REVIEW OF INTERNATIONAL MODELS OF TRANSMISSION CHARGING ARRANGEMENTS

A REPORT FOR OFGEM

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Final Report

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CONTENTS

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IMPORTANT NOTICE

1. INTRODUCTION AND PROJECT OVERVIEW

Cambridge Economic Policy Associates (CEPA) has been retained by Ofgem to undertake a broad review of transmission charging. In particular, Ofgem sought support on:

- surveying electricity and gas transmission charging models including a review of the coverage, basis and principles for the regime; and
- an evidence based assessment of the strengths and weaknesses of the various models, including some comparison to the existing British system.

The terms of reference are provided as annex 1 to this report. It should be noted that they provide a guide to the coverage of the report but the final coverage of the project was refined based on our proposal.

This project is an element of the ongoing Project TransmiT initiated by Ofgem in 2010. This report is aimed at providing background information germane to possible future reforms to the existing transmission charging regime in Great Britain. In this report, we consider the key characteristics of transmission regimes across jurisdictions.

1.1. Approach

Much has been written about transmission charging and numerous studies have been undertaken considering some, or all, the elements of transmission charging in different jurisdictions. Consequently our approach has been to:

- consider what is actually meant by transmission charging and what factors need to be included when evaluating an approach;
- cover both the gas and electricity sectors although our greatest emphasis has been on the latter;
- draw on the wide range of existing secondary information to form an overview of the main dimensions/elements of transmission charging (but not seeking to be comprehensive in terms of the geographical coverage, rather ensuring that examples of options within each dimension are caught); and
- drilling down on a smaller set of case studies where the detail of the approach can be more adequately described and evidence, albeit anecdotal or based on secondary sources, on the impact considered.

Trying to capture the breadth of transmission charging across multiple jurisdictions leads to a situation where we have to focus on the high-level and often characterise what are complex systems in a quite simple or shorthand manner. That is a weakness of this type of survey but we believe that this type of analysis is useful in providing a broad view of the options and trade-offs that have to be taken when setting a transmission charging system. If readers are interested in more detail on the various examples in this paper the sources we have used are noted and there are numerous primary data sources, such as charging methodologies, grid codes etc that can provide the detail.

The paper is structured as follows:

- Section 2 considers the objectives and underlying principles of transmission charging;
- Section 3 provides an overview of the key dimensions and the options that have been adopted in the gas and electricity sectors;
- Section 4 provides more detailed analysis of aspects of transmission charging for the case studies; and
- Section 5 concludes with several observations drawn from this survey.

A series of annexes provide the overview tables and more detailed case studies and a bibliography noting the wide range of existing studies and material that have formed the base of this report.

Several key individuals in the jurisdictions of the case studies have provided inputs to this study, either through discussions of the case studies or comments on them. We would like to thank those individuals for their time and effort. Of course, no responsibility for the coverage of the case studies and any mistakes or misunderstandings falls on those individuals but rather reflects our own failings.

1.2. Choice of case studies

While the overview provides an illustration of the range of options that exist for the various dimensions of transmission charging and the way in which they fit into the broader context of the energy market, it is difficult to draw much apart from a general sense of the impact. This was done in part by considering the level of development of renewable generation in the markets – detail on which is provided in the annexes.

To provide greater insight into the strengths and weaknesses of the various approaches and the trade-offs inherent in establishing the transmission charging "package" a set of more detailed case studies have been prepared. These case studies are then supported by a couple of additional examples of key dimension options.

The choice of the five case studies is based on achieving:

- a mix of examples;
- experience with a range of different key characteristics; and
- ease of analysis through the availability of information, access to key staff etc.

These criteria are linked to the objectives discussed later in this report.

Table 1.1 summarises the rationale for the five case studies that have been considered.

Table 1.1: Rationale for the choice of case studies

Case	Rationale
Australia	A different approach to locational impacts. Currently investigating whether changes are needed to the system.
Germany	Load only payments and a significant issue re wind based renewables. Review of the use of locational signals underway.
Netherlands	Increasing concerns about congestion and use of alternative approaches (linked to planning) rather than price-based incentives.
Spain	Country with strong growth in renewables and what is perceived as a relatively simple transmission charging system.
PJM (US)	Strong use of sharp locational signals. Link to some broader issues such as financial transmission rights.

2. OBJECTIVES

Before considering the various approaches/packages for delivering the objectives of transmission charging, or the underlying principles, it is important to consider what those objectives or principles might be. This also allows us to place in the context the specific objective of Project TransmiT and the consequent implications that has for our analysis of alternative transmission charging models.

2.1. Broad objectives and principles

Regulation and government intervention is primarily aimed at replicating "competitive" outcomes in situations where the market is unable to deliver those outcomes. As such, an overall objective has to be to ensure allocative, productive and dynamic efficiency since this will ensure consumers are facing the sustainable long-term costs for the industry. Given this overall objective a primary principle underlying transmission charging should be cost reflectivity (of efficient costs).

Cost reflectivity can be interpreted in different ways and applied to different types of cost. The types of cost that can be considered include the costs of connection to the network, the costs of the ongoing operation of the network, and other costs, such as congestion, balancing etc. Whether cost reflectivity relates to each cost or aggregate costs needs to be considered. Other aspects of cost reflectivity and how it can be applied include thinking of costs in terms of:

- time of day/season;
- location;
- short-run and long-run; and
- structure of charges.

The principle of cost reflectivity clearly is key to the two other underlying principles: (i) creating appropriate incentives; and (ii) an appropriate allocation of "who pays" the charges. As such, it may be appropriate to think of this as the prime objective.

These other two principles include:

- What incentives are created? There are several areas where transmission charges can create incentives – both for the operation of the system and its development. With respect to the latter it is important to consider incentives for: (i) timing/sequencing of investment; (ii) location of investments; and (iii) the cost efficiency of the investment. Locational signals can be important in terms of encouraging the siting of new plants at the least cost position with respect to access to input fuels, need for new transmission lines to evacuate power to customers and implications for congestion on the network.

- Who is paying for the services provided? It is possible to charge both generators and load/end-consumers for services. The split of charges between the two can have an impact on the incentives for generators since it is not always the case that all those charges will be passed on to final consumers.[1] There are, however, several routes for the payment to be differentiated between generator and load. For example, a generator may pay some of the operational charges as well as some (or all) the connection charge. This would then affect the level of transmission charges being paid by the customer. Costs allocated to the generator would come through the electricity charge while transmission charges allocated to load would come directly through the transmission network charge. Within this dimension there are options, for example, connection charges can be deep or shallow, if they are deep more of the charge is allocated to the generator/user while if they are shallow more of the cost is possibly socialised and/or captured through the use of system or operational charges. A final aspect of this dimension is the split of transmission charges between capacity and commodity, i.e. between the share of capacity or the actual volume transported.

These principles follow quite closely those that were reported by Richard Green and developed by a working group examining electricity restructuring.[2] Annex 3 reports those principles.

2.2. Objectives and principles in the GB system

Having considered what possible underlying principles or objectives might be, it is now worth considering what exists in Great Britain.[3] This is found in:

- the laws under-pinning the Authority and Ofgem;
- Government guidance on environmental and social issues provided to the Authority; and
- National Grid's licence.

The Authority's principal objective is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition. The Authority has several general duties, which relate amongst other things to security of supply, the protection of vulnerable customers, sustainable development and better regulation.

In addition, as set out in the most recent Guidance issued by the Department of Energy and Climate Change a number of issues linked to the networks are addressed, including:

> "The appropriate development of networks is key to achieving the transition to a lower carbon energy system while maintaining security of supply. The Government expects the Authority, within the parameters of its principal objective and general duties, to carry out its functions in relation to industry governance, charging or other regulatory arrangements, in the manner best calculated to bring about:

[1] We do not believe that it is always the case that all transmission charges levied on generators will be passed on to final customers. When generation bears some of the costs their ability to pass this on to final customers through their generation prices will depend on various factors, including the state of competition in the market, whether they are the marginal price setting producer, the structure of long-run demand, etc.

[2] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3): 177-184

[3] Of course, the rules in Great Britain are shaped by the relevant EU directives. Key in this respect are elements of the third directive linked to cost reflective pricing and the independence of the regulator in determining prices.

- improved access to the electricity networks for new generation, including renewable, nuclear and other low carbon forms of generation. Within its statutory remit, the Authority should identify any aspects of the regulatory framework which could act as an undue barrier to meeting the 2020 EU renewable energy targets and pursue the necessary changes to that framework;

- …..

- an early start by network companies in identifying and planning necessary works, in dialogue with developers, to ensure that those plans are better placed in relation to new generation, including renewable, nuclear and other low carbon developments. The Government expects this to mean that more preparatory work will need to take place before firm commitments are given by generators;

- ….

The Government expected the Authority to look for opportunities, within its role and the scope of its powers, to facilitate the transition to a low carbon gas and electricity system in Great Britain. This will require considering the sector as a whole and ensuring that the relative costs and benefits of different approaches, such as better demand management, are fairly allocated."

Given this guidance it is not surprising that the objective of Project TransmiT, as stated in the initial call for evidence, is: "…*to ensure that we have in place 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*."

Within National Grid's licence there are requirements for it to develop and maintain an efficient, co-ordinated and economical system of electricity transmission and the facilitate competition in the generation and supply of electricity. Further objectives for transmission charging are set out in Licence Conditions C5 (use of system charges) and C6 (connection charging). These licence conditions are primarily focused on:

- the facilitation of effective competition; and
- cost reflective charges (as far as is reasonably practicable).

There is a high degree of commonality in the objectives and principles from different sources as set out above, which is not surprising given the relatively high level nature of the objectives and principles as well as the link to EU requirements etc. However, the objectives and principles are often expressed in different ways. For example, at a general economics level the areas of security of supply and sustainable development are reflected within the objective of dynamic efficiency.

There are, however, some differences. The key difference seems to be around the guidance provided by DECC about environmental objectives. These do not appear to yet be fully reflected in the principles employed by NGET.

2.3. Objectives and principles in other jurisdictions

In other jurisdictions transmission objectives tend to be similar to those imposed on Ofgem. For the case studies considered in this report, and set out in the annexes, all consider efficiency, safety and security as being clear objectives. There are, of course, some differences. Further, there may be differences at a more detailed level. For example, in Spain the principles underlying transmission charging include aspects of coherence with other aspects of the energy market. This may have driven the simple uniform charge that facilitates the broader government support for renewables through policies like the feed-in-tariff.

Comparisons also need to take account of other requirements on regulators which may be made explicit in different ways. For example, aspects which would be covered through the better regulation guidelines in the UK are made explicitly in transmission pricing principles in Spain – such as requirements for transparency, objectivity etc. Of course, the degree of specificity is different. In Spain the requirements are specific to transmission charging while for Ofgem these are general requirements which ought to lead to the same outcome. NGET's licence conditions should also lead to similar outcomes. So, the fact that they are not stated as explicit objectives or principles for a regulator does not mean that they are not objectives or principles.

It is interesting to note that in Australia the ongoing review of transmission charging is subject to terms of reference from the Ministerial Council on Energy which, in some respects, reflect similar issues to the DECC social and environmental guidance.

3. DIMENSIONS OF TRANSMISSION CHARGING

The structure and application of individual components of transmission charges are typically used to meet at least the principal objectives for charging set out in Chapter 2 above. It is important to note, however, that other aspects of the overall energy system (including, for example, transmission system planning, or renewable energy subsidies or carbon pricing mechanisms among others) are used as well to help achieve the full set of objectives.

In the electricity industry there is usually also a close interaction between the structure of the energy market and transmission pricing, in the sense that both can be used to achieve some of the principal goals and also sometimes various cost items are included in one area (e.g., transmission charges) rather than the other (e.g., energy markets). For these reasons, we will describe the principal relevant dimensions of both.

The most common set of types of prices and charging are briefly described below. We note that underlying each of these brief characterisations, there are of course substantial details (and variation of details) of approach to implementation in all cases.

3.1. Energy pricing

In today's competitive energy markets there are a variety of pricing approaches. Here we describe several dimensions of those which are focused on short-term or spot prices[4]. In terms of differences of pricing variation within a trading region, these include:

- Single Market Pricing: A single spot energy price applied to the entire trading region. Great Britain's electricity balancing market price or the gas National Balancing Point could be seen as examples of this.
- Zonal or Regional Energy Prices: Separate zones within the overall energy trading system are used to produce individual prices. Nordpool can be seen as an example of this.
- Locational Marginal Pricing (LMP) or Nodal Spot Prices: Individual prices reflecting incremental marginal costs are computed at each "node" of the network. In the US, the PJM system is such a system with generators selling at individual LMPs and loads purchasing energy at individual LMPs. Argentina (among others) also operates such an approach. In some markets, individual LMPs are instead used to price only generation, with suppliers purchasing energy at zonal prices reflecting the integration of LMPs within an offtake zone.

In addition to geographic variation, different approaches to spot energy pricing can also reflect different levels of time detail, with some markets computing prices hourly, others half-hourly or at shorter time durations.

[4] Most organised competitive electricity markets produce short run prices (whether through a GB-like "balancing mechanism" or through a day-ahead gross energy pool price as in the previous GB trading system, or via nodal spot prices or other mechanisms of other markets) of which we focus on here. Most such markets also often support – either as part of market design, or through access to over the counter trading – longer term trading (e.g., bilateral contracts) or price hedging arrangements.

3.2. Capacity pricing

Some energy markets are designed with specific "capacity obligations" on load serving entities (i.e., energy purchasers), which might be met through either evidence of bilateral contracting for capacity commitments, or through organised capacity trading markets (which themselves might or might not be organised with locational differentials).

In other markets, capacity requirements are not set and capacity is not explicitly priced.

3.3. Connection to the transmission system

Connection charges are typically used to charge transmission system users for physical connection to the network. Broadly, there are two alternative approaches to setting such charges:

- "Shallow" Connection Charges: These are usually based on the simply recovering the costs related to the physical connection assets between the connected party and (usually) the nearest network connection point. This approach is used in the UK, Australia, New Zealand and elsewhere.

- "Deep" Connection Charges: These are based on a combination of shallow charges plus the costs related to any additional "downstream" network reinforcement required to support the load of the connected party. This approach is used in PJM in the US, and for load (not generation) in Germany.

3.4. Use of transmission network

Use of Network charges are typically used to charge transmission users for the shared network infrastructure. Issues with the use of network charges include:

- "Postage Stamp" vs "Zonal" Network Charges: In some cases, network charges are uniform throughout the trading region (referred to as "postage stamp" or postalized), while in others they are differentiated locationally as a function of share of either current or long-run costs related to injections or withdrawals in different zones. Examples of uniform (postalized) charging structures are in Netherlands and Spain; GB uses a zonal system.

- Allocation of Charges between Generators and Load: Different countries take different approaches in allocating the total costs of transmission network services to be recovered from generators and load customers. Many countries make such charges only to load (e.g., Germany, Netherlands) while others (e.g. GB) choose to split charges between generators and load.

3.5. System operational costs

A variety of other "services", including management of congestion, losses, reserves, reactive power, and others are required to both facilitate energy trading and to ensure reliable system operation. We refer to all of these here generally as "system operational costs", though frequently some of these are also often referred to as "ancillary services". Some of these (e.g., congestion costs and losses) might be viewed as more directly related to transmission pricing than others; nevertheless all are needed. We note two principal aspects of the conceptual approaches to these services and their associated costs:

- Acquisition: These services can be acquired by a variety of means, depending on the approach to market structure and design. For example, some services are either implicit in energy market prices themselves (e.g., congestion and often losses are embedded in energy prices in LMP markets), some services are often acquired through the energy spot market or through auction markets similar to energy spot markets (e.g., spinning reserves), while others might more typically be acquired either via negotiated contract or obligatory tariffs. Different markets take different approaches with such acquisition means, and often with resulting differences in cost-reflectivity of acquisition or charging for such services.

- Charging: There are also a variety of ways of charging for such services, in some cases mirroring the acquisition approach. Some services (e.g., black start services) are quite typically socialized over all system users through either transmission network tariffs or perhaps separate ancillary services charges levied either by the transmission or system operator. Certain other costs (e.g., reactive power) might be either treated the same way or might be charged in a more cost reflective use related mechanism (e.g., power factor charging). Finally other costs (e.g., losses, congestion) might be charged as part of socialized ancillary services or system operation cost or instead might be in fact embedded in energy market pricing (as in some LMP energy markets).

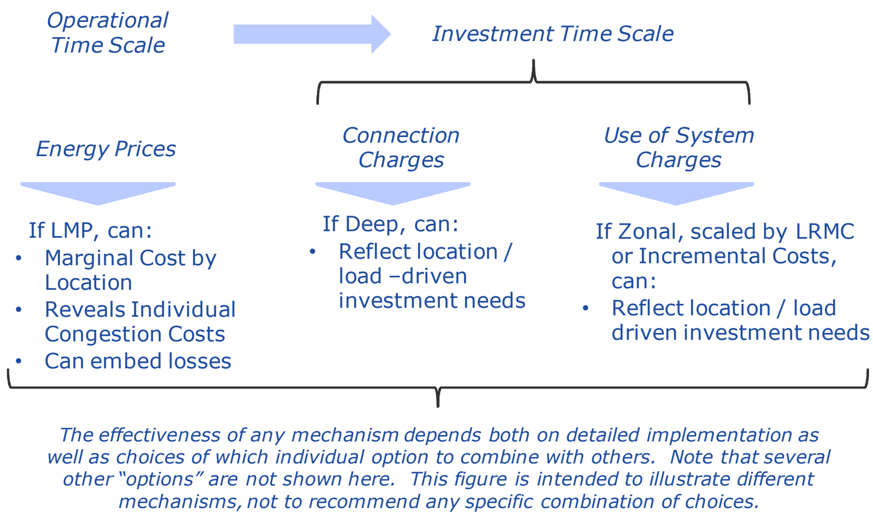
3.6. The package of transmission charges

Although there are a variety of different "choices" for the above set of dimensions, it is important to recognise that a coherent transmission / energy market design is achieved through proactive balancing of options to ensure that overall objectives are met. In doing this it is useful to recognise that at least potentially and conceptually, it is possible to approach a single design objective through different means. For example, it is possible (depending on the details of application) that a combination of "deep" connection charging and postalized use of network charges might achieve more or less the same type of cost reflectivity as a combination of "shallow" connection charging and locationally differentiated use of network charges.[5]

Among the various "choices" of charging mechanisms, there certainly are some which are more specifically designed than others to meet certain dimensions of cost reflectivity. Figure 3.1 below illustrates how several of the different items discussed above might be considered as potentially addressing various aspects of both time and locational cost reflectivity.

