Principles and priorities for transmission charging reform

Project TransmiT: call for evidence

Prepared for ScottishPower

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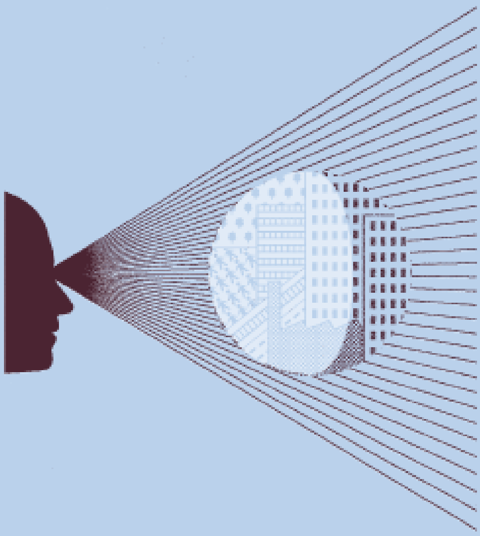

Executive summary

This report provides a review of the economic evidence relevant to the current review of the role of locational transmission network use of system (TNUoS) charges in the GB electricity market. It has been prepared for Scottish Power in response to Ofgem's 'Project TransmiT: A Call for Evidence' and the review of transmission charging arrangements in Great Britain.

The objective of Project TransmiT is to ensure that GB transmission charging arrangements facilitate the timely move to a low-carbon energy sector while continuing to provide safe, secure, high-quality network services at value for money.[1] That is, transmission charging should, like other aspects of market design, support the three objectives of energy policy: efficiency, sustainability and security.

Ofgem's review follows a number of developments in European and GB grid access and transmission charging arrangements. These developments include the adoption of the 'Connect and Manage' regime for transmission connections;[2] and recent announcements on charging for interconnectors, and the socialisation of the costs of accommodating large new nuclear projects, as well as balancing services use of system (BSUoS) costs under DECC's review of grid access.

This report assesses the merits of the current locational signal by comparing the effects of the existing charging structure against a uniform or 'postage stamp' tariff. The purpose of the analysis is to examine the potential impacts of removing the current locational signal, rather than endorsing a postage stamp model per se, although such a regime could be considered to represent a system similar to that used in the majority of other European countries.

The role of locational signals in transmission charges

Transmission charges provide a link between the provision of transmission capacity and investment decisions in generation assets.

In general, market-driven prices can not only compensate the providers of goods or services for the costs they incur, but can also provide important signals about the value that users place on these goods and services, which can lead to an efficient level of supply and use of resources. As such, and in the absence of other policies that dictate electricity market outcomes, transmission charging arrangements can, in principle, play an important role in promoting the efficient operation of the power market, in signalling investment requirements (in both generation and transmission), and in ensuring cost recovery of transmission investment.

However, locational price signals are not relied upon to meet certain transmission charging objectives, including cost recovery and signalling the need for major transmission investments. Furthermore, there are a number of other tensions between electricity market policy objectives that are likely to limit the effectiveness of locational price signals. In particular, reform may need to be considered in order to:

- avoid an unpredictable locational price signal arising because of rapid expansion of renewable generation and significant retirements of existing plant;

[1] Ofgem (2010), 'Project TransmiT: A Call for Evidence', open letter, September 22nd.

[2] See, for example, DECC (2010), 'Government response to the technical consultation on the model for improving grid access', July.

– avoid deterring investment in relatively location-constrained low-carbon plant required to meet the UK's renewable energy targets and carbon budgets;
– recognise that a number of large transmission investment projects will be dictated by regulatory processes separate from any signal from locational prices.

While the current system of locational charges would appear to be able to mimic some of the characteristics of market-based prices in a relatively stable electricity market without restrictions on the generation mix, the policy objectives that will shape the GB electricity market going forward suggest that a more balanced approach may be required.

The impact of current locational charges on renewable prospects

To be able to meet the 2020 renewables targets in the most cost-effective way, it is likely that the UK's onshore wind resource (alongside other relatively low-cost renewables) will need to be exploited to its maximum potential.

Transmission-connected onshore wind developments are subject to TNUoS charges. However, under the current interim arrangements, distributed generation is treated differently, and effectively receives a 'net TNUoS benefit over transmission connected generation'.[3]

National Grid's proposals for reform within GB ECM-23 set out the possible introduction of TNUoS-based charges for distributed generation, on the basis that the impact of distributed generation on the wider transmission network is analogous to directly connected generation.

Although GB ECM-23 has been placed on hold pending the outcome of project TransmiT,[4] given the interim nature of the current arrangements and the principles set out by National Grid on possible reform, the analysis in this report considers the impact of the current locational TNUoS charges on the prospects for both transmission- and distribution-connected onshore wind projects.

This is complemented by a further sensitivity that analyses the impact on transmission-connected developments only.

The current levels of TNUoS charges represent a significant proportion of total onshore wind costs in some regions. A TNUoS charge of £20/kW (ie, similar to that faced by a potential development in North Scotland) represents around 10% of the present value of the costs of onshore wind plant (including capital costs).[5] This is supported by the fact that the impact on the base-case project internal rate of return (IRR) from variations in TNUoS of £29.2/kW (ie, variations from –£6.4/kW to £22.9/kW, assuming similar wind and cost conditions across regions) is equal to 180 basis points.

Analysis presented in this report on the distribution of onshore wind resource and the economics of prospective projects across transmission charging regions suggests that the following broad conclusions can be made about the potential effects of the removal of locational charging signals on onshore wind prospects:

– there is a distribution of project IRRs both between and within regions due to variations in project load factors and local costs;
– the increase in the project IRRs in Northern regions would be far greater than the decrease in southern regions;
– the net impact on the GB development portfolio (on a weighted average basis) would be to increase project IRRs by around 46–53 basis points;

[3] See National Grid (2010), 'Pre consultation. GB ECM-23. Transmission Arrangements for Distributed Generation', p. 1.
[4] National Grid (2010), 'Interim approach to charging modifications', September 21st.
[5] Assuming an 11% discount rate.

– the onshore wind resource potential is significantly higher in those regions that would face lower charges than those that would face higher charges;
– the increase in the number of economic projects in regions that would see a decrease in charges would be greater than any decrease in the number of projects in other regions.

If future distribution-connected onshore wind projects are liable to TNUoS charges (in line with National Grid's proposals under GB ECM-23), replacing locational signals with a postage stamp model could result in an additional 7–8% of the renewables resource being deployed, accounting for regional cost assumptions, and a uniform distribution of plant load factors within regions. This could represent as much as 3.5–4TWh or around 1.4–1.6GW—equivalent to the total onshore wind output in 2006, and over half that generated in 2009 within the Renewables Obligation.[6]

If future distribution-connected onshore wind projects are not likely to be liable to TNUoS charges, replacing locational signals with a postage stamp model might be most likely to affect prospective Scottish developments. The impact of such a change could be to increase the weighted average IRR of Scottish projects by 71–82bp, and could result in an additional 3.5–4.4% of the renewables resource being deployed, which could represent as much as 1.8–2.1TWh or around 0.7–0.9GW.

An increase in onshore wind deployment should result in an improvement in the cost-effectiveness of the Renewables Obligation (RO) (measured as the subsidy per MWh of renewables deployment), since onshore wind receives a lower level of support than most other technologies.

If the UK falls short of its renewables target, an additional 4TWh of onshore wind would increase the proportion of electricity consumption that is generated from renewable sources by more than one percentage point.[7]

If the UK is able to meet its renewable targets, an additional 4TWh of onshore wind could displace 4TWh of relatively more expensive offshore wind. The saving through a reduction in the obligation size to meet the target would be around £164m (in 2009 prices) in each year subsequent to the target being met.

The impact on transmission charges on coal plants and CCS

As well as potentially affecting the deployment of renewable generation, the current system of transmission charges could also have a significant impact on the future GB generation mix. This report has therefore considered the economics of life extensions for relevant GB coal plant, and the implications of alternative retirement profiles for the system capacity, wholesale electricity prices, and the development of CCS.

Locational TNUoS may negatively influence the economics of investments in SCR equipment necessary for some existing coal plant to meet emission limits imposed by the IED. Given that a number of coal plant already compliant with LCPD emission limits are due to retire in the period to 2023 (covered by transitional arrangements for plant that choose to opt out of the IED), it is possible that TNUoS charges could have a material impact on life extensions that would require significant CAPEX for maintenance, replacement of life-expired parts and fitting technologies such as SCR.

Oxera estimates that the SCR investments in Scotland may have an IRR (pre-tax, real) in the region of 6.5%, which is below the hurdle rate range of 7.4–8.6% (pre-tax, real).[8] The

[6] Total onshore wind output in 2006 and 2009 was 3.6TWh and 7.6TWh respectively. See DECC (2010), 'Digest of UK Energy Statistics', Table 7.5.
[7] Assuming that electricity consumption, as defined in the Renewables Obligation Order, is equal to 320TWh in 2020.
[8] Hurdle rate based on Redpoint (2007), 'Dynamics of GB Electricity Generation Investment', May 18th, p. 17.

adoption of a postage stamp TNUoS charge would be expected to increase the IRR of SCR investment in Scotland by around 1.5%, equivalent to an NPV benefit of around £100m. The IRR impact of adopting postage stamp TNUoS would be expected to have a significantly smaller impact on other coal plant, although their IRRs could be within the hurdle rate range mentioned above.

While postage stamp TNUoS may not necessarily mean that SCR investments would be viable for all GB coal plants, it would help to equalise potential returns for these investments across Great Britain, ensuring that the technical and operating characteristics of individual plant have a greater impact on the final plant mix.

To the extent that existing coal plant opt out of the IED or retire (both decisions may be influenced by GB transmission arrangements), this may also have an adverse impact on consumers by bringing forward investment in CCGT capacity in anticipation of the expiry of IED transitional arrangements for opted-out, coal-fired generation capacity that will ultimately be recovered through higher prices.

Oxera estimates that the detriment to consumer welfare of front-loaded new CCGT entry could be around £300m in 2009 prices. These costs could be avoided if the move to postage stamp TNUoS were to result in incremental SCR investments at Longannet.

Finally, to the extent that existing coal plant opt out of the IED or retire, this may limit the opportunities to demonstrate the viability of certain CCS technologies. In turn, this may impede the development of clean coal-fired generation and reduce the potential diversity of the GB generation mix in future.

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1 Introduction

This report provides a review of the economic evidence relevant to the current review of the role of locational transmission network use of system (TNUoS) charges in the GB electricity market. It has been prepared for Scottish Power in response to Ofgem's 'Project TransmiT: A Call for Evidence' and the review of transmission charging arrangements in GB.

The objective of Project TransmiT is to ensure that GB transmission charging arrangements facilitate the timely move to a low-carbon energy sector while continuing to provide safe, secure, high-quality network services at value for money.[9] That is, transmission charging should, like other aspects of market design, support the three objectives of energy policy: efficiency, sustainability and security.

Transmission charging arrangements can have an important role to play in promoting the efficient operation of the power market, signalling investment requirements (in generation and transmission), and ensuring cost recovery of transmission investment. This report provides evidence on the ability of transmission charging arrangements to achieve these objectives, and the potential conflicts they may have with other policy goals—in particular, that of achieving a sustainable and secure energy system.

The merits of the current locational signal are assessed by comparing the effects of the existing charging structure against a uniform or 'postage stamp' tariff. The purpose of the analysis is to examine the potential impacts of removing the locational signal, rather than necessarily endorsing a postage stamp model, although such a regime could be considered to represent a system similar to that used in most other European countries. In particular, analysis is provided to assess whether the predictability of the price signal and investment incentives of a locational charge would be consistent with the government's objective to increase the share of low-carbon technologies in the generation mix, and where a rapid change in the generation mix is likely.

The locational element of TNUoS charges has been the object of considerable debate since the implementation of BETTA, recently and most notably during the consultation process on the Scottish government's proposals to create a uniform TNUoS tariff (GB ECM-17),[10] and during the Select Committee inquiry into Britain's electricity networks.[11]

This report does not seek to restate the arguments made during these debates. Instead, it provides new evidence and explanations on three key aspects of this discussion; namely whether locational TNUoS charges can be expected to:

– affect the need for transmission expansion in the next decade, given that an increasing share of new generation will consist of low-carbon projects; that such projects face different constraints in their siting decisions; and that significant and transformational grid investment will be required in any case in order to facilitate offshore wind and, potentially, the development of an EU-wide supergrid. This argument is relevant to the efficiency objective of energy policy;

– influence the development of low-cost forms of renewable generation in the next decade, given that a large share of the renewable resource in GB is located in areas

[9] Ofgem (2010), 'Project TransmiT: A Call for Evidence', open letter, September 22nd.

[10] National Grid (2009), 'Conclusions report – GB ECM-17 – Transmission charging: a new approach', September 15th.

[11] House of Commons Energy and Climate Change Committee (2010), 'The future of Britain's electricity networks', February 23rd.

subject to relatively high TNUoS charges. This argument is relevant to the sustainability objective of energy policy;

– alter the business case for extending the lives of existing thermal plant. This could lead to additional costs for consumers (the efficiency objective of energy policy) and could have an impact on the ability to achieve an early CCS demonstration (the sustainability and security objective of energy policy).

The questions addressed in this report reflect the notion that transmission charging should be influenced not only by the technical and economic characteristics of the system, but also by considering how best to balance sometimes conflicting energy policy objectives of efficiency, sustainability and security.

The adoption of the 'Connect and Manage' regime for transmission connections already reflects this need for balance, as do recent announcements on charging for interconnectors,[12] and the socialisation of the costs of accommodating large new nuclear projects, as well as balancing services use of system (BSUoS) costs under DECC's review of grid access.

The report is structured as follows.

– Section 2 sets out the high-level principles behind the various objectives that transmission charges might be able to achieve.

– Section 3 discusses the extent to which locational transmission charges are appropriate to signal locational advantages for investment in generation in the current GB context.

– Section 4 provides evidence on the potential effects of locational transmission charging, together with an alternative uniform charging model on renewables investment, efficiency, and security of supply.

– Section 5 concludes.

The appendix summarises past academic work that has examined similar issues.

[12] Ofgem (2010), 'Modification proposal: Use of system charging methodology modification proposal GB ECM-26 "Review of interconnector charging arrangements"', October.

