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Locational Transmission Charging in Decarbonised Power Markets

By Sean Gammons, Richard Druce and Professor Goran Strbac

Energy Market Insights

From the Editor

The move towards low-carbon electricity generation in electricity markets around the world creates challenges in ensuring that the future location of generation development is optimal in terms of the resulting total generation and transmission costs. In this EMI, the authors discuss the transmission charging approaches taken in different markets and the extent to which they provide locational signals for generation investors. Using Great Britain as a case study, the differing impact of locational charging versus uniform charges is quantified based on the resulting differences in transmission system costs (including the costs of constraints and losses, as well as transmission investment) and final power prices. The results highlight that locational signals remain an important element of efficient market design even in decarbonised power markets.

Ann Whitfield, Editor

Overview

In the coming decades, electricity industries around the world require substantial investment in new generation capacity if they are to meet targets for reducing CO_2 emissions and increasing output from renewable energy sources (RES). For both RES and conventional generation, investors face a choice over the location of their projects. They can locate new generation where the costs of developing the project are lowest, e.g., where land prices are lowest and/or access to fuel sources is better or cheaper (or, in the case of wind generators, wind speeds are higher). Or they can locate new generation in more expensive locations that are closer to load centres, thereby reducing the cost of transporting their electricity to customers over the transmission network. All these costs differ greatly between different locations. Developers' choice of site therefore has a significant impact on the total cost of supplying electricity to consumers. Their choices will be more efficient if prices are cost-reflective, but transmission charges, at least, are subject to government regulation. Regulators and policymakers face the challenge therefore of ensuring that electricity markets, transmission access rules, and transmission charges encourage efficient trade-offs between electricity transport costs and the other costs and benefits of new electricity generation, whether these are RES or conventional.

In this paper, we describe a range of options for locational pricing of energy and infrastructure in electricity markets, and illustrate the potential significance of these mechanisms using a case study of the British market, which is targeted for rapid decarbonisation.[1] Drawing on recent project work conducted by London-based members of NERA's Energy, Environment, and Network Industries Practice, in collaboration with Imperial College London, we compare the relative economic efficiency of transmission charges that differ by location, compared with uniform (or "postage stamp") charges. Our modelling suggests that replacing the current system of locational transmission infrastructure tariffs with uniform charges throughout Great Britain (GB) would increase costs to electricity consumers over the period to 2030 by around £20 billion in net present value (NPV) terms.

Transport Costs in Electricity Markets

Electricity is a homogenous product at the points of production and consumption.[2] This characteristic means that all electricity is the same from the perspective of consumers, whatever technology is used to generate it or wherever it was produced. However, like some other commodities, electricity is characterised by significant transport costs. As a result, the location of generation capacity relative to the location of consumption within an electricity grid can significantly affect the overall costs of supplying end-users.[3]

The costs of transporting electricity fall into two broad categories: fixed infrastructure costs and short-run marginal costs (congestion and losses), as defined below:

- **Infrastructure and Operating Costs:** In order to move power from one location to another, investors must build infrastructure including power lines, cables, transformers, and other equipment. The cost of building and maintaining these assets depends on their capacity to transport electricity from one area to another and the distance over which this capacity is provided, regardless of any flow of energy over those assets.

- **Short-Run Marginal Costs:** Once energy starts to flow over the infrastructure assets, it imposes additional costs of two kinds:
  - Constraint Costs: Electricity transport costs show up as congestion within the transmission system when insufficient transport capacity is available to accommodate power flows. In a congested system, instead of using the transmission system to transport power from one area to another, expensive generators that would not be dispatched in an uncongested system have to be dispatched to ensure supply exactly equals demand in all areas. Output from other, cheaper generators that would be producing electricity must be reduced. In this case, electricity transport costs show up as the extra costs of altering the pattern of dispatch to resolve constraints.
  - Losses: Losses are also a cost of transporting electricity between two locations. The further energy travels along a transmission line, the higher the proportion of the energy that is lost. This lost energy has to be replaced, at a cost, by increasing total generation output.