[5] While such different approaches might achieve conceptually the same goals, we do not mean to assert here that individual users would necessarily pay the same charges under different approaches; differences in detail and approach will drive differences in detailed charges. Also, we note that some of the individual potential charging arrangements, for example, "deep" connection, carry with them numerous additional issues of implementation, costs, and rights which themselves have been topics of other studies for many years.

Figure 3.1: Illustrative summary of selected transmission-related signalling mechanisms



As a practical matter, the types of systems adopted in different countries can also sometimes reflect not only proactive attempts to meet stated goals, but also legacy holdovers of past practices, transition arrangements arising from changes from one market structure (or regulatory environment) to another, or even relative negotiation strengths between different stakeholders in countries where the process is not fully "top down".

As a result, the systems adopted in different countries probably have different degrees of efficiency in meeting stated goals. In Table 3.1, we summarise the main features of several systems, compared to the GB system We note that Chapter 4 and Annexes 4 to 8 provide more detailed descriptions of these other countries' systems. Annex 2 also provides further brief summaries of different options as used in different countries.

Finally, as we have noted above, while transmission charging (and energy market design) can be used to meet some of the goals, other mechanisms – including transmission system planning and development, subsidy systems for renewable energy and such – are typically more dominant mechanisms for achieving other goals.

Table 3.1: Energy Market & Transmission Characteristics of Selected Countries

Market	Energy Market	Selected System Operational Costs	Transmission	
			Connection	Use of Network
UK	• Bilateral Trading with single spot balancing price	• Cost of constraints and losses are socialised and recovered through a non-locational Balancing Services UoS charge).	Shallow	• Zonal differentiation (ICRP model) • 27% Generation; 73% Load
Australia	• Zonal (essentially State-wide) energy price reflecting zonal congestion and losses	• Cost of constraints and losses reflected in zonal (State) energy price	Shallow	• Differentiated by offtake node or zone (CRNP model) • 100% Load
Germany	• Bilateral Trading with single spot balancing price	• Cost of constraints and losses incurred by TSO, recovered through socialised UoS charges levied within that TSO's region	Shallow (Generation) Deep (Load)	• Postalized within each separate TSO region • 100% Load
PJM	• Full LMP Market • LMPs reflect losses and congestion at each node	• Cost of constraints and losses reflected in LMPs for both Generation and Load. See Annex 5 for comments related to FTR usage.	Deep	• Postalized within each separate Transmission Owner region • 100% Load
Netherlands	• Bilateral Trading with single spot balancing price	• Cost of constraints and losses incurred by TSO, recovered through socialised UoS charges	Shallow	• Uniform nationally • 100% Load
Spain	• Trading predominantly through day-ahead (non-locational) energy market	• Cost of constraints and losses recovered through uplift on energy market prices	Shallow	• Uniform nationally • 100% load

Note: The reader is referred to the detailed case studies presented in the Annexes as well as Section 4 for selected further information.

We note that where Use of Network charges are referred to as charged 100% to load, there are no use of network charges made to generators.

Sources include those used for the detailed case studies presented in the Annexes, as well as "ENTSO-E Overview of Transmission Tariffs in Europe: Synthesis 2010", "An Overview of the Spanish Electricity Industry", N. Fabra, May 2005 (presentation).

4. TRANSMISSION CHARGING ARRANGEMENTS

In this chapter, we set out brief summaries of the five country / region Case Studies which are set out in full detail in Annexes 3 through 7.

4.1. Australia

The National Electricity Market (NEM) covers five regions (States) in Australia. It can broadly be described as a set of zonal energy markets (each covering one of the regions), each of which separately clears at its own Regional Reference Price. It is an energy only market with no separate capacity market. To ensure generators are able to recover costs the cap on market prices, determined by the value of lost load, is set high.

Summary Aspects of Australian Energy and Transmission Charging

Energy Market	Operational costs	Transmission	
		Connection	Use of Network
• NEM is a gross pool • Separate energy prices within each of five regions, with uniform pricing (for both generators and load) within individual regions.	• Explicit price signals for generation (despatch loss factors and lack of compensation for constraints) • For load, costs of constraints and losses are socialized within pricing zones	Shallow	• 50% of charge is locational (typically varying by offtake node) based on load flow analysis and 50% non-locational • 100% Load

Significant investment has taken place in the transmission network and generation with inter-state interconnection also growing significantly. Locational signals for generation siting are achieved by virtue of the fact that generators are not compensated for being constrained downward (relative to their position in an unconstrained merit order), as well as the fact that generators face nodal loss factors affecting their bid prices. While there is a uniform transmission pricing methodology (the CRNP model), each state can also determine the detail of applying the methodology being implemented and so there are claims by some market participants that a lack of consistency has arisen. A brief summary of the CRNP model is compared to the NGET ICRP in the annex considering Australia.

Renewables is a significant issue but one which is only now being addressed. A review of transmission charging is underway with many of the same questions being raised as have been raised in GB.

4.2. PJM

PJM is a full nodally priced energy market with over 500 participants (including generators, power marketers, load serving entities and others). It serves a peak load of approximately 165 GW and manages a transmission network owned by 17 different transmission owners. It operates both day-ahead and real time energy markets, as well as a forward capacity payment market. It acquires ancillary services through a combination of market mechanisms and other means.

Summary Aspects of PJM Energy and Transmission Charging

Energy Market	Operational costs	Transmission Charging	
		Connection	Use of Network
• Full LMP Market • Capacity Obligation with zonal RPM capacity market	• Losses and congestion included within LMP	Deep	• Postalized within each separate transmission owner area • 100% Load

The PJM achieves locational signals for generation planning through the mechanism of both deep connection charging and nodal energy pricing. In terms of operations, its nodal energy prices reflect competitive generator bids, together with the effects of congestion and marginal energy losses. Generators and load serving entities can hedge against the effect of congestion and losses through use of Financial Transmission Rights that can be acquired at auction. The system is generally viewed as having the net effect of cost reflective pricing, though holdovers of earlier industrial organisation and regulation remain (e.g., separation of transmission network owners and revenue requirements).

Renewables are stimulated in the region through a combination of US Federal Government fiscal incentives, together in some states with renewable portfolio standard obligations on load serving entities. PJM does not discriminate for or against renewable generation in terms of its transmission system planning process, though it is making efforts today to develop better ways to control system operations in an environment of rapidly growing intermittent generation sources.

4.3. Germany

The German energy market covers four separate TSO regions, with approximately 129 GW of installed capacity. Energy trading is via bilateral contracts with a single national balancing price. The transmission system is operated separately by four TSOs. Transmission use of system charges are postalized within each TSO's separate region.

Summary Aspects of Germany's Energy and Transmission Charging

Energy Market	Operational costs	Transmission Charging	
		Connection	Use of Network
• Bilateral Trading with single spot balancing price • No separate capacity market or obligation	• Cost of constraints and losses are incurred by TSO, and recovered through socialised UoS charges levied within that TSO's region	Shallow (generation) Deep (load)	• Postalized within each separate TSO region • 100% Load

The German energy market is perceived as having a generally low level of locational cost reflectivity for both transmission and energy.

Renewables are stimulated through a feed-in tariff system which is perceived to have been effective. Renewable generation is currently testing transmission system capacity with occasions in 2009 where combinations of low system demand and high wind output led to excess deliverability. Onshore renewable generators pay shallow connection charges. The costs of spur transmission lines to offshore wind are included in individual TSOs' network charges.

4.4. The Netherlands

The Dutch energy system is operated by a single TSO (TenneT), covering a system with approximately 24 GW of installed capacity. Energy trading is via bilateral contracts, with a single national balancing price. Transmission pricing is uniform nationally.

Summary Aspects of Netherland's Energy and Transmission Charging

Energy Market	Operational costs	Transmission Charging	
		Connection	Use of Network
• Bilateral Trading with single spot balancing price • No separate capacity market or obligation	• Cost of constraints and losses incurred by TSO, recovered through socialised UoS charges	Shallow	• Uniform nationally • 100% Load

The structure of both energy and transmission pricing in the Dutch market provides for no locational signals for either generation or consumption. It is reported that the Government (Ministry of Economics) and the regulatory body (EK) are increasingly aware of locational pricing, especially as the grid is becoming increasingly congested. However, the current state of debate is that at least in terms of generator location, the questions of planning for sites for production or the direction of transmission network expansion are matters not for pricing structures but rather for long term coordinated central planning.

4.5. Spain

The Spanish electricity market is a bilateral contract market with day ahead and intra-day markets. There is a separate capacity payment based on meeting an operational target (480 hours) in the previous year. The capacity payment is based on the generator's share of total capacity.

Summary Aspects of Spanish Energy and Transmission Charging

Energy Market	Operational costs	Transmission Charging	
		Connection	Use of Network
• Day ahead market accounts for 74% of generation traded, supported by intra-day and bilateral contract markets • Separate capacity payment based on meeting a target level of operation in the prior year	• Losses and congestion costs are socialised through the mark-up on energy prices.	Shallow	• No locational aspect to charge • 100% load

There is no locational charge and generators do not pay any of the use of system charges. Transmission charging has not been a major focus in Spain since de-regulation. Within the transmission charging system these aspects have not been viewed as priorities – the focus has been on the tariff deficit mechanism, explained in more detail in the case study.

Spain has been able to rapidly attract a significant level of renewables but with no apparent systematic bias in the transmission charging regime towards renewable resources. The fact that there appears to be no locational signals for generation may well have facilitated the development of renewable generation (particularly when considered in conjunction with the wider governmental targets for the delivery of wind generation), but this is a "benefit" offered to all generation and not just renewables.

4.6. Summary

Having considered the five case studies it is useful to make a high-level comparison of the cost reflectivity of the various regimes. Cost reflectivity is one of the key objectives and is the area where the greatest divergence in options is seen. This comparison is made against our characterisation of the situation in GB.

Table 4.1: Comparison of apparent high-level structural cost reflectivity of different systems

	Energy pricing	Operational costs	Transmission charges
Great Britain	Low (single spot market)	Low (socialised)	Medium (shallow connection, locational UoS, allocation to both G and Load in UoS)
Australia	Medium (limited number of zones)	Explicit price signals for generation (despatch loss factors and lack of compensation for constraints); Medium cost-reflectivity for load (costs of constraints and losses are socialized within pricing zones)	Medium (shallow connection, locational UoS though allocated only to Load)
PJM	High (full LMP)	High (losses and congestion in LMP)	Medium (deep connection and postalised UoS)
Germany	Low (single spot market)	Low (Socialised within TSO region)	Low (shallow connection, postalised UoS)
Holland	Low (single spot market)	Low (Socialised)	Low (shallow connection, postalised UoS)
Spain	Low (single spot market)	Low (socialised)	Low (shallow connection, postalised UoS)

Note: In the above table, we refer primarily to locational and structural aspects of charging. We do not intend to comment, for example, on issues of whether or not energy market industrial organisations or trading arrangements lead to greater or lesser cost reflectivity.

What can be seen from this table is that compared to continental European systems the GB approach appears to be potentially more cost reflective. However, there is an example of a more cost reflective system, the PJM, and another which achieves perhaps the same sort of overall level of cost reflectivity, Australia. We note that these comparisons and observations are based simply on the *structure* of the various charges. To get a more precise picture of the degree of cost reflectivity in each system, it would be necessary to consider both the application of methodologies leading to levels of various charges as well as an analysis of system pricing in comparison to analytically modelled operating costs.

5. COMMENTS AND OBSERVATIONS

5.1. General comments

Based on our assessment of the various transmission charging packages employed, the following comments can be made.

1. There appear to be different ways of achieving certain of the common fundamental objectives

One of the principal common objectives noted in Section 1 is to try to ensure cost-reflective pricing. As noted earlier, the concept of "cost reflectivity" covers potentially several different dimensions, including time, space (location), type of service, and so on. As a result, it might not be surprising that different approaches or combination of approaches are sometimes used to make progress toward this objective.

Some of these different approaches might be seen as being at least conceptually substitutable. One example is the use of "deep" connection charging together with postalized use of system charging (e.g., as in PJM) in contrast to the combination of "shallow" connection charging together with locationally differentiated use of system charging (e.g., as in GB). Both approaches are seeking to ensure that some signals regarding long-run transmission system costs are passed through to system users, though the precise mechanisms (and, almost certainly, the precise level of costs) differ.

In slight contrast, other different approaches are potentially complementary. For example, fiscal or pricing subsidies to support renewable energy projects might be complemented by programmes of anticipatory build-out of transmission networks.

2. There has been movement in some markets toward increased locational pricing of energy markets since the 1990s, though this trend is not yet widely evidenced in Europe.

Just as technological developments played a role in the initial stages of the development of near real time energy markets, continued technological improvements have played roles in the further development of increasingly more cost-reflective energy market pricing. Today nodally-priced energy markets are emerging (either fully or partly) in many places, including in the US, Latin America, and New Zealand. This trend has, however, not been followed (at least yet) in Europe, with the zonal energy price system of Nordpool probably being an example of one of the most locationally differentiated energy systems in Europe.

Considerations of why different countries or regions do or do not migrate toward the more cost-reflective approaches probably include both considerations of economic cost / benefit of doing so (discussed in the point immediately below) as well as consideration of stakeholder interests and / or influence, and the overall process of making such changes.

3. **While some approaches are probably more cost-reflective than others, the benefits of moving to a more cost reflective system need to be balanced against the costs of doing so.**

The goal of cost-reflectivity leads to consideration of migrating toward systems for both energy and transmission pricing which might be increasingly differentiated in terms of location, time, allocation of charges, etc. However, consideration of implementation of such systems (or any new system) should probably at least in concept take account of balancing the costs of implementation and operation of such systems against the value of differentiated pricing signals that they provide. For example, in systems where transmission constraints are not significant or where generator marginal costs are similar, it may be more important to address other issues before turning to consideration of this type of energy market. Academic studies at different times and in different places have addressed aspects of this sort of cost/benefit issue[6], and such analyses should probably play a role in future considerations.

It is also important to note that other aspects of industrial organisation – including, for example, the structure and behaviour of both the generation and supply markets – will also play roles in determining whether increased cost reflectivity of trading systems and network pricing in fact lead to overall increases in consumer welfare.

4. **The value of locational signals for generator siting decisions is useful in some but perhaps not all cases**

As utility systems have evolved in many countries from centrally planned and controlled entities to decentralised and often competitive (by sector) industries, concerns have grown steadily about the use of locational pricing signals for generation. This is in part because while centralised planning could take into account the full internalised system costs of siting decisions, decentralised planners will, absent other constraints, only take into account externalised costs.

While externalising such costs are important, it is also important to note that in some cases they might be secondary to other considerations. For example, some generation types are strictly limited by planning rules regarding siting (e.g., nuclear) while others are resource-following (e.g., wind). Even so, while externalising locational costs might not influence choices of site for such generation options, they should play a role in overall project development decisions in the planning stages, and in terms of operational decisions once projects are built.

5. **There are important transmission issues to consider with respect to renewable resources**

One of the goals for many Governments (both the UK and elsewhere) is to ensure that promotion and development of renewable energy resources is facilitated, or at least not hindered, by the transmission system.

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[6] See, e.g., "Electricity Transmission Pricing: How much does it cost to get it wrong?", R. Green, Cambridge Working Papers in Economics, September 2004.

Within the (admittedly limited) range of the experience we have surveyed here, it is probably fair to say that transmission charging has not been used *proactively and specifically* to stimulate renewables, with the primary (or sole) stimulus typically coming instead via external mechanisms such as energy pricing mechanisms (e.g., feed-in tariffs), fiscal incentives, or quota systems[7]. Thus, it might appear that there is a more general concept that transmission should not be a barrier to renewable energy development. We do note that if in the future proposals are considered to differentiate transmission charging among generation resource types (e.g., renewable vs non renewable), there would probably also need to be consideration of both the overall transparency of any total support "package" for renewables as well as consideration of whether a "level playing field" might be maintained once carbon prices are fully externalised.

6. The ***structure*** of transmission use of system tariffs might be an issue for renewables generation.

We have not considered the question of detailed tariff structure and design in this report, though it certainly clear that some of the principal typical objectives of tariff design (cost reflectivity and efficiency) match some of the objectives set out earlier in this report.

In order to achieve efficient tariff structures, transmission network (use of system) tariffs have historically most often been structured in terms of charging on the basis of some definition of capacity (though commodity charges are also often included as well if losses are charged as part of the transmission tariff). In some jurisdictions, renewable energy project developers have pointed out that the typically low capacity factors of intermittent energy projects result in requirements to pay for what is often unutilised transmission capacity if traditional tariff designs are applied. The concept of "energy only" transmission tariffs have been proposed for such projects.

The question of whether the historically common approach to transmission tariff structures is appropriate in an environment of increased quantities of intermittent generation sources has been raised for some time.[8] As intermittent generation quantities increase, it may be worth considering the question of network tariff structure once again.

5.2. Observations

In the examples we have briefly reviewed in this paper, there are clear differences in approach in approach in how both transmission-specific charges (e.g., connection and use of system) are designed, and also how energy prices are determined and how related operating costs (e.g., losses, congestion) are reflected.

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[7] With the focus of this paper generally on transmission charging regimes, we have not discussed initiatives considered, or even undertaken, in several jurisdictions related to "anticipatory investment" in transmission infrastructure to support as yet undeveloped renewable resource projects in remote areas.

[8] See, e.g. "Transmission Pricing and Renewables: Issues, Options and Recommendations", S. Stoft, C. Webber and R. Wiser, Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory, May 1997.

