MODELS OF INTER-REGIONAL TRANSMISSION CHARGING

MARCH 2008

A report for the

Australian Energy Market Commission

The Brattle Group

rue Ducale 83
Bruxelles 1000
Belgium

tel: +32.2790.3580
fax: +32.2790.3581
office@brattle.be

Contents

1 Executive Summary

The Australian Energy Market Commission (AEMC) is analysing inter-regional charging for electricity transmission in the context of its work developing the role of a National Transmission Planner (NTP), given the potential for charging arrangements to support or hinder effective trans-regional transmission planning and investment. The ERIG[1] report and the debate over an NTP generally suggest that new investment in interconnection may be a significant issue that is not dealt with well under the current arrangements, and hence that addressing any investment incentives problem associated with inter-regional charging is important.

We have identified three fundamental challenges facing any inter-regional charging system, including any system that might be developed for the Australian electricity market (NEM):

1. **Efficient incentives for network owners (TNSPs)**. TNSPs should have incentives to look for and implement efficient interconnection projects.
2. **Efficient locational signals**. New "footloose" generation and load should have incentives to locate efficiently (i.e., the resource cost of connecting to and using the system should be reflected in its own internal profit calculations).
3. **Equitable cost allocation**. The charging methodology should also address equity concerns by providing for an appropriate sharing of costs and benefits between interconnected networks.

The aim of this report is to describe international experience in addressing these challenges, and draw conclusions for Australia. We have examined three different systems: the ISOs/RTOs[2] in place in the United States, the approach taken on continental Europe through the operation of an "inter-TSO compensation scheme, and the Nordic model. Table 1 below summarises our findings, giving the most relevant features of each system.

---

[1] *Energy Reform: the way forward for Australia*, Energy Reform Implementation Group (January 2007).

[2] Independent System Operator/Regional Transmission Organisations.

Table 1

	US ISOs/RTOs	Continental Europe	Nordic Region
Who pays the cost arising from inter-regional flows?	New assets that are deemed to be "regional" in nature are paid for by all networks in system. In some systems costs related to existing assets are also shared. "Regional" assets are those above a certain voltage threshold.	Cost of new interconnection is shared by two networks involved. Some costs relating to existing infrastructure that is deemed to be involved in transit flows is compensated as part of the Inter-TSO Compensation scheme.	Cost of building or upgrading interconnection is shared by two networks involved. Some costs relating to existing infrastructure that is deemed to be involved in transit flows is compensated as part of the Inter-TSO Compensation scheme.
Who benefits from congestion revenues?	Congestion revenues go indirectly to those parties who invested in the line, including generators that contributed via "deep" connection charges. TSO rights to congestion revenues are auctioned off periodically.	Congestion revenues are collected by the TSOs and shared out based on agreement between two countries involved. This income must be used either to reduce tariffs or to upgrade interconnection; in practise it is usually used to reduce tariffs.	Congestion revenues are collected centrally and shared out based on agreement between all participating countries. This income must be used either to reduce tariffs or to upgrade interconnection.
Do network owners have incentives to increase capacity for inter-regional flows?	Yes. Cost of new assets is shared by all networks in the system. The rights to congestion revenues are auctioned off so little short-term incentive for decreasing capacity available. ISO/RTO takes lead in assessing need for new infrastructure and can appoint third party to build if necessary. Regulator provides financial incentives for increased investment in transmission.	Not really. Vertical integration within European power sector has hampered liberalisation with TSOs failing to improve interconnection so as to protect domestic generator's interests. Despite legal restrictions on its use, direct income from congestion revenues disincentivises reducing congestion.	Weak incentives via voluntary planning and political processes. Cost of new assets is borne by the network in which the asset is located. Nordel takes some lead in assessing priority projects but timeframe is slow on these projects. Despite legal restrictions on its use, direct income from congestion revenues disincentivises reducing congestion.

Conclusions

We draw the following observations from our analysis:

1. International experience seems to confirm the importance of having a mechanism that allows for cost sharing of assets that facilitate inter-regional flows. Even strong political will combined with widespread public ownership of the networks does not appear to be an adequate substitute for financial mechanisms.
2. Such a mechanism can be an explicit cost allocation, or it could be more implicit, for example by having interconnectors used for imports pay network tariffs on the system they connect to in the same way as load. A common pattern seems to be that regional transmission systems are initially developed without such mechanisms, which then arise as the need becomes apparent.
3. There is no simple “theoretically correct” answer to the design of such a mechanism—the main purpose of the mechanism is to overcome concerns about distributional effects of new capacity, for incentive and/or equity reasons, and such concerns inevitably vary from case to case. In practice the details of the design will depend on the need to avoid unacceptable distributional consequences.
4. There is also a possibility that the mechanism will distort the locational signals delivered through locational pricing
5. Nonetheless, experience shows that simple, clear rules are accepted and appear to be successful. The main mechanisms seen in practice are (a) adding specified assets into a “whole region” asset base, and (b) getting exports to pay the load charge (point 2 above).
6. Incentives may be needed to get transmission owners to sign up to a scheme, if initial participation is voluntary (in theory or in practice), especially if the scheme is binding once the network is in it.
7. Depending on the layout of the system, it may be important that any mechanism is able to share the costs of "deep" assets, not just the interconnectors themselves.

2 Introduction

Australian electricity consumers pay transmission tariffs to the owner of the local transmission network. These tariffs allow the network owner to recover its regulated revenue, which consists of the costs it incurs in operating the network, as well as depreciation and a rate of return on its investments in the network. Where two adjacent transmission networks are connected through a regulated interconnector, the transmission tariffs also support the costs of the assets used by the interconnector flows, with the network on each side paying the costs associated with its own assets. Thus these costs are not allocated in a way that reflects which users "cause"[3] the costs: customers on the import side cause costs in the export region.

Furthermore, most of the benefits of the interconnector go to consumers on the importing side of the interconnector because they benefit from imports of cheaper electricity[4] and also benefit from congestion revenues on the interconnector (they benefit because the importing network receives revenue from auctioning Inter-regional Settlement Residues (IRSR) to market participants.[5] These consumers do not contribute to the costs imposed by the interconnector flows on the export side, because they pay transmission tariffs only to their local transmission network.

This situation is potentially unsatisfactory for at least three reasons:

1. It is a barrier to developing further interconnection, and gives the wrong incentives to the network owners. An exporting region would not want to build a new interconnector because its customers would pay but would receive few benefits. In some circumstances an importing region might not want to build a new interconnector because the extra capacity could reduce the IRSR on existing interconnectors.
2. New load may choose where to locate partly on the basis of transmission network charges. If the costs of interconnectors are not fully reflected in the network charges on either side of the interconnection, the location decision of new load customers may be distorted, leading to additional costs for the system as a whole that will not be paid for by the new load.
3. It is likely to be perceived as unfair—customers in an exporting region pay a proportion of the costs of interconnection, but typically receive none of the financial benefits.

[3] See Appendix 1 for a brief discussion of cost causation.

[4] In the sense that the wholesale price in the importing region will be lower than it would have been without the imports.

[5] Here however we should note that the benefits of interconnection go beyond the price and network revenue effects: for example, customers in both regions benefit from the additional security of supply that the interconnector brings. In some circumstances these could be significant, but they are usually very difficult to estimate *ex ante*.

2.1 Fundamental policy issues

These concerns translate to three fundamental policy issues:

1. **Efficient incentives for TNSPs**. Network owners should have incentives to look for and implement efficient interconnection projects.

2. **Efficient locational signals.** New “footloose” generation and load should have incentives to locate efficiently (i.e., the resource cost of connecting to and using the system should be reflected in its own internal profit calculations).

3. **Equitable cost allocation.** The charging methodology should also address equity concerns by providing for a fair sharing of costs and benefits between networks on either side of an interconnection.

These issues are not specific to the Australian market. They arise whenever two networks are connected together. For example, our 2007 AEMC report[6] discussed an ongoing problem in the Nordic region, where the current system presents barriers to efficient transmission investment because certain investments that would have overall positive net benefits would likely require one network to incur costs that would not be adequately compensated by the others. Our report identified the question of inter-regional payments as one of three “key choices” in designing a transmission planning system.[7]

Since interconnection leads to wholesale price rises in the export region and wholesale price falls in the import region, policy makers might want to use changes in transmission charges to redistribute the benefits of interconnection so as to make customers in both regions better off. However this is immediately problematic, for two reasons:

1. Lowering load charges in one region but not another changes the locational incentives on load, and may therefore be incompatible with the second of the three fundamental policy issues listed above.

2. Lowering load charges in the exporting region requires raising load charges in the importing region, so that the TNSPs remain “whole”. However in some cases this could have the effect of making consumers in the importing region worse off, since it is quite possible that the benefit to consumers from price reduction in the importing region is smaller than the cost to consumers from price increases in the exporting region. An alternative would appear to be raising generation charges. However if generation charges are raised in one region but not another then again locational incentives may be

[6] *International Review of Transmission Planning Arrangements*, October 2007, *The Brattle Group*. The issue relates to the possible large scale development of wind power generation in Northern Norway, which would require a significant increase in transmission capacity to move the power southwards. There could be large cost savings if the transmission upgrades took place in Sweden rather than in Norway, because of differences in terrain.

[7] *Ibid*, p.8.

distorted. If they are raised uniformly then that can be expected to be passed through to consumers, leaving the problem unresolved.

