisely how it could be done. Although we have not considered it within the scope of our present study to undertake a detailed, quantified ICREP design and demonstration exercise, we set out some initial suggestions in Appendix 4.

We believe that charges based on some form of ICREP approach would be simple for generators and consumers to interpret and as easy to predict as the current ICRP charges. No significant changes to the industry's systems would be required to charge generators and suppliers on this basis, since MWh generated and supplied are already used by National Grid in calculating BSUoS charges.

Generators will take the charges into account in their operating decisions. This means, for example, that generators remote from the main demand centres will have rather higher variable costs (fuel plus the transmission charge) than similar generators located nearer to them. This is correct even in an unconstrained network, because more of the output from those generators is consumed as losses on the system, and less as useful energy. A charge which incentivises the remote generator to produce slightly less, and the local generator to produce slightly more, can thus help to minimise the total cost of generation and transmission combined. A reduction in remote output may also help to reduce the extent and cost of transmission constraints. However, a very high charge might be needed to make generators self-disconnect (or at least reduce output) while a constraint is binding. In an LMP system, these charges are set when required to resolve congestion, and only at those times – when there is no congestion, the transmission charges are much lower. In ICREP, however, we envisage transmission charges which would be stable throughout the year. Since most transmission constraints only bind for some of the time, pre-set transmission charges which were appropriate at those times would be far too high for the rest of the year. The level of MWh charges for transmission which minimise the overall cost of generation and transmission is something to be determined empirically – the charges would probably exceed marginal costs in some hours, and be lower than marginal costs in others. We suggest that a (published) modelling exercise might be undertaken once per price control period to determine the pattern of MWh charges that minimises these costs, with some mechanism adopted to facilitate both transparency and the transition between one period and the next.[31].

The MWh transmission charges would be passed on to consumers in their unit rates for electricity, and maximum demand charges would fall. As already argued in section 6.1.2 above, this may be no bad thing. Electricity users with low load factors would gain, those with high load factors would lose.

There would be an equivalent shift in the amount paid by generators, although we note that in the long term, this should be reflected in the pattern of wholesale prices. Generators with high load factors would pay more for transmission, while those with low load factors would pay less. We note that where two generators are located in an export-constrained zone, this arrangement would naturally allow them to share transmission capacity and its cost since each generator would only be paying the MWh charges when it is actually exporting power.

6.4.2 Assessment of the method

Economic Efficiency This method of transmission charging would send cost signals calculated on the same principles as the ICRP system. It is thus likely to be as efficient as ICRP in terms of users investment decisions. However, the MWh charges also send a signal for operational decisions. Our concerns regarding ICRP mainly centre around its failure to reflect operational decisions by generators, and ICREP is

[31] One example might be as follows. A constraint might be imposed that total generation MWh charges are in a fixed ratio to the zonal ICRP kW charges for generators, and all demand MWh charges are in a (potentially different) fixed ratio to the zonal demand charges. Different peak and off-peak ratios could be used if the pattern of costs varied enough to justify this. Year-to-year tariff setting would then be on the (more transparent) basis of maintaining these ratios

intended to overcome this. However, if the operational signals under ICREP were too strong, this would also lead to inefficiency, and for this reason, it is unlikely to be appropriate to recover the entire transmission cost in MWh charges.

Robustness This system would have the same advantages and disadvantages as ICRP. Charges within zones are relatively stable, but changes in zonal boundaries can have significant effects on individual generators. If some charges are related to the generator's output, this will act as a kind of insurance for low load-factor plant.

Workability This system is slightly more complex than ICRP pricing, since there would be zonal charges in £/kW and in £/MWh. It would also be possible to have peak and off-peak energy charges. Nonetheless, each generator or demand side user would face a relatively simple tariff and would not need significant changes to their internal systems.

Complexity of regulatory and legislative instruments We believe that this system would not require significant changes to industry codes and procedures.

Stakeholder support Our expectation is that this system would approximate the status quo in terms of geographical winners and losers. However, low load factor generators would be better off while charges to generators with high load factors would increase, (In time, the pattern of wholesale prices or long-term contracts may be expected to adjust accordingly.) Since we expect the system would be more efficient, there should be net reductions in costs, although these may not be in a form that allows for easy redistribution towards those who would otherwise lose from the changes.

6.5 Nodal energy pricing plus financial transmission rights

6.5.1 The basis of the approach

In most organised electricity markets in the US, nodal energy prices are set by a system operator to equal the marginal cost of electricity at each point on the transmission system in each settlement period. There are two main variations of marginal pricing in electricity markets:

- system marginal pricing;
- locational marginal pricing.

Under system marginal pricing the generator offers are stacked in a merit order, and the clearing price is defined by the intersection of this curve with the cumulative load curve, as illustrated in Figure 3. The market clearing price, or System Marginal Price (SMP), normally calculated on an hourly, half-hourly or even 5 minute basis, is then applied to all generators uniformly, regardless of their offer or their location.

As the SMP does not explicitly take into consideration transmission constraints, various rules have been developed to address this. For instance, the Pool in England and Wales first calculated the merit order dispatch without transmission constraints and set SMP on this basis of this schedule. Actual dispatch followed a second, constrained, schedule that took account of network congestion, and side payments were made to generators who had to change their dispatch. In the Scandinavian countries, the NordPool market can split into several zones when there is congestion on the borders between them, and a (potentially) separate marginal price is calculated for each zone.

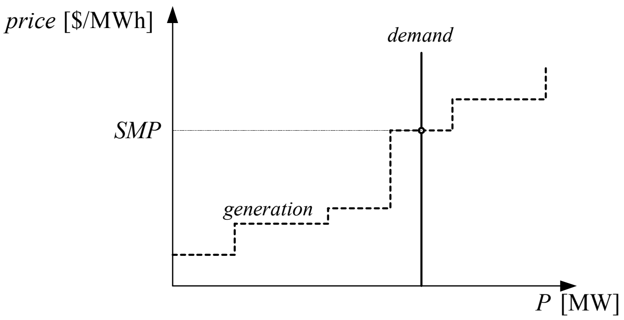

Figure 3. Calculation of SMP

The approach used in the US is referred to as Locational Marginal Pricing (LMP) and is a more complex variation of marginal pricing. As in SMP, the market administrator collects generator offers and estimates load levels (or collects load bids), and calculates the optimal generation dispatch by minimizing cost of generation (or maximizing social welfare). The difference here is that the market clearing is subject to various system constraints such as line load and voltage limits. Several of the markets also take marginal transmission losses into account, setting higher prices in importing areas because part of the power sent to them is lost in the network.

The LMP form of dispatch can be based on a full AC Optimal Power Flow, when calculated LMP prices simultaneously reflect energy prices, network losses and network congestion. However, some practical approaches to LMP calculations use simplified methods. For example, in the PJM market LMP calculations identify three components: energy price, transmission congestion cost and cost of losses. This enables a somewhat simplified three-step LMP calculation process in which each of the components is calculated separately.

While the dispatch algorithm takes account of all generation and demand, the markets run by the system operator are *not* compulsory. Generators can make their own bilateral arrangements with loads or suppliers. They must notify the system operator of their intentions, and can offer prices at which they would increase output (or reduce it), which are also used in the dispatch algorithm.

Generators are paid the locational marginal price at their node, i.e. the estimated marginal cost at that location from the dispatch model, for all the energy they sell through the centralised market. In an area subject to an import constraint, this price will be high, because high-cost local generators have to run if the constraint is to be respected. In an area behind an export constraint, the nodal prices will need to be low to discourage production and ease the constraint.

There is an obvious incentive for a generator in an export constrained area to trade bilaterally if this means that it could achieve a system-wide price, rather than the nodal price depressed by the transmission constraint. To remove this incentive, all physical bilateral transactions have to pay a transmission charge equal to the difference between the nodal prices where the power is taken out and where it is put in, which would obviously need to be specified in the contract. One or both of these might be the (notional) "National Balancing Point" (NBP) where electricity trading is currently deemed to take place. These charges on bilateral trades mean that a generator putting in power at a low-priced node will have to pay a higher transmission charge (since it is subtracting its local price, which is low, when it calculates that charge) than one sited at a high-priced node. A generator at a high-priced node would receive a transmission payment if it traded bilaterally. If the power is injected and withdrawn at the same node, no locational charge is payable. There is thus no incentive to either enter or avoid the centralised market, from the point of view of transmission charges.

Box 1 below shows how the nodal prices, and associated transmission charges, would be calculated in a simplified example.

Box 1 – An LMP example

Consider an electricity market with three nodes, 1, 2 and 3, and several generators at each. The example will illustrate application of LMP for the following situations:

- case i – operation with no transmission congestion
- case ii – operation with congestion

Case i – network with no congestion

This case is shown in Figure B1. The demands, available power and prices at which power is offered are shown in Table B1 along with it would be dispatched if there were no transmission constraints. In this case, the most expensive generator that needs to run would be Fossil 2 (shown in the darkest green shaded area of Table B1), and the market price would be £70/MWh. All the generation with a lower offer price is running, and the most expensive generation (which happens to be at node 3) is not required. The revenues received by generators and payments made by demand through the centralised market are also shown in Table B1.

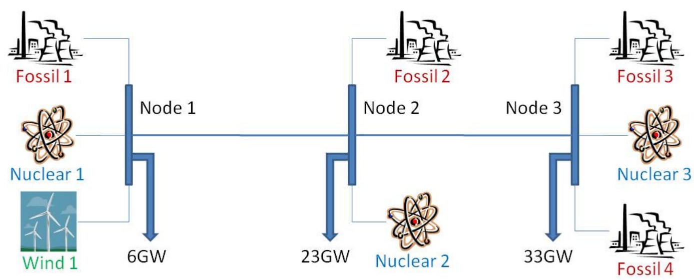

Figure B1: Three bus example in case i

Table B1: Generators, demands and Locational Marginal Prices in case i

Node	Demand (GW)	Generator	Power available (MW)	Price (£/MWh)	Unconstrained dispatch (GW)	Unconstrained dispatch LMP (£/MWh)	Unconstrained dispatch Generator Revenues (£k/h)	Unconstrained dispatch Load Pays (£k/h)
1	6	Wind 1	3	1	3	70	210	420
		Nuclear 1	2	2	2		140	
		Fossil 1	6	60	6		420	
2	23	Nuclear 2	5	2	5		350	1610
		Fossil 2	33	70	32		2240	
3	33	Nuclear 3	4	2	4		280	2310
		Fossil 3	10	50	10		700	
		Fossil 4	10	100	0		0	
Total	62		*73*		*62*		*4340*	*4340*

Case ii – network with congestion

Now consider the same demands, available powers and offer prices as in case i but also that there are in fact binding limits on transmission: only 3 GW of power can flow from node 1 to node 2, and only 13 GW from node 2 to node 3, as shown in Figure B2. Dispatch of power under these conditions is as shown in Table B2. The table shows the marginal generator at each node in darker shading. It also revenues for the generators and payments by demand through the centralised market.

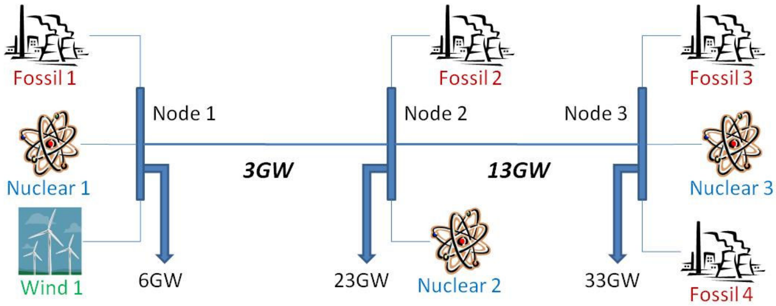

Figure B2: Three bus example showing network transfer limits (case ii)

TableB2: Generator revenues and load payments in case ii

					Constrained dispatch			
Node	Demand (GW)	Generator	Power available (MW)	Price (£/MWh)	(GW)	LMP (£/MWh)	Generator Revenues (£k/h)	Load Pays (£k/h)
1	6	Wind 1	3	1	3	60	180	360
		Nuclear 1	2	2	2		120	
		Fossil 1	6	60	4		240	
2	23	Nuclear 2	5	2	5	70	350	1610
		Fossil 2	33	70	28		1960	
3	33	Nuclear 3	4	2	4	100	400	3300
		Fossil 3	10	50	10		1000	
		Fossil 4	10	100	6		600	
Total	62		*73*		*62*		*4850*	*5270*

The demands at each node and the maximum line capacities between them mean that the system is split into three price areas.

- At node 1 where we can generate no more than 9 GW at node 1 (6 GW of local demand, plus 3 GW of export capacity). The price at this node is now £60/MWh and is determined by generator Fossil 1 as it is the marginal generator for this area (i.e. generating the next MW of power will be at the price of this generator). Compared with the uncongested case and in order to avoiding overloading the line between node 1 and node 2, this generator has had to reduce its output and the net export is lower.
- At node 2, the output from the most expensive generator (Fossil 2) has been reduced compared with case i in order that the line connecting node 2 to node 3 is not overloaded. (Power will not be exported to node 1 as it has cheaper generation). This is the marginal generator at this node; since it had also been the marginal generator in the unconstrained case, the price at node 2 has remained £70/MWh.
- Node 3 has also been affected, but in this case we must generate at least 20 GW there as it has 33 GW of local demand but only 13 GW of import capacity. This additional generation comes from the most expensive generator, Fossil 4, driving the marginal price of energy at Node 3 to £100/MWh.

From the above example it can be concluded that the transmission congestion on these two lines has had a negative impact on generators in areas 1 and 2, because of the reduced price and/or reduced power produced. It has also significantly increased the price seen by demand at node 3, which went from £70/MWh to £100/MWh. However, because of this increase, congested operation has been beneficial for all generators at node 3.

The effect of congestion on case flows

As can be seen from Table B1, in the uncongested case (case i), generators would receive a total of £4.34 million for an hour's operation. It can also be seen that the total revenues of generators are equal to the total payments of all loads.

When there is congestion (case ii), generators and demand will face different prices at different nodes. For example, at node 1, all of the 9 GW of scheduled generation receives £60/MWh; at node 2, the 33 GW of scheduled generation receives £70/MWh; and at node 3, the 20 GW of scheduled generation receives £100/MWh. As can be seen from Table B2, consumers would pay a total of £5.27 million, which is above the value of £4.85 million received by generators. The bill for consumers is larger because relatively more demand is located in the node behind an import constraint, where the price is higher. The difference between the amount paid by consumers and the amount received by generators is £420,000. This difference is called the Merchandising Surplus and could be kept by the transmission owner as a contribution towards its costs. (Other transmission charges would be reduced to offset this.)