With respect to some specific aspects of transmission charging, the survey, case studies and comments allow the following observations about the relative "strength" of the system in GB to be drawn:

- Short-term efficiency of generation is likely to be strongest in PJM and Australia where generation costs associated with losses and congestion are directly built into energy prices (or, in the case of Australia, despatch rules) while GB has more limited signals owing to the socialisation of losses and congestion costs;

- Short-term efficient use of the existing transmission network is harder to assess. Systems like FTRs in the US allow efficient short term operation of generation and locational signalling while still providing the facility to allow at least some generators the effect of firm access to the transmission network. In GB generators effectively have firm access to the transmission network via the congestion payments – while the generators pay a use of system charge based in part on long term locational (zonal) investment requirements. In Australia generators do not have physical firm access to the network but neither do they pay use of system charges nor deep connection charges. Whether one of these approaches is better is not clear, but what is clear is that a mix and match should not take place, i.e. deep connection provides the effect of firm access and shallow (without payment of use of system charges linked to long term investment requirements) should not provide the same effect;

- Long-term generation planning in terms of siting new plant and retiring existing plant is affected by the form of connection charging and whether transmission charges are allocated to generation or the allocation of losses and congestion through the energy price. Again, the PJM example in the US provides a case where strong locational signals are sent through the deep connection charges and the incorporation of losses and congestion into the LMP. Australia, in contrast, has shallow connection charging and no UoS charges allocated to generation, but does not compensate generators for being constrained off and allocates loss factors to their energy market bids, thus achieving some locational signalling. In GB the signals for siting plant come from the allocation of 27% of the locational transmission charges to generation. Other European examples seem to address the problem through other approaches, such as in the Netherlands where the number of possible generation sites are limited, or through administrative allocation;

- Ensuring that transmission capacity is available for evacuating power is an issue for all systems. Transmission charging systems by themselves do not appear to address this. Rather, alternative regulatory actions are often taken, these can include:
    - Encouragement of anticipatory investment as seen in Spain and in some parts of the US, such as Texas;
    - Market mechanisms that allow the users of the network to encourage development (and even undertake the development if the incumbent is not interested). The well-researched Argentinean electricity transmission expansion regime is a good example of this. PJM also has an option potentially similar to this through the ability of "qualified

transmission upgrades" to participate in its capacity market (see Annex 6). Offering additional return for new investment was at the heart of FERC order 2000 and has been used in France to encourage the interconnection of the gas regions in the country;

- It is also clear that the transmission charging regime has to be seen as a part of a much larger whole. This means that aspects of the energy market and broader government policy need to be considered. Spain is a good example of where government policy with respect to the development of renewable generation has led to a significant and rapid increase while the transmission charging regime has not really been a key part of this. In PJM a much more market focused approach has been adopted for transmission charging and the other aspects need to work around this. GB again seems to sit within this range, it is not at the extreme of PJM since DECC's guidance requires a consideration of low carbon energy sector but the overall objectives for the regulator mean that cost reflectivity is important; and
- Finally, it is important to see choices within the transmission charging regime as a package. The same outcome can be reached through different sets of choices about the elements of the package. As such, it is possible to choose the different elements that are realistic in a country while striving to achieve the overall preferred outcome.

It is probably reasonable to conclude that among our case studies, the PJM market probably has the most overall cost-reflective pricing structures, with nodal spot prices which embed losses and reflect real-time constraints, together with deep connection charges and consequently the strongest generator incentives, although it does not allocate use of system charges to generators. At the other end of the spectrum, industries with single geographic spot prices, shallow connections and postalised network and operating costs (e.g., Germany,) probably are less cost reflective. GB is probably somewhere in the middle of the spectrum, with its single spot energy price combined with its zonal transmission network charging system. However, to what extent this current system differs from either end of the spectrum (i.e., is it closer to one end or the other) is a matter requiring analytical work.

ANNEX 1: TERMS OF REFERENCE

Ofgem published the following terms of reference as part of its December 10th 2010 Project TransmiT update.

Consultants

The aim of Ofgem's Project TransmiT is to ensure that we have in place 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. To help inform our review of the current GB transmission charging arrangements and potential alternatives, we are looking to commission an independent report to review the full range of alternative models of transmission charging adopted internationally. We envisage publishing the report and using it as a basis for discussion at a roundtable event.

Scope of the report

We are looking for:

- A survey of the range of electricity and gas transmission charging models that are adopted internationally, including:
  - all aspects of transmission arrangements that are relevant to the allocation of all costs arising in transmission – investment in transmission assets (both local to the connection of generation and demand users, including those to distribution networks that are affected by demand and generation at distribution level), costs of transmission congestion and transmission losses, costs for purchasing ancillary services required for safe and secure operation of the transmission system
  - objectives and principles for the transmission charging arrangements - highlighting any relevant hierarchy of priorities, e.g. between economic efficiency, competition and achievement of low-carbon targets
  - underlying assumptions and other aspects of transmission arrangements relevant to charging – the determination of required transmission capacity (e.g. security standards), rules surrounding the allocation of capacity and management of constraints, costing of relevant cost elements in charging (market based vs administered, average vs marginal, etc), nature of transmission rights (financial firmness, rules of compensation when constrained) and wholesale energy market and system balancing arrangements (to the extent relevant for the transmission costs and their allocation)
  - detailed treatment of individual cost elements as well as the interrelationships amongst these elements (eg longer term marginal cost vs short term marginal cost) and the combined total cost signal to the transmission users
- an evidence-based assessment of strengths and weaknesses of these models. including:

  - impact on short term efficiency of the transmission system – generators production pattern, transmission owners/operators action to make transmission capacity available real time o impact on long term efficiency of relevant parties' investment decisions – siting and timing of development of new generation plant and retirement of existing plant; siting, timing and amount of transmission capacity investment
  - interaction with other key factors that have impact on the short/long term behaviours of parties, such as other key cost elements, government policy on certain types of generators, regulatory incentives on network investment
  - separation of issues inherent to a particular model against issues arising due to implementation choice or other constraints that can be overcome by practical measures
- high-level comparison of the models with the current GB model

ANNEX 2: OVERVIEW OF INTERNATIONAL EXPERIENCE

This annex provides a broad overview of the options within the different dimensions of transmission charging noted in Section 3. As discussed in section 1, the overview draws on published secondary information with the sources noted in a bibliography at the end of the report (and individual references at the end of each table). The electricity sector is considered first and then the gas sector.

While every effort has been made to ensure that the same set of countries is covered in each table, owing to the reliance on published data this means that there are some gaps in the tables. Where possible we have tried to complete this with additional information but such a detailed separate study was beyond the scope of this project.

Table A2.1: Energy market description

Country	Core features	Other features
Great Britain	• BETTA is a 'net pool' design where the majority of energy is traded bilaterally between generators and retailers. • The wholesale market in Great Britain, known as BETTA, is based on a single-price structure, with only one spot price determined in the balancing market.	• There is no separate capacity market.
Europe		
Denmark	• Denmark is part of the 'Nord Pool', along with Norway, Finland and Sweden. In total there are 7 pricing regions. • A zonal market structure is used and there are two bidding areas in Denmark, Eastern Denmark and Western Denmark.	• Nord Pool operates three distinct markets: ○ a physical day-ahead spot market; ○ a financial futures and forwards market; and ○ a balancing market.
France	• In the French electricity market much of the trade takes placed bilaterally and this is accompanied by a day-ahead trade on Power Exchange.	• There is also a balancing market.
Germany	• There are four control zones in the transmission system. • Germany's wholesale electricity market was dominated by bilateral over-the counter (OTC) energy trading. • The European Energy Exchange (EEX) in Leipzig has seen a growing amount of trade in recent years.	• Reserve and balancing are not traded on the EEX.
Ireland	• The Single Electricity Market (SEM) operates in Ireland and Northern Ireland. • The SEM is a gross mandatory pool system, with central dispatch. • All generation in a half-hour period receives the same System Marginal Price (SMP) for its scheduled output.	• In addition to the energy market, there is a capacity payment mechanism in the SEM.
Italy	• There is a day ahead market with zonal prices and a single national price that is an average of zonal prices. This	• There is a balancing market for congestion management, operating reserve and real-time balancing.

Country	Core features	Other features
	generates a system marginal price.	
Netherlands	• There are a number of markets for trading electricity, including long-term bilateral trades and day-ahead spot market trading.	• There is also a Dutch balancing system.
Northern Ireland	• The Single Electricity Market (SEM) operates in Ireland and Northern Ireland. • The SEM is a gross mandatory pool system, with central dispatch. All generation in a half-hour period receives the same System Marginal Price (SMP) for its scheduled output.	• In addition to the energy market, there is a capacity payment mechanism in the SEM.
Norway	• Norway is part of the 'Nord Pool', along with Sweden, Finland and Denmark. In total there are 7 pricing regions. • A zonal market structure is used and there are now three (fixed) regions that exist in Norway.	• Nord Pool operates three distinct markets: ○ a physical day-ahead spot market; ○ a financial futures and forwards market; and ○ a balancing market.
Spain	• There are day and intraday markets which are complemented by bilateral contracts.	• There is an adjustment and balancing market.
Sweden	• Sweden is part of the Nord Pool. • Sweden has a single-price market structure within the region..	• Nord Pool operates three distinct markets: ○ a physical day-ahead spot market; ○ a financial futures and forwards market; and ○ a balancing market.
US		
California	• California's wholesale electricity market is now a nodal market. This market relies on locational marginal pricing. • It is structured as a generator nodal pricing market. • Loads have a zonal aggregated price.	• In addition to locational pricing, California has an integrated day-ahead forward market for energy and ancillary services. • No formal capacity market exists but 'capacity obligations' are placed on market participants. • The introduction of a formal capacity market is being examined.

Country	Core features	Other features
New England	• Locational marginal pricing is used and has a generator nodal pricing structure. • Loads are settled at weighted-average load price across zones.	• New England's wholesale energy markets include a day ahead and real-time energy market; an FTR market; ancillary services and regulation markets; and a capacity market. • Capacity and reserves are managed through a competitive capacity market.
New York	• New York's energy markets use generator-nodal pricing and there is locational marginal pricing. • Loads are settled at a load weighted-average zonal price. There are 11 zones for load settlement.	• The wholesale electricity market includes a day-ahead energy market, a real-time balancing market and separate markets for capacity and ancillary services. • Capacity requirements are managed through a competitive capacity market.
PJM	• In PJM's energy markets, full nodal pricing is used. • Generators and loads are dispatched and settled on their own nodal price.	• PJM's wholesale electricity market includes a day-ahead energy market; a real-time balancing market; a Financial Transmission Right (FTR) market and separate markets for capacity and ancillary services. • In addition to the energy market, there is a competitive capacity market. This involves use of the Reliability Pricing Model (RPM) which provides locational capacity prices and more efficient siting of new capacity.
Texas	• There is a zonal wholesale energy market with five pricing zones. • Each zone has a single price. • Texas has been transitioning to locational marginal pricing through the use of generator nodal pricing.	• There is no formal capacity market.
Latin America		
Argentina	• Based on full-nodal pricing. • Nodal prices are determined by the use of 'nodal factors' including losses and congestion relative to the system load centre.	• Generators receive various capacity payments through the capacity market/capacity mechanism.

Country	Core features	Other features
Chile	• There are 4 independent networks in Chile. • The two larger systems serving the central and the northern districts (the SIC and the SING), have a net pool market operated by independent system operators. • Generators trade around bilateral contract positions at the spot market price. • Loads trade with generators at a regulated 'seasonal node price' set 6-monthly by the energy regulator. • The market is described as 'nodal' because a loss-adjusted price is determined for each generator and distribution substation, however congestion does not appear to be reflected in these prices.	• Prices are determined for energy and capacity.
Australasia		
Australia	• There are 5 regions in the market, including New South Wales, Queensland, South Australia, Tasmania and Victoria. • In the National Electricity Market (NEM) electricity is nodally dispatched but zonally settled. • Each region contains one pricing node – known as the Regional Reference Node where the price for the region is set. • The Regional Reference Price (RRP) is based on the marginal cost of electricity supply at the RRN. Transmission congestion arising between regions is therefore priced. However, intra regional congestion is not priced.	• The NEM is a real-time energy only market and does not include a capacity market.
New Zealand	• The wholesale electricity market uses locational marginal pricing and is based on full nodal pricing. • Generators and loads face different individual node prices.	• The NZ energy market is an energy-only market. • Prices reflecting losses and congestion are generated half-hourly for each of the pricing nodes in the market (approximately 250).

Source: Frontier Economics (2009) "International transmission pricing review", accessed at http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/

Poyry (2010) "Electricity Transmission Use of System Charging: Theory and International Experience", accessed at http://ilexenergy.com/pages/Documents/Reports/Electricity/EDFTransmissionChargingTheoryAndPractice.pdf

Nord Pool (2009) "The Nordic Electricity Exchange and the Nordic Model for a Liberalised Electricity market", accessed at http://www.nordpoolspot.com/upload/Nordic%20power%20market/The%20Nordic%20Electricity%20Exchange%20Nord%20Pool%20Spot%20and%20the%20Nordic%20Model%20for%20a%20Liberalised%20Electricity%20Market.pdf

Morthurst, P.E. (2007) "D4.1 – Detailed investigation of electricity market rules, Cases for France, Germany, Netherlands, Spain and Denmark", accessed at http://www.trade-wind.eu/fileadmin/documents/publications/D4.1_Summary_report_of_market_rules.pdf

Schiavo, L. (2006) "The Electricity Market Reform in Italy", accessed at http://www.erranet.org/index.php?name=OE-eLibrary&file=download&id=3860&keret=N&showheader=N

Table A2.2: Characteristics of the electricity transmission system operator

Country	**Description**
Great Britain	• There is a single wholesale electricity market in Great Britain, including a single transmission system which is operated by National Grid. • The transmission operator is independent of electricity generation and supply.
Europe	
Denmark	• Energinet is the transmission system operator (TSO) for electricity and gas. It was formed in 2005 following a merger between Elkraft, Eltra and Gastra. • The TSO is an independent public enterprise owned by the Danish state and is under the Ministry of Transport and Energy. • The TSO has responsibility for system balance.
France	• There is a central Transmission System Operator, RTE, which handles the operation and development of the transmission grid and also has responsibility for the short-term balancing of the system.
Germany	• There are four TSOs and strongly interconnected control areas in Germany. • TSOs in Germany have responsibility for the operation, maintenance and development of the electricity transmission network. Electricity network regulation relies on the Energy Act of 2005. This act also established the regulator BNetzA and laid the foundation for network regulation. • After two rounds of cost-based reductions of network charges, an RPI-X-like system of incentive regulation started January 1st 2009. Germany is currently in the first regulatory control period.
Ireland	• EirGrid is the independent electricity Transmission System Operator (TSO) for the RoI. The network includes around 6,500km of high voltage lines ranging from 110kV to 400kV and underground cables and over 100 transmission stations. • The Transmission System, often referred to as "The National Grid", is a meshed network of approximately 6,500km of high voltage, 110,000 volts (110kV), 220,000 volts (220kV) and 400,000 volts (400kV), overhead lines and underground cables and over 100 transmission stations. • EirGrid has responsibility for providing balancing and ancillary services and also some responsibility for planning and design work. ESB Networks is the Transmission Asset Owner.
Italy	• The TSO in Italy is Terna Rete Elettrica Nazionale (Terna). Terna was established in 2004 after a merger between the major transmission owner and the system operator. • The company is privately owned. The independent regulatory body is the Autorita per l'energia elettrica e il gas (AEEG).

Country	Description
	The Ministry of Economic Development is responsible for energy policy.
Netherlands	• In the Netherlands, there is one state-owned TSO, called TenneT. • TenneT has been appointed as the grid manager. TenneT has responsibility for monitoring the supply and demand balance but also for maintaining and developing the network. • The regulator is the Energiekamer (previously known as DTE), which is chamber of the competition commission NMa. Network regulation was introduced immediately following implementation of the 1st EU directive at the end of 1990s, and is by and large comparable to UK-style RPI-X regulation.
Northern Ireland	• SONI has a licence obligation to operate, co-ordinate and direct the flow of electricity onto and over the NI Transmission System. • This is complemented by the role of Northern Ireland Electricity (NIE), the Transmission System Owner, which has a licence obligation to plan, develop and maintain the NI transmission system. SONI is required to cooperate and provide assistance to NIE in meeting its licence obligations and there is a Transmission Interface Agreement (TIA) between the two companies. • In November 2007, the power market in NI changed with the establishment of the SEM. The SEM was designed to enable both NI and the Republic of Ireland (RoI) to benefit from reduced electricity costs and increased competition. Generation is now dispatched on an 'all-island' basis. The interconnectors between NI and RoI are treated as internal circuits. • The TSO in RoI is EirGrid and an agreement was developed between SONI and EirGrid, the System Operator Agreement. This agreement sets out the key principles and arrangements between the two companies as TSOs in NI and RoI.
Norway	• In Norway the TSO is Statnett SF. Statnett is the owner and operator of the main grid in Norway. In addition to its TSO role, Statnett is responsible for the development of the main grid infrastructure. • Statnett is the TSO in the Norwegian power system and also the owner and manager of the main grid. The role it plays is therefore not directly compatible with SONI. The regulator in Norway is called NVE.
Spain	• The operation of the national electricity system is the carried out by two independent bodies, the Market Operator and the System Operator. • The Market Operator, OMEL, has responsibility for the daily and intra-day management of the markets. • The System Operator has responsibility for the operation of ancillary services, abnormalities in the market and the settlement and communication of payment obligations and collection rights.

Country	Description
Sweden	• Svenska Kraftnat is responsible for electricity transmission in Sweden. In particular, this state-owned utility monitors the electric and gas grids to ensure that the systems are in balance. • The utility was established in 1992 and it is financed by fees for use of the national grid.
US	
California	• The system operator is California is the California Independent System Operator (CAISO). • CAISO is a non-profit public benefit corporation which operates California's high-voltage wholesale power grid. • CAISO provides access to the grid for all users and plans for the future transmission needs.
New England	• The independent system operator in New England is ISO-NE. • ISO-NE has responsibility for ensuring the day-to-day reliable operation of bulk power in New England. This includes both overseeing the regional wholesale electricity market and managing regional planning processes.
New York	• NYISO is the independent system operator of the transmission system in New York. • NYISO has a number of responsibilities including: managing the transmission network, administering and monitoring the wholesale electricity market, considering the long-term resources and needs of New York; and developing technology to improve the performance of the grid.
PJM	• PJM is a regional transmission organization. • PJM manages the grid and the wholesale electricity market covering 13 states and the District of Columbia.
Texas	• The Electric Reliability Council of Texas operates the electric grid and manages the deregulated market across 75% of the state.
Latin America	
Argentina	• The network operator in Argentina is CAMMESA. It is responsible for the operation of the transmission network and of the electricity markets. • The supply system includes two grids that are interconnected – SADI and Sistema Interconnectado Patagonico (SIP). However, these grids operate independently of each other.
Chile	• The supply system involves two large interconnected grids – Sistema Interconectado del Norte Grande (SING) and Sistema Interconectado Central (SIC). • There are also two isolated grids in the south of the country which are vertically integrated and run by separate utility companies.

