Project TransmiT

Academic Review of Transmission Charging Arrangements

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1 Introduction

Ofgem has recently launched Project TransmiT - an independent and open review of transmission charging and associated connection arrangements. The aim of the review is to ensure that Great Britain has 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 for existing and future consumers.

Ofgem commissioned three academic teams in December 2010 (Newbery, EPRG, the University of Cambridge; Bell et al, Strathclyde and Birmingham Universities; and Baldick et al, from a number of American universities) and asked them to provide their views on the optimal approach to transmission charging for Great Britain given the new challenges networks face.

In February 2011, Ofgem asked the Energy Policy Group (EPG) of the University of Exeter for a fourth short report, addressing the following questions;

- Whether transmission charging arrangements should be a relevant vehicle to promote low carbon generation?
- How the transmission charging arrangements could be structured to either remove barriers to, or to facilitate the deployment of, low carbon generation?
- How such arrangements might fit with the wider context of the Governments' existing and proposed policy for supporting low carbon generation?
- What the implications of doing this might be in both the short and long-run, in terms of the costs seen by customers, security of supply and competition in the generation market?

The structure of this paper reflects these questions. It begins with a contextualisation of the underlying philosophy of the arguments made within the other three Academic reports (Section 1) and then discusses the regulatory duties on Ofgem and National Grid and whether they need to be amended (Section 2). It then provides an overarching discussion of whether transmission charging should be a vehicle to promote low carbon (Question 1, Section 3). It proceeds by considering whether or not existing transmission charging arrangements do represent a barrier to the deployment of low carbon (renewable) generation (Question 2, Section 4.1) and then proposes how identified barriers may be addressed (Question 2, Section 4.2). Finally, the paper goes on to consider how these proposals may fit with wider Government existing and proposed policy (Question 3, Section 5); and what their implications may be for the short and longer term (Question 4, Section 6).

The Energy Policy Group was also asked to provide a critique of the three original academic reports[1]. This critique endeavoured to evaluate at a very high level what recommendations for transmission charging the three reports made and their views of alternative proposals, the extent to which each report answered the questions set out in the Terms of Reference and any issues which could

[1] See http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110322_TransmiT_Charging_Update%20for%20publication.pdf

reasonably have been expected to be evaluated in a little more detail. This paper aims to address some of those latter issues in a qualitative fashion, and particularly the issue of whether an appropriate balance had been struck in key areas of trade off between potentially conflicting objectives.

2 Contextualisation of this Report

The UK is at a very uncertain time with respect to energy policy. It is still not clear what technology pathway Great Britain will follow over the next several decades: it could range from an increasingly electric future, provided by a mix of technologies and fuels but with a large proportion of nuclear power through to a diverse, multi-scaled super-smart energy-efficient gas and electricity future with a high proportion of renewable energy (RE), storage and interconnections. As far as is possible, transmission charging arrangements should recognise this uncertainty and be robust against a range of possible outcomes. However, the two imperatives that GB transmission charging needs to accommodate in the medium term are facilitating the achievement of the UK's Renewable targets for 2020 and the development of a single European electricity market by 2014, in addition to the ever present issues of protecting customer interests and security of supply.

In a perfect, first-best world, it should be possible to address and optimise individual elements of energy policy in isolation, with confidence that the overall policy outcome would also be optimised. However, the world is not perfect and measures designed to deliver desired outcomes in particular policy areas may lead to distortions in other areas, with a consequent need for compensating action. We believe that this is a relevant factor in the case of transmission charging. Rather than considering transmission charging in isolation, the paper argues that this and other issues justify a broader view being taken, including the impacts of transmission charging on the overall costs of achieving our renewable targets. While the paper proposes actions to remove anomalies that should make the existing transmission charging arrangements more cost-reflective, the existence of these market distortions opens up the possibility that going beyond cost-reflectivity and discriminating in favour of intermittent renewable generation might allow the UK's renewable directives to be delivered at lower cost, although more work needs to be done to confirm that this is the case. Furthermore, we believe that recent decisions by the Department of Energy & Climate Change (DECC) in relation to transmission access, by Ofgem in relation to the Balancing System Use of System (BSUoS) charges and by National Grid in relation to the costs of accommodating an increase in the largest system infeed , together with Environmental Guidance issued to Ofgem by DECC, support the view that actions which may not be considered to be cost reflective in a narrow sense, are permissible in pursuit of broader economic and environmental objectives.

Applying this holistic approach, the paper suggests a number of modifications that would both address anomalies in the existing arrangements and potentially reduce the overall cost of delivering the UK's renewable targets. However, modifications to the existing charging methodology may have a relatively limited shelf-life due to the advance of European electricity market integration. The intention to create a single European electricity market by 2014 will require the UK to have market coupling arrangements in place across interconnectors with other European Member States by that time. The option therefore arises of extending market coupling arrangements to deal with internal congestion and moving to a flat or flatter transmission pricing regime. This approach would harmonise UK practice with that adopted in most of European Member States and avoid the possibility of generation in GB being at a competitive disadvantage compared with generation in Europe.

Finally, there is a need to note that, while the questions posed by Ofgem relate to low-carbon generation, the immediate problems to be addressed in terms of transmission charging relate to the deployment of renewables and delivering the UK's renewable targets. The paper therefore effectively substitutes "renewable" for "low carbon" generation. Also, when discussing the implications of renewable support mechanisms for transmission charging, the paper assumes that, whatever arrangements are introduced to replace the Renewable Obligation, the same or similar differentials in support for onshore and offshore wind will remain.

3 Regulatory issues

Ofgem is governed by the Gas and Electricity Markets Authority (GEMA). The Authority's primary duties focus on the protection of customer's interests, where appropriate by promoting competition. In carrying out these primary duties, the Authority is required to have regard to, inter alia, the need to contribute to the achievement of sustainable development. The Government also issues Guidance to Ofgem on the exercise of the Duties in relation to social and environmental policy objectives, which includes specific reference to reducing emissions of greenhouse gases and increasing the level of renewable energy supply to 15% by 2020. The Government expects the Authority, and through it Ofgem, to proactively look for barriers and opportunities which could inhibit or encourage the transition to low carbon energy systems in Great Britain (DECC 2010a).

The degree to which Ofgem takes account of social and environmental issues, and the balance it strikes between these issues and the economic dimension of its duties, has been the subject of debate for several years. The most recent Social and Environmental Guidance would appear to be clear that Ofgem must enable the achievement of the government's policy objectives (DECC 2010 p6):

> The Government considers the Authority's duties to have regard to the interests of vulnerable consumers and to contribute to the achievement of sustainable development to be essential elements of its remit, and to be the basis upon which the Authority must make a significant contribution to the achievement of the Government's social and environmental objectives as set out in this Guidance.

However, the ongoing DECC review of Ofgem's role and activities has highlighted the degree to which the Guidance on social and environmental issues are seen as being 'largely ineffective' and that it is unclear how Ofgem builds the guidance into its decision making (DECC 2010a p3).

It appears inevitable therefore that the Government will have to develop a new approach. This could take two main forms: an amendment to the duties to promote the contribution to sustainable development to a primary duty, or an amendment to the Guidance to ensure greater transparency and greater weight in how it is implemented. Neither approach would be simple: 'sustainable development' is a highly contested concept which would need to clearly defined if it were to be usefully incorporated as a primary duty, while any guidance is by its very nature unenforceable, flexible and open to interpretation by Ofgem .