Bilateral trading in an LMP system

The use of LMPs does not mean that all power has to be traded through the spot market. At the other extreme, consider a case where all trading takes place bilaterally. In this case, generators submit adjustment bids to the system operator that it uses, where necessary, to re-dispatch generation to balance the system and respect transmission limits and to set the LMPs (Galiana 2002 and Kockar 2002). Where there is congestion and there are differences in locational prices at some nodes, the parties to bilateral trades need to make additional payments to the system operator for its provision of network capacity and ancillary services. These are typically based on the nodal price difference between the node where seller is located and the node where the buyer is. (If there was no congestion between these two nodes, the additional payment to the system operator would be zero).

Figure B3 illustrates the cash flows of the revenues and expenditures in a market in which there is both a centralised market and bilateral trading.

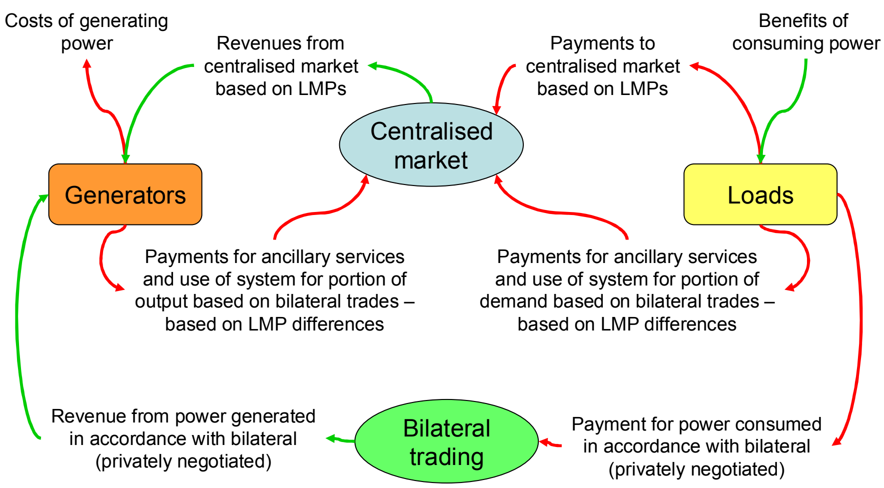

Figure B3: cash flows in an LMP system

To illustrate the effect of bilateral trading, assume that in case ii of the previous example, generators at node 1 have bilateral contracts with demand at node 2. They will be required to pay a transmission charge of $LMP_2 - LMP_1$ = £70/MWh – £60/MWh = £10/MWh to move their power from node 1 to node 2 where LMP_1 is the LMP at node 1 and LMP_2 is the LMP at node 2. Suppliers at node 1 who have bilateral contracts with generators at node 2 also "pay" a transmission charge – the cost of moving power from node 2 to node 1 – which is *minus* £10/MWh ($LMP_1 - LMP_2$ = £60/MWh – £70/MWh = -£10/MWh). Thus, they receive a payment from the system operator because their bilateral trade is causing counter flows.

Generators at node 3 are in a similar position: the cost of moving power from node 3 to node 2 is minus £30/MWh (the price at node 2, £70/MWh, minus the price at node 3, £100/MWh). If a bilateral contract involves generation and delivery at the same node, no payment is required; if a generator at node 1 sold to a supplier at node 3, a payment of £40/MWh would be imposed. Any set of bilateral trades that turns out to be feasible, i.e. no transmission constraint is breached, will have the net effect of moving 3 GW from node 1 to node 2 (at a cost of £10/MWh) and moving 13 GW from node 2 to node 3 (at a cost of £30/MWh). The total cost to the bilateral traders is thus £420,000 an hour, which is exactly the same as the congestion rent (Merchandising Surplus) that the system operator would receive if all trading took place in the centralised market.

In reality, the original set of bilateral trades may not be feasible, and then system operator will have to trade in the balancing mechanism, buying additional power in import-constrained areas and selling power on the export side of constraints until flows fall to acceptable levels. It is actually these trades that would set the LMPs and hence the transmission charges for the remaining bilateral trades. The Merchandising Surplus from trades in the centralised market and the transmission charges from (all the originally scheduled) bilateral trades would still come to £420,000.

One key feature of the nodal markets in the US is that they are fully compatible with a high level of physical bilateral trading. In 2009, 13% of the real-time load in PJM was met by bilateral contracts and 70% by self-supply (generators owned by the company selling the power to customers) although some of this may have been traded through the spot market. Generators with a bilateral contract can submit adjustment bids that allow the system operator to change their output level through spot market sales or purchases – just as British generators can do in the Balancing Mechanism. Generators that do not wish to change their output for any reason submit adjustment bids at such extreme prices that they will almost never be called – although these generators will therefore miss out on some profitable opportunities.[32]

Most of the organised US markets have a day-ahead market, where most power is scheduled, and a real-time market, where payments are based on the differences between the results of the day-ahead market (and bilateral transactions) and what actually happens in real time. The real-time market is thus based almost entirely on adjustment bids, just like the Balancing Mechanism in Great Britain. Prices in the real-time market are more volatile than those in the day-ahead market, however, since only a relatively small amount of flexible plant can respond to unanticipated changes in demand or in the output of other generators. Nonetheless, in principle, National Grid could use the bids and offers it receives in the Balancing Mechanism to calculate the marginal cost of power at each point on the GB electricity system. These nodal marginal costs would be used to calculate transmission

[32] For example, a generator with a marginal cost of £40/MWh might have sold its power in advance at some price above this level. If the wind in its area suddenly rises, the locational price might fall to £30/MWh as there is a surplus of generation and some generators need to be persuaded to sell less power. Our generator has the opportunity to reduce its output, saving £40/MWh in fuel, and to spend only £30/MWh in buying back the power it has pre-sold (or, equivalently, paying someone else to generate on its behalf). If the generator had not submitted an adjustment bid, or had submitted a bid of (say) minus £500, it would not have been called, and would have forgone a profit of £10/MWh for the amount it reduces output. However, the generator would be sensible to submit a very negative bid (requiring a sizeable payment) for any output reduction that forced it to stop generating completely and incur the cost of starting up again later.

prices. It might be appropriate to use locational marginal pricing, rather than the current pay-as-bids system, to remunerate actions in the Balancing Mechanism. The main imbalance prices, however, could still be calculated in the same way as present, if desired. Other key features of the UK market, such as the physical nature of bilateral contracts, could be retained (Galiana 2002 and Kockar 2002), as well as the relatively late time of the gate closure when trading ends, which is more suitable for renewable generators that have generally uncertain output.

National Grid would then set transmission prices for every node, relative to the National Balancing Point, based on the difference between these nodal marginal costs. These prices would be paid by all bilateral trades and imbalances. Since the prices offered and bid in the Balancing Mechanism are used to calculate the transmission charges, the transactions accepted in the BM would not have to pay an additional transmission charge – the charges are implicit in their individual prices. This system would retain national prices for energy and the voluntary nature of the Balancing Mechanism, key features of the current arrangements.

Electricity spot prices are inevitably volatile over time, but locational marginal prices can also be geographically volatile – when a transmission constraint binds, the prices on either side can diverge sharply. Just as volatility over time can be hedged by selling forward (using a physical forward contract or a contract for differences, depending on the nature of the spot market), Financial Transmission Rights allow market participants to hedge geographical variations in prices (Box 2). For a fixed amount of power, the holder of an FTR between two locations is entitled to receive the difference between their prices. If the FTR covers trades that put power into the system at A and take it out at B, then the payment (per MW of the FTR, per hour) will be the price at B minus the price at A. In many cases, one of the two points in the FTR is not a physical location but a "trading hub", which is also used for trading energy. In PJM, the hub prices are weighted averages of the LMPs in an agreed area. In Great Britain, FTRs might be written against the same notional "National Balancing Point" (NBP) where electricity trading takes place.

A generator can acquire an FTR between its own location and the NBP, so that if congestion means its own price is low, it will receive a top-up from the FTR. A trader who is selling power into a city across an import constraint which sometimes binds will occasionally have to pay a large transmission charge to do so. Once again, an FTR which covered this trade would compensate the trader for that charge, since the payment under the FTR rises with the price at which power is taken out of the system. A generator which sells to a supplier in the same area will not generally need an FTR, since the (locational) transmission charge paid by the supplier will be the negative of that paid by the generator, and the two will thus cancel out. If a generator sending power to the NBP simply sells the amount of power covered by the FTR, then the locational part of its revenues is hedged exactly – and a contract to sell energy at the central point could hedge this price, too. However, the FTR payments are independent of the generator's actions (for a given set of market prices). This means that if the price at the generator's site is too low, it may be more profitable for the generator to reduce output, cheaply buying its power back from the system operator. The generator thus faces the correct incentives to respond to system conditions at its own location. If it chooses not to do so, the forward contract and the FTR have locked in its revenues, but if it does respond, it can only increase its profits.

The transmission company also gains from selling FTRs. Part of its income will come from the volatile differences in LMPs, but the FTRs will hedge these price differences. As long as the FTRs that the company sells are feasible – they represent a pattern of power flows that the network could actually accommodate – then any payments that the company makes under the FTRs should be offset by payments that it receives from transmission charges.

Some FTRs will involve net payments, on average. If an FTR covers a power flow from a generator in an export-constrained zone, where prices are typically low, its owner will receive compensation via the FTR payments. Typically, such FTRs would be auctioned, and the prices paid for them would reflect the expected payments. However, if a new transmission charging system meant that some generators would be financially disadvantaged, FTRs could be given to them without payment as a form of compensation. The generators would expect to have to pay transmission charges to move their power from an export-constrained area to the main market, but would receive payments exactly equal to the charges they would face for some preset level of output. This would compensate them, but they would still face the correct (i.e. low) net price for generating at those times, since their FTR payments are fixed but the actual transmission charges they face are based on output.

Box 2: Financial Transmission Rights – an example

We continue with the example from the previous box. The level of output from the wind generator at node 1 depends on the strength of the wind, of course, and if there is no wind, then the fossil and nuclear generators at that node would be able to send their full output (net of the local demand) to node 2 without breaching the transmission constraint. This means that the nodal prices at both node 1 and node 2 would equal £70/MWh. If the wind generators are able to run and there is congestion, the price at node 1 would fall to £60/MWh. While nodal prices that reflect system conditions in this way are good (by design) at sending signals of the desirable pattern of operation, they are also volatile.

Case ii in Box 1 showed that with 3 GW of wind output at node 1 and a constrained line between nodes 1 and 2, the price at node 1 was £60/MWh, £10/MWh below that at node 2 (£70/MWh). Generators at node 1 selling through a centralised market would thus receive £10/MWh less than if they were at node 2, while generators making bilateral trades would have to pay £10/MWh (£70/MWh - £60/MWh) for the transmission service. However, the differences between LMPs can be volatile, exposing the generator to risk. To hedge against this risk, in most LMP-based markets it is possible to obtain Financial Transmission Rights (FTRs). These are the instruments which entitle their holders to collect a payment (for each of a specified number of MWh) that is equal to the difference in LMPs between two specified nodes. They work both in the case of energy being traded centrally and in the case of it being traded via bilateral contracts.

If the generators are trading bilaterally, they can acquire an FTR that pays out the difference in prices between the two nodes in their bilateral contract, and hence hedges their transmission charge (equal to this price difference). If a generator is trading in the centralised market, it can hedge general fluctuations in the price of power at some "hub" location (such as a 'national balancing point', NBP), acquire an FTR between the price at its own location and this hub. The combination of the general hedge and the FTR hedges the actual, location-specific, price received by the generator.

Generators at node 1 selling their power into the centralised market could acquire FTRs from node 1 to node 2: each MW of FTR entitles its holder to a payment equal to the price at node 2, less the price at node 1. With 3 GW of wind output at node 1 and a congested network as in case ii, this payment to the FTR holder would be £10/MWh (£70/MWh - £60/MWh) multiplied by the quantity in MW and the duration of the trading period in which those prices apply. That is, if a wind farm at node 1 acquires an FTR for 3GW between nodes 1 and 2 in case ii, it would be entitled to a revenue of £10/MWh × 3,000 MW = £30,000/h.

The generator is now exposed to fluctuations in the price at node 2, rather than at its own node 1. However, if enough market participants are exposed to the same price, then a market can develop to hedge it. In PJM, hedges are available for the "hub" price (an average across a wide area); in Great Britain, energy hedges are available for trading against the NBP price. It would therefore be sensible to write FTRs in terms of this price. (It would be necessary to define the geographical location of the NBP in order to do so, but contracts can be written in such a way that the choice of location is financially irrelevant – it changes the balance between generation and transmission prices, but not their sum, at any node.)

For a case in which the wind farm wants to sell its energy via a bilateral contract, recall that it would also have to pay a fee for use of the system to facilitate that trade, the fee being equal to the difference in LMPs at the selling and buying nodes involved in the bilateral contract, multiplied by the level of the energy transfer for the trade. In this case, if the wind farm generates and sells 3 GW of energy at node 2 with a bilateral contract, it will have to pay (£70/MWh - £60/MWh) × 3,000 MW = £30,000/h. This is the same as the revenue this generator would collect from its 3GW FTR. Therefore, in the case of it selling its energy via a bilateral contract, if the generator actually generates the amount of energy for which it has FTRs, its payment for the transmission service would be equal to its FTR revenue, and it would be completely hedged against the difference between the LMPs. If there was no wind output in zone 1 and the price was equal to that in zone 2, there would be no payment under the FTR in that hour. In other words, holding the FTR means that the generator at node 1 is exactly compensated for the transmission charges it needs to pay when trading bilaterally.

Note that the payment under the FTR is determined (for given electricity prices) regardless of what the generator did. This means that the marginal revenue received by generators at node 1 for selling an extra MWh of power will equal the market price there (or the system-wide market price, less the transmission charge to move power from node 1 to node 2 in the case of a bilateral trade) and that price can be used to send signals to those generators. Since the generator should be expected to produce all the power for which the marginal revenue exceeds its marginal cost, sending accurate price signals should give optimal results.