The mechanisms used to allocate these transport costs to generators are detailed, complex, and sometimes lacking in transparency. However, they can have material effects on the value of a generator and the value of its output. They can therefore affect generators' locational decisions. Signalling electricity transport costs to generators through energy and infrastructure prices gives them an incentive to make an efficient (i.e., cost-minimising) trade-off between all the factors that vary by location. Making efficient trade-offs will minimise the joint cost of generation and transmission and hence total costs to consumers.

Alternative Models of Transmission Charging

Electricity markets around the world differ markedly in the way they allocate the costs of transmission to generation and "load" (electricity taken from the transmission network to meet consumption). Below, we describe some of the more common models.

Locational Pricing of Energy

The New Zealand electricity market and the PJM and New York markets in the US apply locational marginal pricing (LMP), whereby energy prices reflect the short-run marginal costs of generation and transmission at each node on the network. The costs of losses and congestion then show up as differences between energy prices at different nodes on the network.[4]

Markets such as Nordpool adopt a similar approach, but prices are defined at the level of "zones" rather than nodes.[5] In this case, the market operator attempts to clear the whole market using a single hourly (or half-hourly) price, and when transmission constraints arise between zones, prices are allowed to differ by zone to encourage a feasible pattern of dispatch. The proposed European Union (EU) "Target Model" for electricity market design follows a similar approach. The design focuses on the need to generalize the Nordpool model of "market splitting" across the whole EU. EU Transmission System Operators (TSOs) would be required to implement day-ahead and intraday trading arrangements that recognise persistent transmission constraints at and within the borders of their respective control areas.[6]

On the other hand, some markets define a single wholesale electricity price for a wide region, often defined as the whole national or state jurisdiction. In these cases, the TSO is responsible for resolving transmission constraints in real time by instructing generators to increase or decrease their output compared to the optimal pattern of dispatch in an unconstrained system. In such a market structure, all generators receive, and all consumers pay, a single "unconstrained" market price. The TSO must recover the costs of resolving constraints (e.g., compensating generators for changing their output) through regulated tariffs levied on generators and/or load.

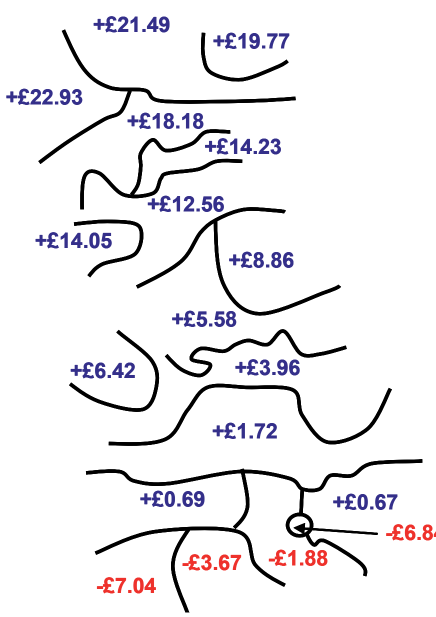
Locational Infrastructure Charging

In single-price markets, fixed infrastructure charges provide the only potential source of locational incentives, either in the form of deep connection charges (i.e., charges that recover the cost of investments undertaken when a new user connects to the network) or locational "use of system" charges. Fixed transmission charges are commonly levied on connected capacity or on the peak-time energy flows into or out of the network (either the system peak, or each individual user's maximum usage).[7]

Where infrastructure charges differ by location, the reason is usually the desire to provide some signal about differences in the long-term costs of investment in transmission. For example, in GB transmission infrastructure charges, known as "transmission network use of system charges" (TNUoS), reflect an estimate of the incremental cost that generators in different zones of the network would impose on the transmission system at peak time.[8] The TSO estimates these costs using a load flow model and a number of other cost allocation algorithms. Tariffs also include a substantial uniform charge, intended to recover the non-incremental costs of the network.[9] Current tariffs are illustrated in Figure 1.

