OPTIONS FOR GB ELECTRICITY TRANSMISSION CHARGING ARRANGEMENTS

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A report to RenewableUK

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EXECUTIVE SUMMARY

Background

Ofgem launched Project TransmiT ('TransmiT') on 22 September 2010. TransmiT is intended to be a comprehensive and open review of the charging regime and connection arrangements linked to electricity and gas transmission networks. The aim of TransmiT is 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.

Purpose of this report

In this context, RenewableUK have commissioned Pöyry Management Consulting (UK) ('Pöyry') to produce an independent public report to examine options for transmission charging in Great Britain. These options were developed to assess the stresses in the current transmission charging arrangements identified by RenewableUK in its response to Ofgem's call for evidence on Project TransmiT[1] and to identify a representative range of different options which would address different stresses.

This report provides our **independent** assessment of ten potential charging options , drawn from a long-list of 18 options. It has not been developed to support a particular pre-identified option or preferred option of RenewableUK. In addition, RenewableUK expressly excluded from the scope of this report the provision of a recommendation for a preferred policy option.

Our Executive Summary provides an overview of the 10 shortlisted options, and reports the performance of each option in addressing the stresses identified by RenewableUK. We then comment on the implications of our analysis for a number of key themes, including the impact on offshore wind.

Stresses in current GB electricity transmission charging arrangements

Table 1 summarises the stresses in current GB electricity transmission charging arrangements identified by RenewableUK in their response to the TransmiT call for evidence.

We were asked by RenewableUK to develop a representative range of options for changes to transmission charging arrangements, with particular consideration as to how each option would address the stresses listed in Table 1.

1 'Response to Project TransmiT Call for Evidence', RenewableUK and Scottish Renewables, November 2010.

Table 1 – Summary of stresses in current electricity transmission charging arrangements in GB (as identified by RenewableUK)

Stress	Elements of stress
Level of financial (pre-connection) user commitment	Disincentive to development of generation, thereby reducing competition Imbalance between user commitment from prospective generators and ongoing commitment after commissioning
Charging for offshore generation	High charges for offshore generation compared to onshore Reduction in onshore charging as a result of offshore payments for local assets
Treatment of HVDC interconnection	Uncertainty about resulting charges High charges for northern generators Integration of DC connection to AC load flow models
Charging for generation on islands remote from demand[2]	High charges for island generation compared to other generators Reduction in charges for other generators as a result of island payments for local assets
Inconsistent treatment of DG compared to transmission-connected generation	Under existing arrangements, generation can avoid transmission charging by connecting to the distribution network Proposal to impose generator TNUoS charges on all DG above 30kW Differential treatment of generation connected to 132kV between Scotland, and England and Wales
Consistency with interconnector imports	Interconnectors do not pay transmission entry charges (e.g. generator TNUoS)
International parity[3]	Need for compatibility with European models for electricity transmission charging to facilitate market integration
Charging for storage and peaking plant	Capacity-based charges disincentive investment in low load factor plants Storage pays TNUoS for imports as well as exports
Impact of SQSS on charges	Linking charging methodology to SQSS can introduce additional uncertainty in charges
Development of coordinated offshore grid	Disincentive for radial connections that do not follow shortest route to onshore grid Differential treatment of offshore wind and interconnectors

Source: RenewableUK

2 On the basis of the proposed charging arrangements put forward by National Grid in the March 2010 TCMF.

3 A full comparison of international transmission charging regimes would need to consider a range of factors beyond ongoing charges, such as the depth of connection charges.

Development of list of options

We developed a total of 18 options for changes to the current transmission charging arrangements in GB. These options were characterised by their impact on different elements of the transmission charge (pre-connection user commitment, infrastructure, operational). They covered changes to the following aspects of transmission charging:

- definition of what can count as pre-connection 'user commitment';
- extent of the recovery of asset costs through local generation charges;
- strength of locational signals for generation and demand;
- timing of locational signals (i.e. in annual charges or in short-term charges);
- ability to fix charges for more than one year;
- determination of charging unit – i.e. TEC, 'adjusted TEC', or energy-based;
- share of charges recovered from generation, both in terms of level (currently set at 27%) and what is included in share (e.g. payments for local assets); and
- absolute level of generator transmission charges (i.e. do generators pay transmission charges; do some types of generators get a technology-based charge).

In developing this longlist of options, we assumed that:

- 'invest and connect' arrangements are excluded from scope;
- shallow connection charges are retained;
- all charging arrangements are assumed to apply equally to current and future generation;
- the options should not directly change the mechanisms for determining allowed revenue for the network operators; and
- changes to the licence obligation on National Grid to socialise congestion charge would be within the scope of a review of **transmission charging arrangements,** such as Project TransmiT.

Based on a high-level review of how each option addressed the stresses identified by RenewableUK, we carried out further assessment on a shortlist of 10 options, as summarised in Table 2. This shortlist is also designed to be representative of the main debates about transmission charging arrangements (share paid by generation, strength and timing of locational signals, capacity or energy based charging, differential treatment for different generators or different types of assets).

Table 2 – Overview of shortlisted options

Option number	Option title	Philosophy of option
1	'Removal of local TNUoS charges'	Remove impact of local asset costs from generation development decision
2	'Postage stamp capacity (TNUoS) charges'	Remove all geographic signals (beyond connection charge) to facilitate connection of generation across GB
6	'Nodal congestion charges'	Shift geographical signal from long-term to short-term and from zones to nodes
7	'Zonal congestion charges with FTRs'	Shift geographical signal from long-term to short-term whilst offering hedging opportunity through FTRs
8	'Nodal congestion charges with FTRs'	Shift geographical signal from long-term to short-term and from zones to nodes, whilst offering hedging opportunity through FTRs
9	'Facilitate generation connection with locational signals'	Support connection of generation whilst retaining existing cost signals
10	'Change allocation of assets to residual TNUoS'	Socialise cost of transmission assets defined as being in national interest (e,g offshore, HVDC, islands)
11	'TEC adjusted for technology and location'	Use charging rules to reflect impact of different generation technologies on the network at different locations
13	'Energy-based locational TNUoS charges'	Support development of generation with low load factors
16	'No TNUoS or BSUoS charges for generation'	Move towards consistency with interconnector exports, and many other European markets

Assessment

Table 3 summarises the results of our assessment of how each option would impact the stresses in the current charging arrangements identified by RenewableUK.

For each option, we also considered:

- the impact on different industry parties (e.g. generators and network operators);
- performance against objectives for transmission charging arrangements (defined as being affordability, delivery of environmental targets, security of supply, and compliance with other obligations); and
- how it could be combined with other options as part of an overall solution for transmission charging arrangements.

Table 3 – Summary of impact of option on stresses

	Option									
Stress	**1**	**2**	**6**	**7**	**8**	**9**	**10**	**11**	**13**	**16**
(Pre-connection) user commitment	✓/×	✓/×	✓/×	✓/×	✓/×	✓✓	✓/×	✓/×	✓/×	✓
Charging for offshore generation	✓✓	✓✓	✓	✓	✓	-	✓✓	✓	✓	✓✓
Treatment of HVDC interconnections	-	✓✓	✓✓	✓✓	✓✓	-	✓✓	-	-	✓✓
Charging for generation on islands remote from demand	✓✓	✓✓	✓/×	✓/×	✓/×	-	✓✓	✓	-	✓✓
Consistency of treatment for DG	-	-	-	-	-	-		✓✓	-	
Consistency with interconnector imports	✓	✓	✓	✓	✓	-	✓	-	-	✓✓
International parity	✓	✓	×	✓✓	✓/×	✓✓	-	-	-	✓✓
Storage and peaking plant	×	×	✓✓	✓✓	✓✓	-	×	✓✓	✓✓	✓✓
Impact of SQSS on charges	-	✓✓	✓✓	✓✓	✓✓	✓	-	×	✓✓	✓✓
Development of coordinated offshore grid	-	✓	✓	✓	✓	-	✓✓	-	✓	✓✓

Observations

In this section, we explore some of the key themes emerging from our analysis, which are:

- importance of trade-offs in determining possible models for transmission charging arrangements;
- grouping of the options;
- impact on offshore wind development, as that is expected to be key to meeting renewables targets in 2020, and possibly beyond);
- impact on distributed generation (DG), which accounts for a significant proportion of existing renewable resource; and
- interaction with developments in Europe, which will help to determine robustness of arrangements to a move to more integrated European electricity markets.

We do not make any recommendation in relation to which options should be taken forward as that was expressly excluded from the scope of this report

Importance of trade-offs

Our set of shortlisted options (as required by the project scope) in general perform strongly against the stresses identified by Renewable UK[4]. However, our shortlist of options also highlights the importance of a number of trade-offs in developing a sustainable solution for transmission charging arrangements:

- **trade-off between stresses –** e.g. increasing the scope of costs recovered through the residual exacerbates the stress on peaking generation and storage by increasing its residual charge;
- **trade-off between performance against stresses and performance against objectives** – the performance against charging objectives will be key for policymakers in developing their preferred options for change;
- **trade-off between policy objectives** – the weighting placed on different objectives will be very important in determining the preferred policy options; and
- **trade-off between short-term and long-term effects** – some options would require a longer transition period to the new charging arrangements, which could slow progress towards the renewable target for 2020.

[4] ‘Response to Project TransmiT Call for Evidence’, RenewableUK and Scottish Renewables, November 2010.

Grouping of options

We can characterise our options into three groupings:

- **Removal or weakening of geographical and/or capacity-based signals in long-term transmission charges for all generators (Options 1, 2, 13 and 16**) – these options support progress towards environmental targets but at the expense of relatively poor performance against the objective of system affordability, although this is dependent on the trade-off between increased transmission costs and greater access to low-cost generation.
- **Introduction of targeted congestion charges to shift geographical signal from long-term to short-term (Options 6, 7 and 8)** – perhaps surprisingly, they also address many of the RenewableUK stresses by not using network load flow modelling to calculate long-term charges. However, the impact of these options are uncertain (without much more detailed quantitative analysis) making it hard for market players to understand the relative costs and benefits of each of the three options.
- **Evolutionary changes (Options 9, 10 and 11)** – these tend to score well across the objectives and are able to be combined with many of the other options. However, there are question marks about robustness of Options 10 and 11 in the long-term, and the extent to which Option 9 addresses the stresses identified by RenewableUK.

Impact on offshore wind

RenewableUK identified two stresses in relation to offshore wind, which is expected to play a very important role in delivering long-term increases in renewable generation. These stresses relate to the application of local charges to offshore wind farms (which are high and which significantly reduce the residual charge paid by all generators), and the development of a coordinated offshore grid.

Almost all of the options address the offshore wind charging stress in one form or another but differ in their expected impact on offshore wind:

- options that remove local charges from offshore wind farms (Options 1, 2,10 and 16) directly address the charging stress and have a strongly positive impact for offshore wind;
- options that change the charging basis can provide some benefits to offshore wind – either through adjusted TEC (Option 11), or through energy-based TNUoS charges (Option 13);
- three options (Options 6, 7 and 8) address the offshore wind charging stress by abolishing the local generation charge but it is unclear what the impact will be on offshore wind, particularly in the long-term; and
- Option 9 does not change the treatment of local assets but is still judged to be positive for offshore wind because of the fall in charges for all generators under this option.

Impact on distributed generation

Distributed generation (DG) currently accounts for a significant proportion of renewable generation in GB. There is an inconsistency in the current and proposed application of generator TNUoS to DG (because it does not reflect the impact of the DG on the transmission network). At the moment, DG does not pay generator TNUoS charges but can benefit from avoided demand TNUoS charges (depending on their output during Triad periods).

With respect to DG, the options can be grouped as follows:

- **opportunity to resolve inconsistency in transmission charging (Option 11)** by adjusting TEC to reflect impact of DG on transmission networks;
- **improvement from status quo (Options 9 and 16)** because increased share of charges paid by demand as a result of reduced generator charges;
- **impact depends on location of DG, operating pattern of DG and/or TNUoS arrangements for DG (Options 2 and 13)**;
- **impact depends on detailed implementation of option (Options 6, 7 and 8)**, also affected by whether or not DG is located beyond significant congestion constraints; and
- **impact depends on how TNUoS charges are implemented for DG (Options 1 and 10)**, if generator TNUoS charges are levied on DG, then DG would pay higher charges under these options than status quo.

Consistency with Europe

The development of transmission charging arrangements in GB needs to take into account the desire to move towards a more integrated European electricity market. Therefore, options that are more compatible with transmission charging arrangements in other European countries and/or European guidelines may be more robust as integration deepens. This would favour options that:

- **set long-term generation charges to zero** (as in Belgium, the Netherlands and Germany), as is done by Option 16 (absolute) and Option 9 (average charges); and/or
- **introduce congestion-based locational charges** (such as Options 6,7 and 8), with Option 7 being most in line with the approach to locational transmission charges in the draft Framework Guidelines on congestion management and capacity allocation.

Summary

In this report, we have developed and assessed a representative range of options for changes to transmission charging arrangements to address the stresses identified by RenewableUK. This has highlighted the trade-offs that will need to be considered in policy development, and some of the key issues emerging from our analysis.

In particular, our analysis demonstrates that different options have contrasting merits depending on relative priorities given to different charging objectives and perceived stresses in current GB charging arrangements. Therefore a given stakeholder's deemed priorities (or commercial position) will naturally select/highlight one or a small subset of compatible options for detailed design and implementation. We highlight that within each of our identified potential options there are various detailed design variants which can subtly influence impact on different market participants.

We anticipate that any Ofgem decision on its preferred option for change will need to be supported by a detailed quantitative impact assessment. We have qualitatively highlighted likely impacts on participants at a high level. However, for some options in particular (and their design variants) detailed modelling is necessary to fully understand the implications for all market participants and to contribute to any such impact assessment by Ofgem. This is analysis we could conduct as the TransmiT process moves towards identifying a detailed transmission charging option for implementation.

1. INTRODUCTION

1.1 Background

Ofgem launched Project TransmiT ('TransmiT') on 22 September 2010. TransmiT is intended to be a comprehensive and open review of the charging regime and connection arrangements linked to electricity and gas transmission networks. The outcome of TransmiT can fundamentally revise the arrangements for transmission charging.

Objectives relating to decarbonisation are at the heart of the review. This is driven by legally binding targets that the UK has for carbon emissions reductions and for the deployment of renewable energy sources (to 2020 and possibly beyond).

Against this backdrop, 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.

1.2 Purpose of this report

In this context, RenewableUK commissioned Pöyry Management Consulting (UK) ("Pöyry") to produce an independent public report to examine options for changes to the transmission charging arrangements in Great Britain. RenewableUK expressly excluded from the scope of this report the provision of a recommendation for a preferred policy option.

This report sets out a list of 18 options for change. It then presents a detailed assessment of a selected shortlist of 10 options, in particular considering the impact of each option on the stresses in the current transmission charging arrangements identified by RenewableUK and Scottish Renewables[5].

For each option, we also:

- describe the impact on different industry parties;
- evaluate the performance against a set of charging objectives; and
- consider the extent to which it can be combined with other shortlisted options.

This report provides our **independent** assessment of potential charging options. It has not been developed to propose or support a particular pre-identified option or preferred option of RenewableUK.

1.3 Conventions

Unless otherwise attributed, the source for all tables, figures and charts is Pöyry Management Consulting.

5 'Response to Project TransmiT Call for Evidence', RenewableUK and Scottish Renewables, November 2010..

1.4 Structure of this report

The structure of this paper is as follows:

- Chapter 2 provides the context for this report, in terms of structure, scope and the drivers for change from the current arrangements identified by RenewableUK and Scottish Renewables;
- Chapter 3 describes options for changes to electricity transmission charging arrangements;
- Chapter 4 assesses a selected shortlist of options against the following:
  - effect on stresses in current transmission charging arrangements identified by RenewableUK and Scottish Renewables;
  - impact on electricity industry parties;
  - performance against objectives of electricity transmission charging arrangements;
  - ability to be combined with other shortlisted options;
- Chapter 5 summarises the performance of each option; and
- Chapter 6 sets out some observations on the implications of the analysis in this report for the options being considered under TransmiT.

The Annexes provide more detailed supporting material on the description of the options (Annex A), the assessment of the options (Annex B) and the compatibility of different options (Annex C).

1.5 RenewableUK

RenewableUK is the trade and professional body for the UK wind and marine renewables industries. Formed in 1978 as the British Wind Energy Association (BWEA), and now with around 650 corporate members, RenewableUK is the leading renewable energy trade association in the UK. In 2004, RenewableUK expanded its wind mission to champion wave and tidal energy and use the Association's experience to guide these technologies along the path to commercialisation.

RenewableUK's primary purpose is to promote the use of wind, wave and tidal power in and around the UK. It acts as a central point for information for the membership and as a lobbying group to promote wind energy and marine renewables to government, industry, the media and the public. RenewableUK researches and develops solutions to current issues and acts as the forum for the UK wind, wave and tidal industry.

2. OVERVIEW OF CURRENT ARRANGEMENTS

2.1 Context

Ofgem launched Project TransmiT ('TransmiT') on 22 September 2010[6]. 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 electricity transmission charging and associated connection issues, such as (pre-connection) user commitment.

2.1.1 Overview of current transmission charging arrangements

The current transmission arrangements are detailed in Table 4 below, according to the design of each element of the transmission charge (pre-connection user commitment, connection infrastructure, operational). This provides a benchmark for the presentation (in Chapter 3 and Annex A) of each option for change.

There is also an ongoing user commitment with the required notice period of 1 year (and 5 days) for existing generators who want to give up their TEC so that they are no longer liable for TNUoS charges. Changes to these arrangements have not been considered in the design of the options as they were not identified by RenewableUK as a source of stress in the current arrangements.

6 'Project TransmiT: A Call for Evidence'. Ofgem, September 2010.