Note that if the system operator issues a set of FTRs that are feasible, in the sense that the power flow they imply could be accommodated by the network, then the revenue to the system operator from transmission charges will be sufficient to cover the FTR payments. The net allocation of 3 GW of FTRs, however, could well consist of 9 GW of FTRs from node 1 to node 2 for generators at node 1, together with 6 GW of FTRs from node 2 to node 1 for suppliers. The latter imply the opposite payment to the generators' FTR (i.e., the price at node 1 minus the price at node 2) and thus require the holder to *pay* the system operator whenever the price at node 1 is below that at node 2, as in our example. With a price difference of £10/MWh, generators holding 9 GW of FTRs from node 1 to node 2 would be paid £90,000 an hour, funded by £60,000 per hour of FTR payments from suppliers holding FTRs from node 2 to node 1, and £30,000 per hour of congestion rents. The FTRs can thus ensure that practically all parties – those generators able to sell power, suppliers and the system operator – are hedged against differences between the LMPs. Generators who do not hold FTRs will not be hedged, however, and in a situation with congestion (and hence more generators behind a constraint than can be accommodated) there may well be a mismatch between actual generation and FTR holdings.

In many US markets, FTRs are auctioned to the highest bidder, at prices which reflect the payments the holder expects to receive. The revenue from the auction effectively replaces the revenue that the transmission company would earn from congestion rents. However, lines that are nearly always congested will see their FTR prices reach the price of the congestion rent. It is possible, however, to allocate FTRs without requiring a payment in exchange. In this case, the transmission company would need a source of funds to make the payments due under the FTR (such as a general increase in its charges) but allocating FTRs in this way allows generators and suppliers to be compensated for a change in the transmission charging system that would otherwise worsen their situation.

One key question concerns how the prices for FTRs are set. In the US, FTRs are mainly auctioned to market participants. In Britain, entry rights for gas transmission have been auctioned. The potential problem with an FTR auction, however, is that in the early years (at least) market participants would have very little information as to the true value of an FTR. In due course, histories of locational electricity price differences would become available, and bidders could use this information to assess an appropriate price to offer for an FTR. At first, however, there is a significant danger that market participants, and particularly smaller participants, could end up paying too much for an FTR, or alternatively fail to secure one and face excessive price volatility from unhedged LMPs. This will be a particular problem for lines that are nearly always congested, which will see FTR prices converge towards the congestion rent[33]. In this situation, the danger that FTR auctions will see generators paying an excessive risk premium is particularly acute, as it will be difficult to predict when the congestion will not occur.

An alternative model, which may be particularly attractive as part of a transition process, is that users should receive FTRs in exchange for paying fixed annual transmission charges to the GB System Operator. These charges could be set according to the current ICRP approach, or following a reformed version as described above. The system could be calibrated in such a way that most users would see no change in the total that they paid for transmission. If they acted in the same way as at present, generators in an export-constrained area would suffer an implicit LMP-based transmission charge during the year arising from the difference between the (higher) price at NBP and the (lower) price at their location, for those hours in which they were generating. However, in return for paying TNUoS, perhaps calculated by ICRP as at present, they would receive the difference between the NBP price and their locational price for the hours covered by their FTR. For a baseload generator that continued to run in every hour of the year, the payments received under the FTR would exactly offset the penalty of the lower location price they received for their energy. However, the FTR payments are fixed, and so the generator's operational decisions should be based solely upon the local energy prices. This sends an accurate signal of the true value of the generator's output and should lead to efficient decisions.

In the above arrangement, the allocation of transmission entry capacity (TEC) and the liability to pay annual TNUoS charges can be seen as being analogous to the allocation of FTRs and the liability to pay for them. One difference is that system users have the choice of whether or not to buy FTRs and how many of them to buy whereas TNUoS is compulsory. Arguably, the analogy was stronger under a previous charging regime in Britain in which connection charging was deeper than it is now. Then, there was some incentive for a new electricity user to choose a simpler, cheaper connection design than that required under the Security and Quality of Supply Standard, provided no other user was adversely affected by the choice. However, the connectee would not have firm access rights and would therefore not be entitled to compensation for loss of access when the network has an export constraint.

Various reforms to arrangements for access to the GB electricity transmission system have been proposed that come very close to different ways of managing the allocation and pricing of FTRs. Some of these proposals are briefly discussed in section 7.5.2. It could then be argued that the key difference between a charging approach based on LMP+FTR and what might be in place in Britain after reform of access would concern the trading arrangements. These are briefly discussed in section 7.5.1.

6.5.2 Assessment of the method

Economic Efficiency LMPs and the associated transmission prices are the most efficient system of charging for transmission, reflecting the actual state of the electricity system and its associated short-run marginal costs. If the transmission companies

[33] In PJM, FTR prices for some lines that were often congested increased significantly in the last auctioning period.

undertake the appropriate investments, these short-run marginal costs should also be a good approximation of the long-run marginal costs of transmission, at least when the former are averaged over time. As discussed earlier, this long-run marginal cost will be less than the average cost, and so some top-up will be required – as with all the methods described here.

Robustness Individual LMPs and the associated transmission charges can sometimes change significantly in response to seemingly small changes in system conditions. However, each price only lasts for a single hour. The individual prices can also be hedged with FTRs. However, if a change in system conditions means that prices at a node will be consistently higher or lower by significant amounts (which can happen[34]) and FTRs are auctioned, then the price of the FTR will change to reflect the expected impact on the node's prices, and market participants will not be able to hedge this risk beyond the lifetime of the FTRs they currently hold. There is also the danger of generators paying an excessive risk premium for their FTRs.

Workability This system is potentially the most complex for industry participants, as they (potentially) have many prices to keep track of. Computer systems would have to record the location of each generator and its associated prices or transmission charges, and contracts would have to be rewritten to reflect the new rules. However, similar markets have been operating successfully in the US for over a decade, and so the systems required to implement them are well-known[35].

Complexity of regulatory and legislative instruments This system would require significant changes to industry codes and procedures, but because US models could be adapted, the industry need not start with a blank piece of paper.

Stakeholder support We suspect that many stakeholders would resent the additional cost of implementing a system of this kind. It may involve stronger signals of the cost of transmission than are currently sent, and would thus tend to disadvantage northern generators and southern consumers. The value of the hedge provided by purchase of FTRs may be difficult to predict and would therefore tend to favour those market participants with greater resources to carry out detailed modelling and those with greater experience of the operation of the GB electricity market. However, if FTRs were allocated to compensate transmission users in return for tariff payments that are close to current levels, this might well dilute their opposition.

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[34] One example of a significant change would be that brought about by a reinforcement to increase the transmission network's power transfer capability. Normally, such a reinforcement would be signalled well in advance though, for example, the Seven Year Statement. However, major transmission reinforcements are subject to uncertainty both in the granting of planning permission and, according to current practice, regulatory approval for the transmission owner to be able to recover the cost. In a set of arrangements in which net congestion rent and the revenues from sale of FTRs are meant both to indicate the need for transmission reinforcement and to fund it, significant complexities can be foreseen.

[35] As a counterpoint to this observation, it might be noted that transition to locational marginal pricing (with financial transmission rights) was considered around 2005/6 for the National Electricity Market in Australia. However, the proposed reform was not taken forward largely in light, as we understand it, of concerns about the total IT cost and revenue adequacy in respect of sale of FTRs and compensation given to holders.

7 Discussion

7.1 Introduction

In this section, we present a comparison of the main models outlined in section 6 in the context of against the assessment criteria presented in section 4.

We regard the ultimate objective of a set of electricity trading and transmission arrangements as being to:

minimise the total cost of electricity in both the short and long-term

subject to

- meeting the 2020 renewable energy targets;
- achieving at least a certain minimum level of reliability of supply.

Thus, we also express our views on the ability of each main charging models to contribute to the minimisation of the cost of electricity and the extent to which it might jeopardise the meeting of the 2020 renewable energy targets or the achievement of a certain level of security of supply. However, we note that a wide range of factors influence both the objective and the meeting of the constraints while only transmission charging arrangements are within the scope of our review. In addition, the approaches described in section 6 above are only a few of the possible approaches – others that we have not discussed might be judged to fit the overall objectives and constraints better though, for many of them, there is likely to be little practical experience. Furthermore, there are a number of details of implementation of the main approaches described in section 6 that can materially affect the outcome relative to the objective and constraints set out above. We do not seek to resolve those details here.

Before starting the discussion of how each model seems to perform with respect to the main objective and constraints, we recall our first high level principle and note that, hitherto, the extent to which consumers of electrical energy can or do respond to different signals about location is limited. The most significant recipients of signals are therefore generators. In the short-term, they can affect the way that existing generation is utilised. In the long-term, they can affect investment in new generation capacity, both its type and its location. In light of the two constraints expressed above – on renewable energy targets and security of supply, it would be useful to recall other influences on generation investment. These have been described by Oxera on behalf of Scottish Power as including (Oxera, 2010):

- the ability to gain Section 36 planning approval;
- local public acceptance of the proposed development;
- proximity to the electric power network and cost of connection to it;
- for fossil fuelled plant, access to fuel such as via the gas transmission network;
- for thermal plant, availability of cooling water;
- land availability and cost;
- for future CCS plant, proximity to CO2 transport and storage facilities;
- impact on local flora and fauna; and
- availability of labour.

To the above might be added, for wind farms, the local average wind speed and visual impact of an energy conversion facility. For generation of all types, we might also note that some of the most significant potential investors are international companies that are likely to judge the attractiveness of investment in generation in Britain in comparison with that in other countries. In all cases, however, the investors will aim to resolve the different influences and the available financial support for low carbon generation in a way that maximises their return.

7.2 Contribution to minimisation of the cost of electricity

7.2.1 Cost-reflective signals as an aid to coordination

To minimise the total cost of electricity, including that of 'production' and 'transport', it seems reasonable to us that signals should be expressed that attempt to coordinate choices of location for generation with those for development of transmission and, as argued in section 3 above, those making decisions should be exposed to their consequences. In a transmission charging context and in order to encourage a minimisation of the overall cost of electricity, this depends *both* on appropriate and accurate 'cost-reflective' signals being given to network users *and* on those users having an opportunity to respond to them. The influences are illustrated in Figure 1 in section 2.3. (As has already been mentioned in relation to the demand side and will be discussed in section 7.3 below in relation to the generation side, network users do not always have this opportunity).

Of the four main methods outlined in section 6, postage stamp pricing performs least well in this respect as it sends no signals that would lead to minimisation of the cost of transmission as part of the overall cost to consumers of electricity. Worse, it may send signals that would drive up the overall cost of electricity as a consequence of new generation capacity connecting in parts of the transmission system that are export limited[36]. In the short-term, this will lead to increased costs; it seems to us that these are most likely to benefit fossil fuelled generation, which seems a perverse outcome if the intention of a postage stamp approach is to encourage development of renewables. (We observe that these cost implications are also true of the UK government's 'connect and manage' policy). In the longer term, it should be possible to limit the level of constraint costs by investment in appropriate additional transmission capacity, but this also has a cost.

The other methods all provide signals that ought to contribute to the minimisation of the cost of electricity. Many academic authors have argued that locational pricing of electricity would bring about the greatest economic efficiency (Hogan, 1992; Brunekreeft, 2005). In respect of short-run signals and with adequate liquidity in the market this is likely to be true. The opportunity for incumbent or future generators to exploit export constraints would be reduced and any attempt by 'must run' generators in import limited areas to exploit their situation should lead directly to network reinforcements[37]. Differences in prices between locations ought to signal appropriate resolutions of production costs and transmission costs, network

[36] In theory and as consequence of an increase of transmission charges in importing areas, another outcome might be to help bring forward the closure of generation in those areas and either put security of supply in those areas at risk or else increase constraint costs as a consequence of increasing dependence on a few 'must-run' generators for long periods.

[37] We are not sufficiently aware of the industry situation in parts of the US where LMP has been implemented to say if high locational prices driven by import constraints have led to investment in additional transmission capacity to give consumers in those high price areas access to cheaper electricity generated elsewhere.

losses (in the short-term) being an important part of the latter. However, the effect in the longer-term would depend on the degree to which differences in short-run prices would influence decisions on location of new generation and investment in additional transmission capacity to give expensive locations access to power at cheaper locations.

7.2.2 Uncertainty and accuracy

One of the main anxieties about locational pricing of energy is the variability of prices and the difficulty of forecasting them and hence of driving 'correct' responses to them. It has been argued that uncertainties around locational prices can be offset by market participants buying FTRs which have the effect of compensating for short-run differences in prices (or transmission charges) between locations. However, whatever the computational tools that might be available to market participants and the party responsible for making FTRs available (usually the System Operator), there is still some uncertainty about how many FTRs should be made available (usually for auction) as the actual transfer capability varies through the year and, for market participants, how many they should buy and at what price. Judgement is required to answer these questions (or to define a mechanistic approach to answering them) and it is usually the case that uncertainty brings with it higher costs.

The need for quite sophisticated analysis and decision making would seem normally to favour larger market players over smaller ones, although it might be argued that 'aggregators' might help groups of smaller players to manage their risks. Moreover, large companies with market power may be able to manipulate prices in a system based on LMPs, just as they have exploited transmission constraints under non-geographical pricing in Great Britain (Offer, 1992). Under an LMP system, generators behind an export constraint may be careful to offer so little power to the market that the constraint does not bind, and their price does not fall to the level which the constraint might suggest. Under uniform pricing, generators may attempt to schedule large amounts of power to flow across a constraint, and then refuse to buy it back except at a very low price. Green (2007) found that a system of geographically differentiated prices was less vulnerable to market power than a uniform price, but we do not regard that paper to be the last word on the subject.

The comparison between LMP and uniform pricing exposes differences between the way in which a set of locational marginal prices reveals the 'cost' of a transmission constraint and the way in which it is revealed under Britain's current trading arrangements. It could be asked which gives the truer reflection of the 'real' cost of constraints, something which is very important to the overall electricity cost not only because consumers, in the end, pay the cost of constraints, but also because the apparent cost of constraints will be used in determining the level of investment seemingly needed for additional transmission capacity and because income from a variety of balancing services might be finally make the difference to a generator's overall commercial viability.

As will be discussed briefly in section 7.5.1, the two sets of trading arrangements differ in a number of important respects, and all must be considered when evaluating the overall effect. However, the timescales over which prices are set are also important. In the GB balancing mechanism, the set of 'final physical notifications' is revealed only an hour before the start of the trading period to which they relate. Unless the system operator has been able to make some forecasts and to strike 'pre-gate' or availability contracts, they and the generators that are the main contributors to balancing actions therefore have little time in which to act. It could therefore be argued as being inevitable both that actions to increase generation have much higher prices than actions to decrease output as they are much more costly to effect (especially at short notice)[38], and that 'offer' prices exhibit significant volatility[39].