In some cases the presence of an additional generator would allow the TSO to avoid the cost of reinforcing the network, so that the incremental cost element of the TNUOS charge is negative. In some cases, the negative incremental cost element is larger than the positive non-incremental element, so that overall the generator receives a payment from the TSO, instead of paying a charge. Currently the annual difference in charges between the cheapest zones in the south and most expensive zones in the north is around £28.5/kW, or £14 million per year for a 500 MW generator. The north-south spread in charges reflects the surplus of generation compared to peak demand in the north of GB, and the relative shortage of generation capacity compared to peak demand in the south of GB; constraints on the transmission system along key north-south transmission corridors mean that north-south energy flows at peak times create a need for incremental investment.[10]

Figure 1: Current Transmission Charges in GB (£/kW/yr)



Source: NGET Charging Statement.[11]

Most other systems around the world rely on some form of "deep" connection charge to provide locational incentives to minimise infrastructure costs, or ignore the need for locational incentives by allocating all infrastructure costs direct to load through flat charges.

Case Study: Great Britain

Locational Signals in the GB Market

GB is an example of a market with a single energy price. Following a recent decision by the UK government (known as the "connect and manage" decision),[12] constraint costs are also socialised and recovered through a uniform per MWh charge on generators and suppliers.[13] Losses are allocated to generators and load through non-locational adjustments to metered production and consumption that are applied within the settlement system. Trading arrangements in the GB electricity market therefore provide generators with no price signals in real time that reflect the transport costs of the energy they produce.[14] Hence, TNUoS charges provide the only signals of electricity transport costs to British generators.

Project TransmiT: Reform of Access Arrangements

In September 2010, the British energy regulator Ofgem launched a review of charges for access to Britain's electricity and gas transmission networks, known as Project TransmiT.[15] The review is considering whether the current regime for network charges can continue to support the move to a low-carbon energy sector.

In the context of this review, RWE npower recently commissioned NERA and a team from Imperial College London to model the impact of replacing the current locational TNUoS methodology with a uniform (i.e., postage stamp) charge. Our study compared two scenarios:

- **Locational scenario**: We assume the current transmission charging regime continues indefinitely.
- **Uniform scenario**: We assume that all generators pay a uniform "postage stamp" transmission access charge per kW of Transmission Entry Capacity (TEC) so that all generators pay a single £/kW charge that is invariant to their location on the GB transmission system.[16]

Modelling the Impact of Uniform TNUoS Charges

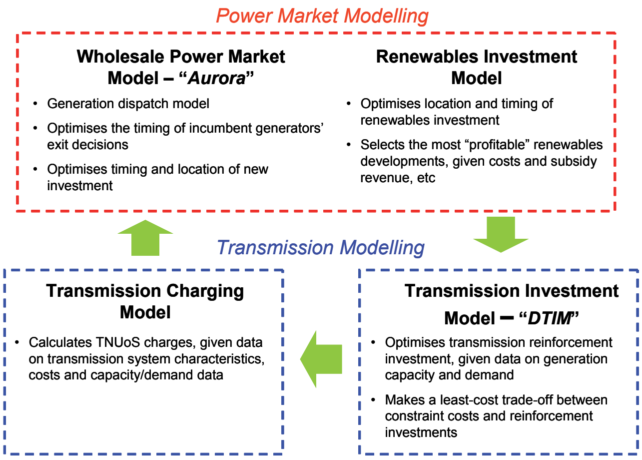
As we describe below, we conducted analysis to test the relative performance of the two approaches in terms of (1) the costs to consumers, and (2) the change in total costs in the GB electricity industry.

Modelling Approach

To compare the locational and uniform charging regimes, we developed a modelling framework that combines wholesale power market models with models of transmission investment requirements and TNUoS charges, as illustrated in Figure 2.[17] Given the interdependency between generation investment decisions, both entry and exit, and transmission investment and charges, we iterated between the transmission system and power market models to identify a long-term equilibrium pattern of investment and charges.

