



ELECTRICITY TRANSMISSION USE OF
SYSTEM CHARGING: THEORY AND
INTERNATIONAL EXPERIENCE

A report to EDF Energy

November 2010

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INTERNATIONAL EXPERIENCE



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EXECUTIVE SUMMARY

New electricity paradigm

The electricity sector is undergoing a fundamental transformation. Decarbonisation and renewable objectives have changed the energy policy landscape. If the UK is to put itself on a path to delivering a secure, low-carbon energy system, unprecedented levels of investment in the electricity generation sector are required over the next 10 to 15 years, with likely spend of over £200bn being mooted. This includes investment in low carbon generation technologies themselves and in supporting transmission infrastructure.

The expectation of a much increased level of potentially geographically remote low carbon generation (particularly wind) and an associated step-change in network investment, brings into focus the role of the electricity transmission charging arrangements in support of the transition to a decarbonised electricity sector. These issues are the focus of Ofgem's Project TransmiT.

Role of transmission charging

The government's stated energy policy objective is to achieve a secure, affordable and low carbon energy mix. Traditionally, energy policy focused upon delivering affordability through the promotion of competition and the charging arrangements have supported this. However, the policy balance has now changed with a much increased emphasis on carbon emission reductions and renewables targets, with specific policy measures, such as the Renewables Obligation, already in place to support the deployment of renewable generation sources.

The transition from old to new policy agenda creates a tension for the objectives that should be attached to future transmission charging arrangements. Multiple objectives can be attached legitimately to transmission charging arrangements, ranging from efficiency and cost-reflectivity through to stability and predictability.

There is a clear distinction between the priority charging objectives for delivering energy security and affordability on one hand versus those for achieving carbon emission reductions alone:

- **Carbon emission reductions:** supported by stable and predictable charging arrangements and charges that reflect the public good component of transmission.
- **Energy security:** supported by arrangements that promote efficient participant and grid behaviour, while recognising the public good component of transmission.
- **Affordability:** supported by arrangements that promote efficient participant and grid behaviour, with charges that target grid investment costs upon those driving the investment requirement.

Given the revised emphasis of policy priorities, there is a case for revisiting the balance between the charging objectives to ensure that charging arrangements remain compatible with and do not work against policy goals. Therefore, TransmiT may conclude that a different compromise between the charging objectives needs to be reached, leading to revised charging arrangements.

Assessment of transmission charging options

A range of charging options is available. Different options perform differently against each policy objective. Common features of charging options that deliver against the priority objectives can be assessed. The conclusions from this preliminary analysis are powerful:

- **Carbon emission reductions:**
 - *Non-locationally varying generation charges support the majority of renewable generation projects.* This is because resource potential for many renewable projects is generally at its best in northern areas of the system that currently attract high transmission charges, so uniform charges would help to lower costs for these projects (although not necessarily for more southerly renewable projects), thereby supporting carbon emission reductions from renewable generators in general but not from the broader low carbon generation class.
 - *Differentiated charges support low carbon generation more generally (including renewable projects).* This distinguishes between low carbon and high carbon generation technologies, not just renewable generation, thereby delivering carbon emission reductions across the range of low carbon generation technologies.
- **Energy security and affordability:**
 - *Options incorporating locationally varying generation charges improve the efficiency of generation investment and network investment.* These provide economic signals of the cost of connecting to different parts of the system. This outcome promotes both energy security and affordability.

These conclusions highlight the tension that exists in the achievement of the policy objectives in the new policy paradigm. Traditionally, policy focus has been firmly upon affordability and thus locationally varying charges have a central role to play in promoting competition and efficiency. Now that policy focus has developed to place greater emphasis on reducing carbon emissions and delivering energy security in particular, there is pressure for transmission charging arrangements to evolve accordingly. This could imply a deviation away from the traditional emphasis upon locationally varying charges to create economic signals which encourage efficient behaviour from market participants. However, it is important to reflect before drawing this conclusion:

- **Encouraging efficient grid investment remains a binding transmission charging principle**
Transmission investment still needs to be demonstrably economic in order to provide value to consumers, especially given the expected future expansion of the grid. Transmission charging arrangements will continue to be a critical driver of efficient transmission investment going forward. This suggests that it is appropriate for some form of locationally varying charges to be retained in order to promote efficient generation investment decisions and consequential grid development. It is also true that the charging arrangements affect generation investment decisions, but they are one tool amongst many in this context. Investment in low carbon technologies can be supported by means other than amendments to the transmission charging arrangements.
- **Transmission investment costs still driven by capacity**
Transmission investment costs will continue to be predominantly driven by capacity requirements and not system utilisation. In order to provide appropriate economic signals in a period of anticipated grid expansion, charges should continue to be set with reference to MW and not MWh, whatever the exact method for deriving them.

- **Charging arrangements should avoid undue discrimination**
Charging arrangements should continue to be developed to be non-discriminatory, recognising that they apply to all generation technologies (including demand side management) and not just low carbon technologies. If revisions to the charging arrangements are to be made in support of achieving carbon emission reductions, the benefit should be applied to all low carbon generation technologies and not just renewables.

International experience

The transmission charging arrangements employed in international electricity markets are many and varied. Whilst international solutions can provide useful insights into options that could be considered for GB, they must be viewed in the context of the prevailing energy market arrangements and supply/demand fundamentals. Many of these are different to those seen within the GB market. It is important that GB charging arrangements should reflect these GB specific drivers and not approaches adopted internationally which suit different market circumstances.

Conclusions

The policy landscape has changed, altering the balance between energy policy objectives away from the traditional priority focus of affordability. In GB, there is now a much increased emphasis on renewable energy and carbon emission reductions within policy.

Project TransmiT is considering how the transmission charging regime, and the current balance of objectives which drive it, fits within the revised policy landscape. While this is timely, the starting point should not be that the existing arrangements are broken. Many of the existing charging principles remain valid going forward:

- economic and efficient transmission investment remains critical for delivering value to existing and future consumers;
- charges should still be based on MW, as capacity is the main driver of grid investment cost; and
- charging arrangements should be non-discriminatory for all generation classes or within low carbon and high carbon generation classes.

A rebalancing of transmission charging objectives and some methodological changes are likely to be required given the revised policy landscape, but many of the core existing principles should be retained in order to promote efficient grid investment, whilst supporting GB energy policy. Any change to the charging arrangements will impact upon all users of the transmission system and potentially lead to unintended consequences. Therefore:

- The current transmission charging arrangements should only be substantially revised where they evidently present a potential barrier to policy objectives and it is clear that substantive revision will better support GB energy policy objectives.
- If no such barriers are found and/or all consequences of substantial change are unclear, it may be that the current transmission charging regime subject to relatively minor detailed methodological refinement is deemed to be fit for purpose. In this case, if support for low carbon technologies is still deemed to be required, it should be provided via mechanisms outside the charging arrangements.

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1. INTRODUCTION

1.1 Introduction

Ofgem launched Project TransmiT (TransmiT) on 22 September 2010. TransmiT promises to be a comprehensive and open review of the charging regime and connection arrangements linked to electricity and gas transmission networks. It has the potential to fundamentally revise the arrangements for transmission charging.

Objectives relating to decarbonisation are at the heart of the review. This is driven by the 2008 Climate Change Act, which set legally binding carbon emissions reduction targets: 34% reduction by 2020 and at least 80% reduction by 2050. In response, the UK has a target for 40% of electricity to be from low carbon sources by 2020, with the power sector largely decarbonised by 2030.

Low carbon generation technologies, in particular renewables (mainly wind) and nuclear, are expected to play an ever increasing role in the energy mix if renewable and carbon reduction targets are to be met. Considerable investment in electricity transmission infrastructure is required to support the delivery of low carbon generation. This is particularly the case given that sites for wind generation in particular tend to be geographically remote and, as such, are located at the extremities of the transmission network far away from centres of demand. Ofgem's recent RIIO decision paper¹ suggests that network companies will need to invest an additional £32bn by 2020 to deliver the required network infrastructure.

This step-change in network investment, combined with the expectation of a much increased level of geographically remote low carbon generation, brings into focus the on-going appropriateness of the current electricity transmission charging arrangements. At present, sites that are remote typically attract high generator Transmission Network use of System (TNUoS) charges. There is also the potential for significant year-on-year variations in charges, which creates risk for actual or prospective participants.

In this context, Project TransmiT is seeking to ensure that the transmission charging arrangements facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future customers. Although it has not been explicitly stated at this stage, one of the key issues to be addressed by TransmiT is the appropriateness of locational TNUoS charging within low carbon energy sector. In addition to transmission charging, there are other features of the electricity transmission and market arrangements that will have a bearing upon the delivery of a de-carbonised electricity sector. For example, transmission loss arrangements, like transmission charging arrangements, have the potential to affect the costs of connecting a new generator in a particular area of the system. TransmiT, however, focuses upon transmission charging only.

¹ 'RIIO: A new way to regulate energy networks. Final decision', Ofgem, October 2010.

In this context, EDF Energy has commissioned Pöyry Energy Consulting to prepare an independent paper in relation to electricity transmission use of system charging arrangements. The purpose of the paper is to explore:

- what objectives can be attached to electricity transmission arrangements;
- how straw-man electricity transmission charging arrangements perform against these objectives; and
- how wider market drivers affect the balance between objectives and the performance of straw-man options.

The paper considers these issues from both theoretical and practical perspectives, drawing upon international experience. The objective is for this assessment to feed into the TransmiT process, shaping both the objectives against which potential changes to the electricity transmission charging arrangements can be assessed and the options that are considered.

1.2 Scope and structure of this report

The structure and scope of this paper is as follows:

- Section 2 focuses upon the electricity transmission charging objectives:
 - What objectives can be attached to transmission charging arrangements within the context of DECC’s policy objectives and Ofgem’s regulatory objectives?
- Section 3 develops electricity transmission charging options and appraises them against the defined objectives:
 - What are the key building block components that make up possible transmission charging models and the options at each level?
 - How do the building block options combine to form end-to-end solutions?
 - How do high-level straw-men transmission charging options perform against these objectives?
- Section 4 considers wider market influences on electricity transmission arrangements:
 - What influence do wider market drivers have upon the relative merits of charging objectives and options?
- Section 5 provides an overview of electricity transmission charging models from international markets:
 - What arrangements are in place in international markets and how/why do they differ from those in GB?
 - What does this mean for GB electricity transmission charging options?
- Section 6 draws together the preceding sections, highlighting key messages of relevance for Transmit.
- Annex A provides details of the international markets review:
 - What building block options have been combined to form end-to-end solutions in international markets?
 - What circumstances have shaped the evolution of these models?

2. ELECTRICITY TRANSMISSION CHARGING OBJECTIVES

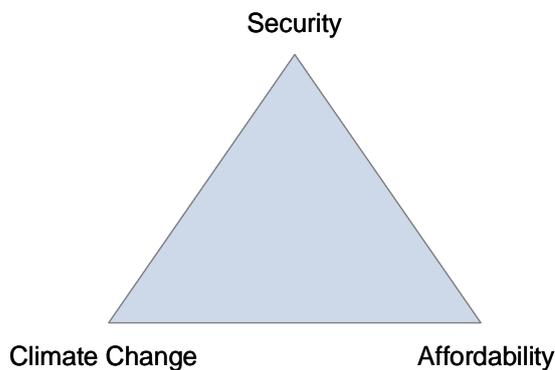
2.1 Introduction

This section focuses upon the objectives linked to transmission charging. It begins by considering current energy policy objectives, which provide the framework within which transmission charging must operate. The remainder of this section considers potential transmission charging objectives, the relationships between them and their interactions with the wider policy objectives².

2.2 Energy policy and regulatory objectives

Over recent years, environmental objectives have become increasingly important in the energy sector. Energy policy and regulation objectives have evolved as a consequence. In this context, DECC's stated objective is to achieve a **secure, affordable and low carbon energy mix**, while Ofgem's traditional remit to protect the interests of consumers by promoting competition has been modified to take explicit account of **greenhouse gas reductions and security of supply**. The three key objectives for energy policy are, therefore energy security, affordability and reduced carbon emissions. The policy space is illustrated in Figure 1.

Figure 1 – Energy policy objectives



However, these objectives cannot necessarily be pursued simultaneously, as there is tension between them. For example, if the UK is to put itself on a path to delivering a low-carbon energy system, unprecedented levels of investment in the electricity generation sector are required over the next 10 to 15 years, with likely spend of over £200bn being mooted. Delivering this scale of investment will adversely impact fulfilment of affordability objectives.

² Regional policy decisions taken by central government and policy decisions taken by Devolved Administrations have the potential to influence energy market outcomes. For example, policies adopted by the Scottish Executive could influence energy infrastructure within the region, with consequential implications for the GB energy market. The focus here, however, is on DECC's energy policy objectives.

Given the potential for conflict between the three key objectives, the balance of priority between them is influenced by the prevailing challenges facing the energy sector. At present delivery of a secure, low carbon energy system is the primary goal shaping energy policy. Therefore, energy security and reduced carbon emissions are the key objectives. Affordability remains a key focus still, but it is being squeezed by scale of investment and development required in the sector. While the balance between the objectives may change in future, given the scale of the challenge facing the GB energy sector, this balance can be expected to prevail over the course of the next decade.

Project TransmiT is seeking to ensure that the transmission charging arrangements facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future customers.

2.3 Mapping policy/regulatory objectives onto charging objectives

Electricity transmission charging arrangements form an important element of the electricity market framework. The charging arrangements have the potential to influence market participant behaviour, which can, in turn, affect transmission investment and operation. For example, transmission charges influence generation investment (and exit) decisions. In terms of generation investment, transmission charges can influence each of the following:

- level of investment;
- location of investment;
- type of investment; and
- timing of investment.

The resultant generation trajectory has implications for the transmission system, both in terms of the need for network investment and the impact upon system operation. As a consequence, the transmission charging arrangements have the potential to affect the delivery of each of the policy objectives, as illustrated in Table 1.