Table 4 – Description of status quo

Charge	Key elements of each charge	Status quo for generation	Status quo for demand
Pre-connection charge	**What is form of (refundable) pre-connection 'user commitment'?**	**Financial user commitment** designed to discourage 'speculative' development	
Connection charges	**What costs are charges designed to recover?**	**Provision and maintenance of connection asset** assets that solely facilitate connection of individual users to the National Electricity Transmission System (NETS),	**Provision and maintenance of connection assets** assets that solely facilitate connection of individual users to the National Electricity Transmission System (NETS),
	When are charges paid?	**Mixture of upfront and ongoing charges**	**Mixture of upfront and ongoing charges**
	What signals do connection charges provide to network users?	**Shallow charges** calculated on basis of cost of providing and operating assets specific to individual user	**Shallow charges** calculated on basis of cost of providing and operating assets specific to individual user
Infrastructure charges	**What costs are charges designed to recover?**	**Provision and maintenance of all infrastructure assets** Local and shared assets that facilitate access to the NETS,	**Provision and maintenance of all infrastructure assets** Assets that facilitate access to the NETS
	How often are TNUoS charges reset?	**Annually (ex-ante)**	**Annually (ex-ante)**
	How are total infrastructure charges split between different user types?	**G= 27%** residual charges ensure that Generation pays for 27% of costs of infrastructure assets[7]	**D=73%** residual charges ensure that Demand pays for 73% of costs of infrastructure assets
	How are local assets defined for calculation of local8 TNUoS charge?	**Current definition of local assets for generation** ex-ante annual charge represents the cost of the first transmission substation + (where applicable) the cost of link between local substation and nearest MITS substation	**No local charge for demand** Because no local TNUoS charge for demand
	How is the locational TNUoS charge calculated?	**Zonal generation TNUoS charges (+/-£1/kW)** Nodal charges averaged over zone, where zone defined such that all nodes in zone are within a nodal cost range of +/-£1kW	**(Non-negative) zonal demand TNUoS charges (+/-£1/kW)** Nodal charges averaged over zone, where zone defined such that all nodes in zone are within a nodal cost range of +/-£1kW, with no negative demand tariffs
	How is the TNUoS charge differentiated by generation technology?	**No generation technology differentiation in TNUoS charge**	**n/a**
	On what basis are TNUoS charges levied?	**TNUoS charge paid per kW of (peak) TEC (in year)**	**TNUoS charge paid per Triad kW for large demand and per kWh of annual energy consumption for small demand**
Operational charges	**How do users pay for network constraints between zones?**	**All inter-zonal network constraints paid for through BSUoS charges**	**All inter-zonal network constraints paid for through BSUoS charges**
	How do users pay for network constraints within zones	**All intra-zonal network constraints paid for through BSUoS charges**	**All intra-zonal network constraints paid for through BSUoS charges**
	How do users pay for system operation costs?	**All system operation costs recovered through BSUoS charges**	**All system operation costs recovered through BSUoS charges**
	How often are BSUoS charges reset?	**Half hourly (ex-post)**	**Half hourly (ex-post)**
	How are BSUoS charges allocated between different user types?	**G= 50% (**Generation pays 50% of costs)	**D= 50% (**Demand pays 50% of costs)
	How is the locational charge calculated for BSUoS charges?	**Non-locational BSUoS**	**Non-locational BSUoS**
	How is the BSUoS charge differentiated by generation technology?	**No technology differentiation in BSUoS charge**	**n/a**
	On what basis are BSUoS charges levied?	**Charge paid per kWh of metered volume in half-hour**	**Charge paid per kWh of metered volume in half-hour**

7 The cost of local assets (for generation) has already been completely recovered from local TNUoS charges on generation. Therefore, as the value of local generation assets increases relative to total infrastructure assets (as with connection of lots of offshore wind), the residual charge paid by all generators is reduced to make sure that generators only pay 27% of the total cost of local and shared infrastructure assets.

8 The technical annex to the Call for Evidence for TransmiT defines 'local assets' as 'the infrastructure assets that are local to the generator as opposed to the assets in the deeper transmission infrastructure known as the main interconnected transmission system ('MITS).

2.1.2 Key drivers for Project TransmiT

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. This is reflected in changes to Ofgem's objectives to take explicit account of greenhouse gas reductions and security of supply.

In addition, the Renewable Energy Directive[9] has set the UK a target of delivering 15% of energy from renewable sources by 2020. In its National Renewable Energy Action Plan[10], the UK has stated that it expects around 30% of its electricity to be generated from renewables, up from just below 10% in 2010.

Discussions have already started about longer-term renewables targets. The Committee on Climate Change will publish its renewable review in May 2011, helping to inform the debate about the long-term targets for renewables in the UK. In early May 2011, Connie Hedegaard, the EU climate commissioner, noted that extending renewables targets out to 2030 would help to send a clear long-term signal of the need for continued renewable investment.

Low carbon generation technologies, either renewables (mainly wind), CCS and/or nuclear, must play an ever increasing role in the energy mix if renewable and carbon reduction targets are to be met. Onshore wind tends to be in (electrically) remote regions far from major centres of demand, off-shore wind can require significant network infrastructure to connect and integrate potentially large clusters to the core GB transmission network, and any new nuclear plants are likely to be larger than existing plants and in relatively remote locations.

Therefore, considerable investment in electricity transmission infrastructure is required to support the delivery of low carbon generation. Ofgem's RIIO decision paper[11] suggests that network companies will need to invest an additional £32bn by 2020 to deliver the required network infrastructure.

The government's stated energy policy objective is to achieve a secure, affordable and low carbon energy mix. Therefore, 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.

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9 'DIRECTIVE 2009/28/EC of the European Parliament and of the council of 23 April 2009 on the promotion of the use of energy from renewable sources', Official Journal of the European Union, June 2009.

10 'National Renewable Energy Action Plan for the United Kingdom. Article 4 of the Renewable Energy Directive 2009/28/EC', DECC, July 2010.

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

Increased deployment of intermittent[12] generation will place stress on the current charging arrangements, which are based on the premise that generation will require a stable level of firm capacity at all times. A parallel can be drawn with the developments in the technical system requirements, as set out in the SQSS, to reflect the operation of intermittent forms of generation.

The projected 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, in particular in relation to the following areas:

- objectives of transmission charging arrangements,
- scope of transmission charges; and
- evolution of transmission charges over time.

2.2 Stresses in current transmission charging arrangements

In response to Ofgem's call for evidence on Project TransmiT[13], RenewableUK identified a number of stresses in the current transmission charging arrangements in Great Britain (with a focus on the impacts on wind, wave and tidal generation).

These included:

- **level of financial (pre-connection) user commitment;**
  - acting as a disincentive to development of generation, thereby reducing competition;
  - creating an imbalance between the user commitment required from prospective entrants into the generation sector and the ongoing commitment required after commissioning;
- **charging for offshore generation;**
  - the high costs of transmission charges for offshore generators relative to other generators;
  - the reduction in onshore charging that results from the impact of offshore payments for local assets on the residual pot[14];
- **treatment of HVDC interconnections;**
  - uncertainty about resulting charges;
  - high charges for northern generators;
  - integration of DC connection to AC load flow model;

12 'Intermittent' is the term generally used by the industry, Ofgem and DECC to denote forms of renewable generation, such as wind and solar, seeking to indicate they are not controllable in the conventional sense, i.e. they are essentially dependent on weather. Whilst Poyry recognises that many wind farm developers are not comfortable with this description, it is widely understood and used, including by Poyry in other publications. Therefore, we have retained this term to collectively describe wind generation in the context of this report.

13 'Response to Project TransmiT Call for Evidence', RenewableUK and Scottish Renewables, November 2010.

14 The issue is about the extent to which connection of offshore generation results in a fall in (£/MW) charges for onshore generation beyond what would be expected from an increase in total generation capacity connected to the transmission network.

- **charging for generation on islands remote from demand[15];**
  - the high costs of transmission charges for these generators relative to other generators;
  - the reduction in charging for other generators that results from the impact on the residual pot of payments from island generation for local assets;
- **inconsistency of treatment of distributed generation (DG) compared to transmission-connected generation;**
  - under existing arrangements, some DG can escape transmission charging by embedding[16] even though it might export onto the transmission network, which can be inequitable with transmission connected generators;
  - under NGET proposals, generator TNUoS charges would be imposed on all DG above 30kW (adding a cost of about £20/kWannum);
  - generation connected to 132kV in Scotland has a discount on TNUoS charges due to the difference in treatment of 132kV between Scotland and England and Wales, which creates an ongoing risk of review;
- **consistency with interconnector imports;**
  - interconnectors don't pay transmission entry charges i.e. generation TNUoS;
- **international parity[17];**
  - transmission charging rules need to be compatible with European models to create a level playing field to facilitate market integration;
- **charging for storage and peaking plant;**
  - current capacity-based arrangements favour high load-factor plant because low-load factor peaking plant and storage can pay high levels of TNUoS even if it doesn't use transmission at peak times of transmission use (e.g. located alongside wind and providing system flexibility during times of low wind);
  - storage plant pays TNUoS for imports as well as exports;
- **impact of SQSS on charges;**
  - if chargeable capacity for generation is linked directly to SQSS mechanisms, then subsequent changes to SQSS could feed through into material changes into charges[18]; without limited (if any) consultation on changes to the charging methodology;

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15 This stress was identified on the basis of the proposed charging arrangements put forward by National Grid (in the March 2010 TCMF), as discussed in the RenewableUK response to the TransmiT Call for Evidence. Therefore, for the purposes of this report, these proposed charging arrangements are assumed to form part of the status quo.

16 Under these arrangements, the DG benefits from avoided demand TNUoS. The magnitude of these benefits will be determined by the extent to which DG operates in Triad periods (determined by periods of peak demand on transmission network). High output from distribution-connected wind could reduce demand on transmission network making it less likely that wind could capture the Triad benefits.

17 A full comparison of international transmission charging regimes would need to consider a range of additional factors, such as the depth of connection charges. However, there is no standard model across Europe with some countries (including Netherlands and Germany) having zero generator charges and shallow connection charges (according to ENTSO-E).

18 Even if these changes are consulted upon, it increases the possibility for change (and hence uncertainty) in the level of charges faced by a generator.

- **development of a coordinated offshore grid;**
  - TNUoS charges could discourage radial connections which do not follow the shortest route to the onshore grid; and
  - TNUoS charges differentiate between offshore windfarm and interconnectors.

2.3 Key assumptions and impact on options considered

The range of options considered in this report reflects the scope of Project TransmiT. This means we have assumed that:

- 'invest and connect' arrangements are excluded from scope – i.e. there will be **no changes to the transmission access arrangements –** this is with consistent with the letter from the Secretary of State to Ofgem stating that the review should not reopen 'areas that have been resolved by the Connect and Manage regime' [19]**;**
- shallow charges are retained – i.e. there will be **no changes to the depth of connection charges;**
- **all charging arrangements are assumed to apply equally to current and future generation**[20], which rules out any options that are specifically designed to provide favourable treatment for existing generation[21] (e.g. by exempting them from locational charges, or allowing them to fix charges but not giving that option to new generators); and
- the options **should not directly change the mechanisms for determining allowed revenue for the network operators**, as this will be considered by the RIIO process. This includes the process for allowing 'investment' made by the network operators.[22]

This set of assumptions rules out a number of the options put forward in the academic papers published in relation to TransmiT, including:

- a full locational marginal pricing (LMP) model with **deep** connection charging (Newbery[23]); and
- a shift away from 'connect and manage' to a 'generation follows transmission' system based **entirely** on anticipatory investment by the TO (as proposed by Baldick, Bushnell, Hobbs and Wolak [24]).

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19 Letter from the Secretary of State for Energy and Climate Change (Chris Huhne) to Chairman of Ofgem (Lord Mogg) on 7 August 2010.

20 Some options will be more beneficial for some types of generation that may be more extensively developed in the future than others (e.g. offshore wind rather than hydro). However, this is different from actively discriminating between generation, purely on the basis of whether or not it is existing at present.

21 This would not necessarily rule out grandfathering arrangements introduced as part of a transition to a new set of charging arrangements.

22 However, we note that if revisions to the transmission charging arrangements are deemed to weaken the efficiency of signals for transmission investments, then Ofgem could introduce new mechanisms to check whether the costs of such investments can be included in allowed revenue that is recovered from customers.

23 'High level principles for guiding GB transmission charging and some of the practical problems of transition to an enduring regime', David Newbery (EPRG, University of Cambridge), revised 15 February 2011.

24 'Optimal Charging Arrangements for Energy Transmission: Draft Final Report', Baldick, Bushnell, Hobbs and Wolack, 17 February 2011.

We also ruled out options that were specifically designed to increase the share of transmission charges paid by generation. This is not an option that has been put forward in any of the documents issued in relation to Project TransmiT, and would be not consistent with a move to greater harmonisation of transmission charges across Europe. The association of European TSOs (ENTSO-E) suggest that Great Britain is already the market with the highest share of transmission costs borne by generation[25].

We also note the interaction between TransmiT and the ongoing Energy Market Reform process being led by DECC , particularly in reference to any introduction of 'locational marginal pricing' (LMP) and in the overall support framework for low-carbon generation. Locational short-run congestion charges could be introduced without locationally-varying energy prices, e.g. through a national energy price with locational short-run network charges.

National Grid currently has a licence obligation to socialise congestion costs, which is consistent with the views expressed by DECC on locational BSUoS as part of the transmission access review. However, we believe that review of this licence obligation would fall within the scope of Project TransmiT, as it is a review of all aspects of transmission charging. For example, our options cover potential changes to pre-connection user commitment, local charges, locational (or zonal) charges, basis for charges (capacity or energy).

Therefore, we hence have considered options that could require the development of locational charges for at least some of the elements currently recovered through BSUoS charges. This is supported by our interpretation of the letter from the Secretary of State to Ofgem[26], which states that TransmiT should only consider areas of direct relevance to the charging regime. This would seem to include all elements of the charging regime, such as BSUoS.

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25 'ENTSO-E Overview of Transmission tariffs in Europe: Synthesis 2010', ENTSO-E, 2010.

26 Letter from the Secretary of State for Energy and Climate Change (Chris Huhne) to Chairman of Ofgem (Lord Mogg) on 7 August 2010.

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3. OPTIONS FOR CHANGE

This chapter describes the full set of options that we developed for changes to transmission charges, consistent with the key assumptions detailed in Section 2.3. It then sets out the shortlist of 10 options taken forward for assessment, based on a high-level review of the extent to which the option would be expected to directly address the stresses in current charging arrangements identified by RenewableUK. The shortlist of assessed options is also intended to provide a representative sample of different types of realistic options.

3.1 Description of options

We have developed options that are designed to address the stresses and pick up the themes identified in the response by RenewableUK to the Call for Evidence[27]. We have also reflected the options put forward in other relevant material on TransmiT, particularly the academic studies commissioned by Ofgem, international reviews by Pöyry and CEPA of transmission charging methodologies.

For ease of presentation, we have separated the options for change into two tables, based on whether the option is focused on changing locational signals for all generators (Table 5) or encouraging investment in (some types and/or location of) generation (Table 6).

These tables summarise each option in terms of:

- **guiding philosophy** – each option is designed around a particular theme, which means that some of them can be combined, as discussed further in paragraph 4.3;
- **the main changes from the status quo** – described in relation to each type of transmission charge, with most options in general focused around changes to the infrastructure (or TNUoS) charge; and
- **possible design variants**, which would not affect the guiding philosophy of the option but illustrates the range of possible combinations whilst keeping the options list to a manageable number.

Annex A contains a more detailed description of these options.

All of our options share the following charging elements:

- connection charge arrangements remain as per the status quo – shallow connection charges are used to recover costs of provision and maintenance of connection assets;
- no option contains **local** TNUoS charges for demand[28]; and
- all system operation costs (excluding network constraints) are always paid for through BSUoS charges, which are ex-post, non-locational and are paid based on metered volumes in each half hour.

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27 ‘Response to Project TransmiT Call for Evidence’, RenewableUK and Scottish Renewables, November 2010.

28 Under current charging arrangements, generators pay a local charge relating to the cost of the first transmission substation + (where applicable) the cost of link between local substation and nearest substation on the main interconnected transmission system (MITS).

We have not considered changes to the rules for the calculation of the level (as opposed to the form) of user commitment, either pre-connection or ongoing. Where options lead to changes in the infrastructure (or TNUoS) charge, this could impact on levels of user commitment where it is linked to expected TNUoS charges.

Options 6, 7 and 8 are based around the introduction of short-term locational signals. They raise the following questions for implementation, which are outside the scope of this report which is designed to present a range of high-level options for change to charging arrangements:

- Are signals provided through local wholesale markets (an LMP approach) or through a proxy set of charges based on current market structures (e.g. bids and offers in balancing mechanism)?
- What changes would be required to wholesale market rules?
- What would be the impact on transmission access rights and constraint payments?
- Is the FTR is an obligation (whereby the holder has to pay the congestion charges if the flow is in the wrong direction compared to its FTR holding) or an option (where the holder only receives the congestion charges and is never liable for it)?
- How would any long-term financial transmission rights (FTRs) be allocated? (e.g. grandfathering or auctions)
- How would any long-term financial transmission rights (FTRs) be priced? (e.g. administered prices or auction results).

During a transition period, use of administered prices may be useful given difficulties for participants to price FTRs at their right value at least during the first years (as pointed out by Bell et al.). However, it may not be sustainable to maintain administered pricing (based for example on current TNUoS charges) as there is likely to be a disconnect between the price of the FTR and its value (in terms of an expected stream of congestion payments).