The attempt to schedule large amounts of power across an export constraint and offer only very low – or negative – prices to buy it back is known as 'the dec game' and it might be supposed that it can be played, for example, on the northern side of the 'Cheviot' constraint in Britain. However, it might also be worth noting that most of the cost of constraints is for the replacement energy (through accepted 'offers', which typically range between £25/MWh and £180/MWh) to balance an output reduction action (effected through accepted 'bids', typically ranging between £5/MWh and £50/MWh) (National Grid, 2009)[40].

It has been noted above that overall economic efficiency depends both on signals of cost implications being given to inform actions and the opportunity for actors to respond to them. It is obviously important that the signals should be accurate in their reflection of costs. In this respect, it was noted in section 6.2 that, largely because of changes in the drivers for the main enhancements to capacity of the main interconnected transmission system, the simple long-run approach used in the present TNUoS methodology is not entirely accurate. In principle, more refined long-run approaches should be more accurate though, depending on the details of their implementation, the derivation of cost signals can be highly complex and highly dependent on a forecast of the generation and demand 'background'. An approach based on LMP, while theoretically accurate in reflecting on trading of electrical energy the impact of lack of transmission capacity, is also complex and is influenced by many factors; how network users respond to signals, in terms of acquisition of FTRs and selection of locations for new power generation facilities, depends, it seems to us to a greater extent than the other methods, on the quality of their own analysis, judgment and their attitude to risk. Moreover, as has been noted above, LMPs seem not to be immune to the problems associated with lack of competition in particular areas of a power system.

7.2.3 Who pays charges?

It may be recalled (a) that one purpose of transmission charging is to provide signals to transmission users regarding location (the other being the recovery of reasonable costs) and (b) that much demand for electricity is relatively unresponsive to price signals, particularly in respect of location. On the other hand, generation does seem to be sensitive to locational signals. That would seem to indicate that transmission charges should be levied only on generation – in order to influence generators' investment and operational decisions – and not on demand. However, there are some classes of demand that one would expect would be

[38] Nuclear and wind would generally be expected to be dispatched at their maximum available outputs and would therefore have no headroom for increments of power. However, reductions in power for these may be very expensive. For nuclear stations, it may be very difficult and time-consuming to subsequently increase output again, and this would likely be factored into 'bid' prices. For wind, reduction in output would entail loss of income from, under present industry arrangements, renewable obligation certificates. This, too, would be factored into 'bid' prices.

[39] One of the arguments presented in Ofgem (2010) for introduction of a capacity mechanism is that these prices are not high enough.

[40] In National Grid (2009), it is noted that a bid price for reduction of wind output of -£450/MWh is being assumed for constraint cost forecasting, i.e. the system operator should pay the wind farm operator £450 for each MWh of reduced output. This figure might be compared with lost income from inability to register output for Renewable Obligation Certificates, which are typically worth around £50/MWh.

sensitive to locational signals (industrial demand, in particular) and there is the prospect of greater demand side response in future; there is no overwhelming reason that we can think of why future demand side response should not have a locational element and be exposed to the cost implications of decisions. In other words, both generation and demand should face a locational element in their transmission charges. However, as we have already observed in section 6.1, locational elements of charging or pricing generally do not succeed in recovering the total cost of the network. This is equally true of the locational element of present day TNUoS and of the 'congestion rent' accruing to the system operator from a system of locational marginal prices. Some additional charge should be levied and, as suggested in section 6.1, this might be done on a 'postage stamp' basis and be levied exclusively on demand since all charges will eventually find their way through to a bill for consumption anyway.

One final cost implication concerns the impact on trading electricity between countries. If one country only charges consumers for transmission, then wholesale prices that reflect generators' costs will be lower than in a second country which splits transmission charges between consumers and generators. With higher costs, the generators have to recover these through higher wholesale prices. This would place them at a competitive disadvantage when it came to trading power with the first country. This could distort trade flows, so that the country which charged its generators for transmission would tend to import more power, and export less, than if both countries recovered the entire cost directly from consumers. The circumstances of individual country pairs would determine whether such a distortion was in fact economically significant. In some cases, charges for using the interconnector between the countries might offset the different treatment of transmission costs, although we note that such charges would have to be consistent with EU policy. Alternatively, in order to minimise distortion of power flows due to different components of the cost of electrical energy and its transport being levied on generators in different countries, transmission charging in each country – including Britain – might be designed so that the total charge levied on generators was zero. However, this need not be the same thing as saying the charge for each and every generator will be zero; rather, because locational signals remain important, some charges would be negative and some positive so that the average – and the total recovered from generators – is zero.

7.3 Effect on meeting renewables targets

The key consideration in respect of the renewables targets and the impact of transmission charging arrangements is whether those arrangements would make investment in renewable generation capacity so difficult or unattractive that insufficient volumes would be delivered by 2020. Up to 2020, we expect the majority of the new capacity to be in the form of wind farms. Achievement of the 2020 targets would be adversely impacted if the locational transmission charging differentials were so large that

a) investment in wind generation in what, in other respects, would be the most attractive locations is made commercially unviable by the cost of access to and use of the transmission system; and
b) investment in wind generation in other locations is made commercially unviable by the low load factors of those locations and the consequential impact on revenue from sale of energy, presentation of Renewable Obligation Certificates or, depending on the outcome of Electricity Market Reform, income from feed-in tariffs, or

c) development of wind generation in other locations is delayed or prevented by, in particular, difficulties in gaining planning permission.

Without detailed, quantified analysis (which is outside our present scope), it is very difficult for us to judge precisely the consequences of the main different transmission charging approaches in respect of the above. Nevertheless, it might be judged that, of the four main approaches outlined in section 6 and given that the best wind resources tend to be remote from the main demand centres in Britain, a postage stamp approach would seem to be the most benign in respect of the risk of breaking the renewables target constraint. However, that is not the same thing as saying that the others *would* cause it to be broken.

Without access to commercially sensitive data and with our own analysis of the viability of generation projects being outwith the scope of the present project, it is hard for us to judge the material effect of the locational tariff differences on generation investment. Connections of wind farms, and applications to connect, in the more expensive parts of the network are still taking place (National Grid, 2010c). At least one wind farm project has been said to have been abandoned by its developer as a direct consequence of high TNUoS charges, and another by the combination of TNUoS charges and 'final sums liabilities' (SSE, 2010), although we also understand that the former was bought by another developer. Moreover, that particular project was on Orkney and would have required a new undersea cable connection to the Scottish mainland. If the TNUoS tariff on Orkney was significantly higher than that in TNUoS tariff zone 1 ("North Scotland") and correctly reflected the cost of the cable, the load factors on Orkney were similar to those at feasible sites in zone 1 and all other things were equal, then we would argue that a correct signal was sent. Otherwise, whether the connections and applications to connect are fewer than would otherwise have been the case is impossible for us to say.

As mentioned, detailed analysis would be required to be able to comment with confidence on the relative effects of the three main cost-reflective methodologies on the meeting of renewables targets. However, it seems to us that an approach that is more complex will be more of a deterrent to investors than one that is simpler, and one that provides greater certainty of charges will be better than one with less certainty. This would seem to indicate a preference for simple long-run pricing such as in the present TNUoS methodology. Furthermore, it should be noted that different instruments are already used to offset apparent cost disadvantages of one technology with respect to another if doing so is consistent with wider energy policy. In principle, such extra support might be extended to particular locations to ensure that projects that wider energy policy considerations seem to indicate are required remain economic. This is discussed further in section 7.6 below.

7.4 Effect on security of supply

'Strong' cost-reflective pricing is what the principle of economic efficiency and minimisation of the total cost of electricity would seem to require. It has been noted above that that might cause problems for the meeting of renewables targets if the only sites that can developed are in locations at which transmission charges (and other costs) are so high that developments are no longer commercially viable. However, if required, those negative effects might be counteracted with stronger support measures for renewables (or, indeed, other low carbon plant).

It might be expected that strong cost-reflective transmission pricing would also deter investment in fossil fuelled generation in locations remote from the main demand centres. For the foreseeable future, such plant is likely to remain extremely important to 'security of supply'; thus, cost-reflective, locational pricing might be argued to put security of supply at risk.

One scenario that might be envisaged would involve existing coal plant in the north of Britain being only marginally viable commercially so that the locational disadvantage it faces by virtue of cost-reflective transmission charging is enough to persuade its owners either to retire it immediately or decline to invest in life extension. With a squeeze on plant margins already anticipated (DECC, 2010d), this would seem to make a bad situation worse as far as security of supply is concerned. However, another scenario might be envisaged: postage stamp transmission pricing would reduce the locational advantage for fossil fuelled plant in the south enough for them to cease to be commercially viable so that their owners either retire them or decline to invest in life extension.

Either of the above scenarios would seem to be bad for security of supply. However, it should also be noted that the UK government is proposing to establish a mechanism for contracting with generation to provide sufficient capacity to meet some target plant margin (DECC, 2010d). This may be expected to counteract an adverse transmission charging effects. Moreover, it is suggested in DECC (2010d) that such a capacity mechanism may have a locational element to recognise the different value different amounts of generation capacity have in different parts of the network due to finite limits on power transfer capabilities. Thus, whatever is gained (or lost) by peaking plant in respect of a non-locational (or locational) transmission charging arrangement may be taken away (or gained) by a locational capacity contracting arrangement.

In practice, the contribution to security of supply of peaking generation in the areas remote from demand depends on there being sufficient network capacity for it to be used. Its security of supply benefits (compared with comparable plant nearer the main demand centres) would seem to depend on transmission, and it would seem correct that the cost of transmission is taken into account when evaluating the cost-effectiveness of different options. However, one should also consider the future system conditions under which such plant would be needed.

In a future system in which there is much more wind generation than there is now, the conditions under which reserve generation capacity, generally expected to be fossil fuelled,[41] would be required would be those when the wind power available is low. Under these circumstances, wind generation in the remoter parts of the network would not need to use the network's capacity; fossil fuelled reserve generation would then be able to use it instead. In other words, a particular level of network capacity can be shared between wind and fossil fuelled plant; the amount of network capacity that would need to be built would be less than if the simultaneous operation of both classes of generation needed to be accommodated. This lower need for transmission should then be reflected in the transmission charging arrangements as lower locational tariffs than would otherwise have been the case. However,

[41] It has been suggested in some quarters that the demand side can, in future, play a significant part in providing response and reserve. We agree with this view. However, the demand side's contributions depend on the timescales over which it is required and are unlikely to obviate the need for generation – or interconnector – capacity to cover, for example, high pressure conditions arising in winter that linger for some days in which little or no wind power is available.

as will be discussed in section 7.5, present transmission access and trading arrangements in GB do not seem to lend themselves to this outcome[42].

7.5 Interactions with other electricity industry arrangements

As will have become apparent from the foregoing discussion, different options for transmission charging arrangements and their seeming impacts interact with other electricity arrangements, in particular those for trading and transmission access. Although these are outside the scope of our review, we believe it is important that the interactions are noted.

7.5.1 Trading arrangements

A major feature of trading arrangements is the way in which the system is balanced in 'real time'. In Britain at the moment, the system operator's costs in operating the system and procuring balancing services are recovered via the Balancing Services Use of System (BSUoS) charge, which is levied on a MWh basis in a 'postage stamp' manner. While we believe that, for the purposes of overall economic efficiency, cost-reflectivity should be part of the recovery of the system operator's costs, it seems that this has been ruled out by DECC in its decision to 'socialise' the costs of 'connect and manage' (DECC, 2010c)[43].

A major influence from existing trading arrangements is exerted on the apparent need for investment in additional transmission capacity, something that a cost-reflective charging methodology is designed to signal. As described in section 2.2, one of the drivers is to reduce constraint costs. While reference to this has always been possible as a justification for reinforcement, the connection of, in particular, wind generation in areas remote from the main demand centres is arguably making it more important. However, while historic constraint costs provide a good starting point for a cost-benefit analysis, there is much uncertainty around future constraint costs. They depend not only on the volume of constraint actions – measured in MWh, undertaken at different times of the year – and their individual costs but also on the initial dispatch of generation and the presence (or otherwise) of outages on the network (Bell, 2010). It might also be argued that the nature of the trading arrangements in Britain tend to exaggerate constraint costs – the system operator is obliged to

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[42] It has been argued by some that the system design criteria in the Security and Quality of Supply Standard (SQSS) do not permit such a 'sharing' of network capacity. However, it has never been the case that sufficient transmission capacity is built to permit levels of export associated with all generation in an area running at 100% output, not even at time of peak demand when exports under such generation conditions would be lower than at off-peak times. In other words, the network has never been designed to be constraint-free. On the other hand, the level of simultaneous output of generators in an area that a transmission planner should design the network to accommodate does not, as written in the present SQSS, seem to treat wind in a clear and robust manner. It is this issue that was the initial prompt for the ongoing review of security standards. Nevertheless, it should also be recognized that the proportion of a generator's possible output that the network should be able to accommodate is dependent not only on the technical characteristics of that generator but also on market interactions and the level of access rights that the generator has bought. The issue is therefore closely tied to trading and access arrangements.

[43] "DECC's view is that the analysis [of different 'connect and manage' – C&M – options] also highlighted the complexity of implementation and monitoring arrangements associated with the non-socialised C&M models. The sensitivity analysis … also suggests that the non-socialised C&M models would lead to unpredictable and highly volatile charges in specific parts of the network under certain scenarios. These factors (complexity, unpredictability and volatility) would in DECC's view increase the perceived risk to investors and has the potential to deter investment in generation." (DECC, 2010a)

accept bids and offers to change a dispatch determined by the generators themselves rather than for the initial dispatch to be determined on a system-wide basis. Although the scope would be reduced by the use of post-fault actions[44] or the striking of forward contracts by the system operator with relevant generators, the presence of few individual generating companies in a particular constrained area would seem to leave both initial dispatches and (for exporting areas) bids or (for importing areas) offers open to manipulation.

In comparison with the arrangements described above, the partial centralisation of dispatch[45] that is an important feature of trading arrangements based on locational marginal pricing would seem to have some attractions. However, notwithstanding the apparent benefits of LMP complemented by 'financial transmission rights' (FTR), it would seem that, on the face of it, its adoption in Britain would necessitate a major change to trading arrangements, something on which the UK government, insofar as it is addressed in the recent consultation on Electricity Market Reform, is less than keen (DECC, 2010d).