This suggests that overcoming the incentive problem in full may require a more radical solution, i.e., merging all regional TSOs into a single network owner, or at least, appointing an NTP with the power to direct all needed investment. This clearly solves the problem of incentives. However, this is outside the scope of the present paper.

2.2 Structure and content of this report

This report aims to provide insight into possible ways of addressing these policy issues, by assessing inter-regional charging methodologies in the European Union, the Nordic region, and the United States. In each case we ask:

1. For an asset that is mainly / entirely used for flows between regions, who pays for the cost of the asset?
2. Who pays for the costs of assets which are only partly used for inter-regional flows?
3. How are the costs of any “loop flows” allocated?
4. In relation to questions 1 and 2, how does the allocation of these costs relate to the methodology that is used to allocate the costs of assets which are not used for inter-regional flows? (i.e., is it the same or a similar methodology, or not?)
5. If there are congestion rents because of price differences between the two networks, who gets the rents?
6. Is there a risk that network owners have an incentive not to build new interconnectors (or to size them too small, or to limit capacity on existing ones through operational restrictions), because they have a financial interest in the congestion revenues?
7. Do network owners have a positive financial incentive to increase interconnection?

We end the report with a series of conclusions concerning possible lessons for Australia from the international experience surveyed here. We generate a set of options based on international experience and including the options which have already been proposed in the NEM, and we set out some initial thoughts on the advantages and disadvantages of each.

3 US model

In this section we describe inter-regional[8] charging in the US, focusing on arrangements in Independent System Operator/Regional Transmission Organisations (ISO/RTO)[9] markets. ISOs/RTOs cover about half of the US,[10] and although the US electricity industry is rather diverse both in terms of ownership, industry structure and regulation, inter-regional charging arrangements across ISO/RTO markets are quite similar. We have focused on ISO/RTO arrangements because these regions have competitive wholesale markets, and are therefore a relevant comparator for the NEM in Australia.

An ISO/RTO region consists of a number of separately-owned transmission networks, all of which are operated in an integrated manner by the ISO/RTO. The ISO/RTO schedules generation, operates the wholesale market, collects tariff revenue on behalf of its member transmission owners, and plays an important part in network planning.[11] The ISO/RTO itself is a non-profit organisation, set up and operated under Federal Energy Regulatory Commission (FERC) rules set out by FERC in Order 2000.[12]

3.1 Who pays the costs arising from inter-regional flows?

3.1.1 Investment costs

Prior to the formation of ISOs/RTOs across much of the US, cost allocation rules were quite simple. The costs of building a transmission asset were always paid by the customers connected to the transmission network that owned the asset (and typically each network often owned all the transmission assets in its service territory). These charges to customers, however, were offset by any transmission charges collected from third-party use of the transmission system (e.g., exports and "wheeling through" service). For some networks, such third-party revenues substantially

[8] In the context of this study, inter-regional transactions means transactions between networks that are part of a single ISO/RTO, unless otherwise stated.

[9] The distinction between ISOs and RTOs is only in how they satisfy certain regulatory requirements. Both types of organization independently operate the transmission operators. RTOs, however, must satisfy stricter standards, e.g., in terms of governance, geographic scope and configuration.

[10] See, for example, the *IRC Sourcebook*, ISO/RTO Council, October 2007, which gives an overview of the 10ten ISOs and RTOs in North America (http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_2007%20Sourcebook.pdf)

[11] The role of ISOs/RTOs in network planning is described in chapter 2 of our 2007 report for the AEMC *International Review of Transmission Planning Arrangements*. This report also describes the relevant regulatory framework.

[12] *Regional Transmission Organisations*, 89 FERC ¶ 61,285, 1999 (http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf).

reduced transmission costs to the network owner's own customers.[13] This situation still exists in regions of the US that are not covered by an ISO/RTO.[14]

Within most RTOs, the costs of an individual transmission owner's existing network is recovered from the transmission-owner's own customers. This is referred to as "licence plate" charges as the rates differ across the service areas of the RTO members. In these ISO/RTO areas, however, new assets that will facilitate flows between different networks within the ISO/RTO area will not be paid for only by the customers of the network that builds and owns the asset. Instead, the asset will be deemed to bring "regional benefits" to customers across the ISO/RTO, and thus its costs will be shared among all customers in the ISO/RTO. When costs are shared on a *pro rata* basis throughout the RTO (e.g., in proportion to each network's peak load), the charging arrangement is known as "postage stamp" pricing because, for these assets, all customers within the ISO/RTO pay the same tariff.

When ISOs/RTOs were first formed the "licence-plate" charging system was adopted, thereby more-or-less maintaining the pre-ISO/RTO arrangements, in order to facilitate the process of forming ISOs/RTOs (although some utilities were compelled through legislation to join, membership is optional for most companies). The cost of the individual networks that comprise an RTO can vary widely, so licence-plate rates (which reflect these variations) avoid a potentially significant redistribution of transmission costs among the RTO's customers. Rather than viewing the licence-plate system as having its own intrinsic merits, it was rather the case that regulators preferred to minimise the impact of ISO/RTO membership on tariffs, at least initially, by keeping the pre-ISO/RTO tariff arrangements.

Such simple arrangements are not mandated by FERC: Order 890[15] does not specify precise rules for how the costs of transmission investment should be recovered from users. However, it does set out three factors that FERC will consider in deciding on cost allocation for projects involving several TOs or "economic" investment projects:

- FERC will consider the extent to which charging proposals are "fair" in so far as they allocate costs to the users that cause them and the users which benefit from investment;
- it will consider whether the charging proposals give adequate incentive to construct new capacity; and

[13] In some cases, the utility may have contracted with neighbouring utilities that would pay for the use of its network under a "contract path" model. These revenues would be lost on joining an ISO/RTO, leading to a rise in transmission tariffs for the customers of that utility who would have to make up the lost revenues.

[14] Transmission revenues from exports and wheeling through service also offsets the transmission costs within RTOs, but to a much smaller extent because these charges apply only at the edges of the often very large RTO footprint, and there are no equivalents within the RTO footprint.

[15] *FERC Order 890: Preventing Undue Discrimination and Preference in Transmission Service*, FERC February 16 2007.

- it will take into account whether or not proposals have the support of state regulators and other stakeholders.

Which assets count?

Which kind of assets qualify for region-wide cost sharing varies across different ISO/RTO regions, but the rules are generally simple. In California all new assets above 200 kV are deemed to be "regional", and thus their costs are shared across all utility service areas in the ISO's footprint.[16] Individual licence-plate rates for existing assets above 200kV are also being merged into a single postage stamp rate over a 10 year period, which will be completed in 2010.

In Eastern regions, the voltage threshold tends to be higher: it is 500 kV in PJM and the Midwest ISO.[17] In the East a further distinction is generally made between assets that are primarily required to improve system reliability (i.e., "reliability" projects) and those which primarily justified by economic benefits ("economic" projects). Based on recent FERC orders[18] for PJM and the Midwest ISO, the costs of reliability projects at 500kV or above are shared by all customers in the region, whereas the costs of "economic" projects at or above 500kV are only shared by the subset of networks within the region whose customers are expected to benefit from lower prices as a result of the upgrade.

Transmission investments are identified as reliability upgrades if the upgrade is deemed necessary to help meet an established network reliability standard that would otherwise be breached. "Economic" upgrades, in contrast, are not specifically needed to meet reliability standards but are justified on the basis that their costs will be outweighed by quantified economic benefits such as reduced overall costs of generation within a certain region or reduced congestion. In practice, almost all transmission projects have been classified as reliability projects, perhaps for practical reasons: such investments are more likely to clear permitting hurdles (i.e., permission to "site" the necessary assets). In addition, ISO/RTO planning processes to identify and evaluate "economic" upgrades are still in their infancy.[19]

Which customers pay?

In California and for "reliability" upgrades in Eastern ISOs/RTOs, there is no attempt to identify which regions of the ISO/RTO benefit from the new assets: the assumption is that customers in all of the networks of the ISO/RTO benefit, and hence that they should all contribute to the cost. For "economic" upgrades in the East, detailed modelling is undertaken in order to justify why the upgrade should be built (for example, looking at the expected impact of the upgrade on congestion costs). This modelling will include making forecasts of prices in each

[16] This change to the CAISO tariffs was made in "Amendment 27". The relevant documents can be found on the CAISO website at http://www.caiso.com/docs/2000/04/03/2000040311152611461.html.

[17] See for example FERC's decision on PJM's high voltage assets: 119 FERC ¶ 61,063, April 2007.

[18] For example, 119 FERC ¶ 61,063, April 2007.

[19] For further detail on the distinction between "reliability" and "economic" upgrades see chapter 1 of our previous paper for the AEMC.

member network of the RTO. Those networks that do not benefit (in terms of reduced generation costs and prices) do not need to make a contribution to the upgrade: the costs of the upgrade will be shared only by customers in networks that are expected to see reduced costs and prices.

A further distinction between the approach taken in California and that taken in the Eastern ISOs/RTOs is that in the East only the cost of new assets is shared, whereas in California the cost of existing high voltage assets is also shared.

An interesting detail of the original arrangements in California when the CAISO was first set up was that member networks were required to pay transmission tariffs to adjacent networks to the extent they "depended" on those networks for imports of power. As it happened, none of the member networks did in fact "depend" on its neighbours in that way for imports (only imports not covered by existing contracted transmission rights counted)—but the rules provided for a transmission fee to be paid for deficient import capacity by the importing network to the exporting one, with the fee determined in the same way as if the exports had been consumed by a load customer in the export network.[20] Presumably this arrangement was an attempt to get any importing but transmission-deficient new member networks to help support costs associated with inter-regional flows caused by their customers that they would not otherwise bear.