Table 5 – Description of each option for changing locational signals for all generators

Item	Transmission charge component	Option 1 – 'Removal of local TNUoS charges'	Option 1a – 'Removal of local TNUoS charges from G:D split'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 3 – 'Caps on zonal differentials'	Option 4 – 'Sharpening locational signals'	Option 5 – 'Nodal TNUoS charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'
Philosophy of option		Remove impact of local asset costs from generation development decision	Remove impact of local asset charges on residual charges paid by other generators	Remove all geographic signals (beyond connection charge) to facilitate connection of generation across GB	Cap the strength of the locational signal to reduce costs of developing generation in areas most remote from demand centres	Change the basis for incremental cost calculation to strengthen locational signals, to encourage more efficient siting decisions	Increases the geographical targetting of locational signals	Shift geographical signal from long-term to short-term and link it to nodes not zones	Shift geographical signal from long-term to short-term whilst offering hedging opportunity through FTRs	Shift geographical signal from long-term to short-term and link it to nodes not zones whilst offering hedging opportunity through FTRs
Main changes from status quo	**pre-connection charge**	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo
	connection charge	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo
	infrastructure charge	**No local TNUoS charges for generation**	**Calculation of residual (to have generation paying 27% of charges) does not take into account payments for local assets**	**No local TNUoS charges for generation** **No locational TNUoS charges for generation or demand**	**Less differentiated zonal TNUoS charges for generation and demand**	**More differentiated zonal TNUoS charges for generation and demand**	**Nodal TNUoS charges for generation and demand**	**Charges recover cost of infrastructure assets net of congestion rents** **No local TNUoS charges for generation;** **No locational TNUoS charges for generation or demand**	**Charges recover cost of infrastructure assets net of congestion rents** **No local TNUoS charges for generation** **No locational TNUoS charges for generation or demand**	**Charges recover cost of infrastructure assets net of congestion rents** **No local TNUoS charges for generation** **No locational TNUoS charges for generation or demand**
	operational charges	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	**Nodal energy-based congestion charges**	**Zonal energy-based congestion charges with FTRs**	**Nodal energy-based congestion charges with FTRs**
Possible design variants	**pre-connection charge**									
	connection charge									
	infrastructure charge	Cost of local assets included in zonal charges rather than residual		Retain locational signals for demand or generation only	Include local charges when capping spread of charges			Retention of local and/or zonal charges to provide some long-term locational signal	Retention of local and/or zonal charges to provide some long-term locational signal	Retention of local and/or zonal charges to provide some long-term signal
	operational charges							Zonal congestion charges	Remove opportunity for hedging provided by FTR	

Table 6 – Description of each option for encouraging investment in (some types and/or location of) generation

Item	Transmission charge component	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 12 – 'Dynamic calculation of TEC'	Option 13 – 'Energy-based locational TNUoS charges'	Option 14 – 'Energy-based postage stamp charges with local asset charges'	Option 15 – 'No TNUoS charges for generation'	Option 16– 'No TNUoS or BSUoS charges for generation'	Option 17 – 'Technology-differentiated TNUoS charges'
Philosophy of option		Support connection of generation whilst retaining existing cost signals	Socialise cost of transmission assets defined as being in national interest (e.g offshore, HVDC, islands)	Use charging rules to reflect impact of different generation technologies on the network at different locations	Fees paid by network users more closely reflect the impact they have on the system	Support development of generation with low load factors	Support development of generation with low load factors and/or in areas remote from demand, whilst retaining some geographical signal	Move towards consistency with interconnector exports, and many other European markets	Move towards consistency with interconnector exports, and many other European markets	Support development of low-carbon generation
Main changes from status quo	**pre-connection charge**	**Sunk costs count as user commitment'**	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo
	connection charge	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo
	infrastructure charge	**G=0%, D=100%** **Option for multi-year (ex-ante) fixed charges**	**Exemption of offshore and island assets from local generation TNUoS charges** **HVDC link assets included in residual not in locational charging calculation**	**Generation TNUoS charge levied per kW of 'adjusted TEC' which is linked directly to the SQSS arrangements; (taking into account technology and location)**	**Generation TNUoS charge levied per kW of 'adjusted TEC'; (based on modelled impact of plant on network)** **Large demand TNUoS charge levied per kW (based on modelled impact on network)**	**TNUoS charges for generation and demand paid per kWh of metered volume**	**TNUoS charges for generation and demand paid per kWh of metered volume** **No local TNUoS charges for generation or demand** **Retention of local charges for generation**	**G=0%, D=100%** **No TNUoS charges for generation**	**G=0%, D=100%** **No TNUoS charges for generation**	**Discount on TNUoS charges for low-carbon generation**
	operational charges	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	As per status quo	**G=0%, D=100%** **No BSUoS charges for generation**	As per status quo
Possible design variants	**pre-connection charge**									
	connection charge									
	infrastructure charge	Fixing elements of TNUoS charge not whole charge Length of period for fixing; Size of discount for fixing	Narrowing or broadening definition of assets 'deemed to be in the national interest' and hence recovered through residual	Increase scope and sophistication of rules for adjusting TEC Extend rules to demand	Changes to the specification of model used to determine requirements placed on network	Recover charges on a postage stamp basis	Retain locational signals for demand or generation only	Retain zonal charges for demand	Retain zonal charges for demand	Size of discount; Definition of technologies qualifying for discount – renewable only, 'flexible'
	operational charges									Discount on BSUoS charges for low-carbon generation

3.2 Selected options for assessment

We carried out a detailed assessment of 10 shortlisted options in the second stage of the project. These 10 options are designed to be representative of the main debates about transmission charging arrangements (share paid by generation, strength and timing of locational signals, capacity or energy based charging, differential treatment for different generators or different types of assets). They also each address one or more of the stresses identified by RenewableUK.

The shortlisted options are described in turn below, with:

- an overview of the key features of the option;
- a discussion of the Renewable UK stresses that they are targeted at (with Chapter 4 containing an assessment of actual performance against the stress); and
- a summary of how they compare and contrast with other options.

Option 1 – Removal of local TNUoS charges

This option recovers the cost of local assets through the residual (rather than local) charge.

By removing local charges, it directly addresses the stresses for offshore and island generation identified in the Renewable UK response to Call for Evidence, but does so rather bluntly.

The option provides a useful comparator to Option 10 (a more targeted change to the definition of local assets), which we are also putting forward for assessment.

Option 2 – Postage stamp capacity (TNUoS) charges[29]

This option removes the local and locational element to TNUoS charges for generation and demand.

By eliminating the link between assets and TNUoS charges, this option directly addresses the stresses related to offshore wind, HVDC links, island generation and SQSS (by removing the opportunity for changes in network modelling and rules to feed through into charges).

The assessment of this option will also provide insight into other options which would change the strength of locational signals, such as weakening (Option 3), strengthening (Option 4) or removing (Option 16). The usefulness of local and wider locational signals is one of the key issues for the TransmiT project.

[29] In this option, we assumed that postage stamp charges were applied to both generation and demand. Other variants are possible, such as postage stamp for generation and locational charges for demand but support for this variant would need to be clear on the reason for treating generation and demand differently with respect to geographical signals

Option 6 – Nodal congestion charges, Option 7 – Zonal congestion charges with FTRs, and Option 8 – Nodal congestion charges with FTRs

The academic papers published as part of the TransmiT project put forward a number of options based around short-run locational signals in transmission charges based on metered volumes. These three options capture different permutations for geographical definition (zonal or nodal) of these charges, and the existence or otherwise of financial transmission rights (FTRs). In all three options, long-term TNUoS charges become non-locational (i.e. postage stamp charges with no local element).

By eliminating the link between assets and TNUoS charges, this option directly addresses the stresses related to offshore wind, HVDC links, island generation and SQSS. The use of (targeted) energy charges should support the operation of flexible plant like peaking and storage. Finally, Option 7 is consistent with the spirit of the draft European Framework Guidelines on the management of congestion on transfer capacity between price zones.

Comparing the performance of these three options will provide insight into the impact of FTRs and moving between zonal and nodal definitions of congestion.

Option 9 – Facilitate generation connection with locational signals

This option seeks to support the development of generation by setting the average generator TNUoS charges to zero and broadening the definition of assets that can be counted as pre-connection user commitment. At the same time, it retains (locational and capacity-based) cost signals for generation to encourage efficiency in siting decisions.

Option 9 is the only option to directly address the stress identified by RenewableUK in relation to pre-connection user commitment, whereas the other options only impact on pre-connection user commitment to the extent to which it is linked to TNUoS charges. This option also addresses the stress of international parity as a number of other European countries have (average) generation charges of zero.

This option effectively represents a middle ground between the status quo and Option 16, which sets absolute (rather than average) generator charges to zero.

Option 10 – Change asset-specific cost allocation to residual TNUoS

This option uses residual charges to recover the costs of specified assets (e.g. those designated to be in the national interest for meeting decarbonisation and/or renewable targets).

It therefore addresses on a targeted basis the stresses identified by RenewableUK in relation to asset-based charging – namely for offshore wind, HVDC and island generation.

By adopting a more targeted approach to (local) asset definition, this option will be a useful comparator with Option 1.

Option 11 – TEC adjusted for technology and location

Under this option, TEC would be adjusted according to a set of rules about the expected network impact of a generator type in a particular zone. It is consistent with current proposals for TEC calculation being developed by National Grid under the SQSS process (which would adjust TEC for wind plants), and we assume that there would be a direct link between the SQSS provisions and calculation of chargeable capacity.

This option is the only one to directly address the stress of the inconsistent treatment of DG, by offering a way of introducing ‘net’ charges which relate to the expected impact of the DG on the transmission network. Similarly, it could also support the development of storage and peaking plant, by reducing the chargeable capacity if those types of generation do not generate at times of peak (zonal) network flows.

It provides a useful comparator to Options 6,7,8 and 13, which also change the basis for the levying of transmission charges on generators (using metered volumes for some if not all charges).

Option 13 – Energy-based locational TNUoS charges;

This option replaces the existing capacity-based cost signals with charges based on annual metered volumes.

Therefore, it directly addresses two stresses – the level of charges faced by low load factor storage and peaking plant, and the link between the SQSS and charges (as the basis for charging is energy rather than capacity based, meaning that there is no risk of changes to the definition of capacity) .

This option could be most usefully compared to other options that change the basis rather than level of transmission charging (e.g Options 6, 7, 8 and 11).

Option 16 – No TNUoS or BSUoS charges for generation;

This option removes all ongoing transmission charges from generation.

It would address most stresses because they are related to the way in which charges are levied on generation (and therefore, would be eliminated if charges are removed). This covers the asset-based stresses and the stresses related to parity with imports[30] and foreign generation[31]. The only stress not addressed by this option is the treatment of DG, as DG would still benefit from avoided demand TNUoS (even if it exports onto the transmission network).

This option is a useful addition to the short list, as unlike the other nine options, it removes all scope for ongoing transmission charges to provide investment or operational signals for (transmission-connected) generation.

3.2.1 Summary of stresses targeted by the shortlisted options

Table 7 summarises how our selected options address the stresses identified by RenewableUK in their response to the Call for Evidence for Project TransmiT. Further details of how each option is designed to address the set of stresses are available in Annex A, which also discusses in more detail how Options 6, 7 and 8 could operate in practice.

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30 In practice, this option may result in BSUoS charges also being removed from interconnector imports as they are entirely recovered from demand. We note that this option would not mean that demand is treated consistently with exports, which do not pay TNUoS charges – however, this was not a stress identified by RenewableUK.

31 There are a number of European countries in which transmission-connected generators (e.g Belgium, Netherlands and Gemany) face shallow connection charges and zero use of system charges (according to ENTSO-E statistics).

Table 7 – Stresses targeted by the options taken forward for assessment

	Option										
Stress	**1**	**2**	**6**	**7**	**8**	**9**	**10**	**11**	**13**	**16**	**No of options**
(Pre-connection) user commitment						Yes					1
Charging for offshore generation	Yes	Yes	Yes	Yes	Yes		Yes			Yes	7
Treatment of HVDC interconnections		Yes	Yes	Yes	Yes		Yes			Yes	6
Charging for generation on islands remote from demand	Yes	Yes	Yes	Yes	Yes		Yes			Yes	7
Consistency of treatment for DG								Yes			1
Consistency with interconnector imports										Yes	1
International parity				Yes		Yes				Yes	3
Storage and peaking plant			Yes	Yes	Yes			Yes	Yes	Yes	6
Impact of SQSS on charges		Yes	Yes	Yes	Yes				Yes	Yes	6
Development of coordinated offshore grid										Yes	1
Number of stresses	2	4	5	6	5	2	3	2	2	8	

3.3 Options not taken forward for full assessment

In this section, we briefly discuss the reasons why the following options (which were described in Table 5 and Table 6) were not selected for the shortlist for assessment.

Option 1a – removal of local TNUoS charges from G:D split

This is a variation on Option 1 that would remove the local asset charges from the calculation of the 27%:73% split of TNUoS charges between generation and demand. It was not taken forward to the shortlist because although it did not address both elements of the offshore and island stresses (particularly the relative level of charges. Also, it would have increased the overall share of transmission charges paid by generation (which was explicitly ruled out for our main options in Section 2.3).

Option 3 – caps on zonal differentials

There were already a number of options in the shortlist based around changing locational signals, which reduces the benefits of assessing this intermediate option.

Option 4 – sharpening locational signals

This option does not address any of the stresses identified by RenewableUK. Insight into its performance can be taken from the assessment of other options changing locational signals (such as Option 2).

Option 5 – nodal TNUoS charges

This option does not address any of the stresses identified by RenewableUK. Insight into its performance can be taken from the assessment of other options that introduce nodal charges (such as Options 6 and 8).

Option 12 – dynamic calculation of TEC;

An extension of Option 11, this option uses network modelling to develop plant-specific adjustment factors for TEC, with Option 11 being more consistent with the current proposals under the SQSS review.

Option 14 – 'Energy-based postage stamp charges with local asset charges'

This option is consistent with a proposal by the Scottish Government, SSE and SP that would rely on local asset charges to provide a cost signal for the siting of generation.

We decided to take forward Option 13 for assessment rather than Option 14, as this allowed the assessment to separate out the effects of moving to energy charging (Option 13) and removing zonal charges (covered in Option 2). In addition, Option 14 would have addressed few of the RenewableUK stresses (although it would have benefited northern onshore renewables).

Option 15 - no TNUoS charges for generation;

Option 16 removes TNUoS charges **and** BSUoS charges from generation. Therefore, there is limited benefit from also assessing Option 15, which is a less extreme option.

Option 17 – technology differentiated TNUoS charges;

We have not taken this option forward for assessment as it is not likely to be consistent with the concept of no undue discrimination of transmission charging. It would be increasingly unsustainable with higher levels of low-carbon and/or renewable generation as there would be a declining generation share paying 'full charges. In addition, other mechanisms (outside of transmission charging) for the support of low-carbon and/or renewable generation are available and are being developed (under the EMR process).

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4. ASSESSMENT OF OPTIONS

This chapter describes and summarises the outcome of the assessment of the 10 selected options against an extensive set of criteria. In addition, it also details whether the options can be combined or not, providing useful insight into their potential implementation.

4.1 Assessment process

There are a number of elements to the assessment process to deliver a comprehensive evaluation of the performance of each option:

- what is the impact of the option on the stresses that RenewableUK has identified under existing charging arrangements? – see Table 8;
- how does the option affect different industry parties – see Table 9 and Table 10; and
- how does the option perform against criteria for transmission charging arrangements? – see Table 11 and Table 12.

In each case, the tables in this chapter provide a high-level summary of the assessment results, with a more detailed discussion included in Annex B.

4.1.1 Objectives of transmission charging

The stated objective of TransmiT is to 'ensure that we (GB) have in place (transmission charging) arrangements that facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers'[32].

In addition, in a public letter to Ofgem[33], the Secretary of State to Ofgem, set out three policy objectives for transmission charging arrangements – economic efficiency, facilitate low-carbon generation and support for security of supply[34].

Finally, in deciding upon appropriate transmission charging arrangements, Ofgem (and DECC) will need to comply with a number of other obligations, particularly in relation to EU policy and regulations (e.g. to support greater integration of European electricity markets).

Therefore, we have assessed each option against each of the **individual** objectives (with no prioritisation given to one objective over another).

32 'Project TransmiT: A Call for Evidence', Ofgem, September 2010.

33 Letter from the Secretary of State for Energy and Climate Change (Chris Huhne) to Chairman of Ofgem (Lord Mogg) on 7 August 2010.

34 The letter also noted three key principles of fairness (which could be characterised as no undue discrimination), accessibility, and lasting and predictable.

The objectives are:

- **Affordability** – delivering efficient outcomes for customers by providing appropriate transmission cost signals for investment and operation decisions, facilitating competition, and minimising complexity of transition to and administration of new arrangements.
- **Environment –** supporting the progress of the UK towards its environmental targets, particularly targets for renewable electricity and reductions in emissions of carbon dioxide .
- **Security of supply** – supporting (efficient) investment in and operation of generation and transmission.
- **Compliance with other obligations** – primarily European obligations but also taking account other obligations on Ofgem, such as the principles of better regulation.

To support the assessment against these objectives, we have developed a longer list of assessment criteria. Annex B explains how the assessment criteria map onto, and hence inform the score for, each objective.

4.1.2 Scoring

In all cases, we assess the performance of each option in relation **to the expected status quo** (as discussed in Chapter 2) rather than against each other.

In Table 9 and Table 10, we assess the absolute impact of the option for the industry party, rather than the change in its position relative to other industry parties.

In the other assessment tables in thi section, we use a simple qualitative assessment approach to compare the impact of each option **compared to the status quo.** This is based around the following scoring system:

- ✓✓: option performs strongly compared to the status quo;
- ✓: option expected to perform better than the status quo;
- – : no material expected in performance of option compared to status quo;
- ✗: option expected to perform worse than the status quo;
- ✗✗: option expected to perform much worse than the status quo; and
- ✓/✗: performance of option will be better in some circumstances and worse in other.

When assessing performance against our four high-level objectives (Table 11), we use two additional scores to give us the required granularity of assessment:

- ✓✓✓: option performs exceptionally well compared to the status quo; and
- ✗✗✗: option performs exceptionally badly compared to the status quo.

4.2 Summary of assessment results

The following tables summarise the results of the assessment for each option:

- Table 8 provides an overview of the impact of the option on the stresses that RenewableUK has identified under existing charging arrangements;
- Table 9 describes how the option affects different types of generation;
- Table 10 highlights how the options could affect other industry parties (i.e. network companies and demand); and
- Table 11 and Table 12 set out how the option performs against the proposed criteria and objectives for transmission charging arrangements.