2 Transmission charging principles

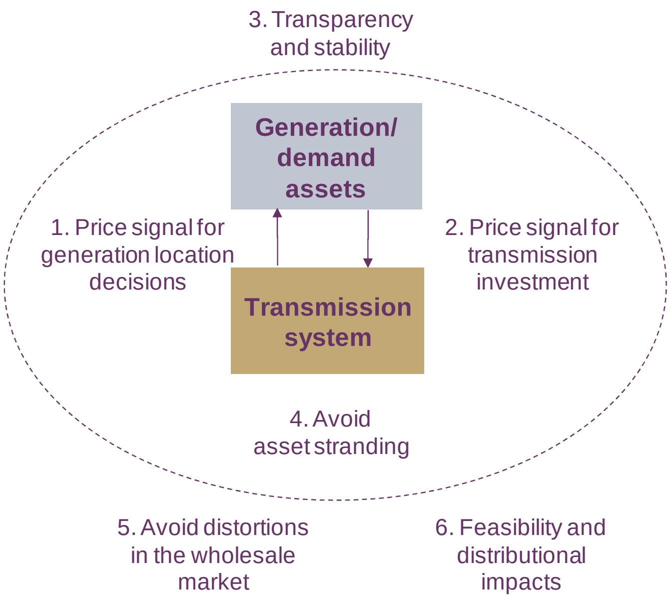
Transmission charges provide a link between the provision of transmission capacity and investment decisions in generation assets.

In general, market-driven prices not only compensate the providers of goods or services for the costs they incur, but can also provide important signals about the value that users place on these goods and services, which can lead to an efficient level of supply and use of resources. As such, and in the absence of other policies that dictate electricity market outcomes, transmission charging arrangements can, in principle, play an important role in promoting the efficient operation of the power market, in signalling investment requirements (both in generation and transmission), and in ensuring cost recovery of transmission investment.

An important feature of any price signal is that it must be transparent and predictable. Without this, those market participants that could in principle respond to a price signal will at best face blunted incentives.

Figure 2.1 highlights the interactions between the providers and users of transmission capacity and the potential role that transmission charges can play. It shows the number and direction of signals between market participants that can help coordinate their behaviour, as well as three overarching principles (outside the dotted line).

Figure 2.1 Transmission charging principles



Source: Oxera based on Green, R. (1997), 'Electricity transmission pricing: an international comparison', *Utilities Policy*, **6**:3.

The assessment below considers the ability of transmission charging arrangements in general to achieve these six principles, the role of locational signals and the conflicts that may arise with other policy goals—in particular, the requirements to achieve an energy system that is both sustainable and secure.

1. The role of price signals to influence generation and demand location decisions

Locational price signals can be effective only if generators are able to respond to them.

Low-carbon projects, which could be expected to represent an increasing share of generation investment in the next decade, might not be capable of responding to the TNUoS signal, for both technical and economic reasons.

As many renewable projects tend to be developed at the geographical periphery of the transmission network, a locational signal by its very design will act to deter some of those investments and make the economics of locating alternative projects closer to demand more attractive.

This may be efficient in a market without additional policy constraints; however, in the presence of binding renewable targets and carbon budgets, it will be likely to encourage the need for further financial support to ensure that sufficient projects overcome (and negate) this signal.

The rationale for having a generic locational signal, given the relatively inflexible siting requirements of renewable, CCS and nuclear plant, forms the focus of section 3.

2. The role of price signals to provide transmission investment incentives

In practice, many countries do not rely on marginal cost price signals to incentivise transmission investment, for a number of possible reasons, including the following:[13]

– investments are lumpy and ex post prices may be significantly lower, and hence fail to reward the transmission owner for their investment in the absence of some commitment to ex ante prices;
– there may be perverse incentives if the transmission owner can maximise (transmission charge) revenues from high prices by under-supplying network capacity.

As a result, price controls are commonly used, in which capital expenditure plans are assessed ex ante and ex post and cost recovery in ensured through a price-setting formula linked to the asset base.

Given the scale of transmission investment needed to accommodate the rapid decarbonisation of the electricity sector, obligations to accommodate generators' requests for transmission capacity and to separate processes for large transmission projects (eg, TIRG) would also be required.

Thus, locational signals might be expected to be of limited use to meet this principle, and this is likely to be increasingly the case given the scale of transformation required in GB to accommodate offshore wind and potentially EU-wide grid interconnection.

3. The need for transparency and stability of the price signal

A price signal must be transparent and relatively stable (or at least predictable) in order for participants to respond to it.

Locational transmission charges, as they currently apply in GB, could face a number of challenges in meeting this objective.

– Anticipated plant closures (eg, due to the Directives on Large Combustion Plants and on Industrial Emissions, nuclear closures, etc) and installation of new plant (eg, renewable and nuclear) are likely to result in significant changes to the supply/demand balance in certain zones, resulting in a reconfiguration of TNUoS zones and charges.

[13] See, for example, Green (1997), op. cit.

– In general, uncertainty over zone boundaries could lead to volatile and unpredictable TNUoS charges, further deterring investment. This may also lead to 'first-mover disadvantage', in that incremental investments could trigger significant TNUoS changes which could be highly 'discontinuous' (eg, as a result of the significant investment in HVDC 'bootstraps').

– Demand-side charges are based on the triad,[14] although future network requirements will be driven by demand outside of the winter peak due to wind intermittency. Triad pricing does not provide any incentive for demand-side management outside the winter peak, and is likely to be incompatible with increased market integration at the EU level.

– The significant uncertainty created by the treatment of future grid investments, such as the proposed HVDC sub-sea cables being considered as part of the ENSG review. An initial projection from National Grid, which is to be revised given the uncertainty of the effects, suggested that charges in Scotland could increase by two to three times should the current methodology be applied to these grid investments.[15]

– The prospect of significant offshore wind developments presents further uncertainty about the level and regional differences between transmission charges.

4. The role of charges to avoid transmission asset stranding

Providing transmission owners with an adequate return on their investment is a design feature central to transmission charging arrangements in many countries, otherwise it will not be possible to attract sufficient investment.[16]

Locational charges typically play a minor role in achieving cost recovery, as highlighted by the fact that a considerable proportion of transmission revenues received from generators are contained within the residual element of transmission charges—of the £432m recovered from generators in 2010/11 through TNUoS charges, £296m (69%) was recovered through the residual element.

Locational signals are largely redundant in terms of their ability to meet this principle.

5. Avoiding distortions in the wholesale market

In theory, locational charges can help provide incentives for generators to locate in certain parts of the network so as to minimise constraints and losses. However, this must be balanced against other factors. The location decision of new flexible plant has been, and will be likely to continue to be, driven by a range of considerations, such as:

– the ability to secure Section 36 planning approval;
– local public opinion on the proposed development;
– proximity to the electricity transmission system (to reduce local asset and connection costs)
– proximity to the gas transmission system;
– availability of civil engineering and existing power plant infrastructure (eg, from an existing generating site);
– availability of cooling water;
– land cost;

[14] The three settlement periods of highest transmission system demand within a financial year: the half-hour settlement period of system peak demand and the two half-hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least ten clear days, between November and February of the financial year inclusive. See National Grid (2010), 'The statement of the use of system methodology. Effective from April 2010', p. 34.

[15] National Grid (2010), 'ENSG "Bootstraps". Potential charging treatment of HVDC links operated in parallel with the AC network', March, presentation at Transmission Charging Methodology Forum.

[16] In the UK, the regulator is required to set price controls at a level that enables regulated functions to be funded. This will generally secure the finances of the transmission owner against underuse of an asset, although it does not in itself ensure that only those assets that are likely to be well utilised are built. This is normally done through discussion of the business plans in price control negotiations and other mechanisms, such as TIRG.

– land availability to demonstrate carbon-capture readiness;
– coastal location (to facilitate transport of CO_2 to areas such as the North Sea);
– availability and access potential from existing roads and infrastructure;
– habitats and biodiversity;
– local skills and employment.

In certain circumstances locational incentives may nevertheless continue to be a relevant consideration for new thermal generation projects, and initial thoughts about such mechanisms are considered in more detail in section 3.

6. Distributional impacts and feasibility of implementation

Any system of transmission charges is likely to lead to distributional impacts. In accordance with the principles of better regulation, any change should be proportionate, targeted and transparent.

Given the complexity of competing policy objectives and some tension between the objectives of a transmission charging regime in the absence of other policy constraints, the most effective solution may be the one that is most simple and pragmatic—in a similar vein to the conclusions reached by DECC in promoting the Connect and Manage model without location-specific charges to recover system balancing costs.[17]

Summary

The above discussion highlights that locational price signals are not relied upon to meet certain transmission charging objectives, while there are a number of other tensions between electricity market objectives that are likely to limit the effectiveness of these price signals.

The need for a significant shift in the generation mix, restrictions on the location of low-carbon generation and the scale of the resultant network investment imply that the alignment of these objectives through location-based transmission charges is likely to become increasingly difficult.

While the current system of locational charges would appear to be able to mimic some of the characteristics of market-based prices in a relatively stable electricity market without restrictions on the generation mix, the policy objectives that will shape the GB electricity market going forward suggest that a more pragmatic approach may be required.

In particular, reform may need to be considered in order to:

– avoid the creation of an unpredictable price signal;
– avoid deterring investment in relatively location-constrained low-carbon plant required to meet other policy objectives; and
– recognise that a number of large transmission investment projects will be dictated by regulatory processes separate from any signal from locational prices.

[17] See, for example, DECC (2010), 'Government response to the technical consultation on the model for improving grid access', July.

3 The role of signals to influence generation location decisions

One of the roles of locational TNUoS charges is to incentivise generators to internalise the costs of transmission expansion when locating their plant. In principle, if the charges are well calibrated, they can lead to the least-cost combination of generation and transmission investment in the system.

However, the questions remain of whether a broad-based locational TNUoS charge would be the most effective way of achieving this objective in the policy and market environment created by the transition to a low-carbon power system; and whether the signals created might inhibit potential life extensions to existing plant facing environmental restrictions, the closure of which may be adverse to energy policy objectives.

Locational signals might be expected to be applicable if the following conditions hold:

– a significant proportion of new plant have sufficient flexibility in their siting decision to respond to the price signal; and

– there are no alternative mechanisms for providing an equivalent incentive to those plant that do have sufficient flexibility in their siting decision.

This section considers these two conditions in turn, to test whether:

– low-carbon projects, which are likely to represent an increasing share of generation investment in the next decade, might not in any practical sense be capable of responding to the TNUoS signal for technical and economic reasons (section 3.1); and

– options exist other than the current arrangements to provide appropriate incentives for new thermal generation for which there is some flexibility in where it is sited (section 3.2).

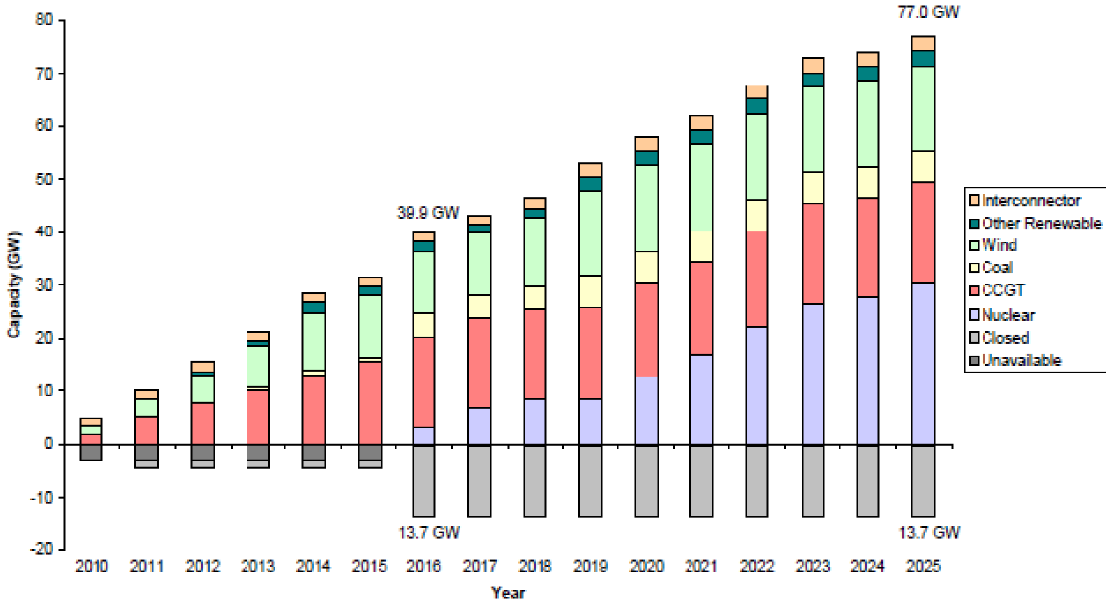
Taken together, these conditions suggest that the price signals provided by locational TNUoS charges will be less relevant in the next decade than previously, and that a removal of these signals would not necessarily lead to major inefficiencies in the development of the power system.

This section also provides an overview of the charging methodologies applied in other European countries (section 3.3). This overview suggests that few European countries use price signals to the same extent as GB, even though they face similar issues.

3.1 Locational signals for low-carbon generation

The transition to a low-carbon power sector requires a shift in generation investment from fossil-fuel to low-carbon technologies. National Grid’s projections indicate that, of the total generation capacity that is expected to be built by 2025 and that is not yet under construction, 66% will be nuclear and wind, 27% will be gas and coal, with the remainder made up of biomass and interconnection capacity (see Figure 3.1 below).

Figure 3.1 Expected changes in generation capacity



Source: National Grid (2010), '2010 NETS Seven Year Statement', p. 9.

All generators face technical and economic constraints in their decisions to locate—for example, transporting fuel to a site can be an important cost for fossil-fuel generators (especially for coal-fired plant). However, these constraints are arguably more significant for low-carbon plant in that they significantly limit the extent to which project sponsors can respond to the price signals produced by the current charging methodology.

For **nuclear generation**, the options are effectively limited to the eight sites identified in the revised nuclear National Policy Statement.[18] Site-specific factors other than TNUoS charges (eg, land availability, local public acceptance, the conditions for the supply of cooling water, wildlife and other environmental considerations) appear to be responsible for the order of the development of some of these sites, as evidenced by the earlier commissioning date proposed by Horizon Nuclear Power for Wylfa (2017) than Oldbury (2020), according to National Grid's TEC register, despite Wylfa's relative disadvantage in the level of transmission charges. Given this evidence and the announced plans of the utilities. TNUoS charges are unlikely to have any material impact on the 'end state' configuration of the system as regards new nuclear plant.[19]

[18] DECC (2010), 'Revised draft national policy statement for nuclear power generation (EN-6)', October.