It is not our intention to conduct a review of different options for trading arrangements but we note the following choices that would normally need to be made. Locationally differentiated pricing may be achieved on a node-by-node basis as in full LMP or on a zonal basis as has existed, for example, in some regions of the US, in the 'NordPool' in Scandinavia and is understood to be being considered by the European Commission for implementation of a single European electricity market[46]. In the latter case, decisions need to be made about the delineation of the zones and, ideally, about how they might be changed to reflect different background conditions as they develop. Alternatively, as was the case in the former England and Wales 'Pool', there may be a single, system wide price. Another choice in trading arrangements concerns the dispatch of generation, whether it should be 'centralised' as in the former England and Wales 'Pool' or the current single electricity market on the island of Ireland, or decentralised as in the current GB arrangement[47]. Finally, it should be decided whether generators should all be paid according to a 'marginal price' or should be 'paid as bid'.[48] Any reform of trading arrangements should consider these and other design dimensions in a robust manner in light of some clearly defined electricity trading objectives set in the context of wider energy policy.

It has been suggested by some that something approximating LMP could be synthesised by the addition of a locational transmission signal to a single energy price. Such a single energy

[44] Normally, power transfer limits are consequences of the need to 'secure' the system, i.e. prevent breach of operational limits were a 'secured event' such as an unplanned outage to occur. The most common such events are faults, and, depending on the nature of the critical operational limit, corrective actions after the fault may suffice instead of pre-fault preventive actions.

[45] The option of bilateral trading remains.

[46] In Baldick (2011), arguments are presented in favour of a nodal approach and against a zonal one.

[47] It was argued in reform of the electricity market on the island of Ireland that centralised dispatch should be preferred as the more efficient means of managing the variability of wind energy. A similar argument was mentioned in Newbery (2011).

[48] Arguably, the two main effects of the 'New Electricity Trading Arrangements' (NETA) introduced in England and Wales in 2000 were to move from centralised to decentralised dispatch and for generators to be paid as bid. The latter was (controversially) argued as mitigating the exercise of market power in setting the marginal price that was paid to all dispatched generators regardless of their offer. (In a pay-as-bid system, it might be expected that all offers would rise relative to those under marginal pricing, but some might rise by less than others).

price might be represented by the 'System Buy Price' (SBP) in BETTA[49], though, in reality, there may be no need for such a single price to be articulated – it might suffice for the locational element of a price to be expressed[50]. To have a good match with LMP, the locational transmission signal ought to be one that is time dependent and is updated at the same rate as the wholesale energy price, i.e. the value of the signal depends on system conditions (and constraints) in a particular settlement period. This might appear to look a lot like a locational BSUoS charge, but this was seemingly ruled out by DECC's decision to 'socialise' the additional constraint costs associated with 'connect and manage' (DECC, 2010b). Nevertheless, a further option would seem to remain: for the locational transmission signal to be a long-run one, based on some kind of capture of transmission constraints and costs over the course of, say, a year. This starts to look a lot like a locational TNUoS charge with an energy element. While there are clearly different options for how that locational TNUoS charge is worked out and much is likely to depend on the detail, the model is functionally the same as currently exists.

7.5.2 Access arrangements and 'user commitment'

Transmission access rights in Britain, for generators, concern the right to export up to a certain amount of power onto the transmission system. It is outside the scope of the current review to address the many concerns that have been raised within the industry in Britain about access rights. However, we do highlight a few because of the way they interact with transmission investment and hence, because of the way that transmission charges should reflect the costs of the transmission network, transmission charging.

An analogy between allocation and pricing of FTRs and allocation of TEC and levying of TNUoS charges has been suggested in section 6.5.1. Arrangements in the US around locational marginal pricing and financial transmission rights include some features that would not depend on reform of trading arrangements. However, they would involve reform of access arrangements and include measures intended to allocate scarce transmission capacity and gain clearer, 'market-driven' signals on the need for additional transmission capacity. Such measures include auctions for access rights and have been considered as part of the still ongoing review of transmission access (Ofgem, 2009a). They have a clear link with the charges that transmission users would need to pay and, in the choice between 'firm' and 'non-firm' access rights, entitlement to compensation for loss of access (analogous to gaining a system energy price) or not (analogous to gaining only a local energy price).

One of the criticisms typically made of the present TNUoS methodology is that charges actually levied often turn out differently from those that had been forecast. One of the main

[49] SBP in a particular settlement period in the GB Balancing Mechanism is a function of offers accepted solely for 'energy', i.e. it does not include offers tagged as being necessary for the resolution of network power transfer constraints or consequential to them.

[50] One difficulty with the wholesale trading arrangements in Britain at present is that the majority of energy is traded – and priced – bilaterally and prices in the balancing mechanism concern changes to physical dispatches of (mainly) generation where the initial dispatches are driven by the bilateral trades. Moreover, within the balancing mechanism, two 'cash out' prices are articulated – 'system buy price' and 'system sell price'. It would therefore seem to be difficult to say what a single wholesale energy price in any one trading period would be. In the UK government's recent consultation on Electricity Market Reform, it was suggested that a 'contract for difference' based feed-in tariff for low carbon generation would use a single electrical energy 'wholesale price' as the 'strike price' (DECC, 2010d). It did not say how this wholesale price would be calculated.

reasons for this is the access rights sought by generators and subsequently awarded often differ from those that National Grid had anticipated when carrying out the TNUoS forecast. While generators seeking new rights must apply for them to the system operator and must await and sign an offer before they can be exercised, the same uncertainty about the future access rights that generators will use affects transmission system planning. Notable among the uncertainties are: rights offered for some future time are not necessarily exercised; rights can be given up at short notice.

The aforementioned review of transmission access had, as one of its objectives, the desire to give greater certainty on the future need for transmission. One proposal involved the following (Bell, 2009):

1. the submission to the system operator of applications for the rights to enter up to a certain amount of power onto the system at some future time;
2. a forecast by the system operator of what that would mean for transmission reinforcement and for TNUoS charges, and the publication of those charges;
3. the opportunity for applicants to revise their applications in light of the forecast;
4. processing of a revised set of applications and making of offers;
5. the signing of offers by generators which as well as granting rights would also entail a certain commitment by network users to pay future TNUoS charges.

The chance for generators to revise their applications and the last step of 'user commitment' were intended to improve certainty and provide a firmer base for more 'strategic' development of the network[51]. However, another feature was intended to address one of the difficulties in transmission system planning: judgement on the total transmission capacity that it would be economic to provide to accommodate the aggregate output of a group of generators in an area. Implicit in that judgement are the degree to which those generators might be regarded as 'sharing' capacity, and how much it would cost to constrain one or more generators off in the event that the 'final physical notifications' they submit to the balancing mechanism exceed the network's export capability. It had been proposed that this might be achieved by not only requiring applicants for rights to specify how much power they might enter onto the system but also (a) how much they expect to actually operate in the course of a year, i.e. what is their anticipated 'load factor' or 'capacity factor', and (b) how much it would cost to reduce their output should network limits otherwise be breached. Especially in respect of interactions between wind farms and 'marginal' fossil fuelled plant, this is potentially very important for determining how much transmission should be built and what the TNUoS charges should be. As noted in section 2.1, in a future system with more wind generation than there is at present, wind and 'marginal' fossil fuelled plant in the same area would not generally be expected to operate at the same time – the 'marginal' plant would normally only operate when wind speeds are low or demand is high (and when demand in an exporting area is high, the net export will be reduced). In other words, the two facilities might 'share' the same transmission capacity.

As an alternative to indicating the cost to the system operator of buying back access rights given to generators, rights of access to the system for periods much shorter than a year might be sought by 'marginal' generators and made available to them when network capacity would

[51] The development, mooted in both 'Project Discovery' (Ofgem, 2010) and DECC's December 2010 consultation on Electricity Market reform (DECC, 2010d), of some kind of capacity mechanism in which generators receive quite long-term contracts for being available could, depending on its final form, be argued to go some way to reducing uncertainty about the future generation 'background'.

not be exceeded. By making themselves available at times when alternatives are few, these generators would provide a service to the system operator without imposing additional constraint or network infrastructure costs. In effect, they would share the network capacity with other, higher merit plant. In return, the charges these 'marginal' generators would pay for use of the system in those periods might be expected to be minimal[52].

Neither the above proposal to require generators to quote capacity factors and buy back prices nor the other major reforms mooted in Ofgem (2009a) have been implemented except for 'connect and manage'. It is not our intention to explore the reasons why or to debate the various options, but simply to note our view that current arrangements for granting of rights – which, as previously observed, give rights holders full freedom to set their own initial dispatch and quote a price for reducing output – would tend to increase the transmission capacity that should be built compared with that which would needed were capacity to be 'shared' in an efficient manner, and hence would increase the transmission charges levied on generators in exporting areas.

7.6 Interactions with energy policy developments

In a number of places in sections 7.3 and 7.4, possible interactions of transmission charging arrangements with wider energy policies have been noted. In addition, our principles in conducting this review included consistency with the policies of government in the UK and EU Directives, insofar as they are apparent and we can interpret them correctly. Some of these interactions are therefore discussed in this section.

7.6.1 Policies in the UK

We have noted above that economic efficiency depends both on signals that reflect the consequences of actions and the opportunity for actors to respond to them. A key signal of transmission cost concerns location, and it may be asked whether renewables developers have the chance to respond to it, and this depends on the availability of choice. It seems to us that they do have a choice – at least, at the moment they do[53] – of different high wind locations, e.g. in the Western Isles, in the south of Scotland or off the south-east coast of England. It is clearly in consumers' best interests if the cheapest of those locations is developed; given the cost of offshore wind farms and of a new connection from the Western Isles to the main transmission system, in the example it would seem to be the south of Scotland. It would seem to be correct that transmission charging arrangements would signal that.

While legally binding targets motivated by reduction of carbon emissions associated with energy use are currently focused on renewable energy, the recent DECC consultation on Electricity Market Reform addresses low carbon energy (DECC, 2010d). In addition to renewables, this includes both nuclear power and fossil fuelled generation with carbon capture and storage (CCS) facilities. Although nuclear power and CCS do not have complete freedom of location, they, too, do still have some degree of choice and would be expected to

[52] Attempts have been made to develop short-term access products in GB. However, our understanding is that they have faced significant difficulties in determining, in some simple and useful way, quite how much extra generation can be accommodated.

[53] In the longer term as the 'best' sites get developed, this might not remain true for the next set of developments.

resolve the different influences, e.g. cost of electricity transmission versus access to fuel versus access to carbon transport and storage facilities. It thus seems correct that cost-reflective transmission signals should be sent that encourage an economically optimal solution.

It has been reported that delays to gaining or failure to gain planning permission is a major influence on wind farm development (RenewableUK, 2010). Moreover, developers are well aware of regional differences in success rates for planning applications. In the longer term as the sites that are most attractive from both a wind resource and local impact point of view are developed, this is likely to be increasingly important. In this context, we feel it is worth reflecting on the position of offshore wind.

It is widely accepted that the construction, connection and operation of offshore wind farms are significantly more expensive than those onshore, though it may also be anticipated that, as technology develops and reliability improves, the gap will narrow. Nevertheless, both the UK and Scottish Governments have seen fit to encourage its development by making extra ROCs available. Such extra support for offshore wind – through ROCs, some future Feed-In Tariffs or some other mechanism – might be justified relative to onshore wind in view of two things: the vastness of the offshore resource; and (in principle, at least) fewer planning issues.

A more favourable planning regime that reduces risks associated with projects that, otherwise, seem adequately to balance increased revenue consequential to increased load factor with increased cost of transmission access would clearly help. Nevertheless, it seems to us that it would not be inconsistent with current arrangements for offshore for extra support to be given for areas onshore where the wind resource is attractive, the development of capacity there is needed for the meeting of renewables targets but where costs of accessing and using the transmission system turn out to be prohibitively high. Alternatively, one might ask whether treatment of offshore network costs is entirely consistent with principles of cost-reflectivity.

It might be argued that postage stamp charging would achieve the objective of increasing the commercial viability of renewables developments in key locations. However, this is likely to be exploited by generation other than renewables and is only one tool among the many that can be envisaged.

In general, we do not support the engineering of electricity transmission arrangements (whether in respect of charging, trading or anything else) to target – or penalise – particular technologies. This would fall foul of existing transmission licence conditions that forbid discrimination (though changes to those conditions might be sought). On the other hand, the forbidding of discrimination might be judged to be in contradiction of the *positive* discrimination (in favour of renewables) seemingly called for by EU Directive 2009/28/EC (see Appendix 2 below). Nevertheless, we believe it should be recognised that support for different renewable energy and other low carbon electricity generation technologies, whether motivated by, for example, climate change mitigation targets, industrial policy, regional economic development or some combination of those objectives, is a complex matter that should be determined by elected policy makers; for those responsible for transmission charging to try to second guess those policy decisions, manage their interactions or react to major changes[54] would not, in our opinion, be reasonable.

We believe that, as far as possible, different signals to development of generation should be kept clean from each other and as transparent as possible. Transmission charging signals should reflect simply the cost of transmission. The generation developers themselves, rather than the designers of transmission charging arrangements, are best qualified to weigh up different influences on investments such as those outlined in section 7.1 above and to make most effective use of any available support mechanisms. This is as true of investments in nuclear power stations and fossil fuelled plant with carbon capture and storage facilities as wind farms. We believe that such an approach would be best both for electricity consumers and, through minimising the chance of unintended consequences, the meeting of climate change mitigation targets.

7.6.2 EU policy

Extracts from a number of relevant EU Directives are reproduced in Appendix 2 below. We present our view of their implications for transmission charging here.

EU Directive 2009/28/EC requires that the sharing of costs, for example for connection and grid reinforcements, shall take into account "the benefits which initially and subsequently connected producers … derive from the connections."

Directive 2009/28/EC also calls for priority or guaranteed grid access for renewables and for priority to be given to them by system operators in dispatch decisions and curtailment of energy from renewables minimised insofar as doing so would not threaten security of supply. However, it also notes that rules for network reinforcements and grid codes should be non-discriminatory and take account of costs and benefits. Directive 2009/72/EC says that the dispatching of generation and interconnectors "shall take into account the economic precedence of electricity from available generating installations or interconnector transfers and the technical constraints on the system". It also directs that the rules and tariffs for balancing services shall be established in "a non-discriminatory and cost-reflective way".

Article 4 of Regulation (EC) No 1228/2003 on access to the network for cross-border exchanges says that "Charges applied by network-operators for access to networks shall be transparent, take into account the need for network security and reflect actual costs incurred." However, it also says that "those charges shall not be distance-related" and that the proportion of charges borne by producers shall be less than borne by consumers. Furthermore, "the level of the tariffs applied to producers and/or consumers shall provide locational signals at European level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure." (It also notes that Member States shall not be prevented from providing locational signals within their territory.