Table 1 – Impact of transmission charging on policy objectives

Policy objective	Potential influence of transmission charging
Carbon emission reductions (incl. renewable targets)	Charges may influence the scale and nature of generation deployment (low carbon and non-low carbon alike) and energy consumption. This can impact upon the level of carbon emission reductions achieved across the generation sector, including demand side response.
Energy security	Charges have the potential to affect the diversity of generation technologies and characteristics (e.g. blend of flexible and non-flexible capacity and differing load factors) in the energy mix through their impact upon entry/exit decisions as well as energy consumption patterns. This has consequential implications for energy security.
Affordability	Through their impact upon market participant behaviour, charges influence the ultimate costs faced by consumers, present and future. For example, the incentives created by charging for generator investment will influence both generation costs and network investment/operation costs.

Therefore, electricity transmission charging arrangements have a potential role to play in the delivery of a secure, low carbon energy system³. They are, however, not the sole (or primary) mechanism for delivering this transition and should be viewed as a part of the policy jigsaw alongside other measures. The objectives associated with transmission charging arrangements must, therefore, be compatible (or at least not incompatible) with the wider policy and regulatory objectives. This requirement provides a framework within which to consider the objectives of transmission charging arrangements.

With this in mind, Table 2 outlines a set of objectives (in no particular order of precedence) to be considered in the assessment of any electricity transmission charging arrangements. As with the wider policy objectives, there are interactions and potential tensions between objectives. Where this applies, it is important for a balance to be struck such that relative priorities between transmission charging objectives complement the prevailing balance between wider policy objectives. It is important to note that the identification of areas of commonality or diversity between objectives is influenced by the interpretation attached to an objective. Therefore, it is possible for one objective to share common ground with seemingly opposed objectives (e.g. non-discrimination can be delivered by cost reflectivity and public good reflectivity alike).

³ The exposure of distribution connected generators to transmission charges is an important extension of this sentiment, as many renewable projects either do or are expected to connect to distribution networks.

Table 2 – Potential transmission charging objectives

Objective	Comment
1 Efficient participant behaviour	<p data-bbox="481 391 1814 462">Do charges promote efficient and economic behaviour from market participants in respect of individual investment/operation decisions?</p> <p data-bbox="481 510 2038 614">This objective seeks to ensure that market participants have commercial incentives to take explicit consideration of grid costs when taking investment/operation decisions (i.e. long-term and short-term decisions), to encourage efficient usage of and investment in network.</p> <p data-bbox="481 662 1030 694">Favours: locational transmission charges</p> <p data-bbox="481 742 1523 774">Commonality with: efficient grid behaviour, cost-reflectivity, non-discrimination</p> <p data-bbox="481 821 1209 853">Tension with: stability, ease of administration/simplicity</p>

Objective	Comment
2 Efficient grid behaviour	<p data-bbox="488 300 1563 330">Do charges promote efficient and economic grid investment and system operation?</p> <p data-bbox="488 384 2029 448">This objective is closely linked to the efficiency of participant behaviour. It seeks to ensure that the charging framework encourages efficient grid investment and system operation decisions (i.e. long-term and short-term decisions).</p> <p data-bbox="488 502 1025 533">Favours: locational transmission charges</p> <p data-bbox="488 587 1608 617">Commonality with: efficient participant behaviour, cost-reflectivity, non-discrimination</p> <p data-bbox="488 671 1211 702">Tension with: stability, ease of administration/simplicity</p>
3 Cost reflective	<p data-bbox="488 762 1928 826">Do charges appropriately target costs of grid investment and system operation onto market participants that are responsible for these costs?</p> <p data-bbox="488 880 2011 975">This objective seeks to deliver charges that provide economic signals to participants based on the implications of their commercial decisions on grid costs. Participants then have appropriate signals to respond to when taking individual commercial decisions, with individual parties facing exposure to the costs that they contribute to.</p> <p data-bbox="488 1029 1025 1059">Favours: locational transmission charges</p> <p data-bbox="488 1114 1391 1144">Commonality with: efficient participant behaviour, non-discrimination</p> <p data-bbox="488 1198 1514 1228">Tension with: ease of administration/simplicity, public good reflectivity, stability</p>

Objective	Comment
4 Public good reflective	<p data-bbox="488 304 1585 331">Do charges reflect the public good characteristics of transmission, such as reliability?</p> <p data-bbox="488 387 2024 515">Where elements on transmission are non-rivalrous and non-excludable, such as reliability or delivering energy security, they are to the mutual benefit of all participants and can be deemed a public good. This objective seeks to ensure that costs associated with public good aspects of transmission are treated appropriately within charges, such that the costs are shared.</p> <p data-bbox="488 571 999 598">Favours: uniform transmission charges</p> <p data-bbox="488 654 1391 681">Commonality with: efficient participant behaviour, non-discrimination</p> <p data-bbox="488 737 875 764">Tension with: cost reflectivity</p>
5 Non-discriminatory	<p data-bbox="488 834 1010 861">Do charges avoid undue discrimination?</p> <p data-bbox="488 917 2047 976">This objective is closely linked to cost reflectivity and public good reflectivity. The objective seeks to ensure that charges are determined such that they do not result in undue discrimination between participants.</p> <p data-bbox="488 1032 1312 1059">Favours: can favour locational or uniform transmission charges</p> <p data-bbox="488 1115 1648 1142">Commonality with: efficient participant behaviour, cost reflectivity, public good reflectivity</p> <p data-bbox="488 1198 1095 1225">Tension with: ease of administration/simplicity</p>

Objective	Comment
6 Stable	<p data-bbox="488 300 878 331">Are charges stable over time?</p> <p data-bbox="488 386 1930 450">In order to provide consistent economic signals through transmission charges for participants to respond to, this objective places emphasis upon relative stability of charges from year-to-year.</p> <p data-bbox="488 504 1370 536">Favours: longer-term perspective for transmission charge derivation</p> <p data-bbox="488 590 922 622">Commonality with: predictability</p> <p data-bbox="488 676 1128 702">Tension with: cost reflectivity, non-discrimination</p>
7 Predictable	<p data-bbox="488 762 1205 794">Can market participants reliably predict future charges?</p> <p data-bbox="488 849 2020 944">In order for participants to make informed commercial decisions, they should be able to reasonably accurately predict charges for, at least, the near-term. This objective places emphasis upon the ability of participants to do this within the charging framework.</p> <p data-bbox="488 999 1559 1031">Favours: understandable, transparent approach for transmission charge derivation</p> <p data-bbox="488 1085 1326 1117">Commonality with: efficient participant behaviour, transparency</p> <p data-bbox="488 1171 833 1197">Tension with: robustness</p>

Objective	Comment
8 Robust	<p data-bbox="488 300 1554 330">Is the charging methodology robust to anticipated evolutions in system conditions?</p> <p data-bbox="488 384 1984 483">Here, the emphasis is upon ensuring that the charging methodology can accommodate possible changes to system conditions (supply/demand fundamentals) whilst still producing appropriate charges and signals for participants to respond to.</p> <p data-bbox="488 537 1518 568">Favours: dynamic, forward-looking approach for transmission charge derivation</p> <p data-bbox="488 622 1346 652">Commonality with: efficient participant behaviour, cost reflectivity</p> <p data-bbox="488 707 1211 737">Tension with: stability, ease of administration/simplicity</p>
9 Transparent	<p data-bbox="488 794 1361 825">Is the basis for deriving charges transparent to market participants?</p> <p data-bbox="488 879 1991 978">In order for participants to make informed commercial decisions, there should be transparency and appropriate information provision with regard to the charging model, the underlying methodology and the resultant charges. The emphasis of this objective is upon delivering the required level of transparency.</p> <p data-bbox="488 1032 1570 1062">Favours: understandable, well-defined approach for transmission charge derivation</p> <p data-bbox="488 1117 1568 1147">Commonality with: efficient participant behaviour, ease of administration/simplicity</p> <p data-bbox="488 1201 826 1232">Tension with: robustness</p>

Objective	Comment
10 Easy to administer / simple	<p data-bbox="488 304 1435 331">Is the charging methodology simple to administer, apply and understand?</p> <p data-bbox="488 387 2007 483">A simplistic charging methodology which is straightforward to understand and apply may add clarity to and reduce complexity with commercial decision making. This objective assesses the ease of administration and simplicity of the charging arrangements.</p> <p data-bbox="488 539 1263 566">Favours: static approach for transmission charge derivation</p> <p data-bbox="488 622 1104 649">Commonality with: transparency, predictability</p> <p data-bbox="488 705 1431 732">Tension with: efficient participant behaviour, cost reflectivity, robustness</p>

A broad range of objectives can, therefore, be attached legitimately to transmission charging arrangements. There are tensions between the different categories, with the consequence that they cannot all be achieved simultaneously. Relative priorities can be ascribed based upon the relevance of each charging objective for the delivery of the wider policy objectives. Priority transmission charging objectives in the context of the wider policy goals are identified in Table 3, which flags for each policy objective when considered in isolation, the most important transmission charging objectives. The key priorities have been identified based upon judgement.

Table 3 – Priority transmission charging objectives

Policy objective	Priority objectives for transmission	Comment
Carbon emission reductions (incl. renewable targets)	<ul style="list-style-type: none"> ▪ Public good-reflectivity ▪ Stable ▪ Predictable 	<p>Delivery of this policy objective requires significant investment in a range of low carbon generation technologies. As such, the investment environment is critical. Measures to improve certainty within the investment environment are expected to facilitate investment. Stability and predictability will enhance the investment environment. Similarly, if transmission investment is deemed to be a public good and costs are socialised, then many renewables projects will locate in currently expensive areas of the transmission system (given resource potential). Other low carbon investors may, however, be adversely impacted by a socialised charge for grid investment.</p>
Energy security	<ul style="list-style-type: none"> ▪ Efficient participant behaviour ▪ Efficient grid behaviour ▪ Public good-reflectivity 	<p>Energy security requires diversity in the generation mix, with a balance of new vs. old and conventional vs. low carbon plant on the system plus efficient grid investment and operation. As such, efficient behaviour from market participants and grid alike is essential. If some elements of grid investment can be deemed a public good i.e. delivering energy security to all, then this component of costs could be reflected in charges.</p>
Affordability	<ul style="list-style-type: none"> ▪ Efficient participant behaviour ▪ Efficient grid behaviour ▪ Cost-reflectivity 	<p>The affordability objective places most emphasis upon efficiency and cost-reflectivity. This is on the basis that costs are best managed through the provision of economic signals that provide appropriate commercial incentives for participants to respond to. Grid investment costs linked to individual generation projects should be targeted at those driving the investment requirement (in its purest sense this cost-reflectivity argument counters the public-good reflectivity argument above).</p>

This suggests that there is a clear distinction between the priority charging objectives for delivering energy security and affordability on one hand versus those for achieving carbon emission reductions. Consequently, there is a balance to be struck between the policy objectives to reflect the relative emphasis being placed upon each by policymakers, creating the potential need for a compromise position between the charging objectives.

Traditionally, energy policy has focused upon delivering affordability through the promotion of competition and the charging arrangements have supported this. However, the policy balance has changed with a much increased emphasis on carbon emission reductions, as discussed previously. The transition from old to new policy agenda creates a tension for the objectives that should be attached to transmission charging arrangements going forward, given the change in direction implied by the revised policy objectives. Resolving this tension and identifying the compromise position between different charging objectives under the new energy policy context is at the heart of the TransmiT process.

3. ELECTRICITY TRANSMISSION CHARGING OPTIONS

3.1 Introduction

This section considers the components or building blocks that combine to create electricity transmission charging arrangements. It then collates end-to-end transmission charging models that combine different decisions at each building block level, before going on to assess these strawman models against the charging objectives identified in Section 2.

3.2 Transmission charging building blocks

Transmission charging options can be broken down into a series of decision points or building blocks. Decisions at each building block level can then be combined to form viable end-to-end transmission charging solutions. Table 4 provides a non-exhaustive list of building blocks, which provide an illustration of the options that can influence transmission charging arrangements.

Table 4 – Strawmen building blocks

Building block	Comments
Generation or demand	Are charges levied upon generation, demand or both?
Short-term or long-term pricing	Are charges based upon the short-term or long-term cost of transmission provision?
Locational or non-locational	Are charges locationally differentiated or uniform?
Zonal or nodal	Where charges are locational, are they calculated for each node or for aggregations of nodes within zones?
Capacity or commodity	Are charges levied on the basis of MW generation/demand capacity or MWh production/consumption?
Peak or annual	Are charges levied based upon production/consumption at system peak or in aggregate over the course of a year?
Single or multiple system conditions	Are charges calculated based upon a single snapshot of system conditions (e.g. at peak) or are multiple snapshots used?
Dynamic or static	Are charges calculated based upon the existing network infrastructure or the future network taking into account planned network reinforcements and connections?
Ex-post or ex-ante	Are charges calculated in advance or after the event?
Shallow or deep connection	Are use of system charging arrangements accompanied by shallow or deep connection charging arrangements?

3.3 Transmission charging strawman options

The building blocks outlined in the previous section can be used to describe the prevailing transmission charging arrangements in GB and to scope out potential variations. The existing GB TNUoS regime is outlined in Table 5 to provide the baseline for future comparison. In GB, Balancing Services Use of System (BSUoS) charges are also levied to recover the day-to-day operational costs of system operation. Table 5 summarises the BSUoS baseline also. The principal focus thereafter is upon alternate TNUoS arrangements.

Table 5 – Baseline

Building block	Baseline TNUoS	Baseline BSUoS
Generation or demand	G: 27% D: 73%	G: 50% D: 50%
Short-term or long-term pricing	Long-term	Short-term
Locational or non-locational	Locational: combination of zonal and residual charges	Non-locational
Zonal or nodal	Zonal: 20 G zones, 14 D zones	n/a
Capacity or commodity	Capacity	Commodity
Peak or annual	Peak	n/a
Single or multiple snapshots	Single: system peak	n/a
Dynamic or static	Static	n/a
Ex-post or ex-ante	Ex-ante	Ex-post
Shallow or deep connection	Shallow	n/a

Taking the baseline as the starting point, Table 6 sets out a non-exhaustive selection of strawman options which represent potential deviations from the existing system. They are intended to be a representative sample of options which bring out key differences between different potential sets of arrangements. Key features of the strawmen which are different to the current baseline are underlined for ease of comparison. Some represent non-fundamental revisions to the existing baseline from a methodological perspective, although their impact upon market participants may be considerable, while others would require a more significant shift in the energy market arrangements more widely. Collectively, the options provide insight into the range of solutions that could be applied to the GB transmission regime in theory. None of the options presented vary the connection policy approach (shallow or deep) and so this line is not included in Table 6.