Our modelling framework accounted for the UK government's CO_2 emissions targets by using government projections of the CO_2 price in the model. We also accounted for the impact of current renewables incentive schemes when modelling investment decisions.

Figure 2: Overview of Modelling Framework



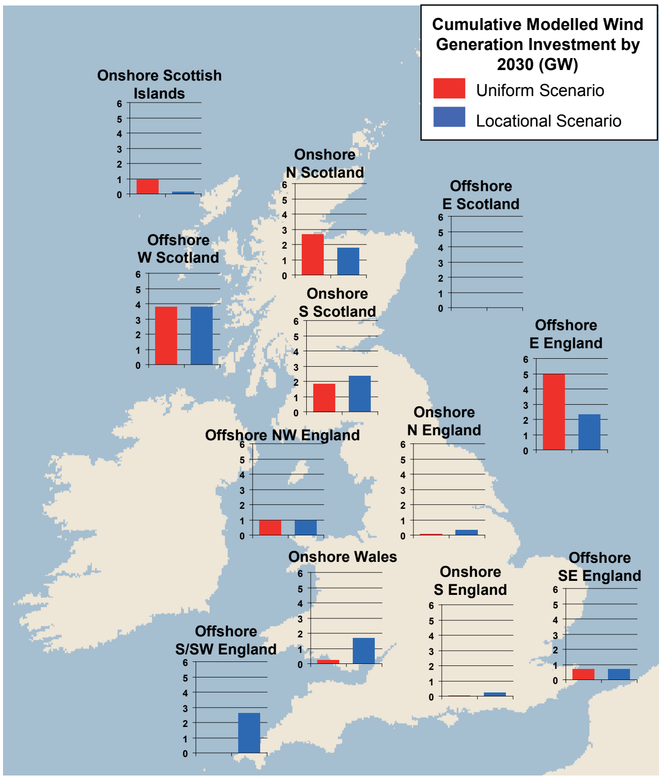
Source: NERA/Imperial Analysis.

Modelled Generation Investment Patterns

As Figure 3 shows, in the locational scenario our model predicts that new wind generation investment takes place across most areas of the country, with a mix of onshore and offshore wind sites selected by the model. By contrast, in the uniform scenario renewables investment is more heavily concentrated in Scotland and offshore along the east coast of GB, with very little wind development onshore in England and Wales. The reason for this is that the introduction of uniform TNUoS charges reduces the cost of developing wind capacity in Scotland, and raises costs in the south. As a result, the uniform scenario tends to shift modelled new wind investment towards the north of GB.

Moreover, uniform charges also incentivise a shift in wind development to sites located further from shore, e.g., by shifting offshore wind development from the Bristol Channel, 24 kilometres from the coast of southwest England, to the Dogger Bank, between 125 and 195 kilometres off the east coast of England. It also results in more development on remote Scottish islands. In these areas, charges are relatively high in the locational scenario due to the cost of the infrastructure required to connect these projects to the GB transmission system. However, with uniform TNUoS, these areas become more attractive for wind development due to the high load factors achievable in these more remote locations. Hence, as we describe above, the absence of locational signals in the uniform scenario means wind developers no longer need to make a trade-off between load factors and the costs of developing the transmission infrastructure required to support them.

Figure 3: Location of Modelled Renewables Investment



Source: NERA/Imperial Analysis.

In both scenarios our model predicts investment in a range of new nuclear, CCGT, and OCGT generation capacity, with a similar mix of technologies in both cases. However, as Figure 4 shows, there is a significant impact on the locational decisions of new conventional and renewable generators.

In the locational scenario, a larger proportion of new conventional generation capacity is located in Wales and the south of GB, relatively close to the major load centres in the southeast. Some investment takes place in the southwest and the midlands, in response to low TNUoS charges in these areas of the country. By contrast, in the uniform scenario new gas-fired generation capacity locates along the east coast of England and Scotland and in south Wales, where gas transmission charges are lowest.