Table 8 – Summary of performance of each option against RenewableUK stresses

Stress	**Option 1 – 'Removal of local TNUoS charges'**	**Option 2 – 'Postage stamp capacity (TNUoS) charges'**	**Option 6 – 'Nodal congestion charges'**	**Option 7 - 'Zonal congestion charges with FTRs'**	**Option 8 - 'Nodal congestion charges with FTRs'**	**Option 9 – 'Facilitate generation connection with locational signals'**	**Option 10 – 'Change allocation of assets to residual TNUoS'**	**Option 11 – 'TEC adjusted for technology and location'**	**Option 13– 'Energy-based locational TNUoS charges'**	**Option 16– 'No TNUoS or BSUoS charges for generation'**
(Pre-connection) user commitment	✓/✗	✓/✗	✓/✗	✓/✗	✓/✗	✓✓	✓/✗	✓/✗	✓/✗	✓
Charging for offshore generation	✓✓	✓✓	✓	✓	✓	-	✓✓	✓	✓	✓✓
Treatment of HVDC interconnections	-	✓✓	✓✓	✓✓	✓✓	-	✓✓	-	-	✓✓
Charging for generation on islands remote from demand	✓✓	✓✓	✓/✗	✓/✗	✓/✗	-	✓✓	✓	-	✓✓
Consistency of treatment for DG	-	-	-	-	-	-	-	✓✓	-	-
Consistency with interconnector imports	✓	✓	✓	✓	✓	-	✓	-	-	✓✓
International parity	✓	✓	✗	✓✓	✓/✗	✓✓	-	-	-	✓✓
Storage and peaking plant	✗	✗	✓✓	✓✓	✓✓	-	✗	✓✓	✓✓	✓✓
Impact of SQSS on charges	-	✓✓	✓✓	✓✓	✓✓	✓	-	✗	✓✓	✓✓
Development of coordinated offshore grid	-	✓	✓	✓	✓	-	✓✓	-	✓	✓✓

Table 9 – How do proposed options affect different types of generation?

	Option 1 – 'Removal of local TNUoS charges'	**Option 2 – 'Postage stamp capacity (TNUoS) charges'**	**Option 6 – 'Nodal congestion charges'**	**Option 7 - 'Zonal congestion charges with FTRs'**	**Option 8 - 'Nodal congestion charges with FTRs'**	**Option 9 – 'Facilitate generation connection with locational signals'**	**Option 10 – 'Change allocation of assets to residual TNUoS'**	**Option 11 – 'TEC adjusted for technology and location'**	**Option 13– 'Energy-based locational TNUoS charges'**	**Option 16– 'No TNUoS or BSUoS charges for generation'**
Which types of generation particularly benefit under this option?	Generators located far from the MITS, such as **offshore wind, marine generation** and **island generation**	Generators located far from demand and/or MITS, such as **offshore wind** and **onshore wind, marine generation**, **island generation, hydro and northern thermal generation**	Generators in areas of 'excess demand' behind congestion constraints (which are likely to change over time) and flexible generation	Generators in areas of 'excess demand' behind congestion constraints (which are likely to change over time) and flexible generation	Generators in areas of 'excess demand' behind congestion constraints (which are likely to change over time) and flexible generation	(Flexible) **DG** benefits from higher demand charges , with lower TNUoS charges for all transmission-connected generation, with opportunity to fix charges. Future generation also benefits from reduced financial element to pre-connection user commitment.	Generators relying on offshore, island and HVDC assets, so primarily **offshore wind, marine generation island generation, onshore wind, hydro and northern thermal generation**	Intermittent[35] generation and peaking generation, **such as wind and marine generation,** with increased consistency between DG and transmission-connected generation	Peaking or intermittent generation, **such as renewables,** (where have positive charges) and baseload generation with negative charges (e.g in the south such as **nuclear** (as they can have negative charges)	(Flexible) **DG** benefits from higher demand charges with zero TNUoS for all transmission-connected generation
Which types of generation are worse off under this option?	Generators close to MITS such as **nuclear, CCS, fossil fuel, hydro**	Generators located close to demand and/or MITS	Generators in areas of 'excess supply' behind congestion constraints (which are likely to change over time) and less flexible generation	Uncertain because depends on level of FTR cost and allocation methodology	Uncertain because depends on level of FTR cost and allocation methodology	None	Generators located close to demand and/or MITS	Baseload generation, such as **nuclear**, **hydro**	Baseload generation in the north , and peaking or intermittent generation (if have negative charges)	Only generators who otherwise would have had negative TNUoS charges

35 'Intermittent' is the term generally used by the industry, Ofgem and DECC to denote forms of renewable generation, such as wind and solar, seeking to indicate they are not controllable in the conventional sense, i.e. they are essentially dependent on weather. Whilst Poyry recognises that many wind farm developers are not comfortable with this description, it is widely understood and used, including by Poyry in other publications. Therefore, we have retained this term to collectively describe wind generation in the context of this report.

Table 10 – How do proposed options affect industry parties other than generation?

	Option 1 – 'Removal of local TNUoS charges'	**Option 2 – 'Postage stamp capacity (TNUoS) charges'**	**Option 6 – 'Nodal congestion charges'**	**Option 7 – 'Zonal congestion charges with FTRs'**	**Option 8 – 'Nodal congestion charges with FTRs'**	**Option 9 – 'Facilitate generation connection with locational signals'**	**Option 10 – 'Change allocation of assets to residual TNUoS'**	**Option 11 – 'TEC adjusted for technology and location'**	**Option 13 – 'Energy-based locational TNUoS charges'**	**Option 16 – 'No TNUoS or BSUoS charges for generation'**
Which types of network operator particularly benefit under this option?	OFTO	TO OFTO	SO	SO	SO	SO TO OFTO DNO	OFTO	SO OFTO DNO	TO OFTO	TO OFTO DNO
Which types of network operator are worse off under this option?	SO	SO	TO	TO	TO					
Which types of demand particularly benefit under this option?		Southern demand	(Flexible) demand in areas of 'excess supply' behind congestion constraints (which are likely to change over time)	(Flexible) demand in areas of 'excess supply' behind congestion constraints (which are likely to change over time)	(Flexible) demand in areas of 'excess supply' behind congestion constraints (which are likely to change over time)				Large demand that cannot avoid Triad periods	
Which types of demand are worse off under this option?		Northern demand	(Flexible) demand in areas of 'excess demand' behind congestion constraints (which are likely to change over time	Uncertain because depends on level of FTR cost and allocation methodology	Uncertain because depends on level of FTR cost and allocation methodology	Large demand that cannot avoid Triad periods			Large demand that can avoid Triad periods	Large demand that cannot avoid Triad periods

Table 11 – How do the options perform against assessment criteria?

Criteria	Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 – 'Zonal congestion charges with FTRs'	Option 8 – 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No TNUoS or BSUoS charges for generation'
Supporting efficient (dis)investment decisions for generation[36]	×	××	✓	✓	✓	-	×	✓	-	××
Supporting efficient (dis)investment decisions for transmission	×	××	✓	✓	✓	-	✓/×	✓	✓	××
Supporting efficient operation decisions	-	-	✓✓	✓	✓✓	-	-	-	-	×
Cost reflectivity for generation	×	××	✓✓	✓	✓✓	-	×	-	×	××
Facilitation of competition in GB	✓	✓✓	-	-	-	✓	✓✓	-	✓	✓✓
Facilitation of generation competition in the EU	✓	✓✓	-	✓	-	✓	✓✓	-	✓	✓✓
Facilitate investment to meet renewable targets (15% RES = 30%RES-E)	✓	✓✓	××	×	×	✓	✓✓	✓✓	✓✓	✓✓
Facilitate investment to meet low-carbon targets	✓	✓	×	-	-	✓✓	✓	✓	✓	✓✓
Facilitate operation to meet renewable targets (15% RES = 30%RES-E)	-	-	×	×	×	-	-	-	×	-
Facilitate operation to meet low-carbon targets	-	-	-	-	-	-	-	-	-	-
Within-year predictability	-	-	×	✓/×	✓/×	-	-	-	-	-
Between year predictability	-	✓	×	-	✓	✓✓	-	-	×	✓/×
Consistency with EU congestion management	-	-	×	✓	-	-	-	-	-	-
Non-discrimination	✓/×	✓/×	✓	✓	✓	✓/×	✓/×	✓	✓/×	-
Better regulation principles	-	✓	××	×	×	✓	✓	✓	✓/x	✓/×
Administrative complexity	✓	✓✓	×	××	××	×	×	×	-	✓✓
Ease of implementation for grid and participants	-	-	×	××	××	-	-	×	×	✓✓
Ease of understanding	✓	✓✓	×	××	××	-	-	×	✓	✓✓

36 This criteria relates to ensuring that transmission cost signals are appropriately taken into account in the generation investment decisions. An assessment of the overall efficiency of generation investment decisions would need to take into account factors such as wholesale market arrangements and support mechanisms, both of which are under review in the EMR process, which is outside the scope of this report. We note that decisions on the level of support for renewable and/or low-carbon generation may take transmission charging arrangements into account.

Table 12 – How do the options perform against assessment objectives?

Objectives	**Option 1 – 'Removal of local TNUoS charges'**	**Option 2 – 'Postage stamp capacity (TNUoS) charges'**	**Option 6 – 'Nodal congestion charges'**	**Option 7 - 'Zonal congestion charges with FTRs'**	**Option 8 - 'Nodal congestion charges with FTRs'**	**Option 9 – 'Facilitate generation connection with locational signals'**	**Option 10 – 'Change allocation of assets to residual TNUoS'**	**Option 11 – 'TEC adjusted for technology and location'**	**Option 13– 'Energy-based locational TNUoS charges'**	**Option 16– 'No TNUoS or BSUoS charges for generation'**
Affordability	×	××	✓✓	✓	✓✓	✓	×	✓✓	-	×××
Environment	✓	✓✓	××	×	×	✓✓	✓	✓	✓✓	✓✓✓
Security of supply	-	✓	-	-	-	✓✓✓	-	✓✓	✓	✓
Other compliance	-	-	-	✓✓	✓	-	✓	✓	✓	✓

4.3 Interaction between the changes made in different options

Table 13 describes the impact of adding **the changes** made in one option to **the changes** made in another option. There are three possible outcomes (described in more detail in Annex C):

- **duplicate** option – the combination of changes gives the same result as an existing option because the **changes** in one option are a subset of **changes** in the other option;
- **new option** – the changes combine to create a new option (although the new option may not necessarily be in the same spirit as the two individual options); and
- **conflicting changes** – the two options have conflicting changes on a particular element of transmission charges.

The table is symmetrical because the order of changes does not effectively matter because if both options change a particular element, the combination is classified as 'conflicting changes' rather than one of the changes taking priority.

Six options (Options 1, 2, 6, 7, 8 and 10) change the nature of long-term geographical signal in TNUoS charges, and therefore are (largely) mutually exclusive. This is either because of duplication or because they make conflicting changes to short-term charges (Options 6, 7 and 8). The one novel combination of these options involves Options 1 and 10, with the composite option having no local changes and specified assets removed from the locational (zonal) charging calculation.

Option 9 can be combined with every other option because it is the only one to change pre-connection user commitment, and so never leads to duplication. In addition, it doesn't **change** any other element of charges in a different way to another option and so never conflicts.

There is a conflict between Options 11 and 13 because they both change the basis on which long-term changes are levied (e.g. the volume for the charge). However, they can each be combined with all of the other options (except Option 16) because the other options are generally focused on changes to price of long-term access (through amendments to the level or structure of charges).

Option 16 can only be combined with Option 9 to create a new option. The combination of Option 16 and five other options leads to duplication because Option 16 sets local, locational and residual charges to zero. This covers the changes in Options 1, 2 and10, and makes redundant the revisions to the charging basis in Options 11 (amended TEC) and Option 13 (metered volumes). The changes in Option 16, with the removal of short-term charges, conflicts with the introduction of locational short-term signals in Options 6, 7 and 8.

Table 13 – Can the options be added together to create new options?

What happens if changes in option below are added to option to the right?	Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No ongoing transmission charges for generation'
Option 1 – 'Removal of local TNUoS charges'	n/a	Duplicate (Option 2)	Duplicate (Option 6)	Duplicate (Option 7)	Duplicate (Option 8)	New option	New option	New option	New option	Duplicate (Option 16)
Option 2 – 'Postage stamp capacity (TNUoS) charges'	Duplicate (Option 2)	n/a	Duplicate (Option 6)	Duplicate (Option 7)	Duplicate (Option 8)	New option	Duplicate (Option 2)	New option	New option	Duplicate (Option 16)
Option 6 – 'Nodal congestion charges'	Duplicate (Option 6)	Duplicate (Option 6)	n/a	Conflicting changes	Duplicate (Option 8)	New option	Duplicate (Option 6)	New option	New option	Conflicting changes
Option 7 - 'Zonal congestion charges with FTRs'	Duplicate (Option 7)	Duplicate (Option 7)	Conflicting changes	n/a	Conflicting changes	New option	Duplicate (Option 7)	New option	New option	Conflicting changes
Option 8 - 'Nodal congestion charges with FTRs'	Duplicate (Option 8)	Duplicate (Option 8)	Duplicate (Option 8)	Conflicting changes	n/a	New option	Duplicate (Option 8)	New option	New option	Conflicting changes
Option 9 – 'Facilitate generation connection with locational signals'	New option	New option	New option	New option	New option	**n/a**	New option	New option	New option	New option
Option 10 – 'Change allocation of assets to residual TNUoS'	New option	Duplicate (Option 2)	Duplicate (Option 6)	Duplicate (Option 7)	Duplicate (Option 8)	New option	n/a	New option	New option	Duplicate (Option 16)
Option 11 – 'TEC adjusted for technology and location'	New option	New option	New option	New option	New option	New option	New option	n/a	Conflicting changes	Duplicate (Option 16)
Option 13– 'Energy-based locational TNUoS charges'	New option	New option	New option	New option	New option	New option	New option	Conflicting changes	n/a	Duplicate (Option 16)
Option 16– 'No ongoing transmission charges for generation'	Duplicate (Option 16)	Duplicate (Option 16)	Conflicting changes	Conflicting changes	Conflicting changes	New option	Duplicate (Option 16)	Duplicate (Option 16)	Duplicate (Option 16)	n/a

5. RELATIVE MERIT OF OPTIONS

This chapter provides a summary of the outcome of the assessment process for each of our 10 selected options.

Option 1 – removal of local TNUoS charges

This option is specifically designed to support the development of generation that is currently subject to high local charges, primarily offshore and island generation. Therefore, the costs of local assets are recovered (or 'socialised') through the residual, rather than locational, TNUoS charge. This option could also benefit OFTOs because of the encouragement given to offshore generation.

Designed specifically to address the stresses of high charges for island and offshore generation, this option also helps to bring transmission charging for generation in GB closer to the arrangements for interconnectors and in many other European countries. The increase in the residual charges though may exacerbate the stress of the current charging arrangements for peaking generation and storage. The fall in TNUoS charges for offshore and island generation could also reduce the size of user commitment required, if it is linked to the level of TNUoS charges.

Although the increase in the residual charge will increase costs for other generators, the (net) increase in the charge per kW will be small relative to the size of local charges for offshore and island generation, because they form a relatively small part of the asset base (in the near-term).

This option is sensitive to future changes in the definition of local TNUoS charges. If reinforcement leads to local asset becoming shared asset, then generator would lose benefits of not paying local charge if their zonal charge increased or they were allocated to a zone with higher charges.

Because it supports investment in renewable generation offshore and on the islands, this option scores well against the environmental objective for charging arrangements. However, it performs badly against the criteria of affordability, as it is expected to increase the amount of 'local' assets with the additional network investment costs outweighing any benefits from increased competition between generators.

The option does not have a material positive or negative impact on security of supply because the benefits of renewable investment for security of supply are offset by the weakening of the efficiency of locational signals for generation, which could result in increased constraints (and hence greater challenges for the SO).

Option 2 – postage

Option 2 is designed to directly address the stresses in relation to the level of charges for offshore (and hence the impact on the offshore grid) and island generation, and the potential widening of zonal differentials resulting from a HVDC link (because of uncertainties about the proposed methodology for the treatment of these costs in the load flow modelling). By removing locational charges, it also eliminates the impact of any changes in the network modelling resulting from amendments to the SQSS.

The removal of local and locational (zonal) generation TNUoS charges generally encourages the development of onshore wind generation (as well as offshore and island generation). This provides strong support for progress towards environmental targets, particularly with respect to renewable penetration. The revised transmission charging arrangements would also be much simpler, and hence more transparent.

The increased connection of generation, particularly onshore wind, offshore and island generation, will increase the level of network investment (and hence the asset base) for the TOs and for OFTOs, pushing up the investment costs to be recovered through TNUoS charges, particularly after the removal of the locational signals.

This means that the option scores badly against the affordability objective for charging arrangements as there is no incentive for plant to take transmission costs into account in their siting decision This offsets the benefits of the boost to competition between generators in GB and between British renewables and European renewables. In addition, the siting decisions made in the absence of locational signals (for generation and demand) could increase the level and frequency of network constraints, making the task of the SO more difficult.

However, recovering all generation charges through the residual charge could worsen the impact of the current charging arrangements on peaking generation and storage, which would partly offset the security of supply benefits from the high investment in renewable generation. It would also lead to a significant increase in TNUoS charges for generators located close to demand.

Removing the locational elements to the demand TNUoS charge will generally reduce charges for demand in the South and increase charges for demand in the North. This will also impact on distributed generation (with consequent impact on distribution networks) that has located in the South to help avoid high demand charges. This wouldn't be the case in the variant on this option in which demand charges remain locational. However, that variant would need to be supported by convincing reasons for the very different treatment of generation and demand with respect to geographical signals.

Option 6 – nodal congestion charges

Under this option, geographical signals are moved from long-term (i.e. annual) charges for infrastructure to short-term charges (i.e. half-hourly) for congestion. Therefore, if long-term charges remain, they are postage stamp (with no local element).

This option would address many of the stresses identified by RenewableUK, such as offshore connection, the treatment of HVDC links, charges for island generation, charges for peaking generation and storage, and the interaction with the SQSS. This is because use of short-term congestion (energy-based) charges is a move away from (local and locational) charges based on allocation of asset costs. However, the impact on offshore and island generation in practice is uncertain as it depends on some of the detailed implementation issues, such as process for allocating FTRs. This option could also worsen the situation with regards tointernational parity as nodal congestion charges without FTRs is is not a model used in Europe.Benefits will be expected to accrue to generation that is in areas of 'excess demand' behind congestion constraints and/or is able to respond to the short-term signals based on actual network conditions (which helps the option to score well on the criteria of non-discrimination). This latter feature could support peaking generation, which may also help the SO to manage the system.

The removal of local generator charges may also help some generators located far from the main transmission system (such as offshore wind), depending on the demand/supply balance at the node that it connects at.

This highlights why it is unclear (without very detailed quantitative modelling) exactly which groups of generators would benefit or lose out under this option because it depends on:

- (the stability of) the supply/demand balance at each node;
- the incidence of congestion (now and in the future); and
- the current level of TNUoS charges paid by the generator.