Table 6 – Strawman options

Building block	Uniform £/kW generation charges	Differentiated £/kW generation charges	Zero absolute £/kW generation charges	Zero average £/kW generation charges	Annual £/kWh utilisation charges	Dynamic £/kW charges	Short-run locationally varying £/kWh charges	£/kWh nodal energy pricing
Generation or demand	G: 27% D: 73%	<u>G: 27% 'discount' for low-carbon</u> D: 73%	<u>G: 0% (absolute)</u> <u>D: 100%</u>	<u>G: 0% (average)</u> <u>D: 100%</u>	G: 27% D: 73%	G: 27% D: 73%	G: 27% D: 73%	G: 27% D: 73%
Short- or long-term pricing	Long-term	Long-term	Long-term	Long-term	Long-term	Long-term	<u>Short-term</u>	<u>Short-term</u>
Locational or non-locational	<u>Non-locational charges for generation</u>	Locational: combination of zonal and residual charges (<u>'discount' for low carbon</u>)	<u>No charges for generation</u>	Locational: combination of zonal and residual charges	Locational: combination of zonal and residual charges	Locational: combination of zonal and residual charges	Locational	Locational
Zonal or nodal	Zonal: <u>1 G zone</u> , 14 D zones		Zonal: <u>0 G zones</u> , 14 D zones	Zonal: 20 G zones, 14 D zones	Zonal: 20 G zones, 14 D zones	Zonal: 20 G zones, 14 D zones	Zonal	<u>Nodal</u>
Capacity or commodity	Capacity	Capacity	Capacity	Capacity	<u>Commodity</u>	Capacity	<u>Commodity</u>	<u>Commodity</u>
Peak or annual	Peak	Peak	Peak	Peak	<u>Annual</u>	Peak	n/a	n/a
Single or multiple snapshots	Single: system peak	Single: system peak	Single: system peak	Single: system peak	Single: system peak	<u>Multiple: several system snapshots</u>	<u>Multiple: prevailing conditions</u>	<u>Multiple: prevailing conditions</u>
Dynamic or static	Static	Static	Static	Static	Static	<u>Dynamic</u>	Static	Static
Ex-post or ex-ante prices	Ex-ante	Ex-ante	Ex-ante	Ex-ante	Ex-ante	Ex-ante	<u>Ex-post</u>	<u>Ex-post</u>

The key features of the strawman options are as follows (with aspects not specifically flagged assumed to remain as for the baseline although this does not necessarily have to be the case):

- **Uniform £/kW generation charges:**
 This strawman alters the charges faced by generators by removing the locational element of generator charges (locational charges do remain in place for the demand side, however). Instead, a uniform £/kW charge is applied to all generators, regardless of location, such that 27% of allowed revenue is recovered from generators in aggregate.
- **Differentiated £/kW generation charges:**
 Under this option, generator charges are differentiated such that low carbon generation sources face more favourable charges compared to equivalent high carbon generation sources. This may take the form of a discount on charges for low carbon generation (in a similar vein to the small generator discount under the current arrangements). Locationally varying £/kW charges are maintained for both generation and demand, with 27% of allowed revenue still recovered from generation in aggregate.
- **Zero absolute £/kW generation charges:**
 This option removes all generator charges, locational and non-locational alike. Generators, therefore, face no charges, while 100% of allowed transmission revenue is recovered from demand participants.
- **Zero average £/kW generation charges:**
 Under this model, locationally varying £/kW charges are maintained for both generation and demand. However, charges from generation participants average out such that zero revenue is recovered in aggregate from generators. Charges levied on demand recover 100% of allowed transmission revenue.
- **Annual £/kWh utilisation charges:**
 This option changes the basis upon which charges are recovered. Rather than £/kW capacity charges levied based on generation/consumption at peak, charges are levied on a £/MWh basis based on annual generation/consumption under this option.
- **Dynamic £/kW charges:**
 This option changes the basis upon which charges are calculated. Charges are calculated with a transport model that takes into account anticipated developments in respect of transmission infrastructure, generation connection and demand patterns. It also models multiple snapshots of system conditions. So in addition to winter peak conditions, the model could consider, for example, patterns of flow on the system at times of differing demand and wind conditions (e.g. peak demand with high wind, peak demand with low wind, off-peak demand with high wind, off-peak demand with low wind, etc.).
- **Short-run locationally varying £/kWh charges:**
 This strawman incorporates transmission charges based upon short-run marginal costs of transmission provision, rather than long-run marginal costs. This means that charges are based upon the costs of managing constraints (and potentially transmission losses) during system operation. The charge is effectively based upon the difference between the national energy price and a zonal energy price which includes local congestion (and losses) costs. The charge is levied on a per MWh basis. Actual charges are only known after the event, although it is possible to forecast forward transmission prices (as for energy prices). Under this option transmission charges could be levied in the form of a type of locational (zonal)

BSUoS charge. Short-run charges can be accompanied by financial transmission rights (FTRs)⁴, which provides a means to hedge against variability in short-run charges. The price of FTRs within this model is determined ex-ante based upon a LRMC methodology, as at present.

- **£/kWh nodal energy pricing:**

This option incorporates locationally varying nodal energy prices accompanied by FTRs. Nodal prices are calculated to be consistent with the actions taken by the system operator to balance the system, intended to reflect the marginal costs of a small increment in demand at each node on the system. So the nodal price reflects the costs of energy provision including local constraint (and losses) costs. The charge is levied on a per MWh basis, with the actual price known after the event. This option requires a revision to the energy market as well as the transmission charging arrangements.

3.4 Assessment of strawman options

The strawman options presented in Table 6 can be assessed against the criteria outlined in Section 2.3. A high-level qualitative assessment of these options is presented in Table 7. This assessment has not been informed by a quantitative appraisal of the options and is based upon the principles attached to the strawman options. Performance against the objectives will vary depending upon the implementation of the option and the details of the methodology for determining charges under the methodology.

The assessment ranking system is simplistic and is explained as follows:

- ✓: anticipated positive impact upon delivery of individual charging objective;
- -: anticipated neutral impact upon delivery of individual charging objective; and
- × anticipated negative impact upon delivery of individual charging objective.

Where anticipated performance against an objective is less clear-cut, combinations of the above rankings are applied. With respect to non-discrimination, it is possible to make arguments in either direction for the majority of options. On this basis, the assessment made reflects the range of possible arguments which could be made.

Table 7 does not allocate relative weightings to each objective, which could imply that each objective will have equal weighting. However, some prioritisation of objectives is to be expected in order to reflect the energy policy balance struck by policymakers. Overall assessment of the options will, therefore, be influenced by the relative weighting attached to individual objectives. If, for example, greater emphasis is placed upon the efficiency-related criteria, then rankings against these objectives will have a greater bearing upon overall option appraisal, with performance against other objectives discounted to some extent given their lower priority. To illustrate, the adoption of locational charging in the current arrangements reflects the priority attached to cost-reflectivity and efficiency objectives in order to deliver affordability.

⁴ Financial Transmission Rights (FTR) are financial instruments that entitle the holder of the FTR to receive a share of the excess payments collected for congestion costs that arise when the transmission grid is congested in the day-ahead market.

Table 7 – Charging criteria and strawman performance⁵

Objective	Uniform £/kW generation charges	Differentiated £/kW generation charges	Zero absolute £/kW generation charges	Zero average £/kW generation charges	Annual £/kWh utilisation charges	Dynamic £/kW charges	Short-run locationally varying £/kWh charges	£/kWh nodal energy pricing
Efficient participant behaviour	x	- / ✓	x	✓	x / -	✓	✓	✓
Efficient grid behaviour	x	- / ✓	x	✓	x / -	✓	✓	✓
Cost reflective	x	- / ✓	x	✓	x / -	✓	✓	✓
Public good reflective	✓	✓	✓	x / -	✓	x	x	x
Stable	✓	-	✓	- / ✓	x / -	x / -	x*	x*
Predictable	✓	- / ✓	✓	- / ✓	x / -	x / -	x*	x*
Robust	-	- / ✓	-	-	-	✓	✓	✓
Transparent	✓	-	✓	- / ✓	-	x / -	x	x
Easy to administer / simple	✓	x / -	✓	-	x / -	x	x	x
Non-discriminatory	x / ✓	x / ✓	x / ✓	x / ✓	x / ✓	x / ✓	x / ✓	x / ✓

* - can be improved by existence of FTRs

⁵ Table and rankings contained within it to be read in conjunction with the assessment rationale on page above, noting that no weightings are assigned here to individual objectives to reflect policy priorities.

The rationale for the assessment reached against the individual criteria is summarised in the sections below:

- **Uniform £/kW generation charges:**

Generator charges under this model are non-locationally varying. As such, generators do not face economic signals of the relative costs of connecting to and operating at different points on the network. This means that charges are not cost-reflective and generators do not have a commercial incentive to take full account of the impact of an investment upon transmission costs when taking siting decisions. Other things being equal, this is expected to impair the efficiency of participant behaviour and increase generation connections in areas with relatively high transmission costs. In turn this will adversely affect the efficiency of grid operations.

Uniform £/kW generation charges are expected to be relatively stable and predictable, whilst also being simple to understand and administer.

- **Differentiated £/kW generation charges:**

Locationally differentiated charges are maintained in this model, meaning that economic signals in relation to transmission investment costs are provided, which should encourage efficient investment decisions. The economic signals are dampened, however, for low carbon generators (and correspondingly accentuated for high carbon generators) due to the effective 'discount' on low carbon charges.

This differentiated approach has a relatively neutral impact upon stability and transparency, whilst offering some benefits in terms of predictability for low carbon generators as the possible range of charges is narrowed. However, the opposite effect is likely for high carbon generation.

- **Zero absolute £/kW generation charges:**

If generation does not bear any charges for transmission, it does not have any economic signals in relation to its use of the system. Without any commercial incentives to mitigate exposure to transmission costs, the efficiency of generation investment decisions will be reduced. Increased generation connection in relatively expensive areas of the system from a transmission cost perspective, reducing the efficiency of grid investment and operation.

The advantage of zero absolute £/kW generation charges is that it is stable, predictable and simple.

- **Zero average £/kW generation charges:**

While zero revenue is collected in aggregate from the generation sector, this option maintains locationally differentiated charges that provide economic signals of the impact upon transmission investment costs of connection to different parts of the network. This cost-reflectivity means that generators have incentives to consider the implications of their behaviour upon transmission costs, improving the efficiency of their decisions. This, in turn, facilitates efficient investment in and operation of the transmission system.

This approach offers some benefits in terms of charge stability, predictability and transparency insofar as it may be possible to streamline the methodology as the requirement to recover a positive cashflow from generators in aggregate has been removed.

- **Annual utilisation £/kWh charges:**

Levying charges on the basis of annual MWh dampens the incentive to avoid/reduce consumption at peak demand. In addition, it can be argued that basing generation charges on annual MWh generation does not appropriately reflect usage of the system in peak conditions. This could reduce the efficiency of participant decisions, with consequential implications for the efficiency of grid behaviour also.

Stability and predictability of charges may be adversely affected because each user's charges will be dependent upon own generation/consumption levels, as well as generation/consumption levels of other parties. This may also be to the detriment of the simplicity of the solution.

- **Dynamic charges:**

This option maintains locationally differentiated charges. This should provide economic signals of relative transmission costs that encourage efficient investment and operation decisions on behalf of market participants and grid. The appropriateness of the economic signals delivered may be enhanced under this option by taking account of multiple sets of potential system conditions when deriving charges.

By taking a dynamic approach, anticipated grid and generation developments can be reflected in the derived transmission charges, improving the robustness of the resultant charges to future system conditions. This may, however, impair predictability and stability of charges in the event that anticipated developments do not occur with implications for future charges.

- **Short-run locationally varying £/kWh charges:**

Locationally varying transmission charges based upon short-run marginal costs provide economic signals of the cost of transmission. These signals encourage efficient behaviour on behalf of market participants and grid.

While the existence of FTRs may allay these issues, this option may not aid stability or transparency of transmission charges. The system is also complex to administer and understand.

- **£/kWh nodal energy pricing:**

The assessment of nodal energy pricing is similar to that for short-run locationally varying charge. The difference is that by having nodal granularity, this option may lead to greater efficiency, whilst also being more complex.

Linking the appraisal of the strawman options above back to the priority objectives for transmission outlined in Table 3, provides some insight into the common features of the strawman options that deliver against the priority objectives. This is illustrated in Table 8.

Table 8 – Features of options that deliver priority transmission objectives

Policy objective	Priority objectives for transmission	Common features of strawman options that fulfil priority objectives
Carbon emission reductions (incl. renewable targets)	<ul style="list-style-type: none"> ▪ Public good-reflectivity ▪ Stable ▪ Predictable 	<ul style="list-style-type: none"> ▪ Uniform £/kW generation charges (zero or non-zero) – works for the majority of renewable generation given expected location in northern areas, but not all forms of low carbon generation (potentially including southerly renewable projects) ▪ Differentiated £/kW generation charges – suits low carbon generation generically
Energy security	<ul style="list-style-type: none"> ▪ Efficient participant behaviour ▪ Efficient grid behaviour ▪ Public good-reflectivity 	<ul style="list-style-type: none"> ▪ Degree of locationally varying £/kW generation charges
Affordability	<ul style="list-style-type: none"> ▪ Efficient participant behaviour ▪ Efficient grid behaviour ▪ Cost-reflectivity 	<ul style="list-style-type: none"> ▪ Locationally varying £/kW generation charges

The conclusions from this preliminary analysis are powerful.