We note that, in accordance with an EU Directive, since October 2010 interconnectors are no longer charged for use of transmission systems in Europe and are not regarded as being 'generation' or 'demand' as such. Our understanding of the intention of this aspect of the

[54] An example of a significant shift is that implied by the December 2010 DECC consultation on Electricity Market Reform that follows on from the change of government in Westminster and is the apparent move from support of 'renewables' to support of 'low carbon' generation (DECC, 2010d).

Directive is that there should be fair rules for cross-border exchanges, enhanced competition across all Member States and the protection of cross-border flows from exposure to multiple network access charges. However, there should also be some kind of 'Inter TSO Compensation' (ITC) mechanism that compensates TSOs for costs arising as a consequence of cross-border flows and is paid for by the TSO that causes the flows (Pielage, 2010). It is not clear to us how the ITC will work.

While some of the Directives and Regulations might seem, on the surface, contradictory in places, we interpret them as placing no particular constraints on the design of transmission charging arrangements except that they should be 'non-discriminatory', interconnectors should be treated as neither generation nor demand and transmission costs should not be recovered only from producers. It is possible to argue that a tariff that charges all users the same amounts does not discriminate against any of them. However, it is our view that a tariff that accurately reflects differences in costs between users is also non-discriminatory. Indeed, if there are differences in costs, many economists would argue that it would actually be discriminatory to charge the same amount.

7.7 A test case: some 'thought experiments'

As noted in section 2.3, the GB transmission licensees and other members of the Electricity Networks Strategy Group expect the biggest set of investments in enhanced network capacity in decades to be required in the next 5-10 years in order to accommodate new renewable generation (ENSG, 2009). The biggest single component of it is the proposed 'bootstrap' between the south west of Scotland and Deeside. (A further, east coast 'bootstrap' may also be required). It seems to us that this represents an important test of the fitness for purpose of the different methodologies discussed in section 6. While it is outside the scope of our review to conduct a detailed, quantified analysis, in this section we therefore present a simple, very high level 'thought experiment' to explore the treatment of the 'bootstrap' in each of the main methodologies outlined in section 6.

Our understanding of the main effects of the different charging methodologies with respect to the west coast 'bootstrap' is summarised in Table 3. We discuss some of the apparent implications below.

Principles of economic efficiency suggest that, in an export constrained area, charges should be higher (or potential earnings should be lower) than on the other side of the constrained boundary in order to reflect the cost either of upgrading the boundary transfer capability or of constraining generation in network operation to accommodate additional generation in the area. The north of Britain is just such an area which ought, therefore, to have higher charges (or lower income for generators) than the south. All the methods except the postage stamp give this signal. Indeed, an energy-based postage stamp, i.e. indexed by (for generation) total energy produced, may give lower charges in the north than if the constraint were less severe even though surplus generation in the north (relative to the network's capacity) leads to increased costs of system operation.

As noted in section 6.1, none of the locational methodologies recovers all the costs of the network. Some additional charge, known in the present TNUoS methodology as the 'residual', is necessary.

Table 3: treatment of the west cost 'bootstrap' by different charging methodologies

Methodology	*Before the 'bootstrap'*	*After the 'bootstrap'*
Postage stamp: MW capacity	**Northern generation:** Depends on size of generator **Southern generation:** Depends on size of generator	**Northern generation:** Depends on size of generator but increased **Southern generation:** Depends on size of generator but increased
Postage stamp: MWh produced	**Northern generation:** Depends on type of generator and its relative cost, but output – and charge – may be limited by network constraint **Southern generation:** Depends on type of generator and its relative cost	**Northern generation:** Depends on type of generator and its relative cost, but output – and charge – less limited by network constraint **Southern generation:** Depends on type of generator and its relative cost
ICRP	**Northern generation:** Relatively expensive **Southern generation:** Relatively cheap	**Northern generation:** Locational charge increased **Southern generation:** Relatively cheap
LRIC	**Northern generation:** Relatively expensive **Southern generation:** Relatively cheap	**Northern generation:** Locational charge reduced, residual increased **Southern generation:** Relatively cheap, residual increased
ICREP	**Northern generation:** Relatively expensive, more so for higher capacity factor plant than lower capacity factor plant. **Southern generation:** Relatively cheap	**Northern generation:** Locational charge reduced, residual increased **Southern generation:** Relatively cheap, residual increased
LMP	**Northern generation:** Energy price earned (theoretically) significantly lower than in south **Southern generation:** Income depends on marginal energy price	**Northern generation:** Earnings increased due to energy price being nearer to that in south **Southern generation:** Income depends on marginal energy price

The 'bootstrap' is designed to relieve the constraint on transfers of power out of the north and the justification for it is based on comparison of its cost with the benefit of reducing constraint costs, in this case against an anticipated future generation 'background' that includes new generation in the north.

Following commissioning of the bootstrap, if the cost-benefit case was correct, even though the bootstrap must be paid for, the total cost of transmission in the medium term should be lower than would be the case without it due to the reduction in constraint costs. In spite of this overall reduction, principles of cost reflectivity suggest that generators in the north should pay a higher share of the cost of the bootstrap since they – and their customers – gave rise to it. (In general, a practical investment in additional network capacity would provide some spare capacity so that, while the cost of the investment would need to be recovered, the deterrence signal to future use of the system would not be as strong in the short term as if there were no headroom and any additional generation in the north would require further network investment).

In the LMP approach, the effect of the bootstrap in increasing power transfer capability from the north would be to reduce the extent to which the north seems like a separate market from that in the south, with the northern market having a significant surplus of generation capacity relative to demand. However, depending on how LMP were implemented and how prices are set in the northern market by the few generating companies active there, the price differences – or, in a different implementation, the cost of constraints[55] – between the north and south might not be that big. While that would be a relatively good outcome for generators in the north in the short-term, it would weaken the case for investment in the bootstrap and, as a consequence, lead new generators hoping to connect in the north to expect wider price differentials between north and south (energy prices being lower in the north) and so weaken their cases for investment. On the other hand, if the bootstrap were still to be constructed, the LMP approach would lead to it being paid for out of any income from sale of 'financial transmission rights' and 'residual' network charges, the latter likely to be levied on some kind of 'postage stamp' basis.

In the ICRP approach, if it were to be costed on a similar cost per MWkm basis as overhead lines and underground cables using the full cost of both the cable and the two converter stations, the bootstrap would cost probably in excess of £120/MWkm per year. (This compares with the assumed cost in the present ICRP methodology for a 400kV overhead line of around £11/MWkm per year). As described in section 6.2, when adding an additional MW of generation, the ICRP approach effectively assumes that increased flows would be accommodated by network capacity upgrades on each branch in proportion to the MWkm changes on them. Thus, while the ICRP approach would not assume that every additional MW of generation in the north would cost the same as a MW of extra capacity on the 'bootstrap', the ICRP approach would give a significant increase in the charges paid by generators, possibly so much so that the new generators in the north on which the cost-benefit case for the bootstrap was predicated may have been rendered commercially unviable and will not connect, thus undermining the justification for the bootstrap.

This 'catch-22' could be argued to illustrate the need both for charging signals to be both forward looking (taking into account interactions between charging and future generation investment decisions) and accurate and for some degree of user commitment on which transmission network investment cases can be based.

[55] The two main implementation options seem to us to be: 'pure' LMP in which all generators submit data to a central authority, e.g. the system operator, which carries out a centralised dispatch out of which emerges the locational marginal prices that all generators receive and all suppliers pay; or a synthesised LMP in which, as in present trading arrangements, generators self-dispatch but quote prices to increase or decrease output, some of which are accepted by the system operator in order to balance the system overall and resolve network constraints, the constraint actions being used to set locational short-term network use charges. Both approaches would succeed in revealing differences between locations in what a generator would receive (or pay), albeit one would be dependent on full, 'from the ground up' dispatch and the other on re-dispatches.

7.8 Summary

It was noted in section 5 that there are a number of dimensions to the way in which transmission network users might pay for it and its use. In general, methodologies attempt to signal the effect of a market participant's decision on the total cost of transmission, including both cost of constraints and the cost of network assets and their maintenance and operation. The ways in which these signals are produced differs.

In this section, we summarise our current views on the relative merits of the five main charging models that we presented in section 6. In most of them, there is clearly some centrally administered means of levying charges. In a system involving locational pricing of energy such as LMP, generators will see a signal via their access to higher (in import limited areas) or lower (in export limited areas) energy prices, and they would generally need to make their own forecasts of prices in order to understand their potential impact. However, there may also be some centrally administered facility through which generators can buy financial transmission rights, i.e. FTRs. The precise arrangements for making FTRs available and pricing them are critical to how market participants are able to use them and must therefore be subject to careful consideration. For example, they might be used to add further weight to the locational signals given by locational pricing, e.g. by auctioning financial rights to the network capacity in export limited areas. In addition, we have suggested in section 6.5 that an analogy can be drawn between allocation and pricing of FTRs and the allocation and pricing of TEC via TNUoS.

Finally, before summarising our views on the different options considered in section 6, we recall that cost-reflective charging methodologies generally fail to recover all of a transmission owner's reasonable costs. There is therefore a need for an additional charge, i.e. some kind of 'residual'. As discussed in section 6.1.2, we believe that it is appropriate that this is levied on demand on a postage stamp basis, though it is up for discussion as to whether this should be power (kW) or energy (kWh) based.

Economic efficiency: the postage stamp approach, either in respect of long-run costs of the costs of operating the system, has no attractions in this regard. Of the others, LMP promises to provide the most faithful link between energy prices and the impact of lack of transmission on them which, in principle at least, should influence decisions by both generators (and, in future the demand side) and transmission owners and lead to economically efficient outcomes. However, we would welcome evidence of its effects in respect of incentives to investment in both generation and transmission[56].

Robustness: by this we mean that the method should not be over-sensitive to small changes in input to the method. Both postage stamp pricing and simple long-run pricing such as ICRP may be expected to perform relatively well in this regard while more refined

[56] Our understanding of the effect in PJM is as follows. Transmission flows are generally from west to east with local energy prices in the east much higher than those in the west as a result of transmission constraints. This has had the result of attracting new generation in the east to benefit from the higher prices there. This new generation has generally been CCGT but not so much of it has connected as to significantly reduce prices there. As it happens, the most attractive areas for development of wind generation are also in the east. We also understand that, in spite of high locational price differences, little or no new transmission has been built which would benefit consumers in high price areas by giving them access to cheaper energy elsewhere. In contrast, in Texas where a new LMP system was implemented in 2009, our understanding is that the most attractive wind areas are where locational prices are low. It remains to be seen, therefore, what the medium to long-term effect will be on investment in new wind farms and new transmission to allow their energy to be used.

long-run methods can give significant step changes in outcomes as network flows approach branch limits. Locational marginal pricing may be expected to demonstrate significant volatility through a period of time and between locations, but each half-hourly price, considered separately, has relatively little impact on participants, compared to the decision to move a generator between ICRP zones, for example.

Workability: That a simple long-run method such as ICRP is workable is evident from the fact that it is what is currently applied in Britain whereas a postage stamp approach is used for the costs of system operation and in other countries also for the 'transmission owner' costs. The operation of more refined long-run methods is unproven for complex, meshed networks in Britain that have many different generation facilities. An LMP-based approach is practised in, for example, different parts of the US. However, its implementation in Britain is likely to be significantly more complex than the other approaches. In addition, it seems to us that interpretation of those signals by users depends on a significant degree of judgement and that efficient setting of energy prices is not guaranteed for areas affected by transmission constraints.

Complexity of regulatory and legislative instruments: An approach based on LMP would be the most complex to implement and would require a number of design choices to be made, in particular regarding the allocation and pricing of FTRs.[57] However, we note that some means exist by which some of its features might be synthesised within the context of current GB trading arrangements while other features might depend on reform of access arrangements.

A postage stamp approach for TNUoS charging would require revision of the transmission licence clause that stipulates cost-reflectivity of charges. The existing GB approach is the simplest in terms of regulatory change since it would need no change.

Stakeholder support: In spite of significant support among academics and some on the utility side of the industry for LMP, our impression is that it would not be widely welcomed by market participants, largely due to its complexities. Some in the industry have argued that, notwithstanding some concerns about details of implementation, the evidence for a change from the present TNUoS charging methodology is weak while others have argued in favour of postage stamp charging on the grounds that it provides the best support for renewables in areas remote from the main demand centres.

It is important to consider the impact of a charging methodology on the meeting of renewables targets and security of supply. It has been noted in section 7.3 that cost-reflective pricing might put the meeting of renewables targets at risk if the only locations in which new renewable generation can practically be developed have such high transmission charges that

[57] Notwithstanding the theoretical possibilities of a 'simultaneous feasibility test' (Hogan, 1992), judgment not entirely dissimilar from that in design of a charging methodology would be required on the part of someone – probably the system operator – on how many rights to make available. The available transmission capacity depends on how many rights have already been awarded and how the holders are assumed to use them and so may lead, as in PJM, to multiple rounds of allocation (PJM, 2011). The desire to accommodate different electricity users' attitudes to risk and the fact that available transmission capacity varies through a year and is influenced by, among other things, planned outages of both generation and transmission, may lead to different access products of different durations made available at different times of the year.

they are no longer commercially viable. However, at present this seems to us not to be the case[58] and renewables – and nuclear power and fossil fuelled plant with CCS – do have some choices that cost-reflective transmission charging should help to inform. Moreover, we note that other instruments for support of low carbon energy are available and that, with reform of these being currently consulted on, there is an opportunity for them to address any perceived threat to investment in renewables and the meeting of renewables targets arising from the costs of electricity transmission. Most importantly, we note our belief that, as far as possible, different signals to development of generation should be kept clean from each other and as transparent as possible. Transmission charging signals should reflect simply the cost of transmission. The generation developers themselves, rather than the designers of transmission charging arrangements, are best qualified to weigh up different influences on investments.

In order to minimise any competitive disadvantage placed on generation located in Britain relative to that elsewhere in Europe, we suggest that the average charge to generators for use of the transmission system in Britain should be zero.

In section 7.4 it has been noted that, by affecting the economics of a particular power station, a particular set of transmission charging arrangements might lead to closure of existing 'peaking' or 'marginal' plant or failure to open new facilities that can operate when, in a future power system more heavily reliant on wind than that in Britain now, the power available from wind is low. However, peaking plant (and demand side measures) generally has greater flexibility of location than other types of plant so it would seem appropriate that cost reflective charges for use of the transmission system should be among the influences on decisions. In addition, we note that peaking plant in areas with the best wind resources ought generally to operate only when the available wind power is low and so it can 'share' transmission capacity with it and also share the benefit, with wind farms, of lower transmission charges arising from a reduced need for transmission capacity compared with the network having been built to accommodate the simultaneous maximum output of both. However, we note that neither the present access arrangements nor the charging methodology ensure this outcome.