[19] HM Government (2010), 'Revised Draft Overarching National Policy Statement for Energy', EN-1, section 3.5.

Table 3.1 Current TNUoS charges applicable to the eight sites potentially suitable for nuclear new build

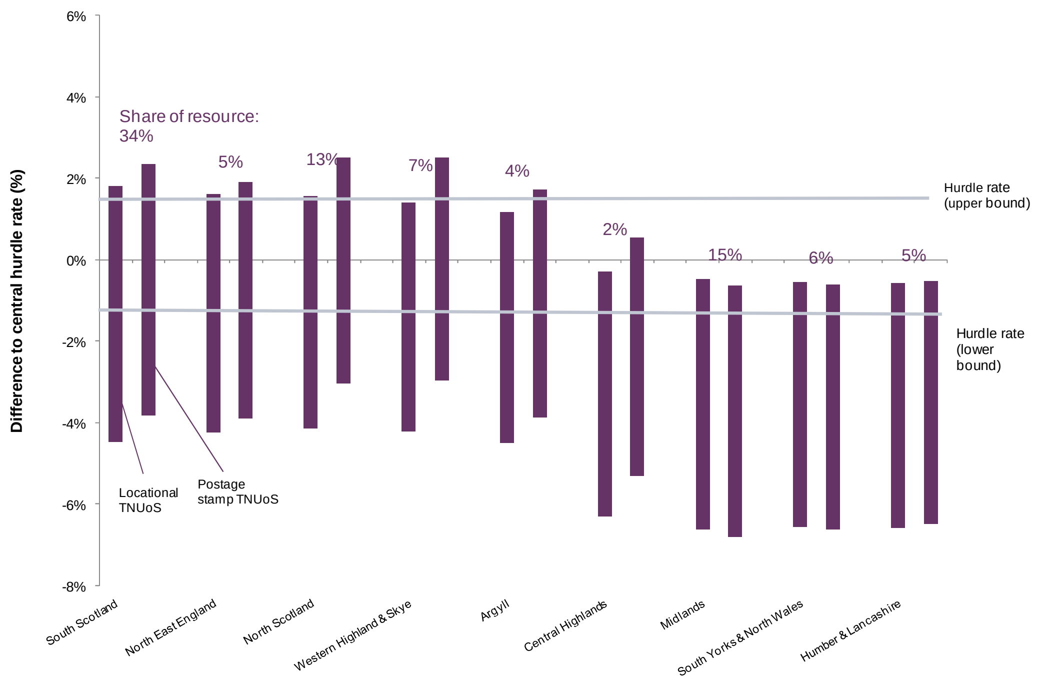
Site	Owner	TNUoS zone	TNUoS charge (£/kW)
Bradwell	EDF Energy	South East	0.8
Hartlepool	EDF Energy	North East England	8.8
Heysham	EDF Energy	Humber and Lancashire	5.4
Hinkley Point	EDF Energy	Wessex	-2.6
Sizewell	EDF Energy	Midlands	1.6
Oldbury	E.ON and RWE	South Wales and Gloucester	0.4
Wylfa	E.ON and RWE	Anglesey	6.8
Sellafield	Iberdrola, GDF, SSE	Humber and Lancashire	5.4

Source: National Policy Statement, National Grid, Oxera.

For **wind generation**, the *relative attractiveness* of different regions is insensitive to a wide range of changes in TNUoS charges. Drawing on the analysis presented in section 4 of this report, Figure 3.2 shows the range of project internal rates of return (IRRs) relative to the possible hurdle-rate benchmarks in the nine regions with the most wind resource, with and without locational TNUoS charges. (The second bar in each region shows the IRR range relative to the hurdle rate under a postage stamp TNUoS charge).

The range of returns within regions shows that although some projects may achieve better performance than others, a significant number of potential projects are likely to be uneconomic or marginal, even within the most resource-abundant areas of Great Britain. Importantly, this also highlights that a move from the current charging regime to a uniform charge would not materially affect the ranking of project IRRs between different transmission zones.

Figure 3.2 IRR ranking under the current model and under a postage stamp model



Note: The methodology and assumptions underpinning these estimates are described in section 4. Data labels refer to estimates of the distribution of onshore wind resource in each region.
Source: Oxera.

Despite this, TNUoS charges are not irrelevant to the economics of wind generation.

The analysis provided in section 4 of this report suggests that a move to a postage stamp model would potentially increase the *absolute* number of sites that are viable, and, by default, the overall scale of onshore wind development, even though it would not materially affect the *relative* attractiveness of different sites. This is because the change would improve the business case of a large number of sites that are currently marginal (which would thereby become viable), while worsening the business case of relatively fewer sites elsewhere. In other words, if the location of wind generation is relatively inflexible, locational signals are likely to change the quantity rather than the location of the projects that are viable.

As such, from an economic perspective, the order in which projects are developed is more likely to be determined by the quality of the resource than by locational signals in transmission charges. Arguably, this might also be a desirable outcome from a policy perspective. Given that the achievement of emissions reduction targets in 2020 depends on the amount of renewable energy generated, rather than on the amount of capacity installed, and given that the industry is likely to face technical and financial constraints in the rate at which it can build new capacity, it would make sense to develop the sites with the highest load factor first.

In summary, low-carbon projects are unlikely to react to locational signals to the same extent that new fossil-fuel projects may be able to do so, or, if they do react to such signals, it is likely to be more in terms of the total capacity developed rather than the location of this capacity.

3.2 Locational signals for new fossil-fuel generation

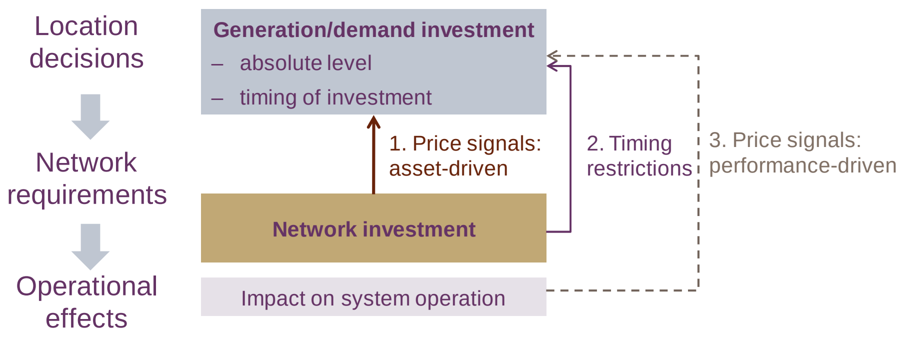
A locational incentive is likely to be desirable to incentivise new fossil-fuel projects to take into account the impacts of their siting decisions on the transmission system.

Arguably, the locational element of TNUoS charges is currently the only feature of BETTA that provides this incentive. This might suggest that if locational signals were removed for the majority of new generation, modified arrangements could conceivably be appropriate for new thermal projects.

Such modification could guard against unnecessary new transmission investment or increased constraints on the existing transmission network. The key question is whether a system of locational TNUoS charges is the most effective means of delivering this signal, given that developers need to consider a wide range of issues in their siting decisions (as outlined in section 2).

Figure 3.3 illustrates the various charging bases on which a modified mechanism could be based. It highlights the broad principle that price signals or timing restrictions for new developments can be used to affect location decisions (although creating predictable and well-targeted price signals is likely to vary between options, and be more problematic for signals related to the costs of system operation).

Figure 3.3 Bases for transmission charging options



Source: Oxera.

Within this framework, some examples of options in these categories are set out below.

- **Price signals**
  - charges for new thermal generation using a methodology similar to the current locational signal in TNUoS—ie, based on an assessment of the incremental transmission investment required to accommodate additional generation ;
  - charges for new thermal generation based on a modified version of the existing arrangements (eg, with reduced zonal variation or an alternative calculation to reduce the possible volatility in charges over time);
  - deep connection charges for new thermal generation;
  - application of zonal transmission losses for new thermal generation.

- **Timing restrictions**
  - Connect and Manage exemption for new thermal generation until grid investment is complete.

The optimal policy response to send the appropriate signals to new thermal generation while protecting the public interest is likely to need further evaluation as part of the review within Project TransmiT alongside the issues raised in this report.

3.3 Regulatory precedent

The review by the European Network of Transmission System Operators for Electricity (ENTSO-E) of transmission charging methodologies in the EU indicates that only three markets other than GB have locational elements in use-of-system (UoS) charges. A number of countries apply deep connection charges (although there is some subjectivity in where the network boundaries lie within this distinction), which arguably have a comparable effect to locational UoS charges, albeit to a lesser extent (see Table 3.2).

It is of note that, among the other differences in renewable policy design, three of the countries that have been the most successful at developing renewable generation (Germany, Spain and Denmark) have no locational signals in their transmission charges, even though they face issues similar to those in GB in terms of renewable resources being located far from load. In Germany, for example, the highest concentration of installed wind power is in the north of the country, while the main consumption area is in the centre of Germany. In this case, there has been a deliberate attempt to remove locational elements from transmission charges in order to facilitate the development of renewable energy—notably, by opting for a 'super-shallow' connection charging methodology for offshore wind.[20]

[20] Orash et al. (2009), 'Promoting grid-related incentives for large-scale RES-E integration into the different European Electricity systems – Deliverable 8 – report on economic incentives for grid operators in grid regulation', GreenNet-Eu-27 Deliverable.

Conversely, Sweden and Norway (two of the other countries that do apply locational TNUoS) face less stringent targets in terms of renewable deployment owing to the existing share of hydropower in their energy mix (renewables account for 54% of installed capacity in Sweden and almost 99% in Norway). As such, and given the relatively permanent and controllable nature of hydropower capacity, these markets require significantly less new build of renewable or flexible generation.

The European Commission has commissioned a number of studies on the factors affecting the integration of wind power in European electricity market (collectively these studies are known as the 'Greennet-EU-27' project). As part of this project, the study that compared the effect of transmission and connection charging arrangements in different countries reached the following conclusion:

> If energy policy makers want to reduce the barriers for new large-scale RES-E deployment, the major part of the grid integration costs, especially the so called 'deep costs', should be covered by the grid operator. Hence, if the major objective is to have accelerated RES-E grid integration with fewer barriers than the status quo, then the strategy should be to socialize all RES-E grid integration costs.[21]

Table 3.2 Locational signals in transmission charging in Europe

Electricity Regional Initiative (ERI)	Country	Locational signals in use-of-system charges (generation share)	Depth of initial connection charges
France–UK–Ireland	France	No	Shallow
	Great Britain	**Yes (27%)**	Shallow
	Ireland	**Yes (20%)**	Shallow
Central West	Belgium	No	Shallow
	Germany	No	Shallow
	France	No	Shallow
	Luxembourg	No	Shallow
	Netherlands	No	Shallow
Central East	Czech Republic	No	Shallow
	Hungary	No	**Deep**
	Austria	No	**Deep**
	Germany	No	Shallow
	Poland	No	Shallow
	Slovak Republic	No	Unclear
	Slovenia	No	**Deep**
Central South	Austria	No	**Deep**
	Greece	No	Shallow
	Italy	No	Shallow
	Germany	No	Shallow
	France	No	Shallow
	Slovenia	No	**Deep**
Northern	Denmark	No	Shallow
	Finland	No	Shallow
	Norway	**Yes (35%)**	Shallow
	Poland	No	Shallow
	Germany	No	Shallow

[21] Swider et al. (2006), 'Comparison of conditions and costs for RES-E grid integration in selected European countries', in GreenNet-Eu-27 (2006), 'Guiding a least cost integration of REE-Electricity in an extended Europe – deliverable D9 – case studies on conditions and costs for RES-E grid integration'.

Electricity Regional Initiative (ERI)	Country	Locational signals in use-of-system charges (generation share)	Depth of initial connection charges
	Sweden	**Yes (28%)**	**Deep**
South West	Portugal	No	Shallow
	Spain	No	Shallow
	France	No	Shallow
Baltic	Latvia	No	**Deep**
	Lithuania	No	**Deep**
	Estonia	No	**Deep**

Source: ENTSO-E (2010), 'Overview of transmission tariffs in Europe: Synthesis 2010', September.

The EU has also been concerned that variations in TNUoS charges applied to generation may distort cross-border trade in the internal market.[22] Given that interconnectors are not liable to TNUoS charges, there is a risk that generators subject to high UoS charges may be at a disadvantage compared with generators that are not subject to such charges. At present, Great Britain has an exemption from the EU guidelines' recommended level of TNUoS charges borne by generation (€0–0.5/MWh).[23]

3.4 Summary

The current charging arrangements in Great Britain attempt to mimic some of the characteristics and benefits of market-based prices in order to help coordinate the behaviour of users and providers of transmission assets, as set out in section 2. However, the arguments developed in this section suggest that these arrangements are likely to become less relevant in a policy and economic context that is likely to dominate in the next decade and beyond, for two main reasons, as follows:

– the low-carbon projects that are required to meet policy targets do not have sufficient flexibility in their siting decisions to be able to react to the price signals provided; and

– the new conventional projects that do have such flexibility could face appropriate incentives through a range of alternative mechanisms.

As such, it is not evident that removing the locational element in TNUoS charges would necessarily alter the location decisions of the majority of future new power generation projects.

This, combined with the challenge that significant changes in the generation mix will place on maintaining a predictable and effective price signal under the current charging system (as highlighted in section 2) and the possible negative effects of the current differentials on the volume of low-carbon generation and other energy policy goals (explored further in section 4), suggests that there may be a case for considering a more balanced approach to promote low-carbon investment while maintaining some locational signals for new conventional generation projects.

[22] European Commission (2008), 'Consultation document on the inter-TSO compensation mechanism and on harmonisation of transmission tarification', December.
[23] Commission Regulation (EU) No 774/2010 of 2 September 2010.

4 The impact of transmission charging on renewables and coal plants

The structure and level of transmission charges have a direct impact on the economics of a project and can affect generation investment and retirement decisions. This section analyses the impacts of the current structure of locational transmission charges on renewable and other forms of low-carbon investment, as well as coal-fired generation and CCS, by comparing the effects of the current charging structure against a uniform or 'postage stamp' tariff. The following analysis is presented.