The use of nodal short-run charges provides the most efficient operational signals (along with Option 8) of the assessed options. This should feed through into long-term investment signals for generation and transmission, with the strength of these signals depending on the extent to which the short-run charges are 'predictable' over longer timescales.

Moving to targeted short-term charges (as opposed to fully socialised BSUoS) may worsen the situation with regards to short-term (and long-term) predictability of charges, particularly in the absence of FTRs.

This option would not be consistent with the proposed European guidelines on congestion management, which are focused around zonal charging areas with FTRs. It would represent a radical departure from previous regulatory policy, whether it was implemented through an LMP approach (which would require coordination with the EMR process which would be very challenging given the timescales for that paper) or locational BSUoS.

With respect to the charging objectives, this option seems to trade-off strong performance on affordability against poor performance on the environmental objective , particularly in the short-term given the impact of extended transition to any new arrangements. This is likely to discourage investment until parties feel that they have a better understanding of how the new system would operate in practice.

Option 7 – zonal congestion charges with FTRs

This option shares a number of features with Option 6:

- the shift in geographical signals from the long-term to the short-term with the consequent improvement in operational efficiency (i.e. long-term charges are postage stamp with no local element);
- benefits for peaking (or 'flexible') generation and/or generation in areas of excess demand behind congestion constraints;
- move away from asset-based (local and locational) charges that would address many of the stresses identified by RenewableUK; and
- uncertainty over predictability of charges.

The key differences are around the definition of the charging area, which is wider (zonal) in this Option, and the availability of FTRs[37]. Zonal charges are more consistent with both draft European guidelines, possibly facilitating competition with other European generators and helping to address the stress of international parity.

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37 Financial transmission rights (FTRs) give the holder the right to be paid the congestion charge between two specified areas (be they zones or nodes). They can be obligations (in which case the holder of the FTR has to make a payment if the price differential is in the opposite direction to their FTR) or option (where the holder of the FTR receives the maximum of zero and the price differential).

FTRs provide generators with an opportunity to hedge against the short-run price differentials, whilst retaining the marginal price signal for efficient operation. However, the impact of the FTRs will depend on their allocation method, particularly as this will help to determine the price of FTRs relative to existing TNUoS charges. The allocation methodology will also affect the balance between the revenue received by the network operators from the sale of the FTRs and the payments made to the holders of FTRs. This will then affect the amount of money that has to be recovered through long-term infrastructure charges.

Free allocation would undermine the investment signals provided by the zonal congestion charges – therefore, it may be more appropriate (possibly as a transitional measure) for existing generators who only have a limited ability to respond to the (dis)investment signal. However, these generators are already exposed to locational (zonal) charges.

The use of an administered price would require the development of a charging methodology, which could reintroduce the issues around the existing TNUoS arrangements. However, this means that the costs of the FTR may be similar to current TNUoS charges (and hence limit the immediate impact of this option). It is difficult to assess the impact at this stage in the absence of detailed quantitative modelling of network flows, which is beyond the scope of this report.

If auctions are used to allocate the FTRs, then this may lead to a cost of FTR significantly different to current TNUoS charges (which is derived from a load-flow model). In theory, the auctioning is economically more efficient because it enables market players to signal to the network operator the expected value of congestion rents over the period of the FTR (e.g, annual). However, in practice, participants may have difficulties to price FTRs at their right value especially during the first years, possibly reducing the benefits of this practice (as pointed out by Bell et al.).

Therefore, in our assessment, we believe that FTRs could ameliorate, but may not remove, the negative impact of FTRs on investment in variable renewable generation, particularly in the short-term.

In terms of the charging objectives, Option 7 has a more balanced performance than Option 6, scoring positively on both affordability and compliance, and performing less badly on environmental objectives. This also reflects the fact that the use of a zonal definition is more consistent with the existing charging arrangements, which may reduce the length of the transition period required. However, it reduces the improvement in operational efficiency from the status quo (compared to Option 6) as there is no targeting of charges for constraints within a zone[38].

Option 8 – nodal congestion charges with FTRs

This option is a mixture of options 6 and 7 (with long-term charges that are postage stamp with no local element). This means that it also could address the asset-based stresses identified by RenewableUK (offshore charges, HVDC links, island charges, storage and peaking plant, and interaction with SQSS). However, the impact in practice on offshore wind and island generation will depend on some of the detailed implementation issues, such as the FTR allocation process (as discussed under Option 7).

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38 A key implementation question for this option would be the definition of a zone. Given the move away from long-term charges based on the load flow model, the current approach to zone definition may not be sustainable. The draft EU guidelines on congestion management support the definition of zones as areas within which there is no structural congestion.

Option 8 has similar characteristics to Options 6 and 7 in terms of operational efficiency and cost reflectivity (which is enhanced by nodal rather than zonal signals). The option will provide,benefits for generation that can 'follow' demand.The combination of FTRS and nodal charges is expected to lead to a more predictable set of charges. Despite this, the generator would still exposed to the marginal signal from the 'nodal price' (however that is defined) as the congestion payments are received under the FTR irrespective of generation level. This nodal market price will be sensitive to changes in supply and demand around the node (including incidences of congestion).

Judged against the charging objectives, this option is the best performing of the three congestion charging options (Options 6, 7 and 8), with strong performance on affordability and good performance on security of supply and compliance. However, it scores poorly against the environmental objective. This is primarily the result of impact on renewable investment (in relation to 2020 targets) of the uncertainty caused by such a large departure from current policy, rather than any firm evidence of the relative impact on different types of generators.

Option 9 – lower generation costs with retention of signals

All generation is expected to benefit under this option as it reduces the average generator charge to zero (whilst maintaining the current distribution). This is consistent with the share of transmission charges paid by generators in many European countries, helping to address the stress of international parity.

This is the only option to directly address the user commitment stress, providing benefits to future generation projects. This should help to support the investment required to meet environmental and security of supply targets. However, it could (in theory) encourage more speculative applications, and higher levels of project failure, with the consequent costs socialised across all network users.

Under this option, generators (and demand) have the opportunity to fix TNUoS charges for a number of years thereby increasing the predictability of charges over that period, (although this may increase the volatility of charges for other users). This option does make any changes to locational signals in TNUoS charges, which means that it can be combined with many of the other shortlisted options to produce a new composite option. Under current charging arrangements, distributed generation will receive higher benefits from avoiding the larger demand charges. On the flip side, the rise in the demand share of transmission charges will increase the exposure of large customers to Triad charges.

As the existing locational signals are retained, there is no change in performance from the status quo in terms of efficiency of investment and operational signals. This also means that the option does not address the stresses identified by RenewableUK in relation to the asset allocation approach in the current charging methodology (e.g. high charges for offshore and island generation).

This option has a good performance across the objectives for charging arrangements, scoring very well on security of supply (because of encouragement for generation investment) and well on environmental and affordability objectives.

Option 10 – asset-specific cost allocation to residual TNUoS

This option is specifically dedicated to addresses the stresses identified in the current treatment of assets in charges for offshore wind, island generation and HVDC links. However, the recovery of these asset costs through the residual will push up charges for other types of generation, and may exacerbate the stresses for peaking generation and for storage (and for distributed generation).

The change in asset allocation approach should support investment in offshore and island generation, and in HVDC links (supporting development of onshore wind in areas far from demand centres).

As a result, the option scores well on the environmental and security of supply objectives described for charging arrangements. This is consistent with the guiding principle of this option that the assets allocated to the residual pot are in the 'national interest'. However, the benefits of increased competition for affordability are offset by the weakening of cost signals, which will feed into higher residual charges for generators.

Option 11 – TEC adjusted for technology and location

National Grid are currently developing rules on adjusting TEC (under the auspices of the SQSS review) to reflect the operating pattern of different plants. This process recognises the fact that peak capacity may not be a strong indicator of requirements that they place on the network (as peak output may not coincide with peak transmission flows).

This option is the only one to directly address the stress of the inconsistency of (current and proposed) TNUoS charging arrangements for DG. It offers a middle ground between the assumption that DG only reduces (and never increases) transmission flows (current arrangements) and the assumption that DG exports its entire capacity onto the transmission network (proposed arrangements). Under this option, rules will be developed to adjust a TEC measure for DG in line with expected patterns of export onto the transmission network.

Low-load factor, such as storage and peaking plant could benefit from an effective reduction in TEC based on their operating characteristics, addressing one of the RenewableUK stresses. Intermittent renewable generation, such as offshore wind, may also benefit in particular, depending on how the adjustments vary by location (i.e. onshore wind may benefit less where it is more clustered together in a zone).

As there are no changes to long-term locational signals, this option can be combined with most of the other shortlisted options to produce a novel composite option. The only exceptions are Option 13 (as that also changes the basis for TNUoS charges), and Option 16 (as the removal of generator TNUoS charges makes TEC irrelevant from a transmission charges perspective).

Developing a more sophisticated approach to the definition of TEC should provide more efficient investment signals, and arguably represent an improvement in terms of non-discrimination. This is because generators are treated differently according to their expected impact on the network rather than as a result of simple rules that don't take account of differences in operating patterns. It would also represent a targeted intervention based on reasonably transparent rules, which would be consistent with the principles of better regulation.

This option would reduce the total charge paid by intermittent and peaking generation, and hence increase the charges paid by baseload generation, such as nuclear (depending on the precise rules for TEC adjustment). This would support development of renewable and flexible generation, which could both increase the challenge for the SO and provide it with more system management tools.

Option 11 is at the simple end of the spectrum of changing the approach to calculating chargeable capacity, with Option 12 (not assessed) at the more complex and comprehensive end. These options therefore reflect a trade-off between aims of transparency and cost-reflectivity.

The risk for Option 11 is that the rules for determining charging capacity become increasingly complicated (and subject to lobbying efforts) undermining the expected benefits of administrative simplicity. This could increase instability in the arrangements, explaining why it scores poorly on between year predictability.

This option scores the best of all options across the charging objectives, with positive scores on each objective, and particularly strong performance on security of supply. However, it fails to address a number of the stresses identified by RenewableUK, In particular, it makes the 'adjusted TEC' calculation subject to the results of network modelling. This could mean that TNUoS charging volumes as well as prices are sensitive to changes to the SQSS.

Option 13 – energy-based locational charges

Under this option, the £/kW charges in current TNUoS charges would all be replaced by £/MWh charges. However, the level of charge would still vary on a locational basis. Indeed, as this option does not amend long-term locational signals, it can fit together with most of the other shortlisted options. The two exceptions are Option11 (as that also changes the basis for TNUoS charges), and Option 16 (as the removal of generator TNUoS charges makes the basis for charging an academic question).

By moving to entirely energy-based charging, this option benefits plants with low load factors (such as peaking generation and wind). These plants currently face high costs (if measured per kWh of output) under the current capacity-based charging arrangements. Indeed, the treatment of peaking generation and storage is one of the two main stresses designed to be addressed by this option. The other is the link to the SQSS as the use of metered volumes removes the risk of changes to the TEC calculation, which would lead to revised TNUoS costs.

Conversely, charges would increase for baseload generation with high load factor, such as nuclear. Therefore, this option will have a bigger benefit for renewable targets than for carbon reduction goals. Overall, the impact on the environmental objective of charging is therefore slightly positive.

The move to locational energy-based charges for all demand would eliminate the Triad risk for large customers. But it also removes the Triad signal for large customers that can reduce demand, who would be very adversely affected.

This could increase the level and frequency of network constraints, making the task of the SO more difficult. However, the support for peaking generation and storage should provide the SO with more options for resolving constraints, leaving it unclear as to what the net effect would be on the SO.

In summary, this option performs well against the environmental objective, particularly for renewables targets. By addressing the stress in current arrangements for storage and peaking plant, the option scores positively on security of supply arrangements.

On the other hand, it is uncertain whether the option would be good or bad for affordability. Although capacity is a key driver of transmission network investment costs, energy-based charges mean that TNUoS charges will be affected by plant operation. However, the charges will still be asset-based and therefore not reflective of the actual network conditions and operational costs for the system, including congestion costs. This is expected to reduce the efficiency of operational decisions.

Option 16 – no on-going TNUoS and BSUoS charges for generation

Generators would pay no TNUoS or BSUoS charges under this option. Therefore, it would benefit all generators, particularly those currently facing high charges because of their location and/or operating pattern (e.g. offshore wind, island generation).

Most of the stresses identified by RenewableUK are related to the level and determination of charges paid by (transmission-connected) generators. Therefore, this option scores very well against the stresses because it removes all charges from these generators. The main exception is the consistency of the treatment of DG, which would not be resolved by this option.

Higher demand charges could benefit distributed generation, but would increase exposure of large customers to Triad charges. Similarly whilst charges will be entirely predictable for generators, they will become more volatile for demand customers (as total charges to be recovered from demand increases by a third).

The removal of locational signals for generation could increase the level and frequency of network constraints, making the task of the SO more difficult However, the support for peaking generation and storage should provide the SO with more options for resolving constraints, leaving it unclear as to what the net effect would be on the SO.

Despite the benefits expected from greater competition, the absence of any cost signals for generation investment and operation means that this option scores badly on affordability, However, it scores well on supporting progress towards environmental targets as it should encourage generation investment.

6. OBSERVATIONS

In this report, we have developed a longlist of 18 potential changes to the transmission charging arrangements in Great Britain. From this longlist, we selected 10 options for more detailed assessment. This section summarises our observations from this assessment. It does not include a recommendation of which options should be taken forward as this is expressly outside the scope of this report.

The themes explored in this section are:

- importance of trade-offs in determining possible models for transmission charging arrangements;
- grouping of the options;
- impact on offshore wind development, as that is expected to be key to meeting renewables targets in 2020, and possibly beyond;
- impact on distributed generation (DG), which accounts for a significant proportion of existing renewable resource; and
- interaction with developments in Europe, which will help to determine robustness of arrangements to a move to more integrated European electricity markets.

6.1 Importance of trade-offs

We have developed a set of options that in general perform strongly against the stresses identified by Renewable UK. To some extent, this is to be expected given that by design, the options were targeted at addressing these stresses. However, our shortlist of options also highlights the importance of trade-offs in developing a sustainable set of transmission charging arrangements.

6.1.1 Trade-off between stresses

There are two clear trade-offs within the set of stresses.

Firstly, options that shift assets into the residual (e.g. Options 1, 2 and 10) exacerbate the stress on peaking generation and storage by increasing the residual charge to which they are exposed.

Secondly, the development of rules for adjusting TEC (the basis of generator TNUoS charging), as embodied in Option 11, strengthens the link between TNUoS charging methodology and the SQSS. This could worsen the stress identified by RenewableUK of potential instability in charges resulting from linking together the SQSS and the charging methodology.

6.1.2 Trade-off between stresses and objectives

The stresses identified by RenewableUK are important in helping to define the challenge for transmission charging arrangements. Ultimately, however the performance of the options against an agreed set of charging objectives will be vital in identifying options attractive to policy-makers. In addition, the impact on different generators (and demand) will influence industry support for any proposed solution.

For some options, strong performance against the stresses must be traded off against weaker performance against the policy objectives. The clearest example of this trade-off is for Option 16 (the removal of generator TNUoS and BSUoS charges). Somewhat unsurprisingly, this addresses all of the stresses identified in relation to the charges levied on transmission-connected generation. This leaves only one remaining stress, the inconsistency of the treatment of DG, which would benefit from (higher) avoided demand TNUoS charges.

6.1.3 Trade-off between policy objectives

Although Option 16 also supports progress towards environmental targets by encouraging generation investment, it scores badly against the charging objective of affordability. This would make it much less attractive to policy-makers who are concerned about cost-effective delivery of a low-carbon and secure electricity supply. This highlights the importance of the weighting placed on different objectives in developing the policy solution.

6.1.4 Trade-off between short-term and long-term effects

There are a group of options (Options 6, 7 and 8), around which there remains uncertainty about what their impact would be in practice, particularly with respect to which parties would be the winners and losers. The move away from long-term asset-based charging to short-run congestion charging would seem to address a number of the RenewableUK stresses (which relate to the link between assets and charges). However, it is difficult to assess the impacts on different industry parties, particularly after the necessary period of transition, and on performance against the charging objectives.

This assessment requires two types of information, both outside the scope of this report:

- **Detailed network modelling to understand how congestion charges might compare to current TNUoS levels –** this would require scenario analysis given the uncertainty about timing and location of developments in generation, networks and demand.
- **Development of detailed options for implementation,** for example covering the approach to definition of charging (or pricing) zones, and the allocation and pricing of FTRs.

6.2 Grouping of options

We can characterise our options into three groupings according to the impact on the nature of transmission charging arrangements:

- removal or weakening of geographical or capacity-based signals in long-term transmission charges for all generators (Options 1, 2, 13 and 16);
- introduction of targeted congestion charges to shift geographical signal from long-term to short-term (Options 6, 7 and 8); and
- evolutionary changes (Options 9, 10 and 11).

6.2.1 Removal or weakening of geographical and/or capacity-based signals

Options 1, 2, 13 and 16 are focused around the weakening of geographical and/or capacity-based signals in transmission charges for all generation. They typically perform strongly in helping the system to meet its environmental goals but at the expense of the charging objective of system affordability.

The negative impact on system affordability reflects the fact that removing (or significantly weakening) the geographical signals means that the impact on transmission costs would not be as significant a factor as now in investment and operational decisions. The impact of this on overall system costs will depend on the trade-off between increased transmission costs and the ability to access lower-cost sources of generation. This will be influenced by the extent to which current transmission charging arrangements are judged to provide appropriate transmission cost signals.

6.2.2 Shifting geographical signals to short-term charges

The introduction of targeted congestion charges (and postage stamp long-term TNUoS charges) in Options 6, 7 and 8 shifts the geographical signal from long-term to short-term charges. Perhaps surprisingly, these options would seem to address many of the stresses identified by RenewableUK because they remove assets (and location) from the calculation of long-term charges.

However, without the integrated modelling of network flows and generating patterns, it is hard to assess the performance of these options in terms of stresses, impact on market players and charging objectives. This highlights some of the drawbacks of these options. They are much more complicated for market players to understand, and would introduce additional complexity into the charging arrangements. This could extend the required transition period, which may lead to a delay in generation investment owing to increased uncertainty.