Location of Modelled Conventional Generation Investments

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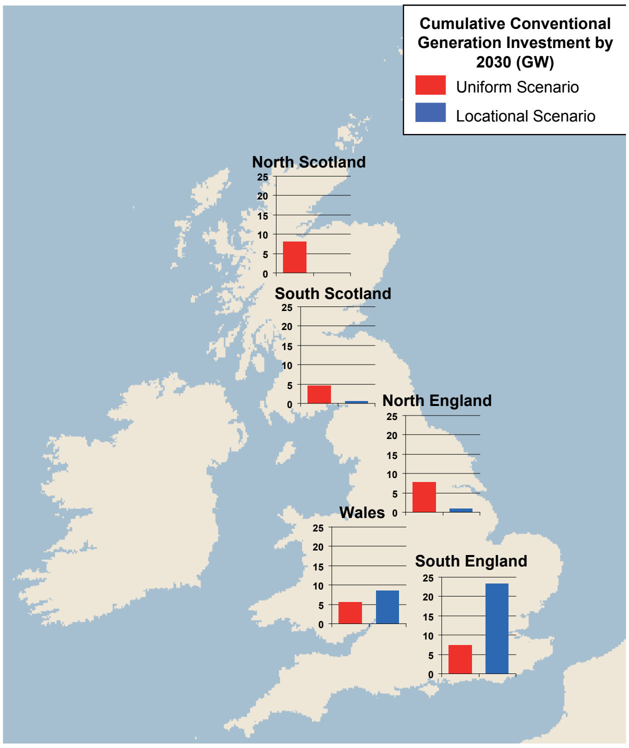
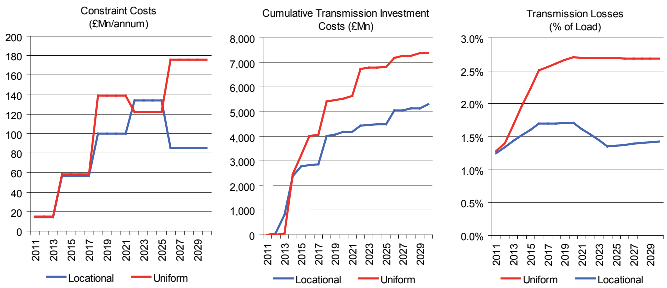
Figure 4: Location of Modelled Conventional Generation Investments



Source: NERA/Imperial Analysis.

As Figure 5 shows, these different patterns of generation investment have substantial effects on transmission investment costs, constraint costs, and losses, which are all higher in the uniform scenario than in the locational scenario.

Figure 5: The Impact on Transmission System Costs



Source: NERA/Imperial Analysis.

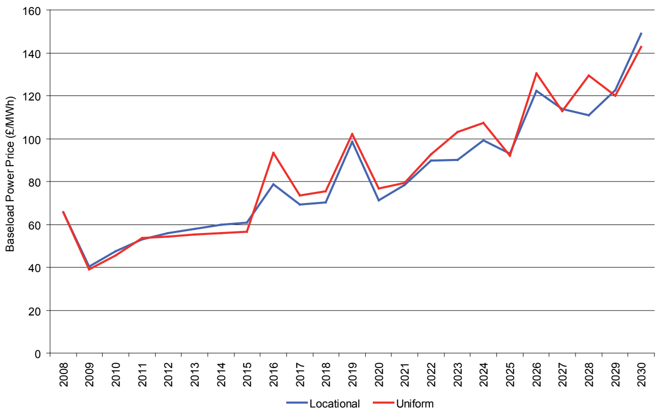
Cumulative transmission expenditure by 2030 is 40% higher in the uniform scenario than the locational scenario, due to the need for infrastructure to transport energy from more remote locations, both on and offshore, to the main load centres. The higher proportion of capacity in the north also necessitates investment along the main north-south transmission corridors. Constraint costs are also higher in the uniform scenario, although the size of the increase depends on the trade-off made by the DTIM model between transmission investments and constraint costs.[18]

Losses are also substantially higher in the uniform case because a high proportion of the new generation fleet (both renewable and conventional) is developed in the north of GB, and offshore wind capacity tends to be located further offshore. Hence, power has to be transported across longer distances, making more use of DC lines that exhibit higher losses than AC lines.