– **Renewables generation**. The effects of TNUoS charges on onshore wind economics are assessed in section 4.1. The distribution of potential onshore wind capacity and plant characteristics are described alongside an analysis of the impact that a change in TNUoS charges could have on plant economics in different regions. This is combined to show the net effect that a uniform charge may have on overall investment, and the associated costs and benefits this could bring in delivering the UK's renewables targets.

– **Coal-fired generation and CCS**. The impacts of a move to a postage stamp tariff on the economics of investments necessary to support life extensions to existing LCPD opted-in coal plant and the implications for CCS demonstration are presented in section 4.2.

The renewables generation analysis suggests that the net benefit from a change to a postage stamp charging model on the economics of the GB onshore wind development portfolio would be positive, with potential for increased onshore wind generation of around 2–4TWh (0.7–1.6GW). There are likely to be a number of marginal wind projects where onshore wind resource is most abundant that would benefit from such a change. In turn, this could increase the total number of economic onshore wind projects in Great Britain.

The analysis of thermal generation suggests that more coal life extension projects could be made viable from a move to a postage stamp charging model. Such a development could reduce the costs to consumers through its impact on electricity prices, by avoiding or delaying generation projects with higher capital costs, and helping to ensure early demonstration of CCS technology in the UK.

4.1 The impact of transmission charges on renewables

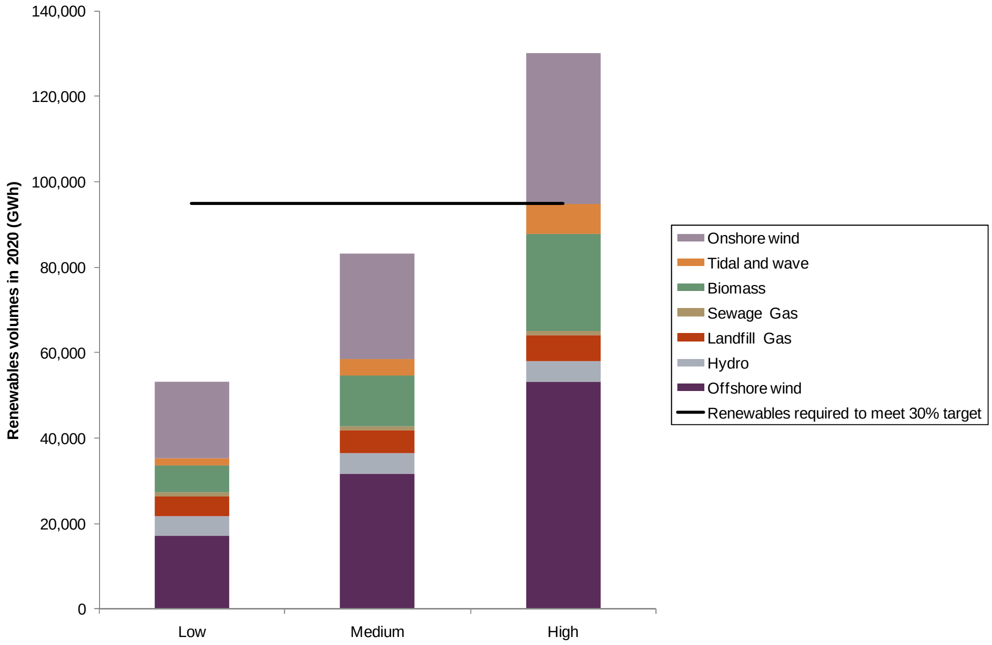
The full exploitation of the UK's onshore wind resource (alongside other relatively low-cost renewables) is likely to be essential to meet the 2020 renewables targets in the most cost-effective way.

Ensuring that the regulatory environment is supportive of the deployment of a relatively mature technology at scale, such as onshore wind, might also be expected to attract investment in other renewable technologies, as developers seek to establish confidence in the market arrangements and to expand and diversify their portfolios.

Figure 4.1 shows the 2020 renewables resource scenarios compiled for DECC, with the renewables volumes required to meet the 2020 target if 30% of electricity consumption is to be sourced from renewables.[24]

[24] Renewable resource constraints exclude economic considerations, and reflect supply chain constraints, planning constraints, and grid constraints. See SKM (2008), op. cit.

Figure 4.1 Renewables resource versus requirements to meet the 2020 target



Note: The low-growth scenario assumes that current constraints remain in place. The medium-growth scenario assumes that some constraints are relaxed, and the high-growth scenario assumes that additional constraints are relaxed. Electricity demand is assumed to equal 306TWh in 2010, with annual demand growth of 0.5% from 2011 to 2019, and 0.2% from 2020 onwards.
Source: Renewables volumes from See SKM (2008), 'Quantification of Constraints on the Growth of UK Renewable Generating Capacity', June; electricity demand growth assumptions from Oxera.

Figure 4.1 highlights that, in both the low- and medium-growth scenarios, exploiting the full onshore wind resource is likely to be essential to ensuring that the UK meets a substantial part of the renewables target in the electricity sector (albeit a risk remains that even if all technologies are fully exploited, there may be a shortfall relative to the required renewables output). Only in the high-growth scenario, and where all other technologies achieve their high-growth potential, can the 2020 targets be achieved without full exploitation of onshore wind. Given this dependence on onshore wind, it would appear critical to understand the location of the UK's wind resource and the impact of transmission charges on the economics of those projects.

The geographic distribution of practical available onshore wind resource can be assessed by first estimating the total accessible resource (ie, based on the distribution of mean wind speeds and excluding land where wind turbines could not be physically located or would face environmental restrictions), and making adjustments for assumptions on wind farm grouping, build-rate constraints and network limitations.

Accessible resources might be expected to be relatively constant over time, as these exclude more dynamic aspects such as supply chain constraints or network limitations. Table 4.1 presents a high-level split of onshore wind resource potential between Scotland, England and Wales, and Northern Ireland, before accounting for network constraints based on a comprehensive estimation of resource potential undertaken for the government in 2000.

While the estimated level of the total accessible resource is likely to have changed over time with greater understanding of the implications for deployment potential of topology, wind turbulence and wind speed, the broad split of resource across regions from previous studies should still be expected to hold. Table 4.1 highlights that around 78% of GB's accessible onshore wind resource is in Scotland.

Table 4.1 UK onshore wind accessible resource

	England and Wales	Scotland	Northern Ireland	UK
Capacity (MW)	20,291	68,824	20,564	109,679

Source: ETSU (2000), 'New and Renewable Energy: Prospects in the UK for the 21st Century: Supporting Analysis'.

A snapshot of the current practical resource, which considers network capability and high-level project economics, can be gained from looking at the distribution of current projects and those in planning, consented or under construction, although this may underestimate the potential resource that can be exploited through further grid reinforcement. Table 4.2 highlights that around two-thirds of the current onshore wind projects (including those consented and in planning) are in Scotland.

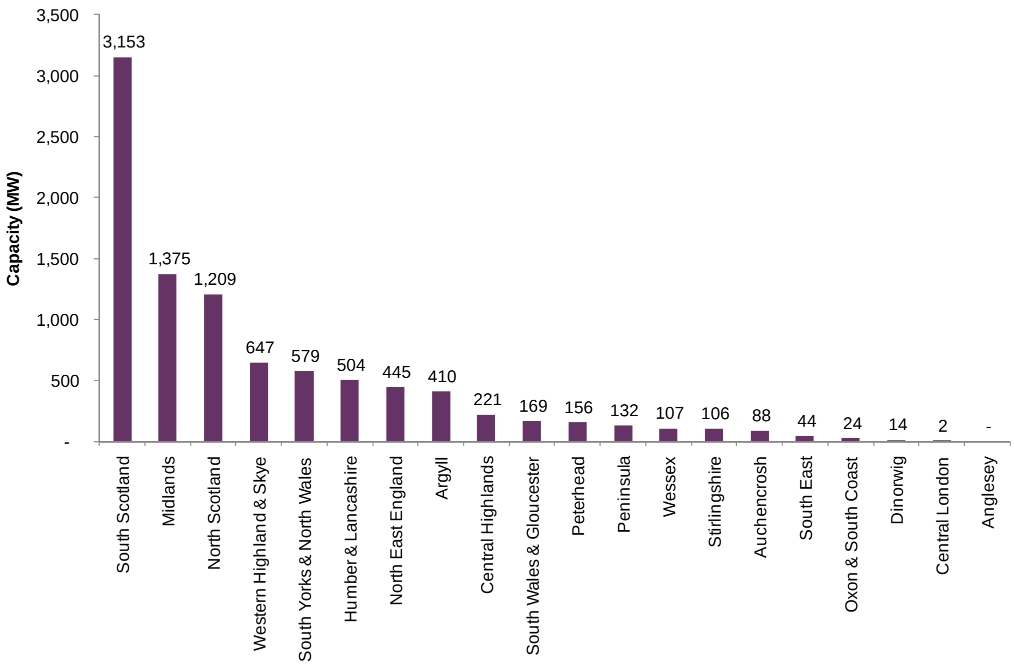
Table 4.2 High-level distribution of GB onshore wind prospects (MW)

	Operational	Under construction	Consented	In planning	Total
England & Wales	1,726 (43%)	130 (12%)	1,490 (45%)	1,775 (35%)	**5,120 (38%)**
Scotland	2,314 (57%)	928 (88%)	1,833 (55%)	3,229 (65%)	**8,304 (62%)**
GB	4,041 (100%)	1,058 (100%)	3,323 (100%)	5,004 (100%)	**13,425 (100%)**

Source: British Wind Energy Association (BWEA) and Oxera analysis.

Figure 4.2 summarises the geographic distribution of the GB onshore wind development portfolio by TNUoS charging zone.

Figure 4.2 Distribution of the current GB onshore wind prospects by TNUoS zone



Note: Prospects include projects under construction, consented and in planning reported in Table 4.2.
Source: BWEA and Oxera analysis.

Figure 4.2 highlights that South Scotland has the largest volume of onshore wind capacity currently in planning, consented or under construction, and represents around 34% of the portfolio of current wind projects that are in construction or being considered across Great Britain.

The nine charging zones that contain the most resource in terms of capacity under consideration (ranging from South Scotland to Central Highlands in Figure 4.2) represent around 90% of the total portfolio. The analysis in this sub-section focuses on these nine regions, given that a more complete dataset on plant costs and potential load factors is available for these regions.

4.1.1 Sensitivity of project economics to variations in TNUoS

Transmission-connected onshore wind developments are subject to TNUoS charges. However, under the current interim arrangements, distributed generation is treated differently, and effectively receives a 'net TNUoS benefit over transmission connected generation'.[25]

National Grid's proposals for reform within GB ECM-23 set out the possible introduction of TNUoS-based charges for distributed generation, on the basis that the impact of distributed generation on the wider transmission network is analogous to directly connected generation.

On this basis, National Grid set out that this similarity could be reflected through a modification to the charging arrangements via the Gross Nodal Supplier Agency Model (GNSAM):

> The GNSAM seeks to address the above issues associated with DG by treating all generation (both directly connected to the transmission system and embedded in the distribution network) equally [26]

Although GB ECM-23 has been placed on hold pending the outcome of Project TransmiT,[27] given the interim nature of the current arrangements and the principles set out by National Grid on possible reform, the analysis below considers the impact of the current locational TNUoS charges on the prospects for both transmission- and distribution-connected onshore wind projects.

This is complemented by a further sensitivity that analyses the impact on transmission-connected developments only.

The current levels of TNUoS charges represent a significant proportion of total onshore wind costs in some regions. A TNUoS charge of £20/kW (ie, similar to that faced by a potential development in North Scotland) represents around 10% of the present value of onshore wind plant costs (including capital costs).[28]

Base-case onshore wind cost assumptions are set out in Table 4.3 based on recent work undertaken for DECC. While variations will exist around this, the base-case cost assumptions and load factors with a TNUoS charge of –£6.4/kW to £22.9/kW, combined with power price and ROC price estimates based on Oxera modelling, yield an IRR (pre-tax, real) between 8.5% and 10.4%. This compares to estimates in other work commissioned by DECC of a required hurdle rate by developers of a mid-sized onshore wind farm, of 9–12%.[29]

Overall returns might also be expected to fall over time as the higher-yielding sites with strong economics will have been constructed in the early stages of technology deployment.

[25] See National Grid (2010), 'Pre consultation. GB ECM-23. Transmission Arrangements for Distributed Generation', p. 1.

[26] Ibid., p. 15.

[27] National Grid (2010), 'Interim approach to charging modifications', September 21st.

[28] Assuming an 11% discount rate.

[29] This suggested a post-tax nominal hurdle rate range of 9.4–11.9% for a medium-sized onshore wind farm. Adjusting for the effective tax rate and inflation assumptions, this yields a pre-tax real hurdle rate range of 9–12%. See Redpoint (2008), 'Implementation of EU 2020 Renewable Target in the UK Electricity Sector: Renewable Support Schemes', p.95.

Table 4.3 Base-case cost assumptions

Capital costs (£'000s/MW)	Annual fixed costs (£/kW/yr)	TNUoS (£/kW)	Other transmission costs (£/kW)	Variable costs (£/MWh)	Load factor (%)	IRR (pre-tax, real)
1,520	51.3	–6.4 to 22.9	6	0	27.4	8.5– 10.4%

Source: Mott MacDonald and Oxera analysis.

This highlights that, given the likely variations in project costs and achievable load factors within regions, and the range of possible hurdle rates between developers, a number of potential projects are likely to be both marginal and highly sensitive to possible changes in transmission charges. This is supported by the fact that the impact on the base-case project IRR from variations in TNUoS of £29.2/kW (ie, variations from–£6.4/kW to £22.9/kW, assuming similar wind and cost conditions across regions) is equal to 180 basis points (bp).

The impact of regional variations in onshore wind load factors and costs

Project economics vary between regions due to differences in wind speed, and hence expected load factors, TNUoS, and other cost differences. Load factor and cost variations also lead to a distribution of projects within regions.