[58] Any clear evidence to the contrary would be welcome.

8 Conclusions

In this section we present the main conclusions resulting from our work to date, and make some recommendations for further work arising from our main conclusions.

We have proposed a number of high level principles that have driven our review and informed the development of our assessment criteria. These principles for transmission charging arrangements are:

1. They should encourage efficient investment and operating decisions by the transmission companies, generation companies and consumers such that the overall cost of electricity is, as far as practicable, minimised.
2. They should be consistent with the realisation of climate change mitigation targets set by government in the UK.
3. They must be compatible with EU directives and regulations.
4. They should be consistent with the future integration of energy markets across Europe.
5. They should not present undue barriers to the realisation of adequate security of supply.
6. They should not be over-sensitive to small changes in the transmission system and its users.
7. They should be as simple as possible to achieve their objectives, and no simpler.
8. They should command sufficient stakeholder support to be implementable.

To minimise the total cost of electricity, including that of ‘production’ and ‘transport’, it seems reasonable to us that signals should be expressed that attempt to coordinate choices of location for generation with those for development of transmission and that those making decisions should be exposed to their consequences. In a transmission charging context and in order to encourage a minimisation of the overall cost of electricity, this depends *both* on appropriate and accurate ‘cost-reflective’ signals being given to network users *and* on those users having an opportunity to respond to them.

We note that various issues aside from transmission system charging might limit users’ ability to respond and, if transmission charges are high and other measures are not taken to compensate for them, might put the meeting of renewables targets and security of supply at risk. (Because the 2020 targets are legally binding, we regard them as imposing a strong constraint on policy, including transmission charging. We also note the wider importance of the UK transitioning to a low carbon economy). However, at present, there do still seem to be choices available for the development of wind farms, nuclear power stations and fossil fuelled plant with carbon capture and storage facilities. Moreover, we note that other instruments for support of low carbon energy are available and that, with reform of these being currently consulted on, there is an opportunity for them address any perceived threat to investment in renewables and the meeting of renewables targets arising from the costs of electricity transmission.

We believe that it is important that accurate signals of the cost of transmission are sent to developers of new generation facilities to enable their resolution of the various influences on investment. Moreover, we believe that, as far as possible, different signals to development of generation should be kept clean from each other and as transparent as possible. Transmission charging signals should reflect simply the cost of transmission. The generation developers themselves, rather than the designers of transmission charging arrangements, are best qualified to weigh up different influences on investments.

In respect of security of supply, we note that, in future, it is likely to depend largely on contributions by 'peaking' fossil fuelled plant (and also from demand side measures). Choices do exist for the location of such plant; accurate signals of the cost of electricity transmission should be provided to help inform those decisions. However, we also note that peaking plant and wind farms located in the same area might generally be expected to 'share' network capacity as they would not normally operate at maximum output simultaneously. That would reduce the amount of transmission needed (compared to when it is designed to accommodate simultaneous high outputs from both) and hence reduce the cost of transmission to which both the wind farm and the peaking plant would be exposed.

We have considered in some detail five main classes of transmission charging approach. These are postage stamp pricing, a 'simple' long-run cost based method, more refined long-run cost based methods, a method based on long-run costs but with at least some part of payments based on energy rather than capacity and an approach based on locational marginal pricing (LMP) and financial transmission rights (FTRs).

It has been outside the scope of the present study to conduct a quantified analysis of these options, though we would recommend that, in order to test the possible effect on cost of electricity and the investment environment for generation developers, some such analysis is carried out, at least of what seems, from a qualitative analysis, the preferred option(s). Instead, we have carried out a high level appraisal of their relative merits in respect of economic efficiency, robustness, workability, complexity of regulatory implementation and stakeholder support. We have also considered their possible impact on the meeting of the 2020 renewables targets and security of supply.

Based on our high level appraisal, summarised in section 7.8, our main conclusion is that while 'refined' long-run based methods and an approach based on LMP+FTRs have their attractions, neither of these or a 'postage stamp approach' is ideal. These options are variously, it seems to us, inconsistent with encouragement of economic efficiency, rather sensitive to small changes in the transmission system and its users, highly complex, in need of considerable further work to develop implementation details or lacking wide stakeholder support.

While a simple approach to long-run pricing, when considering all of our evaluation criteria, seems to be the least imperfect, we regard it, in its present guise, as having some critical flaws that both compromise its cost-reflectivity and give rise to some outcomes that would appear to be, under some circumstances, anomalous. Moreover, while it has been outside of the scope of this study to develop and evaluate them, some discussions with various industry parties and some of our own very initial analysis suggest that options are available that would facilitate improvements in respect both of cost-reflectivity and minimisation of risk to the investment case for generation, in which regard we particularly note the need for sufficient investment in renewables to meet the 2020 targets. It seems to us that the development of improvements need not be an excessively lengthy process.

We note that the GB system operator's costs in balancing the system are currently recovered via 'Balancing Services Use of System' charging, and that this is a postage stamp, i.e. non-locational, approach indexed by energy generated or consumed in the course of a year. We believe that cost-reflectivity is important in ensuring overall efficiency in operation of the system but note that the decision by the Department of Energy and Climate Change that additional system operation costs associated with 'connect and manage' should be 'socialised' seems to preclude that.

We recall that the locational elements of cost-reflective charging methodologies – whether a specifically designed tariff such as TNUoS, the congestion rent from locational marginal pricing or the net income from sale of FTRs and compensation to FTR holders – generally fail to recover all of a transmission owner's reasonable costs. There is therefore a need for an additional element, i.e. some kind of 'residual'. We believe that it is appropriate that is levied on a postage stamp basis and, because the charge would normally be passed through to consumers anyway, should be levied only on demand. However, it is up for discussion as to whether the charge should be power or energy based.

We note that different approaches in different countries to the levying of transmission charges on generators can lead to generators having to recover those costs through wholesale prices and to disadvantage relative to their competitors in other countries[59]. This could distort trading of electrical energy across national boundaries. To minimise that effect, we would recommend that the average charge levied on generators for use of the transmission system should be zero.

8.1 Recommendations for further work

Although we have concluded that, for charging for use of the transmission system, the best compromise option among the five that we have considered is a 'simple' long-run approach, we believe that the present ICRP methodology is inadequate and, if its general form is to be retained, should be revised to provide more accurate reflections of the drivers for network investment. In particular, we note that much investment in enhanced transmission network capacity in Britain in the next decade arises from the need to accommodate new wind farms located in power exporting areas remote from the main demand centres. Given that the cost of constraining wind power off will be very high, the level of reinforcement required may be said to be driven more by economics than by security of supply. Thus, the charging methodology is not driven simply by generation capacity, i.e. power, and network conditions around the time of peak demand for electricity, but rather should reflect, at least to some degree, conditions that arise in the course of a year of operation and the efficient decisions for network reinforcement that would be made. It would thus have at least some energy element.

The question of exactly how much extra capacity on the main interconnected transmission system is required and how that need should be articulated in the design criteria of the 'Security and Quality of Supply Standard' is the subject of a long-running review. While security of supply can be expected to still influence network investment in at least some parts of the network (so that power capacity remains important), energy produced has an influence as well as the initial dispatches of plant determined by market participants and the prices that

[59] It has not been our intention to compare charging arrangements in different countries and we recall that Ofgem has commissioned a separate international comparison (CEPA, 2011). However, we also note that care should be taken when drawing conclusions about charging arrangements. For example, while a particular country might not levy charges for use of the main transmission infrastructure on generators, it might apply deep connection charging to generators whereas another country might levy infrastructure charges on generators but have shallow connection charging.

the system operator would need to pay to change that dispatch in order to respect network limits. That is, the need for additional capacity might be said to be a very complex function of power. We recommend that attention is paid to how changed drivers for investment in network capacity can be better represented in a transmission charging methodology that remains as simple as possible but more cost-reflective with a reduced likelihood of perverse outcomes.

While not precluding further work on more far reaching reforms such as a transition to locational marginal pricing and different arrangements for transmission access analogous to making the option of purchase of FTRs available, we would recommend work on development of a refinement of ICRP that, as well addressing what we believe to be its present shortcomings, includes an energy element. We have coined the term ICREP for that refinement of ICRP. That work should explore different options for incorporation of an energy element and provide quantified evidence of their effects for a number of different scenarios, both present day and for the possible future GB system. We believe that such a development can complement what we understand to be the timescales of DECC's electricity market reform process and the wider industry's desire for decisions to be made quite quickly.

We note that 'marginal' or 'peaking' generation located in the same power export areas as wind farms have the potential to 'share' network capacity with them. This is because such marginal plant, certainly for off-peak conditions, would normally be expected to run only when the available wind power is low. This would give rise to a need for less transmission capacity than if the network had to be built to accommodate high simultaneous outputs from both classes of plant. This, in turn, would entail lower use of system charges for both than would have been the case. In other words, if such 'sharing' behaviour could be relied on to take place, low load factor generation might be expected to have lower use of system charges than high load factor plant in exporting areas. However, we note that rights granted to generators within current access arrangements do not give the necessary degree of confidence, nor does the current ICRP methodology take account of such effects of low load factor generation. Although access arrangements are outside the scope of review, we would recommend that both these issues are addressed.

In addition to some element of charging for energy, we would recommend that some other aspects of the present transmission charging methodology are given attention. These include:

- consistency of treatment between onshore generation, offshore generation and generation on islands;
- the 'security factor' and whether a single value is appropriate for all locations;
- the treatment of the proposed HVDC 'bootstraps'.

The last of these concerns the plan, currently under development, that an undersea HVDC connection is made between Ayrshire and Deeside in order to significantly increase the capability of the network to export power from the north of Britain and have the potential to contribute to system stability. (A second HVDC 'bootstrap' is under consideration for the east coast). Such a link would have a cost of between £0.75 billion and £1 billion. There is currently no accepted way for this to be represented in the ICRP model; depending on how it is done, it could be very expensive for generators in the north that are already under development (and thus have no realistic chance to respond to a cost-reflective price signal), perhaps doubling their TNUoS charges. Moreover, a 'naïve' treatment of it in the ICRP methodology might lead to a 'catch-22' outcome. The 'bootstrap' investment is being justified on the basis of a cost-benefit analysis with constraint costs plus annuitised capital costs and losses with the 'bootstrap' being compared with constraint costs and losses without it, all predicated on the expected connection of a particular volume of renewable generation in the north. To reflect the full cost of the 'bootstrap' on network users in the north through ICRP could lead to a significant number of those projects not being taken forward, so undermining the case for the 'bootstrap' in the first place.

It is our understanding that the option of an undersea HVDC connection in parallel with the main AC system has not only been driven by technical considerations but also by practical issues that limit the viability of the main alternatives. Thus, and given its apparent strategic importance to the realisation of the UK's renewable energy targets in the short term, we believe that it might be legitimately asked whether the full cost of it should be borne by generators in the north. In that regard, we note a recent regulatory development in the US where, in December 2010, the Federal Energy Regulatory Commission (FERC) approved the concept of 'multi-value projects', i.e. "projects that are determined to enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple transmission zones" (FERC, 2010). According to the American Wind Energy Association (AWEA, 2010), "The MVP concept is based on the recognition of the numerous, widely shared benefits provided by enhanced transmission infrastructure and, accordingly, spreads the costs for these lines across the [Midwest ISO (MISO)] footprint". We ask whether some similar recognition – and the implication that the costs of 'multi-value projects' should be, in some way, socialised[60] – might be helpful here.

[60] An alternative to full socialisation would be to represent such projects in a charging model as if they were the cheaper reinforcement option that would otherwise have been built, e.g. 400kV overhead line.

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Appendix 1 – Terms of Reference

Ofgem has recently launched Project TransmiT, which is an independent and open review of transmission charging and associated connection arrangements. The aim of the review is to ensure that we have in place arrangements that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers.

We are commissioning three short reports on optimal charging arrangements from independent academic experts in the area of network charging. In particular, we are looking for views on what an efficient charging regime might look like for GB electricity and gas networks given the new challenges we face today. These independent reports will be used to stimulate further debate within the shareholders and to inform our own policy development.

The focus of each report will be on electricity transmission charging, although the principles will be considered in the wider context of both gas and electricity transmission.

We expect the report to draw on relevant international best practice and latest academic thinking. The report will consider all aspects of transmission arrangements that are relevant to the allocation of costs arising in transmission, including: investment in transmission assets, costs of transmission congestion and transmission losses, costs for purchasing ancillary services required for safe and secure operation of the transmission system.

We are looking for views on:

a) appropriate guiding principles for transmission charging that are consistent with meeting the objectives set out above;
b) the broad building blocks of a suitable target charging model that would best achieve the objectives as a whole, taking into account any trade-off amongst these objectives, for example:
    - economic efficiency vs facilitation of carbon reduction;
    - long-run investment efficiency including both transmission and generation vs short-run operational efficiency; and
    - requirements for a self-contained system vs those relevant for closer integration of other European systems cross-border.
c) the interdependencies between the proposed charging model and other aspects of the regulatory regime for electricity and, where relevant, gas networks, including cross-European regulatory and policy developments. Where possible, the report should also provide views on the extent to which these help or hinder under the existing GB arrangements.

Deliverables
In line with our high level timetable for Project TransmiT, which includes a milestone of publishing Ofgem's recommendations in Summer 2011, we require the following deliverables from the advisors:

- An initial note by mid December 2010 on high level principles for transmission charging;

- A first draft report by early February 2011 to be presented to a workshop with key experts;
- A draft final report by end March 2011 that has taken into account the comments from Ofgem and the workshop; and
- A final report submitted by end April 2011 that can be published.

Appendix 2 – EU Legislation

Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC

Article 16

Access to and operation of the grids

1. Member States shall take the appropriate steps to develop transmission and distribution grid infrastructure, intelligent networks, storage facilities and the electricity system, in order to allow the secure operation of the electricity system as it accommodates the further development of electricity production from renewable energy sources, including interconnection between Member States and between Member States and third countries. Member States shall also take appropriate steps to accelerate authorisation procedures for grid infrastructure and to coordinate approval of grid infrastructure with administrative and planning procedures.