While accepting that neither is easy, the former appears preferable on the grounds that it could lead to a clarification of the roles and responsibilities of Government and Ofgem respectively. The approach would require an agreement to be reached between Ofgem and the Government over what constitutes sustainable development. The agreement would need to be reviewed at specified times, for example every two years, and explicitly linked to Government policy, which in turn is linked to the Commission on Climate Change's carbon budgets. The agreement would require general specifications, for example that the barriers within Ofgem's control for achieving low carbon targets should be removed, implementing rules to incorporate the demand side into markets and ensuring access by new entrants and smaller players. In addition, detailed specifications should be incorporated where necessary, an approach already adopted in the Guidance. Lastly, if legislation is enacted at the national or EU level – for examples the 15% renewable energy target for 2020 – Ofgem's presumption should always be in favour of measures to achieve the legislative goals set. The criteria and reasoning behind the agreement would have to be published to ensure clarity and accountability.

At root, the key requirement is to remove the lack of clarity about responsibility for sustainable development and in particular Ofgem's role in enabling a shift to low carbon energy systems. Government is responsible for policy and Ofgem has a role as in enabling the execution of policy. Currently, Ofgem clearly has the ability to interpret its role in relation to sustainability and social and environmental goals, and it is here that the 'role clarity' becomes woolly. An independent regulator carrying out Government policies is potentially problematic if the independence is seen to be compromised. But it is possible to develop a more pragmatic, discursive, transparent and legitimate relationship between Ofgem and Government, whereby Ofgem is explicitly responsible for enabling the execution of Government policies, although within this broad framework the actual means of execution are based on independent regulatory decisions.

It is worth highlighting at this point that while much debate has focused on Ofgem's role in relation to sustainable development, there has been little or no attention given to the responsibilities of transmission companies to contribute to more sustainable energy systems. Currently, neither National Grid's licence conditions, nor those of the Distribution Network Operators, incorporate a requirement to consider or enable a transition to more sustainable energy systems. This is inappropriate given the key role that networks will play in the deployment of more sustainable technologies and the importance that investment decisions made now will play in energy system configuration for decades into the future. Moreover, in practical terms, Ofgem's exercise of a sustainable development duty would to all intents and purposes be impossible if network companies were not also required to build sustainable development into their commercial decision making. Changing network operators' licence conditions therefore plays a vital role in enabling the achievement of government policy goals on social and environmental issues.

4 Whether transmission charging arrangements should be a relevant vehicle to achieve the aim of low carbon generation?

Transmission related charges, i.e. Transmission Network Use of System (TNUoS) charges, connection charges and BSUoS) charges, are designed to recover the costs incurred in investing in, maintaining and operating the transmission system. In accordance with National Grid's license duties, TNUoS and connection charges aim to be cost reflective. However, in the context of the question posed by Ofgem, it appears that the requirement for charges to be cost-reflective is not absolute with a number of recent decisions by DECC, Ofgem and National Grid indicating a preference for socialising transmission-related costs over more cost-reflective alternatives. Examples include DECC's decision to introduce a socialised version of a "connect & manage" transmission access approach[2], Ofgem's decision to veto National Grid's proposal to introduce locational BSUoS charges (GB ECM 18)[3], and National Grid's decision not to proceed with proposals that would allocate the additional costs of reserve associated with the increased largest system loss on those parties responsible for the additional costs[4].

In attempting to address Ofgem's first question, i.e. "should transmission charging policy positively assist the delivery of decarbonisation", it is worth noting that how decarbonisation will be achieved is surrounded by considerable uncertainty. It is not clear, for example, just what contributions technologies such as nuclear, intermittent renewables such as wind, tidal & wave, sequestered coal and gas fired generation or distributed & micro generation technologies will ultimately make to the achievement of the UK's climate change goals. Furthermore, it is not clear what the overall impact of energy efficiency measures together with the electrification of the heat and transport sectors will be on demand to be supplied.

Just how these emerging technologies ultimately contribute to decarbonisation could have significant implications for the shape of the future electricity grid. For example, distributed

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[2] Essentially, DECC considered that the risks of complexity and volatility of targeted BSUoS charges would outweigh any advantage in terms of reduced constraint costs. See; http://www.decc.gov.uk/assets/decc/Consultations/Improving%20Grid%20Access/251-govt-response-grid-access.pdf.

[3] Essentially, Ofgem considered that the risks of additional complexity and volatility introduced targeted BSUoS charges by GB ECM, together with a limited ability of generators to respond, would outweigh any advantages. See Ofgem's decision letter at; http://www.ofgem.gov.uk/NETWORKS/TRANS/ELECTRANSPOLICY/CHARGING/Documents1/GB_ECM-18_Decision_letter.pdfhttp://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/Charging/Documents1/GB_ECM-18_Decision_letter.pdf.

[4] A significant issue in National Grid's decision in not adopting a more cost-reflective methodology for the costs of accommodating an increased largest generation loss, was the potential delay in commissioning the large nuclear plant responsible for the increase, and the impact that this may have had on decarbonisation targets. See National Grid's decision letter at; http://www.nationalgrid.com/NR/rdonlyres/767F1A16-78EB-452E-8CC3-73317F060A99/42700/DecisionLettertoOfgemAugust2010v3_2_18810.pdf.

resources could broadly be expected to deploy uniformly across the UK with some possible bias for example with solar and distributed wind; sequestrated technologies could be expected to locate adjacent to fuel sources, either coal or gas, but may need to “cluster” and locate close to CO2 depositories in order to limit gas transportation costs; new nuclear will locate away from population centres but utilise existing nuclear sites, relatively well served by transmission; offshore wind, wave and tidal resources will need to connect to specific, generally remote, areas of the onshore network, while the deployment of onshore wind is also increasingly being limited and driven to remote areas by planning restrictions.

Although the areas to which the technologies that may contribute to decarbonisation will locate are therefore generally known, the locations are very different and the contribution that each technology might make is uncertain. It is therefore quite difficult to anticipate the optimum topology of the future electricity grid. Until more is known about the contributions that individual technology are likely to make to the UK’s decarbonisation goals, designing a transmission charging mechanism that attempted to discriminate positively in favour of particular technologies would appear to involve some risk, as this could result in stranded transmission assets and decarbonisation being ultimately achieved at a higher cost than was absolutely necessary. Electricity supply assets, whether generation, transmission or distribution, are long-lasting and the consequences of distorted investment decisions brought about by bias in transmission charging that ultimately proved to be misplaced, would also be long-lasting and potentially expensive.

Notwithstanding these general uncertainties, it is clear that wind is the only renewable technology that can currently be deployed at scale and is therefore crucial in terms of delivering the UK’s immediate renewable and low carbon objectives. Onshore wind will be required to make a significant contribution to the 2020 target and it is therefore particularly important that strong locational signals contained within use of system charges do not close down otherwise viable onshore siting options. Onshore capacity not delivered will need to be replaced by considerably more expensive offshore capacity and, to the extent that reduced TNUoS charges for wind will free up additional onshore wind capacity, there may be value in designing locational signals with the aim of delivering the 2020 renewable targets at least cost. Furthermore, it could be argued that transmission or distribution charges are likely to impact more significantly on distributed resources and smaller projects such as onshore wind, compared with nuclear or sequestered technologies whose capital and operating costs are likely to dwarf the costs of transmission access, and that this may be an issue to take into account in designing those charges. In other words, and in accordance with Ramsey pricing principles, any bias in transmission charging should be in favour of “sensitive” technologies and against those less likely to be affected by the magnitude of those charges.

Another argument to support the use of system charging to positively assist in delivering decarbonisation is that electricity pricing is currently used to deliver other policy objectives, notably in the areas of fuel poverty and indeed energy efficiency. While it can be argued that such interventions are not economically efficient, run the risk of unintended consequences and introduce distortions, cross subsidisation and non cost-reflective pricing as a means of accommodating sometimes conflicting policy objectives are a reality in the energy sector. A defence for transmission charging to positively discriminate in favour of renewable resources may also be found in EU legislation, with Directive 2009/28/EC requiring Member States to guarantee the transmission and distribution of energy from renewable sources and to provide guaranteed or priority access to the grid system for that energy.