The introduction of the regional charging arrangements within US ISO/RTO markets seems to have attracted debate and controversy mostly because of its impacts on tariffs in individual networks. The discussions were focused particularly on the tension between (1) avoiding "cost shifts" across member networks; and (2) overcoming barriers to the construction of regional transmission facilities by network owners of costly facilities that clearly benefit more than that one network.

Flows between ISO/RTO regions

The costs of new lines that interconnect two ISO/RTO regions also may be shared. For example, FERC has recently approved an agreement between MISO and PJM under which the costs of an upgrade that increases the transfer capability between the two regions can be shared between the two organisations (and hence recovered from customers in both regions). Assets in either region can be partly paid for from tariffs collected from customers in the other region. The agreement covers any investment in either network that is likely to be partly utilized by customers in both ISO/RTO regions.[21]

Where an ISO/RTO borders a non-ISO/RTO region, although it is not possible to share costs through between network owners, the costs of new interconnection can be shared in a different way by having one party build and own the line beyond its own "border". Thus, for example, CAISO is currently trying to upgrade its connection with the network in Arizona, because it would like to be able to import more power from Arizona. CAISO customers would pay much of

[20] This arrangement was thus equivalent to applying a customer TUoS charge to interconnectors (AEMC's second option).

[21] See *Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C.* (November 2007), paragraph 9.4.3.

the cost of necessary assets on the Arizona side of the border simply because the network owner on the California side of the border would build and own the transmission line all the way to the relevant connection point within Arizona.[22] This arrangement is possible because there is no strict geographical restriction on the extent of transmission networks. However, it might be difficult to apply in all circumstances, because the new assets would have to be an integrated part of the import rather than the export network. It is difficult to see how deep reinforcement in the export network, were that needed, could be operated as part of the import network.

Applying the cost-sharing arrangements

Within ISO/RTO regions, implementing the cost sharing arrangements described above is relatively simple, because the ISO/RTO collects all of the transmission charges paid by customers of its member transmission companies. The ISO/RTO can therefore make the necessary adjustments to ensure that each TO receives its regulated revenue requirement even when the customers who pay that TO's tariffs collectively pay either more or less than the required total, due to the impact of sharing the cost of regional assets. In contrast to the European Inter-TSO compensation scheme described later in this report, for example, there is no need for the member network companies to make payments to one another because the ISO/RTO acts as the clearing house that already collects and redistributes transmission tariff revenues.

Other network assets used by inter-regional flows

In principle, the loading on lines which are not close to the border between two regional networks can be increased (or decreased) by cross-border flows. Cross-border flows can therefore impose costs on the network owner of assets that are not directly related to the connection between the two networks. Identifying such instances and quantifying the impacts can be very difficult.

In US ISO/RTO markets, however, the simple rules described above to determine whether the costs of a particular asset are shared (voltage levels, economic vs. reliability) do not distinguish between interconnector and "deeper" assets, so the issue does not arise.

3.1.2 Internal network congestion

In US ISO/RTO markets network congestion is managed by a centralised system of locational marginal pricing (LMP). The ISO/RTO determines a least-cost schedule of generation dispatch across the entire region, subject to network constraints. Constraints (as well as transmission losses) lead to different prices at various (possibly thousands) of nodes on the system. As a result, the costs of congestion are reflected in energy prices and fall directly onto market participants. In an area where there is insufficient low-cost generation or insufficient import capability the nodal

[22] The Palo Verde to Devers upgrade (PVD2). See deliberations of the Arizona Power Plant and Transmission Line Siting Committee, August 2006. CA users would also pay the access charge of the Arizona network owners for any exports from those networks into CA.

price will rise and load customers will therefore pay more.[23] In an area with excess low-cost generation, nodal prices fall and generators receive less.

3.1.3 Loop flows

There are complicated inter-RTO operating agreements in place under which reliability and congestion issues associated with loop flows are managed between RTOs and between RTO and non-RTO areas. However currently no efforts are made to charge a transmission rate for such loop flows. The regulatory strategy has been to increase the geographic scope of RTOs so as to obviate the need to address loop flow issues: one of FERC's criteria for designating an ISO/RTO is that its scope and configuration take into account the need to manage loop flows.[24] However this has not been fully successful as, in some cases, there are significant loop flows across/between RTOs and neighbouring areas.

3.2 What is the tariff methodology?

The general framework for setting tariffs is that ISOs/RTOs make proposals to FERC for approval. The over-arching pricing methodology is filed by RTOs, but the network owner rather than the RTO files with FERC if it wants changes to its approved transmission costs. If FERC approves the new costs, the new rates are then charged by the RTOs. Some general principals are set out in the main FERC Orders[25] relating to ISOs/RTOs, but otherwise FERC assesses the tariffs on a case-by-case basis. However, the methodology in different ISO/RTO markets is broadly similar.

Generators pay "deep" connection costs, but there is no other mechanism for allocating network costs to specific users. Transmission tariffs are paid by load customers (and exports and wheeling through customers) only, and do not vary within a given network. They are charged in proportion to a user's consumption or contribution to peak load (e.g., the total revenue requirement for that network, divided by that network's peak load, multiplied by the user's peak load). Thus, within an ISO/RTO the transmission tariff varies only by network.

3.3 Who gets congestion revenues?

Congestion revenues within ISO/RTO markets usually benefit whoever paid for the congested line. Thus, a new generator that pays a deep connection charge will be able to receive a

---

[23] Of course, the load-serving entities that serve such customers can purchase "financial transmission rights" to hedge themselves against the cost of congestion.

[24] FERC has stated that "Most commenters agree that the formation of RTOs, with their widened geographic scope of transmission scheduling and expanded coverage of uniform transmission pricing structures, provide an opportunity to "internalize" most, if not all, of the effect of parallel path [or "loop"] flow in their scheduling and pricing process within a region.", Order 2000, pp. 390–1. Under the second "minimum characteristic" of an RTO (Scope and Regional Configuration) FERC determined that an RTO should be "of sufficient regional scope [that it] would internalize loop flow and address loop flow problems over a larger region.", Order 2000, p. 255.

[25] Orders 679, 888, and 2000.

portion of the future congestion revenues on the assets it has paid to reinforce. Congestion revenue associated with assets not paid for by generators will generally go to the network owner. However, the rights to the congestion revenues typically must be auctioned-off periodically, so the network owner actually receives the auction revenue rather than the congestion revenue itself.[26]

3.4 Do network owners have incentives to increase capacity for inter-regional flows?

3.4.1 Impact of cost allocation on incentives

Before rules were established which allow the costs of inter-regional assets to be shared, network owners faced a disincentive to invest in assets to support certain flows because the costs would fall entirely on their own customers, but the benefits of the flows might go partly or even entirely[27] to customers of other networks. This disincentive has been largely removed with respect to high-voltage assets which qualify for cost sharing. For example, in California there are three main transmission networks. Under the new arrangements, an upgrade to a high-voltage asset above 200kV in one of the networks would cost its customers roughly one third of what it would have cost them under the old arrangements (although under both old and new methods those customers could also lose the benefit of congestion revenues on routes where the upgrade relieved congestion). Some upgrades may have benefits that are not equally distributed, and in such cases the equal sharing of costs may seem arbitrary or unfair. However, in practice the rule seems to work well, as judged by recent levels of investment.

3.4.2 Impact of congestion revenues on incentives

Where network owners have a financial stake in congestion revenues, they could have a disincentive to expand the transmission system as doing so would not only mean the network owner would incur the cost of the new facilities, but would also result in reduced congestion revenues. It could also lead to operational decisions, for example in scheduling maintenance, that could increase congestion revenues in the short term. In US ISO/RTO markets these potential problems are addressed in two ways. First, the rights to collect congestion revenues are typically auctioned off, so that in the short term network owners do not have a financial stake and therefore should not have an incentive to schedule maintenance to increase congestion.[28] Second, as far as system expansion is concerned, the ISO/RTO itself takes the lead on identifying and scoping expansion possibilities, and there are "backstop" powers for the ISO/RTO to require investments to be made.[29] FERC has paid considerable attention to governance issues at the ISO/RTO to

---

[26] This is similar to the IRSR system in the NEM.

[27] For example, flows from region A through region B to region C could benefit A (profits on exports) and C (reduced generation cost) without benefiting B at all, yet B would pay for most of the necessary infrastructure.

[28] Moreover, transmission maintenance schedules are reviewed and approved by the RTO.

[29] For example, if TOs refuse to carry out a CAISO proposal a mechanism will be developed for third parties to carry out the work, following competitive tender.

ensure that it operates independently and is able to perform regional transmission planning functions effectively.[30]

3.4.3 Other incentives

For a number of years there has been a perception of underinvestment in transmission: US transmission capacity has not increased in line with increases in peak demand,[31] and investment in transmission declined in real terms from the mid 1970s until 2000. Partly in response to such concerns, and also prompted by the Western power crisis of 2000–1 and the Northeastern blackout of 2003, regulators have offered incentives to attract investment in transmission. The *Energy Policy Act 2005* requires FERC to offer "incentive-based", i.e. enhanced, rates of return for transmission investment. For example, FERC may grant a one percentage point premium as the incentive component of the return on equity.[32] Enhanced rates of return are in principle available to all major new transmission investment, irrespective of whether it is expected to facilitate inter-regional flows.