Modelled Power Prices

Uniform TNUoS charging also removes the possibility for new entrant CCGTs and OCGTs to locate in zones with negative TNUoS charges, and hence increases the annual fixed operating costs of the marginal source of new entry in the GB power market. Because the fixed costs that the marginal new entrant needs to recover through the power market increase, the wholesale power prices required to incentivise entry by new CCGTs and OCGTs also increase.[19] This effect increases long-term power prices, as Figure 6 shows.[20]

Figure 6: The Impact on Power Prices



Source: NERA/Imperial Analysis.

Welfare Implications

In net present value terms,[21] we estimate that the costs of transmission infrastructure investment, constraints, and losses would increase by around £5.6 billion with uniform TNUoS. We also estimate that the additional costs of renewable and conventional generation (excluding TNUoS costs) would increase by around £2.0 billion.

In addition, we estimated the impact of these higher costs on the prices paid by end users through higher power prices and an increase in transmission system costs that are passed through to consumers.[22] Overall, we estimate that uniform TNUoS charges would increase costs to consumers by £19.8 billion compared to the locational scenario. This equates to £3.56 per MWh of energy demand, or around 2.2% of the energy component of 2020 consumer bills.[23]

Table 1: The Impact on Consumers

NPV to 2030 @ 3.5%, 2010 Prices	£Mn	£/MWh
Wholesale Purchases	13,899	2.50
Renewable Subsidies	262	0.05
Losses	4,082	0.74
Constraints	344	0.06
Demand TNUoS Charges	1,181	0.21
Total	19,768	3.56

Conclusions

Our analysis demonstrates that locational signals conveyed to generators through transmission charges can have a material impact on economic efficiency, even in jurisdictions like GB where the government has chosen to direct much of the necessary new investment through subsidies for renewables and other forms of low carbon generation. In the British setting, this result stems from the fact that a wide choice of locations exists for both low-carbon and conventional thermal generators. In other settings, low-carbon generators may face more restricted choices (e.g., because the renewable resource is all in one place), but even in these settings conventional thermal generators will normally face a wide choice of location, and the low-carbon power systems of the future will still need significant amounts of conventional thermal capacity even if only as back-up. Hence, locational signals are set to remain an important element of efficient market design.

Contributors

Sean Gammons is an Associate Director in NERA's Energy Team
Tel: +44 207 659 8564; Email: sean.gammons@nera.com

Richard Druce is a Consultant in NERA's Energy Team
Tel: +44 207 659 8540; Email: richard.druce@nera.com

Professor Goran Strbac is Professor of Electrical Energy Systems at Imperial College, London; Email: g.strbac@imperial.ac.uk