5 How the transmission charging arrangements could be structured to either remove barriers to, or to facilitate the deployment of, low carbon generation?

In attempting to address Ofgem's second question, , it is necessary to first identify to what extent, if any, existing transmission charging methodology creates barriers to renewable or low carbon generation. The following paragraphs suggest a number of areas where existing arrangements may indeed create barriers, and then go on to suggest options to either remove those barriers or possibly discriminate in favour of renewable generation.

5.1 Potential barriers

5.1.1 Treatment of intermittent generation.

It has been demonstrated that the existing charging methodology can, in some instances, discriminate against intermittent renewable generation (Strbac, 2007) (National Grid, 2010). The cause of this discrimination lies in the nature of the Security and Quality of Supply Standards (SQSS), the peak-related nature of the TNUoS methodology used to recover the costs caused by the application of the SQSS and in the nature of transmission rights allocated via Transmission Access Capacity (TEC).

Essentially, intermittent renewable generation generally requires less transmission investment than does the same amount of conventional generation capacity. Traditionally, the transmission system has been designed to ensure that generation, mostly conventional, can contribute to meeting winter peak demand with little or no constraint. However, as wind makes little or no contribution to winter peak demand, there is little point in providing the same amount of transmission capacity as for conventional generation that can provide a more substantial contribution. However, as well as continuing to ensure that generation can contribute to meeting winter peak demands, the transmission system will increasingly need to able to accommodate both the output of large amounts of intermittent renewable generation when its primary resource is available, and replacing conventional generation when renewable output is low. It will not be economic to provide sufficient transmission to allow all generation to operate simultaneously, and conventional and intermittent renewable generation will therefore need to “share” available transmission capacity. Neither the accepted concept of TEC or transmission charging methodology are capable of recognising the “sharing” of transmission capacity in their current form.

Both the “peak contribution” and “sharing” issues suggest that the current TNUoS methodology over-charges intermittent renewable generation for use of the transmission system and is not therefore truly cost-reflective. The “sharing” issue also suggests that conventional generation that is prepared to share transmission capacity with intermittent renewable generation should similarly pay less for using the transmission system than conventional generation that is not so prepared. It should be noted that the “peak contribution” and sharing” arguments do not apply to other renewable generation technologies as these are not generally resource-constrained, nor to high load factor conventional generation such as nuclear, as the output of these technologies will tend to be “additive” and need to be accommodated simultaneously by the transmission system.

5.1.2 Ability of intermittent renewable generation to respond to locational signals.

Most conventional generation will have some choice about where to connect to the transmission network and will therefore be able to respond to locational signals delivered via TNUoS charges. The impact of TNUoS charges will be only one of many considerations in determining the location of a conventional generating station but, at the margin, locational TNUoS charges are capable of influencing locational decisions. In the case of existing conventional generation, locational signals will be one of the issues taken into account when considering ongoing economic viability and closure timescales.

The same may not be true for intermittent and some other (i.e. hydro) renewable technologies. The need to seek out economic levels of primary resource and an increasingly restrictive planning regime are likely to require intermittent technologies like wind to locate in specific areas not well served by transmission and where high TNUoS charges apply. However, where intermittent renewables have some choice as to where to connect, it is appropriate to apply locational signals. Taking the example proposed by Strathclyde and Birmingham Universities in their review of transmission charging (Bell, 2011), if the preferred site for a wind project was Orkney for reasons of increased load factor, but the project chose to locate on the northern Scottish mainland because the revenue that would flow from that increased load factor would not compensate for the increased TNUoS charges, then the correct economic signal would have been given. However, if the increased TNUoS charges that apply make wind farms in Orkney uneconomic, then it may be necessary to replace that sterilised wind capacity by offshore capacity, which could result in the overall cost of achieving the UK’s renewable obligations more expensive than necessary.

The Oxera report commissioned by Scottish Power (Oxera, 2010) analyses this situation in some detail and concludes that “flat” transmission charges could boost deployment of onshore wind by around 4-8%, or up to 4TWh, due to the exploitation of marginally economic sites. As the capital cost of offshore wind at around £2,700/kW is almost twice that of onshore wind, then the analysis suggests that applying locational signals to wind via TNUoS charges is likely to make efforts to achieve the UK’s renewable targets more expensive than necessary. Oxera suggest that protecting wind from locational signals would either increase the chances of the UK meeting its 2020 renewable target or, assuming that the target is achieved, potentially accrue savings of some £160 million in each subsequent year. Presumably, a similar increase in onshore wind capacity could be obtained by providing additional ROC income to projects in areas with high TNUoS charges. This would, however, appear to be a potentially more expensive solution as renewable support costs would increase. Adjusting locational signals within TNUoS on the other hand would simply reapportion costs within the generation community with no overall impact on the total costs recovered.

It should be noted that, while reducing locational signals for intermittent renewable generation by some amount could potentially reduce the overall costs of achieving the UK’s renewable targets, a move to “flat” transmission charges for all generation, without any compensating locational messages being delivered, for example, through energy prices, could well have the opposite effect. The removal of all locational signals is likely to result in conventional plant locating in Scotland, thereby competing with intermittent renewable generation for scarce transmission capacity and increasing the need for expensive transmission reinforcement, in addition to increasing transmission losses. The introduction of flat transmission charges for all generation would, therefore, be likely to increase the overall costs meeting the UK’s decarbonisation goals and costs to end-users in general.

5.1.3 Proposed changes in the methodology for charging license- exempt embedded generation for use of the transmission system.

Currently, unlicensed generation connected to the distribution system is treated as negative demand and is not required to pay TNUoS charges. Subject to negotiation with its associated supplier, the generator is paid a proportion of the TNUoS demand tariff, to reflect the fact that the supplier’s exposure to TNUoS charges is reduced due to the output of the distribution-connected generator during triad periods. The generator is, of course, also liable for distribution use of system charges.

If TNUoS generation and demand charges were entirely locational and equal and opposite, the current charging arrangements would present no problem. However, the need for a non-locational residual element to ensure that the correct levels of revenue are collected results in a net TNUoS benefit to distribution connected generation over generation connected to the transmission network. This benefit is estimated by National Grid (National Grid, 2010) as around £20/kW.

In response to this charging anomaly, and in the belief that currently generators are incentivised to connect to the distribution rather than the transmission system, National Grid appear to favour a “gross” charging solution[5] that could expose all distribution-connected generation above some de-minimis capacity to full TNUoS generation charges, in other words there would be no distinction between distributed and transmission connected generation in terms of transmission charges. While the starting point in attempting to address the issue of charging distributed generation for using the transmission system should be cost-reflectivity, the prospect of “gross” charging raises a number of major concerns. Not only would some distribution-connected generation see a significant increase in network charges, but the rational for “gross” charging ignores the fact that the impact that distribution networks have on transmission investment is driven by power flows across the network interface, rather than the impact of the output of individual distribution-connected generators alone.

While any transmission costs incurred by flows across the transmission-distribution interface should be reflected in charges imposed on users of the distribution system, those charges also need to take into account broader issues of decarbonisation and security of supply. Distributed generation, including smaller and micro-generation technologies can make a significant contribution to both, and it is important that the charges they face in utilising the electricity network do not act as deterrent to deployment.

[5] See GB ECM-23 “Transmission arrangements for Distributed Generation – Pre Consultation; http://www.nationalgrid.com/NR/rdonlyres/B630B1A6-679B-4D13-8BF8-B597189DB6A1/39333/GBECM23TransmissionArrangementsforDistributedGener.pdf

5.1.4 Connection charges

Existing requirements to provide financial commitments to secure infrastructure investments places a disproportionate burden on smaller generators and in our view both undermines competition and represents a potential barrier to decarbonisation. When applying to connect to the transmission system, applicants are required to provide financial guarantees via cash payments to Escrow accounts, letters of credit or parent company guarantees etc to protect licensees and ultimately customers from the cost of abortive transmission investment. Liabilities are based on either the Final Sums or Interim Generic User Commitment (IGUC) methodologies. While these financing arrangements may present less difficulty for large generating companies developing large capacity projects, smaller companies with limited credit history developing smaller projects, sometimes involving innovative and emerging, more risky, technologies, may find the requirements prohibitive, particularly in the timescales before planning consents have been achieved. There is ample evidence to suggest that the requirement for securitisation has prevented smaller projects from proceeding and caused significant delays in the deployment of larger renewable projects.