The *Energy Policy Act 2005* also gave FERC new powers to site transmission facilities in designated "National Interest Electricity Transmission Corridors". These corridors are designated by the US Department of Energy based upon a study of grid constraints and the cost (in terms of reliability, congestion costs, lost trade opportunities, etc.) associated with such constraints. In these areas, FERC has the authority to approve the siting of transmission lines if they fail to gain the necessary approvals from state and local officials. This new federal siting authority may benefit inter-regional proposals.

Finally, FERC also offers incentives, such as enhanced rates of return, to network owners that join ISO/RTOs.[33] This may act indirectly to promote regional transmission investment, because such investment is more likely to occur inside ISO/RTOs than outside.

---

[30] The first "minimum characteristic" of an RTO as expressed in FERC's Order 2000 is independence—"both in reality and in perception" (Order 2000, p. 193).

[31] *FERC Order 890 Preventing Undue Discrimination and Preference in Transmission Service*, FERC February 16 2007, paragraph 421.

[32] For example, see Opinion 480, 117 FERC 61,129, October 2006.

[33] See FERC Order 679, 116 FERC ¶ 61,057, paragraph 326.

4 Continental European model: the Inter-TSO Compensation scheme

Electricity transmission networks in continental Europe are owned and operated by one or more distinct TSOs[34] in each country, but they are synchronised and extensively interconnected. Within the European Union[35] both national and European Union-level legislation applies. Each Member State has its own energy regulator, which have varying degrees of autonomy from central government and varying remits and legal powers. Some, but not all, of the arrangements concerning interconnectors are common because they are set out in European legislation (the Regulation on cross-border exchanges is particularly important).[36] Other aspects are agreed bilaterally between the networks and/or governments concerned, with energy regulators involved to varying degrees, depending on the country. Since interconnectors cross national borders, some kind of inter-governmental agreement is likely to be a pre-requisite for new links,[37] and political considerations are likely to have played a part in the construction of existing links, almost all of which pre-date the main liberalising legislation.

European legislation forbids network operators from charging fees at their borders. Market participants can only be charged to send electricity across national borders when there is congestion, and congestion must be managed by charging "market-based" fees (i.e., by auctions or related mechanisms). Recognising that cross-border flows can impose costs that might not in general be recovered from connected users,[38] the Regulation also calls for a system of "inter-TSO compensation"—payments between TSOs to compensate for any such under-recovery of

[34] In all European countries apart from Scotland the transmission system operator is also the owner of the network. In many countries (e.g., France, Germany) the transmission system operator is owned by a major generator in the same country.

[35] Much of the relevant legislation applying to transmission and other parts of the electricity industry is European Union level, and as such applies only to the Member States of the European Union. Operationally, however, most of the Member States (but not, for example, Great Britain, or most of Nordpool) are part of the synchronised UCTE system, which also extends beyond the EU. ETSO's ITC scheme described in this section now covers all of the EU.

[36] See *Regulation No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity* (26 June 2003) and *Directive 2003/54/EC concerning common rules for the internal market in electricity and repealing Directive 96/92/EC* (26 June 2003).

[37] See, for example, recent inter-governmental agreements relating to expansion of capacity between France and Spain (RTE press release, January 10th 2008).

[38] In many countries generators pay little or no transmission tariffs: as a result, export flows make little or no direct contribution to the costs of the network. Furthermore, given the meshed nature of much of the network in continental Europe, transit flows (exports from country A to country C via country B) are significant, and there is no direct mechanism for transit countries (i.e., country B) to receive tariff payments associated with such flows.

revenues.[39] The Regulation therefore in principle covers the main issues that are interesting in relation to inter-regional charging.

European TSOs, through their trade association ETSO, have been operating an inter-TSO compensation (ITC) scheme since 2002 (pre-dating the legislation referred to in the preceding paragraph). The voluntary ETSO scheme was supposed to have evolved into a mandatory scheme, through codification in "guidelines", which are a kind of secondary legislation.[40] However, although the relevant primary legislation dates from 2003, no guidelines have yet been adopted (due primarily to disagreements between TSOs and regulators, discussed below).

In the most recent version of the ITC scheme,[41] TSOs are compensated for costs associated with transit flows only (transit flows are those which occur when a country simultaneously imports and exports on different interconnectors). Assets used by transit flows are identified through network modelling, and the associated costs are estimated using the same methodology as used to set national required regulated revenues. Thus the ITC scheme initially generates a central fund which represents the total costs incurred by all TSOs because of transits. Each TSO pays into the fund in proportion to net cross-border flows, measured on an hour-by-hour basis.[42]

4.1.1 Development of ETSO's ITC scheme

The historical context for the current ITC scheme is that prior to the introduction of the current European legislation, TSOs used to levy fees on cross-border transactions to recover the costs associated with transit flows. However, this arrangement led to a number of problems, including that of "pancaking": under a transaction-based charging scheme, flows could cross more than one border and pick up export charges at each one. Furthermore, some TSOs hosted significant "loop" flows, physical flows not obviously associated with any commercial transactions, and these were not compensated at all. In the late 1990s policy-makers' views were that the cross-border fees should be abolished (in any case they appeared to conflict with EU legal principles on free movement of goods), and that TSOs should instead compensate each other for costs associated with cross-border flows. The net compensation would then be recovered from the TSOs' customers.

---

[39] In the absence of a centralised ISO-type body as in the US or Great Britain, customers pay transmission charges only to the owner of the local transmission network. Mis-matches between the regulated revenue requirement of that network and the total tariffs due from its local customers therefore have to be handled by payments between network owners, since there is otherwise no mechanism for customers to make payments to other network owners.

[40] Guidelines are adopted by the process of "comitology": following advice from the European energy regulators, the European Commission drafts guidelines which must be agreed by a committee of Member State representatives. Despite the name, they are binding.

[41] See *ITC agreement 2008-9*, ETSO (October 2007).

[42] Thus a TSO which imports 100 MW and (simultaneously) exports 100 MW would not make any payments.

Unfortunately, it proved impossible to get agreement on a suitable scheme among the various TSOs and between the TSOs and regulators. An ITC scheme has been under discussion[43] since 1998: for the first time, the 2008 scheme has the unanimous support of European TSOs,[44] but it does not appear to reflect earlier positions expressed by regulators[45] (and regulators have not yet given their views on the latest scheme). The main areas of difficulty exposed by the disagreements among the various parties during the evolution of the scheme seem to be the following:

- whether to compensate for all cross-border flows or just “transits”;
- how (technically) to determine which assets are loaded by cross-border flows; and
- how to determine the costs of these assets.

The ITC scheme results in significant payments by some TSOs. The size of these flows,[46] and the fact that different technical options for implementing the scheme (the method for determining which assets are loaded by cross-border flows) can give very different results is one reason why agreeing the scheme has taken so long. For example, in a European Commission-sponsored technical report comparing four different approaches to calculating compensation payments for 2003 (one of them the then operating ETSO scheme), Italy’s payments ranged from €43m to €510m, and Germany’s receipts from –€46m to +€398m.[47]

4.1.2 Access to interconnector capacity

As a result of the liberalisation process, TSOs are required to provide non-discriminatory third-party access to these interconnectors. As discussed above, TSOs are not allowed to charge for access to unconstrained interconnectors, and the legislation requires[48] that TSOs use market-based mechanisms to manage congestion—in practice, this means either explicit auctions of the capacity, or market coupling,[49] or a combination. Regulation 1228/2003 also specifies that the

[43] See, for example, *A Study on the Inter-TSO Compensation Mechanism*, Florence School of Regulation, 2005.

[44] *Pan-European Inter-TSO Compensation Scheme 2008–9*, ETSO press release, November 30th 2007.

[45] For example, the ETSO schemes have always been based on compensating transit flows, whereas regulators have consistently argued that *all* cross-border flows should be compensated.

[46] For example, under the current ETSO scheme in 2008-9 France is expected to pay €57m per annum and Switzerland is expected to receive €70m per annum.

[47] *Study on the further issues relating to the Inter-TSO compensation mechanism*, Frontier Economics and Consentec, February 2006.

[48] Article 6.1.

[49] Also known as “implicit auctions”, market coupling is a process by which exchanges in neighbouring countries use interconnector capacity made available by the TSOs to trade with one another such that prices in the markets tend to equalise. If there is sufficient capacity, prices will be equal; if not, they will diverge (and the exchanges will collect congestion revenue). Market coupling tends to be used to manage short-term capacity.

revenues from congestion management on interconnectors must be used either to fund new investment or to reduce (national) network tariffs.[50]

4.2 Who pays the costs arising from inter-regional flows?

In the first instance, the two TSOs on either side of a border fund the assets associated with cross-border flows, and there are no general rules about allocating investment costs. However, in those cases we have reviewed (interconnectors between France and Spain, and between the Netherlands and Germany), costs are shared equally in respect of assets that do not obviously form part of either one network or the other (most clear in the case of sub-sea interconnectors), and each TSO pays its own network reinforcement costs.[51]

4.2.1 Internal network congestion

The costs of internal network congestion generally fall in the first instance on the TSO, and are then passed on to customers through tariffs. There are instances in which market participants[52] and/or regulators suspect that TSOs reduce the availability of capacity on interconnectors, including in order to help manage internal congestion costs. An example from Sweden is discussed later in this report (see section 5).

4.2.2 Loop flows

Loop flows are significant in parts of Europe, because the network is relatively dense and meshed. The ITC scheme takes into account loop flows because it is based on physical flows.