All of this means that the overall impact on charging objectives is uncertain - these options typically score well on affordability but perform poorly on environmental objectives, reflecting the impact of lengthy transition period in discouraging investment in the short-term at least. It also reflects the fact that much renewable (and other forms of low-carbon) generation may not be able respond (e.g. by turning up or down) as fully to other forms of generation to the short-term operational signals provided under these options. This means that they could be exposed to periods of high short-run transmission charges.

6.2.3 Evolutionary changes

The third set of options (9, 10 and 11) are based around an evolution of the existing arrangements, with the retention of geographically differentiated capacity-based charges. These options are the only ones to specifically address the stresses of pre-connection user commitment (Option 9) and inconsistency of treatment of DG (Option 11). Option 10 addresses a broader range of stresses by specifically targeting assets to be included in the residual, including assets related to offshore wind, HVDC links and island generation.

These options tend to score reasonably well across all of the charging objectives. They can also be combined with many of the other options, because they make only relatively limited changes to current charging arrangements. Although in a number of cases for Option 10, no new option is formed as a result of combination with another option (but rather a duplicate of one of the shortlisted options).

However, there are drawbacks for these options. Option 9 would benefit all existing and future transmission-connected generators but would not address the stresses identified by RenewableUK in relation to particular generators and asset types.

In addition, by simply adjusting the current arrangements, these options may not be particularly robust in the longer-term. For example, if lots of generation has fixed its transmission charges for a number of years (under Option 10), this could increase the volatility of charges for remaining generators, including future generators. These could feed through into a rise in the level at which they are able to fix charges.

The calculation of adjusted TEC under Option 11 will become increasingly complicated as more and more renewables come onto the system. In addition, if a significant share of the generation fleet benefits from 'adjusted TEC' lower than the actual TEC, then the benefits of the adjustment will reduce. This option also raises the risk that, if the 'adjusted TEC' is linked directly to the SQSS, then siting decisions by other generation and/or by demand could affect the level of 'adjusted TEC' (as well as the level of zonal charges themselves, as under current arrangements). This could increase uncertainty for generators about their exposure to future payments for use of the transmission system.

6.3 Impact on offshore wind

Based on estimated resource potential, the deployment of offshore wind is expected to play a very important role in delivering long-term increases in renewable generation (to 2020 and beyond). For example, the National Renewable Energy Action Plan[39] forecasts 13GW of offshore wind to be installed by 2020 (if the UK is to meet its 15% renewable energy target.

RenewableUK identified two stresses in relation to offshore wind – the application of local charges to offshore wind farms, and the development of a coordinated offshore grid. Under the current arrangements, the charging stress for offshore wind has two elements. The first is the impact of the payments for local assets by offshore wind that reduces the residual charge paid by all generator, and the second is relatively high level of charges paid by offshore wind compared to other generators.

Almost all of options address the offshore wind charging stress in one form or another. The exception is option 9, which is still judged to be positive for offshore wind because of the fall in charges for all generators. However, it does not change the treatment of local assets, the key source of the offshore wind charging stress.

Therefore, options that remove local charges from offshore wind farms (Options 1, 2,10 and 16) directly address the charging stress and have a strongly positive impact for offshore wind (and hence the achievement of environmental targets).

Offshore wind also benefits from options that change the charging basis – either through TEC adjustments reflecting the operating pattern of the plant (Option 11), or by moving to energy-based TNUoS charging (Option 13).

The final set of options (Options 6, 7 and 8) address the offshore wind charging stress by abolishing the local generation charge. However, it is uncertain the extent to which there will be a positive benefit for offshore wind generation, both in the short-term and the long-term. In the short-term, offshore wind investment might be delayed by a lengthy transition to new arrangements. The impact on investment in the long-term will depend on generation, network and demand developments (driving incidence of congestion), and the availability and cost of FTRs (which are not a feature of Option 6) for offshore wind farms.

39 'National Renewable Energy Action Plan for the United Kingdom. Article 4 of the Renewable Energy Directive 2009/28/EC', DECC, July 2010.

6.4 Impact on distributed generation

Distributed generation (DG) currently accounts for a significant proportion of renewable generation in GB. As identified by RenewableUK, there is an inconsistency in the current and proposed application of generator TNUoS to DG (because it does not reflect the impact of the DG on the transmission network). This means that the impact on distributed generation of the different options is uncertain because it is dependent upon the framework for applying transmission charges to DG.

At the moment, DG does not pay generator TNUoS charges but can benefit from avoided demand TNUoS charges (depending on their output during Triad periods). As recognised by RenewableUK, this can distort the decision as to whether to connect to the distribution or transmission network.

With respect to DG, the options can be grouped as follows:

- **Opportunity to resolve inconsistency (Option 11)** by adjusting TEC to reflect impact of DG on transmission networks.
- **Improvement from status quo (Options 9 and 16)** because increased share of charges paid by demand (and hence larger benefits of avoided demand TNUoS under current arrangements) and reduced generator charges (which would be beneficial if all DG was liable to generator TNUOS).
- **Impact depends on location of DG (Options 2)** with the impact also depending on TNUoS charging arrangements for DG – i.e. Option 2 better for southern DG under current DG charging arrangements but better than status quo for northern DG if generator TNUoS applied to DG.
- **Impact depends on nature of DG (Option 13**), which is beneficial for less flexible forms of generation (e.g. removes Triad under current DG charging arrangements) and/or lower load factor generation (e.g. if generator TNUoS applied to all DG).
- **Impact depends on implementation of option (Options 6, 7 and 8)**, depending on whether congestion charges implemented through TNUoS charges (and how these are applied to DG), or through wholesale market reform, as well as whether or not DG is located in congested areas.
- **Impact depends on how TNUoS charges are implemented for DG (Options 1 and 10)**, under current arrangements for DG charges, shifting charges into the generator residual would not affect DG charges. However, if generator TNUoS charges are levied on DG, then DG would pay higher charges under these options than status quo (because of increase in residual charge for generators).

6.5 Consistency with Europe

The development of transmission charging arrangements in GB needs to take into account the desire to move towards a more integrated European electricity market. This raises two key issues:

- consistency with transmission charging arrangements in other European countries; and
- consistency with EU guidelines and regulations.

Although a full comparison of European transmission charging regimes is beyond the scope of this report, it is clear that there is no standard European model at present.

However, in the near-term, the GB market is expected to become more closely integrated with the markets of Central West Europe (CWE, covering the Netherlands, Germany, Belgium, France and Luxembourg), and then with the Nordic markets (through the links between Nordpool and CWE at first).

According to the association of European TSOs (ENTSO-E), the Netherlands, Germany and Belgium have zero charges on generation alongside shallow connection boundaries. In contrast, Great Britain is reported to be the market with the highest share of transmission costs borne by generation[40].

These differences in transmission charging arrangements could (along with a number of other factors) affect siting and operational decisions for generation in a more integrated regional market. Therefore, the options which would set (average) generation charges to zero (Option 9 and Option 16) may be consistent with the development of a more integrated market.

At the same time, the European regulators have issued draft Framework Guidelines on capacity allocation and congestion management ('Framework Guidelines'). These will inform legally binding network codes that will be developed by ENTSO-E over the next two to three years. A network code will be developed for each of the four objectives set out in the Framework Guidelines:

- 'to ensure optimal use of transmission network capacity in a coordinated way' (through appropriate mechanisms for capacity calculation and definition of zones);
- 'to achieve reliable prices and liquidity in the day-ahead capacity allocation';
- 'to achieve efficient forward market'; and
- 'to design efficient intraday market capacity allocation'.

The guidelines are designed to apply to the allocation of transmission capacity between price zones. At present, this is expected to relate to the treatment of interconnection capacity between markets. However, the Framework Guidelines raise the possibility that where there is significant internal congestion within one control area (or market), then the control area should be split into several price zones.

This could introduce short-term locational signals within GB for example. This is consistent with the direction of the changes included in Options 6, 7 and 8 whereby geographical signals are driven by congestion not by asset costs from load flow modelling – in particular, Option 8 with zonal charges (or prices) and FTRs is very close to the model proposed in the Framework Guidelines.

[40] 'Overview of Transmission tariffs in Europe: Synthesis 2010', ENTSO-E, 2010.

ANNEX A – FURTHER DETAILS ON OPTIONS

This Annex starts by providing additional background on the operation of Financial Transmission Rights in Options 7 and 8. It then gives further details on all of the options presented in Table 5 and Table 6 through:

- **a detailed description of each option** (in Table 14 and Table 15) according to the design of each type of transmission charges in which changes from the status quo are highlighted in red; and
- **a summary of how each option is designed to address the stresses** (Table 16 and Table 17) identified in the response of RenewableUK to the Call for Evidence for Project TransmiT[41].

We have classified the options according to the design of each of the following types of transmission charge, which are:

- **pre-connection charge –** usually described as(pre-connection) 'user commitment' and designed to discourage speculative applications for connection;
- **connection charge** – under shallow connection charging arrangements, this charge covers assets that solely facilitate connection of individual users to the National Electricity Transmission System (NETS);
- **infrastructure charge –** (annual) charge designed to recover the cost of local and shared assets that facilitate access to and the flow of power across the NETS, which currently takes the form of TNUoS charges; and
- **operational charges** – (short-term) charges designed to recover the costs of resolving network constraints and other system operation activities, which currently takes the form of BSUoS charges.

As discussed in Chapter 3, none of the options make any changes to connection charges, and hence that element of charges is not shown in Table 14 and Table 15.

A.1.1 Operation of Financial Transmission Rights (FTRs)

Options 7 and 8 are based on the use of Financial Transmission Rights (FTRs). FTRs are financial instruments that entitle the holder 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. They provide generators with an opportunity to hedge on the medium to long-term, against the short-run price differentials and therefore play a key role in bringing predictability to options based on short-term pricing of congestion charges. The example below illustrates how FTRs work in practice.

In the example below, plant C, located in zone A, wants to send electricity to zone B, as prices are higher in this zone that in zone A. It will pay a congestion charge of £20/MWh.

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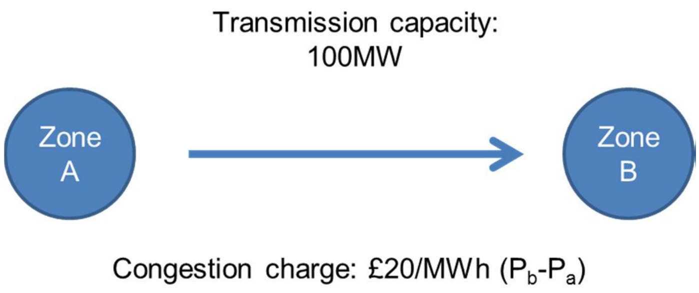
[41] 'Response to Project TransmiT Call for Evidence', RenewableUK and Scottish Renewables, November 2010.

Figure 1 – Scenario for the FTR illustration



This congestion charge should reflect the different prices at which supply and demand is balanced in each zone (as shown by Pb and Pa). Therefore, the congestion charge (in terms of direction and magnitude) depends on the relative balance between supply and demand in the two zones in each period.

If plant C holds an FTR for 1 MW, then it would receive the price differential of £20/MWh. (in this period). Therefore, this would offset the congestion charge and means that plant C can effectively access the price in zone B despite being located behind a congestion constraint in zone A. However, this payment is made to plant C irrespective of whether or not it generates. Therefore, it is not taken into account in its generation decision which remains based on a comparison of SRMC of generation and the expected price in Zone A.

FTRs can be allocated in different ways, i.e. either directly given by the TO or auctioned off to the participants. In theory, the auctioning is economically more efficient because it enables market players to signal to the network operator the expected value of congestion rents over the period of the FTR (e.g, annual). However, in practice, participants may have difficulties to price FTRs at their right value at least during the first years, possibly reducing the benefits of this practice (as pointed out by Bell et al.).

The allocation methodology may affect the balance between the revenue received by the network operators from the sale of the FTRs and the payments made to the holders of FTRs. This will then affect the amount of money that has to be recovered through long-term infrastructure charges.

There are a number of other design considerations beyond the allocation methodology, (which are too detailed for consideration in this report) including:

- interaction with wholesale market;
- impact on transmission access rights and constraint payments; and
- whether the FTR is an obligation (whereby the holder has to pay the congestion charges if the flow is in the wrong direction compared to its FTR holding) or an option (where the holder only receives the congestion charges and is never liable for it).

Table 14 – Detailed description of each option for changing locational signals for all generators

Transmission charge	Key elements of charge	Option 1 – 'Removal of local TNUoS charges'	Option 1a – 'Removal of local TNUoS charges from G:D split'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 3– 'Caps on zonal differentials'	Option 4 – 'Sharpening locational signals'	Option 5 – 'Nodal TNUoS charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'
Pre-connection charge	What is form of 'user commitment'?	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment
Infrastructure charges	What costs are charges designed to recover?	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets net of congestion rents	All infrastructure assets net of congestion rents and FTR revenue	All infrastructure assets net of congestion rents and FTR revenue
	How often are TNUoS charges reset?	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)
	How are total infrastructure charges split between different user types?	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure (exc local asset charges)	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure
	How are local assets defined for calculation of local TNUoS charge for generation?	No local TNUoS charges for generation	Current definition of local assets for generation	No local TNUoS charges for generation	Current definition of local assets for generation	Current definition of local assets for generation	Current definition of local assets for generation	No local TNUoS charges for generation	No local TNUoS charges for generation	No local TNUoS charges for generation
	What is the locational element of the TNUoS charge levied on generation?	Zonal generation TNUoS charges	Zonal generation TNUoS charges	No locational generation TNUoS charge	Less differentiated zonal generation TNUoS charges (cap on spread)	More differentiated zonal generation TNUoS charges (e.g. AC substations in incremental costs)	Nodal generation TNUoS charge (i.e. no averaging across charging zone)	No locational generation TNUoS charge	No locational generation TNUoS charge	No locational generation TNUoS charge
	How is the TNUoS charge differentiated by generation technology?	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge
	On what basis are TNUoS charges levied for generation?	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC
	What is the locational element of the TNUoS charge levied on demand?	Zonal demand TNUoS charges (as now)	Zonal demand TNUoS charges (as now)	No locational demand TNUoS charge	Less differentiated zonal demand TNUoS charges (cap on spread)	More differentiated zonal demand TNUoS charges	Nodal demand TNUoS charge (i.e. no averaging across charging zone)	No locational demand TNUoS charge	No locational demand TNUoS charge	No locational demand TNUoS charge
	On what basis are TNUoS charges levied for demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand

Transmission charge	Key elements of charge	Option 1 – 'Removal of local TNUoS charges'	Option 1a – 'Removal of local TNUoS charges from G:D split'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 3– 'Caps on zonal differentials'	Option 4 – 'Sharpening locational signals'	Option 5 – 'Nodal TNUoS charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'
Operational charges	**How do users pay for network constraints between zones?**	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	**Nodal energy--based congestion 'charges'**	**Zonal-based congestion 'charges' with FTRs**	**Nodal energy--based congestion 'charges'with FTRs**
	How do users pay for network constraints within zones?	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	**Nodal energy--based congestion 'charges'**	All paid for through BSUoS charges	**Nodal energy--based congestion 'charges'with FTRs**
	How are BSUoS charges allocated between user types?	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS

Table 15 – Detailed description of each option for encouraging investment in (some types and/or location of) generation

Transmission charge	Key elements of charge	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change asset-specific cost allocation to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 12 – 'Dynamic calculation of TEC'	Option 13 – 'Energy-based locational TNUoS charges'	Option 14 – 'Energy-based postage stamp charges with local asset charges'	Option 15 – 'No TNUoS charges for generation'	Option 15 – 'No TNUoS or BSUoS charges for generation'	Option 17 – 'Technology-differentiated TNUoS charges'
Pre-connection charge	What is form of 'user commitment'?	Sunk costs count as user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment	Financial user commitment
Infrastructure charges	What costs are charges designed to recover?	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets	All infrastructure assets
	How often are TNUoS charges reset?	Option for multi-year (ex-ante) fixed charges	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)	Annually (ex-ante)
	How are total infrastructure charges split between different user types?	G= 0% and D=100% for infrastructure	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure	G= 27% and D=73% for infrastructure	G= 0% and D=100% for infrastructure	G= 0% and D=100% for infrastructure	G= 27% and D=73% for infrastructure
	How are local assets defined for calculation of local TNUoS charge for generation?	Current definition of local assets for generation	Exemption of offshore and island assets from local generation TNUoS charges	Current definition of local assets for generation	Current definition of local assets for generation	Current definition of local assets for generation	Current definition of local assets for generation	No local TNUoS charges for generation	No local TNUoS charges for generation	Current definition of local assets for generation
	What is the locational element of the TNUoS charge levied on generation?	Zonal generation TNUoS charges (as now)	Zonal generation TNUoS charges (as now)	Zonal generation TNUoS charges (as now)	Zonal generation TNUoS charges (as now)	Zonal generation TNUoS charges (as now)	No locational generation TNUoS charge	No locational generation TNUoS charge	No locational generation TNUoS charge	Zonal generation TNUoS charges (as now)
	How is the TNUoS charge differentiated by generation technology?	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	No technology differentiation in generation TNUoS charge	Discount on TNUoS charges for low-carbon generation
	On what basis are TNUoS charges levied for generation?	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC	Per kW of TEC (adjusted for technology and location)	Determined by modelled impact on transmission network	TNUoS charge paid per kWh of annual metered volume	TNUoS charge paid per kWh of annual metered volume	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC	TNUoS charge paid per kW of (peak) TEC
	What is the locational element of the TNUoS charge levied on demand?	Zonal demand TNUoS charges (as now)	Zonal demand TNUoS charges (as now)	Zonal demand TNUoS charges (as now)	Zonal demand TNUoS charges (as now)	Zonal demand TNUoS charges (as now)	No locational demand TNUoS charge	Zonal demand TNUoS charges (as now)	Zonal demand TNUoS charges (as now)	Zonal demand TNUoS charges (as now)
	On what basis are TNUoS charges levied for demand?	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	modelled impact on transmission network; per kWh of annual consumption for small demand	TNUoS charge paid per kWh of annual metered volume	TNUoS charge paid per kWh of annual metered volume	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand	per Triad kW for large demand; per kWh of annual consumption for small demand

Transmission charge	**Key elements of charge**	**Option 9 – 'Facilitate generation connection with locational signals'**	**Option 10 – 'Change asset-specific cost allocation to residual TNUoS'**	**Option 11 – 'TEC adjusted for technology and location'**	**Option 12 – 'Dynamic calculation of TEC'**	**Option 13 – 'Energy-based locational TNUoS charges'**	**Option 14 – 'Energy-based postage stamp charges with local asset charges'**	**Option 15 – 'No TNUoS charges for generation'**	**Option 16 – 'No TNUoS or BSUoS charges for generation'**	**Option 17 – 'Technology-differentiated TNUoS charges'**
Operational charges	**How do users pay for network constraints between zones?**	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges
	How do users pay for network constraints within zones?	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges	All paid for through BSUoS charges
	How are BSUoS charges allocated between different user types?	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	G= 50% and D=50% for BSUoS	**G=0% and D=100% for BSUoS**	G= 50% and D=50% for BSUoS

Table 16 – What are the stresses that each option for changing locational signals for all generators is primarily designed to address?