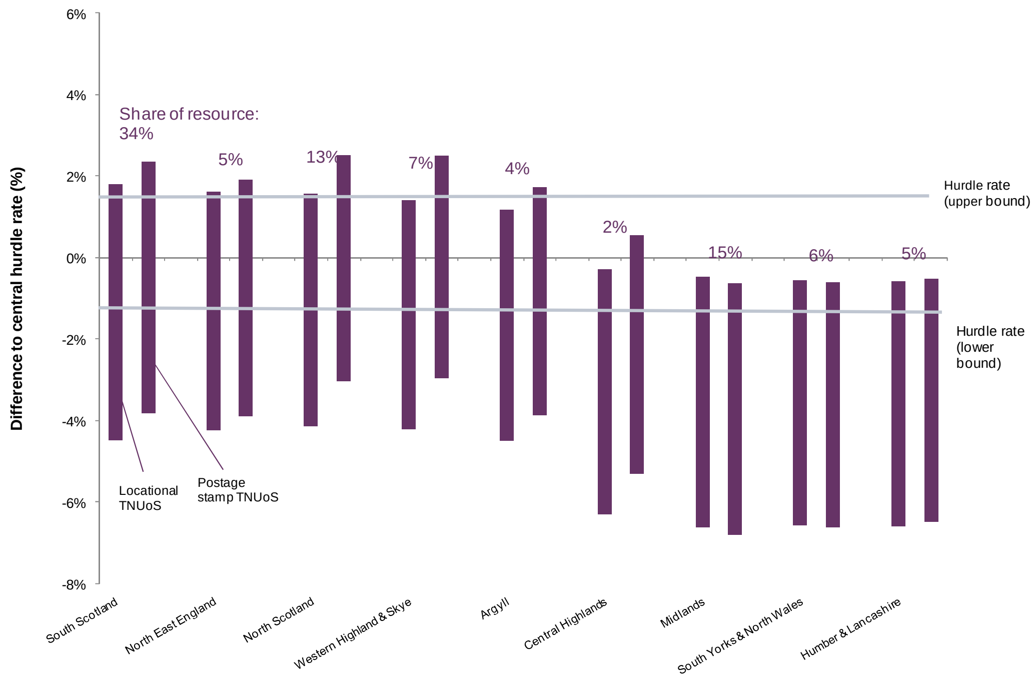
Table 4.4 combines the regional differences in costs and load factors for representative plant in each of the nine most significant charging zones with respect to wind resource, as identified in Figure 4.2, which presents an assessment of the returns to developments across transmission charging zones under the existing differentiated charging regime, as well as those under a uniform postage stamp charging model relative to the central hurdle rate estimate. Figure 4.3 illustrates this.

Table 4.4 Impact of transition to postage stamp TNUoS on regional project IRRs (pre-tax, real)

TNUoS generation zone	TNUoS (£/kW)	CAPEX index	Fixed O&M index	Load factor (%)	Change from transition to postage stamp (bp)
Western Highland & Skye	22.8	1.0	1.3	26–36	109 to 125
North Scotland	20.1	1.0	1.1	24–34	95 to 109
Central Highlands	17.6	1.0	1.3	22–32	82 to 100
Argyll	13.3	1.0	1.3	24–34	55 to 63
South Scotland	12.5	0.9	1.1	22–32	55 to 64
North East England	8.8	1.0	1.0	22–32	29 to 33
Humber & Lancashire	5.4	1.1	0.9	19–29	8 to 10
South Yorks & North Wales	3.6	1.1	1.0	19–29	–3 to –4
Midlands	1.6	1.0	0.9	18–28	–16 to –20

Note: The CAPEX and fixed O&M indices represent the ratio of regional costs to a national base case. Regional variations are based on cost estimates of prospective projects. Cost variations are applied to the base case in Mott MacDonald (2010), op. cit. Cost indices for West Highlands are assumed to equal those in Argyll. Zonal load factors are based on Oxera analysis and data on historical load factors of plant.
Source: Mott MacDonald, ScottishPower and Oxera analysis.

Figure 4.3 IRR versus hurdle rates



Source: Oxera analysis.

The range of returns within regions shows that, while some projects may perform better than others, a significant number of potential projects are likely to be uneconomic or marginal, even within the most resource-abundant areas of Great Britain. The dataset used to create these ranges is described in Box 4.1.

Box 4.1 Cost and load factor assumptions

The base-case onshore wind plant cost assumptions have been obtained from Mott MacDonald (2010), op. cit. These have been adjusted for estimated regional differences across TNUoS zones using project cost information obtained from ScottishPower's portfolio of prospective projects averaged across regions. The average level of fixed costs across regions has also been adjusted upwards in line with recent market experience, leading to the following increase in costs for prospective projects:

- changes to the structure of rates, which have increased the costs faced by Scottish developments by up to a factor of two, and those in England and Wales by a factor of four;
- increases in rent to reflect increasing market expectations;
- increases in community benefit contributions;
- recent experience of higher operating and maintenance contract costs as the turbine warranty periods for early projects have expired.

The central load factor in each zone has been estimated from consideration of the relative load factors from actual plant. The average load factor across zones is equal to the Mott MacDonald (2010, op. cit) capacity factor adjusted for plant availability (27%).

High- and low-load-factor ranges have been estimated based on one standard deviation of actual plant variations. A five-percentage-point standard deviation of load factors has been used based on an estimate of the standard deviation of load factors of all GB plant, which lies in the range 4–8%, depending on the size of the plant considered.

The impact of replacing the current TNUoS charging system with a postage stamp model on onshore wind economics can be compared against the effects from National Grid's proposal to introduce a TNUoS discount for intermittent generation.[30]

This modification would correspond to an average discount of around £4/kW per annum for Scottish projects, and £0.2/kW for those in north-east England from 2011/12.[31] However, modelling undertaken by ScottishPower suggests that the way in which the discount is to be calculated means that this discount will reduce over time, and be unlikely to provide a significant benefit after five years.

Table 4.5 highlights the impact of the proposed discount on onshore wind projects across different charging zones, assuming that the illustrative discount presented in National Grid's consultation document is maintained for five years. The table shows that the impact on project economics of a move to a postage stamp model would be significantly greater (by a factor of five to ten) than the possible improvement in project economics due to the proposed discount that could be available under GB ECM-25.

Table 4.5 Impact of postage stamp charges on IRRs relative to GB ECM 25

Zone	Change in IRR (bp) from postage stamp	Illustrative GB ECM-25 TNUoS discount (£/kW)	Change in IRR (bp) from GB ECM-25
Western Highland & Skye	109 to 125	6.9	15 to 17
North Scotland	95 to 109	5.3	11 to 13
Central Highlands	82 to 100	4.7	10 to 11
Argyll	55 to 63	1.4	3 to 3
South Scotland	55 to 64	3.4	9 to 10
North East England	29 to 33	not reported	n/a
Humber & Lancashire	8 to 10	0.2	1 to 1
South Yorks & North Wales	–3 to –4	1.4	3 to 3
Midlands	–16 to –20	–0.4	–1 to –1

Source: Oxera analysis.

Impact on the prospects for onshore wind deployment

Table 4.6 combines the expected change in project economics from moving to a postage stamp charging system with an estimate of the potential wind resource in each region in order to calculate a weighted average change in the prospects of the GB onshore wind portfolio.[32]

This demonstrates that the increase in IRRs for developments in Scotland and North England from moving to a postage stamp model (around 30bp for North East England and 125bp for projects in Western Highlands & Skye) is significantly larger than the potential decrease in southern charging zones.

[30] The discount proposed under GB ECM-25 is designed to reflect the different impact that intermittent generation has on the required investment to meet system peak, rather than seeking to alter wind project economics per se. See National Grid (2010), 'Consultation Document. GB ECM-25. Review of Intermittent Generation Charging', June, Appendix 4.

[31] National Grid (2010), 'Consultation Document. GB ECM-25. Review of Intermittent Generation Charging', June, Appendix 4.

[32] Potential wind resource is calculated according to the distribution of projects in planning, consented, or under construction.

Table 4.6 Impact of postage stamp charges on IRRs

Zone	Change in IRR (bp)	% of GB wind resource
Western Highland & Skye	109 to 125	7
North Scotland	95 to 109	13
Central Highlands	82 to 100	2
Argyll	55 to 63	4
South Scotland	55 to 64	34
North East England	29 to 33	5
Humber & Lancashire	8 to 10	5
South Yorks & North Wales	–3 to –4	6
Midlands	–16 to –20	15
Weighted average change in IRR	**+46 to +53**	

Source: Oxera analysis.

Table 4.6 highlights that under a range of power price, ROC price, cost and load factor assumptions, a move to a postage stamp charging system could result in a net increase of 46–53bp in GB onshore wind IRRs. The weighted average increase of Scottish regions is 71–82bp, and that for all regions that benefit from a change is equal to around 63–73bp compared with a 12–15bp reduction in regions where returns on wind plant are reduced by increases in TNUoS from current levels.

Figure 4.4 compares the change in the potential range of regional project IRRs from moving to a postage stamp charging system to the range of hurdle rates used in previous analysis commissioned by DECC. The labels also highlight the proportion of onshore resource in each region based on projects in planning, consented and under construction.

Plant with IRRs between the upper and lower hurdle rates represent marginal projects that are most likely to be affected by changes in transmission charging. This highlights the following:

– some projects across all northern zones may be marginal and could benefit from the adoption of a postage stamp model;
– some projects in the Midlands and South Yorkshire & North Wales may be marginal and could be adversely affected (albeit it to a lesser extent) from the adoption of postage stamp model;
– the resource potential is greater for projects in regions most likely to be marginal that would benefit from a move to a postage stamp model;

Analysis of the possible change in onshore wind deployment due to the introduction of postage stamp charging is presented in Table 4.6.

Potential onshore wind capacity in each zone is assumed to be uniformly distributed across the range of IRRs presented in Figure 4.4. Using this assumption, the potential renewables capacity with an IRR above the hurdle rate is estimated separately under locational charging and postage stamp charging. The increase in such capacity due to postage stamp charging provides an estimate of the increase in potential renewables deployment following the introduction of postage stamp charging for each zone. The GB-wide increase in potential renewables volumes is estimated as the average of this increase, weighted by each zone's share of total renewable resource potential.

The analysis in Table 4.7 below suggests that the introduction of a postage stamp charge could result in an additional 7–8% of the onshore wind resource being deployed in a situation where both transmission- and distribution-connected projects face the current level of locational charges.

Based on SKM's assessment that some 49TWh (20GW) of resource may be available by 2030, this could represent as much as 3.5–4TWh per annum or around 1.4–1.6GW.[33] This is equivalent to the total onshore wind output in 2006, and over half that generated in 2009 within the Renewables Obligation.[34]

Table 4.7 Impact of postage stamp charging on onshore wind deployment

TNUoS generation zone	% of total renewable resource	Increase in percentage points of resource above the hurdle rate due to postage stamp (lower hurdle rate)	Increase in percentage points of resource above the hurdle rate due to postage stamp (upper hurdle rate)
South Scotland	34	10	9
Western Highland & Skye	7	22	18
North East England	5	5	5
Argyll	4	11	4
North Scotland	13	19	17
Central Highlands	2	15	0
Humber & Lancashire	5	1	0
South Yorks & North Wales	6	–1	0
Midlands	15	–3	0
Weighted average across all zones		**+ 6.9 to +7.8**	

Source: Oxera analysis.

Sensitivity analysis to assess the impact on transmission-connected projects only

The analysis above is based on the assumption that future distribution-connected onshore wind projects may face TNUoS charges, in line with the principles set out in GB ECM-23. If such developments do not take place, the additional onshore wind resource that might be developed through reform of transmission charging arrangements would be limited to prospective transmission-connected developments.

Table 4.8 below presents an assessment of the impact of introducing a postage stamp model on prospective transmission-connected projects by restricting the impact on project economics to developments in Scotland, and scaling the total resource in those regions by the proportion of existing Scottish capacity that is liable to transmission charges (54%).[35]

[33] Assumes a 27% capacity factor.

[34] Total onshore wind output in 2006 and 2009 was 3.6TWh and 7.6TWh respectively. See DECC (2010), 'Digest of UK Energy Statistics', Table 7.5.

[35] Based on the onshore wind capacity in National Grid's TEC register with a bilateral connection agreement (BCA) relative to total installed capacity in Scotland.

Table 4.8 Impact of postage stamp charging on transmission-connected onshore wind deployment

TNUoS generation zone	Potential transmission-connected resource as a % of total resource	Increase in percentage points of resource above the hurdle rate due to postage stamp (lower hurdle rate)	Increase in percentage points of resource above the hurdle rate due to postage stamp (upper hurdle rate)
South Scotland	18%	10	9
Western Highland & Skye	4%	22	18
North East England	–	–	–
Argyll	2%	11	4
North Scotland	7%	19	17
Central Highlands	1%	15	0
Humber & Lancashire	–	–	–
South Yorks & North Wales	–	–	–
Midlands	–	–	–
Weighted average across all zones		**+3.6 to +4.4**	

Source: Oxera analysis.

This highlights that the move to a postage stamp model could result in an additional 3.6–4.4% of onshore wind being deployed.

Summary of onshore wind analysis

The above analysis highlights the following broad conclusions that can be made about the removal of locational charging signals for GB generators on onshore wind prospects:

- there is a distribution of project IRRs both between and within regions due to variations in project load factors and local costs;
- the increase in the project IRRs in northern regions would be far greater than the decrease in southern regions;
- the net impact on the GB development portfolio (on a weighted average basis) would be to increase project IRRs by around 46–53bpoints;
- the onshore wind resource potential is significantly higher in those regions that would face lower charges than those that would face higher charges;
- the increase in the number of economic projects in regions that would see a decrease in charges would be greater than any decrease in the number of projects in other regions.

If future distribution-connected onshore wind projects are liable to TNUoS charges, in line with National Grid's proposals under GB ECM-23, replacing locational signals with a postage stamp model could result in an additional 7–8% of the renewables resource being deployed, which could represent as much as 3.5–4TWh or around 1.4–1.6GW.

If future distribution-connected onshore wind projects are not likely to be liable to TNUoS charges, replacing locational signals with a postage stamp model might be most likely to affect prospective Scottish developments. The impact of such a change could be to increase the weighted average IRR of Scottish projects by 71–82bp, and could result in an additional 3.5–4.4% of the renewables resource being deployed, which could represent as much as 1.8–2.1TWh or around 0.7–0.9GW.

Either outcome may be likely to have the following effects:

- the potential increase in onshore wind deployment would allow greater confidence in achieving the UK's legally binding targets for renewable energy by 2020;

– the cost of delivering this policy objective should be materially lower than if Scotland and North East England's onshore wind capability were not maximised, as a result of differential subsidies applied to onshore and offshore wind (as analysed below).

4.1.2 The impact on overall cost-effectiveness of meeting the UK's renewables targets

Table 4.7 presents an assessment of the impact of an increase in onshore wind deployment on the ability of the UK to meet its renewables targets and the impact of renewables subsidy costs.