Country	Description
Australasia	
Australia	• In Australia, the National Electricity Market (NEM) is operated by an independent not-for-profit system operator, known as the Australian Energy Market Operator (AEMO). • AEMO has responsibility under the National Electricity Rules (NER) for ensuring that the power system is operated in a safe, secure and reliable manner. AEMO also plays a role in national transmission planning and long-term market planning. • In addition to operating the NEM, AEMO is the system operator for the wholesale gas markets in Victoria and hubs in Adelaide and Sydney. A further hub is to be established in Brisbane in 2011.
New Zealand	• Transpower New Zealand Limited (Transpower) is the state-owned enterprise which is the owner and operator of the national grid in New Zealand. • As part of its System Operator role, Transpower manages the real-time operation of New Zealand's power network. • The Commerce Commission in New Zealand is currently in the process of making a decision on the individual price-quality path to apply to Transpower under Part 4 of the Commerce Act 1986. The final decisions paper will be published in December 2010, including a price-quality path for Transpower and the related input methodologies.

Source: Energinet (2007) "Experience of the Danish Transmission System Operator", accessed at http://www.iea.org/work/2007/grids/Abildgaard_Energinet.pdf; SONI (2009) "Transmission Seven Year Capacity Statement", accessed at http://www.soni.ltd.uk/upload/Transmission%20Seven%20Year%20Statement%202009-2015.pdf; EirGrid website, http://www.eirgrid.com/transmission/; Transpower (2010) "System Operator", accessed at http://www.systemoperator.co.nz/; BnetzA-websites: http://www.bundesnetzagentur.de/; NMA, Sept 2010, METHODEBESLUIT SYSTEEMTAKEN TENNET and Besluit van de Raad van Bestuur van de Nederlandse Mededingingsautoriteit als bedoeld in artikel 41e, eerste en tweede lid van de Elektriciteitswet 1998, No. 103339_1 / 136.BT831; NVE, Annual Report 2009; Svenska Kraftnat (2010), accessed at http://www.svk.se/Start/English/About-us/; Claifornia ISO (2010), accessed at http://www.caiso.com/; ISO-NE (2010), accessed at http://www.iso-ne.com/aboutiso/index.html ; NYISO (2010), accessed at http://www.nyiso.com/public/about_nyiso/nyisoataglance/purpose/index.jsp ; PJM (2010), accessed at http://www.pjm.com/about-pjm.aspx ; ERCOT (2010), accessed at http://www.ercot.com/; gtz (2007) "Energy-policy Framework Conditions for Electricity markets and renewable Energies", accessed at http://www2.gtz.de/dokumente/bib/07-1264.pdf

Table A2.3: Type of electricity connection charging

Country	Connection charge - type	Who pays?
Great Britain	Shallow	• Connecting parties pay for the cost of connecting a party to the grid, including the cost of particular assets that can only be used by that party.
Europe		
Denmark	Shallow to partially shallow[9]	• For certain types of generation technology the connecting party only pays the cost of connection to the 10-20 kV grid system. However, if the generation plant owner chooses a higher voltage then they are responsible for meeting this cost.
France	Shallow[10]	• Connecting parties are required to pay the cost of connection to the grid network and also for any network reinforcements at the connection voltage.
Germany	Deep (customers); Shallow (power plants)	• Under the Renewable Energy Law in Germany, plant operators pay for the costs of connecting plants to the grid and for the related appliances. • Costs for upgrading the grid due to newly connected plants are paid by the grid operator. These can be passed on in the use of system fees.
Ireland	Shallow to Partially Deep	• Connecting parties pay for connecting to the grid. The method used is based on the Least Cost Technically Acceptable shallow connection method. This means the cost

[9] Charges may be calculated to a notional point that is closer than the physical connection point.

[10] The connection is made to the nearest available substation with an appropriate voltage level.

Country	Connection charge - type	Who pays?
		depends on the availability of appropriate transmission infrastructure.
Italy	Shallow[11]	• The connecting party has responsibility for costs arising directly from the connection with the new plant. • Additional network reinforcement is paid by the network operator but only in the case that the connection is shared amongst a number of customers.
Netherlands	Shallow to partially shallow	• Connecting parties with connections up to 10MVA are shallow, however, connections over 10MVA need to be negotiated on a case-by-case basis.
Northern Ireland	Shallow	• Connecting parties pay for connecting to the grid. The method used is based on the Least Cost Technically Acceptable shallow connection method. This means the cost depends on the availability of appropriate transmission infrastructure.
Norway	Shallow	• Connecting parties pay an investment contribution for the cost of connecting new customers to the network.
Spain	Shallow	• Connecting parties make an upfront payment for the connection cost, including network reinforcement. However, if new users connect within a period of 5 years they are required to make a pro-rata payment for the costs.
Sweden	Deep	• Connecting parties pay deep connection

[11] Grid users build their own connection lines and general grid enhancements are included in the use of system tariff.

Country	Connection charge - type	Who pays?
		charges when connecting to the grid.
US		
California	Shallow	• Connecting parties pay the shallow connection costs of joining the network.12
New England	Shallow	• Connecting parties are not responsible for any reliability network upgrades that result from their connection. 13
New York	Shallow	• Connecting parties are not responsible for their impact on the reliability of the system hence the system has been classified as having shallow connection costs.14
PJM	Deep	• Connecting parties pay deep connection costs. This is to ensure that PJM's reliability is not adversely affected by the new connection.
Texas	Shallow	• Texas is not subject to FERC regulation but has adopted similar measures and hence connecting parties are subject to shallow connection charges.
Latin America		
Argentina	Shallow	• Connecting parties pay a charge to cover the operating and maintenance costs.
Chile	Shallow	• Connecting parties pay a charge for the cost of the operating equipment that links

[12] Some sources have claimed that California makes use of a deep connection charge.
[13] Other sources have stated that New England has deep connection charging.
[14] Note however that some sources state that New York has deep connection charging.

Country	Connection charge - type	Who pays?
		them to the transmission system.
Australasia		
Australia	Shallow	• Connecting parties pay only for the connection assets they require to connect to the grid. • Where a generator requests an augmentation that is not justified on the basis of producing a net economic benefit or on the basis of reliability, then the generator may pay for the augmentation.
New Zealand	Shallow	• Connecting parties pay for connection assets needed to connect to the network. Connecting parties do not pay for augmentations to the core grid that arise from their connection.

Source: Frontier Economics (2009) "International transmission pricing review", accessed at http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/;

ENTSO-E (2010) "ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2010", accessed at https://www.entsoe.eu/fileadmin/user_upload/_library/Market/Transmission_Tariffs/20100914_Transmission_Tariffs_Synthesis_2010.pdf

Knight, R.C. et al (2005) "Deliverable 2.1, Issue 1, Distributed Generation Connection Charging within the European Union, Review of Current Practices, Future Options and European Policy Recommendations", accessed at http://www.elep.net/files/WP%202.1%20Connection%20charging.pdf

Eirgrid (2008) "Transmission Connection Charging Methodology Statement", accessed at http://www.allislandproject.org/en/generation.aspx?article=16f054e8-4338-4c77-a6bb-0c6eb1fa18cf

Table A2.4: Type of Operational/Transmission Use of System Charges for electricity

Country	Type of use of system charge	Incidence	Recovery of losses and congestion
Great Britain	Locational	Generation: 27%; Load: 73%	Losses are recovered through the energy market. Congestion costs are included in the transmission charge.
Europe			
Denmark	Non-locational	Generation: 2-5%; Load: 95-98%	Losses and congestion costs are captured through the transmission charge.
France	Non-locational	Generation: 2%; Load: 98%	Losses and congestion costs are captured through the transmission charge.
Germany	Non-locational	Load	Losses and congestion costs are captured through the transmission charge.
Ireland	*Generation:* locational	Generation: 20%; Load: 80%	Losses are recovered through the energy market.
Italy	Non-locational	Load	Congestion is recovered though the transmission charge. Losses are not.
Netherlands	Non-locational	Load	Losses and the net congestion charges are captured through the transmission charge.
Northern Ireland	Non-locational	Generation: 25%; Load: 75%	Losses are recovered through the transmission charge. Congestion charges are not.
Norway	Locational	Generation: 35%; Load: 65%	Losses and congestion costs are captured through the transmission charge.
Spain	Non-locational	Load	Losses are included as part of the energy price. Congestion costs are included in the transmission charge.
Sweden	Locational	Generation: 28%; Load: 72%	Losses and congestion costs are captured through the transmission charge.
US			
California	Locational	Load	Yes
New England	Locational	Load	Yes

Country	Type of use of system charge	Incidence	Recovery of losses and congestion
New York	Locational	Load	Yes
PJM	Locational	Load	Yes
Texas	Locational	Load	
Latin America			
Argentina	Locational	Generation and Load	Yes
Chile	Locational	Generation: 80%; Load: 20%	Yes
Australasia			
Australia	Non-locational and locational	Load	Yes
New Zealand	Locational	*Core grid:* Load *HVDC link:* Generation	Yes[15]

Source: Frontier Economics (2009) "International transmission pricing review", accessed at http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/;

ENTSO-E (2010) "ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2010", accessed at https://www.entsoe.eu/fileadmin/user_upload/_library/Market/Transmission_Tariffs/20100914_Transmission_Tariffs_Synthesis_2010.pdf

PJM (2010) "Operating Agreement of PJM Interconnection L.L.C.", accessed at http://www.pjmtechnologies.com/~/media/documents/agreements/oa.ashx

NYISO (2010) "NYISO Tariffs, OATT Schedules", accessed at http://www.nyiso.com/public/webdocs/documents/tariffs/oatt/oatt_schedules.pdf

CAISO "Locational Marginal Pricing (LMP)", accessed at http://www.caiso.com/2458/2458db661ba00.pdf

ISO NE (2010) "Locational Marginal Pricing (LMP)", accessed at http://www.iso-ne.com/support/faq/lmp/index.html#faq2

FERC (2010) "Transmission Investment", accessed at http://www.ferc.gov/industries/electric/indus-act/trans-invest.asp

[15] Rentals arising from losses and congestion are refunded by Transpower to market participants who pay for the assets that generate the rentals.

Table A2.5: Other electricity charges

Country	Balancing charges	Ancillary Services, their charges and incentives
Great Britain	• There is a non-locational balancing charge. • These charges relate to the costs of the day-to-day operation of the transmission system. • Charges for the recovery of constraint costs and losses are included.	• Included in the balancing use of system charge are system services including: o Reserves; o Internal congestion management o Congestion management on interconnections o Black start; and o Reactive power. Incentives for minimising these costs are included in the control.
Europe		
Denmark	• The costs less the benefits of balancing are included.	• Included in the TSO charge are system services including: o Reserves; o Internal congestion management o Congestion management on interconnections o Black start; and Reactive power.
France	• No charge is included.	• Included in the TSO charge are system services including: o Reserves (not tertiary); o Internal congestion management o Black start; and Reactive power.
Germany	• No charge is included.	• Included in the TSO charge are system services including:

Country	Balancing charges	Ancillary Services, their charges and incentives
		○ Reserves; ○ Internal congestion management ○ Congestion management on interconnections ○ Black start; and ○ Reactive power. • From 2010 ancillary services were regulated through an incentive-based scheme, rather than cost-pass-through.
Ireland	• No charge is included.	• Included in the TSO charge are system services including: ○ Reserves; ○ Black start; and ○ Reactive power. Incentives are included in the regulatory control to minimise these costs..
Italy	• The costs of balancing are included.	• Included in the TSO charge are system services including: ○ Reserves; ○ Internal congestion management ○ Black start; and ○ Reactive power. • Incentives for cost minimisation were created around three of these indicators.
Netherlands	• The costs of balancing are included.	• A separate tariff for ancillary services includes: ○ Reserves (not primary); ○ Internal congestion management

Country	Balancing charges	Ancillary Services, their charges and incentives
		○ Black start; and ○ Reactive power. • The regulator recently changed the system to incentive-based regulation. The new system will run from 2011 to 2013 (3 years).
Northern Ireland		• Ancillary services in Northern Ireland have a separate tariff covering: ○ Reserves; and Reactive power.
Norway	• No charge is included.	• Included in the TSO charge are system services including: ○ Reserves (only primary); ○ Internal congestion management Congestion management on interconnections
Spain	• The costs of balancing are included.	• Included in the energy market charge are system services including: ○ Reserves; ○ Internal congestion management ○ Congestion management on interconnections ○ Black start; and Reactive power.
Sweden	• No charge is included.	• Included in the TSO charge are system services including: ○ Reserves (only tertiary); ○ Internal congestion management ○ Congestion management on interconnections ○ Black start; and

Country	Balancing charges	Ancillary Services, their charges and incentives
		Reactive power.
US		

California		• California has a day-ahead forward market for ancillary services.
		• Services include:
		  ○ Regulation;
		  ○ Spinning reserve; and
		  ○ Non-spinning reserve.

New England		• New England has an ancillary services market.
		• Services include:
		  ○ Operating reserves; and
		  ○ Regulation.

New York		• New York has a separate market for ancillary services.
		• Services include:
		  ○ Scheduling, system control and dispatch service;
		  ○ Voltage support service;
		  ○ Regulation and frequency response service;
		  ○ Energy imbalance service; and
		• Operating reserve service.

PJM		• PJM operates two markets for ancillary services: • Synchronised reserves – supplies electricity where the grid unexpectedly needs more power. • Regulation – corrects for short-term electricity use changes that may impact on system stability. • Black start service – supplies electricity for system restoration where the entire grid would lose power.

Country	Balancing charges	Ancillary Services, their charges and incentives
Texas		• ERCOT operates day ahead ancillary services markets for the following services: o Regulation down and regulation up; o Responsive reserves; o Non-spinning reserves; and o Replacement reserves
Australasia		
Australia		• There are three main categories of ancillary services: o Frequency control ancillary services o Network control ancillary services o System restart ancillary services • AEMO, as a not for profit organisation, is not subject to any explicit incentive scheme in relation to its role as the system operator.
New Zealand		• Transpower provides the following ancillary services through contracts: o Frequency regulating reserve; o Instantaneous reserves; o Over-frequency reserve; o Voltage support services; and o Black start. • Incentives were provided in relation to: o Loss of supply event frequency; o HVAC circuit unavailability; and o Total duration of interruptions.

Source: SONI (2009) "Transmission Seven Year Capacity Statement", accessed at http://www.soni.ltd.uk/upload/Transmission%20Seven%20Year%20Statement%202009-2015.pdf; EirGrid website, http://www.eirgrid.com/transmission/; Transpower (2010) "System Operator", accessed at http://www.systemoperator.co.nz/; BnetzA-websites: http://www.bundesnetzagentur.de/; NMA, Sept 2010, METHODEBESLUIT SYSTEEMTAKEN TENNET and Besluit van de Raad van Bestuur van de Nederlandse Mededingingsautoriteit als bedoeld in artikel 41e, eerste en tweede lid van de Elektriciteitswet 1998, No. 103339_1 / 136.BT831; NVE, Annual Report 2009; PJM (2010) "Ancillary services", accessed at http://www.pjmtech.com/markets-and-operations/ancillary-services.aspx

CAISO (2007) "The Evolution of Ancillary Service Procurement at the CAISO", accessed at http://www.ieee.org/organizations/pes/meetings/gm2007/html/SLIDES/PESGM2007P-000540.PDF; ISO NE (2010) "Ancillary Services", accessed at http://www.iso-ne.com/nwsiss/grid_mkts/how_mkts_wrk/anc_svcs/index-p1.html; NYISO (2010) "Ancillary Services Manual", accessed at http://www.nyiso.com/public/webdocs/documents/manuals/operations/ancserv.pdf; Baldick, R. and H. Niu (2010) "Recent History of Electricity Market Restructuring in Texas", accessed at http://users.ece.utexas.edu/.../394V/Recent%20history%20of%20Texas.ppt; EirGrid and SONI (2010) "Harmonised Ancillary Services Consutlation", accessed at http://www.soni.ltd.uk/upload/Harmonised%20Ancillary%20Services%202010-11%20Consultation.pdf; ENTSO-E (2010) "ENTSO-E Overview of transmission tariffs in Europe: Synthesis 2010", accessed at https://www.entsoe.eu/fileadmin/user_upload/_library/Market/Transmission_Tariffs/20100914_Transmission_Tariffs_Synthesis_2010.pdf

Table A2.6: Energy market description – gas

Country	Pricing structure	Market Design
Great Britain	• The transmission capacity market in Great Britain is a nodally priced decoupled entry-exit tariff regime. • Entry prices are set on the basis of auctions for capacity with any shortfall being recovered through a commodity charge – this makes the capacity/commodity split variable. • Short-term entry capacity is available at a discount to the auction price.	• A daily balancing regime is also in operation. Nomination and capacity rights together generate an end of day expectation of delivery. Residual imbalances in the system are then contractually cleared by the transmission system operator. • Shippers have primary responsibility for maintaining balance in the gas system and are incentivised to do this on a daily basis.
Europe		
Denmark	• The transmission system operator, Energinet.dk, applies a regulated entry-exit tariff system for gas transmission. • Transmission tariffs include a capacity and a commodity charge, where the capacity charge comprises 75% of the TSO's costs.	• Energinet.dk is also responsible for the balancing of the transmission grid. Balancing is done on a daily basis.
France	• The transmission system operators in France, GRTgaz and TIGF, operate a three-zone transmission system with entry-exit tariffs. • Tariffs are based solely on capacity with no commodity charge being applied.	• Both transmission system operators also operate a balancing regime.
Germany	• A (primarily) decoupled entry-exit system was introduced in 2006/07. The German gas market includes a number of players and the relevant law and regulation prescribes the cooperation of network operators, within a market area and between different market areas. • Charges are 100% capacity based.	• The German gas network has operated a daily balancing regime since October 2008. • Each market area has a balancing transmission system operator.
Ireland	• Ireland has a decoupled, entry-exit tariff regime for transmission capacity. • Entry capacity is priced differently for two entry points. Additionally, a discount is applied for short-term capacity	• Shippers are required to maintain a zero imbalance through the day. The transmission system operator provides a residual balancing function.