Stress	Option 1 – 'Removal of local TNUoS charges'	Option 1a – 'Removal of local TNUoS charges from G:D split'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 3– 'Caps on zonal differentials'	Option 4 – 'Sharpening locational signals'	Option 5 – 'Nodal TNUoS charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'
(Pre-connection) user commitment									
Charging for offshore generation	Removes local generation TNUoS charges	*Removes local generation charges from calculation of residual charges for all generators*	Removes local generation TNUoS charges				Removes local generation TNUoS charges	Removes local generation TNUoS charges	Removes local generation TNUoS charges
Treatment of HVDC interconnections			Costs of HVDC link recovered through residual TNUoS charge	Weakens incremental cost charging in TNUoS charges			Costs of HVDC link recovered through residual TNUoS charge	Costs of HVDC link recovered through residual TNUoS charge	Costs of HVDC link recovered through residual TNUoS charge
Charging for generation on islands remote from demand	Removes local generation TNUoS charges	*Removes local generation charges from calculation of residual charges for all generators*	Removes local and locational generation TNUoS charges	Reduces range of zonal charges			Removes local generation TNUoS charges	Removes local generation TNUoS charges	Removes local generation TNUoS charges
Uncertainty for DG									
Consistency with interconnector imports									
International parity								Zonal congestion charges with FTR are consistent with framework guidelines on congestion management	
Storage and peaking plant							Congestion charges determined by actual network conditions	Congestion charges determined by actual network conditions	Congestion charges determined by actual network conditions
SQSS			Residual is only TNUoS charge (and is not linked to SQSS)				Residual is only TNUoS charge (and is not linked to SQSS)	Residual is only TNUoS charge (and is not linked to SQSS)	Residual is only TNUoS charge (and is not linked to SQSS)
Development of coordinated offshore grid									

Table 17 - What are the stresses that each option for encouraging investment in (some types and/or location of) generation is primarily designed to address?

Stress	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 12 – 'Dynamic calculation of TEC'	Option 13 – 'Energy-based locational TNUoS charges'	Option 14 – 'Energy-based postage stamp charges with local asset charges'	Option 15 – 'No TNUoS charges for generation'	Option 16 – 'No ongoing transmission charges for generation'	Option 17 – 'Technology-differentiated TNUoS charges'
(Pre-connection) user commitment	Reduces financial exposure of project developers to project failure								
Charging for offshore generation		Removes local generation TNUoS charges for offshore generation					Removes local generation TNUoS charges	Removes local generation TNUoS charges	Reduces generation TNUoS charges for low-carbon and/or renewable generation
Treatment of HVDC interconnections		Costs of HVDC link recovered through residual TNUoS charge					Costs of HVDC link recovered through residual TNUoS charge	Remove incremental cost charging from TNUoS charges	
Charging for generation on islands remote from demand		Removes local generation TNUoS charges for island generation					Removes all generation TNUoS charges	Removes all generation TNUoS charge	Reduces generation TNUoS charges for low-carbon and/or renewable generation
Uncertainty for DG			Could be consistent with net TNUoS charges for DG (if adjusted TEC approach applied to DG)	Consistent with net TNUoS charges for DG					
Consistency with interconnector imports							Removes all generation TNUoS charges	Removes all generation TNUoS charges	
International parity	Set average generation charge to 0, which is model used in many European countries						Removes all generation TNUoS charges, which is line with many European countries	Removes all generation TNUoS charges, which is line with many European countries	
Storage and peaking plant			TEC adjusted to reflect expected impact on network	TEC adjusted to reflect modelled impact on network	TNUoS charges are based on metered volumes not TEC	TNUoS charges are based on metered volumes not TEC	Removes all generation TNUoS charges	Removes all generation TNUoS charges	
SQSS					TNUoS charges are based on metered volumes not TEC	TNUoS charges are based on metered volumes not TEC	Removes all generation TNUoS charges	Removes all generation TNUoS charges	
Development of coordinated offshore grid							Removes all generation TNUoS charges	Removes all generation TNUoS charges,	

ANNEX B – ASSESSMENT OF OPTIONS

This Annex includes the following tables containing additional information on the assessment of the options, as summarised in Chapter 4:

- Table 18 presents an extended assessment against the stresses identified by RenewableUK (discussing in more detail the assessment summarised in Table 8);
- Table 19 details the impact of the options on different industry parties (as summarised in Table 9 and Table 10); and
- Table 20 explains how the assessment criteria map onto charging objectives and Table 21 details the assessment against the criteria (supporting the assessment shown in Table 11 and Table 12).

Table 19 focuses on the generation types identified by RenewableUK in its scope for this work. Obviously, there are many other generation types, such as hydro and northern thermal, and some generators that do not fit the characterisation of the generation type in Table 19 – for example, onshore wind located in the south of England. For these generators, an overall impact can be assessed by collecting together the scores based on the characteristic of a generator for each of the following elements:

- distance from demand;
- distance from MITS;
- typical operating pattern;
- timing of development; and
- level of connection (i.e. distribution connected or transmission connected).

Therefore, this table can be used to assess the performance for the very many different (existing and future) generators in GB, which cannot all be separately addressed in Table 19.

Table 18 – Assessment of performance of the options against the stresses

Stress	Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No ongoing TNUoS or BSUoS charges for generation'
(Pre-connection) user commitment	✓/× Changes size of user commitment if linked to TNUoS charge, with impact depending on size of local charge	✓/× Changes size of user commitment if linked to TNUoS charge, with impact depending on location	✓/× Changes size of user commitment if linked to TNUoS charge, with impact depending on location	✓/× Changes size of user commitment if linked to TNUoS charge, with impact depending on location	✓/× Changes size of user commitment if linked to TNUoS charge, with impact depending on location	✓✓ Reduces financial exposure of project developers to project failure	✓/× Changes size of user commitment if linked to TNUoS charge, with impact dependent on exposure to asset costs	✓/× Changes size of user commitment if linked to TNUoS charge, with impact depending on TEC adjustment	✓/× Changes size of user commitment if linked to TNUoS charge, with impact depending on operating pattern	✓ Removes user commitment if linked to TNUoS charges
Charging for offshore generation	✓✓ Removes local generation TNUoS charge	✓✓ Removes local generation TNUoS charge	✓ Removes local generation charge but overall impact depends on detailed design	✓ Removes local generation charge but overall impact depends on detailed design	✓ Removes local generation charge but overall impact depends on detailed design	-	✓✓ Removes local generation TNUoS charges for offshore generation	✓ Adjusted TEC should benefit intermittent generation	✓ Favours low load factor generation	✓✓ Removes local generation TNUoS charges
Treatment of HVDC interconnections	-	✓✓ Costs of HVDC link recovered through residual TNUoS charge	✓✓ Costs of HVDC link recovered through residual TNUoS charge	✓✓ Costs of HVDC link recovered through residual TNUoS charge	✓✓ Costs of HVDC link recovered through residual TNUoS charge	-	✓✓ Costs of HVDC link recovered through residual TNUoS charge	-	-	✓✓ Costs of HVDC link recovered through residual TNUoS charge
Charging for generation on islands remote from demand	✓✓ Removes local generation TNUoS charge	✓✓ Removes local and locational generation TNUoS charges	✓/× Removes local and locational TNUoS charges but overall impact depends on detailed design	✓/× Removes local and locational TNUoS charges but overall impact depends on detailed design	✓/× Removes local and locational TNUoS charges but overall impact depends on detailed design	-	✓✓ Removes local generation TNUoS charges for island generation	✓ Adjusted TEC should benefit intermittent generation	-	✓✓ Removes all generation TNUoS charges
Impact on consistency for DG	-	-	-	-	-	-	-	✓✓ Allows way of ensuring exposure to transmission charges reflects net export pattern	-	-

Stress	Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No ongoing TNUoS or BSUoS charges for generation'
Consistency with interconnector imports	✓ Interconnectors not pay local TNUoS charge	✓ Interconnectors not pay local or locational TNUoS charge	✓ Interconnectors not pay local or locational TNUoS charge	✓ Interconnectors not pay local or locational TNUoS charge	✓ Interconnectors not pay local or locational TNUoS charge	-	✓ Interconnectors not pay local TNUoS charge	-	-	✓✓ Removes all generation TNUoS charges
International parity	✓ Weakens geographical signal, as in a number of other European countries	✓ Weakens geographical signal, as in a number of other European countries	× Lacks long-term hedging opportunity which is key part of framework guidelines on congestion management	✓✓ Zonal congestion charges with FTR are consistent with framework guidelines on congestion management	✓/× In line with spirit of European congestion management guidelines, but nodal rather than zonal	✓✓ Set average generation charge to 0, which is model used in many European countries	-	-	-	✓✓ Sets generation charge to 0, which is model used in many European countries
Storage and peaking plant	× Increases residual TNUoS charge for generation	× Increases residual TNUoS charge for generation	✓✓ Congestion charges determined by actual network conditions	✓✓ Congestion charges determined by actual network conditions	✓✓ Congestion charges determined by actual network conditions		× Increases residual TNUoS charge for generation	✓✓ TEC adjusted to reflect expected impact on network	✓✓ TNUoS charges are based on metered volumes not TEC	✓✓ Removes all generation TNUoS charges
Impact of SQSS on charges	-	✓✓ Residual is only TNUoS charge (and is not linked to SQSS or network modelling)	✓✓ Residual is only TNUoS charge (and is not linked to SQSS or network modelling)	✓✓ Residual is only TNUoS charge (and is not linked to SQSS or network modelling)	✓✓ Residual is only TNUoS charge (and is not linked to SQSS or network modelling)	✓ Option to fix charges for a number of years	-	× More closely link TEC to changes in SQSS	✓✓ Energy-based charging removes link to SQSS	✓✓ Removes all generation TNUoS charges
Development of coordinated offshore grid	- Although this option addresses stresses of offshore wind and import parity, it provides a strong incentive to avoid interconnector or bootstrap being connected to an offshore generator substation as that would put local offshore assets into zonal charging bucket	✓ Removes local generation TNUoS charge	✓ Supports offshore generation and consistency with interconnectors	✓ Supports offshore generation and consistency with interconnectors	✓ Supports offshore generation and consistency with interconnectors	-	✓✓ Removes local generation TNUoS charges for offshore generation	-	✓ Supports offshore generation and consistency with interconnectors	✓✓ Removes all generation TNUoS charges

Table 19 – How do proposed options affect different industry parties?

		Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No TNUoS or BSUoS charges for generation'
Distance of generation from demand centre	Located far from demand centres	-	✓✓ no locational charge	✓/✗ Uncertain, depends on pattern of congestion	✓/✗ Uncertain, depends on pattern of congestion	✓/✗ Uncertain, depends on pattern of congestion	-	✓ costs of HVDC link in residual	-	-	✓✓ no locational charge
	Located close to demand centres	-	✗✗ higher residual charge	✓/✗ Uncertain, depends on pattern of congestion	✓/✗ Uncertain, depends on pattern of congestion	✓/✗ Uncertain, depends on pattern of congestion	-	✗ costs of HVDC link in residual	-	-	-
Distance of generation from main interconnected transmission system (MITS)	Located far from MITS	✓✓ no local charge	✓✓ no local charge	✓ no local charge but impact depends on node definition	✓✓ no local charge	✓ no local charge but impact depends on node definition	-	✓ offshore and island assets excluded from local charge	-	-	✓✓ no local charge
	Located close to MITS	✗ higher residual charge	✗ higher residual charge	✗ higher residual charge	✗ higher residual charge	✗ higher residual charge	-	✗ higher residual charge	-	-	-
Typical operating pattern of generation	Intermittent generation	-	-	✗✗ cannot respond to strong short-term signals	✗ cannot respond to short-term marginal signal	✗ cannot respond to short-term marginal signal	-	-	✓ reduction in TEC, although varies by location	✓✓ (+ve TNUoS) charges paid on metered volume not TEC	✓ no capacity-based charge
	Peaking generation	-	-	✓ can respond to strong short-term signals	✓ can respond to short-term signals	✓ can respond to short-term signals	-	-	✓ reduction in TEC, although varies by location	✓✓ (+ve TNUoS) charges paid on metered volume not TEC	✓ no capacity-based charge
	Baseload generation	-	-	✗✗ does not respond to strong short-term signals	✗ does not respond to short-term marginal signal	✗ does not respond to short-term marginal signal	-	-	✗✗ bears increased share of charges because little, if any, reduction in TEC	✗✗ bears increased share of (+ve TNUoS) charges because higher share of generation than capacity	-

		Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No TNUoS or BSUoS charges for generation'
Timing of generation development	Past commissioning	-	-	-	-	-	-	-	-	-	-
	Future commissioning	-	-	-	-	-	✓ Sunk costs can count towards user commitment	-	-	-	-
Level at which generator is connected (under current charging arrangements)	Connection to DG	-	✓/× Depends on location due to pattern of changes in demand charges				✓ Increases average demand charge (and lowers generation charge if generator TNUoS applied to all generation)	-	✓/× Depends if adjusted TEC approach applied to DG	✓/× Depends on ability to direct generation to Triad period	✓ Increases average demand charge (and removesgeneration charge if generator TNUoS applied to all generation)
	Direct connection	-	-	-	-	-	-	-	-	-	-

		Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No TNUoS or BSUoS charges for generation'
Generic forms of low-carbon generator	Onshore Wind (remote from demand and intermittent)	✓/✗ depends on distance from MITS	✓✓ no locational charge	✓/✗ exposed to short-term signal with overall impact varying by location	✓/✗ exposed to short-term signal with overall impact varying by location	✓/✗ exposed to short-term signal with overall impact varying by location	✓ reduction in average charge, with option to fix charges	✓ costs of HVDC link in residual	✓ reduction in TEC for intermittent generation, although varies by location	✓ locational charges paid on metered volumes	✓✓ no generation charges
	Offshore Wind (located far from MITS and intermittent)	✓✓ no local charge	✓ no local charge but overall impact varies by charging zone	✓/✗ no local charge but exposed to short-term signal with overall impact varying by location	✓/✗ no local charge but exposed to short-term signal with impact varying by location	✓/✗ no local charge but exposed to short-term signal with overall impact varying by location	✓ reduction in average generation charge, with option to fix charges	✓✓ no local charge for offshore assets	✓ reduction in TEC for intermittent generation, although varies by location	✓ locational charges paid on metered volumes	✓✓ no generation charges
	Wave & Tidal (all new generation, remote from demand located far from MITS and intermittent)	✓✓ no local charge no local charge	✓✓ no local charges and no locational charge	✓/✗ exposed to short-term signal with overall impact varying by location	✓/✗ exposed to short-term signal with overall impact varying by location	✓/✗ exposed to short-term signal with overall impact varying by location	✓✓ sunk costs can be user commitment and lower average charge, with option to fix charges	✓✓ no local charge for offshore assets, and costs of HVDC link in residual	✓ reduction in TEC for intermittent generation, although varies by location	✓ locational charges paid on metered volumes	✓✓ no generation charges
	Nuclear (close to MITS, not remote from demand and baseload)	✗ higher residual charge	✗ higher residual charge	✓/✗ higher residual and does not respond to short term signal but overall impact depends on location	✓/✗ higher residual and does not respond to short term marginal signal but overall impact depends on location	✓/✗ higher residual and does not respond to short term marginal signal but overall impact depends on location	✓ reduction in average generation charge, with option to fix charges	✗ higher residual charge	✗✗ bears increased share of +ve TNUoS charges because little, if any, reduction in TEC	✗✗ bears increased share of charges because higher share of generation than capacity	✓ no generation charges
	CCS (close to MITS and baseload/mid-merit)	✗ higher residual charge	✓/✗ higher residual charge but overall impact varies by charging zone	✓/✗ Higher residual with impact dependent on location and ability to respond to short term signal	✓/✗ higher residual with impact dependent on location and ability to respond to short term signal	✓/✗ higher residual with impact dependent on location and ability to respond to short term signal	✓ reduction in average generation charge, with option to fix charges	✗ higher residual charge	✗ bears increased share of +ve TNUoS charges because little, if any reduction in TEC	✗ bears increased share of charges	✓ no generation charges

		Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No TNUoS or BSUoS charges for generation'
High-carbon generation	Fossil Fuel (close to MITS and mid-merit/peaking)	× higher residual charge	✓/× higher residual charge but overall impact varies by charging zone	✓/× higher residual with overall impact dependent on location and ability to respond to short term signal	✓/× higher residual with overall impact dependent on location and ability to respond to short term signal	✓/× higher residual with overall impact dependent on location and ability to respond to short term signal	✓ reduction in average generation charge, with option to fix charges for a number of years	× higher residual charge	✓/× impact on TEC depends on operating pattern	✓/× impact depends on operating pattern	✓ no generation charges
Network operator	SO	× Increased constraints	× Increased constraints	✓ support for peaking generation	✓ support for peaking generation	✓ support for peaking generation	✓ support for peaking generation		✓ support for peaking generation	- SO has more problems and more options	- SO has more problems and more options
	TO		✓ more remote generation increases asset base	× discourages remote generation, which would increase asset base	× discourages remote generation, which would increase asset base	× discourages remote generation, which would increase asset base	✓ more remote generation increases asset base			✓ more remote generation increases asset base	✓ more remote generation increases asset base
	OFTO	✓ supports offshore generation	✓ supports offshore generation				✓ supports offshore generation	✓ supports offshore generation	✓ supports offshore generation	✓ supports offshore generation	✓ supports offshore generation
	DNO						✓ supports DG	-	✓ If facilitate more consistent treatment of DG		✓ supports DG

		Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No TNUoS or BSUoS charges for generation'
Location of demand	Northern		× No locational signals for demand	✓/× Depends on congestion not location	✓/× Depends on congestion not location	✓/× Depends on congestion not location					
	Southern		✓ No locational signals for demand	✓/× Depends on congestion not location	✓/× Depends on congestion not location	✓/× Depends on congestion not location					

		Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No TNUoS or BSUoS charges for generation'
Type of demand	Large demand that cannot avoid Triad			✓/× No Triad but may not be able to respond to short-term signals	✓/× No Triad but may not be able to respond to short-term signals	✓/× No Triad but may not be able to respond to short-term signals	× Increases costs recovered by Triad charge			✓ Removes Triad charge	× Increases costs recovered by Triad charge
	Large demand that can avoid Triad			✓/× Removes Triad but may be able to respond to short-term signals	✓/× Removes Triad but may be able to respond to short-term signals	✓/× Removes Triad but may be able to respond to short-term signals				× Removes benefit of avoiding Triad periods	

Table 20 – Objectives of transmission charging arrangements and associated assessment criteria

Criteria \ Objectives	Affordability	Environment	Security of Supply	Other compliance
Supporting efficient (dis)investment decisions for generation	✓✓		✓✓	
Supporting efficient (dis)investment decisions for transmission	✓✓		✓✓	
Supporting efficient operation decisions	✓✓	✓	✓✓	
Cost reflectivity for generation	✓✓			✓✓ Requirement of 3rd package
Facilitation of competition in GB	✓✓		✓	
Facilitation of competition in the EU	✓✓			✓✓ Requirement of 3rd package
Facilitate investment to meet renewable targets (15% RES = 30RES-E)		✓✓	✓✓	
Facilitate investment to meet low carbon targets		✓✓	✓✓	
Facilitate operation to meet renewable targets (15% RES = 30RES-E)		✓✓	✓✓	
Facilitate operation to meet low carbon targets		✓✓	✓✓	
Within-year predictability	✓✓		✓✓	
Between year predictability	✓✓		✓✓	
Consistency with European guidelines on congestion management				✓✓ Draft FG on congestion management
Non-discrimination (including treatment of peripheral generation)				✓✓ Requirement of 3rd package
Better regulation principles (transparent, accountable, proportionate, consistent, targeted)				✓✓ Ofgem duty
Administrative complexity	✓✓			
Ease of implementation	✓✓			
Ease of understanding for users	✓✓			

Table 21 – How do proposed options perform against assessment criteria

Criteria	Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No ongoing TNUoS or BSUoS charges for generation'
Supporting efficient (dis)investment decisions for generation	× TNUoS charges do not provide signal with respect to requirements for local assets	×× TNUoS charges provide no locational signals	✓ Locational signals based on actual network flows	✓ Locational signals based on actual network flows	✓ Locational signals based on actual network flows	-	× narrower scope of local signals in TNUoS charges	✓ adjusted TEC should reflect network impact	-	×× no signals to directly-connected generation beyond connection charge
Supporting efficient (dis)investment decisions for transmission	× TNUoS charges do not provide signal with respect to requirements for local assets	×× TNUoS charges provide no locational signals	✓ Locational signals based on actual network flows	✓ Locational signals based on actual network flows	✓ Locational signals based on actual network flows	-	✓/× narrower scope of local signals in TNUoS charges but consistency in treatment of DC and AC	✓ adjusted TEC should reflect network impact	✓ Locational signals based on network flows and not capacity	×× no signals to directly-connected generation beyond connection charge
Supporting efficient operation decisions	-	-	✓✓ Short-run locational signals based on actual network conditions	✓ Averaging of short-run locational signals based on actual network conditions	✓✓ Short-run locational signals based on actual network conditions	-	-	-	-	× constraint costs no longer socialised across generators
Cost reflectivity for generation	× TNUoS charges do not provide signal with respect to requirements for local assets	×× TNUoS charges provide no locational signals	✓✓ Locational signals based on actual network conditions	✓ Averaging of locational signals based on actual network conditions	✓✓ Locational signals based on actual network conditions	-	× narrower scope of local signals in TNUoS charges	-	× TNUoS charges provide no capacity-based signals	×× no signals to directly-connected generation beyond connection charge
Facilitation of competition in GB	✓ support connection of offshore and island generation	✓✓ support connection of offshore and island and remote generation	-	-	-	✓ support connection of generation	✓✓ support connection of offshore, island and remote generation	-	✓ support peaking generation	✓✓ support connection of generation

Criteria	**Option 1 – 'Removal of local TNUoS charges'**	**Option 2 – 'Postage stamp capacity (TNUoS) charges'**	**Option 6 – 'Nodal congestion charges'**	**Option 7 - 'Zonal congestion charges with FTRs'**	**Option 8 - 'Nodal congestion charges with FTRs'**	**Option 9 – 'Facilitate generation connection with locational signals'**	**Option 10 – 'Change allocation of assets to residual TNUoS'**	**Option 11 – 'TEC adjusted for technology and location'**	**Option 13– 'Energy-based locational TNUoS charges'**	**Option 16– 'No ongoing TNUoS or BSUoS charges for generation'**
Facilitation of generation competition in the EU	✓ support competition between renewables	✓✓ support competition between renewables	-	✓ consistent with approach in draft FG on congestion management	-	✓ Average generation charge set to 0 (in line with many other European countries)	✓✓ support competition between renewables	-	✓ support peaking generation	✓✓ support connection of generation
Facilitate investment to meet renewable targets (15% RES = 30%RES-E)	✓ support connection of offshore and island generation	✓✓ support connection of offshore, island and remote generation	×× intermittent renewables may not to be able to respond to short-term locational signals	× Hedging through FTRs means that intermittent renewables are only exposed to marginal not average price signals	× Hedging through FTRs means that intermittent renewables are only exposed to marginal not average price signals	✓ support connection of generation, whilst retaining locational signals	✓✓ support connection of offshore, island and remote generation	✓✓ support connection of intermittent generation	✓✓ support intermittent and peaking generation	✓✓ support connection of generation
Facilitate investment to meet low-carbon targets	✓ support connection of offshore and island generation	✓ support connection of offshore, island and remote generation, but may discourage investment in other low-carbon technologies	× unclear as to how other low-carbon generation will be able to respond to short-term locational signals	-	-	✓✓ support connection of generation	✓ support connection of offshore, island and remote generation	✓ support connection of intermittent generation, but may discourage investment in baseload low-carbon technologies	✓ Negatively affects baseload nuclear generation, but this is dampened by locational signal. Support intermittent and peaking renewable generation	✓✓ support connection of generation
Facilitate operation to meet renewable targets (15% RES = 30%RES-E)	-	-	× impact on renewables operation may be offset by benefits of incentives for flexibility	× impact on renewables operation may be offset by benefits of incentives for flexibility	× impact on renewables operation may be offset by benefits of incentives for flexibility	-	-	-	× TNUoS charges are affected by plant operation but do not reflect operational costs	-
Facilitate operation to meet low-carbon targets	-	-	-	-	-	-	-	-	-	-

Criteria	**Option 1 – 'Removal of local TNUoS charges'**	**Option 2 – 'Postage stamp capacity (TNUoS) charges'**	**Option 6 – 'Nodal congestion charges'**	**Option 7 - 'Zonal congestion charges with FTRs'**	**Option 8 - 'Nodal congestion charges with FTRs'**	**Option 9 – 'Facilitate generation connection with locational signals'**	**Option 10 – 'Change allocation of assets to residual TNUoS'**	**Option 11 – 'TEC adjusted for technology and location'**	**Option 13– 'Energy-based locational TNUoS charges'**	**Option 16– 'No ongoing TNUoS or BSUoS charges for generation'**
Within-year predictability	-	-	✗ affected by actual plant operation	✓/✗ Depends on allocation and pricing of FTRs	✓/✗ Depends on allocation and pricing of FTRs	-	-	-	-	-
Between year predictability	-	✓ TNUoS charges not affected by siting decisions of other users	✗ affected by actual plant operation	-	✓ Hedging through FTRs, and nodal charges limits impact of decisions of other parties	✓✓ Option to fix charges for number of years (although may increase volatility of non-fixed charges)	-	-	✗ Harder to predict energy ex ante than capacity	✓/✗ Highly predictable for generators, but more volatile for demand
Consistency with EU guidelines	-	-	✗ Draft FG based around zonal pricing with FTRs	✓ Draft FG based around zonal pricing with FTRs	-	-	-	-	-	-
Non-discrimination	✓/✗ Depends on interpretation of non-discrimination (on grounds of location)	✓/✗ Depends on interpretation of non-discrimination (on grounds of location)	✓ Locational signals based on network conditions	✓ Locational signals based on network conditions	✓ Locational signals based on network conditions	✓/✗ Depends on interpretation of non-discrimination (existing v future generation)	✓/✗ Depends on interpretation of non-discrimination (DC v AC; location)	✓ TEC based on network impact	✓/✗ Depends on interpretation of non-discrimination (on grounds operating pattern)	-
Better regulation principles	-	✓ Increased transparency of charges	✗✗ Radical departure from previous policy position and spill over into other areas currently under review (e.g. EMR)	✗ Departure from previous policy position and spill over into other areas currently under review (e.g. EMR)	✗ Departure from previous policy position and spill over into other areas currently under review (e.g. EMR)	✓ Targeted measures whilst retaining locational signals in line with existing policy	✓ Targeted measures whilst retaining overall locational signals in line with existing policy	✓ Transparent and targeted measures	✓/x Transparent approach but not targeted	✓/✗ Transparent approach but not targeted and not consistent with previous policy position

Administrative complexity	✓ Remove asset category	✓✓ Charges are postage stamp	× Need to assure coherence with rest of market framework	×× Change philosophy, need to assure coherence with rest of market framework , implement FTRs	×× Change philosophy, need to assure coherence with rest of market framework , implement FTRs	× Monitoring of 'sunk costs' and need to manage differences between generation on fixed and floating charges	× Needs to define the assets selected	× Needs to define the technology and location (although this may be done through SQSS process anyway)	-	✓✓ Transmission charges are removed for generation
Ease of implementation for grid and participants	-	-	× Change philosophy of arrangements	×× Change philosophy of arrangements and need to allocate FTRs	×× Change in philosophy of arrangements and need to allocate FTRs	-	-	× Increases lobbying pressure on grid, and creates additional variable for users that could change	× Need to link energy and charges	✓✓ All charges are passed to demand
Ease of understanding for users	✓ All local TNUoS charges are removed – no exception	✓✓ All generation pays the same charge	× Users need to understand the new philosophy, including new risks	×× Users need to understand the new philosophy and value FTRs	×× Users need to understand the new philosophy and value FTRs	-	-	× Depends on transparency and complexity of rules for making adjustments	✓ Charges are paid on an energy basis	✓✓ Generation doesn't pay

ANNEX C – INTERACTION BETWEEN DIFFERENT OPTIONS

Table 22 contains a detailed discussion of how the different options could be combined (as summarised in Table 13).

Table 22 – How can the options be combined to create new options?

What happens if changes in option below are added to option to the right?	Option 1 – 'Removal of local TNUoS charges'	Option 2 – 'Postage stamp capacity (TNUoS) charges'	Option 6 – 'Nodal congestion charges'	Option 7 - 'Zonal congestion charges with FTRs'	Option 8 - 'Nodal congestion charges with FTRs'	Option 9 – 'Facilitate generation connection with locational signals'	Option 10 – 'Change allocation of assets to residual TNUoS'	Option 11 – 'TEC adjusted for technology and location'	Option 13– 'Energy-based locational TNUoS charges'	Option 16– 'No ongoing transmission charges for generation'
Option 1 – 'Removal of local TNUoS charges'	n/a	**Duplicate** (Option 2 has no local charges)	**Duplicate** (Option 6 has no local charges)	**Duplicate** (Option 7 has no local charges)	**Duplicate** (Option 8 has no local charges)	**New option** (Option 9 with no local charges)	**New option** (Option 1 with amended calculation of locational charges)	**New option** (Locational and residual charges applied to adjusted TEC)	**New option** (Energy-based locational and residual charges)	**Duplicate** (Option 16 has no local charges)
Option 2 – 'Postage stamp capacity (TNUoS) charges'	**Duplicate** (Option 2 has no local charges)	n/a	**Duplicate** (Option 6 has no local or locational TNUoS charges)	**Duplicate** (Option 7 has no local or locational TNUoS charges)	**Duplicate** (Option 8 has no local or locational TNUoS charges)	**New option** (like Option 16 with revised user commitment)	**Duplicate** (Option 2 has no local or locational charges)	**New option** (postage stamp charges applied to adjusted TEC)	**New option** (postage stamp charges applied to metered volumes)	**Duplicate** (Option 16 has no local or locational charges)
Option 6 – 'Nodal congestion charges'	**Duplicate** (Option 6 has no local charges)	**Duplicate** (Option 6 has no local or locational TNUoS charges)	n/a	**Conflicting changes** (congestion charges cannot be both nodal and zonal)	**Duplicate** (Option 8 is Option 6 with FTRs)	**New option** (generator TNUoS effectively zero, with nodal congestion charges)	**Duplicate** (Option 6 has no local or locational TNUoS charges)	**New option** (postage stamp TNUoS charges applied to adjusted TEC, with short-run nodal congestion charges)	**New option** (postage stamp TNUoS charges applied to adjusted TEC, with short-run nodal congestion charges)	**Conflicting changes** (Option 6 targets short-run charges but Option 16 removes them)
Option 7 - 'Zonal congestion charges with FTRs'	**Duplicate** (Option 7 has no local charges)	**Duplicate** (Option 7 has no local or locational TNUoS charges)	**Conflicting changes** (congestion charges cannot be both nodal and zonal)	n/a	**Conflicting changes** (congestion charges cannot be both nodal and zonal)	**New option** (generator TNUoS effectively zero, with zonal congestion charges)	**Duplicate** (Option 7 has no local or locational TNUoS charges)	**New option** (postage stamp TNUoS charges applied to adjusted TEC, with short-run zonal congestion charges)	**New option** (postage stamp TNUoS charges applied to adjusted TEC, with short-run zonal congestion charges)	**Conflicting changes** (Option 7 targets short-run charges but Option 16 removes them)
Option 8 - 'Nodal congestion charges with FTRs'	**Duplicate** (Option 8 has no local charges)	**Duplicate** (Option 8 has no local or locational TNUoS charges)	**Duplicate** (Option 8 is Option 6 with FTRs)	**Conflicting changes** (congestion charges cannot be both nodal and zonal)	n/a	**New option** (generator TNUoS effectively zero, with nodal congestion charges)	**Duplicate** (Option 8 has no local or locational TNUoS charges)	**New option** (postage stamp TNUoS charges applied to adjusted TEC, with short-run nodal congestion charges)	**New option** (postage stamp TNUoS charges applied to adjusted TEC, with short-run nodal congestion charges)	**Conflicting changes** (Option 8 targets short-run charges but Option 16 removes them)
Option 9 – 'Facilitate generation connection with locational signals'	**New option** (Option 9 with no local charges)	**New option** (like Option 16 with revised user commitment)	**New option** (generator TNUoS effectively zero, with nodal congestion charges)	**New option** (generator TNUoS effectively zero, with zonal congestion charges)	**New option** (generator TNUoS effectively zero, with nodal congestion charges)	n/a	**New option** (Option 9 with amended local and locational signals)	**New option** (Option 9 with adjusted TEC)	**New option** (Option 9 with TNUoS charges applied to metered volumes)	**New option** (Option 16 with revised user commitment)

Option 10 – 'Change allocation of assets to residual TNUoS'	**New option** (Option 1 with amended calculation of locational charges)	**Duplicate** (Option 2 has no local or locational charges)	**Duplicate** (Option 6 has no local or locational TNUoS charges)	**Duplicate** (Option 7 has no local or locational TNUoS charges)	**Duplicate** (Option 8 has no local or locational TNUoS charges)	**New option** (Option 9 with amended local and locational signals)	n/a	**New option** (amended TNUoS charges applied to adjusted TEC)	**New option** (amended TNUoS charges applied to metered volumes)	**Duplicate** (Option 16 has no local or locational charges)
Option 11 – 'TEC adjusted for technology and location'	**New option** (Locational and residual charges applied to adjusted TEC)	**New option** (postage stamp charges applied to adjusted TEC)	**New option** (postage stamp TNUoS charges applied to adjusted TEC, with short-run nodal congestion charges)	**New option** (postage stamp TNUoS charges applied to adjusted TEC, with short-run zonal congestion charges)	**New option** (postage stamp TNUoS charges applied to adjusted TEC, with short-run nodal congestion charges)	**New option** (Option 9 with adjusted TEC)	**New option** (amended TNUoS charges applied to adjusted TEC)	n/a	**Conflicting changes** (both options change basis for levying TNUoS charges)	**Duplicate** (Option 16 has no TNUoS charges so charging basis is irrelevant)
Option 13– 'Energy-based locational TNUoS charges'	**New option** (Locational and residual charges applied to metered volumes)	**New option** (postage stamp charges applied to metered volumes	**New option** (postage stamp TNUoS charges applied to metered volumes, with short-run nodal congestion charges)	**New option** (postage stamp TNUoS charges applied to metered volumes, with short-run zonal congestion charges)	**New option** (postage stamp TNUoS charges applied to metered volumes with short-run nodal congestion charges)	**New option** (Option 9 with TNUoS charges applied to metered volumes)	**New option** (amended TNUoS charges applied to metered volumes)	**Conflicting changes** (both options change basis for levying TNUoS charges)	n/a	**Duplicate** (Option 16 has no TNUoS charges so charging basis is irrelevant)
Option 16– 'No ongoing transmission charges for generation'	**Duplicate** (Option 16 has no local charges)	**Duplicate** (Option 16 has no local or locational charges)	**Conflicting changes** (Option 6 targets short-run charges but Option 16 removes them)	**Conflicting changes** (Option 7 targets short-run charges but Option 16 removes them)	**Conflicting changes** (Option 8 targets short-run charges but Option 16 removes them)	**New option** (Option 16 with revised user commitment)	**Duplicate** (Option 16 has no local or locational charges)	**Duplicate** (Option 16 has no TNUoS charges so charging basis is irrelevant)	**Duplicate** (Option 16 has no TNUoS charges so charging basis is irrelevant)	n/a

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