Two scenarios of the increase in onshore wind deployment are considered: a shortfall in the UK's renewable targets in which a 4TWh increase helps to get closer to the target; and, where the targets are met, a 4TWh increase in onshore wind provides a substitute to more expensive offshore wind output.

An increase in onshore wind deployment results in an improvement in the cost-effectiveness of the RO, measured as the subsidy per MWh of renewables deployment, since onshore wind receives a low level of support relative to other technologies.

In the scenario in which the UK falls short of its renewables target, and would otherwise generate 24% of electricity consumed from renewable sources by 2020, an additional 4TWh of onshore wind could increase this level to over 25%.

In the scenario in which the UK meets its renewable target, each unit of offshore output displaced by onshore saves 1 ROC plus the associated headroom. When multiplied by the buyout price, this gives a saving of £164m (in 2009 prices) in each year subsequent to the target being met. This saving could be realised by limiting the support to develop further projects beyond those required to meet the UK's targets.

Contrary to the reasoning considered in the study summarised in Appendix 1,[36] the mechanics of the RO would not be well suited to respond through higher prices if sufficient onshore wind in not forthcoming in the absence of changes to transmission charges. This is because ROC prices are projected to remain close to the level of the buyout price in future years as the obligation size is set by the headroom mechanism. If the amount of ROCs generated is future years is low due to deterred onshore development, but still above the statutory obligation level, the obligation size, as set by the headroom mechanism, would be correspondingly lower and there would be no reaction in price.

4.2 The impact on transmission charges on coal plants and CCS

As well as potentially affecting the deployment of renewable generation, the current system of transmission charges could also have an impact on the future GB generation mix. This is primarily due to the impact of the existing charging framework on the economic viability of coal plant life extensions in the context of the introduction of the Industrial Emissions Directive (IED).[37] This section considers the economics of life extensions for relevant GB coal plant, and the implications of alternative retirement profiles for the system capacity, wholesale electricity prices, and the development of CCS. It does not consider the impacts of possible electricity market reforms, such as the potential introduction of capacity mechanisms or an enhanced carbon price signal.

[36] Scottish Energy Environment Foundation, University of Cambridge, ICF Consulting, Garrad Hassan, University of Edinburgh (2005), 'Impact of GB Transmission Charging on Renewable Electricity Generation', February.

[37] The IED was originally proposed by the European Commission in 2007 to combine several existing air pollution directives, notably the Large Combustion Plant Directive and the Integrated Pollution Prevention and Control Directive. The European Parliament endorsed the terms of the new IED directive on July 7th 2010, and it is expected to be in force from January 1st 2016. The IED sets stricter limits on pollutants such as nitrogen oxides (NOx), sulphur dioxide (SO2) and particulates. See European Commission (2007), 'Directive of the European Parliament and of the Council on industrial emissions (integrated pollution prevention and control)', December 21st.

In the absence of further reforms, at least three potential effects of existing transmission arrangements on coal-fired thermal generation are likely to be important to the evolution of the GB electricity market:

– TNUoS may influence the economics of investments in selective catalytic reduction (SCR) equipment or other NOx-reduction technologies necessary for some existing thermal power plants to meet emission limits imposed by the IED. Given that a number of coal plants that are already compliant with LCPD emission limits are due to retire in the medium term (ie, in the period covered by transitional arrangements for plants that choose to 'opt out' of the IED, and thereby potentially retire earlier that would otherwise be the case), it is possible that TNUoS charges could have a material impact on life extensions that would require significant capital expenditure for maintenance, replacement of life-expired parts and fitting technologies such as SCR;

– to the extent that existing coal plants opt out of the IED or retire (both decisions may be influenced by GB transmission arrangements), this may also have impact on consumers through higher wholesale prices. Coal plant closures or foregone opportunities for life extensions affect the generation mix and system capacity margin, which has a direct impact on the system marginal price and the capacity premium included in wholesale electricity prices. A further consequence of failing to extend the lives of these assets is that investment in other capital intensive generation is brought forward in time with associated higher costs for consumers; and

– to the extent that existing coal plants opt out of the IED or retire (both decisions may be influenced by GB transmission arrangements), this may limit the opportunities to demonstrate the viability of certain CCS technologies. In turn, this may impede the development of clean coal fired generation and reduce the potential diversity of the GB generation mix in future.

Each of these effects are discussed in turn below.

4.2.1 Impacts of TNUoS on SCR investment and coal plant life extensions

SCR is a process for the reduction of nitrogen oxides (NOx) in exhaust gases from power plants and other combustion installations, based on the reduction of NOx with ammonia or urea in the presence of a catalytic process.[38] SCR is a key technology that is expected to be necessary for large (ie, >50MW) GB coal plants to be compliant with the more stringent emission limits under the IED (as compared to emission limits currently in force under the LCPD), which comes into effect from January 1st 2016.[39]

Consequently, coal plants that are currently compliant with the LCPD face a decision over whether or not to install SCR or equivalent NOx reducing technology, since other LCPD opted out coal plants are required to retire by December 2015 at the latest. This investment decision would be expected to be materially affected by the following drivers of revenues, costs, and risks:

– changes to plants' expected load factors and the available spreads or margin between wholesale power prices and the costs of fuel and other variable costs (for example increased wind penetration is likely to reduce load factors for conventional generation);
– incremental capital expenditure necessary to both fit SCR and to maintain the existing plant to enable life extension;
– incremental fixed operating costs associated with SCR and life extension;
– incremental TNUoS charges;

[38] European Commission (2006), 'Integrated Pollution Prevention and Control: Reference Document on Best Available Techniques for Large Combustion Plants', July, p106.
[39] Poyry Energy Consulting (2010), 'The Industrial Emissions Directive', July 23rd, p. 1.

– risks associated with measures required to meet further emission performance standards as may be implemented by the government after the SCR investment decision has been made; and
– risks and opportunities associated with the electricity market reform agenda.

Plants that do not fit SCR may nevertheless operate under the opt out provisions in the IED. These stipulate that plants must operate under the existing LCPD emission limits for a maximum of 17,500 hours between January 1st 2016 and December 31st 2023.[40] Table 4.9 shows affected large GB power stations.

Table 4.9 Large GB coal plants with the potential to fit SCR

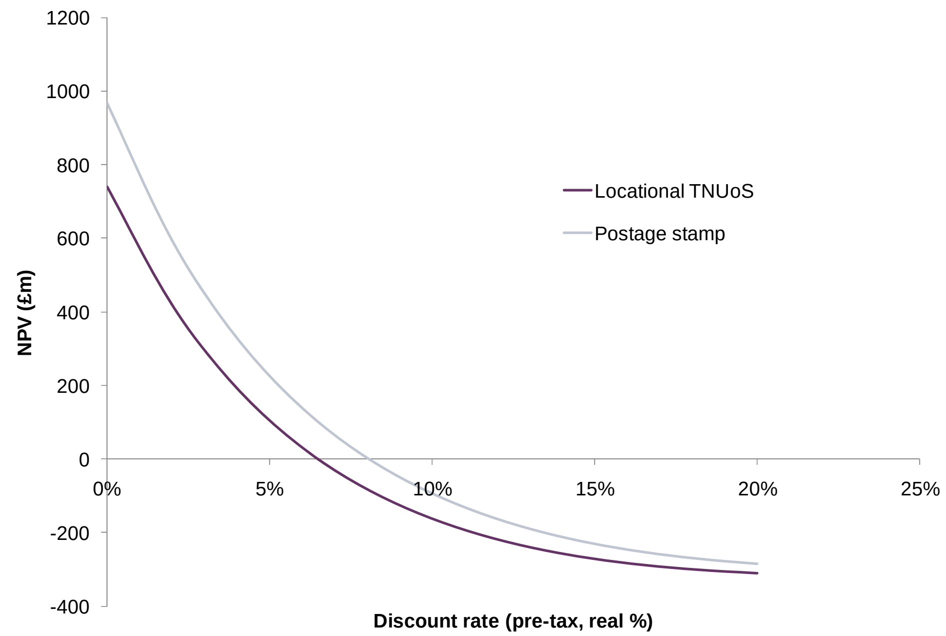
Power plant[1]	Scheduled retirement date[2]	Total capacity (MW) / Capacity with FGD (%)[3]	TNUoS zone	TNUoS charge (£/kW)	Benefit of moving to postage stamp tariff (£/kW)[4]
Longannet	2016	2,304 / 75%	Stirlingshire	13.44	9.3
Fiddlers Ferry	2020	1,961 100%	Humber & Lancashire	5.42	1.3
Ferrybridge C	2016	1,990 / 50%	Humber & Lancashire	5.42	1.3
Eggborough	2021	1,960 / 50%	Humber & Lancashire	5.42	1.3
Drax	2026	3,870 / 100%	Humber & Lancashire	5.42	1.3
West Burton	2021	1,972 / 100%	South Yorks & North Wales	3.59	–0.5
Cottam	2019	2,008 / 100%	South Yorks & North Wales	3.59	–0.5
Rugeley B	2022	996 / 100%	Midlands	1.56	–2.5
Ratcliffe On Soar	2021	2,000 / 100%	Midlands	1.56	–2.5
Aberthaw B	2021	1,455 / 100%	South Wales & Gloucester	0.39	–3.7

Note: [1]All plants are opted into the LCPD by having some FGD equipment currently installed; does not include Fifoots Point (Uskmouth) due to its relatively small capacity. [2] Based on assumed asset lives; does not consider potential for extended operations under IED opt-out nor SCR investment.
[3] Includes both existing (operational) and committed capacity with FGD. [4] Based on a postage stamp TNUoS of 4.1 £/kW; positive and negative values denote an expected reduction or increase in TNUoS charges with a move to postage stamp TNUoS charging, respectively.
Source: Oxera analysis.

Figure 4.4 summarises the impact of the above mentioned drivers of the SCR business case based on a discounted cash flow model for an existing coal plant already fitted with FGD located in Scotland. This analysis is based on typical SCR project costs provided by ScottishPower and revenues based on scenarios developed with Oxera's model of the GB wholesale electricity market.

[40] DECC and Ofgem (2010), 'Statutory security of supply report', November, p. 11.

Figure 4.4 Impact of TNUoS on Scottish SCR investment



Source: ScottishPower and Oxera analysis.

Figure 4.4 shows that for coal plants located in Scotland moving from a locational TNUoS charges to a postage stamp charging methodology could increase the IRR by around 1.5%. Put another way, the NPV impact of moving to postage stamp TNUoS could be expected to be around £100m.

It is important to note that the discounted cash flow model referred to above does not include the impact of certain Balancing Mechanism revenues that result from the current elevated level of constraints experienced on interconnections between Scotland and England. This is because the impact of these revenues would not be expected to influence investment decisions in other TNUoS zones, and because the source of these revenues is being mitigated by network enhancements. They would therefore not be expected to continue indefinitely, and the uncertainty associated with these revenues may lead generators to discount them more heavily (or possibly completely) for the following reasons:

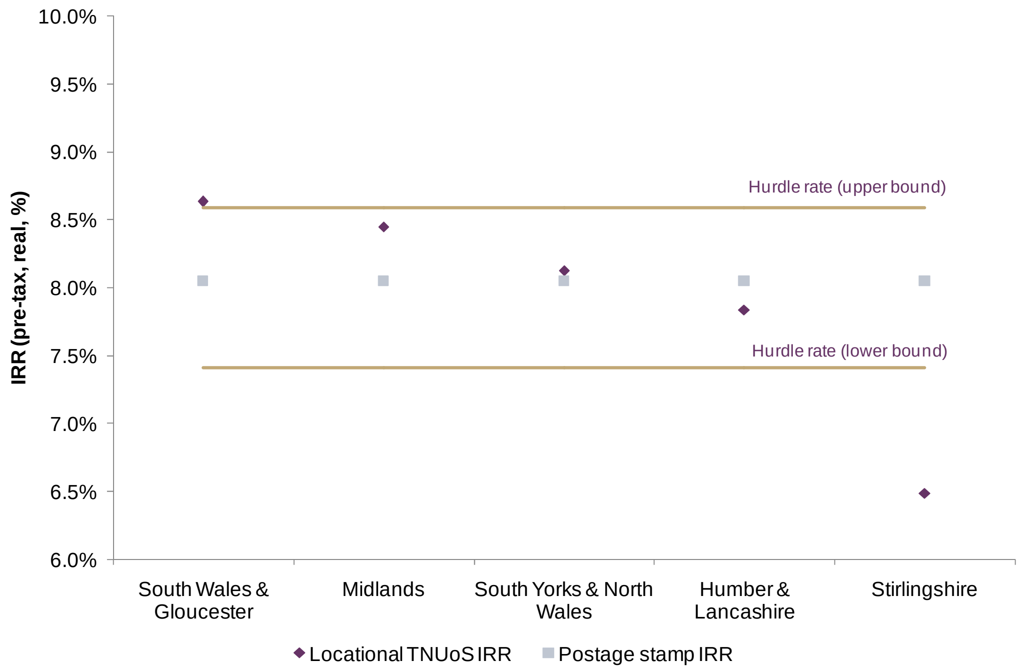
– the time limited nature of current grid constraints at the Cheviot (B6) transmission boundary, given that the major network outage works planned for the 2008 to 2010 period are expected to be nearing completion;[41]
– the existence of direct and growing competition between generators and between alternative products in the provision of constraint management services;[42]
– an expectation of reduced system constraints as a result of major transmission network investment to facilitate new sources of low carbon generation.[43]

Figure 4.5 shows the impact of varying locational TNUoS charges across the zones in Table 4.8, as well as the impact of moving to a postage stamp charging methodology. A key implication of this figure is that a locational TNUoS charge has a significant adverse effect on the economics of SCR investment for coal plant located in Scotland and, to a lesser extent, the north of England. Also, the move to a postage stamp TNUoS charging methodology

[41] Electricity Networks Strategy Group (2009), ''Our Electricity Transmission Network: A Vision for 2020', Full report, July, p. 122.
[42] Oxera (2010), 'Economic annex: CAP170 competition assessment', prepared for ScottishPower's response to Ofgem's letter of 26 January 2010 on competition issues regarding CAP170, para 3.10.
[43] Electricity Networks Strategy Group (2009), op cit., p. 122.

would help to improve the economics of coal plant life extensions, although SCR investments may not necessarily be viable for every plant. Indeed, the move to a postage stamp tariff would help to equalise the returns for these investments across GB, ensuring that the technical and operating characteristics of individual plants have a greater impact on the final plant mix and configuration. For example, if it is considered beneficial that only relatively efficient coal plants achieve life extensions, then postage stamp TNUoS charges could help to achieve this objective.