The removal of wider infrastructure works from the Final Sums calculation is helpful to generation that opt for that securitisation route in that the level of potential liability is reduced, and a similar modification to the IGUC arrangements would be welcome. In addition, the adoption of a “connect & manage” approach to transmission access could be expected to reduce the securitisation burden, insofar as connection can occur prior to the completion of wider transmission reinforcements. However, securitisation arrangements can represent a significant barrier to the connection of renewable generation and further progress needs to be made.

5.2 Removing barriers and facilitating the deployment of low carbon generation

The analysis above suggests that the current charging arrangements, both for using and connecting to the transmission system, do present barriers to the deployment of low carbon generation. Furthermore, it is suggested that National Grid’s proposals for addressing anomalies in the current methodology for charging distribution-connected generation for use of the transmission system could, if implemented, create additional barriers. In response to Ofgem’s second question, the following paragraphs suggest how these barriers may be addressed.

5.2.1 Use of system charging.

It has been proposed that the inability of the existing transmission charging arrangements and access arrangements to differentiate between technologies effectively discriminates against intermittent renewable generation, which generally imposes less cost on the transmission network than some other generation technologies, including other renewable and low carbon technologies. The analysis also questions the usefulness of applying locational signals to intermittent renewable generation in situations where that generation may be unable to respond and refers to work by Oxera, which suggests that removing locational signals from renewable generation may reduce the overall cost of achieving the UK’s renewable targets. The following paragraphs discuss the relative merits of alternative charging mechanisms in addressing these issues, which appear to represent barriers to the deployment of intermittent renewable generation and delivery of the UK's renewable and decarbonisation goals.

These alternative charging mechanisms, namely "flat charging", "market splitting" and full "nodal pricing", together with possible refinements to the existing " Investment Cost Related Pricing (ICPR)" methodology are likely to be well understood by readers of this report and no attempt will be made to describe the design or details of each mechanism here. A comprehensive description of the existing charging arrangements is given by Technical Annex of the Project TransmiT call for evidence[6], while the alternative charging arrangements are described and discussed in the three Academic reports commissioned by Ofgem as part of Project TransmiT. (Baldick, 2011) (Bell, 2011) (Newbery, 2011).

5.2.1.1 *"Flat" or "postage stamp" charging*

If the locational element of the current ICRP transmission charging regime is seen to discriminate against intermittent renewable generation and cause the delivery of the UK's renewable goals to more expensive than necessary, why not move to a system of "flat" or "postage stamp" charging? Flat charging represents the simplest form of transmission charging methodology and would be more in line with charging practice in Europe, an issue that will be discussed in more detail later. However, "flat" charging would deliver no signals as to the costs that generation at different locations impose on the transmission system and would therefore result in a cross subsidy from generation located in "low cost" areas of the transmission system to generators located in "high cost" areas. New intermittent renewable generation could be expected to locate in the highest renewable resource areas, such as the Northern Isles, as they would be indifferent to the increases costs imposed on the transmission system. Similarly, new conventional generation could be expected to "move North" adding to congestion across the Cheviot boundary, increasing transmission losses and giving rise to the need for additional transmission capacity. If applied across the national transmission system, i.e. offshore as well as onshore, offshore wind projects could also be expected to seek locations that delivered the highest expected load factor as any additional connection costs would be socialised across all transmission system users[7].

5.2.1.2 *Discounted charges for intermittent renewable and other generation*

An alternative to moving to "flat" transmission charging for all generation (and demand), while still addressing the issue that intermittent renewable generation appears to be "overcharged" under the current charging regime, would be to retain the existing ICRP methodology, but apply a discount to the charges faced by intermittent renewable generation to reflect the lower costs imposed on the transmission system.

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[6] http://www.ofgem.gov.uk/networks/trans/pt/Documents1/TransmiT_Call_for_Evidence_Letter.pdf

[7] Since publication of the draft report, analysis undertaken by NERA and Imperial College for RWE has been published, which supports the intuitive views set out in this paragraph. The analysis concludes that, with uniform or "flat" TNUoS charges, renewable development will be more heavily concentrated in Scotland and offshore in the North Sea. New conventional generation could be expected to locate along the East coast of England and Scotland and also in South Wales, where access to gas is cheapest. Offshore wind development could be expected to moves to sites that are further from shore. The NERA/ Imperial College report for RWE can be viewed at:
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=94&refer=Networks/Trans/PT/WF

The justification for discounting TNUoS charges for intermittent renewable generation is based, in part, on the concept of "sharing" available transmission capacity with conventional generation – i.e. intermittent renewable generation utilising scarce capacity when its primary resource was available with conventional generation operating when it was not. In a decarbonised electricity system, where total connected generation capacity will need to exceed demand to be supplied by a considerable margin, available transmission capacity will fall well short of that necessary to allow all generation to operate simultaneously. Available transmission capacity will therefore need to be shared, either via auctions, trading or other voluntary arrangements. As the concept of trading transmission access rights via auctions and trading would be complex, particularly disadvantageous to intermittent renewable generation[8] and appears to have been ruled out[9], other arrangements need to be considered. It therefore seems appropriate that conventional generation willing to share transmission capacity with intermittent renewables should also be offered a TNUoS discount. Conventional generation willing to forgo their rights to compensation when constrained to accommodate renewable output should also be offered discounted TNUoS charges that reflect the reduced requirement to invest in additional transmission capacity. In fact, generators could be offered a menu of options, balancing a loss of access rights with reductions in TNUoS charges. The arrangements would be entirely voluntary, removing any issues associated with the forced removal of perceived transmission access rights. In fact, conventional generation would be offered exactly the same "bargain" as intermittent renewable generation, the option to trade access rights in return for reduced TNUoS charges. However, as low or zero marginal cost intermittent technologies such as wind would always naturally be dispatched before higher-marginal cost conventional generation, the rights of those intermittent technologies are unlikely to be much affected in practice.

Just what level of discount could be justified would need to be determined by further analysis. However, in their review of intermittent generation charging, GB ECM-25[10], National Grid suggest that very substantial reductions in the charges applied to intermittent renewable generation could be justified in some areas. For example, GB ECM-25 states that 2014/15 TNUoS charges for intermittent renewable generation located in Northern Scotland might fall to £11.00/kW compared with charges of £19.18/kW for conventional generation. Conversely, intermittent renewable generation in other areas may see an increased charge, for example intermittent generation located on the South West peninsular would see a charge of -£0.28/kW compared with -£4.23/kW for conventional generation.

If National Grid's analysis is accurate, and noting that the work needs to be extended to include conventional generation including pumped storage willing to share transmission capacity, then not to introduce some form of differential TNUoS charges would appear to be discriminatory and

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[8] Intermittent generation such as wind would be in the position of wanting to buy transmission access during congested periods when the value of access was high, while conventional generation would need access when the value of access was low.