EndNotes

1. Locational cost signals can be conveyed to developers of generation through regulated transmission infrastructure tariffs—the locational pricing of electricity—including charges for recovering transmission congestion costs and losses. In this work, we have not tried to define the mechanisms that should be used to allocate infrastructure costs, constraint costs, and losses to generators. These mechanisms are also widely used to convey locational signals to consumers of electricity (i.e., load) as well as generators. This paper does not discuss the optimal allocation of costs between generation and load. Instead, we discuss the effects of the different tariffs that might emerge from such mechanisms.
2. Some people may object that "renewable" or "low carbon" electricity is not the same as electricity generated from conventional (i.e., fossil) fuels. In fact, the electricity produced from all sources is identical and is traded on an equal basis in British markets (as it is elsewhere). The special status of RES generation is recognised through a separate market for the product known as "Renewables Obligation Certificates", the demand for which derives from legal obligations.
3. In Great Britain, the costs of transmission infrastructure charges (recovered through "TNUoS" charges), transmission losses and the costs of congestion (recovered through "BSUoS" charges) comprised 9.5% of average electricity bills in 2009 across all types of consumer (domestic, commercial, industrial etc). We estimate this figure using a range of data sources including Platts Powervision, the Digest or UK Energy Statistics (DECC), and Electricity Industry Review 15 (Electrica Services Limited).
4. As we describe further below, markets with LMP have separate arrangements to recover the costs of transmission infrastructure from generation and load, which may include varying degrees of locational cost variation.
5. In practice, the zones in Nordpool are not defined by reference to LMPs and the zonal prices are not averages of LMPs. Instead, they result from a constrained market-clearing algorithm that defines a single market clearing price for each pre-defined zone based on a transmission-constrained stacking of bids and offers across all zones.
6. See, for example: "Target model for European congestion management," Asta Sihvonen-Punkka, Vice-Chair of ERGEG, Chair of Electricity Working Group, CEEPEX Workshop, 12 April 2010, Vienna.
7. Electricity markets must also specify rules for allocating the costs of transmission losses between market participants. These costs may be included in energy prices (as in the LMP system) or in "use of system" charges, in which case they may vary by location or be allocated uniformly.
8. In total, the TNUoS charges collected from generators contribute 27% of the revenue that the transmission system operators are allowed to collect to cover the costs of developing, operating, and maintaining the transmission infrastructure. The TSO levies TNUoS charges as an annual charge per kW of generators' transmission entry capacity (TEC). Generators' TEC is defined as the amount of generation a generator wishes to export onto the National Electricity Transmission System (NETS) and is stated in megawatts (MW). Source: National Grid website, visited on 4 July 2011. URL: http://www.nationalgrid.com/uk/Electricity/GettingConnected/FAQs/WhatIsTEC.htm
9. In GB, only a small share of infrastructure costs are recovered through upfront connection charges levied on generators when they first connect to the grid. The boundary of connection charges is "shallow", so they only cover the costs of assets used solely by the connecting generator.
10. The current TNUoS charging philosophy is based on the assumption that peak demand conditions drive network investment. In other words, the assumption is that there is no congestion outside the peak period. Strictly speaking, this assumption was never true, but it is becoming less and less valid because of the increasing penetration of wind generation on the Great Britain system, which is leading to significant congestion during high wind and low demand conditions.
11. The Statement of Use of System Charges: Initially effective from 1 April 2010 and Updated from 1 December 2010 (Issue 6 Revision 1), Schedule 1. Viewable at: http://www.nationalgrid.com/NR/rdonlyres/32D29FD7-5FEC-48FA-854C-6445A1D35DC3/44195/UoSCI6R1v1_2010.pdf
12. See, for example: DECC, Proposals for improving grid access: Impact Assessment, 27 July 2010.
13. Improving Grid Access – Technical consultation on the model for improving grid access: Consultation Document, DECC (URN 10D/567), 3 March 2010.
14. The possible exception to this conclusion relates to those generators situated behind transmission constraints. In some situations, such generators may be able to extract a higher market value of their output than the GB-wide wholesale price through the balancing mechanism where the TSO accepts bids and offers to resolve transmission constraints.
15. Project TransmiT: A Call for Evidence, Ofgem (119/10), 22 September 2010.