- **Carbon emission reductions:**
 - *Non-locally varying generation charges support renewable generation projects.* This is because resource potential for many renewable projects is generally at its best in northern areas of the system that currently attract high transmission charges, so uniform charges would help to lower costs for these projects (although not necessarily for more southerly renewable projects), thereby supporting carbon emission reductions from renewable generators in general but not from the broader low carbon generation class.
 - *Differentiated charges support low carbon generation more generally (including renewable projects).* This distinguishes between low carbon and high carbon generation technologies, not just renewable generation, thereby delivering carbon emission reductions across the range of low carbon generation technologies.
- **Energy security and affordability:**
 - *Options incorporating locationally varying generation charges improve the efficiency of generation investment and network investment.* These provide economic signals of the cost of connecting to different parts of the system. This outcome promotes both energy security and affordability.

These conclusions highlight the tension that exists in the achievement of the policy objectives in the new policy paradigm. Traditionally, policy focus was firmly upon affordability and thus locationally varying charges had a central role to play in promoting competition and efficiency. Now that policy focus has developed to place greater emphasis on reducing carbon emissions and delivering energy security in particular, there is pressure for transmission charging arrangements to evolve accordingly. This could imply a deviation away from the traditional emphasis upon locationally varying charges to create economic signals which encourage efficient behaviour from market participants. However, it is important to reflect before drawing this conclusion:

- **Encouraging efficient grid investment remains a binding transmission charging principle**
 Transmission investment still needs to be demonstrably economic in order to provide value to consumers, especially given the expected future expansion of the grid. Transmission charging arrangements will continue to be a critical driver of efficient transmission investment going forward. This suggests that it is appropriate for some form of locationally varying charges to be retained in order to promote efficient generation investment decisions and consequential grid development. It is also true that the charging arrangements affect generation investment decisions, but they are one tool amongst many in this context. Investment in low carbon technologies can be supported by means other than amendments to the transmission charging arrangements.
- **Transmission investment costs still driven by capacity**
 Transmission investment costs will continue to be predominantly driven by capacity requirements and not system utilisation. In order to provide appropriate economic signals in a period of anticipated grid expansion, charges should continue to be set with reference to MW and not MWh, whatever the exact method for deriving them.
- **Charging arrangements should avoid undue discrimination**
 Charging arrangements should continue to be developed to be non-discriminatory, recognising that they apply to all generation technologies (including demand side management) and not just low carbon technologies. If revisions to the charging arrangements are to be made in support of achieving carbon emission reductions, the benefit should be applied to all low carbon generation technologies and not just renewables.

4. DRIVERS AFFECTING ELECTRICITY TRANSMISSION CHARGING ARRANGEMENTS

4.1 Introduction

The shape that electricity transmission charging arrangements take is influenced by multiple drivers. These include factors that are specific to the electricity market itself and broader influences related to the wider economy and the political environment. This was illustrated in Section 2, where the interaction between energy policy goals and transmission charging objectives was considered.

It is important to consider these drivers and the impact that they may have upon electricity transmission charging design. The following sections provide an illustration of these drivers and their impact within GB.

4.2 Drivers

4.2.1 Political

The political agenda sets the energy policy framework (as discussed above) and so has a strong influence upon transmission arrangements:

- Government goals in respect of renewable energy and decarbonisation necessitate considerable investment in renewable/low carbon generation assets. This needs to be connected to the grid and managed within the operation of the system.
- Energy efficiency objectives are expected to influence electricity demand levels with potential implications for transmission.
- Electrification of heat and transport sectors could place considerable additional demands on the transmission system.

4.2.2 Economic

Economic factors also have an important influence upon transmission. For example:

- The performance of the economy in general is closely correlated to demand for electricity. Economic growth may require expansion of the transmission system, whereas economic contraction may lead to consolidation of the system.
- Renewable generation projects are dependent upon support linked to actual output, with the consequence that they have a bias towards locating in locations with the best resource potential. If these locations are geographically remote, this creates a requirement for additional transmission infrastructure.

4.2.3 *Social*

Actions of society will increasingly have a bearing on transmission development. For example:

- Expectations regarding the functionality and impact of ‘smart’ appliances mean that consumers at all levels will increasingly have both the information and ability to actively manage their energy consumption. This could have profound implications future supply/demand fundamentals and the role of the grid.
- Energy efficiency measures taken by consumers are expected to provide reductions in overall energy usage, all other things being equal.
- Electrification of heat and transport is expected to increase the bulk power flows that the transmission system must accommodate.

4.2.4 *Technological*

Advances in technology and changes in the relative roles of different technologies will affect transmission arrangements. For example:

- The prospect of genuine and significant demand side participation in the electricity market via ‘smart’ grids is increasing and the demand-side is changing from being passive and non-responsive to being active and dynamic. This may affect demand at peak and throughout the day/year, with potential implications for transmission system investment and usage.
- Changes in the generation mix (e.g. balance of intermittent vs. non-intermittent, flexible vs. non-flexible generation) create new challenges for the transmission system to deal with through system operation and/or grid investment.
- The need to connect and accommodate significant volumes of often geographically dispersed renewable generation sites (notably offshore wind) means that the transmission system is in a period of expansion rather than consolidation/contraction.

4.2.5 *Environmental*

Environmental objectives are at the heart of the majority of anticipated developments to the energy sector, as illustrated in each the drivers considered so far. For example:

- Renewable energy and de-carbonisation goals are expected to alter the generation mix and require substantial investment in both generation and transmission assets.
- The geographic dispersion of many renewable generation sources creates additional demand for transmission infrastructure.
- The electricity sector is expected to be the principle vehicle for delivering renewable energy goals, with electrification of heat and transport expected to have a significant impact on electricity demand and so transmission requirements.

4.2.6 Legislative

EU and domestic legislation, plus industry code frameworks, create legal requirements which have direct or indirect implications for electricity transmission. For example:

- Legally binding renewable and low carbon energy targets create pressure for connection of new generation sources which may require additional transmission infrastructure.
- Requirements for priority or guaranteed access to the grid for renewable electricity sources.
- Connect and manage arrangements now contained within the CUSC has the potential to advance generation connection ahead of wider system reinforcement with implications for transmission constraint costs in the short-term.

4.3 Implications for electricity transmission charging

Environmental objectives are at the heart of the majority of the prevailing drivers. In this context, transmission infrastructure has a key part to play in:

- connecting low carbon generation sources;
- continuing to accommodate bulk power flows from an evolving generation mix;
- enabling greater flexibility from demand-side participants; and
- supporting the electrification of heat and transport.

Therefore, transmission is an important enabler in the delivery of a low carbon economy. Given the political emphasis upon achieving this objective, it seems likely that the charging arrangements will need to be framed such that they support the achievement of this goal. Therefore, it seems likely that the transmission charging arrangements will be designed in recognition of these drivers in order to facilitate delivery of the current GB energy policy.

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5. INTERNATIONAL ELECTRICITY TRANSMISSION CHARGING MODELS

5.1 Introduction

Transmission charging is a component of electricity markets throughout the world. Reviewing the arrangements in place in other jurisdictions could provide valuable insight in the options available for transmission charging in GB in future. This section provides a preliminary analysis of a number of international markets, seeking to highlight the key characteristics of the charging regime in the context of the local electricity market. The markets focused on are as follows:

- GB (to provide a baseline for comparison);
- Germany;
- Ireland;
- Norway;
- Sweden;
- Pennsylvania Jersey Maryland (PJM);
- Texas; and
- Australian NEM.

Each market is summarised in Annex A. The key messages from the international review are summarised below.

5.2 Lessons learnt and implications for GB

5.2.1 *International experience overview*

Based on the preceding section, Table 9 provides a summary of the key market characteristics and Table 10 provides an overview of the key charging features for each of the case study markets.

Table 9 – International market summary

Feature	Country							
	GB	Germany	Ireland	Norway	Sweden	PJM	Texas	NEM
Energy market	Bilateral	Bilateral	Pool	Bilateral, LMP	Bilateral, LMP	Day-ahead, LMP	LMP	Real-time, LMP
Generation mix	Thermal dominated, growing renewables	Thermal dominated, growing renewables	Thermal dominated, growing renewables	Hydro dominated	Hydro and, nuclear dominated	Thermal and, nuclear dominated	Thermal dominated	Thermal dominated
Generation - demand location relativity	Separated	Less separated	Separated	Separated	Separated	Less separated	Separated	Separated
Generation investment	High Growth	Growth	High Growth	Stable	Stable	Stable	Stable	Growth
Transmission investment	High Growth	Stable	Growth	Stable	Stable	Stable	Stable	Growth

Table 10 – International market overview using strawman building blocks

Building block	Country							
	GB (TNUoS)	Germany	Ireland	Norway	Sweden	PJM	Texas	NEM
Generation or demand	G: 27% D: 73%	G: 0% D: 100%	G: 25% D: 75%	G: ~25-35% D: ~65-75%	G: 25% D: 75%	G: 0% D: 100%	G: 0% D: 100%	G: 0% D: 100%
Short-term or long-term pricing	Long-term	Long-term	Long-term	Short-term mainly	Mixed	Mixed	Mixed	Mixed
Locational or non-locational	Locational	Non-locational	Locational	Locational	Locational	Locational	Non-locational	Locational
Zonal or nodal	Zonal	n/a	Nodal	Nodal	Nodal	Nodal	Zonal*	Zonal
Capacity or commodity	Capacity	Commodity	Mixed	Commodity mainly	Commodity mainly	Mixed	Commodity	Mixed
Peak or annual	Peak	Annual	Mixed	Mixed	Mixed	Mixed	Peak	Mixed
Single or multiple system conditions	Single	n/a	Single	Multiple	Multiple	Mixed	Single: system peak	Mixed
Dynamic or static	Static	Static	Static	Mixed	Mixed	Mixed	Static	Mixed
Ex-post or ex-ante	Ex-ante	Ex-ante	Ex-ante	Ex-post	Ex-post	Mixed	Ex-ante	Ex-ante
Shallow or deep connection	Shallow	Mixed	Shallow	Shallow	Deep	Deep	Shallow	Shallow

* Moving towards a nodal structure at the end of 2010

5.2.2 Implications for GB

The transmission charging arrangements employed in international electricity markets are many and varied (and the range of options is likely to widen further as more international case studies are considered). There is no common model which can be applied to the GB context. However, a review of approaches taken in international markets is informative and it highlights a range of possible transmission charging techniques which can be considered for GB as part of the TransmiT process.

These insights include:

- **Charging objectives/features**

- Diversity exists in relation to the exposure of generators to transmission charges. A number of the case study countries do not apply charges to generators, with demand paying 100% of charges. Where generators do face transmission charges, the collective share paid by the generation sector is in the region of 25%. This has implications for the incentives that generators face when taking commercial decisions.
- In the US markets in particular, energy prices incorporate transmission-related costs (e.g. losses and local congestion) to produce locational marginal prices (LMP). This means that short-run marginal costs of transmission provision are priced and reflected in dispatch. Where LMP prices exist, parties have incentives to consider the impact of their location on transmission costs.
- Where energy prices do not vary locationally (as in LMP markets), locational differentiations between transmission costs can be reflected in the allocation of charges to different parts of the network. A number of case study markets recover charges based on the long-run marginal cost of transmission on a locationally varying basis (for generation only or for generation and demand). This creates economic signals for parties to consider when making investment decisions. However, this is not the case in all non-LMP markets considered.
- Whether charges are recovered on a capacity or a commodity basis varies.

- **Transferability to GB**

- Models that apply zero charges to generation (in absolute terms) are common in international markets, with multiple examples within Europe, including Germany. There are no technical reasons why such an approach cannot be implemented in the GB market. However, applying zero generation charge raises issues of principle. Much generation and transmission investment is anticipated in the GB market in the near-term. It is important for transmission investment to be economic. It is questionable whether economic transmission expansion will be supported if generators face zero transmission charges and so no economic signals of transmission investment costs.
- Transmission investment costs continue to be driven by capacity provision. Anticipated expansion of the transmission system in GB strengthens the rationale for the continuation of capacity based charges, rather than commodity based charges as in other markets.

- As for GB, locationally varying generation charges are present in multiple markets in Europe, the US and Australia. While the exact model of locational charging varies between different markets, the underlying motive is to provide economic signals to generators of transmission investment costs, in order to promote efficient grid development and operation. This international experience is, therefore, supportive of some form of locationally varying charge for generation.
- The LMP model, applied in the US in particular, includes short-term transmission costs within the energy price. Clearly, the GB market is not an LMP model at present. Direct transfer of the approaches taken in LMP markets is affected as a result. Short-run transmission costs could be reflected, however, through the application of a charge akin to a locational BSUoS charge, which reflects local congestion (and losses) costs. This, however, could run contrary to DECC's endorsement of socialisation of constraint costs in its connect and manage decision.

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6. CONCLUSIONS FOR TRANSMIT PROCESS

The conclusions to be considered within the TransmiT process that emerge from this paper are as follows:

Policy objectives

Traditionally, energy policy focused upon delivering affordability through the promotion of competition and the charging arrangements have supported this. However, the policy balance has now changed with a much increased emphasis on carbon emission reductions and renewables targets.

The transition from old to new policy agenda creates a tension for the objectives that should be attached to transmission charging arrangements going forward. In this context, Project TransmiT:

- Is seeking to ensure that the transmission charging arrangements facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future customers.
- Should be considered as an opportunity to review the appropriateness of the current regime in the first instance, followed by the opportunity to make refinements as considered necessary to reflect the revised policy landscape. However, changes should not be made for change's sake and the existing charging principles should be retained wherever they remain appropriate.

Role of transmission charging

Multiple objectives can be attached legitimately to transmission charging arrangements, ranging from efficiency and cost-reflectivity through to stability and predictability. There are tensions between different objectives, with the consequence that they are not easily achieved simultaneously.

There is a clear distinction between the priority charging objectives for delivering energy security and affordability on one hand versus those for achieving carbon emission reductions alone. Historically, the priority focus has been on affordability and the charging arrangements have supported this. Given the revised emphasis of policy priorities, there is a case for revisiting the balance between the charging objectives to ensure that charging arrangements remain compatible with and do not work against policy goals. Identifying whether a revised balance between different charging objectives is required in the new energy policy context is at the heart of the TransmiT process.