Figure 4.5 Impact of TNUoS on SCR investment in key TNUoS zones



Note: Hurdle rate range based on a post-tax, nominal discount rate of 7.8–8.8% for investment in a coal-fired generation by a vertically integrated generator. This range is presented in pre-tax, real terms adjusting for the effective tax rate and inflation assumptions.
Source: Redpoint (2007), 'Dynamics of GB Electricity Generation Investment', May 18th, p. 17; Oxera analysis.

4.2.2 Implications for the evolution of the GB wholesale electricity market

As seen in section 4.2.1, the level and variation of TNUoS charges throughout GB has the potential to significantly affect the economics of life extensions for some coal plants. Some other plants may not be expected to be materially affected by a move from locational to postage stamp TNUoS, although these plants' investments in SCR are perhaps likely to be marginal in terms of viability.

In order to illustrate the wider impact of retaining locational TNUoS charging arrangements on the wholesale market and, ultimately, on consumers, this section presents the results of two scenarios of coal plant closure decisions. Both scenarios have been modelled using Oxera's model of the GB wholesale electricity market and use the same commodity input price assumptions.

– **Committed SCR**—in this scenario Ratcliffe and Drax are assumed to invest in SCR. Ratcliffe is the only plant currently committed to life extension, and given that Drax is the most efficient and the largest coal station in GB (and the importance to the Drax group of its coal-fired generation assets) it is arguably likely to consider investment in SCR as a strategic priority.[44] The remaining coal stations in Table 4.8 are assumed to opt out of the IED, which implies that the operating hours for these plants are limited to 17,500 in

[44] See http://www.draxpower.com/

2016–2023 and that some additional maintenance and capital expenditure requirements to facilitate this is forthcoming.

This scenario reflects the uncertain viability of SCR investment cases for nearly all plants in Figure 4.5.

– **Enhanced SCR investment**—in this scenario Longannet is assumed to invest in SCR, along with Ratcliffe and Drax (as in the 'committed SCR' scenario). Again, the remaining coal stations in Table 4.8 are assumed to opt out of the IED, therefore assuming that their operating hours are limited to 17,500 in the 2016–23 period.

  This scenario reflects the fact that the potential for a postage stamp tariff to significantly improve the viability of SCR at Longannet. Also, the remaining plants are not assumed to proceed with life extensions due to a combination of one or more of the following factors:[45]

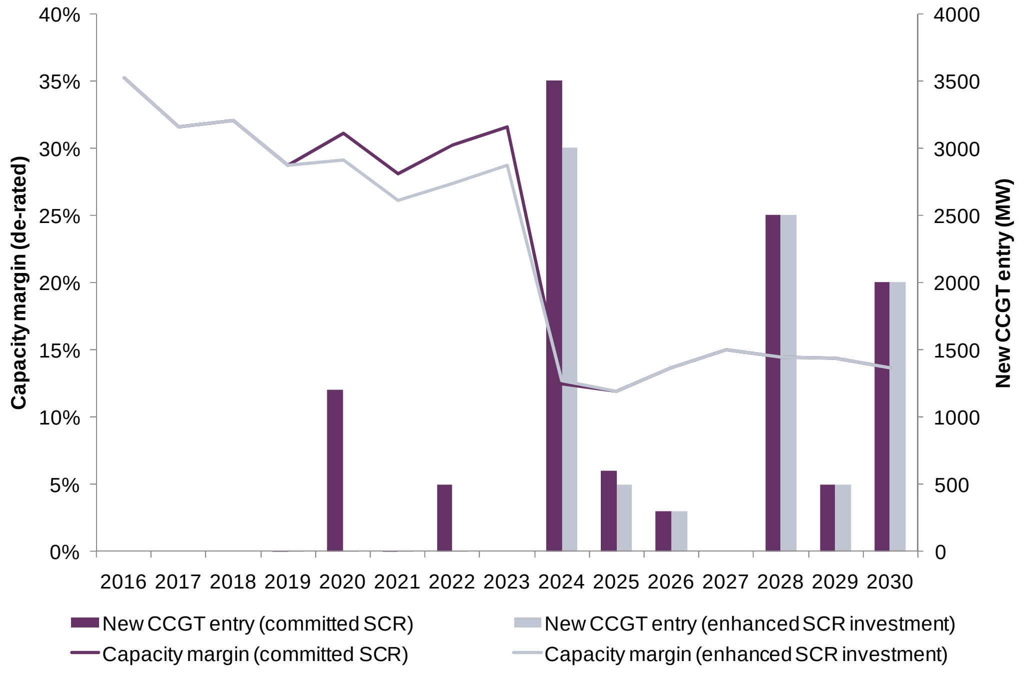
  – some plants may be too inefficient or require too much accompanying plant maintenance and capital investment to make SCR life extension viable;
  – wider investment programmes combined with perceived constraints on capital raising may make SCR investment less of a priority;
  – the potentially adverse impacts of moving to a postage stamp tariff may further deter some plants from adopting SCR; and
  – the IED opt out provisions may enable plants to meet their strategic development plans.

The impacts of these scenarios are presented in Figures 4.7 and 4.8 showing the evolution of capacity margins and prices, respectively.

Figures 4.6 and 4.7 show the key market dynamics under the 'committed SCR' and 'enhanced SCR investment' scenarios. The primary driver of the different evolution of these scenarios is the extent of coal-fired generation capacity affected by limited operating hours in the period 2016–23 and the coal capacity retained in GB post-2023, the expiry of IED transitional arrangements. This change in thermal generation capacity has an impact on electricity prices (and spreads), since a capacity premium is added to the SRMC component of prices based on the extent to which expected available capacity exceeds demand at each point on the load–duration curve. In turn, this price impact drives investment in new generation capacity, notably inducing new gas-fired generation (CCGT) entry, which itself exerts downward pressure on prices. The paths shown in Figures 4.6 and 4.7 show the market responding to changing SCR investment scenarios and reaching an equilibrium between capacity retirement and new entry.

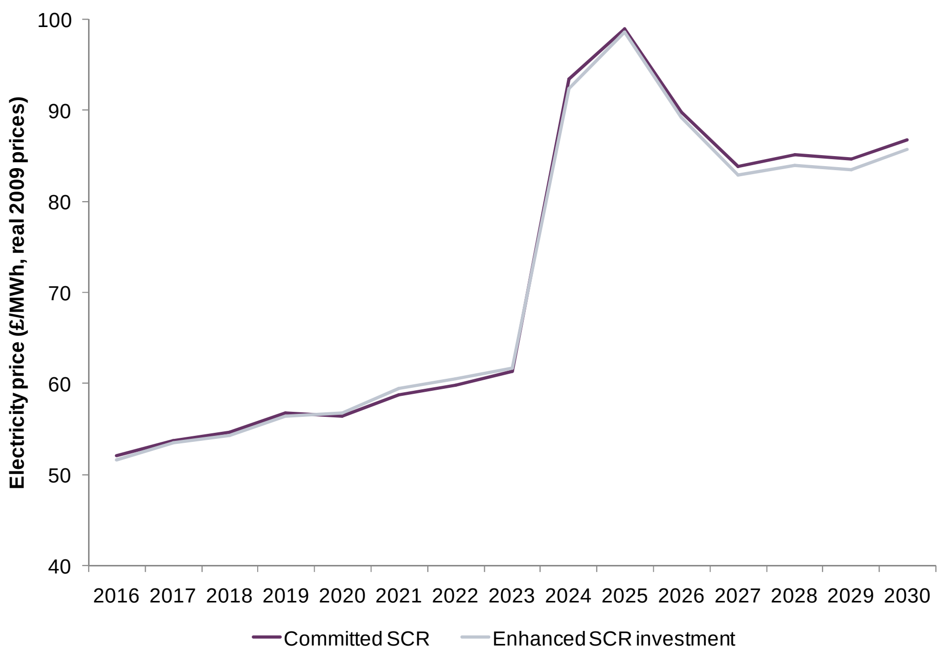
[45] For example, SSE may have suggested similar reasons for not pursuing SCR at Fiddlers Ferry and Ferrybridge. See SSE (2010), 'Financial report for the six months to 30 September 2010', November 10th.

Figure 4.6 Reliable capacity margin and new entry



Note: The 'reliable' or de-rated capacity margin is estimated by giving a declining capacity credit to renewable generation as renewables volumes increase.
Source: Oxera analysis.

Figure 4.7 Impact of coal plant closure scenarios on power prices



Source: Oxera analysis.

Key features of the above figures are as follows:

– while the committed SCR scenario ultimately results in lower levels of coal-fired generation capacity remaining on the system after 2023 (when Longannet is assumed to retire in this scenario), this provides an expectation of higher prices and spreads which would be sufficient to induce new CCGT entry from 2020 onwards (Figure 4.7);

– between 2020 and 2023, new CCGT entry under the committed SCR scenario results in only a minor reduction in prices relative to the enhanced SCR investment scenario (Figures 4.8);

– significant new CCGT entry occurs in 2024–2026 following a sharp decline in coal-fired generation capacity in 2023 and the resulting reduction in the capacity margin, which has the effect of bringing the capacity margins under both scenarios to similar levels, with the result that price and spread differentials between the two scenarios are removed (Figures 4.6 and 4.7).

Overall, the impact of more limited SCR investment would therefore be to bring forward investment in CCGT capacity in anticipation of the expiry of IED transitional arrangements for opted out coal fired generation capacity. Therefore:

– assuming that the capital intensity of new CCGT entry is around 718 £/kW, and using a social time preference rate of 3.5%, gives a present value of the cost front loaded CCGT investment under the committed SCR scenario relative to the enhanced SCR investment scenario of around £289m (2009 prices); and [46, 47]

– as a cross-check, assuming an average annual electricity consumption of around 333TWh in the period 2020–2030 and a social time preference rate of 3.5%, gives a net present value of the cost to consumers of relatively higher prices under the committed SCR scenario relative to the enhanced SCR investment scenario of around £305m.[48]

The implication of the above modelling is that if adopting a postage stamp TNUoS charging methodology were to result in Longannet incrementally fitting SCR due to it becoming economically viable to do so (see Figure 4.5), then this may increase consumer welfare by around £300m in 2009 prices.

To give an indication of the sensitivity of this incremental welfare estimate to alternative SCR investment scenarios, if it is assumed that adopting postage stamp TNUoS would result in both Longannet and Drax incrementally fitting SCR then the welfare impact could be as much as £1.2 billion.

It is important to note that the rise in prices in 2024 (Figure 4.7) is partly due to the fall in capacity margin (Figure 4.6), which is driven by anticipated plant retirements (mainly coal and nuclear). It may be that individual coal plants that could be affected by a move to a postage stamp TNUoS charge may adopt different operating strategies to those modelled by Oxera. This would affect the period over which they reach the maximum number of operating hours (ie, 17,500). This implies that the reduction in capacity could be more gradual than shown in Figure 4.7. To the extent that this results in new CCGT entry earlier than shown in Figure 4.6, this would increase the consumer welfare benefits of adopting a postage stamp TNUoS charge.

It is also important to note that, given that a number of transmission reinforcements may be planned to accommodate additional renewable generation in Scotland by 2018, SCR life

[46] Mott MacDonald (2010), 'UK Electricity Generation Costs Update', June.

[47] Akin to the risk-free rate, the social time preference rate is used by the government to reflect consumers' preference for current consumption. The current suggested rate is 3.5% per year—see HM Treasury (2010), *The Green Book, Appraisal and Evaluation in Central Government*.

[48] Conceptually, these estimates of consumer welfare should be equivalent since prices and capacity margin are functionally related through the capacity premium, and because price signals ultimately provide the incentive for new generation entry. When considering the change in consumer welfare between the committed SCR and enhanced SCR investment scenarios, consumers therefore either bear the costs of front loaded new entry costs or the impact on prices of extended Longannet life extension. In practice, these estimates are not exactly equivalent due to the specific assumptions used above.

extension at Longannet would not be expected to result in further incremental transmission investment.[49]

4.2.3 Implications for CCS demonstration and deployment

Another potential implication of the decision of some operators not to fit SCR to existing coal plants shown in Table 4.8 is the reduction in the number of sites available for the demonstration of the technical and commercial viability of CCS. In turn, this may impede the development of clean coal technologies, thereby potentially reducing the diversity of the GB generation mix in the long term.

As highlighted in the government's recent impact assessment for the policy framework to encourage the development of clean coal technology, CCS demonstration, if successful, is expected to result in a range of benefits, including:[50]

- value to the UK economy through growth of CCS industries;
- reduces costs of mitigation and increasing probability of achieving CO2 stabilisation goals;
- delivery of low carbon security of supply; and
- further potential climate change benefits with the deployment of CCS power stations globally.

Estimates from AEA Technology highlighted that the impact on CCS development could have a significant macroeconomic impact in the coming decades. For example, the benefits in terms of gross value added (GVA) to the UK in global markets for advanced coal generation plant with either fitted or retrofitted CCS could be around £4 billion per year by 2030, but that with slower CCS uptake the benefits would be in the region of £2 billion per year.[51]

The primary rationale for CCS was predicated on the IEA's Energy Technology Perspectives 2008 report which concluded that CCS would need to contribute around 20% of greenhouse gas emission reductions if a 50% reduction target by 2050 was to be met cost effectively.[52] Without CCS it concluded that it would cost an additional 70% to achieve that same reduction.

However, DECC also recognised in its impact assessment that:[53]

> There is a risk that investors would not come forward to build and run the CCS demonstration projects given the policies acting on coal generation, and decide to invest in CCGT as in the counterfactual. This would result in a greater proportion of gas-fired power stations in the UK's energy mix, i.e. less diversity. This would increase the UK's exposure to gas price and gas supply risks. The UK runs the risk of experiencing periods of tight supply. During such periods there is a greater likelihood of price spikes and supply shortfalls for electricity consumers.

For CCS to make a meaningful contribution to this DECC considered that CCS would need to be technically and economically 'proven' and available for deployment in the early 2020s.[54] Clearly, sufficient time for successful end-to-end CCS demonstration is needed for this timetable to be feasible. In recognition of this, DECC's first CCS competition stipulates that the winner must be operational by 2014. It is also important to note that demonstration

[49] Electricity Networks Strategy Group (2009), op. cit., p. 16.