Country	Pricing structure	Market Design
	booking. • Exit capacity is subject to a single price for all long-term exit capacity, with a discount for short-term capacity in the network. • Allowed revenue is divided between capacity and commodity in a ratio of 90:10.	
Italy	• In Italy an entry-exit tariff system is applied. • Local gas transport is treated in a different way to cross-border transport. • A capacity/commodity split of 70/30 applies.	• The transmission system operator is primarily responsible for keeping the national gas system in balance.
Netherlands	• GTS operates a regulated and decoupled entry-exit tariff system for gas transmission. • The transmission tariff is charged on contracted capacities.	• The transmission system operator has the main responsibility for maintaining the national gas system in balance. • Under the new balancing regime, GTS charges the costs of balancing to the party causing the imbalance in the grid.
Northern Ireland	• Tariffs across Northern Ireland are charged on a postalised basis where all suppliers are subject to the same charge no matter where gas is exited. • Tariffs are calculated on the basis of a 75/25 capacity/commodity split.	
Spain	• Spain applies an entry-exit model with a single balancing zone. • The charge for entry points is a uniform value, irrespective of which entry point the capacity was reserved at. • The exit tariff is dependent on capacity reserved and usage. • Transmission tariffs are differentiated on the basis of local and cross-border service.	• There is a single balancing area. The balancing period is one day.

Country	Pricing structure	Market Design
Sweden	• The Swedish transmission system operator is Svenska Kraftnat, however, tariffs are set by the gas transmission owners. • The largest owner is Swedegas AB (with 70% of the network). Swedegas applies a postage-stamp tariff without any locational elements. • Tariffs are charged on the basis of contracted capacities.	• The transmission system operator has responsibility for keeping the national gas system in balance.
Australasia		
Australia	• Providers of covered pipelines are required to publish reference tariffs and other conditions of access. • The tariffs reflect factors such as transportation distances, underlying capital costs, the age and extent of depreciation on the pipeline, technological and geographical differences and spare capacity.	
New Zealand	• The Maui Pipeline Operating Code (MPOC) governs parties using the Maui pipeline and the Vector Transmission Code (VTC) provides for access to the Vector network. • Generally parties are free to agree the price of transport of gas under the MPOC and VTC.	

Source: KEMA and Regional Centre for Energy policy Research (2009) "Study on methodologies for Gas Transmission Network Tariffs and Gas Balancing Fees in Europe – Annex", accessed at http://ec.europa.eu/energy/gas_electricity/studies/doc/gas/2009_12_gas_transmission_and_balancing_annex_fact_sheets.pdf

ACCC (2009) "Gas Transmission", accessed at http://www.accc.gov.au/content/item.phtml?itemId=904614&nodeId=67a053a813b3db39f76965af4451dfea&fn=Chapter%209%20%20Gas%20transmission.pdf

CER and Utility Regulator (2009) "Common Arrangements for Gas Project", accessed at http://www.uregni.gov.uk/uploads/publications/20090420_CAG_CBA_Stage_Two.pdf

International Comparative Legal Guide Series (2010) "Gas Regulation – New Zealand", accessed at http://www.iclg.co.uk/index.php?area=4&country_results=1&kh_publications_id=130&chapters_id=3407

Table A2.7: Characteristics of the gas transmission system

Country	Description
Great Britain	• NGG is the owner, operator and developer of the high pressure network transmission system. NGG is a part of National Grid plc. • In addition, there are a number of smaller networks that are owned and operated by Independent Gas Transporters. • There are also eight gas distribution networks which cover different areas of GB.
Europe	
Denmark	• The transmission grid is owned and operated by Energinet.dk. This company is state-owned.
France	• There are two transmission system operators for gas in France. These include GRT Gaz and Total Infrastructure Gaz France (TIGF). GRTgaz and TIGF operate a three-zone transmission system. • The management of the transportation network is required to be carried out by a separate legal entity to the production and supply of gas.
Germany	• The pipeline network in Germany is divided into six market areas. There are approximately 438,000 kilometres of pipelines. • Under the German Energy Act and regulations grids cannot be operated by legal entities that are also involved in energy production or trade.
Ireland	• From 4 July 2008, Gaslink Independent System Operator Limited was established as the independent system operator for the network. Bord Gais is the owner of the network. • Arrangements between Bord Gais and Gaslink are set out in an operational agreement. Gaslink is licensed as the Transmission System Operator Bord Gais is licensed as the distribution system and transmission system owner.
Italy	• The transmission network operators are Snam Rete Gas, Societa Gasdotti Italia and Edison Stoccaggio. • From 2002 gas transportation has been separated from other activities carried out in the gas sector, except storage.
Netherlands	• The transmission network is owned and operated by GTS. GTS is a subsidiary of a state-owned company. • There are also regional gas networks which are operated by 12 regional network operators.
Northern Ireland	• There are three TSOs in Northern Ireland. These are Premier Transmission Limited (PTL), Belfast Gas Transmission Limited (BGTL) and BGE (UK) Ltd. • Transmission companies have responsibility for preparing plans for operating, developing and maintaining the

Country	Description
	transportation system.
Norway	• Gas from Norway is transported to other parts of Europe, including the United Kingdom. • The transportation system is mainly owned by Gassled. The Gassled transportation system is operated by Gassco which is a 100% owned state entity. • Gassco gas responsibility for both maintenance of the system and access to the pipelines.
Spain	• The main transportation company is Enagas. The other major transportation companies are Gas Natural Transporte, S.A and Naturgas Energia Transporte. • Gas transportation is a regulated activity due to its monopolistic nature.
Sweden	• There are two transmission companies in Sweden, these include Nova Naturgas and E.ON Sverige.
Australasia	
Australia	• There are a number of private and state-owned transmission pipelines. Transmission pipelines are mostly interconnected in eastern Australia but separate pipelines operate in Western Australia and the Northern Territory. • Only some transmission pipelines are subject to the national third party access regime, implemented by the AER.
New Zealand	• The transmission pipelines in New Zealand are owned by Maui Development Limited (MDL) and Vector Gas Limited (Vector). • For parties shipping gas through the Maui pipeline there is the Maui Pipeline Operating Code. Similarly, non-discriminatory access to the Vector network is required by the Vector Transmission Code.

Source: International Comparative Legal Guide Series (2010) "Gas Regulation 2010", accessed at http://www.iclg.co.uk/index.php?area=4&kh_publications_id=130; Utility Regulator (2010) "Energy Retail Report", accessed at http://www.uregni.gov.uk/uploads/publications/2nd_ERR_20101109.pdf

Table A2.8: Other gas charges

Country	Balancing charges	Are losses captured?	Ancillary Services	Incentives
Great Britain	• Daily balancing regime • Shippers have primary responsibility for maintaining balance and are incentivised to balance on a daily basis. • Users are subject to the System Marginal Price for any residual imbalance. This is multiplied by the daily imbalance quantity to determine the Imbalance Charge.	• The TSO has responsibility for managing for the residual system end of day imbalance position and ensuring that system pressures are maintained.	• At the auctions it is possible to buy incremental entry capacity between two and 16 years. • Incremental exit capacity is available as enduring daily rights through an application period process. • Interruptible entry capacity is available on a day-ahead basis.	• The TSO has commercial incentives on its residual balancing activities. This incentive involves a price performance measure and a linepack management incentive to ensure an appropriate mix of internal and external balancing actions.
Europe				
Denmark	• Energinet.dk is responsible for balancing transmission. • Balancing is carried out on a daily basis. • The balancing charge for imbalances applies to the daily accumulated imbalance exceeding the individual balance margin.	• Imbalances are settled individually with shippers but shippers are allowed to pool imbalances between deliveries and offtake. • Shippers have a free balance margin of 5% of their maximum daily quantity. This can be increased by a Balancing Service Agreement or transferred through a Balance Transfer Facility.	• Interruptible capacity is offered. This is differentiated between capacity which has become available due to backhaul flows and capacity from extraordinary backhaul flows or non-use of other interruptible capacity. • Gas transfer, capacity transfer and balance transfer facilities are offered by Energinet.dk.	
France	• Imbalances outside allowed	• Shippers are offered a	• Interruptible capacity is	

Country	Balancing charges	Are losses captured?	Ancillary Services	Incentives
	tolerances are subject to a charge. The charge is differentiated between imbalances above below the daily tolerance level and imbalances above this level.	standard tolerance band as a decreasing proportion of their booked capacity. Shippers can also acquire an optional tolerance band of +/- 3%.	available on a point-specific basis. • Conversion capacity of H gas to L gas is available for the Northern H and L gas zones.	
Germany	• A daily balancing system is operated. • Imbalance settlement prices are based on a price basket. • Positive imbalances are 'bought' by the TSO and negative imbalances are sold.	• Small customers have a 15% tolerance and large metered customers have a tolerance of 2%.	• Interruptible contracts are available from several TSOs. • Some TSOs offer additional products such as backhaul and shorthaul capacity. • Short-term capacity is offered at varying conditions.	• There are hourly incentives for balancing.
Ireland	• There are two tiers of imbalance prices. The first tier applies within the permitted tolerance and reflect the marginal cost of gas on the day. Second tier prices include a penalty for being outside the tolerance level.		• Capacity overrun • Exit capacity overrun • Shrinkage costs • Scheduling charges • Reconciliation charges • Failure to interrupt charges	
Italy	• A fixed price is used for the settlement of the imbalance volume between entry and exit. Shortages and surpluses are settled using the same price.		• backhaul • Interruptible capacity	

Country	Balancing charges	Are losses captured?	Ancillary Services	Incentives
Netherlands	• Prices listed on the gas exchange are used as a basis for the settlement of the imbalance volume between entry and exit.	• The TSO has primary responsibility for keeping the gas system in balance. A bandit of tolerance is provided per shipper on an ex ante basis.	• Interruptible capacity is supplied in 2 tiers. • Diversion of contracted capacity at an entry or exit point. • Reposition – where capacity is moved to another exit point for a specific period of time. • Quality conversion • Peak delivery • Title transfer facility subscription	
Northern Ireland	• There is no formal balancing point		• There is an interruptible product available on the Scotland to Northern Ireland Pipeline and the Belfast Gas Transmission Pipeline.	
Spain	• The penalty on network imbalances outside the tolerance are as follows: • If the daily stock level is above 50% and below 70%, the penalty is 1.1 T • If the daily stock level is above 70% and below 100%, the penalty is 1.5 T • •If the daily stock level is above 100%, the penalty is 15 T	• Shippers are considered to be in balance as long as their gas volumes are within the ranges established as tolerance margins.		

Country	Balancing charges	Are losses captured?	Ancillary Services	Incentives
	• If the daily stock level is below 0%, and the network user has a stock of LNG inside the Spanish system, the penalty is 1.1 T • If the daily stock level is below 0%, and the marketer does not have a stock of LNG inside the Spanish system, it must pay a daily fine equivalent of 15% of the reference price.			
Sweden	• Positive imbalances are priced at 50% of the balance base price or the system balancing gas price, whichever is lower. Negative imbalances of BRPs (BRP is buying balance gas) are priced at 150% of the balance base price or system balancing gas price, whichever is lower.	• The TSO is the responsible party for keeping the national gas system in balance.		

Source: KEMA and Regional Centre for Energy policy Research (2009) "Study on methodologies for Gas Transmission Network Tariffs and Gas Balancing Fees in Europe – Annex", accessed at http://ec.europa.eu/energy/gas_electricity/studies/doc/gas/2009_12_gas_transmission_and_balancing_annex_fact_sheets.pdf

CER and Utility Regulator (2008) "Common Arrangements for Gas – Transmission Tariff Methodology and Regulation in Ireland and Northern Ireland, Consultation Paper", accessed at http://www.allislandproject.org/en/cag_publications.aspx?year=2008&section=1

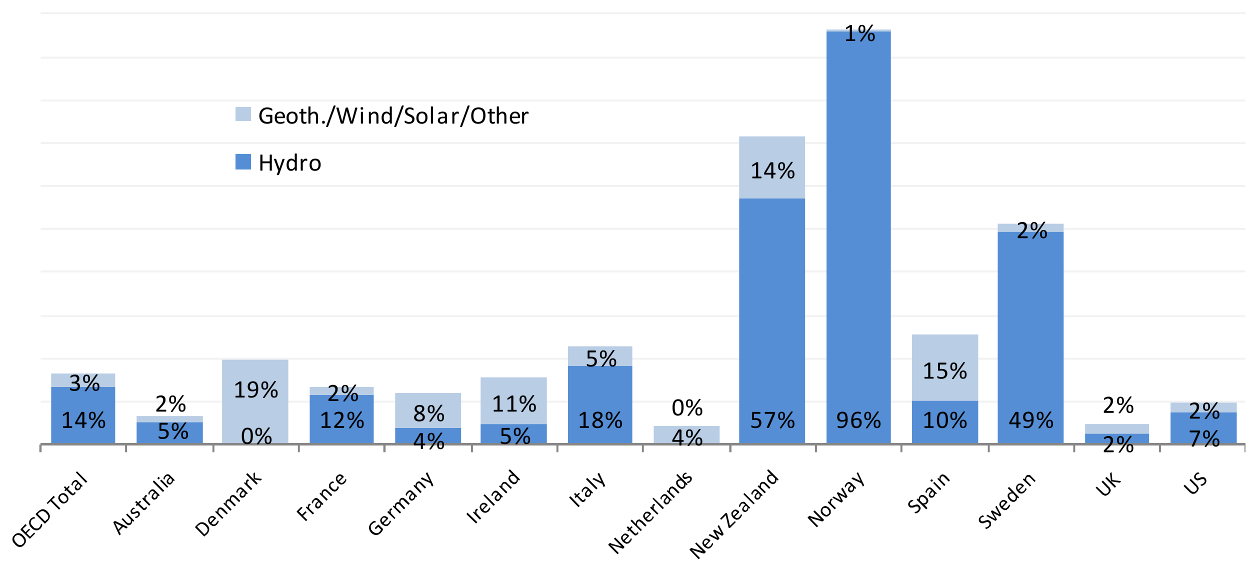
A2.2 Current electricity production from renewable sources

Table A2.9: Proportion of electricity produced from renewable sources in selected OECD countries, 2009

Country	Total Electricity Produced (TWh)	Hydro (TWh)	Hydro (%)	Geoth./Wind/ Solar/Other renewable (TWh)	Geoth./Wind/ Solar/Other renewable (%)
Australia	242	12	5	4	2
Denmark	35	0	0	7	19
France	518	61	12	8	2
Germany	561	22	4	44	8
Ireland	27	1	5	3	11
Italy	279	51	18	13	5
Netherlands	108	0	0	5	4
New Zealand	42	24	57	6	14
Norway	132	126	96	1	1
Spain	283	29	10	43	15
Sweden	131	65	49	2	2
United Kingdom	355	9	2	9	2
United States	4,001	295	7	88	2
OECD Total	9,865	1,337	14	277	3

Source: IEA (2010) "Monthly Electricity Statistics"

Figure A2.1: Proportion of electricity produced from renewable sources in selected OECD countries, 2009



Source: CEPA chart based on IEA (2010) "Monthly Electricity Statistics"

ANNEX 3: GREEN'S PRINCIPLES OF TRANSMISSION CHARGING

A3.1 Overall principles

In a 1997 paper, Green set out six principles for designing electricity transmission prices that were developed during a discussion amongst a working group organised by the Energy Modelling Forum at Stanford University.[16] The principles were that prices should:

- "Promote the efficient day-to-day operation of the bulk power market;
- Signal locational advantages for investment in generation and demand;
- Signal the need for investment in the transmission system;
- Compensate the owners of existing transmission assets;
- Be simple and transparent; and
- Be politically implementable".[17]

The paper suggested that the first principle is concerned with short-term efficiency, the next three principles with long-term efficiency and the final two principles are concerned with implementation.[18]

Further detail on the principles is set out below:

Promoting the efficient day-to-day operation of the bulk power market

For economic efficiency, the electricity market co-ordinator is required to dispatch electricity in a way that meets demand at the lowest possible cost. This dispatch should take into account the marginal costs of transmission, which include the cost of transmission losses and the opportunity cost that arises from transmission constraints. With transmission losses, less electricity can be consumed than was actually generated and it is necessary for this cost to be accounted for. In the case of constraints, an expensive generator may be used over a low cost generator and this cost also needs to be taken into account.

Green outlines three approaches for dealing with these short-run costs:

- Ignore them: under this approach the system is treated as if all generation is at a single point. This system has the advantage of being easy to administer but can be problematic if transmission losses are significant or if constraints are a serious problem.
- Act as if generation occurs at one point and include charges to cover the marginal costs of transmission: Under this approach the co-ordinator sets a system-wide price but the price for

[16] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3): pp.177-184
[17] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3)at p.178
[18] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3)at p.178

generators varies based on location. This is considered to be a good way of sending a message about approximate costs but it works best where costs are predictable.