2. Subject to requirements relating to the maintenance of the reliability and safety of the grid, based on transparent and non-discriminatory criteria defined by the competent national authorities:

(a) Member States shall ensure that transmission system operators and distribution system operators in their territory guarantee the transmission and distribution of electricity produced from renewable energy sources;

(b) Member States shall also provide for either priority access or guaranteed access to the grid-system of electricity produced from renewable energy sources;

(c) Member States shall ensure that when dispatching electricity generating installations, transmission system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria. Member States shall ensure that appropriate grid and market-related operational measures are taken in order to minimise the curtailment of electricity produced from renewable energy sources. If significant measures are taken to curtail the renewable energy sources in order to guarantee the security of the national electricity system and security of energy supply, Members States shall ensure that the responsible system operators report to the competent regulatory authority on those measures and indicate which corrective measures they intend to take in order to prevent inappropriate curtailments.

3. Member States shall require transmission system operators and distribution system operators to set up and make public their standard rules relating to the bearing and sharing of costs of technical adaptations, such as grid connections and grid reinforcements, improved operation of the grid and rules on the non-discriminatory implementation of the grid codes, which are necessary in order to integrate new producers feeding electricity produced from renewable energy sources into the interconnected grid.

Those rules shall be based on objective, transparent and non-discriminatory criteria taking particular account of all the costs and benefits associated with the connection of those producers to the grid and of the particular circumstances of producers located in peripheral regions and in regions of low population density. Those rules may provide for different types of connection.

4. Where appropriate, Member States may require transmission system operators and distribution system operators to bear, in full or in part, the costs referred to in paragraph 3. Member States shall review and take the necessary measures to improve the frameworks and rules for the bearing and sharing of costs referred to in paragraph 3 by 30 June 2011 and every two years thereafter to ensure the integration of new producers as referred to in that paragraph.

5. Member States shall require transmission system operators and distribution system operators to provide any new producer of energy from renewable sources wishing to be connected to the system with the comprehensive and necessary information required, including:

(a) a comprehensive and detailed estimate of the costs associated with the connection;

(b) a reasonable and precise timetable for receiving and processing the request for grid connection;

(c) a reasonable indicative timetable for any proposed grid connection.

Member States may allow producers of electricity from renewable energy sources wishing to be connected to the grid to issue a call for tender for the connection work.

6. The sharing of costs referred in paragraph 3 shall be enforced by a mechanism based on objective, transparent and non-discriminatory criteria taking into account the benefits which initially and subsequently connected producers as well as transmission system operators and distribution system operators derive from the connections.

7. Member States shall ensure that the charging of transmission and distribution tariffs does not discriminate against electricity from renewable energy sources, including in particular electricity from renewable energy sources produced in peripheral regions, such as island regions, and in regions of low population density. Member States shall ensure that the charging of transmission and distribution tariffs does not discriminate against gas from renewable energy sources.

8. Member States shall ensure that tariffs charged by transmission system operators and distribution system operators for the transmission and distribution of electricity from plants using renewable energy sources reflect realisable cost benefits resulting from the plant's connection to the network. Such cost benefits could arise from the direct use of the low-voltage grid.

Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC

Article 15

Dispatching and balancing

1. Without prejudice to the supply of electricity on the basis of contractual obligations, including those which derive from the tendering specifications, the transmission system operator shall, where it has such a function, be responsible for dispatching the generating installations in its area and for determining the use of interconnectors with other systems.

2. The dispatching of generating installations and the use of interconnectors shall be determined on the basis of criteria which shall be approved by national regulatory authorities where competent and which must be objective, published and applied in a non-discriminatory manner, ensuring the proper functioning of the internal market in electricity. The criteria

shall take into account the economic precedence of electricity from available generating installations or interconnector transfers and the technical constraints on the system.

3. A Member State shall require system operators to act in accordance with Article 16 of Directive 2009/28/EC when dispatching generating installations using renewable energy sources. They also may require the system operator to give priority when dispatching generating installations producing combined heat and power.

4. A Member State may, for reasons of security of supply, direct that priority be given to the dispatch of generating installations using indigenous primary energy fuel sources, to an extent not exceeding, in any calendar year, 15 % of the overall primary energy necessary to produce the electricity consumed in the Member State concerned.

5. The regulatory authorities where Member States have so provided or Member States shall require transmission system operators to comply with minimum standards for the maintenance and development of the transmission system, including interconnection capacity.

6. Transmission system operators shall procure the energy they use to cover energy losses and reserve capacity in their system according to transparent, non-discriminatory and market-based procedures, whenever they have such a function.

7. Rules adopted by transmission system operators for balancing the electricity system shall be objective, transparent and non-discriminatory, including rules for charging system users of their networks for energy imbalance. The terms and conditions, including the rules and tariffs, for the provision of such services by transmission system operators shall be established pursuant to a methodology compatible with Article 37(6) in a non-discriminatory and cost-reflective way and shall be published.

Article 23

Decision-making powers regarding the connection of new power plant to the transmission system

1. The transmission system operator shall establish and publish transparent and efficient procedures for non-discriminatory connection of new power plants to the transmission system. Those procedures shall be subject to the approval of national regulatory authorities.

2. The transmission system operator shall not be entitled to refuse the connection of a new power plant on the grounds of possible future limitations to available network capacities, such as congestion in distant parts of the transmission system. The transmission system operator shall supply necessary information.

3. The transmission system operator shall not be entitled to refuse a new connection point, on the ground that it will lead to additional costs linked with necessary capacity increase of system elements in the close-up range to the connection point.

Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity

Article 4

Charges for access to networks

1. Charges applied by network-operators for access to networks shall be transparent, take into account the need for network security and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and applied in a non discriminatory manner. Those charges shall not be distance-related.

2. Producers and consumers ("load") may be charged for access to networks. The proportion of the total amount of the network charges borne by producers shall, subject to the need to provide appropriate and efficient locational signals, be lower than the proportion borne by consumers. Where appropriate, the level of the tariffs applied to producers and/or consumers shall provide locational signals at European level, and take into account the amount of network losses and congestion caused, and investment costs for infrastructure. This shall not prevent Member States from providing locational signals within their territory or from applying mechanisms to ensure that network access charges borne by consumers ("load") are uniform throughout their territory.

Article 6

General principles of congestion management

1. Network congestion problems shall be addressed with non-discriminatory market based solutions which give efficient economic signals to the market participants and transmission system operators involved. Network congestion problems shall preferentially be solved with non transaction based methods, i.e. methods that do not involve a selection between the contracts of individual market participants.

2. Transaction curtailment procedures shall only be used in emergency situations where the transmission system operator must act in an expeditious manner and redispatching or countertrading is not possible. Any such procedure shall be applied in a non-discriminatory manner.

Except in cases of "force-majeure", market participants who have been allocated capacity shall be compensated for any curtailment.

3. The maximum capacity of the interconnections and/or the transmission networks affecting cross-border flows shall be made available to market participants, complying with safety standards of secure network operation.

4. Market participants shall inform the transmission system operators concerned a reasonable time ahead of the relevant operational period whether they intend to use allocated capacity. Any allocated capacity that will not be used shall be reattributed to the market, in an open, transparent and non-discriminatory manner.

5. Transmission system operators shall, as far as technically possible, net the capacity requirements of any power flows in opposite direction over the congested interconnection line in order to use this line to its maximum capacity. Having full regard to network security, transactions that relieve the congestion shall never be denied.

6. Any revenues resulting from the allocation of interconnection shall be used for one or more of the following purposes:

(a) guaranteeing the actual availability of the allocated capacity;

(b) network investments maintaining or increasing interconnection capacities;

(c) as an income to be taken into account by regulatory authorities when approving the methodology for calculating network tariffs, and/or in assessing whether tariffs should be modified.

Appendix 3 – Pertinent transmission licence conditions

Licence condition B12:

The objectives of the transmission licensees are (inter alia):

- "the development, maintenance and operation of an efficient, economical and coordinated system of electricity transmission;
- facilitating effective competition in the generation and supply of electricity;
- protection of the security and quality of supply and safe operation of the GB transmission system insofar as it relates to interactions between transmission licensees."

Licence Condition C5: Use of system charging methodology

" 'the relevant objectives' [of the Use of System Charging Methodology] shall mean the following objectives:

a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;
b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); and
c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses."

Appendix 4 – ICREP design options

In section 6.4, it was suggested that the present day drivers for investment in additional transmission capacity – and the consequences of lack of capacity for constraint costs – might be better reflected through the existing TNUoS methodology by the inclusion of an energy element. We suggest that such an approach might be called Investment Cost-Related Energy pricing, or ICREP.

A number of options might be thought of for precisely how it could be done. Although we have not considered it within the scope of our present study to undertake a detailed, quantified ICREP design and demonstration exercise, we set out some initial suggestions in this appendix. These fall into four basic approaches. In each case, we assume that what we regard as the main flaws in the present ICRP process have been corrected. (See section 6.2 for a discussion of these).

1. Leave the locational element of TNUoS alone and introduce an energy element into the way the residual is calculated.
2. Levy a proportion of the locational element of TNUoS via an energy-related charge.
3. Set the initial condition of the load flow from which MWkm figures are derived in the locational element of TNUoS by reference to the relative annual energy production of each generator. In order words, apply not only a single, uniform scaling to ensure that total generation matches total generation in the load flow, but, first, apply a generator specific scaling proportional to its annual load factor and then a uniform scaling to ensure that total generation in the load flow matches demand.
4. Calculate 'shadow costs' at each node, i.e. the change to the total cost of transmission consequential to an additional MW of generation or demand at a node for some indicative hours of operation, each weighted in a final charge in such a way as to approximate the overall impact on cost of transmission,

Approach 1 is self-explanatory but would require some trial and error to ensure that the final charges levied on individual users are reasonably reflective of the transmission costs they impose.

In respect of approach 2, National Grid might calculate zonal costs as at present (with amendments as we suggested in section 6.2). However, some proportion of the resulting charges would then be converted from £/MW to £/MWh. For demand charges, this would require an estimate of the ratio of the system peak demand (perhaps measured on National Grid's "Triad" basis) to the total energy demand over the year. For generation charges, this would require an estimate of the ratio of installed capacity to energy generation over the year. The charges in £/kW would be multiplied by these ratios to give charges in £/MWh. Even though the ratios are only estimates, these charges could be set in stone before the start of each year, and any revenue surplus or shortfall could be rolled forward to the next year's calculations, as already happens under the price control methodology.

Approach 3 is similar to the approach mooted by National Grid for intermittent generation (National Grid, 2010b) but would apply to all generation regardless of type. (Some indicative studies on the effect of these were conducted by an MSc student at Strathclyde as part of her final individual project. The results have not been published and would need to be verified but suggest that for the planned 2015/16 transmission network before commissioning of the first HVDC 'bootstrap' where generation capacity factors are taken into account, charges levied on low capacity factor plant in the north (such as wind farms) would be around the same level as would be the case for a postage stamp approach. However, under a postage stamp approach, demand in the north would pay more than under a cost-reflective approach).

Approach 4 would represent an extension to ICRP that would take into account relative energy outputs from different generators but also proximity of power flows to network limits. It would have a number of features that promise greater accuracy in reflecting costs of transmission but at the expense of greater complexity in the modelling compared with approach 3. An acceptable compromise between accuracy and simplicity would need to be investigated.

Unlike LRIC described in section 6.3, ICREP approach 4 would look only a year ahead and so would not be nearly as sensitive to variations in forecasts. Unlike ICRP, it would not assume that each branch of the network is, in effect, already at its limit. Rather, its actual limit would be used. The action consequential to a limit being reached would be determined by an optimisation to estimate its cost. The costed action would be either to undertake balancing actions (paid for via bid and offer acceptances), reinforcement of an overloaded branch or a combination, whichever was cheapest. (Bid and offer prices would be typical averages, as would costs per MWkm of reinforcements, the latter rather as in ICRP). In so doing, it would attempt to represent the decision that a planner would take. However, if significant complexity arising from the need for many conditions – different demand levels, different generation 'merit orders' and different fault outages – is to be avoided, some simplifications could be used. For example, the initial condition for generation would be a scaled condition similar to that suggested in approach 3. Just one representative demand level might be considered, or a small number of different ones, with total constraint costs estimated by use of suitable durations for each modelled condition. In the latter case in the setting of initial conditions, different generator capacity factors could be used that are appropriate to the season or time of day that the demand condition represents. Finally, a large set of outages (representing either faults or, for spring, summer or autumn conditions, planned outages) might be modelled in a 'security-constrained optimal power flow'. Alternatively, to reduce the number of constraints in the optimisation and the time needed for the computation to be carried out, only the intact network case might be represented albeit with individual branch ratings scaled down to represent the need for pre-fault loadings to be low so as to leave some headroom for post-outage conditions (an adjustment analogous to that of the 'security factor' in ICRP). Some experimentation would be needed to calibrate the model initially and determine an appropriate number of conditions to model or the scaling of branch ratings so as to reasonably reflect actual costs without requiring what users might see as excessive complexity. (Note that voltage or stability limits would normally be neglected – it would be assumed that most system reinforcements or balancing actions would be due to thermal limits being reached, and these can be quite well approximated by so-called 'DC optimal power flow' which has the advantage of being simpler and more robust than the 'AC' version. However, transfer limits arising from voltage or stability constraints might be added artificially, based on offline analysis, although it would remain to be determined how to cost remedies to such limits).

Some points of detail apply to all the approaches that use an annual capacity factor and would relate to the way in which that capacity factor is calculated.

- In order to minimise opportunities for playing the ‘dec game’, the capacity factor might be calculated based on the ‘final physical notifications’ (FPNs) submitted by individual ‘balancing mechanism units’ rather than by final physical output that may have been subject to balancing actions. (Generators tempted to ‘over declare’ their FPNs would end up paying higher TNUoS charges than if they had submitted lower FPNs).
- To smooth out year-by-year variations caused by changes in, for example, wind conditions, rainfall or major generator outages, the ‘capacity factor’ used in the methodology might be based on, say, 5 year averages of FPNs. (For new generators, in the first year, a forecast would be used and thereafter outturns used as they become available).

A further design option would concern whether the industry is content with a zonal approach in which nodal costs are averaged across nodes with comparable nodal costs, or whether a nodal approach is preferred. (One disadvantage with a zonal approach is that if a zonal boundary change seems to be required, a transmission user at a node that is moved from one zone to another might see a significant step change in their charges).

The above implementation suggestions are simply that: suggestions. We offer them not as the last word but simply as ideas from which to start and in order to help readers begin to form a view of what ICREP might look like.

We envisage a programme of work that would investigate the above options and make recommendations for the detailed implementation. We would foresee such a programme of work being much simpler and shorter than that to effect the regulatory changes necessary to implement LMP and FTRs, for example.