[9] See DECC consultation document "Improving Grid access" : http://www.decc.gov.uk/assets/decc/Consultations/Improving%20Grid%20Access/1_20090825120038_e_@@_090825gridaccesscondoc.pdf

[10] See National Grid's consultation document "Review of intermittent generation charging"; http://www.nationalgrid.com/NR/rdonlyres/6EA5A608-1C5B-4BF7-8FAA-D0989C3E4C80/41918/GBECM25ReviewofIntermittentChargingConsultation.pdf

therefore in breach of National Grid's licence duties. Just how differential charges would play out in the context of delivering the UK's renewable goals at lowest cost probably needs more analysis in the style of that carried out by Oxera for Scottish Power, particularly given the negative impact on TNUoS charges seen by intermittent renewable generation located in areas such as the South West. However, given that the bulk of intermittent renewable connection activity seems likely to occur in areas that would benefit from a discounted approach (including for example the East Coast charging zones to which much offshore wind would ultimately connect), then the overall impact seems likely to be positive.

5.2.1.3 "Commoditised" transmission use of system charges

An alternative to discounting TNUoS charges for generation prepared to "share" transmission capacity, would be to charge system users on a commoditised basis. Rather than charging generation on a capacity basis, charges could be applied - either wholly or partially - on a per kWh basis. Demand could also be charged on a per kWh basis, or the existing triad arrangements could be retained. Low load factor plant, such as wind, would gain from commoditised charging, while high load factor plant, such as nuclear, would pay higher charges. Work carried out by National Grid and published in pre-consultation document GB ECM 13 (National Grid, 2008), which examined the implications of commoditising the residual element of TNUoS charges only, indicated that a wind generator situated in Scotland achieving a load factor of 30%, might see a reduction in TNUoS charges of around 7%, while a similar wind generator situated in the South West might see an increase in TNUoS payments of around 20%. Larger reductions would apply if the locational element of TNUoS charges were also charged on a per kWh basis.

The reductions in TNUoS charges that would flow from a commoditised approach would be helpful for wind and other intermittent renewable technologies. Commoditised charges would also overcome a disadvantage of capacity-based TNUoS charges in that an operational signal would be sent, which generators would need to take into account. As noted in the Academic report produced by Strathclyde and Birmingham Universities (Bell, 2011), if the locational element of TNUoS charges were to be commoditised, generation located further from demand would see higher operational costs than those located closer to demand.

Although commodity based transmission charging would appear to have some advantages, the approach does not appear to be based on sound principles, as transmission investment is primarily driven by capacity rather than energy issues. It can also be argued that basing generation charges on annual kWh output does not reflect usage of the system at time of peak demand (Poyry, 2010). The generation to gain most from commoditised TNUoS charges would be low load factor peaking plant, which arguably places no less of a burden on the transmission system in terms of capacity requirement and investment than does high load factor nuclear generation.

5.2.1.4 Nodal Pricing, market coupling and market splitting

The consensus of the Academic reports is that "locational marginal pricing" or "nodal pricing" is the theoretically correct solution to transmission pricing (Newbery, 2011) (Baldick, 2011) and therefore should be a serious contender in Ofgem's current review of transmission charging arrangements. It would, however, represent a radical departure from existing electricity market arrangements and any proposal to implement full nodal or locational pricing would need to demonstrate very significant advantages to justify the significant disruption and cost that would be incurred by market participants.

A move towards the principles of nodal pricing would, however, be seen to some extent inevitable. The implementation of a single European electricity market by 2014 will be via a "Target Model" applied to interconnection between Member States, based on the concept of "market coupling" at the day-ahead and intra-day trading timeframes. Market coupling will allow adjacent electricity markets to coordinate sales and purchases of energy at the day ahead and intra-day stages so as to satisfy total demand at the lowest price, without the need to establish a single power exchange. Where the interconnection between the adjacent markets is un-congested, a single energy price will apply. However, where congestion exists, individual market energy prices will diverge, giving rise to a "congestion rent" equal to the product of the interconnector flow and energy price differential. A locational signal will be delivered via the energy price differential for generation to locate in the market area with the highest energy prices. The reverse locational signal is, of course, given to demand. A hedge against energy price differentials can be obtained by purchasing interconnector capacity via capacity auctions prior to the day ahead timeframe, i.e. by obtaining transmission rights.

The adoption of market coupling on interconnection between Member States will effectively establish a system of "zonal" pricing across Europe. These "zones" may equate to national boundaries but more logically would bound areas of similar energy prices, i.e. market coupling would apply to congested boundaries within, as well as between, national electricity systems. Ultimately, and this has been the experience in the US (Baldick, 2011), zonal pricing could be expected to develop into full blown nodal or locational pricing in response to issues associated with redispatch.

As the UK will be required to adopt the principles of nodal pricing across interconnection with other Member States, there would appear to be some logic in extending those principles to deal with internal congestion within the GB transmission system. Adopting "market splitting" (market coupling but involving a single market exchange rather than separate exchanges) would seem particularly appropriate once the UK has additional interconnection with the Netherlands and Ireland, and might result in quite different interconnector flows than would be the case if a single GB energy price was maintained.

Market splitting would have clear implications for transmission charging as the locational signals delivered though energy price signals may sit uncomfortably with those emanating from ICRP pricing. A more elegant solution may be to rely on market splitting to deliver locational signals within GB, and to adopt a flat or flatter transmission charging regime to cover any shortfall in the total annual revenues TSOs are allowed to recover. This would also bring GB closer to the flat transmission charging format that generally prevails in Europe.

The energy price differentials that market splitting might open up across a congested Cheviot boundary would reflect differences in "offers" to run made by generation on either side of the boundary and could be expected to be considerably less than the typical Balancing Mechanism "bid – offer" differentials currently seen. Where the marginal plant on both sides of the congested boundary was of the same technology, i.e. coal, then the price differential could be small. Where the marginal technologies where not the same, i.e. coal replacing gas generation, the price differential would be greater (Poyry, 2008). Overall, however, the costs of managing congestion could be expected to be lower that with the current Balancing Mechanism arrangements and this could ultimately impact on the need for transmission reinforcements, potentially reducing the costs to customers in the longer term.

It is worth noting however, that on occasions when wind became the marginal plant in Scotland, price differentials across the Cheviot boundary could be high. Scottish wholesale energy prices could, for example, collapse or even go into negative on those occasions when wind output was constrained, as generators attempted to retain ROC income. Demand customers in Scotland would, of course, reap the benefits of low and possibly negative wholesale energy prices and a clear signal would be given to customers to increase demand during these periods, which would act to reduce congestion and again reduce the need for additional transmission.

The locational signals delivered via market splitting in the presence of congestion would be indifferent to technology. The issue again therefore arises of whether it is useful to impose locational signals on intermittent renewable generation, which may have little or no opportunity to respond. Conventional generation will generally have a choice of whether to locate on the import side of a congested transmission boundary, where energy prices will be higher in the presence of congestion, or on the export side, where energy prices will be lower. It seems entirely appropriate therefore, that conventional together with non-intermittent renewable and low carbon generation that has a choice where to connect to the transmission system, should be exposed to locational signals emanating from energy price differentials. However, intermittent renewable generation will generally be required to locate in areas of high renewable resource that are likely to export energy when that resource is available and experience lower energy prices when the export boundary is congested.

Transmission reinforcement in response to large price differentials across constrained boundaries would result in those differentials being reduced. However, in the presence of congestion, one means of addressing the issue of intermittent renewable generation not being able to respond to locational signals delivered via energy price differentials would be to give preference in the allocation of transmission rights across the congested boundary. Currently, transmission rights are awarded via the acquisition of "transmission entry capacity" (TEC), with TEC holders being compensated when prevented from operating due to congestion. However, the market coupling/ splitting arrangements envisaged by the European Target Model would not compensate constrained generation and access rights across congested boundaries to support bilateral trades would need to have been previously obtained via explicit auctions[11]. Dealing with internal congestion is, however, a matter for individual Member States and other methods of allocation could be envisaged, for example awarding access rights to incumbents or to some other class of generator such as intermittent renewables. Giving preference to intermittent renewables in terms of the allocation of transmission rights across congested boundaries would not only address the inability of that plant to

[11] Prior to the day-ahead timeframe the European Target Model envisages that interconnector capacity be allocated by auction. At the day ahead stage energy flows need to be nominated or interconnection capacity given up to the day-ahead market, where it is auctioned implicitly via the market coupling process.

respond to locational signals but would be consistent with the requirements of Article 16 of EU Directive 2009/28/EC[12], which requires that Member States provide priority or guaranteed access to the grid for renewable energy and ensure priority for dispatch. Alternative arrangements for allocating transmission rights across congested boundaries, for example via auction or by giving those rights to incumbents, could conceivably result in conventional generation having preference over renewable sources in both access to the grid and dispatch and could arguably be at odds with the requirements placed on Member States by Directive 2009/28/EC.