- Explicitly include losses and constraints: In this case, generators would be paid the spot price at their node and losses and constraints would be accounted for. This should lead to optimal dispatch unless generators have the ability to manipulate their bids.[19]

Signalling locational advantages for investment in generation and demand

While short-term scheduling decisions may affect the cost of transmission, a far more important factor is the location of generation and demand. The system co-ordinator has few options for changing this in the short term, however, there is some scope for influencing the location of generation in the longer term. For small projects where generators pay spot prices the investment incentives should be correct. However, for larger projects that will change the flow of power both spot prices and the system-wide impact of the project needs to be taken into account.[20]

Signalling the need for investment in the transmission system

Transmission prices may also signal that new investment is needed in the transmission system. This signal is only useful, however, if prices are based on marginal costs. There are three potential problems in using price differentials to signal the need for investment in the transmission system. First, most investments are lumpy. This will therefore lead to significant changes in flows and prices. The second problem occurs when transmission ownership and investment is not the decision of one party but is shared between a number of parties. In this case, the problem of externalities arises. The final problem is divided among several companies and the actions of one could create significant externalities. The third problem is the potential for a perverse incentive to be created for the transmission owner whose revenue will be increased under marginal pricing with significant constraints or losses.[21]

Compensating the owners of existing transmission assets

This objective has been important in transmission pricing. One reason is that for investment to occur in the transmission grid, investors will need a credible commitment that they will receive some return on their investment. In general, transmission charges have been set to allow transmission owners to recover a regulated level of revenue. This allowed revenue is generally greater than the value which would be recovered under the 'signalling' approach. A problem that arises when historic costs are recovered using transmission prices is that this cost recovery can dominate the marginal price signals.[22]

[19] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3)at pp.179-180
[20] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3)at pp.180-181
[21] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3)at pp.181-182
[22] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3)at p.182

Simplicity and transparency

Transmission prices need to be simple and transparent in order to send useful signals to consumers. Where users are unclear about the price they are paying for transmission services then they will not change their actions as a result. However, it is noted that if prices are reflective of marginal costs they will not be entirely simple to understand. The use of zonal pricing rather than nodal pricing is given as an example of a common simplification.[23]

Political implementation

Where influential agents are likely to lose from a proposed pricing system, it will be in their interests to ensure that the proposed approach is not implemented. In the case of transmission pricing, moving towards marginal cost pricing can significantly increase the costs for some users and these users are likely to object to such a change. However, since such schemes have been introduced in various jurisdictions it seems that these objections are surmountable.[24]

A3.2 Principles relating to renewables

With renewable being added to the system, Green suggests that additional investment in electricity networks will be required and that this will lead to an increase in both costs and prices. In this case, having strong incentives to minimise costs may mean that investment in renewable energy is not possible. The process for developing additional transmission facilities is time consuming and it may be that regulators should allow companies to recover the costs of making plans for new lines that seem to be needed but that ultimately are abandoned due to changes in circumstances. In California, the independent system operator, CAISO, has a Location Constrained Resource Interconnection Policy which requires a financial commitment from a renewable generator that 60% of the capacity of a new line will be used. The costs of this line are then included in the general transmission tariff.[25]

A second important issue is how payments are distributed between network users. Green suggests that transmission charges should be based either on the capacity of a generator or on the energy generated over the course of a year, potentially with a weight for the time of production. The overall system of transmission charges should provide a signal of the costs of using the transmission system and should ensure that efficiently incurred costs are recovered. Where other parts of the pricing system send locational signals, leaving network charges to recover a lump sum, then a uniform national charge may be appropriate. Where generators and customers do not face charges that reflect the variation in transmission costs, then transmission charging needs to vary over space.[26]

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[23] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3)at pp.182-183

[24] Green, R. (1997) "Electricity transmission pricing: an international comparison" *Utilities Policy* 6(3)at p.183

[25] Green, R.(2010) "Energy Regulation in a Low Carbon World", at pp.22-23, accessed at http://www.economics.bham.ac.uk/research/2010-discussion/10-16.pdf

[26] Green, R.(2010) "Energy Regulation in a Low Carbon World", at pp.23-25, accessed at http://www.economics.bham.ac.uk/research/2010-discussion/10-16.pdf

However, transmission charges may not have much impact on the locational choices made by renewable generators. Rather, these generators will choose sites that maximise their output. Therefore minimising the rents that can be obtained by well-located generators might be more important than sending explicit signals. However, the impact on conventional generators must also be considered as these generators have more flexibility in choosing sites and will benefit from having signals for transmission costs.[27]

A final issue is the regulation of the transmission system operator, rather than the owner. The system operator buys operating reserves and, where pricing is not nodal, resolves congestion by buying and selling power on either side of a constraint. As the amount of renewable energy increases, these costs will also increase. The benefits from giving the system operator strong incentives to control costs are also likely to rise. For an independent system operator, it may be difficult to give strong financial incentives as they have limited assets to deal with unforeseen events. If significant transmission assets are owned by an independent company which is also the system operator, however, then there is a suitable cushion for strengthening the system operator's incentives. Green suggests that the increase in renewable energy provides an additional argument for establishing independent transmission companies, as opposed to independent system operators.[28]

[27] Green, R.(2010) "Energy Regulation in a Low Carbon World", at p.26, accessed at http://www.economics.bham.ac.uk/research/2010-discussion/10-16.pdf

[28] Green, R.(2010) "Energy Regulation in a Low Carbon World", at pp26-.27, accessed at http://www.economics.bham.ac.uk/research/2010-discussion/10-16.pdf

ANNEX 4: AUSTRALIA CASE STUDIES

Australia's Electricity Transmission Regime

Overview

The Australian National Electricity Market (NEM) consists of five regions. Each region contains a pricing node where the regional reference price is set. Electricity is dispatched in a real-time nodal market and is settled zonally. The NEM is considered to be an energy-only market and does not include a separate capacity market. The NEM operates as a gross pool, with all sales of electricity occurring through the spot market. In Western Australia a net pool arrangement is used.

There are a number of different types of Transmission Network Service Providers (TNSPs) in Australia. These include the TNSPs which operate in the NEM which are subject to the National Electricity Rules (NER) and regulated by the Australian Energy Regulator (AER). In addition, there is Western Power in Western Australia which is subject to the Western Australian Access Code. This company is not subject to the NER but is instead regulated by the Economic Regulatory Authority of Western Australia. There is also the Power and Water Corporation in the Northern Territory which does not own any transmission assets.

For the TNSPs regulated by the NER, there are a number of different regulation schemes. We focus here on the TNSPs regulated under Chapter 6A of the NER.

Included costs

Under Chapter 6A of the NER TNSPs must develop prices for the following transmission services:

- Entry services;
- Exit services;
- Prescribed Transmission Use of System (TUOS) services – locational;
- Prescribed TUOS services – non-locational; and
- Prescribed common transmission services.

Connection costs are charged on a shallow basis. That is, those connecting to the network only pay for the 'connection assets' they require. However, there are some exceptions to this. Where a generator requests changes to the network that cannot be justified as providing a net economic benefit or a reliability improvement then the generator may choose to pay for this itself.

Shared network costs that arise in the NEM are recovered from loads. Congestion and loss rentals that arise from inter-regional transmission links are also used to recover some shared network costs. These rentals are auctioned to participants through Settlement Residue Auctions.

Form of charges

Charges include entry and exit services and TUOS services. For TUOS services there are locational and non-locational components. Half of the Annual Service Revenue Requirement (ASRR) for prescribed TUOS services is allocated initially to each of the locational and non-locational components unless different allocation shares can be justified. The locational component is then to be allocated to connection points by using either a cost-reflective network pricing (CRNP) methodology or a modified CRNP methodology.

Who pays?

For prescribed common transmission services, the ASRR and opex is to be recovered from customers and connection points. For shared transmission costs around 50% are collected from non-locational charges on loads. The remainder is recovered from loads on the basis of the CRNP methodology noted above. Under the CNRP load-flow analysis is applied so that the costs of network elements, such as lines and substations, are allocated to different load connection points based on their hypothesised increased flow on the relevant network element.

Principles and objectives

General principles underlying the transmission pricing rules in the NEM, as put forward by the AER, include:

- Locational transmission prices should reflect the costs of making use of the network at various locations, to encourage the most efficient utilisation of the existing network.
- The purpose of the fixed charge elements of the transmission pricing arrangements should be to recover the fixed and common costs of the transmission network in the least distortionary manner.
- The AER also has a preference for these fixed charges to be stable over time. Stability enables network users to make investment decisions on the basis of predictable costs.

The AEMC also released a rule determination which endorsed the following themes:

- The desirability of consistency across the NEM;
- Price stability;
- Maintaining the status quo in transmission pricing while providing scope for future innovation;
- Removing prescriptive elements of transmission pricing arrangements from the NER; and
- Adopting the ‘causer pays’ principle.

The overarching NEM objective is to:

- Promote efficient investment in, and efficient use of electricity service for the long term interests of consumers of electricity with respect to price, quality reliability and security of supply of electricity and the reliability, safety and security of the national electricity system.

Delivery of renewables

Beginning in August 2008, the Ministerial Council on Energy (MCE) established the Review of Energy Market Frameworks in light of Climate Change Policies. The review was intended to consider the existing energy market frameworks following commencement of the Carbon Pollution Reduction Scheme (CPRS) and the Renewable Energy Target (RET).

The review recognised that the characteristics of renewable generation mean that there are likely to be clusters of new generators in remote locations. To facilitate efficient network investment, the review recommended that customers should be exposed to the costs of connection assets in the case that forecast new generation connections do not occur. Further, the Australian Energy Regulator will have the capacity to reject investment proposals.

The review also recommended that transmission charges be introduced between regions to improve cost-reflectivity and to remove the implicit cross-subsidies that currently exist between customers in different regions. It was also thought that a locational price signal for generators would lead to more efficient decisions being made. Hence recommendations were made for charges to generators to vary by location to reflect differences in network costs arising from connection and use. Further, where possible, it was suggested that the prices received by generators in the wholesale spot market should be adjusted to reflect the presence of material and transient congestion.

In relation to system operation, it was suggested that the Australian Energy Market Operator (AEMO) might benefit from being able to contract for reserve capacity in shorter timeframes.

Strengths and Weaknesses

The NEM is a regional market where shared costs are partially recovered through the load-flow-based CRNP usage charge. The CNRP is intended to signal the long-run marginal cost of the network. While there is a locational element to transmission pricing, generators are not subject to locational pricing. It has been suggested that this may lead to an under-signalling of network costs to new generators. However, it has also been suggested that the lack of significant regional congestion justifies the lack of more targeted locational energy pricing.

The AEMC is currently conducting a review of the arrangements for providing and using transmission services. The final report from this review is expected in November 2011.

Annexure: The CRNP

The following box compares the systems used in Australia and Great Britain for determining their respective zonal use of system charges.

	NGET ICRP	Australia CRNP
Regulatory Authority	Ofgem	AER and State Regulators (for detailed implementation)
Split of Charges	27% generation; 73% load	100% Load
Number of Zones	20 Generation zones (15 originally) 14 Demand zones (12 originally)	Individual offtake points (possibly sometimes aggregated) within each State. For example, Victoria State has 35 individual offtake points, each with separate locational charges.
General Approach	Zone-specific Transport Component: Calculates required LR transmission investment to accommodate incremental generation / consumption in appropriate zones using load flow models and expansion cost constant. Aggregate Security Component: Remaining difference between revenue requirement and transport component is postalized across all zones	Charges are computed on a State-by-State basis. In general, within each State, the net revenue requirement ascribed to transmission use of system is apportioned, with 50% of the value used to form non-locational (postalized within State) charges to all load, and 50% allocated to individual offtake points via a load-flow simulation process.

Key sources

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Australian Energy Regulator (2010) "State of the Energy Market 2010", accessed at http://www.accc.gov.au/content/item.phtml?itemId=961581&nodeId=f714a6c6af0491bef243741843dd55d0&fn=State%20of%20the%20energy%20market%202010%E2%80%94complete%20report.pdf

Australian Energy Market Commission (2009) "Transmission pricing review", accessed at

http://www.aemc.gov.au/Media/docs/Report%20on%20the%20Transparency%20of%20Transmission%20Pricing%20(Network%20Advisory%20Services)-445499e4-02e7-48bc-8ec3-b3a097fbc195-0.PDF

Australian Energy Market Commission (2009) "Review of Energy Market Frameworks in light of Climate Change Policies: Final Report", accessed at http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html

Frontier Economics (2009) "International transmission pricing review", accessed at http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/

Australia’s Gas Transmission Regime

Overview

In Australia, gas producers sell natural gas in wholesale markets to major industrial, mining and power generation customers. Gas is also sold the energy retailers who subsequently sell it to business and residential customers. Wholesale gas is primarily sold via confidential, long-term contracts which generally run for at least five years.

There have been moves to increase the transparency and competition in Australian gas markets with the recent establishment of the National Gas Market Bulletin Board and short term trading markets for Sydney and Adelaide. In Victoria there is a wholesale spot market, established in 1999, which manages gas flows on the Victorian Transmission system. Supply imbalances are traded on a daily basis in the market.

The regulatory framework for the gas transmission sector is set out in the National Gas Law (Gas Law) and the Gas Rules. The Australian Energy Regulator (AER) took over responsibility for the regulation of gas pipelines in Australia, except for Western Australia. The Gas Law and Gas Rules only apply to ‘covered’ pipelines and currently there are seven transmission pipelines with full regulation requiring an access arrangement to be submitted to the regulator. Four additional transmission pipelines are subject to light regulation where access prices and terms and conditions need to be published online.

Included costs

This section focuses on the reference tariff for the GasNet system (or Principal Transmission System) in Victoria. The GasNet system is owned and maintained by APA Group while the transmission system operator is the Australian Energy Market Operator (AEMO). AEMO is responsible for the shipment of gas through GasNet. Transmission tariffs are charged for entry and exit from the system. More specifically, shippers enter into a Transmission Payment Deed with APA Group and where shippers intend to withdraw from the market they must also make a connection agreement with a distribution company or APA.

For pipelines covered under the Gas Law reference tariffs need to be published. Tariffs reflect a number of factors including transportation distance, underlying capital costs, the age and depreciation of the pipeline, technological and geographic differences and the availability of spare capacity.

The Gas Rules stipulate the use of a building block approach for determining total revenue and deriving tariffs. Total revenue needs to be set at a level that allows a business to recover efficient costs, including operating costs, taxation, asset depreciation and a return on capital. The Gas Rules allow for incentive mechanisms to reward efficient operating practices.

Form of charges

The Transmission Payment Deed is an agreement to pay transmission tariffs. These tariffs are Transmission Use of System (TUOS) charges which reflect the cost of delivering gas from the seven injection points to the 27 withdrawal zones and points on the GasNet system.

Who pays?

Payments are imposed on shippers.

Principles and objectives

The National Gas Objective, as set out in the National Gas Law, is stated as being the promotion of efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.

Delivery of renewables

The review of energy market frameworks in light of climate change policies considered both electricity and gas markets. In general, the review found that the energy market framework was capable of addressing the impacts of climate change policies, aside from the particular recommendations made in the final report. These recommendations related generally to the electricity industry, rather than to the gas industry.

Key sources

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ANNEX 5: GERMAN CASE STUDIES

Germany – electricity TSOs

Overview

There are four TSOs and four strongly interconnected control areas in Germany. Due to load-remote wind in the north and transit form north-east to south-west, the network is getting congested at high speed. These congestions are not related to individual TSOs and are both TSO-internal as well as between different TSOs. With massive offshore wind under construction, the onshore transmission network needs to be expanded significantly.

Electricity network regulation relies on the Energy Act of 2005. This act also established the regulator BNetzA and laid the foundation for network regulation. After two rounds of cost-based reductions of network charges, an RPI-X-like system of incentive regulation started January 1st 2009. Germany is currently in the first regulatory control period.

The regulatory treatment of ancillary services is laid down in the regulatory ordinance, but was adjusted in November 30, 2009. The changes started beginning 2010. The major change was that ancillary services were previously regulated as a cost-pass-through, whereas it was changed to an incentive-based scheme, very similar to the system in the UK.

Germany (together with Luxemburg) joined the Open Market Coupling (OMC) system of the Netherlands, Belgium and France on Nov.9, 2010, thereby forming the pentalateral OMC. Two next steps are first to expand the OMC with Scandinavian countries and second to modify the system to be flow-based.

Included costs

The network revenues of the TSOs are to recover the following cost components:

- (network) infrastructure;
- ancillary services, including primary, secondary and minute reserve (and redispatch); and
- system losses.

Basically, these cost components are recovered by Use-of-System charges.

Ancillary services include primary, secondary and minute reserve. The required capacities are determined by stochastic analysis. Required capacities for all three reserves are tendered by the TSOs. Primary reserve bids a capacity price only. Secondary and minute reserve bid a capacity price and a commodity price. The procedures and results are published on the internet.

The TSOs are responsible for the take-off obligation of RES and act as marketeers. The TSOs pay the RES suppliers a guaranteed feed-in charge and bring the RES to the market and receive the going market price. The TSO can pass-through the difference between expenditure and revenue to end-users which makes the system budgetary neutral for the TSOs.

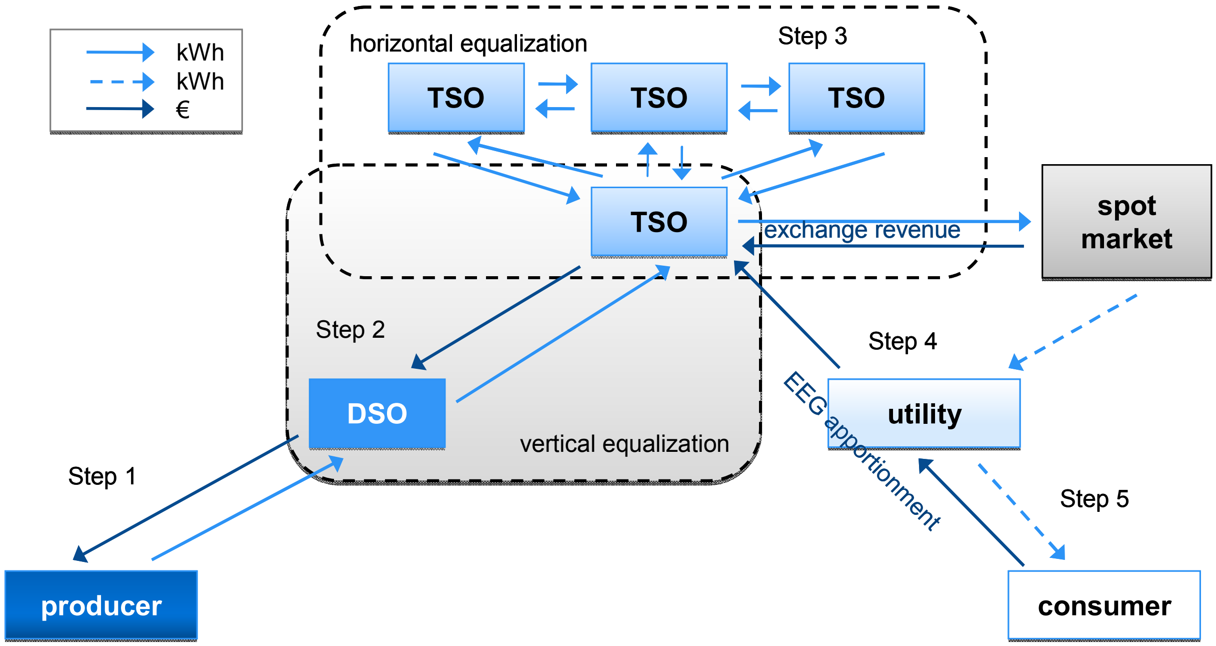


Figure: the mechanism behind the feed-in system for RES in Germany.