4.3 What is the tariff methodology?

The costs of each TSO’s net contribution to (or receipts from) the ITC scheme feed into national transmission tariffs. In most countries tariffs are not locational, and load pays most of the total cost (in many countries the generator tariff is zero). Leaving aside the Nordpool countries described in section 5.2, the proportion paid by generators varies from 0% to 27%, and only Romania and the UK have locational load tariffs.[53]

---

[50] Article 6.6.

[51] See, for example, *France-Spain electric interconnection: RTE and REE set to create a joint venture for developing a new line through the Eastern Pyrenees*, RTE and Red Electrica press release, January 10th 2008; *Tennet RWE Memorandum of Understanding*, December 11th 2006.

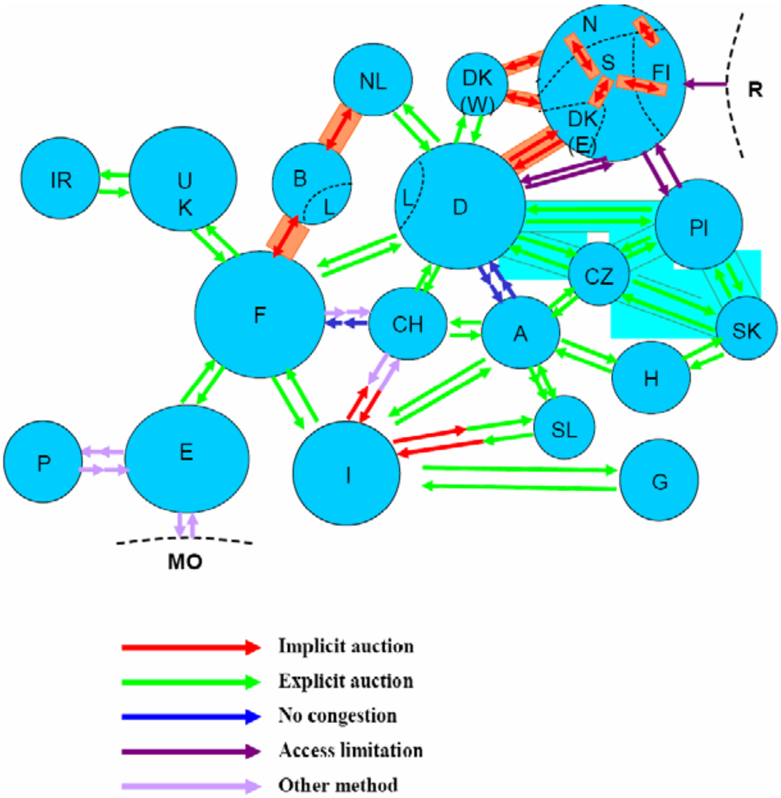
[52] See, for example, position papers from the European Federation of Energy Traders (EFET), e.g., *More transmission capacity for European cross border electricity transactions without building new infrastructure: Improving firmness of capacity rights and maximising capacity allocation using new Regulatory incentives for transmission system operators,* EFET 2006.

[53] *ETSO Overview of transmission tariffs in Europe Synthesis 2006.*

4.4 Who benefits from congestion revenues?

Regulation 1228/2003 introduced guidelines for congestion management, under which congestion must be managed using market-based mechanisms. There are no uniform rules for providing access to the interconnectors between countries, although regulators have a general preference for implicit auctions. Figure 1 shows the allocation methods currently in use. Over time the number of interconnectors using other methods (first-come-first-served or pro-rata rationing) is expected to fall.

Figure 1: interconnector access allocation methods[54]



Under both implicit and explicit auctions for capacity, the TSOs obtain congestion revenue: directly, in the case of explicit auctions, and through the market coupling/splitting for implicit auctions.[55] There are no general rules for deciding on how the congestion revenue should be split: the Congestion Management Guidelines state that the TSOs should agree the split of revenues,

---

[54] Taken from *Report on the experience gained in the application of the Regulation (EC) No 1228/2003 "Regulation on Cross-Border Exchanges in Electricity"*, European Commission (May 2007).

[55] For example, power exchanges in neighbouring markets together find a price that clears both markets. If such a price threatens to overload the interconnector between the market, the exchanges set different prices in each market such that the interconnector is not overloaded. In this situation, the total payments by load bids exceeds the total payments to generation offers.

with the criteria to be reviewed by regulators. In a number of cases (for example, England–Netherlands and France–Germany)[56] the split is equal, but this may not always be the case.[57]

Congestion revenues must be used either to fund new interconnectors or to reduce network tariffs.[58] However, in aggregate congestion revenues appear to be much greater than TSO investment in expanding interconnection: the Commission's Sector Inquiry found that congestion revenues for 2001–2005 were around four times greater than spending on interconnectors and network reinforcement.[59]

4.5 Do network owners have incentives to increase capacity for inter-regional flows?

The European Commission and others have expressed the view that the liberalisation of Europe's electricity market, and competition within that market, have been frustrated by the actions of vertically-integrated companies in many Member States. For example, the Commission's view, informed by an 18-month formal investigation by its competition authority, is that to protect their generation affiliates from imports some network companies have chosen not to expand interconnection with neighbouring Member States.[60]

In principle, new interconnectors in Europe can be operated on a merchant basis through being granted an exemption from third-party access regulations.[61] However, all existing interconnectors are regulated, and, in practice, all new AC interconnectors will be regulated and will be built as joint ventures between the network operators on either side. Investment in new interconnection therefore depends on the regulatory framework rather than merchant investors building interconnectors in order to exploit price differentials.

---

[56] See *BritNed – Europe's link for the future*, NGC, and *Report on the use of the French–German interconnection 2006,* La Commission de Régulation de l'Energie and Bundesnetzagentur.

[57] *Rapport de la Commission de Régulation de l'Energie sur la Gestion et l'Utilisation des Interconnexions Electriques en 2006* gives total congestion revenues for all of the French interconnectors and the total which accrued to the French network operator, but the latter amount is more than half the total sum.

[58] See Electricity Regulation, Article 6.6.

[59] *Energy Sector Inquiry, First Phase*, DG Competition 2007, Table 26.

[60] See the discussion below of the Sector Inquiry.

[61] Subject to a number of conditions, including that competition must not be harmed as a result, new interconnectors can be exempt from third-party access rules.

5 Nordpool model

In this section we describe inter-regional charging in the Nordpool[62] region. The main part of Nordpool is made up of the transmission systems of Denmark, Norway, Finland, and Sweden. It is connected to but mostly not synchronised with the main continental European system. Nordpool operates as a pool type system, similar to the NEM in Australia: generators offer a schedule of output and prices, loads bid a schedule of demands and prices, and the TSOs dispatch a least-cost generating schedule. There is no overall system operator but there is close co-operation between the national TSOs, and the TSOs together own the Nordpool market operator.

Because connections between countries and regions of Nordpool do not have enough capacity to always accommodate unrestricted flows, the market is usually split into between two and eight different price regions. Each price region is a country or lies within a single country, i.e., the regions are defined partly on political rather than economic/technical criteria. For the purposes of this report, the more interesting issues arise on the connections across national borders, because for these links the network on either side is owned by a different company.

Inter-regional transmission is particularly significant in Nordpool for two reasons:

- there is a long history of co-operation between the Nordic countries, particularly in electricity; and
- the generation systems of the different countries are quite diverse, so inter-regional flows are particularly efficient / beneficial, allowing hydro-based systems to import thermal power in dry years, and export in wet years.

5.1 Who pays to transmit inter-regional flows?

New interconnectors and upgrades between the national systems in Nordpool are paid for by the two TSOs concerned. The default arrangement appears to be that for assets in neither TSO's area (i.e., a sub-sea cable), the costs are shared equally, and otherwise each TSO pays the costs of assets in its own country. Thus, for a land border crossing, each TSO would pay for the assets on its side of the substation nearest to the border.[63] However the arrangement is arrived at by bilateral negotiation, so TSOs are free to agree to alternative sharing rules.

There is no mechanism in place for the TSOs to pay each other's costs.[64] Reinforcements that benefit Nordpool as a whole through facilitating inter-regional flows are in principle identified by a planning process run by Nordel, the association of Nordic TSOs. In recent years Nordel has

---

[62] More detail on the Nordpool system can be found in section 3 of *International Review of Transmission Planning Arrangements*, October 2007, *The Brattle Group*.

[63] See the description of the new Finland–Sweden link in *Extension of Fenno-Skan HVDC link*, Fingrid, and the description of costs in *Prioritised cross-sections Reinforcement measures within the Nordic countries—Status June 2007* Nordel.

[64] We describe below the mechanism for the TSOs to share congestion revenues.

concentrated on achieving five “priority upgrades” which would help to relieve some of the most important constraints on inter-regional flows.[65] However, investment decisions are taken only by the one or two TSOs concerned and it is not clear to what extent region-wide benefits are taken into account in the investment decisions. Nordel’s view seems to be that since its programme of regional upgrades involves all of the TSOs, the distribution of costs is broadly fair.[66] Table 2 shows that the costs are not evenly distributed.[67] Cost–benefit assessments for the network upgrades are not published so we do not know how benefits are expected to be distributed. However, it appears likely that Denmark will see at least some of the benefits from investment in Sweden (see discussion of the competition complaint described below).

