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Electricity transmission arrangements in Great Britain: Time for change?

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H I G H L I G H T S

- We identify three key areas of concern with the current transmission arrangements.
- We then propose three options for transmission network planning and delivery.
- Key strengths and weaknesses of each above option are identified and studied.
- We conclude that the most appropriate option for GB would be that of an ISO.

A R T I C L E I N F O

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A B S T R A C T

In Great Britain (GB) and across Europe significant investment in electricity transmission is expected over the coming years as decarbonisation and market integration efforts are intensified. However, there is also significant uncertainty with the amount, location and timing of new generation connection, which in turn will drive the transmission investment needs. Given the absence of efficient market design, we identify three key areas of concern with the current transmission investment arrangements: (i) a misaligned incentives framework for transmission investment and operation; (ii) lack of coordination of investment and operation; and (iii) conflicts of interest. We then propose three options for future evolution of transmission regimes, which cover the full spectrum of institutional arrangements with respect to transmission planning and delivery, i.e. how and who plans, owns, builds and operates the transmission system. For each option we present: key characteristics; evolution of the current regimes; the ability of the option to address the concerns; and key strengths and weaknesses. Overall, we conclude in the case of GB (this conclusion could be extended to other European countries) that the most appropriate option would be that of an Independent System Operator (ISO) who would be responsible for planning and operating the transmission system.

1. Introduction

In Great Britain (GB) it is projected that a very significant amount of transmission investment will be needed in the coming years to support efficient integration of low carbon generation within the EU context (e.g. Ofgem, 2012a). Indicatively, these investments will be the largest transmission network reinforcements since post-World War II expansion. In Table 1 the projected range of onshore, offshore and cross-border investments to 2030 is presented against the estimated asset values.[1]

As Table 1 indicates, not only is there expected to be an exceptionally large transmission investment programme over the next years but there is also significant uncertainty regarding the amount, location and timing of new generation connection. As described in ENTSO-E (2012) similar investment programmes in

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[1] The expected investment ranges have been established by considering minimum and maximum investment scenarios from a number of sources including Ofgem (2012a), Imperial College and NERA Consulting (2012) and the National Grid Electricity Ten Year Statement available at ⟨http:/www.nationalgrid.com/uk/electricity/ten-year-statement/⟩.

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Table 1
Current and projected transmission Regulatory Asset Value (RAV) (£bn).

	Estimated asset value at 2012 (£bn)	Expected investment to 2030 (£bn)
Onshore	8.4	6.2–12.4[a]
Offshore	2.5	8–20
Interconnection	2	8–20

[a] To 2021.

terms of scale are under way in continental Europe as well as other parts of the world.

This paper reviews whether the current arrangements for system planning and delivery are fit for purpose in meeting the identified investment challenges in a timely and efficient manner and in particular aims to answer the following key questions:

- *Planning*: Will the current arrangements deliver an optimum level of transmission that will maximise social welfare?
- *Delivery*: Will this investment be undertaken in an efficient manner and delivered at minimum cost?
- *Options*: If not, what are the options for improvement of the present regimes?

This paper identifies that the overarching weaknesses of the current transmission arrangements in GB and across Europe stem mainly from the lack of efficient transmission access pricing due to the absence of locational marginal energy prices as proposed in Hogan (2011). However, recognising that a radical market design change is unlikely in the short to medium term, we have identified three key areas of concerns that would need to be addressed if efficient transmission pricing is not implemented. Subsequently, we propose three options for future evolution of transmission regimes, which cover the full spectrum of institutional arrangements with respect to transmission planning and delivery. For each option we present: key characteristics; evolution of the current regimes; the ability of the option to address the concerns; and key strengths and weaknesses.