Germany has pass-through system for avoided network expenditure of distributed generation that is non-RES and non-CHP (as these are subsidized under different systems). Distributed generation receives a bonus to the extent that the network to which it is connected avoids network payments to the network one level higher. The system runs up to the highest level and ultimately the costs are borne by the TSOs. The TSOs will then increase their network charges, after which the increases cascade down again. With this, the bonus for DG is effectively socialized over all network users.

Incentive regulation:

- RPI-X, with international TOTEX-benchmarking; in practice, the benchmark results are applied with utmost caution;
- Use of investment budgets, which can be requested at any time during the regulatory period. There is a two year time-lag in the revenue flow, which is considered a finance-barrier by the TSOs;
- The investment budgets have an asymmetrical "sliding scale" for budget over- and underspend. The TSOs must pass through underspend and cannot pass-through overspend, unless the TSO can show that the overspend was beyond its control. On paper, incentives are not sophisticated, but in practice, it may be not that harsh; and
- Network expansion has highest priority, especially to facilitate transport of offshore wind north-south, and therefore there is some discussion to more strongly incentivize investments.

The system for ancillary services includes incentives for the TSOs to improve efficiency. The system in place since early 2010 is basically a sliding-scale mechanism.

- The target level is determined ex-ante and updated for market prices annually;
- The SO-determined target level is then annually reduced by 1.25% (which corresponds to the current general-X-factor in the RPI-X regulation); and
- The sliding-scales mechanism has a symmetrical penalty and reward of 25%. Thus, 25% of the budget-overspend is borne by the TSOs and 25% of the budget-underspend may be kept by the TSO.

Forms of charges

Shallow connection charges (to the first point of connection to the network) are cost-based.

Use-of-system charges:

- Two-part charges: a capacity price (€/kW/year) and a commodity part (ct/kWh). The capacity price depends on annual peak load; and
- These are optional depending on the coincidence factor. It is possible for users to request a combination of a low capacity price and a higher commodity price, if the load is unevenly distributed during the year.

The Use-of-System charge is an exit-model. Only users pay. The calculation base is the point of connection to the network. The network-cost follow a cascading principle, passing through network charges from successive higher levels.

The pricing mechanism for settling imbalances is as follows:

- prices for balancing group deviations are calculated on a 15 min basis;
- they are determined on the basis of the TSO's payments for or revenues from the secondary control and minutes reserve energy used;
- a symmetrical single price per 15 min, i.e. no price spread between positive and negative balancing group deviations;
- balance responsible parties showing a surplus get paid the price for balancing group deviations; and
- balance responsible parties showing a deficit have to pay the price for balancing group deviations.

As mentioned above, there is a Use-of-System bonus for non-RES DG for avoided network expenditures.

Congestion management is re-dispatch. There is on-going discussion to introduce more sophisticated congestion management mechanisms but without success so far. The main discussion is to have zonal pricing (possibly three zones) within Germany, to address the north-south network constraint. However, the system is not politically feasible, as it is opposed by both the government and industry. However, we should note that this view may be changing as it becomes clear that congestion is increasing rapidly and that network expansion will not come fast enough to handle the problem.

The TSOs have auction revenues from network congestion, which however by EU-regulation is earmarked revenue and can only be used for re-investment to resolve the bottleneck. In practice, it seems that the TSOs have only limited incentive to use these funds for network expansion and rather not spend it at all. (Basically, the argument is that the effective net rate of return on the earmarked money is zero and it may be more profitable to acquire funds from the capital market and get a small positive net rate-of return if the allowed rate of return is higher than the cost of capital.)

Who Pays?

Basically, network costs are paid by load and are widely socialized almost always trying to achieve national equality. The lead principle of nationwide solidarity is politically very important and can easily block economically sensible ideas.

Generators neither pay deep connection charges, nor Use-of-System charges, i.e. the G/L split is 0/100. Generators will however contribute to balancing costs, in as far as they are out of balance.

Power plants do pay for the connection costs from the plant to the network (shallow charging). However, the ordinance "KraftNEV 2007" has exempted offshore windparks from this rule; the designated TSOs (Tennet TSO and 50 Hertz) are obliged to facilitate offshore connection and are allowed to socialize the costs (nationwide).

Principles/Objectives

The government and thereby the regulator work with the energy-policy triangle:

- Efficiency and affordability;
- Sustainability; and
- Supply security.

The sustainability objective is by far the most important driver at the moment. In case of doubt, the authorities give priority to (short term) sustainability goals and sacrifice (short- and long-term) efficiency. As Germany has high stakes in on- and offshore wind, the vital role of the TSO has become overwhelmingly clear. The RES-promotion scheme, better balancing to use the existing network more efficiently and the required network expansion has top priority and drives much of the discussion on system reform.

Delivery of RES

The subsidy scheme is a feed-in charge system with a take-off obligation, and a priority rule for RES in case of network congestion.

It seems that the system is reaching its limits; especially 2009 saw negative prices due to a combination of high wind supply and low demand.

(Voluntary) curtailment of RES turns out to be politically sensitive. It can be done if system reliability requires this. It cannot be done for economic reasons.

Also, the volumes of RES with which the TSOs, being the marketeers of RES, have to trade, can cause very significant cash-flow fluctuations and can easily cause liquidity problems.

The experience with the feed-in system has been very good. It seems that the feed-in system adequately reduced investors' risk and triggered substantial RES. However, we note that this only seems to work and is only necessary as long as RES is small. Meanwhile, the system reaches its limits.

It seems that the political debate of a RES-subsidy-scheme is moving towards a Spain-like premium-model.

Strengths and weaknesses

Network regulation relies strongly on efficiency incentives. Given investment requirements, the regulatory framework may need revision to better incentivize investments.

Congestion management system within the country (i.e. not cross-border) is unsophisticated and will need revision. Presumably, zonal pricing with two or three zones will address the north-south problem quite well.

There are no, or hardly any, locational network pricing components. The transmission network pricing is treated as if there is no congestion and as if network expansion is not necessary. It may be necessary to rethink the lead principle that generators do not pay for the network. At least locational differentiation will be desirable.

The use of social-cost-benefit-analyses for transmission network expansions is limited.

Presumably, the fixed feed-in charge system for RES promotion has reached its institutional limits. A Spain-like premium model may be a feasible alternative.

Case Study: Germany – gas TSOs

Overview

Germany has 10 long-distance gas-TSOs. The incumbents (amongst which EON/Ruhrgas) and the new transportation network operator Wingas.

Gas network regulation relies on the Energy Act of 2005. This act also established the regulator BNetzA and laid the foundation for network regulation. After two rounds of cost-based reductions of network charges, an RPI-X-like system of incentive regulation started January 1st 2009. Germany is currently in the first regulatory control period.

The long-distance gas-TSOs have been exempted from ex-ante regulation until recently. Due to some pipe-to-pipe competition (the "Wingas" effect) and the presence of some gas-substitution, the industry got its way against the ideas of the regulator. In 2008, this was changed. The TSOs are now also subject to ex-ante regulation and are subject to a DEA-based benchmark in group of 10 long-distance gas-TSOs. After an initial round of cost-based P_0-reduction, RPI-X regulation for the gas TSOs started in 2010.

Included costs

Included costs are:

- Cost of infrastructure;
- Cost of imbalance;
- Operational balancing; and
- Market operation.

Note, however these cost components need not always be incurred by one and the same agent.

Forms of charges

Reflecting historical development and different networks (although interconnected), Germany has different "market areas":

- A market area is a (combination of) network area(s) within which there is no network congestion (by mechanism) and the demarcations of which are network constraints between market areas;
- Each market area has a virtual trading point; and
- Each market area has a designated market area marketeer, or a clearing agency. In a way, these can be seen system operators.

The number of market areas has constantly decreased. The set target is to have only three market areas by April 2011:

- One L-gas market area
- Two H-gas market areas

The basic model is a two-contract approach in the form of an entry-exit model for each market area:

- An entry-contract is the right of transport from the entry point to the virtual trading point;
- An exit-contract is the right of transport from the virtual trading point to the exit point; and
- Any trader (network user) needs these two contracts.

Thus, within a market area, trading is path-independent. Going from one market area to another, path-dependence arises.

Anything that happens between the entry and exit within the market area, but which crosses different networks is to be arranged between the network operators. To do so, the network operators have worked out an Agreement of Cooperation, which is now in its third version (2008); this is similar to a grid code.

The capacity contracts are distinguished between firm contracts and interruptible contracts. They are available on a yearly, quarterly, monthly and daily basis.

At the moment, contracts are not adequately available which is considered to impede the development of the market. It is now agreed that:

- There will be a common trading platform by Aug. 2011, both for the primary and secondary market;
- The primary allocated contracts, designated for trading, should be auctioned at the latest by Oct 2011;
- There is a use-it-or-lose-it rule to promote secondary trading; and
- Excess revenues, stemming from the primary auction, are to be used for network expansion.

Charges for the cost of imbalances:

- The imbalances are allocated per rule to the take-off network operator, that will have to pass cost and benefits through to the traders;
- The pricing rule for imbalances is asymmetrical (to avoid manipulation):
    - The base is the daily price at four trading points (TTF, NBP, Zeebrugge, EGT VP);
    - The price for negative imbalance: base-price times 0.9; and
    - The price for positive imbalance: base-price times 1.1.

The cost of balancing (internal or external procurement) are socialized over the balancing groups

Who Pays?

At transportation level (i.e. not distribution), the cost are borne by network users, as defined as those who need entry and or exit contracts. Therefore both the feed-in side as well as take-off side contribute:

- These contracts contain only capacity charges; and
- As explained, this system is path-independent.

The sum of prices of entry and exit contracts should by and large recover network costs.

The cost of the network are allocated to entry and exit in a reasonable ratio.

The charges should:

- Take supply security and network reliability into consideration;
- Be non-discriminatory; and
- Set incentives for efficient use of network capacity.

The third point is notable. For the gas network the network charges can be used explicitly for scarcity signals. As noted above, for the electricity network this considered to be a problem.

Principles/Objectives

The most important driver currently is to make the market work and liquid. This accounts for the commodity as well as the transportation market.

Market design and incentives for market players all head into that direction.

Efficiency plays a lesser role than in electricity.

Except for biogas, sustainability issues are not very important.

Delivery of RES

Biogas is getting increasingly important and has an exempted position:

- There is an obligation to connect biogas feeders to the network and facilitate transportation;
- Biogas feed-in has priority in case of network congestion;
- Network owners bear a large part of network adjustment if so required by biogas quality issues. In a way this is shallow pricing; and
- Biogas feed-in receives bonus to the extent of avoided network expenditure, very similar to the case for distributed generation connection onto the electricity grid, as explained above.

ANNEX 6: PJM CASE STUDY

Background

PJM is a Regional Transmission Organisation (RTO) responsible for managing the real-time operation of the transmission grid and wholesale power market in an area covering all or part of 13 mid-Atlantic region States and the District of Columbia in the US. It is incorporated as a limited liability company with an independent board elected by its members.

In managing the grid and the power market, PJM serves its members who are market participants. Today PJM has over 550 members, which include power generators, transmission owners, electricity distributors, power marketers, and individual large customers. Its system size is currently approximately 165 GW capacity, serving a peak load of about 144 GW. The transmission system which is managed by PJM is itself owned by 17 different entities, most of whom are former (prior to the large-scale restructuring of the US industry which began in the mis-1990s) regional vertically integrated monopoly utilities.

The PJM market structure provides a day-ahead energy market with locational (nodal) prices, but also allows bilateral trading outside of that energy market. A real-time locational spot energy market is also available to serve users of either trading option. All load in PJM must also participate in a capacity market which acts to provide locationalised availability incentives for capacity. Transmission system users can use either "network" or "point-to-point" transmission services, typically according to the type of transactions they wish to execute.

More details of all these aspects of the market structure are described in the sections below.

Energy & Capacity Markets

PJM operates two separate energy markets – the Day Ahead Energy Market and the Real-Time Energy Market, as well as the RPM Capacity Market. Related to the energy markets, PJM also conducts periodic auction markets in Financial Transmission Rights. Participation in any of these organised markets is not obligatory for PJM members; members also have the option of organising "physical bilateral" transactions using appropriate transmission services.

The Energy Markets

Both the Day Ahead Energy Market and the Real Time Energy Market are structured as full Locational Marginal Pricing (LMP) markets. The Day Ahead Energy Market calculates hourly day ahead prices at each network node based on generator offers, demand bids, and available transmission capacity. The Real Time Energy Market calculates hourly prices at each network node during real time operations.

Both markets are settled with market-clearing prices defined at each node in the network. All generators selling at a single node at a single time within a market receive the same clearing price; all loads pay the analogous clearing price at their own network nodes.

As with the financial operation of all LMP markets, the process of buying and selling at nodal marginal prices results in net congestion rents accruing initially to the account of the Market Operator. In PJM, these congestion rents are paid to holders of "Financial Transmission Rights" (FTRs) which give the holder the right to collect the difference in congestion prices[29] between two defined nodes on the network for a defined amount of capacity.

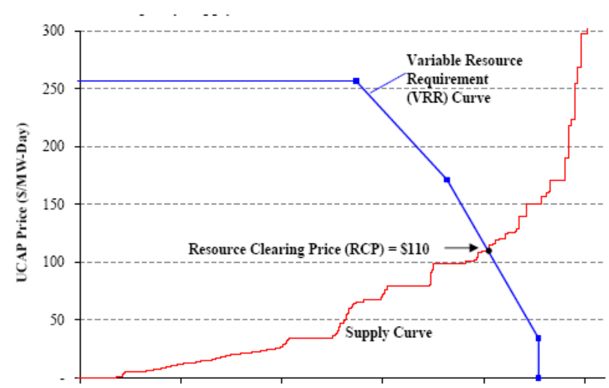
Holders of FTRs can thus hedge against the costs of congestion between different points in the network. PJM conducts auctions of FTRs with varying time durations for the FTRs auctioned. The revenues from these auctions are returned to the holders of "Auction Revenue Rights" (ARRs). ARRs are allocated annually to PJM members according to a rule-based system; as a practical matter, the dominant holders today are legacy load-serving entities (suppliers). PJM manages the FTR auction process to ensure that congestion rents actually collected over a year will in fact yield adequate revenues to pay FTR holders; to the extent that any excess congestion rents might occur (which to date has not happened), such rents would be rebated to offset transmission usage charges.

The Day Ahead market is generally used by participants to execute transactions, with the real time market being used to manage what amounts to balancing of their commitments made in the day ahead market or via out-of-market bilateral transactions. The real time market is also used for transactions by participants wishing (or needing) to make spot rather than day-ahead transactions, though it is estimated today that only a small portion (perhaps 5%) of real time market activity is used for this purpose.

The Capacity Market

Every Load Serving Entity (LSE) in PJM must meet a capacity obligation (based on its estimated peak load plus a calculated reserve margin) either through either self supply (specific capacity resource ownership or contracts) or by making capacity payments through PJM's capacity payment market.[30]

Figure 1: Illustration of RPM Capacity Market Clearing Price for 2011 / 2012 Auction (after Chao, 2008)



PJM's capacity payment market is today the "Reliability Pricing Model (RPM) Capacity Market".

[29] The nodal prices (LMPs) calculated at each node of the network reflect marginal energy costs plus (since 2007) marginal system losses at each node. FTRs allow users to hedge against differences in marginal energy costs at each node but do not reflect marginal losses.

[30] Strictly speaking, all LSEs must participate in PJM's capacity market, though those entities with self-supply participate only to the extent of their "net" uncovered resource requirements (which might be zero, if the LSE is fully covered by its own or contracted generation).

This market uses bid prices by generators or demand-side resources (e.g., despatchable load) together with an administratively determined demand curve (based on PJM forecasts of LSE peak load, defined reserve margins, etc) to determine market clearing prices (which are expressed in $/MW-day). The maximum capacity price reached by the demand curve is today set at 150% of the economic capacity cost of a new entrant peaking unit. Figure 1 shows the aggregate interaction of the supply and demand curves for the RPM Capacity Market auction for prices during the 2011 / 2012 period.

The market clearing prices are determined separately for a number of capacity "zones" (Locational Deliverability Areas, or LDAs) which are themselves defined by persistent transmission constraints. In concept, there could be as many as 23 different capacity zones throughout PJM, though experience with the RPM Capacity Market to date suggests that typically clearing prices vary only across about four or so broad capacity zones.

The RPM Capacity Market auction takes place annually, with the auction results applicable to the year three years subsequent to the auction year (this is to allow yet-uncompleted or even yet-unstarted projects to participate in the auction, providing planning incentives). Auction winners are (in the appropriate year) paid the auction clearing price on a daily basis, subject to availability. Winners are required to participate in the Day Ahead energy market.

As noted above, demand side resources can bid into the RPM Capacity Market. Currently about 7.5% of RPM required capacity is met by such resources. In concept at least, RPM is also intended to accept bids by transmission owners for projects which would relieve congestion between zones (i.e., allow increased transfer of capacity from zones with high reserve margins into zones with lower reserve margins) via so-called "qualified transmission upgrades" (QTUs) though so far (since the RPM Capacity Market was put in place in 2007) no such projects have participated in the market.

Transmission

PJM incorporates 17 separate transmission owners. The relevant revenue requirement for each of these transmission owners is regulated by the US federal energy regulator, FERC.