International experience

The transmission charging arrangements employed in international electricity markets are many and varied. There is no common model which can be applied to the GB context. However, a review of approaches taken in international markets is informative and it highlights a range of possible transmission charging techniques which can be considered for GB as part of the TransmiT process.

For example, a number of international markets provide insights into the experience of locational marginal pricing and its incorporation of the short-run marginal costs of transmission provision into energy pricing. Other markets offer insight at the other end of the spectrum, where demand bears all transmission costs on a non-locationally varying basis, dampening any economic signals linked to transmission costs.

Whilst transmission charging solutions from international markets can provide useful insights into options that could be considered for GB, they must be viewed in the context of the prevailing energy market arrangements and supply/demand fundamentals when considering potential lessons for use in GB. Many of these are different to those seen within the GB market. Thus the appropriateness of international models for the GB market must be considered in terms of their suitability for the specific drivers facing GB. For GB, the key drivers are that transmission infrastructure has a key part to play in:

- connecting low carbon generation sources;
- continuing to accommodate bulk power flows from an evolving generation mix;
- enabling greater flexibility from demand-side participants; and
- supporting the electrification of heat and transport.

It is important that GB charging arrangements should be developed to reflect these GB specific circumstances and drivers; and not simply adopt other approaches employed elsewhere internationally which suit different market circumstances.

Assessment of transmission charging options

A range of charging options is available. Assessing the strawman options against suggested transmission policy objectives provides some powerful preliminary conclusions:

- **Carbon emission reductions:**
 - *Non-locationally varying generation charges support the majority of renewable generation projects.* This is because resource potential for many renewable projects is generally at its best in northern areas of the system that currently attract high transmission charges, so uniform charges would help to lower costs for these projects (although not necessarily for more southerly renewable projects), thereby supporting carbon emission reductions from renewable generators in general but not from the broader low carbon generation class.
 - *Differentiated charges support low carbon generation more generally (including renewable projects).* This distinguishes between low carbon and high carbon generation technologies, not just renewable generation, thereby delivering carbon emission reductions across the range of low carbon generation technologies.
- **Energy security and affordability:**
 - *Options incorporating locationally varying generation charges improve the efficiency of generation investment and network investment.* These provide economic signals of the cost of connecting to different parts of the system. This outcome promotes both energy security and affordability.

The revised policy focus creates pressure for transmission charging arrangements to evolve accordingly. This could imply a deviation away from the traditional emphasis upon locationally varying charges to create economic signals which encourage efficient behaviour from market participants. However, it is important to reflect before drawing this conclusion:

- **Encouraging efficient grid investment remains a binding transmission charging principle**

Transmission investment still needs to be demonstrably economic in order to provide value to consumers, especially given the expected future expansion of the grid. Transmission charging arrangements will continue to be a critical driver of efficient transmission investment going forward. This suggests that it is appropriate for some form of locationally varying charges to be retained in order to promote efficient generation investment decisions and consequential grid development. It is also true that the charging arrangements affect generation investment decisions, but they are one tool amongst many in this context. Investment in low carbon technologies can be supported by means other than amendments to the transmission charging arrangements.
- **Transmission investment costs still driven by capacity**

Transmission investment costs will continue to be predominantly driven by capacity requirements and not system utilisation. In order to provide appropriate economic signals in a period of anticipated grid expansion, charges should continue to be set with reference to MW and not MWh, whatever the exact method for deriving them.
- **Charging arrangements should avoid undue discrimination**

Charging arrangements should continue to be developed to be non-discriminatory, recognising that they apply to all generation technologies (including demand side management) and not just low carbon technologies. If revisions to the charging arrangements are to be made in support of achieving carbon emission reductions, the benefit should be applied to all low carbon generation technologies and not just renewables.

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ANNEX A – INTERNATIONAL MARKET REVIEW

A.1 Great Britain

Reason for selection

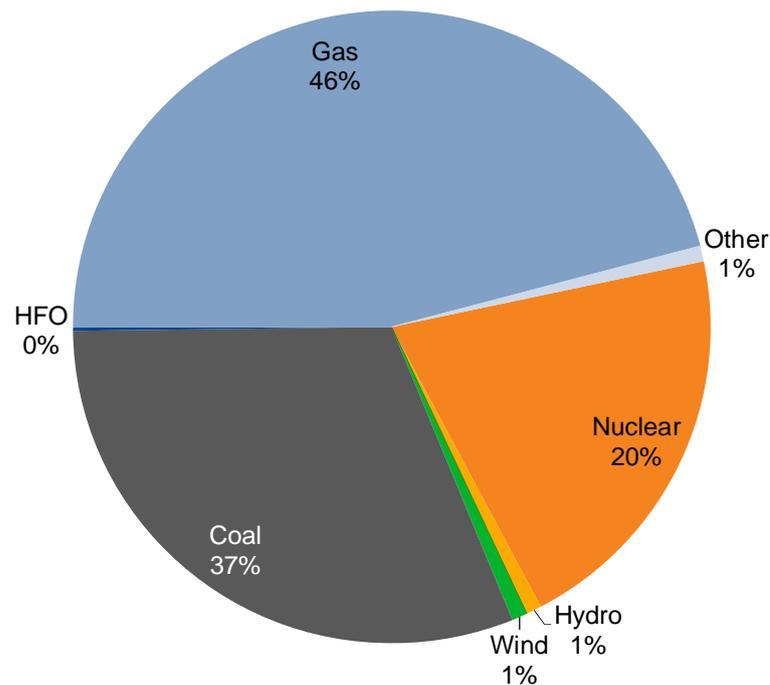
The GB is the focus of TransmiT. It is included here to provide a baseline against which other international market arrangements can be compared.

Supply/demand fundamentals

Britain’s electricity consumption⁶ is estimated at 334 TWh in 2008, according to the IEA⁷.

The electricity supply is based on a mix of three main primary sources of energy. Fossil fuels represent 77% of all generation, among which gas accounts for 46% of the total and coal 37%. Nuclear makes up 20% of the production. The role of renewable sources of energy remains marginal – as they only account for 2% of the total – and future transmission charging schemes will have a significant impact on their development.

Figure 2 – Gross electricity production mix in GB in 2009



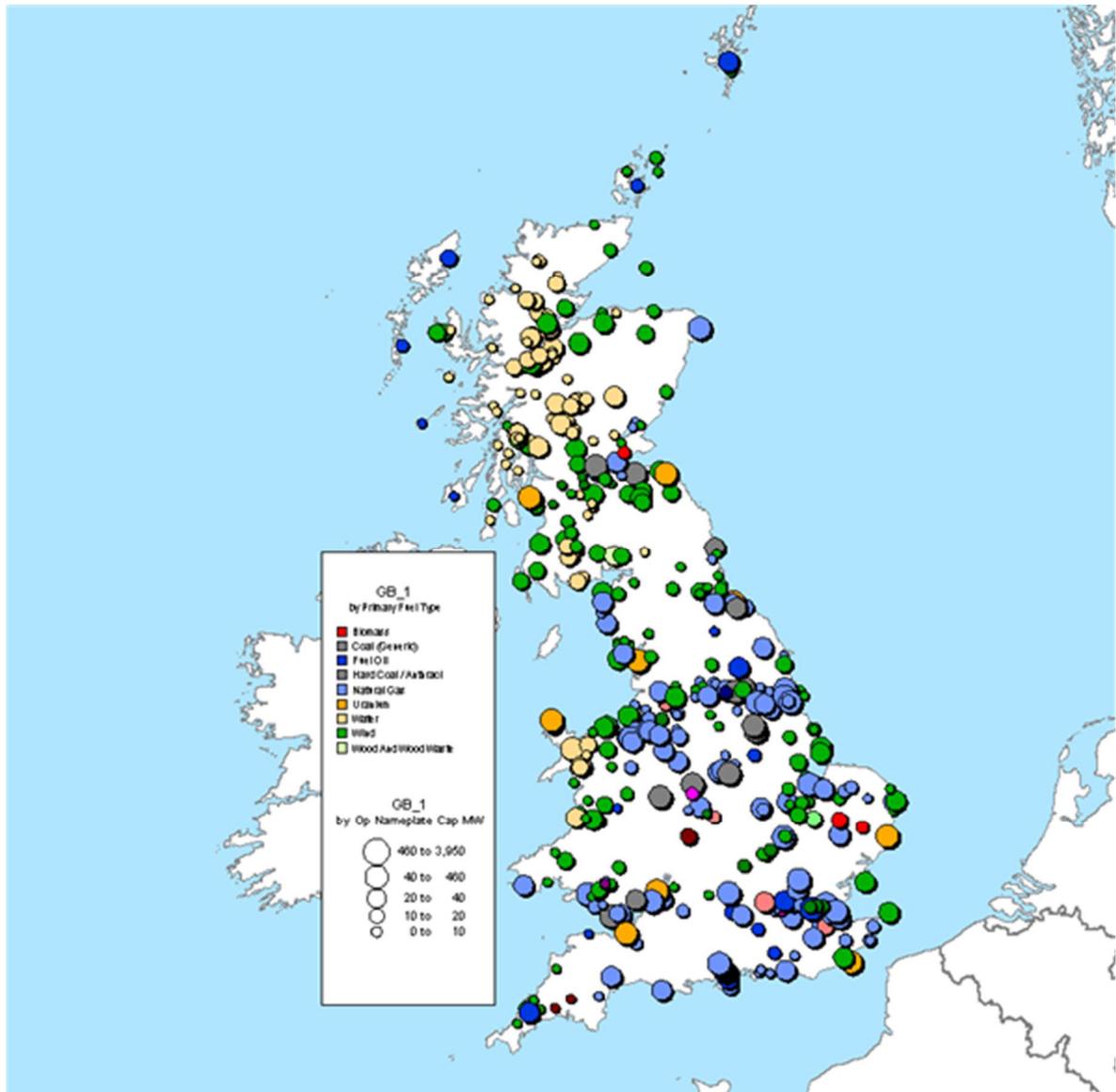
Source: IEA data, Pöyry's analysis

⁶ In this section, electricity consumption is defined as gross production plus imports minus exports

⁷ Electricity Information 2010, IEA, Paris, 2010

Historically, in Britain electricity has flowed from north to south, from generation centres in the north (particularly coal-fired generation) to demand centres in the south. While coal-fired generation is expected to reduce, particularly as a result of closures linked to the Large Combustion Plant Directive (LCPD), resource potential for renewable generation is at its greatest in the north, suggesting that this general flow pattern will continue in the future

Figure 3 – Power generating stations in GB



Source: Platts Powervision

The British electricity market is described as “moderately concentrated” by the EU DG TREN⁸, and has the lowest Herfindahl-Hirschman Index (HHI) among all EU members at 901. Eight different players have a market share above 5%. The three largest players represent 42% of the capacity (the lowest figure in the EU) although around 75% of the generation market is operated by six participants.

Energy market structure

The Great Britain electricity market is an energy-only market, with no explicit capacity mechanism, based on a single-region and national energy price. Trading is conducted bilaterally between parties up until Gate Closure, one hour ahead of real-time. Parties self-dispatch with only a residual balancing role for the system operator, who takes actions on the Balancing Mechanism or via balancing services contracts to deliver real-time balancing. While trade prices are agreed bilaterally, common, nationwide imbalance prices are applied to contractual imbalances (there is a dual imbalance price system, with a System Buy Price applied to those contractually short and a System Sell Price applied to those contractually long). Local congestion (and losses) costs are not included in the energy price.

Transmission charging arrangements

Transmission Network Use of System (TNUoS) charges are levied on both generators and demand. Generators pay 27% and demand pay 73% of allowed transmission revenue. The TNUoS charge has a locational and a residual component. The locational charge varies by generation and demand zone. Its objective is to reflect the Long-Run Marginal Cost (LRMC) of transmissions services in various zones. This creates zonal differentiation between different parts of the country:

- in the north of the country, which has surplus generation capacity, charges are relatively high for generators, while being relatively low for demand; and
- in the south, charges are relatively low or even negative for generators in demand-rich areas, while being relatively high for demand.

The residual charge aims at recovering residual costs. This is a non-locational charge.

Tariffs are levied on generators and demand as follows:

- in the case of the majority of generators, in accordance with their maximum installed capacity (kW) (tariffs for generators in negative charging zones are based on the average metered volume in the ‘triad’ periods (see below)); and
- in the case of demand, based on the ‘triad’ approach – that is, the average demand (kW) during the three half-hours (separated by 10 clear days) between November and February during which system demand is at its greatest.

At present there are 14 demand zones, corresponding to the 14 Grid Supply Points (GSPs) in the market, and 20 generation zones.

⁸ Technical annex to the “Report on progress in creating the internal gas and electricity market” COM/2010/84, Brussels, 2010

Therefore, the GB market has a system of locational transmission charges. In addition to TNUoS, the Balancing Services Use of System (BSUoS) charge is levied on generation and demand to recover the day to day costs of system operation. BSUoS is recovered on a 50:50 basis from generation and demand and is a non-locationally varying charge.

A.2 Germany

Reason for selection

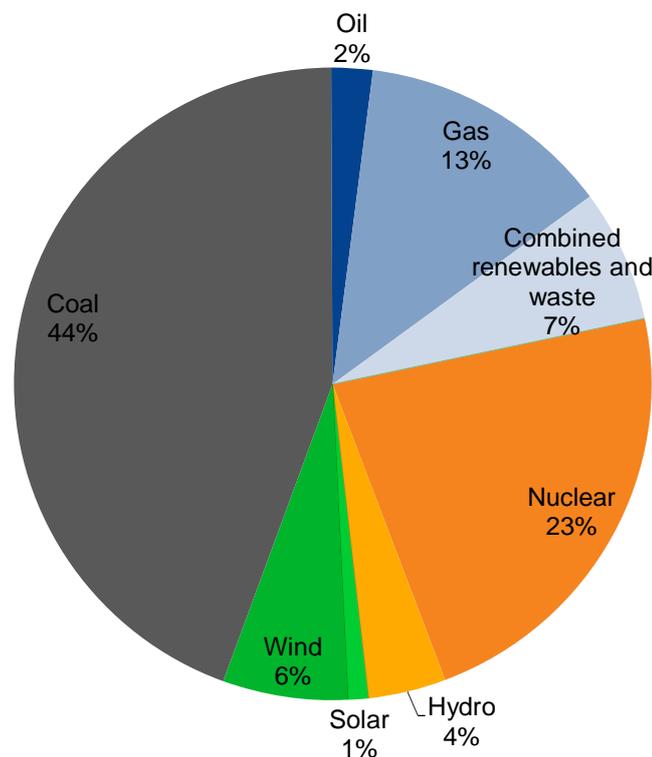
In the German electricity market, generators do not face transmission charges. Demand faces 100% of transmission charges, with common, non-locationally varying tariffs applied across the country. This makes it an interesting contrast to GB. In addition, it is characterised by a growing proportion of renewable generation capacity, particularly wind generation.