The analysis presented in this paper was carried out as part of Ofgem's Integration Transmission Planning and Regulation (ITPR[2]) and as a result it is focused on the GB transmission arrangements. However, related issues are faced by the majority of European countries that operate under similar market designs to GB, making the conclusions of this paper relevant for evaluating the efficiency of their national transmission arrangements. In addition, in order to realise the significant benefits of EU energy market integration, as quantified by Booz & Company et al. (2013), efficient transmission operation and investment in both national and cross-border levels will be required. Beyond GB and Europe, this paper aims to inform the ongoing debate, identified by Chawla and Pollitt (2013), on which is the set of transmission arrangements that represents the best practice.

The paper is structured as follows: in Section 2 we present our method of analysis where we compare implemented against theoretically ideal institutional arrangements. As a result of our analysis, in Sections 3 and 4 we identify the key current regime weaknesses and the options for change, respectively. In Section 5 we conclude and discuss policy implications. In order to increase the clarity of the paper for non-GB audiences we have also included an Appendix with a list of abbreviations and definitions of the GB related nomenclature used throughout this paper.

[2] More information available at: ⟨https://www.ofgem.gov.uk/electricity/transmission-networks/integrated-transmission-planning-and-regulation⟩.

2. Method of analysis

In this section we firstly examine (i) the main aspects of the current GB transmission investment arrangements in light of the challenges going forward, and then (ii) the theoretically ideal alternative arrangements for efficient transmission investment. Based on a comparative analysis between implemented and theoretically ideal institutional arrangements that can deliver efficient transmission investment, we aim at identifying the key current regime weaknesses and thus propose alternative regimes for addressing these weaknesses.

2.1. Current transmission arrangements and future challenges

The GB electricity market is a bilateral market with non-location specific energy pricing. Currently there are three distinct transmission arrangements, namely the onshore, offshore and interconnection regime. Next sections give a high level description of the three regimes and their main interactions.

2.1.1. Onshore regime

The onshore system is owned by three companies: National Grid owns the 275 and 400 kV network in England and Wales and two vertically integrated utilities, Scottish Power Transmission Limited (SPTL) and Scottish Hydro-Electric Transmission Limited (SHETL), own the 132, 275 and 400 kV system in Scotland. For simplicity the Scottish Transmission Owners (TOs) will be only referred to as TOs for the remainder of this paper. National Grid is an unbundled transmission utility and also acts as the GB System Operator. Throughout this paper National Grid will be referred to as the NETSO when referring to its role as GB system operator and NGET or TO when referring to its function of transmission owner of the England and Wales transmission system. Theoretically, these two functions of National Grid are internally separated. Transmission planning and delivery is in broad terms reactive, in the sense that firm financial user commitment is required so as to trigger transmission investment, which is subject to regulatory approval through the price control regime. The TOs are mainly responsible for planning and delivering transmission investment in their own jurisdictions, although there is a certain degree of co-ordination between them with regards to planning and delivering wider works (i.e. major transmission infrastructure with nation-wide impact). Moreover, there are certain provisions for anticipatory investment mainly driven by the need for integrating renewable energy, which is predominantly located in Scotland and offshore in the future. Although the price of energy is location non-specific, there are annual transmission tariffs, called Transmission Network Use of System charges (TNUoS), which are paid by the market participants to the NETSO, who then distributes this revenue to the TOs. These charges consist of annually fixed regulated locationally varying tariffs and additional non-location specific flat tariffs (known as the residual) and range from around £20/kW/yr in Northern Scotland to −£5/kW/yr in South West England for generators. Currently, the majority of system costs (c. 75%) are collected through the residual flat charges implying a high level of cost socialisation. The regulated revenue to be collected is split 27/73 between generation (27 price zones) and demand (14 price zones). The locational part of the TNUoS tariffs is computed using the published ICRP methodology (National Grid, 2010), which intends to reflect the long run marginal costs of transmission investment. The current asset value of the onshore network is estimated to be £8.4 bn, whereas transmission investment to 2021 is expected to be between £6.2 bn and £12.4 bn subject to specific triggers, which mainly depend on the level of renewables connecting to the system (National Grid, 2012).