Broadly, the transmission charging structure incorporates deep connection charges with use of system charges paid by transmission system users which in most cases are LSEs. While transmission tariffs have uniform structure (design) throughout PJM, the actual level of the tariff paid is a function of in which transmission ownership area the transmission transaction sinks. This mechanism is intended to ensure that each separate transmission owner recovers its own revenue requirement.[31] Ancillary services are postalised across all of PJM and charged to load.

Further details of these arrangements are described below.

[31] Thus, the individual revenue requirements of the various transmission owners are not combined and postalised in order to form a pan-PJM uniform transmission tariff. Instead the approach taken by PJM (referred to as "license plate" in contrast to "postage stamp") is to retain regional differentiation of charging along the boundaries of the different transmission owners.

Connection Charges

Connecting parties are required to pay deep connection charges. The level of the charge is determined by what investments are required (which in some cases might be zero) in order to maintain PJM's reliability criteria in the presence of the new connection.

In return for paying deep connection charges, connected parties receive an ARR for the FTR which will be auctioned between the point of connection and the location for which the deep investments relieved potential congestion.

Use of System Charges

PJM offers two different types of transmission services:

- Network Service: This service provides transmission services for users with one or more sources serving one or more sinks (bulk supply points or offtake nodes). This service would typically be used by LSEs or by individual transmission connected customers using multiple generation sources.

- Point to Point Service: This service provides for transmission between two designated points on the network. The service can be either "firm" or "non-firm" (i.e., highest priority for curtailment due to constraints). It would typically be used by entities scheduling import or export transactions, or end users using single bilateral supply contracts.

Requests for transmission service are made through PJM's open access scheduling system and at any time are subject to availabilities limited by calculations of available transfer capacity and existing long term transmission commitments.

For both type of service, transmission charges are based on the sink location of the transaction and paid for by the "transmission customer". Typically, the transmission customer is an LSE or directly connected large industrial customer. However, transmission customers could also include power marketers or generators scheduling interchange (export) transactions, or others.

Ancillary Services

Ancillary Services are acquired by PJM and charged (based on PJM-wide postalised costs) to load[32].

The principal Ancillary Services include:

- Synchronised (Spinning) Reserve

Synchronized Reserve service supplies electricity if the grid has an unexpected need for more power on short notice. PJM acquires synchronised reserve through the on-the-day Synchronised Reserve Market. In this market, generators and despatchable load are able to make an offer price for providing reserve services; they will anticipate recovering (at least) this offer price plus any lost opportunity cost (i.e., lost sales at the local LMP as a result of being selected to operate at reduced

[32] As with capacity requirements, LSEs also have the option to self-supply some or all ancillary services to their required specified levels. Thus, PJM actually acquires and charges for net (non-self-supplied) ancillary services requirements.

load) if they are selected for reserve service. The Synchronised Reserve market constructs a supply curve based on offers plus estimated opportunity costs and pays a market-clearing price to selected reserve providers.

- Regulation

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. PJM operates an on-the-day Regulation Market which functions analogously as the Synchronized Reserve Market described above. Resources selected for one service (i.e., either Synchronized Reserve or Regulation) through the operation of these markets are excluded from the other service.

- Day-Ahead Scheduling Reserve (DASR)

PJM recently began operating an additional day-ahead market intended to ensure adequate on-the-day availability for the operation of the two on-the-day reserve markets. The DASR market is clears on the basis of bids from generators or despatchable load. Selected resources are obliged to be available to provide services in the later on-the-day markets.

- Reactive power

Generators are obliged to provide reactive power to PJM upon request according to a tariff set by FERC.

- Black Start

PJM and individual transmission owners identify the black start resources included in each transmission owner's system restoration plan. PJM does not have a market to provide black start service, but compensates black start resource owners according to a regulated tariff.

RES Issues

New renewable resources in PJM's operating area typically arise in response to US Federal fiscal incentives or renewable portfolio standard requirements placed on LSEs in some State regulatory jurisdictions.

In terms of capacity, the most significant renewable developments today and in the coming years will be onshore wind. For example, as of late 2009 PJM had slightly less than 5 GW of installed wind capacity, though over 35 additional GW were in notified planning processes for construction by 2015. Much of the new generation is in areas requiring transmission investment and / or reinforcement. In contrast to other US RTOs (e.g., ERCOT, CalISO), PJM is currently not pre-building (and charging to load) transmission in areas of potential investment; rather it is treating new wind investments identically as other generation types would be charged for connection. PJM is also studying the implications for system operation in a world of significantly greater intermittent, undespatchable energy resources.

Summary

Some of the key observations in regard to the PJM RTO include:

- The energy and capacity markets include explicit nodal and zonal level locational signals. Suppliers can hedge against much of the adverse locational costs through the FTR / ARR system, though locational marginal prices will remain observable.
- PJM revised its capacity market in 2007, with changes designed to both "smooth" the level of capacity payments (through the introduction of a sloped demand curve from the previously-used vertical demand curve) and introduce demand-side resources (and potentially transmission projects) into the capacity resource supply curve. It seems likely that continued development of the RPM Capacity Market will continue as experience is gained.
- PJM's Market Monitoring Unit's most recent full assessment of the state of the market (see the 2009 State of the Market report) has concluded that all PJM's markets (with the exception of the market for and Ancillary Service of Regulation) were competitive. Interestingly, despite confirming the competitiveness of the primary energy markets, the Monitoring Unit also recommended consideration of requiring marginal cost-reflective bidding into the Day Ahead Energy Market.
- Certain aspects of PJM's overall market structure and approach probably reflect the legacy "starting position" of the entity as a collection of regionally vertically integrated monopoly utilities as recently as the mid-1990s.

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ANNEX 7: NETHERLANDS CASE STUDY

Overview

The Netherlands has one state-owned TSO, called TenneT.

The regulator is the Energy Chamber (*Energiekamer*) which is a chamber of the competition agency NMa.

The main picture at the moments is:

- The transmission charging system in the Netherlands contains few locational signals.
- The transmission network is getting increasingly congested.
- In response, TenneT is expected to expand the transmission network. The regulator works on investment allowances to facilitate these.
- Transmission expansion is quite strongly centrally planned and subject to various political influences.
- There is a new variation for congestion management, which introduces some locational signals; these are short run, but obviously have long term effects.
- There is discussion on priority rules for RES, which may be useful for RES, but of course worsens the network congestion problem.

Included costs

The network revenues of the TSOs are to recover the following cost components:

- (network) infrastructure;
- ancillary services; and
- system losses.

Forms of charges

Shallow connection charges (to the first point of connection to the network) are cost-based.

Tennet works with three components:

- Connection tariff;
- Transport tariff; and
- System services tariff.

The connection charge is shallow and contributes to the costs of the connection to the main network only. It consists of a one-off payment and an annual payment for maintenance. The connection charge is tailor-made and therefore location specific; however, it is a shallow charge.

The transport tariff can best be seen as the Use-of-System charge and consists of a non-transmission-related consumer tariff (TOVT) and a transmission-related consumer tariff (TAVT). The latter is a price in euros per kW and is differentiated to load coincidence.

Lastly, system service tariffs covers balancing services, including not-covered remainders of the cost of congestion management.

In July 2010, the regulator decided on a new form of congestion management within the Netherlands. Congestion management is basically market-based re-dispatch, with bidding run through APX in Amsterdam. This explicit congestion management applies to identify areas where consistent congestion is expected one year ahead.

Regulation of ancillary services

The regulator changes the system to incentive-based regulation with the main argument to improve incentive for cost-management.

The new system will run from 2011 to 2013 (three years).

Regarding the task of providing ancillary services, the regulator distinguishes between procurement costs and implementations costs. The latter are regulated with a standard type revenue cap, where the main discussion points were about benchmarking and WACC.

For our purposes, the procurement costs are the more interesting:

- Procurement costs will be regulated with an ex-ante revenue cap;
- There is no sliding scale (or more precisely, the sliding scale factor is 100%), shifting all risk to the TSO;
- the revenue cap will be determined annually based upon a rolling average of the previous three closed book-years (t-4 to t-2);
- the allowed budget is a revenue cap which thus takes explicit account of volume fluctuations; and
- Because the cap is adjusted annually following real costs, the cap is not subject to any X-factors.

The regulator explicitly mentions an aim to ease the rules on procurement procedures to allow TenneT to find the best deal.

Who Pays?

Basically, network costs are paid by load and are widely socialized.

Generators neither pay deep connection charges, nor Use-of-System charges, i.e. the G/L split is 0/100. Generators will however contribute to balancing costs, in as far as they are out of balance.

Principles/Objectives

The government and thereby the regulator work with the energy-policy triangle:

- Efficiency and affordability;
- Sustainability; and
- Supply security.

The transmission network is getting congested, basically due to wind in coastal areas and especially planned offshore, and besides, new coal plants are also planned at location in the coastal areas. These developments will congest the existing network. TenneT published a study (Tennet Vision 2030) describing in detail different scenarios for transmission expansion necessary to address the problems.

The government, Ministry of Economics and the regulator (EK) are getting increasingly aware of locational pricing. However, current state of the debate is that planning of sites for large scale production, and planning of transmission expansion is not a matter of pricing but a matter of long term coordinated central planning.

The upfront reasoning is that locational signals:

- may be relatively ineffective;
- the number of sites is restricted anyhow;
- that such mechanisms may be cost-ineffective (i.e. costs, which include redistribution effects, may be higher than benefits); and
- there is no G-component.

In the background is certainly a more political wish that large scale planning of G-sites and T-expansion includes other dimension like land-use and regional development and legal issues. Moreover, currently the issues are under control of the ministry; were it to be part of the tariff framework, the control would shift to the regulator.

Delivery of RES

CHP plays a special role in the Netherlands. Due to the prevalence of greenhouses, CHP has a large share. Where is it is connected it tends to congest the distribution networks. The distribution networks also do not work with explicit locational pricing or deep pricing, but there are some small exemptions where unreasonable network costs can be avoided.

There is quite a bit of discussion on the extent of priority rules for RES in case of network congestion. The issue is not entirely settled yet.

There is a lot of political uncertainty about subsidies for offshore wind. This has severe consequences for the network.

Strengths and weaknesses

The current state is that there are no explicit locational signals in transmission pricing.

Although the network will become increasingly congested depending on the development of offshore wind, this will be addressed by planned transmission expansion. In other words, network development follows generation locations and is not optimized.

The incentives for TenneT to optimize the overall system and use signals to network users in the transmission charge framework are not very strong.

ANNEX 8: SPANISH CASE STUDIES

Spain's Electricity Transmission Regime

Overview

The Spanish electricity market was liberalised in 1997. A wholesale electricity market was established, with a degree of separation of the distinct activities of vertically integrated electricity companies.

The regulatory framework has evolved as it has encountered numerous challenges. One particular feature has been that although prices for different activities have been separate from the start, there has been an overall revenue cap for the system. When wholesale prices have been high, this has led to a "tariff deficit", the cost of which is recovered through access charges.

There are four main integrated companies active in generation, distribution and supply: Endesa (owned by ENEL), Iberdrola, Acciona, and EDP. Additional generation is owned by Gas Natural (gas), Iberdrola Renovables (Iberdrola's renewables subsidiary), and EDP Renovaveis (EDP's renewables subsidiary).

Electricity transmission is owned and operated by Red Eléctrica de España (REE). Formed in 1985, it was the world's first independent transmission company. Until 2010, other companies active in the Spanish electricity market also owned transmission assets. Law 14/2007 of 4 July established REE as the sole transmission owner and operator in Spain and required transfer of these assets to REE. These transactions completed in 2010.

There are a number of ways of trading in the energy market, including:

- Bilateral forward trading: this involves negotiation between the parties or by auction in the market;
- Daily market (day ahead) trading: this allows bilateral contracts, trading through bids and voluntary integration of forward positions;
- Intraday market: this market is open to both those who have traded on the daily market and those with bilateral contracts; and
- Technical management: this allows trading to guarantee the security and reliability of the system.

There is no locational differentiation in the Spanish market.

There is a capacity payment mechanism for generators in Spain. This payment is made regardless of whether the plant was actually dispatched or not and is dependent on the generator having operated for the equivalent of 480 hours in the past year. The share due to each generator is based on that generator's share of total available generation capacity.

The distinctive feature of Spain, and the reason why it is included here, is the rapid growth of renewable energy, in particular wind, that has been observed.

Included costs

Transmission tariffs only include transmission system owner and operator costs, i.e. sufficient revenue to cover operating costs and to recover investment costs over the life of the asset. Investments built prior to 2008 receive revenue that increases by RPI-X; for assets built from 2008 on there is an explicit revenue allowance for each asset based on recognised investment costs and indexed operating costs.

Losses are included in the energy costs.

Other system costs (equivalent to the balancing system costs in the UK) are also included in the energy charges, through the wholesale electricity market mechanisms. These are added to the revenue in each hourly settlement period. In 2009, they accounted for 6.2% of the average price (of €42.65/MWh).

Form of charges / who pays?

Charges are shallow in form. Generators pay for their own line for connection to the system, but any costs beyond that are socialised in the national tariff. Charges are levied on customers through a settlement system operated by the CNE. Access charges differ by connection voltage, with a fixed and a variable component of charges. On average, 54% of revenues is recovered from the capacity component, and 46% from the energy component (see ENTSO-E 2010).

Use of system charges are paid by load and are non-locational.

Principles / objectives

A range of objectives have been identified by the CNE in its 2008 consultation of access charges (which included transmission access as well as the other costs included in the access charge).

- Sufficient to cover costs of the system.
- Cost reflectivity. Charges should reflect costs imposed on the network by users.
- Transparency. The method and parameters for setting charges should be transparent.
- Stability. Price signals should be sufficiently stable to allow system users to plan effectively.
- Simplicity. The structure should be as simple as possible.
- Objectivity. The method must rely on objective data rather than subjective judgement.
- Coherence. The method should fit with the objectives of the rest of the system.

Delivery of renewables

A key feature of the Spanish electricity system has been the remarkable growth of renewable energy. At 31 December 2010, Spain had 19.959GW wind capacity connected out of a national total of 103.086GW (of which 19.8GW and 97.4GW respectively were on the mainland). This compares to 10.1GW wind in 2005. Increased connection of wind and other renewables is expected to continue. There has been a significant increase in transmission capacity to accommodate this and other growth, with annual spending of REE increasing from €420m in 2005, to over €800m annually to 2014.

Rapid growth in renewables began in Spain in 2005 and was promoted by a number of royal decrees with incentives for renewable generation. As an example, feed in tariffs were set for wind that guaranteed a price per kilowatt hour equal to the market price Another decree set feed in tariffs for wind that guarantee a price per kilowatt hour equal to either the market price plus a premium or a specified minimum for a period of 25 years. Incentives vary in line with the day-ahead market. There is also a 'special regime' for renewable generation.

Clearly the transmission charging mechanism has not been a barrier to this. REE is obliged to connect renewables, and the rapid system expansion, in plans set by government, has been required to accommodate this. Renewable energy resources in Spain tend to be located far from load centres and the grid and it appears that the planning process has led to some overcapacity in construction. REE has also needed to research and develop ways to accommodate the volatility in wind generation, the costs of which fall to consumers in the balancing market.

REE makes plans for reinforcing, modernising and expanding the grid. These plans require approval by the Ministry of Industry, Tourism and Commerce and once approved, the transmission tariff is adjusted to accommodate REE's expenditure. The transmission tariff is non-locational and therefore there is no price signal based on location to limit the development of renewable resources. It has been suggested that around 20% of REE's grid expansion budget includes renewables projects. REE is the only entity that builds and owns transmission assets and cost allocation has not been an issue.

Numerous other initiatives have been taken to accommodate renewables, including priority in despatch when there is congestion, and the creation of a separate control centre for renewable energy.

Strengths and weaknesses

Transmission charging has not been a major focus in Spanish regulation since de-regulation. There are good reasons for this. The absence of locational generation and demand signals for transmission is not as significant a problem as the distortions caused for example by the tariff deficit mechanism.

What the Spanish experience shows is that it is possible to get large quantities of wind generation connected. This has happened because there is a national focus on it, with regional targets for delivery. The transmission operator receives premium returns on new investment, and therefore there is a strong incentive to deliver on investments needed to connect, and there may be an incentive to build excess transmission capacity.

The issue with such a system is whether it offers value for money for the ultimate customers who pay.

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Spain's Gas Transmission Regime

Overview

The main player in the gas distribution market in Spain is Gas Natural (GN). GN is the vertically integrated former monopoly. The TSO has been unbundled, however, distribution activities have not been fully unbundled within GN. The gas transmission operator is Enagas.

Competition in the retail market has been promoted through a gas release programme. This occurred in 2001 and made 25% of imported gas available to traders on the free market. By 2005, GN's market share had fallen to 48%. New entrants to the market included large electricity companies and foreign companies such as BP, Shell and Gaz de France.

Tariffs are applied using an entry-exit model with a single balancing zone. For entry points, the charge is a uniform value for capacity reserved at any entry point on the system. The exit point tariff is based on capacity reserved and usage. Capacity is allocated on a first-come-first-served basis.

Transmission tariffs are differentiated on the basis of whether the service provided is local or cross-border; firm or interruptible; and the duration of the contract. For the transmission service within Spain, there is no tariff differentiation on the basis of location.

There is one balancing zone in Spain. The balancing period is one day and trade can occur within the day to adjust balances. Balancing is achieved using linepack and underground storage and LNG facilities. The system operator also runs a daily auction mechanism to restore any deviations to the accepted bounds.

Included costs

As noted above, Spanish transportation tariffs within the national market are postalised and include a capacity fee and a throughput charge. These charges depend on the pipeline pressure and volume.

Forms of charges

Tariffs are applied using an entry-exit model with a single balancing zone. For entry points, the charge is a uniform value for capacity reserved at any entry point on the system. The exit point tariff is based on capacity reserved and usage. Capacity is allocated on a first-come-first-served basis.

Transmission tariffs are differentiated on the basis of whether the service provided is local or cross-border; firm or interruptible; and the duration of the contract. For the transmission service within Spain, there is no tariff differentiation on the basis of location.

Who pays?

Tariffs are paid by shippers.

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