Supply/demand fundamentals

Electricity consumption reached 541 TWh in Germany in 2008 according to the IEA⁹.

The German electricity mix is dominated by fossil fuels, accounting for 59% of the total, with coal itself representing 44% of all production. The remaining production is achieved through nuclear (23%) and a growing mix of renewables. It is noticeable that Germany has the largest wind generation capacity of the reviewed electricity markets.

Figure 4 – Gross electricity production mix in Germany in 2009

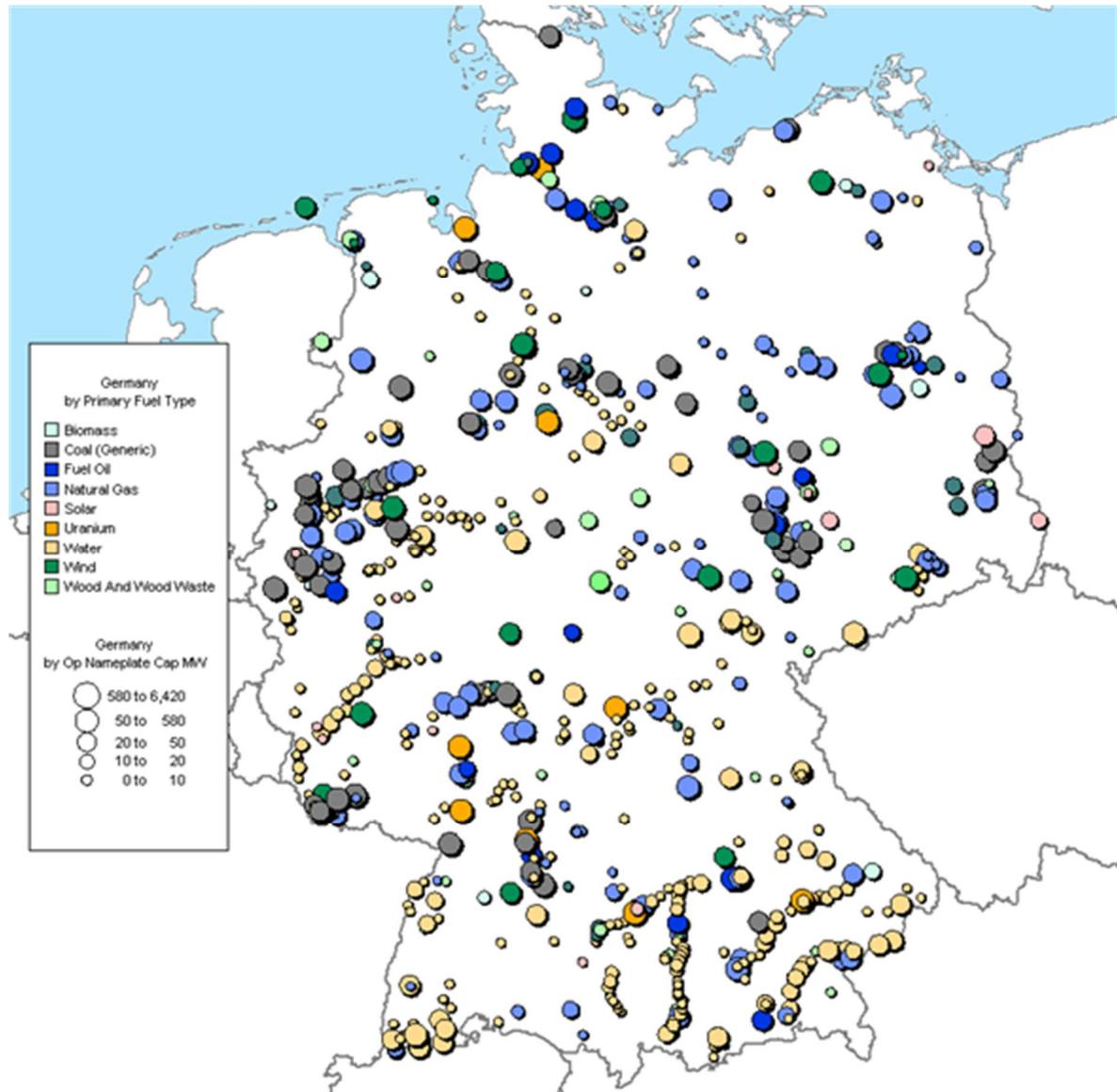


Source: IEA data, Pöyry's analysis

⁹ Electricity Information 2010, IEA, Paris, 2010

German generation shows an interesting geographical divide. Most of the hydro production is done in the south of the country, while the north is the main provider of electricity from wind. Nuclear is concentrated in the western part of the country. Consumption is relatively dispersed but more concentrated in northern and western regions.

Figure 5 – Power generating stations in Germany



Source: Platts Powervision

German electricity market is considered as “highly concentrated” according to the EU DG TREN¹⁰, with a HHI of 2008 in 2008. Four companies have more than 5% of the generation capacity, among which the three largest represent 85% of the total. Recent liberalisation and the presence of large historical players explain the high degree of concentration in this market.

¹⁰ Technical annex to the “Report on progress in creating the internal gas and electricity market” COM/2010/84, Brussels, 2010

Energy market structure

Electricity is traded in Germany using a number of different markets including over-the-counter (OTC) transactions characterised by bilateral contracts, and exchanges for both spot and forward products. The Leipzig-based European Energy Exchange (EEX) provides a hub for trading activity, including day-ahead. EEX has seen an increasing volume of trade through its day-ahead market in recent years. The German market does not include any locational signal, as there are no zones or nodes. Reserve and balancing are not traded on the EEX, the major German grid operators buy these services at auction.

Transmission charging arrangements

Unlike in GB, demand pays for the entire network costs in Germany. This cost is levied through a Grid Utilisation Charge (GUC), and varies in function of voltage and utilisation time, but does not include any locational component.

An additional flat transportation charge applies when power is traded between domestic trading areas and/or between Germany and a neighbouring country.

A.3 Ireland

Reason for selection

The Irish market faces many of the same issues that exist in Great Britain. Ireland has targets to achieve 42.5% renewable generation by 2020. As in GB, much of Ireland's renewable generation is likely to be provided by wind. In order to deliver this target it needs to connect a significant quantity of wind generation, supported by the necessary transmission infrastructure. In terms of renewable penetration achieved to date, Ireland is at a more advanced stage than GB (in percentage of generation terms) and is facing the challenges that this creates for transmission arrangements already. These factors make Ireland a relevant comparator.

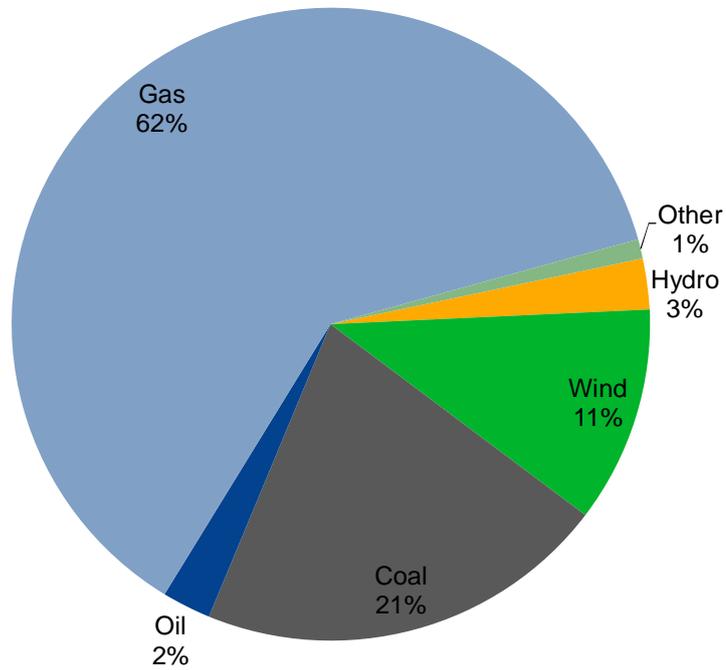
Supply/demand fundamentals

Electricity demand on the Island of Ireland is estimated at 35 TWh in 2008 of which the Republic of Ireland accounts for 72%¹¹.

The Island of Ireland mainly relies on gas for electricity generation, supplied principally by interconnectors to Great Britain. Coal remains the second most important source of primary energy for electricity production. Among the reviewed markets, Ireland has the largest share of wind generation (11%).

¹¹ Electricity Information 2010, IEA, Paris, 2010

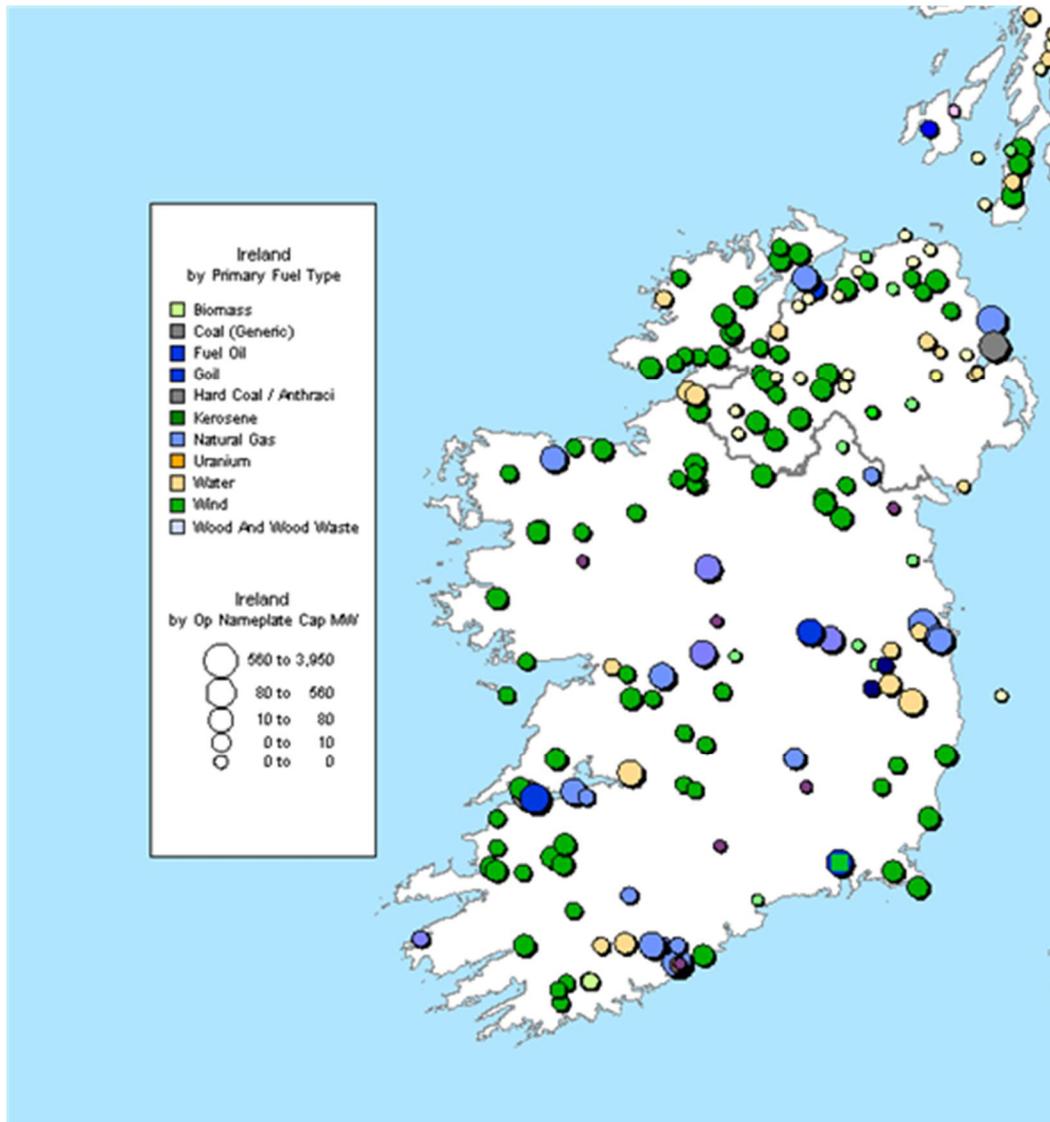
Figure 6 – Gross electricity production mix in the Island of Ireland in 2009



Source: IEA data, Pöyry's analysis

The geographical location of power generating stations in the Isle of Ireland shows a high density in Northern Ireland and a lower density in the Republic of Ireland. The general direction of energy flows is from north to south and from west to east to serve the major demand areas.

Figure 7 – Power generating stations in the Island of Ireland



Source: Platts Powervision

The Irish electricity market is ‘moderately concentrated’ according to the EU DG TREN¹², although no HHI value is provided. In 2008, four players owned more than 5% of the generation capacity, among which the three largest share 86% of the total capacity. Along with the Netherlands, Ireland is the only electricity market in the EU where concentration has increased between 2007 and 2008.

¹² Technical annex to the “Report on progress in creating the internal gas and electricity market” COM/2010/84, Brussels, 2010

Energy market structure

The Single Electricity Market (SEM) operates in both Ireland and Northern Ireland. This is a gross mandatory pool system, with central dispatch. All generation in a particular half-hour receives the same System Marginal Price (SMP) for its scheduled output, with SMP determined ex-post. In addition to the energy market, a Capacity Payments Mechanism operates in the SEM.