5.2.2 Charging license-exempt distribution-connected generation for use of the transmission system

The fact that boundary flows across the transmission-distribution interface are the driver for distribution network-driven transmission investment, rather than the output of individual generation or consumption of individual demand, suggests that a "net" rather than a "gross" charging solution to the issue of how distribution-connected generation should pay for using the transmission system is required. Although other mechanisms are possible, the most obvious and logical approach would be that DNOs should in future be charged for the impact that power flows to and from their networks have on the transmission system and transmission investment, and that DNOs should pass on those charges to individual generators or suppliers in some appropriate fashion. This implies a fundamental change in industry charging relationships and an increased role for DNOs (or DSOs) in the technical and commercial operation of the grid. However, this would be entirely consistent with a future in which "smart" distribution networks, consisting of controllable generation and demand, make an increasing contribution to a sustainable and decarbonised future. The alternative, of directly exposing generation not connected to the transmission system to TNUoS charges seems inconsistent with that future. The development of new micro and distributed generation technologies, together with "smart" appliances and flexible demand will result in new roles, responsibilities and relationships between customers, suppliers and network operators. DNOs should be encouraged to embrace these changes and develop "system operator" capabilities that would allow them to manage connected generation and demand so as to optimise the operation of their networks and to provide services to the transmission system. Adopting a "net" charging model would be consistent with this concept and would expose distribution-connected generation and demand to charges that reflected the actual impact of their operations on the need for transmission investment.

5.2.3 Securitisation and connection charges

While there is a need to protect customers from the risk of stranded assets, the current securitisation arrangements seem disproportionate and particularly detrimental to smaller projects. Options for reducing the securitisation burden for connecting generators will involve a rebalancing of asset stranding risk between generators, both connecting and connected, National Grid/TOs and customers. While connecting generators should bear their fair share of risk, the status of existing generation represents an equal risk of asset stranding and the allocation of securitisation requirements between existing and connecting generation should therefore be symmetrical. Customers should also bare some risk, as they will receive the benefits flowing from the connection

[12] EU Directive 2009/28/EC; http://eur-ex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0016:0062:en:PDF

of new generation and of decarbonisation. Currently, however, National Grid and the Scottish TOs do not appear to be exposed to the financial consequences of asset stranding to any significant extent and this needs to change. National Grid and the TOs are in a unique, if not ideal, situation in terms of access to available information necessary to guide appropriate investments and they should be exposed to the associated risks and rewards of making those investments.

National Grid is proceeding with a CUSC proposal for an enduring user commitment connection charging methodology (CMP 192)[13] that will seek to address issues such as risk the equitable treatment of commissioning and commissioned generation. Other options to reduce the burden of securitisation , particularly for smaller players, could include somehow taking project investment into account as an indication of a project's viability and as a proxy for securitisation. A precedent for this is the pre "connect & manage" approach to queue management, which took project status into account in determining queue position.

In addition, Ofgem has consulted on options for incentivising the TOs facilitate the timely connection of new generation under the new "connect & manage" regime and intends to develop output measures via the RIIO process[14]. Hopefully, these initiatives will result in arrangements that allow connection timescales to more closely match the requirements of developers and remove unnecessary delays. However, in terms of delivering the UK's renewable targets and decarbonisation goals, more needs to be done.

5.2.4 Anticipatory transmission investment

Given the need to exploit areas of high renewable resources in order to achieve the UK's climate change goals, and the challenging timescales involved, a more proactive approach to providing the enabling infrastructure necessary to release those resources in advance of individual project commitment is required. This would provide the impetus required to initiate the projects necessary to harvest those resources and, even if some individual projects fell by the wayside, other projects would be likely to take their place – provided that the "anticipatory" infrastructure reinforcements correctly identify strategic development areas.

The Academic review of transmission charging arrangements raised the issue of whether transmission development should follow generation, or whether a "central planning" approach should be adopted with generation following the provision of transmission (Baldick, 2011). The current "connect & manage" regime is firmly in the former camp, however in reality an element of generation follows transmission will always exist, due to the need for physical connection and concerns over congestion and congestion costs.

While connect & manage is an appropriate response to the need to ensure renewable projects are connected in a timely fashion, the need for enabling works and concern over congestion costs will continue to cause delays. There appears to be a case therefore, for incentivising TOs through regulation to anticipate demand for transmission capacity and initiating transmission development

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[13] See CUSC modification proposal CMP 192
http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

[14] See Ofgem document
http://www.ofgem.gov.uk/NETWORKS/TRANS/PT/Documents1/110322_TransmiT_Connections_Consultation_FINAL.pdf

that will release the renewable resource necessary to deliver the UK's renewable targets. Useful proposals for possible incentives were set out in Ofgem's Transmission Access Review – initial Consultation on Enhanced Transmission Investment Incentives[15], however these appear not to have been developed further. Instead, TSO's are required to submit proposals for transmission expenditure over and above that approved by the current Price Control for detailed assessment by Ofgem and Ofgem's consultants. This raises the issue of who is actually planning the system and seems an unnecessarily bureaucratic approach to delivering transmission investment, with at least three organisations involved in analysing investment need. National Grid and the Scottish TOs are best placed to make decisions about the need for investment and they should be incentivised to get on with the job – rewarded for making appropriate decisions and penalised if transmission investments become under-utilised.

Such an approach would not be without difficulties, for example the problem of deciding in the short term whether investments are likely to be fully utilised or not. However, the asymmetrical nature of the costs and consequences of investing early and of not investing in time tips the balance very firmly in favour of earlier investment. This fact needs to be recognised and, together with the challenging timescales for delivering the UK's renewable objectives, makes a strong case for incentivising National Grid and the Scottish TOs to anticipate future demand for transmission capacity and invest accordingly.

6 How such arrangements might fit with the wider context of the Government's existing and proposed policy for supporting low carbon generation?

6.1 Use of system charging

6.1.1 "Flat" or "postage stamp" charging

While "flat" transmission charges could be expected to release more onshore wind capacity due to the much reduced capital cost of onshore projects compared with offshore projects, the lack of any locational signals could be expected to markedly increase the costs of connection and the need for wider infrastructure reinforcement, almost certainly involving expensive offshore cabled HVDC systems, to accommodate increased power flows from Scotland. Overall, therefore, "flat" transmission charging could be expected to increase the cost of achieving the UK's renewable and decarbonisation goals, as well as increasing costs to end-users generally. In the absence of any other means of delivering locational signals, for example via energy prices, there seems to be little to recommend a move to "flat" transmission charging, other than possibly issues of simplicity and transparency in charging methodology, together with a convergence with general European charging practice. In isolation therefore, "flat" transmission charges would not appear to fit particularly well with Government policies for supporting low carbon generation.

[15] See http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/TAR/Documents1/081219_TOincentives_consultation_FINAL.pdf

6.1.2 Discounting TNUoS charges for intermittent renewable sources and other generation.

There is evidence that the current charging arrangements discriminate against intermittent renewables in areas of high TNUoS charges and possibly discriminate in favour of those technologies in areas where generation TNUoS charges are negative. National Grid have responded to this apparent discrimination through a review of charging for intermittent generation (GB ECM – 25), although they have apparently concluded that a specific charging solution cannot be taken forward without a broader view being taken of similar issues for other generation technologies[16]. A number of respondents to GB ECM – 25 suggested that the issue of intermittent generation charging should be taken up as part of Project TransmiT.