Table 2: Costs of the "prioritised cross-sections" (€m)

Link	Finland	Denmark	Norway	Sweden
Fenno-Skan 2	117			140
Nea-Järpströmmen			37	29
South Link				190
Skagerrak IV		130	130	
The Great Belt		160		
Total	117	290	167	359

Notes
Based on figures in *Prioritised cross-sections-Reinforcement measures within the Nordic countries-Status June 2007*, Nordel.
Figures include both interconnector and local reinforcement costs.
We assume that costs of interconnector assets are shared equally.

The costs of interconnectors are recovered by the TSOs from transmission tariffs paid by their own customers:[68] there is no mechanism for inter-TSO payments to share the costs of inter-regional flows more widely, apart from the ITC scheme which applies only to transits.[69] The

[65] These upgrades are described in sections 3.2 and 3.5 of *International Review of Transmission Planning Arrangements*, October 2007, *The Brattle Group*.

[66] “The five Nordic projects gives a satisfactory balance between TSO investments”, Nordel presentation at the *2nd North Europe Electricity Miniforum* (2006).

[67] Note, however, that Finland and Norway are net contributors to the ITC scheme, whereas Denmark and Sweden are net beneficiaries (see section 6).

[68] “Until now TSOs have financed grid investments bilaterally or unilaterally. Decision-making and financing for a new interconnection have originated in negotiations between the TSOs directly involved in the project and owning the adjacent transmission network. Each TSO investigates its own benefit of a given interconnection and decides if it will invest in this interconnection. The interconnection is financed via the TSOs’ national tariffs.” *Enhancing Efficient Functioning of the Nordic Electricity Market*, Nordel (2005).

[69] The Nordpool TSOs have been part of the ETSO “inter-TSO compensation” (ITC) scheme described in section 4 since 2004, and thus they receive compensation for hosting transit flows (and pay for their own contribution to transit flows on other networks).

TSOs can also make use of congestion revenue to defray part of the cost of upgrades (albeit that new investment is likely to reduce congestion revenue).[70] However, since the only legal alternative use of congestion revenue would be to reduce tariffs,[71] using congestion revenue is in effect just another way of raising national tariffs. Congestion revenue is discussed further below (section 5.3). Nevertheless, congestion revenue is relevant because it is a mechanism which, in effect, allows for payments from customers in one region to the TSO in a second region.

5.1.1 Other network assets used by inter-regional flows

The Nordel planning process identifies internal network constraints that are significantly limiting inter-regional flows. However, in the planning processes of the individual TSOs no systematic attempt appears to be made to identify the extent to which network congestion is affected by inter-regional flows. Internal network reinforcements are made when the TSO concerned considers that the reinforcement is needed either for grid reliability or to manage congestion. All internal network upgrades are funded by the TSO concerned, even if they have significant effects on other parts of the Nordel region.[72]

5.1.2 Internal network congestion

Internal network congestion associated with inter-regional flows is a significant issue in some parts of Nordpool. This is because there are two distinct mechanisms for managing congestion: first, the market-splitting process[73] operates to manage congestion between different price areas; and second, within a price area, the TSO manages congestion by "counter-trade" on the wholesale market. The difference between the two mechanisms is that in the first case the costs of congestion fall on market participants in the two price areas directly, and in the second case they fall in the first instance on the TSO.

In Nordpool the areas which can potentially have their own price as a result of market splitting are defined in advance. Whether in fact prices will diverge in adjacent areas depends on whether unconstrained flows are likely to exceed interconnector constraints. However, the capacity of the interconnectors is not fixed: the TSOs are able to declare reduced availability of interconnector capacity, thereby making market splitting more likely and reducing the degree of internal congestion. There are significant disputes within Nordpool over the extent to which the TSOs do or should reduce the capacity of interconnectors in order to manage internal congestion. In particular, Sweden is a single price area but has significant internal constraints and the

---

[70] "Congestion rent from the elspot market is allocated to Nordic investments (115 M€ 2005)", Nordel presentation at the *2nd North Europe Electricity Miniforum* (2006).

[71] Although note that regulation of the Nordpool TSOs, which are state-owned, is not always as formal as in other jurisdictions. For example, in Sweden the tariffs are set by the TSO and the regulator reviews them *ex post* to determine whether they were "reasonable". In practice regulation in the Nordic region tends to be more consensual than in jurisdictions such as the US or the UK.

[72] There are constraints within Sweden, for example, that have significant impacts on inter-regional flows. See *Prioritised cross-sections Reinforcement measures within the Nordic countries—Status June 2007* Nordel.

[73] This is similar to the arrangements in the NEM.

Swedish TSO is accused of reducing the capacity of links to Norway and Denmark in order to manage the cost of its internal constraints. Such actions are to the detriment of consumers in Norway and Denmark, because prices in those countries tend to rise as a result of market splitting with Sweden in these situations. An association of Danish energy companies has lodged a complaint with the European Commission's Competition Authority alleging that the Swedish TSO's actions constitute abuse of a dominant position.[74] The complaint is discussed further in section 5.4.2 below.

5.1.3 Loop flows

Costs associated with loop flows are dealt with under the ITC scheme (see section 4).

5.2 What is the tariff methodology?

The costs of the transmission system in each country, as well as that TSO's share of interconnector assets, are recovered from network users through transmission tariffs. The tariff methodology makes no distinction between interconnector and other assets. Table 3 shows that almost all of the tariff is paid by load customers, and that with the exception of Sweden tariffs are essentially flat (i.e., do not vary with location).[75]

Table 3: transmission tariffs

Country	% paid by generators	Locational element?
	[A]	[B]
Denmark	up to 5%	no
Sweden	25%	yes
Norway	35%	exceptionally for G
Finland	12%	no

Notes
[A] based on *ETSO Overview of transmission tariffs in Europe: Synthesis 2006* .
[B] excluding losses; see discussion in *International Review of Transmission Planning Arrangements* (AEMC 2007).

In Denmark and Finland connection costs are mostly "shallow", whereas in Sweden and Norway they are "deep".[76]

[74] The issue is quantified in a study commissioned by the complainant: *The economic consequences of capacity limitations on the Oeresund connection, Summary report*, Copenhagen Economics, December 2006.

[75] In Sweden and Norway the tariff is approximately 50% based on capacity and 50% based on energy, whereas in Denmark and Finland it is almost entirely capacity-based.

[76] *ETSO Overview of transmission tariffs in Europe: Synthesis 2006*.

5.3 Who benefits from congestion revenues?

The market operator, Nordpool Spot, collects congestion revenues from market participants and pays them to the TSOs. The division of congestion revenues is determined by agreement among the TSOs, but it is not clear on what principles they make this decision (for example, whether they take into account the split of network upgrade costs in Table 2). Table 4 shows the division of congestion revenue. In future, congestion revenue will be equally split.

Table 4: Congestion revenues (€m)

Year	Denmark	Finland	Norway	Sweden	Total
2005	23.4	15.0	20.8	43.1	102.3
2004	15.2	8.0	11.5	13.9	48.5
2003	42.5	14.9	18.1	17.9	93.4
2002	42.6	16.2	19.7	19.8	98.3
2001	11.4	3.7	7.6	10.4	33.1

Notes
Based on Table 3.1 of *Congestion Management in the Nordic Region* , NordREG (2007).

5.4 Do network owners have incentives to increase capacity for inter-regional flows?

5.4.1 Impact of cost allocation on incentives

The TSOs in Nordpool recover the costs of investment in interconnectors, as well as internal network upgrades, from their own customers. In contrast, at least some of the benefits of the investment go to customers outside the region: for example, when the Swedish TSO carries out internal network upgrades, it increases the availability of capacity on its interconnectors with Norway and Denmark, and the resulting increase in trade brings benefits outside the Swedish market.[77]

At the stage of investment planning, the Nordpool TSOs individually or through Nordel are supposed to carry out a cost–benefit test of potential upgrades employing a “Nordic” perspective.[78] Cost–benefit assessment of upgrades is potentially contentious because it is possible that the benefits and costs will fall in different regions. For example, benefits associated with increased trading could fall mostly outside a national market, whereas the costs of an upgrade could fall mostly or entirely within a single network. Thus it is possible that an upgrade could fail a cost–benefit test from a national perspective, but pass the test from a “Nordic” perspective. However, cost–benefit assessments, are not published so it is not clear to what extent

[77] Since the Nordpool TSOs are part of the ITC scheme, they will receive compensation for some of the costs they incur in hosting flows that support trade. However, even if the ITC scheme works well to reflect such costs, it only captures transit flows (i.e., flows which are imported from one neighbouring country and simultaneously exported to a second).

[78] Nordel’s cost–benefit assessment is described in chapter 3 of *International Review of Transmission Planning Arrangements*, October 2007, *The Brattle Group*.

the current programme of agreed upgrades reflects a wider-than-national perspective. The fact that these upgrades can have negative impacts on an individual TSO's customers may make the TSO reluctant to carry them out.

There are signs that the current arrangements for identifying and delivering upgrades to the Nordic transmission system are not working well. There is disagreement between the TSOs on whether and how to improve the current arrangements, with the Norwegian TSO in particular promoting a more centralised approach with less reliance on voluntary co-operation.[79] The Nordel process also seems to be slow: the five "priority" investments were selected in 2002,[80] but agreement at individual TSO level was not reached until December 2006, and completion is not foreseen until 2013.[81] The slowest project is an internal upgrade within Sweden. Finally, the ongoing competition complaint against the Swedish TSO alleges that the Swedish TSO curtails capacity on its interconnectors in order to reduce the costs of congestion management (counter-trade). This may be an indication that the ITC scheme is not effective in compensating the costs associated with cross-border flows, and hence that the Swedish TSO may be reluctant to invest to reduce congestion.