Transmission charging arrangements

At present, different transmission charging methodologies apply in each jurisdiction. In Northern Ireland, a common, non-locationally varying £/MW capacity charge is levied upon all eligible generators such that 25% of allowed transmission revenue is recovered from generators. The remaining 75% of allowed revenue is recovered from demand, based on a combination of peak usage and estimated load duration.

In the Republic of Ireland, generator transmission charges vary by location, while demand charges are non-locational. Each generator's charge is determined based upon its use of the system as determined by load flow modelling. As in Northern Ireland, 25% of allowed transmission revenue is recovered from generators via a locationally varying £/MW capacity charge principally. The remaining 75% of revenue is recovered from demand using a combination of capacity and commodity charges.

Efforts are underway to harmonise transmission charging arrangements across jurisdictions to deliver consistent arrangements for the SEM as a whole.

A.4 Norway

Reason for selection

Norway is particularly relevant in the context of this study because it has been addressing the issue of transmission charging in a virtually all-renewables electricity market for a significant period. The solutions that are in use give an indication on how transmission charges can be set in this context.

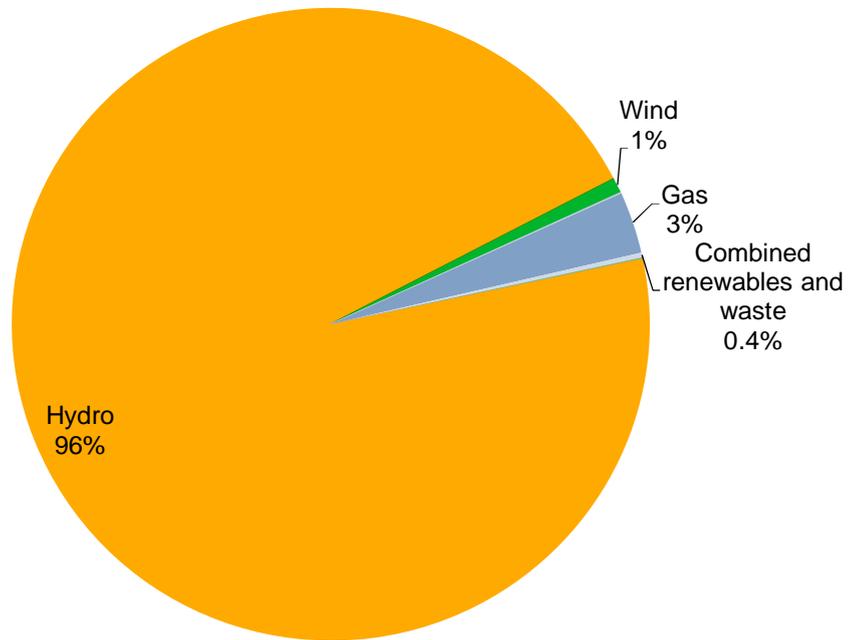
Supply/demand fundamentals

Electricity consumption in Norway reached an estimated 115 TWh in 2008 according to the IEA¹³.

The production mix is largely dominated by hydro, accounting for 96% of the total. Other sources include gas, wind and combined renewables and waste.

¹³ Electricity Information 2010, IEA, Paris, 2010

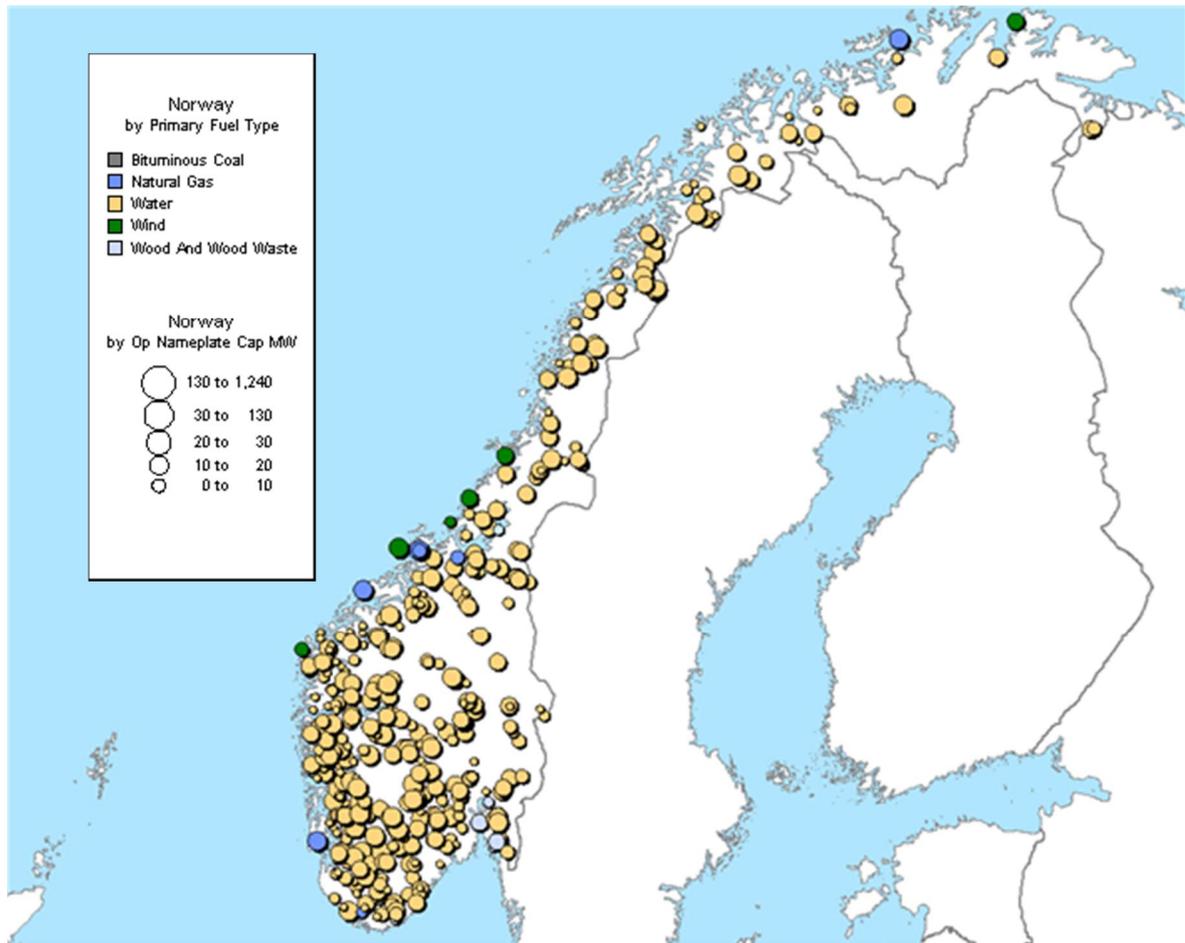
Figure 8 – Gross electricity production mix in Norway in 2009



Source: IEA data, Pöyry's analysis

Hydro production is largely decentralised in Norway, along the multiple lakes and rivers located in various parts of the country. Load centres are concentrated in the south of the country.

Figure 9 – Power generating stations in Norway



Source: Platts Powervision

The Norwegian electricity market can be described as “highly concentrated” according to the EU DG TREN¹⁴, with a HHI index of 1826 in 2008. Six companies have more than 5% of the generation capacity, among which the three largest share 43% of the capacity.

¹⁴ Technical annex to the “Report on progress in creating the internal gas and electricity market” COM/2010/84, Brussels, 2010

Energy market structure

Norway is part of the four-country Nordic power market 'Nord Pool', along with Sweden, Finland and Denmark. Nord Pool is a zonal market. Nord pool is always cleared at a system price (unconstrained price) in the first instance. If there are constraints, zonal prices emerge after the second market clearing (constrained price). This produces locational marginal prices (LMP) which reflect the marginal cost of losses and local congestion. Norway currently has 3 pricing regions, in which three distinct markets operate:

- a physical day-ahead spot market (Elspot);
- a financial futures and forwards market (Eltermin); and
- a balancing market (Elbas).

In addition, participants also bilaterally trade OTC contracts.

Transmission charging arrangements

Norway has a 'point of connection' tariff system, which means that users are charged nodally based upon the costs imposed by injections/withdrawals upon losses and congestion. As a result transmission charges are split among generators and demand. On average, generators pay approximately 25-35% of shared network costs while demand pays the remaining 65-75%, although the exact split varies depending upon system conditions.

Shared network costs are recovered by three different mechanisms:

- an energy charge, based on the extent to which a party increases or reduces losses at a given node;
- a congestion charge, reflecting the difference between prices in an unconstrained model and a constrained model; and
- a residual charge allowing recovery of remaining costs. Generators are charged based on historical average annual output, while demand is charged based on historical peak consumption.

A.5 Sweden

Reason for selection

Like Norway, Sweden has an electricity mix based on non-CO₂ emitting technologies. However, unlike its Nordic neighbour, Swedish generation is split between renewable and nuclear technologies. Therefore, the study of the Swedish electricity market can give interesting insights on how a mixed non-carbon power sector deals with the issue of transmission charging.

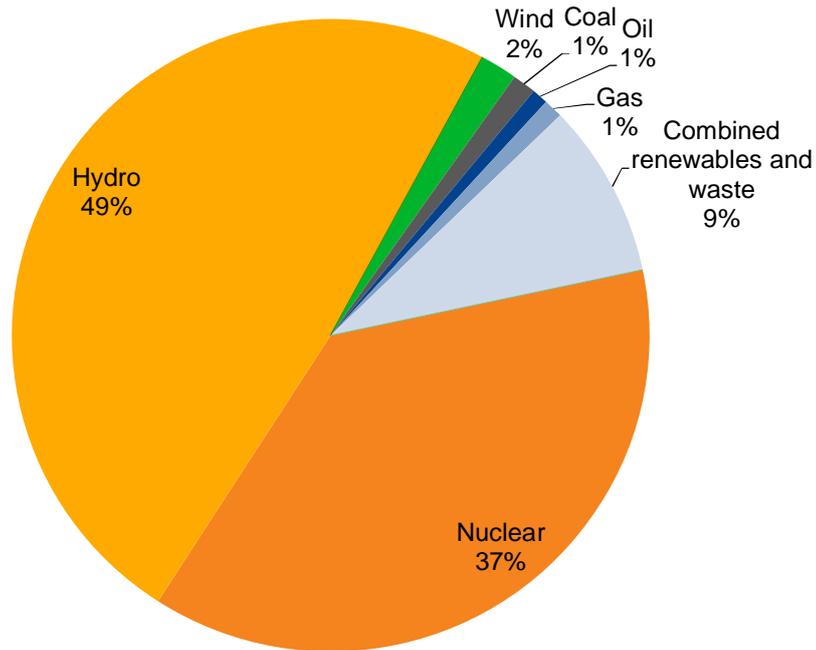
In addition, the geographical location of Sweden's electricity generation is in some way comparable to the GB case: the north of the country produces most of the renewables and has a relatively low consumption, while the South is characterised by a high consumption and a relatively minor role in electricity production from renewable sources.

Supply/demand fundamentals

Electricity consumption reached 132 TWh in 2008 according to the IEA¹⁵.

Hydro and nuclear represent respectively 49% and 37% of generation. Fossil fuels are only used in peak period as a marginal supplier, as reflected by their low share in the production mix.

Figure 10 – Gross electricity production mix in Sweden in 2009

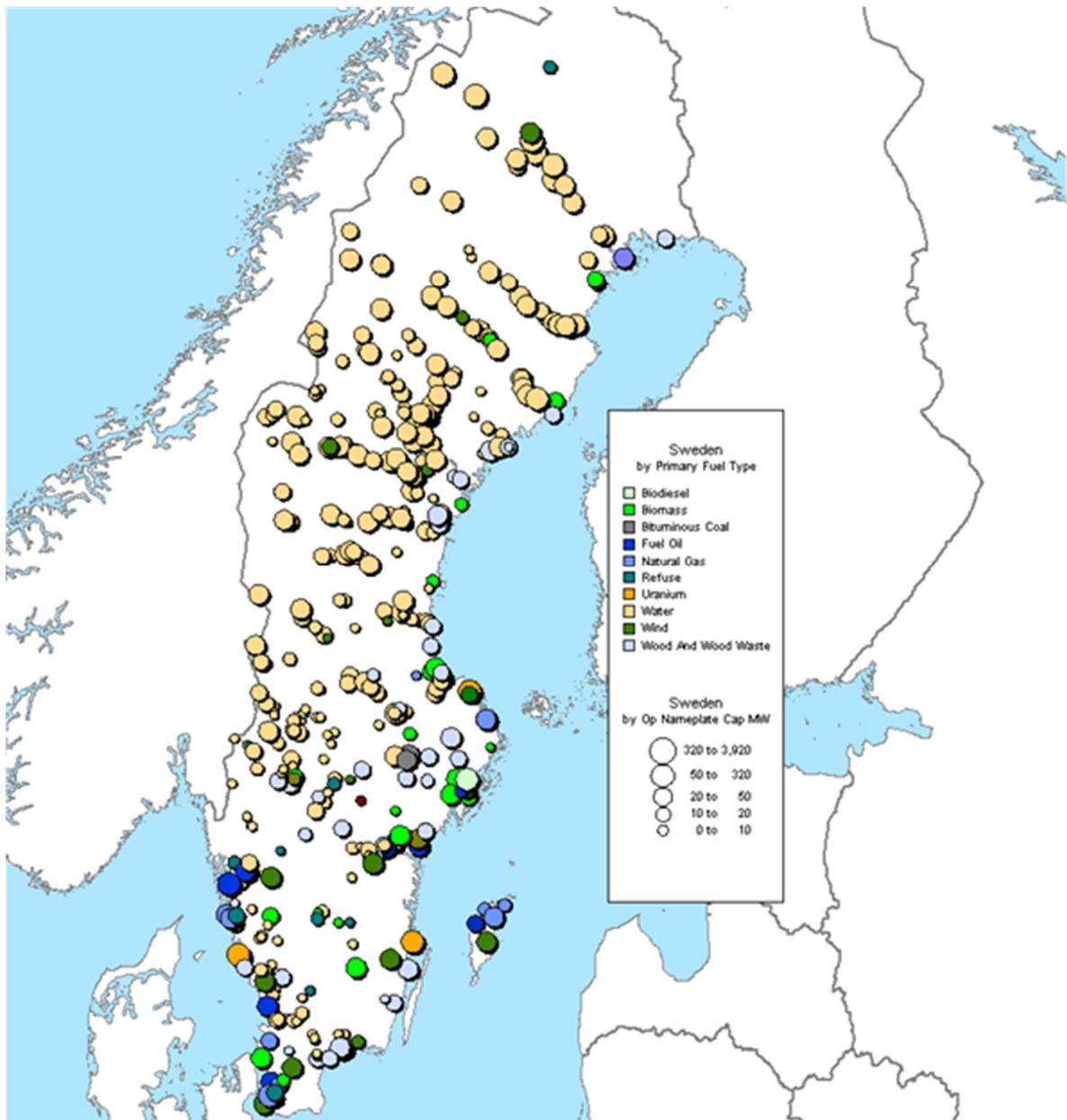


Source: IEA data, Pöry's analysis

Sweden's generation capacity is evenly shared between the north and the south of the country. Most of the hydro production comes from remote areas and electricity needs then to be transmitted to high-consumption areas.