Assuming the analysis set out in GB ECM-25 to be robust and noting that it needs to be extended to include other generating technologies, then adopting a transmission charging regime that differentiated on the basis of technology and offered both intermittent renewable and conventional generation a discount on TNUoS charges in return for sharing transmission capacity and reduced access rights, would complement the Government's existing and proposed policies for supporting low carbon technologies. National Grid's analysis suggests that such a regime would lead to TNUoS charges in areas such as northern Scotland being significantly discounted, reflecting a reduced requirement for transmission investment. Furthermore, Oxera's analysis suggests that reduced transmission charges could result in additional deployment of wind generation as some marginal Scottish wind sites become economically viable. Wind connecting in some areas such as the South West would see a slight increase in TNUoS charges and this might result in some marginal sites becoming uneconomic. However, as most onshore wind generation is likely to locate in Scotland, the overall impact of discounting TNUoS charges for intermittent technologies would seem likely to be an overall increase in the contribution made by onshore to the UK's renewables obligations, and a reduction in the overall cost of delivering those obligations.

6.1.3 Ability of intermittent renewable generation to respond to locational signals.

Similar arguments, i.e. that reducing TNUoS charges for intermittent or other renewable generation may reduce the overall costs of achieving the UK's renewable targets, could be made for going "beyond" cost-reflectivity and positively discriminating in favour of technologies that are effectively forced to locate in remote areas and therefore have little ability to respond to locational signals. While those technologies have some ability to respond, there is a case for maintaining those signals to enable developers to make economically efficient locational decisions. However, where the ability to respond is eroded, then locational signals applied via TNUoS charges simply add to project costs and may, as suggested by Oxera, add to the overall costs of achieving the UK's renewable targets.

As discussed when considering "flat" transmission charging, going too far in reducing transmission charging for intermittent renewable generation could conceivably increase the overall cost of achieving the UK's renewable targets. Further work is required to understand the impact of TNUoS charges on the deployment of intermittent renewables and identify how the overall cost of

[16] See National Grid's open letter on the review of charging for intermittent generation, 02 December 2010 at; http://www.nationalgrid.com/NR/rdonlyres/8CBA9489-95E8-41D7-B059-196317C9BA81/44309/GB_ECM25_IndustryLetter_021210.pdf

delivering the UK's renewable targets can be minimised. However, taking this broader view of transmission charging and its implications in terms of renewable deployment, would fit well with the Governments policies for supporting low carbon generation.

6.1.4 "Commoditised" transmission use of system charges

Applying TNUoS charges on an energy rather than a capacity basis would favour lower load factor generation and technologies such as wind could expect to see a reduction in charges or, if situated in negative charging areas, an increase in payments. However, commoditisation does not seem to be based on sound principles in that the link between transmission charges and the costs imposed on the transmission system by individual generators, would be weakened. Furthermore, the charges applied to some low carbon technologies, such as nuclear, would be increased.

The reduced transmission charges seen by wind generation could be expected to release additional onshore capacity and commoditisation could, therefore, be seen as helpful in terms of the Government's policies to support low carbon generation. However, the increased transmission charges applied to nuclear generation would not be helpful in this context.

6.1.5 Nodal pricing, market coupling, market splitting and flat or flatter charging

The intended creation of a single European electricity market via market coupling by 2014 creates the opportunity to apply locational signals though short run energy prices, rather than capacity-based transmission charges. There is a general consensus, reflected in the three Academic reports, that locationally differentiated energy prices represent the most appropriate and efficient method of delivering locational messages and the adoption of these principles across interconnection between Member States could be extended to manage internal system congestion. Managing congestion in this fashion would involve the adoption of flat, or flatter, transmission charges bringing GB more in line with general European practice. Overall, the adopting of flatter transmission charges and market coupling principles to manage both internal and interconnector congestion seems a more elegant solution to that of continuing with capacity based locational transmission charges and restricting the use of market coupling to interconnectors. Adopting flatter transmission charges, possibly allocated entirely to load, would remove the potential for GB generators to be disadvantaged compared with their European competitors.

While the adoption of flatter transmission charges and the management of internal congestion through locational short run energy prices would be more consistent with European policies, it is not entirely clear how they would fit with wider Government policies for promoting low carbon generation. The locational signals delivered by energy price differentials across congested boundaries would be experienced by all generation technologies and the energy prices available to most intermittent renewables such as wind are likely to be reduced. Some relief for these reduced energy prices could be arranged if preference in the allocation of rights to congested transmission was to be given to intermittent renewables, justified by the limited ability of these technologies to respond to locational signals. Such preferential treatment would be consistent with the "clean first" principles set out for example in Directive 2009/28/EC and compliment Government policy in relation to supporting low carbon technologies, or at least the intermittent renewable subset of low carbon technologies.

Although not a matter for Project TransmiT it is worth noting that, in the context of Government policy for supporting low carbon technologies, the proposals set out in DECC's recent Energy Market Reform (EMR) consultation[17] appear somewhat at odds with policies to create a single European electricity market. Market integration will require that energy prices within national electricity systems are "consistent" in nature, in order to reduce the potential for distortions in cross border trade. The proposed UK approach to decarbonisation set out in the EMR, involving CfDs for low carbon plant, a carbon floor price and selective capacity payments, all have the potential to impact on energy prices. The same is true for support measures adopted by other Member States and, unless those support measures are harmonised across Europe or alternatively market coupling mechanisms evolve to deal effectively with the impact of the various support options adopted by Member States, then the potential for cross border trade distortions will be very real.

6.2 Transmission charges for license-exempt embedded generation

The treatment of license-exempt embedded generation as negative demand under the current transmission charging arrangements effectively provides a benefit (compared with transmission-connected generation) to distribution-connected generation that is equal to the sum of the residual elements of the generation and demand tariff. While this benefit probably has a positive impact on the deployment of distributed generation, much of which is likely to be renewable or low carbon, and therefore compliments the Government's policies in this area, its continuation would need to be justified on those grounds. As discussed in the previous section, a logical and cost reflective approach would suggest that distribution-connected generation, and demand, should be exposed to the costs imposed on the transmission system. However, this approach would increase the costs seen by distribution-connected generation and the impact of those additional costs need to be weighed against the risks of deployment and of a reduced contribution to the UK's renewable and decarbonisation goals.

What is clear, however, is that National Grid's preferred "gross" charging approach would seem to sit uncomfortably with the Government's policies for supporting low carbon generation. A "gross" charging approach would not reflect the real driver for transmission investment, i.e. flows across the transmission-distribution system interface, and would be inconsistent with the concept of smart grids and of DNOs or other aggregators coordinating distribution connected generation and demand in order to provide services at the system level.

6.3 Securitisation and connection charging

The requirement for generation wishing to connect to the transmission system to financially secure associated transmission investment has the potential to delay the deployment of renewable and low carbon technologies, thereby frustrating the delivery of the UK's renewable and decarbonisation objectives. The current securitisation requirements also place a disproportionate burden on smaller generators and therefore discourage competition. While there is a need to reduce the risk of abortive transmission reinforcement and protect customers from the costs of stranded assets, a revised approach is needed that re-apportions risk between new and existing generation, customers

[17] http://www.decc.gov.uk/Media/viewfile.ashx?FilePath=Consultations/emr/1041-electricity-market-reform-condoc.pdf&filetype=4&minwidth=true

and National Grid/TOs. Reducing the securitisation burden, particularly for smaller projects, would sit well with the Government's overall policies for supporting renewable and low carbon generation.