5.4.2 Impact of congestion revenues on incentives

Congestion revenues on interconnectors are shared among the TSOs. To the extent that interconnector or other upgrades would tend to reduce congestion, the TSOs have a disincentive to invest. Such a disincentive is reduced if the congestion revenues are effectively "netted off" the TSOs allowed revenues. Regulators are required, under the congestion management guidelines,[82] to publish details of congestion revenues earned and what they are used for. This extra transparency should reduce the extent to which ownership of congestion revenues on interconnectors provides a disincentive to investment.

[79] See the discussion in *ibid.* section 3.4 and *Coordination of network operations and system responsibility in the Nordic electricity market*, Norden (2006).

[80] See 2003 Nordel Annual Report.

[81] *Prioritised cross-sections Reinforcement measures within the Nordic countries—Status June 2007* Nordel.

[82] Paragraph 6.5.

6 Synthesis

We draw a number of observations from the survey given above.

1. International experience seems to confirm the importance of having a mechanism that allows for cost sharing of assets that facilitate inter-regional flows. Even strong political will combined with widespread public ownership of the networks, as in the Nordic system, does not appear to be an adequate substitute for financial mechanisms. A common pattern seems to be that regional transmission systems are initially developed without such mechanisms, which then arise as the need becomes apparent. Of the three areas we have looked, the US is most advanced in having developed robust rules for sharing the cost of transmission investments. In Nordel such mechanisms are limited as yet, but there is an active and ongoing debate as to needed reforms. Continental Europe is in a sense the least developed of these, although as a highly meshed system it has rather idiosyncratically already developed a mechanism for sharing the costs of transits.
2. Such a mechanism can be an explicit cost allocation, or it could be more implicit, for example by having interconnectors used for imports pay network tariffs in the same way as load, on systems they connect to.[83]
3. There is no simple "theoretically correct" answer to the design of such a mechanism—the main purpose of the mechanism is to overcome concerns about distributional effects of new capacity, and such concerns inevitably vary from case to case. In practice the details of the design will depend on the need to avoid unacceptable distributional consequences. There is also a possibility that the design will distort the locational signals delivered through locational pricing.
4. Nonetheless, US experience shows that simple, clear rules are accepted and appear to be successful. The main mechanisms seen in practice are (a) adding specified assets into a "whole region" asset base, and (b) getting exports to pay the load charge (see note above). Conversely, we suspect that the complexity of the EU's ITC has not added to transparency of the process or the effectiveness of the scheme.[84]
5. Incentives may be needed to get transmission owners to sign up to a scheme, if initial participation is voluntary (in theory or in practice), especially if the scheme is binding once the network is in it. In the US there are significant financial incentives for utilities to join RTOs, and the design of cost allocation rules has in part reflected the need to make participation initially attractive.
6. Depending on the layout of the system, it may be important that any mechanism is able to share the costs of "deep" assets, not just the interconnectors themselves (the concerns about incentivising Swedish internal system upgrades discussed in the text illustrate this point).

[83] That is, if region A imports from region B, then the interconnector in region A would pay transmission charges to the owner of the network in region B.

[84] It is also plausible that there is a link between the complexity of the rules seen and the complexity of the system "geometry".

6.1 Key design parameters

Based on the discussion above, we can draw some conclusions on the key design parameters of an inter-regional transmission charging scheme.

6.1.1 Which assets should be supported by the scheme?

The scheme could be limited to supporting the costs of interconnectors themselves: i.e., the wires between the two substations on either side of the border between the two systems. Alternatively, the scheme could extend to assets deeper within the network on either side, recognising that inter-regional flows make use of assets within both networks. In the latter case, a methodology is needed to identify the network assets or to determine the proportion of a given asset that should be supported. This can be done very simply, by defining a broad class of assets as inter-regional (e.g., the highest voltage assets), or on the basis of network modelling.[85] Costs could be allocated to the inter-regional charging mechanism in proportion to the loading due to the inter-regional flows, possibly subject to a de-minimis cut-off threshold.

There is a separate question of whether the scheme should apply only to new interconnectors or to existing ones as well.

6.1.2 Who should pay?

The status quo arrangement in Australia is that all transmission assets are ultimately paid for by customers in the relevant region, and no distinction is made between assets that support inter-regional flows and those that do not. In order to better reflect the cost of inter-regional flows in transmission tariffs, customers that “cause” the costs associated with inter-regional flows could be charged some or all of those costs. The logical way to do this is to add the costs (identified as described in section 6.1.1) to the revenue requirements of the networks concerned, and recover the additional costs from each network’s customers using the standard transmission charging methodology. For example, if load customers rather than generators generally pay most or all of their “host” network costs, load customers could additionally pay the costs associated with import flows.

In practice, the tariff would probably be set on the basis of expected flows, possibly with a correction in subsequent years to take account of the difference between expected and actual out-turn flows.[86]

---

[85] See Appendix 1. Network modelling in principle estimates the loading on each asset (line, transformer, etc) due to inter-regional flows.

[86] i.e., the import TSO pays the export TSO a “load charge” on the basis of actual imports. The import TSOs customers would be paying a contribution to this cost in their network tariffs, set *ex ante* to recover costs based on expected flows.

Alternatively, a simpler approach of allocating costs equally to customers in the networks on either side, or even among all interconnected networks in the NEM may have merits. It could be argued that:

- interconnectors contribute to system reliability, even if the interconnector is normally expected to be exporting, and without the interconnector the export network might have to pay for alternative sources of reliability;
- even if an interconnector is currently expected to operate mostly in one direction, it might in future operate the other way, and customers in the export network benefit from this “option”; and
- in the system as a whole, there may be enough interconnection potential that, in the long run, all customers would end up paying a roughly similar amount.

The preceding paragraphs discuss allocating costs on the basis of “causation”, in order to better reflect interconnector costs in locational transmission tariffs for load customers. This is likely to give a cost allocation that is similar to the distribution of benefits, in the sense that the costs associated with an interconnector that mostly exported would be mostly paid for by the importing customers. Of course it is possible that customers on the export side could still be worse off as a result of the interconnector, because of changes in wholesale prices resulting from the export flows.

As noted above, any allocation of costs that does not reflect causation gives inefficient locational signals through the transmission tariffs.

6.1.3 How to divide Inter-regional Settlement Residues

Congestion on interconnectors in the NEM gives rise to congestion rents in the form of IRSR.[87] In principle, returning IRSR to customers can be problematic in that it risks distorting the locational signals delivered through tariffs. Thus the best way of doing it may be just to choose a mechanism that distorts signals as little as possible. However, since interconnectors can result in significant distributional impacts through wholesale price changes, there could be pressure to allocate IRSR in such a way that they are returned to those customers adversely affected by wholesale price rises resulting from interconnector flows.

6.1.4 Addressing planning and incentive issues

The impact of interconnectors on transmission tariffs and regulated revenue requirements can influence the incentives that network operators face in planning and operating interconnectors. This can be the case even if the regulatory framework is successful in ensuring that networks

[87] The importing network operator auctions the rights to IRSR to market participants, and uses the receipts in the auction to reduce tariffs. In effect, therefore, the network receives a market forecast of future congestion revenue; market participants pay this and receive in return the actual out-turn congestion revenue.

recover prudently-incurred costs:[88] a network may find it politically difficult to implement investment which causes either its tariffs, or wholesale prices paid by its customers, to rise.

There is an irreconcilable tradeoff between minimising such problems and setting cost-reflective tariffs. In practical terms, it is likely that the distribution of congestion revenue is the best way of making desirable interconnector investments more acceptable to all parties (although in principle there is no reason why the amount of "compensation" should be limited by the availability of congestion revenue).[89] Where there are state-owned generators the issue may be easier to manage because generator profits are to some extent recycled to customers (*qua* taxpayers).

6.2 Options for allocating the costs of inter-regional flows

The AEMC has already outlined[90] three options for inter-regional charging. Given the discussion in sections 6.1.3 and 6.1.4, the split of IRSRs can probably best be considered separately, after considering the allocation of interconnector costs. There is no reason for the costs of inter-regional flows to bear any relation at all to the value of IRSRs, so there is little reason to make an explicit link through earmarking IRSR (alone) to fund the costs of inter-regional flows.[91]

The AEMC three options for allocating costs are therefore:

1. Costs paid by customers connected to the network in which the costs fall, as now.
2. Importing networks pay the load charge in the export network.
3. Set all transmission tariffs on a NEM-wide basis, allowing for NEM-wide cost allocation.

We can categorise the international experience described in this report along these lines, with the addition of two further options:

4. Costs shared by both networks.

---

[88] If the regulatory framework did not do this, additional incentive problems could arise. For example, if network owners were able to earn additional returns from congestion revenues (i.e., they did not return these revenues to customers through reduced tariffs), the network owners would have an incentive to plan interconnectors "too small" in order to maximise congestion revenues rather than to maximise the social welfare benefits.

[89] It is possible that an interconnector might cause prices on the export side to rise and prices on the import side to fall (compared to the situation without the interconnector), but for there to be no congestion at all if the interconnector is optimally sized. In this case there is thus no congestion revenue to distribute as "compensation" to the customers in the export region.

[90] See *National Transmission Planning Arrangements Issues Paper*, AEMC (November 2007), section 5.4.

[91] In some situations, an optimally-sized interconnector may not be congested at all, so IRSR would be zero and could thus make no contribution at all to funding the costs of inter-regional flows. In other situations the IRSR might exceed the costs of inter-regional flows.