¹⁵ Electricity Information 2010, IEA, Paris, 2010

Figure 11 – Power generating stations in Sweden



Source: Platts Powervision

According to the EU DG TREN¹⁶, the Swedish electricity market is among the seven more concentrated markets in the EU, although no HHI value is provided. Three Swedish companies own 75% of all market capacity and the largest following player has less than 5% market share.

¹⁶ Technical annex to the “Report on progress in creating the internal gas and electricity market” COM/2010/84, Brussels, 2010

Energy market structure

Sweden is part of the Nord Pool market discussed in more detail above (see 'Norway'). However, there are significant differences between the Swedish and Norwegian electricity markets.

While Norway's market has three different zones and prices, Sweden has a single-price market structure, i.e. one zone and market price. As a result, while losses are included in the LMP, congestion within the national region is not included in the energy price. The system operator must manage congestion through re-dispatch.

Transmission charging arrangements

All network users pay towards the costs of the shared network. Historically, generators have paid 25% while demand has paid 75%, although these values are not fixed. The Swedish market is geographically divided between north and south. Since the majority of Sweden's generation is located in the north of the country, power predominantly flows from north to south. As such, Sweden's transmission pricing regime imposes relatively high charges on generation in the north and demand in the south, with nodally varying charges. This north/south distinction echoes the situation in Great Britain.

Sweden's shared network costs are recovered via two key charges:

- An energy charge, based on the extent to which a party increases or reduces losses at a given node.
- A capacity charge, depending on the capacity at each connection point. In practice, this charge reflects the regional divide of the Swedish market. The charge for injections is highest in the north and reduces linearly with latitude in the south. The opposite is true for withdrawals, with charges being higher in the South and lower in the north.

A.6 Pennsylvania Jersey Maryland (PJM)

Reason for selection

PJM couples a nodal pricing system and a Financial Transmission Right (FTR) market. A nodal pricing mechanism differs from the approach currently adopted within GB offers an alternative option for energy and transmission arrangements.

Supply/demand fundamentals

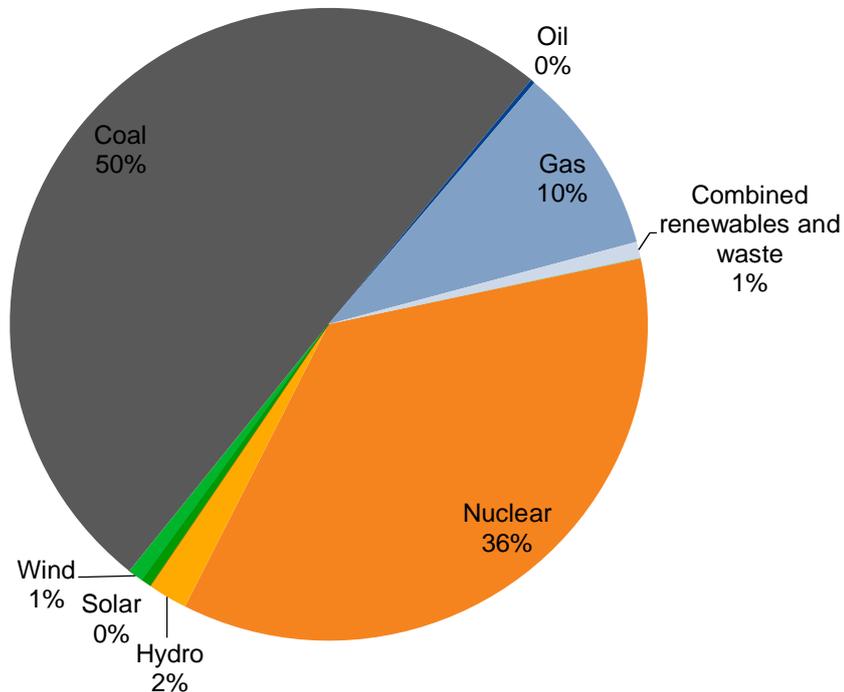
PJM covers all or most of Delaware, District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia and parts of Indiana, Illinois, Kentucky, Michigan, North Carolina and Tennessee.

2009 electricity demand reached 693 TWh¹⁷.

Coal represents half of the total mix and nuclear accounts for one third. Renewables are relatively marginal in comparison to the American average, representing only 4% of total generation.

¹⁷ 2009 State of the Market Report for PJM, Monitoring Analytics, LLC, 2010

Figure 12 – Gross electricity production mix in PJM in 2009



Source: Monitoring Analytics, LLC, Pöyry's analysis

According to the HHI index, PJM physical markets are moderately concentrated. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

Energy market structure

PJM's physical electricity markets utilise a nodal structure, in which all generators and demand are dispatched and settled on the basis of their own nodal price (LMP).

PJM includes a day-ahead energy market, a real-time balancing market and a financial transmission right (FTR) market. In addition, adequate capacity/reserve is managed through a competitive capacity market.

Transmission charging arrangements

Demand pays 100% of shared network costs, via three different mechanisms:

- Usage charges aiming at reflecting the impact of congestion and losses. These costs can be hedged via the use of FTRs.
- Network integration transmission service charges, which are locationally differentiated commodity charges levied on daily peak demand. Charges differ between zones, providing a locational signal.
- Point-to-point transmission service charges, which are postage stamp, capacity charges.

Rights to accrued congestion rents in PJM are allocated as FTRs to demand. Owners of assigned FTRs, in exchange for surrendering FTRs to auction, receive a share of auction revenues in accordance with their share of FTRs. Owners of assigned FTRs may re-purchase FTRs at auction if they wish.

A.7 Texas

Reason for selection

Texas electricity mix shows some similarity with GB. In both cases, coal accounts for about one third of generation, while gas represents slightly less than 50%. Texas electricity market (ERCOT) is currently experiencing a radical change in its structure, as it moves from a zonal architecture to a nodal structure.

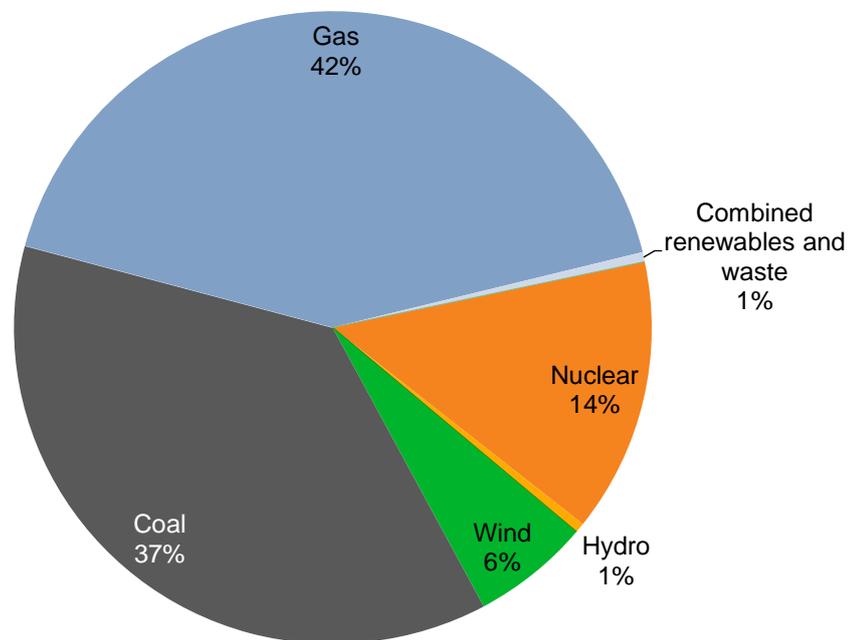
Supply/demand fundamentals

ERCOT is the major network in Texas, serving 75% of Texas land and 85% of Texas demand.

Electricity consumption was of 308 TWh in 2009 according to ERCOT¹⁸.

Fossil fuels accounts for 79% of total generation. ERCOT is one of the US market where coal plays the least role, only representing 37% of all production. Local resources of gas in the Gulf of Mexico explain why gas is the largest fuel in electricity production.

Figure 13 – Gross electricity production mix in Texas’ ERCOT in 2009



Source: ERCOT, Pöyry's analysis

¹⁸ ERCOT 2009 Annual Report, Austin, 2010

ERCOT is a moderately concentrated market. Since electrical deregulation was implemented in Texas in 2002, the degree of concentration has been decreasing.

Energy market structure

ERCOT is currently a zonal market, with five pricing zones. There is no formal capacity market. The market is expected to become nodal in the final quarter of 2010, with the following structure:

- generators will be settled on nodal prices; and
- demand will be settled on the basis of a weighted average nodal price.

Transmission charging arrangements

Under the current market structure, demand pays 100% of shared network costs, via:

- a demand-based access fee based upon average consumption in the peak demand period in June, July, August and September in the previous year; and
- a zonal usage charge, which reflects the price differential between pricing zones in the presence of congestion.

Rights to accrued congestion rent are auctioned to participants as FTRs in monthly and annual auctions.

A.8 Australia NEM

Reason for selection

The Australian National Electricity Market (NEM) has an interesting mixed structure, as it is a nodally-dispatched but zonally-settled market. It allows different prices in the same market.

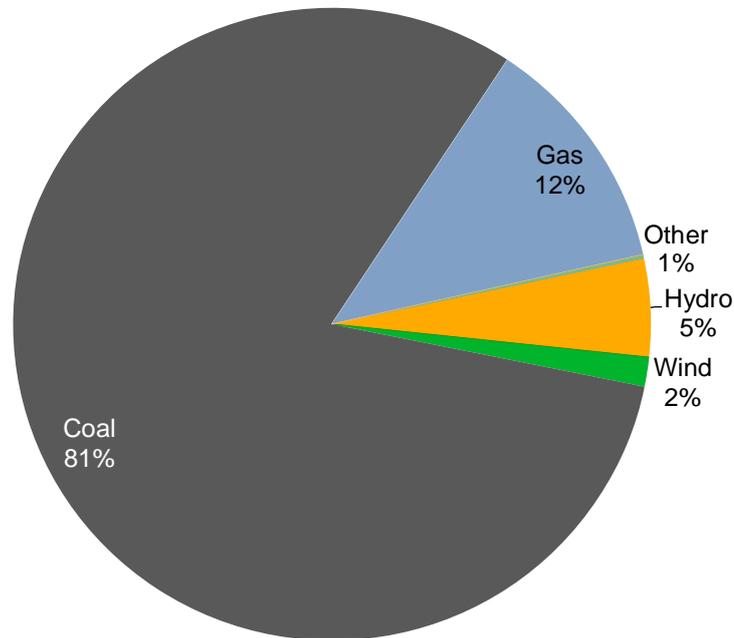
Supply/demand fundamentals

The NEM regroups the majority of the Australian electricity market. It includes the following states and territories: Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.

Electricity demand in the NEM is estimated at 208 TWh in 2008¹⁹. Coal largely dominates the production mix, with an 81% market share – mainly due to important local reserves – and gas represents a significant 12%. Hydro and wind only account for a marginal share of electricity production mix.

¹⁹ Energy in Australia 2010, Australian Government, Canberra, 2010

Figure 14 – Gross electricity production mix in Australia's NEM in 2009



Source: AEMO, Pöyry's analysis

Energy market structure

The NEM is dispatched on a nodal basis but settled on a zonal basis across five regions. In each region, a Regional Reference Price is settled, based on the marginal cost or value of electricity supply at the Regional Reference Node (RRN). As a consequence, RRP reflects transmission congestion between two different zones, but does not take account of intra-zone congestion, which can lead to sub-optimal results when dispatching generation.

As an energy-only market, the NEM does not include any separate capacity market. As a result, generators must earn in excess of their fuel costs in order to make a return on the generator investment.

Transmission charging arrangements

Demand pays 100% of the transmission costs. Costs are recovered via three different charges.

- Congestion and loss rentals arising on inter-regional transmission links, known as Inter-Regional Settlement Residues (IRSRs), are auctioned off to participants.
- Half of the remaining shared transmission costs are recovered through a postage-stamp charge on demand, which can be either \$/MW or \$/MWh based at the customer's discretion.
- The remaining shared network costs are recovered from demand on the basis of the 'cost-reflective network pricing' (CRNP) allocation methodology. This methodology aims to reflect the long run marginal cost of using the network at each local connection point. It allocates the cost of network elements to local connections points on the extent to which a hypothetical increment of demand at this point increases flow across the network. Each customer pays a \$/MW and a \$/MWh calculated on this basis.

QUALITY AND DOCUMENT CONTROL

Quality control		Report's unique identifier: 2010/618
Role	Name	Date
Author(s):	Simon Bradbury Mike Wilks	November 2010
Approved by:	Mike Wilks	November 2010
QC review by:	Beverly King	November 2010

Document control			
Version no.	Unique id.	Principal changes	Date
v1_0	2010/618	Client Version	November 2010

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