16. RWE asked us to assume that the uniform charge would be structured as an annual charge per unit of each generators' TEC (in £/kW/year), as opposed to a uniform charge on energy production (£/MWh). Note that under the present GB TNUoS charging regime generators pay "local" and "wider" TNUoS charges based on their TEC capacity. In the uniform scenario, we assumed that all locational costs were socialised in the uniform scenario, thus removing all locational elements from TNUoS charges.
17. The Aurora software is provided by EPIS Inc. Aurora selects patterns of generator dispatch accounting for both variable costs of production (fuel and CO_2 costs, variable O&M costs, etc) and unit commitment costs (minimum stable generation, ramp rates, start-up costs, etc). The model accounts for unit commitment costs by only "committing" a unit when it expects to earn sufficient margins to recover its unit commitment costs over the following week through power market sales. Simultaneously, Aurora uses an iterative algorithm to project entry/exit decisions based on an assessment of the profitability of existing and future generation capacity. The entry/exit decisions and prices that result from this algorithm represent an economic equilibrium in which all generators that find it profitable to remain in the market or enter the market earn sufficient margins in present value terms to cover their fixed costs, including any capital costs.
18. Due to the assumptions we have made, we believe this forecast of constraint costs to be low relative to a range of plausible projections. For instance, we assumed that generators bid into the balancing mechanism at their short-run marginal cost of generation, ignoring unit commitment costs, dynamic constraints, and the impact of market power, which may result in spreads between their bid and offer prices, which will tend to understate constraint costs. We also assume that new transmission infrastructure comes online as soon as our modelling suggests it is required. In reality, delays in commissioning new transmission lines (e.g., due to planning delays) may increase costs. Finally, to estimate transmission investment costs, we used an average investment cost of £50/MW/km/yr which is the lowest cost estimate that National Grid uses in its own modelling with DTIM.
19. In the uniform scenario, the TNUoS and NTS charges incurred by a new CCGT developed anywhere in the country come to around £6.5/kW/year on average between 2020 and 2030. Hence, the total fixed costs of a new CCGT come to £89.5/kW/year, or £17/MWh. In the locational scenario, new CCGTs are developed exclusively in zones where TNUoS charges are negative, so the TNUoS and NTS costs incurred by a new CCGT are around minus £6.6/kW/year on average between 2020 and 2030. Hence, in practice, the total fixed costs of a new CCGT come to £76.4/kW/year, or £14.5/MWh. This difference means that the costs of developing new CCGT capacity increase by approximately £13/kW/year in the uniform scenario compared to the locational scenario, which equates to £2.5/MWh in higher energy prices.
20. By increasing the marginal cost of new entry, and hence increasing long-term power prices, introducing uniform TNUoS charges increases rents to existing generators. Our modelling indicates that the increase in generation costs is less than the increase in wholesale prices.
21. Discounting over the period between 2011 and 2030 at a real discount rate of 3.5%, in line with the UK government's recommended rate for policy appraisal.
22. We assume consumers face the costs of constraints and losses directly as a mark-up on the price they are required to pay for their electricity, and the share of transmission infrastructure costs recovered through demand TNUoS charges. In estimating the costs to consumers, we account for the share of the higher transmission infrastructure costs that would be recovered from generators (as well as any other changes in generation costs) through the impact they have on wholesale power prices.
23. Recent projections from DECC suggest that the energy component of consumer bills in 2020 (including the cost of government subsidy schemes) will reach £160/MWh in real 2009 prices. £160/MWh in 2009 prices is equal to £162.5 in 2010 prices. £3.56 / £162.5 = 2.19%.

    Source: Estimated impacts of energy and climate change policies on energy prices and bills, DECC, July 2010.

NERA
ECONOMIC CONSULTING

NERA Contacts

EUROPE

Sean Gammons
Associate Director
15 Stratford Place
London W1C 1BE, UK
tel: +44 20 7659 8564
fax: +44 20 7659 8565

Rue de la Loi 23 Wetstraat
B-1040 Brussels
Belgium
tel: +32 2 282 4354
fax: +32 2 282 4360
sean.gammons@nera.com

NORTH AMERICA

Jonathan Falk
Vice President
1166 Avenue of the Americas
29th Floor
New York, NY 10036
tel: +1 202 345 5315
fax: +1 202 345 4650
jonathan.falk@nera.com

AUSTRALIA/NEW ZEALAND

Ann Whitfield
Associate Director
Darling Park Tower 3
201 Sussex Street
Sydney NSW 2000
Australia
tel: +61 2 8864 6503
fax: +61 2 8864 6549
ann.whitfield@nera.com

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