6.4 Anticipatory investment

Notwithstanding the introduction of "connect & manage", the need for physical connection and concern over congestion costs can introduce significant delays in the connection of renewable and other low carbon generation. Consideration should therefore be given to incentivising National Grid and the Scottish TOs to anticipate demand for transmission capacity and to initiate strategic transmission reinforcement ahead of need. Useful proposals have been made by Ofgem and these should be pursued via RIIO-T1 to replace the "micro-management" of strategic developments currently in place. Such arrangements would result in the earlier release of renewable resource and would be entirely consistent with Government policies for supporting renewable and low carbon generation.

7 What the implications of doing this might be, in both the short-run and long-run.

The following paragraphs consider the possible implications of transmission charging options in terms of costs seen by customers, security of supply and competition in the generation market.

7.1 Flat transmission charges

7.1.1 Cost to customers

Revenues to be collected from transmission charges would remain unchanged under a flat charging regime, therefore total costs seen by customers would remain unchanged in the short term. The removal of locational signals from demand would, however, impact on individual customers depending on location. Over time, the removal of locational signals seems likely to result in inefficient locational decisions by generators, increased transmission losses, increased congestion and, ultimately, the need for additional transmission capacity. In the longer term, therefore, costs to customers seem likely to increase[18].

[18] The analysis undertaken by NERA and Imperial College for RWE suggests that uniform or flat TNUoS charges would result in the need for increased transmission investment, an increase in the costs of congestion (although this would presumably be reduced by additional investment) and an increase in the cost of transmission losses. The analysis also suggests that there might be some increase in wholesale electricity prices. Overall, NERA & Imperial College estimate that uniform TNUoS charges might increase costs to customers by £19.8 billion in NPV terms between 2011 and 2030. The NERA/Imperial College report for RWE can be viewed at;
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=94&refer=Networks/Trans/PT/WF

7.1.2 Security of supply

Flat charging seems unlikely to have any significant impact on security of supply, although changed locational decisions by conventional plant, i.e. a move from areas that currently have low or negative TNUoS charges to areas that currently have high TNUoS charges could have some local impacts.

7.1.3 Competition in the generation market

Flat transmission charging and the associated loss of locational signals would effectively result in generation connected to "low cost" transmission areas subsidising generation in "high cost" transmission areas. Introducing a cross subsidy in favour of generation connected in high cost transmission areas would arguably reduce competition in the generation market.

7.2 Discounting TNUoS charges for generation willing to share transmission capacity

7.2.1 Cost to consumers

Refining the current transmission charging arrangements to allow discounts to be offered to those generators willing to share transmission access capacity and access rights would be unlikely to directly impact on costs seen by customers, as the revenues collected via transmission charges in total would be unchanged. The reduced revenue collected from generators opting to share transmission capacity would require charges seen by other generators to increase so as to maintain the 73/27% split between demand and generation. However, the costs of resolving congestion across constrained boundaries would decrease and less transmission reinforcement may therefore be justified. In addition, to the extent that discounted TNUoS charges for onshore intermittent renewable generation realised more onshore capacity and reduced the contribution required from offshore wind generation to meet the 2020 renewable targets, the cost of achieving those targets is likely to reduce. Overall, discounting TNUoS charges to reflect the sharing of transmission capacity seems likely to reduce costs seen by customers over the longer term.

7.2.2 Security of supply

Discounting TNUoS charges for some generation seems unlikely to impact significantly on security of supply, however some positive effects may occur if the financial viability of mid merit and peaking generation is improved and plant closures are delayed.

7.2.3 Competition in the generation market

The proposal seems unlikely to have any major impact on competition. There may be some rebalancing of TNUoS charges, however the changes would be cost reflective and any impacts on competition should therefore be positive.

7.3 Commoditised transmission charges

7.3.1 Cost to customers

Charging users of the transmission system partially or wholly on an energy rather than a capacity basis is unlikely to impact on costs seen by customers as the overall revenue collected via transmission charges would be unchanged. However, the operational signals delivered via commoditised charges could influence actual operation to some extent and may therefore conceivably result in some reduction in the cost of dealing with congestion, which is ultimately passed on to customers.

7.3.2 Security of supply

Commoditisation seems unlikely to have any major impacts on security of supply, although the lower charges seen by low load factor peaking generation could improve the viability of that plant and may, therefore, have some positive impact.

7.3.3 Competition in the generation market

To the extent that commoditised transmission charges appear to be less cost reflective that capacity based charges, there may arguably be some negative impact on competition in the generation market. Nodal or zonal pricing

7.4 Nodal or zonal pricing

7.4.1 Cost to customers

Nodal pricing is generally held to be the most economically efficient method of energy pricing and, as such, should result in the lowest cost to customers. The costs of resolving congestion should reduce considerably, as the large bid-offer differentials seen in the Balancing Mechanism would be replaced by differential fuel costs. Experience in the US suggests that zonal pricing may be somewhat less efficient, to the extent that re-dispatch is necessary within energy price zones.

The reduced cost of managing congestion should result in the need to build less transmission, thereby reducing costs to customers in the longer term. In the short term the considerable costs of transitioning to full nodal pricing may increase costs seen by customers. However the costs of moving to zonal pricing via market splitting should be less and may in part need to be incurred anyway, due to the introduction of market coupling across interconnectors by 2014 .

7.4.2 Security of supply

It seems unlikely that the introduction of nodal or zonal pricing need have any significant impact on security of supply.

7.4.3 Competition in the generation market

As the most economically efficient means of energy pricing, nodal pricing should enhance competition in the generation market, although issues of local market power and reduced liquidity could arise. Zonal pricing may be less prone to issues of localised market power and reduced liquidity than full nodal pricing, but the opportunities to “game” intra-zonal congestion through redispatch would be greater.

To the extent that nodal or zonal pricing allowed flat or flatter transmission pricing, then GB would better align with European practice. Most Member States do not impose locational signals through transmission pricing and most allocate charges to demand. If GB maintained a locational element to transmission pricing and continued to levy charges on generation, European generators would have a competitive advantage.

7.5 Charging distribution-connected generation for use of the transmission system

7.5.1 Cost to customers

Adopting a net rather than gross approach to charging distribution-connected generation for use of the transmission system is unlikely to impact on customer costs, as the total revenue to be recovered from transmission charges would remain unchanged. However, introducing a "net" approach to charging would involve changes to industry charging arrangements and could involve additional costs in the short term.

7.5.2 Security of supply

Distribution-connected generation arguably has a positive impact on security of supply due to its proximity to demand, although the contribution made by intermittent resources such as wind is clearly reduced. If this general rational is accepted, then the negative impact on the deployment of distributed generation of removing the financial benefit associated with being treated as negative demand is likely to impair security of supply. To the extent that "net" charging would be less harmful to distributed generation deployment than a "gross" charging approach, then the impact of security of supply would also be less.

7.5.3 Competition in the generation market.

To the extent that treating distributed generation as negative demand results in a charging anomaly, then removing that anomaly would enhance competition in the generation market. However, a "gross" approach to charging could unnecessarily penalise distributed generation and is therefore less attractive from a competition point of view that a "net" approach.

7.6 Connection charging, securitisation and anticipatory investment.

7.6.1 Cost to customers

Amending connection charging and securitisation arrangements to achieve the more timely connection of renewable generation seems unlikely to have significant impacts on the costs seen by customers, although there may be some long term reduction in the costs of achieving the UK's renewable targets if more onshore renewable capacity can be deployed earlier. Similar arguments can be applied to measures designed to encourage anticipatory transmission investment, however there must be some additional risk of either stranded assets or increasd TO revenues that might result in increase costs to customers. In terms of the stranded assets risk it should however be noted that the costs and negative consequences of "late" transmission investment significantly outweigh those associated with investing "early".

7.6.2 Security of supply

No significant security of supply impacts seem likely

7.6.3 Impacts on completion in the generation market

No significant impacts on competition in the generation market seem likely.

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