5. Payments between networks based on the costs of cross-border flows.

In the following paragraphs we describe each option in more detail, and give an initial assessment of advantages and disadvantages.

Option 1: costs lie where they fall

Option 1 is similar to the status quo in the NEM, where network operators pay all of the costs for assets in their own networks, although there is the option for negotiation over the sharing of IRSR. Option 1 has the obvious benefit of simplicity, but it is not cost-reflective and would presumably make it harder to build interconnectors where a significant proportion of the costs fall in the exporting region. We have not found this option used in any other jurisdictions.

Option 2: imports pay a load charge

We define two versions of option 2. Under option 2a, costs are initially paid by customers in the region where the assets are (as in option 1), but additionally the importing network pays a charge to the exporting network that is equal to the export network's load tariff in the zone where the interconnector starts. Alternatively, under option 2b the export network's load charge would be paid by the users of interconnector on the import side (i.e., holders of interconnector capacity). Option 2 is used in much of the US, although in the US there is no distinction between 2a and 2b because the importing network would typically be vertically integrated.

Options 2a and 2b have the merit of being relatively simple, and, to the extent that transmission tariffs generally reflect costs, give cost-reflective charges in respect of the costs of inter-regional flows. However, since unlike "normal" tariffs, these interconnector load charges result directly or indirectly in payments between network operators, it is possible that the tariff methodology used to determine them could attract much more controversy than usual. Nevertheless, in principle, the same techniques for determining cost causation would be used to set load tariffs generally as would be used to allocate deeper network costs associated with inter-regional flows.

One difference between options 2a and 2b is that 2a would apply a charge based on physical flows on the interconnector, whereas 2b would apply the charge based on commercial transactions. For AC interconnectors there can be a significant difference between the two, and in some situations it may not be obvious which network user is "causing" the physical flow, such as is the case with loop flows.

In addition to the normal difficulties of allocating network costs, a further disadvantage with option 2 is that in some circumstances it may not be possible to allocate costs in one region without looking at costs in other interconnected networks.[92] The significance of this problem depends on the degree to which networks are meshed.

---

[92] For example, suppose network A is connected to B and C, and that B and C are also connected. It may not be possible to make a realistic model of flows in any of the three networks individually without considering the pattern of flows within the other two networks.

Option 3: NEM-wide tariff methodology

Option 3 involves a central body looking at the costs of all parts of all the transmission networks in the NEM at once, and applying a single methodology to determine tariffs. This is how tariffs are set in Great Britain, but we have not otherwise found this mechanism in general use.[93]

Under option 3 tariffs would be set to recover total required revenues, and payments between networks (or from a central pot) would be required to redistribute the revenue so that each network received its individual revenue requirement. This option requires a new institution. It is probably more complicated than allocating costs within individual networks, but in theory results in a better (more accurate) allocation of costs. In practice, the degree to which this is an improvement over option 2 will probably depend on the complexity of the network topology. A major advantage of this option is that the existence of a central institution can help overcome the controversy that is otherwise associated with payments between networks. By the same token, setting up the central institution might be very difficult.

Option 4: costs shared equally

Option 4 would see the costs associated with inter-regional flows being shared between either the two networks on either side of the interconnector (option 4a), or by all networks in the NEM (option 4b), along the lines described in section 3 (US ISO/RTO markets). For example, costs associated with export flows that would have been paid entirely by customers in the exporting region under option 1, or entirely by the importing region under option 2, would be shared by both the export and import regions under option 4a. Option 4b would see certain assets/costs identified as “NEM-wide” costs paid for by all customers in the NEM.

Costs might be shared equally on a normalised basis – for example, in proportion to each network’s peak load. Payments between the network operators would effect the sharing. Option 4b is used in ISO/RTO markets in the US, although relatively simple rules are used to identify the costs.

The rationale for options 4a and 4b is that interconnectors bring benefits (for example, through improving reliability) to the networks on either side. Even if an interconnector almost always exports, the exporting network still benefits from the option to be able to import. Over time, as the electricity system evolves, it might be that interconnector flows reverse: holding the option to import in the future may therefore be valuable. Assessing the costs and benefits of interconnection can be very uncertain, so an equal split of costs might seem reasonable, especially since reaching agreement on the split of costs may well be difficult in any case.

It is difficult to say to what extent options 4a or 4b would reflect costs without looking at a specific cases.

[93] *International Review of Transmission Planning Arrangements*, October 2007, *The Brattle Group*.

Option 5: compensation for cross-border flows

In Europe (and Nordpool), network owners initially fund all of the assets in their network, but they then make "compensation" payments to each other to reflect the costs each bears for hosting cross-border flows. In Europe the compensation payments relate only to the costs of "transit" flows under the current scheme. Option 5 would be similar to this arrangement, but would compensate for all cross border flows. Compensation payments would be determined on the basis of detailed flow modelling to determine which assets are being loaded by cross-border flows, and to what extent.

Option 5 is related to option 3: costs are assessed on an NEM-wide basis, but option 5 disconnects inter-regional charging arrangements from the charging arrangements used to set tariffs within each network. Option 5 only sets tariffs relating to the costs of inter-regional flows, whereas option 3 would set all components of the tariff in all networks centrally. Option 5 is therefore consistent with a system in which tariffs in some networks are not cost-reflective (e.g., do not vary with location), or a system in which the split between load and generator network tariffs is different in adjacent networks.

Option 5 may be easier to implement than option 3 because it applies only to a small fraction of total network costs, and this probably explains why it exists in Europe. The major disadvantage with this option is that the experience in Europe suggests that it may be difficult to get agreement on the results of any methodology without a strong central institution able to enforce a solution. Not only is it technically complex, but different possible approaches can give very different results, so there is a risk that networks may argue in favour of the approach which gives them the best financial result.

6.3 Options for allocating IRSR

The AEMC has already suggested[94] a simple "rule of thumb" approach to splitting IRSR. This approach is very similar to what we have found elsewhere: we have not found explicit policies in the jurisdictions we have examined that explain fundamental principles for how congestion revenues should be split. In practice it seems that an equal split is a common arrangement. In Nordpool, for example, it is the approach that will be applied from 2011 onwards.

An alternative could be to allocate IRSR to the exporting network, on the grounds that this gives customers in that network compensation for any increase in wholesale prices. Since there are no strong principles governing the split, it might also be appropriate for it to be negotiated on a case-by-case basis, but with the ability to impose an outcome,

If the costs of inter-regional flows are allocated where they fall (option 1 in section 6.2), there might be additional merit in assigning more of the IRSR to the region bearing most costs. Again, this would probably best be considered in light of analysing specific cases in the NEM.

[94] See *National Transmission Planning Arrangements Issues Paper*, AEMC (November 2007), section 5.4.

Appendix I : Cost causality and inter-regional flows

Trade in power markets is in some ways more complex than in other goods or services. When one company exports manufactured goods to a neighbour, it is possible to point to the goods crossing borders in trucks or railcars and as a result identify specific transport costs. Assigning transportation costs to cross-border power flows can be more difficult. While cross-border power flows may require the construction of specific long lines between the two regions, they can also affect the capital costs of other parts of the network.[95] In particular, the flows may require capacity on the network which would otherwise be available for flows entirely within the network. Thus, for example, flows transiting a network from one border to another use capacity that could otherwise be used to serve generators and load customers within that network. In the long run, therefore, the network owner is obliged to expand the network (due to load growth), sooner than would otherwise be the case.[96]

Note also that flows that arise as a result of trade between two regions can impose costs on a third, due to the existence in some networks of "loop" or "parallel" flows where network capacity in parts of the network not directly associated with the interconnector can be reduced as a result of the existence of the interconnector. This issue (which only arises with AC interconnectors) is a significant problem in highly "meshed" networks such as that of continental Europe. For example, exports from France to Germany typically give rise to increased flows not only on interconnectors on the France-Germany border, but also on the route France-Belgium-Netherlands-Germany. It is much less of a problem in less meshed (more "radial") networks such as that of the NEM.

In general it is not possible to measure which assets in a network are being loaded by flows between any two points on the network: the load on any part of the network is, in principle, a function of the amount of energy injected onto or withdrawn from the network at every connection point. However, for both operational and investment planning purposes, network operators maintain detailed technical models of their systems, and using these models it is possible to estimate the impact on asset loading, starting from the status quo, of *additional* injections/withdrawals at any point. These models are used, for example, to estimate which assets would be loaded as a result of a new interconnector being built. Thus the models can be used to assign costs to inter-regional flows: the models can estimate the degree of loading of every asset in the network as a result of a new inter-regional flow. The "cost" caused by that flow could then be defined as the cost of replacing each asset, multiplied by the degree of loading.

In general there may be a number of different ways to carry out the technical modelling referred to in the previous paragraph, and, particularly for "meshed" networks, the results may be

---

[95] Inter-regional flows can also increase transmission losses, but the costs associated with losses are typically much smaller than the costs associated with providing additional capacity.

[96] Cross-border flows could also reduce capital costs relative to a no trade counterfactual. For example, generation in the UK tend to flow from North to South, but there are about 2GW import capacity from France to the south of England. Without those flows National Grid might have to spend significantly more on reinforcing the north-to-south flow capacity.

sensitive to the type of model being used or how it is run. Furthermore, there may be different ways to estimate the cost of loading a particular asset (for example, whether replacement or historic cost, or the size of the capacity increment used in estimating the unit incremental cost). For all of these reasons estimating network costs is often contentious.