[50] DECC (2009), 'Impact Assessment of Coal and Carbon Capture and Storage requirements in 'A framework for the development of clean coal', November, p. 4.

[51] AEA Technology (2008), 'Future Value of Coal Carbon Abatement Technologies to UK Industry', December, p. 21.

[52] Ibid., p. 7.

[53] Ibid., p. 18.

[54] Ibid., pp. 8–9.

projects must be operational by 2015 to qualify for EU ETS New Entrants Reserve (NER) funding.[55]

Following the withdrawal of Kingsnorth from the first CCS demonstration competition in October 2010, Longannet is likely to be the only coal station that could feasibly support the objective of having an operational CCS demonstration by 2014. Given that the first CCS demonstration competition was launched in November 2007, the lead times experienced in the planning and design of the CCS demonstration project at Longannet may suggest that there are few, if any, alternatives to meeting the 'demonstration era' timescales (see also Box 4.2).[56]

The importance of SCR investment and life extension at Longannet is therefore that it could be on the critical path for the demonstration of CCS in the UK. In particular, this would be the case if the IED opt out provisions are not expected to provide sufficient time for any CCS demonstration project to return sufficient knowledge of the long-term economics and operational performance of the technology used.

Box 4.2 CCS development timescales

DECC has yet to publish a CCS Roadmap to 2050, although it recognises such a tool is required to set out potential trajectories for CCS deployment and the barriers that will need to be addressed. It is planning to publish a roadmap in late Spring 2011. This would help enable CCS to be commercially deployed and contribute to the UK meeting its commitment to reduce greenhouse gas emissions to 80% of 1990 levels by 2050.

UKERC and the UK Carbon Capture and Storage Consortium have developed such a roadmap based on a questionnaire survey of stakeholders and participants in Industry, Government, Academia and environmental NGO's. This was followed by a two-day workshop in mid 2007 with a representative group of invited experts as a first step towards the government's roadmap.

This workshop highlighted the urgent need to establish learning and feedback loops before 2015, which would be expected to require a CCS demonstration to at least be identified and detailed works started (and coordinated with the SCR investment). A key component of this vision was the original intention to establish a UK demonstration project by 2012 in order that its performance could be used as a catalyst to influence public opinion, and derive the financial and regulatory framework for commercial deployment by 2015. Given the lack of alternatives, this is perhaps likely to require Longannet to pursue SCR life extension to ensure continued operations beyond 2023.

Source: UKERC (2007), 'The UKERC/UKCCSC Carbon Capture and Storage Road Map. Workshop report', May.

[55] Ibid., p. 8.

[56] http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/whatwedo/energy/sources/sustainable/ccs/ccs-demo/page40961.html

5 Conclusions

This report has set out theoretical and quantitative analysis to help assess the role of transmission charges in achieving the UK's electricity market objectives.

The current locational charging arrangements attempt to mimic some of the characteristics and benefits of market-based prices to help coordinate the behaviour of users and providers of transmission assets. However, locational price signals are not relied upon to meet certain transmission charging objectives, such as cost recovery and signalling new transmission investment, while there are a number of other tensions between electricity market objectives that are likely to limit the effectiveness of locational price signals.

This suggests that reform may need to be considered in order to:

– avoid an unpredictable locational price signal that may otherwise result from rapid expansion of renewable generation and significant retirements of existing plant;
– avoid deterring investment in relatively location-constrained low-carbon plant required to meet the UK's energy renewables targets and carbon budgets;
– recognise that a number of large transmission investment projects will be dictated by regulatory processes separate from any signal from locational prices.

The impact of current locational charges on renewable prospects

Evidence on the UK's practical renewable resource suggests that the full exploitation of the UK's onshore wind resource (alongside other relatively low-cost renewables) is likely to be essential to meet the 2020 renewables targets in the most cost-effective way.

Transmission-connected onshore wind developments are subject to TNUoS charges. However, under the current interim arrangements, distributed generation is treated differently, and effectively receives a 'net TNUoS benefit over transmission connected generation'.[57]

National Grid's proposals for reform within GB ECM-23 set out the possible introduction of TNUoS-based charges for distributed generation, on the basis that the impact of distributed generation on the wider transmission network is analogous to directly connected generation.

Although GB ECM-23 has been placed on hold pending the outcome of Project TransmiT,[58] given the interim nature of the current arrangements and the principles set out by National Grid on possible reform, the analysis in this report considered the impact of the current locational TNUoS charges on the prospects for both transmission- and distribution-connected onshore wind projects.

This was complemented by a further sensitivity that analysed the impact on transmission-connected developments only.

The current levels of TNUoS charges represent a significant proportion of total onshore wind costs in some regions. A TNUoS charge of £20/kW (ie, similar to that faced by a potential development in North Scotland) represents around 10% of the present value of onshore wind plant costs (including capital costs).[59]

[57] See National Grid (2010), 'Pre consultation. GB ECM-23. Transmission Arrangements for Distributed Generation', p. 1.
[58] National Grid (2010), 'Interim approach to charging modifications', September 21st.
[59] Assuming an 11% discount rate.

The impact on the base-case project IRR from variations in TNUoS of £29.2/kW (ie, variations from–£6.4/kW to £22.9/kW assuming similar wind and cost conditions across regions) is equal to around 180bp.

The analysis presented in this report on the distribution of onshore wind resource and the economics of prospective projects across transmission charging regions suggests that the following broad conclusions can be made about the removal of locational charging signals on onshore wind prospects:

- there is a distribution of project IRRs both between regions and within regions due to variations in project load factors and local costs;
- the increase in the project IRRs in Northern regions would be far greater than the decrease in southern regions;
- the onshore wind resource potential is significantly higher in those regions that would face lower charges than in those that would face higher charges;
- the net impact on the GB development portfolio (on a weighted average basis) would be to increase project IRRs by around 46–53bp;
- across the range of likely hurdle rates, the regions likely to contain most marginal projects are also likely to benefit from lower transmission charges.

If future distribution-connected onshore wind projects are liable to TNUoS charges, in line with National Grid's proposals under GB ECM-23, replacing locational signals with a postage stamp model could result in an additional 7–8% of the renewables resource being deployed, which could represent as much as 3.5–4TWh or around 1.4–1.6GW. This is equivalent to the total onshore wind output in 2006, and over half that generated in 2009 within the Renewables Obligation.[60]

If future distribution-connected onshore wind projects are not likely to be liable to TNUoS charges, replacing locational signals with a postage stamp model might be most likely to affect prospective Scottish developments. The impact of such a change could be to increase the weighted average IRR of Scottish projects by 71–82bp, and could result in an additional 3.5–4.4% of the renewables resource being deployed, which could represent as much as 1.8–2.1TWh or around 0.7–0.9GW.

If the UK is able to meet its renewable targets, an additional 4TWh of onshore wind could displace 4TWh of relatively more expensive offshore wind. This implies that the associated annual saving through a reduction in the obligation size to meet the UK's renewable target could be around £164m (in 2009 prices) in each year subsequent to the target being met.

The impact on transmission charges on coal plants and CCS

As well as potentially affecting the deployment of renewable generation, the current system of transmission charges could also have a significant impact on the future GB generation mix. This report has therefore considered the economics of life extensions for relevant GB coal plant, and the implications of alternative retirement profiles for the system capacity, wholesale electricity prices, and the development of CCS.

Locational TNUoS may negatively influence the economics of investments in SCR equipment necessary for some existing coal plant to meet emission limits imposed by the IED. Given that a number of coal plant already compliant with LCPD emission limits are due to retire in the period to 2023 (covered by transitional arrangements for plant that choose to opt out of the IED), it is possible that TNUoS charges could have a material impact on life extensions that would require significant CAPEX for maintenance, replacement of life-expired parts and fitting technologies such as SCR.

[60] Total onshore wind output in 2006 and 2009 was 3.6TWh and 7.6TWh respectively. See DECC (2010), 'Digest of UK Energy Statistics', Table 7.5.

Oxera estimates that the SCR investments in Scotland may have an IRR (pre-tax, real) in the region of 6.5%, which is below the quoted hurdle rate range of 7.4–8.6% (pre-tax, real). The adoption of a postage stamp TNUoS charge would be expected to increase the IRR of SCR investment in Scotland by around 1.5%, equivalent to an NPV benefit of around £100m. The IRR impact of adopting postage stamp TNUoS would be expected to have a significantly smaller impact on other coal plant, although their IRRs are could be within the hurdle rate range mentioned above.

While postage stamp TNUoS may not necessarily mean that SCR investments would be viable for all GB coal plants, it would help to equalise potential returns for these investments across GB, ensuring that the technical and operating characteristics of individual plant have a greater impact on the final plant mix.

To the extent that existing coal plant opt out of the IED or retire (both decisions may be influenced by GB transmission arrangements), this may also have an adverse impact on consumers by bringing forward investment in CCGT capacity in anticipation of the expiry of IED transitional arrangements for opted out coal fired generation capacity.

Oxera estimates that the detriment to consumer welfare of front loaded new CCGT entry could be around £300m in 2009 prices. These costs could be avoided if the move to postage stamp TNUoS would result in incremental SCR investments at Longannet.

Finally, to the extent that existing coal plant opt out of the IED or retire, this may limit the opportunities to demonstrate the viability of certain CCS technologies. In turn, this may impede the development of clean coal fired generation and reduce the potential diversity of the GB generation mix in future.

A1 Review of a 2005 study on the impact of transmission charges on renewables

This appendix summarises analysis from a study in 2005 by Scottish Energy Environment Foundation (SEEF) and others quantifying the effects of GB-wide locational transmission charging on renewables deployment in the north of Scotland in 2005.[61] The appendix highlights the more narrow scope of the 2005 study than the analysis in this report, and outlines why the results of that study may no longer be valid.

A1.1 Context and approach

National Grid's proposals in 2003 for the introduction of GB-wide locational TNUoS charges raised concerns that the level of future tariffs in northern Scotland would impede the achievement of the government's 2010 renewables targets.

The SEEF study was used to provide evidence on whether a specified area within northern Scotland was critical to achieving the government's 2010 renewables targets, either with or without a dispensation from the new TNUoS charges (under Section 185 of the Energy Act).

Two alternative approaches were used in the analysis: a 'dynamic' financial approach that simulated renewables policy measures to predict the investment in future capacity of renewables technologies; and a 'static' financial approach that assessed the impact of TNUoS charges on returns to renewables plant.

The latter approach is similar to that used by Oxera in the analysis in this report.

A1.2 Findings

The results of the SEEF study varied according to the methodological approach used in the analysis, although the overall conclusion was that a dispensation from TNUoS charges would have a limited impact on renewables deployment.

It was concluded that, under the 'dynamic' approach, dispensation from TNUoS charges was likely to have a limited impact on renewables deployment (a maximum of 0.17% in any year to 2010) for the following reasons:

– the average IRR of Scottish onshore wind developments was higher than those in other regions of GB, despite higher TNUoS charges;

– the RO mechanism was self-adjusting to shortfalls against meeting the obligation, with lower renewables deployment resulting in higher Renewables Obligation Certificate (ROC) prices stimulating further investment;

– with embedded generation not facing TNUoS charges under the BETTA proposals, such plant were in a neutral or improved position under the GB-wide TNUoS proposals than previously;

– the study considered a ten-year dispensation scheme, which had a limited impact on plant built towards the latter part of the dispensation period.

[61] Scottish Energy Environment Foundation, University of Cambridge, ICF Consulting, Garrad Hassan, University of Edinburgh (2005), 'Impact of GB Transmission Charging on Renewable Electricity Generation', February.

The study noted that the modelling did not consider a number of factors affecting renewables deployment, including that:

– any unpredictability in TNUoS charges was likely to increase the cost of capital for developers;

– ROC prices in power price agreements may not be as sensitive to changes in renewables volumes as implied by the modelling.

The ‘static’ approach found a greater impact of TNUoS charging on renewables deployment. It estimated that a dispensation from TNUoS charges would lead to an increase of up to 372MW of onshore wind capacity in Northern Scotland. Furthermore, in addition to the increase in onshore deployment, it found that a dispensation from TNUoS charges would provide opportunities to invest in other new and developing technologies.

The static approach differed from the ‘dynamic’ approach in that it excluded the feedback effects of renewables deployment on ROC prices.

The SEEF study highlighted that a ‘static’ approach may be more representative of how conservative developers behave.

A1.3 Are the results of the SEEF study still valid?

Changes to the market and policy environment imply that some of the above factors resulting in the relatively small effect of dispensation from TNUoS charges in the dynamic analysis no longer hold.

– The study highlights that the average IRR on Scottish onshore wind was higher than those in other regions of GB despite higher TNUoS charges. In addition to considering average IRRs, it is important to look at a range of potential plant load factors and IRRs within regions. Although plant with relatively high IRRs will continue to be profitable under locational TNUoS charges, plant at the lower end of the IRR range will only become viable with a reduction in TNUoS charges. To the extent that a greater volume of potential renewable resource is available in Scotland, the net impact is likely to be an increase in renewables deployment across GB, with more plant in zones with high TNUoS charges benefiting from the reduction in charges than lose out in low TNUoS charge zones. This has been highlighted in the analysis carried out by Oxera in this report. Notably, the SEEF study also highlights that onshore wind in England and Wales would have only a limited ability to fill any gap in supply if capacity in northern Scotland is reduced.

– The mechanics of the RO have changed since the SEEF study was carried out. In particular, the introduction of the headroom mechanism implies that ROC prices are no longer likely to be self-adjusting to changes in renewables deployment. ROC prices are a function of the difference between the targeted size of the obligation under the RO and the outturn levels of renewables deployment. With the imposition of the headroom mechanism, as volumes of renewables deployment increase, the obligation size will be determined such that it remains fixed at ten percentage points higher than renewables deployment. This will result in a broadly constant ROC price that will not vary with variations in renewables deployment, other than short-term fluctuations due to forecasting errors. Consequently, a reduction in onshore wind deployment due to higher TNUoS charges will not result in an increase in the ROC prices and the feedback loop described in the dynamic case will not apply.

– A significant proportion of onshore wind resource is in Scotland. Due to the lower transmission voltage levels and scope for larger wind developments, this means that significant growth potential is liable to TNUoS charges, as outlined in section 4.

– As the study itself highlights, the ten-year dispensation period is unlikely to be sufficient to have a significant impact on plant built towards the latter part of the period. Even for plant built towards the early part, the estimated effect of the dispensation is likely to be reduced given the relatively long asset lives of wind plant (around 25 years).

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